Responses to Comments

on the

Low Carbon Fuel Standard Regulation

California Environmental Protection Agency
AIR RESOURCES BOARD

Released September 21, 2015

to be considered at the

September 24, 2015 Board Hearing

This page intentionally left blank.

TABLE OF CONTENTS

This page intentionally left blank.

I. SUMMARY OF COMMENTS AND AGENCY RESPONSE

Written comments were received during the 45-day comment period in response to the February 19, 2015 public hearing notice, and written and oral comments were presented at the Board Hearing.

Comment Code	Comment Period Received
OP	Comments received during the 45-day comment period of the original proposal, Jan. 2 – Feb. 18, 2015
B	Comments received as written materials during the board hearing , Feb 19, 2015
T	Comments received as testimony at the board hearing, Feb 19, 2015
FF	Comments received during the first 15-day comment period June 4 – June 19, 2015
SF	Comments received during the second 15-day comment period June 23 – July 8, 2015
TF	Comments received during the third 15-day comment period July 31 – August 17, 2015
SB	Comments received as written materials during the second board hearing, September 24, 2015
ST	Comments received as testimony at the second board hearing on September 24, 2015

The comment letters were coded by the order and the comment period in which they were received, and also tagged LCFS, and the name of the organization or individual commenting. For instance, below, 01-OP-LCFS-CNGVC is the first comment received during the 45-day comment period, and is an LCFS comment sent by the California Natural Gas Vehicle Coalition. Listed below are the organizations and individuals that provided comments during the 45-day comment period:

Several comment letters were directed at both the LCFS rulemaking and the Alternative Diesel Fuel (ADF) rulemaking. The comments directed at the LCFS rulemaking are responded to below. The comments directed at the ADF rulemaking are responded to in the ADF Final Statement of Reasons.

Comment Letter Code	**Commenter**	**Affiliation**
1-OP-LCFS-CNGVC	Carmichael, Tim	California Natural Gas Vehicle Coalition
2-OP-LCFS-TAC	Rauch, Marc	The Auto Channel
3-OP-LCFS-AWTE	Sterzinger, George	American Waste to Energy
4-OP-LCFS-SVLG	Mielke, Mike	Silicon Valley Leadership Group
5-OP-LCFS-USC	Martin, Jeremy	Union of Concerned Scientists
6-OP-LCFS-CalETC	Tutt, Eileen	California Electric Transport Coalition
7-OP-LCFS-CRE	Simpson, Harry	Crimson Renewable Energy
8-OP-LCFS-RFA	Cooper, Geoff	Renewable Fuels Assoc.
9-OP-LCFS-NSP	Duff, John	National Sorghum Producers
10-OP-LCFS-CRF	Schlyer, Lyle	Calgren Renewable Fuels
11-OP-LCFS-E2	Solecki, Mary	Environmental Entrepreneurs (E2)
12-OP-LCFS-WPE	Peine, Derek	Western Plains Energy
13-OP-LCFS-CEP	Durler, Matt	Conestoga Energy Partners
14-OP-LCFS-CALSTART	Hall, Jamie	CalSTART
15-OP-LCFS-Knapp	Knapp, Jamie	Supportive Group of Organizations
16-OP-LCFS-Proterra	McCarthy, Eric	Proterra
17-OP-LCFS-NBB	Neal, Shelby	National Biodiesel Board
18-OP-LCFS-ABBI	Silva, Bernardo	Brazilian Industrial Biotechnology Assoc.
19-OP-LCFS-Tutt	Tutt, Eileen	California Electric Transportation Coalition
20-OP-LCFS-CInc	Johnson, Timothy.	Corning Incorporated
21-OP-LCFS-USC	Martin, Jeremy	Union of Concerned Scientists
22-OP-LCFS-NRDC	Mui, Simon	California Vehicles and Fuels Natural Resources Defense Council
23-OP-LCFS-Tetra	Mui, Simon	California Vehicles and Fuels Natural Resources Defense Council
24-OP-LCFS-BIO	Erickson, Brent	Biotechnology Industry

Comment Letter Code	Commenter	Affiliation
		Organization
25-OP-LCFS-AofA	Menotti, Alexander	Airlines for America
26-OP-LCFS-Aemetis	Foster, Andy	Aemetis Advanced Fuels Keyes
27-OP-LCFS-WE	Tjiong, Carol	White Energy
28-OP-LCFS-GPS	O'Donnell, John	Glass Point Solar
29-OP-LCFS-CATF	Lewis, Jonathan	Clean Air Task Force
30-OP-LCFS-CRF	Schlyer, Lyle	Calgren Renewable Fuels
31-OP-LCFS-IWP	Wright, Curtis	Imperial Western Products
32-OP-LCFS-BP	Moran, Ralph	BP America
33-OP-LCFS-CIPA	Zieman, Rock	California Independent Petroleum Assoc.
34-OP-LCFS-CBA	DuBose, Celia	California Biodiesel Alliance
35-OP-LCFS-AAUSA	Stone, Kelly	ActionAid USA
36-OP-LCFS-NLB	Case, Jennifer	New Leaf Biofuels
37-OP-LCFS-Alberta	Ryan, Chris	Government of Alberta
38-OP-LCFS-Chevron	Gilstrap, Don	Chevron
39-OP-LCFS-PGE	Plummer, Matthew	Pacific Gas & Electric
40-OP-LCFS-WSPA	Reheis-Boyd, Cathy	Western States Petroleum Assoc.
41-OP-LCFS-Tesoro	Heller, Miles	Tesoro
42-OP-LCFS-NGO	Mui, Simon	NGO Coalition Supporting LCFS
43-OP-LCFS-POET	Willter, Joshua	Sierra Research for Poet
44-OP-LCFS-P66	Sinks, Daniel	Phillips 66
45-OP-LCFS-Dillard	Dillard, Joyce	Individual
46-OP-LCFS-GE	Willter, Joshua	Sierra Research for Growth Energy
47-OP-LCFS-GE	Willter, Joshua	Sierra Research for Growth Energy
48-OP-LCFS-GE	Willter, Joshua	Sierra Research for Growth Energy
49-OP-LCFS-GE	Willter, Joshua	Sierra Research for Growth Energy
50-OP-LCFS-GE	Willter, Joshua	Sierra Research for Growth Energy
51-OP-LCFS-GE	Willter, Joshua	Sierra Research for Growth Energy
52-OP-LCFS-Kern	Hicks, Melinda	Kern Oil & Refining Co.
53-OP-LCFS-CAHealth	Bard, Jenny	California Health Group
54-OP-LCFS-EFC	Detchon, Reid	Energy Future Coalition
55-OP-LCFS-EFC	Detchon, Reid	Energy Future Coalition

Comment Letter Code	Commenter	Affiliation
56-OP-LCFS-EFC	Detchon, Reid	Energy Future Coalition
57-OP-LCFS-BGA	Nakasone, Ross	Blue Green Alliance
58-OP-LCFS-EFC	Detchon, Reid	Energy Future Coalition
59-OP-LCFS-EFC	Detchon, Reid	Energy Future Coalition
60-OP-LCFS-CBD	Nowicki, Brian	Center for Biological Diversity
61-OP-LCFS-Neste	Delahoussaye, Dayne	Neste Oil
62-OP-LCFS-LCA	Unnasch, Stefan	Life Cycle Associates
63-OP-LCFS-Neste	Delahoussaye, Dayne	Neste Oil
64-OP-LCFS-FBE	Kinesche, Ted	Fulcrum BioEnergy
65-OP-LCFS-LCA	Unnasch, Stefan	Life Cycle Associates
1-B-LCFS-Unica	Phillips, Leticia	UNICA
2-B-LCFS-Sutherland	Lafferty, Susan	Sutherland
3-B-LCFS-Poet	Darlington, Thomas	Poet
4-B-LCFS-CU	Baker-Bransletter, Shannon	Consumers Union & Consumer
5-B-LCFS-Alon	Grimes, Gary	ALON USA
6-B-LCFS-ALA	Holmes-Gen, Bonnie	American Lung Assoc.
7-B-LCFS-CATF	Lewis, Jonathan	Clean Air Task Force
8-B-LCFS-NGC	Murphy, Colin	NextGen Climate
9-B-LCFS-LCFC	Noyes, Graham	Low Carbon Fuels Coalition
10-B-LCFS-BIV	Gershen, Joe	Individual
11-B-LCFS-CF	Mortenson, Lisa	Community Fuels
12-B-LCFS-GE	Willter, Joshua	Sierra Research for Growth Energy
1-T-LCFS-TOlsen	Olsen, Tim	California Energy Commission
2-T-LCFS-TTaylor	Taylor, Tim	Sacramento Metropolitan AQMD
3-T-LCFS-MMiyasato	Miyasato, Matt	South Coast AQMD
4-T-LCFS-MPassero	Passero, Michelle	TNC
5-T-LCFS-GGrey	Grey, Gina	Western States Petroleum Assoc.
6-T-LCFS-HClay	Clay, Harrison	Clean Energy Renewables
7-T-LCFS-MSolecki	Solecki, Mary	E2
8-T-LCFS-MHeller	Heller, Miles	Tesoro
9-T-LCFS-NEconomides	Economides, Nick	Chevron
10-T-LCFS-MHicks	Hicks, Melinda	Kern Oil and Refining Company
11-T-LCFS-DDelahoussaye	Delahoussaye, Dayne	Neste Oil
12-T-LCFS-GGrimes	Grimes, Gary	Paramount Petroleum

Comment Letter Code	Commenter	Affiliation
13-T-LCFS-CDuBose	DuBose, Celia	California Biodiesel Alliance
14-T-LCFS-JCase	Case, Jennifer	New Leaf Biofuel
15-T-LCFS-SNeal	Neal, Shelby	National Biodiesel Board
16-T-LCFS-RTeall	Teall, Russell	Biodico Sustainable Biorefineries
17-T-LCFS-JLevin	Levin, Julia	Biodiesel Association of California
18-T-LCFS-JLMendoza	Mendoza, Jerliyn Lopez	Southern California Gas
19-T-LCFS-MPlummer	Plummer, Matthew	Pacific Gas & Electric
20-T-LCFS-CWright	Wright, Curtis	IWP
21-T-LCFS-JODonnell	O'Donnell, John	Glass Point Solar
22-T-LCFS-RNakasone	Nakasone, Ross	Blue Green Alliance
23-T-LCFS-SUnnasch	Unnasch, Stefan	Life Cycle Associates
24-T-LCFS-CWhite	White, Chuck	Waste Management
25-T-LCFS-TDarlington	Darlington, Thomas	POET
26-T-LCFS-JDavid	David, Jesse	Growth Energy
27-T-LCFS-HSimpson	Simpson, Harry	Crimson Renewable Energy
28-T-LCFS-TCampbell	Campbell, Todd	Clean Energy
29-T-LCFS-JLewis	Lewis, Jonathan	Clean Air Task Force
30-T-LCFS-LPhillips	Phillips, Leticia	Unica
31-T-LCFS-TKoehler	Koehler, Tom	Pacific Ethanol
32-T-LCFS-BHolmesGen	Holmes-Gen, Bonnie	American Lung Assoc. Calif.
33-T-LCFS-TCarmichael	Carmichael, Tim	CNGVC
34-T-LCFS-DCox	Cox, David	Coalition for Renewable Natural Gas
35-T-LCFS-JBarbose	Barbose, Jason	Union of Concerned Scientists
36-T-LCFS-LMortenson	Mortenson, Lisa	Community Fuels
37-T-LCFS-JGershen	Gershen, Joe	Individual
38-T-LCFS-CMurphy	Murphy, Colin	Next gen Climate America
39-T-LCFS-SFrank	Frank, Susan	California Business Alliance for a Green Economy
40-T-LCFS-SMui	Mui, Simon	California Vehicles and Fuels Natural Resources Defense Council
41-T-LCFS-ETutt	Tutt, Eileen	California Electric Transportation Coalition
42-T-LCFS-RMoran	Moran, Ralph	BP America

Comment Letter Code	Commenter	Affiliation
43-T-LCFS-BMagavern	Magavern, Bill	Coalition for Clean Air
44-T-LCFS-GNoyes	Noyes, Graham	Low Carbon Fuels Coalition
45-T-LCFS-JHall	Hall, Jamie	CALSTART
46-T-LCFS-SHedderich	Hedderich, Scott	Renewable Energy Group
47-T-LCFS-KPhillips	Phillips, Katherine	Sierra Club, California
48-T-LCFS-TOConner	O'Conner, Tim	Environmental Defense Fund
49-T-LCFS-KJames	James, Kirsten	Ceres
50-T-LCFS-MAddy	Addy, McKinley	Adtra
51-T-LCFS-CHessler	Hessler, Christopher	AW, Inc.
1-FF-LCFS-Proterra	Leacock, Kent	Proterra
2-FF-LCFS-BE	Rubin, Elon	Beyond Energy
3-FF-LCFS-BNSF	Elgie, Rocky	BNSF Railway Company
4-FF-LCFS-GP	O'Donnell, John	GlassPoint Solar
5-FF-LCFS-Koehler	Koehler, Tom	Pacific Ethanol
6-FF-LCFS-Vidak	Senator Andy Vidak Senator Jean Fuller	California State Senators, districts 14 and 16
7-FF-LCFS-IBEW	Elrod, Jim	Int'l Brotherhood of Electrical Workers
8-FF-LCFS-PPRF	Gomez, Steven	Plumbers, Pipe and Refrigeration Fitters Union
9-FF-LCFS-ALON	Grimes, Gary	Paramount Petroleum
10-FF-LCFS-NBB	Neal, Shelby	National Biodiesel Board
11-FF-LCFS-AJW	Hessler, Christopher	AJW, Inc.
12-FF-LCFS-WSDE	Guilfoil, Elena	Washington State Dept. of Ecology
13-FF-LCFS-CalETC	Tutt, Eileen	California Electric Transport Coalition
14-FF-LCFS-MPP	Constantino, Jon	Manatt, Phelps & Phelps
15-FF-LCFS-POET	Darlington, Tom	Poet
16-FF-LCFS-POET	Darlington, Tom	Poet
17-FF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
18-FF-LCFS-CE	Campbell, Todd	Clean Energy Fuels
19-FF-LCFS-WSDE	Guifoil, Elena	Washington State Dept. of Ecology
20-FF-LCFS-FHR	Guillemette, Phillip	Flint Hills Resources
21-FF-LCFS-HG	Del Core, Rob	HydroGenics
22-FF-LCFS-EEEA	Edgar, Evan	Efgar & Associates
23-FF-LCFS-SF	Duff, John	National Sorghum Producers
24-FF-LCFS-LCA	Pont, Jennifer	Life Cycle Associates

Comment Letter Code	Commenter	Affiliation
25-FF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
26-FF-LCFS-AltEn	Meeker, Bryce	AltEn
27-FF-LCFS-DuPont	Koninckx, Jan	DuPont
28-FF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
29-FF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
30-FF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
31-FF-LCFS-Murex	Draney, Lisa	Murex
32-FF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
33-FF-LCFS-Nuvera	Block, Gus	
34-FF-LCFS-FHR	Guillemette, Phillip	Flint Hills Resources
35-FF-LCFS-NVGC	Carmichael, Tim	Natural Gas Vehicle Coalition
36-FF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
37-FF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
38-FF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
39-FF-LCFS-UNICA	Phillips, Leticia	UNICA
40-FF-LCFS-Tesoro	Heller, Miles	Tesoro
41-FF-LCFS-CP	Smart, Anne	ChargePoint
42-FF-LCFS-NS	Van De North, John	NexSteppe, Inc.
43-FF-LCFS-WSPA	Reheis-Boyd, Catherine	Western States Petroleum Assoc.
44-FF-LCFS-RPMG	Hoffmann, Jessica	RPMG, Inc.
45-FF-LCFS-GE	Willter, Joshua	Sierra Research for Growth Energy
46-FF-LCFS-Salas	Assemblyman Rudy Salas	California State Assemblyman district 32
47-FF-LCFS-CE	Waen, Jeremy	Marin Clean Energy
48-FF-LCFS-WE	Tjiong, Carol	White Energy
49-FF-LCFS-Kern	Hicks, Melinda	Kern Oil & Refining Co.
50-FF-LCFS-BIO	Batchelor, Stephanie	Biotechnology Industry Organization
51-FF-LCFS-NRDC	Barrett, Will	American Lung Assoc. in California
52-FF-LCFS-RPMG	Hoffmann, Jessica	RPMG
53-FF-LCFS-NRG	Lee, Kevin	NRG EVgo

Comment Letter Code	Commenter	Affiliation
54-FF-LCFS-FCP	Elrick, Bill	California Fuel Cell Partnership
55-FF-LCFS-CRR	Pauley, Clarke	CR&R
56-FF-LCFS-Solazyme	Ellis, Graham	Solazyme
57-FF-LCFS-CBA	DuBose, Celia	California Biodiesel Alliance
58-FF-LCFS-BTC	Spaulding, John	Building Trades Council
59-FF-LCFS-CalETC	Tutt, Eileen	California Electric Transportation Coalition
60-FF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
1-SF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
2-SF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
3-SF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
4-SF-LCFS-HBC	Caldwell, Logan	Houston BioFuels Consultants
5-SF-LCFS-GHI	Greene, John	GHI Energy
6-SF-LCFS-Ensyn	Connors, Karen	Ensyn Corporation
7-SF-LCFS-Enerkym	Labrie, Marie-Helene	Enerkym
8-SF-LCFS-GE	Willter, Joshua	Growth Energy
9-SF-LCFS-CNGVC	Carmichael, Tim	California Natural Gas Vehicle Coalition
10-SF-LCFS-WE	Tijong, Carol	White Energy
11-SF-LCFS-DuPont	Koninckx, Jan	DuPont
12-SF-LCFS-RFA	Cooper, Geoff	Renewable Fuels Association
13-SF-LCFS-SI	Ellis, Graham	Solazyme
1-TF-LCFS-DuPont	Koninckx, Jan	DuPont
2-TF-LCFS-GE	Willter, Joshua	Growth Energy

A. COMMENTS PRESENTED PRIOR TO THE FEBRUARY 19, 2015 HEARING

Sixty-five comment letters were received during the 45-day comment period. Each comment letter is reproduced below with responses following. Comment letter **46_OP_LCFS_GE** is 308 pages long and will be reproduced in discrete sections with the responses following each section for readability.

This page intentionally left blank.

Comment letter code: 1-OP-LCFS-CNGVC

Commenter: Tim Carmichael

Affiliation: California Natural Gas Vehicle Coalition

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

California Natural Gas Vehicle Coalition

NGVAMERICA
Natural Gas Vehicles for America

THE COALITION FOR RENEWABLE NATURAL GAS

1_OP_LCFS_CNGVC

January 21, 2015

Richard Corey
Executive Officer
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Re: Additional Comments on the Low-Carbon Fuel Standard and Revisions to the CA-GREET Model

Dear Executive Officer Corey:

The California Natural Gas Vehicle Coalition (CNGVC), NGVAmerica (NGVA), and the Coalition for Renewable Natural Gas (RNGC) are pleased to provide these latest joint comments regarding ARB's proposed reauthorization of the Low Carbon Fuel Standard (LCFS) regulation and proposed update to the CA-GREET model (CA-GREET 2.0). For more information about our three organizations and respective memberships, please refer to the previous formal comment letters (dated October 24 and December 15, 2014) that we uploaded to the ARB LCFS comments website.

As stated in those letters, we continue to strongly support ARB's re-authorization of the LCFS regulation. We are committed to continue working closely with ARB staff. Like ARB, we want to ensure that the proposed CA-GREET 2.0 model is based on the most up-to-date, accurate methodologies and data available at the time of its expected adoption in July 2015. LCFS 1-1

Recent Cooperative Efforts and Progress by ARB Staff

Our three organizations greatly appreciate the time and effort put forth by ARB staff over the last 60 days to meet with our representatives and address our specific concerns. We are pleased that ARB has made changes that corrected erroneous information and updated obsolete inputs found in early drafts of CA-GREET 2.0. LCFS 1-2

We also appreciate your general willingness to work with our industry. Most recently (January 11, 2015), you sent a cooperative, positive email communication to CNGVC President Tim Carmichael. In that email, you confirmed ARB's intent to continue working with California NGV industry stakeholders towards the following specific goals:

- Conduct further discussions to better quantify lifecycle GHG emissions;
- Understand and incorporate new research results as they become available over the next 12 months; LCFS 1-3
- Continue to engage with all stakeholders on CA- GREET 2.0, right up until the Board meeting in July 2015 at which the LCFS item will be heard (although, you noted that no "additional workshops" have yet been planned or scheduled);
- Incorporate any further updates to CA-GREET 2.0 through ARB's normal 15-day change rulemaking process; and

- Draft proposed "resolution" language for the Board's consideration at its February meeting; this resolution will confirm the previous bullet. LCFS 1-3 cont.

Ongoing Concerns Needing Resolution

Notwithstanding the significant cooperative efforts by ARB staff and the clear progress that has been made, our organizations and respective members continue to have significant and substantive concerns with Staff's direction towards finalizing LCFS recommendations to the Board for the July 2015 meeting. Our concerns fall within two general areas: 1) unresolved technical issues with the CA-GREET 2.0 model; and 2) the lack of a formal, transparent process for stakeholders to provide inputs and/or new information to help correct such problems. Addressing both issues will improve the CA-GREET model's accuracy and enhance the LCFS Program's fidelity, credibility and defensibility.

Within this context, our specific concerns are described below.

1. Unresolved Technical Issues

There are several major issues associated with the current CA-GREET model's natural gas pathways that remain unresolved to our satisfaction. These unsettled technical issues each relate to the critical parameter of fugitive methane emissions (both upstream and downstream). All issues were originally described in the two detailed letters and reports[1] that we previously submitted to ARB via the formal LCFS comment process. The following summarizes our updated technical concerns.

a) Tailpipe Methane Slip Emission Factors – This is our industry's most-important technical concern with the current version of CA-GREET 2.0. As we have described in past letters, the model's methodology and the data used to calculate methane tailpipe emission factors (EFs) were inaccurate in the first iteration of the proposed CA-GREET 2.0. We appreciate that ARB staff were responsive to our comments and made adjustments to the model, which then emerged in the current working draft of CA-GREET 2.0. Unfortunately, the quality of the subsequent data and methodology for tailpipe methane emissions in CA-GREET 2.0 remains poor. The new methodology utilizes modeled emission factors for gasoline and diesel from an outdated version of the EPA MOVES model, combined with unreferenced scaling factors to convert conventional fuel EFs to natural gas EFs. This approach is not scientifically defensible, and the resulting estimates for methane emissions are not consistent with recent vehicle testing and engine certification data for heavy-duty vehicles. LCFS 1-4

   We continue to strongly recommend that ARB incorporate the most up-to-date tailpipe methane methodology and emissions factors based on actual NGV emissions data. Peer-reviewed sources include SCAQMD's report from West Virginia University on in-use testing of heavy-duty vehicles (July 2014), and the soon-to-be released Argonne National Lab (ANL) Heavy Duty Vehicles report. Notably, the methane slip values in the ANL report for Class 8 heavy-duty trucks are four to six times lower than those currently being used by ARB staff. It appears that ARB staff already have an advanced copy of the ANL report, as it is referenced in the December 16, 2014 CA-GREET 2.0 Supplemental Document.

b) Methane Leakage from RNG Production Facilities – We appreciate that ARB staff responded to our concerns and reduced (from two to one percent) the assumed methane leakage factor for facilities LCFS 1-5

[1] This refers to the ICF International report commissioned by our organizations and submitted to ARB with our October 24, 2014 letter. Additional technical comments about CA-GREET based on this report were submitted to ARB with our December 15, 2014 letter.

that capture landfill gas. However, the current draft of the CA-GREET 2.0 continues to neglect the fact that a leakage rate of even one percent is both unfounded and inconsistent with existing Federal and state level regulations to control methane leakage at landfills, which require industry best practices to comply. The ANL reports and methodology cited by ARB are based on European studies for anaerobic digester facilities; they are simply not applicable to U.S. RNG production from landfill gas. U.S. landfills are subject to New Source Performance Standard (NSPS) operational requirements for collection and control systems. Moreover, California landfills are subject to more-stringent landfill methane rules requiring leak testing of any components that contain landfill gas under pressure. This includes the entire upgrading and treatment system. Specifically, California regulation 17 CCR 95464 (b)(1) sets very stringent leakage limits of 500 ppmv[2] and would translate into less than 0.1 percent leakage. Under Federal law, 40 CFR 60.753 prohibits <u>any</u> leakage of gas from landfill collection and processing systems. Consequently, we continue to support the position that the methane leakage rate at RNG production facilities located at any North American landfill is effectively *zero*. We see no credible or defensible basis for staff's position that a leakage rate of one percent must be assumed. LCFS 1-5 cont.

c) <u>Methane Leakage from Conventional Natural Gas Processes and Transport</u> – Assumptions currently in CA-GREET 2.0 for this category of methane leakage are based on a national-level EPA methodology. Inputs come from the 2014 national GREET model. These leakage rates are lower than the 2013 version of the national GREET model, and reflect the downward trend in methane emissions from the natural gas supply chain over the last 24 years (during very significant increases in natural gas production). Our concern is that using these emissions rates in the current CA-GREET 2.0 model is clearly not representative of California's natural gas distribution systems or the primary gas-producing basins supplying natural gas to California. ARB's ISOR (Appendix D) acknowledges that the release of more up-to-date studies on system leakage are imminent; these will <u>include California-specific data</u>. While we concur with ARB staff's apparent decision to wait for release of these studies before revising leakage values, we want to emphasize the importance of incorporating this new data set before CA-GREET 2.0 is finalized and implemented. LCFS 1-6

To further improve the accuracy of model inputs and outputs, we continue to recommend that ARB develop a California-centric assessment of natural gas systems and supplies, similar in concept to the OPGEE model used to calculate CI values for petroleum fuels. Our organizations and members are ready to assist by providing inputs for this model. For example, Southern California Gas Company reports that modernization efforts over the last 20 years have reduced leakage rates in its territory to levels <u>20 to 80 percent lower than those assumed in the currently proposed CA-GREET 2.0 model</u>. Other utilities and natural gas producers indicate that actual leakage rates attributable to California gas supply are significantly lower than assumed in the proposed CA-GREET update. We strongly urge ARB to work with these industry resources to incorporate and account for unique attributes of the California natural gas system. LCFS 1-7

d) <u>Methane Leakage as a User Modifiable CA-GREET Input</u> – We request that ARB make methane leakage rate a user-modifiable input in the CA-GREET model. This will enable fuel producers *that are able to provide supporting documentation* to submit site-specific values for methane leakage. LCFS 1-8

e) <u>Double Counting of Methane Leakage During Pipeline Distribution</u> – In the current draft of the CA-GREET 2.0 model, methane leakage during pipeline distribution (i.e., via lower-pressure pipelines) is LCFS 1-9

[2] Parts per million, by volume

erroneously being double counted. We have made ARB staff aware of this issue, and expect that the error will be corrected before ARB finalizes and implements the CA-GREET 2.0 model. LCFS 1-9 cont.

2. Concerns with the Stakeholder Review Process

We have the following significant concerns regarding the process used by ARB staff to work with our industry (and other stakeholders) in revising the LCFS and updating the CA-GREET model. While we appreciate the time and attention staff has taken to meet with us thus far, these meetings have been more on an ad-hoc basis and at the request of the NGV industry. Building on the productive dialogue to date, we see opportunity for further improvement of the science, assumptions and calculations being used in the CA-GREET model.

Further, commitments have been made by ARB staff during past ad hoc meetings that have not been reflected in subsequent releases of the CA-GREET model and/or other LCFS Program supporting documentation. An example is provided below in item 2.a). LCFS 1-10

It is for these reasons that we believe a more formal process is warranted. Such a process will help ensure that the best-available data and science are used in updates to the LCFS Program. It will establish a clear, transparent and formal record for stakeholder engagement on these issues, thereby resulting in defensible and credible updates for the revised CA-GREET model and LCFS Program.

a) Publication of CI Values in the ISOR - In our formal joint letter of October 14, 2014, we urged ARB to refrain from publishing preliminary CI values for any fuel pathway, including those for CNG, LNG and RNG. We pointed out that much uncertainty exists with key parameters that dictate CI values; this is especially true regarding fugitive methane emissions during both upstream and downstream processes. Furthermore, more-robust data on such critical issues will emerge over the next six to twelve months; it is highly likely that some of this will be available to ARB staff well before the Board considers adoption of the revised LCFS in July 2015. We emphasized that CI values are an important determinant for end-user fleets when considering a potential switch to NGVs, and publishing interim values would only serve to introduce confusion into the marketplace. This could potentially destabilize the LCFS credit trading market, delay or halt investment plans developed to comply with the LCFS, and/or create hesitation among end users as they consider the adoption and use of lower-carbon transportation options for their fleets. Given the ability for an end-user fleet to make strong investments in NGVs and fueling infrastructure today, and transition these operations to very-low-CI RNG in the future (if not immediately), it is extremely important for the State to encourage rather than hinder such adoption in the market. Given these facts, we requested that ARB continue to use existing CI numbers from the still-active CA-GREET model (1.8b), until better and newer data are available. LCFS 1-11

During a meeting on December 12, 2014 at ARB headquarters, your staff indicated it would be necessary to publish updated CI values, even if preliminary. Staff cited the need to include “illustrative scenarios” in the ISOR for various fuel pathways. In follow-up discussions, Staff communicated that ARB management was willing to compromise by using a combined CI (70 g/mj) for conventional natural gas (fossil CNG and LNG), and a CI range (15 to 25 g/mj) for RNG. Our NGV industry team accepted that approach – although our clear preference has been that ARB not publish any new CI values. We have been consistent that continued use of existing CI values from CA-GREET 1.8b makes the most sense; meanwhile, ARB could note that they would most likely change upon implementation of the revised LCFS program (2016).

Unfortunately, for illustrative scenarios in the actual ISOR (Appendix B), Staff used a single CI of 25 for RNG rather than the range of 15 to 25, to which Staff had committed. While this change may have been inadvertent, our concern is that Staff did not follow through on an important commitment, upon public release of the ISOR and its appendices. This type of disconnect is a key reason that we are requesting a more formal process for obtaining, documenting and responding to stakeholder inputs (see the next item).

The ramifications to such process breakdowns can be significant. The ISOR language notes that "these values approximate the average CIs expected to be applied to these fuels." As such, we are very concerned that publishing only RNG's upper CI value (which is itself a place holder) will have a lasting and negative effect on decisions to make capital investments in California RNG infrastructure and related vehicle deployments. We strongly believe that the draft ISOR should have incorporated the range of 15 to 25 per the agreement made with Staff during our December 12 meeting.

LCFS 1-11 cont.

b) Lack of a Transparent, Effective Process to Incorporate Stakeholder Input – Issues such as the one described above (the CI range for RNG) point to the need for a more effective and transparent process for ARB staff to work with stakeholders to revise this very important regulation and supporting model. As previously stated in our formal letters and during meetings with Staff, we believe it is essential that ARB implements an improved process to obtain and document public input, as well as provide a timely and iterative approach to reviewing and integrating the latest technical information. This should include establishment of an ARB-industry working group that can convene several times within the period between the February 19-20th and July 23-24th board meetings. This will help ensure that legitimate stakeholder concerns and questions are addressed, while also improving the pipeline of useful technical inputs from industry to ARB staff.

This need for stakeholders to make CA-GREET 2.0 inputs during a more formal, transparent process is of paramount importance to our industry. We have been repeatedly assured by ARB staff that "nothing is cast in stone" for CA-GREET 2.0, and that changes can routinely be made by ARB right up until the Board considers adoption in July 2015. However, much of the critical details remain a mystery. For example, we have been told by Staff that after the LCFS issue comes before the Board at its February 2015, "the public record will be closed" until the LCFS Program is again heard at the July 2015 board meeting.

LCFS 1-12

Thus, under a worst-case scenario, our industry assumes that: 1) no formal meetings could take place between the February and July board meetings, 2) ARB staff would not continue to meet with our industry on these issues, 3) no additional data could be considered, and 4) no public testimony could be heard at the July board meeting. If this is the case (we do not have formal clarification and confirmation), we have very significant concerns that ARB's process will not be able to accommodate further industry inputs needed for important CA-GREET 2.0 model modifications. Again, adoption of a more formal and public process that can accommodate critical emerging information will help make this program better for ARB, program stakeholders and the general public.

As noted earlier, we do appreciate your recent email to CNGVC President Tim Carmichael that pledges ARB staff to "continue to engage with stakeholders" up to the July Board meeting. We urge you to now act on this, through the establishment and scheduling of an NGV industry working group. We recommend convening this group for up to three full-day working sessions before Staff finalizes its recommendation to the Board. Our organizations stand ready to engage in such a working group to support ARB staff in the development of a CA-GREET model that incorporates the best-available methodology and data inputs.

Summary of Conclusions and Recommendations

Our three organizations continue to strongly support reauthorization of the LCFS regulation. We genuinely appreciate the cooperation that ARB staff have shown in working with our industry representatives to improve the program, especially the critically important CA-GREET model. Leading up to the February and July Board meetings, we urge you to 1) expeditiously address unresolved technical issues in the current draft CA-GREET 2.0 model, as identified in this letter; 2) fully integrate critical new information that is likely to emerge in the coming months, and 3) plan, schedule and implement a robust public workshop process over the next several months that includes establishment of a natural gas industry working group.

LCFS 1-1 cont.
LCFS 1-4 cont.
LCFS 1-12 cont.

Thank you for the opportunity to comment. We look forward to working with ARB staff on this important issue. If we can provide additional information, please do not hesitate contact any of us.

Sincerely yours,

Tim Carmichael   Matthew Godlewski   David Cox

Tim Carmichael, President
California Natural Gas Vehicle Coalition
916-448-0015

Matthew Godlewski, President
NGVAmerica
202-824-7360

David Cox, Director of Operations & General Counsel
Coalition for Renewable Natural Gas
916-678-1592

1_OP_LCFS_CNGVC Responses

1. Comment: **LCFS 1-1**

   This comment supports the re-adoption of the LCFS regulation.

   Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

2. Comment: **LCFS 1-2**

   This comment supports the revisions to and re-adoption of the LCFS regulation.

   Agency Response: ARB staff appreciates support for the recommended changes to the California-modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET) 2.0 model.

3. Comment: **LCFS 1-3**

   This comment supports ARB staff's efforts in working with stakeholders toward additional goals with the LCFS regulation.

   Agency Response: Staff committed to continue working with California Natural Gas Vehicle Coalition, NGVAmerica, Coalition for Renewable Natural Gas, and other natural gas vehicle industry stakeholders towards the goals specified in above comment. Staff held a workshop on April 3rd, 2015 to discuss CA-GREET 2.0 updates and natural gas and biomethane CI values, and will continue to periodically refine CIs to reflect latest science.

4. Comment: **LCFS 1-4**

   The comment states concerns regarding the quality of the data and methodology for tailpipe methane emissions in CA-GREET 2.0.

   Agency Response: As the commenter has suggested, ARB staff has reviewed the publication, "The GREET Model Expansion for Well-to-Wheels Analysis of Heavy-Duty Vehicles," (Argonne National Laboratory, May 25, 2015) and adopted emission factors from this report in CA-GREET 2.0 to estimate methane (CH_4) and nitrous oxide (N_2O) emissions from heavy duty natural gas vehicles (NGV). Light duty NGV emission factors are calculated using data from GREET1_2014. GREET1_2014 data is drawn from a variety of sources which are referenced in the 2015 Initial Statement of Reasons (ISOR) Appendix C. Fuel consumption data by vehicle class, obtained from the U.S. Energy Information Administration (EIA) and the 2014 LCFS Reporting Tool Database, is used to determine a weighted average emission factor which represents all LNG vehicles operating in California, and a separate emission factor representing the CNG fleet. Staff has recorded the details of these changes since the ISOR in the CA-GREET 2.0 Supplemental Document, which was added to the record in the first round of 15-day changes to the regulation and available for review here: http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm.

5. Comment: **LCFS 1-5**

The comment asserts that CA-GREET 2.0 neglects that methane leakage from RNG production facilities at a rate of one percent is not consistent with state and federal guidelines.

Agency Response: The one percent factor represents leakage during processing (purification to pipeline quality) of landfill gas (LFG), not fugitive emissions from landfills. Fugitive emissions that escape collection at the landfill (estimated to be 10-25 percent) are considered to be outside of the system boundary for LFG fuel pathways, because under the alternative reference case (business-as-usual scenario) where LFG is captured and flared, the same amount of methane is assumed to escape to the atmosphere. Therefore, CA-GREET 2.0 is consistent with the federal regulation of landfill methane emissions because it does not debit the pathway for leakage during the LFG recovery stage, and assesses a credit for avoided flaring.

California regulation 17 CCR 95464 (b)(1) requires leak testing on collection and control as well as gas processing systems and specifies a 500 ppmv limit; however, this limit represents a detectable concentration at one point in time, which is not sufficient to quantify methane emissions as a fraction of throughput.

No studies have been identified by ARB staff or by stakeholders that are relevant to leakage in LFG processing. The biogas studies used to develop the one percent leakage factor were considered to be representative of leakage during LFG processing, as the biogas produced by anaerobic digestion and by landfills have similar methane concentrations and impurities, implying that processing methods and equipment would be similar.

In response to stakeholder feedback and due to the uncertainty and lack of data on these operations, ARB staff has agreed to make methane leakage in renewable natural gas (RNG) processing a user-modifiable input. Regular leak testing, the use of calibrated revenue meters, and third-party verification are among the requirements that applicants will have to meet to substantiate the user-input value. ARB staff will consider results of future peer-reviewed studies and revise the default leakage factor as appropriate in future rulemakings.

6. Comment: **LCFS 1-6**

The commenter states that the emission rates in CA-GREET 2.0 are not representative of California's natural gas distribution system.

Agency Response: Limited data was available in 2009 to estimate leakage from natural gas life cycle stages, and only 0.58 percent of natural gas was presumed to be lost in recovery, processing, and transmission and distribution. This is now considered to be a significant underestimate. ARB staff cannot propose the use of a value that is known to be incorrect. Future studies may show that leakage across the supply chain is higher or lower than the 1.15% leakage currently estimated over the natural gas life cycle; however, studies such as Brandt et al (2014) indicate this is a reasonable estimate.

Methane leakage from natural gas recovery, processing, and transmission and distribution systems is an evolving area of research and current literature estimates can vary significantly. The proposed factors are based on the U.S. EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (2014) and have been used in many state-level GHG inventories. Additional studies may not confirm the commenter's expectation that leakage is lower, but ARB staff will remain attentive to emerging studies and will consider updates to methane leakage factors for the whole supply chain in future rulemakings, allowing ample opportunity for stakeholder review and feedback.

Staff recognizes this is an ongoing area of study and plans to closely monitor progress in understanding and controlling this source of emissions. Staff will consider updating these parameters as appropriate in future rulemakings.

7. Comment: **LCFS 1-7**

The commenter suggests a California-centric assessment of natural gas systems to be developed.

Agency Response: A contract for the development of a California-centric assessment of natural gas, similar in concept to the OPGEE model is being explored.

8. Comment: **LCFS 1-8**

The commenter requests that ARB make methane leakage rate a user-modifiable input to CA-GREET.

Agency Response: ARB staff does not believe that all leaks across the entire natural gas supply chain can be detected and more accurately quantified by any given pathway applicant. Given the uncertainty associated with this parameter, and to avoid the potential for conflicting data from various applicants about the same portions of the natural gas supply chain, this is a parameter that will remain common to all applicants.

9. Comment: **LCFS 1-9**

The commenter asserts that methane leakage is currently double-counted in the CA-GREET model.

Agency Response: Transmission leakage is a distance-dependent parameter (g CH4 per MMBtu per mile), but distribution is expressed as a flat value (g CH4 per MMBtu of natural gas). No double counting occurs as long as users enter only the transmission distance in this field (as it is labeled in the model) and not transmission and distribution as one value. Maps of the natural gas (NG) transmission pipeline system are available to assist in making these estimates.

The user input distance only applies to NG transported by pipeline for use as a vehicle fuel. The upstream impacts of natural gas used in power plants and stationary sources are calculated separately, using the national average transmission distance of 680 mi (ISOR, p. C-72 Table 42).

10. Comment: **LCFS 1-10**

The comment requests a more formal process by which updates are made to the LCFS regulation and the GREET model in particular.

Agency Response: Including preliminary carbon intensity (CI) values is part of the LCFS regulatory process for re-adoption. Such CI values were derived from the most up-to-date scientific data and the Argonne GREET 2013 model.

Based on stakeholder feedback received over the last several years and advances in lifecycle analysis, ARB updated our CA-GREET to CA-GREET-2.0. Future changes will be made as needed through the process set forth in the APA, which is an open, public process.

11. Comment: **LCFS 1-11**

The comment requests that ARB refrain from publishing CI values, due to the uncertainty of them.

Agency Response: Publication of preliminary CI values is essential for any meaningful stakeholder review. All of the CI values given in the ISOR, Appendix B, Table B were assumed point estimates of CI, rather than ranges. The high-end of the range determined for renewable natural gas (RNG), 25 gCO_2e/MJ, was selected for the compliance scenarios as a conservative value, to provide greater confidence that the expected compliance was achievable and not overly optimistic.

The commenter's request for a "more effective and transparent" public process is at odds with its request to hold industry-only working groups and refrain from publishing preliminary CI values.

12. Comment**: LCFS 1-12**

The commenter requests more transparency in regulatory development, by way of the creation of an LCFS working group.

Agency Response: The LCFS re-adoption public process was complete, extensive, and robust. As part of this public process, ARB staff met with all stakeholder groups, including the California Natural Gas Vehicle Coalition (CNGVC), upon request. Staff has been available and responsive to each request for meetings with the CNGVC and all other stakeholders.

Workshops for the proposed CA-GREET-2.0 were conducted throughout the year in the months of March, April, May, August, October, and November of 2014.

During the April 2014 public meeting, it was announced that the CA-GREET-2.0 would be based on a publicly available GREET-1 2013 model from Argonne Laboratory. In May, the two-tiered framework for pathway applications was presented. In August, a preliminary CI comparison was released. Finally, an early draft of the CA-GREET-2.0 model was released in October, along with a comprehensive table of all the parameter decisions reached up to that point.

In April of 2015 an additional workshop was held with a heavy focus on the issues raised by the natural gas vehicle industry.

Comment letter code: 2-OP-LCFS-TAC

Commenter: Marc Rauch

Affiliation: The Auto Channel

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

2_OP_LCFS _TAC

California Environmental Protection Agency
Air Resources Board

Comment Log Display

BELOW IS THE COMMENT YOU SELECTED TO DISPLAY.
COMMENT 2 FOR LOW CARBON FUEL STANDARD 2015 (LCFS2015) - 45 DAY.

First Name: Marc
Last Name: Rauch
Email Address: mjrauch@theautochannel.com
Phone Number: 916-273-8320
Affiliation: The Auto Channel

Subject: Low Carbon Standard
Comment:
If I was to write a kind response to your Low Carbon Standard initiative I would say, "Shucks, looks like you missed the mark again."

The problem with that response is that I would be dishonest. The honest response is to say that once again the California government and it's self-interested appointee organizations is about to level another scam that milks and bilks the working public of its hard-earned income.

If CARB or CALSTART really had any interest in low-carbon fuels; freeing us from foreign oil dependency; and trying to make the environment healthier; they would have long ago mandated the use of the two fuels that are available to do the job. These two fuels are compressed natural gas (CNG) and ethanol. Instead, they continue to favor electric power, a solution that won't be affordable and in meaningful availability for 2, 3, 4, 5 maybe 6 decades from now.

CNG and ethanol is available right now - today - and can be used by the overwhelming majority of passenger vehicles that are currently on the road; and in the case of ethanol, these vehicles would not even require any engine conversions to use the fuel. Starting immediately we could make an enormous reduction in harmful emissions, while saving the public billions of dollars. LCFS 2-1

Nearly three years ago, to the day, California's Air Resources LCFS 2-2

Board unanimously approved a package of new emissions rules that they claimed would save drivers money, create jobs, and cut smog and greenhouse gases under what was labeled "The Advanced Clean Car Program."

This program only referred to electric. They never talked about the contribution that ethanol and CNG could make. What was particularly ironic was that the report from CARB stated that they relied in part on Ron Cogan and his GREEN CAR JOURNAL to help them make their decision to support their electric car program. But there was a problem with this: they never consulted Ron Cogan, and Mr. Cogan was not in favor of CARB's program. I know this because I discussed it with him at the Los Angeles Auto Show that convened a few months later. LCFS 2-2 cont.

Even more interesting was the fact that just prior to CARB unveiling this program, Mr. Cogan had bestowed (one again) his company's Green Car Of The Year Award on the Honda Civic GX, car powered exclusively by CNG. Honda won this award for virtually the same vehicle just a few years earlier.

In addition, although CNG has received great press in the past couple of years, California continues its refusal to allow existing gasoline-powered passenger vehicles to be converted to CNG. If you purchase a vehicle that was legally converted to CNG in another state, and bring it into California, you can not register the vehicle. CNG conversions are performed everyday around the rest of the world. If there was a danger in doing so, we would be hearing terrible stories about this everyday, rather than the terrible stories we do hear everyday caused by people who are supported by oil dictators.

Moreover, although today's CALSTART article finally does mention CNG, they never said anything about the dearth of available new CNG powered cars. For the past several years only Honda is regularly producing CNG-powered vehicles - that is, if you can describe annual production runs of about 2,000 vehicles to be regular. The auto manufacturers make more electric vehicles per year than that, and that low number is just a totally meaningless. If California (and the EPA) removed their unjustified restrictions on CNG conversions, at least millions of cars could be converted even if there is no increase in the production of new CNG vehicles. LCFS 2-3

Not only is the number of electric cars being produced meaningless, they are too expensive: for the consumers and for the auto manufacturers. Consumers who purchase an electric car are paying a significant premium over the true value of the car, and auto manufacturers lose thousands of dollars on every electric car they sell. Sergio Marchione, CEO of Chrysler-Fiat says it best: "Our electric Fiat 500 is great, but please don't buy them; we lose too much money." LCFS 2-3 cont.

Added to the cost and availability problems with electric cars is the fact that battery production makes us dependent on China. At present, there's little to suggest that reliance on China is any better than reliance on foreign petroleum oil.

Incidentally, 100% of our CNG and ethanol supply is produced domestically, and none of the ethanol producers are owned by foreign or terrorist controlled regimes. No American serviceman or woman have ever been killed defending the domestic production and distribution of ethanol. LCFS 2-1 cont.

So when CARB, CALSTART, Jerry Brown and the California Legislature say "Let's Keep Going," what they mean is let's keep milking and bilking the working public; let's keep padding our staffs with additional friends, relatives and campaign donors.

Attachment:

Original File Name:

Date and Time Comment Was Submitted: 2015-02-03 18:45:42

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

This page intentionally left blank.

2_OP_LCFS_TAC Responses

13. Comment: **LCFS 2-1**

    The commenter suggests CNG and ethanol as a method of compliance for the LCFS.

    Agency Response: ARB staff agrees that ethanol is a method of compliance. Because the LCFS allows fuel producers to choose what fuels to produce and how to comply, including using ethanol, there is no need to change the proposed LCFS.

14. Comment: **LCFS 2-2**

    The commenter discusses the Advanced Clean Car program, and that it only addresses electric cars, and not ethanol or CNG.

    Agency Response: This comment is outside the scope of the proposal.

15. Comment: **LCFS 2-3**

    The commenter does not appreciate that California refuses “to allow existing gasoline-powered passenger vehicles to be converted to CNG.”

    Agency Response: This comment is outside the scope of the proposal.

This page intentionally left blank.

Comment letter code: 3-OP-LCFS-AWTE

Commenter: George Sterzinger

Affiliation: American Waste to Energy

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

CLERK OF THE BOARD
COMMENTS ON STAFF REPORT:
INITIAL STATEMENT OF REASONS
FOR PROPOSED RULEMAKING

3_OP_LCFS_AWTE

OFFERED BY AMERICAN WASTE TO ENERGY

George Sterzinger
American Waste to Energy
gsterzinger@gmail.com
202-255-8119

1. American Waste to Energy (AWE) appreciates the opportunity to offer these comments to the Air Resources Board as part of its consideration of the Staff Report: Initial Statement of Reasons for the Proposed Rulemaking.
2. AWE currently directs substantial effort towards developing and commercializing innovative technologies to reduce the carbon intensity of the fossil fuels produced, refined and distributed in California. AWE supports the ARB use of permits (and the financial support the permits would provide) to attract existing and innovative programs to lower the carbon intensity particularly of the fossil fuel sector of California.
3. AWE supports both the Low Carbon Fuel Standard and the Cap-and-Trade Program. AWE supports the simultaneous application of these two programs. Basically, any program that complies with the Cap-and Trade Program can also contribute to compliance with the LCFS provided the specific action leads to a reduction in the carbon intensity of the fuel supply. LCFS 3-1
4. AWE's comments focuses on two closely related points.
    a. First, the Cap-and Trade program and the LCFS are two programs that are meant to be consistent. A program that meets the requirements of the Cap-and-Trade bill to lower carbon intensity can also lower the carbon intensity of the sectors related to fossil fuels. If those conditions are met

then the programs will be awarded permits under both the Cap-and-Trade and the LCFS program. This is intentional. The Air Resources offers this as an incentive to encourage actions to lower carbon intensity under both the Cap-and-Trade and the LCFS.

b. Second, those same principles should be extended to the Innovative Technologies for Crude Oil Production program outlined in the Proposed Rulemaking. Ant Innovative Technology that can achieve a sustained commercial breakthrough should be eligible for inclusion under the Cap-and-Trade and the LCFS programs. Any decision to limit access to or eligibility under the LCFS program is counter-productive. It reduces the incentives to support the innovation and will ultimately harm the LCFS program. LCFS 3-2

5. AWE supports the basic simultaneous access to the Cap and Trade (C&T) program and the Low Carbon Fuel Standard (LCFS). The Staff responses to issues raised by the Department of Finance underlines the important this consistency. The Staff states: <u>"The LCFS and the Cap-and-Trade program are designed to complement one another. Investments made to comply with one of the programs will result in reduced compliance requirements for the other program. Reductions in the carbon intensity of fuel due to the LCFS reduce compliance obligations under the Cap-and-Trade Program. Similarly, selling cleaner fuels to comply with Cap-abd-Trade helps meet the requirements of the LCFS." (Title 17. California Air Resources Board: Notice of Public Hearing to Consider a Low Carbon Fuel Standard, pg. 24)</u> LCFS 3-3

6. AWE's strongly supports this. The Staff properly finds that any program that meets the requirements of both the Cap-and Trade and the LCFS should be recognized and benefit from both programs. Such programs should receive tradable permits under BOTH the Cap-and-Trade and the LCFS programs. This consistency is emphasized by the Staff as an important way to provide potentially important financial support for efforts undertaken to lower the carbon intensity of the fossil fuel sectors of the California economy. LCFS 3-4

7. AWE's point here is to extend this basic consistency between the Cap-and Trade and the LCFS. It should logically be extended to include Innovative Technologies that have not yet achieved full commercial breakthrough. LCFS 3-2 cont.
8. AWE is particularly urges the ARB to recognize the potential of technological innovation with biomass-based fuels to lower the carbon intensity under the Cap-and-Trade and the LCFS. AWE stresses that this recognition is nothing more than the recognition of a potential. If the potential cannot be realized, i.e. the technology cannot be brought to commercial status, then nothing happens. From the viewpoint of the ARB this recognition of the potential does not have a downside. On the other hand, the premature decision to reject any biomass based technology innovation removes a potential benefit for no reason.
9. AWE is aware that the ARB Staff has considered and rejected the use of 'biomass steam, heat, and electricity production as innovative methods'. AWE urges ARB to reconsider this across-the-board rejection for general and specific reasons. As a general proposition, ARB's broad rejection of the use of biomass will exclude potential technology innovations that have not yet been developed. Going back to AWE's initial point: such a rejection only serves to unnecessarily eliminate potential breakthroughs. Broad rejection unnecessarily removes a potential. Allowing the possibility of a breakthrough is a cost-free benefit that deserves the possibility to prove itself. The Staff also raises several specific concerns about biomass based LCFS fuels. Specifically that: LCFS 3-5
    a. <u>Combustion of waste biomass will produce excess 'criteria pollutants'.</u> The innovations being considered do not rely on combustion but instead use a variety of gasification and even enzymatic processes. Moreover, if any method violated air standards on criteria pollutants the technology will not be permitted. LCFS 3-6
    b. <u>Waste biomass is not generated as part of the 'life cycle of crude oil production' and will result in the 'shuffling' of biomass among other competing uses.</u> The simplest point here is that the same would hold true for solar steam generated in Concentrating Solar technologies. The second LCFS 3-7

point is that under current California Energy Commission rules, waste biomass cannot be used to produce renewable qualified electricity. LCFS 3-7 cont.

c. <u>The standard applies to biomass produced anywhere 'in the world' which would raise difficult to impossible monitoring requirements.</u> This concern is easily addressed. To qualify under Cap-and-Trad and the LCFS biomass must be evaluated using the ASTM D 6866 test. That test determines the organic carbon faction of the biomass fuel. That test must be applied to any biomass regardless of point of origin. The tests must be done as random samples. Tests must be done on a regular basis and resukts must be reported to the ARB. LCFS 3-8

d. <u>Finally, greenhouse gases from biomass will exceed emission reductions expected from 'solar or wind power' and for that reason should be rejected.</u> First, this conclusion is not supported with evidence. But more importantly, the LCFS standard is not offered as the 'best' options. (All our children cannot be above average.) The challenge for the LCFS and for the Cap-and-Trade program is to reduce CO2 emissions and intensity as much as possible. Any and all measures that produce a marginal, positive reduction will help reach that goal and should be accepted under the Cap-and-Trade and the LCFS. LCFS 3-9

10. Under the Cap-and-Trade program the ARB has issued Final Orders specifically defining materials that qualify as biomass and specified the American Society of Tests and Measures (ASTM) to determine the percent of the organic carbon-based materials to qualify as biogenic CO2 emissions. Biogenic CO2 emissions must be reported but do not require permits to cover the emissions. Thee standards should be required for any Innovative Technology option seeking commercial status. Here are the specific standards required by the ARB: LCFS 3-10

ARB Definition of Biomass (From the Final Order)

(31) "Biomass" means non-fossilized and biodegradable organic material originating from plants, animals, and microorganisms, including products, by-products, residues, and waste from agriculture, forestry,

and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material. For the purpose of this article, biomass includes both California Renewable Portfolio Standard (RPS) eligible and non-eligible biomass as defined by the California Energy Commission.

Article 5: CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND
MARKET-BASED COMPLIANCE MECHANISMS, pg A-8.

§ 95852.2. Emissions without a Compliance Obligation.
Emissions from the following source categories and fuel types as identified in sections 95100 through 95199 of the Mandatory Reporting Regulation count toward applicable reporting thresholds but do not count toward a covered entity's compliance obligation set forth in this regulation article unless those emissions are reported as Other Biomass CO2 under MRR. These source categories Emissions without a compliance obligation include:

LCFS 3-10 cont.

Combustion emissions from the folowing biomass-derived portion of biomass-derived fuels (except biogas
from digesters) from the following
sources:

(1) Solid waste materials, including the biogenic content of solid waste materials that are not 100 percent biomass, as determined by methodology specified in ASTM D6866, based on exhaust sampling or fuel sampling (and fuel usage record keeping) at the specified frequency and tires which may use alternative tests.

3_OP_LCFS_AWTE Responses

16. Comment: **LCFS 3-1**

    The comment expresses support for the re-adoption of the LCFS regulation.

    Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

17. Comment: **LCFS 3-2**

    The comment requests that any emission reduction technology should qualify for credit under the LCFS Innovative Crude Production Method provision.

    Agency Response: The LCFS may recognize emissions reductions that occur at crude oil production facilities in two different ways. First, the LCFS will recognize all emissions reduction efforts employed at crude production facilities through calculation of a reduced carbon intensity (CI) for the crude. Second, the LCFS may award credit for emissions reductions achieved through methods deemed innovative. The innovative crude production method provision was designed to promote those technologies that are truly innovative. Technologies included in the provision have been proposed by stakeholders and vetted through a deliberative process involving workshops, stakeholder feedback, and Board consideration. In conclusion, all emission reduction efforts at crude facilities are recognized under the LCFS through a reduced crude CI, but only those deemed to be truly innovative are approved for credit generation under the innovative method provision because this provision is expressly designed to encourage development and use of innovative methods.

18. Comment: **LCFS 3-3**

    The comment supports the goals of the Cap-and-Trade program as well as the LCFS regulation.

    Agency Response: ARB staff appreciates the support for both the Cap-and–Trade Program and the LCFS regulation.

19. Comment: **LCFS 3-4**

    The comment states that Cap and Trade and LCFS should have tradable “permits” or offsets that can work in either program.

Agency Response: ARB thanks the commenter for their support of the statements in the Staff Report regarding the complementary nature of the Cap-and-Trade and LCFS programs. While investments made to comply with one program will generally result in reduced compliance obligations for the other program, there is no central permit shared between the two programs. The LCFS credit and Cap and Trade allowance markets are intentionally distinct with different "currencies" and rules that govern the markets. Unlike Cap and Trade, the LCFS requires development and use of low-carbon fuels that will be necessary in the long term for future GHG and criteria pollutant reductions. Moreover, changes to the Cap-and-Trade Regulation are outside the Scope of the current rulemaking.

20. Comment: **LCFS 3-5**

The commenter requests that ARB recognize the potential of biomass use under the Innovative Crude Production Method provision.

Agency Response: As part of the current LCFS re-adoption process, ARB staff considered direct biomass combustion to produce steam, heat or electricity for inclusion as an innovative crude production method. ARB staff's rationale for rejecting biomass combustion as an innovative method is discussed in the Initial Statement of Reasons (ISOR) on page II-19. Staff does not believe those technologies that employ direct combustion of waste biomass meet the qualifications of an innovative crude method. See response to **LCFS 3-2**.

If the commenter has a specific technology that they would like considered for inclusion under the innovative crude provision, ARB staff welcome a discussion and a deliberate public process for consideration in next related regulatory amendment process.

21. Comment: **LCFS 3-6**

The commenter states that new non-combustion technologies for biomass usage such as gasification and enzymatic processes are being considered.

Agency Response: See response to **LCFS 3-5**.

As part of the current LCFS re-adoption process, ARB staff considered direct biomass combustion to produce steam, heat or electricity for inclusion as an innovative crude production method. Staff became aware of the biomass gasification technology and enzymatic processes proposed by the commenter in the 45-day comment period, and will fully evaluate them in future regulatory proposals.

22. Comment: **LCFS 3-7**

Commenter disagrees with the claim expressed in the staff report concerning biomass resource shuffling.

Agency Response: See response to **LCFS 3-5**. ARB staff is concerned about shuffling of waste biomass under competing uses because staff wants to ensure that GHG emissions reductions credited under the innovative crude method provision are additional. Development of a solar steam project at a crude production facility meets this criterion. Shuffling of biomass from producing energy under one emissions reduction program to producing energy under the LCFS does not meet this standard.

23. Comment: **LCFS 3-8**

The commenter requests biomass testing at the point of origin to be used to satisfy ARB's concern regarding source of biomass.

Agency Response: See response to **LCFS 3-5**.

The American Society for Testing and Materials (ASTM) test recommended by the commenter can be used to determine the organic carbon fraction of the biomass fuel; however it does not determine whether the biomass is waste. ARB staff's concern expressed in the ISOR is that it would be very difficult to ensure that biomass fuel used in many parts of the world would be waste biomass.

24. Comment: **LCFS 3-9**

The commenter disagrees with ARB staff's conclusion that GHG's from combustion of biomass for steam or electricity production will exceed those from solar or wind power. The commenter also argues that any technology that produces even marginal emission reductions should be included under the innovative crude provision.

Agency Response: See response to **LCFS 3-2** and **LCFS 3-5**.

ARB staff believes that, as a whole, evidence supports the conclusion that direct combustion of biomass to produce steam, heat, or electricity is more emissions-intensive than solar or wind-based processes. While there may be some sources of waste biomass that compete with solar or wind with regard to GHG emissions, this is generally only possible if not using the waste biomass can be proven to result in generation of greenhouse gases more potent than CO2 (e.g., the waste biomass would otherwise be deposited in an uncontrolled landfill and decompose anaerobically over a relatively short time horizon to generate methane). Moreover, the innovative crude provision is intended to promote technologies that produce significant, not marginal, GHG emissions reductions as compared to the industry norm. While marginal emission reduction efforts at crude facilities are recognized under the LCFS through a reduced crude CI, only those deemed to be truly innovative are approved for credit generation under the innovative method provision.

25. Comment: **LCFS 3-10**

The comment suggests that LCFS use the same ASTM methods and regulatory language as Cap-and-Trade to provide credit for biogenic CO_2 emissions under the innovative crude provision.

Agency Response: See responses to **LCFS 3-2**, **LCFS 3-5**, and **LCFS 3-8**.

Comment letter code: 4-OP-LCFS-SVLG

Commenter: Mike Mielke

Affiliation: Silicon Valley Leadership Group

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

2001 Gateway Place, Suite 101E
San Jose, California 95110
(408)501-7864 svlg.org
CARL GUARDINO
President & CEO
Board Officers:
GREG BECKER, Chair
SVB Financial Group
KEN KANNAPPAN, Vice Chair
Plantronics
JOHN ADAMS, Secretary/Treasurer
Wells Fargo Bank
TOM WERNER, Former Chair
SunPower
AART DE GEUS, Former Chair
Synopsys
STEVE BERGLUND, Former Chair
Trimble Navigation
Board Members:
MARTIN ANSTICE
Lam Research
SHELLYE ARCHAMBEAU
MetricStream, Inc.
ANDY BALL
Suffolk Construction
GEORGE BLUMENTHAL
University of California, Santa Cruz
JOHN BOLAND
KQED
CHRIS BOYD
Kaiser Permanente
BRADLEY J. BULLINGTON
Bridgelux
HELEN BURT
Pacific Gas & Electric
DAVID CUSH
Virgin America
CLAUDE DARTIGUELONGUE
BD Biosciences
CHRISTOPHER DAWES
Lucile Packard Children's Hospital
MICHAEL ENGH, S.J.
Santa Clara University
TOM FALLON
Infinera Corporation
BRANT FISH
Chevron Corporation
HANK FORE
Comcast
KEN GOLDMAN
Yahoo!
RAQUEL GONZALEZ
Bank of America
DOUG GRAHAM
Lockheed Martin Space Systems
LAURA GUIO
IBM
JAMES GUTIERREZ
Insikt
JEFFREY M. JOHNSON
San Francisco Chronicle
GARY LAUER
eHealth
ENRIQUE LORES
HP
MATT MAHAN
Brigade
TARKAN MANER
Nexenta
KEN MCNEELY
AT&T
STEVEN MILLIGAN
Western Digital Corporation
KEVIN MURAI
Synnex
JES PEDERSON
Webcor
KIM POLESE
ClearStreet
MO QAYOUMI
San Jose State University
VIVEK RANADIVÉ
TIBCO
STEVEN ROSSI
Bay Area News Group
ALAN SALZMAN
VantagePoint Capital Partners
RON SEGE
Echelon Corporation
ROSEMARY TURNER
UPS
RICK WALLACE
KLA-Tencor
DAN WARMENHOVEN
NetApp, Inc.
JED YORK
San Francisco 49ers
Established in 1978 by
DAVID PACKARD

4_OP_LCFS _SVLG

February 9, 2015

Mary Nichols, Chairman
California Air Resources Board
1001 I Street, PO Box 2815
Sacramento, CA 95812

Re: Support for LCFS

Dear Chairman Nichols and Members of the Air Resources Board:

On behalf of the Board of Directors and member companies of the Silicon Valley Leadership Group, I am writing to offer our support of the California Air Resources Board's continued leadership on our state's pioneering climate policies and to urge the swift re-adoption of the Low Carbon Fuel Standard (LCFS). The Silicon Valley Leadership Group, founded in 1978 by David Packard of Hewlett-Packard, represents almost 400 of Silicon Valley's most respected educational institutions and high-tech, bio-tech, and clean-tech employers; our members collectively provide nearly one of every three private sector jobs in Silicon Valley.

We support the LCFS and believe it is an important component of the state's overall strategy to reduce greenhouse gas and other harmful air emissions and drive clean tech innovation. Further, we believe that continuing the transition to lower carbon transportation fuels helps:

- **Diversify the state's fuel supply mix and drive innovation.** From 2011 to 2013 alternative fuels comprised a steadily increasing share of transportation energy use in California[i] and the clean fuels market has grown faster than anticipated. [ii] LCFS 4-1
- **Save consumers money.** Introducing choice in the market drives competition which will help California households save money on their transportation fuel bills. This is complemented by other policies such as more fuel efficient cars and mass transit. LCFS 4-2
- **Improve air quality**. The LCFS has already cut carbon emissions by about 9 million metric tons, the equivalent of removing almost 2 million passenger cars from the road each year.[iii] By 2020, it is estimated the LCFS can help reduce emissions by 35 million metric tons, the equivalent of removing about 7 million passenger cars from the road per year.[iv] LCFS 4-3
- **Improve public health.** It is estimated that the LCFS will result in $1.4 to $4.8 billion in societal benefits by 2020, accruing from reduced air pollution.[v] The benefits could be even greater, $10.4 billion by 2020 and $23.1 billion by 2025, when other state fuels policies are included.[vi] LCFS 4-4
- **Secure California's cleantech market leadership.** California has approximately 40,000 businesses serving advanced energy markets, employing roughly 431,800 people.[vii] It is estimated that the LCFS could contribute up to 9,100 new jobs, and potentially many more if the state continues to attract more clean fuel providers.[viii] LCFS 4-5

We believe that there is a strong business case for clean fuels, and that clean air and a growing economy go hand-in-hand. We applaud your leadership and urge you to re-adopt the LCFS.

Sincerely,

Mike Mielke
Senior Vice President, Environment and Energy
Silicon Valley Leadership Group
408-501-7858

CC: Governor Jerry Brown
Senate President pro Tempore Kevin DeLeón
Assembly Speaker Toni Atkins

---

[i] UC Davis, *Status Review of California's Low Carbon Fuel Standard*, July 2014

[ii] ICF International, *California's Low Carbon Fuel Standard: Compliance Outlook & Economic Impacts*, April 2014

[iii] NRDC Fact sheet. 9 MMT reduced. Calculated from http://www.epa.gov/cleanenergy/energy-resources/calculator.html

[iv] ARB ISOR estimates 35 MMT from the LCFS alone. In combination with other fuel and vehicle standards, the program is expected to result in 63 MMT. Calculated from http://www.epa.gov/cleanenergy/energy-resources/calculator.html

[v] ICF International (2014).

[vi] American Lung Association in California and Environmental Defense Fund. *Driving California Forward*, May 2014

[vii] Advanced Energy Economy Institute, *California Advanced Energy Employment Survey*, December 2014

[viii] ICF International (2014).

4_OP_LCFS_SVLG Responses

26. Comment: **LCFS 4-3 and LCFS 4-4**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

27. Comment: **LCFS 4-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

28. Comment: **LCFS 4-2**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

29. Comment: **LCFS 4-5**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

This page intentionally left blank.

Comment letter code: 5-OP-LCFS-USC

Commenter: Jeremy Martin

Affiliation: Union of Concerned Scientists

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

[Union of Concerned Scientists

ucsusa.org Two Brattle Square, Cambridge, MA 02138-3780 t 617.547.5552 f 617.86
1825 K Street NW, Suite 800, Washington, DC 20006-1232 t 202.223.6133 f 202.223
2397 Shattuck Avenue, Suite 203, Berkeley, CA 94704-1567 t 510.843.1872 f 510.843.
One North LaSalle Street, Suite 1904, Chicago, IL 60602-4064 t 312.578.1750 f 312.578.1751

5_OP_LCFS_UCS

February 12, 2014

Chairman Mary Nichols and board members
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Dear Chairman Nichols and board members,

On behalf of our 73,000 supporters in California, the Union of Concerned Scientists (UCS) urges you to support moving forward with the re-adoption process for the Low Carbon Fuel Standard (LCFS) at the Air Resources Board (ARB) meeting on February 19th.

A year ago more than 100 leading California climate scientists and economists sent the attached letter urging the Governor and Legislature "to adopt a science-based, heat-trapping emissions target for 2030 that puts California on a path to meeting our 2050 goals." The letter also highlighted the need for additional policies that "promote renewable energy, low carbon fuels, and cleaner transportation." LCFS 5-1

The LCFS is a critical element in the comprehensive approach California has taken to achieve the state's climate goals while continuing to thrive economically. Readopting the LCFS will address some technical and legal obstacles that have slowed progress on developing and deploying clean fuels and put California back on track for a 10 percent reduction in carbon intensity by 2020. The LCFS also provides critical support for the Governor's call last month to cut petroleum use in cars and trucks in half by 2030.

Resolving these legal and technical issues with the current LCFS is critical, but to create a sustainable and stable market for clean fuels, state policy should focus on a time horizon longer than 5 years. We therefore urge the ARB to begin developing the next phase of the LCFS out to 2030. Such long-term policy support in conjunction with similar polices enacted by Pacific Coast Collaborative partners in Oregon, Washington and British Columbia will create a large, stable and steadily growing market for clean fuels that will support investment and innovation and bring down the cost of clean fuels. LCFS 5-2

UCS supports several important technical changes have been proposed to strengthen the LCFS including: (1) an update of the lifecycle analysis based on the best available science, (2) innovative crude and refinery provisions that will encourage the oil industry to reduce emissions from its own supply chain, and (3) a cost containment mechanism that will maintain a stable investment climate for low carbon fuel production while ensuring that any unforeseen delays will not destabilize the policy or hurt California consumers. LCFS 5-3

UCS has been performing analysis and providing technical feedback on the LCFS since its inception, and we are confident that diverse sources of low carbon fuel are available to LCFS 5-4 achieve the 10 percent carbon intensity target by 2020. I am attaching a recently released study on LCFS compliance from the consulting firm Promotum that UCS commissioned together with the Natural Resources Defense Council and the Environmental Defense Fund. The study finds that compliance is indeed feasible through 2020 and beyond. The study also demonstrates that in order to ensure investment in the cleanest fuels it is important to establish regulatory stability out beyond 2020. LCFS 5-4 cont.

It is also important to ensure that the cap price in the cost containment mechanism is not so low that is discourages investment in the cleanest fuels. The proposed $200 per ton cap is a minimum to ensure the clean fuels industry has a strong incentive to make the large investments needed to scale up the clean fuels needed to keep moving forward beyond 2020. LCFS 5-5

Thank you for your consideration. I am also attaching several recent UCS publications that discuss how the LCFS fits into the broader suite of transportation policies, recent progress in cellulosic biofuel commercialization, and the latest developments on indirect land use change. Please let me know if you have any questions about our analysis.

Sincerely,

Jeremy Martin, Ph.D.
Senior Scientist and Fuels Lead
Clean Vehicles Program

Enclosures:
Open Letter on Climate Change from California Climate Scientists and Economists
Promotum study on LCFS compliance
UCS fact sheet “Driving Progress, Fueling Savings”
Five UCS blogs on biofuels technology, policy and indirect land use change emissions

Union of Concerned Scientists

An Open Letter on Climate Change
from California Climate Scientists and Economists

May 19, 2014

Dear Governor Brown and California State Legislators:

California's leadership is needed now more than ever to address the risks of a dangerously warming climate. We urge the state's policy makers to adopt a science-based, heat-trapping emissions target for 2030 that puts California on a path to meeting our 2050 goals.

The science is clear that human activity is the dominant cause of warming over the last half century.[i] If global emissions continue to rise, the scope and severity of impacts will accelerate. Already communities across California are being forced to cope with many risks, including increased wildfires, more frequent and extreme heat waves, a strained water management system, growing risks to high value agricultural commodities, greater summer electricity demand, and more coastal flooding.[ii]

While we must adapt to the impacts of a changing climate, California must also take ambitious steps to reduce heat-trapping emissions that would cause much more devastating impacts in the decades to come. We are well-positioned to lead the world in this effort. The state has a goal of 80 percent reduction in global warming emissions below 1990 levels by 2050, established by Executive Order S-3-05. More importantly, California's policy makers deserve tremendous credit for adopting and implementing the California Global Warming Solutions Act of 2006 (AB 32) and numerous coordinated sustainability actions. The state has brought innovative climate policies off the drawing board and into practice, spurring investment, innovation, and jobs in a growing "green technology" sector. Moreover, the state's progress demonstrates that it is possible for a growing major economy to reduce emissions substantially at very modest cost.

California must continue to play a leadership role and to serve as a model for much-needed federal and international action. Maintaining a price on carbon dioxide and other global warming pollutants is key, but not sufficient to adequately reduce emissions. Policies that promote renewable energy, low carbon fuels, and cleaner transportation are also critical.

Yet as we approach 2020, we need medium-term targets to continue the progress we have begun. To achieve the steep reductions necessary to limit the worst impacts of climate change, lawmakers and regulators should adopt and implement enforceable emissions caps for 2030 and beyond. Every sector involved in addressing climate change, from energy to transportation, will need sufficient time to prepare to meet new targets. The longer we wait the harder and more costly it will be. Please begin now to set a science-based, heat-trapping emissions target for 2030.

i. Climate Change 2013: The Physical Science Basis. Working Group I Contribution to the IPCC 5th Assessment Report - Changes to the Underlying Scientific/Technical Assessment. 2013. Intergovernmental Panel on Climate Change. Available online at http://www.ipcc.ch/report/ar5/wg1
ii. Moser, S., J. Ekstrom, G. Franco. 2012. Our Changing Climate 2012 Vulnerability & Adaptation to the Increasing Risks from Climate Change in California. Prepared for the California Energy Commission and the California Natural Resources Agency. Publication # CEC-500-2012-007. Available online at http://climatechange.ca.gov/climate_action_team/reports/third_assessment/ index.html

The signers of this letter are scientists, researchers and economists who live or work in California and hold a Ph.D. All signers have expertise relevant to our understanding of climate change, its impacts, or solutions.

Those included on this page contributed to the development of this letter.

Kenneth Arrow, Ph.D.
Professor Emeritus
Department of Economics
Stanford University
Stanford, CA
Nobel Laureate, Economics

Roger C. Bales, Ph.D.
Founding Professor of Engineering
Sierra Nevada Research Institute
School of Engineering
University of California, Merced
Merced, CA

Hilda Blanco, Ph.D.*
Interim Director, Center for Sustainable Cities and Research Professor
Sol Price School of Public Policy
University of Southern California
Los Angeles, CA

Gary Griggs, Ph.D.†
Director, Institute of Marine Sciences and Professor of Earth Sciences
Department of Earth and Planetary Sciences
University of California, Santa Cruz
Santa Cruz, CA

W. Michael Hanemann, Ph.D.*†
Chancellor's Professor
Department of Agricultural and Resource Economics
University of California, Berkeley
Berkeley, CA

Daniel M. Kammen, Ph.D.*
Professor of Energy and Professor of Public Policy
Co-Director, Berkeley Institute of the Environment
Founding Director, Renewable and Appropriate Energy Laboratory
University of California, Berkeley
Berkeley, CA

Pamela A. Matson, Ph.D.
Professor and Senior Fellow
Woods Institute for the Environment
Department of Environmental Earth System Science
Stanford University
Stanford, CA

Richard Norgaard, Ph.D.*
Professor Emeritus
Energy and Resources Group
University of California, Berkeley
Berkeley, CA

Richard C. J. Somerville, PhD.*
Professor Emeritus and Research Professor
Scripps Institution of Oceanography
University of California, San Diego
San Diego, CA

Institutional affiliation listed for identification purposes only

*Intergovernmental Panel on Climate Change (IPCC) Lead Author
† Third Assessment from the California Climate Change Center Principal Researcher

David Akey, Ph.D.
Retired Researcher
Western Cotton Research Center
U.S. Department of Agriculture
Los Osos, CA

Steven Allison, Ph.D.
Associate Professor
Department of Ecology and Evolutionary Biology
University of California, Irvine
Irvine, CA

Richard Ambrose, Ph.D.
Professor
Department of Environmental Health Sciences
University of California, Los Angeles
Agoura Hills, CA

Cort Anastasio, Ph.D.
Professor
Department of Land, Air and Water Resources
University of California, Davis
Davis, CA

Linda Anderson, Ph.D.
Researcher Emeritus
Institute of Marine Sciences
University of California, Santa Cruz
Felton, CA

Ray Anderson, Ph.D.
Riverside, CA

Tim Arnold, Ph.D.
Postdoctoral Scholar
Scripps Institute of Oceanography
University of California, San Diego
La Jolla, CA

William Ascher, Ph.D.
Professor
Departments of Government and Economics
Claremont McKenna College
Claremont, CA

Bevin Ashenmiller, Ph.D.
Professor
Department of Economics
Occidental College
Los Angeles, CA

Maximilian Auffhammer, Ph.D.*†
Associate Professor
Department of Agricultural and Resource Economics
University of California, Berkeley
Walnut Creek, CA

Kamil Murat Aydin, Ph.D.
Associate Researcher
Department of Earth System Science
University of California, Irvine
Irvine, CA

Paul Baer, Ph.D.
Climate Economist
Union of Concerned Scientists
Alameda, CA

Dennis Baldocchi, Ph.D.
Professor
Department of Environmental Science
University of California, Berkeley
Berkeley, CA

Asmeret Asefaw Berhe, Ph.D.
Assistant Professor
Department of Life and Environmental Sciences
University of California, Merced
Merced, CA

Jessica Blois, Ph.D.
Assistant Professor
Department of Life and Environmental Sciences
University of California, Merced
Merced, CA

Adam Brandt, Ph.D.
Assistant Professor
Energy Resources Engineering
Stanford University
Menlo Park, CA

Lewis Branscomb, Ph.D.
Professor Adjunct
Institute for Global Conflict and Cooperation
University of California, San Diego
La Jolla, CA

Holger Brix, Ph.D.
Assistant Researcher
Adjunct Assistant Professor
Department of Atmospheric and Oceanic Sciences
University of California, Los Angeles
Altadena, CA

Chris Busch, Ph.D.
Director of Research
Energy Innovation: Policy and Technology
San Francisco, CA

Ken Caldeira, Ph.D.*
Senior Scientist
Department of Global Ecology
Carnegie Institution for Science
Stanford, CA

Monika Calef, Ph.D.
Assistant Professor
Department of Environmental Studies
Soka University of America
Huntington, CA

Peter Castro, Ph.D.
Professor Emeritus
Department of Biological Sciences
California State Polytechnic University, Pomona
Claremont, CA

Institutional affiliation listed for identification purposes only

*Intergovernmental Panel on Climate Change (IPCC) Lead Author
** IPCC Contributing Author
† Third Assessment from the California Climate Change Center Principal Researcher

Robert Cervero, Ph.D.
Professor and Chair
Department of City and Regional Planning
University of California, Berkeley
Berkeley, CA

Yihsu Chen, Ph.D.
Associate Professor
School of Engineering
School of Social Sciences
University of California, Merced
Merced, CA

Juliet Christian-Smith, Ph.D.
Climate Scientist
Union of Concerned Scientists
El Cerrito, CA

Patrick Chuang, Ph.D.
Professor
Department of Earth and Planetary Sciences
University of California, Santa Cruz
Santa Cruz, CA

David Cleveland, Ph.D.
Professor
Environmental Studies Program
Department of Ecology, Evolution, and Marine Biology
Department of Geography
University of California, Santa Barbara
Santa Barbara, CA

Martha Conklin, Ph.D.
Professor
Department of Environmental Systems
University of California, Merced
Catheys Valley, CA

Eugene Cordero, Ph.D.
Professor
Department of Meteorology and Climate Science
San Jose State University
San Jose, CA

Helen Cox, Ph.D.
Professor
Department of Geography
California State University, Northridge
Thousand Oaks, CA

Helen Dahlke, Ph.D.
Assistant Professor
Department of Land, Air and Water Resources
University of California, Davis
Davis, CA

Gretchen Daily, Ph.D.
Bing Professor of Environmental Science
Department of Biology
Stanford University
Stanford, CA

Frank Davis, Ph.D.
Professor
Bren School of Environmental Science and Management
University of California, Santa Barbara
Santa Barbara, CA

Steven Davis, Ph.D.
Professor
Department of Earth System Science
University of California, Irvine
Irvine, CA

David DeSante, Ph.D.
President
The Institute for Bird Populations
Point Reyes, CA

Michael Dettinger, Ph.D.
Research Associate
Climate Research Division
Scripps Institution of Oceanography
San Diego, CA

Susan Ustin Doyle, Ph.D.
Professor
Department of Land, Air and Water Resources
University of California, Davis
Davis, CA

Jeff Dozier, Ph.D.
Professor and Founding Dean
Bren School of Environmental Science and Management
University of California, Santa Barbara
Santa Barbara, CA

Ellen Druffel, Ph.D.
Fred Kavli Professor
Department of Earth System Science
University of California, Irvine
Irvine, CA

Tim Duane, Ph.D.
Professor
Department of Environmental Studies
University of California, Santa Cruz
Santa Cruz, CA

Ann Ehrlich, Ph.D. (equivalent)
Senior Research Scientist
Department of Biology
Stanford University
Stanford, CA

Paul Ehrlich, Ph.D.
Bing Professor of Population Studies
Department of Biology
Stanford University
Stanford, CA

Institutional affiliation listed for identification purposes only

*Intergovernmental Panel on Climate Change (IPCC) Lead Author
** IPCC Contributing Author
† Third Assessment from the California Climate Change Center Principal Researcher

Julia Ekstrom, Ph.D.†
Science Fellow
Oceans Program
Natural Resources Defense Council
El Cerrito, CA

Deborah Elliott-Fisk, Ph.D.
Professor Emeritus
Geography Graduate Group
Department of Wildlife, Fish, and Conservation Biology
University of California, Davis
Davis, CA

Valerie Eviner, Ph.D.
Associate Professor
Department of Plant Sciences
University of California, Davis
Davis, CA

Emily Farrer, Ph.D.
Postdoctoral Fellow
Department of Environmental Science, Policy, and Management
University of California Berkeley
Berkeley, CA

Marvin Feldman, Ph.D.
Principal Economist
Resource Decisions
San Francisco, CA

James Fine, Ph.D.
Alameda, California

Anthony Fisher, Ph.D.
Professor
Department of Agricultural and Resource Economics
University of California, Berkeley
Orinda, CA

Melanie Fitzpatrick, Ph.D.
Climate Scientist
Union of Concerned Scientists
Albany, CA

Graham Fogg, Ph.D.
Professor
Department of Land, Air and Water Resources
University of California, Davis
Davis, CA

Henry Forman, Ph.D.
Distinguished Professor
Department of Life and Environmental Sciences
University of California, Merced
Studio City, CA

Peter Frumhoff, Ph.D.*
Director of Science and Policy
Union of Concerned Scientists
Menlo Park, CA

Jed Fuhrman, Ph.D.
McCulloch-Crosby Chair of Marine Biology
Department of Biological Sciences
University of Southern California
Topanga, CA

Steven Gaines, Ph.D.
Dean
Bren School of Environmental Science and Management
University of California, Santa Barbara
Santa Barbara, CA

Terry Galloway, Ph.D.
Chief Technology Officer
Intellergy Inc.
Berkeley, CA

Mariano Garcia, Ph.D.
Postdoctoral Researcher
Department of Land, Air and Water Resources
University of California, Davis
Davis, CA

Catherine Gautier, Ph.D.
Professor Emerita
Department of Geography
University of California, Santa Barbara
Santa Barbara, CA

Alexander Gershenson, Ph.D.
Assistant Professor
Department of Environmental Studies
San Jose State University
Santa Cruz, CA

Peter Gleick, Ph.D.
President and Co-founder
Pacific Institute
Berkeley, CA

Daniel Gluesenkamp, Ph.D.
Executive Director
California Native Plant Society
San Francisco, CA

Wilson Goddard, Ph.D.
Principle Research Engineer
Goddard & Goddard Engineering
Lucerne, CA

Richard Grotjahn, Ph.D.
Professor
Department of Land, Air and Water Resources
University of California, Davis
Davis, CA

Institutional affiliation listed for identification purposes only

*Intergovernmental Panel on Climate Change (IPCC) Lead Author
** IPCC Contributing Author
† Third Assessment from the California Climate Change Center Principal Researcher

Karen Grove, Ph.D.
Professor and Chair
Department of Earth and Climate Sciences
San Francisco State University
San Francisco, CA

Andrew Gutierrez, Ph.D.
Professor Emeritus
Department of Environmental Science, Policy, and Management
University of California, Berkeley
Kensington, CA

Andrew Gunther, Ph.D.
Executive Director
Center for Ecosystem Management and Restoration
Oakland, CA

Steven Hackett, Ph.D.
Professor
Department of Economics
Humboldt State University
Arcata, CA

Bronwyn Hall, Ph.D.
Professor Emerita
Department of Economics
University of California, Berkeley
Berkeley, CA

Darwin Hall, Ph.D.
Professor Emeritus
Department of Economics
Department of Environmental Science and Policy
California State University, Long Beach
Long Beach, CA

John Harte, Ph.D.
Professor of Ecosystems Sciences
Energy and Resources Group
University of California, Berkeley
Berkeley, CA

Rod Hay, Ph.D.
Dean
Department of Natural and Behavioral Sciences
Professor
Department of Geography
California State University, Dominguez Hills
Carson, CA

Barbara Haya, Ph.D.
Research Fellow
Stanford Law School
Stanford University
Oakland, CA

Elizabeth Herbert, Ph.D.
Chair
Science Advisory Panel
Board of Directors
Sempervirens Fund
Santa Cruz, CA

David Herbst, Ph.D.
Research Scientist
Sierra Nevada Aquatic Research Lab
University of California, Santa Barbara
Bishop, CA

Karen Holl, Ph.D.
Professor
Department of Environmental Studies
University of California, Santa Cruz
Felton, CA

John Holtzclaw, Ph.D.
Retired
San Francisco, CA

Jan Hopmans, Ph.D.
Professor
Department of Hydrology
University of California, Davis
Davis, CA

Benjamin Houlton, Ph.D.
Professor
Department of Land, Air and Water Resources
University of California, Davis
Davis, CA

Edward Huang, Ph.D
Principal Researcher
Department of Education and Research
California Institute of Environmental Design and Management
Arcadia, CA

Louise Jackson, Ph.D.†
Professor
Department of Land, Air and Water Resources
University of California, Davis
Davis, CA

Kathleen Johnson, Ph.D.
Assistant Professor
Department of Earth System Science
University of California, Irvine
Irvine, CA

Brian Kahn, Ph.D.
Staff Scientist
Atmospheric Infrared Sounder Group
NASA Jet Propulsion Laboratory
California Institute of Technology
Altadena, CA

Carrie Kappel, Ph.D.
Associate Project Scientist
National Center for Ecological Analysis and Synthesis
Pacific Grove, CA

Kris Karsten, Ph.D.
Professor
Department of Biology
California Lutheran University
Thousand Oaks, CA

Institutional affiliation listed for identification purposes only

*Intergovernmental Panel on Climate Change (IPCC) Lead Author
** IPCC Contributing Author
† Third Assessment from the California Climate Change Center Principal Researcher

Michael Kiparsky, Ph.D.
Associate Director
Wheeler Institute for Water Law and Policy
University of California, Berkeley
Berkeley, CA

Peter Kirchner, Ph.D.
Postdoctoral Scholar
Joint Institute for Regional Earth System Science and Engineering
University of California, Los Angeles
Sierra Madre, CA

Alexander Koltunov, Ph.D.
Project Scientist
Center for Spatial Technologies and Remote Sensing
Department of Land, Air and Water Resources
University of California, Davis
Davis, CA

Jeffrey Koseff, Ph.D.
Professor
Department of Civil and Environmental Engineering
Stanford University
Stanford, CA

Janet Kubler, Ph.D.
Senior Research Scientist
Department of Biology
California State University, Northridge
Valencia, CA

Emilio Laca, Ph.D.
Professor
Department of Plant Sciences
University of California, Davis
Davis, CA

Steve LaDochy, Ph.D.
Professor
Department of Geography and Urban Analysis
California State University, Los Angeles
Temple City, CA

Sherman Lewis, Ph.D.
Professor Emeritus
Department of Political Science
California State University, East Bay
Hayward, CA

Michael Loik, Ph.D.
Professor
Department of Environmental Studies
University of California, Santa Cruz
Santa Cruz, CA

Bruce Luyendyk, Ph.D.
Professor Emeritus
Research Professor
Department of Earth Science
University of California, Santa Barbara
Santa Barbara, CA

Wade Matin, Ph.D.
Professor and Chair
Department of Economics
California State University, Long Beach

Adam Martiny, Ph.D.
Professor
Department of Earth System Science
University of California, Irvine
Irvine, CA

Edwin Maurer, Ph.D.
Associate Professor
Department of Civil Engineering
Santa Clara University
Santa Clara, CA

Carl Mears, Ph.D.**
Vice President for Research
Remote Sensing Systems
Cotati, CA

Adam Millard-Ball, Ph.D.**
Assistant Professor
Department of Environmental Studies
University of California, Santa Cruz
Santa Cruz, CA

Norman Miller, Ph.D.**
Adjunct Professor
Department of Geography
University of California, Berkeley
Berkeley, CA

Brent Mishler, Ph.D.
Director
University and Jepson Herbaria
Professor
Department of Integrative Biology
University of California, Berkeley
Berkeley, CA

Jean Moran, Ph.D.
Associate Professor
Department of Earth and Environmental Sciences
California State University, East Bay
Livermore, CA

Max Moritz, Ph.D.†
Cooperative Extension Specialist
Department of Environment Science, Policy, and Management
University of California, Berkeley
Berkeley, CA

Susanne Moser, Ph.D.†**
Director
Susanne Moser Research & Consulting
Santa Cruz, CA

Institutional affiliation listed for identification purposes only

*Intergovernmental Panel on Climate Change (IPCC) Lead Author
** IPCC Contributing Author
† Third Assessment from the California Climate Change Center Principal Researcher

Jens Muhle, Ph.D.
Project Scientist
Scripps Institution of Oceanography
University of California, San Diego
La Jolla, CA

Dustin Mulvaney, Ph.D.
Assistant Professor
Department of Environmental Studies
San Jose State University
Ben Lomond, CA

Deb Niemeier, Ph.D.
Professor
Department of Civil and Environmental Engineering
University of California, Davis
Davis, CA

Gretchen North, Ph.D.
Professor
Department of Biology
Occidental College
Valley Village, CA

Michael O'Hare, Ph.D.
Professor
Goldman School of Public Policy
University of California, Berkeley
Berkeley, CA

Stuart Oskamp, Ph.D.
Professor Emeritus
Department of Psychology
Claremont Graduate University
Claremont, CA

Edward Parson, Ph.d.*
Professor
School of Law
Institute of the Environment and Sustainability
University of California, Los Angeles
Los Angeles, CA

Manuel Pastor
Professor
Program for Environmental and Regional Equity
University of Southern California
Pasadena, CA

John Pearse, Ph.D.
Professor Emeritus
Department of Ecology and Evolutionary Biology
University of California, Santa Cruz
Pacific Grove, CA

Stacy Philpott, Ph.D.
Santa Cruz, CA

Richard Plevin, Ph.D.
Research Engineer
Institute of Transportation Studies
University of California, Davis
Berkeley, CA

Michael Prather, Ph.D.*
Professor
Department of Earth System Science
University of California, Irvine
Irvine, CA

Jessica Pratt, Ph.D.
Professor
Department of Ecology
University of California, Irvine
Irvine, CA

Daniel Press, Ph.D.
Professor
Department of Environmental Studies
University of California, Santa Cruz
Santa Cruz, CA

Mike Pritchard, Ph.D.
Professor
Department of Earth System Science
University of California, Irvine
Carlsbad, CA

Isha Ray, Ph.D.
Associate Professor
Energy and Resources Group
University of California, Berkeley
Berkeley, CA

David Riano, Ph.D.
Associate Project Scientist
Department of Land, Air and Water Resources
University of California, Davis
Davis, CA

Eric Rignot, Ph.D.*
Professor
Department of Earth System Science
University of California, Irvine
Irvine, CA

William Riley, Ph.D.**
Staff Scientist
Earth Sciences Division
Lawrence Berkeley National Laboratory
Berkeley, CA

David Roland-Holst, Ph.D.
Professor
Department of Agricultural and Resource Economics
University of California, Berkeley
Berkeley, CA

Lynn Russell, Ph.D.
La Jolla, CA

Institutional affiliation listed for identification purposes only

*Intergovernmental Panel on Climate Change (IPCC) Lead Author
** IPCC Contributing Author
† Third Assessment from the California Climate Change Center Principal Researcher

Joshua Schimel, Ph.D.
Professor
Department of Ecology, Evolution, and Marine Biology
University of California, Santa Barbara
Santa Barbara, CA

Peter Schwartz, Ph.D.
Associate Professor
Department of Physics
California Polytechnic State University, San Luis Obispo
San Luis Obispo, CA

Roger Seapy, Ph.D.
Professor Emeritus
Department of Biological Science
California State University, Fullerton
Los Alamitos, CA

Seth Shonkoff, Ph.D.**
Executive Director
Physicians, Scientists, and Engineers for Healthy Energy
Environmental Researcher
Department of Environmental Science, Policy, and Management
University of California, Berkeley
Oakland, CA

James Sickman
Professor
Department of Environmental Sciences
University of California, Riverside
Riverside, CA

Leonard Sklar, Ph.D.
Associate Professor
Department of Earth and Climate Sciences
San Francisco State University
Albany, CA

David Smernoff, Ph.D.
Chief Technology Officer
Heliobiosys
Portola Valley, CA

Kirk R. Smith, Ph.D.*
Professor
School of Public Health
University of California, Berkeley
Berkeley, CA

Raymond Smith, Ph.D.
Professor Emeritus
Department of Geography
University of California, Santa Barbara
Santa Barbara, CA

Soroosh Sorooshian, Ph.D.
Distinguished Professor and Director
Department of Civil and Environmental Engineering
University of California, Irvine
Irvine, CA

Roger Sparks, Ph.D.
Professor
Department of Economics
Mills College
Oakland, CA

Wayne Spencer, Ph.D.
Director of Conservation Planning
Conservation Biology Institute
San Diego, CA

Michael Springborn, Ph.D.
Assistant Professor
Department of Environmental Science and Policy
University of California, Davis
Davis, CA

Scott Stephens, Ph.D.
Professor
Department of Environmental Science, Policy, and Management
University of California, Berkeley
Berkeley, CA

Iris Stewart-Frey, Ph.D.
Associate Professor
Department of Environmental Studies and Sciences
Santa Clara University
San Jose, CA

Christopher Still, Ph.D.
Associate Professor
Department of Geography
University of California, Santa Barbara
Santa Barbara, CA

Eric Stoutenburg, Ph.D.
Lecturer
Department of Energy Resources Engineering
Stanford University
Palo Alto, CA

Sharon Strauss, Ph.D.
Professor
Department of Evolution and Ecology
University of California, Davis
Davis, CA

Andrew Szasz, Ph.D.
Professor and Chair
Department of Environmental Studies
University of California, Santa Cruz
Santa Cruz, CA

Slawek Tulaczyk, Ph.D.
Professor
Department of Earth and Planetary Sciences
University of California, Santa Cruz
Santa Cruz, CA

Institutional affiliation listed for identification purposes only

*Intergovernmental Panel on Climate Change (IPCC) Lead Author
** IPCC Contributing Author
† Third Assessment from the California Climate Change Center Principal Researcher

Isabella Velicogna, Ph.D.**
Professor
Department of Earth System Science
University of California, Irvine
Irvine, CA

Jasper Vrugt, Ph.D.
Assistant Professor
Department of Civil and Environmental Engineering
University of California, Irvine
Irvine, CA

Zhi Wang, Ph.D.
Associate Professor
Department of Earth and Environmental Sciences
California State University, Fresno
Fresno, CA

Michael Wara, Ph.D.
Associate Professor
Stanford Law School
Stanford University
Stanford, CA

Stuart Weiss, Ph.D.
Chief Scientist
Creekside Center for Earth Observation
Menlo Park, CA

Hartwell Welsh, Ph.D.
Research Wildlife Biologist
Pacific Southwest Research Station
Forest Service
United States Department of Agriculture
Arcata, CA

Anthony Westerling, Ph.D.†
Associate Professor
Sierra Nevada Research Institute
University of California, Merced
Mariposa, CA

Charlie Zender, Ph.D.
Professor
Department of Earth System Science
University of California, Irvine
Irvine, CA

David Zilberman, Ph.D.
Professor
Agricultural Economics
University of California, Berkeley
Berkeley, CA

Institutional affiliation listed for identification purposes only

*Intergovernmental Panel on Climate Change (IPCC) Lead Author
** IPCC Contributing Author
† Third Assessment from the California Climate Change Center Principal Researcher

California's Low Carbon Fuel Standard:
Evaluation of the Potential to Meet and Exceed the Standards

Promotum
10 Chauncy Street
Cambridge, MA
02138

February 2, 2015

Contents

1. Regulatory Background

California's adoption of the Global Warming Solutions Act of 2006, also known as Assembly Bill (AB) AB32, set in motion a series of policies to reduce greenhouse gas (GHG) emissions in the state to 1990 levels by 2020 – roughly a 20 percent reduction – while also protecting public health. Under AB32, the California Air Resources Board (ARB) developed a series of GHG reduction strategies as part of a Scoping Plan for achieving the 2020 goal. For the transportation sector, the key programs ARB adopted include standards for cleaner, more efficient cars and trucks; a clean fuels standard; a cap-and-trade regulation; and established targets to reduce emissions through more sustainable, transit friendly and walkable communities.

The state's clean fuels standard, known as the Low Carbon Fuel Standard (LCFS), was adopted in 2009 as an early-action measure under AB32 and in furtherance of Executive Order S-01-07 by then Governor Arnold Schwarzenegger. In addition, in his recent fourth inaugural address, current Governor Jerry Brown provided targets for a series of new environmental goals for 2030, including reducing current petroleum use in cars and trucks by 50 percent.[1]

California's LCFS is a performance-based standard requiring petroleum refiners and other fuel providers to reduce the carbon-intensity of transportation fuels used in California by 10 percent by 2020. The carbon-intensity of each fuel is measured on a full lifecycle basis, which includes accounting for GHG emissions from production of a feedstock, transport, refining, distribution, and end-use combustion. Because the standard is technology-neutral, companies can earn LCFS "credits" any number of ways, including improving their processes or through switching to renewable feedstocks and inputs. Each LCFS credit nominally represents one metric ton of reductions in GHG emissions. The LCFS is designed to include market-based features that allow LCFS credits to be sold, banked, or utilized to help meet the requirements.

2. Project Scope

To inform the dialogue about the re-adoption of the LCFS and establishment of revised annual compliance requirements, Promotum Inc., an independent technical and management consulting firm focused on fuels and chemicals, was commissioned by the Natural Resource Defense Council (NRDC), Union of Concerned Scientists (UCS) and the Environmental Defense Fund (EDF) to evaluate likely scenarios for compliance and the impact of credit values on incentivizing greater production and volumes of low Carbon Intensity (CI) fuels to the state.[2]

Promotum reviewed and analyzed fuel availability, prior supply studies, data from obligated parties (fuel suppliers) quarterly reporting to the ARB, California Energy Commission (CEC)

[1] http://gov.ca.gov/news.php?id=18828
[2] The conclusions and views contained herein are solely those of the consultant and do not necessarily reflect those of NRDC, UCS, and EDF.

information, U.S. Energy Information Administration (EIA) data, and consulted with a wide number of industry participants with specific sector expertise to develop a forecast of supplies and a model of future low carbon fuel production.

As part of the creation of these scenarios we sought to incorporate the latest technology and commercialization developments. For example, 2014 saw the startup of the first two commercial scale cellulosic ethanol facilities in the U.S. with a third scheduled for launch in early 2015. We sought to understand how likely advances in technology would impact future cost of production. Ultimately, we looked at the impact of LCFS credit value both producing additional lower CI fuels in California, and on moving them into California.

For analytical purposes the study evaluated two scenarios: a Reference Case and Low Case.

- The Reference Case assumes the value of credits within the LCFS market remains at roughly $100 per metric ton reduction ($100/MT) over the 2015 to 2025 timeframe. This case is consistent with the estimate currently included in ARB's assessment under its regulatory analysis, provided as part of its 2014 staff report
- The Low Case assumes an LCFS Credit Value below $50/MT. This case is consistent with credit values observed throughout 2014.[3]

3. Key Findings

The key findings of this study are:

Supply Potential

- **The petroleum industry can meet current LCFS compliance requirements through 2020 by taking advantage of the program's performance-based incentive for reducing greenhouse gas (GHG) emissions.** The LCFS credit system provides obligated parties sufficient incentive to reduce their carbon emissions in a timely manner. Promotum's analysis shows that a $100 per MT credit value, (an amount utilized by ARB for their regulatory proposal), provides sufficient incentive to achieve a 10% reduction in fuel carbon-intensity by 2020 through three mechanisms: (1) providing greater volumes of alternative fuels in California, (2) reducing the carbon-intensity of traditional fuels, and (3) reducing emissions at refineries and throughout the petroleum value chain.

- **Diesel substitutes, lower carbon-intensity (CI) ethanol, and reductions in the carbon footprint across the petroleum value chain are primary pathways for meeting a 10% target.** Shifts toward lower-carbon feedstocks, including recycled fats and oils and the

[3] http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm

production of cellulosic ethanol, including ethanol made from agricultural residue will reduce carbon intensity. Using electricity as fuel for cars and trains will also significantly contribute to meeting the LCFS.

- **California can extend the LCFS beyond a 10% carbon-intensity (CI) reduction in 2020 to 15% in 2025.** At $100/MT there is sufficient biofuel supply and incentive to support an additional one percent per year reduction from 2020 through 2025.

- **Even under relatively low LCFS credit values, below the historical 2012 and 2013 credit value, California can meet existing requirements through 2020.** However, sustained low credit values may be insufficient to provide the enough incentive to achieve a15% reduction by 2025.

Benefits

- **The LCFS program will contribute significantly to meeting California's goal of cutting petroleum use in half by 2030.** Alternative fuels use is increasing, up from supplying only 6% of transportation energy to 14% by 2020 and 20% by 2025. For diesel, much of the growth in demand for cleaner, alternative fuels will be met through biodiesel, renewable diesel, as well as natural gas including biomethane. Growth on the gasoline side will occur largely through increases in lower CI ethanol and electricity.

- **The LCFS is estimated to result in over 70 million metric tons of GHG emission reductions over the next five years through 2020**. Increasing the requirements to 15% by 2025 could generate 183 MMT CO_2e of reductions over the next ten years through 2025, equivalent to the emissions of nearly five coal fired plants operating for ten years.[4]

Reduction Opportunities, Value Creation, and Economics

- **The petroleum industry can achieve a significant portion of the standard by reducing the carbon-intensity of gasoline and diesel through improvements at petroleum refineries and crude oil production facilities.** Just as alternative fuel companies can achieve reduced overall carbon-intensity though efficient production and processing, the petroleum sector has significant potential to reduce the CI of gasoline and diesel through energy efficiency improvements, integration of renewable energy inputs such as biomethane, and use of innovative technologies including solar thermal. This study estimates these three measures alone will result in a 1.5% reduction in carbon-

[4] U.S. EPA Greenhouse Gas Equivalencies Calculator. http://www.epa.gov/cleanenergy/energy-resources/calculator.html

intensity across petroleum-based gasoline and diesel by 2020, growing to a 3% reduction in CI by 2025.

- **Under the Reference Case of $100 per metric ton value, energy efficiency projects at refineries would be significantly more attractive to fuel suppliers.** Based on information generated by energy efficiency audits for California refineries' past and currently proposed projects, the LCFS credit value could more than double the operating savings at the facilities.[5] In addition to garnering operational savings associated with energy efficiency investments, refineries would be further incented under the LCFS to reduce the carbon-intensity of fuel products, such improvements also allow fuel producers to forgo purchasing pollution permits under the state's cap-and-trade regulation.

- **Biomethane use at refineries and crude oil facilities to displace fossil natural gas use is a potentially attractive option to reduce carbon-intensity or gasoline and diesel. Such uses are in addition to use of biomethane in natural gas vehicles.** At the end of the Fall 2014, the LCFS incentive had resulted in an increase in the use of biomethane for natural gas vehicles to 40% of the mix, primarily from biogas capture at landfills.[6] However, a much greater volume of natural gas in California is currently consumed by refineries and crude oil facilities. Full substitution of this end-use with biomethane going forward would represent a potential of 12 MMT of reductions of carbon annually, such that even partial substitution could meet a significant portion of the LCFS.

- **Future capital and operating costs for cellulosic ethanol will decrease over time.** While it is possible for California entities to import hundreds of millions of gallons of ultra-low CI cellulosic ethanol at some point in the future, it is difficult to predict exactly when those gallons will be available. However, cellulosic technology providers have successfully reached commercial scale at some plants and the first wave build out is well underway. Future validation of the first wave of cellulosic production facilities will pave the way for financing of the second and third wave of cellulosic plants. It is widely expected, based on industry experience and learning, that the second wave and later facilities will have lower capital costs and improved efficiency.

- **Even remaining conservative on the timing and volumes for cellulosic ethanol in 2020, given the uncertainty of the second wave of production plants, other low-carbon fuels and technologies can provide sufficient credits under the scenarios**

[5] Air Resources Board (2013), *Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources Refinery Sector Public Report*, Issued June 6, 2013. http://www.arb.ca.gov/cc/energyaudits/eeareports/refinery.pdf
[6] Air Resources Board (2014), *Low Carbon Fuel Standard Reporting Tool Quarterly Summaries*, http://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm.

evaluated. Since the LCFS is technology-neutral and performance based standard, and also includes an ability for parties to "bank" or save credits, regulated entities have enormous flexibility to comply. No single technology is required to generate the reductions needed.

- **Over-compliance over the 2015 to 2018 period will allow for compliance in later years through 2020**. The so-called "banking" provisions of the LCFS allow companies to flexibly utilize credits generated in earlier years to comply with future years. As of the end of 2014, parties registered within the LCFS have registered an over-compliance of approximately six million metric tons, with those credits banked for use in future years.[7]

Potential Barriers Moving Forward

- **The LCFS needs underlying regulatory stability to achieve a 10% reduction by 2020 and a 15% level by 2025.** As a result of lawsuits brought against the state by oil and corn ethanol industry groups, the current LCFS reduction mandate has remained at a 1% CI reduction level since 2013, resulting in significant over-compliance with the standard. As the same time, LCFS credit prices have dropped from nearly $80 per ton in December of 2013 to $26 per credit in December of 2014.[8] Under a scenario where LCFS credit prices remain under $50/ton for 2016 and beyond, the sustained low credit price causes an insufficient market signal, with the overall LCFS market generating annual deficits beginning in 2018 and regulated industries fully using all banked credits by 2020. In 2020 and beyond, the LCFS would experience net cumulative deficits. Accordingly, for the LCFS to achieve full compliance, sufficient regulatory certainty must exist to provide a sufficient market signal to spur additional alternative fuel supplies.

- **Reductions in the carbon-intensity on the gasoline side will be slower than on the diesel side unless greater expansion of E15 and E85 occurs.** While credit values at $100/ton will be sufficient for production of low CI ethanol, further capital investments are needed to develop the next wave of cellulosic ethanol facilities. Furthermore, additional infrastructure investments will be needed to expand the use of low CI ethanol beyond E10 (e.g. E15 or E85) and allow the industry to achieve a larger reduction. This includes ethanol producers overcoming limitations due to lack of upgraded ethanol infrastructure including tankage and blender pumps.

[7] Air Resources Board (2014), *Low Carbon Fuel Standard Regulation: Initial Statement of Reasons*. December 31, 2014. http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm
[8] Information based on reporting of the credit values by ARB. http://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm.

- **Long-term regulatory stability and firm commitment with both the Low Carbon Fuel Standard and the federal Renewable Fuels Standard is necessary for financing of new facilities**. Major investors are sensitive to regulatory instability and require long-term time horizons before financing major capital projects. Ensuring forward momentum will, at minimum, require the LCFS credit value to be sufficiently robust to achieve compliance.

4. Methodology

Promotum developed spreadsheets for each fuel technology. Where available we developed supply inputs based on prior studies, and discussions with industry experts and stakeholders. The modeling evaluated a Reference Case and Low Case, with calculations and accounting following ARB's methodology as presented in its regulatory analysis.[9]

For consistency we adopted ARB's baselines for gasoline and diesel CIs; forecasts for gasoline and diesel consumption; the proposed compliance curve from 2015 to 2020; and the banked LCFS credits estimated for 2014. For assumptions on CI, we used the CI look up table from ARB's *Initial Statement of Reasons* (ISOR) Appendix B "average annual CI assumptions." Using the CI values and forecasts, we calculated the overall compliance credits and deficits annually to evaluate compliance each year. Where available we utilized obligated party reporting (2013 and 2014) to ground the model, information that ARB makes publicly available.[10]

The fuel volume tables for the 2015 to 2025 period of study assume that refiners and fuel importers must reduce the lifecycle GHGs produced from gasoline and diesel. This includes crude oil production, transportation, refining, distribution, and combustion. LCFS deficits can be offset by blending lower CI gasoline and diesel substitutes, purchasing credits, utilizing banked credits, or generating credits directly from refinery investment projects or applying innovative technologies at crude oil production facilities. In cases where producers use blending as a compliance strategy, they will largely use ethanol and biodiesel. Additional credits accrue from electric vehicles, both fossil-based and bio-based natural gas (or biomethane), and hydrogen used for fuel cell vehicles. These categories are currently small but growing in their contributions to meeting the standard.

For each case we developed biofuel supply curves for 2015 to 2025. There are many pathways and approved biofuels, but the major substitutes include:

Major Gasoline Substitutes and Technologies	Major Diesel Substitutes and Technologies
Ethanol (Corn, Sorghum/Wheat, Sugar, Cellulosic)	Biodiesel (Soy, Corn Oil, Waste Grease/Used Cooking Oil, Animal Tallow)
Electricity	Renewable Diesel (similar feedstocks)
Petroleum Improvements	Compressed Natural Gas or Liquefied Natural Gas, (Fossil and biomethane)
Renewable Gasoline	Petroleum Improvements

[9] http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm
[10] http://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm

This report also examined potential GHG reductions in the petroleum value chain. Promotum believes there is significant opportunity to reduce the overall CI of traditional gasoline and diesel, principally by utilizing steam derived from biogas or solar thermal energy sources for Enhanced Oil Recovery (EOR) operations at the well head, substituting biomethane for fossil natural gas at refineries, and utilizing off-the-shelf energy efficiency technology and improved operations at refineries. Promotum did not evaluate use of carbon capture and sequestration (CCS) at petroleum facilities.

5. Scenarios

Promotum created two hypothetical cases to evaluate the effects of credit prices on potential achievement of LCFS targets. For each case, we calculated the LCFS deficits (MT CO_2e generated) produced by the petroleum value chain and the combustion of traditional gasoline and diesel. To this obligation, we added back the LCFS credits produced (MT CO_2e reduced) by substituting in biofuels and through reductions in emissions from the petroleum value chain. We then added previously banked credits before comparing the annual and cumulative total against ARB's compliance curve.

For purposes of the study, we assumed steady state average pricing for Low Carbon Fuel Standard credits. Based on these prices, we evaluated how much low carbon fuel could be produced or imported to California for each fuel type.

The basic strategy was to add as much low CI substitute biofuel as possible, taking into account limitations in available supply or potential new capacity, and then backfilling with the best available corn ethanol and biodiesel. We used compliance data filed quarterly with ARB to set starting levels of blended ethanol and biodiesel. The starting blend rate for ethanol was 10.6% (by volume) and about 2% for biodiesel.

To calculate the GHG reductions currently required by the LCFS, we used the currently proposed compliance schedule for 2016 through 2020 in ARB Staff's *Initial Statement of Reasons.* According to the analysis, by 2020 the LCFS requirements would effectively require enough credits to reach a 10% reduction in carbon-intensity for gasoline and diesel.

To calculate the GHG reductions required under an LCFS that extended to 20205, we extended the LCFS requirements to a 15% CI reduction, increasing at an additional rate of 1% per annum. Figure 1 shows the compliance requirements used for both scenarios.

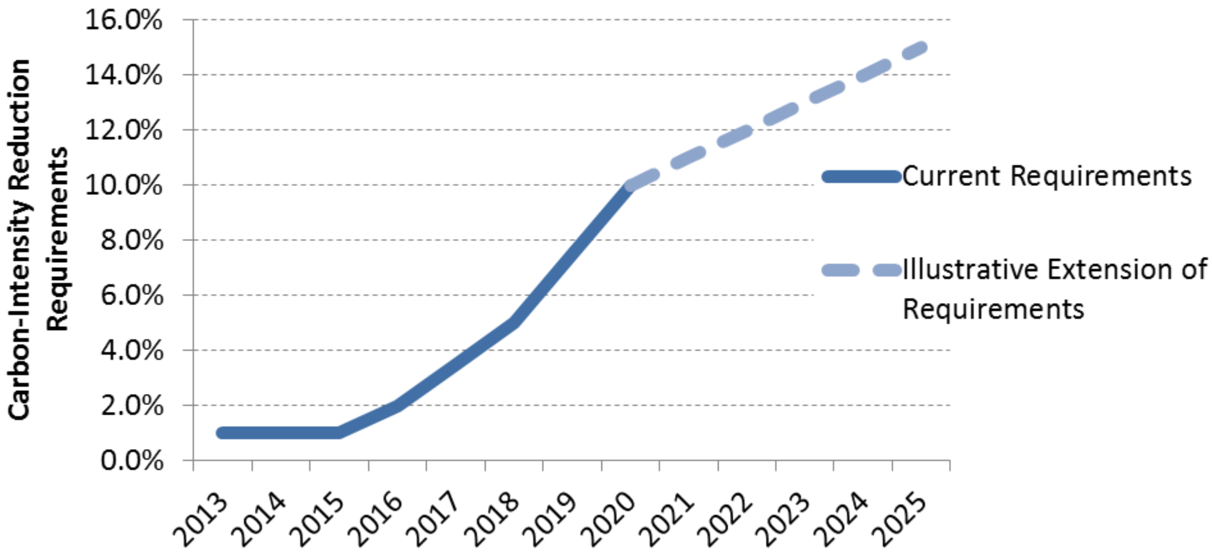


Figure 1: Current proposed requirements achieving 10% by 2020 and extension of requirements to 15% by 2025.

6. Issues and Considerations

Assessing the feasibility of LCFS reductions and differential credit values and the effect of those credit values on biofuel supplies is a considerable and complicated subject. We describe some of the complexities in the following section.

A. Internal LCFS Market Conditions

Since the program's inception, the credit values have experienced market fluctuations. Commodity market experts, such as at Argus, suggest the reasons for volatility encompass a number of factors[11]:

- Regulatory and legal uncertainty in the initial three years,
- Over-compliance occurring due to the low standard—1%—maintained since 2013,
- A short spot market due to producers banking surplus credits in expectation of future shortfalls, and
- A thin LCFS credit market due to a limited numbers of buyers, sellers, and volumes of credits able to be bought and sold.

[11] *Argus White Paper: California Environmental Markets: Factors that Affect LCFS and GHG Trading,* Argusmedia.com

B. Combined Effects of the LCFS and the Renewable Fuel Standard

In addition, understanding the implications of the California GHG reduction measures must account for the federally mandated Renewable Fuel Standard (RFS) managed by the U.S. Environmental Protection Agency (EPA). The RFS requires increasing volumes of biomass-based fuels, with specific volumetric requirements for different categories of fuels meeting GHG reduction thresholds. Fuels that qualify are eligible to generate Renewable Identification Numbers (RINs), a serial number that both allows for tracking of fuel and allows for trading among parties. Like LCFS credits, RINs have a market value for those that own them. In addition, RINs become separable after biofuels are blended - meaning producers can choose to buy and retire RINs instead of blending biofuels themselves.

As a result, if the LCFS credit value plus RIN value exceeds transportation cost to California for a given gallon of biofuel, this should provide enough incentive for producers to make more biofuels and sell them into the California market. Figure 2 demonstrates how RINs and LCFS credit work in tandem to increase supplies of the biofuel.[12]

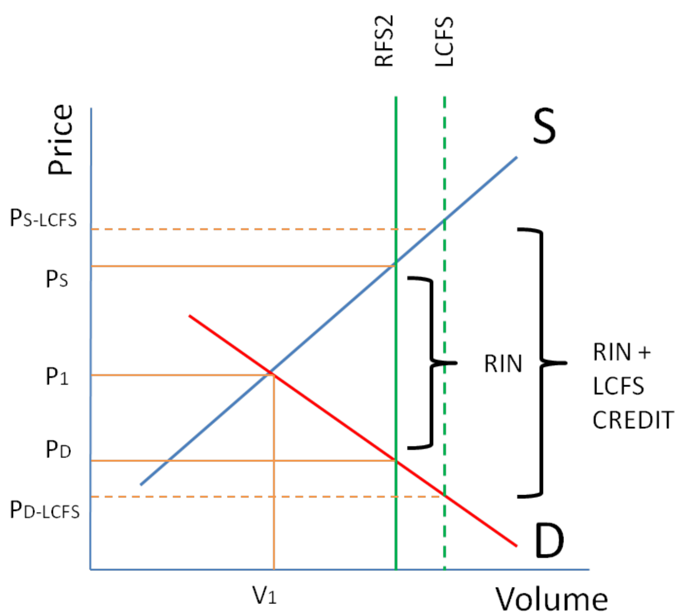


Figure 2: Illustrative figure of the value of RINs and LCFS credits

[12]N. Miller et al (2013), *Measuring and addressing the investment risk in second-generation biofuels* industry, International Council on Clean Transportation, 2013. http://www.theicct.org/addressing-investment-risk-biofuels

S = Supply curve
D = Demand curve
RFS2 = Federal mandate
V_1 = Equilibrium volume w/o RFS or LCFS
P_1 = Equilibrium price w/o RFS or LCFS
P_S = Supply price at RFS mandate
P_D = Demand price at RFS mandate
P_{S-LCFS} = Supply price a LCFS mandate
P_{D-LCFS} = Demand price at LCFS mandate
Redrawn from Miller, Christensen, Park, Baral, Malins, Searle

C. Technology and infrastructure development

Notwithstanding the impact of overlapping LCFS and RIN credit prices, the market signal for Low-CI fuel development gets more complicated when considering the stages of technology development and production capacity for many low CI fuels (i.e. advanced biofuels). Based on present market conditions, it remains evident that much of the nation's prospective supply of low-CI fuels is still maturing. Significant infrastructure issues need to be addressed for many biofuels before the market is truly efficient with high price elasticity.

Under these circumstances technology developers are making investments in technology and capacity based on market expectations, including the future of the RFS and the LCFS programs in terms of regulatory certainty and the RIN and LCFS credit markets. The diagram below based on biofuel supply curves generated by Nathan Parker at UC Davis describes the situation graphically.[13] For our purposes we assumed that LCFS credit values will signal prospective suppliers in anticipation of a future efficient market.

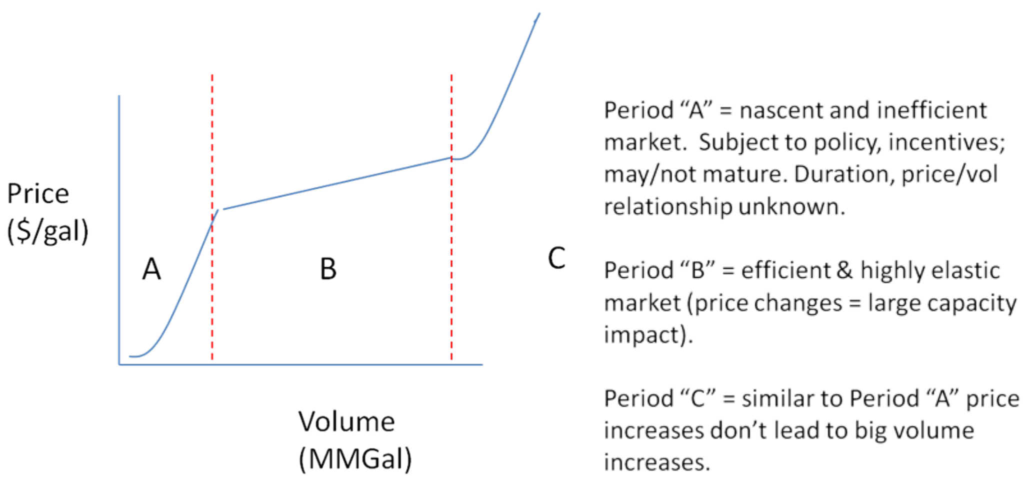


Figure 3: Biofuel supply at varying price points

[13] N. Parker (2011), *Modeling Future Biofuel Supply Chains Using Spatially Explicit Infrastructure Optimization*, Dissertation, Univeristy of California, Davis. http://www.its.ucdavis.edu/research/publications/publication-detail/?pub_id=1471

For each of our cases we estimated the biofuels volumes, which after analysis we believed would be available in California based on the LCFS credit value, constrained by our understanding of the current state of technology, infrastructure and US or global forecast capacity. To understand the value of each biofuel to California we calculated how much each fuel resulted in reduced carbon dioxide emissions and then what additional value was associated with the fuel, on a dollar per gallon gasoline or diesel equivalent energy basis ($/gge or $/dge), depending on which fuel they substituted for.

D. LCFS incentive value for alternative fuels

Figure 4 translates LCFS credit value for gasoline and diesel substitutes to a dollar per gallon gasoline equivalent basis. The range represents a low of $50/MT to a high of $150/MT.

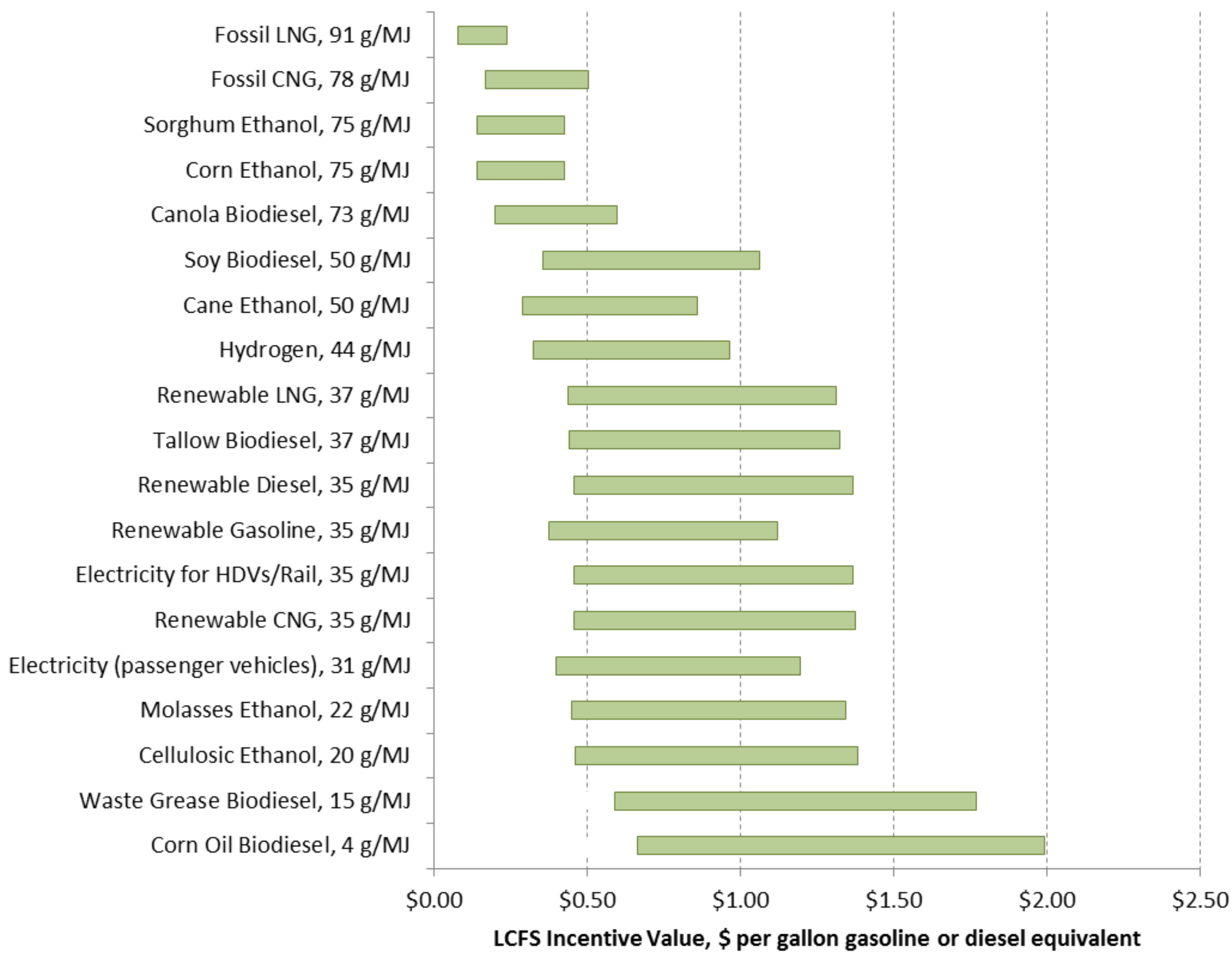


Figure 4: Incentive value provided by the LCFS. Range represents $50 to $150 per MT CO2e reduction.

As shown in Figure 4, the Reference Case of $100 per MT carbon dioxide reduction, translates into $0.92/gallon for cellulosic ethanol. Theoretically, as long as the LCFS credit value together with the associated cellulosic RIN prices exceed transportation costs, we should see producers ramping up capacity and selling into California as well as California producers expanding and increasing production.

An important distinction to make is that RINs and LCFS credits are not production credits, but are instead blender credits, i.e. it is the obligated party, who creates and captures the value upon blending. While producers do not benefit directly from these credits there is some sharing of rents within the value chain. .

In the Low Case ($50/MT reduction), the value for cellulosic ethanol translates to $0.46/gallon in addition to the RIN value. Higher LCFS credit values, of course, are possible and would theoretically provide greater incentive for domestic production or greater importation. However, other factors, such as the state of technology development and availability for financing of new facilities, may be more critical in establishing necessary volumes than the incentive value of RINs and LCFS credits.

E. LCFS incentive value to reduce petroleum sector emissions

The LCFS also provides incentives and returns credit value to petroleum companies that choose to reduce lifecycle oil and gas emissions directly. These companies may generate credits by reducing the CI of crude oil production and refineries through greater use of energy efficiency, innovative technologies, or renewable inputs. Like other fuels, these investments can yield LCFS credits which have higher or lower value based on the overall credit price.

One example of the value of the LCFS for petroleum company investments can be extrapolated from self-reported data on energy efficiency investments by California petroleum refineries to the ARB. [14] As reported, there are over four hundred past and planned energy efficiency and co-generation projects at refineries in California, with a total capital cost of approximately $2,600 million - resulting in annual energy savings of about $200 million for refineries and 2.8 million metric tons of reduced GHGs.

Using past projects identified to ARB as an illustration, if refineries were to invest in future energy efficiency improvements that resulted in an additional 2.8 million metric tons of reductions and achieved the same annual operating savings, the additional LCFS credit value generated could be between $140 to $280 million dollars annually (at a $50 to $100/ton credit price respectively). In addition California refineries would avoid having to purchase permits, or allowances, within the state's cap-and-trade regulation to cover their remaining CO_2 emissions, yielding an additional cost saving of about $35 million annually, assuming current permit prices

[14] http://www.arb.ca.gov/cc/energyaudits/eeareports/refinery.pdf

of just over $12 per ton. These savings, in theory, would increase the overall annual savings from $200 million (energy savings) to $375 to $515 million annually at refineries with the additional LCFS credit value and avoided need to purchase cap and trade pollution permits. While further analysis in this area is warranted to provide finer resolution on a project-specific basis, initial calculations suggest that the LCFS could more than halve the payback period for investments in energy efficiency projects in some cases, making these projects significantly more attractive for petroleum companies.

7. Key Outputs

Promotum's analysis incorporates three major mechanisms that drive reductions in the carbon intensity of transportation fuels. The first is to increase the volume of renewable fuels we currently use (grow the market); the second is to improve the carbon-intensity (CI) of the fuel (improve the fuel in the market); and the third is reduce emissions directly at refineries and crude oil production facilities using energy efficiency, renewable energy, and innovative technologies. To achieve the greatest reductions, California will likely need to spur all three mechanisms to varying degrees.

In our estimate, compliance with the LCFS will result in the alternative fuels market growing to 14% of the transportation energy mix by 2020 and 20% by 2025. Constraints on growth include the E10 blendwall as well as the rate at which biodiesel can expand and be utilized in California. We will need more ethanol and biodiesel to achieve compliance. This means California will need to accelerate E15 and E85 deployment as well as biodiesel blends above B5 levels.

In terms of improving the carbon-intensity of fuels, achieving the LCFS will require migration toward lower-carbon feedstocks; improvements at the biofuel plant and at the agricultural level. The LCFS is already sending a market signal, but regulatory certainty is necessary to ensure sufficient value for technology improvements to continue.

Improvements along the petroleum value chain remains, to date, one of the largest untapped areas of potential for CI reductions across the existing fuel pool. While alternative fuels will increase in market share, the large majority of transportation fuels will remain petroleum-based over the timeframe. Even small changes in CI, when spread across large fuel volumes, will lead to significant reductions.

The analysis of the effects of credit prices demonstrates three findings. First, the LCFS credit value is an important factor in increasing low-carbon fuel supply and reductions in GHG emissions we can achieve. Second, ARB's regulatory analysis, showing credit prices around $100/ton, would be sufficient to allow for a 10% requirement to be met by 2020 while extending the standard to a 15% level by 2025. Third, if credit values remain low – as we saw in the past year, due to regulatory uncertainty– then sufficient incentive will not exist for low-carbon fuel production, and compliance beyond 2020 will be unlikely to occur.

Beyond the recent decreases in oil prices, the most significant barrier to the supply of low CI fuels in California remains uncertainty with the regulatory environment. Oil companies, alternative fuel companies, and other energy investors make large capital commitments and require enough time to achieve acceptable returns.

LCFS Reference Case:

Figure 4 demonstrates annual and cumulative credit balance over time for the Reference Case.

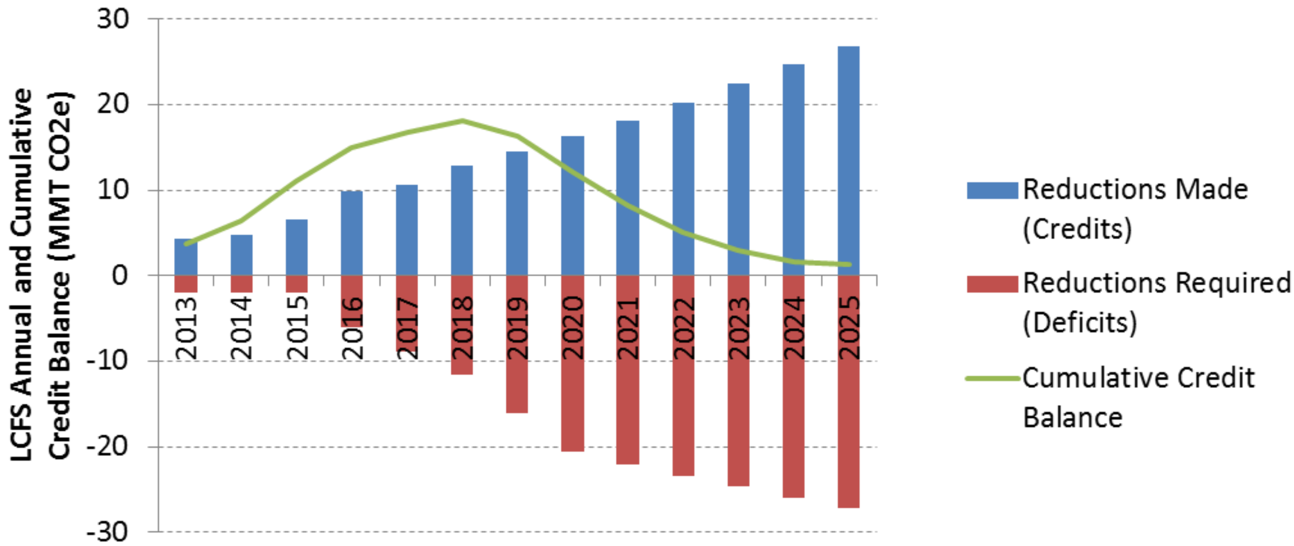


Figure 3: LCFS Annual Credit and Deficits, with the Cumulative Credit Balance (LCFS Reference Case)

The LCFS Reference Case is comprised of the following scenario:

- An LCFS credit value of $100/MT
- Assumes that the current requirement of 10% CI reductions by 2020 is increased to 15% CI reductions by 2025
- Biomass-based diesel, including biodiesel and renewable diesel, become a principal tool of compliance, taking advantage of underutilized production capacity and RIN and LCFS credit values to utilize waste greases, animal tallow, corn oil, and soy oil among other feedstocks.
- Blend rates of biodiesel grow to a 7% by volume mix in diesel (B7) by 2020 taking into account existing infrastructure constraints and restrictions on increased NOx. Blend rates increase to B12 in 2025 as the new NO_x control technologies on trucks are phased in by 2023.
- Direct emission reduction from the petroleum value chain make significant contributions to LCFS compliance
- Electricity used in passenger vehicles, as well as for off-road mobile and truck applications, also make significant contributions.

- Credit value is sufficient to incent the production and import of low CI cellulosic and sugarcane ethanol from existing facilities, but other factors related to investment and financing of new facilities, distribution infrastructure, and other issues limit availability.

The LCFS Low Case:

Figure 5 demonstrates annual and cumulative credit balance over time for the Low Case.

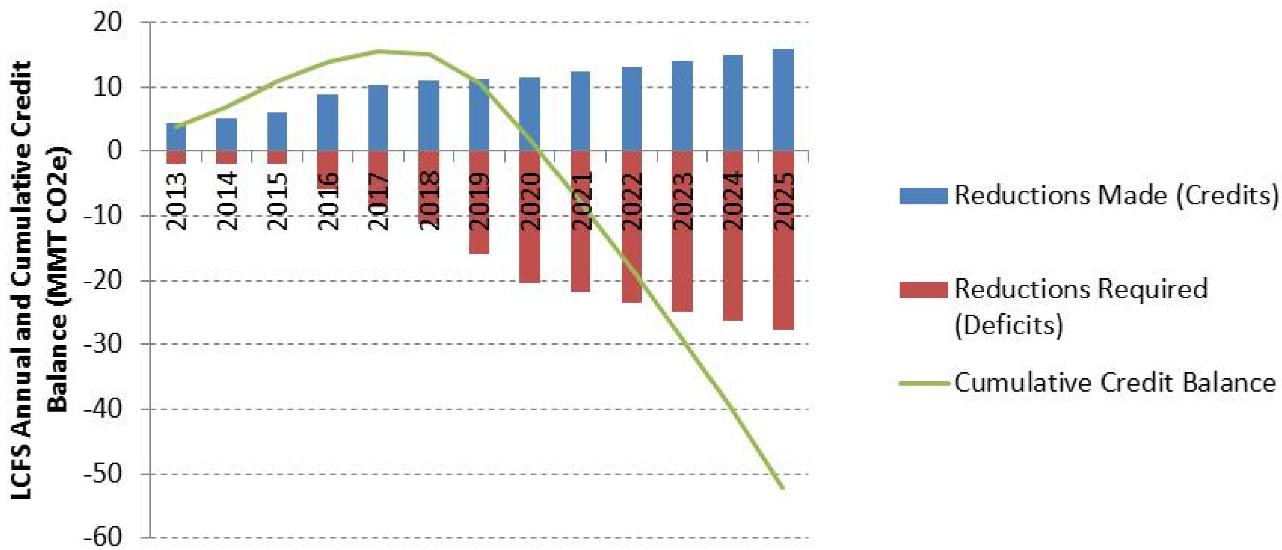


Figure 4: LCFS Annual Credit and Deficits, with the Cumulative Credit Balance (LCFS Low Case)

The LCFS Low Case is comprised of the following scenario:

- LCFS credit value below $50/MT
- Assumes that the current requirement of 10% CI reductions by 2020 is increased to 15% CI reductions by 2025
- Inexpensive and local waste based fuels come to the fore, which is positive, but under this scenario the incentive amount is not sufficient to persuade waste based biodiesel and renewable diesel producers to sell much more than the 2013/2014 volumes currently utilized in the state.
- California's LCFS market may achieve the Low Case scenario in the near term, but soy biodiesel (and other existing seed or vegetable oils) are not sufficiently incented to drive compliance.
- Absent large amounts of credits generated from diesel substitutes as in the Reference Case, greater ethanol demand occurs. In this scenario, a blend rate of 19% ethanol,

including 2.5 billion gallons of mid-CI ethanol (e.g. corn, sorghum, wheat-based) would be required to achieve compliance in 2020.

- While there is enough ethanol production capacity, under a Low Case, significant investments in ethanol infrastructure to support E15 or E85 distribution are needed, including investments in storage tankage and retail blend pumps.
- In the Low Case, the LCFS incentives would be insufficient to allow for compliance beyond 2020.

Tables and additional descriptions of the compliance pathways are provided in the Appendices.

Appendix A: Description of compliance pathways

Reference Case ($100 per ton credit value)

Ethanol - Prior to the LCFS, requirements for reformulated gasoline to reduce smog – together with the federal RFS volume requirement – have effectively led to the growth in the use of ethanol to E10 levels. Corn-based ethanol has been the primary biofuel utilized in California. The LCFS has driven improvements in the carbon-intensity of the ethanol mix over the past three years. ARB has approved many ethanol pathways and the CIs of ethanol produced as well as imported into California continue to drop significantly. In our Reference Case we see a tapering of corn ethanol consumption starting in 2015, dropping steadily to 650 MMG in 2025 as other lower CI ethanol feedstocks and fuels become available.

Traditionally the US receives 50% to 60% of Brazil's cane ethanol exports and despite current challenges in the Brazilian marketplace, we expect imports of this low CI fuel to continue. These challenges, including sugar versus corn pricing and Brazil's domestic policies, will likely temper California's imports. Ultimately, we see consumption growing to 300 million gallons per year (MMGY) by 2020.

While it is easy to envision the importation of hundreds of million gallons of ultra-low CI cellulosic ethanol into California, it is difficult to predict exactly when those quantities will be available. Cellulosic ethanol (c-etoh) volumes remain highly uncertain.

Cellulosic technology providers have successfully reached commercial scale and the first wave build out is well underway. Based on separate estimates from Bloomberg New Energy Finance (2014) and Environmental Entrepreneurs (2015), about 220 million gallons per year of capacity of cellulosic ethanol is already built or forecasted to be completed by end of 2015, with about 100 million gallons of this capacity located in the U.S.[15] We expect availability of c-etoh to emerge in 2015 with the launch of the Abengoa, POET and DuPont facilities in the U.S. However, capacity utilization will likely be modest for the early years. Based on a healthy LCFS credit value and discussions with c-etoh technology providers, we expect a significant fraction of the available pool to make its way to California.

Coming validation will pave the way for financing of the second and third wave of cellulosic plants. At this time the facilities are more expensive and smaller than first generation ethanol plants. However, both capital and operating expenditures will decrease significantly over time as technology and operations improve. Cost of production estimates for cellulosic ethanol abound. Promotum reviewed publically available studies and analysis by academics as well as government agencies that incorporate theoretical cost models. In addition, Promotum spoke directly to several technology providers . We incorporated available data into our supply curves

[15] Bloomberg New Energy Finance data (http://about.bnef.com/). Environmental Entrepreneurs (2015), *Advanced Biofuel Market Report 2014*.

for the Reference Case and Low Case and this informed our thinking. We believe the estimates are conservative but reasonable.

US c-etoh facilities will largely be green field construction, scaling in modular fashion from 25 million gallons per year capacity followed by 50 and 75 MMGY plant capacities. Given issues around herbaceous feedstock transportation, achieving 100 MMGY capacity in any one plant is doubtful. Based on conversations with cellulosic ethanol technology providers we believe the price of cellulosic ethanol will fall on a fully loaded basis from $2.75/gallon today to about $1.70/gallon in 2030, including the cost of capital.

Electricity and Hydrogen –While internal combustion engine vehicles remain the current predominant technology on the road, automakers are rapidly investing in fuel efficient technologies, including various combinations of electric-drive vehicles, from plug-in hybrids to full battery electrics, even offering initial hydrogen fuel cell vehicles. As electric-drive vehicle sales continue to displace gasoline powered vehicles, demand for low CI electricity will increase and credits will be generated. We see electricity consumption almost quadrupling from 0.44GWhr in 2015 to 1.6GWhr in 2020 and nearly 4.4GWhr in 2025. For hydrogen, we believe the opportunities for fuel cell vehicles are good, but we have conservatively kept consumption at modest levels in the study, given potential hydrogen infrastructure constraints. We also note that improvements in the CI of electricity and hydrogen are expected, particularly if California meets targets to reach 50% renewable by 2030 in addition to the existing 33% Renewable Portfolio Standard requirements by 2020. To be conservative, however, we kept CI constant, as assumed in ARB Staff's *Initial Statement of Reasons*.

Petroleum Supply Chain Improvements – This study estimates GHG emission reductions in the petroleum value chain, including at the well head and refinery level will make up a significant percentage of overall compliance in the Reference Case.

Three technologies were included in this assessment using a study by TetraTech/NRDC (2014) as a starting point. These include use of solar thermal for steam generation in enhanced oil recovery, broader use of energy efficiency at refineries, and use of biomethane by the petroleum industry. These estimates may be conservative given the wider array of technologies available as well as industry experience with some of these technologies already.

For solar thermal, it is assumed that approximately 10% of the fossil natural gas used for steam injection projects is displaced in California by 2025. These estimates do not include an assessment of the potential for crude oil imported into the state, which currently represent 63% of the mix used in California, to utilize this technology. We estimate that by 2025, just over 0.7 MMT of reductions annually can be generated.

For refinery energy efficiency (EE) investments, it is assumed that at $100/ton, the incentive is sufficient to more than double the payback of EE, such that a reduction of 1.5% per year improvement in GHG emissions at refineries across the industry. We estimate that reductions from EE investments grow linearly from 2017 to 2025, reaching 4.3 MMT in annual reductions by 2025.

In terms of renewable energy inputs, we consider the use of biomethane to replace fossil natural gas at crude oil facilities, a fuel consumed at refineries, and a feedstock for hydrogen production utilized by refineries. We assume that 15% of the natural gas used by California crude oil and refining facilities could be displaced via biomethane purchases by 2020, growing to nearly 40% by 2025. The reductions would grow to 1.1 MMT annually by 2020 and 2.8 MMT annually by 2025. Significant volumes of biogas, which can be cleaned and processed into biomethane, are currently emitted, flared, or captured from landfills, dairy digesters, and waste-treatment facilities throughout the U.S.[16]

The study projects CI reductions, applied as credits for crude oil producers or refineries respectively, would be approximately 1.5% by 2020 and 3% by 2025 over the entire lifecycle of petroleum gasoline and diesel. This CI reduction level corresponds to 16% and 32% of the standard in 2020 and 2025 respectively being met in those years from direct petroleum supply measures. We believe the current environment of relatively low oil prices also lends itself to implementation of downstream projects, including refinery energy efficiency and GHG reduction projects, as other capital investments in the upstream and midstream are reduced in the U.S.

When combined, we see opportunities for 4.2MM MT of GHG reduction in 2020 reaching 8.8MM MT in 2025 from these three categories of technologies.

Renewable Diesel – We see opportunities for renewable diesel (R-Diesel) to play an important role in California's biofuel portfolio, based on existing domestic and international plant capacity, reaching 400 MMGY in 2020. This represents almost 50% of the ~850 million gallon global capacity, but is consistent with the estimates by the Air Resources Board staff in their regulatory analysis.[17] To some extent we have concerns with regard to the sustained availability of international supplies (~650 million gallons per year) and the high cost of new capacity. We do believe domestic capacity for hydrotreating waste oils will be constrained. We also believe there will be considerable competition for this capacity with military aviation fuel. Continued uncertainty around the US production tax credit will also inhibit financing capacity expansion.

Biodiesel – Biodiesel is a primary driver of compliance in the Reference Case. In California and the United States there are hundreds of millions of gallons of underutilized biodiesel production capacity. The technology is simple and mature, utilizes low carbon feedstocks and produces a low CI diesel substitute. We see an important opportunity to grow the blend rate beyond the currently anemic 2% levels by volume. Waste grease (used cooking oil),increasing volumes of corn oil biodiesel and soy biodiesel will contribute. We see total biodiesel consumption reaching 265 MMGY in 2020 and more than 500 MMGY in 2025.

[16] NREL (2013), *Biogas Potential in the United States*, NREL/FS-6A20-60178, October 2013, National Renewable Energy Laboratory, Energy Analysis, Golden, CO. Also see EPA Landfill Gas candidate project lists: http://www.epa.gov/lmop/projects-candidates/index.html.

[17] http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm

Availability of corn oil depends primarily on the penetration of necessary unit operations within corn wet mills. Starting from approximately 59% in 2015 we see penetration increasing to ~90% by 2025. We forecast 68 million gallons of inedible corn oil biodiesel reaching California in 2020 out of an estimated US pool of 475 million gallons and greater than 100 million gallons in 2025.

Biodiesel from used cooking oil (waste grease) will continue to make an important contribution to the BD pool. We estimate 51 million gallons will be available to California in 2020 and 77 million gallons in 2025. While the very low CI makes it particularly attractive, community collection by its nature will remain a constraint.

Swing biodiesel feedstock will come in the form of soy oil. While often spurned because of its nominal association with food, soy oil is separated, from soy protein prior to utilization. A healthy LCFS credit value overcomes traditional soy pricing problems, which have mothballed many biodiesel facilities and left many others operating below capacity. With an improving CI profile we predict 51 million gallons of soy biodiesel in the California market in 2020 and 77 million gallons in 2025. We do not see a big role for canola based biodiesel in the US or California.

Natural Gas – We expect natural gas usage in fleets to increase and be utilized to comply with the LCFS. We also assume that an increasing share will come from biomethane captured from landfills and other sources, including anaerobic digestion and waste-treatment facilities. We find approximately 170 million diesel gallon equivalents of liquefied natural gas will be utilized by 2025 and 306 million diesel gallon equivalents of compressed natural gas being utilized. We assume approximately 80% of these volumes will be derived from biomethane sources by 2025, given the increased value for biomethane producers and current levels in California approaching 40%.

Low Case (less than $50 per ton credit value)

Ethanol – In a Low Case scenario, inexpensive corn, wheat, or sorghum based ethanol becomes the primary tool of compliance. Instead of the tapering we saw in the Reference Case, a dramatic increase in these feedstocks occurs, reaching blending level of 2.5 BGY in 2020, together with an additional 140 MMGY of low-CI ethanol. This represents an effective blend rate of 19%-21% in the years 2020-2025.

Electricity and Hydrogen – We find that similar levels of electricity and hydrogen consumption for the transportation sector will occur between the LCFS Reference and Low Case. However, we have not analyzed the use of electricity credits by utilities and the effects on the market, given the lack of current data.

Petroleum Supply Chain Improvements – Lower credit values decrease the incentive for refinery and well head improvements. Significant reductions still occur, reaching 2.1MMT in 2020 and 5 MMT in 2025, but the pace of implementation is slower.

Renewable Diesel – R-Diesel remains relatively expensive from 2015 to 2025 and lower LCFS credit values mean blending remains stuck at circa 2015 levels, approximately 100MMGY.

Natural Gas – While we find that NGV usage and natural gas demand for transportation to remain at similar levels to the Reference Case, we see a significant drop in biomethane use to only double from current levels, growing to only 30 MMGY (diesel equivalent).

Appendix B: Fuel Volumes and Carbon-Intensity Tables

Reference Case ($100 per ton credit value)

Reference Case														
Gasoline Replacements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Corn Ethanol	mm gal	1,220	1,275	1,255	1,200	1,150	1,000	975	850	800	775	725	675	650
Cane Ethanol	mm gal	150	100	100	100	100	200	200	300	300	300	300	300	300
Diversified Ethanol (sorghu	mm gal	150	170	170	190	215	235	235	235	235	235	235	235	235
Cellulosic Ethanol	mm gal	0	0	5	25	35	45	55	65	75	85	95	105	115
Renewable Gasoline	mm gal	0	0	0	0	0	5	15	25	50	75	100	125	150
Hydrogen	mm gal GGE	0	0	2	5	8	11	15	21	25	30	36	44	52
Electricity for LDVs	1000 MWH	200	400	440	596	759	982	1,276	1,629	2,064	2,563	3,127	3,757	4,374
Total Ethanol (MM gal)		1,520	1,545	1,530	1,515	1,500	1,480	1,465	1,450	1,410	1,395	1,355	1,315	1,300
CARBOB (energy adjusted)		12,848	12,950	12,814	12,666	12,519	12,365	12,197	12,021	11,776	11,510	11,256	10,997	10,723
Gasoline As CARFG + E85		14,340	14,495	14,344	14,186	14,034	13,870	13,712	13,546	13,286	13,030	12,761	12,312	12,023
Ethanol (vol %)		10.60%	10.66%	10.67%	10.68%	10.69%	10.67%	10.68%	10.70%	10.61%	10.71%	10.62%	10.68%	10.81%
Diesel Replacements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Soy Biodiesel	mm gal	5	5	5	15	30	85	105	135	175	215	255	285	300
Waste Grease Biodiesel (U	mm gal	33	35	37	39	41	43	45	47	49	51	53	55	57
Corn Oil Biodiesel	mm gal	11	20	34	48	61	68	68	68	68	82	102	122	142
Tallow Biodiesel	mm gal	4	5	10	10	10	10	10	10	10	10	10	10	10
Canola Biodiesel	mm gal	6	5	5	5	5	5	5	5	5	5	5	5	5
Renewable Diesel	mm gal	118	107	180	260	290	320	360	400	400	400	400	400	400
LNG	mm gal DGE	28	26	30	30	30	30	30	30	30	30	30	30	30
CNG	mm gal DGE	61	70	70	70	70	70	70	70	70	70	70	70	70
Renewable LNG	mm gal DGE	5	5	30	39	51	63	76	90	100	110	120	130	140
Renewable CNG	mm gal DGE	6	11	45	59	77	94	114	136	156	176	196	216	236
Electricity for HDVs/Rail	1000 MWH	-	-	900	900	900	900	900	900	900	900	900	900	900
Total HD NG (DGEs)		100	112	175	198	228	257	290	326	356	386	416	446	476
Total Biodiesel (MM gal.)		59	70	91	117	147	211	233	265	307	363	425	477	514
Diesel (non-adjusted)		3,677	3,732	3,788	3,845	3,903	3,961	4,021	4,081	4,142	4,204	4,267	4,331	4,396
Diesel (energy adjusted)		3,404	3,447	3,324	3,253	3,222	3,162	3,128	3,082	3,074	3,054	3,029	3,014	3,014
Total biodiesel (vol %)		1.65%	1.93%	2.53%	3.21%	4.02%	5.03%	5.94%	6.94%	7.99%	9.01%	10.02%	11.09%	11.94%
Renewable Diesel (vol %)		3.29%	2.95%	5.01%	7.16%	7.92%	8.66%	9.67%	10.67%	10.58%	10.48%	10.38%	10.28%	10.18%

Petroleum Value Chain Reductions

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
MMT Reductions	-	-	-	0.4	0.4	1.3	2.3	3.2	4.2	5.3	6.5	7.6	8.8
CI reduction (g/MJ)	-	-	-	0.2	0.2	0.6	1.1	1.5	2.0	2.5	3.1	3.7	4.3

Low Case (Less than $50 per ton credit value)

Gasoline Replacements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Corn Ethanol	mm gal	1,220	1,500	1,800	1,900	2,200	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
Cane Ethanol	mm gal	150	100	100	100	100	100	100	100	100	100	100	100	100
Diversified Ethanol (sorghu	mm gal	150	170	170	170	170	170	170	170	170	170	170	170	170
Cellulosic Ethanol	mm gal	0	0	5	25	35	35	35	35	35	35	35	35	35
Renewable Gasoline	mm gal	0	0	0	0	0	5	15	25	25	25	25	25	25
Hydrogen	mm gal GGE	0	0	2	5	8	11	15	21	25	30	36	44	52
Electricity for LDVs	1000 MWH	200	400	440	596	759	982	1,276	1,629	2,064	2,563	3,127	3,757	4,374
Total Ethanol (MM gal)		1,520	1,770	2,075	2,195	2,505	2,605	2,605	2,605	2,605	2,605	2,605	2,605	2,605
CARBOB (energy adjusted)		12,848	12,798	12,447	12,208	11,842	11,608	11,429	11,243	10,996	10,745	10,489	10,228	9,969
Gasoline As CARFG + E85		14,340	14,568	14,522	14,408	14,362	14,238	14,059	13,873	13,626	13,375	13,119	12,833	12,574
Ethanol (vol %)		10.60%	12.15%	14.29%	15.23%	17.44%	18.30%	18.53%	18.78%	19.12%	19.48%	19.86%	20.30%	20.72%
Diesel Replacements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Soy Biodiesel	mm gal	5	5	5	5	5	5	5	5	5	5	5	5	5
Waste Grease Biodiesel (U	mm gal	33	35	37	39	41	43	45	45	45	45	45	45	45
Corn Oil Biodiesel	mm gal	11	20	34	48	61	61	61	61	61	61	61	61	61
Tallow Biodiesel	mm gal	4	5	10	10	10	10	10	10	10	10	10	10	10
Canola Biodiesel	mm gal	6	5	5	5	5	5	5	5	5	5	5	5	5
Renewable Diesel	mm gal	118	107	100	100	100	100	100	100	100	100	100	100	100
LNG	mm gal DGE	28	26	30	30	30	30	30	30	30	30	30	30	30
CNG	mm gal DGE	61	70	70	70	70	70	70	70	70	70	70	70	70
Renewable LNG	mm gal DGE	5	5	10	10	10	10	10	10	10	10	10	10	10
Renewable CNG	mm gal DGE	6	11	20	20	20	20	20	20	20	20	20	20	20
Electricity for HDVs/Rail	1000 MWH	-	-	900	900	900	900	900	900	900	900	900	900	900
Total HD NG (DGEs)		100	112	130	130	130	130	130	130	130	130	130	130	130
Total Biodiesel (MM gal.)		59	70	91	107	122	124	126	126	126	126	126	126	126
Diesel (non-adjusted)		3,677	3,732	3,788	3,845	3,903	3,961	4,021	4,081	4,142	4,204	4,267	4,331	4,396
Diesel (energy adjusted)		3,404	3,447	3,449	3,491	3,534	3,591	3,648	3,708	3,770	3,832	3,895	3,959	4,024
Total biodiesel (vol %)		1.65%	1.93%	2.50%	2.88%	3.25%	2.77%	3.13%	3.08%	3.03%	2.99%	2.94%	2.90%	2.85%
Renewable Diesel (vol %)		3.29%	2.95%	2.75%	2.70%	2.66%	2.62%	2.58%	2.54%	2.50%	2.46%	2.43%	2.39%	2.35%

Petroleum Value Chain Reductions

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
MMT	-	-	-	0.2	0.7	1.1	1.6	2.1	2.7	3.2	3.8	4.4	5.0
CI reduction (g/MJ)	-	-	-	0.1	0.3	0.5	0.8	1.0	1.3	1.5	1.8	2.1	2.4

Annual average carbon-intensity (g $CO2_e$/MJ)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Corn Ethanol	82.24	82.24	82.24	70.00	69.30	68.61	67.92	67.24	66.57	65.90	65.24	64.59	63.95
Cane Ethanol	72.5	72.5	72.5	40.0	39.5	39.0	38.5	38.0	37.5	37	36.5	36	35.5
Sorghum/Corn Ethanol	79.1	79.1	79.1	70.0	69.3	68.6	67.9	67.2	66.57	65.9	65.24	64.59	63.95
Misc Corn Ethanol	91.5	91.5	91.5	70.0	69.3	68.6	67.9	67.2	66.57	65.9	65.24	64.59	63.95
Sorghum/Corn/Wheat Ethanol	72.8	72.8	72.8	65.0	64.4	63.7	63.1	62.4	61.81	61.2	60.58	59.98	59.38
Cell. Ethanol[1]	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Molasses Ethanol	22.1	22.1	22.1	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
Renewable Gasoline[2]	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Hydrogen	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9
Electricity for LDVs	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Soy Biodiesel	83.3	83.3	50.0	49.5	49.0	48.5	48.0	47.5	47	46.5	46	45.5	45
Waste Grease Biodiesel	15.0	15.0	14.0	12.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Corn Oil Biodiesel	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Tallow Biodiesel	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2
Canola Biodiesel	62.6	62.6	62.6	73.2	73.2	73.2	73.2	73.2	73.2	73.2	73.2	73.2	73.2
Renewable Diesel	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
LNG	80.9	80.9	80.9	90.9	90.0	89.1	88.2	87.4	86.5	85.6	84.7	83.8	82.9
CNG	70	70	70	70	70	70	70	70	70	70	70	70	70
Renewable LNG	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Renewable CNG	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Electricity for HDVs/Rail	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9
CARBOB	99.2	99.2	99.2	100.6	100.6	100.6	100.6	100.6	100.6	100.6	100.6	100.6	100.6
CARB Diesel	98.0	98.0	98.0	102.8	102.8	102.8	102.8	102.8	102.8	102.8	102.8	102.8	102.8

8. About Promotum

Promotum is a technology based management consulting working at the convergence of fuels, chemicals and biologics. We are a team of standout engineers, scientists and accomplished MBAs, who are as passionate about science and technology as we are about business. By focusing on the convergence of energy, materials, and biology we deal daily with complex issues and disciplines. Promotum is growth focused helping clients enter new markets, evaluate or create them. Our expertise allows us to maximize results for our clients around the world. Promotum is headquartered in Cambridge, Massachusetts.

Functional Practices

- Business Development
- Business Strategy & Planning
- Corporate Development
- Competitive Intelligence
- Due Diligence
- Investment/Financial Analysis
- Licensing
- Market Analysis
- New Venture Creation
- Policy Analysis
- Technology Commercialization

Industrial Practices

- Bio/Pharma
- Biomass to Energy
- Energy Efficiency
- Environmental Sciences
- GHG Life Cycle Analysis
- Green Chemicals
- Green Polymers
- Next Generation Fuels
- Next Generation Vehicles

Union of Concerned Scientists

FACT SHEET

Driving Progress, Fueling Savings

How California Is Tackling Global Warming, Cutting Oil Use, and Saving Drivers Money

CALIFORNIA DRIVES PROGRESS

California has implemented a suite of practical strategies to reduce carbon emissions from cars and trucks, benefiting state residents in many ways. In addition to helping prevent the worst impacts of global warming and spurring investment and innovation in clean transportation technologies, the state's clean vehicle and fuel policies are reducing oil use, saving consumers money, and improving public health—particularly in communities most affected by air pollution.

Oil companies, however, are trying to stop this progress, using misinformation and scare tactics to weaken public support for state climate policies. But California's climate policies are working—and setting an example for other states and the federal government to follow—and it's critical that the state keep moving toward a clean transportation future.

The California Global Warming Solutions Act of 2006, also known as Assembly Bill (AB) 32, is a ground-breaking law that calls for reducing the state's global warming emissions to 1990 levels by 2020, laying the foundation for a low-carbon future. Since the bill's passage, the California Air Resources Board (CARB) has implemented a suite of practical policies to meet this target—including reducing emissions from cars and trucks, which represent the single largest source of the state's carbon pollution. California has enjoyed many benefits related to these policies, from reduced consumer spending on gasoline and improved public health in communities affected by air pollution, to increased private-sector investment and innovation in the next generation of climate-friendly technologies.

Perhaps not surprisingly, oil companies are standing in the way of progress. Despite the fact that transportation accounts for nearly 40 percent of California's emissions (see Figure 1), the oil industry wants to be exempt from California's climate policies (CARB 2014a). They are using scare tactics, such as skyrocketing gas prices, to avoid accountability for their carbon emissions and delay the transition to cleaner fuels. Californians should not be fooled by the oil industry's misleading claims. The state's climate policies are working—bringing lower transportation costs, cleaner air, and more transit choices to communities.

© iStock/mccaig

A major focus of California's climate policies is reducing emissions from transportation, the largest source of emissions in California.

The Benefits of California's Clean Transportation Solutions

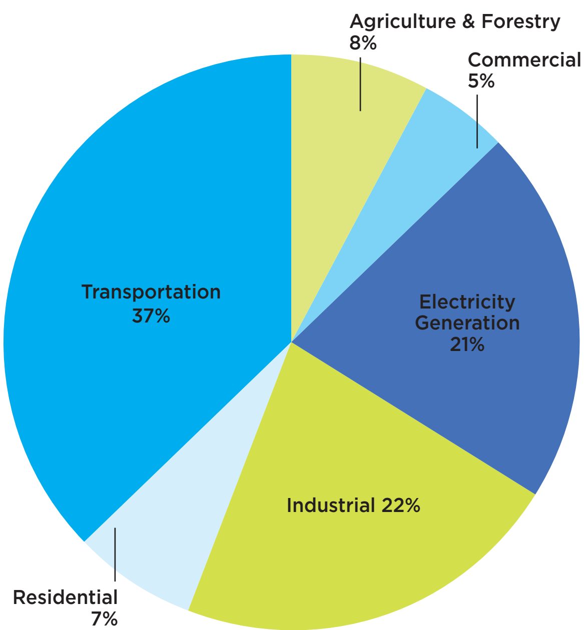
California has pursued successful strategies to reduce carbon emissions from cars and trucks. These include a flexible market-based cap on carbon emissions (see Box 1), stringent emissions standards for new vehicles, a requirement that automakers produce electric cars and other advanced-technology vehicles, a policy to scale up the use of clean fuels, and improved land-use and transportation planning to improve walkability and access to transit in local communities. In addition to reducing the state's carbon emissions, these policies are delivering important benefits to Californians.

REDUCING OIL USE

The price of gasoline has historically had large fluctuations, but has tended to go up over the long run. In California, the average per-gallon price of gasoline climbed from $2.47 in 2009 to $3.89 in 2013 (see Figure 2), and the average California driver spent $2,475 on gasoline in 2013 (CEC 2014a). Oil companies like to point to taxes and regulations as a reason for high fuel prices, but the majority of the cost of gasoline actually comes from the cost of the oil itself: for every $50 spent to fill up a vehicle's gas tank within the past five years, $30 went to pay for the crude oil that was turned into gasoline while $9 went to refining, distribution, and marketing (UCS 2013a).

The real solution to high and volatile gasoline prices is simply to use less oil. Fortunately, California's low-carbon transportation policies are making progress toward this goal. Oil consumption fell 12 percent from 2006 to 2012, helping Californians save money on fuel and reduce emissions (EIA 2014). Going forward, gasoline consumption is forecast to decline—by about 2 billion gallons annually in 2022 compared with 2012—thanks primarily to the state's requirements for less-polluting, more-efficient vehicles (CEC 2014b). In

FIGURE 1. California Global Warming Emissions by Sector, 2012



Transportation is the largest source of heat-trapping global warming emissions in California, accounting for nearly 40 percent of the state's total annual global warming emissions.

Note: Emissions are measured in terms of carbon dioxide equivalent. Electricity generation includes in-state and imported generation.

SOURCE: CARB 2014A.

BOX 1.

Transportation Fuels and California's Cap-and-Trade Program

A cornerstone policy in California's effort to tackle global warming is a market-based program to limit carbon emissions, known as cap-and-trade. The program creates economic incentives for major carbon polluters—oil refineries, electric utilities, and other large industries—to cut their emissions. Cap-and-trade encourages companies to find the least-expensive ways to reduce their emissions, either by upgrading their facilities and equipment or purchasing carbon permits.

The central framework is a declining cap on global warming emissions that requires major carbon polluters to acquire a permit, known as an "allowance," for every ton of carbon pollution they emit. The total level of carbon pollution collectively emitted by the covered entities cannot exceed the number of allowances available under the cap, which declines 2 to 3 percent each year through 2020.

By including gasoline and diesel fuel in the program, California is holding oil companies accountable for their global warming pollution. Any exemption or delay in accounting for fuel emissions under the cap-and-trade program would undermine California's ability to meet its carbon-reduction goals.

addition, the state's Low Carbon Fuel Standard (LCFS) is helping drive production of non-petroleum-based vehicle fuels such as electricity and advanced biofuels. In 2012, alternative fuels accounted for more than 7 percent of fuel used by cars and trucks, and the share of transportation powered by cleaner alternatives is rising as electricity, advanced biofuels, and other clean fuels scale up (CEC 2014b).

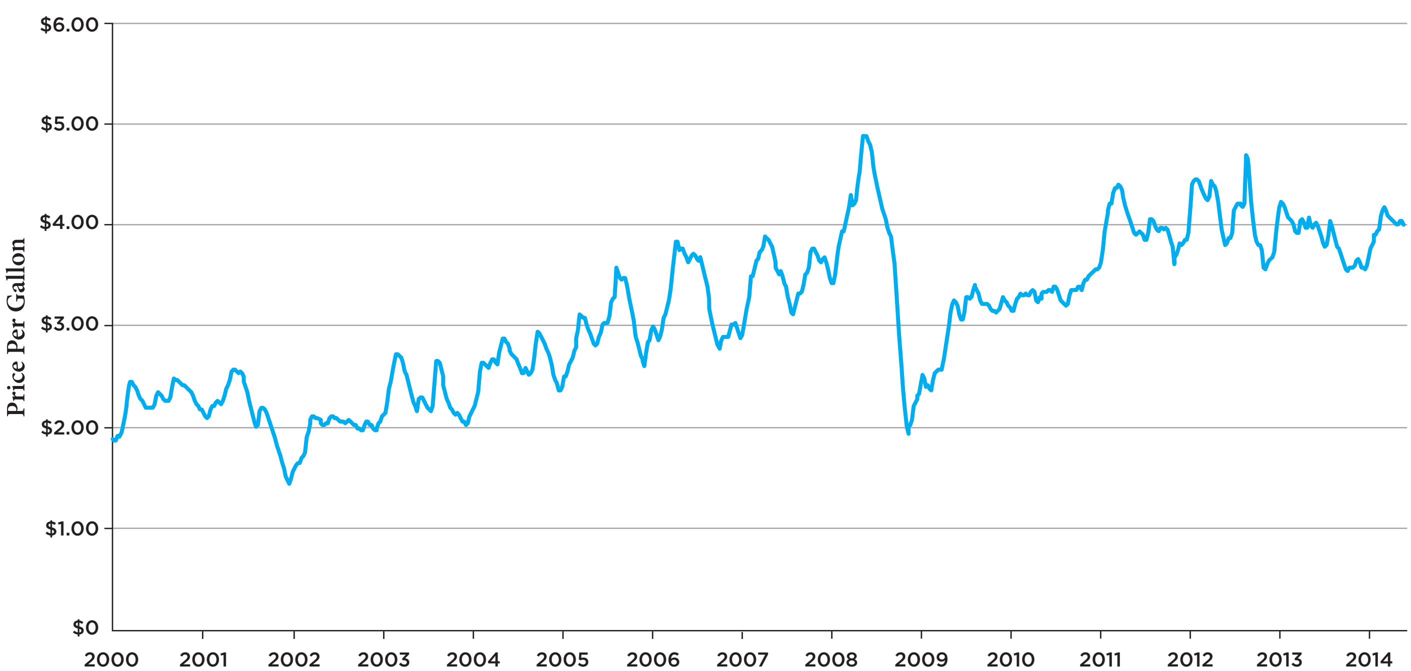
REDUCING PAIN AT THE PUMP

California's cleaner fuels and vehicle policies are saving consumers money. A California driver who purchases an average new model year 2015 car, for example, can expect to save an estimated $3.90 each week over the life of the vehicle, compared with a driver who purchased a new vehicle in 2008 (see Figure 3).[1] The comparative savings grow to $5.20 per week for the owner of a new vehicle in 2020 and $9.00 per week for someone buying a new vehicle in 2025. California's low-carbon transportation policies will also help those looking to purchase a used vehicle; according to UCS analysis, a 10-year-old used car in 2025, for example, will save its driver $7.50 a week, or nearly $400 a year, over the remaining lifetime of the vehicle compared with a 10-year-old used car purchased in 2015.[2]

IMPROVING PUBLIC HEALTH AND SUPPORTING DISADVANTAGED COMMUNITIES

California's transportation system is the primary source of smog-forming nitrogen oxide and diesel particulate matter emissions in the state (CARB 2013)—emissions that do not affect all Californians equally. Low-income communities are more likely to live in close proximity to transportation corridors, and therefore face greater exposure to diesel particulate matter and other toxic air pollutants (Hricko et al. 2014). Fortunately, the state's carbon-fighting strategies are improving air quality, both in these vulnerable communities and statewide. A recent study found that California's LCFS and cap-and-trade programs will save $8.3 billion in health costs between now and 2025 by reducing

FIGURE 2. California Gasoline Prices, 2000–2014



Gasoline prices have increased significantly since 2000, and are vulnerable to extreme volatility.

Note: Year markers represent per-gallon prices on the first Monday in January of that year. Historic gas prices have been adjusted for inflation.

SOURCE: BLS 2014, CEC 2014A.

asthma attacks, hospitalizations, and other health impacts associated with poor air quality (EDF/ALAC/TT 2014).

In addition, at least one-quarter of the proceeds from the sale of carbon permits in the cap-and-trade program are being invested to benefit communities that are disproportionately impacted by air pollution. In California's 2014–2015 fiscal year, more than $200 million will be spent to benefit disadvantaged communities. This funding includes investments in public transit and advanced freight technologies such as electric trucks and buses.

CLEAN TRANSPORTATION INVESTMENT AND INNOVATION

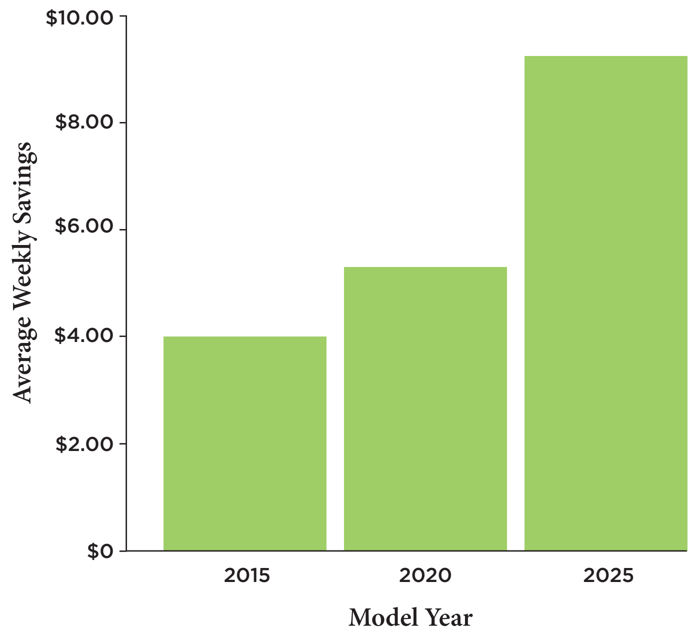
California's climate policies are driving a clean technology boom in the state. More than $5 billion in venture capital was invested in California's clean transportation sector between 2006 and 2013 (NXT 2014) and California's share of total U.S. patent registrations in this sector nearly doubled, jumping from 4.9 percent in 2006 to 9.4 percent in 2011 (Collaborative Economics Inc. 2013). In 2012 and 2013, California had the most or second-most new patents among states for battery, hybrid-electric, and fuel cell systems, and for biofuel and biomass technologies. Clean technology investments are also leading to more jobs; employment in California's clean transportation sector more than doubled between 2002 and 2012, to 8,500 jobs (NXT 2014).

Overcoming Oil Industry Opposition

Chevron, Exxon-Mobil, and other large oil companies lead the list of major carbon polluters, responsible for most of the carbon that has been emitted into the atmosphere over the last 150 years (Heede 2013). These companies make huge profits from the status quo and have a significant interest in ensuring oil continues to be the dominant transportation fuel. It is not surprising, therefore, that the oil industry is fighting California's climate policies.

> ***At least one-quarter of the proceeds from the sale of carbon permits in the cap-and-trade program are being invested to benefit communities that are disproportionately impacted by air pollution.***

FIGURE 3. Average Weekly Savings Over Lifetime (vs. Model Year 2008 New Vehicle)



California's clean transportation policies save drivers money over the lifetime of the vehicle, and as vehicles become more fuel-efficient these savings will grow.

Note: This figure represents the net savings over the lifetime of an average new vehicle purchased in 2015, 2020, and 2025 compared with a new vehicle in 2008, and reflects costs from California's global warming emissions and zero-emissions vehicle standards, Low Carbon Fuel Standard, and cap-and-trade program. For our methodology, see *www.ucsusa.org/ab32saves*.

Oil companies are attempting to weaken public support for California's clean transportation policies by focusing on the price of gasoline. But as UCS analysis has shown, the savings from more efficient vehicles more than offset the modest costs of improving fuel efficiency and producing cleaner fuels. The industry also seeks to obscure the fact that the only long-term solution to rising gas prices is to use less oil—which is precisely what California's clean transportation policies will achieve— while also downplaying the consequences of climate change (see Box 2) and lobbying against long-term emissions reductions.

California's climate policies are reducing carbon emissions, saving consumers at the pump, cutting oil use, and cleaning our air. It's a clean transportation future that works for *all* Californians, and sets a leading example for other states—and ultimately, our federal government—to follow. It's critical that the state keep moving forward toward this goal.

BOX 2.

The Costs of Inaction

Communities across California are already coping with many impacts of climate change, which are certain to worsen without strong action to reduce emissions.

Wildfires. California is experiencing hotter, drier conditions, which are contributing to larger wildfires and longer wildfire seasons. The wildfire season in the Western United States has grown from five months, on average, in the 1970s to seven months today, and the annual number of large wildfires has increased by more than 75 percent over the same time period (UCS 2013b). California has suffered seven of the 10 most costly wildfires in the nation, including three that cost between $1.6 billion and $2 billion in insured losses (UCS 2014).

Drought. Rising temperatures, reduced snowpack, and earlier snowmelt have exacerbated drought conditions in California. As temperatures have warmed over the past century, the prevalence and duration of drought has increased in the American West (Andreadis and Lettenmaier 2006). Droughts can be devastating for ecosystems and the economies that depend on them. A study by the University of California–Davis found that, during the summer of 2014, drought directly cost the state's agriculture industry nearly $1.5 billion, mostly due to having to leave many fields fallow (Howitt et al. 2014). Droughts can also lead to increased energy costs for California ratepayers as relatively inexpensive hydropower is lost. During the 2007–2009 dry period in California, ratepayers were charged an additional $2 billion to cover the purchase of electricity from natural gas plants, which was needed to replace diminished hydropower generation (Christian-Smith, Levy, and Gleick n.d.).

Heat waves. Global warming is increasing the frequency and duration of heat waves in California—and not just during daytime hours. Recent modeling finds that extreme heat waves with high nighttime temperatures are at least five times more likely in California now than 40 years ago (Mera, Mote, and Allen 2014). Heat waves with a strong nighttime component exacerbate the impact of daytime heat, possibly increasing mortality rates. Extreme heat brings greater risk of death from dehydration, heat stroke, heart attack, and other heat-related illnesses, particularly for vulnerable populations. An extended California heat wave in 2006 contributed to more than 650 deaths (Hoshiko et al. 2010).

Coastal flooding. Rising temperatures are leading to increased sea levels due to thermal expansion of warming oceans as well as melting land ice (glaciers, ice caps, and ice sheets). The risks of rising seas include tidal flooding, shoreline erosion, saltwater intrusion, larger storm surges, and permanent inundation. California currently has at least 260,000 people and $50 billion in property vulnerable to a 1-in-100-year coastal flood (a flood that has a 1 percent chance of occurring in any single year). As early as 2050, given current projections of sea-level rise, today's 100-year storm could occur once every year. By the end of this century, rising seas could put around 480,000 people (nearly half a million) at risk from a 1 in 100-year coastal flood (CEC 2009).

Photo credits: © U.S. Forest Service (wildfire); © Peter Gleick (drought)

California is already dealing with harmful consequences of climate change, including larger wildfires and exacerbated drought. Climate policies enacted as a result of AB32 are reducing the heat-trapping emissions that are primary cause of global warming.

ENDNOTES

1 A model year 2008 vehicle is used as the basis for ownership cost comparisons because California's global warming emissions vehicle standards first came into effect with model year 2009.

2 For all underlying assumptions related to this analysis, see www.ucsusa.org/ab32saves.

REFERENCES

Andreadis, K.M., and D.P. Lettenmaier. 2006. Trends in 20th century drought over the continental United States. *Geophysical Research Letters* 33(10).

Bureau of Labor Statistics (BLS). 2014. Consumer price index. Washington, DC: U.S Department of Labor. Online at *www.bls.gov/cpi*.

California Air Resources Board (CARB). 2014a. Greenhouse gas inventory data: 2000 to 2012. Sacramento, CA. Online at *www.arb.ca.gov/cc/inventory/data/data.htm*.

California Air Resources Board (CARB). 2014b. Advanced clean cars – AB1085 background materials for emissions data, economic data and public health impacts. Sacramento, CA. Online at *www.arb.ca.gov/msprog/clean_cars/clean_cars_ab1085/clean_cars_ab1085.htm*.

California Air Resources Board (CARB). 2013. Almanac emission projection data: 2012 estimated annual average emissions. Sacramento, CA. Online at *www.arb.ca.gov/app/emsinv/2013/emssumcat_query.php?F_YR=2012&F_DIV=-4&F_SEASON=A&SP=2013&F_AREA=CA*.

California Energy Commission (CEC). 2009. The Impacts of Sea-Level Rise on the California Coast. Sacramento, CA. Online at *http://www.energy.ca.gov/2009publications/CEC-500-2009-024/CEC-500-2009-024-F.PDFhttp://www.energy.ca.gov/2009publications/CEC-500-2009-024/CEC-500-2009-024-F.PDF*

California Energy Commission (CEC). 2014a. California average weekly retail gasoline prices. Sacramento, CA. Online at *http://energyalmanac.ca.gov/gasoline/retail_gasoline_prices.html*.

California Energy Commission (CEC). 2014b. 2013 integrated energy policy report. Sacramento, CA. Online at *www.energy.ca.gov/2013_energypolicy*.

Christian-Smith, J., M. Levy, and P. Gleick. No date. Maladaptation to Drought: A Case Study from California. *Sustainability Science*. In press.

Collaborative Economics, Inc. 2013. California's advanced transportation industry clusters of opportunity: Driving market expansion, technology, innovation and job growth. San Mateo, CA. Online at *www.coecon.com/assets/ca_advancedtransportclusters_2013*.pdf.

Energy Information Administration (EIA). 2014. State energy data system (SEDS): 1960–2012 (complete). Table CT1. Washington, DC: Department of Energy. Online at *www.eia.gov/state/seds/seds-data-complete.cfm?sid=US#Consumption*.

Environmental Defense Fund/American Lung Association in California/Tetra Tech (EDF/ALAC/TT). 2014. Driving California forward: Public health and societal economic benefits of California's AB 32 transportation fuel policies. Online at *www.edf.org/sites/default/files/content/edf_driving_california_forward.pdf.*

Heede, R. 2013. Tracing anthropogenic carbon dioxide and methane emissions to fossil fuel and cement producers, 1854–2010. *Climatic Change* 122(1–2):229–241. Online at *http://link.springer.com/article/10.1007/s10584-013-0986-y*.

Hoshiko, S., P. English, D. Smith, and R. Trent. 2010. A simple method for estimating excess mortality due to heat waves as applied to the 2006 California Heat Wave. *International Journal of Public Health* 55:133-137.

Howitt, R., J. Medellín-Azuara, D. MacEwan, J. Lund, and D. Sumner. 2014. Economic analysis of the 2014 drought for California agriculture. Davis, CA: UC–Davis Center for Watershed Sciences. Online at *https://watershed.ucdavis.edu/files/biblio/DroughtReport_23July2014_0.pdf.*

Hricko, A., G. Rowland, S. Eckel, A. Logan, M. Taher, and J. Wilson. 2014. Global trade, local impacts: Lessons from California on health impacts and environmental justice concerns for residents living near freight rail yards. *International Journal of Environmental Research and Public Health* 11(2):1914–1941. Online at *www.mdpi.com/1660-4601/11/2/1914*.

Mera, R., P. Mote, and M. Allen. 2014. Attribution of Extreme Temperature Events for the Western US using a Superensemble of Regional Climate Model Simulations. Presentation the American Meteorological Society Annual Meeting, Atlanta, February 5. Online at *https://ams.confex.com/ams/94Annual/webprogram/Paper234401.html*.

Next 10 (NXT). 2014. California green innovation index. San Francisco, CA. Online at *next10.org/sites/next10.huang.radicaldesigns.org/files/2014%20Green%20Innovation%20Index.pdf.*

Union of Concerned Scientists (UCS). 2014. Playing with fire: How climate change and development patterns are contributing to the soaring costs of western wildfires. Cambridge, MA. Online at *www.ucsusa.org/assets/documents/global_warming/playing-with-fire-report.pdf.*

Union of Concerned Scientists (UCS). 2013a. Where your gas money goes: How oil companies profit from your pain at the pump. Cambridge, MA. Online at *www.ucsusa.org/assets/documents/clean_vehicles/Where-Your-Gas-Money-Goes.pdf.*

Union of Concerned Scientists (UCS). 2013b. Western wildfires and climate change. Infographic. Cambridge, MA. Online at *www.ucsusa.org/global_warming/science_and_impacts/impacts/infographic-wildfires-climate-change.html*.

Union of Concerned Scientists

FIND THIS DOCUMENT ONLINE: **www.ucsusa.org/ab32saves**

The Union of Concerned Scientists puts rigorous, independent science to work to solve our planet's most pressing problems. Joining with citizens across the country, we combine technical analysis and effective advocacy to create innovative, practical solutions for a healthy, safe, and sustainable future.

NATIONAL HEADQUARTERS
Two Brattle Square
Cambridge, MA 02138-3780
Phone: (617) 547-5552
Fax: (617) 864-9405

WASHINGTON, DC, OFFICE
1825 K St. NW, Suite 800
Washington, DC 20006-1232
Phone: (202) 223-6133
Fax: (202) 223-6162

WEST COAST OFFICE
500 12th St., Suite 340
Oakland, CA 94607-4087
Phone: (510) 843-1872
Fax: (510) 843-3785

MIDWEST OFFICE
One N. LaSalle St., Suite 1904
Chicago, IL 60602-4064
Phone: (312) 578-1750
Fax: (312) 578-1751

WEB: **www.ucsusa.org**

PRINTED ON RECYCLED PAPER USING VEGETABLE-BASED INKS.

© SEPTEMBER 2014 UNION OF CONCERNED SCIENTISTS

Union of Concerned Scientists

The Equation
a blog on independent science + practical solutions

Low Carbon Fuels: How Clean Fuels Can Power the West Coast and Beyond

February 2, 2015 ***Jeremy Martin, senior scientist, Clean Vehicles***

UCS-commissioned research released today is the latest to find that, with stable policies, we can achieve ambitious clean fuels goals. Recent publications from UC Davis, the International Council on Clean Transportation and E4Tech have drawn similar conclusions. As California prepares to readopt their 2010 Low Carbon Fuel Standard, we are seeing clear evidence that diverse types of clean fuel can be make a significant contribution to cutting oil use and transportation carbon pollution.

A year ago more than one hundred leading California scientists and economists sent an open letter on climate change to Governor Jerry Brown and the California Legislature urging them to maintain California's leadership on climate change. These experts said that a clear price on carbon is "key, but not sufficient to adequately reduce emissions. Policies that promote renewable energy, low carbon fuels, and cleaner transportation are also critical." Policymakers should look beyond the current policies, and prepare now to reach emissions targets between 2020 and 2030.

> *"Every sector involved in addressing climate change, from energy to transportation, will need sufficient time to prepare to meet new targets. The longer we wait the harder and more costly it will be. Please begin now to set a science-based, heat-trapping emissions target for 2030."*

California is taking up this challenge. In addition to policies that put a price on carbon, California has a comprehensive suite of policies that will clean up transportation including a low carbon fuel standard (LCFS) that shifts the market steadily towards cleaner fuels. And the state is starting to look beyond 2020. Governor Brown recently set a 2030 goal of cutting oil use in half, making it clear that 2020 is just the first step. The steady growth of clean fuels is key to meeting this goal.

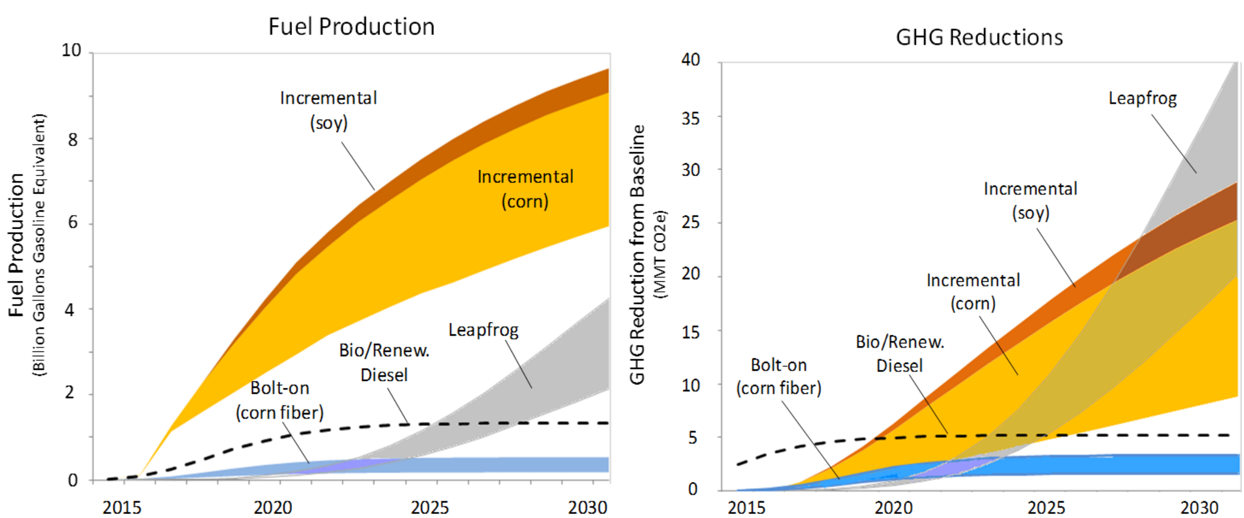
Three recent studies look into the potential for clean fuels in the US, the West Coast and California, and together illustrate why the future for clean fuels is bright, provided the policies are in place to support them.

California kicked off a transition to clean fuels with its LCFS in 2010, and later this month the California Air Resources Board will consider the readoption of the LCFS, making technical updates, resolving legal issues and getting the policy back on track to cut carbon pollution from transportation fuels by 10% per unit of energy by 2020. As they do so, they need to start planning for the next phase, from 2020 to 2030.

Accelerating the transition to clean fuels now will support innovation, cutting oil use and reducing transportation emissions and ensuring that investments in the clean fuels of the future replace dead end investments in ever dirtier sources of oil.

National: UC Davis NextSTEP's study
Experts at UC Davis' Institute for Transportation Studies examined three distinct ways cleaner biofuels of different types are emerging across the United States (recently published in Energy Strategy Reviews).

- First, *incremental* progress is being made at existing biofuel facilities, as they adopt cleaner and more efficient production processes.
- Second, *transitional* progress is being made as existing corn ethanol biorefineries start making cellulosic ethanol from corn fiber together with corn ethanol at existing corn ethanol facilities.
- Finally, *leapfrog* progress is being made as firms build new facilities specifically to make cellulosic biofuel.

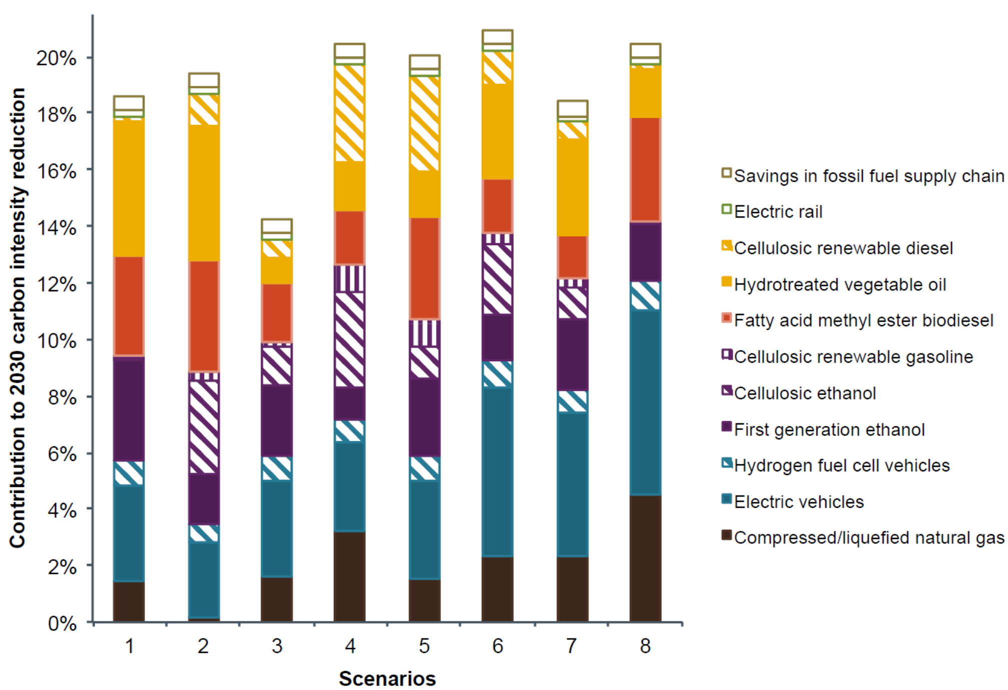


Notice that the incremental approaches are likely to come on more quickly between now and 2020. But the leapfrog approach is the one with the potential to deliver the largest oil savings and emissions reductions by 2030. The transitional route also plays an important role in building early experience with cellulosic biofuel technology in a context that is less risky and capital intensive. This lower risk learning is especially important today, with policy uncertainty delaying investment in the most ambitious projects.

The bright future described in this study is by no means guaranteed. Strong policy support is needed to scale up low carbon fuels. These policies lead to steadily increasing production, which accelerates learning and brings down the costs of cellulosic biofuel over time. And the broader the market for the fuels, the faster this learning will accumulate. While US policy is stalled, the west coast is working on creating a large and steadily growing clean fuels marketplace.

West Coast: ICCT and E4tech

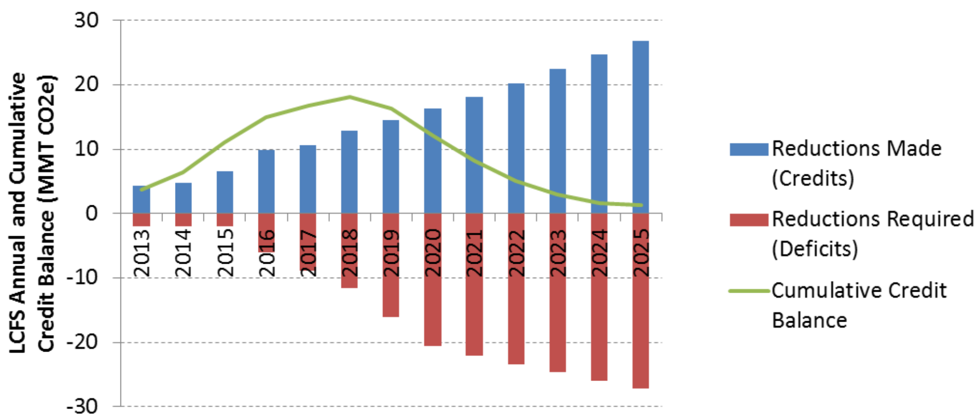
Last month the International Council on Clean Transportation and E4tech released a study on the potential low-carbon fuel supply to the Pacific Coast region of North America. They find that California, Oregon, Washington and British Columbia, acting in concert to create coordinated clean fuels policies, can triple the use of low carbon fuels and replace a quarter of the region's gasoline and diesel use by 2030. That's a massive reduction in carbon pollution and oil use. The report also highlights the diversity of potential fuels and pathways, with eight distinct scenarios and different amounts of low carbon fuels emerging as electricity, renewable natural gas, ethanol, biodiesel, and other low-carbon fuels ramp up at different rates.



Their study reinforces that there are many routes to a low carbon future, and with a flexible policy framework like a low carbon or clean fuel standard, policy makers are committing to the outcome, rather than picking specific fuels or technologies needed to get there. I've written in the past about the importance of flexibility in clean fuels policies, and my colleague Josh just posted a blog on how Oregon's clean fuels program is making it work for them.

California: NRDC/UCS/EDF Promotum Study

Today UCS, the Natural Resources Defense Council and the Environmental Defense Fund released a study of compliance options for the California Low Carbon Fuels Standard over the next ten years. The study was conducted by Promotum and addresses endless oil industry claims that moving to cleaner fuels is infeasible. Our study examines where clean fuels can come from to meet both a 10% reduction in carbon intensity (carbon pollution per unit of energy) by 2020 that California adopted back in 2010, and looks beyond 2020, to a 15% standard in 2025.



The oil industry likes to focus on whether biofuels or Electric Vehicles (EVs) are ready to scale up quickly enough to meet ambitious targets. This study indicates that they are, and also that the oil industry can meet 15% of its clean fuel obligations in 2020 by improving efficiency and integrating renewable energy inputs into the production of oil and the refining of gasoline and diesel. Promotum evaluated the impact of credit prices of $100 a ton (LCFS credits are measured by ton of avoided emissions), and found that the available options would exceed the requirements of the policy in 2020, and allow compliance with steadily increasing targets that hit 15% in 2025.

2020 is just the beginning

It took more than a century to build today's oil industry, and it will take longer than five or ten years to scale up the clean fuels industry that will succeed it. The three studies provide a roadmap for successfully achieving low carbon goals the states are setting today, which will create a steadily growing regional marketplace for clean fuels. When you consider that the combined economies of California, Oregon, Washington and British Columbia would rank fifth in the world, behind Germany and ahead of France, it is clear this marketplace can provide major step forward towards a clean transportation future.

About the author: Jeremy Martin is a scientist with expertise in the technology, lifecycle accounting, and water use of biofuels. He is working on policies to help commercialize the next generation of clean biofuels (made from waste and biomass rather than food) that can cut U.S. oil dependence and curb global warming. He holds a Ph.D. in chemistry with a minor in chemical engineering.

Union of Concerned Scientists

The Equation
a blog on independent science + practical solutions

The Latest on Biofuels and Land Use: Progress to Report, but Challenges Remain

January 23, 2015 ***Jeremy Martin, senior scientist, Clean Vehicles***

Carbon pollution caused indirectly by the increasing use of crops to produce biofuels has been a contentious topic for the last 7 years. In this post I look back at what we have learned since then about indirect land use change (ILUC) emissions, as this phenomena is generally called. The headline 7 years ago – that crop-based biofuels are far worse than fossil fuels – no longer holds.

Both the studies and the world have changed. Agricultural markets are more flexible, deforestation has fallen in some key areas (Brazil in particular) and biofuels production is getting more efficient. The overall result is that biofuels are getting cleaner over time, and most biofuels are cleaner than gasoline. But the central importance of reducing biofuels impact on food and forests has been reaffirmed. Expanding the production of food-based fuels will not deliver the low carbon fuels we need to cut projected oil use in half and address climate change, and will cause many other problems. Fortunately we have better options.

What are indirect land use change emissions and why do they matter?

Prior to 2008, biofuels were considered a guilt-free energy source: cleaner than gasoline, good for farmers that produced the feedstocks, and available domestically at seemingly limitless scale. In February 2008 that changed when important papers in Science Magazine, particularly one by Searchinger and coauthors, raised the specter that as US corn ethanol consumed an ever greater share of U.S. crop production, cropland overseas was expanding to fill the void in food markets. Most concerning was the conversion of tropical forests to farmland. Since deforestation is itself a major source of carbon emissions, this shift undermines the potential climate benefits of crop-based biofuels. Searchinger and coauthors estimated that emissions from ILUC for corn ethanol were higher than the total emissions of using gasoline, leaving no potential for corn ethanol or other crop based biofuels in a low carbon transportation future. This concept resonated powerfully, reinforced by the related concern that using food for fuel could make food more expensive and aggravate food insecurity. Since then ILUC emissions have become an important and contentious part of the lifecycle analysis of biofuels and in the administration of fuel regulations that are based on such analyses.

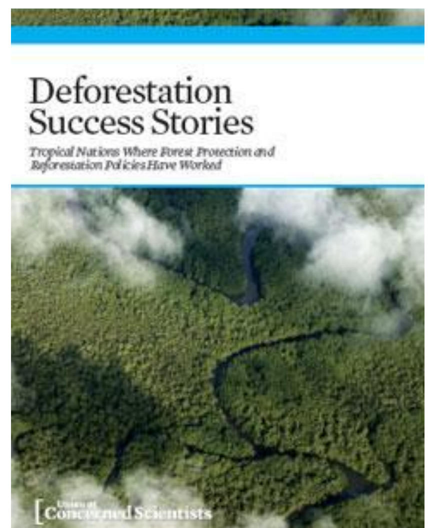
Experts across the country have been hard at work on this topic for the last 7 years, and have learned a great deal about ILUC. The headline conclusion of the 2008 paper, that corn ethanol's emissions are much higher than gasoline, has not survived careful scrutiny. Subsequent analyses found more flexibility in the agricultural system to expand production without large increases in deforestation, and deforestation in Brazil has slowed. California's most recent analysis finds ILUC emissions of about 20 grams of CO_2equivalent carbon pollution per megajoule of energy for the fuel produced (g /MJ), about 80% lower than the Searchinger's result. Nailing these numbers down remains challenging, and an uncertainty analysis finds plausible estimates range from 11 g/MJ to 37 g/MJ. However, these revised values mean that – when ILUC emissions are combined with all other emissions – corn ethanol produced at an average Midwestern facility using natural gas as a source of process heat is 20% cleaner than gasoline, and the cleanest facilities are better still.

Expanding agriculture to make more biofuels has real costs

However, the underlying notion that biofuels expansion is profoundly impacting agriculture has only gotten clearer. Numerous studies have looked at how biofuels expansion impacts land use, crop prices, food consumption, livestock, and the use of irrigation. The global food and agricultural system is complex, to say the least, and incorporating these modelling approaches into a regulatory framework is and will remain a major challenge. But every credible study finds that biofuels are a major player in global agricultural markets. It is clear that, going forward, sustainable biofuels must not only cut oil use and reduce emissions, but also protect food security and complement the agricultural system. For reasons ranging from climate change to water pollution to food price stability, expanding biofuels by moving more and more grain and vegetable oil into fuel markets is not smart transportation policy or smart food and agricultural policy.

Biofuels don't need to drive deforestation

Much of the analysis of ILUC has focused on corn ethanol and soybean biodiesel produced in the US and its link to deforestation in Brazil. This makes sense since the US and Brazil are the largest producers of ethanol and soy biodiesel and the largest producers of corn and soybeans, and Brazil is historically among the largest sources of carbon emissions from deforestation. But what was just starting to come into focus in 2008 was how much of an improvement Brazil was making in reducing deforestation. As my colleagues have described in their recent report, Deforestation Success Stories, Brazil has cut the rate of deforestation by three quarters and they have done this even as soybean and cattle production continue to grow.



Strategies for reducing deforestation are working in a variety of places. Understanding these success stories can help us turn them into a global success story.

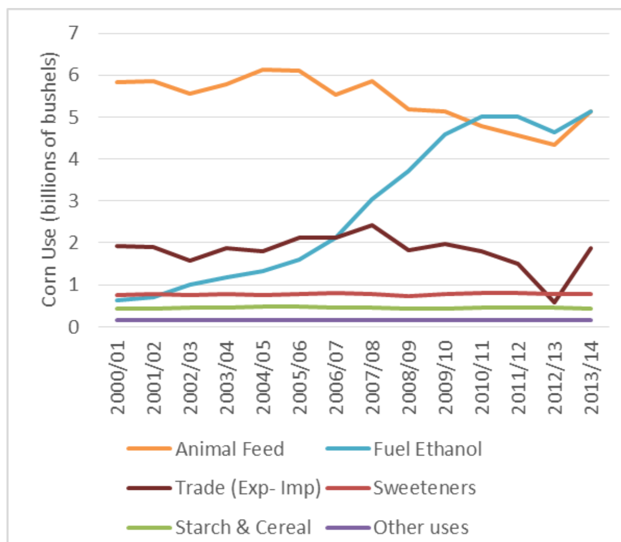
California's latest ILUC analysis suggests that most Brazilian cropland expansion is likely to come from pasture land , as cattle producers raise more cattle on fewer acres. Another important shift is *where*expansion is occurring, with cropland and pasture expansion occurring on previously cleared land in response to more robust forest protection. And recent analysis from Iowa State has shown that much of the increased production in Brazil from 2004 to 2012 came from farmers growing two or more crops per season, or harvesting more of what they plant. The progress in protecting forests together with these opportunities for intensification mean that the magnitude of deforestation associated with corn, soybeans and beef expansion is going down, which is great news.

The bad news is that deforestation in Southeast Asia is still a major concern, particularly driven by the expansion of palm oil production.Because of this, California's recent analysis found that palm oil biodiesel has ILUC emissions of 71 g/MJ, more than twice as high as soybean biodiesel and more than three times as high as corn ethanol. This means that palm oil-based biodiesel is more polluting than petroleum diesel. In the U.S. we don't use a lot of palm oil for biodiesel, but my colleagues are putting pressure on the major companies that use palm oil in household products and foods to stop the expansion of palm oil onto forests. And they are succeeding in getting important commitments from major U.S. companies (for example Hershey, General Mills and Proctor & Gamble) and global agricultural traders (for example Wilmar and Bunge).

Increasing biofuels production and supply chain efficiency

When assessing the performance and potential of a biofuel, it's important to look at ILUC alongside other factors. In 2008 when the ILUC debate got going, the general understanding (based on a model called GREET from Argonne National Lab) was that corn ethanol from a typical Midwestern facility would reduce emissions by about 20% compared to gasoline. Adding 103 g/MJ as Searchinger and coauthors suggested made corn ethanol far worse than gasoline, and even the 30 g/MJ (~30%) California's 2010 analysis found, was enough to make corn ethanol from a typical facility equal to or a little worse than gasoline. But corn ethanol production has been getting more efficient, and an updated version of GREET that reflects these efficiency gains finds that the direct emissions for Midwestern corn ethanol produced using natural gas are about 60 g/MJ or 40% cleaner than gasoline. Adding 20 g/MJ to account for ILUC emissions still leaves typical corn ethanol about 20% cleaner than gasoline. And for corn ethanol producers that adopt the most efficient technology in their production process, for example installing efficient combined heat and power systems, the emissions can come down even further.

Just because corn ethanol can be cleaner than gasoline doesn't mean we need more



While ILUC is just one factor of the lifecycle, the lifecycle itself is still just part of the story for biofuel impacts. And where corn ethanol is concerned, we have to talk about scale. U.S. corn ethanol production expanded rapidly over the last decade, as ethanol changed its role from a minor blending component (an oxygenate required to address air quality problems in some key regions) to its present role as a source of octane in E10 (a 10% ethanol gasoline blend) that is the main type of gasoline sold in the U.S. today. As consumption of corn for ethanol increased by 400 percent in just a decade, ethanol went from being a relatively minor use of corn to being the single largest use worldwide.

Continuing this expansion will make things worse, starting with the harm corn ethanol expansion has caused to water quality, but also the damage to the long term productivity of our agricultural system. My colleagues have outlined the need for a more balanced approach to farming, and for both dietary and environmental reasons, doubling down on corn won't help us get there.

The future of clean transportation is fueled by better biofuels (and electricity)

While more corn won't get us where we need to go, the good news is that we have a lot of biomass resources that are a better choice. These are waste materials from our cities andagricultural residues like corn stalks, as well as environmentally friendly perennial grasses. With these materials we can make enough cellulosic biofuel to easily double or triple biofuels production in the next twenty years, and these non-food based cellulosic biofuels can cut emissions up to 90% compared to gasoline. Just as important, these cellulosic biofuels can scale up while moving our agricultural system in a healthy and sustainable direction. Cellulosic biofuel production is coming on line now, and with policies that support the best biofuels, as well as more electric vehicles and continued efficiency improvements across the transportation sector, we can keep moving towards our goal ofcutting oil use in half in the next twenty years.
My conclusion after working in this area for 7 years is that we need to focus on three distinct areas

- **Make biofuels cleaner:** Move to more efficient and lower carbon production processes to reduce direct emissions along the whole supply chain.
- **Make biofuels out of better biomass:** Make a transition from food crops to sustainable sources of biomass.
- **Scale matters for food and forests:** Sources of waste fats and oils are available to produce a billion gallons of biodiesel a year but cause problems at 2 billion. Corn ethanol is already problematic at its current scale of more than 10 billion gallons a year, but would be catastrophic at 20 billion. And as biomass based fuels scale to more than 10 billion gallons a year, which will take a decade of steady growth, we'll need to calibrate their scale to not just meet our fuel needs, but to protect land for food, forests, and other needs as well.

About the author: Jeremy Martin is a scientist with expertise in the technology, lifecycle accounting, and water use of biofuels. He is working on policies to help commercialize the next generation of clean biofuels (made from waste and biomass rather than food) that can cut U.S. oil dependence and curb global warming. He holds a Ph.D. in chemistry with a minor in chemical engineering.

The Equation
a blog on independent science + practical solutions

Policy Matters: Why Clean Fuels Forecasts Come Up Short

October 27, 2014 ***Jeremy Martin, senior scientist, Clean Vehicles***

Cellulosic biofuel facilities are opening this year to much fanfare and a renewed promise that we can look forward to a quickly increasing supply of clean, non-food biofuels. At the same time, forecasts about the future of cellulosic biofuel have recently gotten more pessimistic, with the Energy Information Administration forecasting a plateau once these first plants open. What to believe? I use a simple model to show how progressive, consistent clean fuels policies will lead to lower costs over time.

Learning by doing drives costs down

Experience with production brings many small improvements that reduce costs. Photo Credit: The Henry Ford Foundation.

As with any other new industry, scale-up issues have emerged for the cellulosic industry that were not apparent in the lab or at pilot scale. The pace of learning always accelerates dramatically once you spend hundreds of millions or even billions of dollars to start commercial scale production. This is exactly what I saw when we visited the Poet DSM and DuPont facilities in Iowa this summer. Everything from how to stack bales to the enzyme cocktail to the filter press that cleans the water at the end of the line are in a state of optimization. In theoretical treatments they call this process "learning by doing," and across a broad range of industries it has been observed that when you first start making something, whether it is a Model T or a solar cell, the cost per unit drops as cumulative experience with production rises (see this article in the Economist for some background).

Experience with production brings many small improvements that reduce costs. Photo Credit: The Henry Ford Foundation.

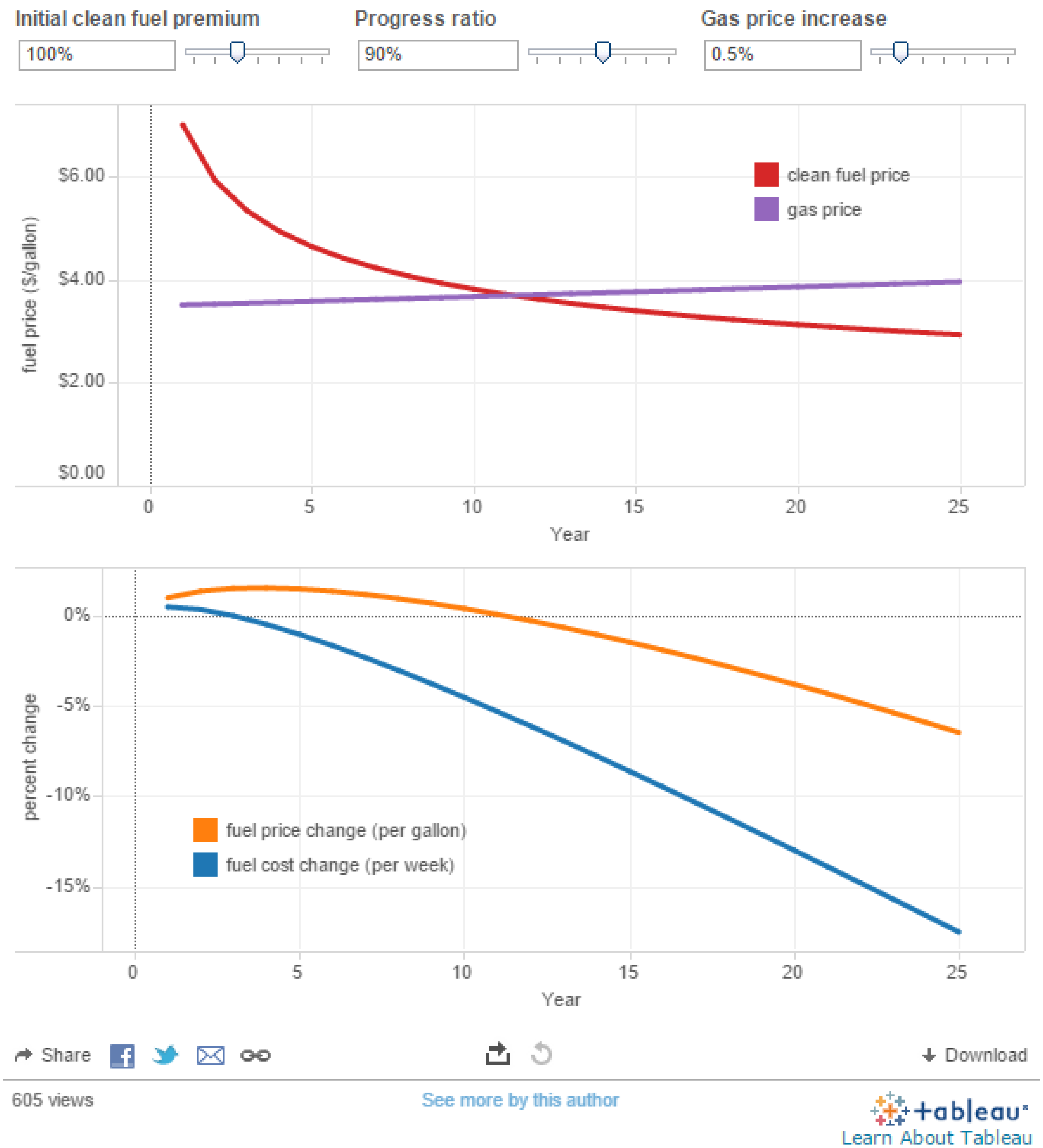
Predicting the future is hard

Fuel markets are complex, as are the models used to forecasts them – yet ultimately the predictive power of the models is rather poor. One of the most authoritative models about fuel that we all rely on is the Annual Energy Outlook published each year by the Energy Information Administration (EIA). It is really a collection of linked models that examine how policies, infrastructure, and economic factors in the vehicles, fuels, and the rest of the world interact. A complex model is needed to help think through complex questions, but the complexity can make it hard to see the big picture. Some key dynamics are best illustrated with simple model with just a few parameters.

Building a simple model

To see what this means for clean fuels, let's construct a simple model of a Low Carbon Fuel Standard. Let's assume we have just two kinds of fuel, ordinary gasoline that costs $3.50 a gallon, and super-duper clean gasoline, which is carbon neutral and currently sells at a 100% premium or $7/gallon. At twice the price, demand for clean fuel is quite low until a low carbon fuel standard (LCFS) is adopted. The LCFS requires fuel producers to reduce emissions from their fuels by 1% each year, and in our simple model this means replacing 1% of the fuel with clean fuel in the first year, 2% the second, etc.

You might think that switching gradually from $3.50/gallon to $7.00 a gallon fuel would get expensive, but remember, the producers of clean fuel have a lot of room for improvement, and as the volume of production rises, experience starts to bring down prices. I put this into a simple model below so you can see the results for yourself. For illustration I started with a 100% initial price premium for clean fuel and used a simple model of learning where each doubling of cumulative production brings prices to 90% of their previous level, called the progress ratio (in other words prices fall by 10%). Finally we assume that gasoline prices rise by 0.5% annually. You can choose different values for these three parameters using the tabs at the top of the chart.



Results that speak for themselves

What you see is that while clean fuel prices start high, they fall rapidly. And since the policy ramps up the share of clean fuel gradually, the net result is that the per gallon price of blended fuel rises slightly for the first few years, peaks 1.5% above the baseline on the 4thyear, and then starts falling. And taking into consideration that cars are getting more efficient, so that average fuel consumption is falling by 0.5% a year, total fuel cost (the blue line) drops steadily almost from the beginning. Changing the parameters will change the numbers, but across a broad range of reasonable values the basic outline of the story remains the same.

Back in the real world, there are a lot of other details that matter. One important fact to keep in mind is that there are more than two types of fuels. Some of today's clean fuels, likeelectricity, are already less expensive than gasoline. And different vehicles and infrastructure constraints also complicate the story, which is why more complex models are necessary. But it remains true that the **cost of producing clean fuels will fall as volumes rise and firms get more experience.** This is an uncontroversial point, based on both theory and empirical observation.

Policy matters—it is the dog that wags the clean fuel tail

So why then, does EIA have such a pessimistic view of the future? Their model evaluates the current state of technology and policy and suggests that in EIA's view, current policy is not adequate to support the investment in production and distribution infrastructure needed to get clean fuels to a scale at which they can compete effectively. It does not anticipate various scenarios under which the policy environment has changed, so cannot paint a rosier picture than a current snapshot.

This creates a negative feedback loop: uncertainty about the future of clean fuel policies is delaying additional investment in the industry; the delayed investment is fueling (pun intended) uncertainty about whether the clean fuel policies are realistic. The oil industry is amplifying this negative feedback, arguing that policy makers should wait until the clean fuels are cheap and plentiful before moving forward with policies that support these fuels. But this cynical tactic is letting the tail wag the dog. Instead, policy makers in California, Oregon, and Washington should move boldly to support clean fuels production, and policy-makers in DC should resolve the uncertainty in the federal fuels policy landscape to reestablish the stable policy framework needed to support investment in clean fuels.

About the author: Jeremy Martin is a scientist with expertise in the technology, lifecycle accounting, and water use of biofuels. He is working on policies to help commercialize the next generation of clean biofuels (made from waste and biomass rather than food) that can cut U.S. oil dependence and curb global warming. He holds a Ph.D. in chemistry with a minor in chemical engineering.

Union of Concerned Scientists

The Equation

a blog on independent science + practical solutions

5 Things I Learned in Iowa about Biofuels

August 12, 2014 ***Jeremy Martin, senior scientist, Clean Vehicles***

In July my colleagues and I, together with the Great Plains Institute, organized a Cellulosic Summit in Iowa. We brought together experts in clean transportation (many from California) with experts in sustainable agriculture (many from Iowa) to see for themselves the latest developments in cellulosic biofuel commercialization.

Cellulosic biofuels are a key element of our strategy to help cut projected oil use in half in 20 years, and today we're at a critical juncture, with the long-awaited commercial production of millions of gallons of cellulosic biofuel beginning this year.

I'll be thinking about what I saw and learned for months to come, but here are the top five things I learned:

1. Big refineries signal technological breakthrough

The Poet-DSM and DuPont cellulosic biofuels facilities poised to open this year are a big deal for clean transportation and sustainable agriculture. These early facilities, which represent hundreds of millions of dollars of investments, will work through the technology and logistics challenges of producing cellulosic biofuel at commercial scale, and serve as a proving ground for the technology. Walking through these huge, complex biorefineries is awe-inspiring, and a testament to the innovative spirit and technological know-how being brought to bear to meet our energy challenge.

2. Lots of corn = Lots of biomass

It is well known that Iowa grows a lot of corn—more, in fact, than all but three countries. But a harvested corn plant is only about 50 percent corn grain, and the other half is cellulosic biomass (the stalks, leaves and cobs, called stover). While it's important to leave some stover behind to protect the soil, we can harvest enough to add a billion gallons of ethanol production in Iowa, without using another kernel of corn. Other states throughout the country also produce large amounts of agricultural residues and manure, which can be made into biofuels, renewable electricity and biogas.

Andy Heggenstaller, DuPont Pioneer in front of corn stover bales. Photo credit Brendan McLaughlin.

3. … Yet lots of corn = Lots of problems

90 percent of Iowa is farmland, and 70 percent of that land is planted with just two crops:corn and soybeans. Common farming methods leave bare soil exposed most of the year to increasingly severe weather. Storms can wash tons of Iowa's famous black soil into waterways in just a few days, and fertilizer coming off farm fields (and through subsurface drainage) creates major pollution problems both in Iowa and downstream in the Gulf of Mexico.

Photo showing soil erosion after five inches or more of rain fell in one hour across portions of Western Iowa in 2013. Photo credit USDA NRCS.

4. Smart biofuels means smart farming

The only way to make sustainable biofuels is to practice sustainable farming. Iowa State University and companies like AgSolver are employing complex modeling tools to help farmers make smart economic decisions on their land: where to plant corn, where it makes sense to use part of their corn stover to make ethanol, and where they should plant perennial grasses (highly productive sources of cellulosic biomass) instead or corn. Not only can this make the farmers' operations more profitable, it can keep pollution out of the water, reduce erosion, and someday soon, produce biomass for cellulosic biofuel.


Cereal rye cover crop planted into corn stubble. Photo credit USDA NRCS.

5. Perennial crops have a big role to play

For the foreseeable future, Iowa will continue to grow a lot of corn and soybeans, but integrating perennial grasses into the system can provide benefits far in excess of the land they occupy. Scientists from the STRIPS research team (Science-based Trials of Row-crops Integrated with Prairie Strips) have shown that by strategically converting as little as 10 percent of a row-cropped field to perennial prairie—in narrow patches along contours and foot slopes—farmers and landowners can reduce soil erosion and fertilizer runoff by 85-95 percent. As cellulosic biofuel production scales up, there will be a growing market for these clean, sustainable crops.


Professor Matt Helmers from Iowa State showed us around the STRIPS project. Photo credit Amanda Bilek.

To cut oil use and carbon emissions from transportation and make our agricultural system more resilient and sustainable, we need to change the way we produce fuel and the way we farm. Experts in Iowa are hard at work making that happen. Seeing the beginning of large-scale production of corn-stover based cellulosic biofuel is exciting: the technology is working, and sets us up well to begin growing and harvesting perennial crops to feed the growing industry. It's an important milestone on the road to clean fuels and sustainable agriculture.

About the author: Jeremy Martin is a scientist with expertise in the technology, lifecycle accounting, and water use of biofuels. He is working on policies to help commercialize the next generation of clean biofuels (made from waste and biomass rather than food) that can cut U.S. oil dependence and curb global warming. He holds a Ph.D. in chemistry with a minor in chemical engineering.

Production Begins At Second Cellulosic Biofuel Facility

October 17, 2014 ***Jeremy Martin, senior scientist, Clean Vehicles***

You don't often hear Kansas and Spain mentioned in the same sentence. Yet today Spanish company Abengoa is bringing another big cellulosic biofuel facility online in Hugoton, a small community in the Southwest corner of the state. This is the second big plant starting up this year, showing that after some predictable yet highly scrutinized delays, the cellulosic fuel industry is truly beginning to establish itself and making critical contributions to oil savings and climate goals.

Abengoa's plant in Hugoton Kansas will produce 25 million gallons of cellulosic biofuels and 21 MW of electricity per year – enough to power the plant and sell some back to the local Stevens County community. Photo credit: Abengoa

It wasn't long ago that cellulosic biofuels were the punchline of a joke: a phantom fuel that could not be economically produced in large volumes. Fast forward to today, and we see headlines like "Advanced Ethanol Makers Are Trying to Give Big Oil a Run for Its Money."

I wrote recently about the two cellulosic biofuels facilities we visited in Iowa, and about the use of landfill and dairy digester gas to power compressed natural gas and electric vehicles. The Abengoa plant will double the production capacity on line for cellulosic ethanol, and do it without consuming a kernel of corn. The Abengoa plant is also worth noting because it represents an investment in America's clean energy future by a major international company, and it is by no means the only one.

Large companies making big investments

Major companies from all over the world have come to the US to invest in cellulosic biofuel as the result of our smart people, our abundant biomass resources, and a policy environment committed to steady growth in clean fuels. Yet the US is certainly not the only place that cellulosic biofuels are coming on line. There is also a major cellulosic biofuels facility in Italy, and a cellulosic biorefinery just started up in Brazil, which has a longstanding commitment to renewable fuels.

Beta Renewables' cellulosic ethanol facility in Crescentino, Italy opened in October of 2103, and uses enzymes made by Novozymes to produce ethanol from wheat straw and perennial grasses. Photo credit: Novozymes

The cellulosic plant that opened in Iowa in August is a collaboration of Poet, a major US ethanol company, and Royal-DSM, a company from the Netherlands (they are not kidding about the royal part either: King Willem-Alexander of the Netherlands was there for the grand opening). Another major player in cellulosic biofuels is Danish firm Novozymes, which makes enzymes to power cellulosic biofuel production and has major facilities in Nebraska and North Carolina.

It is worth pointing out that major international companies, not just Royal-DSM and Novozymes but also Beta Renewables that just started the cellulosic facility in Brazil, are investing both in Brazil and the United States. And as the U.S. policy landscape has looked less attractive, investment is moving to Brazil. The question is no longer whether or not cellulosic biofuels will arrive; it's how big a part in the industry our country will play.

GranBio started up Brazil's first commercial scale cellulosic ethanol facility in in Alagoas, where sugarcane straw and bagasse are made into ethanol and renewable electricity. Photo credit: GranBio

Policy instability = Lost investment

Seven years ago, we set a course to cut oil use by improving the efficiency of our vehicles and by expanding the use of renewable fuels. The Renewable Fuel Standard, which calls for increasing biofuels production steadily over time, is central to that plan. Yet as opposition to the standard (driven largely by the oil industry) has increased, what was once a stable policy landscape has begun to shift.

I disagree with some biofuels supporters who suggest that any adjustments to the RFS will spell the end of investment in advanced biofuels. I have been arguing for a couple years that a more flexible approach to RFS is needed, and that EPA was right to make some adjustments. I am less concerned about exactly what production volume target EPA sets for 2014 or 2015 than with how they reset the policy in the timeframe 2016 to 2022 and beyond. Establishing policy stability over the next 5 to 10 years is what will support the next round of investment. And strong regional policies like the California Low Carbon Fuels Standard and related clean fuels policies in Oregon and Washington can accelerate the trend further, drawing investment in clean fuels technology from around the world to the US and to these states in particular.

Steady progress on cutting oil use

Oil use has been steadily growing for about 100 years, so our half the oil plan was never going to be something we could execute overnight, but the progress to date is very encouraging: vehicle efficiency is improving and biofuel production has doubled since the RFS was signed in 2007.

The bulk of the oil savings so far have come from technology that was available and ready to scale up rapidly. But to make the deep reductions in oil use and carbon emissions we need to respond to climate change, we need to move on to more advanced technologies like electric vehicles and cleaner biofuels made from abundant and environmentally friendly sources of biomass.

The progress of the policies put in place in 2007 is encouraging, and also a reminder that it takes time to move technology from labs, to pilot plants, to full-scale production. The Abengoa plant opening is the latest evidence that these advanced technologies are making progress also.

About the author: Jeremy Martin is a scientist with expertise in the technology, lifecycle accounting, and water use of biofuels. He is working on policies to help commercialize the next generation of clean biofuels (made from waste and biomass rather than food) that can cut U.S. oil dependence and curb global warming. He holds a Ph.D. in chemistry with a minor in chemical engineering.

5_OP_LCFS_UCS Responses

30. Comment: **LCFS 5-1**

    The comment supports the re-adoption of the LCFS regulation.

    Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

31. Comment: **LCFS 5-2**

    The commenter supports the goals of the LCFS program but states the timeline should be longer than five years.

    Agency Response: The regulation recommended to the Board retains the requirement for a 10 percent carbon intensity reduction in 2020 and beyond. Additionally, further reductions are feasible beyond 2020. Staff will return to the Board with a proposal for additional reductions beyond 2020 if the Board so directs.

32. Comment: **LCFS 5-3**

    The commenter supports several technical updates which strengthen the LCFS regulation.

    Agency Response: ARB staff appreciates the support for the proposed changes to the lifecycle analysis and the innovative crude provision and the support for the inclusion of the refinery investment and cost containment provisions.

33. Comment: **LCFS 5-4**

    The commenter supports the LCFS regulation and 2020 goals and recommends that the time-frame for the regulation extend beyond 2020.

    Agency Response: See response to **LCFS 5-2**.

34. Comment: **LCFS 5-5**

    The comment supports the cost-containment provisions in the LCFS regulation.

    Agency Response: ARB staff appreciates the support for the cost containment provisions.

This page intentionally left blank.

Comment letter code: 6-OP-LCFS-CalETC

Commenter: Eileen Tutt

Affiliation: California Electric Transport Coalition

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

CalETC
California Electric Transportation Coalition

6_OP_LCFS
_CalETC

February 13, 2015

Honorable Chairman Mary D. Nichols and Honorable Board Members
California Air Resources Board
1001 I Street
P.O. Box 2815
Sacramento, CA 95812

Re: SUPPORT for Re-Adoption of the Low-Carbon Fuels Standard

Dear Chairman Nichols and Honorable Board Members:

The California Electric Transportation Coalition (CalETC) appreciates the opportunity to comment in support of re-adoption of the Low Carbon Fuels Standard (LCFS). CalETC is a non-profit association with a board of directors that includes: Los Angeles Department of Water and Power, Pacific Gas & Electric, Sacramento Municipal Utility District, San Diego Gas & Electric and Southern California Edison. Our membership also includes major auto makers and we work closely with our colleagues in the alternative fuels community.

First, we laud the California Air Resources Board (CARB) in the design and implementation of the LCFS. The regulation sets a standard for the regulated industry and allows the industry to determine how best to meet that standard, providing flexibility in an industry long constrained by the transportation sector's near-total dependence on only one fuel. The LCFS program has resulted in unanticipated innovation in both fuels and vehicles and expanded consumer choice. In the first years of implementation of the LCFS, industry is over-complying, credits are being generated from unanticipated and innovative sources, and consumers are responding to expanding choices in fuels and vehicles. LCFS 6-1

We respectfully submit the following comments:

- CalETC appreciates the addition of forklifts and fixed guideway systems in the LCFS program. The definition of transportation fuel in LCFS includes non-road uses of transportation fuel. Including forklifts and fixed guideway systems ensures that expanded transportation fuel opportunities are available for both the regulated industry and the fuel providers. LCFS 6-2
- CalETC supports the staff's proposal to stay the course and meet a ten percent (10%) reduction in the carbon content of fuels sold in California by 2020. This is essential to providing market certainty for alternative fuel providers, particularly given the overwhelming market advantage the predominant fuel has in the transportation fuels sector. LCFS 6-3
- CalETC supports the staff's proposal for a credit clearance option to cost containment. We respectfully suggest that additional analysis be conducted to determine the appropriate maximum price per credit in the clearance market. Establishing a maximum price which is too low may have negative implications, such as stifling innovation and inhibiting the market. LCFS 6-4

We also respectfully suggest that additional analysis be completed to develop a minimum price per credit, or price floor, for LCFS credits. Certainty for the regulated parties and credit generators can be achieved through both cost containment and price floor mechanisms. LCFS 6-5

In closing, CalETC supports re-adoption of this groundbreaking and essential regulation. Thank you for your consideration and ongoing leadership. LCFS 6-6

Regards

Eileen Wenger Tutt, Executive Director
California Electric Transportation Coalition

EWT/kmg

6_OP_LCFS_CalETC

35. Comment: **LCFS 6-1**

The comment supports the cost-containment provisions in the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

36. Comment: **LCFS 6-2**

This comment supports the inclusion of forklifts and fixed guideway systems provisions in the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the inclusion of forklifts and fixed guideway systems provisions.

37. Comment: **LCFS 6-3**

This comment supports the proposed compliance curves in the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the proposed compliance curves.

38. Comment: **LCFS 6-4**

This comment gives support for the credit clearance option in the cost containment provision. Additionally, it was suggested to perform additional analysis before the price ceiling has been determined.

Agency Response: ARB staff appreciates the support for the credit clearance option to the cost containment provision.

ARB staff proposes that the cost containment threshold for 2016 be set at $200 per metric ton of carbon dioxide-equivalent (MTCO2e) and adjusted annually using a Consumer Price Index deflator to keep pace with inflation and remain at a constant price, in real terms. Staff is further proposing that any compliance debt (in $MTCO_2e$) that is carried over into the next compliance year after the annual credit clearance process has been completed be assessed a five percent interest on that debt until such time that the debt is paid off. Furthermore, all deferred deficits must be repaid within five years. These provisions will encourage regulated parties to erase any compliance debts that they may accrue as soon as possible.

Reducing both these sources of uncertainty is anticipated to increase the incentives for investment. Potential investors may be hesitant to invest in low-CI fuel production facilities given conditions of undue uncertainty, particularly because production facilities for low-CI fuels are typically capital-intensive projects with relatively long payback periods.

39. Comment: **LCFS 6-5**

The comment suggests ARB staff perform additional analysis to develop a price floor.

Agency Response: ARB staff analyzed the potential benefits of a price floor to send a stronger price signal to increase investments in low-CI fuels and to further reduce market uncertainty and credit price volatility. Staff chose not to move forward with this concept in this rulemaking because we believe the compliance curve will send appropriate signals for investment and because of the challenges in setting an appropriate value for the floor. Staff appreciates the ongoing dialogue with, and feedback from, stakeholders regarding whether this topic should be proposed as a future LCFS amendment.

40. Comment: **LCFS 6-6**

This comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

Comment letter code: 7-OP-LCFS-CRE

Commenter: Harry Simpson

Affiliation: Crimson Renewable Energy

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

7_OP_ADF_CRE

7_OP_LCFS_CRE

CRIMSON RENEWABLE ENERGY, LP

17731 Millux Road
Bakersfield, CA 93311
Tel: (661) 617-8610
Fax: (720) 475-5399

February 13, 2014

Chairwoman Mary Nichols
California Air Resources Board
1001 I Street
Sacramento, CA 95812

CC: All California Air Resources Board Members

Via online submission at http://arb.ca.gov/lispub/comm/bclist.php.

RE: comments regarding the proposed Alternative Diesel Fuel (ADF) Regulations and the Low Carbon Fuel Standard

Dear Chairwoman Nichols:

As California's largest in-state producer of biodiesel (we utilize used cooking oil and distiller's corn oil to produce an ultra-low carbon alternative diesel fuel with an average quarterly carbon intensity for 2013 and 2014 of 12 to 16.5) , we are naturally very interested in the proposed Alternative Diesel Fuel (ADF) Regulations and the Low Carbon Fuel Standard (LCFS). Any proposed ADF regulations and/or changes to LCFS could have a profound impact on the California biodiesel market and on the ultimate viability of our Bakersfield biodiesel plant. The Crimson team would like to thank members of the ARB staff and Board Members for their hard work on this rulemaking and their ongoing willingness to engage with us and other industry stakeholders. We greatly appreciate the time that ARB staff members have taken and the positive relationships they've encouraged.

Economic Impact

Before getting into our comments on the proposed ADF regulations and the future direction of LCFS, I would like to provide some additional information about our biodiesel production facility in Bakersfield, California. Specifically, I hope this information will provide the Air Resources Board and its affiliated regional air districts a context to better understand the economic impact of proposed ADF regulations and LCFS.

Our biodiesel production facility in Bakersfield currently has 25 full time employees, and an additional 6 long term, full-time contractors. The plant was built in order to serve the market for very low carbon fuels created by the LCFS.s Based on our spending in 2014, our annual direct economic contribution was $40 million, of which approximately 87% was spent within California and significant portion of this was spent in Bakersfield and other parts of the Central Valley. The average annual 2014 compensation per person employed at the plant not including the senior management positions is approximately $64,000. Furthermore, several of our plant employees came to us without the full range of experience that is required and we have invested significantly in their training.

We are also currently in the midst of an expansion project that began in early 2014 and will be completed in summer 2015 entailing a total investment of nearly $10 million. The first phase of this project was completed in May 2014 enabling us to increase our annualized production rate from 9.5 mil gal/yr to 14mil gal/yr. Upon completion, our plant capacity will grow to 22 mil gal/yr. At that point, the plant will make a direct economic contribution of $70 - $90 million per year (depending on raw material prices) with 89-93% of this being spent within California, and 36-38 full time employees and long-term contractors.

ADF 7-1

Thus we believe that our biodiesel production facility is making a strong and growing economic and job creation contribution locally (which is also considered an economically disadvantaged area) and within California. However, it is important to note that we are but one plant out of 5 current biodiesel producers. The California Energy Commission estimated that in 2014 biodiesel production within California will be approximately 40 million gallons. Based on our Bakersfield plant's spending this year, this would come out to a total direct economic contribution of approximately $122 million in 2014. The CEC has projected in-state biodiesel production to grow to 55 million gallons in 2016, representing an economic contribution of approximately $200 million. These figures deserve serious

CRIMSON
RENEWABLE ENERGY, LP

17731 Millux Road
Bakersfield, CA 93311
Tel: (661) 617-8610
Fax: (720) 475-5399

acknowledgement given the fact that the ADF Rulemaking will reduce the market opportunity for biodiesel in California and this would be disproportionately felt by in-state producers such as Crimson, especially given the markedly higher costs of operating in California as compared to elsewhere in the U.S. or internationally. The same is true if the ARB decides to push back the timeline for LCFS carbon reductions.

ADF 7-1 cont.

Emissions / Health Benefits

As we and other stakeholders have pointed out previously to ARB staff, biodiesel is a solution to very specific problems associated with petroleum diesel's emissions profile – namely the well-known toxics, particulates, and carcinogens that are currently causing unacceptable levels of respiratory illness in California, especially in the Central Valley, the areas surrounding the Port of Long Beach and Port of Los Angeles, and especially among California's children and elderly and its economically disadvantaged communities (such communities tend to be concentrated near industrial areas where truck traffic is disproportionately higher than in other communities). Indeed, "Biodiesel's reduction in PM emissions and associated risks" were acknowledged in the ARB staff presentations at previous ADF Rulemaking Workshops and some air districts in California are out of compliance for PM reductions. Besides PM reduction, biodiesel also provides significant reductions in polycyclic aromatic hydrocarbons (PAHs), nitrated PAHs, and the ozone potential of spectated hydrocarbons. According to the Union of Concerned Scientists and the American Lung Association (http://www.ucusa.org/clean_vehicles/trucks_and_buses/page.cfm/pageID=1429), PM and other hydrocarbon emissions within California are responsible for an estimated 3,000 premature deaths , 2,700 cases of bronchitis, and 4,400 hospital admissions, ultimately creating additional healthcare costs totaling $21+billion.

Biodiesel also provides very large reductions in carbon/GHG emissions (85-95% reduction in carbon/GHG for biodiesel made from used cooking oil and distiller's corn oil from ethanol plants) that are critical to meeting LCFS carbon reduction requirements. According to ARB, in Q1/2014 biodiesel provided 18% of all LCFS credits generated.

Thus we strongly urge the ARB to consider the PM, hydrocarbon toxics, and carbon/GHG reductions and associated health benefits when evaluating any ADF regulatory proposal. Additionally, we urge the ARB to consider that the proposed ADF regulations would be in effect during a period when New Technology Diesel Engines (NTDEs, which reduce all tailpipe NOx emissions by 90% regardless of type of fuel) are being phased in due to existing California law.

ADF 7-2

Comments on LCFS Reauthorization and Specific Aspects of the Proposed ADF Regulations

We ask that ARB Members consider the following points as it continues deliberations on LCFS reauthorization and the proposed ADF regulations.

1. LCFS is working as intended – ARB reporting on LCFS credit generation and deficits from 2011 through Q3/2014 shows 9.80 mil MT credits generated and 5.84mil MT in deficits, creating excess credits of 3.96 mil MT. This data is consistent with original ARB staff projections for the rate of credit generation at this point in the program. Clearly the LCFS has created sufficient market signals to attract the necessary volumes of alternative fuels. Our plant in Bakersfield is but one example among many of how LCFS has influenced investment decisions to create alternative fuel production capacity.

LCFS 7-1

2. LCFS carbon reduction timelines – We strongly urge the ARB and its Members to maintain the original LCFS CI reduction at 10% by 2020. We further encourage the ARB to establish stronger compliance curves to continue progress beyond 2020. Maintaining the 10% reduction is 2020 is absolutely critical to send the right market signals to encourage the availability of large volumes of alternative fuels, development of new low carbon fuel technologies, and incentivize significant alternative fuel utilization. Any pushing back of this timeline would send the opposite signal, devalue alt fuel investments made thus far, and discourage future investment. We believe the 10% reduction is fully achievable in 2020. We agree with the findings in the 2/2/15 Promotum report sponsored by the National Resource Defense Council, stating a $100/MT LCFS credit price will incentivize sufficient volumes of alt fuels to be produced and imported into California and reducing CI intensity of petroleum based fuels. Using alternative diesel fuels as a case in point, there is sufficient excess industry-wide production capacity to greatly increase the volumes of biodiesel and renewable diesel

LCFS 7-2

CRIMSON
RENEWABLE ENERGY, LP

17731 Millux Road
Bakersfield, CA 93311
Tel: (661) 617-8610
Fax: (720) 475-5399

imported into California (the National Biodiesel Board reports 2.5 bil gal of current U.S. biodiesel production capacity vs actual 2014 domestic production of 1.6 bil gal). LCFS 7-2 cont.

3. LCFS Program integrity – In line with creating transparent and predictable market rules, ARB should adopt rule proceedings in the event that fraudulent credit trades or other invalid activities are discovered. We would recommend that ARB carefully consider the experience of the US Environmental Protection Agency in its enforcement of the Renewable Fuel Standard (RFS). Delayed prosecutions and a lack of concern for collateral damage caused to good faith market participants undermined respect for the RFS program and the value of RFS credits. We would encourage ARB to insulate good faith market participants from disproportional impacts and to avoid wholesale invalidation of credits. Due to the complex and novel nature of environmental attribute markets, ARB must invest in sufficient resources and personnel to ensure effective enforcement. LCFS 7-3

4. Impact of ADF Regulations on California Biodiesel Industry – From a California biodiesel producer's perspective the proposed ADF regulations are not ideal for the simple fact that, despite the various economics , emission and health benefits offered by biodiesel, limits will be placed on biodiesel usage in California. However, we do believe that the proposed ADF regulations reflect input from the biodiesel industry and many other stakeholder groups. ARB Staff was really done outstanding job in reaching out to all stakeholders for consistent engagement. As such we feel that the biodiesel usage limits prescribed by the proposed ADF regulations are not unreasonable. They are workable and will achieve the desired goals for NOx management while retaining the ability to meaningfully take advantage of the significant benefits offered by biodiesel blending in California. ADF 7-3

5. ADF Regulation implementation timeline – The proposed ADF regulations will require significant change within the industry, including new labeling at each retail dispenser and the joint development of new compliance and tracking mechanisms. Other agencies such as the Division of Weights and Measures will require time to adapt their biodiesel related regulations (there may be a need to change the current California labeling requirements at retail dispensers).Thus we believe the implementation timelines as stated in the proposed ADF regulations are reasonable and necessary. ADF 7-4

6. Mitigation options - We applaud the ARB's understanding that DTBP additive is not an ideal mitigation option for several safety, financial and operational reasons, and thus preserved in the proposed ADF regulations the ability to approve other NOx mitigation additives. We would only add that we hope ARB staff will diligently pursue this in a timely manner in partnership with the biodiesel industry, and consider the use of current commercially available cetane enhancers. ADF 7-5

7. Accounting for NTDE and Sunset Provisions -. NTDE vehicles which reduce NOx by 90%+ already make up 25%+ of the current heavy duty diesel fleet in California and will grow to 95% by 2023 as required by ARB fleet turnover regulations. In light of this, we believe it is completely reasonable and appropriate that the ADF regulations will sunset when vehicle miles travelled by NTDE heavy duty vehicles reach 90% of the total miles travelled by the California heavy-duty diesel vehicle fleet. ADF 7-6

We greatly appreciate this opportunity to comment. Please feel free to contact me should you have any questions.

Sincerely yours,

Harry Simpson
President
hsimpson@crimsonrenewable.com
Tel: 720-475-5409

This page intentionally left blank.

7_OP_LCFS_CRE Response

41. Comment: **LCFS 7-1**

This comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

42. Comment: **LCFS 7-2**

The comment strongly suggests that ARB continue the LCFS timeline beyond 2020.

Agency Response: See response to **LCFS 5-2**.

43. Comment: **LCFS 7-3**

The comment urges ARB to monitor the LCFS program to retain program integrity and to insulate good faith market participants.

Agency Response: ARB staff agrees that monitoring, auditing and enforcement of the LCFS Program are critical to ensure the emission benefits of the program are realized. The ARB's Enforcement Division is authorized to enforce the regulations adopted by our Board. Enforcement and LCFS Program staff persons coordinate efforts to ensure that rules are fully followed. Additionally, LCFS Program management has paired with Cap-and-Trade Program management to create a branch within ARB that verifies the underlying data used to create credits. The new branch will facilitate a consistent agency approach regarding transportation fuels.

ARB staff is aware of the voluntary quality assurance plan provisions that the U.S. Environmental Protection Agency (U.S. EPA) has adopted in the Renewable Fuel Standard (RFS) Program. ARB staff has had discussions with U.S. EPA staff regarding their implementation experience with this recently-adopted provision, as the RFS uses a similar "buyer-beware" approach. The RFS Program requires that all retired credits which are found to be invalid must be offset by valid credits with real emission benefits. Currently, LCFS market participants can do their own due diligence to ensure the validity of the LCFS credits, and these efforts will be taken into consideration if invalid credits are found.

If fraud is discovered, the Health and Safety Code and a host of other state and federal statutes may apply and provide civil and criminal consequences. ARB staff will investigate the most culpable party available to replace invalid credits and face other legal consequences; however, because identifying and locating a “most culpable” party is sometimes difficult or impossible, staff does not deem it wise to immunize other parties who hold or previously held invalid credits. To do so would be to risk losing the programs benefits in cases where the culpable party could not be found or compelled to replace credits. This “buyer beware” policy should also incent all parties to perform appropriate due diligence prior to purchasing credits.

Comment letter code: 8-OP-LCFS-RFA

Commenter: Geoff Cooper

Affiliation: Renewable Fuels Assoc.

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

RENEWABLE FUELS ASSOCIATION

8_OP_LCFS _RFA

February 16, 2015

Mary Nichols
Chairwoman
California Air Resources Board
1001 "I" Street
Sacramento, CA 95812

Dear Chairwoman Nichols,

The Renewable Fuels Association (RFA) appreciates the opportunity to provide comment on the California Air Resources Board's (CARB) Initial Statement of Reasons (ISOR) regarding re-adoption of the Low Carbon Fuel Standard (LCFS). While the proposal for re-adoption marks a slight improvement over the current regulation, we remain deeply concerned by several aspects of the proposal and believe it threatens the long-term durability of the LCFS program. Thus, RFA believes the ISOR needs significant revision before it can be presented to the Board for approval.

Grain-based ethanol has made a substantial contribution to LCFS compliance in the first four years of the program. Indeed, ethanol has accounted for **59% of total credits** generated from 2011Q1 through 2014Q3, and 95% of the ethanol used for compliance has been grain-based ethanol, according to CARB reporting data. If not for the LCFS credits generated by grain-based ethanol, deficit generation would have certainly outpaced credits by now, and compliance with the program would be extremely difficult, if not impossible. Thus, it is not an exaggeration to state that the LCFS has endured so far **only because of the contributions of grain ethanol**. Yet, the ISOR proposes to continue punitive carbon intensity (CI) penalties for grain ethanol and other crop-based biofuels based on purported indirect land use change (ILUC) emissions. If finalized, the proposed re-adoption regulation will make the use of most grain ethanol infeasible for compliance as early as 2016. Why would CARB use flawed and prejudicial analysis to purposely diminish the compliance viability of the low-carbon fuel that has provided the largest volume of credits to date? LCFS 8-1

As the attached comments show, CARB's ILUC analysis remains technically and methodologically flawed, and grossly overstates the land use impacts associated with biofuels expansion. A November publication by the Center for Agricultural and Rural Development (CARD) at Iowa State University makes a remarkably important contribution to the debate over ILUC modeling. The report marks the first time that actual land use changes over the past decade (i.e., the period in which commodity crop prices rose to record levels) have been quantified and discussed in the context of CARB's ILUC modeling results. The CARD/ISU paper, which is discussed in detail in the attached comments, found that "[t]he pattern of recent land use changes suggests that **existing estimates of greenhouse gas emissions caused by** LCFS 8-2

land conversions due to biofuel production are too high because they are based on models that do not allow for increases in non-yield intensification of land use." In essence, the authors found that the primary response of the world's farmers to higher crop prices "…**has been to use available land resources more efficiently rather than to expand the amount of land brought into production**." LCFS 8-2 cont.

The CARD/ISU research was submitted to CARB in early December. However, CARB's ISOR fails to even mention or acknowledge the work in any way. For the first time, we have real-world data that provides important insight into actual market responses to increased biofuels demand and higher crop prices. As described in the attached comments, we believe CARB must take into account the new CARD/ISU research and use it to immediately re-calibrate the GTAP model. LCFS 8-3

We appreciate CARB's consideration of our attached comments, which also address CA-GREET model revisions and assumptions used in CARB's illustrative compliance scenarios. We welcome further dialog on this subject and look forward to responses to any of the comments offered in the attached document.

Sincerely,

Geoff Cooper

Geoff Cooper
Senior Vice President

RENEWABLE FUELS ASSOCIATION

COMMENTS OF
THE RENEWABLE FUELS ASSOCIATION
IN RESPONSE TO THE CALIFORNIA AIR RESOURCES BOARD
STAFF REPORT: INITIAL STATEMENT OF REASONS
TO CONSIDER
RE-ADOPTION OF THE LOW CARBON FUEL STANDARD (LCFS)

The Renewable Fuels Association (RFA) offers the following comments in response to the California Air Resources Board's (CARB) release of its Initial Statement of Reasons (ISOR) proposing re-adoption of the Low Carbon Fuel Standard (LCFS)

I. Indirect Land Use Change Analysis

CARB continues to rely on a fundamentally flawed approach to predicting indirect land use change (ILUC) that favors hypothetical modeling results over empirical data, real-world observations, and improved assessment methods.

Nearly six years have passed since CARB originally adopted the LCFS, which included carbon intensity (CI) penalties for certain biofuels for predicted ILUC. In the intervening years since the program was adopted, the scientific understanding of land use change has significantly progressed. Retrospective analyses of global agricultural land use have been conducted, actual market responses to increased demand and higher commodity prices have been observed and characterized, the reliability of predictive economic models has been improved, and new data has emerged to better guide certain modeling assumptions.

Yet, in spite of these advances in the science, CARB continues to rely on the narrow—and completely unsubstantiated—view that "[a] sufficiently large increase in biofuel demand in the U.S. would cause non-agricultural land to be converted to cropland both in the U.S. and in countries with agricultural trade relations with the U.S." LCFS 8-4

CARB's entire approach to ILUC is founded on the notion that farmers are limited to only two responses to increased demand for crops. While CARB recognizes four potential market responses to heightened demand for crops, its predictive modeling framework essentially allows only two of these responses to play out. The four potential market responses acknowledged by CARB are shown below.

- **Response 1**: "Grow more biofuel feedstock crops on existing crop land by reducing or eliminating crop rotations, fallow periods, and other practices which improve soil conditions";
- **Response 2**: "Convert existing agricultural lands from food to fuel crop production";
- **Response 3**: "Convert lands in non-agricultural uses to fuel crop production"; or
- **Response 4**: "Take steps to increase yields beyond that which would otherwise occur."

CARB theorizes that there is essentially no crop yield response to increased demand (Response 4 above), and an artificially low elasticity value is used to reflect this belief in CARB's economic model. Further, the CARB modeling framework does not allow double-cropping or reduction of fallow/idle cropland; thus, Response 1 above is also eliminated. *As a result, CARB assumes increased demand for crops can only be met through displacement of animal feed and conversion of non-agricultural lands to crop production (Responses 2 and 3 above).* Not coincidentally, Responses 2 and 3 have the most significant GHG impacts.

CARB has produced no evidence whatsoever that such land conversions have actually occurred on a meaningful scale in response to the LCFS or growth in U.S. biofuels demand. Indeed, empirical evidence suggests that demand growth has been primarily met through Responses 1 and 4 above, which are effectively excluded from CARB's modeling framework. LCFS 8-4 cont.

Instead of tuning the modeling framework to reflect these observed market responses, CARB continues to rely on conjectural assumptions and model predictions to penalize biofuels for hypothetical market outcomes. In essence, CARB is using the exact same approach to estimating ILUC emissions that it used six years ago, making only minor adjustments to certain model parameters based on "judgment calls."

RFA believes the principles of sound policymaking and regulation demand that CARB recognize and incorporate the best available science and data in the LCFS process, particularly when empirical data is available to fill important knowledge gaps.

a. A New Publication by Babcock & Iqbal Has Important Implications for CARB's ILUC Analysis. CARB Should Give Serious Consideration to the Findings of the Paper, and Adjust its ILUC Estimation Methodology Accordingly

In mid-November, Babcock & Iqbal at the Center for Agricultural and Rural Development (CARD) published Staff Report 14-SR 109, "Using Recent Land Use Changes to Validate Land Use Change Models."[1] The paper (Attachment 1) makes a remarkably important contribution to the debate over ILUC modeling. The report marks the first time that actual global land use changes over the past decade (i.e., the period in which commodity crop prices rose to record levels) have been quantified and discussed in the context of CARB's ILUC modeling results. <u>The report was submitted to CARB staff in early December 2014, yet there is not a single mention of the paper (nor is there a response to its findings) in the ISOR.</u> LCFS 8-5

Babcock & Iqbal examined historical global land use changes from 2004-2006 to 2010-2012 and determined that "…the primary land use change response of the world's farmers from 2004

[1] Babcock, B.A. and Z. Iqbal (2014), Using Recent Land Use Changes to Validate Land Use Change Models. Center for Agricultural and Rural Development Iowa State University Staff Report 14-SR 109. Available at: http://www.card.iastate.edu/publications/synopsis.aspx?id=1230

to 2012 has been to use available land resources more efficiently rather than to expand the amount of land brought into production."[2] Among other important revelations, the paper shows that key regions where CARB's GTAP analysis predicts biofuels-induced conversion of forest and grassland have actually experienced substantial *losses* of cropland.

Unfortunately, CARB's GTAP analysis does not take into account the methods of intensification (e.g., double-cropping, increases in the share of planted area that is harvested, return of fallowed land to production) that have been observed in the real world over the past decade. According to Babcock & Iqbal, GTAP and other models "…do not capture intensive margin land use changes so they will tend to ***overstate land use change at the extensive margin and resulting emissions***."[3] This finding is corroborated by Langeveld et al (2013) (Attachment 2), who found GTAP and other models have "…limited ability to incorporate changes in land use, ***notably cropping intensity***," and "[t]he increases in multiple cropping have often been overlooked and should be considered more fully in calculations of (indirect) land-use change (iLUC)."[4]

LCFS 8-5 cont.

Ultimately, the Babcock & Iqbal work calls into question the plausibility of CARB's GTAP results and demonstrates that CARB's ILUC results are directionally inconsistent with real-world data and observed market behaviors in many regions. The data and discussion presented in the paper challenge the very underpinnings of CARB's analysis and are simply too important for the agency to ignore. Thus, as described more fully in the comments below, <u>we believe CARB should move immediately to calibrate its GTAP model using the real-world land use data made available by Babcock & Iqbal</u>.

b. Countries and regions where cropland has decreased and/or forestland and grassland have increased over the past decade should be presumed to not have converted pasture or forest to crops in response to biofuel-induced higher prices. CARB should calibrate its GTAP model to reflect the absence of extensive land use change in these countries and regions.

At the outset, it is important to note that the lack of a "counterfactual case" to compare to the real-world data (i.e., the *ceteris paribus* principle) is not sufficient reason to ignore the Babcock & Iqbal results. CARB has stated that comparing GTAP results to real-world data is "not productive," because it is not possible to compare real-world data to a counterfactual case in which biofuel expansion did not occur. Appendix I to the ISOR further states:

LCFS 8-6

> GTAP-BIO is not predicting the *overall aggregate* market trend—only the incremental contribution of a single factor to that trend. If GTAP-BIO projects reduced exports, for example, this should be understood to mean that exports will be lower than what they would have been in

---
[2] *Id,* Executive Summary.
[3] *Id,* Executive Summary. (emphasis added)
[4] Langeveld, J. W.A., Dixon, J., van Keulen, H. and Quist-Wessel, P.M. F. (2014), Analyzing the effect of biofuel expansion on land use in major producing countries: evidence of increased multiple cropping. Biofuels, Bioprod. Bioref., 8: 49–58. doi: 10.1002/bbb.1432. (emphasis added)

> the absence of the effect being modeled (increased ethanol production, in this case). It is the difference between predicting an absolute change and a relative change.[5]

This statement by CARB seems to misunderstand the recommendation from stakeholders to consider and integrate empirical data and observed outcomes into CARB's modeling work. *RFA and other stakeholders fully understand that CARB's GTAP modeling exercise is meant to isolate only the impacts of biofuels expansion on land use.* However, empirical data can be useful for checking the directional consistency and general reasonableness of model predictions. According to the Babcock & Iqbal, "…the historical record of land use changes can be used to provide insight into the types of land that were converted…"[6]

Comparing empirical land use data to GTAP predictions is particularly useful in regions where cropland has contracted over the past decade. That is, if cropland in a certain region *decreased* according to historical data, then there is no justification for asserting—as GTAP does—that biofuel expansion caused extensive margin conversion of natural forest and grassland in that region. In other words, if there was no cropland expansion resulting from biofuels expansion *and all other factors combined* (i.e., in aggregate), then there certainly is no rationale for arguing that biofuels expansion in isolation of other factors led to cropland expansion.

That is not to say, however, that biofuels expansion did not have an impact on land use in the region. Indeed, cropland may have contracted *even more* in a "world without biofuels" (i.e., the counterfactual case). In other words, some additional cropland might have gone out of production in the absence of biofuels, and the function of biofuels demand may have been to keep that cropland engaged in production. Thus, the appropriate question for regions that have experienced cropland *contraction* over the past decade is whether there was foregone sequestration because of biofuels—***not*** whether there was extensive conversion of forest and grassland and soil carbon loss because of biofuels. According to Babcock & Iqbal:

> The countries in Figure 8 that either had negligible or negative extensive land use changes **should be presumed to not have converted pasture or forest to crops in response to biofuel-induced higher prices**. Rather, the presumption should be that **any predicted change in land used in agriculture came from cropland that did not go out of production**.[7]

Figure 8 from Babcock & Iqbal is embedded below. Note that many countries and regions for which CARB's latest GTAP analysis predicts extensive change from forest and grassland to crops actually showed cropland losses or no change. This includes Canada, EU, Japan, China, India, Russia, the U.S., and Oceania. Further, the amount of corn ethanol-induced conversion of

LCFS 8-6 cont.

[5] ISOR, Appendix I at I-20.
[6] Babcock, B.A. and Z. Iqbal (2014) at executive summary.
[7] *Id*. at 26.

forest and grassland in the U.S. predicted by CARB's GTAP model is two to four times larger than the actual extensive land use change in the U.S. driven by ***all factors in aggregate***.

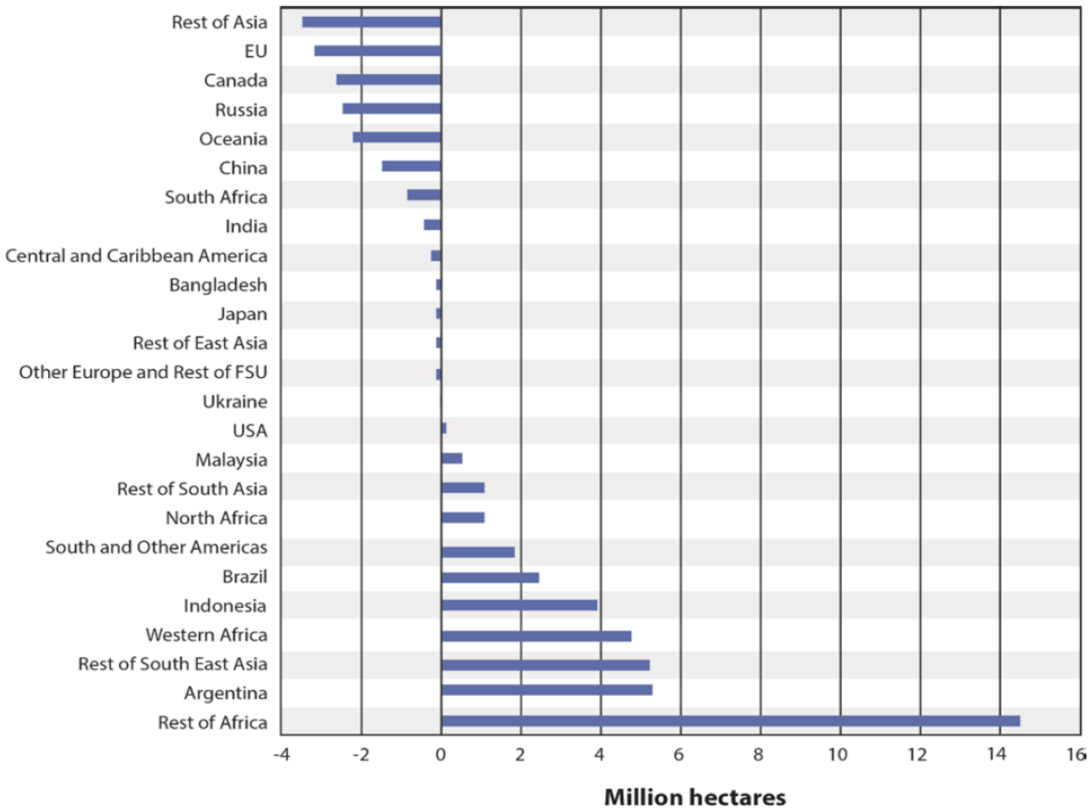


Figure 8. Change in Arable Land Plus Permanent Crops: 2004–2006 to 2010–2012

According to Babcock & Iqbal, the land use emissions implications in countries and regions where cropland decreased or stayed the same are that:

> …the type of land converted to accommodate biofuels was not forest or pastureland but rather **cropland that did not go out of production**. Calculation of foregone carbon sequestration depends on what would have happened to the cropland if it did not remain in crops which, in turn, depends on where the cropland is located and the potential alternative uses. **The magnitude of the change in estimated CO2 emissions from cropland that is prevented from going out of production relative to forest that is converted to cropland is potentially large.**[8]

Unfortunately, CARB's GTAP analysis suggests there was conversion of forest and grassland to crops in regions where real-world data show cropland actually contracted. The disagreement

LCFS 8-6 cont.

[8] *Id.*

between GTAP predictions and real-world data highlights the implausibility of GTAP results for certain regions. CARB can—and should—correct its analysis to better align with real-world land use patterns. The following section provides a method for calibrating CARB's GTAP model to better reflect observed land use changes. LCFS 8-6 cont.

c. CARB should use data from Babcock & Iqbal (2014) to immediately calibrate its GTAP model to reflect real-world land use change patterns in key regions.

LCFS 8-7

As stated in the Babcock & Iqbal paper, CARB should not presume that higher crop prices have caused conversion of forest and grassland to crops in countries and regions where cropland has actually decreased over the past 10 years. Thus, we believe CARB should calibrate its GTAP model to disallow forest and grassland conversion in AEZs and regions for which empirical data show forest or grassland expansion and/or cropland contraction. This can be easily accomplished by excluding GTAP predicted land conversions for the countries in Figure 8 of Babcock & Iqbal that show negative extensive change (i.e., loss of cropland). A more detailed method for accomplishing this calibration is available in comments submitted to CARB by Air Improvement Resource on Dec. 4, 2014.[9]

It could be argued that these countries should still be subject to emissions penalties for foregone sequestration, in that biofuels demand may have caused some cropland to remain in production that may otherwise have transitioned to some other use. But this should only be done if it can be demonstrated that the alternative use of the land would have resulted in carbon sequestration that is greater than the sequestration achieved if the land remained engaged in crop production.

For the countries in Figure 8 that *do* show extensive land use change over the past 10 years, CARB can continue to rely on GTAP predictions, but should also conduct more intensive research to better understand the precipitating causes of land conversions at the extensive margin in those countries. For example, while Sub-Saharan Africa (excluding South Africa) shows significant extensive change over the past decade, it is likely unrelated to biofuels expansion in the U.S. According to Babcock & Iqbal, "The extent to which extensive expansion in African countries was caused by high world prices is likely small for the simple reason that higher world prices were not transmitted to growers in many African countries."[10]

In the longer term, CARB should migrate to the soon-to-be-released dynamic version of GTAP that contains updated baseline economic data. Further, CARB should closely monitor efforts to validate and back-cast the new version of GTAP and be prepared to consider new results from these exercises.

d. CARB's GTAP Analysis Should Adopt CA-GREET2.0 Assumptions for Co-products Displacement Rates

LCFS 8-8

[9] Air Improvement Resources comments available at: http://www.arb.ca.gov/fuels/lcfs/regamend14/air_12042014.pdf
[10] Babcock, B.A. and Z. Iqbal (2014) at 16.

The recently released CA-GREET2.0 model correctly assumes that distillers grains from ethanol production displace both corn and soybean meal in livestock and poultry rations.[11] The total mass of corn, soybean meal, and urea displaced by 1 pound of distiller grains is 1.111 pounds. While this assumption has modest impacts for the direct emissions associated with corn ethanol's lifecycle, the impacts on land use are significant. We have detailed these impacts in many previous comments to CARB, dating back to 2008.

Unfortunately, CARB's GTAP analysis continues to assume 1 pound of distillers grains displaces only 1 pound of corn. This is problematic for at least two reasons: 1) CARB's assumptions and boundary conditions for estimates of direct and indirect emissions should be consistent and uniform, 2) CARB's current GTAP assumptions on distillers grains displacement are simply inconsistent with the reality of how distillers grains are fed.

LCFS 8-8 cont.

We are fully aware that there is no simple method for setting displacement ratios in GTAP, as interactions amongst the various sectors in the model are characterized in terms of economic values (e.g., expenditures, receipts, etc.). However, the economic values representing ethanol co-products in CARB's GTAP model are based on the 2004 database. Obviously, there have been significant changes in the distillers grains market since 2004; the ways in which these co-products are traded, priced, and fed have evolved dramatically. As we have discussed in previous comments to CARB, the agency can better reflect real-world feeding practices (i.e., some displacement of soybean meal) by adjusting the economic values associated with co-product trade in GTAP. RFA believes CARB must make this adjustment to ensure consistent boundaries and assumptions across its direct and indirect emissions analysis.

e. CARB <u>Still</u> Has Not Justified its Proposal to Use a Yield-Price Elasticity Value That is Lower than Recommended by Both Purdue and CARB's Own Expert Work Group. CARB Should Use 0.25 as the Central Value, Not the Proposed Value of 0.185.

Despite new data and published scientific papers supporting the use of a range for YPE of 0.14-0.53, CARB continues to propose using a range of 0.05-0.35. CARB staff has continued to ignore input from stakeholders, academia, and its own Expert Work Group on this parameter, instead relying on input from paid contractors at UC Davis and its own "expert judgment."

LCFS 8-9

In Appendix I, CARB states that "[a]n expert from UC Davis, contracted to conduct a review and statistical analysis of data from a few published studies also concluded that YPE values were small to zero." Yet, it is quite clear from the brief (and somewhat unclear) report from the UC Davis contractor that the YPE response was examined only over the short term (i.e., 1-2 years).

This is inappropriate and scientifically indefensible, as demonstrated by previous stakeholder comments and remarks from Purdue University. For example, during the March 11 workshop on

[11] The latest version of CA-GREET2.0 is available at: http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm

ILUC, Purdue University Prof. Wally Tyner explained why it is inappropriate to include short-run estimates in the range used for CARB's analysis, stating:

> The yield-price elasticity is a *medium-term elasticity*…and we normally think of that as about 8 years. I personally think, and our group thinks, that any of those papers in the literature that represent one year are *totally irrelevant* to this. They may be fine for a one-year estimate, but a one-year estimate is totally irrelevant. Most of the short-term estimates are very low and most of the medium-term [estimates] were much higher—in the range of the 0.25 that we currently use.[12]

Tyner underscored this point again in a note to CARB following the March 11 workshop: "The yield to price elasticity does not measure changes over one crop year. In fact, ***any estimate done over one year would be totally inappropriate for GTAP and should be excluded from consideration in determining appropriate values for the parameter***."[13]

Babcock and other members of the Expert Work Group's Elasticity Subgroup agreed that the use of a short-run elasticity is inappropriate for the purposes of CARB's GTAP scenario runs: LCFS 8-9 cont.

> …to the extent that existing studies provide reliable one-year estimates, they underestimate the long-run response of yields to price. There are sound theoretical reasons for believing that there are lags in the response to higher crop prices. Farmers have an incentive to adopt higher-yielding seed technologies and other management techniques with higher prices. Switching from one seed variety or technology such as seed-planting populations, may require more than a single season to accomplish. And there are likely five to 15 year lags involved in developing new seed varieties and new management techniques that may be only profitable under high prices.[14]

The Schlenker work, which has served as the basis of CARB's use of inappropriately low YPE values, was critiqued by the EWG's Elasticities Subgroup. The subgroup raised several concerns with the Schlenker data, none of which (to our knowledge) have been adequately addressed by CARB staff. In short, the Elasticities Subgroup found that, "[t]he Roberts and Schlenker (2010) results provide ***no evidence that there is not a price-yield relationship***,

---

[12] Audio of Prof. Tyner comments are available at: http://domesticfuel.com/2014/03/12/carb-stresses-iluc-update-is-preliminary/. (emphasis added)
[13] See Appendix B of March 11, 2014 RFA comments, available at: http://www.arb.ca.gov/fuels/lcfs/regamend14/rfa_04092014.pdf. (emphasis added)
[14] ARB Expert Work Group. 2011. "Final Recommendations from the Elasticity Values Subgroup." Available at: http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/010511-final-rpt-elasticity.pdf

they just find evidence that any short-run price yield relationship is overwhelmed by variations in yields caused by weather."[15] LCFS 8-9 cont.

f. The GTAP model's inability to explicitly consider double-cropping further justifies the use of a higher range of price-yield elasticity values.

As explained by CARB's EWG, "…higher prices give farmers a greater incentive to double crop."[16] Indeed, Babcock & Iqbal adds to the body of empirical evidence that double-cropping has significantly increased during the recent period of higher commodity prices (see also Babcock & Carriquiry[17]). Unfortunately, GTAP simulations do not explicitly allow increased demand for agricultural commodities to be satisfied through increased double-cropping. <u>While we believe the best way to account for the impact of double-cropping is to calibrate the GTAP model to the Babcock & Iqbal data (as described in previous sections), and alternative method would be to raise the yield-price elasticity in regions where double-cropping is known to occur</u>. LCFS 8-10

The EWG Elasticities Subgroup recommended that the price-yield elasticity parameter could be used to partially account for double-cropping responses. In its final report, the subgroup explained that "the reality of double cropping" *by itself* justified the use of a positive (i.e., non-zero) value for the price-yield elasticity.[18] The subgroup recommended that "…for countries that have the opportunity to double crop, such as the U.S., Brazil, Argentina, and some Asian rice producing countries such as Thailand…an additional increment should be given to the price-yield elasticity."[19] To date, CARB staff has failed to account for increased double-cropping in its GTAP modeling scenarios. At a minimum, 0.25 should be used as an average value, and an additional increment of 0.1 should be added (total = 0.35) for regions where double-cropping is known to occur.

II. The New CA-GREET2.0 Model Marks a Major Improvement Over CA-GREET1.8b. However, Certain Improvements to CA-GREE2.0 Are Still Needed to Better Reflect the Direct Carbon Intensity of Ethanol Pathways

In general, RFA supports CARB's decision to revise and update its CA-GREET model based on the Argonne National Laboratory GREET1_2013 model. We believe Argonne's GREET1_2013 model contains a number of important improvements and updated inputs that more accurately reflect the current CI performance of corn ethanol and many other fuel pathways. Much has changed since CARB released the original CA-GREET model more than six years ago; ethanol and feedstock producers have rapidly adopted new technologies and practices that have significantly reduced the fuel's lifecycle CI impacts. Thus, it is encouraging to see the CA- LCFS 8-11

---

[15] *Id*. (emphasis added)
[16] *Id*.
[17] Babcock, B. A. and M. Carriquiry, 2010. "An Exploration of Certain Aspects of CARB's Approach to Modeling Indirect Land Use from Expanded Biodiesel Production." Center for Agricultural and Rural Development Iowa State University Staff Report 10-SR 105.
[18] ARB Expert Work Group. 2011. "Final Recommendations from the Elasticity Values Subgroup." Available at: http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/010511-final-rpt-elasticity.pdf
[19] *Id.*

GREET model finally catching up to the actual state of the industry. However, we believe the CA-GREET2.0 model could be further improved by adopting the recommendations below. LCFS 8-11 cont.

a. CARB Should Reduce Denaturant Content in Fuel Ethanol to 2.49% to Reflect Real-World Conditions

In order to comply with Federal requirements, ethanol producers limit the denaturant content of commercial fuel ethanol to 2.49% or less. GREET1_2013, upon which CA-GREET2.0 is based, appropriately assumes denaturant content is 2%. However, Appendix C to the ISOR specifies that CA-GREET2.0 assumes the non-ethanol content of denatured fuel ethanol is 5.4%, with 2.5% being denaturant, 1% being water, 0.5% being methanol, and 1.4% being "other." While denatured fuel ethanol does contain trace amounts of water (1% or less), methanol and "other" components are generally absent from the fuel or present in amounts below those specified by CARB. Further, CARB assumes that all non-ethanol constituents of denatured fuel ethanol—including *water* and "other"—have the same carbon intensity as CARBOB. This is an unsubstantiated and unfair assumption. CARB should fix the denaturant content at 2.49% and treat any remaining non-ethanol constituents (which would be mostly water) as having the same CI as the ethanol. LCFS 8-12

b. CARB Should Include the GREET1_2013 Default Value for Enteric Fermentation Impacts in the Corn Ethanol Pathway

For the CA-GREET2.0 model, CARB is proposing to exclude the GREET1_2013 credit for methane emissions reduction resulting from feeding DDGS. We strongly disagree with this proposal and CARB's rationale for the exclusion. We recommend that CARB adopt the GREET1_2013 methane emissions reduction credit for use in CA-GREET2.0.

CARB states that an "expanded system boundary" would be required for inclusion of methane emission reductions resulting from feeding DDGS to livestock. This implies that CARB views methane emissions reductions as a potential indirect or consequential effect. It could be argued that reduced methane emissions from livestock are a direct effect of corn ethanol expansion (via increased DDGS feeding). Nonetheless, even if we accept the argument that methane emission reductions are an *indirect* effect, CARB has no defensible reason for excluding these emission reductions. That is because CARB *already has expanded the boundary conditions for its corn ethanol pathways to include consequential/indirect effects such as purported land use changes*. CARB has also proposed to include indirect emissions associated with irrigation constraints, and at one point CARB was considering inclusion of hypothetical emissions that would indirectly result from "holding food consumption constant." Thus, CARB is proposing to include a number of potential indirect/consequential emissions sources in the corn ethanol lifecycle, but plans to selectively exclude potential emissions reductions (i.e., credits). This reflects inconsistent and asymmetrical boundary conditions (and possible bias) in CARB's analysis of corn ethanol emissions. LCFS 8-13

III. CARB's Compliance Scenario Assumptions Regarding the Availability of Sugarcane Ethanol and Related Credit Generation Seem Highly Implausible

CARB's new compliance scenarios continue to grossly over-estimate the amount of imported sugar-derived ethanol that is likely to be available to the U.S. and California marketplace in the future. As a result, CARB adopts an overly optimistic view of potential LCFS credit generation in the 2015-2020 timeframe.

In Appendix B, CARB states that its sugarcane ethanol estimate is derived from the Food and Agricultural Policy Research Institute's (FAPRI) World Agricultural Outlook. It should be noted that due to budget constraints, FAPRI has not produced a comprehensive World Agricultural Outlook report since 2011. It is unfathomable that CARB would rely on the 2011 FAPRI publication for its projections of sugarcane ethanol availability when more current projections are available from multiple sources.

Indeed, FAPRI itself continues to publish annual "Projections for Agricultural and Biofuel Markets."[20] These projections are published in March of every year. Much has changed in the Brazilian and world sugar and ethanol sectors since 2011, and FAPRI has since significantly revised its outlook for U.S. imports of sugarcane ethanol.

FAPRI's 2014 projections include yearly estimates of U.S. ethanol imports through 2023. FAPRI projects that U.S. ethanol imports will average **182 mg per year** in the 2015-2023 timeframe, with exports never exceeding 197 mg in any single year. *Importantly, these projections include the effects of the California Low Carbon Fuel Standard*. According to FAPRI: LCFS 8-14

- "Sugarcane ethanol imports from Brazil continue to decline in 2014 before leveling out."
- "Lower RFS requirements for advanced biofuel could imply reduced ethanol imports."
- "However, *low-carbon fuel requirements in California provide some incentive for continued ethanol imports*."

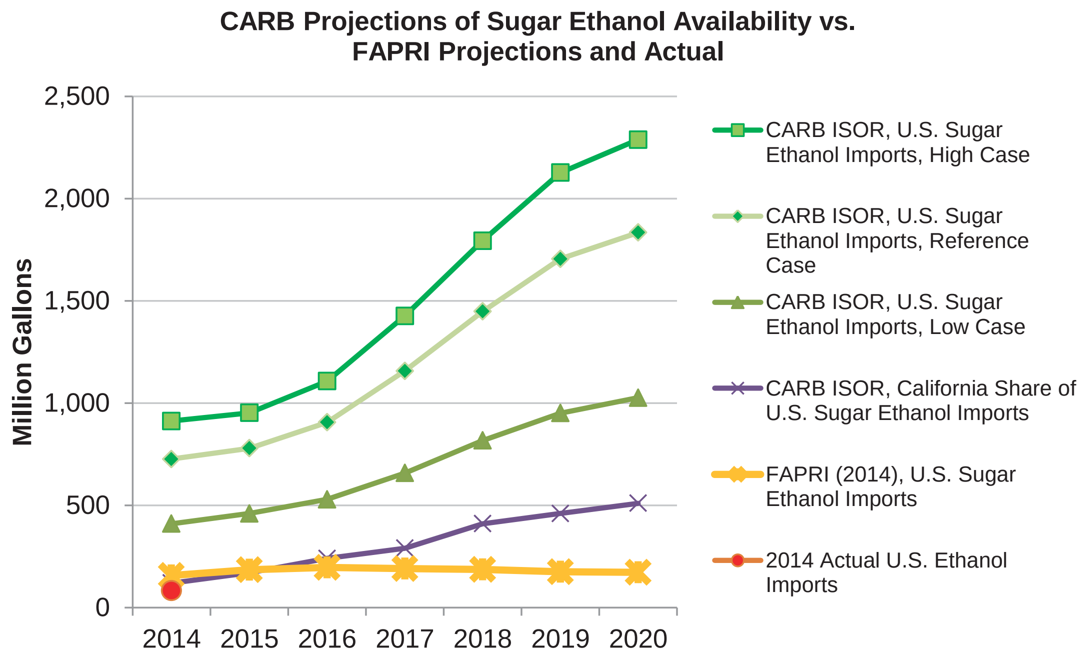
<u>Thus, CARB's current 2020 projections (Appendix B reference, high and low cases) of sugarcane- and molasses-based ethanol are roughly 6-13 times higher than FAPRI's current outlook, which *do* take into the account the likely "pull" from the LCFS.</u> Further, total ethanol imports to the entire United States (most of which were sugar-derived) were just 84 million gallons in 2014, compared to CARB's compliance scenario assumption of 410-912 million gallons. In fact, CARB's projection that California would receive 120 million gallons of sugar-related ethanol in 2014 is 42% larger than actual imports to the <u>entire U.S.</u> Of the 84 million gallons imported by the U.S., only 7.96 million gallons—or 9.5% of the U.S. total—entered through California ports. Thus, actual California imports in 2014 were equivalent to just <u>6.6%</u> of the volume anticipated by CARB.

[20] 2014 FAPRI Baseline available here: http://www.fapri.missouri.edu/outreach/publications/2014/FAPRI_MU_Report_02_14.pdf

Similarly, CARB's projection that California will receive 510 million gallons of sugar-derived ethanol in 2020 compares to FAPRI's projection that the entire U.S. will receive only 172 million gallons of sugar ethanol that year.

CARB has suggested that higher LCFS credit values could lure larger volumes of sugar ethanol to California than projected by FAPRI. However, empirical data from the past four years show no discernible relationship between credit values and sugarcane ethanol imports to California.[21] It is also worth noting that Brazil is soon increasing its ethanol blend rate, which will further reduce the amount of sugarcane ethanol that is available to export.

LCFS 8-14 cont.



We strongly recommend that CARB refine its estimates of sugar-related ethanol and use FAPRI's latest projections of sugarcane ethanol availability when conducting its analysis of potential fuel availability.

* * * * *

Thank you for considering RFA's comments on the ISOR for the re-adoption of the LCFS. We would be pleased to address any questions you may have regarding the contents of these comments or any other issues related to ethanol's role in the LCFS.

[21] See analysis of sugarcane ethanol import response to LCFS credit prices at: http://www.ethanolrfa.org/exchange/entry/the-california-lcfs-and-sugarcane-ethanol-wheres-the-flood/

APPENDIX A:

Babcock, B.A. and Z. Iqbal (2014), Using Recent Land Use Changes to Validate Land Use Change Models. Center for Agricultural and Rural Development Iowa State University Staff Report 14-SR 109.

Using Recent Land Use Changes to Validate Land Use Change Models

Bruce A. Babcock and Zabid Iqbal

Staff Report 14-SR 109

Center for Agricultural and Rural Development
Iowa State University
Ames, Iowa 50011-1070
www.card.iastate.edu

Bruce A. Babcock is Cargill Chair of Energy Economics, Department of Economics, Iowa State University, 468H Heady Hall, Ames, IA 50011. E-mail: babcock@iastate.edu.

Zabid Iqbal is a graduate research assistant, Department of Economics, Iowa State University, 571 Heady Hall, Ames, IA 50011. E-mail: zabid@iastate.edu.

This publication is available online on the CARD website: *www.card.iastate.edu*. Permission is granted to reproduce this information with appropriate attribution to the author and the Center for Agricultural and Rural Development, Iowa State University, Ames, Iowa 50011-1070.

The authors gratefully acknowledge research support provided to Iowa State University by the Renewable Fuels Foundation and the Bioindustry Industry Center.

For questions or comments about the contents of this paper, please contact Bruce A. Babcock, *babcock@iastate.edu.*

Iowa State University does not discriminate on the basis of race, color, age, ethnicity, religion, national origin, pregnancy, sexual orientation, gender identity, genetic information, sex, marital status, disability, or status as a U.S. veteran. Inquiries can be directed to the Interim Assistant Director of Equal Opportunity and Compliance, 3280 Beardshear Hall, (515) 294-7612.

Executive Summary

Economics models used by California, the Environmental Protection Agency, and the EU Commission all predict significant emissions from conversion of land from forest and pasture to cropland in response to increased biofuel production. The models attribute all supply response not captured by increased crop yields to land use conversion on the extensive margin. The dramatic increase in agricultural commodity prices since the mid-2000s seems ideally suited to test the reliability of these models by comparing actual land use changes that have occurred since the price increase to model predictions. Country-level data from FAOSTAT were used to measure land use changes. To smooth annual variations, changes in land use were measured as the change in average use across 2004 to 2006 compared to average use across 2010 to 2012. Separate measurements were made of changes in land use at the extensive margin, which involves bringing new land into agriculture, and changes in land use at the intensive margin, which includes increased double cropping, a reduction in unharvested land, a reduction in fallow land, and a reduction in temporary or mowed pasture. Changes in yield per harvested hectare were not considered in this study. Significant findings include:

- In most countries harvested area is a poor indicator of extensive land use.
- Most of the change in extensive land use change occurred in African countries. Most of the extensive land use change in African countries cannot be attributed to higher world prices because transmission of world price changes to most rural African markets is quite low.
- Outside of African countries, 15 times more land use change occurred at the intensive margin than at the extensive margin. Economic models used to measure land use change do not capture intensive margin land use changes so they will tend to overstate land use change at the extensive margin and resulting emissions.
- Non-African countries with significant extensive land use changes include Argentina, Indonesia, Brazil, and other Southeast Asian countries.
- Given the lack of a definitive counterfactual, it is not possible to judge the consistency of model predictions of land use to what actually happened in each country. Some indirect findings are that model predictions of land use change in Brazil are too high relative to other South American countries; and model predictions of increasing extensive land use that are larger than what actually occurred are consistent with actual land use changes only if cropland was kept from going out of production rather than being converted from forest or pasture.

The contribution of this study is to confirm that the primary land use change response of the world's farmers from 2004 to 2012 has been to use available land resources more efficiently rather than to expand the amount of land brought into production. This finding is not necessarily new and it is consistent with the literature that shows the value of waiting before investing in land conversion projects; however, this finding has not been recognized by regulators who calculate indirect land use. Our conclusion that intensification of agricultural production has dominated supply response in most of the world does not rely on higher yields in terms of production per hectare harvested. Any increase in yields in response to higher prices would be an additional intensive response.

Using Recent Land Use Changes to Validate Land Use Change Models

In the mid-2000s prices for major agricultural commodities began a long, sustained increase. Prices increased dramatically due to growth in demand for food and biofuel producers, underinvestment in agricultural infrastructure and technology, and poor growing conditions in major producing regions. Figure 1 shows the percent change in inflation-adjusted prices received by US producers for corn, soybeans, wheat, and rice relative to the previous five-year average.[1] The predominance of negative changes shows that since 1960 average real prices for these commodities have dropped. These figures show that the commodity price boom in the early 1970s resulted in the largest increase in real prices, but the recent increase in prices since 2006 resulted in the longest sustained increase, especially for corn and soybeans. For wheat and rice, real prices increased sharply in the mid-2000s and have stayed high even though the year-over-year increases were not as long lasting as for corn and soybeans. The magnitude of these real price increases after such a prolonged and sustained period of flat or falling prices presents a unique opportunity to quantify how world agriculture responds to incentives to produce more.

The United States, California, and the EU have enacted regulations based in part on model predictions of agricultural supply response to price increases induced by increased biofuel production. The model predictions of land use changes are called indirect land use changes because the predicted changes are due to a modeled response to higher market prices rather than a direct response to the need to grow more feedstock for biofuel production. Thus, for example, the corn used to produce corn ethanol in the United States was met by US corn production; however, the diversion of corn from other uses increased corn prices and crop prices of other commodities that compete with corn for market share and land. Because corn and other commodities are traded on world markets, prices in other countries also increase. The response in the US and in other countries to these higher prices is what the models measure.

[1] Prices are average annual prices received by US farmers adjusted by the US CPI.

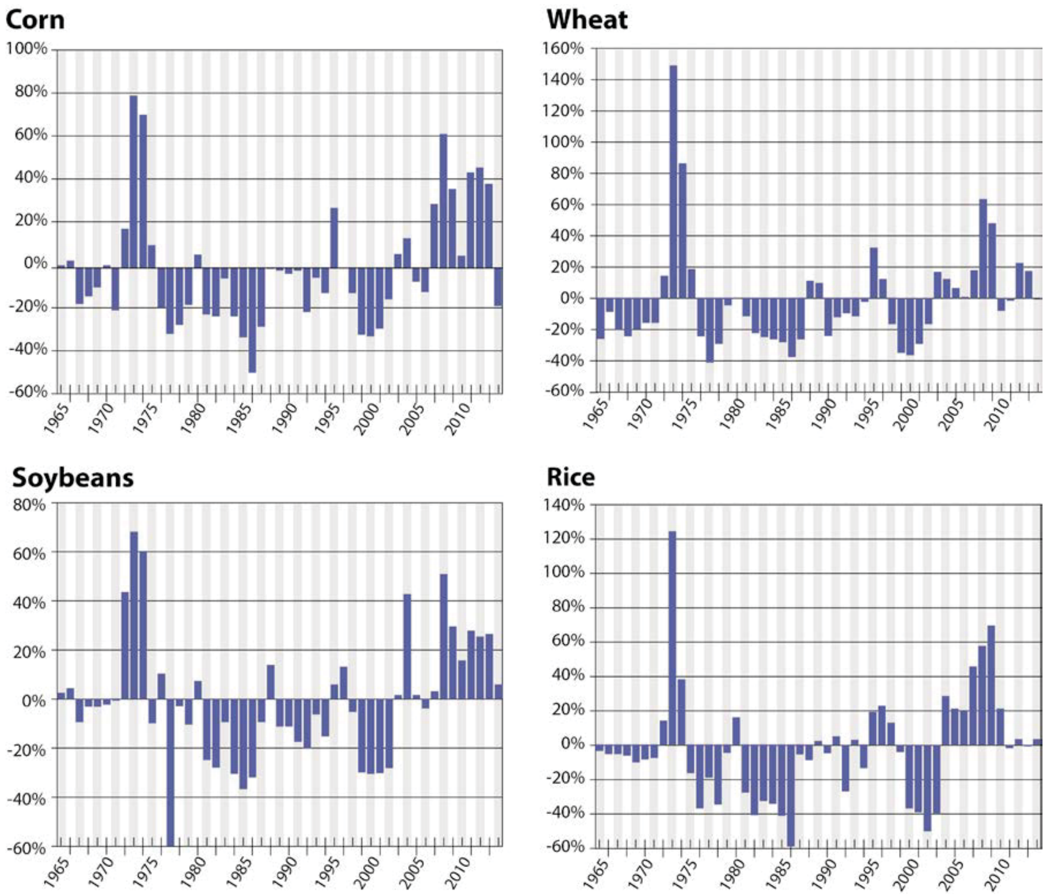


Figure 1. Deviations in Real US Commodity Price Levels from Lagged Five-Year Average Measuring World Land Use Changes

Some portion of the higher prices since the mid-2000s was caused by increased biofuel production. For example, Fabiosa and Babcock (2011) estimate that 36% of the corn price increase from 2006 to 2009 was due to expanded ethanol production. Carter, Rausser, and Smith (2010) estimate that 34% of the corn price increase between 2006 and 2012 was due to the US corn ethanol mandate. This implies that a portion of the actual response of land use since this price increase is due to US ethanol production. Other factors such as crop shortfalls and other sources of increased demand account for the rest of the price increase.

Because indirect land use is a response to higher market prices, model predictions of land use change should be similar whether the higher prices came from increased biofuel production, increased world demand for beef, or from a drought that decreased supply in one or more major producing areas. This implies that the pattern of actual land use changes that we have seen since the mid-2000s should be useful to determine the reliability and accuracy of the models that have been used to measure indirect land use. The purpose of this paper is to look at what has happened over approximately the last 10 years in terms of land use changes and to determine whether and how these historical changes can provide insight into the reliability of model-predicted changes in land use. We address the following questions in this paper:

- How has cropland changed around the world in approximately the last 10 years?
- What were the major drivers of observed land use changes?
- When can actual land use changes be compared with model predictions?
- What can be said about the types of land that were actually converted?

How Has Harvested Area Changed Since 2004?

The most complete source of data on annual cropland is from the Statistics Division of FAO (FAOSTAT), which measures annual harvested area by crop and country. These data have been widely used to measure the impact of biofuel production on expansion of land used in agriculture (Roberts and Schlenker 2013) and to calibrate the land cover change parameter in the GTAP model (Taheripour and Tyner 2013). Figure 2 shows the change in harvested land according to FAO. The data are smoothed by calculating the change in harvested area as the average in 2010, 2011, and 2012 minus the average in 2004, 2005, and 2006. The earlier period measures harvested area before the large increase in price. The later period represents harvested area after prices had increased substantially. India, China, Africa, Indonesia and Brazil had the largest increase in harvested land. These data seem to suggest that these countries had the largest increase in land conversion; however, harvested land is not equal to planted land. Harvested land will deviate from planted land when a portion of planted land is not harvested and when a portion of land is double or triple cropped.

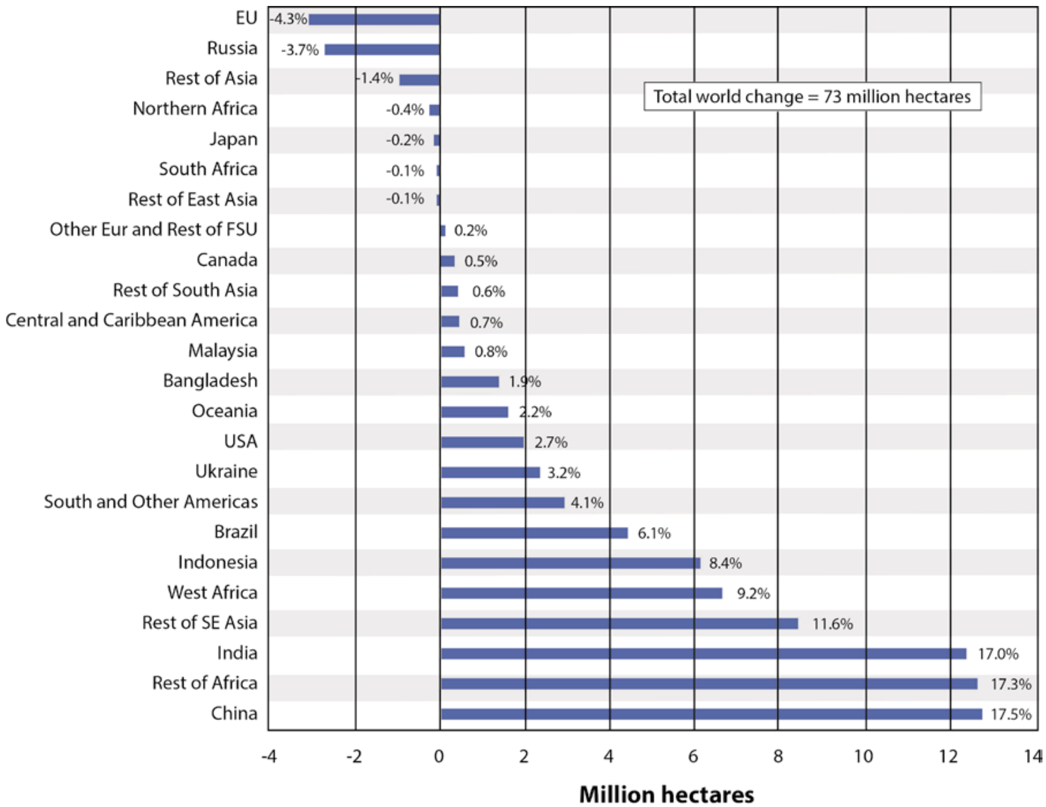


Figure 2. Change in Harvested Land 2010–2012 Average Minus 2004–2006 Average and Country's Share of Total World Change
Source: FAOSTAT

Suppose that a portion of land that is planted to a first crop is not harvested and that a portion of first crop land that is harvested in a country is double-cropped, which simply means that a second crop is planted on land that was already planted to a crop in the same year.[2] By definition, total harvested land, H, equals total harvested land from the first crop, H_1, plus total harvested land from the second crop, H_2. Total harvested land from the first crop equals total land planted to the first crop, P_1 minus land that was planted but not harvested, a_1. Thus we have in any year t

$$P_{1,t} = H_t - H_{2,t} + a_{1,t}$$

[2] Throughout this article land the phrase double crop should be interpreted as two or more crops being grown on a single parcel of land.

For the purpose of greenhouse gas emissions from land use changes, it is most relevant to calculate the change in planted area between two time periods $t = T$ and $t = 0$. Thus, we have

$$P_{1,\mathrm{T}} - P_{1,0} = (H_T - H_0) - (\mathrm{H}_{2,\mathrm{T}} - H_{2,0}) + (a_{1,\mathrm{T}} - a_{1,0})$$

If second crop acreage has increased over time, then use of FAO data on total harvested land overstates land use change by this amount. If the change in first crop land that is not harvested also increases over time, then at least some portion of this upward bias in measuring land use change is overcome. If, instead, the amount of unharvested land has decreased over time then the upward bias is increased. A more in-depth examination of data available for a few countries gives insight into the extent to which use of FAO harvested area data provides a good indication of land use changes.

United States

Figure 3 illustrates that reliance on harvested area as an indicator of land use change can lead to a large bias, and shows annual changes in harvested and planted land to corn in

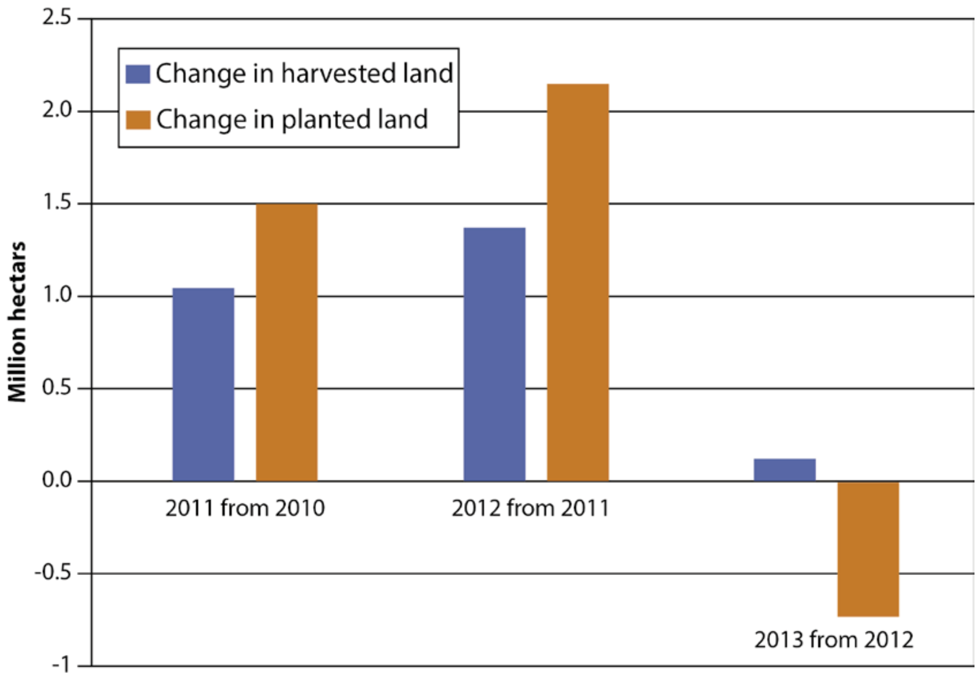


Figure 3. Annual Change in Harvested and Planted Corn Land in the United States

the United States from 2011 to 2013. A widespread drought in the United States resulted in an increase in the amount of planted land that was not harvested. Thus in 2012, use of harvested land to measure land use change understates land use change, whereas in 2013, it overstates land use change. Taking average changes over some time period will reduce the impact of an outlier like 2012, but it will not eliminate it. Thus, use of 2012 harvested data in the United States will tend to understate land use change relative to an earlier period and overstate it relative to a later period. Because data on US planted land is available from USDA's National Agricultural Statistics Service, it makes much more sense to use these data rather than FAO harvested land data.

Brazil

Brazil is another country that collects data on both harvested and planted land.[3] In addition, Brazil collects data on land that is double cropped. Figure 4 shows total harvested land and total harvested land from double cropped land. The axes have been set to the same scale to show that a large proportion of the increase in Brazilian harvested land is a result of increased double cropping. The change in total harvested land from 2004–2012 is 5.4

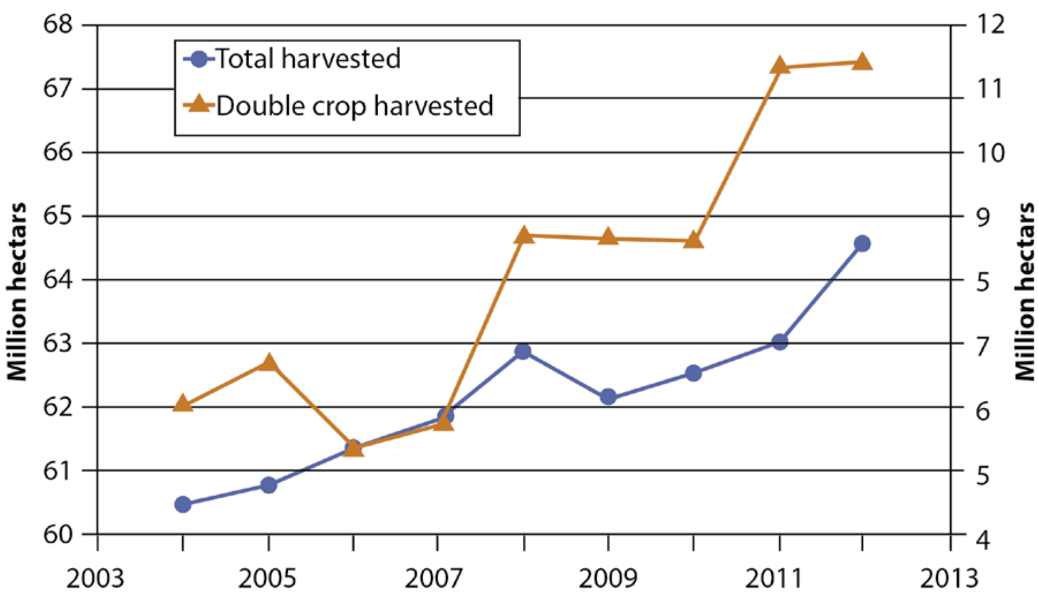


Figure 4. Brazil Harvested Land Data

[3]Brazilian IBGE data is available at http://www.sidra.ibge.gov.br/bda/pesquisas/pam/default.asp?o=27&i=P

million hectares. The change in double cropped land is 4.1 million hectares. Thus, more efficient use of land accounts for 76% of the change in harvested land in Figure 4.

India

Figure 2 shows that India increased harvested area by 6.8% from 2004–2006 to 2010–2012 which is 12.4 million hectares. Given India's long agricultural history it seems unlikely that so much land would be suitable for conversion to crops in such a relatively short time. India collects data on both planted and harvested land as well as double cropped land (India Ministry of Agriculture). Figure 5 shows that the variation in multiple crop area explains most of the variation in total planted area, which includes double cropped area. Subtracting double cropped area from total planted area shows that net planted area decreased by 147,000 hectares between 2004–2006 and 2010–2012. What then accounts for the increase in harvested area? Figure 6 shows that the proportion of planted area that is harvested has increased dramatically over this time period. An examination of previous years' data shows that the wide gap between planted and harvested

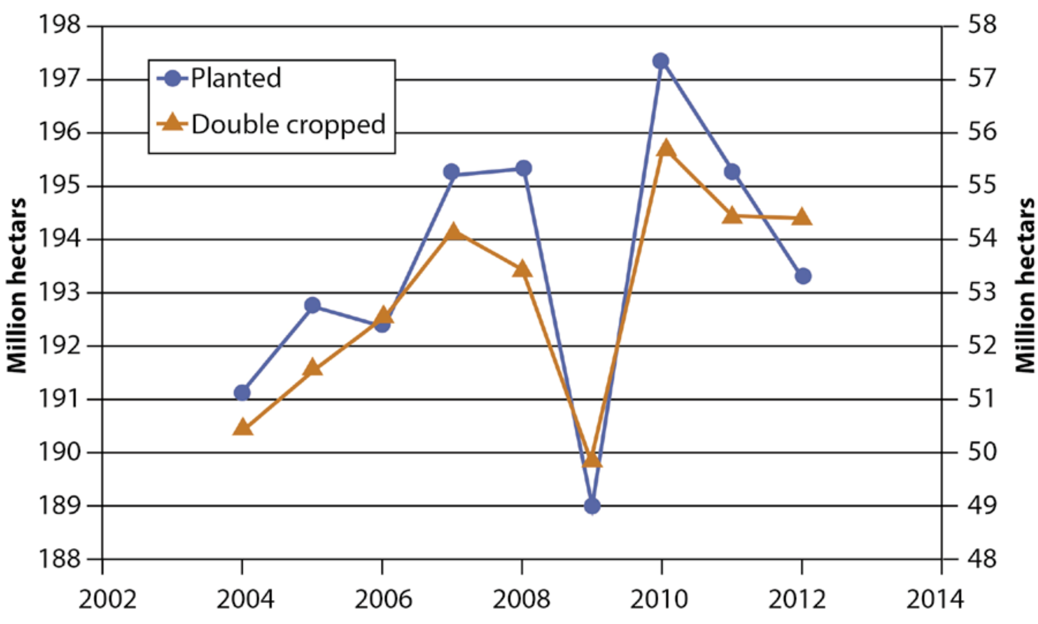


Figure 5. Total Planted and Multiple Crop Area in India

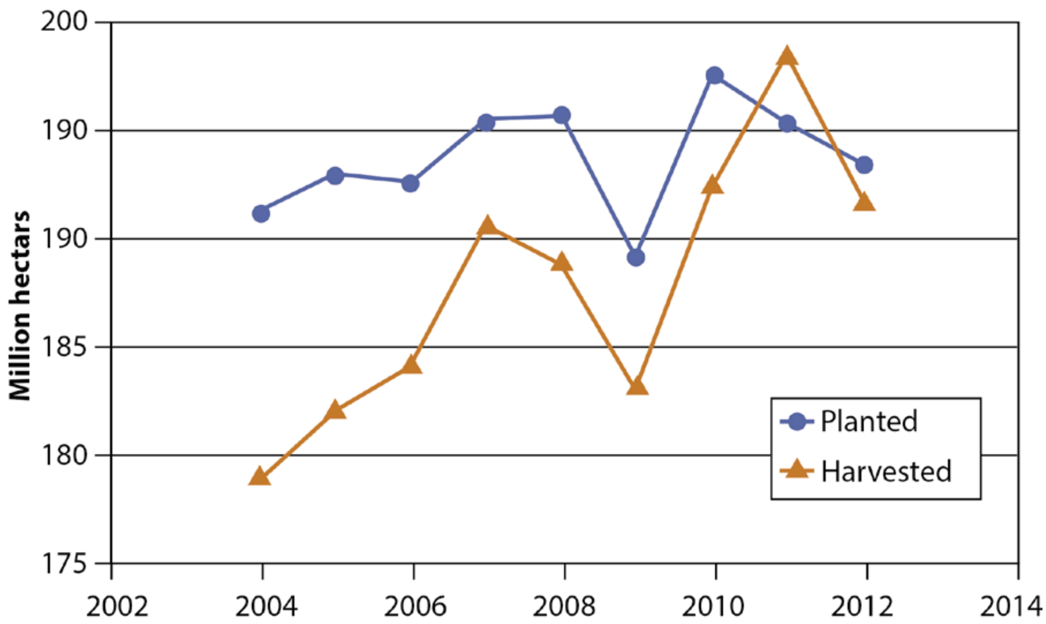


Figure 6. Total Planted and Harvested Area in India

area shown in Figure 6 from 2004 to 2006 was typical. For example, the 2004–2006 gap averages 10.6 million hectares, and the gap from 1992 to 2000 averages 10.4 million hectares. The average gap in 2010 and 2012 is 3.4 million hectares. Thus, an increase in double cropped area accounts for about 3.5 million hectares of the increase in harvested area, and a decrease in non-harvested area accounts for another 7 million hectares. Thus, all of the increase is harvested area is accounted for by intensification of land use. One reason why non-harvested area has increased so much is the 6 million hectare increase in irrigated area from 2004 to 2011. More irrigation allows a greater proportion of planted area to grow to maturity, thereby making it worth harvesting. In addition, India increased support prices and input subsidies in the mid-2000s to combat stagnant growth in the agricultural sector. These actions, combined with the expansion of irrigation, increased the opportunity cost of not harvesting land.

China

FAO harvested area data shows an increase of 8% from 160 million hectares to 173 million hectares from 2004–2006 to 2010–2012. Figure 2 in Cui and Kattumuri (2012) shows that total cultivated land in China dropped from about 130 to about 122 million hectares from 1996 to 2008. The four reasons cited for the loss of agricultural land are urbanization, natural disasters, ecological restoration, and agricultural structural adjustment, with restoration and urbanization accounting for about 80% of losses. Cui and Kattumuri (2012) claim that the loss of agricultural land slowed down in 2004 and 2005 only because of "…stringent land protection policies" (p. 14). Based on this conclusion, it seems that economic forces in China were trying to reduce cultivated land, not increase it, in the mid-2000s. If correct, then it seems highly unlikely that a significant portion of the increase in harvested area was caused by an increase in the amount of land cultivated. If both FAO harvested area data and data used by Cui and Kattumuri (2012) are correct, then at least 38 million hectares of harvested area came from double cropped land in 2004–2006 and 51 million hectares of harvested area came from double cropped areas in 2010–2012.

Sub-Saharan African Countries

Figure 2 shows that sub-Saharan African countries have been large contributors to increases in harvested land. With some exceptions, much of African crop production is carried out by small-scale producers without use of modern technologies. While differences exist between countries, typically most production is consumed domestically and most commercial trade occurs between adjoining African countries (Minot 2010). Sub-Saharan African countries account for 34 of the top 50 countries in the UN data base in terms of population growth rates in 2010.[4] The average population growth rates for these 34 countries in 2010 was 2.93%. Leliveld et al. (2013) show that food production in Tanzania has just about matched population growth and that almost all of the food production increase has been due to an increase in the amount of land planted. Although it is possible to plant more than one crop in many African countries by developing shorter-season varieties and better management (Ajeigle et al. 2010), a lack of access to technology and capital is one defining characteristic of traditional agriculture in sub-Saharan Africa, so there is no evidence that double cropping is widely adopted. Thus, the change in harvested land shown in Figure 2 for African countries is likely a better measure of the change in planted land than in other countries.

[4] Population growth rates are available at http://data.worldbank.org/indicator/SP.POP.GROW/countries?display=default

Indonesia

Figure 7 shows the change in area harvested from 2004–2006 to 2010–2012 for the top eight crops and for all other crops in Indonesia according to FAOSTAT. As shown most of the expansion has occurred in rice and palm oil fruit. Because perennial crops do not generally produce more than one crop per year, the extent to which FAO harvested land data overstates the change in planted land is limited. Adding the change in harvested land of palm, rubber, coffee, coconuts, and cocoa together accounts for 54% of the change in harvested area. According to USDA-FAS (2012) the availability of suitable rice-growing land is severely restricted in Indonesia. Most of the increase in harvested rice area that has been achieved has come about from investment in irrigation facilities that allow two or three crops of rice to be planted on the same land rather than a single crop. The extent to which intensification explains the 1.4 million hectare increase in rice harvested area shown in Indonesia cannot be determined by harvested area data alone. However, given that Indonesia is one of the world's most densely populated countries, and 1.4 million hectares represents a 12% increase in harvested production, it is unlikely that a significant portion of this 1.4 million hectares is new land. According to USDA-FAS (2012) about

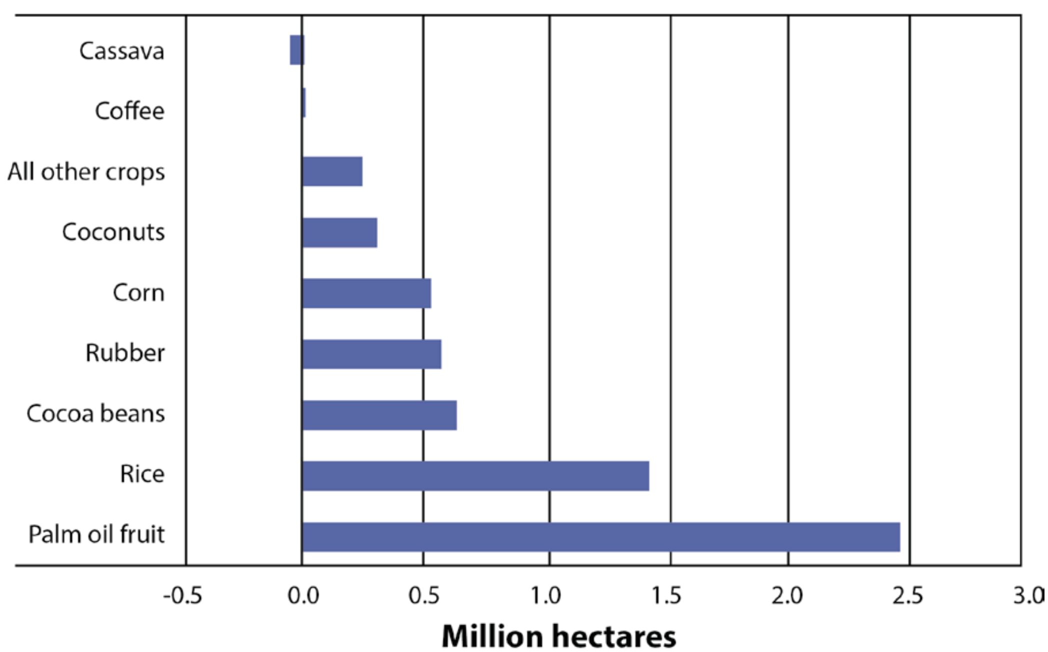


Figure 7. Change in Harvested Area by Crop for Indonesia as Reported by FAO

50% of Indonesian rice area grew rice in both the rainy and dry seasons in 2011, which implies that there is significant room for harvested area growth with greater irrigation. Thus it is likely that most of the increased rice area in Indonesia is accounted for by increased double and triple cropping.

Swastika et al. (2004) explain that most corn production in Indonesia is grown on land that produces two crops. Corn is typically grown with tobacco, cassava, another corn crop, or sometimes with rice. Given land constraints in Indonesia and the significant expansion of palm oil production, which has been accomplished by converting forestland and cropland (Susanti and Burgers 2013; Koh and Wilcove 2008), it is likely that a significant portion of the corn production increase came about by increasing double cropped area.

An Alternative Measure of Land Use Change

Use of harvested area to measure land use change can lead to a large bias in estimates of how much land has been converted to crops from other uses. While this may be an obvious point, it is too often missed in analysis of land use changes. Reliable country-specific data, such as in the United States, that can measure the change in net planted area should be used when available. Where it is not available, land cover data can be used. For global coverage FAOSTAT data on arable land and land planted to permanent crops are available. The FAO definition of arable land is "the land under temporary agricultural crops (multiple-cropped areas are counted only once), temporary meadows for mowing or pasture, land under market and kitchen gardens, and land temporarily fallow (less than five years). The abandoned land resulting from shifting cultivation is not included in this category."[5] This definition is different than the common meaning of arable land—land that is capable of producing a crop rather than land that is actually in crop production. Adding FAO's measure of arable land to land that is in permanent crop provides a measure of land use that is appropriate to use in determining the amount of new land that has been brought into production. Figure 8 reproduces Figure 2 using this measure with the exception of the United States, for which USDA's NASS planted area data is used. For the United States, total planted area of principal field crops minus double crop area is

[5] http://faostat.fao.org/site/375/default.aspx

used instead of FAOSTAT data because FAOSTAT reports a 9 million hectare loss in total cropland because of a sharp reduction in temporary pasture.

The implications of Figure 8 are strikingly different than Figure 2. Furthermore the Figure 8 data is much more consistent with the country-specific data in China, India, Brazil, Indonesia, and Africa. Figure 8 data suggest that the net change in global cropland over this period is 24 million hectares. African countries increased cropland by 20 million hectares. Other countries with more than a million-hectare increase include Argentina, Indonesia, Brazil, Rest of Southeast Asia, Rest of South Asia, and South and Other Americas. Countries with significant reductions in cropland include the EU, Canada, China, Russia, and South Africa.

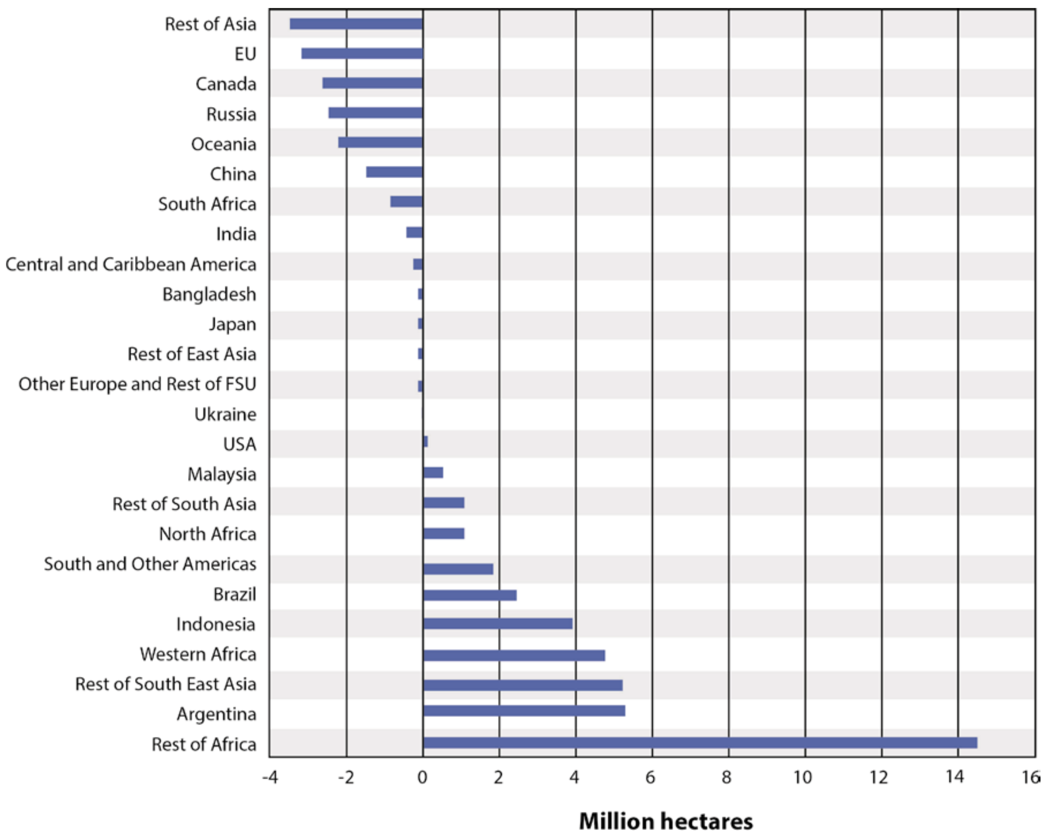


Figure 8. Change in Arable Land Plus Permanent Crops: 2004–2006 to 2010–2012

The data in Figures 2 and 8 can be used to determine the relative importance of land use changes at the intensive and extensive margin. Intensive margin changes are changes in double cropped area and a reduction in land that is available to plant but that is not harvested. The total change in harvested area in Figure 2 is the sum of extensive changes and intensive changes to land use. Thus, intensive changes equal the total change in harvested area from Figure 2 minus the changes in cropland given in Figure 8.[6] Both intensive and extensive changes are shown in Figure 9. Countries are sorted from the left according to their level of extensive acreage changes.

Most of the change in land use in African countries and Argentina is at the extensive margin. Most or all of the response in the developed world, India, China, South Africa, and the rest of Asia is at the intensive margin. The response in Indonesia and Brazil is mixed.

Major Drivers of Recent Land Use Changes

Broadly speaking, the land use changes shown in Figure 9 are consistent with a model of the world in which countries that have available land to convert to agriculture will have relatively more extensive land use change than countries that have long histories of agricultural development and limitations on available land. Thus, one major driver of recent land use changes is the availability of land to convert to agriculture. Most developed countries, along with China and India, have little land available, however, countries in Africa and South America have abundant land resources. There are striking differences, however, in land use indicated by Figure 9 that must be due to other drivers.

Growing demand for soybean imports was a major driver of land use decisions in Argentina, Brazil and the United States. The increased demand for soybeans resulted mainly from China's decision to meet its domestic needs for soybeans through imports rather than domestic production. This decision freed up resources in China to devote to production of other commodities and led to much higher soybean area in Argentina, Brazil, and the United States. Higher demand for high-protein foods in China and other developing countries increased the demand for soybean meal.

[6]One other use of this measure as an indicator of the amount of land that is used in agriculture is OECD-FAO (2014) when total agricultural land is discussed.

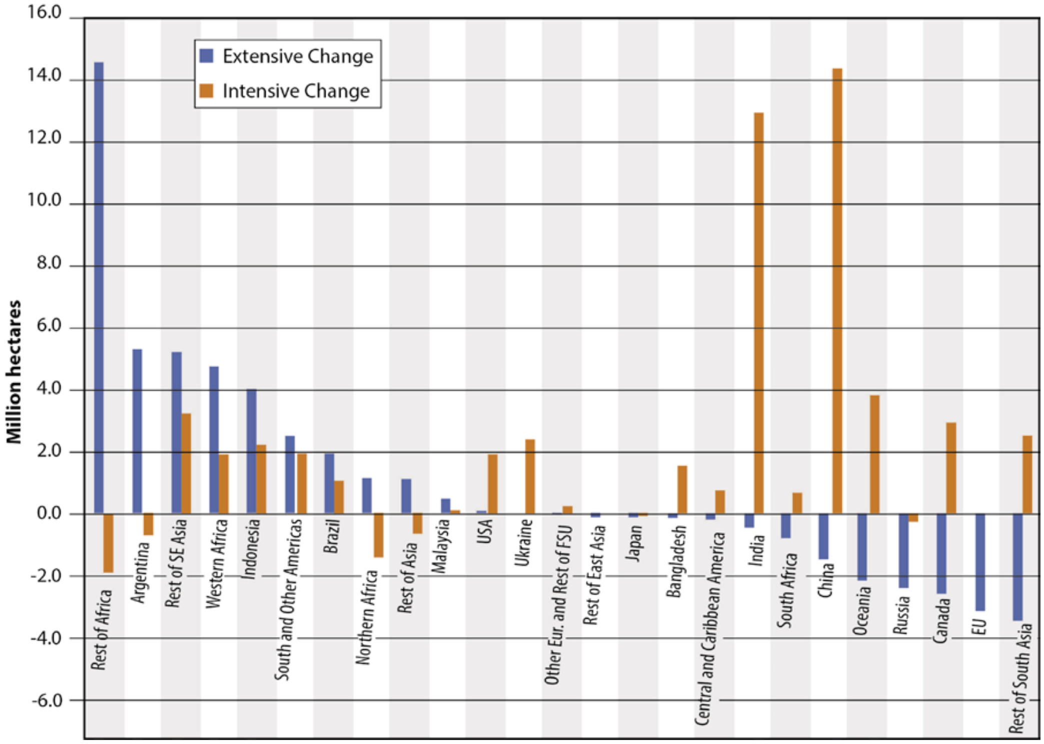


Figure 9. Extensive and Intensive Land Use Changes: 2004–2006 to 2010–2012

Increased demand for vegetable oils for food production, cooking, and biodiesel increased the demand for soybean oil.

Brazil responded to this increased soybean demand by expanding soybean area, however, a second crop of corn was planted on a good portion of expanded soybean acreage. This expansion in double cropping reduced the amount of corn area planted to the first crop of corn. Thus, Brazil expanded at both the extensive and intensive land use margins.

Argentina also expanded soybean area, but it did so at the extensive margin rather than by intensifying land use. The prime soybean production areas in Argentina are farther south than in Brazil, which shortens the time period available for double cropping. However, a second crop of soybeans can be planted in Argentina after winter wheat is harvested in December. One explanation for a lack of intensification is that Argentine area planted to wheat has declined from about 6 million hectares in 2005 to 3.6 million hectares in 2012. This decline simply means that there is less land available for double cropping soybeans after wheat. Therefore, if soybean area needs to increase, less wheat land means less land available for double cropping, thus, soybean first crop area by definition must increase. The decline in wheat area has been mainly driven by government policy interventions in the form of export taxes and export subsidies that were implemented in a way that favored soybeans over corn and wheat (Nogues 2011). This suggests that government policy is what caused a lack of an intensive land use response in Argentina, in contrast to the significant intensive response shown in Figure 9 in Brazil and other South American countries.

As discussed, Indonesian expansion of palm production was accomplished at least in part at the extensive margin. This expansion resulted from increased investment drawn to the industry due to higher profit margins caused by higher prices and higher yields. The higher prices resulted from an overall increase in demand for vegetable oil, driven by increased demand for food production, cooking oil, biodiesel, and other uses. The data show that Indonesian expansion of rice and corn harvested area was done at the intensive margin because the area devoted to perennial crops in Figure 7 is greater than the total extensive expansion shown in Figure 9.

Sugarcane and soybeans account for nearly all of the land expansion in Brazil. Increased sugarcane production was used to meet growing demand for sugar and to meet growing domestic demand for ethanol. The number of flex vehicles in Brazil grew by 20 million from 2005 to 2012. If all of these vehicles used ethanol, Brazilian consumption of ethanol in 2012 would have exceeded 24 billion liters just from these vehicles, and additional consumption would have come from the 15 million gasoline vehicles in Brazil. Actual consumption in Brazil was about 18 billion liters.[7] These figures demonstrate that the growth in sugarcane area was primarily driven by the Brazilian government policy that increased the sales of flex vehicles in Brazil. The expansion in Brazilian soybean area was driven by increased world demand for soybean imports, which was mainly driven by China, as previously discussed. The ability to plant a second crop of corn after soybean due to adoption of shorter-season soybeans and agronomic advances reduced the amount of new land that was needed to accommodate this expansion.

[7] All figures on Brazilian vehicle numbers and ethanol consumption were obtained from UNICA: http://www.unicadata.com.br/?idioma=2

In China, India, and most of the developed world, agricultural land resources are limited. Limited land resources means that expansion at the extensive margin is costly relative to expansion at the intensive margin. Thus, we see a large response in both China and India at the intensive margin rather than the extensive margin. Cui and Kattumuri (2012) argue that Chinese intensification would have been even greater but for the government policy objective of maintaining a minimum of 120 million hectares of land in agriculture. India's intensification was facilitated by government investment in irrigation facilities and price subsidies that increased agricultural profitability (OECO-FAO 2014).

The lack of a large extensive response in Ukraine, Russia, and other FSU countries is somewhat surprising given the availability of land. The lack of response at the extensive margin could be due to a lack of investment in the agricultural sectors of these countries.

How much of the changes in land use shown in Figure 9 can be attributed to high commodity prices cannot be known precisely without observing an alternative history in which the run-up in commodity prices did not occur. Economic theory suggests that some portion of the changes in Figure 9 came about because of high prices in those countries where high world prices were transmitted to farmers. However, some of the changes in land use would have occurred even if prices had remained constant at their 2004–2006 levels.

The extent to which extensive expansion in African countries was caused by high world prices is likely small for the simple reason that higher world prices were not transmitted to growers in many African countries. Minot (2010) concludes that domestic grain prices in Tanzania bear little relationship to world prices. In a more complete study, Minot (2011) studies price transmission in multiple markets in Ethiopia, Ghana, Uganda, Zambia, Mozambique, Tanzania, Kenya, South Africa, and Malawi. Of the 62 markets studied, he found that only 13 showed a statistically significant long-run relationship with world prices. He found some evidence of a linkage in large urban centers and in coastal markets, which is consistent with markets in cities and in coastal ports being more integrated with world markets. However, given his overall findings, these limited linkages to world prices did not find their way through to rural areas where most crops are grown. With such weak evidence supporting price transmission to rural areas one can conclude that the main driver of land expansion in many African countries was not higher world prices.

Empirical Measures of Land Use Changes

Aggregating land use changes across all countries, the aggregate world extensive change was a net increase of 24 million hectares from 2004–2006 to 2010–2012. The aggregate world intensive land use change was 49.1 million hectares. Thus, across all countries, more intensive use of existing land was double the change from more extensive use of land. Outside of African countries, the aggregate intensive change in land use was almost 15 times as large as extensive changes. This wide disparity between more intensive use of land and more extensive use means that the reliability of current models used to estimate indirect would be dramatically increased if they were modified to account for non-yield intensification of land use.

The recent historical changes in land use can provide some guidance about the effect of dramatically higher prices on land use change over an eight-year period. An estimate of the amount of extensive land use change that can be attributed to higher commodity prices can be made under fairly restrictive assumptions.

First is assuming that land use change at the extensive margin due to high prices is zero in those countries or regions in Figure 9 that had negative extensive changes. This assumption implies that the forces that caused countries to lose agricultural land during this time would have caused the same amount of loss even without the high prices. Clearly, it would seem that at least some land in these countries was kept in production from the high prices, so this assumption understates land use change at the extensive margin. From a greenhouse gas perspective, this assumption is equivalent to saying that the net amount of carbon sequestration that would have occurred on land that was kept in production by high prices in these countries is negligible.

Second is assuming that all the extensive margin changes in Figure 9 in countries and regions that have positive changes are due to high world prices. This too is an extreme assumption because some land would have been brought into production even if commodity prices had not increased. Thus this assumption overstates the response of land use at the extensive margin.

If we include extensive changes in Africa, then world extensive land use changes equals 41.2 million hectares, which represents a 2.68% increase over the average level of land in production in 2004–2006. If we assume that the extensive land use changes in

Africa were primarily caused by internal domestic food demand from growing populations and income, and they would have occurred even without high world commodity prices, then the extensive land use increase equals 20.7 million hectares or 1.35%.

It is instructive here to make a rough estimate of the response of the world extensive margin to aggregate higher commodity prices. The average real prices of corn, soybeans, wheat, and rice received by US farmers increased by 123%, 85%, 59%, and 47% respectively in 2010–2012 relative to 2004–2006. A simple average of these price increases is 78%. With this real price increase, the elasticity of the world extensive margin is 0.034 if African extensive response is included, and 0.017 if the African extensive response is not included.

Similarly, if the intensive response in countries and regions where the response is negative is set to zero, then the aggregate intensive response to high prices is 49.1 million hectares if we attribute all the intensive response to higher prices. Without the African country response, the aggregate response is 47.2 million hectares. The resulting elasticities of intensive response are 0.041 and 0.039. Thus, if we attribute all the African extensive land use changes to high prices, then the world intensive elasticity is 19% higher than the extensive elasticity. If none of the African response is attributed to higher prices than the non-African intensive elasticity is almost three times as great as the extensive response.

These rough estimates demonstrate that the primary land use change response of the world's farmers in the last 10 years has been to use available land resources more efficiently rather than to expand the amount of land brought into production. This finding is not new and is consistent with the literature that finds significant option value in waiting to convert land (Song et al. 2011). OECD-FAO (2009) recognized that intensive land use change has been the driving force behind higher production levels, however, this finding has not been recognized by regulators who calculate indirect land use. Note that our measure of more efficient land use does not include higher yields in terms of production per hectare harvested. Any increase in yields would be an additional intensive response. Rather the intensive response measured here is due to increased multiple cropped area, a reduction in unharvested planted area, a reduction in fallow land, and a reduction in temporary pasture. Because greenhouse gas emissions associated with an intensive response are much lower than emissions caused by land conversions (Burney, Davis, and Lobell 2010), ignoring this intensive response overstates estimates of emissions associated with land use change because most of the land use change that has occurred is at the intensive rather than extensive margin.

Comparison of Actual Land Use Changes with Model Predictions

Model predictions of land use change from increased biofuel production are conceptually appealing. This is because the effects of higher biofuel production on land use are measured in isolation—the effects of everything else that influences agriculture are held constant. Thus, the effects of biofuel production alone can, at least conceptually, be measured. The way that the models assume increased production impacts land use is through higher prices. Thus, if the actual changes in land use in Figure 9 were the result of a response to the large increase in commodity prices that actually occurred, then it seems reasonable to compare model predictions to the actual changes that occurred. However reasonable this seems, we simply do not know with certainty what land use changes would have occurred without the increase in commodity prices. What needs to be compared to model predictions is the difference in land use with the commodity price increase relative to what it would have been without the commodity price increase.

What information then can be gleaned from a comparison of model predictions with actual changes? At one extreme, if none of the observed changes in extensive land use were the result of high prices, then we know that indirect land use is not empirically important because land use changes are caused by other forces. At the other extreme, if extensive land use would have stayed constant at base period levels if prices had not increased then all of the observed changes resulted from high prices. In this case it would be valid to judge the accuracy of model predictions with observed changes, because both would be caused by price responses. Reality likely falls somewhere in between these two extremes in that land use in 2012 would have been different than in 2004 even without the price increase, and that at least some portion of the observed changes we see can be attributed to higher prices. Taheripour and Tyner (2013) use observed land use changes as a guide to selection of a key model parameter in GTAP in an attempt to reconcile model predictions with observed changes. Hence, they assume that observed changes in land use are a useful guide to determine how the GTAP model should predict how land use changes in response to a change in commodity prices.

The two most widely used international models used in the United States to predict land use changes associated with increased biofuel production are GTAP and FAPRI (Gohin 2014). Both models allowed crop yields to respond to higher prices, and neither model allowed land use intensity, as measured here, to increase. Given that the primary way that non-African countries have increased effective agricultural land was through intensification, both models have an upward bias in their predictions of land use change at the extensive margin in non-African countries.[8]

Figure 10 shows the predicted increases in cropland from the FAPRI model that was used by the Environmental Protection Agency to determine greenhouse gas emissions

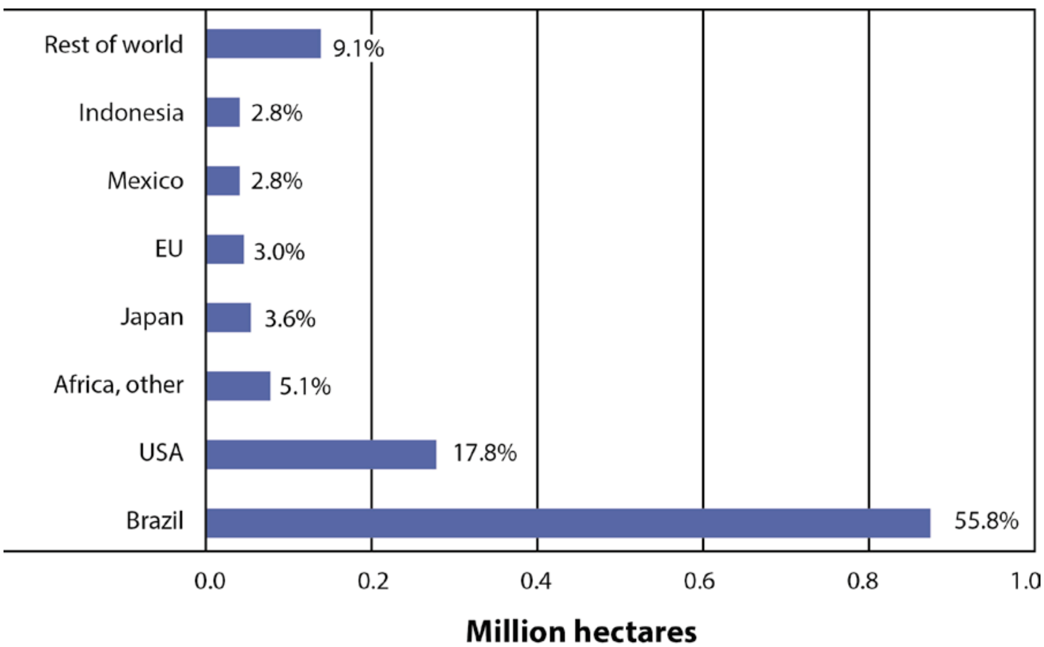


Figure 10. Predicted Land Use Change in EPA "All Biofuel" Scenario: Hectares and Share of World Total

[8] One way that production per unit of agricultural land can increase in the GTAP model is through its yield elasticity, therefore at least some of the upward bias in GTAP's prediction of extensive land use changes is offset by using a yield elasticity value that is higher than can be supported empirically.

associated with land use changes from increased biofuels. What is illustrated is the difference between EPA's "Control Case" that includes levels of biofuels in the RFS and EPA's "AEO Reference Case," which contains lower levels of biofuels (EPA 2010). This scenario simulated increases in many different biofuels including biodiesel made from vegetable oil and waste greases, corn ethanol, sugarcane ethanol, and cellulosic ethanol. How these land use changes were calculated is that the FAPRI predictions of land use in the AEO Reference Case were subtracted from the predictions in the Control Case. The total predicted world change in land use is 1.45 million hectares.

What is striking about Figure 10 is the concentration of predicted land use change in Brazil and the United States. These two countries account for almost 75% of the total predicted change in land use, with Brazil alone accounting for more than half of all change in the world at the extensive margin. In the AEO Reference Case total cropland in Brazil is increasing, thus the predicted increase in area must come from conversion of land that would have been devoted to other uses.

The first valid comparison that can be made between the CARD-FAPRI model prediction and what actually occurred is that the predicted land use change in Brazil due to higher prices is far too high relative to land use changes that actually occurred at the extensive margin in Argentina and other South American countries. As shown in Figure 9 Argentina and other South American countries together increased land use at the extensive margin by almost four times as much as did Brazil. The CARD-FAPRI model results used by EPA predicted almost no land use change in Argentina and other South American countries due to higher prices. It is notable that the CARD-FAPRI model predicted that growth in Brazil cropland from 2002 to 2009 would be about 9.1 million hectares, whereas Argentina's growth would be 3.7 million hectares in the Reference Case. Thus, the larger increase in agricultural area in Argentina that actually occurred cannot be attributed to the model being right about predicting a larger baseline increase in Argentina than in Brazil. The first conclusion one can draw from this comparison is that the CARD-FAPRI model dramatically over-predicted land use change in Brazil relative to Argentina and other South American countries.

The CARD-FAPRI prediction that the United States would account for about 18% of the world's increase in extensive land use seems inconsistent with the large changes that occurred in African countries and Argentina. The only way that the US land use prediction is consistent with the historical record is if cropland in the United States would have dropped by a large amount in the absence of the large price increase. The CARD-FAPRI model predicted that US crop area would decline in both the Reference and Control Cases.

The CARD-FAPRI model includes some South African production and a limited number of other crops in a limited number of African countries. The CARD-FAPRI model implicitly assumes that most of African agricultural production of major crops is isolated from world markets. As discussed above if this isolation is in fact a correct characterization of African agriculture, then the large land use changes in African countries shown in Figure 9 would have occurred even without the high commodity prices. The only other conclusion that can be drawn regarding African countries is that the CARD-FAPRI model underpredicts land use changes there to the extent that land use in African countries responded to world prices.

The commodity price increases that led to the Figure 10 predicted changes in land use were a 3.1% increase in corn prices and a 0.8% increase in soybean prices. These simulated price changes are dwarfed by the actual price changes that have occurred as shown in Figure 1. The FAPRI model prediction of a small increase in extensive land use in Japan and the EU due to small changes in price seems inconsistent with the fact that land use in Japan has been largely unchanged over the last 10 years and the EU has experienced a decline in land use. Again, it is not possible to know the extent to which a small increase in world commodity prices would have kept a small amount of land in production in the EU.

The small model-predicted change in Indonesia in extensive land use is generally consistent with observed changes if we assume that no changes would have occurred except for the higher market prices that actually occurred and not from government development priorities.

Figure 11 shows predicted land use changes by the GTAP model. [9] GTAP predicts that 38% of land use changes occur in the United States. As discussed, although

---

[9] GTAP model predictions of land use changes associated with biofuels vary across publications. Figure 11 land use change predictions were taken from Hertel et al. (2009) which were published about the same time that California's Air Resources Board was making their determination of greenhouse gas emissions from land use change that relied on GTAP model predictions. For the purposes of this paper, we assume that the

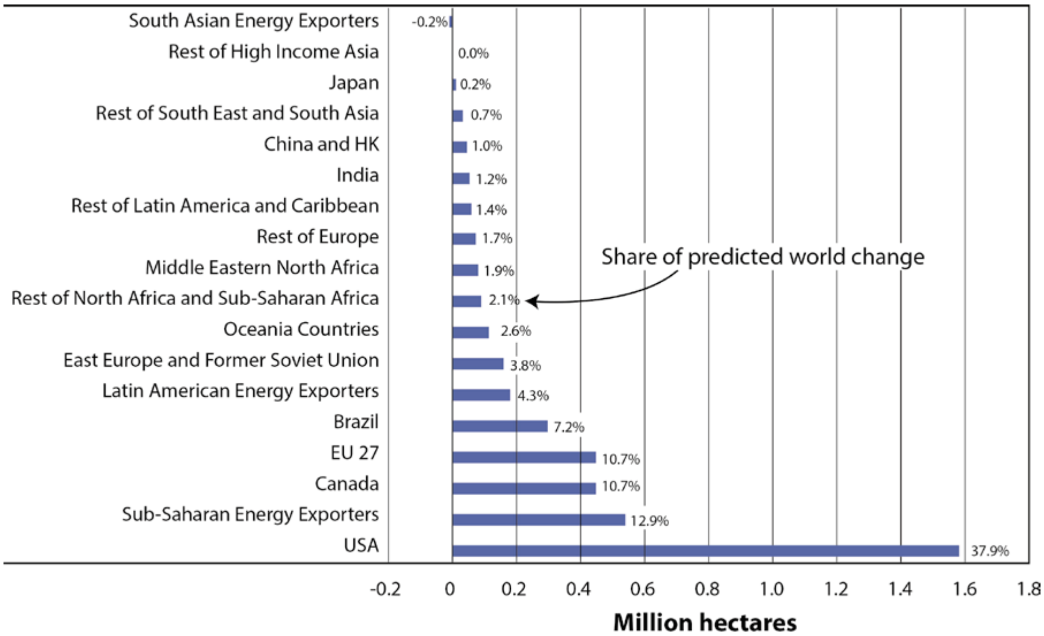


Figure 11. GTAP Predictions of Indirect Land Use Change from Corn Ethanol
Source: Hertel et al. (2009)

this seems like a large over-prediction of the US contribution, it is not possible to say this prediction is inconsistent with the recent historical data given that we cannot observe what land use would have been without the price increase. However, for this prediction to be true, the fairly small price increase simulated by GTAP would have kept a sizeable amount of land in production in the United States.

As with the CARD-FAPRI model, GTAP over-predicts the land use change for Brazil relative to other Latin American countries assuming that the baseline in Hertel et al. (2009) shows Brazil's area increasing more than agricultural area in the rest of Latin America. This baseline level of data was not available for inspection but GTAP's baseline was developed using 2001 data that incorporates land use changes that occurred in previous years. Brazil's agricultural land was expanding in this prior period, so it is reasonable to assume that Brazil's land use in the baseline was increasing more than in

Figure 11 land use changes are consistent with those used by California. There exist many GTAP-based estimates of land use change due to biofuels. An alternative estimate was provided by Tyner (2010). First and Second Generation Biofuels: Economic and Policy Issues, Presented at the Third Berkeley Bioeconomy Conference, June 24, 2010, http://www.berkeleybioeconomy.com/wpcontent/uploads//2010/07/TYner%20Berkeley%20June%202010.pdf.

other South American countries. This would imply that the predicted change in Brazil relative to the rest of Latin America is too large.

Despite the large discrepancies between model predictions and the actual land use changes that have occurred since 2004 it simply is not possible to conclude with certainty that the model predictions have been proven wrong and should be disregarded. For example, the Hertel et al. (2009) prediction that large land use changes from output price increases resulting from US corn ethanol production would occur in the United States, Europe, and Canada seems inconsistent with the fact that cultivated land decreased in the EU and Canada and stayed constant in the United States despite price changes that were many times larger than those predicted by the model. However, it could be that the amount of actual land reduction that would have occurred in the EU and Canada would have been much larger without the commodity price boom and that if actual land use changes were calculated relative to what would have happened without the price impact then the GTAP model predictions would be consistent with what we observe. Thus, without being able to observe the alternative history that did not contain the commodity price boom, it is not possible to conclude with certainty that the model predictions are wrong. As Babcock (2009) pointed out, economists who run models to predict future land use changes are in the enviable position that skeptics of the predictions will find it difficult to use the actual land use change data to prove that the model predictions were wrong. However the historical record of land use changes can be used to provide insight into the types of land that were converted assuming that the model predictions are correct.

Using the Historical Record to Guide Estimates of Land Conversion

Table 1 below presents some GTAP results that were used by California's Air Resources Board to calculate CO_2 emissions associated with land conversion due to corn ethanol production. By regressing emissions on the amount of land converted, it is possible to obtain a rough estimate of how each of the four land conversions affect estimated emissions separately. Table 2 provides the regression results.

An increase in land conversion increases GTAP's estimates of emissions. Conversion of a million hectares of forest increases emissions much more than conversion of pasture. How to interpret these coefficients is that a one million hectare increase in, for

Table 1. GTAP Model Predictions of Land Conversion and Associated GHG Emissions

	Forest Converted		Pasture Converted		
Scenario	**U.S.**	**ROW[a]**	**U.S.**	**ROW**	**LUC Emissions**
		million hectares			*gCO_2e/MJ*
A	0.70	0.34	1.04	1.96	33.6
B	0.36	0.01	0.79	1.53	18.3
C	0.82	0.64	1.19	2.83	44.3
D	0.81	0.08	1.31	2.34	35.3
E	0.48	0.52	0.66	1.35	27.1
F	0.46	0.27	1.00	2.10	27.4
G	0.40	0.15	0.92	2.18	24.1

Source: Provided by staff at the Renewable Fuels Association
[a]ROW means Rest of World

Table 2. Impact on CO_2 Emissions of a Million Hectare Increase in Land Conversion

Land Type Converted	**Impact on Emissions**
	gCO_2e/MJ
US Pasture	6.17
ROW Pasture	3.08
US Forest	22.69
ROW Forest	14.41

Source: Estimated from Table 1.

example, US pasture to crops, leads to a 6.17 increase in emissions measured by grams CO_2 per MJ of gasoline energy replaced by corn ethanol. Across all seven scenarios the average prediction of forest conversion in the United States is 0.58 million hectares.

Multiplying 0.58 by 22.69, which is the coefficient relating conversion of forest to emissions, results in an estimate of the average contribution of US forest conversion to the final CO_2 emission number. The result is that GTAP estimates that conversion of US forests contributes 13.06 gCO_2/MJ or 43% of total estimated emissions.

As shown in Figure 8, US cropland did not appreciably increase at the extensive margin in response to higher prices on average in 2010–2012 relative to 2004–2006.[10] As

[10] A more detailed examination of US data is provided in the next section, which shows there is some evidence of an increase in planned area to be planted from 2007 to 2013. The 2004–2006 and 2010–2012 time periods were used to make US data consistent with available data for other countries.

discussed in the previous section, it is not possible to conclude whether the GTAP model prediction that US cropland would be 1.6 million hectares higher due to higher prices is inconsistent with what actually happened, because it could be that US cropland would have declined from 2004 to 2012 if the higher prices had not occurred. For example, if US cropland would have declined by 5 million hectares if the high prices had not occurred, then the GTAP prediction that 1.6 million of these hectares would have been kept in production is consistent with the historical record. More formally, a necessary condition for consistency of the model prediction of an increase in US cropland due to higher prices is that US cropland would have declined by at least the amount of the model prediction were it not for the higher prices that actually occurred.

So suppose that there would have been a 5 million hectare decline in US cropland were it not for the higher prices and the GTAP prediction is correct that 1.6 million hectares of this land would have been kept in production because of higher prices caused by corn ethanol production. This means that the type of land converted to accommodate biofuels was not forest or pastureland but rather cropland that did not go out of production. Calculation of foregone carbon sequestration depends on what would have happened to the cropland if it did not remain in crops which, in turn, depends on where the cropland is located and the potential alternative uses. The magnitude of the change in estimated CO_2 emissions from cropland that is prevented from going out of production relative to forest that is converted to cropland is potentially large. For example, from Table 2, converting one million hectares of grassland instead of forest would reduce land-based CO_2 emissions by 11.3 gCO_2e/MJ in the rest of the world and by 16.5 gCO_2e/MJ in the United States. If foregone carbon sequestration is less than the amount of carbon lost from converting pasture to crops then the magnitude of the emission reduction would be larger.

The countries in Figure 8 that either had negligible or negative extensive land use changes should be presumed to not have converted pasture or forest to crops in response to biofuel-induced higher prices. Rather, the presumption should be that any predicted change in land used in agriculture came from cropland that did not go out of production. From Figure 11 this would include Canada, the EU, Russia, the Ukraine, and India.

The countries in Figure 8 that had significant extensive land increases cannot be presumed to have only kept cropland in production because of biofuels. Whether the expanded cropland due to the portion of the actual price increase attributable to biofuels expansion came from cropland that would have gone out of production or from pasture is an accounting decision. For these countries that expanded extensive land use, the historical pattern of where in the country the land use expansion occurred provides insight into the type of land that was converted to crops.

Brazil is one country that expanded extensive land use and has data on where this expansion occurred. Figure 12 shows each state's share of extensive land use change in Brazil measured by the change in the 2010–2012 average from the 2010–2012 average.[11] Not surprisingly extensive land use increased the most in Mato Grosso. Expansion of sugarcane area in Sao Paulo explains its increase. The states of Goias, Maranhao,

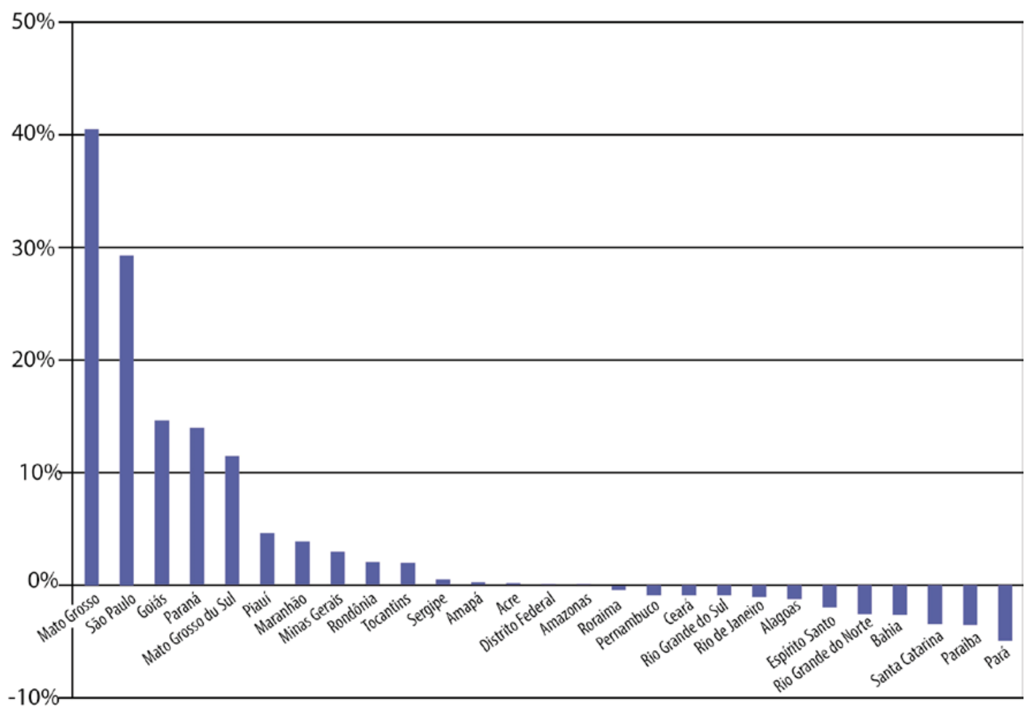


Figure 12. State Share of Brazil's Change in Extensive Land Use from 2004–2006 to 2010-2012.

[11]Only land that was planted to crop was considered in calculating each state's share of extensive land use change. The cropland planted data comes from the IBGE website: http://www.sidra.ibge.gov.br/bda/acervo/acervo9.asp?e=c&p=PA&z=t&o=11. Total planted cropland in Brazil is less than FAOSTAT data on arable land plus permanent crops that was used to determine extensive and internsive land use changes in Figure 10 and 11.

Tocantins, and Piaui all have large land areas in the vast Brazilian Cerrado biome which has also seen large-scale development (The Economist). Rondonia is the only state in the Amazon biome that shows an increase in cropland. Where cropland has expanded in Brazil (and in other countries where data allows) can be used as a guide to determine if model predictions of the type land converted are accurate.

A More Detailed Look at US Extensive Area Data

Figure 13 shows what has happened to one measure of US cropland from 1993 to 2013. This measure is area planted to US principle crops as measured by USDA-NASS, less double cropped harvested area, plus fallow cropland. This measure reached its peak in 1996. In 2007, this measure increased after a long downturn, suggesting some impact of higher prices. However, in 2010 it fell below 130 million hectares before increasing in 2011 and 2012. It is somewhat surprising that total land in agriculture has not increased more than indicated since 2006 because land enrolled in the Conservation Reserve

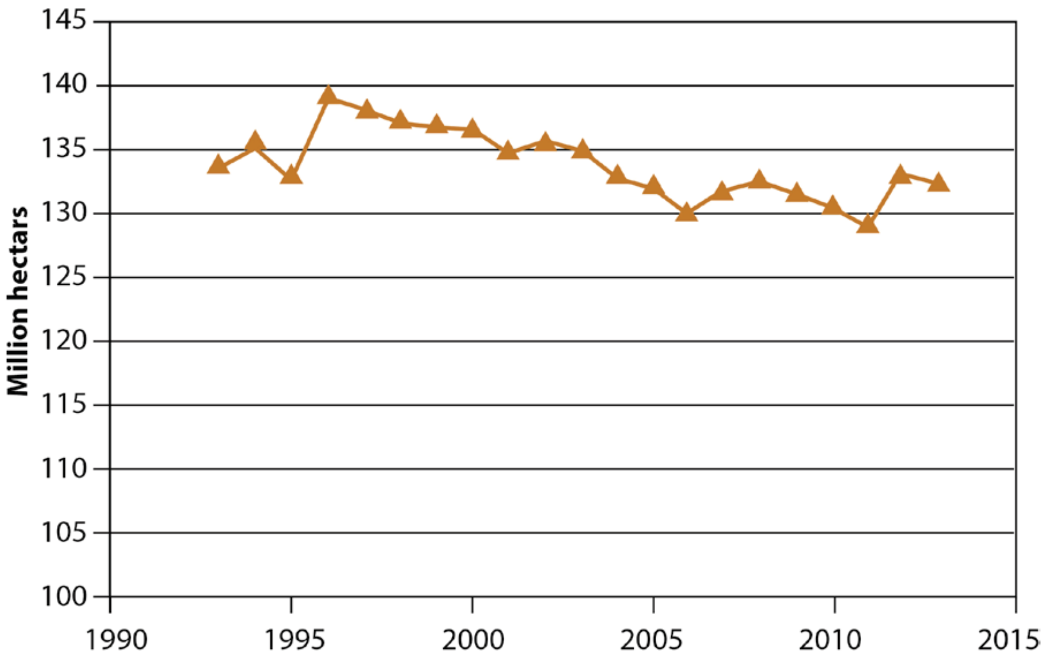


Figure 13. US Cropland Since 1993

Program (CRP) declined by 4 million hectares from 2007 to 2013. One explanation for a lack of response in this measure of land use could be an increase in area that is reported as prevented planting area.

The US crop insurance program creates an incentive for farmers to report area that they had planned to plant but were not able to due to adverse weather. This land is called prevented planted acres. Farmers who buy crop insurance receive a crop insurance payment on these acres. Aggregate data on the amount of prevented planted acres can be added to the Figure 13 data to measure how much land US farmers intend to plant each year. Data on the area designated as prevented planting area are available since 2007.[12] Figure 14 shows the change in CRP land since 2007 (grey line), the change in US cropland since 2007 (blue line calculated from Figure 13), and the change in intended planted land since 2007 (orange line). It is striking how close the change in intended

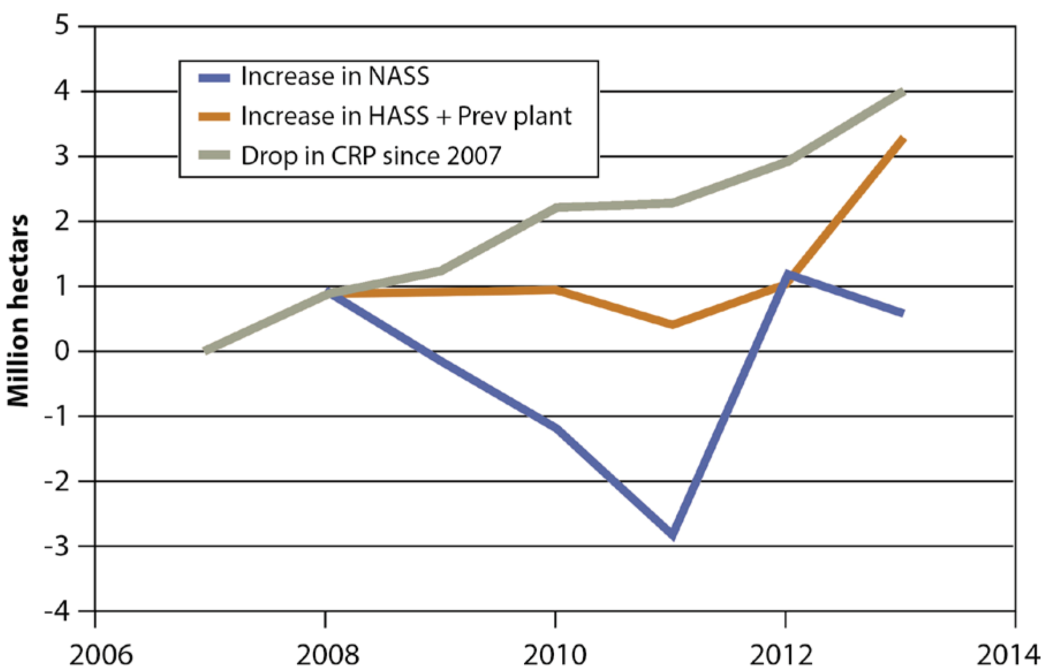


Figure 14. CRP Land Showing up as Increased Prevented Planting Acres

[12] Prevented planting has been part of the US crop insurance program before 2007 but data on total area designated as prevented planting are not readily available.

planted land is to the reduction in CRP, and it is also striking how little of the land that is no longer enrolled in CRP shows up as land in production.

What can be concluded from this more detailed examination of extensive land use in the United States is that the data seem to indicate a reversal of a long-term trend of declining total US cropland since 1996 beginning in 2007—the first crop planted in response to significantly higher prices for US corn and soybeans. The large reduction in land enrolled in CRP is much greater than the amount of land that is reported as being in productive use in crop production. This suggests that there is an abundance of ex-CRP land that is available for planting or that a large proportion of ex-CRP land has not yet been available for crop production and is being reported as having been prevented from being planted. The data are consistent with any increase in extensive land use since prices increased in 2006 as coming from a stock of available land that had been planted to crops previously or from land that was enrolled in CRP. This finding is consistent with USDA (2013), which found that the only net contributor to US cropland from 2007 to 2010 was a reduction in CRP land. There was no net increase in cropland from conversion of forests, from conversion of urban land, or from conversion of pasture.

Conclusions

That countries primarily responded to higher world prices by intensifying land use rather than by converting land from forests and pastures should not be surprising. Many countries, such as China and India, simply do not have available land to bring into agriculture. In countries with land suitable for crops, the investment and other transaction costs of developing new land make the process quite costly relative to the cost of increasing the intensity of land use. In addition, the value of waiting to invest in land conversion projects is large, which leads to a significant delay in land conversions.

The pattern of recent land use changes suggests that existing estimates of greenhouse gas emissions caused by land conversions due to biofuel production are too high because they are based on models that do not allow for increases in non-yield intensification of land use. Intensification of land use does not involve clearing forests or plowing up native grasslands that lead to large losses of carbon stocks.

The recent data on land use changes reveals the importance of policy in determining land use decisions. In Argentina, higher export taxes and quotas on corn and wheat relative to soybeans caused soybean area to increase and wheat area to decrease. The drop in wheat area limits the availability of land on which soybeans can be double cropped which means that expansion of soybeans can only take place by replacing existing crops or by expanding onto new lands. In Brazil, increased enforcement of laws restricting clearing of forests and the resulting drop in the rate of deforestation is consistent with Brazil expanding land use at both the intensive and extensive margin.

It might be argued that recent data are a poor indicator of what we should expect to happen if more time passes because supply response is always larger in the long-run than in the short-run. Land conversion takes time but the time gap used here to measure land use change is long enough to allow a significant amount of change to happen. In addition, the incentive to expand agricultural supply between 2006 and 2012 was as strong as any period since at least 1960. Furthermore, if the recent sharp declines in commodity prices continue then the incentive to expand supplies in the future will be muted.

We plan on extending our analysis of land use changes by attempting to develop a statistical model to explain more systematically why some countries expanded land use more at the extensive margin and others expanded more at the intensive margin. Such a model could provide better insights into the role that policy, price transmission, and resource availability plan in determining agricultural supply response. Improved understanding could be useful to future attempts at estimating greenhouse gas emissions caused by extensification of agricultural production.

References

Babcock, B.A. and J.F. Fabiosa. 2011. "The Impact of Ethanol and Ethanol Subsidies on Corn Prices: Revisiting History." CARD Policy Brief 11-PB5.

Babcock, B.A. 2009. "Measuring Unmeasurable Land Use Changes from Biofuels." *Iowa Ag Review* 15: 4–11.

Barr, K.J., B.A. Babcock, M.C. Carriquiry, A.M. Nassar, and L. Harfuch. 2011. "Agricultural Land Elasticities in the United States and Brazil." *Applied Economic Perspectives and Policy* 33: 449–62.

Berry, Steven T. 2011. "Biofuels Policy and the Empirical Inputs to GTAP Models." California Air Resources Board Expert Workgroup Working Paper.

Burney, J.A., J.D. Steven, and B.L. David. 2010. "Greenhouse Gas Mitigation by Agricultural Intensification." *Proceedings of the National Academy of Sciences* 107: 12052–12057.

Carter, C., G.C. Rausser, and A. Smith. 2010. "The Effect of the US Ethanol Mandate on Corn Prices." *unpublished paper, University of California.*

"The Miracle of the Cerrado." 2010. The Economist. http://www.economist.com/node/16886442

EPA. 2010. "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Final Rule, March 26, 2010." 40 CFR Part 80: 14669–15330.

EPA. 2010. "Renewable Fuel Standard Regulatory Impact Analysis." EPA-420-R-10-006, February 2010.

Gohin, A. 2014. "Assessing the Land Use Changes and Greenhouse Gas Emissions of Biofuels: Elucidating the Crop Yield Effects." *Land Economics* 90: 575–86.

Ajeigbe, H.A., B.B. Singh, A. Musa, J.O. Adeosun, R.S. Adamu, and D. Chikoye. 2010. "Improved Cowpea–Cereal Cropping Systems: Cereal–Double Cowpea System for the Northern Guinea Savanna Zone." *International Institute of Tropical Agriculture (IITA), pp. 17.*

Hertel T.W., A.A. Golub, A.D. Jones, M. O'Hare, R.J. Plevin, and D.M. Kammen. 2009. "Global Land Use and Greenhouse Gas Emission Impacts of U.S. Maize Ethanol: The Role of Market Mediated Responses." GTAP Working Paper No. 55.

India Ministry of Agriculture. 2014. Directorate of Economics and Statistics, Department of Agriculture and Cooperation. http://eands.dacnet.nic.in/

USDA-FAS. 2012. "Indonesia: Stagnating Rice Production Ensures Continued Need for Imports." *USDA-FAS Commodity Intelligence Reports - South East Asia.* http://www.pecad.fas.usda.gov/highlights/2012/03/Indonesia_rice_Mar2012/

Koh, L.P and D.S. Wilcove. 2008. "Is Oil Palm Agriculture Really Destroying Biodiversity?" *Conservation Letters* 1: 60–64.

Minot N. 2010. "Staple Food Prices in Tanzania." Presented at Comesa policy seminar on 'Variation in Staple Food Prices, Causes, Consequence, and Policy Options." Maputo, Mozambique 25–26 January 2010.

Minot, N. 2011. "Transmission of World Food Price Changes to Markets in Sub-Saharan Africa." *Discussion Paper 01059. International Food Policy research Institute.*

OECD-FAO Agricultural Outlook. 2009. "Chapter 5: Can Agriculture Meet the Growing Demand for Food?" http://www.oecd-ilibrary.org/agriculture-and-food/oecd-fao-agricultural-outlook-2009/can-agriculture-meet-the-growing-demand-for-food_agr_outlook-2009-5-en

OECD-FAO Agricultural Outlook. 2014. "Chapter 2: Feeding India: Prospects and Challenges in the Next Decade." http://www.oecd-ilibrary.org/agriculture-and-food/oecd-fao-agricultural-outlook-2014/feeding-india-prospects-and-challenges-in-the-next-decade_agr_outlook-2014-5-en

Roberts, Michael J., and Wolfram Schlenker. 2013. "Identifying Supply and Demand Elasticities of Agricultural Commodities: Implications for the US Ethanol Mandate." *American Economic Review* 103(6): 2265–95.

Shunji, Cui, and Ruth Kattumuri. 2010. "Cultivated Land Conversion in China and the Potential for Food Security and Sustainability." Asia Research Centre Working Paper 35.

U.S. Department of Agriculture. 2013. "Summary Report: 2010 National Resources Inventory." Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa.

Song F., J. Zhao, and S.M. Swinton. 2011. "Switching to Perennial Energy Crops under Uncertainty and Costly Reversibility." *American Journal of Agricultural Economics* 93: 768–83.

Susanti, A., G. Mada, and P. Burgers. 2012. "Oil Palm Expansion in Riau Province, Indonesia: Serving People, Planet, and Profit?" Background paper to the European Report on Development 2011/2012: Confronting Scarcity: Managing Water, Energy and Land for Inclusive and Sustainable Growth.

Swastika, D.K.S., F. Kasim, K. Suhariyanto, W. Sudana, R. Hendayana, R.V. Gerpacio, and P.L. Pingali. 2004. "Maize in Indonesia: Production Systems, Constraints, and Research Priorities." Mexico, DF: CIMMYT.

Taheripour F. and W.E. Tyner. 2013. “Biofuels and Land Use Change: Applying Recent Evidence to Model Estimates.” *Applied Science* 3(1): 14–38.

Tyner, Wally. 2010. “First and Second Generation Biofuels: Economic and Policy Issues.” Presented at the Third Berkeley Bioeconomy Conference, June 24, 2010. http://www.berkeleybioeconomy.com/ wpcontent/uploads//2010/07/TYner%20Berkeley%20June%202010.pdf.

Data Sources

Brazil: http://www.sidra.ibge.gov.br/
India: http://eands.dacnet.nic.in/
FAO: Area harvested: http://faostat3.fao.org/download/Q/QC/E
FAO: Land Cover: http://faostat3.fao.org/download/R/RL/E
USA: USDA-NASS: http://quickstats.nass.usda.gov

APPENDIX B:

Langeveld, J. W.A., Dixon, J., van Keulen, H. and Quist-Wessel, P.M. F. (2014), Analyzing the effect of biofuel expansion on land use in major producing countries: evidence of increased multiple cropping. Biofuels, Bioprod. Bioref., 8: 49–58. doi: 10.1002/bbb.1432.

Modeling and Analysis

Biofpr Biofuels Bioproducts & Biorefining

Analyzing the effect of biofuel expansion on land use in major producing countries: evidence of increased multiple cropping

Johannes W.A. Langeveld, Biomass Research, Wageningen, the Netherlands
John Dixon, Australian Centre for International Agricultural Research (ACIAR), Canberra, Australia
Herman van Keulen, Wageningen University and Research Centre, Wageningen, the Netherlands
P.M. Foluke Quist-Wessel, Biomass Research, Wageningen, the Netherlands and AgriQuest, Heteren, the Netherlands

Received May 21, 2013; revised June 17, 2013; and accepted June 24, 2013
View online at Wiley Online Library (wileyonlinelibrary.com); DOI: 10.1002/bbb.1432;
***Biofuels, Bioprod. Bioref.* (2013)**

Abstract: Estimates on impacts of biofuel production often use models with limited ability to incorporate changes in land use, notably cropping intensity. This review studies biofuel expansion between 2000 and 2010 in Brazil, the USA, Indonesia, Malaysia, China, Mozambique, South Africa plus 27 EU member states. In 2010, these countries produced 86 billion litres of ethanol and 15 billion litres of biodiesel. Land use increased by 25 Mha, of which 11 Mha is associated with co-products, i.e. by-products of biofuel production processes used as animal feed. In the decade up to 2010, agricultural land decreased by 9 Mha overall. It expanded by 22 Mha in Brazil, Indonesia, Malaysia, and Mozambique, some 31 Mha was lost in the USA, the EU, and South Africa due to urbanization, expansion of infrastructure, conversion into nature, and land abandonment. Increases in cropping intensity accounted for 42 Mha of additional harvested area. Together with increased co-product availability for animal feed, this was sufficient to increase the net harvested area (NHA, crop area harvested for food, feed, and fiber markets) in the study countries by 19 Mha. Thus, despite substantial expansion of biofuel production, more land has become available for non-fuel applications. Biofuel crop areas and NHA increased in most countries including the USA and Brazil. It is concluded that biofuel expansion in 2000–2010 is not associated with a decline in the NHA available for food crop production. The increases in multiple cropping have often been overlooked and should be considered more fully in calculations of (indirect) land-use change (iLUC). © 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

Keywords: biofuels; land use change; iLUC; food vs. fuel; ethanol; biodiesel; co-products; Brazil; USA; EU; China.

Correspondence to: Johannes W.A. Langeveld, Biomass Research, P.O. Box 247, 6700 AE Wageningen, the Netherlands.
E-mail: hans@biomassresearch.eu

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

Introduction

Increased biofuel production has led to criticism and concerns about food availability while it is feared that rising demand for cropland will lead to deforestation, grassland conversion and increased Greenhouse Gas (GHG) emissions from these land use changes. The main criticism is based on expected impacts of biofuel production following the introduction of dedicated biofuel targets and policies.[1–3]

Commonly used economic models in biofuel policy evaluation include multimarket partial equilibrium models such as the FAPRI-CARD, ESIM, and IMPACT model, and computable general equilibrium (CGE) models such as the Global Trade Analysis Project (GTAP), LEITAP and the Modeling International Relationships in Applied General Equilibrium (MIRAGE) model. Most models were originally developed to evaluate agriculture or climate policies and were later adapted to incorporate biofuel production.[4–6] This has consequences for the way the models have been implemented. Early applications, for example, did not consider generation of co-products (by-products of the biofuel production process which are mostly used as animal feed)[1,7] while second-generation biofuel production technology, at least in early applications, was not included.[4]

Other restrictions include limited ability to adjust to accelerations in yield improvement[7] or to changes in crop rotation.[9] Most models do not consider double-cropping (cultivation of two or more crops on the same plot within a given year), while changes in fallow or other unmanaged land can only be accommodated to a limited extent,[8] which is considered a significant drawback of model results.[7] Changes in programs offering farmers compensation for not cultivating arable land (Conservation Reserve Program (CRP) in the USA and Set-Aside in the EU), for example, were often not adequately represented. Further, models do not fully incorporate impacts of trade policies (e.g. preferential biofuel imports[8]), crop tillage,[10] or agro-ecological conditions in crop production areas.

While the exact consequences of these limitations remain unclear, there is a risk that relevant changes in crop production patterns, partly triggered by biofuel policies, may not be sufficiently covered in the analysis. Scenarios for future crop production published by the Food and Agriculture Organization (FAO) suggest that increasing cropping intensity will be an important source of additional crop biomass. According to Nachtergaele *et al.*,[11] cropping intensity is projected to increase by a total of 4% in developing countries between 2006 and 2050. For developed countries, however, the forecast increase is 7%. Global average is projected to increase by 6%.

Central to the debate on the impact of biofuel production is the question to what extent current policies are causing alienation of land from food and feed production. At the core is the way increased biomass requirements are to be met by area expansion, yield improvement or by increased cropping intensity. Bruinsma[12] estimated that 80% of the projected growth in crop production in developing countries up to 2050 would come from intensification in the form of yield increases (71%) and higher cropping intensities (8%). Higher shares are projected in land-scarce regions such as South Asia and the Near East/North Africa where increases in yield would need to compensate for the expected decline in the arable land area. Arable land expansion will remain an important factor in crop production growth in many countries of sub-Saharan Africa and Latin America; although less so than in the past.

Given the large (albeit possibly temporary) increases in crop prices, the general expectation that biofuels will permanently push up demand for food crop biomass plus the fact that farmers in the past have shown to be able to respond effectively to changes in crop demand might have to be moderated. Especially the projected increases in cropping intensity may be on the low side. Using data for 1962–2007, OECD-FAO[13] for example calculated that half of the realized increases in the harvested area were attributable to increased cropping intensity (the other half have been related to area expansion).

More recently, reduction of (fodder and) CRP area and increased double-cropping have been reported for the USA.[14] For example, about 16% of 2008 corn and soybean farms had brought new acreage into production since 2006. This new, formerly uncultivated, land accounted for approximately 30% of the reported farm's expansion in total harvested acreage. Most acreage conversion came from uncultivated hay. Some 15% of corn and soybean farms reported a harvested acreage (summing up all crops) exceeding their arable area in 2008, implying an increase in double-cropping. These farms reported greater expansion in harvested biofuel crop acreage than other farms, suggesting double-cropping is a quick and effective strategy to generate additional biofuel crop biomass.

Given the above limitations, economic model impact assessments of biofuel policies should be considered with care. Consequences of the limitations on the modeling outcome are difficult to assess but they may be considerable. The introduction of co-products in a GTAP evaluation of US and EU biofuel policies, for example, was

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

assessed to reduce the need for land conversion with 27%.[6] According to Croezen and Brouwer,[15] scenarios including second-generation biofuel technologies resulted in land-use requirements that were 50% lower as compared to scenarios which did not include lignocellulosic biofuel conversion technologies.

In summary, the use of estimates of biofuel scenarios based on incomplete information could generate misleading estimates. Another risk is the inadequate input use, which could give an incorrect impression with respect to day-to-day crop management practices such as input use efficiency. Consequently, perspectives for (sustainable) biomass production for biofuel and food/feed applications may be estimated incorrectly.

With a view to improving the accuracy of data for evaluations of biofuel policy impacts, this paper assesses data from different sources of biomass production of eight major biofuel producers. We analyze biofuels and feedstock increases of major biofuel feedstocks between 2000 and 2010, and their impacts on land use in Brazil, the USA, the EU, China, Indonesia, Malaysia, South Africa, and Mozambique. Together, these countries represent a large majority of global biofuel production. Local conditions for crop and biofuel production will be described in a generalized way. In order to determine the impact of biofuel policies, production volumes will be compared to those of 2000, clearly before most countries introduced biofuel-related policy measures. An important distinction will be made between the amount of biomass (crop feedstocks) that is used to generate biofuels, the amount of land that is needed to produce the biomass, and the average number of harvests that can be generated from arable land (resulting from the prevalence of fallow and double-cropping in a given region). The paper will make use of the following concepts:

- Harvested area: the crop area that is harvested in a country or region in a given year. This differs from the amount of arable land, as land may be harvested several times, while fallow land is not harvested at all.
- Agricultural area in a given country or region. This includes arable land (cultivated with arable crops, i.e. food and feed crops), permanent grassland and agricultural tree crops (fruits, beverages, stimulant crops)
- Cropping intensity: the ratio of harvested crop area to the amount of arable land.*

The relation between these concepts is the following equation:

- Harvested area = arable area * cropping intensity (1)

In our analysis, we estimate land and biomass balances. Based on the volume of biofuels produced, the equivalent amount of biomass and the required area of land is calculated. These estimates are based on detailed material collected and analyzed for a book on biofuel crop production systems currently in preparation. The review is organized as follows. First, it describes available land resources in the study countries. Next, it presents biofuel production in 2010 which is compared to that in 2000. Implications of biofuel expansion for land use are given, as are other changes in land use that have been observed. This is followed by a discussion and some conclusions.

Land resources

An overview of land cover and land use in the study countries is presented in Table 1. China, Brazil, and the USA are the largest countries, Brazil having the largest forest area (nearly 40% of the study countries total). Agricultural area is high in China, the USA and (on a relative scale) the EU, Mozambique, and South Africa. Most arable land is found in the USA, China, and the EU, permanent grasslands being important in China (hosting more than one-third of the study area grassland), the USA, and Brazil. We calculated cropping intensity, expressed as the sum of all harvested crop area during a given year divided by the total arable land (the Multiple Cropping Index or MCI). MCI was originally introduced as a measure for cropping intensity of tropical farming systems,[16] but can be calculated for temperate regions as well.[12] MCI in the study countries varies between 0.53 in South Africa, 1.45 in China. It is around 0.8 in Brazil, the USA, and the EU.

Biofuel production

Sugarcane is the predominant feedstock for ethanol production in tropical regions (Table 2). In temperate areas, ethanol is mostly made from cereals (corn in the USA and China, wheat in the EU and China). Main biodiesel feedstocks are soybean (Brazil, USA), rapeseed (EU), and oil palm (Indonesia and Malaysia). There are other feedstocks of minor importance, such as castor beans in Brazil, sunflower in the EU and Jatropha in Mozambique, but these are not included in the analysis.

Large differences exist in the way fields are prepared for biofuel production. There are a number of practices which

*Note: this is not similar to the intensity of crop production (amount of inputs used per ha or amount of yield realized per ha).

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

Table 1. Land cover and land use (million ha).

Region	Land area	Forest	Agricultural area	Permanent grassland	Arable area	Multiple Cropping Index (-)
Brazil	846	520	273	196	50	0.86
USA	914	304	411	249	160	0.82
EU	418	157	187	68	107	0.84
Indonesia and Malaysia	214	115	62	11	25	1.21
China	933	207	519	393	111	1.45
Mozambique	88	39	49	44	5	1.08
South Africa	121	9	97	84	13	0.53

Source: FAOSTAT (2013).[18]

Table 2. Biofuel production chains included in the analysis.

Region	Feedstock	Biofuel	Field preparation	Input use
Brazil	Sugarcane	Ethanol	Pre-harvest burning is phased out	Moderately low
Brazil	Soybean	Biodiesel	Mostly no-till	Low
USA	Corn	Ethanol	Mostly plowed	High
USA	Soybean	Biodiesel	Half under no-till	Moderately low
EU	Wheat	Ethanol	Plowing	High
EU	Rapeseed	Biodiesel	Plowing	High
EU	Sugarbeet	Ethanol	Plowing	Moderately high
Indonesia and Malaysia	Palm oil	Biodiesel	Pre-harvest burning	Moderately low
China	Corn	Ethanol	Plowing	Very high
China	Wheat	Ethanol	Plowing	Very high
Mozambique	Sugarcane	Ethanol	Pre-harvest burning	Moderately high
South Africa	Sugarcane	Ethanol	Pre-harvest burning	High

determine the performance of the biofuel production chain including pre-harvest burning of sugarcane leaves and plowing for arable crops. Burning leaves of sugarcane is common practice before manual harvesting in order to avoid injuries to laborers. This causes a considerable loss of leaf material and soil organic matter, while emissions of particulate matter cause a threat to the laborers' lungs. This practice is gradually being phased out in Brazil where mechanical green harvesting is becoming more common. Plowing arable fields, causing loss of soil carbon, is common in the EU and in China, but less so in the Midwest of the USA and soybean cultivation in Brazil, who have adopted conservation agriculture. Use of fertilizers and agro-chemicals is highly variable. Input use in feedstock production is low to moderately low in Brazil and in the USA (corn), Indonesia, Malaysia and Southern Africa. It is high in the production of cereals (USA, EU, and China) and rapeseed. Sugarbeet holds an intermediate position.

The main output data are presented in Table 3. Crop yield is high for sugarcane (Brazil, South Africa), sugarbeet, and oil palm. Cereal yields are high for corn in the USA, but less so for corn and wheat in the EU and China. Rapeseed and soybean yields are modest. Ethanol yields are highest for sugarbeet, and sugarcane (Brazil). Highest biodiesel yields were observed for oil palm (Indonesia, Malaysia). Generation of co-products is also quantified, as these can be applied in the livestock industry. Major biofuel crops are well established feed crops, which holds especially for corn and soybean. Co-products considered in this study include dried distillers' grains with solubles (DDGS), soy meal, rapeseed meal, beet pulp, and palm meal. It was decided to use a simple mass balance approach to distinguish between crop biomass used for biofuel production and for feed applications. Biofuel land claims were calculated by allocating a share of total land use according to the ratio of total crop feedstocks used for biofuels. Co-product yields were calculated using conversion data and converted into tons per ha equivalent

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

Table 3. Crop, biofuel and coproduct yields.

Region	Feedstock	Crop yield (ton/ha)	Biofuel yield (l/ha)	Biofuel yield (GJ/ha)	Co-product yield (ton/ha)
Brazil	Sugarcane	79.5	7200	152	–
Brazil	Soybean	2.8	600	18	1.8
USA	Corn	9.9	3800	80	4.2
USA	Soybean	2.8	600	18	1.8
EU	Wheat	5.1	1700	37	2.7
EU	Rapeseed	3.1	1300	43	1.7
EU	Sugarbeet	79.1	7900	168	4.0
Indonesia and Malaysia	Palm oil	18.4	4200	90	4.2
China	Corn	5.5	2200	46	2.9
China	Wheat	4.7	1700	36	2.5
Mozambique	Sugarcane	13.1	1100	23	–
South Africa	Sugarcane	60.0	5000	107	–

Source: crop yields calculated from FAOSTAT (2013),[18] biofuel and co-product yields calculated from literature.

which allows better comparison. Co-product yields are high for corn (USA), oil palm, and sugarbeet. Yields are low for rapeseed and soybean, while no co-products for the food or feed market are generated by sugarcane-ethanol.

Ethanol production in the study countries, amounting to 17 billion litres in 2000, rose to 86 billion litres in 2010 (Table 4). Most of the increase was realized in the USA, which was responsible for a production of 50 billion litres in 2010. Brazil is the second-largest producer with 28 billion litres, followed by the EU and China. Increases have been relatively high in China, the USA, and the EU. Biodiesel production rose from 0.8 to 15 billion litres. The EU is the highest producer, followed by Brazil and the USA. Indonesia, Malaysia, Mozambique, or South Africa are not producing significant amounts of biofuels, although they may be important producers in their respective regions. Biofuel production in the study countries (86 and 15 billion litres of ethanol and biodiesel, respectively) represents 97% and 77% of the global total production level. Thus, conclusions of global significance can be drawn from the analysis of the study countries.

Table 4. Biofuel production in the study countries (billion l).

	Ethanol			Biodiesel		
	2000	2010	Increase	2000	2010	Increase
Brazil	9.7	27.6	17.9	Neg.	2.1	2.1
USA	6.1	49.5	43.4	Neg.	2.1	2.1
EU	1.5	6.4	4.9	0.8	10.3	9.5
Indonesia and Malaysia	N.i.	N.i.	N.i.	Neg.	0.2	0.2
China	Neg.	2.1	2.1	Neg.	0.4	0.4
Mozambique	Neg.	0.02	0.02	Neg.	0.05	0.05
South Africa	Neg.	0.02	0.02	Neg.	0.05	0.05
All	17.3	85.6	68.3	0.8	15.1	14.3

Notes: N.i. = not included; Neg. = negligible.

Land use

Land used for biofuel expansion was calculated by dividing increased biofuel production presented in Table 4 by biomass to biofuel conversion rates taken from literature. Since 2000, biofuel expansion in the study countries has claimed an additional 25 million ha of cropland (Table 5). As 11 million ha is allocated to co-products, net biofuel expansion amounts to 14 million ha. Over 85% of area expansion occurred in the USA, where increased biofuel production has occupied over 5 million ha, and in the the EU and Brazil. Co-product generation is relatively high in the USA and the EU. The main crops used to produce biofuels (corn, wheat, soybean, and rape), are dominant feed crops whose nutritive characteristics have long been known. Low co-product ratio in Brazil is explained by the high share of sugarcane, whose residues are mostly used in the production of biofuels or electricity (co-generation). Vinasse is recycled and used as fertilizer.

Since 2000, countries of the study area have seen a net decline in agricultural area by 9 million ha. Loss of agricultural area in the USA, the EU, China, and South Africa amounted to 31 million ha, which is mostly compensated

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

Table 5. Net changes in land availability.

	Increased land requirement (mln ha)	Associated with co-products (mln ha)	Net biofuel area increase (mln ha)	Changes in agricultural area (mln ha)	Extra harvested area due to increased MCI (mln ha)	Change in NHA (mln ha)
Brazil	4.9	1.8	3.1	12.0	4.9	13.8
USA	11.0	5.9	5.1	–3.5	10.9	2.3
EU	6.6	3.2	3.4	–11.5	3.6	–11.2
Indonesia, Malaysia	0.02	0.01	0.01	8.9	2.0	10.9
China	2.2	0.4	1.8	–13.4	20.3	5.1
Mozambique	0.13	0.03	0.1	1.3	0.9	2.0
South Africa	0.12	0.04	0.1	–2.7	–1.2	–4.0
All	24.9	11.4	13.5	–9.0	41.5	19.0
Global total				–47.8	91.5	

by expansion of agricultural land in Brazil (plus 12 million ha), Indonesia/Malaysia (plus nine million ha), and Mozambique. Net global loss of agricultural area amounted to 48 million ha. In many cases, loss of agricultural area has been much larger than net expansion of biofuel area. This was the case in the EU, China, and South Africa. It is only in the USA that biofuel expansion is the dominant cause of agricultural land use loss.

Increasing the cropping frequency on arable land – reflected by an increase of the MCI – allows farmers to increase the harvested area on shrinking agricultural areas. This has facilitated *additional* crop harvests equivalent to 42 million ha. More than half of this expansion was realized in China, where government policy has been oriented toward improving (maintaining) food production capacity. MCI also added considerable harvested areas in the USA, Brazil, the EU, Indonesia, and Malaysia. The role of MCI in improving agricultural output since 2000 can hardly be overemphasized. Global increases, equivalent to 92 million ha of harvested crops, have been more than sufficient to compensate for losses of agricultural area.

Improvement of MCI in all but one case is more than sufficient to compensate for expansion of biofuel area: this is the case in Brazil (where MCI generated 5 million ha while biofuels required 3 million ha – a positive balance of nearly 2 million ha), the USA (11 *vs.* 5 million ha), EU (0.2 million ha balance), Indonesia/Malaysia (plus 2 million ha), China (19 million ha) and Mozambique (0.8 million ha). South Africa, which noted a decline of MCI, is the exception to the rule of increased cropping intensity.

The combined effect of biofuel expansion, changes in agricultural area, and improvement of MCI generally is positive. Together, countries included in the study increased harvested area for non-biofuel purposes of 19 million ha. This increase allowed improved availability of crop production for traditional food, feed, and fiber (FFF) markets. Net FFF area increased in most of the cases, except for the EU and South Africa.

Discussion

Following changes in biofuel policies in the course of the first decade of the twenty-first century, a strong expansion in biofuel production was observed in the USA, the EU, China, and many other countries. The 34 study countries realized an increase in ethanol production of 68 billion litres and 14 billion litres of biodiesel in 2010 as compared to 2000. These increases, however, were not sufficient to fully satisfy biofuel policy objectives in the USA and the EU. China, Indonesia, and Malaysia have adjusted policies in response to substantial consumption of food cereals and high palm oil prices, respectively. For the near future, further expansion of biofuel production is expected especially in the USA, Brazil, Argentina, and the EU. Smaller, but significant, development may be expected elsewhere.

Land devoted to biofuel production was calculated at 32 million ha in 2010, an increase of 25 million ha as compared to 2000. Of this increase, 11 million ha can be allocated, using standard conversion rates, to co-products. This means that nearly half of the increase in biofuel area in fact is used to generate crop biomass for the livestock feed market. Clearly, ignoring co-product generation in early biofuel impact assessments has led to an overestimation of land requirements, in most cases by 40% or more. The contribution of feed co-products is relatively high in the USA, China, and the EU due to the large share of cereals with high feed yields. It is low in Brazil where ethanol production is dominated by sugarcane which generates no

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

feed co-products. However, it should be noted that the co-generation of electricity from sugar cane residues has not been included in the calculations.

Biomass used for biofuel production, calculated from biofuel literature and FAO statistics, amounted to 527 million ton in 2010. This is an increase of 334 million ton, of which 80 million tons is for co-product generation. Biofuel expansion therefore required 254 million tons of crops. Area expansion, amounting to 25 million ha (including co-products), has been relatively stronger due to a shift from high yielding (ton per ha) sugarcane to cereals like corn and wheat and to oil crops like soybean and rapeseed all which have much lower yields than sugarcane. Implications for land use will, however, also depend on the role of yield improvement. In literature, different assumptions on yield improvement can be found. For US corn, for example, Searchinger *et al.*[19] assumed a maximum of 20% yield improvement in 30 years. Others have suggested that a considerable share of corn used in biofuels in the USA could be generated by yield improvements.[20] One should be extremely careful comparing crop yields as these tend to show large year-to-year variations. However, US corn yields calculated from FAOSTAT data suggest that a significant part of these yield improvements already has taken place between 2000 and 2010. Indicative yield improvements (3-year averages) during this period of sugarcane in Brazil and wheat in the EU have been 17% and 11%, respectively.

The changes in land use that were reported are most revealing. The loss of agricultural area due to urbanization, etc., in industrial countries (USA, EU, South Africa) is two times larger than biofuel expansion (31 *vs.* 14 million ha). Expansion of agricultural area in other countries (Brazil, Indonesia, Malaysia, and Mozambique) amounted to 22 million ha. Changes in intensification of arable cropping are even larger. On a global scale, the MCI increased by 7% in a period of ten years. This may not seem high, but as it applies to an area of 1.4 billion ha, the implications are enormous. In the study area, improvement of cropping intensity has been variable. It rose by 14% in China, 10% in Brazil and Mozambique, and 4% in the EU. Other countries take an intermediate position.

For the entire study area, 42 million ha of crop harvested area has been generated. Consequently, the reduction of unutilized arable land (CRP in the USA, set-aside in the EU plus fallow) and an increase in double-cropping has been sufficient to generate nearly three times the amount of biofuel land expansion. Both fallow reduction and double-cropping seem to have been largely ignored in the debate so far which is a serious omission. Improved MCI was identified as a major source of increased harvested area by OECD-FAO,[12] but the consequences for land availability vis-à-vis future biofuel expansion tend to have been overlooked. Bruinsma[11] focused mainly on yield improvement. Economic models used in evaluation of biofuel policies appear to have neglected the potential contribution of MCI.

In the future, MCI may be expected to show further increases. The magnitudes will, however, depend on crops and farming systems. Tropical regions have a larger potential for double-cropping (provided sufficient water is available). Cereals and pulses, having relatively short growing cycles, provide good perspectives. Sugarcane, occupying land year round, has limited potential for increased MCI. Climate change may, however, also offer new opportunities for temperate regions, for example, when temperatures in spring allow early harvesting of winter cereals.[17]

The approach that was followed has a number of advantages. Calculating full biomass balances allowed the assessment of biofuel feedstocks available for animal feed and – consequently – gives a realistic assessment of the amount of feedstocks required for biofuel production. Requirements of biofuel production for biomass and land resources were calculated with local data, thus incorporating a realistic assumption of cultivation practices, crop rotations, yields, and conversion efficiencies. The use of full land balances has put land demand for biofuels in perspective, integrating many processes which affect land requirement and changes in land use. Limitations of the approach are related to the large number of data that are needed. Data on crop rotations and cultivation practices often have a local nature which makes it difficult to obtain a more generic picture at the national level. Data on double-cropping and biomass to biofuel conversion are extremely difficult to obtain while the exact relation between biofuel production and increased MCI needs to be investigated. Calculations, finally, have been restricted to major biofuel feedstocks.

Notwithstanding these limitations, the implications of the findings are substantial. The impact of the increases in cropping intensity can hardly be overemphasized. On the one hand, observed MCI improvement since 2000 demonstrates that projected biofuel crop areas (estimated up to 50 million ha in 2050) can easily be compensated. In one decade, enhanced cropping intensity generated as much as 92 million ha of extra harvested crops worldwide. This is surprisingly high, and the consequences are clear. While biofuel production may occupy a significant amount of crop land in the future, there are strong drivers of crop area expansion which may be able to generate similar – or larger – additional harvested areas

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

in biofuel countries. Thus, there is little reason to expect that biofuel expansion will lead to substantial reductions of area of food/feed production. For the first decade of the twenty-first century, net harvested area for traditional (non-biofuels) biomass markets in the study area increased by 19 million ha.

The outcomes of this study are relevant to the debates related to biofuel production. Our review clearly shows that biofuel expansion has not been the major factor causing land-use change. Loss of arable land due to urbanization, etc., has claimed over twice as much land. This loss is almost certainly permanent, which is not the case for biofuel production. Further, increased intensity of arable land use has generated more than sufficient harvested area to fully compensate biofuel expansion. This makes claims of land-use changes caused by biofuel expansion (as caused by biofuel policies) less convincing.

Consider, for example, projected land use change caused by EU biofuel policies. In 2020, an additional area of 0.5 million ha has been projected to be devoted to biofuels in Brazil.[2] Only 15% of this is associated with deforestation. These are small figures, which suggest that the role of biofuel expansion as a major driving force for deforestation in Brazil needs to be reconsidered (26 million ha of forest was lost since 2000). Projected land-use change due to EU policies should also be compared to the increase of MCI observed in Brazil, generating almost (five million ha or) *ten* times the amount lost to EU biofuel exports in just one decade. In the light of these figures it is hard to imagine that biofuel policies alone are the dominant source of land-use change or deforestation.

The food *versus* fuel debate, further, needs to be enriched. While biofuel expansion in the study area has claimed 14 million ha of arable land, this area is more than compensated for by increased cropping intensity. FAOSTAT data clearly show that harvested area for food/feed markets has increased. They also show that biomass availability for food and feed applications has gone up. Further, it is not biofuel expansion but loss of agricultural land due to urbanization, etc., that is the major threat to land (biomass) availability. All this needs to be considered in the debate. The outcomes of this study show that it is essential for policy impact analyses to use statistical data to check model projections. Further, the analysis should be based on full – and not partial – biomass and land balances. Initial restrictions in model applications, ignoring co-product generation, seem to have given strongly misleading conclusions. Excluding double-cropping or cropping intensity in biofuel policy analysis has been another limitation which has had a major impact on the results. It is suggested, therefore, to incorporate local and national data on crop cultivation (e.g. crop rotations) in assessment studies of biofuel policies.

Keeney and Hertel[8] indicated that forecasting environmental impacts of biofuel policies requires both careful model formulation as well as sufficient empirical knowledge of supply and demand. Currently, only a few key parameters (e.g. yield elasticity, acreage response elasticity) determine the outcome of land-use change modeling studies. It should be checked to what extent popular analytical models correctly predicted adjustments in crop production and land-use practices. Essential elements that may have been lacking include changes in fallow and double-cropping, accelerations in yield improvement, and loss of agricultural land due to urbanization, infrasructure and industry.

Special attention is merited for cropping intensity, as well as non-biofuel crop yield improvement.[7] In this process, predicted changes in crop production and land use should be critically evaluated. Keeney and Hertel,[8] for example, predicted an increase of crop production to coincide with a reduction of forest and pasture areas in the USA, the EU, and Latin America. FAO statistics have shown that, during the last decade, forest area in the USA and EU has *increased* while grassland area remained constant in the USA and in Brazil.

The implication of this analysis for estimations of GHG emissions from biofuel production is potentially substantial. Very high assessments of carbon releases due to indirect land-use changes[2,18] have been used to underpin adjustments in biofuel policies in the EU. This review shows that a careful reconsideration of the generally assumed view that biofuels are important causes of indirect land use change is in place. Whereever feasible, this should be done using observed – rather than modeled – data.

Conclusion

This review addressed the impact of increased biofuels production on land use in major biofuel producing countries using full land balances based on land and crop statistics. Biofuel expansion is often considered a major threat for biomass availability for food and feed production and an important source of land use change. However, this analysis based on FAO statistics on crop production and land use in the period 2000 to 2010 shows that the impact of biofuel expansion on land use has been limited. An increase of 14 million ha was noted in 34 major biofuel producing nations over a period of a decade.

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

During the same period, increased cropping intensity generated over 42 million ha of extra crop land – three times the biofuel expansion. Further, an area of 31 million ha of agricultural area was lost (amongst other due to urbanization) in the USA, the EU, China, and South Africa. Consequently, there are strong drivers for expansion of land availability for traditional food and feed markets which has led to increased food and feed crop area. With the exception of the USA, biofuel expansion has not made up more than a quarter of the total loss of agricultural land.

This information should be considered in discussions on food vs. fuel debate and land-use change caused by biofuel policies. Existing frameworks need to be reconsidered. For example, biofuels *cannot* be identified as the most important or single global cause of land-use change. Other drivers have caused more (and more permanent) loss of agricultural area including process of urbanization, infrastructure development, tourism and even conversion into nature (an additional 8 million ha of forest have been established in the USA and the EU since 2000). Observed changes in land use caused by biofuel policies are very small in comparison to other changes.

Models used to evaluate biofuel policies should be enriched by incorporating more and better information on (changes in) land use and local cropping patterns, as well as differences in current and potential productivities in different agro-ecologies and farming systems. Finally, the relation between increased multiple cropping and biofuel production should be further investigated.

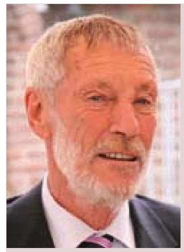
References

1. Banse M, van Meijl H, and Woltjer G, Biofuel policies, production, trade and land use. In: H. Langeveld , J. Sanders and M. Meeusen (eds.), *The Biobased Economy. Biofuels, materials and chemicals in the post-oil era.* Earthscan, London, pp. 244–258 (2010).
2. Al-Riffai P, Dimaranan B, and Laborde D, Global trade and environmental impact study of the EU biofuels mandate. International Food Policy Research Institute, Washington DC, (2012).
3. Elobeid AE, Carriquiry MA, and Fabiosa JF, Land-use change and greenhouse gas emissions in the FAPRI-CARD model system: addressing bias and uncertainty. *Climate Change Economics* **3:**1250014 (2012). DOI: 10.1142/S2010007812500145
4. Pérez Domínguez I and Müller M (eds), Modelling of energy crops in agricultural sector models. A review of existing methodologies. Joint Research Centre/Institute for Prospective Technological Studies, Seville, Spain (2008).
5. *CBES Land-Use Change and Bioenergy*: Report from the 2009 workshop. [Online]. US Department of Energy, Office of Energy Efficiency and Renewable Energy and Oak Ridge National Laboratory, Center for Bioenergy Sustainability Oak Ridge National Laboratory (2009). Available at: http://www.ornl.gov/sci/ees/cbes/workshops/LandUse_Report.pdf [July 8, 2013].
6. Khanna M and Zilbermann D, Modeling the land-use and greenhouse-gas implications of biofuels. *Climate Change Economics* **3:**1250014 (2012).
7. Golub AA and Hertel ThW, Modeling land-use change impacts of biofuels in the GTAP-BIO framework. *Climate Change Economics* **3:**1250015 (2012). DOI: 10.1142/S2010007812500157
8. Keeney R and Hertel ThW, The indirect land use impacts of US biofuel policies: The Importance of acreage, yield, and bilateral trade responses. GTAP Working Paper No. 52. Purdue University, Lafayette, Indiana (2008).
9. Beach BH, Zhang YW, and McCarl BA, Modeling bioenergy, land use, and GHG emissions with FASOMGHG: model overview and analysis of storage cost implications. *Climate Change Economics* **3:**1250012-1-1250012-34 (2012). DOI: 10.1142/S2010007812500121
10. Rosegrant MW, Ewing M, Msangi S, and Zhu T, Bioenergy and global food situation until 2020/2050. WBGU, Berlin (2008).
11. Nachtergaele F, Bruinsma J, Valbo-Jorgensen J and Bartley D, Anticipated trends in the use of global land and water resources. Food and Agricultural Organization of the United Nations, Rome (2011).
12. Bruinsma J, The resource outlook to 2050: By how much do land, water use and crop yields need to increase by 2050? [Online]. 33 pp. *Expert Meeting on How to Feed the World in 2050.* FAO and ESDD, Rome (2009). Available at ftp://ftp.fao.org/docrep/fao/012/ak542e/ak542e06.pdf [16 January 2012]
13. OECD-FAO, *Agricultural outlook 2009-2018.* OECD, Paris; FAO, Rome (2009).
14. Wallander S, Claassen R, and Nickerson C, *The ethanol decade. An expansion of U.S. Corn production, 2000-09*. [Online]. United States Department of Agriculture, Washington DC (2011). Available at http://www.ers.usda.gov/media/121204/eib79.pdf . [April 9, 2013].
15. Croezen H and Brouwer F, *Estimating indirect land use impacts from by-products utilization*. CE, Delft (2008).
16. Beets WC, Multiple cropping and tropical farming systems. Gower, Aldershot, UK (1982).
17. Nafziger E, Cropping systems. *Illinois Agronomy Handbook*. [Online]. (2008). Available at: http://extension.cropsci.illinois.edu/handbook/ [8 March 2013]
18. FAOSTAT, [Online]. (2013) Available at: http://faostat.fao.org/site/291/default.aspx [May 10, 2013].
19. Searchinger T, Heimlich R, Houghton RA, Dong F, Elobeid A, Fabiosa J *et al.*, Supporting online material for 'Use of U.S. Croplands for Biofuels Increase Greenhouse Gases Through Emissions from Land-Use Change'. *Science* **319**: 1238 (2008). DOI: 10.1126/science.1151861
20. Gallagher P, Corn ethanol growth in the US without adverse foreign land use change: defining limits and devising policies. *Biofuels Bioprod Bioref* **4:2**96–309 (2010).

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

Hans Langeveld

Hans Langeveld, agronomist, develops and evaluates bioenergy and biobased production chains. His main focus is on feedstock availability, land use change, soil carbon dynamics and GHG emissions. He studied sustainable land use in five continents and co-authored many scientific papers as well as books on farming systems and the biobased economy.



Herman van Keulen

Herman van Keulen was trained as a soil scientist and production ecologist at Wageningen University. During his carreer, he wrote many crop growth models. Herman developed innovative concepts in soil water modelling and sustainability research and has been an expert on crop growth, animal production systems and sustainable land use for over four decades.

John Dixon

John Dixon is Principal Regional Adviser, Asia and Africa, Australian Centre for International Agricultural Research. He has over 30 years of developing country experience with agricultural research and development, including cropping systems, economics and natural resource management with the CGIAR system and the FAO UN.

Foluke Quist-Wessel

Foluke Quist-Wessel is senior agronomist and director of AgriQuest. She holds an MSc. in Tropical Crop Science (Wageningen University) and focuses on agricultural production systems, rural development, food security and chain development. Previously, she worked at Plant Research International (Wageningen UR), and Biomass Research.

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

8_OP_LCFS_RFA Responses

44. Comment: **LCFS 8-1**

The comment alleges that the LCFS has enjoyed success thus far, in large part, due to the contributions of grain ethanol, however it also states that the LCFS penalizes grain ethanol with a higher CI due to land usage issues.

Agency Response: The LCFS uses the most accurate information available to quantify the full lifecycle emissions, including the indirect land use change (iLUC), of fuel pathways. Therefore, the LCFS is not penalizing corn ethanol, but accurately assesses its emission impacts. The existence of iLUC effect and corresponding emissions related to biofuel expansion has been demonstrated by scientific and academic research. The U.S. Environmental Protection Agency (U.S. EPA) has included iLUC emissions in their lifecycle analysis of biofuels for their Renewable Fuel Standard (RFS). A peer review conducted in 2009 agreed on the need to include iLUC emissions to fully account for the effects of additional feedstock demand for biofuel production. The Board, in 2009, recognizing the need to account for all effects in the evaluation of GHG emissions from transportation fuels approved the inclusion of iLUC emissions in the evaluation of crop-based biofuels. Following the Board's directive in 2009, staff convened experts in land use science, economics, agriculture, carbon emissions, etc. to review and recommend modifications to iLUC. This group, called the Expert Working Group, acknowledged the need to include iLUC emissions in the lifecycle analysis of crop-based biofuels. Studies and reports since 2009 have also supported the existence of such effects from crop-based biofuels.

The comments related to flawed analysis or prejudicial treatment for corn ethanol is not warranted. The analysis methodology used for corn ethanol is the same approach used for the other crop-based biofuels in the current regulation such as sugarcane ethanol, soy biodiesel, sorghum ethanol, palm oil biodiesel, and canola biodiesel. In 2009, the Board recognized that the use of the GTAP model to estimate iLUC was scientifically defensible, and not flawed as suggested by the commenter. They approved iLUC values for the LCFS regulation in 2009. Since 2009, ARB staff has made several refinements to the methodology to account for improved data, advancements in land use science and advances in modeling methodologies. The current set of iLUC values are determined using the average of 30 scenario runs and have utilized the same modeling approach for all six biofuels. The approach used by ARB staff has been harmonized for all biofuels and is therefore not prejudicial to any particular biofuel. This is also supported by the results of the independent peer review which demonstrate, that staff continues to make every effort to use the best science in evaluating ilUC emissions.

It is worth noting that other commenters have stated that ARB staff's choice of data has resulted in a corn ethanol value that is too low.

45. Comment: **LCFS 8-2**

The commenter states that ARB staff's iLUC analysis is "technically and methodically flawed."

Agency Response: The iLUC analysis conducted by ARB staff is based on numerous scientific studies and reports as referenced in the Initial Statement of Reasons (ISOR) and is not technically or methodologically flawed. Outputs of the model are driven by a few critical parameters and ARB staff, after conducting a comprehensive review of scientific literature, used a range to values to reflect the findings from the review conducted. The land conversions outputs are realistic and ARB staff believes that our modeling methodology for land conversions is appropriate for the six biofuels. The comment that staff's approach does not account for non-yield intensification is not valid. The economic modeling accounts for crop switching, crop rotations and other agricultural practices by accounting for them implicitly using calibrated elasticity parameters. For modeling iLUC, an input to the GTAP model included a specific volume of biofuel which constituted a 'shock' (e.g., for corn ethanol, the input shock was 11.54B gallons which was derived from 15B gallons, a RFS2 mandate, minus 3.46B gallons of ethanol production that already existed in 2004, the baseline year for the GTAP model).   When the model is shocked, the response represents the summation of decisions taken by growers to maximize profits.

46. Comment: **LCFS 8-3**

The commenter states that CARD/ISU data was submitted in December 2014, and is puzzled that those analyses were not reflected in the ISOR.

Agency Response: Since refinements to iLUC values used in the current ARB analysis are not based on the Center for Agricultural and Rural Development at Iowa State University (CARD/ISU) report. Therefore, ARB staff did not perceive the utility of citing this report just to acknowledge its availability. Preliminary review of the CARD/ISU report indicated that additional data would be required to fully evaluate issues raised, that the report comments on previous-older ARB analysis, and that it does not comment on the latest analysis as proposed for this rulemaking. Because there was insufficient time for ARB staff to collect and evaluate data in order to complete a comprehensive review of this report, analysis of the issues highlighted in the report was not included in the ISOR. Furthermore, the existing structure of the Global Trade Analysis Project (GTAP) model could not accommodate the evaluation of some of the issues raised. Staff continues to follow developments in iLUC measurement and modeling so that future improvements can be considered and incorporated in future amendments as appropriate.

47. Comment: **LCFS 8-4**

The comment alleges that ARB's iLUC is fundamentally flawed especially with respect to conversion of non-agricultural land.

Agency Response: See response to **LCFS 8-1**.

ARB's iLUC methodology and models are peer-reviewed, scientifically sound, and use the most up-to-date data available. Land use change effects occur when the acreage of agricultural production is expanded to support increased biofuel production. Lands in both agricultural and non-agricultural uses may be converted to the cultivation of biofuel crops. Some land use change impacts are indirect or secondary. When biofuel crops are grown on acreage formerly devoted to food and livestock feed production, supplies of the affected food and feed commodities are reduced. These reduced supplies lead to increased prices, which, in turn, stimulate the conversion of non-agricultural lands to agricultural uses. The land conversions may occur both domestically and internationally as trading partners attempt to make up for reduced imports from the United States. The land use change will result in increased GHG emissions from the release of carbon sequestered in soils and land cover vegetation. These emissions constitute the iLUC impact of increased biofuel production. Since 2009, there have been numerous peer-reviewed literature and scientific reviews of iLUC for biofuels. Empirical data, real-world observations, updated modeling methodology, and improved assessment methods have all been considered in these scientific publications. ARB staff has reviewed such articles and implemented appropriate modifications to the methodology for the current iLUC analysis.

The GTAP model includes elements to capture all of the potential effects specified in the four “responses”. The model accounts for crop switching, crop rotations and other agricultural practices by accounting for them implicitly using calibrated elasticity parameters. When the model is shocked, a response represents the summation of all decisions (Response 1) taken by growers to maximize profits. This includes decisions that result in increasing yields beyond average (Response 4) that could result from the increased use of fertilizers and other agricultural chemicals. The analysis by ARB staff uses a range of Yield Price Elasticity (YPE) values and accounts for potential increase in yields (YPE values spanning the range 0.05 to 0.35) and <u>does not use a single low elasticity value</u> as mentioned by the commenter. The baseline crop production data includes double cropping information. Increase in crop production and yields implicitly ensure that these effects propagate through the model results. The ARB modeling approach also includes the effects of converting lands that are either idle, or from other uses, to agricultural production.

The iLUC analysis conducted by ARB staff is based on numerous scientific studies and reports as referenced in the ISOR. The current version of the model has also been tuned using new data and updated land use science. Though the approach to iLUC analysis is the same as used for the 2009 analysis, significant updates to data and modeling methodology have been incorporated into the current analysis. The datasets are recent and obtained from sources such as the U.S. Department of Agriculture (USDA), the Food and Agricultural Organization of the United Nations (FAO), the International Monetary Fund (IMF), and other national and international repositories on agriculture and trade information.

48. <u>Comment</u>: **LCFS 8-5**

The comment directs ARB to a new publication by Babcock and Iqbal, which they feel has “important implications for CARB’s iLUC analysis.”

<u>Agency Response</u>: See response to **LCFS 8-3**.

The Babcock and Iqbal report attempts to utilize actual land use change into the analysis of an iLUC model. However, the complexities of real-world impacts do not allow for an accurate assessment of just the impact of increased crop demand. In the real-world, a decrease or increase in cropping area in a region is the sum totality of numerous factors (i.e., population and economic growth, weather conditions, drought, flooding, reforestation, GHG reduction incentives for agriculture, etc.), not just increased demand for feedstocks used for the production of biofuels. Some factors may increase cropping area and some may decrease the overall need for cropland. The results of the GTAP analysis presented by ARB staff includes only the impacts related to the increased production of biofuels and not the results of all of the activities that could effect changes in cropland at various regions of the world. Though the current version of ARB's GTAP model is capable of estimating the effects of biofuels expansion, it is incapable of modeling the impacts of all other activities in the global marketplace. In the future, if appropriate modifications can be made to the model to estimate the effects of all global activities, it may allow for comparison of model outputs to the totality of observed changes in land cover.

The GTAP model includes in it a parameter (Yield Price Elasticity) to account for intensification effects directly resulting from increases in prices of agricultural commodities. However, data related to reversal of fallow land to crop production and changes in share of planted to harvested area are not available for many regions of the world. Therefore, this analysis cannot be performed with the current version of the model. At a future date, when data becomes available, staff may incorporate appropriate modeling structures and parameters to account for such effects in the iLUC analysis.

The database used in the GTAP model includes in it double cropping data for appropriate regions of the world. Therefore, outputs from the model implicitly include impacts from double cropping, though we do not explicitly disaggregate contributions from such effects. A preliminary review of agricultural data for the U.S. has concluded that double cropping is small and not expected to contribute significantly to 'intensification effects' as mentioned in the Babcock paper. As for other regions of the world, significant work has to be completed to collect and disaggregate data to provide accurate information on double cropping across the world. When detailed data becomes available, ARB staff will consider updates to modeling structure to explicitly account for double cropping in the analysis. It should also be noted that double cropping benefits are offset by increased use of fertilizers and pesticides and these impacts also need to be accounted in the analysis (not included in the current ARB analysis).

Current predictions by the GTAP model are similar to that reported by Babcock. As discussed in comment **LCFS 8-2** above, GTAP estimates reflect the impacts related only to the increased production of biofuels but real-world data is the net result of all global activities (i.e., population growth, agriculture, deforestation for mining, etc.). Considering that GTAP estimates reflect the impacts related to a single sector, but real-world data reflects the combined impacts of all activities and sectors, it will be highly challenging to match GTAP outputs with the totality of land cover changes and market behaviors across the world.

Calibration of the model with real-world data assumes that the model is capable of evaluating the effects of all factors that affect real world behavior. The current version of the ARB GTAP model is capable of estimating the effects related to one factor, biofuel expansion. No model currently available contains the modeling structures and data to model all activities in the global economy that could impact land conversions across all regions and doing so would be outside the scope of this rulemaking.

49. Comment: **LCFS 8-6**

The comment asks ARB staff to calibrate the GTAP model "to reflect the absence of extensive land use change" in countries or regions where grassland or forestland has increased over the past decade.

Agency Response: ARB does not agree with comment that in regions where cropland contracted, demand for biofuel crops had no effect on land use. In the real-world, changes in cropland, forest, and grassland in a region is the sum totality of numerous factors (i.e., population and economic growth, weather conditions, drought, flooding, reforestation, GHG reduction incentives from agriculture, etc.) and not just increased demand for feedstocks used for the production of biofuels. Some factors may increase the requirements from these types of land cover and some may decrease the overall need for land. The net result may be negative or positive. The results of the GTAP analysis by ARB includes only the impacts of one factor, increased production of biofuels, and not the results of all of other activities that could affect changes in land in various regions of the world. See also response to **LCFS 8-5** and **LCFS 8-7**.

50. Comment: **LCFS 8-7**

The commenter contends that CARB should have used the information contained within Babcock and Iqbal report, published December 4, 2014, to calibrate its GTAP model.

Agency Response: ARB staff does not agree with the comment that in regions where there has been no change in cropland, demand for biofuel crops had no effect on land use. See response to **LCFS 8-6**.

An assessment of emission penalties on countries for foregone sequestration is not a provision under the LCFS. Determination of alternative use of land in a country is also not a provision under the LCFS. Indirect Land Use Change (iLUC) serves to estimate GHG emissions from land conversions in regions of the world resulting from an increased demand for biofuel feedstocks.

ARB staff will complete comprehensive testing of a dynamic version of the model when it becomes available to validate model behavior and response. ARB staff remains committed to evaluating new data and updates to land use science when it becomes available and accordingly refining iLUC analysis in the future.

51. Comment: **LCFS 8-8**

The commenter points out that the DDGS -- corn displacement ratio in CA-GREET 2.0 differs from the ratio in GTAP, a difference that the commenter finds problematic

Agency Response: The different ratios are appropriate because the GTAP is based on past land conversions for the period 2004-2010. The relevant land conversions have already occurred. On the other hand, CA-GREET 2.0 is intended to represent current practices.

52. Comment: **LCFS 8-9**

The commenter contends that ARB has not justified the use of their Yield Price Elasticity value, which is lower than the commenter's recommended value.

Agency Response: YPE is one of the most important parameters within the GTAP model and has significant impacts on the outputs of the model. ARB staff used a multi-dimensional approach to considering YPE that includes:

- Conducting a comprehensive review of literature for YPE,
- Contracting with Steve Berry at Yale University and a statistical expert at UC Davis to analyze data related to YPE, and
- Considering recommendations on YPE by the Expert Working Group (EWG).

Literature reviews concluded that there is likely a wide range of values for YPE and this has been detailed in Appendix I of the ISOR. The EWG recommended using a reasonable increment between values (0.05) for the short-run elasticity to account for long-run effects. The members suggested using an average value between 0.1 and 0.25.

A review of studies and data from some of the studies by a statistical expert at UC Davis concluded that yield prices elasticities are generally small. Steve Berry's findings support zero to small values for YPE based on his analysis of data. The net conclusion is that there is a wide range of likely values based on econometric/statistical treatment applied to estimate YPE. To include impacts from a range of likely values for YPE, ARB staff used a range between 0.05 and 0.35 in the scenario analysis for each biofuel. Also, most of the available data is for corn grown in the U.S. and may not represent behavior of other crops grown in the U.S. and worldwide.

Use of YPE to accommodate double cropping as suggested by stakeholders is not possible with the present version of the model. It will require more detailed land data for each location and modeling of YPE for each case. In the absence of data, YPE as currently structured for use in the model, cannot replicate double cropping in model simulations. When complete data sets for double or triple cropping are available by crop and region, appropriate structural modifications could be considered to account for such cropping patterns.

53. Comment: **LCFS 8-10**

The comment points out perceived weaknesses in the GTAP model, as a justification for using a higher price-yield elasticity value.

Agency Response: The database used in the GTAP model includes double cropping data for appropriate regions of the world. Outputs from the model, therefore, implicitly include impacts from double cropping. The contributions from such effects cannot be explicitly disaggregated. Regarding the use of YPE to accommodate double cropping, see response to **LCFS 8-9**.

The elasticity sub-group of the EWG consisted of members who are not GTAP experts. Experts of the GTAP model (academics at Purdue University who developed the model), however, were not in favor of using ad-hoc adjustments to YPE until detailed data was available to conduct comprehensive testing of model responses was completed. However, the commenter's requested value of 0.35, proposed by the commenter, was included in the range of values for YPE in the scenario analysis conducted by ARB staff for all of the biofuels. See also response to **LCFS 8-9**.

54. Comment: **LCFS 8-11**

The comment states that although the CA-GREET 2.0 is an improvement, more work is needed on the CI of ethanol pathways.

Agency Response: ARB staff appreciates the support for the proposed revisions to the CA-GREET model. See responses to **LCFS 8-12 and 8-13** to address specific concerns.

55. Comment: **LCFS 8-12**

The comment directs ARB to reduce denaturant content in ethanol to reflect "real-world" conditions.

Agency Response: ARB did consider real-world conditions and changed the proposal to reflect current industry practice of using up to 2.5% denaturant by volume. ARB has reviewed producer data confirming that blending 2.5% denaturant by volume represents standard industry practice. Rather than use a fixed constant CI for denaturant, the formula for denaturant CI now in CA-GREET 2.0 factors in the CI of the ethanol to yield an appropriate value in each instance. A more detailed spreadsheet calculator (http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm) is available to help clearly demonstrate and document the data sources and assumptions used in determining this result.

56. Comment: **LCFS 8-13**

The commenter wishes for ARB to include the GREET1_2013 default value for enteric fermentation impacts resulting from the co-product distillers grains with solubles (DGS) in the corn ethanol pathway.

Agency Response: Based upon the reasoning below and the contents of ISOR Appendix C on this topic, ARB will not include a credit for avoided enteric fermentation. ARB staff did not intend to imply or suggest that methane emission reductions from feeding distillers grains with solubles (DGS) to cattle are an indirect (consequential) lifecycle analysis (LCA) effect; however, such effects may be considered if staff included DGS-fed animals in the LCFS LCA system boundary. The commenter argues that this credit is warranted by drawing a parallel between it as an indirect effect and the iLUC values applied to corn ethanol. The commenter does not address other aspects discussed in Appendix C of the LCFS ISOR related to the incomplete LCA surrounding the enteric methane emissions credit or the complexity of applying this credit to all grain ethanol LCFS pathways.

ARB staff did not include the direct or consequential (indirect) emissions for specific types of animals in the existing LCFS LCA DGS credit determination (CA-GREET 1.8b). Under the existing regulation (CA-GREET 1.8b basis), the transportation of DGS to the animal feedlot, the emissions related to feeding the many types of animals that are fed DGS, and any aspect related to the DGS co-product credit or emissions (reduced or increased) of specific groups of animals were not considered. In the current and proposed LCFS regulations, the LCA boundary stops at displacing primary agricultural products used to feed these animals. For example, a credit for transportation of feedstock to the ethanol plant is granted as part of the DGS co-product credit. This distance relates to the transport of the primary agricultural crop to the ethanol plant, as if the ethanol plant never received this displaced feedstock, and in the proposed regulation, the transportation credit applies to both feedstocks and urea. The transportation credit does not include the distance required to transport the primary agricultural crop to the actual animal feedlot, which could be in China. Therefore, the boundary of the DGS credit does not extend to the animal, but stops on the farm where the displacement occurs regardless of what the ultimate fate of the DGS is (ARB staff does not track spoiled DGS, poor quality DGS, actual use of DGS for feeding livestock, etc.).

In CA-GREET 2.0, ARB staff is using the aggregated displacement ratio for U.S. and export markets for DGS, which are used in GREET1 2013 (see LCFS ISOR, Appendix C) because staff cannot determine what sub-markets ethanol plants will sell their DGS into over the lifetime of the applicant’s LCFS fuel lifecycle pathway. Similarly, staff cannot determine if a specific applicant will sell their DGS into the necessary market (e.g., cattle) for the duration of their LCFS fuel pathway to obtain the reduced enteric methane emissions credit, assuming the LCA of the animals being fed was as complete, as current research indicates that it is not. This incomplete analysis is explained in Appendix C of the LCFS ISOR. Staff also explains in Appendix C that overall emissions may not be reduced if animals were considered in the LCA. Specifically, the LCA presented in GREET1 2013 (and earlier versions) appears incomplete based on a review of current scientific literature. ARB staff or the scientific community may be able to conduct a LCA that would evaluate the body of scientific literature in this area of research. Staff understands there are challenges posed for fuel pathway analyses in areas where scientific research is ongoing and consensus has not yet been reached. This is also discussed by staff in Appendix C.

It is unclear whether the commenter suggests that all grain ethanol pathways that produce DGS should receive the credit based upon the incomplete LCA used in GREET1 2013 and earlier GREET models. Appendix C explains that ARB staff believes there is significant work to be done in order to assess credits or deficits at the animal feeding level through digestion, excrement, the ultimate fate of the animals (or rather the DGS embodied in the animals) and any indirect effects. In the absence of monitoring and verification requirements for LCFS fuel pathways, further research into the areas of uncertainty is needed before ARB staff can thoroughly evaluate and consider providing a DGS credit in LCFS.

57. Comment: **LCFS 8-14**

The comment suggests that the compliance scenario assumptions made by ARB are highly implausible, with regard to availability of sugarcane ethanol and related credit generation.

Agency Response: ARB staff disagrees that the available supplies of cane ethanol will be insufficient to provide the levels presented in the illustrative compliance scenario. Staff recognizes that the level of cane ethanol imports to California in 2014 was very low relative to the two previous years, and staff has adjusted the estimates of 2014 credit generation from this fuel accordingly. However, this low level of imports was simply reflective of conditions in place in 2014. These included low LCFS credit prices, low prices for corn ethanol, no need for federal Renewable Identification Number (RIN) credits from cane ethanol, and adequate LCFS credits from other sources. The ability of Brazilian producers to export considerable volumes of ethanol will continue as will the capability to ship and import the volumes envisioned in the illustrative compliance scenario. As the LCFS becomes more stringent the attractiveness of cane ethanol will increase and imports are expected to rise. As with all of the fuel volumes presented in the illustrative compliance scenario, these are not *predictions* of the future; the level of actual use of cane ethanol could be higher or lower than presented, depending on the price and availability of other credit generating fuels as well as other market factors.

This page intentionally left blank.

Comment letter code: 9-OP-LCFS-NSP

Commenter: John Duff

Affiliation: National Sorghum Producers

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

9_OP_LCFS _NSP

February 16, 2015

Mary Nichols, Chairman
California Air Resources Board
1001 I Street
Sacramento, CA 95812

RE: LCFS Re-adoption

Chairman Nichols,

National Sorghum Producers (NSP) is a trade association representing the interests of over 50,000 sorghum producers on issues related to legislative and regulatory policy in Washington as well as various state capitals. NSP led efforts to secure an advanced biofuel pathway for sorghum under the RFS2 and has performed extensive analysis on several models and datasets over the last four years, including several datasets similar to those used by the Argonne National Laboratory as well as the ARB in modeling the CI of sorghum ethanol.

NSP applauds the ARB for undertaking an extensive update of the LCFS and is very appreciative of the time committed by ARB staff to ensure not only the integrity of the data used but their representativeness of real-world conditions as well. NSP also generally supports the data underlying the sorghum portions of CA-GREET 2.0 and thanks the ARB for its special attention to sorghum iLUC, sorghum fertilizer requirements and N_2O emissions from sorghum stover. In addition to these areas, NSP strongly recommends that the ARB focus attention on information related to sorghum root:shoot ratios, and as it becomes available, incorporate this information into future versions of CA-GREET.

LCFS 9-1

LCFS 9-2

Thank you for the opportunity to provide feedback. We feel with this re-adoption, sorghum ethanol can play an even larger role in helping California meet the greenhouse gas reduction goals set by the LCFS while at the same time promoting the use of water-sipping crops like sorghum.

Please do not hesitate to let me know if you have any questions.

Regards,

J.B. Stewart
Chairman
National Sorghum Producers
4201 N. Interstate 27
Lubbock, TX 79403
Phone: (806) 749-3478

This page intentionally left blank.

9_OP_LCFS_NSP Responses

58. Comment: **LCFS 9-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

59. Comment: **LCFS 9-2**

The commenter appreciates ARB's special attention to sorghum in CA-GREET 2.0 but recommends that the ARB focus attention on information related to sorghum root:shoot ratios, and as it becomes available, incorporate this information into future versions of CA-GREET.

Agency Response: ARB staff continues to build upon and improve our knowledge base of fuel lifecycle analyses, including the effect of grain sorghum (typically S. bicolor) root shoot ratios and the impact of those ratios on the agricultural lifecycle phase of grain sorghum biofuel pathways. Staff will consider incorporating the root shoot ratio information and its effect on the fuel lifecycle pathway for grain sorghum in future rulemakings to the extent it can be accurately quantified, monitored and verified. ARB staff plans to make regular updates to the CA-GREET model on a periodic basis, currently envisioned to be no less than once every three years. The periodic update to CA-GREET will consider changes to all fuels and feedstocks and would not be limited to grain sorghum. Nevertheless, staff appreciates the commenters calling attention to this important LCA parameter for grain sorghum and staff will review additional information as it is made available.

This page intentionally left blank.

Comment letter code: 10-OP-LCFS-CRF

Commenter: Lyle Schlyer

Affiliation: Calgren Renewable Fuels

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

10_OP_LCFS _CRF

California Environmental Protection Agency
Air Resources Board

Comment Log Display

BELOW IS THE COMMENT YOU SELECTED TO DISPLAY.
COMMENT 10 FOR LOW CARBON FUEL STANDARD 2015 (LCFS2015) - 45 DAY.

First Name: Lyle
Last Name: Schlyer
Email Address: lschlyer@calgren.com
Phone Number: 5597301154
Affiliation: Calgren Renewable Fuels

Subject: Comments on LCFS Readoption
Comment:
Dear Chairman:

Calgren Renewable Fuels is a California ethanol producer that desires to use more grain sorghum as feed stock. Sorghum is low-water and, we believe, will help us reduce the carbon intensity of our fuel ethanol. We are in close touch with the National Sorghum Producers (NSP) and understand they will also submit comments.

While bemoaning the fact that others in the ethanol industry saw the need to file suit against the ARB regarding the LCFS, we applaud the ARB's reaction - re-authorizing the LCFS and working to improve the accuracy of carbon intensity scores sends the right message. LCFS 10-1

As will the NSP, we thank the ARB for paying special attention to sorghum iLUC, sorghum fertilizer requirements, and nitric oxide emissions from sorghum stover. We would ask that the ARB be alert for future information on sorghum root;shoot ratios and incorporate it into future versions of CA-GREET. LCFS 10-2

Lyle Schlyer
President, Calgren Renewable Fuels

Attachment:

Original File Name:

Date and Time Comment Was Submitted: 2015-02-16 16:20:17

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

10_OP_LCFS_CRF Responses

60. Comment: **LCFS 10-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

61. Comment: **LCFS 10-2**

The commenter appreciates ARB's attention to sorghum in CA-GREET 2.0.

Agency Response: See response to **LCFS 9-2**.

This page intentionally left blank.

Comment letter code: 11-OP-LCFS-E2

Commenter: Mary Solecki

Affiliation: Environmental Entrepreneurs (E2)

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

ENVIRONMENTAL ENTREPRENEURS®

The *Independent* Business Voice for the Environment

www.e2.org

11_OP_LCFS_E2

February 17, 2015

California Air Resources Board
1001 I Street
Sacramento, CA 95812

Dear Member of the Air Resources Board,

We applaud your continued work to implement and improve the Low Carbon Fuel Standard (LCFS). E2 encourages you to vote to re-adopt the LCFS. As a direct result of the LCFS, California is leading the world in the effort to establish commercially-viable fuel options that will contribute to lower greenhouse gas (GHG) emissions from transportation. LCFS 11-1

E2 is a nonpartisan, national community of business leaders who promote sound environmental policies that grow the economy. We are entrepreneurs, investors, and professionals from every sector of the economy who collectively have been involved in the financing, founding or development of more than 1,700 companies that have created more than 570,000 jobs. Our members manage billions of dollars in venture and private equity capital that will flow over the next several years into new companies in Oregon and beyond.

Importantly, the LCFS is already driving tangible and valuable business activities in California. Companies are investing in infrastructure to expand retail availability of the low carbon-intensity (CI) fuels they are currently selling in the state. Meanwhile, California is the focus both for efforts to pioneer additional low CI fuel options and for investments to reduce the CI of conventional fuels such as petroleum and ethanol.

We have helped develop, implement and refine the LCFS since its conception. Over the years we have seen the market grow in some unpredicted ways, such as the rise of natural gas and renewable diesel. What we did expect was the array of alternative fuels that would all scale to meet the standard, and now have proof positive that the standard is working as intended. To date, we have seen the flexibility of the LCFS encourage credit trading from dozens of fuel types, and expect even more fuel diversity by 2020.

E2 conducts an annual assessment of the domestic advanced biofuel industry. According to our 2014 report, North America's advanced biofuel industry reached a production capacity of more than 800 million gallons in 2014, almost double the capacity in 2011. This is roughly enough to fill an entire lane of Interstate 5 from Seattle to San Diego with nothing but large tanker trucks filled with advanced biofuel.

The report, "E2 Advanced Biofuel Market Report 2014," projects that by 2017, as many as 180 companies are expected to produce 1.7 billion gallons of advanced biofuel, doubling current capacity.[1] Additionally, the work recently completed by ICCT shows how advanced biofuels will

---

[1] Scodel et al. E2 Advanced Biofuel Market Report, 2014. Available at: http://cleanenergyworksforus.org/wp-content/uploads/2015/01/E2-Biofuel-Market-Report-2014.Final_Web.pdf

NORTHERN CALIFORNIA, PACIFIC NORTHWEST & ROCKY MOUNTAINS
111 Sutter Street, Fl 20
San Francisco, CA 94104

NEW YORK & NEW ENGLAND
40 West 20th Street
New York, NY 10011
TEL 212 727-2700 FAX 212 727-1773

LOS ANGELES & SAN DIEGO
1314 Second Street
Santa Monica, CA 90401
TEL 310 434-2300 FAX 310 434-2399

combine with other alternative fuels to meet or exceed 2020 reduction targets, especially if the standard is expanded into Oregon and Washington. Overall, low-carbon fuels could reduce the carbon intensity of on-road transportation fuels across the Pacific coast state by 14-21% by 2030.[2]

As the Air Resources Board (ARB) considers re-adoption of the LCFS, E2 recommends that the program be strengthened in ways that will increase and accelerate private sector investment activities. To that end, we wish to identify certain elements of the re-adoption proposal that will help strengthen the program, and propose additional considerations for staff to develop in the future:

1. E2 strongly supports ARB's proposal to keep LCFS compliance at 10% in 2020. The ARB should maintain this compliance curve through 2020 and establish stronger compliance curves to continue progress beyond 2020. Compliance curves will be the foundation for investment in infrastructure and in innovative production strategies in California. LCFS 11-2

2. Adoption of a Credit Clearance Market will protect markets in the event of a lack of liquidity in supply of either low CI fuels or LCFS credits. The ARB should adopt transparent and predictable market rules to ensure that temporary challenges in the supply of low CI fuels or LCFS credits will not disrupt the market. LCFS 11-3

3. E2 supports ARB staff's recommendation to include petroleum emission reductions from refineries. This supports the technological neutrality and carbon reduction goals of the program, and provides obligated parties with additional compliance flexibility. LCFS 11-4

Future staff proposals and considerations should include:

4. In complement to the proposed Credit Clearance Market, a credit price floor may serve to secure additional investment in low carbon fuels, thus helping ARB maximize emission reductions in a cost effective manner. The purpose of a LCFS credit price floor would be to reduce uncertainty in the minimum value of credits, to spur investment into new low-carbon fuel projects, and thereby further AB 32's goal to reduce greenhouse gas emissions in California. LCFS 11-5

5. In line with creating transparent and predictable market rules, ARB should more clearly define the penalty and enforcement provisions in the event fraudulent credit trades are discovered in the market. Clearly defined rules regarding the nature and scope of violations, culpable parties, and penalties will help deter violators, enable market participants to operate within demarcated compliance boundaries, and may facilitate the discovery of fraudulent credits by ARB. LCFS 11-6

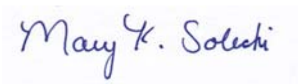
6. Since lifecycle analysis is a continuously developing science, carbon intensity pathways will be updated on an ongoing basis. Providing a clearly defined process and timeline by which new science is considered and incorporated into pathways will provide more investor certainty, and inform alternative fuel project development. LCFS 11-7

[2] Malins et al. Potential Low Carbon Fuel Supply to the Pacific Coast Region of North America. International Council on Clean Transportation. Available on the web at: http://bit.ly/PacificLCF

7. Expanding the credit trading market to third parties in parcel with developing an exchange can: increase credit price transparency and frequency of trades; alleviate long-term staff resources to broker a credit market; allow ARB to focus on the regulation of credit transactions and credit verification; and provide a platform by which other states may easily harmonize with the LCFS credit market. LCFS 11-8

The future program considerations we have outlined may be integrated at a later date. **Today, we encourage the Board to re-instate the LCFS by voting to re-adopt the program.** We commend the Board for your collective leadership and guidance on this landmark regulation.

Sincerely,



Mary Solecki
E2 Western States Advocate
mary@e2.org

This page intentionally left blank.

11_OP_LCFS_E2 Responses

62. Comment: **LCFS 11-1**

    The comment supports the re-adoption of the LCFS regulation.

    Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

63. Comment: **LCFS 11-2**

    The comment urges ARB to establish stronger compliance curves for the LCFS program beyond 2020.

    Agency Response: See response to **LCFS 5-2**.

64. Comment: **LCFS 11-3**

    The comment supports the credit clearance provision as part of the re-adoption of the LCFS regulation.

    Agency Response: ARB staff appreciates the support for the inclusion of the credit clearance provision.

65. Comment: **LCFS 11-4**

    The comment supports the refinery investment provision as part of the re-adoption of the LCFS regulation.

    Agency Response: ARB staff appreciates the support for the inclusion of the refinery investment provision.

66. Comment: **LCFS 11-5**

    The comment suggests a credit price floor would reduce uncertainly and maximize emissions reductions in a cost effective manner.

    Agency Response: See response to **LCFS 6-5**.

67. Comment: **LCFS 11-6**

    The commenter suggests ARB should more clearly define the penalty and enforcement provisions in situations of fraudulent transactions.

    Agency Response: See response to **LCFS 7-3**, **LCFS 32-20**, and **LCFS 40-41**.

68. <u>Comment</u>: **LCFS 11-7**

The comment requests ARB review the program and make updates at regular intervals, as the state of the science improves.

<u>Agency Response</u>: ARB staff seeks to maintain a balance between the latest science and market certainty. To do so, staff will update the model at predictable intervals to be determined, likely every three years.

69. <u>Comment</u>: **LCFS 11-8**

<u>Agency Response</u>: ARB staff agrees with the commenter's suggestion to evaluate possible expansion of the credit market to third parties as a consideration for a future rulemaking.

Comment letter code: 12-OP-LCFS-WPE

Commenter: Derek Peine

Affiliation: Western Plains Energy

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

12_OP_LCFS _WPE

California Environmental Protection Agency
Air Resources Board

Comment Log Display

BELOW IS THE COMMENT YOU SELECTED TO DISPLAY.
COMMENT 12 FOR LOW CARBON FUEL STANDARD 2015 (LCFS2015) - 45 DAY.

First Name: Derek
Last Name: Peine
Email Address: dpeine@wpellc.com
Phone Number: 7856728810
Affiliation: Western Plains Energy, LLC

Subject: LCFS and Sorghum ILUC
Comment:
Chairman Nichols,

Western Plains Energy, LLC (WPE) is a Kansas-based sorghum ethanol producer. WPE feels that sorghum has an important role to play in helping California meet the greenhouse gas reduction goals set by the LCFS and reducing water usage on irrigated acres.

We have a strong affiliation with the National Sorghum Producers (NSP) and understand they are submitting comments as well. As NSP does, we applaud the ARB for its update of the LCFS and appreciate its special attention to sorghum iLUC, sorghum fertilizer requirements and N2O emissions from sorghum stover. We also recommend that the ARB focus attention on information related to sorghum root:shoot ratios, and as it becomes available and incorporate this information into future versions of CA-GREET.

LCFS 12-1

LCFS 12-2

Thank you for the opportunity to comment.

With Kindest Regards,
Derek Peine
Chief Executive Officer
Western Plains Energy
Oakley, KS

Attachment:

Original File Name:

Date and Time Comment Was Submitted: 2015-02-17 06:41:20

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

12_OP_LCFS_WPE Responses

70. Comment: **LCFS 12-1**

    The comment supports the re-adoption of the LCFS regulation.

    Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

71. Comment: **LCFS 12-2**

    The comment directs ARB to include more sorghum information into future versions of CA-GREET.

    Agency Response: See response to **LCFS 9-2**.

This page intentionally left blank.

Comment letter code: 13-OP-LCFS-CEP

Commenter: Matt Durler

Affiliation: Conestoga Energy Partners

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

13_OP_LCFS _CEP

California Environmental Protection Agency
Air Resources Board

Comment Log Display

BELOW IS THE COMMENT YOU SELECTED TO DISPLAY.
COMMENT 13 FOR LOW CARBON FUEL STANDARD 2015 (LCFS2015) - 45 DAY.

First Name: Matt
Last Name: Durler
Email Address: matt.durler@conestogaenergy.com
Phone Number: 620-626-2053
Affiliation: Conestoga Energy Partners

Subject: Conestoga Energy Partners Comments on LCFS Re-adoption
Comment:
Chairman Nichols,

As I stated in the previous comment period, Conestoga Energy Partners owns and operates 3 ethanol plants in Southwest Kansas and the Texas panhandle. I believe that sorghum plays an important role in helping California reach its greenhouse gas reduction goals and our company to improve the sustainability or agriculture in our production region by reducing water usage.

I would like to echo the comments of the National Sorghum Producers applauding the ARB for its update of the LCFS and am particularly supportive of the attention given to the sorghum production systems. LCFS 13-1 I would however encourage ARB to continue to focus attention on sorghum root:shoot ratios and as the information becomes available incorporate it into future versions of CA-GREET. LCFS 13-2

I appreciate the opportunity to comment, and your continued efforts in GHG reduction.

Sincerely,

Matt Durler

Attachment:

Original File Name:

Date and Time Comment Was Submitted: 2015-02-17 06:31:43

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

13_OP_LCFS_CEP Responses

72. Comment: **LCFS 13-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

73. Comment: **LCFS 13-2**

The comment requests that ARB continue to add sorghum information to new versions of CA-GREET.

Agency Response: See response to **LCFS 9-2**.

This page intentionally left blank.

Comment letter code: 14-OP-LCFS-CALSTART

Commenter: Jamie Hall

Affiliation: CalSTART

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

14_OP_LCFS _CALSTART

February 17, 2015

Honorable Chairman Mary D. Nichols and Honorable Board Members
California Air Resources Board
1001 I Street
Sacramento, CA 95812

Clean Transportation Technologies and Solutions

www.calstart.org

Board of Directors

Mr. John Boesel
CALSTART

Mr. Michael Britt
United Parcel Service

Mr. Jack Broadbent
Bay Area Air Quality Management District

Ms. Caroline Choi
Southern California Edison

Mr. Ron Goodman
Southern California Gas Company

Ms. Karen Hamberg
Westport Innovations

Mr. Brian Olson
QUANTUM Technologies World Wide Inc.

Mr. Puon Penn
Wells Fargo Bank

Mr. Dipender Saluja
Capricorn Investment Group

Mr. Chris Stoddart
New Flyer Industries Limited

Mr. George Survant
Time Warner Cable

Mr. Stephen Trichka
BAE Systems

Re: SUPPORT for Re-Adoption of the Low-Carbon Fuel Standard

Dear Chairman Nichols and Board Members:

CALSTART supports the re-adoption of the Low Carbon Fuel Standard (LCFS) and we applaud the leadership of the Board Members and staff in developing and implementing this important policy.

CALSTART is a nonprofit organization focused on supporting the growth of the clean transportation technologies industry. CALSTART has nearly 150 member companies working to bring about a cleaner, lower carbon transportation future. Based on our work with our membership, we believe that policies like the LCFS – together with AB 32, incentives, and other complementary policies – are needed to support the transition to cleaner vehicles and fuels. We encourage the Board to support re-adoption and we look forward to continuing to work with you on implementation of California's climate and clean transportation policies.

LCFS 14-1

The LCFS is working as intended. Fuel providers are making investments and carbon intensities are dropping. Though the mix of fuels may differ from what was expected when the policy was put in place, this is to be expected. The structure of the LCFS – a flexible, performance-based standard – allows for a mix of fuels to contribute to goals and encourages innovation. The contributions of some of the diesel substitutes, including renewable diesel, have exceeded expectations. To ensure continued progress, it will be important to maintain clear market signals and ensure that the program reflects the best science. These goals can be achieved within the framework of the existing policy.

LCFS 14-2

Targets are achievable through 2020 and beyond with the right policies in place. Multiple independent studies have shown a range of compliance pathways for the 2020 LCFS targets. Moreover, a recent study from the International Council on Clean Transportation and E4Tech looking at the Pacific Coast region of North America showed that low-carbon fuels can reduce the overall carbon intensity of on-road transportation fuels in the Pacific Coast region by 14%–21% by 2030. The key is to ensure strong policy and market signals, and this is the role of the LCFS.

LCFS 14-3

OFFICES IN:
48 S. Chester Ave PASADENA, CA 91106 • 626.744.5600 • FAX: 626.744.5610 | 14062 Denver West Pkwy Suite 300 LAKEWOOD, CO 80401-3188 • 303.825.7550 • FAX 626.744.5610
501 Canal Blvd., Suite G RICHMOND, CA 94804 • 510.307.8700 • FAX: 510.307.8706 | 68 Jay Street, Suite 201 BROOKLYN, NY 11201 • (860) 729-5700

Additional market and regulatory certainty is needed. CALSTART supports re-authorizing the LCFS with the 10% carbon reduction target for 2020. Maintaining this goal is crucial for providing signals to the market. Additionally, our discussions with industry leaders suggest that we could see even greater investment and innovation with more certainty over credit values. Staff is proposing a cost-containment mechanism that provides certainty as to the upper bound of credit prices. We believe it would be beneficial to continue investigation of a minimum price, or price floor, which can provide additional certainty to investors and fuel providers. LCFS 14-4

In conclusion, CALSTART supports re-authorization of the LCFS. This is a vitally important regulation and it is functioning as intended. LCFS 14-2 cont. Indeed, we believe now is the time to begin discussions about longer term targets and plan to continue the progress being made in California. We would like to thank both the board and the staff for the hard work and leadership to date. LCFS 14-3 cont.

Sincerely,

Jamie Hall
Policy Director

14_OP_LCFS_CALSTART Responses

74. Comment: **LCFS 14-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

75. Comment: **LCFS 14-2**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the continued support for the LCFS regulation.

76. Comment: **LCFS 14-3**

The comment directs ARB to extend the program past 2020.

Agency Response: See response to **LCFS 5-2**.

77. Comment: **LCFS 14-4**

The commenter supports the 10 percent carbon reduction target in 2020 and requests for ARB to consider a price-floor for credits, to ensure market and regulatory certainty.

Agency Response: ARB staff appreciates the support for the compliance targets and the cost containment provision.

With respect to the portion of the comment pertaining to the price-floor concept, please see response to **LCFS 6-5**.

This page intentionally left blank.

Comment letter code: 15-OP-LCFS-Knapp

Commenter: Jamie Knapp

Affiliation: Supportive Group of Organizations

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

15_OP_LCFS _Knapp

February 17, 2015

Mary Nichols, Chairman
California Air Resources Board
1001 I Street, PO Box 2815
Sacramento, CA 95812

Dear Chairman Nichols and Members of the Board:

The undersigned businesses, associations and organizations are writing to support the California Air Resources Board's continued strong, steady leadership on the state's pioneering clean energy and climate policies and to urge the Board's swift re-adoption of the Low Carbon Fuel Standard, or LCFS, in 2015. We believe that clean fuels, clean air and a growing economy can go hand-in-hand, and add our voices to the tens of thousands of Californians who support the LCFS.

Transitioning to lower carbon transportation fuels benefits all Californians by:

- **Diversifying the state's fuel supply and increasing independence from fluctuating oil prices that create market and economic uncertainty.** The LCFS is already working. From 2011 to 2013 alternative fuels comprised a steadily increasing share of transportation energy use in California. An abundance of alternative fuels exists—enough to meet the LCFS by 2020—and the market has grown faster than anticipated. Furthermore, available low carbon fuels could grow to replace up to 400,000 barrels [16.8 million U.S. gallons] of gasoline and diesel use *per day*, reducing the overall carbon intensity of on-road transportation fuels in California and the Pacific Northwest by 14% to 21% by 2030. LCFS 15-1
- **Making consumers less vulnerable to price swings at the pump, saving money in the long run, and keeping transportation fuel dollars at home to grow the local economy.** California households are expected to save, on average, over $800 annually by 2020, growing to over $2,000 annually by 2030 in their transportation fuel bills, thanks to a combination of state policies that will spur more efficient cars and diverse fuel choices, and more walkable communities with transit. When consumers spend less on fuel, they have more to spend in their communities. LCFS 15-2
- **Benefitting society by spurring greater use of clean alternative fuels and vehicles.** The LCFS will result in $1.4 to $4.8 billion in societal benefits by 2020 from reduced air pollution and increased energy security. The benefits could be even greater, $10.4 billion by 2020 and $23.1 billion by 2025, when other state fuels policies are also included. LCFS 15-3
- **Helping to cut air pollution and improve public health.** To date, the LCFS has cut carbon emissions by about 9 million metric tons – that's equivalent to removing about 1.9 million passenger cars from the road for a year. Looking forward, from 2016 to 2020, the state estimates the LCFS will cut emissions by 35 million metric tons – the equivalent of removing about 7.4 million passenger cars from the road for a year. LCFS 15-4
- **Retaining the state's innovation leadership in a domestic clean fuels industry**. California is home to more than 40,000 businesses serving advanced energy markets, employing roughly 431,800. The LCFS, alone, could contribute at least 9,100 new jobs, and potentially many more if the state attracts more clean fuel production facilities and technology providers. LCFS 15-5

The science is clear: the time to act is now. We applaud your commitment to ensuring a healthy and economically vibrant California today and for future generations.

Sincerely,

Javier Garoz, CEO
Abengoa Bioenergy

Ed Duggan, President
Alton Energy, Inc.

Bonnie Holmes-Gen, Senior Director, Air Quality and Climate Change
American Lung Association in California

Richard Eidlin, Vice President, Policy & Campaigns
American Sustainable Business Council

Fernando Garcia, Senior Director, Scientific & Regulatory Affairs
Amyris

Brigid McCormack, Executive Director
Audubon California

Russ Teall, President & Founder
Biodico

Julia Levin, Executive Director
Bioenergy Association of California

Allen Barbieri, CEO
Biosynthetic Technologies

JB Tengco, California Director
BlueGreen Alliance

Tom Bowman, President
Bowman Change, Inc.

Matt Read, Director, Statewide Government Relations
Breathe California

Ron Davis, General Manager
Burbank Water and Power

Susan Frank, Director
California Business Alliance for a Clean Economy

Eileen Tutt, Executive Director
California Electric Transportation Coalition

Margie Gardner, Executive Director
California Energy Efficiency Industry Council

Jena Price, Legislative Affairs Manager
California League of Conservation Voters

Dave Modisette, Executive Director and Chief Executive Officer
California Municipal Utilities Association

Tim Carmichael, President
California Natural Gas Vehicle Coalition

Nancy Rader, Executive Director
California Wind Energy Association

Nick Lapis, Legislative Coordinator
Californians Against Waste

John Boesel, President and CEO
CALSTART

Tim Brummels, CEO
Canergy, LLC

Elena Christopoulos, Energy/Business Development Director
Capo Projects Group [CPG]

Bobbi Larson, Executive Director
CASA (California Association of Sanitation Agencies)

Katelyn Roedner Sutter, Environmental Justice Program Director
Catholic Charities, Diocese of Stockton

Ann Hancock, Executive Director
Center for Climate Protection

Tim Frank, Director
Center for Sustainable Neighborhoods

Mindy Lubber, President
Ceres

Colleen C. Quinn, Vice President, Govt. Relations and Public Policy
ChargePoint

Vijendra Sahi, Partner/VP of Business Development
Clarkstreet Associates

Vandana Bali, Principal
Clean Air Advocates

Andrew J. Littlefair, President and CEO
Clean Energy

Andrew Grinberg, Oil and Gas Program Manager
Clean Water Action

Jason Anderson, President
Cleantech San Diego

Gary Gero, President
Climate Action Reserve

Lisa Hoyos, Director
Climate Parents

Jonathan Parfrey, Executive Director
Climate Resolve

Gregg Small, Executive Director
Climate Solutions

Bill Magavern, Policy Director
Coalition for Clean Air

Bradley E. Baker, CEO and Chairman
Codding Investments, Inc.

Bahram Fazeli, Director of Research & Policy
Communities for a Better Environment

Lisa Mortenson, Co-Founder and CEO
Community Fuels

Ellen Friedman, Executive Director
Compton Foundation

Shannon Baker-Branstetter, Policy Counsel for Energy and Environment
Consumers Union

Wes Bolsen, Business Development & Public Affairs
Cool Planet

Jan Koninckx, Global Business Director, Biorefineries
DuPont Industrial Biosciences

Jennifer Krill, Executive Director
Earthworks

Holly Kaufman, CEO
Environment & Enterprise Strategies

Travis Madsen, Global Warming State Campaign Director
Environment America

Michelle Kinman, Clean Energy Advocate
Environment California

Tim O'Connor, Senior Attorney & Director, California Climate
Environmental Defense Fund

Mary Solecki, Western States Advocate
Environmental Entrepreneurs (E2)

Ted Kniesche, VP Business Development
Fulcrum Bioenergy

John Harrison, Mayor Pro Tem,
City of Redlands

John Plaza, President & CEO
Imperium Renewables, Inc.

Ruben Guerra, Chairman and CEO
Latin Business Association

Helen L. Hutchison, President
League of Women Voters

Nancy Sutley, Chief Sustainability and Economic Development Officer
Los Angeles Department of Water and Power

Graham Noyes, Acting Executive Director
Low Carbon Fuels Coalition

Mark E. Carlson, Director
Lutheran Office of Public Policy - California

Margaret Bruce, Principal Solutionary
Manzanita Consulting Associates

Sandra Itkoff, CEO
Marvel Energy

Bruce McPherson, Supervisor,
Santa Cruz County

David Mogavero, President
Mogavero Notestine Associates, Architects and Developers

Loni Cortez Russell, California Field Manager
Moms Clean Air Force

Shelby Neal, Director of State Governmental Affairs
National Biodiesel Board

Ron Sundergill, Senior Director - Pacific Region Office
National Parks Conservation Association

Simon Mui, Director, California Vehicles and Fuels
Natural Resources Defense Council

Michelle Passero, Senior Climate Policy Advisor
The Nature Conservancy

Neville Fernandes, President
Neste Oil US, Inc.

Daniel Emmett, CEO
Next Energy Technologies, Inc.

Daniel A. Lashof, Chief Operating Officer
NextGen Climate America, Inc.

Nancy C. Floyd, Managing Director
Nth Power

David Turnbull, Campaigns Director
Oil Change International

Courtney Hinkle, Campaign Manager
Operation Free / Truman National Security Project

Jana Gastellum, Climate Program Director
Oregon Environmental Council

Neil Koehler, CEO
Pacific Ethanol

Rob Elam, CEO
Propel Fuels

Joel Ervice, Associate Director
Regional Asthma Management & Prevention (RAMP)

Eric Bowen, Vice President, Corporate Business Dev. & Legal Affairs
Renewable Energy Group, Inc.

Arlen Orchard, General Manager and Chief Executive Officer
Sacramento Metropolitan Utility District

Gavin Carpenter, Policy and Business Development
SeQuential-PacificBiodiesel

Steve Frisch, President
Sierra Business Council

Kathryn Phillips, Director
Sierra Club California

Amee Sas, Executive Director
SoCo Nexus

Graham Ellis, Senior VP, Business Dev. & Strategic Accounts
Solazyme, Inc.

Virginia Klausmeier, CEO
Sylvatex

Paul Scott, VP, Advanced Technologies
Transportation Power, Inc.

Adrienne Alvord, Director, California and Western States
Union of Concerned Scientists

Elena Christopoulos, President
United Nations Association, Pasadena Chapter

Dennis Murphy, Chair
USGBC California

Scott Johnstone, Executive Director
Vermont Energy Investment Corporation (VEIC)

Becky Kelley, President
Washington Environmental Council

Chuck White, Regulatory Affairs Consultant
Waste Management

Ian Thomson, President
Western Canada Biodiesel Association

Amanda Ormond, Managing Director
Western Grid Group

Steve Westly, Founder & Managing Partner
The Westly Group

cc: Governor Jerry Brown
Senate President pro Tempore Kevin DeLeón
Assembly Speaker Toni Atkins

This page intentionally left blank.

15_OP_LCFS_Knapp Responses

78. Comment: **LCFS 15-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the compliance targets.

79. Comment: **LCFS 15-2**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the economic advantages of the re-adoption of the LCFS regulation.

80. Comment: **LCFS 15-3**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the economic advantages of the re-adoption of the LCFS regulation.

81. Comment: **LCFS 15-4**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the air quality advantages of the re-adoption of the LCFS regulation.

82. Comment: **LCFS 15-5**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the economic advantages of the re-adoption of the LCFS regulation.

This page intentionally left blank.

Comment letter code: 16-OP-LCFS-Proterra

Commenter: Eric McCarthy

Affiliation: Proterra

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

PROTERRA
FUTURE-PROOF YOUR FLEET

1 Whitlee Court, Greenville,
Phone (864) 438-0000 Fax (864)
www.pro

16_OP_LCFS
_Proterra

February 13, 2015

Michael S. Waugh, Chief
Transportation Fuels Branch
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Subject: Low Carbon Fuel Standard Energy Economy Ratio Update

Dear Michael Waugh and LCFS Staff,

Thank you for the opportunity to provide comments on the Low Carbon Fuel Standard (LCFS) program. We strongly support the goals of the LCFS program and applaud programs within the California Air Resources Board (ARB) that provide needed incentives to reduce the carbon intensity of fuels to help achieve California's health based air quality standards and aggressive greenhouse gas emission goals. LCFS 16-1

Proterra is the leading U.S. manufacturer of zero-emission commercial transit solutions and makes the world's first all-electric, fast-charge public transit bus. These buses are currently in service in California at Foothill Transit and Stockton RTD, as well as many locations throughout the country. Proterra's buses charge along their routes in less than 10 minutes with an automated roof top charger and then continue on their routes all day long, offering functionally unlimited range. Proterra's CATALYST bus achieves 21+ miles per gallon equivalent performance, 500%+ better than diesel and CNG buses. In addition, Proterra's advanced technology reduces carbon emissions by 70% or more compared to CNG or diesel buses. Zero-emission transit buses provide the opportunity for all Californian's to ride an electric vehicle and realize the health and other associated benefits.

We appreciate ARB updating the Energy Economy Ratio (EER) for heavy-duty battery electric vehicles and request ARB increase the EER to adequately reflect the miles per diesel equivalent of fast-charge battery electric compared to diesel transit buses. The proposed EER of 4.2 for heavy-duty battery electric buses does not accurately represent the real ratio between new fast-charge battery electric buses and new diesel transit bus fleets. The proposed EER for heavy-duty battery electric buses averages the EER among battery electric buses – Proterra and BYD. To help ensure an equal comparison, we recommend averaging the fuel economy across all similar Altoona-tested diesel buses, including Gillig and Nova—in addition to New Flyer. Based on the Altoona testing for the most recent 40ft, low-floor, diesel buses over the three test cycles identified by ARB (Central Business District, Arterial, and Commuter), the Gillig bus averages 4.74 MPG, Nova 2.97 MPG, and New Flyer 4.82 MPG, generating an overall overage of 4.18 MPG. Using the average 20.33 MPG diesel equivalent for battery electric transit buses and the average 4.18 MPG for diesel transit buses, we respectfully request updating the EER to at least 4.86 for heavy-duty, battery electric vehicles in LCFS 16-2

PROTERRA
FUTURE-PROOF YOUR FLEET

1 Whitlee Court, Greenville, SC 29607
Phone (864) 438-0000 Fax (864) 281-1894
www.proterra.com

order to provide an equal comparison of battery electric and diesel transit buses and accurately recognize the significant fuel efficiency and air quality benefits of zero-emission transit buses. LCFS 16-2 cont.

But even an EER of 4.86 does not accurately capture the unique fuel efficiency gains associated with Proterra's fast-charge technology. Therefore, we further request the consideration of a separate LCFS category for fast-charge, battery-electric buses, similar to ARB's additional incentive for fast-charge in the Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP), in order to recognize the technology's functionally unlimited range, efficiency, and greater miles per gallon diesel equivalent. Charging along the route in less than 10 minutes allows the fast-charge, battery-electric buses to operate continuously – similar to a fuel cell or other long-range advanced technology. In addition, the buses have greater efficiency and MPG equivalent due to their light weight and advanced technology, as the fast-charge, battery-electric transit buses have fewer batteries and less weight on-board the vehicle. <u>Therefore, we strongly encourage recognizing a separate LCFS category for fast-charge, battery electric buses with an EER of 5.2—using the 21.72 MPG diesel equivalent achieved at Altoona under three identified test cycles and the average diesel transit bus at the same test cycles of 4.18 MPG.</u> LCFS 16-3

We thank you for the opportunity to provide comments on the Low Carbon Fuel Standard, and appreciate the efforts of the California Air Resources Board to reduce the carbon intensity of fuels to support California's climate goals, help clean the air, and promote clean, low-carbon fuels to improve California's energy security and energy independence.

Sincerely,

Eric J. McCarthy
VP Government Relations & General Counsel
emccarthy@proterra.com

16_OP_LCFS_Proterra Responses

83. Comment: **LCFS 16-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

84. Comment: **LCFS 16-2**

The comment requests ARB staff to update EERs to reflect the significant fuel efficiency and air quality benefits of zero emissions busses.

Agency Response: The proposed EERs for electric buses are based on testing of 3 different buses (including 2 electric buses operating in California: Proterra Electric Bus Model BE-35, and BYD Motors Electric Bus and 1 diesel bus – New Flyer of American Model XD40) performed at the Altoona Pennsylvania Transportation Institute (PTI) at Penn State Test Track. The testing was conducted using a Transit Coach Operating Duty Cycle that comprises of 3 Central Business District (CBD) phases, 2 Arterial (ART) phases and 1 Commuter (COM) phase. All necessary data, including total miles traveled and total energy consumed while driving and charging were recorded. As such, staff believes sufficient testing data were used to establish the EERs for electric buses.

When developing the proposed EERs for electrical buses, staff preferred to have the diesel buses that are most likely to be purchased by transit services as the baseline of fuel efficiency comparisons. As a result, New Flyer of American Model XD40 was selected as the most representative of new buses that could be purchased by transit services.

85. Comment: **LCFS 16-3**

The commenter encourages staff to add another LCFS category for fast-charge electric battery busses.

Agency Response: Staff prefers to keep the EERs generic for categories of vehicles, not for a specific make/model. Staff acknowledges that the electric bus technologies will continue to improve, and as a result, the EERs for electric buses will continue to increase. Staff commits to reevaluate electric bus EER as newer testing data become available.

This page intentionally left blank.

Comment letter code: 17-OP-LCFS-NBB

Commenter: Shelby Neal

Affiliation: National Biodiesel Board

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

National Biodiesel Board
1331 Pennsylvania Ave., NW
Washington, DC 20004
(202) 737-8801 *phone*

National Biodiesel Board
605 Cla...
Jefferso...
(800) 84...

17_OP_LCFS_NBB

8_OP_ADF_NBB

February 16, 2015

Mary D. Nichols
Chair
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95814
Submitted via electronic mail.

Re: Written comments from the National Biodiesel Board on proposed Regulations for the Commercialization of Alternative Diesel Fuels and a Low Carbon Fuel Standard.

Dear Chair Nichols:

Thank you for the opportunity to comment on these regulations. We sincerely value the job you and all ARB board members and staff undertake in protecting the state's environment and public health.

By way of background, the National Biodiesel Board (NBB) serves as the trade association for the U.S. biodiesel and renewable diesel industries. The NBB represents more than 90 percent of domestic biodiesel and renewable diesel production. In addition to governmental affairs activities, the association coordinates the industry's research and development efforts.

Before delving briefly into a few key regulatory areas, I would like to express our appreciation to the Air Resources Board (ARB) for the cooperation we have received over the past several years. Biodiesel has encountered unique regulatory challenges as a result of the fact that it is the first alternative diesel fuel to ascend to commercial scale. I am pleased to report that, in each situation we have encountered, ARB staff have diligently worked through whatever issues were present with great skill, integrity, and professionalism. It has been a pleasure to work with staff on numerous matters of precedent-setting importance. LCFS 17-1

Alternative Diesel Fuel Regulation (ADF)

Speaking candidly, and strictly from a practical standpoint, we view NOx mitigation for biodiesel as unnecessary. This view is based on anticipated levels of biodiesel use in the marketplace and air quality modeling studies sponsored by the National Renewable Energy Laboratory and others. These studies show no measurable impacts on ground level ozone from widespread use of B20 due to the fact that small NOx increases are overwhelmed by large decreases in PM and other pollutants. ADF 8-1

That said, the NBB and its member companies fully support the ADF regulation as drafted. While ARB staff may have chosen a more conservative approach than our industry would have, in a perfect world, preferred, the regulation is clearly underpinned by robust data and technical analysis. Moreover, we view ARB's conservative mindset as appropriate in light of its statutory mission. ADF 8-2

In the final analysis, the ADF regulation should be viewed as an enhancement to the Low Carbon Fuel Standard (LCFS) because it provides much-needed regulatory certainty for California's biodiesel industry and it identifies a clear, certain, and rational path forward, both for biodiesel and other "new" fuels. Importantly, we also believe the regulation provides strong assurances to stakeholders that use of biodiesel under the LCFS will only result in air quality benefits.

ADF 8-2 cont.

Production and Feedstock Growth

Because of the LCFS, every biodiesel producer in the state is in some phase of expansion, waste feedstock collection rates are higher than they have ever been, and California is developing into a hub for "next generation" feedstock research and development with companies such as REG Life Sciences and Solazyme. These investments by environmental entrepreneurs are being made based on the promise of a stable, long-term GHG reduction policy. For this reason, we support maintaining the 10 percent by 2020 carbon intensity reduction requirement.

LCFS 17-2

Implementation Schedule

After careful analysis, we believe the overarching 10 percent by 2020 objective is workable. Certainly, there can be no question that the diesel requirement is achievable since more than 1.4 billion gallons of biodiesel and renewable diesel have been produced domestically each of the past two years. In light of these fuels' widespread availability and attractive pricing (typically the same as, or less than, petroleum), we see diesel substitutes as a highly attractive early compliance option. In addition, we are bullish on the growth prospects for the California biodiesel and feedstock industries. Continued in-state growth and development will make long-term compliance even easier, even less expensive, and even more beneficial to the state's economy.

LCFS 17-3

Biodiesel Fuel Pathways

We are in general agreement with the technical analysis that underpins the changes in lifecycle assessment for soybean oil, canola oil, and inedible corn oil. Of course, every scientist and stakeholder will, to some extent, have differing views on such inherently complex matters but, on the whole, ARB staff have done a superb job in integrating the most advanced science into these fuel pathways.

LCFS 17-4

Thank you, in advance, for your consideration of our views on these important matters. If I may be of any assistance, please feel free to contact me at any time at (573) 635-3893.

Sincerely,

Shelby Neal
Director of State Governmental Affairs

Cc: California Air Resources Board

17_OP_LCFS_NBB Responses

86. Comment: **ADF 8-1 through ADF 8-2**

Agency Response: These comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **8_OP_ADF_NBB**.

87. Comment: **LCFS 17-1**

The comment supports the public process employed during the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for our public process.

88. Comment: **LCFS 17-2**

The comment supports the compliance targets in the LCFS regulation.

Agency Response: ARB staff appreciates the support for the compliance targets.

89. Comment: **LCFS 17-3**

The comment supports the implementation schedule set forth in the LCFS regulation.

Agency Response: ARB staff appreciates the support for the implementation schedule.

90. Comment: **LCFS 17-4**

The comment supports the fuel pathways provision in the LCFS regulation.

Agency Response: ARB staff appreciates the support for the fuel pathways.

This page intentionally left blank.

Comment letter code: 18-OP-LCFS-ABBI

Commenter: Bernardo Silva

Affiliation: Brazilian Industrial Biotechnology Assoc.

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

ABBI
Associação Brasileira de Biotecnologia Industrial

18_OP_LCFS _ABBI

February 17, 2015

To
ARB's Public Information Office
Air Resources Board
1001 I Street
Visitors and Environmental Services Center – First Floor
Sacramento, CA 95814

Re. ABBI's comments on the Proposed Re-Adoption of the Low Carbon Fuel Standard

Dear Sirs,

The Brazilian Industrial Biotechnology Association (*Associação Brasileira de Biotecnologia Industrial* – "ABBI") welcomes this opportunity to provide comments on the Proposed Re-Adoption of the Low Carbon Fuel Standard – LCFS (the "Proposed Re-Adoption"), published on December 30, 2014 by the Air Resources Board – ARB, a body within the California Environmental Protection Agency.

ABBI is a non-profit organization based in São Paulo, Brazil, established with the purpose of acting in a global level to promote the country's biochemical and biofuels industry. The Association is composed of leading global and local industrial biotechnology companies, acting together towards the biotechnology-based industry's sustainable development.

As further detailed below, the adoption of the Brazilian average electricity mix, based on outdated and inaccurate electricity generation data, as established in Table 9 of the CA-GREET 2.0 Supplemental Document and Tables of Changes (page C-22) for the calculation of Carbon Intensity (CI) credits derived from the export of electricity to the grid, if approved as proposed, shall adversely affect Brazilian ethanol producers which already – or plan to – export ethanol to potential off-takers in the State of California. LCFS 18-1

1. Introduction:

The proposed CA-GREET 2.0 adopts the electricity mixes associated with the 26 eGRID subregions, based on the US EPA's Emissions & Generation Resource Integrated Database (eGRID), instead of the 2010 10-region North American Electric Reliability Corporation (NERC) regions, which was used in the replaced GREET1 2013. In addition, the ARB is proposing to create a Brazilian average electricity mix, based on EIA's Country Analysis Brief website report for Brazil, as provided in Table 9 – 2010 Brazil Electricity Resource Mix (page C-22 of the of the CA-GREET 2.0 Supplemental Document and Tables of Changes): LCFS 18-2

Rua General Jardim, 808, conj. 705A – Higienópolis
CEP 01223-010, São Paulo/SP
+55 11 3124-1517

CA-GREET 2.0 Proposed Brazil Electricity Resource Mix, 2010[1]

Brazil Electricity Generation Resource Mix (GREET 2013 category)	EIA Brazil (10^9kWh)	Modified Brazil CA-GREET 2.0 (%)
Fossil (Natural gas)	55	11%
Other renewables (Biomass)	35	7%
Nuclear (Nuclear)	10	2%
Hydro (Hydro)	400	80%
Total	500	100%

Source: California Air Resources Board

2. *Electricity Generation in Brazil:*

According to the Brazilian Energy Research Company (*Empresa de Pesquisa Energética – EPE*), a government agency within the Ministry of Mines and Energy, the Brazilian electricity mix is as follows:

LCFS 18-2 cont.

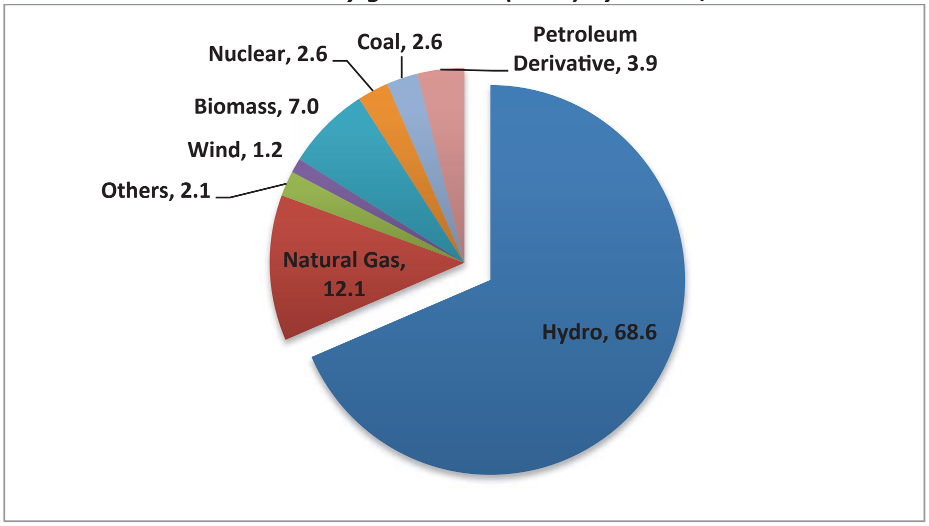
Chart 1: Brazil electricity generation by source (GWh)[2]

Type	Source	2009	2010	2011	2012	2013	2013 part. % (per source)	2013 part. % (per type)
Hydro	Hydro	390.988	403.290	428.333	415.342	390.992	68,6	68,6
Fossil	Natural gas	13.332	36.476	25.095	46.760	69.003	12,1	18,6
	Petroleum	12.724	14.216	12.239	16.214	22.090	3,9	
	Coal	5.429	6.992	6.485	8.422	14.801	2,6	
Biomass	Bagasse, wood and others	21.851	31.209	31.633	34.662	39.679	7,0	7,0
Nuclear	Uranium	12.957	14.523	15.659	16.038	14.640	2,6	2,6
Wind	Wind	1.238	2.177	2.705	5.050	6.576	1,2	1,2
Others	Recoveries, secondary gases	7.640	6.916	9.609	10.010	12.244	2,1	2,1
Total		466.158	515.799	531.758	552.498	570.025	100,0	100,0

Source: Brazilian Energy Research Company (EPE), 2014 Statistical Yearbook of Electricity

[1] Table 9 of the CA-GREET 2.0 Supplemental Document and Tables of Changes (page C-22)
[2]http://www.epe.gov.br/AnuarioEstatisticodeEnergiaEletrica/Anu%C3%A1rio%20Estat%C3%ADstico%20de%20Energia%20El%C3%
[2]http://www.epe.gov.br/AnuarioEstatisticodeEnergiaEletrica/Anu%C3%A1rio%20Estat%C3%ADstico%20de%20Energia%20El%C3%
A9trica%202014.pdf

Chart 2: Brazil 2013 electricity generation (GWh) by source, %



Source: Brazilian Energy Research Company (EPE), 2014 Statistical Yearbook of Electricity

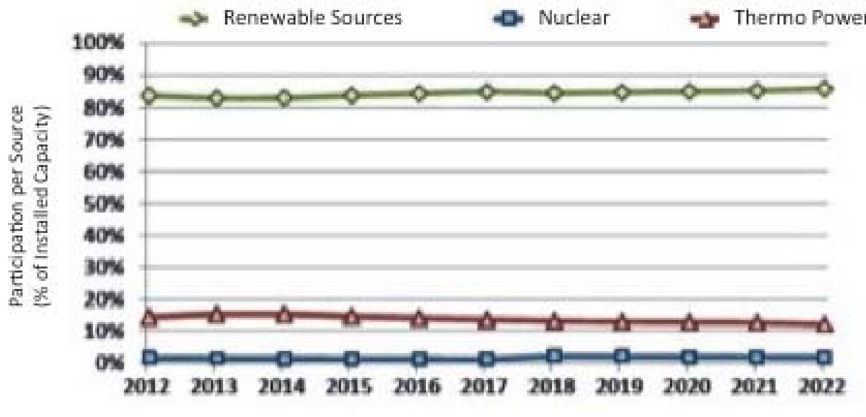
LCFS 18-2 cont.

As seen above (chart 2), the Brazilian electricity mix is still heavily dependent on the generation of electricity from hydro power plants, which includes large plants, such as Itaipú (with an installed capacity of 14,000 MW) and Tucuruí (with an installed capacity of 8,370 MW), as well as small hydroelectric plants (*Pequenas Centrais Hidrelétricas – PCHs*), which are limited to 30 MW capacity each. Hydro power installed capacity in Brazil is currently 89,224 MW and, if all new hydro power plants start operations according to the schedule, by 2021 and additional hydro power capacity of 21,774 MW shall be added to the national grid.

However, due to hydrological crisis which affects Brazil since 2010/2011, the capacity of the hydro power plants' reservoirs are currently below 20% (twenty percent) in the Southeast and Northeast regions[3] (which represents 69% of Brazil's total electricity consumption), meaning that the existing hydro power plants have been operating far below their installed capacity and the additional capacity to be delivered by the new hydro power plants shall not be sufficient to reduce the participation of fossil sources plants in the Brazilian electricity mix, which installed capacity shall account to 14.2% (fourteen point two percent) in 2016 and 12.3% (twelve point three percent) in 2022, according to official estimates prepared by the EPE, as shown in the charts below:

[3] Hydro power plants reservoirs status on Jan 12, 2015: Southeast and Center West regions: 19.29%; South region: 70.04%; Northeast region: 17.9% and North region: 35.06% (Source: ONS);

Chart 3: Development of sources participation on SIN's installed capacity

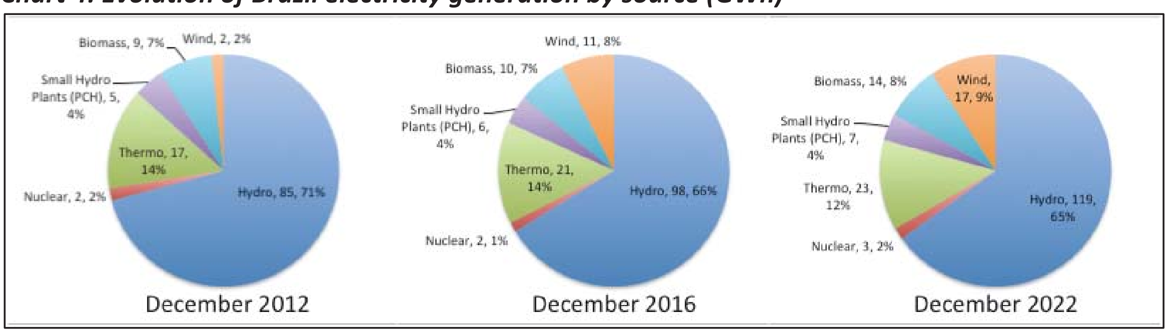


Source: Brazilian Energy Research Company (EPE)

The Brazilian electricity system is connected through the National Interconnected System (*Sistema Interligado Nacional – SIN*), which is monitored by the National Operator of the Electricity System (*Operador Nacional do Sistema Elétrico – ONS*), a non-profit organization regulated by the National Electricity Energy Agency (*Agencia Nacional de Energia Elétrica - ANEEL*). Under the SIN, the hydropower plants, which have lower operational costs as compared to the other sources, operate in full capacity, while fossil sources plants (i.e. natural gas, petroleum products and coal), which have higher operational costs, operate "on demand", by means of the so-called dispatch orders issued by the ONS, according to the system's needs.

LCFS 18-2
cont.

Chart 4: Evolution of Brazil electricity generation by source (GWh)[5]



Source: Ten-Year Plan for Energy Expansion – PDE, Brazilian Energy Research Company (EPE)

Periodically, two reports are prepared by the ONS: (i) the Energy Operation Planning (*Planejamento de Operação Estratégica – POE*), with the purpose of presenting a 5-year planning for the electricity generated to and consumed from the SIN; and (ii) Annual Electricity Operation Planning (*Planejamento de Operação Elétrica Anual – POEA*), a study which offers the diagnosis of the SIN performance and provides a forecast of the generation and consumption of electricity in a 1-year

[5] http://www.epe.gov.br/pdee/forms/epeestudo.aspx

period. The POEA is the study that subsidies ANEEL's decisions to increase or reduce the electricity to be generated by the fossil sources plants within a certain period of time.

Due to (i) the increase of electricity demand over the years; (ii) the severe hydrological crisis which affects the sector since 2011 (as explained above); and (iii) the lack of sufficient investments in new projects; the fossil source plants have been registering, since 2008, the highest increases in installed capacity in Brazil (see Chart 5 below) and, since 2011, have been operating close to full capacity to meet the system's needs.

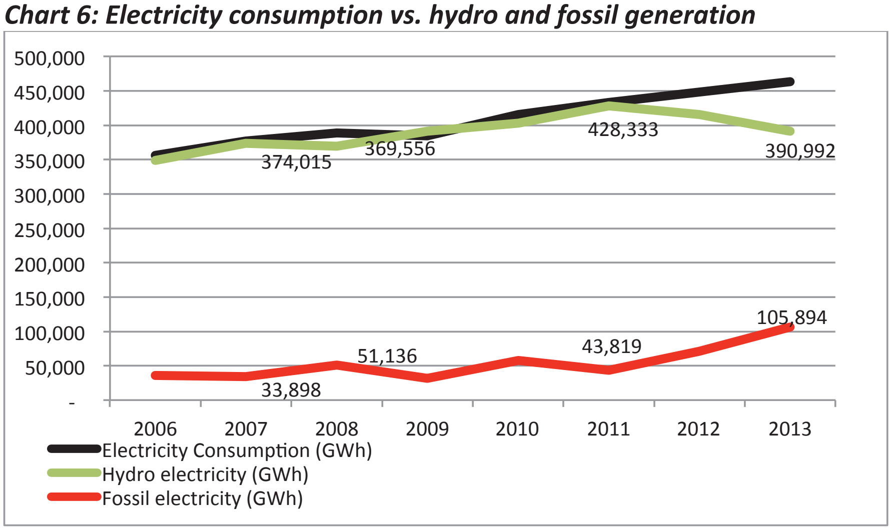
Chart 5: Start-up of new electricity plants (in MW)

	2008	2009	2010	2011	2012	2013	Total	%
Thermal (fossil + biomass)	1.243,90	2.224,00	3.762,80	2.125,54	1.670,08	3.717,35	14.743,67	57,57
Hydro	822,84	1.074,18	2.060,97	1.575,47	1.856,64	1.525,17	8.915,27	34,81
Wind	91,30	266,93	325,60	498,35	456,19	313,19	1.951,56	7,62
							25.610,50	**100**

Source: National Electricity Energy Agency - ANEEL

Until 2010/2011, the generation of hydro electricity was capable of meeting most of Brazil's electricity demand, and other sources of electricity were used only for brief periods of hydro electricity shortages imposed by water scarcity during dry seasons or consumption peaks. As from 2011, the hydro electricity became no longer capable to meet the national needs and the fossil sources' plants started playing a critical role in the Brazilian electricity sector, increasing the electricity generation from 43,819 GWh in 2011 to 105,894 GWh in 2013, as shown below: LCFS 18-2 cont.

Chart 6: Electricity consumption vs. hydro and fossil generation



Source: EPE, prepared by ABBI

The tables and charts above and Chart 7 below prove the reduction of the participation of hydropower plants and the increase of fossil sources plants in the Brazilian electricity mix, from 79.8% and 11.04%, respectively, in 2008, to 68.6% and 18.6% in 2013. They also evidence how dependent is Brazil on the electricity generated by the fossil sources plants (i.e. natural gas, petroleum and coal).

As explained by Vahl and Casarotto Filho, whose study suggests that by 2022 thermal plants shall be the main source of electricity in Brazil, surpassing the hydropower market share, ***"dispatch orders and the energy mix follow seasonal demand peaks in the Brazilian grid. In order to meet demand during peak seasons, especially in summer (from December through March), the Brazilian operator*** **[i.e. ONS]** ***has hired an increasing amount of energy from thermo power plants, which are currently the primary contingency plan for the maintenance of supply and system reliability. Such strategy increases significantly the amount of GHG emissions "***[6].

They continue saying that ***"electricity production from thermal power plants has increased 694% in the Brazilian energy mix from 2005 to 2012, a pace much higher than consumption. Also, the strategy of dispatching energy from thermal power plants only in situations of low hydro energy stored no longer applies for Brazilian scenarios, since the yearly average has also grown regardless of hydro energy stored. Such plants are indeed becoming important suppliers in order to maintain balance between electricity supply and demand***[7]. The recent exploitation of petroleum in the pre-salt area, part of them with massive quantities of natural gas, also poses as a potential factor to increase even further the electricity generation from such source.

Year over year, the hydroelectric capacity has declined while fossil fuel generation has grown. This trend clearly indicates that the marginal power generation resource is from fossil fuels. In other words, as the fossil sources plants are the only ones with capacity to increase production in Brazil, they work as a marginal resource to balance the national electricity supply and demand and should therefore be considered, for any purpose, as the only sources of electricity to compose the Brazilian marginal resource mix.

LCFS 18-2 cont.

Chart 7: Electricity generation 2008 x 2013

Type	Source	2008	% (per source)	% (per type)	2013	% (per source)	% (per type)
Hydro	Hydro	369.556	79,80	79,80	390.992	68,60	68,60
Fossil	Natural gas	28.778	6,21	11,04	69.003	12,10	18,60
	Petroleum	15.628	3,37		22.090	3,90	
	Coal	6.730	1,45		14.801	2,60	
Biomass	Bagasse, wood and others	19.199	4,15	4,15	39.679	7,00	7,00
Nuclear	Uranium	13.969	3,02	3,02	14.640	2,60	2,60
Wind	Wind	1.183	0,26	0,26	6.576	1,20	1,20
Others	Recoveries, secondary gases	8.076	1,74	1,74	12.244	2,10	2,10
Total		463.120	100,00	100,00	570.025	100,00	100

Source: EPE, prepared by ABBI

[6] Vahl, FP., Casarotto Filho, N., 2015, Energy transition and path creation for natural gas in the Brazilian electricity mix, Jornal of Cleaner Production 86 (pg. 221-229);
[7] Vahl, FP., Casarotto Filho, N., 2015, Energy transition and path creation for natural gas in the Brazilian electricity mix, Jornal of Cleaner Production 86 (pg. 221-229);

3. GREET 2.0 Electricity mix methodology: average mix vs. marginal resource mix

The ARB says in the CA-GREET 2.0 Supplemental Document and Tables of Changes (page C-2) that "*Staff has adopted the mixes associated with the 26 eGRID subregions. Average rather than marginal subregional mixed are used*" and continues saying that "*Staff selected average electricity resource mixes primarily due to the uncertainty in determining the marginal resource mix accurately for each subregion*".

ABBI appreciates the difficulties to determine which type of energy should be considered as marginal for the purposes set out in the CA-GREET 2.0 in the US, in view of the different sources of electricity suppliers with availability to increase production to attend the demand. However, that is not applicable to Brazil. As demonstrated above, the only source of electricity that has been substantially increasing in Brazil since 2008 and that has installed capacity and flexibility to increase production in the short or medium term is the fossil energy, primarily from natural gas. LCFS 18-3

Therefore, the fossil energy (i.e. generated by natural gas, petroleum products and coal) should be considered the Brazilian marginal resource mix for any purposes, including for the calculation of Carbon Intensity – CI credits derived from the export of electricity to the grid by Brazilian ethanol producers.

4. Conclusion

In view of the above, ABBI hereby urges the ARB to adopt in GREET 2.0, for the calculation of Carbon Intensity – CI credits derived from the export of electricity to the grid:

(i) The actual marginal resource mix of the region where the respective mill is located. In this case, the Brazilian marginal resource mix should be composed exclusively of natural gas, petroleum and coal power plants; or alternatively, LCFS 18-3 cont.

(ii) the natural gas based electricity mix (i.e. 2010 10-region North American Electric Reliability Corporation (NERC) regions), which was used in GREET1 2013 and previous CA_GREET models, which are the measures that most accurately reflect the savings of GHG emissions caused by the export of electricity to the grid. LCFS 18-2 cont.

ABBI would be glad to provide any further information or document as deemed necessary by the ARB and renew its assurances of full support and the most distinguished consideration for the work carried out by the ARB.

Respectfully submitted,

____

Brazilian Industrial Biotechnology Association – ABBI
Bernardo Mendes de Oliveira e Silva
Executive President

Rua General Jardim, 808, conj. 705A – Higienópolis
CEP 01223-010, São Paulo/SP
+55 11 3124-1517

This page intentionally left blank.

18_OP_LCFS_ABBI Responses

91. Comment: **LCFS 18-1**

The commenter states that the Brazilian average electricity mix in CA-GREET will adversely affect ethanol producers in the country.

Agency Response: With regards to the comment on the incorrect mix of electrical generating assets specified in the draft California-modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET) v2.0 life cycle analysis model, ARB staff concurs with the commenter that the proposed mix had incorrectly grouped several fossil-fueled generating resources (such as petroleum fuel-based generation) with natural gas-based generation. CA-GREET 2.0 was amended to reflect electricity generation data from the Brazilian government.

With regards to the broader comment that the average electricity mix will adversely impact ethanol producers in Brazil, see the response to **LCFS 18-3** below.

92. Comment: **LCFS 18-2**

The comment is an informative display of the historical electrical energy production and usage in Brazil, from 2006 to 2012.

Agency Response: In response to the comment, ARB staff changed the mix of electrical generating assets. The resulting mix is based on data provided in the annual Brazilian Energy Balance[1] prepared by the Ministry of Mines and Energy, Government of Brazil. The correction was made as a 15-day change to the regulation to consider the re-adoption of an updated Low Carbon Fuel Standard (LCFS). Staff thanks the commenter for sharing the average Brazilian mix data.

[1] The average portfolio of electrical generating assets is based upon the Brazilian Energy Balance for years 2010-2012, published by the Empresa de Pesquisa Energetica (EPE) agency of the Ministry of Mines and Energy (http://www.mme.gov.br).

15-day Change to the Average Electrical Generation Mix for Brazil

Electric Generation Mixes: Data Table for Use in GREET (From Annual Energy Outlook 2013)	29-Brazillian Mix	
	Transportation	Stationary
Residual oil	3.4%	3.4%
Natural gas	7.9%	7.9%
Coal	1.9%	1.9%
Nuclear power	2.6%	2.6%
Biomass	7.0%	7.0%
Renewable sources (w/o hydro) and others	77.3%	77.3%

93. Comment: **LCFS 18-3**

The comments states that the marginal electricity use in Brazil has been derived primarily from fossil-based energy sources and request that ARB staff update CA-GREET 2.0 to reflect it.

Agency Response: ARB staff concurs with the commenter that the marginal electrical energy use in Brazil in recent drought-affected years may have been derived primarily from fossil-based energy resources. However, Staff's proposal requires the use of average electricity resource mixes for both grid power consumption and for displacement credit for generated power for pathways submitted under CA-GREET 2.0. Under this framework grid electricity users and exporters to the grid use the same values. This decision was made primarily due to challenges in accurately determining the marginal electricity resource mix for each U.S. subregion or international subregion as explained in Appendix C of the ISOR.

It is challenging to define and distinguish marginal electricity sources accurately. To conduct this type of analysis with the highest degree of certainty requires the use of sophisticated dispatch modelling imposing consistent assumptions across all regions.

Further, different types of self-generation may operate in different modes and have different abilities to displace various grid resources (i.e., intermittent renewables are different from baseload combined-heat-and power, which is also different from dispatchable self-generation). Staff does not have access to robust and comparable marginal unit analysis across all regions and does not have the resources to conduct such an analysis currently.

Staff determined that the simplest, most equitable and defensible method for the current rulemaking is to apply the regional average across all pathways.

This page intentionally left blank.

Comment letter code: 19-OP-LCFS-Tutt

Commenter: Eileen Tutt

Affiliation: California Electric Transportation Coalition

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

19_OP_LCFS
_Tutt

California Environmental Protection Agency
Air Resources Board

Comment Log Display

BELOW IS THE COMMENT YOU SELECTED TO DISPLAY.
COMMENT 19 FOR LOW CARBON FUEL STANDARD 2015 (LCFS2015) - 45 DAY.

First Name: Eileen
Last Name: Tutt
Email Address: eileen@caletc.com
Phone Number:
Affiliation:

Subject: Support for LCFS re Adoption
Comment:
Dear Honorable Chairman Nichols and Members of the Board:

Please consider the attached documents supporting the California Electric Transportation Coalition comments which were submitted on February 13, 2015:

1. An assessment by ICF International characterizing the macroeconomic impacts and associated co-benefits of LCFS compliance. LCFS 19-1

2. An assessment by ICF International in cooperation with industry leaders and investors showing the alternative fuels market has evolved much faster than anticipated and the Low Carbon Fuel Standard is exceeding expectations. The report analyzes recent developments in the transportation sector and presents three scenarios that ratchet down the carbon intensity of transportation fuels 10 percent, to meet the goal of California's Low Carbon Fuel Standard by 2020. All three projections point to an increasingly diverse fuel supply, with more innovation leading to more renewable fuels and advanced vehicles. LCFS 19-2

3. An assessment by TIAX, LLC demonstrating that electricity consumption in on-road and off-road applications has the potential to produce a significant quantity of LCFS credits. LCFS 19-3

4. A powerpoint summarizing a related assessment by ICF LCFS 19-4

International and E3 which demonstrates the benefits of transportation electrification for all Californians, whether or not they drive electric. These benefits extend beyond the air quality and greenhouse gas benefits to include benefits to ratepayers. The full reports are available online at www.caletc.com. LCFS 19-4 cont.

Thank you for your consideration.
Regards,
Eileen Wenger Tutt, Executive Director
California Electric Transportation Coalition

Attachment: www.arb.ca.gov/lists/com-attach/21-lcfs2015-BmoGY1E2VnYGXwh7.zip

Original File Name: LCFS Supporting Documents.zip

Date and Time Comment Was Submitted: 2015-02-17 11:11:25

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

California Low Carbon Fuel Standard (LCFS) Electric Pathway – On-Road and Off-Road

Presentation to:

California Electric Transportation Coalition (CalETC)

November 14, 2012

TIAX LLC
35 Hartwell Avenue
Lexington, MA
02421-3102

www.TIAXLLC.com

Reference No.:

© 2012 TIAX LLC

Electric Credits in the California Low Carbon Fuel Standard

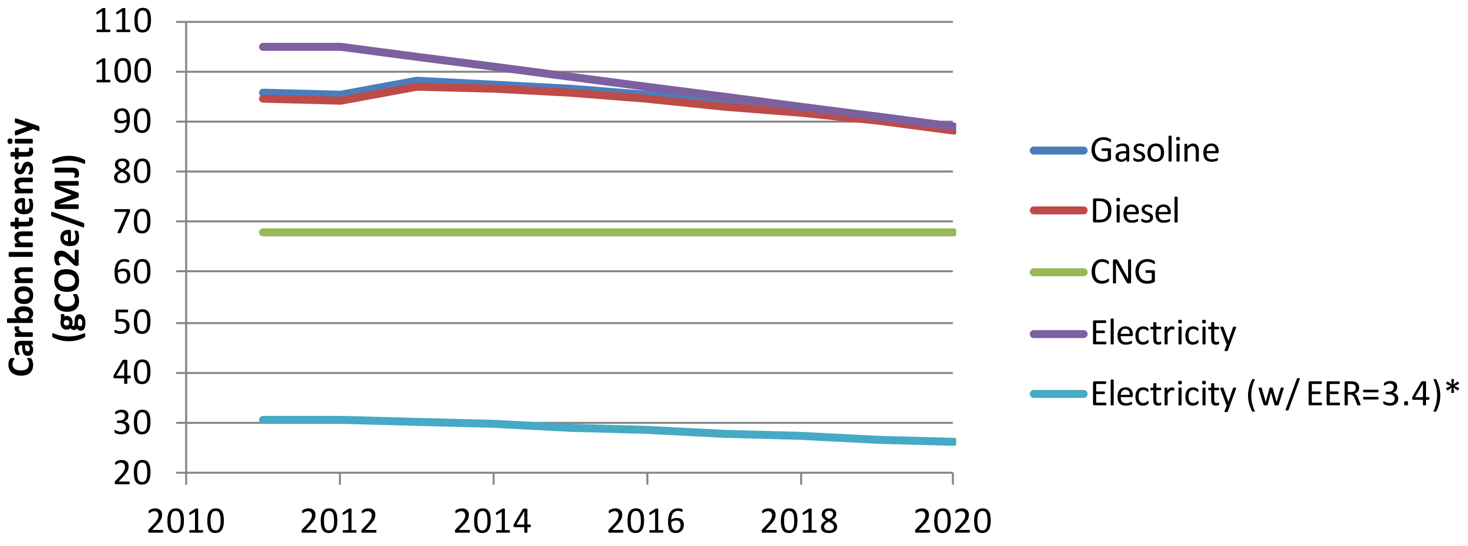
- Electricity consumption in on-road and off-road applications has the potential to produce a significant quantity of LCFS credits
- On-road applications include light-duty plug-in electric vehicles (PEVS) such as battery electric vehicles (BEVs) or plug-in hybrid vehicles (PHEVs)
- Off-road applications include electric passenger rail, electric forklifts and E-transport refrigeration units (e-TRUs)

Not included in this Analysis

- In several ways this analysis is conservative because GHG reductions from several existing and potential segments for electric transportation were excluded
  - Medium and heavy duty PHEVs and BEVs (including over-head wire options)
  - Most of the off-road applications including
    - electric airport ground support equipment,
    - electric golf carts,
    - electric personnel / burden carriers,
    - electric industrial tow tractors,
    - electric sweepers, scrubbers and burnishers
    - electric lawn and garden equipment
    - shore-side electric equipment (cold ironing)
    - electric port cargo handling equipment
    - truck stop electrification
    - electric freight rail and high speed rail
    - expanding market share for electric forklifts and electric TRUs.
- Also this analysis does not count the GHG reductions from PHEVs when they travel in gasoline mode (317,000 tons reduced per year in 2020 for 780,000 PHEVs)

Carbon Intensities

- Gasoline and diesel carbon intensities are the standard values, decreasing from 2011 to 2020, using the September 17, 2012 15 Day Modified Regulatory Order
- CNG carbon intensity stays the same
- RPS regulation has stair-step renewable requirements for electricity between 2013 and 2020; modeled electricity carbon intensity decreasing linearly from 2012 (21.3% renewables; balance natural gas) to 2020 (33% renewables; balance natural gas) for simplicity

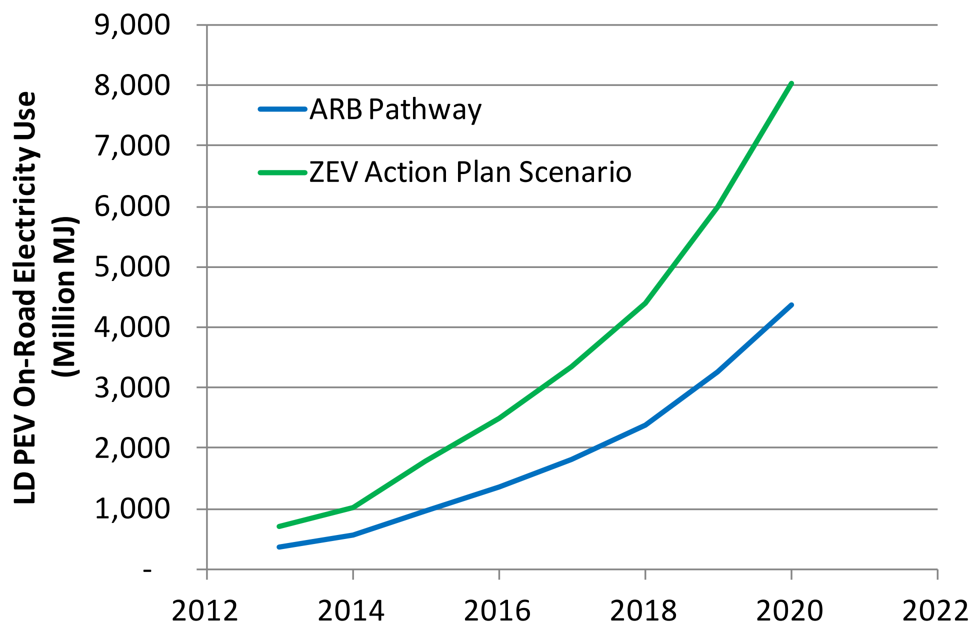


*Taking into account the EER allows for a comparison based on per unit of energy of the replaced fuel (e.g. gasoline or diesel)

On-Road Electrification – LD PEVs (40% PHEV Miles in Electric Mode)

- Electricity consumption based on ARB Illustrative Pathways – 544,000 plug-in vehicles in 2020, 22% of which are BEVs; PHEVs – 40% miles in Electric Mode
- ZEV Action Plan Scenario is 1 million plug-in vehicles in 2020, 22% BEVs and 40% PHEV miles Electric Mode similar to ARB Illustrative Pathways
- ARB Pathway: EER - 3.4; VMT All Vehicles (2020) – 12,000

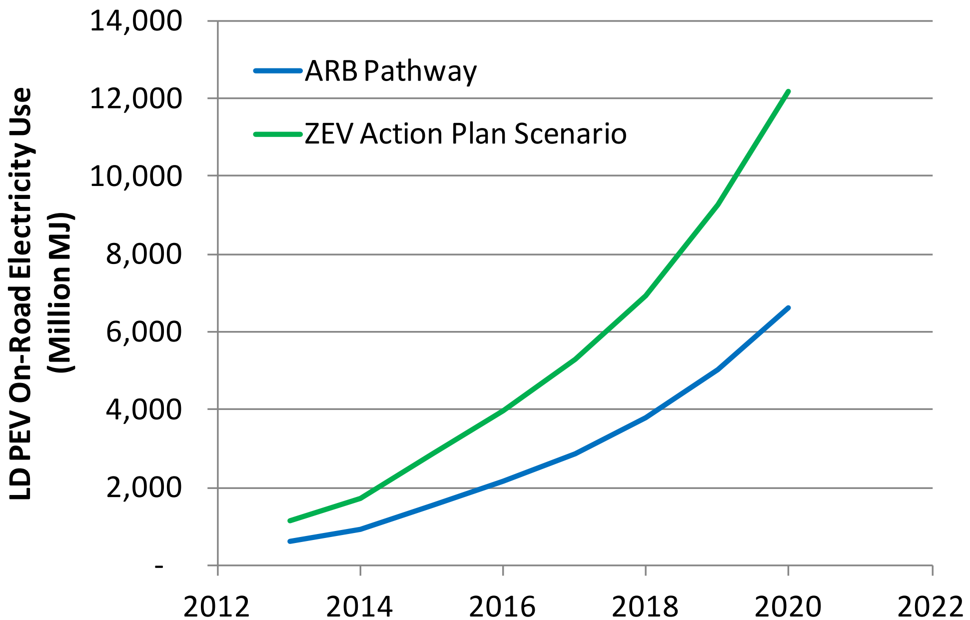
$$(CI^{Gasoline}_{Standard} - CI^{Elec} / EER^{Elec}) * (E^{Elec} * EER^{Elec}) * C = Credits$$



On-Road Electrification – LD PEVs (75% PHEV Miles in Electric Mode)

- Electricity consumption based on ARB Illustrative Pathways – 544,000 plug-in vehicles in 2020, 22% of which are BEVs; PHEVs – 75% miles in Electric Mode
- ZEV Action Plan Scenario is 1 million plug-in vehicles in 2020, 22% BEVs and 75% PHEV miles Electric Mode similar to ARB Illustrative Pathways
- ARB Pathway: EER - 3.4; VMT All Vehicles (2020) – 12,000

$$(CI^{Gasoline}_{Standard} - CI^{Elec} / EER^{Elec}) * (E^{Elec} * EER^{Elec}) * C = Credits$$

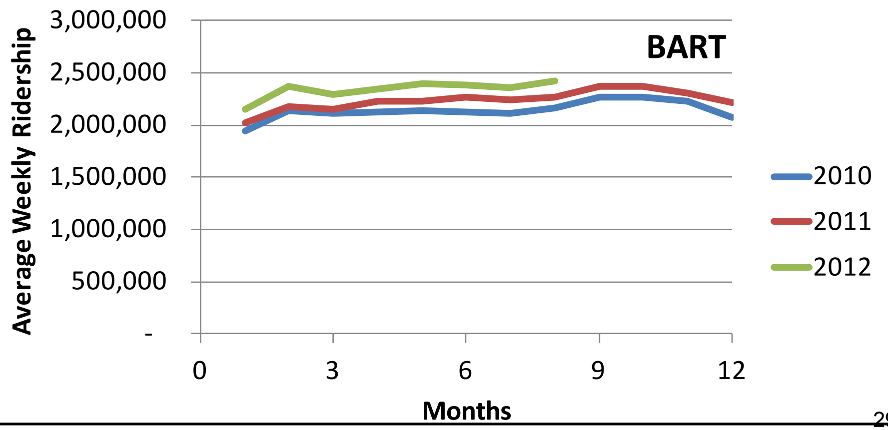


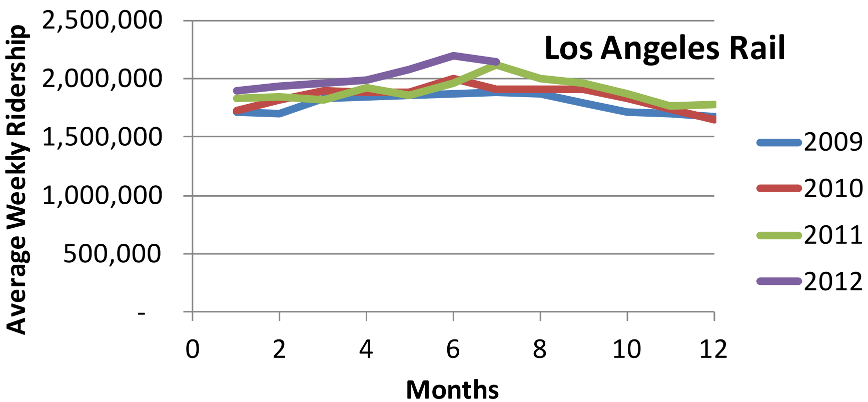
Electric Passenger Rail

- Data from the National Transit Database was used to calculate kWh/mi and MJ/mi for electric rail in California and their corresponding transit bus fleet, rail passenger miles and rail track length in 2010

	Electric Rail		Transit Bus		Rail Passenger Miles	Track Length (mi)
	kWh/mi	MJ(e-)/mi	Fuel	MJ/mi		
Los Angeles HR	0.37	1.34	CNG	3.82	231,935,841	34.1
Los Angeles LR	0.29	1.04	CNG	3.82	333,334,394	116.3
Sacramento	0.42	1.52	CNG	5.54	82,500,482	73.4
San Diego	0.21	0.74	CNG	5.68	186,509,312	102.6
BART	0.20	0.73	Diesel	3.25	1,390,909,655	267.6
San Francisco	0.38	1.36	Diesel	3.25	239,829,549	103.5
Santa Clara	0.45	1.61	Diesel	4.00	50,000,272	79.6

- LA Metro and BART data show ridership has been increasing since 2010 and confirm the use of 2010 data for passenger miles as a conservative assumption



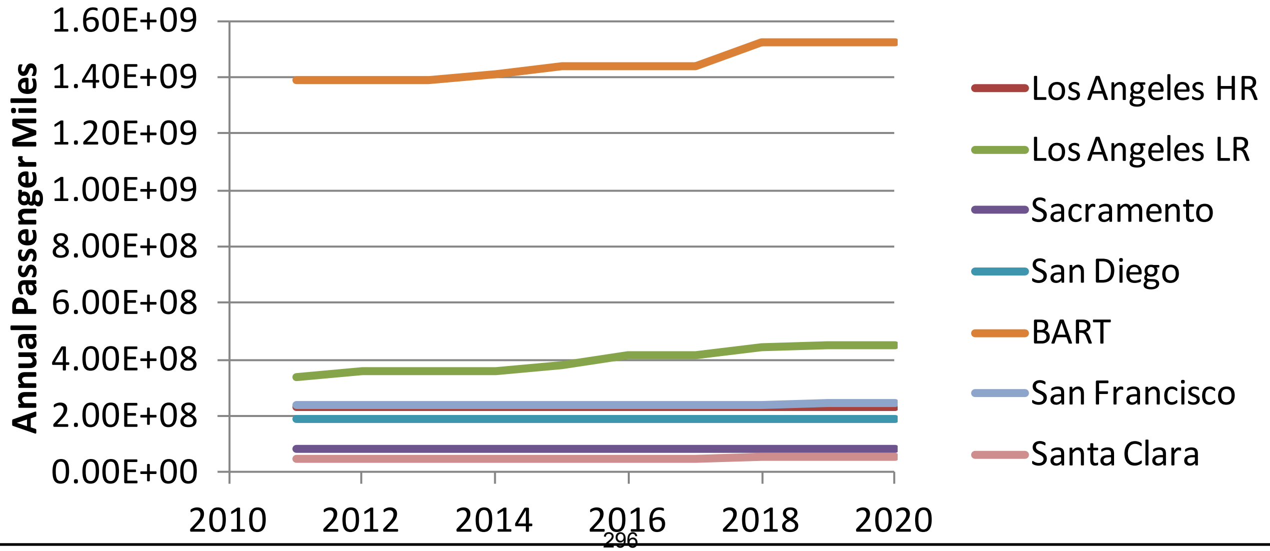


Electric Passenger Rail (cont.)

- Planned and implemented rail expansions taken into account by assuming ratio of passengers to track miles is constant for each transit

2012-2020	Electric Rail Expansion (mi (yr))
Los Angeles HR	none
Los Angeles LR	8.6 (2012); 6.6 (2015); 11 (2016); 8.5 (2018)
Sacramento	1.1 (2012)
San Diego	none
BART	3.2 (2014); 5.4 (2015); 16 (2018)
San Francisco	1.7 (2019)
Santa Clara	10 (2018)

- Increased Passenger-miles based on implemented and planned track increases



Electric Passenger Rail (cont.)

- Used Two (2) Methodologies For Comparison
  - Displacing Light-duty Auto Miles
  - Displacing Transit Bus Miles
- Displacing Light-Duty Auto Miles
  - Used EMFAC fleet average fuel economy (~23.3 mpg) and 1.1 Passenger's per vehicle to calculate MJ/mi (~4.64MJ/mi)

$$\left[(CI_{\text{Standard}}^{\text{Gasoline}} * (MJ / pass-mile)^{Gasoline}) - (CI^{Elec} * (MJ / pass-mile)_{Rail}^{Elec}\right]$$
$$* \; pass-miles_{rail}^{annual} * C = Credits$$

Electric Passenger Rail (cont.)

- Displacing Transit Bus Miles
  - Use MJ/mi from NTD and corresponding fuel Carbon Intensity (CNG or Diesel) for each transit agency
  - Diesel

$$\left[(CI^{\mathrm{Diesel}}_{\mathrm{Standard}} * (MJ / pass - mile)^{Diesel}_{TransitBus}) - (CI^{Elec} * (MJ / pass - mile)^{Elec}_{Rail} \right]$$

$$* \; pass - miles^{annual}_{rail} * C = Credits$$

  - CNG

$$\left[(CI^{\mathrm{CNG}} * (MJ / pass - mile)^{CNG}_{TransitBus}) - (CI^{Elec} * (MJ / pass - mile)^{Elec}_{Rail} \right]$$

$$* \; pass - miles^{annual}_{rail} * C = Credits$$

Electric Forklifts

- Electric forklift population based on US factory shipments of electric rider (Class 1&2) and motorized hand (Class 3) forklifts from 2000-2010[A] (Industrial Truck Association); used year 2000 shipments as a surrogate for 2011 assuming forklifts have an 11 year lifetime and 2011 shipments replace 2000 shipments
- Pro-rated California share of 12% (2010 Census Population Data)
- Split Electric Rider into Class 1 & 2 using the World Industrial Truck Statistics for America[A] in 2009 and 2010 (60% Class 1, 40% Class 2)
- Conservatively estimate current population equals 2013 – 2020 population

	Class 1+2	Class 3
2000-2010 US Shipments	488,853	458,502
CA Share	58,662	55,020
CA Class 1 (60%)	35,197	
CA Class 2 (40%)	23,465	

[A] – Industrial Truck Association http://www.indtrk.org/market-intelligence

Electric Forklifts (cont.)

- EER of 3.0; Assume a diesel standard
- Class 1 and Class 2 estimated battery size of 43.6 kWh[A]
- Class 3 estimated battery size of 12.5 kWh[B]
- 3,150 hrs/yr of operation per forklift[C] (50% single shift; 25% each double and triple shift)
- Assume 80% depth of charge and full battery usage per shift resulting in an average load of 4.36kW for Class 1 and 2 and 1.25 kW for Class 3

$$(CI^{Diesel}_{\text{Standard}} - CI^{Elec} / EER^{Elec}) * (E^{Elec} * EER^{Elec}) * C = Credits$$

[A,B] – Based on spec sheets for Nissan and Crown Class 1 and 2 Forklifts, http://www.crown.com, http://nissanforklift.com/

[C] – Based on TIAX Phase 2 Report for CalETC communications with SCE and industry members

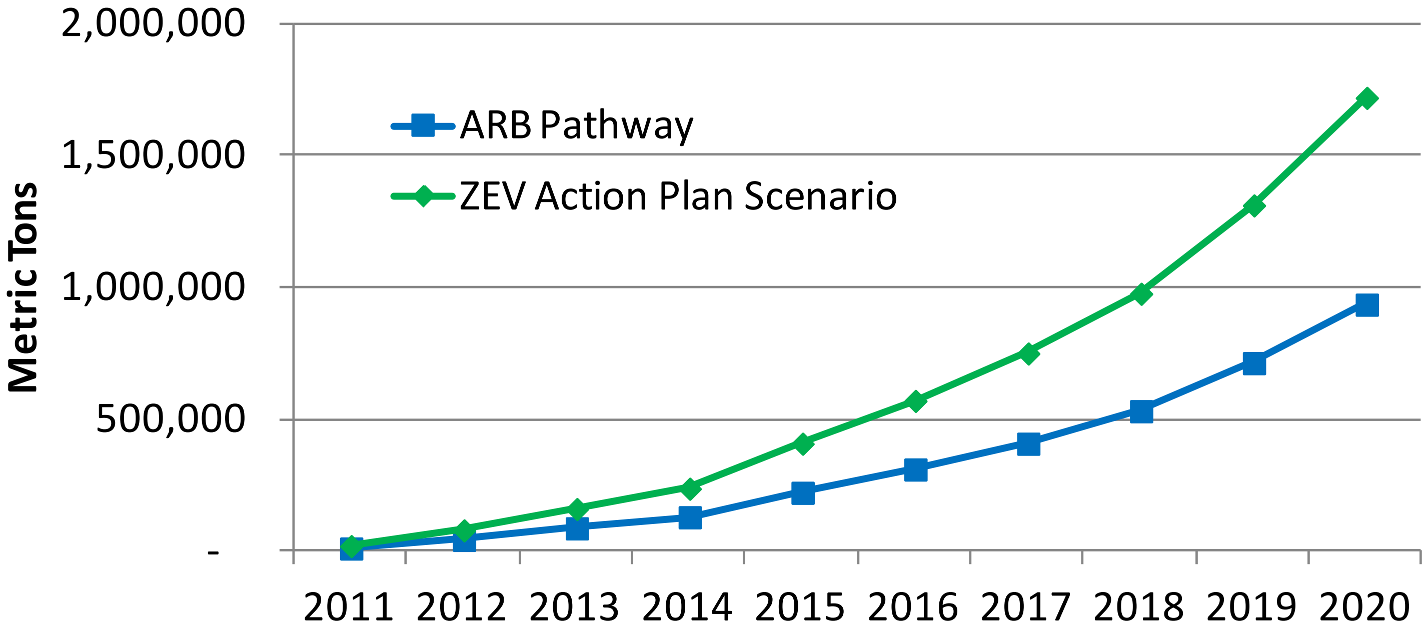
E-Transport Refrigeration Units

- Data Supplied by ARB:
  - 2,100 registered hybrid eTRUs in California
  - Conservatively estimate current population equals 2013 – 2020 population
  - Operate 3hrs/day, 6 days/wk, 52 wks/yr
  - Motor rating of 8 kW and a load factor of 0.75
  - Estimated 11.7 million kWh of electricity consumed each year by e-TRUs
  - Offset diesel consumption
  - EER = 3.0

$$(CI_{\mathrm{Standard}}^{Diesel} - CI^{Elec} / EER^{Elec}) * (E^{Elec} * EER^{Elec}) * C = Credits$$

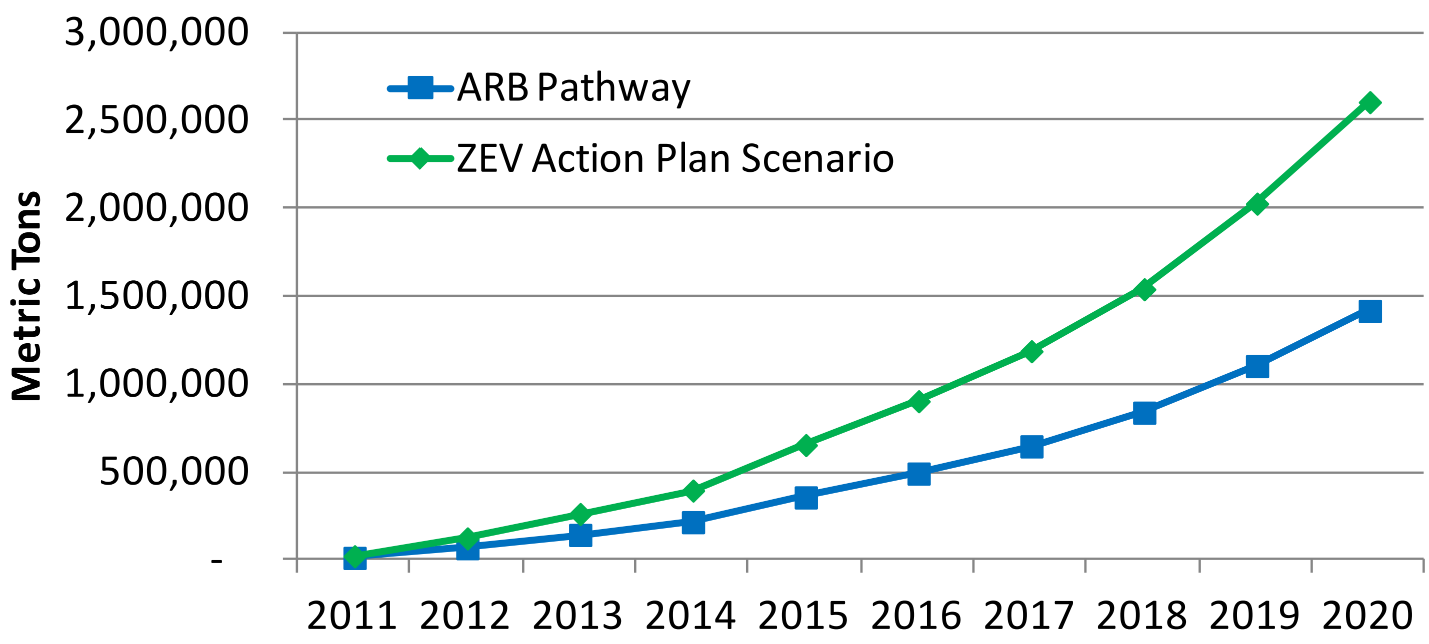
2013-2020 Potential Credits (40% PHEV Miles in Electric Mode)

- LD PEV on-road electrification yields almost 1 million credits in 2020 for the ARB Pathway and over 1.7 million credits in the ZEV Action Plan Scenario with 40% PHEV miles in electric mode



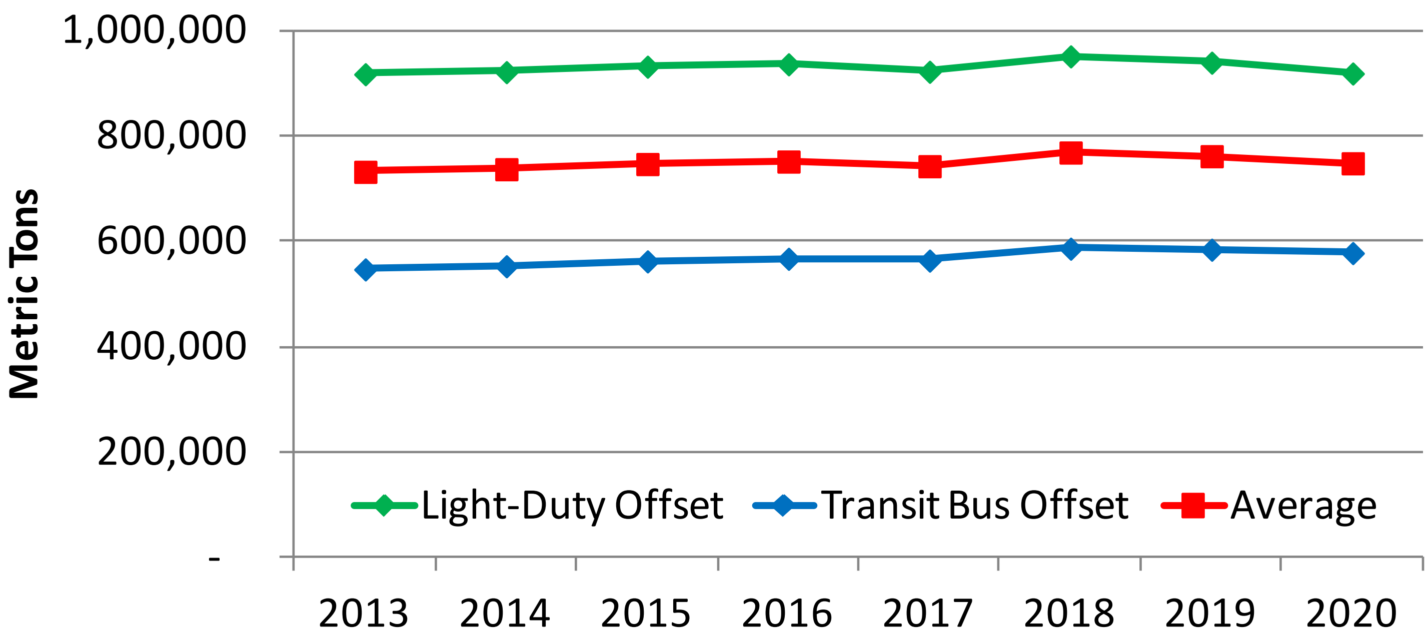
2013-2020 Potential Credits (75% PHEV Miles in Electric Mode)

- LD PEV on-road electrification yields almost 1.5 million credits in 2020 for the ARB Pathway and over 2.5 million credits in the ZEV Action Plan Scenario with 40% PHEV miles in electric mode



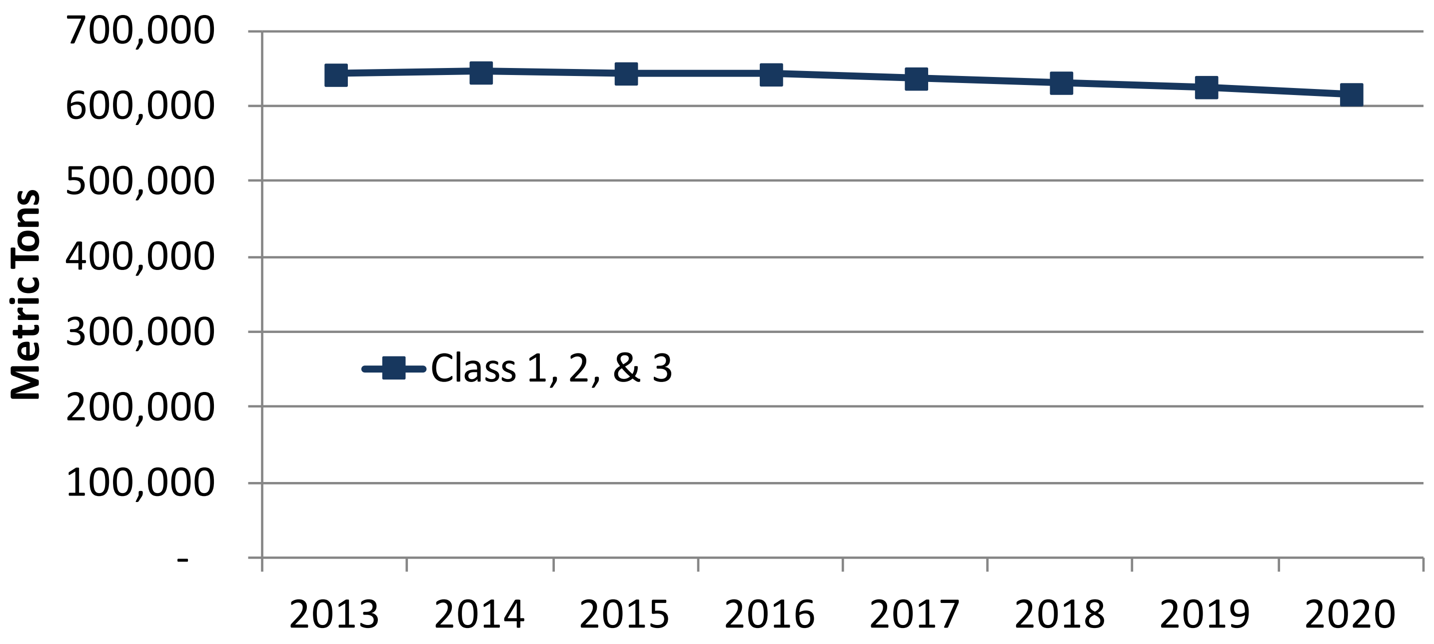
2013-2020 Potential Credits

- Displacing light-duty vehicles yields 910,000-950,000 metric tons of credits per year
- Displacing transit bus usage yields between 540,000-570,000 metrics tons of credits per year
- Average of both methodologies yields between 730,000-770,000 metric tons of credits per year



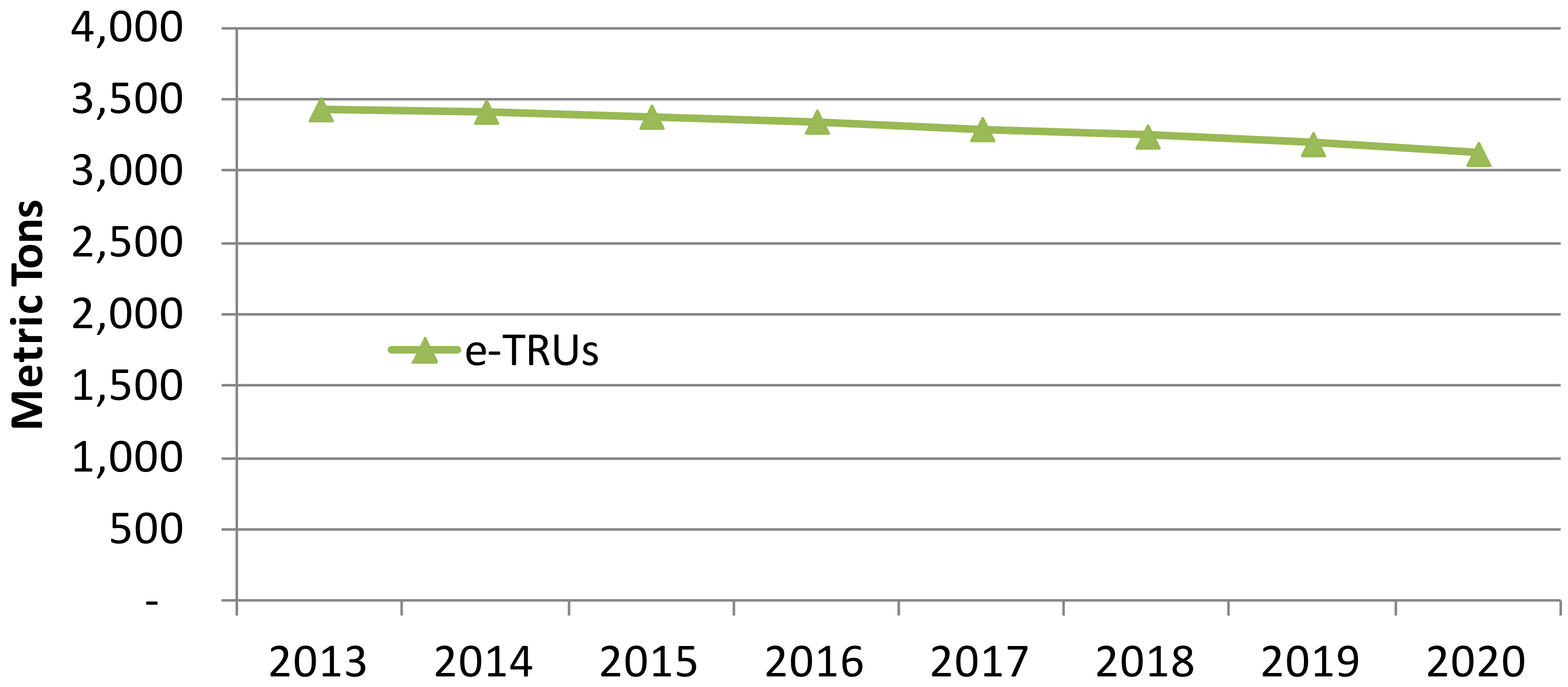
2013-2020 Potential Credits

- E-Forklifts yield over 600,000 metric tons of credits with the estimated current population



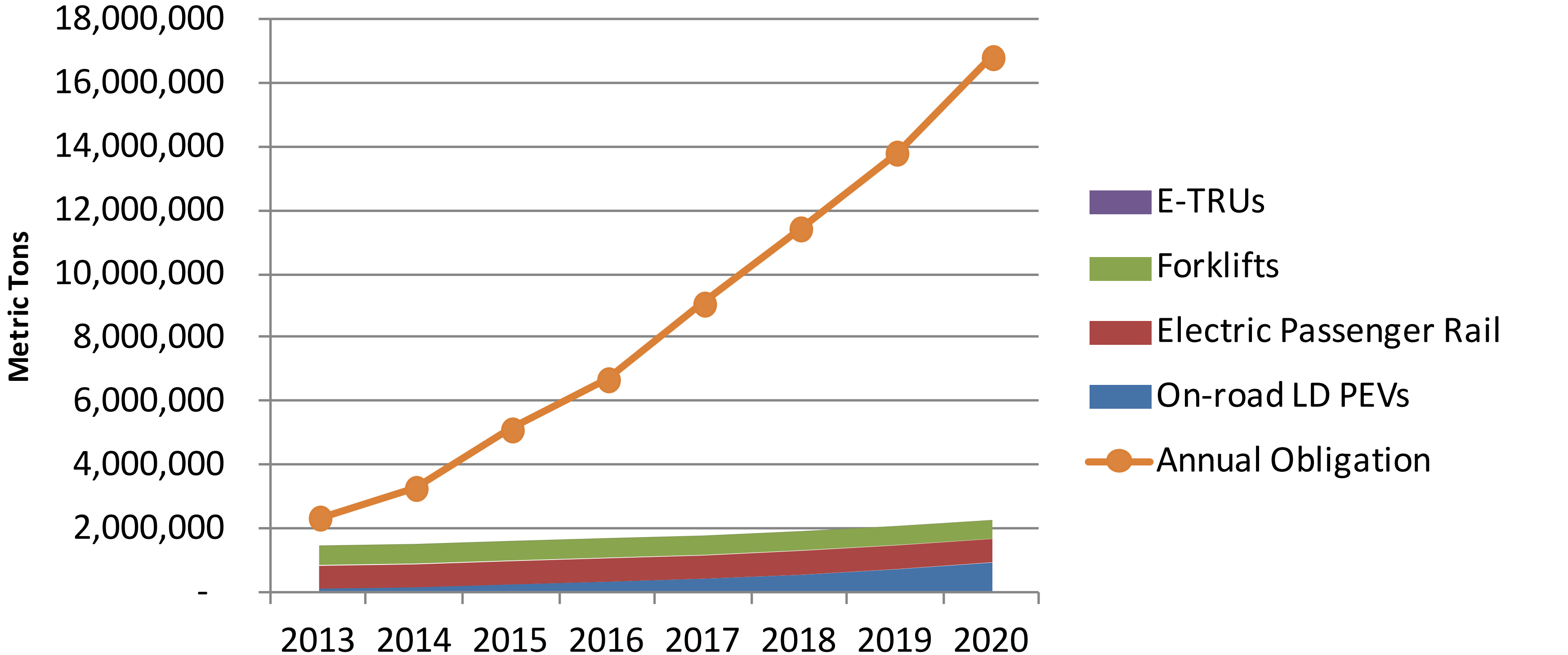
2013-2020 Potential Credits

- E-TRUs yield over 3,000 metric tons of credits per year



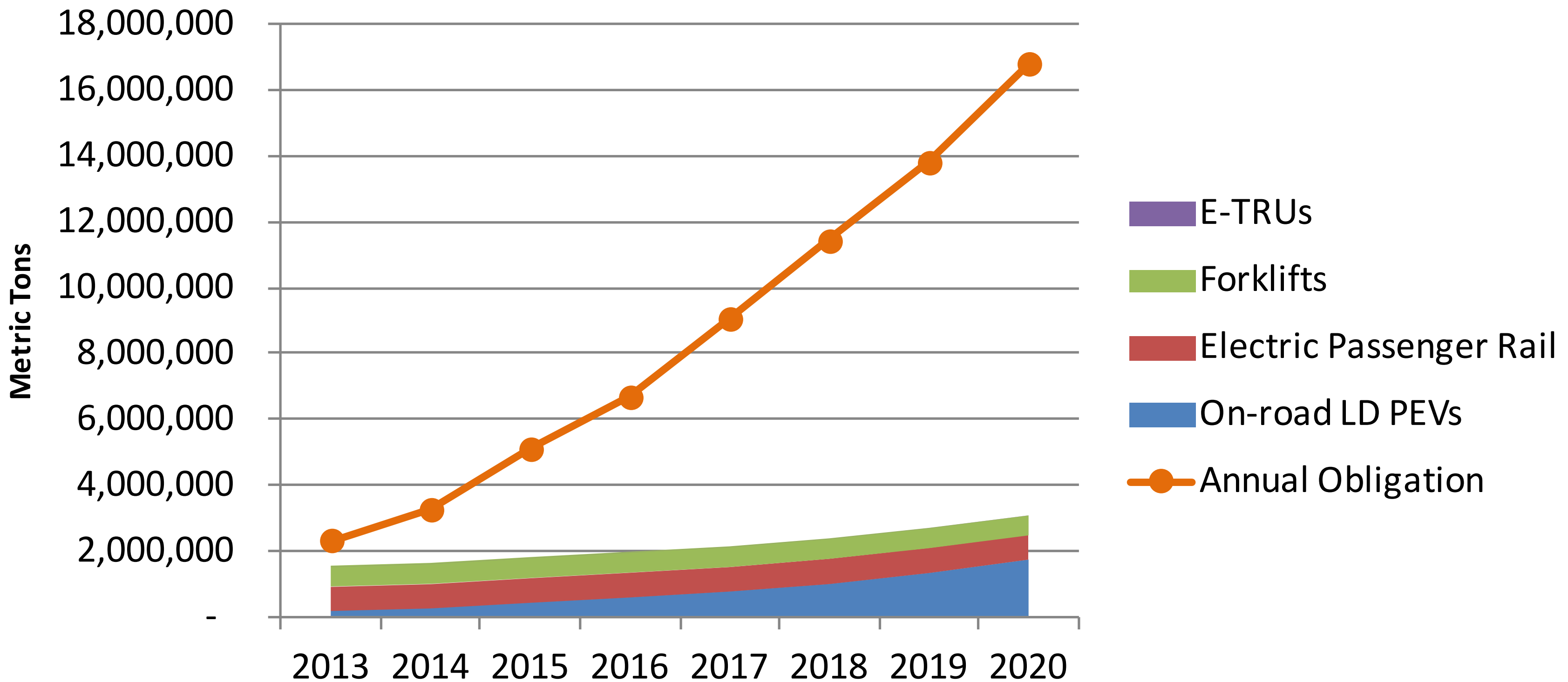
2013-2020 Potential Credits (40% PHEV Miles in Electric Mode)

- Annual obligation and on-road credits in the figure below based on ARB illustrative pathways and 40% PHEV miles in electric mode
- Electric passenger rail credits based on average of light-duty and transit bus offsets



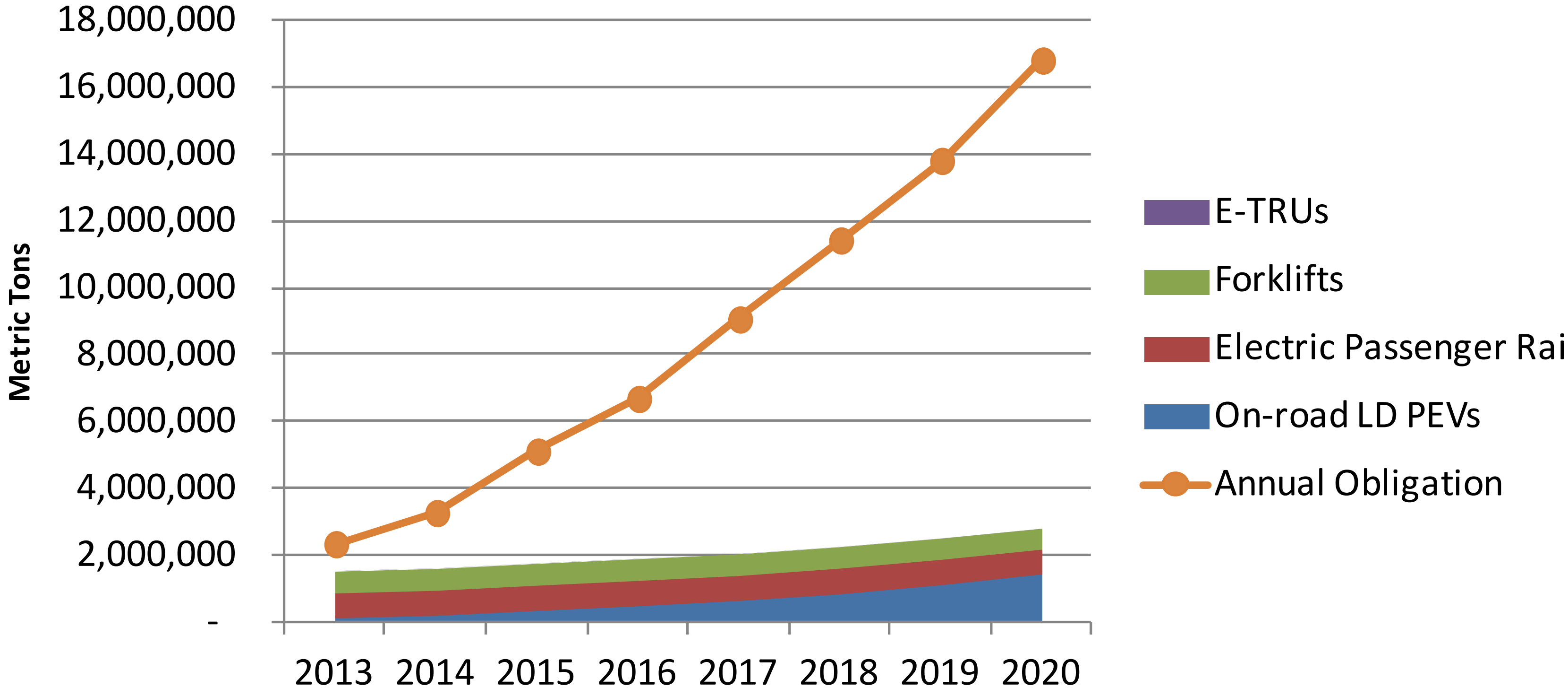
2013-2020 Potential Credits (40% PHEV Miles in Electric Mode)

- Annual obligation in the figure below based on ARB illustrative pathways
- On-road credits based on ZEV Action Plan Scenario and 40% PHEV miles in electric mode
- Electric passenger rail credits based on average of light-duty and transit bus offsets



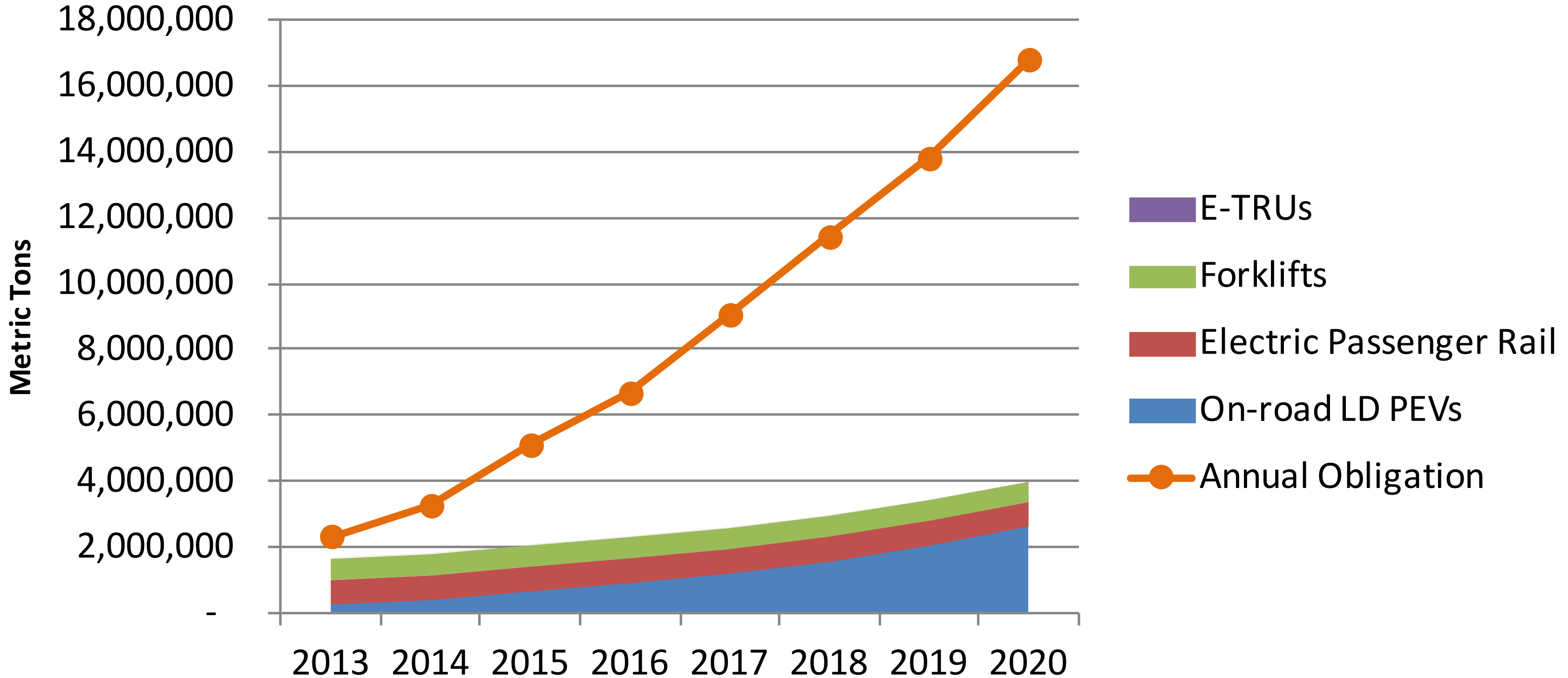
2013-2020 Potential Credits (75% PHEV Miles in Electric Mode)

- Annual obligation and on-road credits in the figure below based on ARB illustrative pathways and 75% PHEV miles in electric mode
- Electric passenger rail credits based on average of light-duty and transit bus offsets



2013-2020 Potential Credits (75% PHEV Miles in Electric Mode)

- Annual obligation in the figure below based on ARB illustrative pathways
- On-road credits based on ZEV Action Plan Scenario and 75% PHEV miles in electric mode
- Electric passenger rail credits based on average of light-duty and transit bus offsets



ICF INTERNATIONAL

Transportation Electrification Assessment

Prepared for:

California Electric Transportation Coalition

Energy+Environmental Economics

December 19, 2014

Overview

- Introductions – Organizations & Key Staff
- Introduction to the Transportation Electrification Assessment
- Cost and Benefits of Electrification Technologies
- PEV Forecasts for Grid Impacts Modeling
- Market Gaps and Barriers and Potential Solutions
- Grid Impacts Modeling

Introduction

Overview of Project

Project Objectives

ICF and E3 are providing analytical support to CalETC and its members to characterize the benefits of electrification technologies. Two key aspects of the study:

- **Utility Coordination**: This project includes active coordination and collaboration from utilities – PG&E, SCE, SDG&E, SMUD, City of Palo Alto, LADWP, and CMUA members. Engagement of so many utilities demonstrates the collective commitment of the industry to develop a coordinated plan related to electrification.

- **Changing landscape**: With the new OIR from the CPUC, there is a change in the landscape for electrification. Generally speaking, the current trajectory in California, as it pertains to electrification, will achieve one class of benefits. This study seeks to determine: What *could* the trajectory be and what benefits are we leaving on the table? And what is the course of intervention to change the current trajectory?

Work Flow (1 of 2)

Phase 1 of Transportation Electrification Assessment

- **Assess existing studies**: Literature review of transportation electrification opportunities. Dozens of reports reviewed. Focusing on 18 segments.
- **Market sizing**: Segment-by-segment forecasting for 2020 and 2030.
- **Cost and benefits of selected segments**: Reviewing the costs and benefits of selected TE segments. Considering incremental up-front costs, the incremental infrastructure costs, incremental benefits including lower operational costs for TE vehicles and equipment, and cost savings from lower electricity fuel costs.
- **Identify market gaps/barriers and potential solutions to address gaps/barriers:** Focusing on mitigation recommendations that could be implemented for whole or partial gaps and barriers. Identifying the party or parties that would be responsible for implementing the solution or corrective action necessary to address the gap or barrier. Keeping in mind that there may be some market gaps barriers for which there is no immediate mitigating solution.

Work Flow (2 of 2)

Phase 2 of Transportation Electrification Assessment

- **Grid impacts of light duty plug-in electric vehicles:** Considering a variety of impacts including generation, energy, transmission/distribution, ancillary services, losses, increased RPS procurement.

Potential Future Work (Phase 3)

- CalETC considering targeting future analysis of the grid impacts of off-road technologies with the largest potential impact (e.g., forklifts)

Costs and Benefits of Electrification Technologies

Electrification Technologies

Detailed Forecasting Update and Cost Analysis	Detailed Forecasting Update	Projection to 2030 from Previous Forecast
• *PEVs (PHEVs and BEVs)* • Forklifts • Truck Stop Electrification • Transportation Refrigeration Units	• Shore Power • Port Cargo Handling Equipment • Airport Ground Support Equipment • High Speed Rail • Light (including trolley buses) and Heavy Passenger Rail (BART, LA Metro, SDMTS) • Commuter Rail (Caltrain) • Dual Mode Catenary Trucks on I-710/SR60 • Medium- and Heavy-Duty Vehicles	• Lawn & Garden • Sweepers/Scrubbers • Burnishers • Tow Tractors/Industrial Tugs • Personnel/Burden Carriers • Turf Trucks • Golf carts

Detailed Forecasting

- **Detailed forecasting includes the following:**
  - Literature review to reassess the current market and future market conditions
  - Contacting industry and government experts (including ARB, CEC and EPA) to characterize the future market conditions and regulatory drivers
  - Forecasting future populations and GWh of electricity consumption for three cases:
    - "In Line with Current Adoption" is a low case based on anticipated market growth, expected incentive programs, and compliance with existing regulations; for build/no-build projects like HSR and I-710 catenary could be zero
    - "Aggressive Adoption" is a high case based on aggressive new incentive programs and/or regulations and make sure the high cases are tangibly aggressive and not simply hypothetical maximum
    - "In Between" is a medium case that will fall somewhere in the middle and will vary by technology
  - A working group consisting of utility representatives helped review the electrification forecasts prior to calculation of benefits and costs

Costs and Benefits of Electrification Technologies

- **Based on the projected GWh and populations for each technology and their comparison conventional fuel technologies, the following societal benefits were calculated for all technologies:**
  – GHG emission reductions
  – Criteria pollutant emission reductions
  – Petroleum displacement

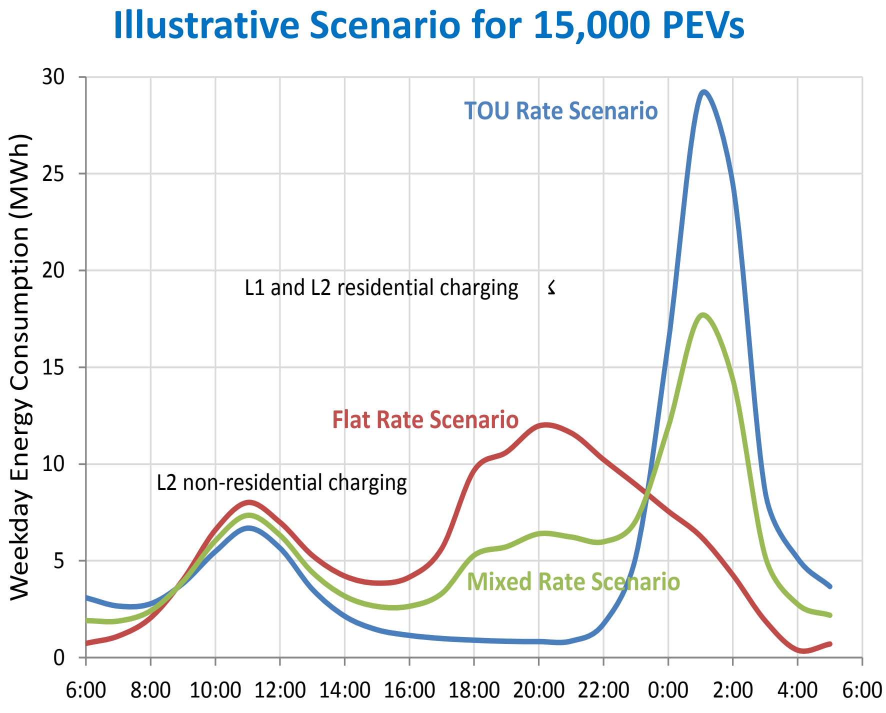
- **The lifecycle cost or savings of electric technologies were analyzed by including the following aspects of lifecycle cost:**
  – Equipment costs
  – Infrastructure costs
  – Operations and maintenance
  – Fuel costs
  – Equipment lifetime

Light-duty PEV Forecasts

Background and Assumptions for
a) Cost-Benefit Analysis and b) Grid Impacts Modeling

Developing scenarios

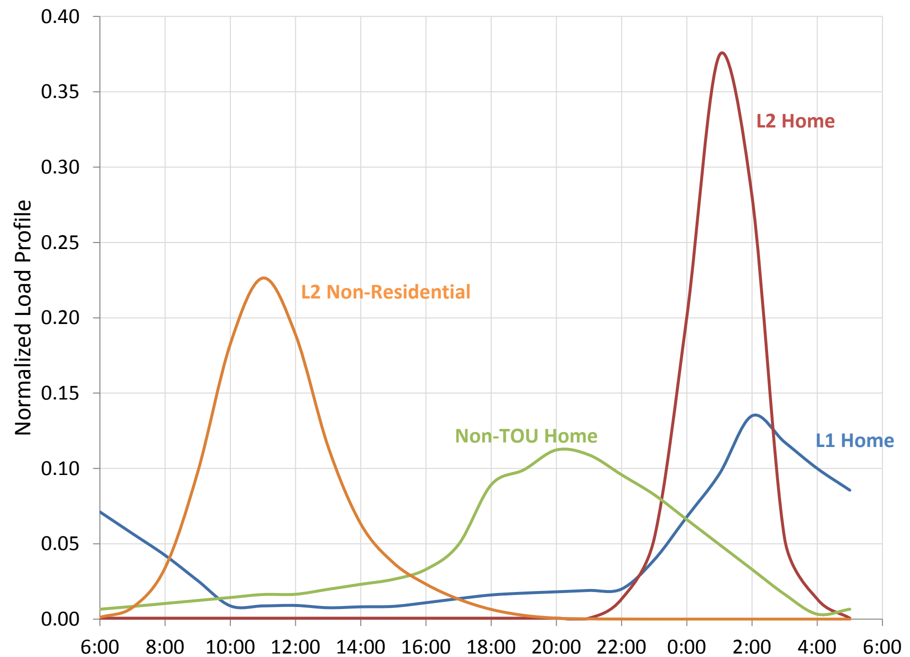
- **Multiple Scenarios**
  - TOU Rate Scenario
  - Domestic Rate Scenario
  - Mixed Rate Scenario
- **Each scenario is developed considering**
  - Load shapes
  - Level of charging: L2 and L1
  - Location: residential and non-residential
  - Vehicle Forecasts: Number and Type (PHEV vs BEV)
  - Energy Consumption



322

Load shapes

- **L2 residential charging, TOU rate:** Level 2 charging at home is a proxy for BEV or PHEV40 charging.
- **L1 residential charging, TOU rate:** Level 1 charging at home is a proxy for charging of PHEVs with smaller batteries, like the PHEV10 or PHEV20. The normalized profile is based on a similar start time as L2 charging; however, it is stretched out over a longer period.
- **Residential charging, Domestic rate:** Residential charging in the non-TOU case is a modified version of what is reported in the EV Project for Nashville, Tennessee – a region without a TOU rate. The modifications were made based on the at-home arrival times (at home) reported in the National Household Transportation Survey (NTHS).
- **L2 non-residential charging:** The non-residential charging is a proxy for workplace charging (weekdays) and public charging (weekends) and is used in the TOU scenario and the Flat Rate Scenario (described in more detail below) and scaled incrementally in a modification to each scenario.

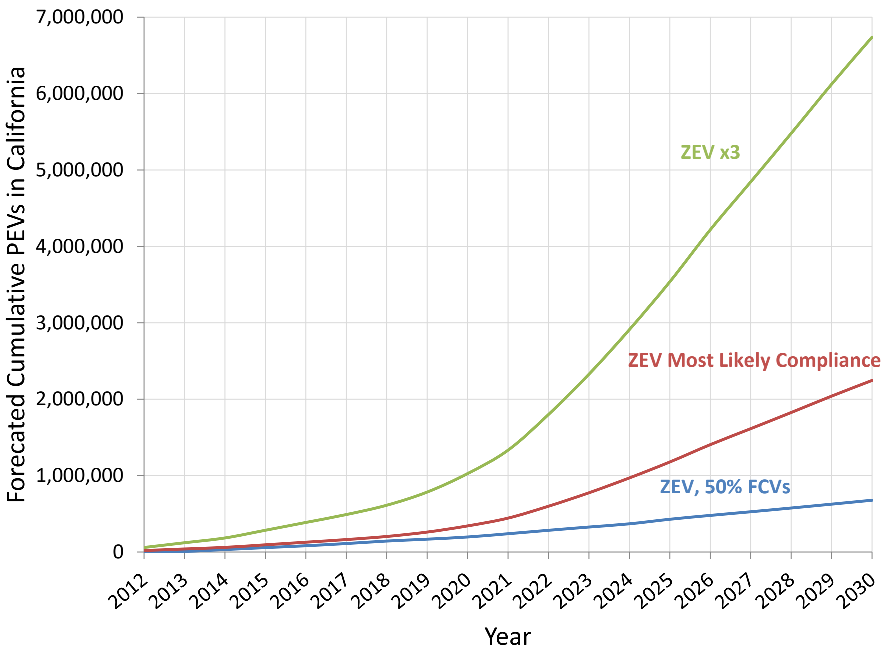


PEV Forecasts – Three Scenarios representing range of adoption

- **ZEV Program with 50% Compliance from FCVs:** Compliance with the Zero Emission Vehicle Program and modifying the most likely compliance scenario to achieve 50% compliance from FCVs.

- **ZEV Program "Most Likely Compliance Scenario" from CARB:** In the development of the Zero Emission Vehicle Program, CARB staff developed a most likely compliance scenario. There were some modifications to this scenario to reflect recent PEV sales data.

- **ZEV Program Scenario x 3:** This scenario is a factor of three larger than the ZEV program's most likely compliance scenario.



Energy Consumption

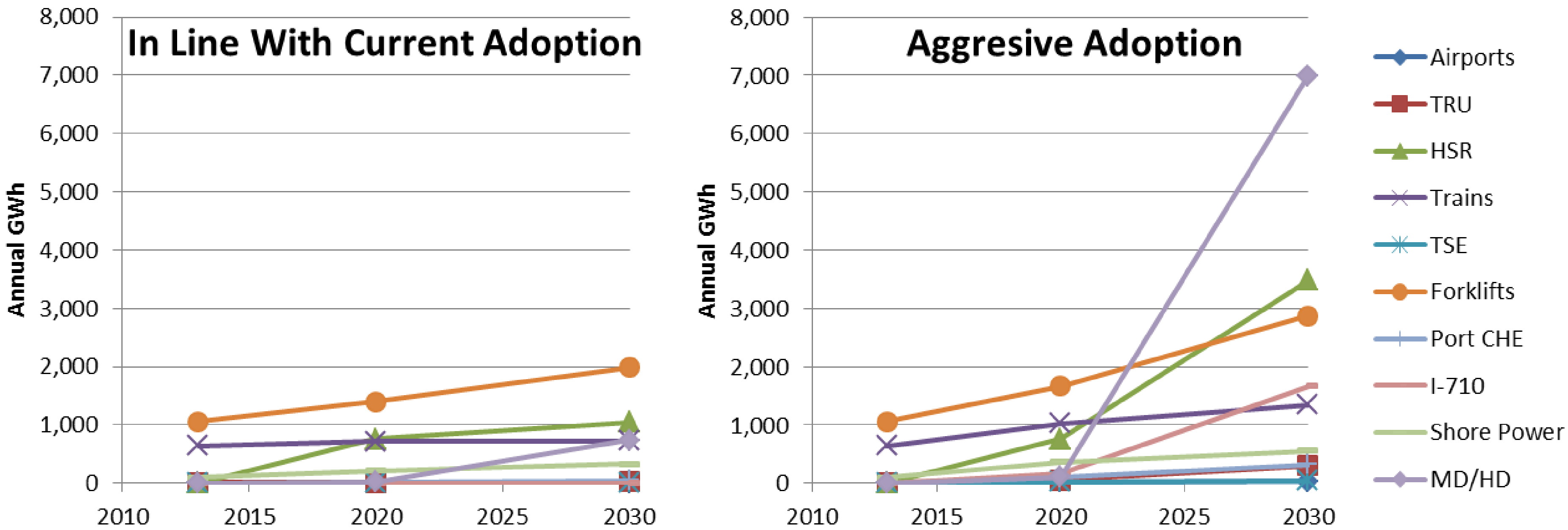
Vehicle Type	VMT		eVMT		Energy Consumption (kWh)					
					Daily			Annual		
	Daily	Annual	Daily	Annual	Res	NonRes	Total	Res	NonRes	Total
PHEV10	41.0	14,965	10.0	3,650	2.8	0.7	3.5	1,022	256	1,278
PHEV20			20.0	7,300	5.6	1.4	7.0	2,044	511	2,555
PHEV40			30.6	11,169	8.6	2.1	10.7	3,127	782	3,909
BEV	29.5	10,768	29.5	10,768	8.3	2.1	10.3	3,016	754	3,770

Developed modification for each scenario whereby the eVMT for each PEV-type is increase by one mile per day per year, not to exceed 39 daily VMT. Additional charging is assumed to happen on commercial circuits.

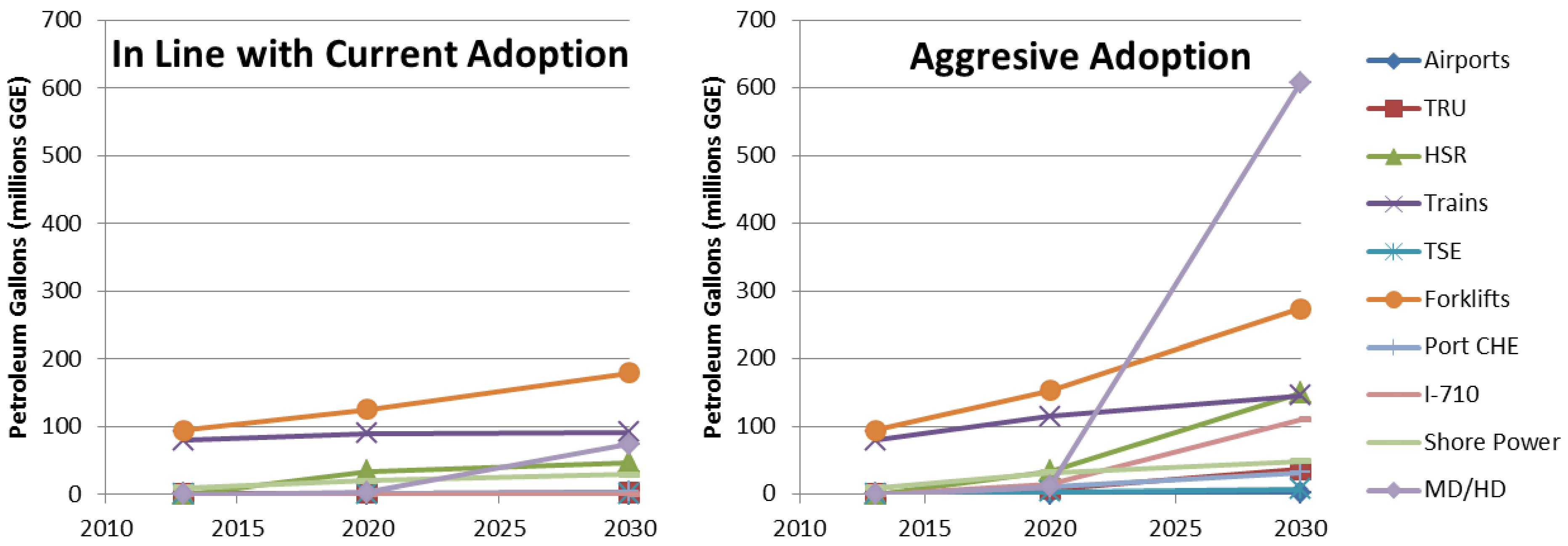
Overview of Results

Electricity Consumption, Petroleum Displacement, GHG Emission Reductions

Electricity Consumption

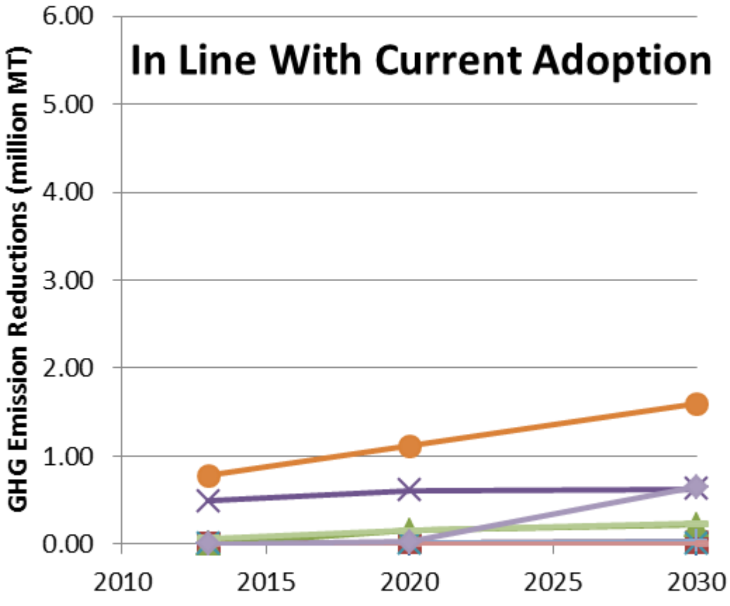


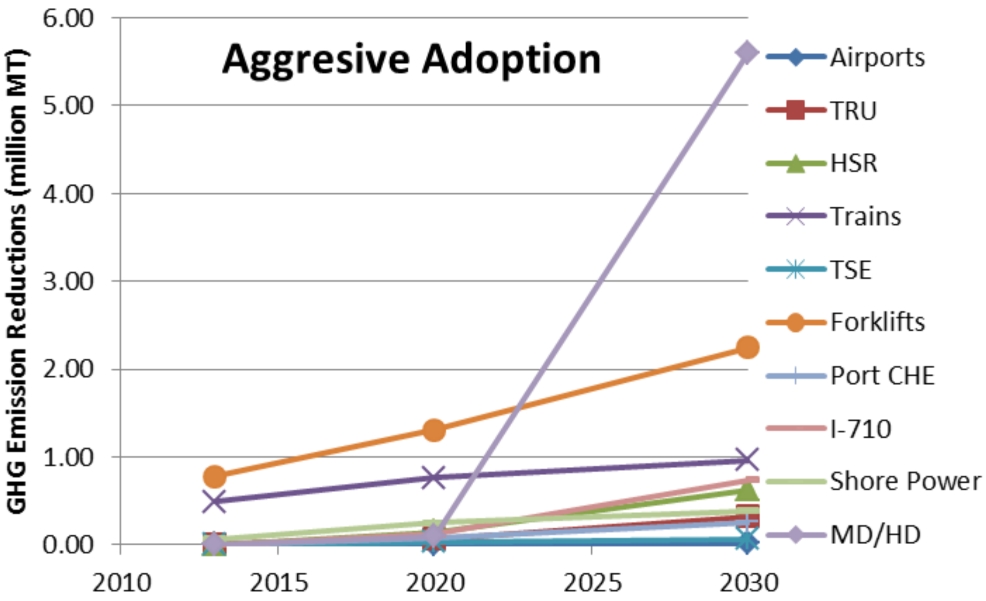
Petroleum Gallons Displaced



328

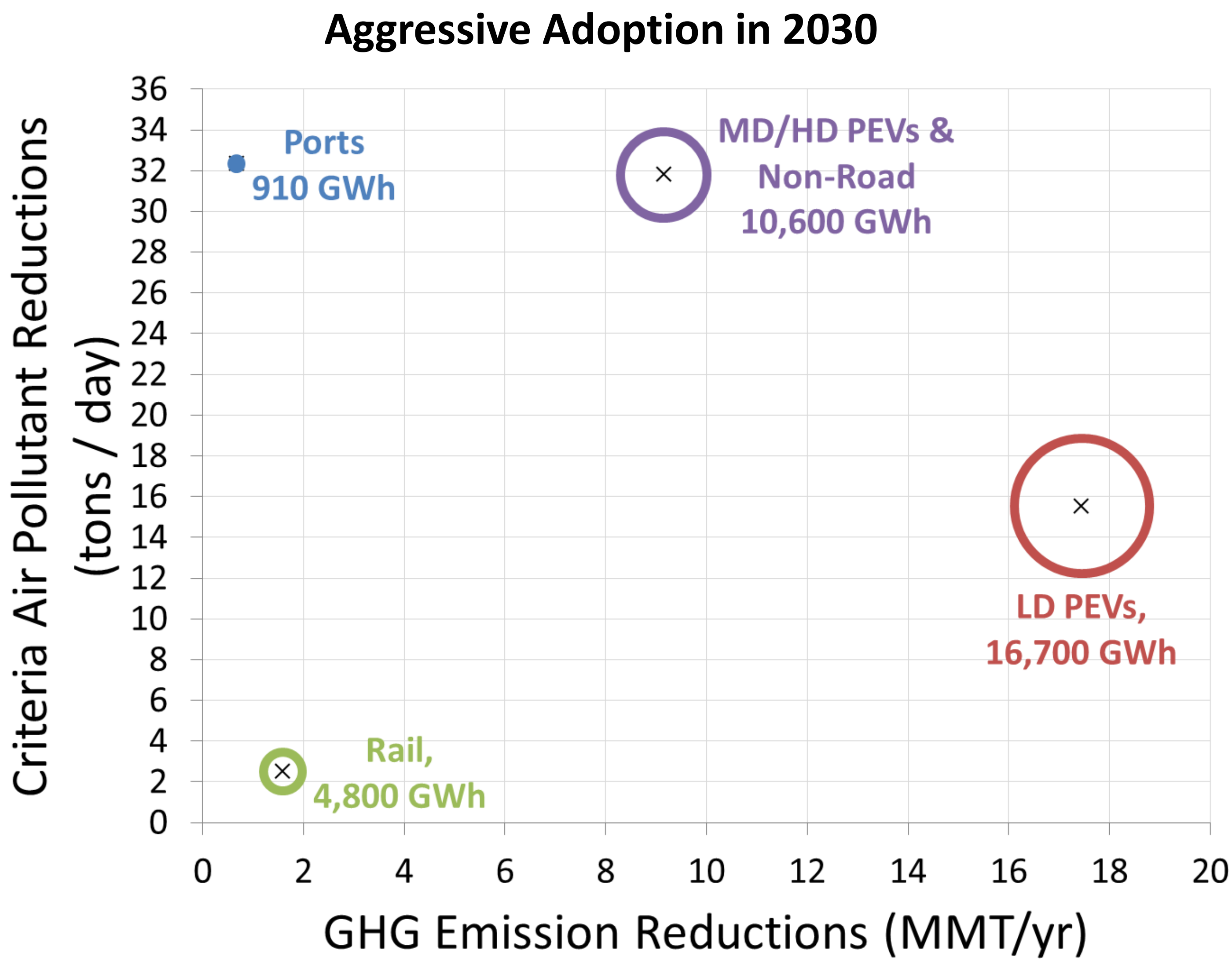
Greenhouse Gas Emission Reductions





329

Comparison of Transportation Electrification Segments in 2030



330

Market Gaps and Barriers and Potential Solutions

Potential Solutions to Maximize PEV Adoption

Main Areas of Focus (1 of 2)

Market Gaps and Barriers		Potential Solutions
Consumer Costs	• Upfront vehicle costs • Upfront charging infrastructure (EVSE) costs • Vehicle operating costs; need for competitive charging rates for PEVs and shift in traditional billing paradigm	• Increased publicity and continued availability of existing incentives • Creative use of utility LCFS credits or utility developed programs (e.g. battery second life) to reduce the upfront vehicle or EVSE costs • Improved PEV charging rate structures to increase the reduced fuel cost benefits for drivers
Charging Infrastructure	• Lack of information available to single family homeowners seeking to decide between Level 1 and Level 2 charging installation • Little to no progress made in deploying charging at multi-dwelling units; MDU installations are particularly challenging due to technical and logistical issues • Lack of investment in workplace charging infrastructure to date	• Engage MDUs/HOAs, employers and workplace parking providers as a trusted advisor regarding optimal and cost-effective EVSE solutions

Main Areas of Focus (2 of 2)

Market Gaps and Barriers		Potential Solutions
Sustainability of Third-Party Ownership of EVSE Networks	• Sustainability of revenue model is frequently challenged and has not been convincingly demonstrated • Demand for non-home charging is unclear due to several factors: vehicle purchasing behavior, consumer willingness to pay for charging, and charging needs/behaviors	• Alternatives to additional public investment in charging infrastructure • Revisiting the CPUC ruling regarding utility investment in charging infrastructure • Improved evaluation of charging infrastructure deployment
Consumer Education and Outreach	• General lack of PEV awareness and knowledge • Total cost of vehicle ownership is poorly understood • Disparate efforts to improve PEV education	• The utility acting as a trusted advisor in the PEV market • Engage with PEV ecosystem partners
Vehicle Features	• Limited vehicle offerings in marketplace	• Modifications to the ZEV program to incentivize the development of PEVs outside of traditional market segments (e.g. subcompacts or midsize sedans)

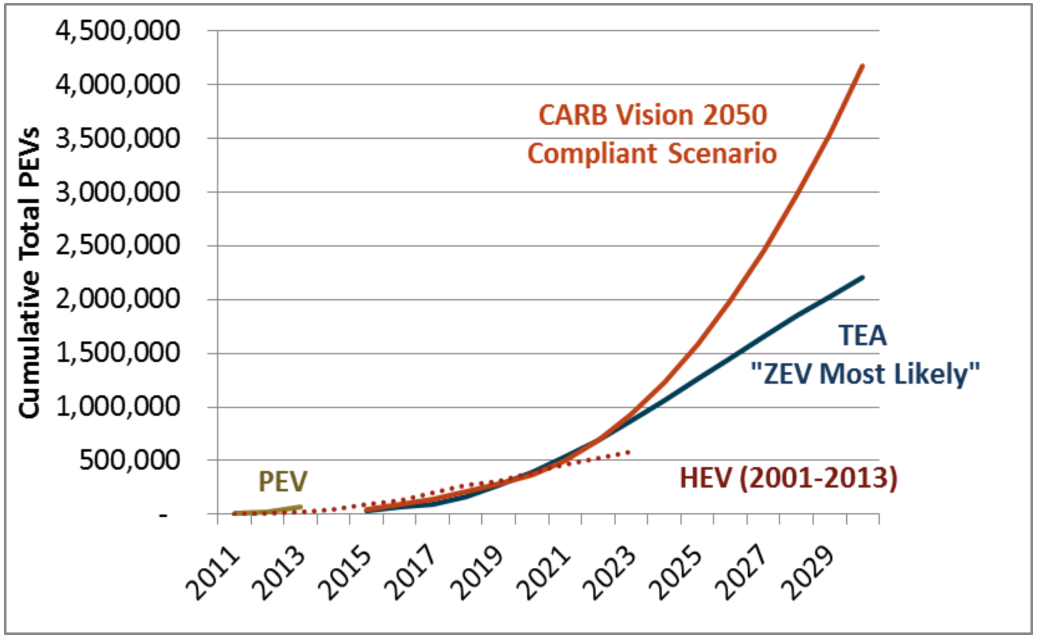
Appendix | Phase 2: Grid Impacts Modeling

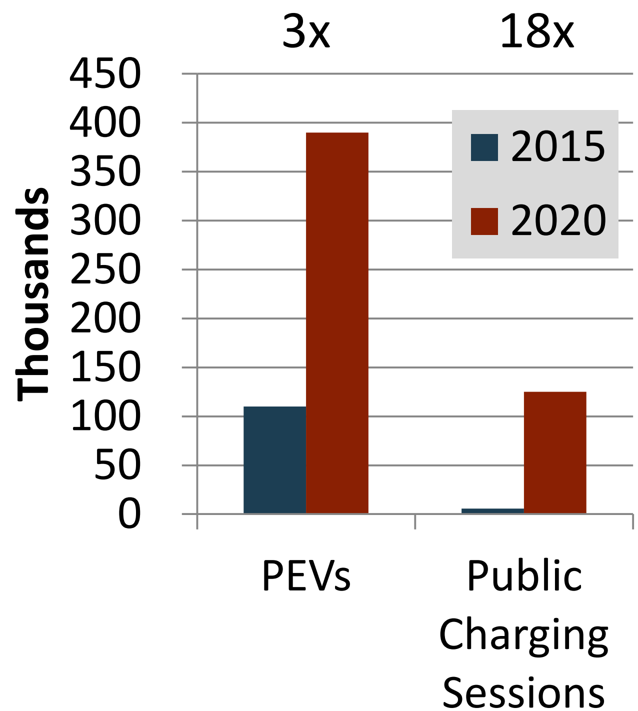
Distributed Energy Resource Modeling

Energy+Environmental Economics

334

Infrastructure Investment Required





- **~90% of car buyers are not familiar with electric vehicles (nationally)**
- **Will saturate early adopter market segment soon**
- **Need to reach beyond single-family home owners**

335

Utility Role in Transportation Electrification

- **Customer, EVSE and utility investment in infrastructure is needed to provide readily accessible charging for higher penetrations of PEVs**

Hearing Room	Board Room
✓ PEVs provide environmental and societal benefits	✓ PEVs increase revenues with "good" load
✓ PEVs will reduce rates for all customers	✓ PEV load creates headroom for capital investment without rate increases
✓ PEVs pass cost-effectiveness tests	✓ PEVs can increase shareholder earnings
✓ Utility investment accelerates PEV adoption	✓ Utility investment provides positive customer engagement

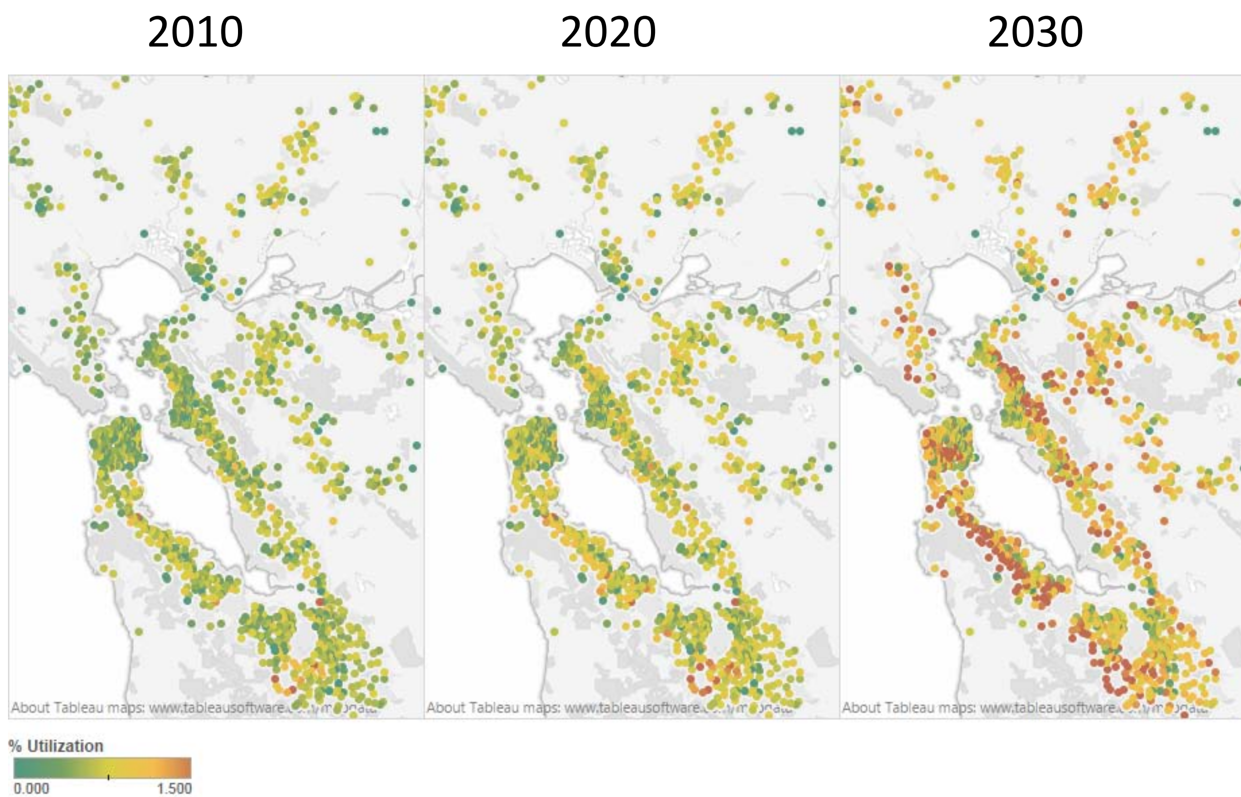
Utility Role in Transforming Transportation

- **Utility planning (Yesterday)**
  - **meet forecasted load with lowest utility costs and emissions**
  - Pass "standard" cost-effectiveness tests

- **Electrifying transportation (Tomorrow)**
  - **meet GHG and criteria pollutant targets at lowest regional cost**
  - Requires rapid adoption of new technologies with cross-sector coordination
  - Requires expanded cost-effectiveness framework with new metrics

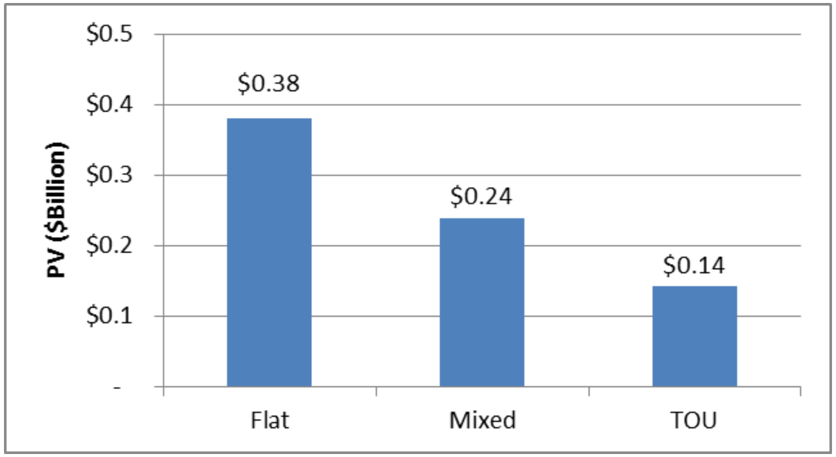
Grid Impact Overview

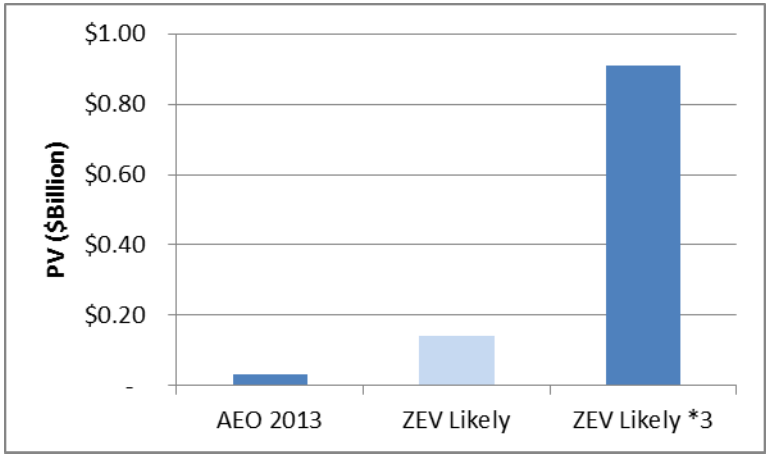
- **Emphasis on quantifying distribution impacts**
- **Map PEV Clusters and load shapes to individual feeders and substations**
- **Utilities provided**
  - equipment rating
  - peak day load shape
  - forecasted load growth
- **Calculate upgrades required at each location**
- **Found minimal upgrade costs even at higher penetration scenarios**



338

Distribution Upgrade Costs





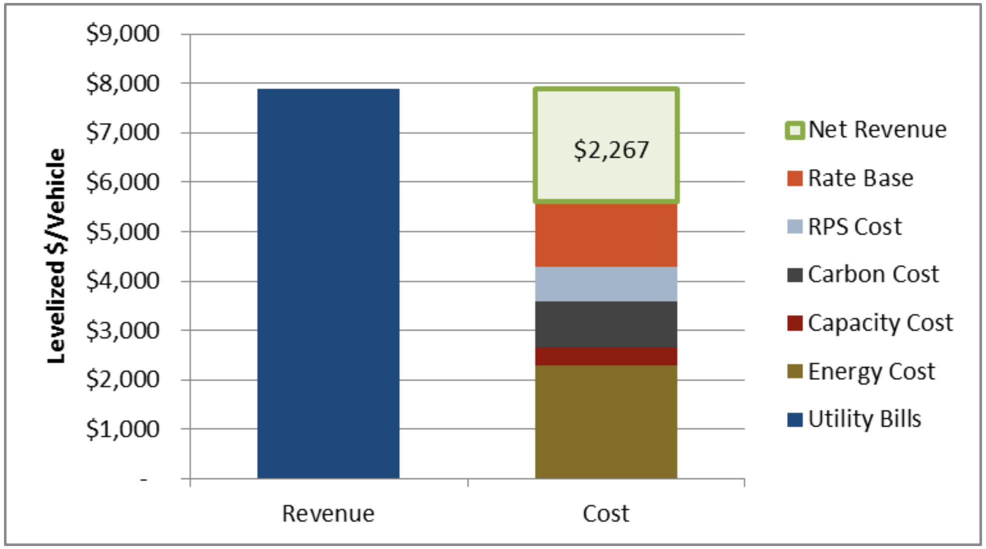
- **Managed charging reduces distribution upgrade costs by 60%**
- **Distribution costs are manageable under current trajectory**

- **Bigger cost challenge: "make-ready" and circuit upgrades for higher concentrations of multi-family, workplace and fast DC charging**

Standard Cost-tests (for EE, DR, DG)

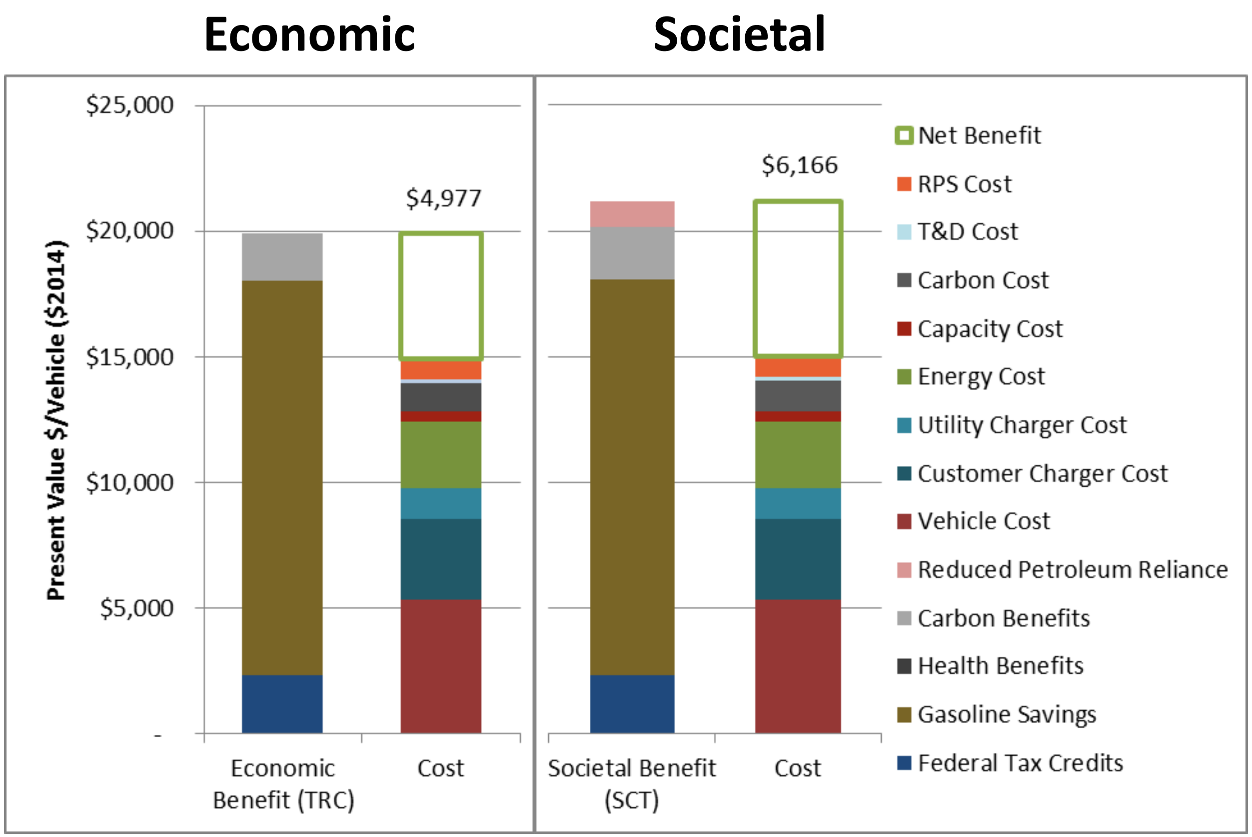
Cost Test		Key Question Answered	Summary Approach
Ratepayer Impact Measure	RIM	**Will utility rates for non PEV owners increase?**	**Comparison of utility infrastructure and supply costs to retail bill revenues**
Total Resource Cost	TRC	**Are there net economic benefits to the region as a whole?**	**Comparison of vehicle, infrastructure and energy costs to reduced gasoline (and GHG) costs and federal tax credit**

PEV Load Benefits to Utility Ratepayers



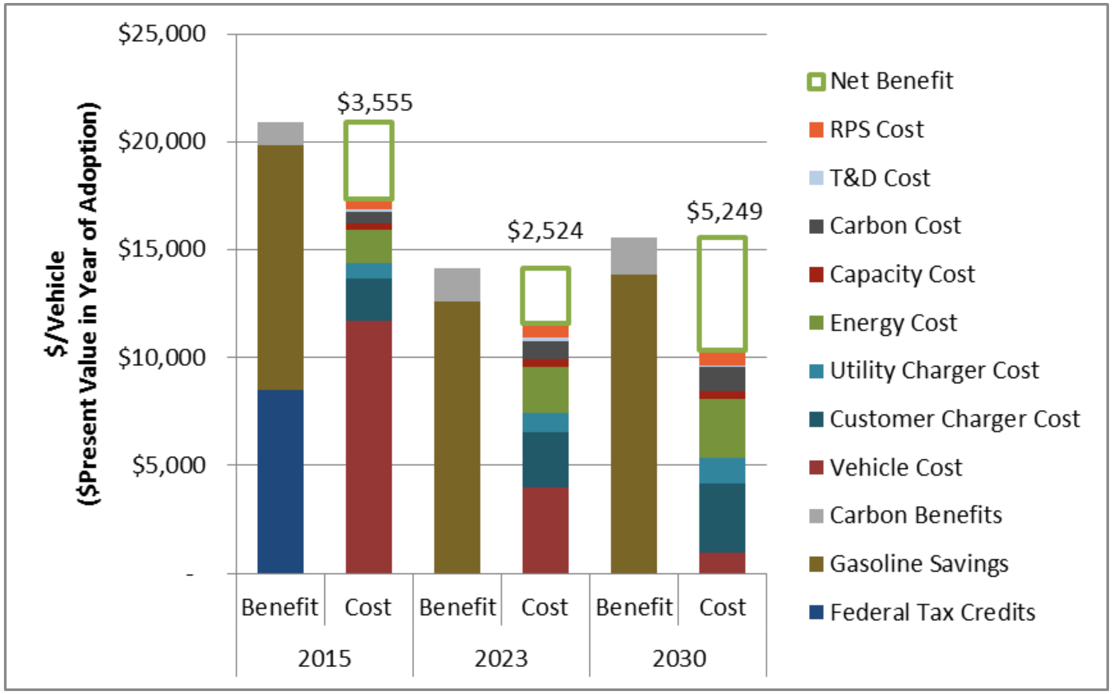
- **Utility rates represent average fixed and variable costs and are higher than the marginal cost of delivered energy in most hours**
- **Typically distributed energy resource programs (EE, DR, DG) reduce customer bills and utility revenues, but increase rates**
- **PEVs are unique in providing environmental benefits while reducing rates**
- **Northwest: true for the region as a whole, but will differ by utility based on BPA Tiered Rate allocation**

TRC and "740.8" SCT Results



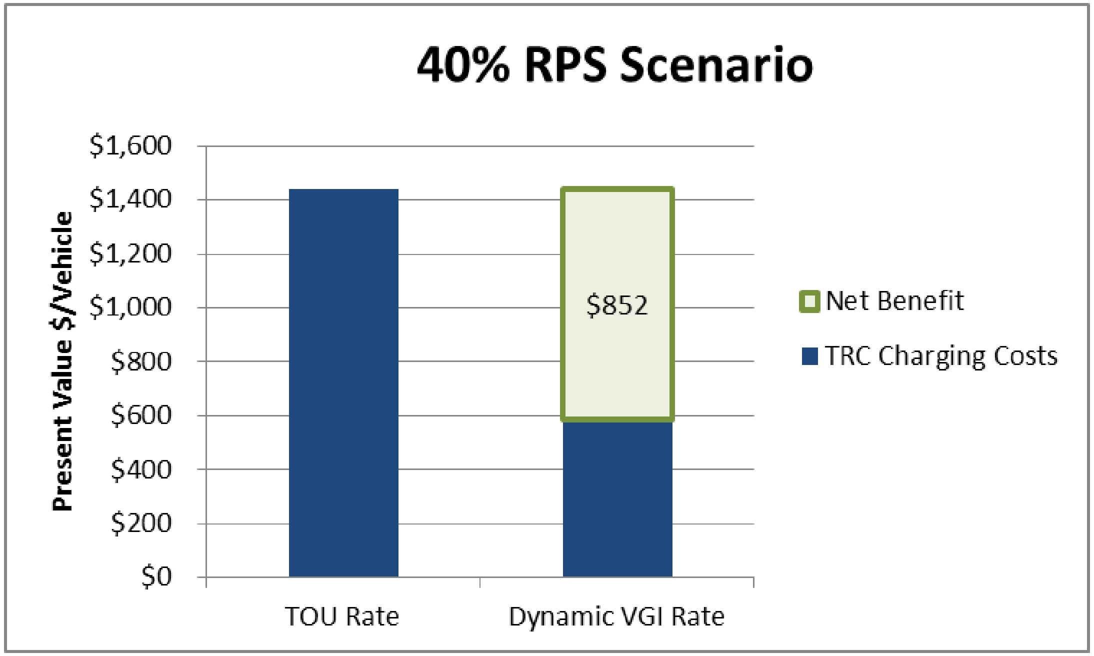
- **"740.8" SCT represents a combination of CARB and CPUC cost-effectiveness methods**
- **Present value net benefits for TRC and "740.8" SCT of $4.7 Billion and $5.8 Billion with ZEV Most Likely vehicle adoption**

How TRC Changes Over Time



- **TRC is positive in 2015 due to federal tax credit**
- **TRC net benefit is lower in 2023 after tax credits presumed to expire**
- **TRC is higher in 2030 with declining incremental PEV costs and higher gasoline prices**

Dynamic Vehicle Grid Integration (VGI) Charging



- **Dynamic VGI charging provides additional benefits, reducing charging costs**
- **TOU Rates discourage charging on-peak**
- **VGI rates encouraging day-time charging during periods of excess renewable generation in Spring and Fall.**

California Utility PEV Applications

SDG&E Vehicle Grid Integration (VGI)	SCE – Charge Ready
$103 Million over 10 years	$355 Million over 5 years
Install up to 5,500 charging stations	Supporting infrastructure for up to 30,000 charging stations
Focus on workplace and multifamily	Focus on expanding availability of long dwell-time infrastructure especially at work places and multifamily dwellings
Day-ahead dynamic hourly VGI rate provides economic incentives to charge when most beneficial for the grid	EV specific TOU rates
Focus on vertically integrated billing and charging solution for customer	Focus on service upgrades needed to install and operate charging infrastructure
Competitively bid, but charging equipment is SDG&E owned.	Host can choose to own and operate charging station

Expanded Cost-tests

- Societal Cost Test (SCT)
  - TRC test plus environmental and societal benefits
  - Benefits include
    - Health and environmental impacts
    - Reduced reliance on petroleum
    - “Social” cost of carbon
  - Included in California Public Utility Code 740.3 and 740.8
  - Combination of public utility and air resources board cost-benefit evaluation

- Cost of meeting GHG and criteria pollutant emission targets
  - Compare costs of alternative strategies (renewables, efficiency, transportation) to reduce emissions

Conclusions

- Distribution system upgrade costs related specifically to PEV charging are manageable in near-term, even under the most aggressive PEV adoption scenario
- **“Make ready” costs for multi-family, public and workplace charging** are larger than distribution upgrade costs and may pose a more significant barrier to PEV adoption
- **Utility investment in enabling technology and infrastructure is needed to accelerate PEV adoption and market transformation**.
- **Such investment may not pass current cost-effectiveness tests in the short-term, but still provide net ratepayer and societal benefits in the long-term**
- Over time, with reduced incremental vehicle costs and increasing gasoline prices, PEVs provide net TRC benefits even without the federal tax credit
- “740.8” SCT as presented here produces net benefits that are 22% higher than the SPM TRC test using health and reduced reliance on imported petroleum benefits

Conclusions

- Current CARB and CPUC cost-effectiveness tests evaluate resource measures largely against "traditional" investments. More comprehensive methods are need to evaluate alternative strategies towards meeting California's ambitious GHG reduction goals
- Over the long-term, PEV rates can be designed to provide sufficient net revenues to more than cover short-term and long-term marginal costs, providing additional fixed cost recovery and lowering average rates for non-PEV owners in the rate class
- The increased benefits provided by TOU rates and VGI charging show that **utility or government programs funding PEV charging infrastructure should also include strong incentives for PEV owners and electric vehicle service entities to engage in managed charging that is responsive to grid needs**

CalETC	ICF	E3
Eileen Wenger Tutt Executive Director California Electric Transportation Coalition (916) 551-1943 eileen@caletc.com	Jeffrey Rosenfeld Manager ICF International (408) 216-2818 jeffrey.rosenfeld@icfi.com	Eric Cutter Senior Consultant Energy and Environmental Economics (415) 391-5100 eric@ethree.com

Standard Practice Manual Cost Tests for PEVs

Component		PCT	RIM	TRC	SCT (740.8)
EV Customer costs and benefits					
	Incremental Vehicle Costs	-		-	-
	Gasoline Savings	+		+	+
	Utility Bills	-	+		
	Federal Tax Credits	+		+	+
	State Tax credits	+			
EV Charger Cost					
	Utility Asset		-	-	-
	Customer Assets	-		-	-
Admin Costs					
	Utility Program Administration		-	-	-
Electricity Supply Costs					
	Energy Costs		-	-	-
	Losses Cost		-	-	-
	A/S Cost		-	-	-
	Capacity Cost		-	-	-
	T&D Cost		-	-	-
	RPS Cost		-	-	-
	Utility GHG Allowance Costs		-	-	-
Societal Benefits					
	Transportation GHG Allowance Costs			+	+
	"Societal" value for CO2				+
	Health benefits				+
	Decreased Petroleum Use				+

350

California's Low Carbon Fuel Standard: Compliance Outlook for 2020

June 2013

Prepared for:

CalETC
California Electric Transportation Coalition

In Partnership with:

National Biodiesel Board

California Natural Gas Vehicle Coalition

Advanced Biofuels Association

Ceres

E2 Environmental Entrepreneurs

Prepared by:

ICF International

Table of Contents

List of Exhibits

Abbreviations and Acronyms

ABFA	Advanced Biofuels Association
BD	Biodiesel
BEV	Battery Electric Vehicle
CalETC	California Electric Transportation Coalition
CARB	California Air Resources Board
CARBOB	California Reformulated Blendstock for Oxygenate Blending
CCS	Carbon Capture and Storage
CEC	California Energy Commission
CNCDA	California New Car Dealers Association
CNG	Compressed Natural Gas
CNGVC	California Natural Gas Vehicle Coalition
CO2	carbon dioxide
CPUC	California Public Utilities Commission
DOE	Department of Energy
E2	Environmental Entrepreneurs
EER	Energy Economy Ratio
EPA	Environmental Protection Agency
EVSE	Electric Vehicle Supply Equipment
FCV	Fuel Cell Vehicle
gge	gasoline gallon equivalent
LCFS	Low Carbon Fuel Standard
LNG	Liquefied Natural Gas
MY	Model Year
NBB	National Biodiesel Board
NRDC	Natural Resources Defense Council
OECD	Organisation for Economic Co-operation and Development
OEM	Original Equipment Manufacturer
OTSG	once-through steam generator
PEV	Plug-in Electric Vehicle
PHEV	Plug-in Hybrid Electric Vehicle
RD	Renewable Diesel
RFS2	Renewable Fuel Standard
ULSD	Ultra Low Sulfur Diesel
ZEV	Zero Emission Vehicle

Executive Summary

Adopted in 2007, California's Low Carbon Fuel Standard requires a 10 percent reduction in the carbon intensity of transportation fuels by 2020, as measured on a lifecycle basis. The goals of the program are to reduce greenhouse gas emissions from the transportation sector, diversify the transportation fuels sector, and to spur investment and innovation in lower carbon fuels.

The LCFS is designed as a performance-based standard using flexible market-based mechanisms that allow regulated parties to select the most cost-effective pathways to achieve compliance. Fuels that have a lower carbon intensity than gasoline or diesel generate LCFS credits. Regulated parties, such as refiners, have the option of producing or blending low carbon fuels, or purchasing credits from other fuel providers, including, but not limited to biofuel producers, natural gas infrastructure providers, electric utilities, and hydrogen producers.

This report represents the first phase of a two-phase, year-long project assessing the economic and environmental impacts of compliance with California's LCFS out to 2020. This phase focuses on the development of compliance scenarios based on market research, consultation with stakeholders, and market forecasts based on best estimates of fuel availability. These compliance scenarios are used to convey the outcomes of our research and analysis: namely, that the LCFS requirements can be achieved through modest changes in the diversity of transportation fuels supplied to California. The second phase of the work will focus on the economic and environmental impacts of these compliance scenarios, including parameters such as gross domestic product, jobs, and avoided damage costs.

ICF developed two scenarios – Scenario 1 and Scenario 2 – to capture the potential market responses to achieve compliance with the LCFS. ICF emphasized probabilistic outcomes for each alternative fuel type based on market constraints and opportunities: where appropriate, ICF defaulted to more conservative estimates of fuel and vehicle penetrations. A stakeholder panel developed a third compliance scenario referred to as the LCFS Enhanced Scenario, which ICF will also be modeling as part of the second phase of our work. The key highlights of the LCFS compliance scenarios include:

- **Compliance with the LCFS can be achieved through modest changes and a diverse supply of transportation fuels.** Broadly speaking, compliance is achieved through biofuel blending (with both gasoline and diesel) and through the deployment of advanced vehicle technologies that use natural gas, electricity, and hydrogen. In both scenarios, the majority of LCFS compliance is achieved through blending biofuels. However, compliance in Scenario 1 depends on more aggressive forecasts for advanced vehicle technologies than Scenario 2, thereby putting less pressure on the demand for biofuels. Regardless, both scenarios were developed to reflect the market-based flexibility of the regulation and recent market developments.
- **The alternative fuels market is evolving rapidly and in unforeseen ways, and the LCFS is driving investment in low carbon ethanol, biodiesel, renewable diesel, and biogas.** ICF has accounted for a variety of market developments in the compliance scenarios. For instance, the immediate availability of lower carbon biofuels such as biodiesel from corn oil, waste greases, and animal fats; renewable diesel from tallow; and ethanol from molasses. Although cellulosic biofuels have been produced at a slower-than-expected rate, these lower

carbon biofuels are available to California in significant quantities today and supply is forecasted to increase dramatically over the next several years. Each of these fuels has a carbon intensity less than 35 gCO_2e/MJ, representing a more than 60 percent reduction in carbon intensity compared to the LCFS compliance schedule. Apart from biofuels, increasing natural gas supplies and lower fuel pricing than diesel have renewed interest in natural gas in the transportation sector. Meanwhile, although plug-in electric vehicles are being purchased by California drivers at modest rates – in some areas, demand has been high enough to cause vehicle supply shortages – electricity consumption is unexpectedly making contributions towards LCFS compliance in these early years of the program.

- **Over-compliance in early years of the regulation (through 2016, at least) is critical, and a significant number of excess credits have already been generated.** As noted previously, LCFS credits can be banked and traded, and do not lose value. In fact, despite the uncertainty regarding the LCFS (e.g., legal challenges) and a fragile economic recovery, the LCFS market generated nearly 1.3 million excess credits by the end of 2012. Because of the way the LCFS compliance schedule is designed, over-compliance in early years is critical towards meeting compliance in later years (e.g., 2019 and 2020). In Scenario 1 and Scenario 2, for instance, credits are banked through 2017 and 2016, respectively. In subsequent years, the banked credits are drawn down to achieve compliance.
- **The diesel sector will likely generate more than its fair share of credits.** ICF developed scenarios that reflect the flexibility of the LCFS guidelines: namely, credits are fungible. It does not matter if credits are generated using fuels that substitute for gasoline or fuels that substitute for diesel. Forecasted diesel consumption in California indicates that diesel will generate about 20 percent of deficits in the LCFS program. However, fuels that substitute for diesel, including biodiesel, renewable diesel, and natural gas, have the potential to generate 40-55 percent of LCFS credits.
- **Biodiesel can make a significant contribution towards LCFS compliance.** Although biodiesel consumption in California has been modest in recent years, there is significant potential to blend biodiesel at lower levels (e.g., 5 percent to 20 percent by volume) with conventional diesel and generate a substantial number of LCFS credits. Infrastructure providers are already responding to this potential, and based on ICF research and stakeholder consultation, the industry is rapidly increasing the ability to store and blend biodiesel at petroleum terminals and at refineries.
- **Renewable diesel will make a modest contribution towards LCFS compliance, even at low volumes.** With no additional distribution infrastructure or refueling infrastructure costs, and no limitations on consumption in vehicles, renewable diesel is an attractive option for LCFS compliance. Furthermore, it is available in significant quantities today. Even at conservative forecasts of 150 million gallons renewable diesel delivered to California by 2020, renewable diesel could generate about 8 percent of the LCFS credits required to achieve compliance.
- **Natural gas consumption will increase rapidly in California and play a significant role in LCFS compliance.** When the LCFS was first developed in 2008, natural gas was expected to play a niche role in compliance. However, the increase in domestic natural gas supply has helped maintain a persistent price differential between natural gas and diesel. Combined with increased engine offerings in medium- and heavy-duty applications, particularly in the goods movement sector, natural gas consumption in the transportation sector is poised to increase significantly and rapidly. The expansion of natural gas consumption in the transportation sector will also facilitate a transition to biogas from landfills, for instance. With a carbon intensity less than 30 gCO_2e/MJ, even modest

penetrations of biogas (e.g., 10 percent of California’s natural gas consumption) are feasible.

- **Small modifications to the LCFS can have a substantive impact on compliance.** ICF also included estimated credits that can be generated through potential modifications to the LCFS, namely electricity used in fixed guideway applications (e.g., light rail in transit) or forklifts. Even though these credits are modest, they decrease the necessity of blending potentially more costly low carbon biofuels or accelerating the adoption of advanced vehicle technologies.

1. Introduction

1.1. California's Low Carbon Fuel Standard

In 2007 Governor Schwarzenegger signed Executive Order S-01-07 establishing California's Low Carbon Fuel Standard (LCFS), which requires a ten percent reduction in the carbon intensity of transportation fuels by 2020. Carbon intensity is measured in grams of carbon dioxide equivalents (gCO_2e) per unit energy (MJ) of fuel and is quantified on a lifecycle or well-to-wheels basis. In 2009, the California Air Resources Board (CARB) adopted the LCFS regulations. The program has been implemented and enforced since the beginning of 2011.

The LCFS is a flexible market-based standard implemented using a system of credits and deficits: transportation fuels that have a higher carbon intensity than the compliance schedule yield deficits, and fuels that have a lower carbon intensity generate credits. Regulated parties are required to have a net zero balance of credits and deficits annually. Credits can be banked and traded without limitations, and credits do not lose value. Transportation fuels that have a lower carbon intensity than the compliance schedule include ethanol, biodiesel, natural gas, electricity, and hydrogen. CARB quantifies and publishes carbon intensity values for all fuel pathways.

The entities that generate credits and deficits are referred to as regulated parties, an d the entity varies depending on the fuel. For instance, refiners are typically the regulated party for gasoline and diesel. Alternative fuel providers are referred to as opt-in regulated parties. The obligated parties vary considerably, including entities such as fuel producers and fueling station owners.

> **The Nuts and Bolts of LCFS**
>
> **Carbon intensity** is measured on a lifecycle or well-to-wheels basis in units of grams of carbon dioxide equivalent per unit energy of fuel (gCO2e/MJ).
>
> The LCFS is implemented using a system of **credits and deficits**, with each credit representing one metric ton of reduction. Credits are generated by transportation fuels that have a carbon intensity lower than the compliance schedule (ranging from about 98 gCO2e/MJ in 2013 to 89 gCO2e/MJ in 2020) and deficits are generated by gasoline and diesel.
>
> At the end of each year, compliance is achieved by offsetting deficits with credits. Credits can be banked and traded, and they do not lose value over time.

1.2. Scope of Work

ICF was retained by the California Electric Transportation Coalition (CalETC), the California Natural Gas Vehicle Coalition, the National Biodiesel Board (NBB), the Advanced Biofuels Association (ABFA), Environmental Entrepreneurs (E2), and Ceres to assess the macroeconomic impacts of the LCFS, using parameters such as gross domestic product and changes in jobs. The project has two phases:

- In the first phase of work, ICF developed scenarios that represent a range of likely outcomes towards LCFS compliance. These scenarios are intended to capture the range of potential market developments that would lead to LCFS compliance given our current outlook on the transportation fuel marketplace. In any forward-looking exercise, it is important to note that there is some uncertainty associated with the availability of lower carbon transportation fuels.

- In the second phase of work, ICF is using the REMI model to analyze the associated macroeconomic impacts of the LCFS compliance scenarios developed in Phase 1. Furthermore, ICF is quantifying and monetizing the GHG emission reductions, criteria pollutant emission reductions, and petroleum reductions associated with each compliance scenario.

This report focuses on the first phase of our work and includes the following sections:

- **Section 2** outlines the methodology that ICF employed, with information regarding conventional fuel projections, how regulatory overlap was included, and compliance strategies considered.
- **Section 3** provides an overview of LCFS compliance scenarios
- **Section 4** provides a more detailed review of the research, analysis, and market developments that were used to develop the LCFS compliance scenarios.
- **Section 5** provides a brief overview of the project’s next steps, including a more detailed discussion of the macroeconomic modeling ICF is conducting using the REMI model.

2. Methodology: Scenario Development

ICF developed three (3) LCFS compliance scenarios in the first phase of our work to estimate the macroeconomic impacts of the LCFS: Compliance Scenario 1 and Compliance Scenario 2 were developed by ICF in collaboration with a Stakeholder Review Panel. The stakeholder group developed the final compliance scenario, referred to as the LCFS Enhanced Scenario. The following subsections review the methodological issues identified in the process of developing LCFS compliance scenarios.

2.1. Stakeholder Input

The table below highlights the organizations that provided input via the Stakeholder Review Panel, which includes representatives from the utilities, the natural gas industry, and biofuel producers.

Exhibit 1. LCFS Study Stakeholder Review Panel

Stakeholder Review Panel Member	Areas of Expertise
California Electric Transportation Coalition	• Electricity transmission and distribution • Electric vehicles and hydrogen fuel cell vehicles • Renewable energy
California Natural Gas Vehicle Coalition	• Natural gas delivery: compressed, liquefied, and biogas • Natural gas vehicles • Natural gas infrastructure
National Biodiesel Board	• Feedstocks • Biodiesel production • Biodiesel infrastructure
Advanced Biofuels Association	• Biofuel production • Investment in biofuels
Environmental Entrepreneurs	• Biofuel production • Investment in biofuels
Ceres	• Alternative fuel investments

2.2. Fuel Volumes, Forecasts, and LCFS Compliance

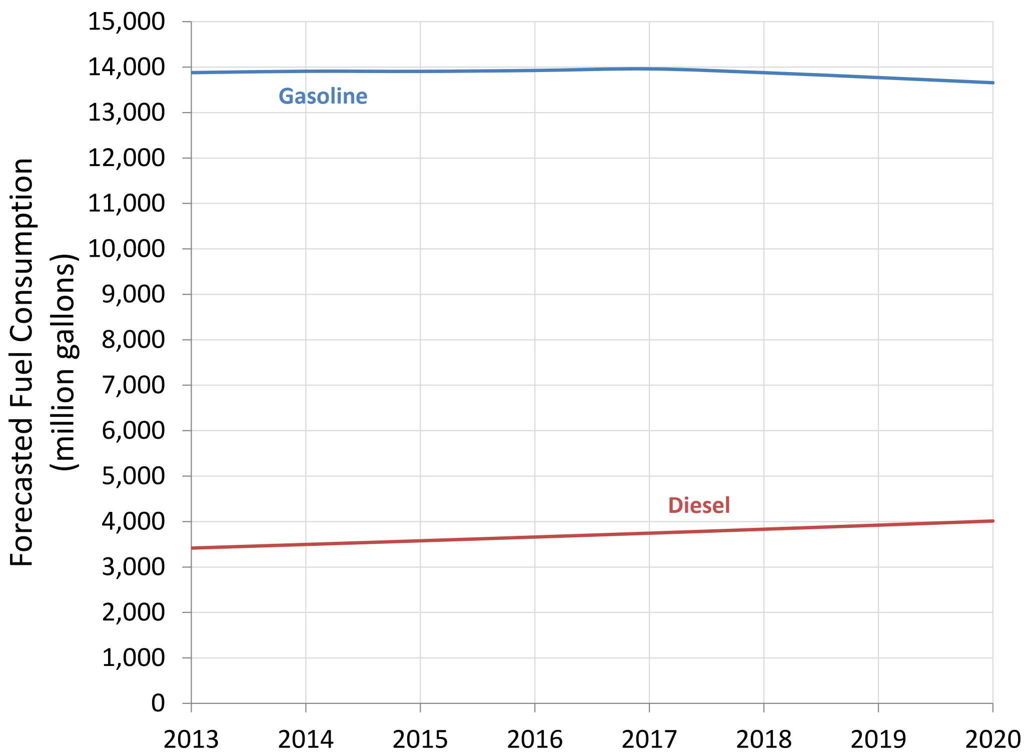
Conventional Fuel Volumes and Forecasts

ICF used a combination of transportation fuel demand forecasts reported by the California Energy Commission (CEC) from the most recent publicly available Integrated Energy Policy Report from 2011[1] and fuel volumes reported to date by regulated parties.[2] The gasoline and

[1] California Energy Commission (CEC). "Transportation Energy Forecasts and Analyses for the 2011 Integrated Energy Policy Report." CEC, August 2011: Available at: http://www.arb.ca.gov/msprog/clean_cars/clean_cars_ab1085/cec-600-2011-007-sd.pdf

diesel demand forecasted trends were applied to actual volumes reported through LCFS reporting from 2011 and 2012. These fuel forecasts account for the most recent fuel economy and GHG tailpipe emission standards for light-, medium-, and heavy-duty vehicles. Although it is likely that there will be additional regulations on medium- and heavy-duty regulations, we only incorporated regulations that have been promulgated into our forecasts.

Exhibit 2. Forecasted Gasoline (blue) and Diesel (red) Consumption in California



Other Regulations Considered in the Analysis

There are many regulations that impact the transportation sector in California. To the extent feasible, ICF accounted for regulatory drivers in the development of LCFS compliance scenarios. Regulatory overlap becomes a more significant issue in the second phase of the project because the attribution of costs associated with LCFS compliance impact the corresponding macroeconomic impacts. This issue is less of a concern in the consideration of LCFS compliance scenarios. Regardless, the following regulatory drivers were considered in the development of LCFS compliance scenarios.

Federal Renewable Fuel Standard (RFS2)

The United States Environmental Protection Agency (EPA) administers the federal Renewable Fuel Standard (RFS2). The RFS2 is a volumetric standard for blending biofuels into the

[2] Yeh, S; Whitcover, J; and Kessler, J. Status Review of California's Low Carbon Fuel Standard, Spring 2013. Available online at: http://tinyurl.com/LCFS-StatusReview2013

transportation fuel mix.[3] Although the RFS2 is a significant driver for biofuel blending nationwide, the regulation does not require a so-called fair-share for California. In other words, because California accounts for about 11 percent of domestic transportation fuel consumption, it would therefore be responsible for the equivalent fair-share of RFS2 obligations. However, regulated parties (e.g., refiners) can in theory comply with the RFS2 without blending biofuels in California. Although regulated parties do comply with the standard by blending biofuels in California, we make the assumption that the RFS2 does not act as a major regulatory driver in California – it plays a role in that it is a complementary regulatory driver for advanced biofuel production. Regulated parties under the LCFS that blend low carbon biofuels will earn credit towards RFS2, however, ICF's analysis assumes that the driver for California consumption is largely the LCFS and not RFS2.

Light Duty Fuel Economy Standards and Tailpipe GHG Standards

Although LCFS focuses on the carbon intensity of transportation fuels, there are other regulatory mechanisms in place in the transportation sector. These other regulations ensure that vehicles are becoming more fuel efficient and that GHG emissions from vehicles are lower. In 2002, California passed AB 1493 (Pavley) which limits light duty vehicle tailpipe GHG emissions. In 2009, the EPA granted California's waiver request, allowing it to regulate vehicle GHG emissions; CARB subsequently adopted amendments to the Pavley standards to reduce light duty tailpipe GHG emissions from new vehicles sold in California from 2009 through 2016. As part of a national agreement with the Obama Administration, agencies, automakers, and other stakeholders, the U.S. Environmental Protection Agency (EPA) and the U.S. National Highway Traffic Safety Administration (NHTSA) issued harmonized GHG and fuel economy standards in partnership with CARB, equivalent to 35.5 mpg by model year 2016.

As part of the AB 32 Scoping Plan, the Plan that describes the approach California will take to reduce GHG emissions to 1990 levels by 2020, CARB began development of the Advanced Clean Cars program. This program is essentially a combination of Low Emission Vehicle III (LEVIII) rulemaking and an update to the Zero Emission Vehicle (ZEV) Program. LEV III reduces tailpipe criteria pollutant and GHG emissions. The GHG portion is referred to as Pavley 2.

The EPA and NHTSA worked in parallel to develop the second phase of the national program, and in 2012 issued new federal light duty GHG and fuel economy standards for model years 2017-2025. EPA's fleet average standard of 163 grams per miles corresponds to 54.5 miles per gallon (mpg) if all reductions are made through fuel economy improvements. As part of the national agreement, CARB allows compliance with the EPA's requirements to serve as compliance with California's standards for those model years.

The light duty fuel economy standards and tailpipe GHG standards were incorporated into gasoline and diesel demand forecasts.

[3] The RFS2 does not include non-biofuels such as electricity, natural gas, or hydrogen. However, the RFS2 does include biogas as an eligible fuel – in a recent proposed rulemaking, the EPA is proposing to amend the biogas pathways to list renewable CNG or LNG as the fuel types and biogas as the feedstock. Furthermore, EPA's recent proposed rulemaking would allow renewable electricity (used in electric vehicles) produced from landfill gas to generate credits under the RFS2. More information is available online at: http://www.epa.gov/otaq/fuels/renewablefuels/documents/nprm-pathways-2-signature-version.pdf

Zero Emission Vehicle Program

ARB adopted the Zero Emission Vehicle (ZEV) Program in 1990 as part of the Low Emission Vehicle (LEV) to reduce criteria pollutant emissions in order to meet health based air quality goals. Today, the ZEV Program requires a certain percentage of light duty vehicles sold in California to be partly or fully zero emitting at the tailpipe. Qualifying technologies include battery electric vehicles (BEVs), plug-in hybrid electric vehicles (PHEVs), and hydrogen fuel cell vehicles (FCVs). ARB recently adopted the changes to the ZEV Program as part of the Advanced Clean Cars Program, with modified requirements over the model year 2014 to 2025 time period. The table below provides light duty vehicle populations for ARB's likely compliance scenario. Note that for the purposes of this study, the so-called transitional zero emission vehicles (TZEVs) are all considered plug-in hybrid electric vehicles (PHEVs).

Exhibit 3. Advanced Vehicle Technology Populations, Most Likely Compliance Scenario for the ZEV Program

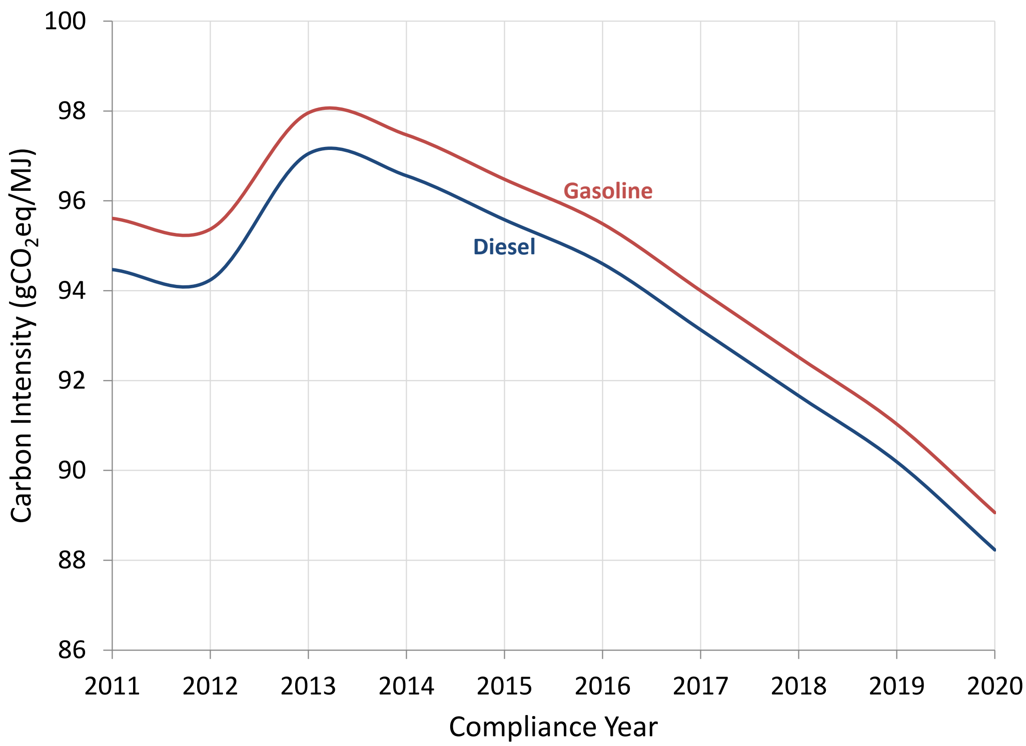
ZEV Type	2017	2018	2019	2020
FCVs	6,337	9,237	15,437	26,037
BEVs	42,832	56,732	84,032	121,732
TZEVs / PHEVs	128,589	189,889	265,189	354,289
Total	177,758	255,858	364,658	502,058

The credits generated by the consumption of electricity and hydrogen in ZEVs to comply with the ZEV Program will generate LCFS credits. ICF considered the credits generated through CARB's most likely compliance scenario as the minimum number of credits for PEVs and FCVs. Any credits generated above and beyond the most likely compliance scenario were attributed to the LCFS and not the ZEV Program.

LCFS Compliance Schedule

The compliance schedule for the LCFS is shown in the figure below.

Exhibit 4. LCFS Compliance Schedule for Gasoline and Diesel



Note that CARB modified the baseline number, which was originally an average of crude oil supplied to California refineries in 2006; the values from 2013 to 2020 reflect the updated average of crude oil supplied to California refineries in 2010.

Note that although there are separate compliance schedules for gasoline and diesel, LCFS credits are fungible across these fuels. For instance, credits generated using a low carbon fuel that substitutes for gasoline can be used to offset deficits generated by diesel. This is an important aspect of LCFS compliance because, based on ICF's research and analysis, there is considerable room for over-compliance in the diesel sector compared to the gasoline sector. There are two prominent reasons for this:

- Firstly, ethanol is already blended into gasoline at a rate of 10 percent by volume. The primary pathway for compliance in the near-term future for gasoline suppliers is simply to blend ethanol from feedstocks with a lower carbon intensity. However, they are blending the same volume of ethanol.
- Secondly, there is very little biodiesel consumed in California today (less than 1 percent by volume in 2010). Biodiesel blends of up to 5 percent (B5) are considered identical to conventional diesel according to the ASTM International. ASTM International is the leading standard-setting organization for fuel in North America and sets science-based standards by consensus of fuel producers, petroleum distributors, original equipment manufacturers, and regulators. As a result, not only can diesel providers blend low carbon biodiesel, they can drastically increase the volume of biodiesel blended and earn credits for those reductions.

2.3. Compliance Options Considered

ICF considered a variety of low carbon fuels to develop representative LCFS compliance scenarios. Furthermore, to determine the balance of deficits and credits in each compliance scenario, ICF made various assumptions regarding how vehicles and fuels will be used in the near-term future towards LCFS compliance. These are distinguished between fuels that substitute for gasoline (the gasoline pool) and fuels that substitute for diesel.

Fuels that Substitute for Gasoline

ICF assumed that ethanol would continue to be blended into gasoline at a rate of 10 percent by volume, consistent with today's reformulated gasoline requirements. ICF limited the blending of ethanol with gasoline at a maximum of 15 percent by volume based on EPA's recently issued waiver for E15 in vehicle model years (MY) 2001 or newer. Although there is no E15 consumed in California today – and very little generally in the United States – ICF anticipates that E15 will be consumed in meaningful quantities in California in the 2017-2018 timeframe as a result of drivers such as LCFS and the RFS2.

ICF considered the following feedstocks for ethanol production:

- **Corn, Conventional**: Corn from conventional processes is typically sourced from the Midwest. Corn has been and continues to be the most common feedstock for ethanol consumed in California. Nearly 1.5 billion gallons of corn ethanol are consumed in California today as an oxygenator in reformulated gasoline.
- **Corn, California-produced**: California currently has seven (7) ethanol production facilities with a combined nameplate production capacity of more than 250 million gallons; however, actual production capacity is close to 200 million gallons annually. For the purposes of this report, we assume that there is potential for modest expansion in California facilities, with a maximum capacity of 220 million gallons. We assumed modest improvements consistent with information provided via consultation with Pacific Ethanol.
- **Corn, low carbon intensity**: There is significant potential to lower the carbon intensity of corn ethanol through a variety of measures. For the purposes of this report, ICF assumed a lower limit of 73 g/MJ for what we term low carbon intensity corn ethanol. There has already been a shift towards more efficient corn ethanol production as a result of the LCFS, with many new lower carbon pathways submitted to and approved by CARB.
- **Sugarcane**: Most sugarcane ethanol is produced in Brazil and shipped via tanker to the United States. In some cases, hydrous ethanol is shipped to a country in the Caribbean Basin Initiative (CBI); the excess water is subsequently removed and the anhydrous ethanol is shipped to the US. This step was more common when the US had a tariff on sugarcane ethanol imported directly from Brazil; the interim step allowed importers to avoid paying the tariff. The ethanol arrives in California in two ways: 1) directly via port or 2) via rail after landing in Texas. For the sake of reference, the United States imported 500 million gallons of sugarcane ethanol in 2012, with an estimated 90 million gallons coming to California.
- **Cellulosic**: Cellulosic ethanol refers generally to ethanol produced from wood, grasses, or other lignocelluosic materials. For the purposes of this report, ICF did not identify feedstocks specifically; rather, we focused on the long-term likelihood (out to 2020) of cellulosic ethanol production and the availability to California.

Although ethanol from various feedstocks is the primary substitute for gasoline today, ICF also considered the following fuels that substitute for gasoline:

- **Renewable gasoline** is a drop-in replacement biofuel for gasoline. To remain conservative in our estimates, ICF assumed that 50% of Energy Information Administration (EIA)-forecasted renewable gasoline production will be available to California, starting in 2015.
- **Electricity** used in plug -in electric vehicles (PEVs), including plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs), stands to play an important role towards LCFS compliance, particularly in later years of the regulation as California's Zero Emission Vehicle (ZEV) Program takes full effect. In each of the compliance scenarios, a minimum number of PEVs was deployed to be consistent with CARB' most likely scenario. ICF also considered the potential for a more rapid expansion of the market for PEVs.
- **Hydrogen** consumed in fuel cell vehicles (FCVs) is another aspect of California's ZEV Program that was also considered. Similarly, ICF deployed a minimum number of FCVs using hydrogen to be consistent with CARB's most likely compliance scenario. ICF also considered the potential for a more rapid expansion of the market for FCVs.
- **Natural gas** has significant potential to displace gasoline consumption in medium-duty and light heavy-duty vehicles.

The table below shows the carbon intensity values used for fuels that substitute for gasoline. In most cases, we employed static carbon intensity values; however, in some cases we did decrease the carbon intensity of a transportation fuel to reflect expected advanced in technologies. Unless otherwise noted, the carbon intensity values were taken directly from CARB's look-up tables.

Exhibit 5. Carbon Intensity Values for Fuels that Substitute for Gasoline

Fuel / Feedstock	Carbon Intensity (gCO2e/MJ)
Ethanol, conventional	95.66
Ethanol, CA corn	80.70; decreasing to 70.70 in 2016
Ethanol, Low CI Corn	73.21
Ethanol, Sugarcane	73.40; decreasing to 67.38 by 2020
Ethanol, Cellulosic	21.30 [a]
Renewable Gasoline	25.00 [b]
Compressed natural gas	68.00
Biogas, landfill	11.56
Electricity, marginal [c]	30.80; decreasing to 26.32 by 2020
Hydrogen [d]	39.42

[a] The average of CARB pathways for ethanol from farmed trees and forest ways
[b] Estimated carbon intensity based on stakeholder consultation.
[c] Includes the energy economy ratio (EER) of 3.4 for electric vehicles
[d] Includes the EER of 2.5 for fuel cell vehicles

Fuels that Substitute for Diesel

The fuel volumes in the compliance scenarios represent a combination of ICF research and input provided by the National Biodiesel Board (NBB), with similar biodiesel blending rates and feedstocks: In the development of the compliance scenarios, we considered the following feedstocks for biodiesel:

- **Soybean oil**: Soybean oil is the largest single feedstock for biodiesel production in the United States. It is a well-established crop with a robust commodity market. While most soybeans are grown in the Midwest and a significant amount of biodiesel production capacity exists in the Midwest, soybean oil is also transported to independent biodiesel production facilities in California and elsewhere.
- **Waste grease**: Waste grease is significant feedstock at California production facilities. As a waste feedstock, waste grease has a low carbon intensity. The production process for biodiesel from waste grease is generally more energy intensive than for vegetable oils because there is generally a higher free fatty acid content. This requires an additional acid-catalyzed esterification reaction, thereby increasing the energy inputs.
- **Animal fats**: Animal fats, like waste grease, are also a significant feedstock for biodiesel production and yield a finished product with a low carbon intensity. Typically, animal fats include poultry, tallow, and white grease (or lard).
- **Corn oil**: Corn oil is a byproduct of corn ethanol production and generally requires retrofitting an ethanol plant. It is a feedstock with significant growth potential for the biodiesel industry. Corn oil extraction is a relatively new commodity for the majority of ethanol production facilities, but represents another high-value co-product. Anecdotal evidence indicates that the majority of corn ethanol facilities in the US will have installed equipment to extract corn oil by the end of 2013.
- **Canola oil**: Canola oil is similar to soybean oil as a feedstock; it is more prominent feedstock in the European Union (referred to there as rapeseed). In North America, canola production historically exists primarily in Canada and northern states of the US. It is increasingly being planted as a winter crop is places like Oklahoma and the Carolinas. Existing transportation infrastructure makes Canola a significant feedstock for biodiesel production on the West Coast.

ICF also considered the following alternative fuels:

- **Renewable diesel**: Like biodiesel, there are multiple feedstocks that can be used to produce renewable diesel, including palm oil, canola (or rapeseed) oil, jatropha oil, camelina oil, soy oil, waste greases, and animal fats (i.e., tallow). ICF considered renewable diesel produced from tallow; this pathway is largely based on the availability of renewable diesel produced by Neste Oil in its Singapore production plant using its renewable diesel production process.
- **Natural gas**: ICF considered the potential for natural gas – compressed, liquefied, and biogas – in heavy-duty applications such as short-, medium-, and long-haul trucks, refuse haulers, and transit buses. For the purposes of this report, and after consultation with the California Natural Gas Vehicle Coalition, we assumed that about 85 percent of natural gas in the heavy-duty sector (Class 7 and Class 8 trucks) will be consumed as LNG in spark-ignited engines and 15 percent will be consumed as CNG in spark-ignited engines for medium-heavy and heavy-heavy duty vehicles.

- **Electricity**: Electricity used in fixed guideway applications (e.g., light- and heavy-rail) and forklifts were considered in the analysis, and are discussed in more detail in Section 4.7. Although BEVs and PHEVs have the potential to displace diesel in the medium- and heavy-duty sector, ICF limited the scope of our analysis regarding electric vehicles to light-duty applications.

The table below includes the carbon intensity values used to determine the balance of LCFS deficits and credits in each scenario. Unless otherwise noted, the carbon intensity values were taken directly from CARB's look-up tables.

Exhibit 6. Carbon Intensity Values for Fuels that Substitute for Diesel

Fuel / Feedstock	Carbon Intensity (gCO2e/MJ)
Biodiesel, soy oil	83.25
Biodiesel, waste grease	13.80
Biodiesel, corn oil	4.00
Biodiesel, canola oil [a]	83.25
Renewable diesel, tallow	19.65
Compressed natural gas [b]	75.56
Liquefied natural gas [c]	77.76
Biogas, landfill [b]	12.51

[a] Biodiesel from canola oil is not in the LCFS look-up tables. ICF used a conservative value equivalent to biodiesel from soy oil.

[b] Includes the EER of 0.9 for spark ignition CNG vehicles

[c] Average of LNG pathways with natural gas liquefied in California with 80% and 90% efficiency.

3. Overview of Compliance Scenarios

From a broad perspective, there are two ways to deploy alternative fuels that will help comply with the LCFS. Firstly, biofuels can be blended into conventional gasoline or diesel for consumption in the existing vehicle fleet. Secondly, advanced vehicle technologies can be deployed, which consume alternative fuels such as natural gas, electricity, or hydrogen. ICF maintains that compliance with the LCFS will require a diverse mix of all of these alternative fuels. Due to constraints on how quickly the vehicle fleet can be turned over, however, biofuel blending is and will likely continue to be a major form of LCFS compliance until advanced vehicle technologies are deployed in higher numbers. The scenarios outlined in the following sections highlight the diversity of alternative fuels that are available or forecasted to be available out to 2020.

ICF developed two compliance scenarios in coordination with the Stakeholder Review Panel. As noted above, both scenarios have significant reliance on biofuel blending to achieve compliance – using a mix of so-called first generation biofuels and advanced biofuels, with an emphasis on fuels that we know are available today. Scenario 1, however, reflects a market that is more dependent on advanced vehicle technologies than Scenario 2, thereby decreasing the pressure on biofuel blending.

The Stakeholder Review Panel developed a third compliance scenario, referred to as the LCFS Enhanced Scenario. This scenario has even greater advanced vehicle penetrations than Scenario 1, and includes additional credits generated from off-road electrification and innovative crude extraction processes.

The table below characterizes broadly the scenarios with more detail in the subsequent sections.

Exhibit 7. Overview of LCFS Compliance Scenarios Developed

Scenario	Ethanol	Biodiesel / Renewable Diesel	Natural Gas	Advanced Vehicles (PEVs / FCVs)	Other
Scenario 1	Maintained E10 blend rate until 2018 E15 introduced 2019 and 2020 Cellulosic/advanced biofuels capped at 50% of volumes reported by E2	Limited blend percentages to 20 percent by volume of conventional diesel.	Linear increase from 2012 to 2020 to 1.2 billion gge 10% biogas Based on estimates from CNGVC	220,000 BEVs; 800,000 PHEVs; and 110,000 FCVs in 2020	Only forklifts and rail with no additional credits for displacement
Scenario 2	Maintained E10 blend rate until 2017 E15 introduced 2018-2020 Cellulosic/advanced biofuels capped at 13% of volumes reported by E2	Limited blend percentages to 20 percent by volume of conventional diesel. Increased corn oil BD Increased RD from tallow in 2018-2020	Linear increase from 2012 to 2020 to 900 million gge, 10% biogas Based on estimates from CNGVC	ZEV Program Compliance	Only forklifts and rail with no additional credits for displacement
LCFS Enhanced	Maintained E10 blend rate Brazilian sugarcane capped at less than 350 MGY until 2018	Limited blend percentages to 20 percent by volume of conventional diesel.	Linear increase from 2012 to 2020 to 1.5 billion gge 10% biogas Based on estimates from CNGVC	240,000 BEVs; 960,000 PHEVs; and 110,000 FCVs in 2020	Marginal incremental calculations for forklifts and rail, no displacement when including ports, small non-truck and truck related
Assumption for all Scenarios	Maximum ethanol is E15 FFVs driving 85% of miles on E85. Maximums for ethanol: • Low CI corn at 1 BGPY • Sugarcane at 500 MGPY			40% PHEV VMT is electric	Compliance achieved in 2011 and 2012 Assumed 1 million banked credits at end of 2012

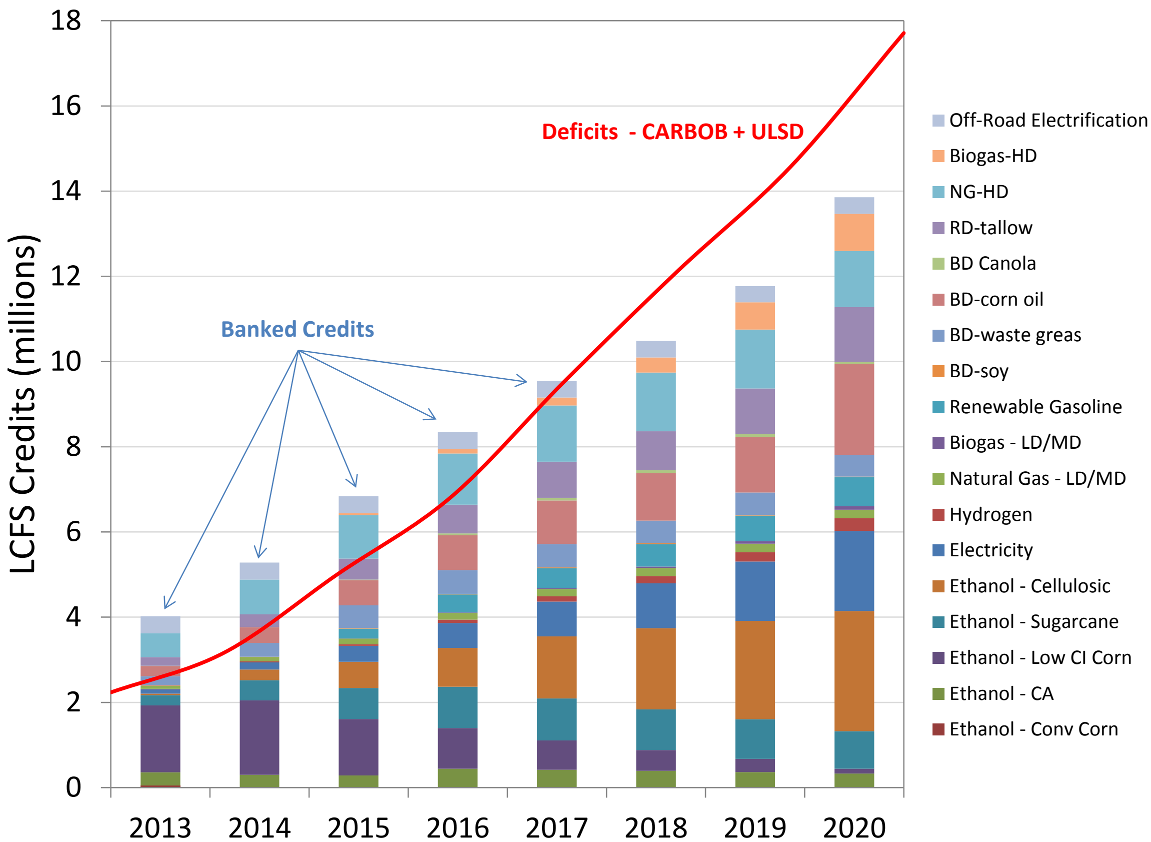
* gge = gasoline gallon equivalent

3.1. Compliance Scenario 1

Summary Overview of Compliance Scenario 1

Exhibit 8 shows the annual balance of credits and deficits (in millions) for Scenario 1. Each colored stacked bar represents credits generated via low carbon fuels; the red line represents the deficits from forecasted CARBOB and ultra low sulfur diesel (ULSD) consumption. When the stacked bars are above the red line (2013-2017) that indicates a year in which more credits are generated than are required to meet compliance. Conversely, in years where the stacked bars are lower than the red line (2018-2020) that indicates a year in which banked credits must be used. The stacked bars are grouped according to the fuel being displaced. The stacked bars at the bottom of the graph are for fuels that displace gasoline; moving up the graph, the stacked bars represent fuels that displace diesel.

Exhibit 8. Balance of LCFS Credits and Deficits in Scenario 1



The table below highlights the deficits generated by forecasted CARBOB and diesel consumption (in millions of deficits) compared to the credits generated by fuels that substitute for gasoline and diesel, respectively. The last two rows of the table show the balance of credits and the number of credits banked after compliance. Note that there is significant over-compliance in the early years of the program. Furthermore, note that although diesel accounts for only about 20 percent of deficits, the fuels that substitute for diesel account for about 45 percent of credits.

Exhibit 9. LCFS Credits and Deficits: Banking in Scenario 1

Fuel		2013	2014	2015	2016	2017	2018	2019	2020
Deficits (millions)	CARBOB	-1.82	-2.55	-4.00	-5.44	-7.62	-9.69	-11.67	-14.24
	ULSD	-0.42	-0.62	-1.01	-1.37	-1.90	-2.43	-2.90	-3.47
Credits (millions)	Gasoline Subs	2.39	3.06	3.73	4.53	5.15	5.72	6.38	7.28
	Diesel Subs	1.63	2.22	3.11	3.81	4.39	4.77	5.39	6.57
	Balance	1.79	2.12	1.83	1.53	0.02	-1.63	-2.80	-3.85
	Banked (Net)	2.79	4.90	6.74	8.27	8.29	6.66	3.86	0.01

Note: The banked balance in 2013 includes one million credits from over-compliance in 2011-2012

Ethanol and Biofuels that Substitute for Gasoline

ICF considered ethanol from the aforementioned feedstocks: corn (with varying production locations and processes), sugarcane, and cellulosic. The table below indicates the volumes (in million gallons) of ethanol broken down by feedstock in Scenario 1.

Exhibit 10. Ethanol Volumes (in million gallons) in Scenario 1

Feedstock	2013	2014	2015	2016	2017	2018	2019	2020
Corn, Conventional	264	0	0	0	0	0	0	0
California Corn	215	220	220	220	220	220	220	220
Low CI Corn	780	884	699	526	408	311	214	87
Sugarcane	120	240	360	480	500	500	500	500
Cellulosic	5	41	100	150	246	328	406	511
Total	1,384	1,385	1,379	1,376	1,374	1,359	1,340	1,318
% EtOH in Gasoline	10%	10%	10%	10%	10%	10%	10%	10%

Biodiesel

The table below shows the volume of biodiesel (by feedstock) consumed in Scenario 1.

Exhibit 11. Biodiesel Consumption in Scenario 1 (million gallons)

Feedstock	2013	2014	2015	2016	2017	2018	2019	2020
Soy Oil	3	5	8	11	14	16	19	23
Waste Grease	19	29	48	51	51	51	51	51
Corn Oil	19	29	48	67	86	95	112	189
Canola Oil	3	5	8	27	49	59	80	62
BD, Total	45	68	113	157	200	221	262	325
Biodiesel Blend (%)	1%	2%	4%	5%	7%	8%	10%	12%

Renewable Diesel

The table below shows the volume of renewable diesel consumed in Scenario 1.

Exhibit 12. Renewable Diesel Consumption in Scenario 1 (million gallons)

Feedstock	2013	2014	2015	2016	2017	2018	2019	2020
Tallow	19	29	48	67	86	95	112	139

Natural Gas

The consumption of natural gas is the medium-level of deployment from the CNGVC's estimates and reaches 1,200 million gasoline gallon equivalents (gge) consumed in 2020, as shown in the table below.

Exhibit 13. Natural Gas Consumption in Scenario 1 (million gge)

	2013	2014	2015	2016	2017	2018	2019	2020
NG, medium-duty	20	30	40	49	58	67	74	81
Biogas, medium-duty	-	-	0	1	2	4	6	9
NG, heavy-duty	250	373	491	606	719	821	908	999
Biogas, heavy-duty	-	-	5	12	22	43	79	111
Total	271	403	536	669	802	934	1,067	1,200

Advanced Vehicle Technologies: PEVs and FCVs

Advanced vehicle technologies were deployed at an accelerated rate in Compliance Scenario 1 relative to the minimum level of deployment to comply with the ZEV Program. The table below shows the consumption of hydrogen in FCVs and electricity in PEVs in gasoline equivalent volumes.

Exhibit 14. Hydrogen and Electricity Consumption in ZEVs in Scenario 1 (million gge)

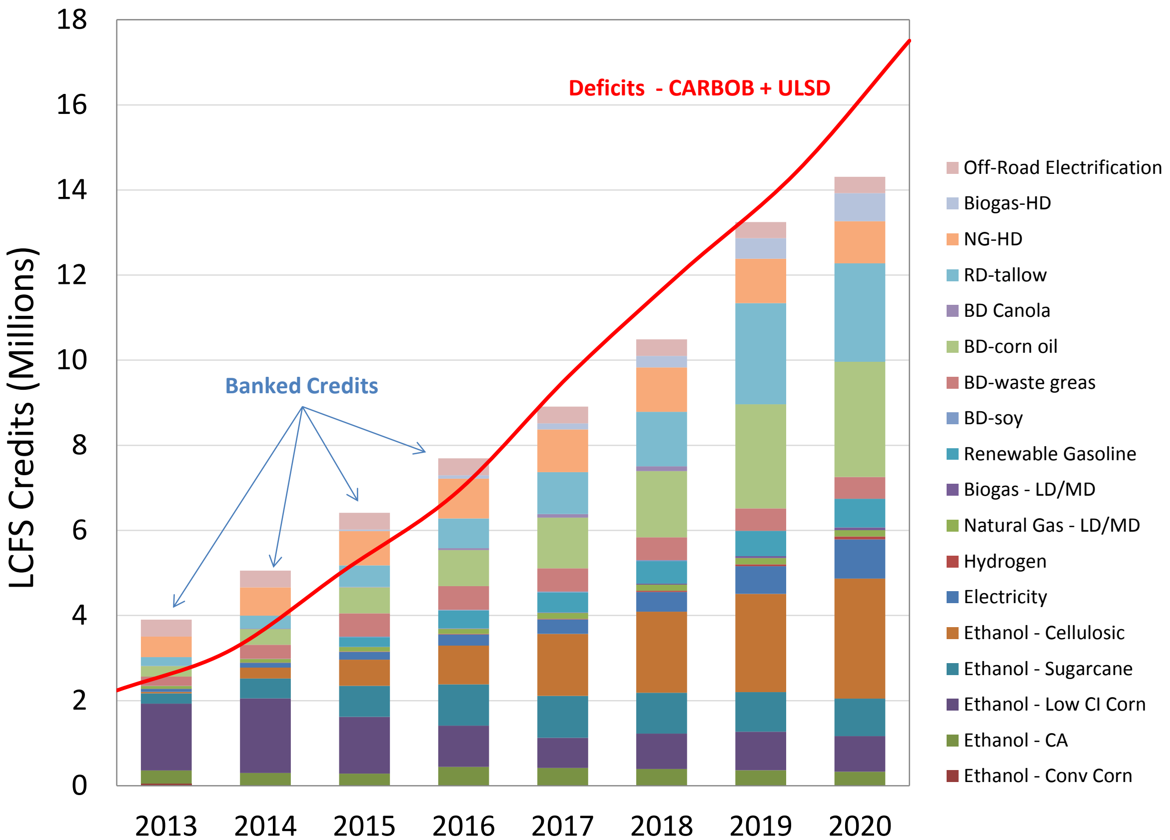
Vehicle	2013	2014	2015	2016	2017	2018	2019	2020
FCVs	0	1	2	5	8	11	15	21
BEVs	4	6	14	23	32	43	58	76
PHEVs	10	16	34	50	69	87	119	153
Total	14	24	51	78	109	141	192	251

3.2. Compliance Scenario 2

Summary Overview of Compliance Scenario 2

Exhibit 15 shows the annual balance of credits and deficits (in millions) for Scenario 1. Each colored stacked bar represents credits generated via low carbon fuels; the red line represents the deficits from forecasted CARBOB and ULSD consumption. When the stacked bars are above the red line (2013-2016) that indicates a year in which more credits are generated than are required to meet compliance. Conversely, in years where the stacked bars are lower than the red line (2017-2020) that indicates a year in which banked credits must be used. The stacked bars are grouped according to the fuel being displaced. The stacked bars at the bottom of the graph are for fuels that displace gasoline; moving up the graph, the stacked bars represent fuels that displace diesel.

Exhibit 15. Balance of Credits and Deficits for Compliance Scenario 2



The table below highlights the deficits generated by forecasted CARBOB and diesel consumption (in millions of deficits) compared to the credits generated by fuels that substitute for gasoline and diesel, respectively. The last two rows of the table show the balance of credits and the number of credits banked after compliance. Note that there is significant over-compliance in the early years of the program. Furthermore, note that although diesel accounts for only about 20 percent of deficits, the fuels that substitute for diesel account for about 50 percent of credits.

Exhibit 16. LCFS Credits and Deficits: Banking in Scenario 2

Fuel		2013	2014	2015	2016	2017	2018	2019	2020
Deficits (millions)	CARBOB	-1.82	-2.55	-4.01	-5.47	-7.69	-9.63	-11.46	-13.85
	ULSD	-0.42	-0.63	-1.03	-1.42	-1.96	-2.47	-2.96	-3.66
Credits (millions)	Gasoline Subs	2.34	2.98	3.49	4.12	4.54	5.28	5.99	6.75
	Diesel Subs	1.56	2.08	2.92	3.58	4.36	5.21	7.25	7.56
	Balance	1.66	1.88	1.37	0.81	-0.74	-1.60	-1.17	-3.20
	Banked (Net)	2.66	4.54	5.91	6.72	5.98	4.37	3.20	0.01

Note: The banked balance in 2013 includes one million credits from over-compliance in 2011-2012

Ethanol and Biofuels that Substitute for Gasoline

The volumes of ethanol (in million gallons) consumed in Scenario 2 are shown in the table below.

Exhibit 17. Ethanol Volumes (in million gallons) in Scenario 2

Feedstock	2013	2014	2015	2016	2017	2018	2019	2020
Corn, Conventional	240	0	0	0	0	0	0	0
California	220	220	220	220	220	220	220	220
Low CI Corn	780	845	644	514	419	532	640	580
Sugarcane	140	280	420	500	500	500	500	500
Cellulosic	5	41	100	150	246	328	406	511
Total	1,385	1,386	1,384	1,384	1,385	1,580	1,766	1,811
% EtOH in Gasoline	10%	10%	10%	10%	10%	11.5%	13.0%	13.5%

Biodiesel

The table below shows the volume of biodiesel and renewable diesel (by feedstock) consumed in Scenario 2.

Exhibit 18. Biodiesel and Renewable Diesel Consumption in Scenario 2 (million gallons)

Feedstock	2013	2014	2015	2016	2017	2018	2019	2020
Soy Oil	3	5	8	12	17	22	0	0
Waste Grease	20	30	49	51	51	51	51	51
Corn Oil	20	30	50	71	101	135	211	239
Canola Oil	3	4	7	29	63	100	0	0
BD, Total	46	69	115	162	232	308	262	290
Biodiesel Blend (%)	1%	2%	4%	5%	8%	11%	9%	10%

Renewable Diesel

The table below shows the volume of renewable diesel consumed in Scenario 2.

Exhibit 19. Renewable Diesel Consumption in Scenario 2 (million gallons)

Feedstock	2013	2014	2015	2016	2017	2018	2019	2020
Tallow	20	30	49	69	99	132	251	251

Natural Gas

The deployment of natural gas is the least aggressive in Scenario 2 and reaches 900 million gge consumed in 2020, as shown in the table below.

Exhibit 20. Natural Gas Consumption in Scenario 2 (million gge)

	2013	2014	2015	2016	2017	2018	2019	2020
NG, medium-duty	17	25	31	38	45	51	56	61
Biogas, medium-duty	-	-	0	1	1	3	5	7
NG, heavy-duty	216	304	388	470	551	623	685	749
Biogas, heavy-duty	-	-	4	10	17	33	60	83
Total	233	328	424	519	614	709	805	900

Advanced Vehicle Technologies: PEVs and FCVs

Advanced vehicle technologies were deployed at minimum ZEV compliance in Scenario 2; the table below shows the consumption of hydrogen in FCVs and electricity in PEVs in gasoline equivalent volumes.

Exhibit 21. Hydrogen and Electricity Consumption in ZEVs in Scenario 2 (million gge)

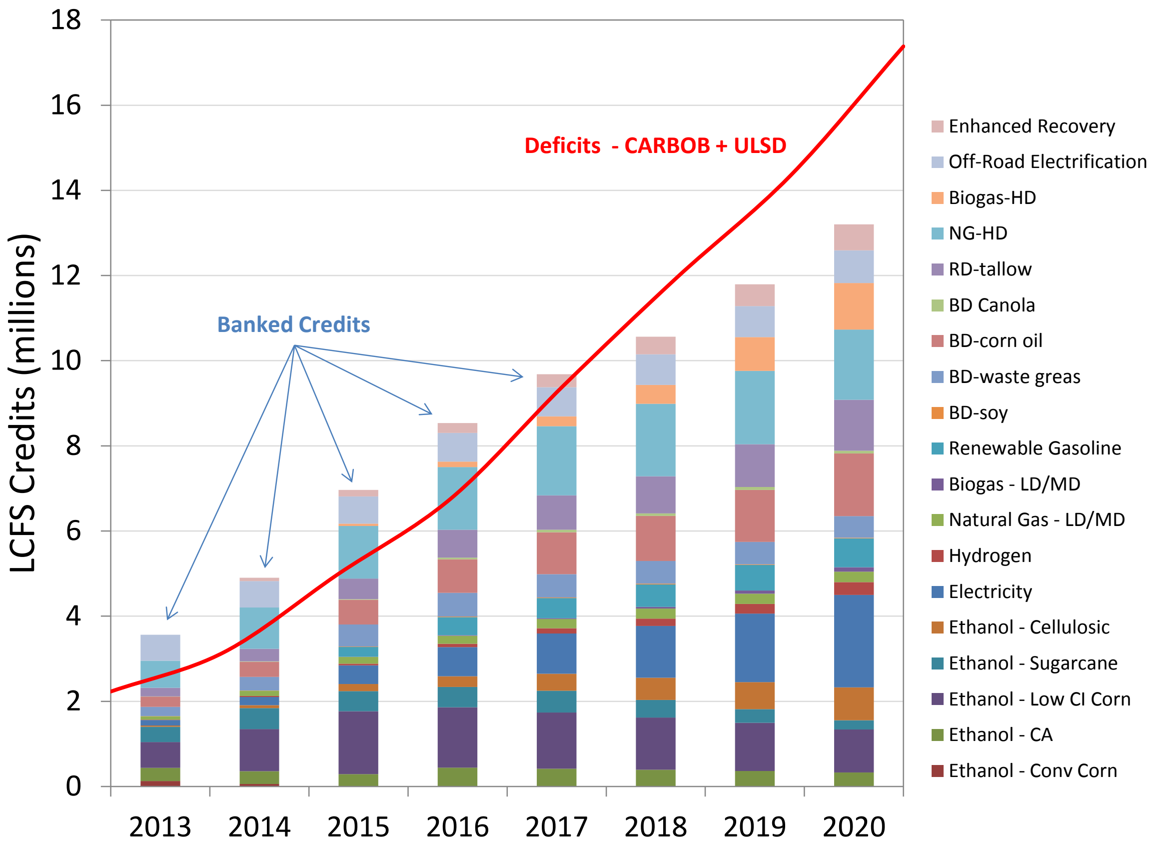
Vehicle	2013	2014	2015	2016	2017	2018	2019	2020
FCVs	0	0	1	1	1	2	3	5
BEVs	3	4	7	10	13	19	27	37
PHEVs	7	10	15	20	25	36	51	68
Total Adv Vehicles	10	14	23	31	39	57	81	110

3.3. LCFS Enhanced Scenario

Summary Overview of LCFS Enhanced Compliance Scenario

Exhibit 22 shows the annual balance of credits and deficits (in millions) for the LCFS Enhanced Scenario. Each colored stacked bar represents credits generated via low carbon fuels; the red line represents the deficits from forecasted CARBOB and ULSD consumption. When the stacked bars are above the red line (2013-2017) that indicates a year in which more credits are generated than are required to meet compliance. Conversely, in years where the stacked bars are lower than the red line (2018-2020) that indicates a year in which banked credits must be used. The stacked bars are grouped according to the fuel being displaced. The stacked bars at the bottom of the graph are for fuels that displace gasoline; moving up the graph, the stacked bars represent fuels that displace diesel. Note that the top stacked bar, labeled Enhanced Recovery, includes credits generated by deploying innovative crude recovery technologies. These technologies reduce the carbon intensity of both gasoline and diesel, and are discussed in more detail below.

Exhibit 22. Balance of Credits and Deficits in the LCFS Enhanced Scenario



The table below highlights the deficits generated by forecasted CARBOB and diesel consumption (in millions of deficits) compared to the credits generated by fuels that substitute for gasoline and diesel, respectively. The last two rows of the table show the balance of credits and the number of credits banked after compliance. Note that there is significant over-compliance in the early years of the program. Furthermore, note that although diesel accounts for only about 20 percent of deficits, the fuels that substitute for diesel account for about 50 percent of credits.

Exhibit 23. LCFS Credits and Deficits: Banking in the LCFS Enhanced Scenario

Fuel		2013	2014	2015	2016	2017	2018	2019	2020
Deficits (millions)	CARBOB	-1.82	-2.54	-3.99	-5.43	-7.60	-9.65	-11.62	-14.15
	ULSD	-0.41	-0.61	-0.98	-1.33	-1.82	-2.30	-2.72	-3.23
Credits (millions)	Gasoline Subs	1.65	2.32	3.43	4.20	4.73	5.16	5.71	6.44
	Diesel Subs	1.92	2.58	3.54	4.33	4.95	5.41	6.08	6.76
	Balance	1.33	1.75	1.99	1.78	0.26	-1.39	-2.55	-4.18
	Banked (Net)	2.33	4.08	6.07	7.86	8.12	6.72	4.18	0.00

Note: The banked balance in 2013 includes one million credits from over-compliance in 2011-2012

Ethanol and Biofuels that Substitute for Gasoline

In the LCFS Enhanced Scenario, cellulosic ethanol was restricted to one quarter of the Scenario 1 and Scenario 2 (or 1/8th of E2's estimated cellulosic ethanol availability). The table below shows the volumes of ethanol consumed in the LCFS Enhanced Scenario.

Exhibit 24. Ethanol Volumes (in million gallons) in the LCFS Enhanced Scenario

Feedstock	2013	2014	2015	2016	2017	2018	2019	2020
Midwest Corn	678	402	100	67	0	0	0	0
California Corn	220	220	220	220	220	220	220	220
Low CI Corn	300	500	780	780	780	780	780	780
Sugarcane	180	250	250	265	302	264	222	170
Cellulosic	5	11	28	41	68	90	111	140
Total	1,383	1,383	1,377	1,373	1,370	1,354	1,333	1,310
% EtOH in Gasoline	10%	10%	10%	10%	10%	10%	10%	10%

Biodiesel

The table below shows the volume of biodiesel (by feedstock) consumed in the LCFS Enhanced Scenario.

Exhibit 25. Biodiesel Consumption in the LCFS Enhanced Scenario (million gallons)

Feedstock	2013	2014	2015	2016	2017	2018	2019	2020
Soy Oil	3	5	8	11	14	15	18	22
Waste Grease	19	29	47	51	51	51	51	51
Corn Oil	19	29	47	65	82	90	106	130
Canola Oil	3	5	8	25	45	54	72	100
BD , Total	45	67	110	151	191	209	247	303
Biodiesel Blend (%)	1%	2%	4%	5%	7%	8%	10%	12%

Renewable Diesel

The table below shows the volume of renewable diesel consumed in the LCFS Enhanced Scenario.

Exhibit 26. Renewable Diesel Consumption in Scenario 2 (million gallons)

Feedstock	2013	2014	2015	2016	2017	2018	2019	2020
Tallow	19	29	47	65	82	90	106	130

Natural Gas

The deployment of natural gas is the most aggressive in the LCFS Enhanced Scenario and reaches 1,500 million gge consumed in 2020, as shown in the table below.

Exhibit 27. Natural Gas Consumption in the LCFS Enhanced Scenario (million gge)

	2013	2014	2015	2016	2017	2018	2019	2020
CNG, medium-duty	23	36	48	60	72	83	92	101
Biogas, medium-duty	-	-	0	1	2	4	8	11
CNG, heavy-duty	285	443	594	742	888	1,019	1,132	1,249
Biogas, heavy-duty	-	-	6	15	27	54	98	139
Total	308	478	649	819	989	1,159	1,330	1,500

Advanced Vehicle Technologies: PEVs and FCVs

Advanced vehicle technologies were deployed assuming aggressive adoption in the LCFS Enhanced Scenario; the table below shows the consumption of hydrogen in FCVs and electricity in PEVs in gasoline equivalent volumes.

Exhibit 28. Hydrogen and Electricity Consumption in ZEVs in the LCFS Enhanced Scenario (million gge)

Vehicle	2013	2014	2015	2016	2017	2018	2019	2020
FCVs	1	1	2	5	8	11	15	21
BEVs	5	7	17	26	37	49	67	88
PHEVs	12	19	41	60	82	104	143	184
Total Adv Vehicles	18	28	61	92	127	165	225	293

Additional Credit-Generating Measures

For the LCFS Enhanced Scenario, additional LCFS credits were calculated for off-road electrification from forklifts and rail for marginal electricity from 2010 consumption. The marginal electricity credits were calculated using the ARB formula which includes diesel displacement. Scenarios 1 and 2 calculated all rail and forklift electricity without diesel displacement. Also, the LCFS enhanced scenario includes additional off-road LCFS credits from ports, small non-road, and truck related applications. These credits were calculated using the base formula which does not include diesel displacement.

ICF also considered LCFS credits that can be earned for purchasing crudes produced using innovative recovery methods, including renewable energy in steam used for extraction and carbon capture and storage.

The table below shows the annual number of credits generated in these two measures.

Exhibit 29. LCFS Credits Earned Through Off-Road Electrification and Innovative Crude Recovery Technologies

	2013	2014	2015	2016	2017	2018	2019	2020
Off-Road Electrification	609,380	624,368	641,487	677,025	684,570	719,512	726,821	765,276
Recovery credits	--	76,778	153,555	230,333	307,110	409,481	511,851	614,221

4. Alternative Fuels Market Assessment

The following subsections include more detailed market research and analysis considered in the development of LCFS compliance scenarios.

4.1. Ethanol

Low carbon intensity corn ethanol

The ethanol industry has already responded to the LCFS by investing in technologies that reduce the carbon intensity of products. Corn ethanol producers have submitted to CARB more than two dozen pathway documents for approval, each of which includes distinctive production processes that help achieve a lower carbon intensity score, including:

- Transition to wet distiller grains. Facilities that have wet distiller grains generally have a carbon intensity score nearly 7 g/MJ lower than for facilities that dry their distiller grains.
- Transition to natural gas. Facilities are seeking to displace energy produced from higher carbon sources by transitioning to natural gas. Similarly, some facilities are seeking to use biogas or biomass for on-site energy consumption.
- Cogeneration. Production facilities are increasingly seeking to use cogeneration at production facilities.
- Feedstock switching. Several corn ethanol producers are adding sorghum or milo to their production facilities to help lower the carbon intensity of ethanol produced. Other facilities have applied for approval of pathways that include wheat slurry.

California represents at least 10 percent of domestic gasoline consumption; with such a sizeable market share, and with LCFS-driven price premium, there is a significant incentive for ethanol producers to continue seeking innovative production processes and technologies that reduce their carbon intensity score. Furthermore, given the uncertainty associated with the availability of lower carbon biofuels e.g., from cellulosic feedstocks, regulated parties will seek out cost-effective reductions from corn ethanol producers where available in the near-term future.

California Corn Ethanol

The California ethanol industry has responded to the LCFS by seeking to reduce their carbon intensity significantly. Most California ethanol today is sold at a carbon intensity of around 80 g/MJ; while interviews with California ethanol producers indicate that they seek to reduce the carbon intensity of their products to 70 g/MJ over the next 3-4 years. There is good reason to believe that the LCFS will continue to drive innovation in California's ethanol production; and given the current carbon intensity of the fuel provided, ICF expects California's ethanol facilities to continue supply the domestic market at near-maximum capacity of around 200 million gallons.

For the purposes of this analysis, California ethanol volumes are reported as corn ethanol; however, there is potential for facilities to reduce their carbon intensity through feedstock switching. For instance, Pacific Ethanol reported that in the 3rd quarter of 2012, about 30 percent of its feedstock was sorghum. Furthermore, Pacific Ethanol has partnered with Edeniq to expand production through the installation of Edeniq's Cellunator™ - a technology that has the potential to improve yields at the plant by 2-4 percent. Similarly, Aemetis recently idled its 60 million gallon per year production plant in Keyes, California plant to upgrade the facility so that it can also operate using sorghum as a feedstock for ethanol production. Aemetis has since restarted its facility and announced a multi-year agreement with Chromatin to supply locally grown sorghum.

Edeniq is funded in part by a $3.9 million grant from the CEC's Alternative and Renewable Fuel and Vehicle Technology Program to help existing corn ethanol production facilities upgrade via addition of Edeniq's cellulosic ethanol production technology.

Brazilian sugarcane ethanol

For the purposes of this project, the ICF team sought to limit the import of Brazilian sugarcane ethanol to California at levels of 500 million gallons annually in an effort to minimize dependence on this compliance option. Even though this is a significant increase from the most recent volumes of Brazilian sugarcane ethanol imported to California (at least 90 million gallons in 2012), there are three reasons why our team is confident that Brazilian sugarcane ethanol will continue to play a significant role in compliance: 1) Brazil has sufficient capacity to meet demand for ethanol, 2) the fuel is priced competitively with corn ethanol, and 3) there is potential to lower the carbon intensity of sugarcane ethanol further. These issues are discussed in more detail here.

Brazilian sugarcane ethanol: Export capacity

Firstly, Brazil has sufficient capacity to export significantly higher volumes of ethanol. In 2012, Brazil exported approximately 800 million gallons of sugarcane ethanol, with about two thirds of that (530 million gallons) coming to the United States. The majority of Brazil's ethanol is exported from the Port of Santos and is either delivered to California via Los Angeles or San Francisco. It is also feasible for the ethanol to be imported via Houston and shipped to California via rail; however, it is unclear how common this practice is. The most recent data from EIA for 2013 indicate that fuel ethanol imports to the US are considerably higher than in the same period in 2012. Through the end of April 2013, the US has imported approximately 100 million gallons of fuel ethanol, up from just 23 million gallons over the same period last year. Furthermore, the likelihood of lower sugar prices and an abundant sugarcane crop for 2013 have led most analysts to project Brazilian ethanol production upwards of 7 billion gallons, up from 5.6 billion gallons over the last couple of years.[4]

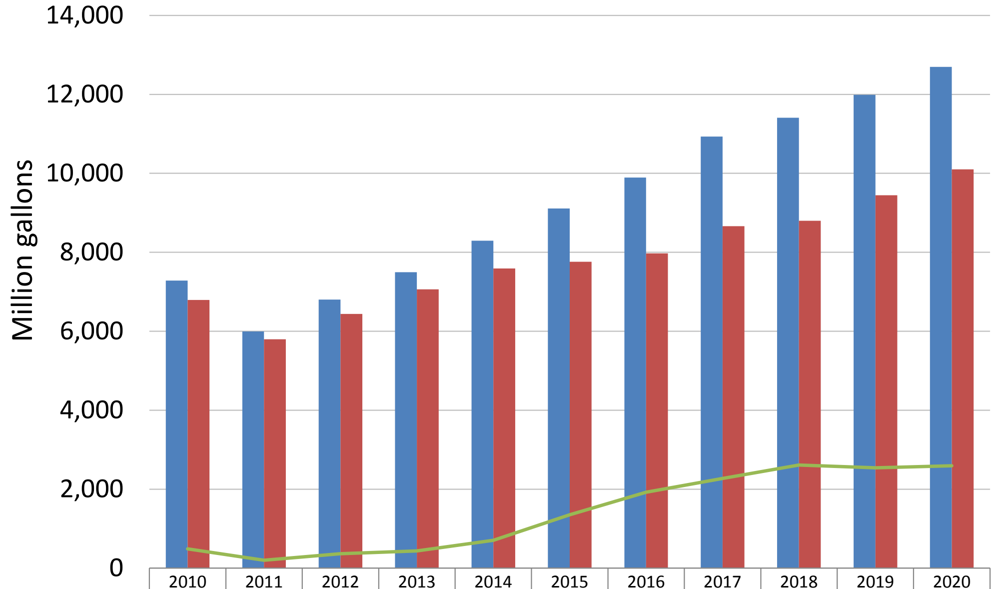
The figure below highlights the Organisation for Economic Co-operation and Development's (OEC) forecast of Brazil's production, consumption, and net export of ethanol out to 2020.[5] Note

[4] Irwin, S and Good, D. Brazilian Ethanol Imports – Implications for US Ethanol and Corn Demand. Farmdoc Daily, University of Illinois, Dept of Agricultural and Consumer Economics, May 2013. Available online at. http://farmdocdaily.illinois.edu/2013/05/brazilian-ethanol-implications.html

[5] OECD-FAO. "Agricultural Outlook: 2012-2021". OECD-FAO, 2012.

that even though production in 2012 was down from the forecasted 6.8 billion gallons, exports were more than double the forecasted 365 million gallons.

Exhibit 30. OECD Forecast of Brazil's production, consumption and net export of ethanol



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Production	7,284	5,997	6,805	7,495	8,294	9,111	9,896	10,932	11,408	11,987	12,695
Consumption	6,795	5,796	6,440	7,061	7,590	7,761	7,972	8,661	8,797	9,444	10,103
Net export	489	201	365	435	704	1,350	1,924	2,271	2,611	2,543	2,592

It is important to note that there will be other export markets for Brazilian sugarcane ethanol. For instance, the European Commission (EC) issued the Fuel Quality Directive (FQD), which requires a six percent reduction in the lifecycle carbon intensity of transportation fuels by 2020, similar to California's LCFS. The EC also has issued the Renewable Energy Directive (RED), which requires 10 percent renewable energy consumption in the transportation fuels market by 2020. Brazilian sugarcane ethanol is likely to play a significant role towards compliance with both of these directives. ICF recently prepared a report for the EC regarding the impact analysis of one of the key provisions of the FQD – in that work, the EC indicated that their internal forecast for Brazilian sugarcane ethanol consumption in the European Union was upwards of 1.3 billion gallons by 2020. Currently, Brazilian sugarcane ethanol exports to the EU are extremely small to non-existent in large part because of tariffs and increased transportation costs. The EU has an import tariff equivalent to about 50 cents per gallon[6] – considerably higher than the *ad valorem* tax (2.5 percent) that is imposed in the US, which is about 7 cents per gallon.[7] Secondly, ICF estimates that the transports costs to the US will continue to be cheaper than those same costs to the EU. Despite these barriers, it seems likely that exports of Brazilian sugarcane ethanol to the EU will increase to comply with the FQD, in part because of limited

[6] The tariff is €0.102 per liter and was converted using current exchange rates for illustrative purposes.

[7] The ad valorem tax is applied at 2.5percent of the value of the imported product, so the tax paid will fluctuate as a function of ethanol prices paid FOB Santos. The 7 cents per gallon is an average based on data from 2010-2012.

ethanol production capacity in the EU. This is one of the reasons that the team sought to limit the import of Brazilian sugarcane ethanol to California.

Brazilian sugarcane ethanol: Price Competitiveness

Recent spot price spreads between ethanol from Brazil (Santos FOB, $2.65 per gallon) and in California (San Francisco and Los Angeles, $2.86) indicate attractive pricing, even after accounting for transportation and a federally imposed *ad valorem* tariff (of 2.5 percent of the total value of the shipment). Even at LCFS credit prices of $40-45, Brazilian sugarcane ethanol produced from average processes (with a carbon intensity of about 74 g/MJ) would only command an 8-9 cent per gallon premium. When blended at 10 percent by volume with California Reformulated Blendstock for Oxygenate Blending (CARBOB), the additional cost is less than a penny per gallon.

Brazilian sugarcane ethanol: Low carbon ethanol

The GHG abatement potential of Brazilian sugarcane ethanol is significant. Even with an indirect land use change (ILUC) emissions factor of 46 g/MJ to its carbon intensity, the pathways for Brazilian sugarcane ethanol range from 58-79 g/MJ. This is one of the major drivers for Brazilian sugarcane ethanol imports to California because it is one of the most cost-effective compliance pathways for regulated parties. The carbon intensity of the sugarcane ethanol only stands to improve moving forward: By 2014, sugarcane producers in Sao Paolo, for instance, will be required to switch from manual harvesting to mechanized harvesting – a process that reduces local air pollution (the fields are burned before manual harvesting) and reduces the average carbon intensity from 73 g/MJ to 58 g/MJ.

Brazilian sugarcane ethanol consumption will likely be bolstered by the recent recommendation from CARB staff that a molasses-to-ethanol pathway be approved for LCFS compliance. Pantaleon Sugar Holdings is producing ethanol from molasses and estimated a carbon intensity of about 23 g/MJ, less than half of the lowest carbon intensity attributed to sugarcane ethanol using mechanized harvesting because it uses a byproduct of the sugar production process. The Pantaleon facility is based out of Guatemala. Given the demand for low carbon biofuels, it is possible that ethanol production facilities using Brazilian sugarcane ethanol – either in Brazil or in CBI countries – implement similar production capabilities to lower the carbon intensity of their product offerings.

Cellulosic ethanol

ICF developed projections for cellulosic ethanol in coordination with Environmental Entrepreneurs (E2). E2 considered the state of financing of various cellulosic ethanol facilities,[8] the likelihood that facilities would be completed, and their proximity to California to determine the maximum potential for cellulosic ethanol consumption in California.

[8] Solecki, M; Dougherty, A; and Epstein, B. Advanced Biofuel Market Report 2012: Meeting US Fuel Standards. Available online at: http://www.e2.org/ext/doc/E2AdvancedBiofuelMarketReport2012.pdf

- E2 identified 27 facilities that are in some advanced stage of financing. These facilities – if completed as announced – would have a combined production capacity of between 337 and 512 million gallons annually by 2015.
- ICF and E2 developed assumptions regarding increased penetration of cellulosic ethanol beyond the initial 27 facilities, increasing the potential capacity of cellulosic ethanol to slightly less than 600 million gallons by 2020.
- Most cellulosic ethanol plants are outside of California; therefore, ICF made assumptions about the percent of the production capacity that would be available to California refineries considering proximity to a cost-effective distribution infrastructure (e.g., rail) and other regulatory drivers (e.g., RFS2). For instance, INEOS Bio built the Indian River County BioEnergy Center, near Vero Beach, Florida – since it is unlikely that this fuel will be shipped to California, even with an LCFS-driven price premium, ICF did not take this facility into account.

ICF understands that there is considerable uncertainty regarding the availability of cellulosic ethanol to achieve California's LCFS. Cellulosic biofuel projects have been slower to come on-line than expected, falling well short of the volumetric requirements established by Congress in 2007 for the RFS2. CARB's original 2009 illustrative compliance scenarios were based, in part, on aggressive cellulosic ethanol volumes as well (even though the LCFS is performance based and allows the most lowest-cost technology to be utilized). Thus, the slower-than-expected advances in cellulosic biofuel production have dominated the discussion regarding both LCFS compliance and RFS2 compliance; however, the scenarios that ICF has developed highlight that cellulosic biofuels are part of a more diverse solution to GHG reductions in the transportation fuels sector. In this regard, the ICF team sought to limit the dependence of the compliance scenarios on cellulosic ethanol availability.

Despite the slower-than-expected deployment of cellulosic ethanol, there is evidence that the industry is looking up. For instance, Edeniq's cellulosic ethanol demonstration facility in Visalia, CA recently completed 1,000 hours of continuous operation, ahead of schedule and higher than projected production. Meanwhile, Zeachem's demonstration facility in neighboring Oregon has had continuous operation since mid-2012 and is producing 250,000 gallons annually, with plans to ramp up to 25 million gallons by 2014.

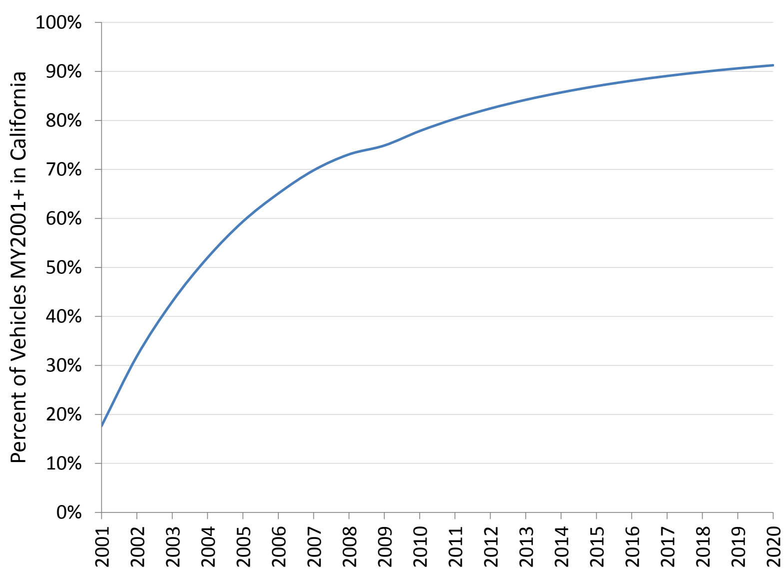
Even in a scenario in which cellulosic ethanol continues to struggle to achieve expected market penetration, innovation is occurring with other waste feedstocks. Most recently, Pantaleon Sugar Holdings applied for a pathway using molasses to produce ethanol with a carbon intensity of 22.75 g/MJ.

Higher blends of ethanol

As noted previously, reformulated gasoline includes 10 percent by volume ethanol. In order to achieve LCFS compliance, ICF considered the potential to move to higher blends of ethanol, including E15 and E85. ICF opted to focus on the introduction of E15 to increase ethanol volumes in California. The US EPA recently approved waivers for E15 consumption in model year 2001 and newer light-duty vehicles. There is considerable uncertainty today regarding the timing of E15 deployment in California. In order for the fuel to be sold in California, CARB would likely initiate a multi-media evaluation and would require modification of the predictive model used for gasoline formulations. Although original equipment manufacturers (OEMs) have strongly expressed hesitation regarding the use of E15 in vehicles, in order for regulated parties (i.e., refiners) to comply with the RFS2, they will likely have to move to higher blends of ethanol such as E15.

ICF used EMFAC2011[9] to estimate the percent of light-duty vehicles (passenger cars and light-duty trucks) that will be model year 2001 (MY2001) or newer by 2020, as shown in the figure below. ICF used this penetration curve to determine the maximum capacity of E15 that could be sold in California. As shown below, by 2018 90 percent of California's light-duty vehicle fleet is anticipated to be MY2001 or newer. An additional 600-650 million gallons of ethanol annually could be blended into gasoline by transitioning to E15.

Exhibit 31. Percent of Light-duty Vehicles MY2001 or Newer in California Fleet



We did not consider the potential for expanded E85 consumption in our scenarios. The potential expansion of the ethanol market via a transition to E15 is similar to the upper limit of an E85 market, assuming that flex-fuel vehicle (FFV) sales were to increase modestly over the next 5 years. Most recently, California drivers have consumed between 10-15 million gallons of E85 in FFVs. There are between 400,000 and 500,000 FFVs on the road in California today. This level of deployment indicates that theoretical consumption would peak around 240 million gallons if FFV drivers were to fuel their vehicles exclusively with E85.

One of the reasons we did not consider E85 more closely is because California drivers do not buy many FFVs. For instance, based on light-duty vehicle sales from 2012 reported by the California New Car Dealers Association (CNCDA), about 115,000-130,000 vehicles sold in California have FFV options. This does not mean that all of these vehicles sold were FFVs; rather, they had FFV models available. This represents about 8-10 percent of the market for

[9] The EMAFC model is issued by CARB and includes the emission factors that represent vehicle fleet, speeds, and environmental conditions associated with a project that are needed to perform project-level air quality modeling. More information is available online at: http://www.arb.ca.gov/msei/modeling.htm

light-duty vehicles and highlights one of the major challenges facing the E85 market: Of the top 10 top selling light-duty vehicles in California for 2012 – Toyota Prius, Honda Civic, Toyota Camry, Honda Accord, Toyota Corolla, Honda CRV, the Ford F-Series, Nissan Altima, Hyundai Sonata, and Toyota Tacoma – only the Ford F-Series offers a FFV model. These 10 models account for nearly 25 percent of the market, and only 7 percent of those sales (or 2 percent of the entire market) has an FFV alternative. In other words, absent changes in vehicle offerings from OEMs such as Toyota, Honda, and Nissan, it is unlikely that California's FFV population will increase significantly over the next 5 years.

4.2. Renewable Gasoline

Renewable gasoline is the term used for biomass-to-liquid processes – such as gasification, pyrolysis, or biochemical processes – that yield a product that can be used as a transportation fuel. The fuel is typically produced in several steps. For instance, fast pyrolysis of biomass yields a bio-oil that needs to be upgraded via hydrotreating; the stabilized oil can then be hydrocracked to produce renewable gasoline. Renewable gasoline is chemically similar to conventional gasoline, and in principle, can be distributed and combusted in the existing infrastructure and vehicles. For the purposes of this analysis, ICF assumed that 50 percent of the forecasted renewable gasoline produced in the United States would be available to California.

Companies such as Dynamic Fuels, KiOR, Sundrop, and UOP all are building commercial plants to manufacture these types of biomass-to-liquid fuels. Similarly, there are other firms, including Ensyn, Sapphire, and Solazyme that are seeking to produce a stable renewable oil from biomass or sugars that can be processed into renewable gasoline, renewable diesel, or renewable jet fuel. The long-term viability of renewable gasoline will be largely dependent on the ability of biofuel producers to reduce the costs of producing a stable oil for processing, which is currently the most expensive production process (see the table below).

Exhibit 32. Renewable Gasoline Production Costs via Pyrolysis (Haq, 2012)

Production Element	Production Costs ($/gallon)		
	2009 State of Technology	2012 Projection	2017 Projection
Feedstocks	$1.33	$0.99	$0.75
Feed drying, sizing, fast pyrolysis	$0.54	$0.52	$0.34
Upgrading to stable oil	$4.69	$2.01	$0.47
Fuel finishing	$0.30	$0.29	$0.11
Balance of plant	$0.82	$0.74	$0.65
Total	**$7.68**	**$4.55**	**$2.32**

Source: Haq, Z; Advanced Biofuels Cost of Production, October 2012. Available online at: http://www1.eere.energy.gov/biomass/pdfs/aviation_biofuels_haq.pdf

Although there have been significant advances in the production cost, the 2017 projections reported in the table above will require significant advances in technology and a stable supply of affordable feedstock. The $0.75 per gallon feedstock projection is equivalent to about $50 per dry ton of biomass; this is a commonly sourced estimate for the cost of biomass for biofuel production. However, ICF urges caution regarding cost projections for waste-based or byproducts because there is so much uncertainty in these markets. This uncertainty is attributable to the markets for many of these products being either emerging or nonexistent; therefore, it is unclear how market pricing will evolve. Despite these notes of caution, ICF's assumptions regarding the availability of renewable gasoline to the California market are conservative, and reach a maximum of about 90 million gallons by 2020.

4.3. Biodiesel

The significant potential for biodiesel to play a key role in LCFS compliance is being realized through a variety of industry investments. As a result of the LCFS and the recent extension of the Biodiesel Mixture Excise Tax Credit, 2013 promises to be a banner year for biodiesel consumption in California.

Biodiesel Production

The biodiesel industry has struggled in recent years with a significant portion of domestic capacity idled as a part of challenging economics. The extension of the tax credit for biodiesel blending will improve the industry's performance for 2013; however, the mid- to long-term outlook is unclear. In California, however, biodiesel consumption is poised to expand rapidly in large part due to very low levels of consumption in recent years (in the range of 20-25 million gallons in 2010, for instance).

There are several significant developments that have and will continue to support increased biodiesel consumption in California. Most notably, the low carbon intensity of biodiesel from corn oil reported by CARB in late 2011 has been a significant driver in the LCFS market to date. To a lesser degree, the low carbon intensity of other feedstocks such as recycled or waste oils has also played an important role in the early stages of LCFS compliance. Biodiesel consumption, mandated through RFS2, was 800 million gallons and one billion gallons in 2011 and 2012, respectively. Biodiesel production has exceeded these targets in both years, however, production volumes were about the same in 2011 and 2012.

As shown in the table below, the production of biodiesel from corn oil and recycled feedstocks were the only two to increase between 2011 and 2012. There is increasing evidence to suggest that these numbers are driven in part by California's LCFS, largely because these feedstocks yield biodiesel with a low carbon intensity. Furthermore, these feedstocks are generally cheaper than soy oil; for instance, corn oil has been selling in the range of 32-38 cents per pound for the past 18 months whereas soybean oil has been selling for closer to 50-55 cents per pound.

Exhibit 33. Feedstock Consumption for Biodiesel Production in the United States, 2011-2012

Feedstock	Feedstock Consumption for Biodiesel (million lbs)		
	2011	2012	Change
Canola Oil	847	787	-60
Corn Oil	304	571	267
Soybean Oil	4,153	4,023	-130
Animal Fats [a]	1,289	840	-449
Recycled Feeds [b]	666	900	234
Total	7,259	7,291	32

a. Includes poultry, tallow, white grease, and other.

b. Includes yellow grease and other.

Source: EIA

The nationwide potential for corn oil is significant: with a yield of approximately 5-7 gallons of corn oil per 100 gallons of corn ethanol, the upper limit of nationwide production is about 720 million gallons in 2020 according to the EIA. By the end of 2011, approximately 40 percent of ethanol production facilities in the US had corn oil extraction in place, and this likely increased further in 2012. ICF research indicates that nearly every corn ethanol production facility that can be retrofitted for corn oil extraction will have done so by the end of 2014. In California, for example, Pacific Ethanol announced plans in November 2012 to install a corn oil extraction system at its Stockton, California plant.

The scenarios developed for our study include 175-240 million gallons of corn oil biodiesel in 2020, representing a maximum of one third of domestic production in the same timeframe. With a carbon intensity of 4 g/MJ and LCFS credits trading at $40-45, the implied premium for corn oil biodiesel today is 47-53 cents per gallon. The LCFS market is likely to remain a strong driver for corn oil biodiesel consumption in California. Given that there is currently no parallel premium for corn oil biodiesel at the national or other state level, our team is confident that our assumptions regarding California consumption of corn oil biodiesel are conservative.

The scenarios also include about 50 million gallons of biodiesel produced from waste grease. Similar to corn oil, with a low carbon intensity and significant potential to expand the biodiesel market in California, we see the LCFS as a significant driver for biodiesel producers that can use feedstocks such as waste grease and animal fats.

In addition, the production of biodiesel in California has been boosted by awards from the CEC's Alternative and Renewable Fuel and Vehicle Technology Program. For instance, the program has awarded:

- Buster Biofuels received a $2.6 million grant for a production facility in the San Diego area that will produce about 5 million gallons per year.

- Eslinger Biodiesel Inc. received a $6 million grant to help build a biodiesel production facility in Fresno with an initial capacity of 5 million gallons per year, with potential expansion up to 45 million gallons per year.
- Springboard Biodiesel LLC received about $760,000 towards the construction of a pilot production facility in Chico with an annual production capacity of about 365,000 gallons.

Biodiesel Infrastructure and Vehicle Compatibility

With regard to infrastructure, pipeline operators and storage terminal operators are expanding storage capacity and biodiesel handling/blending capabilities significantly. As recently as 2010, the CEC reported that biodiesel terminal storage was severely limited.

Kinder Morgan made significant investments to expand biodiesel storage and delivery capacity at its Fresno and Colton terminals, with a reported throughput of 19 to 20 million gallons per year at each facility. As of late last year (2012), Kinder Morgan informed wholesalers that it will only sell B5 (a blend of 5 percent biodiesel with conventional diesel) at its Fresno and Colton facilities. Chevron made a similar announcement regarding the exclusive delivery of B5 at its facility in Montebello. Interviews with industry representatives indicate that at least four (4) refiners within California have proprietary terminals at which they are or have the capacity to blend biodiesel. ICF research indicates that there are at least 230,000 barrels of biodiesel storage capacity in California today. If we assume conservatively that these storage tanks have about 75 turns per year (i.e., the number of times each tank is emptied and filled) and that biodiesel represents about 15 percent of throughput at these facilities, then we estimate a biodiesel blending capacity of around 110 million gallons annually.

Based on ICF analysis and interviews with industry stakeholders, we anticipate storage capacity and blending capabilities in California to continue increasing over the next several years. The low-level biodiesel blend market (B5) will saturate around 200 million gallons per year. There is still significant potential to increase biodiesel blending beyond B5; however, higher blends of biodiesel will require more investment in retail infrastructure and consideration of engine manufacturer warranties, as discussed below.

- **Refueling infrastructure**. Most underground storage tanks (USTs) that are manufactured to store petroleum diesel blends can store B100 (i.e., pure biodiesel);[10] however, it's important to confirm that tank materials such as aluminum, steel, fluorinated polypropylene, and fiberglass make up the tank structure to ensure that degradation does not occur when using biodiesel. These materials must also be used in biodiesel fueling equipment to ensure that piping, spill and release detection equipment, dispensers, and dispenser nozzles are compatible with biodiesel blends.[11] Equipment materials that may lead to oxidation of biodiesel include brass, bronze, lead, zinc, tin, and copper. The U.S. EPA published final guidance on the subject in Volume 76, No. 28 of the Federal Register on July 5, 2011 to assist owners and operators of USTs in complying with the federal UST compatibility requirements promulgated under the authority of Subtitle I of the Solid Waste Disposal Act

[10] Petroleum Equipment Institute, UST Component Compatibility Library, Available online at: http://www.pei.org/PublicationsResources/ComplianceFunding/USTComponentCompatibilityLibrary/tabid/882/Default.aspx

[11] Oregon Department of Environmental Quality, "Biodiesel and Underground Storage Tank Systems", Available online at: http://www.deq.state.or.us/lq/pubs/factsheets/tanks/ust/BiodieselUSTSystems.pdf

(SWDA).[12] This guidance applies to biodiesel blends over 20 percent biodiesel that are stored in USTs. Currently, all newly manufactured USTs are compatible with blends of up to 100 percent biodiesel; however, EPA requires all UST manufacturers to provide a statement of compatibility for their products with biodiesel blends.

- **Engine warranties.** All diesel engine manufacturers selling into the US market provide warranties supporting blends of B20 or higher. The National Biodiesel Board has developed a summary table outlining OEM statements as they pertain to biodiesel blends – with the majority of engine manufacturers indicating that B20 can be used when it meets certain specifications such as ASTM D 6751 or fuel that is sourced from a BQ-9000 accredited producers.[13] Some notable exceptions of vehicle manufacturers that do not warranty above B5 include Kenworth and Peterbilt. Both are divisions of PACCAR Inc., which are still studying approvals for their trucks. It is also noteworthy that the engine manufactures supplying PACCAR have already approved B20.

The CEC has invested a modest amount of funding from the Alternative and Renewable Fuel and Vehicle Technology Program in biodiesel infrastructure, including:

- Pearson Fuels, in partnership with SoCo Group Inc. and InterState Oil Company received $1.8 million in grant funding to build two new biodiesel terminals with in-line blending capabilities.
- Whole Energy Pacific received about $125,000 to design, build, and install a biodiesel blending facility in Richmond, CA.

4.4. Renewable Diesel

Renewable diesel is similar to renewable gasoline in that it is produced via biomass-to-liquid processing. Renewable diesel, however, is currently being produced, primarily via hydrogenation of bio-oils, in commercial quantities and being consumed in California. In terms of chemical and physical properties, renewable diesel meets all the requirements of ASTM D975; in fact, Neste Oil's NExBTL product meets the fuel quality specifications of CARB diesel, meaning no modifications are needed to existing storage and transport infrastructure.

Neste Oil has been the most aggressive producer shipping renewable diesel to California. In 2010, Neste invested billions of dollars to build renewable diesel production plants in Singapore and Rotterdam (the Netherlands), in addition to facilities in Finland. All four of these facilities are operational; the Singapore plant is well situated to deliver renewable diesel fuel to California. It has been estimated that Neste will deliver about 100 million gallons of renewable diesel to consumers in California in 2013. Neste's NExBTL process is capable of using multiple feedstocks: Although the Singapore facility uses palm oil, which does not have a pathway under California's LCFS, the facility also uses tallow from Australia. The tallow based renewable diesel has a carbon intensity of around 33 g/MJ.

The renewable diesel industry will be expanding significantly in the near-term with the completion of Diamond Green's production facility in Norco, Louisiana. Diamond Green – a joint

[12] Federal Register, "Volume 76, No. 2", July 5, 2011, http://www.gpo.gov/fdsys/pkg/FR-2011-07-05/pdf/2011-16738.pdf

[13] Available online at: http://www.biodiesel.org/using-biodiesel/oem-information/oem-statement-summary-chart

venture between Valero and Darling International Inc – has a reported production capacity of 137 million gallons per year. Although the project is behind schedule, the most recent reports indicate that the facility will be online by the second quarter of 2013. Diamond Green has indicated to CARB that it plans to use four feedstocks for renewable diesel production at its facility: soy oil, corn oil, used cooking oil, and animal fat.[14]

4.5. Natural Gas

To develop natural gas projections, ICF consulted with the natural gas transportation fuel industry, analyzed trends within the natural gas market place and used the National Petroleum Councils Future Transportation Fuels Study.[15]

Recent advances in technology used to extract natural gas have drastically changed the landscape for natural gas in many applications. In the transportation sector, ICF considered the potential for increased natural gas consumption given the dramatic increases in supply, an expanding retail fueling infrastructure, and more vehicle offerings. Furthermore, the long-term potential for significant GHG reductions from natural gas in the transportation sector is tied to the deployment of biogas.

Increased Supply of Natural Gas

The increased discovery and production of shale gas reserves in the United States, including the Monterey Shale in the San Joaquin Basin, has decreased the cost of natural gas for all applications including electricity generation and transportation. Natural gas can be used as a transportation fuel as both compressed (CNG) and liquefied (LNG). CNG is favored in medium and light heavy-duty applications where there is a lower VMT per day and refueling can take place each night. This includes many local and regional commercial fleets and transit bus applications. LNG is preferred for heavy-duty applications with higher VMT such as long-haul trucking due to the increased energy density over CNG that requires less refueling.

Natural gas, due to its much lower fuel price, has the potential to contribute significantly to the future transportation fuel mix in California. This is especially true in Southern California where natural gas is required in certain market segments that include refuse applications. The greatest potential market for natural gas is in the medium and heavy duty commercial fleet and transit agency market segments, with significant annual VMT and a heavy emphasis on lifecycle cost. The higher annual VMT takes advantage of the lower fuel price compared to gasoline (medium-duty) and diesel (heavy-duty) and decreases the time needed for payback of the increased vehicle costs.

Expanding Retail Infrastructure

There are still limitations on natural gas as a transportation fuel including infrastructure and vehicle costs. Both CNG and LNG require additional and costly infrastructure to expand access.

[14] More information is available online at: http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/dgd-sum-120112.pdf

[15] NPC Future Transportation Fuels Study: Advancing Technology for America's Transportation Future. Available online at: http://www.npc.org/FTF-80112.html

Natural gas' future in the transportation fuel market is evidenced by significant industry investments in refueling infrastructure. Clean Energy Fuels has teamed up with Pilot Flying J truck stops to create a nationwide network of natural gas refueling stations called America's Natural Gas Highway. As of February, the first 70 of the planned 150+ stations have been constructed. In addition, Clean Energy built 127 stations in 2012 for transit, refuse and airport applications. Shell has an agreement to build refueling stations at as many as 100 TravelCenters of America and Petro Stopping Centers and ENN, a privately held Chinese company, hopes to build 500 filling stations.[16]

To date, the CEC has awarded over $16 million towards natural gas fueling infrastructure through the Alternative and Renewable Fuel and Vehicle Technology Program.

Increased Vehicle Availability

On the vehicle side, UPS is seeking to increase their use of LNG vehicles over seven fold – from 112 to 800 – by the end of 2014, and companies such as Walmart are testing the use of natural gas[17] in their California fleet. Cummins-Westport is the main manufacturer of heavy-duty natural gas engines to date; they recently announced the availability of the Cummins ISX12 G engine, which will be in full production by August 2013. Cummins Westport also announced that it is developing the ISB6.7, a mid-range 6.7 L engine with plans for full production by 2015.

Apart from development in the heavy-duty engine market, there are an increasing number of natural gas vehicle offerings in lower weight categories. For instance, GM introduced the bi-fuel Chevrolet Silverado and GMC Sierra 2500 HD; these packages start at around $11,000. Meanwhile, Chrysler is offering the Ram 2500 CNG to retail customers. Similarly, Westport Innovations now has conversion kits for Ford's F series of medium-duty trucks – one of the top 10 selling vehicles in California during 2012 – at a retail price of $9,500. Wesport's WiNG technology is a bi-fuel system that has been demonstrated and deployed with success in the F-250 and F-350 models; and Westport recently announced that they are expanding the offering to the F-450 and F-550 trucks.

At price increments of $9,500-$11,000 and using current fuel pricing forecasts with natural gas about half to two thirds the cost of diesel, most consumers will see a two-to-three year payback period, which will push sales of natural gas vehicles higher.

Cummins Westport's advances in heavy-duty engines and increased OEM and conversion kit offerings in medium-duty trucks portend significantly higher sales of CNG and LNG in the near-term future. The volumes of natural gas in each of the compliance scenarios only require modest increases in new vehicles sales. For instance, if natural gas vehicles were able to capture 10-15 percent of new vehicles sales by 2020 in targeted vehicle segments, then this would displace upwards of 600 million gge. This would be in addition to California's existing natural gas consumption in the transportation sector of around 120 million gge.

[16] http://www.nytimes.com/2013/04/23/business/energy-environment/natural-gas-use-in-long-haul-trucks-expected-to-rise.html?pagewanted=all&_r=1&

[17] http://www.walmartstores.com/sites/responsibility-report/2012/fleetImprovements.aspx

To date, the CEC has awarded more than $28 million to natural gas vehicles within California through the Alternative and Renewable Fuel and Vehicle Technology Program.[18]

Biogas: Transition to a Lower Carbon Fuel

In the context of the LCFS, another driver for increased use of natural gas is biogas.[19] Biogas converted to CNG and LNG has some of the lower carbon intensity values evaluated by CARB. There is growing interest from regulated parties and natural gas fueling companies to invest in biogas projects since they have the potential to be a significant source of LCFS credits. Based on conversations with industry sources and operational projects sending biogas to California, an estimated 10 percent of natural gas used as a transportation fuel will be coming from biogas due to the LCFS.

4.6. Advanced Vehicle Technologies: PEVs and FCVs

Electricity and hydrogen used PEVs and FCVs, respectively, promise to play significant roles in LCFS compliance, particularly in the later years of program implementation. By 2020, estimated electricity and hydrogen consumption associated with PEV and FCV deployment in CARB's most likely compliance scenario account for nearly five percent of all credits generated.

Vehicle Sales

CARB's most likely compliance scenario yields about 500,000 ZEVs by 2020. Scenario 1 includes 1.13 million ZEVs and the LCFS Enhanced Scenario includes 1.31 million ZEVs by 2020. The projections for Scenario 1 are consistent with the types of sales that would be needed to achieve the long-term goal of the Governor's ZEV Action Plan,[20] which would yield 1.5 million ZEVs on the road by 2025.

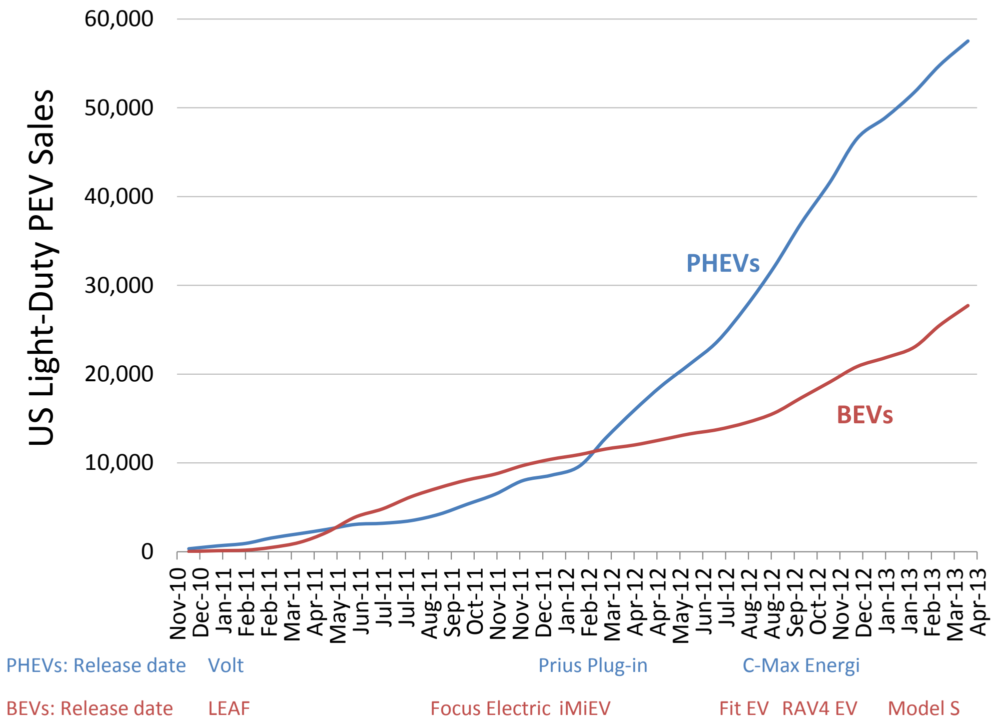
PEV sales in the US have been below some analysts' expectations; however, the initial data indicate that the vehicles are selling at a better rate than the original deployment of hybrid electric vehicles (HEVs) in the early 2000s. Moreover, sales have been bolstered by far more PEV offerings compared to the initial launch of HEVs (see figure below for cumulative PEV sales in the US; the model of vehicles at the bottom of the graph indicate when those became commercially available): Each major OEM is now selling either a PHEV or BEV, and they are competing with upstarts such as Tesla Motors.

[18] http://www.energy.ca.gov/2012publications/CEC-600-2012-008/CEC-600-2012-008-CMF.pdf

[19] Biogas is the gaseous product of anaerobic digestion (decomposition without oxygen) of organic matter.

[20] 2013 ZEV Action Plan: A roadmap toward 1.5 million zero-emission vehicles on California roadways by 2025, Office of Planning and Research. First Draft available online at: http://opr.ca.gov/docs/Governor's_Office_ZEV_Action_Plan_(02-13).pdf

Exhibit 34. Cumulative PEV Sales in the United States through April 2013



Most analysts estimate that about 35-40 percent of PEV sales nationwide are in California. Consumers are drawn to incentives such as rebates of $1,500 for PHEVs and $2,500 for BEVs from the Clean Vehicle Rebate Project (CVRP) and the Green or White Clean Air Vehicle Stickers that provide single occupant vehicles use of high occupancy vehicle (HOV) lanes. The CVRP has been so successful that CARB and CEC recently agreed to add $6 million and $4.5 million respectively to the rebate program's funds to extend the availability of funds until next year's funds are available. Even with the success of the CVRP, conversation with staff at the California Center for Sustainable Energy (CCSE), which administers the CVRP, indicate that there are still a significant number of PEV buyers do not take advantage of the rebate program. CCSE worked with OEMs to determine that in some cases, only 75 percent of owners of select PEVs apply for the rebate.

The PEV deployment scenarios assume that OEMs will continue to have more vehicle offerings at more attractive pricing out to 2020. The more aggressive scenarios include higher penetrations of PHEVs, with more modest increases in BEVs and FCVs. This reflects the automotive industry's focus on PHEV technology. For instance, in a recent survey of automotive industry executives, KPMG reports that 29 percent of OEMs and 23 percent of suppliers are making the biggest investments in plug-in hybrid technology over the next five years, second only to investments in internal combustion engine (ICE) downsizing (see table below).[21]

[21] KPMG's Global Automotive Executive Survey 2013: Managing a multiidimensional business model. Available online at: http://www.kpmg.com/SK/en/IssuesAndInsights/ArticlesPublications/Documents/Global-automotive-survey-2013.pdf.

Exhibit 35. Percentage of OEMs and Suppliers Making Investments in Powertrain Technologies in the Next 5 Years

Powertrain technologies	OEMs	Suppliers
ICE downsizing	31%	24%
Plug-in hybrid	29%	23%
Hybrid fuel systems	18%	11%
Battery (range extender)	10%	18%
Pure battery	6%	13%
Fuel cell	6%	11%
Source: KPMG Global Auto Executive Survey 2013		

Some OEMs have already taken aggressive measures to increase PEV sales. For instance, Nissan LEAF cut the price of the LEAF by $6,400 in 2013, leading to a significant resurgence in sales approaching 5,500 vehicles in the first four (4) months of 2013, or 2.5 times more LEAFs sold in the same period in 2012. Information from Tesla's recent first quarter filings also indicate the competitive nature of the PEV industry. Tesla's first quarter earnings were bolstered considerably by the sale of ZEV credits to other OEMs. Tesla's financial filings indicate sales of $68 million of ZEV credits;[22] each of Tesla's vehicles generated five ZEV credits because their vehicles have a range greater than 200 miles. With estimated sales of 4,900 vehicles, this values the credits at about $14,000 per vehicle. Going forward, there will be a strong financial incentive for other OEMs to develop ZEVs rather than paying out such large sums to competitors like Tesla.

Vehicle sales will likely also be bolstered by decreasing battery prices. Apart from technological improvements and economics of scale, the global capacity of lithium-ion battery manufacturing is drastically over-supplied. For 2013, global production capacity is estimated to be nearly 4,000 MW; however, the demand for batteries is an order of magnitude less – around 400 MW. This over-supply will likely lead to industry consolidation in the next several years and may yield lower battery prices.

CARB and CEC continue to report via surveys of major OEMs that they are planning on rolling out tens of thousands of hydrogen fuel cell vehicles in California over the next 2-4 years. As recently as 2012, OEMs indicated that they plan on achieving sales upwards of 55,000 vehicles by 2017 in California. These numbers are bolstered by action: Hyundai recently announced the limited assembly-line production of its ix35 FCV, and although the vehicle will likely be sold in Europe for the first several years of production, it portends positive developments in the fuel cell vehicle industry.

Fueling Infrastructure for ZEVs

There has been a major push to deploy sufficient infrastructure for PEV and FCV adoption:

[22] Tesla Motors Inc – First Quarter 2013 Shareholder Letter. Available online at: http://tinyurl.com/Tesla1Q

- Level 2 Electric Vehicle Supply Equipment (EVSE) and DC fast charging EVSE are being deployed rapidly around the State of California using grant funding provided by the Department of Energy (DOE) and CEC. Many EVSE were deployed as part of ECOtality's EV Project and Coulomb Technologies' ChargePoint America.
- Furthermore, another $100 million will be spent by NRG as part of a settlement with the California Public Utilities Commission (CPUC) – these funds are dedicated to installing at least 200 so-called Freedom Stations (i.e., DC fast charging EVSE) and 10,000 Make-Readies (i.e., the pre-wiring and conduit required for Level 2 EVSE).
- The CEC is coordinating the deployment of hydrogen fueling stations with funding from the Alternative and Renewable Fuel and Vehicle Technology Program. Current estimates indicate that about 20 publicly available stations will be online by the end of 2013, up from eight today.

4.7. LCFS Enhancements

Electricity Consumed in Non-Road Applications

CARB is actively considering proposed changes to LCFS for electricity used in fixed guideway transportation applications and for forklifts. CARB staff are using a methodology similar to the one developed by ICF staff (previously with TIAX LLC) for CalETC as part of another project.[23]

- For electricity used in fixed guideway applications, the National Transit Database was used to calculate energy consumption per mile for transit agencies in California. These data were coupled with ridership data from Los Angeles Metropolitan Transportation Authority (Metro) and Bay Area Rapid Transit (BART). The research team accounted for planned and implemented rail expansions by holding the ratio of passenger to track miles constant for each transit agency.
- For electricity used in forklifts, the research team developed population estimates based on US factory shipments of electric rider (Class 1 and 2) and motorized hand (Class 3) forklifts from 2000-2010. These shipments were pro-rated (conservatively) based on population statistics to develop California-specific estimates. The potential LCFS credits that could be generated were based on an EER of 3.0, assuming that electricity is replacing diesel, an operational frequency of 3,150 hours per year, and an average daily load of 4.36 kW for Class 1 and Class 2 and 1.25 kW for Class 3.

CARB is actively developing the methodology to present to the Board regarding electricity used in fixed guideway applications and forklifts. These areas have significant potential to increase the number of LCFS credits available and improve the outlook for LCFS compliance.

Innovative Crude Recovery Methods

Pursuant to the November Final Regulatory Order for the LCFS, [24]

[23] California LCFS Electric Pathway – On-Road and Off-Road. TIAX LLC, November 2012. Available online at: http://www.caletc.com/wp-content/uploads/2012/12/TIAX_CalETC_LCFS_Electricity_Potential_FINAL.pdf

[24] http://www.arb.ca.gov/fuels/lcfs/CleanFinalRegOrder112612.pdf

> A regulated party may receive credit for fuel or blendstock derived from petroleum feedstock which has been produced using innovative methods. For the purpose of this section, an innovative method means crude production using carbon capture and sequestration or solar steam generation that was implemented by the crude producer during or after the year 2010 and results in a reduction in carbon intensity for crude oil recovery (well to refinery entrance gate) of 1.00 gCO2E/MJ or greater.

Crude oil recovery in California utilizes a significant amount of steam production through its steam flooding and cycling steam injection operations. The California Department of Conservation Oil and Gas production data from January 2011 to June 2012 show 1,300 thousand barrels per day of steam is utilized for crude production. According to the 2009 Annual Report of the State Oil and Gas Supervisor,[25] Forty two percent of steam produced for oil recovery in California comes from cogeneration and the balance from simple once-through steam generator (OTSG). The steam from OTSG is the potential market for renewable steam generation and carbon capture and storage (CCS). ICF estimated the potential credits generated through innovative crude oil recovery based on work that ICF staff (previously working for TIAX LLC) conducted for NRDC.[26] The research included the following assumptions:

- Renewable steam generation technologies such as BrightSource and GlassPoint could offset GHG emissions from combustion and upstream sources while CCS could only sequester those emissions from combustion.
- Based on the Oil Production Greenhouse gas Emissions Estimator (OPGEE) developed by Stanford University for CARB, OTSG requires 401,537 Btu of natural gas/bbl of steam and 1.9×10^8 MMBtu per year of natural gas. From the CA-GREET model, an estimated 66,677 gCO2e/MMBtu are a result of upstream production and transport of natural gas and combustion while 58,350 gCO2e/MMBtu are a result of combustion alone.
- In their analysis, TIAX did not assume an increase in steam production between 2012 and 2020.
- Furthermore, TIAX assumed a maximum total market share of 10 percent of OTSG steam production in 2020 in California is converted to renewable steam generation and CCS and is split equally between them. Because the standard is performance-based, crude production from other regions could also incorporate similar technologies. This potential was not analysed in this study.

Other GHG reduction options along the supply chain for conventional fuels, including reduced venting, flaring, and leakage were not considered. Moreover, improvements to petroleum refinery energy efficiency, the use of combined heat and power, and incorporation of renewable feedstocks or energy inputs at refineries were not included in this analysis. These types of GHG reduction measures are not currently eligible to receive a carbon intensity reduction under the LCFS.

[25] 2009 Annual Report of the State Oil & Gas Supervisor, California Department of Conservation, 2010. Available online at: ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2009/PR06_Annual_2009.pdf

[26] California Low Carbon Fuel Standard (LCFS): Potential Emission Reductions from Petroleum, TIAX LLC for National Resources Defense Council, February 2013.

5. Next Steps

The first phase of this project has focused on developing LCFS compliance scenarios, harnessing a combination of existing market data with realistic projections of the availability of low carbon fuels out to 2020. These scenarios demonstrate how the LCFS requirements can be achieved through modest changes in the diversity of transportation fuels supplied to California.

5.1. Overview of Macroeconomic Modeling

The second phase of this project focuses on the macroeconomic impacts of the compliance scenarios presented here. ICF is using the REMI model to perform the economic modeling. The REMI model is well suited to assess the dynamic impacts of assessing regulations with impacts into the future, such as California's LCFS. With impacts out to 2020, it is important to have a dynamic model that allows for behavior such as technological change and adaptation. The modeling is performed by determining the changes in economic parameters relative to a reference scenario (or a business-as-usual scenario). Each scenario has associated expenditures in areas such as industry investments required to deploy alternative fuels and consumer expenditures associated with fuel consumption or vehicle purchases. The types of parameters that the macroeconomic impact analysis will consider in detail include the following:

- Changes in gross state/regional product
- Changes in employment and income
- Changes in total economic production
- Inter-industry and aggregate impacts

5.2. Other economic and environmental impacts

Although the second phase of the project focuses on macroeconomic impacts, the ICF team is also assessing the air quality and GHG benefits of the compliance scenarios. Our assessment includes the emission reductions and the corresponding monetization of those benefits. More specifically, our team is investigating the following impacts:

- **Air quality pollutants**: Pollutants are generally considered negative externalities and researchers have attempted to capture the value of avoided emissions in the form of health and environmental benefits. The EPA has developed cost per ton estimates of the health benefits achieved by reducing criteria air pollutant emissions. The health benefits of reducing transportation-related emissions will depend on a large number of local factors, including the overall levels of pollution in the area and the presence of individuals sensitive to air pollution, among others. Further, the unit risk factors, i.e. the estimated health damage per unit of emissions, for several of the emissions are still a matter of research as state and federal agencies differ on their values.
- **GHG emissions**: Recently, estimates have been developed to monetize the benefits of reducing GHG emissions via a parameter termed the social cost of carbon (SCC). The SCC is an economic parameter employed to estimate the economic cost of an addition ton of CO_2-equivalent emissions. More precisely, this term is the "change in the discounted value

of the utility of consumption denominated in terms of current consumption per unit of additional emissions".[27] Most recently, the US government concluded a year-long process to develop a range of values for SCC and these values are to be used in benefit-cost analyses to assess potential federal regulations. In 2007 dollars, the recommended central value is \$21/ton of CO_2 emissions; the final report also recommends conducting sensitivity analyses conducted at \$5, \$35, and \$65.[28]

- **Reduced petroleum dependence**: Paul Leiby at the Oak Ridge National Laboratory (ORNL) estimated the energy security benefits of reduced US oil imports.[29] The research focuses on two components of energy security benefits: monopsony and macroeconomic disruption or adjustment costs. The benefit of displacing imported oil is reported with a mid-point of nearly \$14 per barrel of oil (in 2004 dollars). For the sake of comparison, based on information available from the EIA, about 50% of the oil refined to produce gasoline and diesel is imported. For illustrative purposes, this yields a monetized benefit of reduced U.S. oil imports of about \$0.81 per gallon of diesel or gasoline after adjusting for inflation, with a low/high scenario of \$0.40 and \$1.39 per gallon.

[27] *Estimates of the social Cost of Carbon: Background and Results from the RICE-2011 Model*, Discussion Paper No. 1826, October 2011.

[28] Greenstone et al. *Estimating the Social Cost of Carbon for Use in U.S. Federal Rulemakings: A Summary and Interpretation*, Working Paper No. 16913, December 2011

[29] Leiby, P. Estimating the Energy Security Benefits of Reduced U.S. Oil Imports, Oak Ridge National Laboratory, ORNL/TM-2007/028, 2007. Available online at: http://www.epa.gov/otaq/renewablefuels/ornl-tm-2007-028.pdf

California's Low Carbon Fuel Standard: Compliance Outlook & Economic Impacts

Final Report

April 2014

Prepared for:

California Electric Transportation Coalition

California Natural Gas Vehicle Coalition

Environmental Entrepreneurs

Advanced Biofuels Association

National Biodiesel Board

Ceres

Outline

- Introduction
- Review of Compliance Scenarios
- Introduction to REMI Modeling
- Review of Model Inputs
- Fuel Pricing and LCFS Credit Pricing
- REMI Modeling Results
- Monetized Externalities
- Summary and Conclusions

Introduction

California's Low Carbon Fuel Standard

- In 2007 Governor Schwarzenegger signed Executive Order S-01-07 establishing California's Low Carbon Fuel Standard (LCFS), which requires a ten percent reduction in the carbon intensity of transportation fuels by 2020.
- The LCFS is a flexible market-based standard implemented using a system of credits and deficits:
  - **Carbon intensity** is measured on a lifecycle or well-to-wheels basis in units of grams of carbon dioxide equivalent per unit energy of fuel (gCO2e/MJ).
  - The LCFS is implemented using a system of **credits and deficits**. Fuels with a carbon intensity lower than gasoline and diesel earn credits. Gasoline and diesel generate deficits.
  - At the end of each year, compliance is achieved by offsetting deficits with credits. Credits can be banked and traded, and they do not lose value over time.

Scope of Work

- The objective of this study was to characterize the macroeconomic impacts of LCFS compliance, and the co-benefits. This study had two phases.
- In the first phase of work, ICF developed scenarios that represent a range of likely outcomes towards LCFS compliance.
  - Scenarios are intended to capture the range of potential market developments that would lead to LCFS compliance given our current outlook on the transportation fuel marketplace.
  - In any forward-looking exercise, it is important to note that there is some uncertainty associated with the availability of lower carbon fuels.
- In the second phase of work ICF characterized the macroeconomic impacts and associated co-benefits of LCFS compliance.
  - Macroeconomic impacts were estimated using the REMI model
  - The co-benefits we considered include: GHG emission reductions, criteria pollutant emission reductions, and petroleum reductions.

Review of Compliance Scenarios

Scenario Analysis

- ICF developed a reference scenario and two LCFS compliance scenarios, referred to as Scenario 1 and Scenario 2, in the first phase of our work to estimate the macroeconomic impacts of the LCFS. The stakeholder group developed the final compliance scenario, referred to as the LCFS Enhanced Scenario. The macroeconomic impacts reported are based on the difference between the compliance scenario and the reference scenario.
- A more detailed review of the scenarios, including the fuel volumes, forecasts, compliance options considered, and an alternative fuel market assessment are available in a separate report. That report is available online at: http://www.caletc.com/wp-content/downloads/LCFSReportJune.pdf

REVIEW OF COMPLIANCE SCENARIOS

Summary Table

Scenario	Ethanol	Biodiesel	Adv Biofuels	Electricity / Hydrogen	Natural Gas	Assumptions for all scenarios
Reference Scenario	Limited to E10. Mostly MW corn ethanol.	Very limited; about 25 million gallons	Federal RFS2 identified as only major driver for consumption in California absent LCFS	ZEV Program: most likely compliance scenario; about 500,000 ZEVs on the road by 2020: 26k FCVs, 120k PHEVs, 350k BEVs	Based on CEC projections: about 220 million gallons	Constrained low carbon corn ethanol at 1 billion gallons (200 MGPY in California). Assumed 56% of VMT in PHEVs is electric. Banking/trading of credits is included in our analysis. Over-compliance in early years. Significant room for over-compliance in diesel sector.
Scenario 1	Ethanol blend increased from E10 in 2019-2020. Assume some E15 is consumed. 500 MG sugarcane ethanol.	420 million gallons blended into diesel by 2020: soy, waste grease, corn oil, canola.	410 MG cellulosic ethanol 89 MG drop-in gasoline substitute 125 MG renewable diesel	Proportionally similar distribution to most likely compliance scenario; total of 800k vehicles. Electricity consumed in forklifts and fixed guideway applications included	Aggressive introduction of CNG/LNG in MD/HD sectors. 900 million gallons consumption by 2020. 10% RNG consumption.	
Scenario 2	Limited to E10. 500 MG sugarcane ethanol.	560 MG blended into diesel by 2020: waste grease, corn oil, canola.	430 MG cellulosic ethanol 89 MG drop-in gasoline substitute 220 MG renewable diesel	ZEV Program compliance Electricity consumed in forklifts and fixed guideway applications included	Modest increase in CNG/ LNG consumption. 650 million gallons consumed. 10% RNG consumption.	
LCFS enhanced	Limited to E10. 230 MG sugarcane ethanol	440 MG blended into diesel by 2020: soy, waste grease, corn oil, canola.	50 MG cellulosic ethanol 89 MG drop-in gasoline substitute 130 MG renewable diesel	Accelerated adoption scenario: 1.2 million PEVs on the road by 2020 Electricity consumed in forklifts, fixed guideway, port equipment, e-TRUs, TSE, small non-road applications included	1.1 billion gallons consumption by 2020. 10% RNG consumption.	Includes credits earned through enhanced crude oil recovery techniques e.g., solar powered steam.

Introduction to REMI Modeling

REMI Model Description

ICF employed the REMI Policy Insight Plus v1.4 to measure the wider macroeconomic impacts of the compliance scenarios developed in this study. Some key aspects of the REMI Model:

- Peer reviewed structural economic modeling, forecasting and policy analysis tool
- Dynamic regional economic impact model using a combination of input-output, econometric, and computable general equilibrium techniques
- 70 NAICS-based sectors, 2 regions
- Ability to forecast impacts over time
- All results are presented in 2020 for this study

REMI Model Description, ctd

- REMI can produce a wide variety of economic and demographic outputs:
  - overall employment levels
  - employment by industry sector
  - value added output
  - output by sector
  - changes in income
  - population or demographic shifts.
- This study focused on analyzing the impacts to employment, personal income, and gross state or domestic product (GSP or GDP).
- Inputs to the REMI model for each scenario were derived from the outputs of ICF analysis of each compliance scenario. For example, the compliance scenarios modeled in REMI included expenditures for fuel production, distribution infrastructure (including transportation, storage, retail infrastructure, vehicles, and fuel pricing.

Overview of Model Inputs

Introduction

ICF developed estimates for the investments that would be required to achieve the compliance scenarios. ICF considered three broad types of expenditures:

- **Fuel production / upstream expenditures:** Many of the alternative fuels will require significant investments in expanded production. To the extent feasible, ICF identified production that would happen in California and the rest of the United States.

- **Distribution infrastructure expenditures:** While the compliance scenarios include drop-in fuels that are compatible with existing distribution infrastructure such as renewable diesel and renewable gasoline, other fuels will require infrastructure in storage terminals and refueling equipment. Distribution infrastructure costs were modeled as an increase in exogenous final demand for industries involved in equipment manufacturing or building new infrastructure.

- **Vehicle expenditures:** In the case of electricity, hydrogen, and natural gas, new light- and heavy-duty vehicles will need to be purchased to achieve the levels of fuel consumption included in the penetration scenarios.

Overview of Alternative Fuel Investments

Fuel	Fuel Production	Distribution infrastructure	Vehicle Expenditures
Ethanol	Yes; feedstock specific. Continued CA production, most from Rest of US	E15 infrastructure for S1	N/A; MY2001+ can use E15
Renewable Gasoline	Yes; focused on biomass feedstock. Produced outside of CA	N/A; drop-in fuel	N/A; drop-in fuel
Biodiesel	Yes; feedstock specific. Increased utilization in CA, balance produced in Rest of US	Yes; terminal storage, blending equipment, fueling stations	N/A; overwhelming number of diesel engines warrantied for use up to B20
Renewable Diesel	Yes; focused on tallow. Produced outside of CA	N/A; drop-in fuel	N/A; drop-in fuel
Electricity	Yes; small b/c assumed significant TOU charging and increased utilization of assets	EVSE (L1, L2, DC fast)	PEV cost curves from CalETC study (Roland-Holst 2012) Included federal tax credit
CNG	No; transportation is small fraction of total production	Yes; mix of slow- and fast-fill stations	NGVs in medium-, and heavy-duty sectors
LNG	Yes; mostly liquefied outside of CA	Yes; LNG stations	
Biomethane	Yes; injected in-state and from out-of-state	No; accounted for in CNG and LNG	

Conventional Fuels – Gasoline and Diesel

Overview

LCFS compliance yields varying levels of decreases in gasoline and diesel consumption in California. Although the reduction of petroleum consumption has positive impacts via improved energy security and increased fuel diversity, the decreased consumption of petroleum will also have direct negative impacts on the refining industry – in the same way that the investments in alternative fuels and advanced vehicles will yield positive impacts in the corresponding industries. ICF treated the reduction in gasoline and diesel consumption in the modeling as follows:

- ICF assumed that there were lost margins on 50% of those crude runs that are assumed to be displaced entirely as a result of the LCFS. These margins were estimated based on an ICF analysis of the 3-2-1 crack spread for California-based refiners (estimated at about $15/bbl)

- ICF assumed that the remaining 50% of crude runs representing the reduction in gasoline and diesel consumption in California are exported, rather than displaced entirely. For these exports, ICF assumed a corresponding decrease in revenue in the export markets because of increased freight costs (estimated at $5/bbl).

Fuel Pricing and LCFS Credit Pricing

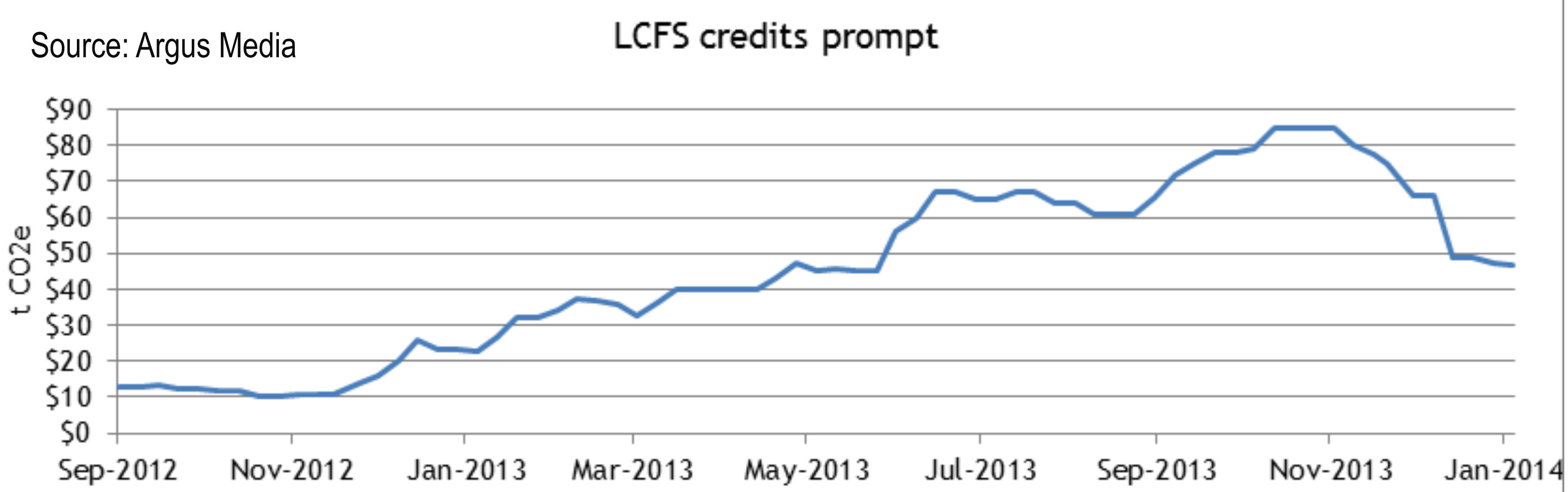
Fuel Pricing

- One of the key limitations of REMI is that it is not explicitly an energy model. Most notably, the model is not designed to predict changes in demand and supply for fuels, or the impacts on fuel pricing. In response, ICF augmented REMI by developing a supplementary estimate of fuel prices through 2020.
- ICF considered several components of fuel pricing as inputs into the REMI modeling. We sought to capture the likely impacts on fuel pricing as a result of LCFS compliance. ICF used fuel pricing forecasts from 2011 Integrated Energy Policy Report (IEPR), adjusted for actual fuel prices reported in California for 2011 and 2012.

Review of LCFS Credit Prices

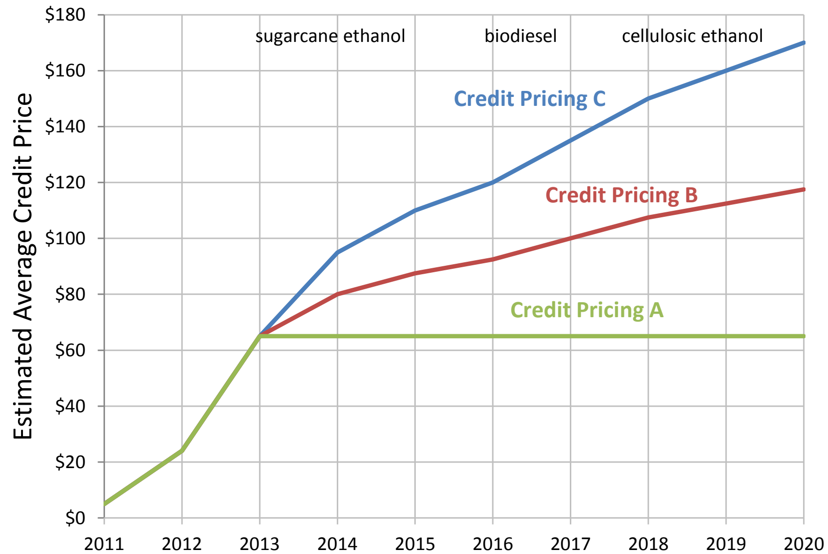
- The LCFS credit market today is relatively illiquid and immature. It is also difficult to determine what is driving credit prices.
  - The majority of credits are being transferred to regulated parties (mainly refiners / importers of fuel), rather than purchased in the LCFS credit market.
  - These credit transfers are currently happening at the point of blending biofuels like ethanol, biodiesel, or renewable diesel into CARBOB or diesel.
  - CARB reports 1.15 million credits have been traded via 271 credit transfers through February 2014. However, over that same period, nearly 6 million credits have been generated.

Source: Argus Media



LCFS Credit Pricing

- Stakeholders identified three credit pricing variations for ICF to model with each compliance option:
  - Pricing A: Future credit prices are fixed at the weighted average of credit prices in 2013, about $65/ton
  - Pricing B: Credit prices are an average of Pricing A (see above) and Pricing C (see below).
  - Pricing C: Credit prices reach a peak of around $170/ton in 2020. The profile for credit increases is a function of what is considered the implied price of carbon based on the premium of the associated alternative fuel. The pricing is largely defined by the premium paid for a) sugarcane ethanol, b) biodiesel (from various feedstocks), and c) cellulosic ethanol.



Treatment of LCFS Credit Prices in REMI

- ICF's treatment of LCFS credit prices was based on the recipient of credits, as outlined by the regulation.
  - For entities that sell the credits or credit generators – such as ethanol producers, biodiesel producers, and natural gas refueling infrastructure owners – ICF modeled credits as a decrease in production costs.
  - ICF modeled credit purchases (made by entities producing or importing CARBOB and ULSD) as an increase in production costs.
  - In the case of credits generated through the use of electricity as a transportation fuel, ICF assumed that the value of the credit would be passed to the consumer, per the requirements of the regulation. There are provisions for entities other than utilities to earn LCFS credits for the use of electricity as a transportation fuel. However, we made a simplifying assumption that the utilities would earn all of the credits generated by electricity consumption.

REMI Modeling Results

Overview

- As noted throughout this report, ICF has generally defaulted to conservative assumptions to enhance the study's credibility. Because the study's assumptions are generally conservative, the results of our modeling likely understate the full magnitude of economic benefits.
- Our results focus on the following changes resulting from the three LCFS compliance scenarios compared to the Reference Scenario:
  - Changes in employment;
  - Changes in personal income; and
  - Changes in gross state product (GSP)
- The following tables report the changes from the Reference Scenario for California:
  - Absolute change
  - Percent change

Employment

Scenarios	Credit Pricing Variations		
	A	B	C
California | EMPLOYMENT, jobs			
Scenario 1	4,100	3,900	3,700
	0.02%	0.02%	0.02%
Scenario 2	-5,300	-6,900	-8,500
	-0.02%	-0.03%	-0.04%
LCFS Enhanced	8,300	8,700	9,100
	0.04%	0.04%	0.04%

REMI MODELING RESULTS

Personal Income

Scenarios	Credit Pricing Variations		
	A	B	C
California | PERSONAL INCOME, $ billions			
Scenario 1	0.44	0.44	0.44
	0.02%	0.02%	0.02%
Scenario 2	-0.28	-0.36	-0.43
	-0.01%	-0.02%	-0.02%
LCFS Enhanced	0.90	0.84	0.89
	0.04%	0.04%	0.04%

REMI MODELING RESULTS

Gross State Product

Scenarios	Credit Pricing Variations		
	A	B	C
California | GSP, $ billions			
Scenario 1	0.43	0.40	0.38
	0.02%	0.02%	0.02%
Scenario 2	-0.50	-0.64	-0.79
	-0.02%	-0.03%	-0.03%
LCFS Enhanced	0.75	0.91	0.95
	0.03%	0.04%	0.04%

Discussion

- There are net positive macroeconomic impacts for each of the three scenarios.

- The macroeconomic impacts, however, are very small.
  - The range of impacts across the parameters considered – employment, income, and GDP/GSP, vary from -0.04% to 0.04%.
  - Despite the significant investments that are necessary to comply with the LCFS, these investments are a small fraction of overall macroeconomic activity.
  - In all cases, economic growth continues – it is not reversed. Even in the case of Scenario 2, in which there are small negative impacts in California, economic growth is not reversed. Rather it is very slightly reduced from its growth trajectory.

Discussion, ctd

- Fuel diversification leads to positive impacts in California.
  - Scenario 1 and the LCFS Enhanced Scenario demonstrate positive impacts in California.
  - The ratio of income/employment (gains), a proxy for the value of the types of jobs added, is nearly double the ratio of income/employment (loss) in Scenario 2 (see next slide). Good indicator that investments towards diversification provide higher value jobs.
  - These scenarios have more significant penetration of electricity and natural gas; but still significant blending of liquid biofuels.
  - Natural gas and electricity help offset some of the higher costs attributed to blending lower carbon biofuels.
  - They also lead to significant investments in infrastructure (charging infrastructure and natural gas stations) and vehicles – both positive drivers in the model.
  - Electric vehicles also benefit from the federal tax credit, which boosts consumer spending by returning money to California.

Discussion, ctd

- Scenario 2 yields small negative impacts in California.
  - Economic growth is not reversed; it is simply slightly reduced from its growth trajectory.
  - The income/employment ratio is lower than Scenario 1 and LCFS Enhanced Scenario – tied to reductions in growth for specific types of jobs.
  - Because ZEVs are deployed at the same level as the baseline case, there is no *incremental* benefit associated with electricity consumption as a transportation fuel or *incremental dollars* flowing to California via the federal tax credit for PEVs.
  - There are some benefits captured from electric forklifts and fixed guideway applications.
  - Scenario 2 has the most significant deployment of liquid biofuels – ethanol, biodiesel, renewable gasoline, and renewable diesel. This leads to two factors:
    - *ICF forecasts – and our data sources such as the EIA and CEC, assume higher near-term costs for liquid biofuels. With less electricity and natural gas consumption to mitigate higher fuel expenditures, this contributes to the small negative impacts.*
    - *ICF assumes that most liquid biofuels will be produced out-of-state.*

Discussion, ctd

- Several sectors consistently show positive economic impacts across all modeling scenarios, with the primary driver(s) in blue:
  - Motor vehicles, bodies and trailers, and parts manufacturing | Increased alternative fuel vehicle sales
  - Chemical manufacturing | Increased biofuel production
  - Utilities | Increased utilization of assets through electric vehicle charging
  - Electrical equipment and appliance manufacturing | EVSE deployment
  - Primary metal manufacturing | Expanded distribution and fueling infrastructure
  - Transportation (via Rail, Marine, Truck) | Liquid biofuel transport
- The Petroleum and Coal Products Manufacturing Sector has the largest percentage decrease in rate of growth in employment across all modeling runs.
  - These impacts are small, ranging from -1.0% to -0.4%.
  - In other words, these impacts are not significant enough to indicate an economic disruption such as a refinery closure.

Monetized Externalities

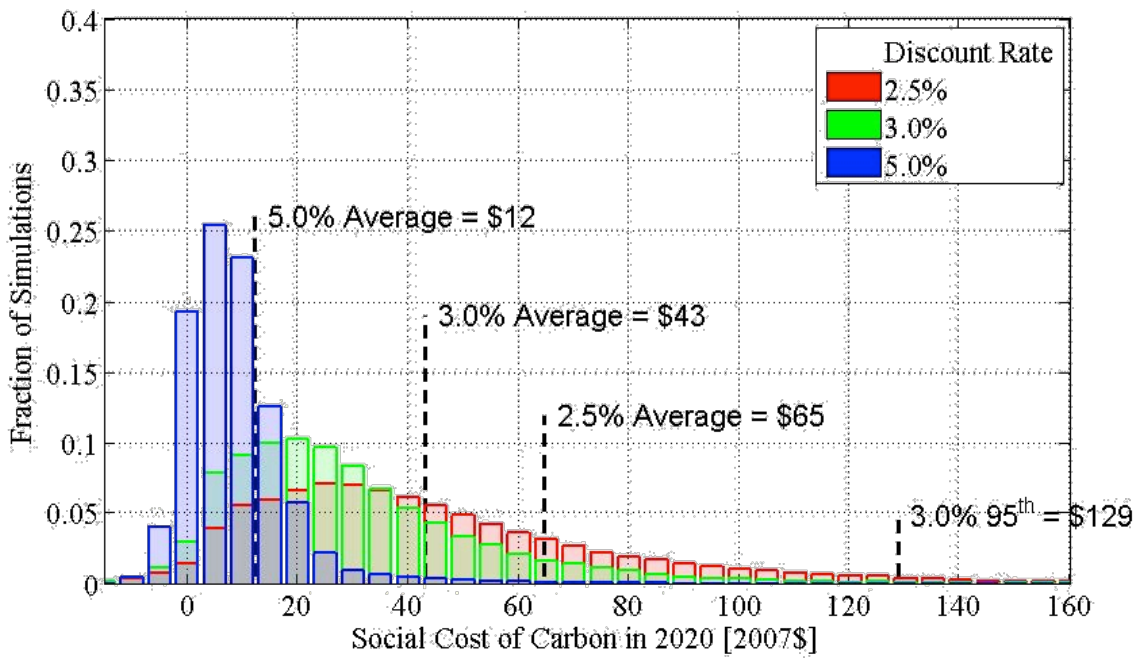
Introduction

Alternative fuels and advanced vehicles have a variety of benefits and costs. Apart from the traditional financial metrics and macroeconomic impacts associated with alternative fuel use, ICF estimated the environmental benefits and associated monetized value of:

- Reduced GHG emissions
- Reduced criteria air pollutants
- Displaced petroleum

GHG Emission Reductions

- The LCFS will result in significant economic benefits associated with avoiding damages associated with incremental increases in carbon emissions. The monetized value of damages avoided as a result of CO_2 reductions, including changes in net agricultural productivity, human health and flooding, is referred to as the social cost of carbon (SCC).



Source: Interagency Working Group on Social Cost of Carbon. Technical Update, US Government, May 2013

GHG Emission Reductions, ctd

ICF INTERNATIONAL

Net Present Value of SCC for LCFS Compliance (2% Discount Rate)

Scenario	R_d`	Net Present Value of SCC ($2010 millions), 2% discount rate								
		2013	2014	2015	2016	2017	2018	2019	2020	Cumulative
Scenario 1	5%	21	35	55	73	89	103	116	131	**623**
	3%	68	117	174	238	296	352	407	469	**2,120**
	2.5%	106	180	265	365	451	533	611	709	**3,220**
	3%, 95th	193	334	499	688	866	1,039	1,212	1,407	**6,237**
Scenario 2	5%	20	32	48	64	78	101	130	155	**628**
	3%	65	108	151	208	259	346	455	556	**2,148**
	2.5%	101	166	231	320	395	524	682	841	**3,260**
	3%, 95th	185	309	434	603	757	1,022	1,353	1,668	**6,331**
LCFS En	5%	17	29	53	73	89	104	119	136	**619**
	3%	54	98	169	236	297	354	417	486	**2,111**
	2.5%	84	151	258	364	453	535	625	734	**3,204**
	3%, 95th	153	280	486	685	868	1,044	1,241	1,457	**6,213**

ˈ R_d is the social discount rate used in the modeling exercise; not the discount rate used by ICF in the analysis.

MONETIZED EXTERNALITIES

GHG Emission Reductions, ctd

Net Present Value of SCC for LCFS Compliance (7% Discount Rate)

Scenario	R_d[1]	Net Present Value of SCC ($2010 millions), 7% discount rate								
		2013	2014	2015	2016	2017	2018	2019	2020	Cumulative
Scenario 1	5%	21	33	50	63	73	81	87	94	**502**
	3%	68	111	158	206	244	277	306	336	**1,706**
	2.5%	106	171	241	317	373	419	458	507	**2,592**
	95th	193	319	453	596	715	818	910	1,007	**5,009**
Scenario 2	5%	20	31	43	55	64	80	98	111	**502**
	3%	65	103	137	180	214	273	341	398	**1,711**
	2.5%	101	158	210	277	326	412	512	601	**2,598**
	95th	185	295	394	522	625	805	1,016	1,193	**5,035**
LCFS En	5%	17	28	49	63	74	81	89	97	**497**
	3%	54	93	154	205	245	278	313	347	**1,690**
	2.5%	84	143	235	315	374	421	469	525	**2,567**
	95th	153	267	441	593	717	822	931	1,042	**4,967**

[1] R_d is the social discount rate used in the modeling exercise; not the discount rate used by ICF in the analysis.

We estimate that the net present value of SCC for LCFS compliance in 2020 ranges from $497 million to $3.26 billion.

The low value corresponds to the LCFS Enhanced scenario using a 7% discount rate (and 5% discount rate for SCC); the high value corresponds to Scenario 2 using a 2% discount rate (and 2.5% discount rate for SCC, see previous slide)

Criteria Air Pollutants

Introduction

- Criteria air pollutants such as nitrogen oxides (NOx) and particulate matter (PM) are considered negative externalities and researchers have attempted to capture the value of avoided emissions in the form of health and environmental benefits. NOx is a precursor to photochemical ozone formation and PM is linked to an array of respiratory problems.

- Two key aspects for consideration in the review of the estimated criteria air pollutant estimates:
  - ICF only considered tailpipe criteria air pollutant emission reductions. It is possible – and in many cases likely – that the criteria pollutant emissions reductions would be larger if our analysis considered lifecycle emission reductions.
  - CARB has developed several programs to reduce criteria pollutant emissions from light-duty and heavy-duty vehicles. The avoided costs reported here are incremental to the benefits of existing CARB programs, such as the Advanced Clean Cars Program (focused on light-duty vehicles) and the Truck and Bus Rule (focused on medium- and heavy-duty vehicles).

Criteria Air Pollutants, ctd

- ICF used damage costs reported by EPA in rulemakings. The magnitude of damage costs (on a dollar per ton basis) for PM2.5 is dependent on the location of emission reductions. Areas with higher population density, for instance, tend to have higher damage costs than less populated areas. ICF developed a population-weighted average for the damage cost of PM2.5 in California, as shown in the table below.

Criteria Pollutant	2015	2020
PM2.5	$1,450,000—1,600,000	$1,600,000–1,740,000
VOC	$1,120–1,220	$1,220–1,320
NOx	$4,675–5,080	$5,080–5,590
The values are shown as ranges; EPA calculated low and high values using 3% and 7% discount rates		

Sources: Diesel Emissions Quantifier Health Benefits Methodology, EPA, EPA-420-B-10-034, August 2010. | EPA/HNTSA, Draft Joint Technical Support Document: Proposed Rulemaking for 2017-2025 Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, EPA-420-D-11-901, November 2011.

Criteria Air Pollutants, ctd

ICF INTERNATIONAL

Monetized Benefits of Criteria Air Pollutant Reductions in LCFS Compliance Scenarios ($2010, millions)

Scenario	Pollutant		2013	2014	2015	2016	2017	2018	2019	2020	Cumulative
Scenario 1	PM2.5	low	0.0	4.2	10.0	17.5	25.7	32.2	36.5	39.6	165.7
		high	0.0	5.3	13.4	24.3	37.0	48.2	56.9	64.3	249.4
	NOx / VOC	low	0.0	0.1	0.2	0.4	0.6	0.7	0.8	0.9	3.7
		high	0.0	0.1	0.3	0.6	0.8	1.1	1.3	1.5	5.7
	NOx	low	1.3	2.9	5.0	7.7	10.8	14.4	18.4	22.8	83.3
		high	1.4	3.1	5.4	8.4	11.8	15.8	20.2	25.1	91.2
Scenario 2	NOx	low	1.2	2.4	3.9	5.9	8.1	10.7	13.6	16.8	62.5
		high	1.3	2.6	4.3	6.4	8.9	11.7	14.9	18.4	68.5
LCFS Enhanced	PM2.5	low	0.0	4.2	10.3	18.3	27.3	35.0	40.7	45.2	181.0
		high	0.0	5.4	13.8	25.3	39.3	52.4	63.5	73.3	273.0
	NOx / VOC	low	0.0	0.1	0.3	0.4	0.6	0.8	0.9	1.0	4.1
		high	0.0	0.1	0.3	0.6	0.9	1.2	1.4	1.7	6.3
	NOx	low	1.3	2.6	4.3	6.5	9.2	12.4	16.1	20.6	73.1
		high	1.5	2.9	4.7	7.1	10.0	13.5	17.7	22.6	80.1

359

Low scenario: Includes low value of EPA-reported dollar-per-ton and a discount rate in ICF's analysis of 7 percent.

High scenario: Includes high value of EPA-reported dollar-per-ton and a discount rate in ICF's analysis of 2 percent.

ICF conservatively estimates the monetized benefit of criteria air pollutant emission reductions attributable to the LCFS program in the range of $63 million to $359 million.

Petroleum Displacement / Energy Security

Introduction

- Petroleum displacement by alternative fuels as part of LCFS compliance will lead to improved energy security. As outlined in a report by Paul Leiby from Oak Ridge National Laboratory regarding energy security benefits, energy security concerns arise from three problems:
  - concentrated crude oil supply in an historically unstable region
  - sustained exercise of market power by oil exporting countries
  - the vulnerability of the economy to oil supply shocks and price spikes
- Leiby estimates the benefits of energy security focusing on two components:
  - Monopsony Component: This component reflects the effect of US import demand on the long-run world oil price. The US remains a sufficiently large purchaser of foreign oil supplies that it affects global oil pricing. This demand is characterized as monopsony power.
  - Macroeconomic Disruption / Adjustment Costs: The second component of Leiby's analysis focuses on the effect of oil imports on disruptions such as a sudden increase in oil prices. These price spikes increase the costs of imports in the short run and can lead to macroeconomic contraction, dislocation, and GDP loss.

Petroleum Displacement / Energy Security, ctd

- The most recently available results from Leiby's analysis regarding the monetized benefits of decreasing oil imports are shown in the table below for the years 2013 and 2022. ICF used the mean values and assumed a linear relationship between 2013 and 2022 to calculate the annual discrete values for energy security.

Component	2013 ($/bbl)		2022 ($/bbl)	
	Mean	Range	Mean	Range
Monopsony	11.40	3.83–19.40	9.82	3.27–16.77
Disruption Costs	7.13	3.41–10.35	7.84	3.80–11.30
Total	18.53	10.03–26.74	17.66	9.88–24.99
Source: Leiby, EPA-HQ-OAR-2010-0133-0252, September 2012				

Petroleum Displacement / Energy Security, ctd

ICF INTERNATIONAL

- The monetized energy security premium for each scenario is shown in the table below for two different discount rates – 2 percent and 7 percent. ICF assumed that 50.3 percent of California's crude oil is imported based on data from the California Energy Almanac for 2011 and 2012.
- **The cumulative benefits of increased energy security resulting from the LCFS scenarios ranges from $796 million to $1.23 billion, depending on the discount rate employed in the analysis.**

Scenario		Energy Security Benefits (NPV, $2010 millions)								
		2013	2014	2015	2016	2017	2018	2019	2020	**Total**
2% discount rate	Scenario 1	16	44	82	119	152	185	216	247	**1,059**
	Scenario 2	10	31	57	88	116	177	236	302	**1,017**
	LCFS Enhanced	20	53	95	136	174	211	250	290	**1,230**
7% discount rate	Scenario 1	16	42	74	103	126	145	162	177	**844**
	Scenario 2	10	30	51	77	96	140	177	216	**796**
	LCFS Enhanced	20	50	86	118	144	166	188	207	**980**

Petroleum Displacement / Energy Security, ctd

- The proportion of foreign oil imported to California refineries has increased significantly as California reserves have been drawn down and as the Alaska North Slope production has continued to decline (starting in 1998). As recently as 2005, only 40 percent of crude oil was imported to California refineries from foreign sources. The decrease in domestic production has been offset by increases in foreign crude imports. While it is likely that ICF has under-estimated the percent of crude oil imported, recent domestic developments and the way that the LCFS is implemented give our team pause with regard to any assumptions that foreign imports are likely to increase significantly beyond the 50 percent estimate. For instance:
  - The production of domestic crude oils, such as the Bakken reserve in North Dakota and West Texas Intermediate – both of which are well suited for refining in California based on their respective crude properties – is strong and they are currently priced attractively relative to other crude oils. Similarly, there is significant potential for tight oil in California – with the EIA estimating that the Monterey/Santos Shale in Southern California has 64 percent of the onshore total shale oil resources in the lower 48 States, or about 15 billion barrels of oil.
  - There is a disincentive for refiners to seek out foreign (or domestic) crude oils that have a high carbon intensity because of the way that CARB determines the annual carbon intensity targets of the LCFS. If the carbon intensity of the crude oils that are refined increases, then the carbon intensity targets in subsequent years will be higher, thereby creating more deficits that must be offset by regulated parties.
- **In other words, it is more likely that imported crude oils will decrease more rapidly than domestic crude oils. However, we assumed a uniform petroleum displacement of imported and domestic crude oils. As a result, the range of benefits reported here is likely a low or conservative estimate of the energy security benefits.**

Summary and Conclusions

LCFS Compliance

To date, some analyses show draconian effects associated with California's LCFS.[1] But such studies harnessed assumptions and methods that lacked transparency and disregarded alternative fuel market developments. This study marks an independent effort to evaluate environmental and economic benefits. ICF uses conservative assumptions to enhance the study's credibility. Because the study's assumptions are generally conservative they likely understate the full magnitude of macroeconomic and environmental benefits.

Our analysis of the LCFS program leads to the following key takeaways:

- LCFS compliance is achievable through modest changes to fuel consumption.
  - The scenarios seek to capture the range of compliance possibilities - generally characterized as biofuel blending and advanced vehicle technology deployment.
  - A review of quarterly reports from the program combined with an alternative fuel market assessment leads ICF to conclude that the program is already working – it is driving increased volumes of alternative fuels into California, innovation, and investment.
- The LCFS program will lead to significant investments in fuel production, distribution infrastructure, and advanced vehicle technologies.

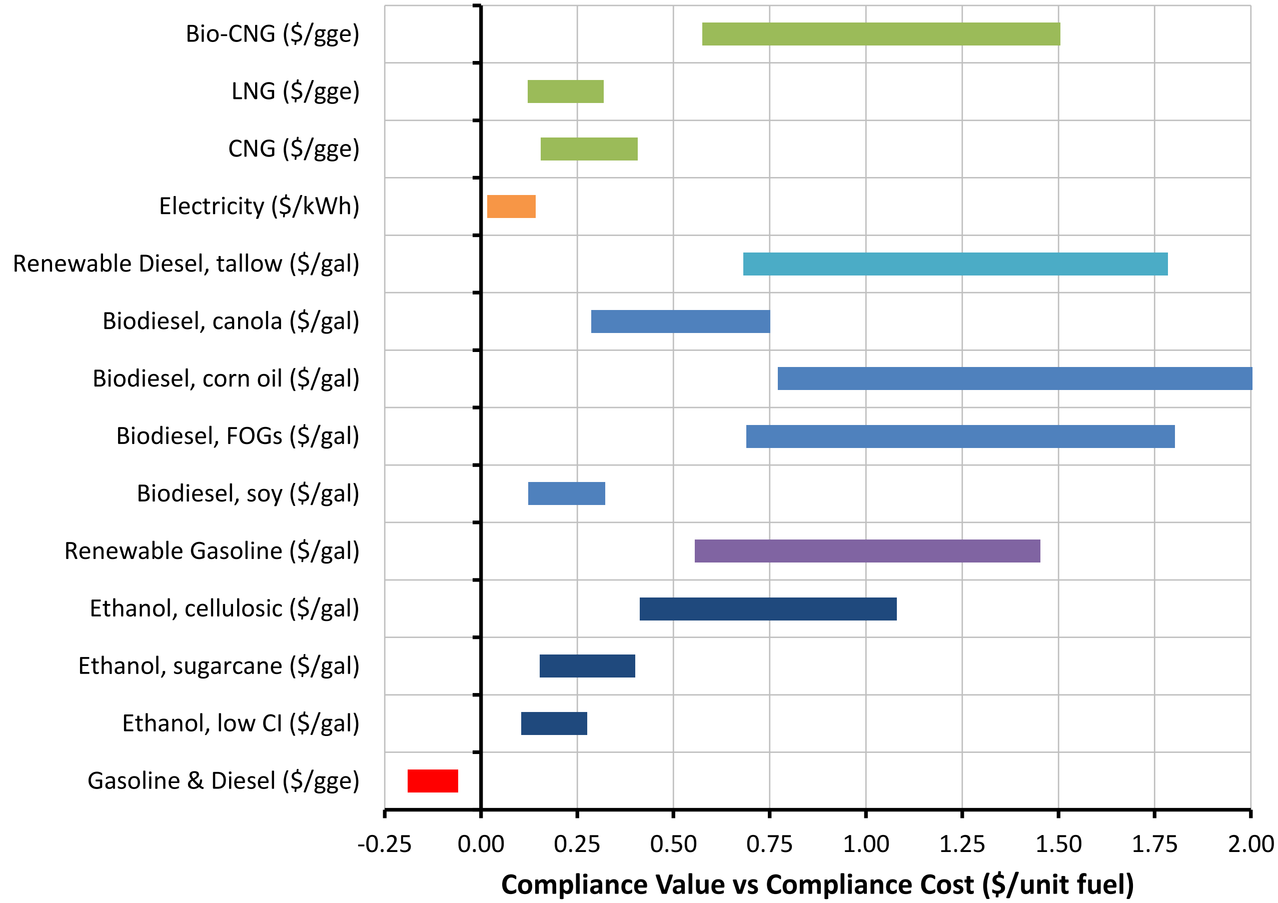
1. For instance: Boston Consulting Group, *Understanding the impact of AB 32*, June 2012 and Andrew Chang & Co, *The Fiscal and Economic Impact of the California Global Warming Solutions Act of 2006*, June 2012.

LCFS Compliance, ctd

- Based on baseline fuel price forecasts from the California Energy Commission (IEPR 2011), the credit pricing variations selected by stakeholders, and ICF's analysis of alternative fuel price forecasts, **the LCFS has a compliance cost ranging from $0.06–$0.19 per gasoline gallon equivalent**. The compliance costs have been normalized to a unit of energy – gasoline gallon equivalent – by accounting for the volumes of gasoline and diesel consumed in each scenario. The range of compliance costs reflects the variation in a) credit pricing and b) likely higher cost of blending low carbon liquid biofuels.
- As a point of comparison, gasoline and diesel prices in California have fluctuated an average of $0.75 per gallon and $0.63 per gallon annually, respectively, since 2010.

LCFS Compliance: Costs vs Value

- The compliance costs for refiners are mirrored by significant value for alternative fuels. The values shown in the graph below represent the LCFS credit range considered: $65-$170/ton



REMI Modeling

- **In all cases, investments in alternative fuels to achieve LCFS compliance yielded net positive macroeconomic impacts in 2020** – including employment, personal income, and gross domestic product (GDP). Total employment increases by up to 9,100 jobs in California.

- **The range of impacts due to the LCFS in California is small,** ranging from -0.04% to 0.04% for all the macroeconomic variables considered across all three scenarios.

- **The scenarios with the highest level of fuel diversity – Scenario 1 and LCFS Enhanced Scenario – yield net positive macroeconomic impacts** across all three credit pricing variations in California.

- **The modeling results from Scenario 2 yield small negative impacts** on employment, personal income, and GDP in California across all three credit pricing variations. This dynamic is largely driven by the fact that compliance in Scenario 2 is more dependent on liquid biofuels, are less likely to generate investment expenditures within California in the timeframe of our analysis (2020).

Research Areas for Further Study

This study's objective is to present an independent macroeconomic assessment of the LCFS. Over the course of our research, ICF has identified three critical areas for further study.

1. **The timeline of our analysis was limited to 2020, which reflects the current implementation timeframe of the LCFS program. Many of the benefits of the LCFS – driven by fuel diversification – are likely to increase significantly in the 2025-2030 timeframe.**
   - For instance, several policy cases examined in *Transitions to Alternative Vehicles and Fuels (2013)*, published by the National Academies Press, do not yield significant monetized benefits until the 2025 timeframe and increase rapidly thereafter.
   - Given that the transportation sector is nearly 95 percent dependent on petroleum-based fuels, it is to be expected that the early stages of a transition to greater alternative fuel use will have some "start-up" costs that do not fully translate into benefits until the post-2020 timeframe. These additional benefits can be attributed to factors such as increased utilization of infrastructure assets, increased competitiveness in fuel markets, increased economies of scale in alternative fuel production, and continued incremental technological improvements.

Research Areas for Further Study, ctd

2. **It is possible to estimate LCFS compliance costs and corresponding fuel pricing impacts using an energy model. The REMI model is not an energy model, and therefore is ill-equipped to forecast fuel pricing changes as a result of increased alternative fuel use. As a result of this limitation, ICF estimated the LCFS compliance costs as exogenous parameters to REMI.**
   - In a more rigorous modeling exercise, a macroeconomic model such as REMI would be paired with an optimization model or fuel/energy pricing model.
   - This is a much more resource intensive exercise, and frankly, ICF is unaware of an off-the-shelf fuel pricing model that is sufficiently sophisticated to capture the dynamics of the LCFS and its interaction with other regulations (e.g., the federal Renewable Fuel Standard).
   - ICF does not think that the pairing of an energy model with the REMI model would materially change the results of our analysis in the 2020 timeframe; however, when considering the LCFS in the post-2020 timeframe (see previous bullet), the pairing of an energy model and the REMI model is strongly recommended to ensure a robust representation of an increasingly competitive fuels market.

Research Areas for Further Study, ctd

3. **ARB is making amendments to the LCFS that are likely to be adopted in 2014 and considering new concepts .**
   - The amendments that require further study include a cost containment provision and revised indirect land use change (ILUC) values for biofuels.
     - *The cost containment mechanism will have an impact on credit pricing in modeling scenarios, thereby changing the macroeconomic impacts and the compliance costs of the regulation.*
     - *The revised ILUC values will change the balance of deficits and credits. These changes will also require modifications to the compliance scenarios because the market demand for some biofuels will likely change significantly.*
   - The new concepts being considered by ARB include GHG emission reductions at refineries, the modification of compliance curves, and modifications to the fuel pathways.
     - *ARB is considering a concept in which refiners can earn credits for GHG reductions at refineries. These types of reductions were not considered in this analysis.*
     - *This analysis assumed a 1% carbon intensity reduction in 2014; however, the carbon intensity reductions for 2015-2020 were based on the existing regulation. Modifications to these will have an impact on the balance of credits and deficits.*
     - *ARB is also considering changing the way fuel pathways are approved. As part of this, they are considering bins for fuels with similar pathways. Depending on the size of these bins, this might have an impact on our analysis.*

Monetized Externalities

The table below aggregates the results of ICF's analysis of the monetized externalities for a) GHG emission reductions, b) criteria air pollutant reductions, and c) increased energy security benefits through petroleum displacement.

Scenario		Monetized Externalities (NPV, $2010 millions)			
		GHG Emissions SCC[1]	Criteria Air Pollutants	Energy Security	Total
Scenario 1	low	$502	$253	$844	$1,599
	high	$3,220	$346	$1,059	$4,625
Scenario 2	low	$502	$63	$796	$1,360
	high	$3,260	$68	$1,017	$4,345
LCFS Enhanced	low	$497	$258	$980	$1,736
	high	$3,204	$359	$1,230	$4,793

[1] For the low SCC estimates, ICF used the values reported at a 5 percent social discount rate; for the high SCC estimates, ICF used the 2.5 percent discount rate

Monetized Externalities, ctd

The monetized environmental and energy security benefits of the LCFS are significant and can be valued in the range of $1.4–4.8 billion out to 2020. The following numbers are shown as cumulative values out to 2020.

- The GHG reductions attributable to LCFS compliance, when monetized using the social cost of carbon, are valued at $497 million to $3.26 billion.
- The criteria pollutant reductions attributable to LCFS compliance, when monetized using avoided damage costs, are valued at about $63–359 million per year.
- The energy security benefits of displacing petroleum consumption – particularly petroleum imports – are valued at $796 million to $1.23 billion per year.

Contact Information

Philip Sheehy, PhD
philip.sheehy@icfi.com | 415.677.7139

Jan Mazurek, PhD
jan.mazurek@icfi.com | 916.231.9534

Glossary of Abbreviations and Acronyms

ABFA	Advanced Biofuels Association
BEV	battery electric vehicle
CalETC	California Electric Transportation Coalition
CARB	California Air Resources Board
CARBOB	California Reformulated Blendstock for Oxygenate Blending
CEC	California Energy Commission
CNG	compressed natural gas
CNGVC	California Natural Gas Vehicle Coalition
CO_2	carbon dioxide
E15	Ethanol blended with gasoline at 15% by volume
E2	Environmental Entrepreneurs
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EVSE	Electric Vehicle Supply Equipment
GDP	Gross Domestic Product
GHG	greenhouse gas
GSP	Gross State Product
IEPR	Integrated Energy Policy Report (prepared by CEC)
LCFS	Low Carbon Fuel Standard
LNG	liquefied natural gas
NAICS	North American Industry Classification System
NBB	National Biodiesel Board
NGV	natural gas vehicle
NOx	nitrogen oxides
NPV	Net Present Value
PEV	plug-in electric vehicle
PHEV	plug-in hybrid electric vehicle
PM	particulate matter
SCC	Social Cost of Carbon
ULSD	ultra low sulfur diesel
VOC	volatile organic compounds

This page intentionally left blank.

19_OP_LCFS_Tutt

94. Comment: **LCFS 19-1**

The comment attaches a report that outlines the macroeconomic benefits of the LCFS regulation.

Agency Response: ARB staff appreciates the support of the re-adoption of the LCFS regulation.

95. Comment: **LCFS 19-2**

The comment references a report that shows that the alternative fuel industry has expanded faster than anticipated and presents three scenarios where industry can comply with the 10 percent compliance target of the LCFS.

Agency Response: See response to **LCFS 5-2**.

96. Comment: **LCFS 19-3**

The comment references a report that concluded that electricity has the potential to generate significant quantities of credits.

Agency Response: ARB staff appreciates California Electrical Transportation Coalition's support of proposed electricity provisions.

97. Comment: **LCFS 19-4**

The comment references a presentation that identifies benefits to Californians from electrifying the transportation sector.

Agency Response: ARB staff appreciates the support of the air quality and greenhouse gas benefits, as stated in the ICF International presentation.

This page intentionally left blank.

Comment letter code: 20-OP-LCFS-CInc

Commenter: Timothy Johnson

Affiliation: Corning Incorporated

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

Jensen, Tracy@ARB

From:	Balcazar, Trinidad@ARB
Sent:	Tuesday, February 17, 2015 9:26 AM
To:	Jensen, Tracy@ARB
Cc:	Whiting, Amy@ARB
Subject:	FW: Deadline for Comments on LCFS?
Attachments:	DOE Storing CO2 with EOR 2009.pdf

Tracy,

See email below. Written submittal that needs to be added to the LCFS rulemaking comment log.

From: Vergara, Floyd@ARB
Sent: Tuesday, February 17, 2015 8:20 AM
To: Whiting, Amy@ARB; Balcazar, Trinidad@ARB
Cc: Kitowski, Jack@ARB; Wade, Samuel@ARB; Scheehle, Elizabeth@ARB
Subject: FW: Deadline for Comments on LCFS?

Amy and Trini,

Can you include the email thread below into the comments log for the LCFS readoption rulemaking record? Mr. Johnson has asked that it be submitted as a formal written comment. Thanks.

Floyd

Floyd V. Vergara, Esq., P.E.
Chief, Industrial Strategies Division
California Air Resources Board
(916) 324-0356
Floyd.Vergara@arb.ca.gov

This e-mail message or attachment(s) contains information that may be confidential, may be protected by the attorney-client or other applicable privileges, and may constitute non-public information. If you are not an intended recipient of this message, please notify the sender at 916-324-0356 or by return e-mail and destroy all copies in your possession. Unauthorized use, dissemination, distribution or reproduction of this message is strictly prohibited and may be unlawful.

From: Johnson, Timothy V [mailto:JohnsonTV@Corning.com]
Sent: Monday, February 16, 2015 3:01 PM
To: Vergara, Floyd@ARB
Cc: Ayala, Alberto@ARB
Subject: RE: Deadline for Comments on LCFS?

Thanks much Floyd.

We will not be able to submit formal public comments, unless you can include this email. We are developing CO2 capture technology that will take CO2 directly out of air. This is in a research phase now, but there is already commercial interest in scaling up and evaluating it. The first market is CO2-based enhanced oil recovery wherein the equipment would be installed at the oil field site. The CO2 captured from air and used for this purpose is mostly sequestered, rendering the oil 70-100% carbon free, according to the attached journal paper from the DOE.

It is important the LCFS is flexible enough to allow oil produced in this method to be considered as a LC fuel upon proper review and certification.

LCFS 20-1

Regards,

Tim Johnson

Timothy V. Johnson, Sc.D.
Director – Emerging Technologies and Regulations
Corning Incorporated

HP-CB-3-1
Corning Incorporated
Corning, NY 14831

+1-607-368-6085 (mobile)
+1-607-974-4627 (fax)

From: Vergara, Floyd@ARB [mailto:fvergara@arb.ca.gov]
Sent: Monday, February 16, 2015 4:39 PM
To: Johnson, Timothy V
Cc: Ayala, Alberto@ARB
Subject: Re: Deadline for Comments on LCFS?

Tim,

Thanks for your note and interest in the LCFS. Unless you will be testifying at our February 19th hearing, all comments must be submitted in writing and must be received by 5 pm Pacific Time, February 17th. Comments can be submitted in writing by regular or electronic mail. Please see the hearing notice, http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15notice.pdf, for additional details on comment submittals.

Feel free to contact me directly if you have further questions.

Floyd Vergara, Chief
Industrial Strategies Division
(916) 324-0356

Sent from my iPhone

On Feb 16, 2015, at 12:42 PM, Johnson, Timothy V <JohnsonTV@Corning.com> wrote:

> Thanks Alberto.
> Mr. Vergara, When is the deadline for submitting comments on the LCFS? See below for our interests.
>
> Regards,
> Tim

ELSEVIER

Available online at www.sciencedirect.com

ScienceDirect

Energy Procedia 1 (2009) 1989–1996

Energy Procedia

www.elsevier.com/locate/procedia

GHGT-9

Storing CO_2 with Enhanced Oil Recovery

Robert C. Ferguson[1], Christopher Nichols[2], Tyler Van Leeuwen[1]*, and Vello A. Kuuskraa[1]

[1]*Advanced Resources International, Inc., 4501 Fairfax Drive, Suite 910, Arlington, VA 22203 USA*
[2]*U.S.Department of Energy National Energy Technology Laboratory, 3610 Collins Ferry Road, Morgantown, WV 26507 USA*

Abstract

CO_2 enhanced oil recovery (CO_2-EOR) offers the potential for storing significant volumes of carbon dioxide emissions while increasing domestic oil production. This presentation, based on a recently completed study for DOE/NETL, examines the domestic oil resource amenable to CO_2-EOR, the size of the related market for CO_2, and the benefits to the power sector from CO_2 sales to the EOR industry. The study finds that, depending on future oil prices and the costs for purchasing CO_2 from power plants and other industrial sources, from 39 to 48 billion barrels of oil could be economically recoverable with CO_2-EOR. In addition, the size of the market for CO_2 offered by the EOR industry is on the order of 7,500 million metric tons between now and 2030. With advances in CO_2-EOR and storage technology, the economically recoverable oil resource would increase to 54 to 70 billion barrels.

The market for CO_2 from the EOR industry is examined in depth from the coal-fueled power plant industry's standpoint. The sale of CO_2 emissions captured from new coal-fueled power plants could provide significant revenue offsets to the cost of installing carbon capture technology. It is estimated these revenue offsets along with a value for carbon abatement could enable 40% (48 out of 121 GW) of the new coal-fueled power capacity expected to be built between now and 2030 to install CCS. With advances in CO_2-EOR and storage technology the number of power plants with CCS could increase to 50 to 70 GWs. This would provide significant assistance toward addressing CO_2 emissions from this sector, helping drive down the costs of installing CCS technology. © 2009 Elsevier Ltd. All rights reserved.

Keywords: CO_2-EOR; carbon capture and storage; enhanced oil recovery; coal power plants; CO_2 emissions

* Corresponding author. Tel.: [1] Tel.: +703-528-8420; fax: +703-528-0439; [2]Tel.: 304-285-4172
E-mail address: [1]vkuuskraa@adv-res.com; [1]rferguson@adv-res.com; [2]Christopher.Nichols@NETL.DOE.GOV; [1]tvanleeuwen@adv-res.com

doi:10.1016/j.egypro.2009.01.259

1. Introduction

CO_2 enhanced oil recovery (CO_2-EOR) offers the potential for storing significant volumes of carbon dioxide emissions while increasing domestic oil production. Four notable benefits would accrue from integrating CO_2 storage and enhanced oil recovery:

- First, CO_2-EOR provides a large, "value added" market for sale of CO_2 emissions captured from new coal-fueled power plants. The size of this market is on the order of 7,500 million metric tons between now and 2030. Sales of captured CO_2 emissions would help defray some of the costs of installing and operating carbon capture and storage (CCS) technology. These CO_2 sales would support "early market entry" of up to 49 (one GW size) installations of CCS technology in the coal-fueled power sector. With advances in CO_2-EOR and storage technology the market could increase to 10,850 million metric tons which would support up to 70 GW of CCS;
- Second, storing CO_2 with EOR helps bypass two of today's most serious barriers to using geological storage of CO_2 - - establishing mineral (pore space) rights and assigning long-term liability for the injected CO_2;
- Third, the oil produced with injection of captured CO_2 emissions is 70% "carbon-free", after accounting for the difference between the carbon content in the incremental oil produced by EOR and the volume of CO_2 stored in the reservoir. With "next generation" CO_2 storage technology and a value for storing CO_2, the oil produced by EOR could be 100+% "carbon free";
- Fourth, the 39 to 48 billion barrels of economically recoverable domestic oil economically recoverable from storing CO_2 with EOR would help displace imports, supporting a path toward energy independence. It could also help build pipeline infrastructure subsequently usable for storing CO_2 in saline formations.

Various analysts and studies have discussed the potential for storing CO_2 with enhanced oil recovery but have noted (incorrectly) that this option is quite small or is counter productive to reducing CO_2 emissions. For example, the "IPCC Special Report on Carbon Dioxide Capture and Storage", while recognizing that depleted oil fields could provide an attractive, early option for storing CO_2 (particularly with CO_2-EOR), concluded that oil fields would provide only a relatively small volume of CO_2 storage capacity.

The report finds that the opportunity for selling captured CO_2 emissions to the EOR industry and storing these emissions in oil reservoirs using CO_2-EOR is largely providing a market for productive use of CO_2 emissions from the nation's large and growing fleet of coal-fueled power plants.

2. Evaluating the Market for Captured CO_2 Emissions Offered by EOR

The size and value of the market for captured CO_2 emissions offered by enhanced oil recovery rests on three pillars: (1) the size and nature of the domestic crude oil resource base, particularly the large portion of this resource base unrecoverable with existing primary and secondary oil recovery methods; (2) the ability of CO_2-EOR to recover a portion of this currently unrecoverable ("stranded") domestic oil, while efficiently storing CO_2; and (3) the impact of alternative oil prices and CO_2 costs on the volume of oil that could be economically produced.

2.1. The Domestic Oil Resource Base

The U.S. has a large, established oil resource base, on the order of 596 billion barrels originally in-place. About one-third of this resource base, nearly 196 billion barrels, has been recovered or placed into proved reserves with existing primary and secondary oil recovery technologies. This leaves behind a massive target of 400 billion barrels of "technically stranded" oil, Table 1.

Table 1. National In-Place, Conventionally Recoverable and "Stranded" Crude Oil Resources

Basin/Area	OOIP* (Billion Barrels)	Conventionally Recoverable (Billion Barrels)	ROIP** "Stranded" (Billion Barrels)
1. Alaska	67.3	22.3	45.0
2. California	83.3	26.0	57.3
3. Gulf Coast (AL, FL, MS, LA)	44.4	16.9	27.5
4. Mid-Continent (OK, AR, KS, NE)	89.6	24.0	65.6
5. Illinois/Michigan	17.8	6.3	11.5
6. Permian (W TX, NM)	95.4	33.7	61.7
7. Rockies (CO,UT,WY)	33.6	11.0	22.6
8. Texas, East/Central	109.0	35.4	73.6
9. Williston (MT, ND, SD)	13.2	3.8	9.4
10. Louisiana Offshore	28.1	12.4	15.7
11. Appalachia (WV, OH, KY, PA)	14.0	3.9	10.1
Total	595.7	195.7	400.0

*Original Oil in Place, in all reservoirs in basin/area; Calculated through internal ARI analysis and EIA production data.
** Remaining Oil in Place, in all reservoirs in basin/area. Source: Advanced Resources Int'l, 2008.

2.2. Technically Recoverable Oil Resources Using CO_2-EOR

Numerous scientific as well as practical reasons account for the large volume of "stranded" oil, unrecoverable with primary and secondary methods. These include: oil that is bypassed due to poor waterflood sweep efficiency; oil that is physically unconnected to a wellbore; and, most importantly, oil that is trapped by viscous, capillary and interfacial tension forces as residual oil in the pore space.

Injection of CO_2 helps lower the oil viscosity and trapping forces in the reservoir. Additional well drilling and pattern realignment for the EOR project helps contact bypassed and occluded oil. These actions enable a portion of this "stranded oil" to become mobile, connected to a wellbore and thus recoverable.

2.2.1. Current CO2-EOR Activity and Production

According to the latest tabulation of CO_2-EOR activity in the U.S., in the 2008 EOR Survey published by the Oil and Gas Journal, approximately 250,000 barrels per day of incremental domestic oil is being produced by 101 CO_2-EOR projects, distributed broadly across the U.S.

2.2.2. Evolution in CO_2 Flooding Practices

Considerable evolution has occurred in the design and implementation of CO_2-EOR technology since it was developed in the 1970's. Notable changes include: (1) use of much larger (up to 1 HCPV*) volumes of CO_2; (2) incorporation of tapered WAG (water alternating with gas) and other methods for mobility control; and (3) application of advanced well drilling and completion strategies to better contact previously bypassed oil. As a result of the changes mentioned above, the oil recovery efficiencies of today's better designed "state-of-the-art" CO_2-EOR projects have steadily improved.

2.2.3. Technically Recoverable Resources

The reservoir-by-reservoir assessment of the 1,111 large oil reservoirs contained in the ARI database amenable to CO_2-EOR shows that a significant volume, 64 billion barrels, of domestic oil may be recoverable with state-of-the-art application of CO_2-EOR. Extrapolating the data base to national-level results indicates that 87.1 billion barrels

(84.8 after subtracting the 2.3 that has already been produced and proven) of domestic oil may become recoverable by applying "state-of-the-art" CO_2-EOR, Table 2.

Table 2. Technically Recoverable Resources from Applying "State-of-the-Art" CO_2-EOR: National Totals

	Technically Recoverable (Billion Barrels)	Existing CO_2-EOR Production/Reserves	Incremental Technically Recoverable (Billion Barrels)
1. Alaska	12.4	-	12.4
2. California	6.3	-	6.3
3. Gulf Coast (AL, FL, MS, LA)	7	-	7
4. Mid-Continent (OK, AR, KS, NE)	10.7	-0.1	10.6
5. Illinois/Michigan	1.2	-	1.2
6. Permian (W TX, NM)	17.8	-1.9	15.9
7. Rockies (CO,UT,WY)	4.2	-0.3	3.9
8. Texas, East/Central	17.6	-	17.6
9. Williston (MT, ND, SD)	2.5	-	2.5
10. Louisiana Offshore	5.8	-	5.8
11. Appalachia (WV, OH, KY, PA)	1.6	-	1.6
Total	87.1	-2.3	84.8

3. Economically Recoverable Resources

3.1. Economically Recoverable Resources: Base Case Scenario

Out of 85 billion barrels technically recoverable using CO_2-EOR technology, 45 billion barrels of incremental oil are economically recoverable in our base case scenario, Table 3. The Base Case evaluates the CO_2-EOR potential using an oil price of $70 per barrel (constant, real) and a CO_2 cost of $45 per metric ton ($2.38 per Mcf) (delivered at pressures around 2,200 psi to the field, constant and real), Table 4. The 40 billion barrels that are not economic to recover in this scenario are contained in reservoirs that cannot provide a sufficient rate of return, 15%, in this scenario, on a CO_2-EOR project's capital costs.

Table 3. Economically Recovemble Resources from Applying "State-of-the-Art" CO_2-EOR: National Totals at Base Case Economics*

Basin/Area	Incremental Technically Recoverable (Billion Barrels)	Incremental Economically Recoverable* (Billion Barrels)
1. Alaska	12.4	9.5
2. California	6.3	5.4
3. Gulf Coast (AL, FL, MS, LA)	7.0	2.2
4. Mid-Continent (OK, AR, KS, NE)	10.6	5.6
5. Illinois/Michigan	1.2	0.5
6. Permian (W TX, NM)	15.9	7.1
7. Rockies (CO,UT,WY)	3.9	1.9
8. Texas, East/Central	17.6	8.3
9. Williston (MT, ND, SD)	2.5	0.5
10. Louisiana Offshore	5.8	3.9
11. Appalachia (WV, OH, KY, PA)	1.6	0.1
Total	84.8	45.0

*Base Case Economics use an oil price of $70 per barrel (constant, real) and a CO_2 cost of $45 per metric ton ($2.38/Mcf), delivered at pressure to the field.

Table 4. Economically Recoverable Resources from Applying "State-of-the-Art" CO_2-EOR: National Totals at Base Case and Alternative Oil Prices/CO_2 Costs

Oil Prices	CO2 Costs			
($ per Bbl)	($ per metric ton)			
	$35	$45*	$55	$60
Lower Prices				
$50	39.1 BBbls			
Base Case				
$70		45.0 BBbls		
Higher Prices				
$90			47.9 BBbls	
$100				48.3 BBbls

*A CO_2 cost of $45 per metric ton (mt) is equal to $2.38 per Mcf. 15% IRR project hurtle rate

4. The Market for Storing CO2 with EOR

Our analysis shows that significant volumes of CO_2 (ranging from 10 to 13 billion metric tons depending on oil price) can be stored with enhanced oil recovery. In general, about 5 to 6 Mcf (0.26 to 0.32 metric tons (mt)) of purchased CO_2 per barrel of oil is injected and stored as part of CO_2-EOR. This is augmented with 5 to 10 Mcf (0.26 mt to 0.52 mt) of recycled CO_2 during the latter stages of a CO_2-EOR process. With incentives for storing CO_2 emissions and "next generation" CO_2 storage technology, considerably larger volumes of CO_2 could be stored.

4.1. Producing "Carbon Free" Domestic Oil

A typical barrel of crude oil contains 0.42 metric tons (mt) of releasable CO_2 (assuming that 3% of the produced and refined oil barrel remains as asphalt or coke). As such, netting the injection and storage of 0.26 to 0.32 mt of CO_2 emissions against the 0.42 mt of CO_2 in the produced oil, makes the domestic oil produced by CO_2-EOR about 70% (62% to 76%) "carbon free".

4.2. Market Demand for CO_2: Power Plant Perspective

The overall demand for CO_2 by the CO_2-EOR industry can be met by three potential sources of CO_2 supply, namely:

- Natural CO_2 supplies already found and defined in geological structures;
- Industrial, high concentration sources of CO_2 (e.g. refineries and fertilizer plants) that are currently being captured and used by the CO_2-EOR industry; and
- The large volumes of low concentration power plant and industrial emissions of CO_2 that needs to be captured and stored to mitigate CO_2 emissions.

Excluding Alaska, which is not projected to build new coal-fueled power plants to any great extent, the demand for CO_2 in the lower-48 states offered by the EOR industry is 9,694 million metric tons (183.4 Tcf)

Table 5 sets forth the net remaining demand for CO_2 by the EOR industry of 7,470 million metric tons for the lower-48 states, after subtracting the 2,224 million metric tons (42.2 Tcf) of CO_2 available, in the next 30 years, from natural CO_2 deposits and high concentration industrial CO_2 sources (e.g., natural gas processing plants, fertilizer plants) already being captured and used for enhanced oil recovery.

The overall conclusion from the analysis is that CO_2-EOR may provide a 7,500 million metric ton market for captured CO2 emissions by the coal-fueled power generation industry, Table 5. While the actual revenues afforded by this market will be established, in the main, by one-on-one negotiations between individual power companies and oil field operators, the potential size of this market could be large.

Using an oil price of $70 per barrel (Base Case), assuming a delivered CO_2 cost of $45 per metric ton, and subtracting $10 per metric ton for transportation and handling, the revenue potential offered by the CO_2-EOR market could reach $260 billion.

Table 5. Economically Feasible Market Demand for CO_2 by EOR: NEMS/EMM Power Generation Regions*

NEMS EMM Region	Purchased CO_2 Requirements (Tcf)	Natural CO_2** (Tcf)	Industrial CO_2** (MMcfd)	Industrial CO_2** (Tcf)	Unmet (Net) Demand for CO_2 (Tcf)	Unmet (Net) Demand for CO_2 (Million mt)
Region 1 - ECAR	1.1	-	15	***	1.1	58
Region 2 – ERCOT	72.2	25	110	1.2	46.0	2,436
Region 3 – PJM (MAAC)	0.1	-	-	-	0.1	4
Region 4 – MAIN	1.9	-	-	-	1.9	100
Region 5 – MAPP	2.1	-	-	-	2.1	109
Region 6 – NY ISO	-	-	-	-	-	-
Region 7 – NW ISO	-	-	-	-	-	-
Region 8 – Florida	0.2	-	-	-	0.2	9
Region 9 – SERC	40.0	8	-	-	32.0	1,695
Region 10 – SWPP	29.7	5	35	0.4	24.3	1,286
Region 11 – WECC/NWPP	7.8	-	175	1.9	5.9	311
Region 12 – WECC/RMPP	2.3	-	65	0.7	1.6	83
Region 13 – WECC/CA	26.0	-	-	-	26.0	1,377
Region 14 - Alaska	39.6	5	-	-	34.6	1,831
TOTAL U.S.	223.0	43	400	4.2	175.8	9,301
TOTAL Lower-48	183.4	38	400	4.2	141.2	7,470

*Base Case: \$70/Bbl oil and \$45/mt CO_2

**Assumed available to be produced and productively used by the CO_2-EOR industry in the next 30 years.

***Less than 0.01 Tcf and thus not included in totals.

5. Using Sale of Captured CO_2 Emission for "Early Market Entry" of CCS Technology

A common feature of EIA carbon management studies is that, in general, CCS is not considered, as of yet, a key part of the solution. The reason, according to EIA's EMM cost model, is that using CCS with coal- or gas-fired power is not economically competitive with other options for generating power with low CO_2 emissions.

However, revenues from selling captured CO_2 emissions into the CO_2-EOR market can change the competitive outlook. For example, as shown in Table 6 and Figure 1, the sale of captured CO_2 emissions at \$25 to \$35 per metric ton can reduce the costs of power generation with CCS by \$17 to \$24 per MWh, significantly offsetting the costs of installing CCS with new coal-fueled power plants.

Table 6. Relationship of CO_2 Sales Price to Cost Offsets in the Coal-Fueled Power Sector (Year 2020)

Sale of CO_2	Sale of CO_2
@ \$25/mt CO_2	@ \$35/mt CO_2
*7,920 btu/kWh x	7,920 btu/kWh x
94 MMmt CO_2/QBtu x	94 MMmt CO_2/QBtu x
90% Capture	90% Capture
Cost Offset: \$16.80/MWh	Cost Offset: \$23.50/MWh

*Advanced Integrated Gasification Combined Cycle (IGCC) plant.

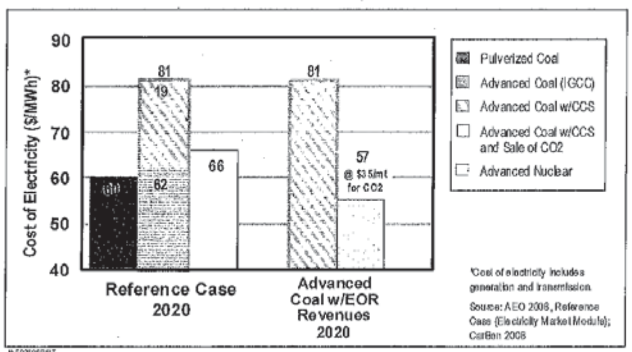


Figure 1. Sale of Captured CO_2 Emissions Can Help Make Coal Plants w/CCS Competitive

The CarBen and EIA EMM models project that 29 new coal-fueled power plants would be placed into operation between 2013 and 2020 in the lower-48. Assuming that half of these power plants are favorably located with respect to oil fields attractive for CO_2-EOR and are able to sell CO_2 at \$35/mt at the plant gate, the integration of CO_2 storage and EOR plus a value for abating CO_2 emissions would support the construction of 15 new advanced coal w/CCS power plants, each with 1 GW of capacity. (A 1 GW advanced coal-fueled power plant built by 2020 is estimated to be able to sell about 5.1 million metric tons of captured CO_2 emissions per year; 15 plants would be able to provide 2,300 million metric tons in 30 years). Sales of captured CO_2 emissions by power plants built after 2020 would support the 33 additional installations of CCS by 2030 for a total of 48 GWs of capacity with CCS.

20_OP_LCFS_Cinc Responses

98. Comment: **LCFS 20-1**

The commenter urges ARB to consider enhanced oil recovery with carbon captured directly from the air at the oil production site.

Agency Response: Under the proposed regulation language, the carbon capture must take place onsite at the crude oil production facilities in order for Carbon Capture with CO_2 Enhanced Oil Recovery to qualify as an innovative crude method. Moreover, carbon capture and storage (CCS) projects must use a Board-approved quantification methodology including monitoring, reporting, verification, and permanence requirements associated with the carbon storage method being proposed for the innovative method. This quantification method is being developed and is expected to be available by 2017. Therefore, the project described by the commenter should qualify as an innovative crude production method, assuming it meets all requirements of the quantification method.

This page intentionally left blank.

Comment letter code: 21-OP-LCFS-USC

Commenter: Jeremy Martin

Affiliation: Union of Concerned Scientists

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

21_OP_LCFS _USC

Union of Concerned Scientists

ucsusa.org Two Brattle Square, Cambridge, MA 02138-3780 t 617.547.5552 f 617.864.9405
1825 K Street NW, Suite 800, Washington, DC 20006-1232 t 202.223.6133 f 202.223.6162
2397 Shattuck Avenue, Suite 203, Berkeley, CA 94704-1567 t 510.843.1872 f 510.843.3785
One North LaSalle Street, Suite 1904, Chicago, IL 60602-4064 t 312.578.1750 f 312.578.1751

February 17th, 2015

Air Resource Board
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

The Union of Concerned Scientists has been working with the Air Resource Board (ARB) to develop a science based Low Carbon Fuel Standard (LCFS) since the program's inception, and has joined other organizations on other letters supporting the readoption in general and making several specific recommendations. However, we have been extensively involved in the getting the science right on the important issue of accounting for biofuels indirect land use emissions (ILUC), and wanted to make some more specific comments on that topic.

First thanks to the ARB staff for tireless work to address stakeholder and expert input on ILUC analysis. With the dedicated work of ARB staff and many contractors and collaborators the models used in 2009 have been adapted to more carefully model animal feed markets, to take into consideration irrigation, and to adapt the model structure of both GTAP and the associated emissions factor model to take into consideration considerably more detailed information, especially about the US and Brazil. This process enhanced the technical foundation of the LCFS, and also advanced the state of the art on the study of land use changes associated with expanded biofuels production. The board is on sound footing to adopt updated emissions values as part of the LCFS readoption.

But despite this important progress, there remain important areas for continued investigation. The most critical of these is related to palm oil. Palm oil is one of the most important drivers of deforestation, and a significant global source of biofuel. The emissions from palm oil are relevant not only for palm biodiesel itself, but for fuels made from other fats, oils or oil biproducts that may substitute for palm oil in the marketplace. The interconnected markets for biodiesel and renewable diesel feedstocks are complicated and the data is imperfect. Moreover, as ARB staff has highlighted, there are likely some structural limitations in GTAP that make it difficult to adjust the model to reflect key market dynamics. But this area of inquiry is clearly critically important going forward. Additional investigation is needed to ensure the link between palm and deforestation is understood, and that California fuel regulations do not inadvertently increase deforestation from palm oil. LCFS 21-1

This is particularly important because LCFS compliance may lead to a significant increase in the use of fuels made from oils and fats. I urge the ARB to seek expert input on key land use issues raised by palm oil in particular, and large increases in the use of bio-based diesel in general. ARB certainly has important technical work to continue, refining the GTAP model LCFS 21-2 and associated emissions factor models, but a broader perspective on the drivers of palm oil deforestation is also critical to ensure that California's fuel regulations avoid becoming an indirect driver of deforestation and support deforestation-free fuels. LCFS 21-2 cont.

My comments are focused on palm oil because it is a leading driver of deforestation and a weakness in ARB's otherwise strong analysis, but the other areas identified for further long term work are also very important. The forestry issues associated with the treatment of unmanaged land in GTAP are very important to ILUC for all fuels, and especially palm oil, and deserve further attention. LCFS 21-3 It is also worth understanding the discrepancy between ARB's irrigation results and those of Taheripour, Hertel and Liu (*Energy, Sustainability and Society* 2013, 3:4). LCFS 21-4 Analysis of fertilizer, paddy rice and livestock emissions, and consideration of a dynamic GTAP model is also worthwhile. LCFS 21-5 And as cellulosic biofuels feedstocks scale up and begin to be significant driver of land use change, it will be important to understand their land use impacts. LCFS 21-6

I also wanted to include some comments on recent publications related to ILUC.

Babcock and Iqbal.

At the highest level, the recent white paper by Babcock and Iqbal suggests that calculations of indirect land use change (ILUC) emissions that ARB finalized in 2009 and related studies US Environmental Protection Agency finalized in 2010 may overestimate ILUC emissions. Of course with the updated analysis the 2010 values are indeed being lowered. But of course there is a lot more to it than that, and I want to comment on four specific points.

1. The findings of the Babcock and Iqbal study are strongly connected with the reduced rate of deforestation in Brazil, which is an important success story (see UCS report *Deforestation Success Stories* – also my colleague's papers in *Tropical Conservation Science* and *Solutions Journal*). This success was no means automatic, and reflects not simply the option value of intensification, but also considerable pressure on soybean traders and the Brazilian government to stop deforestation. Fully accounting for emissions associated with deforestation was part of that pressure, and thus reduced deforestation in Brazil is a success that vindicates the importance of land use change emissions accounting.
2. However, while there is an important success to report in Brazilian soy, the Babcock and Iqbal study also demonstrates that for palm oil production just the opposite is true, with substantial expansion on the extensive margin, primarily from deforestation and expansion onto peat, rather than on the intensive margin. This demonstrates the importance of focusing on emissions from palm oil, pushing customers, traders and governments to invest in yield increases and to block expansion into forests and peat. Palm oil is a significant global source of biofuel, and these first ARB estimates to be released require thorough scrutiny before these results will be up to the same standard the corn, sugar and soy results are now. Additional expert work is LCFS 21-7

needed in this area to ensure the links between palm and deforestation are understood. LCFS 21-7 cont.

3. Also, while the Babcock and Iqbal's analysis makes a compelling case that expansion at the intensive margin is important, this kind of intensification can only go so far before the growing season is fully used and the planted land is fully harvested. Furthermore, for perennial tree crops like oil palm, double-cropping is not feasible and increasing the proportion of the planted area that is harvested has very limited potential. So the mechanisms Babcock identified cannot continue if biofuels production grows indefinitely.
4. Finally, the Babcock and Iqbal study concludes with a promise to extend their analysis into a statistical model that could be incorporated into future attempts at estimating greenhouse gas emissions caused by biofuels or other drivers of agricultural production. This forthcoming model may well enhance the next round of analysis performed by ARB or others, but the opportunity for future improvements is no reason to hold up the updates based on work done over the last five years or the regulation in general. The refinement of models is an ongoing process, and further improvement is always possible. The changes regarding intensification, improved treatment of unmanaged land, and more scrutiny of palm and peat are all warranted. But future changes will need to be incorporated into future policy updates. LCFS 21-8

Searchinger and Heimlich

In a recent World Resources Institute report, Tim Searchinger and Ralph Heimlich argue that in light of the looming challenge of producing food and other needs for the world population in 2050, there is no space for any use of crops to produce fuels on a significant scale. The question of whether crop production will succeed or fail to keep up with demand growth over the next 35 years is not a matter of scientific consensus and depends on many non-technical factors. I agree that competition for land with crops, forests and other land uses must be considered in assessing the limits on the productive scale of bioenergy, so it is a mistake to target an arbitrary fraction of future fossil energy demand, whether 10% or 20%.

Searchinger and Heimlich argue that most bioenergy policies are based on faulty accounting that double counts carbon. They propose that the low carbon fuel standard be dropped in favor of other measures in support of electric or hydrogen vehicles or at a minimum they should disqualify biofuels grown on dedicated land from contributing to low carbon fuel standards. The electricity-only focus is too narrow to meet climate goals, and the remedy of disqualifying biofuels seems to reflect a fundamental misunderstanding of how a performance standard works. By definition all fuels must be included in the standard to fully assess the overall average fuel carbon intensity. Moreover, by including an accounting for indirect land use change, the California LCFS has avoided the basic double counting problems associated with Kyoto accounting, as they call it. The last element of so called double counting Searchinger and Heimlich mention is associated with lost food consumption.

Competition of bioenergy uses of crops with food or with land for growing food is an important policy question, although primarily a moral question rather than a matter of carbon accounting. Biofuels use in California seems unlikely to put significant pressure on global food production in the timeframe of the current LCFS (through 2020), but as more ambitious targets are considered, measures to mitigate food versus fuel conflicts may be an appropriate addition to mechanisms to mitigate ILUC emissions.

The Searchinger and Heimlich report suggests that for crop based bioenergy to have real carbon reductions compared to fossil fuels additional carbon uptake is required, which can only arise in highly restricted situations and not from using current crops like maize or soybeans. It is interesting to compare the findings of this report with the findings of Babcock and Iqbal that much of the increased production of major crops in Brazil arose from double and triple cropping and from increasing the fraction of planted acreage that was harvested. These examples point to the real potential for increases in the utilization of existing land, which would meet the theoretical "additional carbon" test proposed by Searchinger and Heimlich. I mention this to highlight that alternative accounting schemes are not necessarily consistent with their claims that carbon mitigation credit can only arise for residues.

Searchinger et al.'s 2008 paper in Science on indirect land use change was in part responsible for initiating a great deal of detailed research on how increased biofuel production would reverberate through the global agricultural system. The understanding of the world represented by the totality of this research is far more nuanced than the zero sum game portrayed by this latest Searchinger and Heimlich report

The practical reality of transportation fuel markets is that biofuels are now a significant component of the fuel system. The administration of a carbon intensity based fuels policy framework like the LCFS requires a credible climate accounting framework that should be based on the best available science rather than an interest to promote or disqualify any particular fuel. The role of agriculture in energy markets and the impact for food and forest protection are important, but the potential contributions of bioenergy to carbon mitigation cannot be dismissed out of hand, no more than can the ultimate constraints on this contribution.

John DeCicco's Liquid Carbon Challenge paper

In a recent review John DeCicco argues that the combination of consequential and attributional lifecycle analysis in what he calls Fuel Cycle Analysis used to administer the LCFS is fatally flawed, and that "emissions from liquid fuels must be balanced by increasing the rate of net carbon fixation." The uncertainty about the carbon benefits of biofuels arises from the question of whether their expansion comes at the cost of carbon stored in forests and soils, rather than to the annual flows into and out of annual crops. Since the primary changes in forest cover occur in the tropics, and the connection to biofuels use is mediated by global agricultural commodity markets, the uncertainty about these benefits can only be resolved by examining the whole system, and especially the impact on forests and other carbon rich ecosystems. This creates a complicated analytical problem, but not one that is necessarily clarified by changing the accounting framework.

DeCicco's argument about the theoretical challenges associated with combining attributional and consequential lifecycle analysis is well taken, and research in different approaches is advisable. But his argument seem to reach beyond methodological issues and argues that the climate benefits associated with biofuels in the analysis underlying California's LCFS stem from analytical errors. It is not at all clear that his theoretical musings support this conclusion and in any case his paper lacks concrete suggestions that would improve the administration of the LCFS.

In conclusion, we applaud the work ARB staff has done these last five years to advance the state of knowledge on indirect land use change emissions. The LCFS regulation is on solid ground for reauthorization through 2020. As the ARB starts to look beyond 2020, it is appropriate to consider whether other analytical approaches, lifecycle frameworks, and protective measures are needed to ensure that California's low carbon fuels meet diverse policy goals. These goals start with carbon mitigation, but must also ensure that California's climate mitigation strategies do not export problems in food markets or forest protection elsewhere in the world. We look forward to continued engagement with ARB on these issues over the next few years.

LCFS 21-9

Sincerely,

Jeremy Martin, Ph.D.
Senior Scientist and Fuels Lead
Clean Vehicles Program

This page intentionally left blank.

21_OP_LCFS_USC Responses

99. Comment: **LCFS 21-1 through LCFS 21-9**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

Comment letter code: 22-OP-LCFS-NRDC

Commenter: Simon Mui

Affiliation: California Vehicles and Fuels Natural Resources Defense Council

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

22_OP_LCFS
_NRDC

California Environmental Protection Agency
Air Resources Board

Comment Log Display

BELOW IS THE COMMENT YOU SELECTED TO DISPLAY.
COMMENT 22 FOR LOW CARBON FUEL STANDARD 2015 (LCFS2015) - 45 DAY.

First Name: Simon
Last Name: Mui
Email Address: smui@nrdc.org
Phone Number: 415-875-6120
Affiliation:

Subject: Promotum Study on LCFS Compliance to 2025
Comment:
Please find attached a study by Promotum, a fuels and chemicals consultancy, that was commissioned by Natural Resources Defense Council, Union of Concerned Scientists, and Environmental Defense Fund.

The study demonstrates that a 10% target by 2020 is achievable using a variety of lower carbon fuels as well as technologies to reduce the carbon-intensity of refining and crude oil production. If the LCFS provides the credit incentive value assessed in ARB staff's proposed ISOR, a 15% reduction target could even be achieved by 2025. LCFS 22-1

Additional information can be found at:
http://www.nrdc.org/media/2015/150202.asp

Best regards,
Simon Mui, Ph.D.
Senior Scientist and Director
California Vehicles and Fuels
Natural Resources Defense Council

Attachment: www.arb.ca.gov/lists/com-attach/24-lcfs2015-UCAGcgZoBTtSOwRw.zip

Original File Name: Promotum Study.zip

Date and Time Comment Was Submitted: 2015-02-17 12:15:44

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

FOR IMMEDIATE RELEASE

Press contact:
Christine Keeves, NRDC: ckeeves@nrdc.org / 415-875-6155
Debra Holtz, UCS: debbie.holtz@gmail.com / 510-409-7936
Mina Jung, EDF: mjung@edf.org / 415-293-6111

Report: Pump Primed for Three-Fold Growth in Clean, Alternative Fuels by 2025
California's Low Carbon Fuel Standard Targets are Achievable and Will Drive Growth

SAN FRANCISCO (February 2, 2015) – California is capable of tripling its use of alternative fuels over the next 10 years, according to a new report by the fuels and energy consulting firm Promotum. The study examined the growth potential for cleaner fuels under California's Low Carbon Fuel Standard (LCFS), a program requiring the oil industry to reduce the carbon intensity of fuels through the production and use of cleaner fuels.

"It's time for the oil industry to send the lobbyists and lawyers home and put their engineers to work," said Dr. Simon Mui, director of NRDC's work on clean vehicles and fuels in California. "Despite their protests, this shows once and for all that industry can meet and exceed the standard by diversifying to cleaner fuels like advanced biofuels, renewable natural gas, and clean electricity. A range of cleaner options is there for the taking."

The report's findings show that the oil industry can meet the LCFS reduction target – a 10 percent decrease in carbon emissions by 2020 – through known, existing fuels and refinery technologies. This includes expanding the use of lower-carbon biodiesel and renewable diesel, biomethane, electricity, and ethanol, as well as improving the carbon-intensity of existing alternative fuels. It also found that existing oil refineries and crude oil production facilities could dramatically cut their carbon footprint by integrating renewable energy, utilizing innovative technologies, and investing in greater energy efficiency.

The study analyzed different scenarios in which the program would encourage cleaner fuels by rewarding producers based on their environmental performance, measured in tons of carbon pollution reduced. The strong, performance-based incentive provided by the LCFS – worth potentially more than a dollar per gallon for ultra-low carbon fuel producers of fuels such as ethanol made from agricultural waste or biodiesel made from recycled oils – will enable the market to expand and diversify.

"A growing body of evidence shows that the LCFS will be a critical tool toward achieving Gov. Brown's new goal of cutting petroleum use in cars and trucks in half by 2030 to help California meet its climate goals," said Dr. Jeremy Martin, Senior Scientist and Fuels Lead at the Union of Concerned Scientists.

"By providing a steadily growing market for clean fuels, the LCFS supports investments that will energize clean transportation for decades to come."

At its February 19 hearing, the California Air Resources Board will consider its staff's proposal for re-adoption of the LCFS together with a series of enhancements to the program. Together with other clean transportation policies, the standard will enable California to continue reducing carbon emissions that contribute to global warming and poor air quality

"The LCFS is working to diversify California's energy mix. Innovation and investments in clean fuels is growing," said Tim O'Connor, Director of EDF's California Climate Initiative. "As part of a suite of smart policies under our clean energy law, AB32, we're seeing more efficient vehicles, more clean fuel options, and better access to transit. Californians will breathe easier, save money at the pump, and reduce their dependence on oil."

Over the next six years, 70 million tons of carbon pollution will be avoided and 280 million barrels oil will be saved. That's equivalent to avoiding the pollution from nearly 15 million cars and trucks in one year.

As California considers more ambitious future targets, this report – along with a growing body of research over the last several years – demonstrates that the state can reduce the carbon intensity of fuels beyond its current 10 percent reduction target by 2020 to 15 percent by 2025. Long-term regulatory stability is key and will help enable the alternative fuels market to steadily grow to supply 20 percent of California's transportation energy, up three-fold by 2025 compared to when the program began in 2011.

The report was commissioned by the Natural Resources Defense Council (NRDC), the Union of Concerned Scientists (UCS), and the Environmental Defense Fund (EDF).

The full report can be found here: http://www.nrdc.org/transportation/california-low-carbon-fuel-standard.asp

Martin's blog can be found here: http://blog.ucsusa.org/low-carbon-fuels-california-610

O'Connor's blog can be found here: http://blogs.edf.org/californiadream/2015/02/02/a-possible-antidote-to-the-fossil-fuel-economy

Mui's blog can be found here: http://switchboard.nrdc.org/blogs/smui/

###

The Natural Resources Defense Council (NRDC) is an international nonprofit environmental organization with more than 1.4 million members and online activists. Since 1970, our lawyers, scientists, and other environmental specialists have worked to protect the world's natural resources, public health, and the environment. NRDC has offices in New York City, Washington, D.C., Los Angeles, San Francisco, Chicago, Bozeman, MT, and Beijing. Visit us at www.nrdc.org and follow us on Twitter @NRDC.

The Union of Concerned Scientists puts rigorous, independent science to work to solve our planet's most pressing problems. Joining with citizens across the country, we combine technical analysis and effective advocacy to create innovative, practical solutions for a healthy, safe, and sustainable future. For more information, visit us at www.ucsusa.org and follow us on Twitter @UCSUSA

Environmental Defense Fund (edf.org), a leading international nonprofit organization, creates transformational solutions to the most serious environmental problems. EDF links science, economics, law and innovative private-sector partnerships. Connect with us on our California Dream 2.0 blog, Twitter and Facebook.

California's Low Carbon Fuel Standard:
Evaluation of the Potential to Meet and Exceed the Standards

Promotum
10 Chauncy Street
Cambridge, MA
02138

February 2, 2015

Contents

1. Regulatory Background

California's adoption of the Global Warming Solutions Act of 2006, also known as Assembly Bill (AB) AB32, set in motion a series of policies to reduce greenhouse gas (GHG) emissions in the state to 1990 levels by 2020 – roughly a 20 percent reduction – while also protecting public health. Under AB32, the California Air Resources Board (ARB) developed a series of GHG reduction strategies as part of a Scoping Plan for achieving the 2020 goal. For the transportation sector, the key programs ARB adopted include standards for cleaner, more efficient cars and trucks; a clean fuels standard; a cap-and-trade regulation; and established targets to reduce emissions through more sustainable, transit friendly and walkable communities.

The state's clean fuels standard, known as the Low Carbon Fuel Standard (LCFS), was adopted in 2009 as an early-action measure under AB32 and in furtherance of Executive Order S-01-07 by then Governor Arnold Schwarzenegger. In addition, in his recent fourth inaugural address, current Governor Jerry Brown provided targets for a series of new environmental goals for 2030, including reducing current petroleum use in cars and trucks by 50 percent.[1]

California's LCFS is a performance-based standard requiring petroleum refiners and other fuel providers to reduce the carbon-intensity of transportation fuels used in California by 10 percent by 2020. The carbon-intensity of each fuel is measured on a full lifecycle basis, which includes accounting for GHG emissions from production of a feedstock, transport, refining, distribution, and end-use combustion. Because the standard is technology-neutral, companies can earn LCFS "credits" any number of ways, including improving their processes or through switching to renewable feedstocks and inputs. Each LCFS credit represents one metric ton of reductions in GHG emissions. The LCFS is designed to include market-based features that allow LCFS credits to be sold, banked, or utilized to help meet the requirements.

2. Project Scope

To inform the dialogue about the re-adoption of the LCFS and establishment of revised annual compliance requirements, Promotum Inc., an independent technical and management consulting firm focused on fuels and chemicals, was commissioned by the Natural Resources Defense Council (NRDC), Union of Concerned Scientists (UCS) and the Environmental Defense Fund (EDF) to evaluate likely scenarios for compliance and the impact of credit values on incentivizing greater production and volumes of low Carbon Intensity (CI) fuels for sale in the state.[2]

[1] http://gov.ca.gov/news.php?id=18828

[2] The conclusions and views contained herein are solely those of the consultant and do not necessarily reflect those of NRDC, UCS, and EDF.

Promotum reviewed and analyzed fuel availability, prior supply studies, data from obligated parties (fuel suppliers) through quarterly reporting to the ARB, California Energy Commission (CEC) information, U.S. Energy Information Administration (EIA) data, and consulted with a wide number of industry participants with specific sector expertise to develop a forecast of supplies and a model of future low carbon fuel production.

As part of the creation of these scenarios we sought to incorporate the latest technology and commercialization developments. For example, 2014 saw the startup of the first two commercial scale cellulosic ethanol facilities in the U.S. with a third scheduled for launch in early 2015. We sought to understand how likely advances in technology would impact future cost of production. Ultimately, we looked at the impact of LCFS credit value both producing additional lower CI fuels in California, and on moving them into California.

For analytical purposes the study evaluated two scenarios: a Reference Case and Low Case.

- The Reference Case assumes the value of credits within the LCFS market remains at roughly $100 per metric ton reduction ($100/MT) over the 2015 to 2025 timeframe. This case is consistent with the estimate currently included in ARB's assessment under its regulatory analysis, provided as part of its 2014 staff report.
- The Low Case assumes a LCFS Credit Value below $50/MT. This case is consistent with credit values observed throughout 2014.[3]

3. Key Findings

The key findings of this study are:

Supply Potential

- **The petroleum industry can meet current LCFS compliance requirements through 2020 by taking advantage of the program's performance-based incentive for reducing greenhouse gas (GHG) emissions.** The LCFS credit system provides obligated parties sufficient incentive to reduce their carbon emissions in a timely manner. Promotum's analysis shows that a $100 per MT credit value, (an amount utilized by ARB for their regulatory proposal), provides sufficient incentive to achieve a 10% reduction in fuel carbon-intensity by 2020 through three mechanisms: (1) providing greater volumes of alternative fuels in California, (2) reducing the carbon-intensity of traditional fuels, and (3) reducing emissions at refineries and throughout the petroleum value chain.

[3] http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm

- **Diesel substitutes, lower carbon-intensity (CI) ethanol, and reductions in the carbon footprint across the petroleum value chain are primary pathways for meeting a 10% target.** Shifts toward lower-carbon feedstocks, including recycled fats and oils, and the production of cellulosic ethanol, including ethanol made from agricultural residue, will reduce carbon intensity. Using electricity as fuel for cars, trucks, and offroad sources such as trains will also significantly contribute to meeting the LCFS.

- **California can extend the LCFS beyond a 10% carbon-intensity (CI) reduction in 2020 to 15% in 2025.** At $100/MT there is sufficient biofuel supply and incentive to support an additional one percent per year reduction from 2020 through 2025.

- **Even under relatively low LCFS credit values, below the historical 2012 and 2013 credit value, California can meet existing requirements through 2020.** However, sustained low credit values may be insufficient to provide enough incentive to achieve a15% reduction by 2025.

Benefits

- **The LCFS program will contribute significantly to meeting California's goal of cutting petroleum use in half by 2030.** Alternative fuels use is increasing, up from supplying only 6% of transportation energy to 14% by 2020 and 20% by 2025. For diesel, much of the growth in demand for cleaner, alternative fuels will be met through biodiesel, renewable diesel, as well as natural gas including biomethane. Growth on the gasoline side will occur largely through increases in lower CI ethanol and electricity.

- **The LCFS is estimated to result in over 70 million metric tons of GHG emission reductions over the next five years through 2020**. Increasing the requirements to 15% by 2025 could generate 183 MMT CO_2e of reductions over the next ten years through 2025, equivalent to cutting the emissions of nearly five coal fired plants operating for ten years.[4]

Reduction Opportunities, Value Creation, and Economics

- **The petroleum industry can achieve a significant portion of the standard by reducing the carbon-intensity of gasoline and diesel through improvements at petroleum refineries and crude oil production facilities.** Just as alternative fuel companies can achieve reduced overall carbon-intensity though efficient production and

[4] U.S. EPA Greenhouse Gas Equivalencies Calculator. http://www.epa.gov/cleanenergy/energy-resources/calculator.html

processing, the petroleum sector has significant potential to reduce the CI of gasoline and diesel through energy efficiency improvements, integration of renewable energy inputs such as biomethane, and use of innovative technologies including solar thermal. This study estimates these three measures alone could result in a 1.5% reduction in carbon-intensity across petroleum-based gasoline and diesel by 2020, growing to a 3% reduction in CI by 2025.

- **Under the Reference Case of $100 per metric ton value, energy efficiency projects at refineries would be significantly more attractive to fuel suppliers.** Based on information generated by energy efficiency audits for California refineries' past and currently proposed projects, the LCFS credit value could more than double the operating savings at the facilities.[5] In addition to garnering operational savings associated with energy efficiency investments, refineries would be further incented under the LCFS to reduce the carbon-intensity of fuel products. Such improvements also allow fuel producers to forgo purchasing pollution permits under the state's cap-and-trade regulation.

- **Use of biomethane at refineries and crude oil facilities to displace fossil natural gas is a potentially attractive option to the reduce carbon-intensity of gasoline and diesel. Such uses are in addition to the use of biomethane in natural gas vehicles.** At the end of the Fall 2014, the LCFS incentive had resulted in an increase in the use of biomethane for natural gas vehicles to 40% of the mix, primarily from biogas capture at landfills.[6] However, a much greater volume of natural gas in California is currently consumed by refineries and crude oil facilities. Full substitution of this end-use with biomethane going forward would represent a potential of 12 MMT of reductions of carbon annually, such that even partial substitution could meet a significant portion of the LCFS.

- **Future capital and operating costs for cellulosic ethanol will decrease over time.** While it is possible for California entities to import hundreds of millions of gallons of ultra-low CI cellulosic ethanol at some point in the future, it is difficult to predict exactly when those gallons will be available. However, cellulosic technology providers have successfully reached commercial scale at some plants and the first wave build out is well underway. Future validation of the first wave of cellulosic production facilities will pave the way for financing of the second and third wave of cellulosic plants. It is widely

[5] Air Resources Board (2013), *Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources Refinery Sector Public Report*, Issued June 6, 2013. http://www.arb.ca.gov/cc/energyaudits/eeareports/refinery.pdf
[6] Air Resources Board (2014), *Low Carbon Fuel Standard Reporting Tool Quarterly Summaries*, http://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm.

expected, based on industry experience and learning, that the second wave and later facilities will have lower capital costs and improved efficiency.

- **Even remaining conservative on the timing and volumes for cellulosic ethanol in 2020, given the uncertainty of the second wave of production plants, other low-carbon fuels and technologies can provide sufficient credits under the scenarios evaluated.** Since the LCFS is technology-neutral performance based, and also includes an ability for parties to "bank" or save credits, regulated entities have enormous flexibility to comply. No single technology is required to generate the reductions needed.

- **Over-compliance over the 2015 to 2018 period will allow for compliance in later years through 2020**. The so-called "banking" provisions of the LCFS allow companies to flexibly utilize credits generated in earlier years to comply with future years. As of the end of 2014, parties registered within the LCFS have registered an over-compliance of approximately six million metric tons, with those credits banked for use in future years.[7]

Potential Barriers Moving Forward

- **The LCFS needs underlying regulatory stability to achieve a 10% reduction requirement by 2020 and a theoretical 15% requirement by 2025.** As a result of lawsuits brought against the state by oil and corn ethanol industry groups, the current LCFS reduction mandate has remained at a one percent (1%) CI reduction level since 2013, resulting in significant over-compliance with the standard. As the same time, LCFS credit prices have dropped from nearly $80 per ton in December of 2013 to $26 per credit in December of 2014.[8] Under a scenario where LCFS credit prices remain under $50/ton for 2016 and beyond, the sustained low credit price causes an insufficient market signal, with the overall LCFS market generating annual deficits beginning in 2018 and regulated industries fully using all banked credits by 2020. In 2020 and beyond, the LCFS would experience net cumulative deficits. Accordingly, for the LCFS to achieve full compliance, sufficient regulatory certainty must exist to provide a sufficient market signal to spur additional alternative fuel supplies.

- **Reductions in the carbon-intensity on the gasoline side will be slower than on the diesel side unless greater expansion of E15 and E85 occurs.** While credit values at $100/ton will be sufficient for production of low CI ethanol, further capital investments are needed to develop the next wave of cellulosic ethanol facilities. Furthermore, additional infrastructure investments will be needed to expand the use of low CI ethanol

[7] Air Resources Board (2014), *Low Carbon Fuel Standard Regulation: Initial Statement of Reasons*. December 31, 2014. http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm
[8] Information based on reporting of the credit values by ARB. http://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm.

beyond E10 (e.g. E15 or E85) and allow the industry to achieve a larger reduction. This includes ethanol producers overcoming limitations due to lack of upgraded ethanol infrastructure including tankage and blender pumps.

- **Long-term regulatory stability and firm commitment with both the Low Carbon Fuel Standard and the federal Renewable Fuels Standard is necessary for financing of new facilities**. Major investors are sensitive to regulatory instability and require long-term time horizons before financing major capital projects. Ensuring forward momentum will, at minimum, require the LCFS credit value to be sufficiently robust to achieve compliance.

4. Methodology

Promotum developed spreadsheets for each fuel technology. Where available we developed supply inputs based on prior studies and on discussions with industry experts and stakeholders. The modeling evaluated a Reference Case and Low Case, with calculations and accounting following ARB's methodology as presented in its regulatory analysis.[9]

For consistency we adopted ARB's baselines for gasoline and diesel CIs; forecasts for gasoline and diesel consumption; the proposed compliance curve from 2015 to 2020; and the banked LCFS credits estimated for 2014. For assumptions on CI, we used the CI look up table from ARB's *Initial Statement of Reasons* (ISOR) Appendix B "average annual CI assumptions." Using the CI values and forecasts, we calculated the overall compliance credits and deficits annually to evaluate compliance each year. Where available we utilized obligated party reporting (2013 and 2014) to ground the model, information that ARB makes publicly available.[10]

The fuel volume tables for the 2015 to 2025 period of study assume that refiners and fuel importers must reduce the lifecycle GHGs produced from gasoline and diesel. This includes crude oil production, transportation, refining, distribution, and combustion. LCFS deficits can be offset by blending lower CI gasoline and diesel substitutes, purchasing credits, utilizing banked credits, or generating credits directly from refinery investment projects or applying innovative technologies at crude oil production facilities. In cases where producers use blending as a compliance strategy, they will largely use ethanol and biodiesel. Additional credits accrue from electric vehicles, both fossil-based and bio-based natural gas (or biomethane), and hydrogen used for fuel cell vehicles. These categories are currently small but growing in their contributions to meeting the standard.

For each case we developed biofuel supply curves for 2015 to 2025. There are many pathways and approved biofuels, but the major substitutes include:

Major Gasoline Substitutes and Technologies	Major Diesel Substitutes and Technologies
Ethanol (Corn, Sorghum/Wheat, Sugar, Cellulosic)	Biodiesel (Soy, Corn Oil, Waste Grease/Used Cooking Oil, Animal Tallow)
Electricity	Renewable Diesel (similar feedstocks)
Petroleum Improvements	Compressed Natural Gas or Liquefied Natural Gas, (Fossil and biomethane)
Renewable Gasoline	Petroleum Improvements

[9] http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm
[10] http://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm

This report also examined potential GHG reductions in the petroleum value chain. Promotum believes there is significant opportunity to reduce the overall CI of traditional gasoline and diesel, principally by utilizing steam derived from biogas or solar thermal energy sources for Enhanced Oil Recovery (EOR) operations at the well head, substituting biomethane for fossil natural gas at refineries, and utilizing off-the-shelf energy efficiency technology and improved operations at refineries. Promotum did not evaluate use of carbon capture and sequestration (CCS) at petroleum facilities.

5. Scenarios

Promotum created two hypothetical cases to evaluate the effects of credit prices on potential achievement of LCFS targets. For each case, we calculated the LCFS deficits (MT CO_2e generated) produced by the petroleum value chain and the combustion of traditional gasoline and diesel. To this obligation, we added back the LCFS credits produced (MT CO_2e reduced) by substituting in biofuels and through reductions in emissions from the petroleum value chain. We then added previously banked credits before comparing the annual and cumulative total against ARB's compliance curve.

For purposes of the study, we assumed steady state average pricing for Low Carbon Fuel Standard credits. Based on these prices, we evaluated how much low carbon fuel could be produced or imported to California for each fuel type.

As a starting point for the biofuels portion of the scenario assessment, we started with the basic strategy of assuming the penetration of as much low CI substitute biofuel into the California fuels market as was available. This assessment took into account limitations in available supply or potential new capacity. We then backfilled needed fuel volumes with the best available corn ethanol and soy-based biodiesel - using compliance data filed quarterly with ARB to set starting levels of blended ethanol and biodiesel. The starting blend rate for ethanol was 10.6% (by volume) and about 2% for biodiesel.

To calculate the GHG reductions currently required by the LCFS, we used the currently proposed compliance schedule for 2016 through 2020 in ARB Staff's *Initial Statement of Reasons.* According to the analysis, by 2020 the LCFS requirements would effectively require enough credits to reach a 10% reduction in carbon-intensity for gasoline and diesel.

To calculate the GHG reductions required under an LCFS that extended to 2025, we extended the LCFS requirements to a 15% CI reduction, increasing at an additional rate of 1% per annum. Figure 1 shows the compliance requirements used for both scenarios.

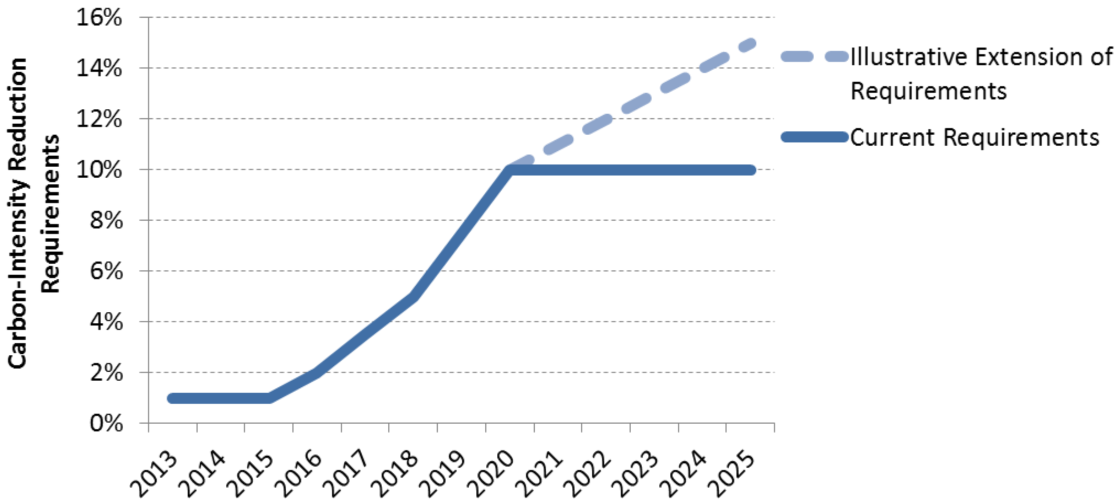


Figure 1: Current proposed requirements achieving 10% by 2020 and extension of requirements to 15% by 2025.

6. Issues and Considerations

Assessing the feasibility of LCFS reductions and differential credit values and the effect of those credit values on biofuel supplies is a considerable and complicated subject. We describe some of the complexities in the following section.

A. Internal LCFS Market Conditions

Since the program's inception, the credit values have experienced market fluctuations. Commodity market experts, such as at Argus, suggest the reasons for volatility encompass a number of factors[11]:

- Regulatory and legal uncertainty in the initial three years,
- Over-compliance occurring due to the low standard — one percent — maintained since 2013,
- A short spot market due to producers banking surplus credits in expectation of future shortfalls, and
- A thin LCFS credit market due to a limited numbers of buyers, sellers, and volumes of credits able to be bought and sold.

[11] *Argus White Paper: California Environmental Markets: Factors that Affect LCFS and GHG Trading,* Argusmedia.com

B. Combined Effects of the LCFS and the Renewable Fuel Standard

In addition, understanding the implications of the California GHG reduction measures must account for the federally mandated Renewable Fuel Standard (RFS) managed by the U.S. Environmental Protection Agency (EPA). The RFS requires increasing volumes of biomass-based fuels, with specific volumetric requirements for different categories of fuels meeting GHG reduction thresholds. Fuels that qualify are eligible to generate Renewable Identification Numbers (RINs), a serial number that both allows for tracking of fuel and allows for trading among parties. Like LCFS credits, RINs have a market value for those that own them. In addition, RINs become separable after biofuels are blended - meaning producers can choose to buy and retire RINs instead of blending biofuels themselves.

As a result, if the LCFS credit value plus RIN value exceeds transportation cost to California for a given gallon of biofuel, this should provide enough incentive for producers to make more biofuels and sell them into the California market. Figure 2 demonstrates how RINs and LCFS credit work in tandem to increase supplies of the biofuel.[12]

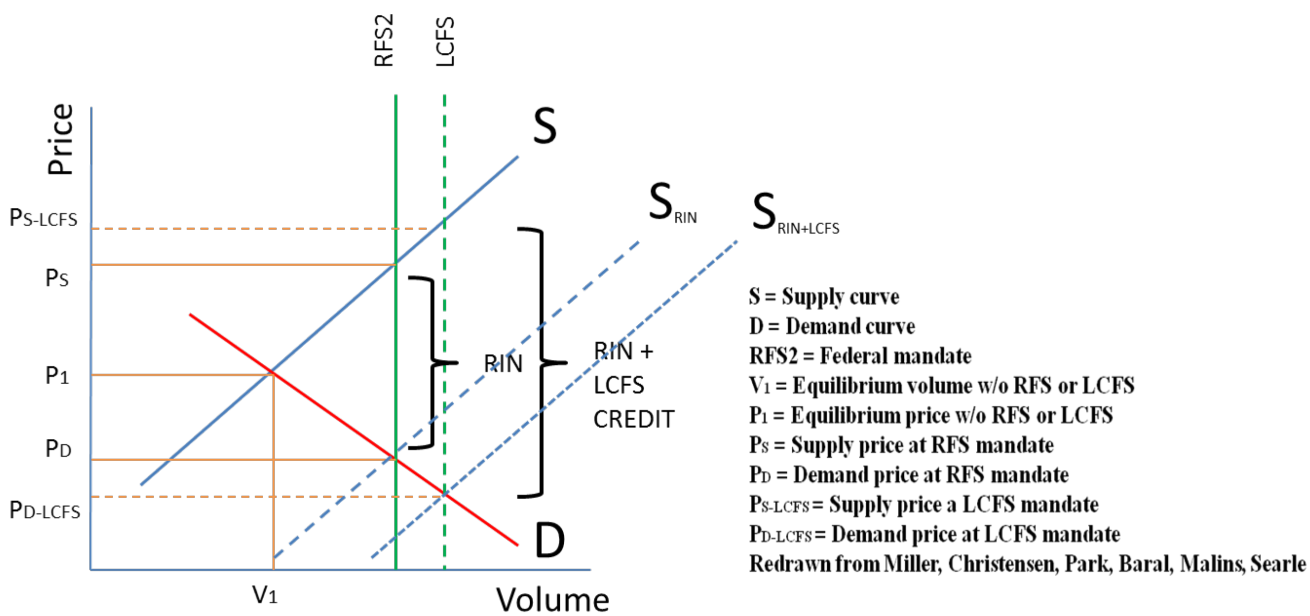


Figure 2: Biofuel economics of LCFS credits and RFS RINs.

[12]N. Miller et al (2013), *Measuring and addressing the investment risk in second-generation biofuels* industry, International Council on Clean Transportation, 2013. http://www.theicct.org/addressing-investment-risk-biofuels

C. Technology and infrastructure development

Notwithstanding the impact of overlapping LCFS and RIN credit prices, the market signal for Low-CI fuel development gets more complicated when considering the stages of technology development and production capacity for many low CI fuels (i.e. advanced biofuels). Based on present market conditions, it remains evident that much of the nation's prospective supply of low-CI fuels is still maturing. Significant infrastructure issues need to be addressed for many biofuels before the market is truly efficient with high price elasticity.

Under these circumstances technology developers are making investments in technology and capacity based on market expectations, including the future of the RFS and the LCFS programs in terms of regulatory certainty and the RIN and LCFS credit markets. The diagram below based on biofuel supply curves generated by Nathan Parker at UC Davis describes the situation graphically.[13] For our purposes we assumed that LCFS credit values will signal prospective suppliers in anticipation of a future efficient market.

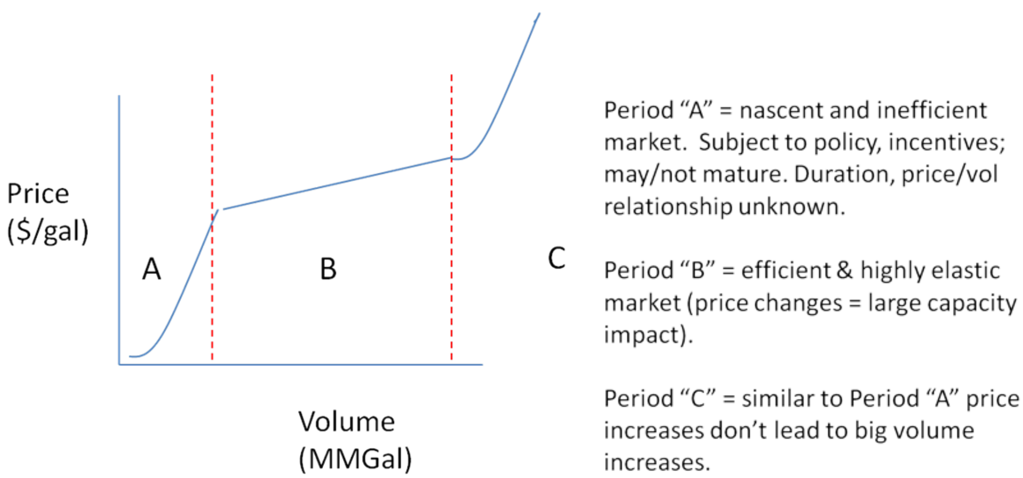


Figure 3: Biofuel supply at varying price points.

For each of our cases we estimated the biofuels volumes, which after analysis we believed would be available in California based on the LCFS credit value, constrained by our understanding of the current state of technology, infrastructure and U.S. or global forecast capacity. To understand the value of each biofuel to California we calculated how much each fuel resulted in reduced carbon dioxide emissions and then what additional value was associated with the fuel, on a dollar per gallon gasoline or diesel equivalent energy basis ($/gge or $/dge), depending on which fuel they substituted for.

[13] N. Parker (2011), *Modeling Future Biofuel Supply Chains Using Spatially Explicit Infrastructure Optimization*, Dissertation, Univeristy of California, Davis. http://www.its.ucdavis.edu/research/publications/publication-detail/?pub_id=1471

D. LCFS incentive value for alternative fuels

Figure 4 translates LCFS credit value for gasoline and diesel substitutes to a dollar per gallon gasoline equivalent basis. The credit value range shown represents a low of $50/MT CO_2e to a high of $150/MT.

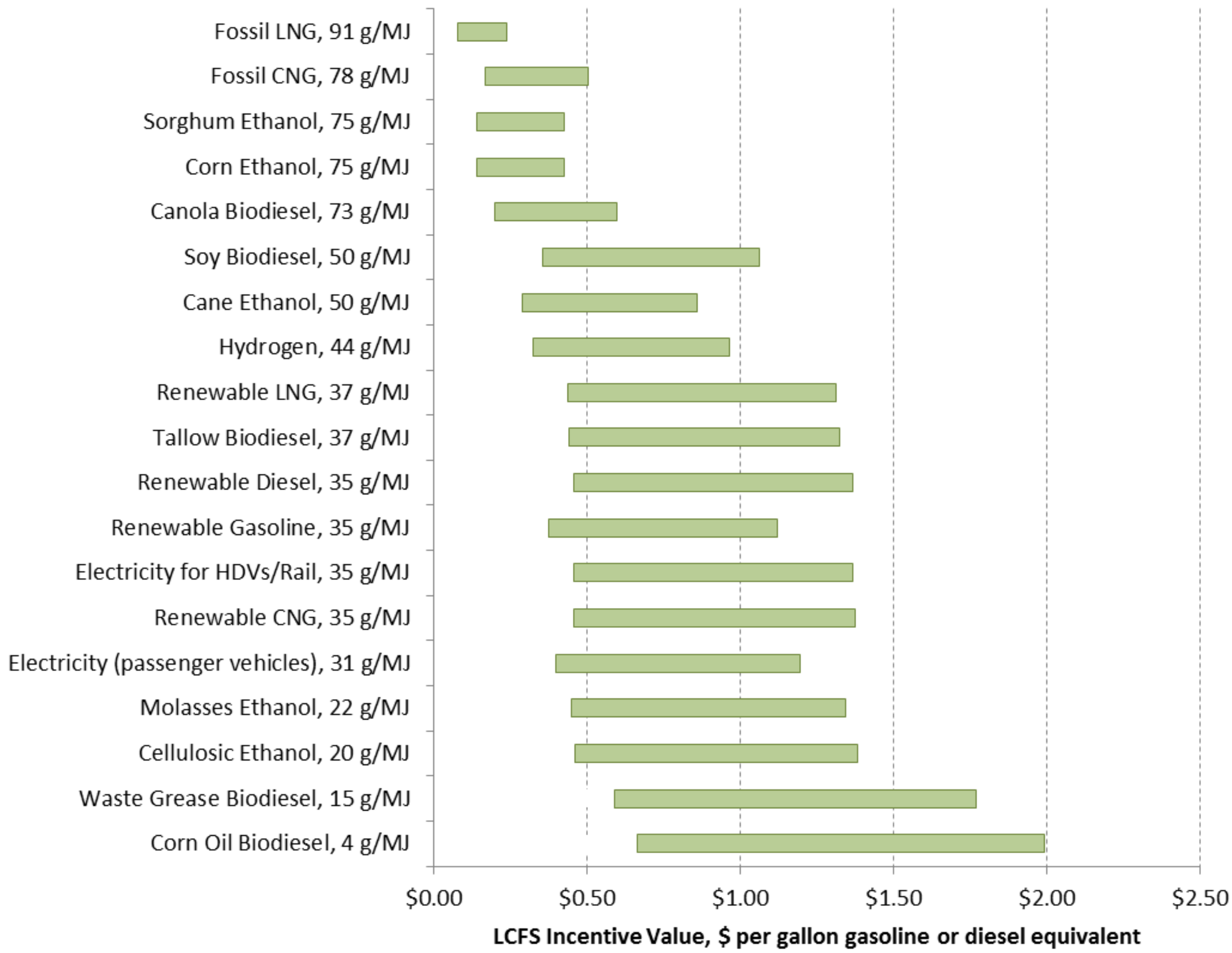


Figure 4: Incentive value provided by the LCFS. Range represents $50 to $150 per MT CO2e reduction.

As shown in Figure 4, the Reference Case of $100 per MT reduced of CO_2e translates into an additional value of $0.92/gallon for cellulosic ethanol. Theoretically, as long as the LCFS credit value together with the associated cellulosic RIN prices exceed transportation costs, we should see producers ramping up capacity and selling into California as well as California producers expanding and increasing production.

In the Low Case ($50/MT reduction), the value for cellulosic ethanol translates to $0.46/gallon in addition to the RIN value. Higher LCFS credit values, of course, are possible and would theoretically provide greater incentive for domestic production or greater importation. However, other factors, such as the state of technology development and availability for financing of new facilities, may be more critical in establishing necessary volumes than the incentive value of RINs and LCFS credits.

E. LCFS incentive value to reduce petroleum sector emissions

The LCFS also provides incentives and returns credit value to petroleum companies that choose to reduce lifecycle oil and gas emissions directly. These companies may generate credits by reducing the CI of crude oil production and refineries through greater use of energy efficiency, innovative technologies, or renewable inputs. Like other fuels, these investments can yield LCFS credits which have higher or lower value based on the overall credit price.

One example of the value of the LCFS for petroleum company investments can be extrapolated from self-reported data on energy efficiency investments by California petroleum refineries to the ARB. [14] As reported, there are over four hundred past and planned energy efficiency and co-generation projects at refineries in California, with a total capital cost of approximately $2,600 million - resulting in annual energy savings of about $200 million for refineries and 2.8 million metric tons of reduced GHGs.

Using past projects identified to ARB as an illustration, if refineries were to invest in future energy efficiency improvements that resulted in an additional 2.8 million metric tons of reductions and achieved the same annual operating savings, the additional LCFS credit value generated could be between $140 to $280 million dollars annually (at a $50 to $100/ton credit price respectively). In addition California refineries would avoid having to purchase permits, or allowances, within the state's cap-and-trade regulation to cover their remaining CO_2 emissions, yielding an additional cost saving of about $35 million annually, assuming current permit prices of just over $12 per ton. These savings, in theory, would increase the overall annual savings from $200 million (energy savings) to $375 to $515 million annually at refineries with the additional LCFS credit value and avoided need to purchase cap and trade pollution permits. While further analysis in this area is warranted to provide finer resolution on a project-specific basis, initial calculations suggest that the LCFS could more than halve the payback period for investments in energy efficiency projects in some cases, making these projects significantly more attractive for petroleum companies.

7. Key Outputs

Promotum's analysis incorporates three major mechanisms that drive reductions in the carbon intensity of transportation fuels. The first is to increase the volume of renewable fuels we

[14] http://www.arb.ca.gov/cc/energyaudits/eeareports/refinery.pdf

currently use (grow the market); the second is to improve the carbon-intensity (CI) of the fuel (improve the fuel in the market); and the third is reduce emissions directly at refineries and crude oil production facilities using energy efficiency, renewable energy, and innovative technologies. To achieve the greatest reductions, California will likely need to spur all three mechanisms to varying degrees.

In our estimate, compliance with the LCFS will result in the alternative fuels market growing to 14% of the transportation energy mix by 2020 and 20% by 2025. Constraints on growth include the E10 blend-wall as well as the rate at which biodiesel can expand and be utilized in California. More volumes of ethanol and biodiesel will be needed to achieve compliance. This means California will need to accelerate E15 and E85 deployment as well as biodiesel blends above B5 levels post 2017 based on the Reference Case scenario.

In terms of improving the carbon-intensity of fuels, achieving the LCFS will require migration toward lower-carbon feedstocks; improvements at the biofuel plant and at the agricultural level. The LCFS is already sending a market signal, but regulatory certainty is necessary to ensure sufficient value for technology improvements to continue.

Improvements along the petroleum value chain remains, to date, one of the largest untapped areas of potential for CI reductions across the existing fuel pool. While alternative fuels will increase in market share, the large majority of transportation fuels will remain petroleum-based over the timeframe. Even small changes in CI, when spread across large fuel volumes, will lead to significant reductions.

The analysis of the effects of credit prices demonstrates three findings. First, the LCFS credit value is an important factor in increasing low-carbon fuel supply and reductions in GHG emissions we can achieve. Second, ARB's regulatory analysis, showing credit prices around $100/ton, would be sufficient to allow for a 10% requirement to be met by 2020 while extending the standard to a 15% level by 2025. Third, if credit values remain low – as we saw in the past year, due to regulatory uncertainty– then sufficient incentive will not exist for low-carbon fuel production, and compliance beyond 2020 will be unlikely to occur.

Beyond the recent decreases in oil prices, the most significant barrier to the supply of low CI fuels in California remains uncertainty with the regulatory environment. Oil companies, alternative fuel companies, and other energy investors make large capital commitments and require enough time to achieve acceptable returns.

LCFS Reference Case:

Figure 5 demonstrates annual and cumulative credit balance over time for the Reference Case.

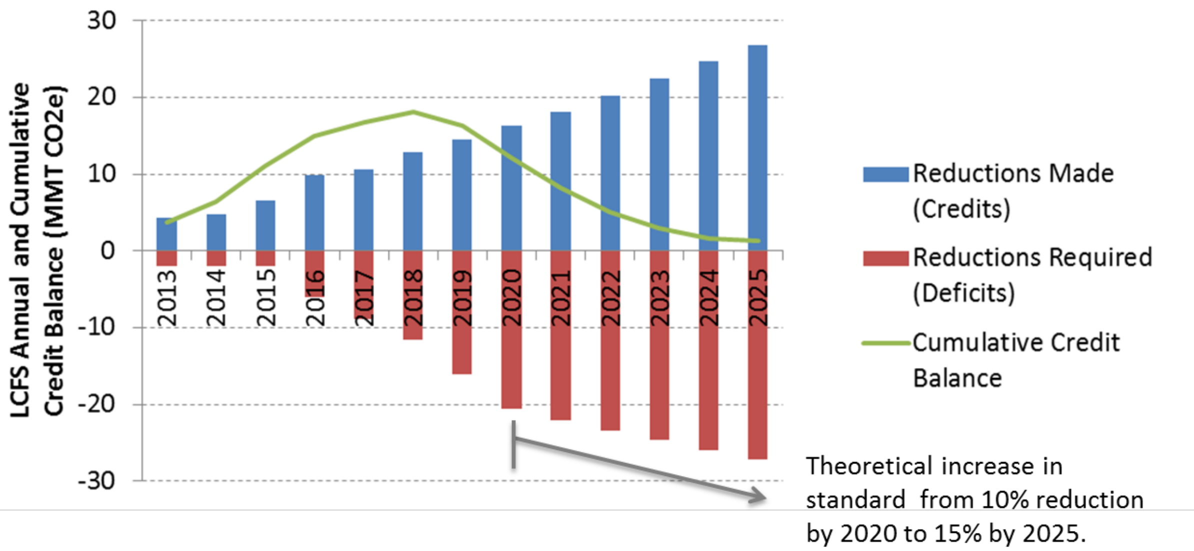


Figure 5: LCFS Annual Credit and Deficits, with the Cumulative Credit Balance (LCFS Reference Case).

The LCFS Reference Case is comprised of the following scenario:

- An LCFS credit value of $100/MT
- Assumes that the current requirement of 10% CI reductions by 2020 is increased to 15% CI reductions by 2025
- Biomass-based diesel, including biodiesel and renewable diesel, become a principal tool of compliance, taking advantage of underutilized production capacity and RIN and LCFS credit values to utilize waste greases, animal tallow, corn oil, and soy oil among other feedstocks.
- Blend rates of biodiesel grow to a 7% by volume mix in diesel (B7) by 2020 taking into account existing infrastructure constraints and restrictions on increased NOx. Blend rates increase to B12 in 2025 as the new NO_x control technologies on trucks are phased in by 2023.
- Direct emission reduction from the petroleum value chain make significant contributions to LCFS compliance
- Electricity used in passenger vehicles, as well as for off-road mobile and truck applications, also make significant contributions.
- Credit value is sufficient to incent the production and import of low CI cellulosic and sugarcane ethanol from existing facilities, but other factors related to investment and financing of new facilities, distribution infrastructure, and other issues limit availability.

The LCFS Low Case:

Figure 6 demonstrates annual and cumulative credit balance over time for the Low Case.

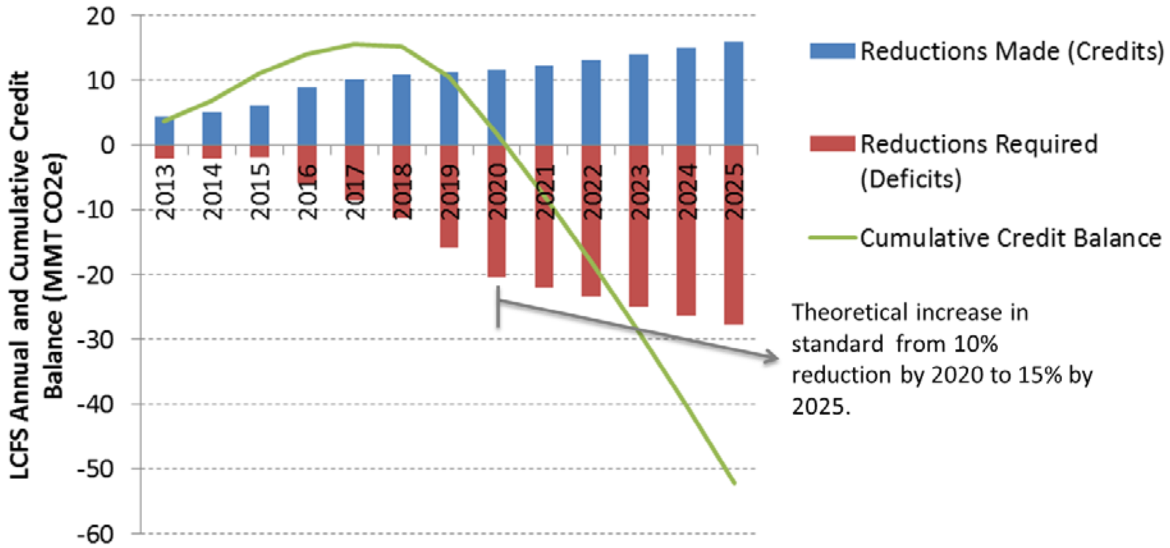


Figure 6: LCFS Annual Credit and Deficits, with the Cumulative Credit Balance (LCFS Low Case).

The LCFS Low Case is comprised of the following scenario:

- LCFS credit value below $50/MT
- Assumes that the current requirement of 10% CI reductions by 2020 is increased to 15% CI reductions by 2025
- Inexpensive and local waste based fuels come to the fore, which is positive, but under this scenario the incentive amount is not sufficient to persuade waste based biodiesel and renewable diesel producers to sell much more than the 2013/2014 volumes currently utilized in the state.
- California's LCFS market may achieve the Low Case scenario in the near term, but soy biodiesel (and other existing seed or vegetable oils) are not sufficiently incented to drive compliance.
- Absent large amounts of credits generated from diesel substitutes as in the Reference Case, greater ethanol demand occurs. In this scenario, a blend rate of 19% ethanol, including 2.5 billion gallons of mid-CI ethanol (e.g. corn, sorghum, wheat-based) would be required to achieve compliance in 2020.
- While there is enough ethanol production capacity, under a Low Case, significant investments in ethanol infrastructure to support E15 or E85 distribution are needed, including investments in storage tankage and retail blend pumps.
- In the Low Case, the LCFS incentives would be insufficient to allow for compliance beyond 2020.

Tables and additional descriptions of the compliance pathways are provided in the Appendices.

Appendix A: Description of compliance pathways

Reference Case ($100 per ton credit value)

Ethanol - Prior to the LCFS, requirements for reformulated gasoline to reduce smog – together with the federal RFS volume requirement – have effectively led to the growth in the use of ethanol to E10 levels. Corn-based ethanol has been the primary biofuel utilized in California. The LCFS has driven improvements in the carbon-intensity of the ethanol mix over the past three years. ARB has approved many ethanol pathways and the CIs of ethanol produced as well as imported into California continue to drop significantly. In our Reference Case we see a tapering of corn ethanol consumption starting in 2015, dropping steadily to 650 MMG in 2025 as other lower CI ethanol feedstocks and fuels become available.

Traditionally the US receives 50% to 60% of Brazil's cane ethanol exports and despite current challenges in the Brazilian marketplace, we expect imports of this low CI fuel to continue. These challenges, including sugar versus corn pricing and Brazil's domestic policies, will likely temper California's imports. Ultimately, we see consumption growing to 300 million gallons per year (MMGY) by 2020.

While it is easy to envision the importation of hundreds of million gallons of ultra-low CI cellulosic ethanol into California, it is difficult to predict exactly when those quantities will be available. Cellulosic ethanol (c-etoh) volumes remain highly uncertain.

Cellulosic technology providers have successfully reached commercial scale and the first wave build out is well underway. Based on separate estimates from Bloomberg New Energy Finance (2014) and Environmental Entrepreneurs (2015), about 220 million gallons per year of capacity of cellulosic ethanol is already built or forecasted to be completed by end of 2015, with about 100 million gallons of this capacity located in the U.S.[15] We expect availability of c-etoh to emerge in 2015 with the launch of the Abengoa, POET and DuPont facilities in the U.S. However, capacity utilization will likely be modest for the early years. Based on a healthy LCFS credit value and discussions with c-etoh technology providers, we expect a significant fraction of the available pool to make its way to California.

Coming validation will pave the way for financing of the second and third wave of cellulosic plants. At this time the facilities are more expensive and smaller than first generation ethanol plants. However, both capital and operating expenditures will decrease significantly over time as technology and operations improve. Cost of production estimates for cellulosic ethanol abound. Promotum reviewed publically available studies and analysis by academics as well as government agencies that incorporate theoretical cost models. In addition, Promotum spoke directly to several technology providers. We incorporated available data into our supply curves

[15] Bloomberg New Energy Finance data (http://about.bnef.com/). Environmental Entrepreneurs (2015), *Advanced Biofuel Market Report 2014*.

for the Reference Case and Low Case and this informed our thinking. We believe the estimates are conservative but reasonable.

US c-etoh facilities will largely be green field construction, scaling in modular fashion from 25 million gallons per year capacity followed by 50 and 75 MMGY plant capacities. Given issues around herbaceous feedstock transportation, achieving 100 MMGY capacity in any one plant is doubtful. Based on conversations with cellulosic ethanol technology providers we believe the price of cellulosic ethanol will fall on a fully loaded basis from $2.75/gallon today to about $1.70/gallon in 2030, including the cost of capital.

Electricity and Hydrogen –While internal combustion engine vehicles remain the current predominant technology on the road, automakers are rapidly investing in fuel efficient technologies, including various combinations of electric-drive vehicles, from plug-in hybrids to full battery electrics, even offering initial hydrogen fuel cell vehicles. As electric-drive vehicle sales continue to displace gasoline powered vehicles, demand for low CI electricity will increase and credits will be generated. We see electricity consumption almost quadrupling from 0.44GWhr in 2015 to 1.6GWhr in 2020 and nearly 4.4GWhr in 2025. For hydrogen, we believe the opportunities for fuel cell vehicles are good, but we have conservatively kept consumption at modest levels in the study, given potential hydrogen infrastructure constraints. We also note that improvements in the CI of electricity and hydrogen are expected, particularly if California meets targets to reach 50% renewable by 2030 in addition to the existing 33% Renewable Portfolio Standard requirements by 2020. To be conservative, however, we kept CI constant, as assumed in ARB Staff's *Initial Statement of Reasons*.

Petroleum Supply Chain Improvements – This study estimates GHG emission reductions in the petroleum value chain, including at the well head and refinery level will make up a significant percentage of overall compliance in the Reference Case.

Three technologies were included in this assessment using a study by TetraTech/NRDC (2014) as a starting point. These include use of solar thermal for steam generation in enhanced oil recovery, broader use of energy efficiency at refineries, and use of biomethane by the petroleum industry. These estimates may be conservative given the wider array of technologies available as well as industry experience with some of these technologies already.

For solar thermal, it is assumed that approximately 10% of the fossil natural gas used for steam injection projects is displaced in California by 2025. These estimates do not include an assessment of the potential for crude oil imported into the state, which currently represent 63% of the mix used in California, to utilize this technology. We estimate that by 2025, just over 0.7 MMT of reductions annually can be generated.

For refinery energy efficiency (EE) investments, it is assumed that at $100/ton, the incentive is sufficient to more than double the payback of EE, such that a reduction of 1.5% per year improvement in GHG emissions at refineries across the industry. We estimate that reductions from EE investments grow linearly from 2017 to 2025, reaching 4.3 MMT in annual reductions by 2025.

In terms of renewable energy inputs, we consider the use of biomethane to replace fossil natural gas at crude oil facilities, a fuel consumed at refineries, and a feedstock for hydrogen production utilized by refineries. We assume that 15% of the natural gas used by California crude oil and refining facilities could be displaced via biomethane purchases by 2020, growing to nearly 40% by 2025. The reductions would grow to 1.1 MMT annually by 2020 and 2.8 MMT annually by 2025. Significant volumes of biogas, which can be cleaned and processed into biomethane, are currently emitted, flared, or captured from landfills, dairy digesters, and waste-treatment facilities throughout the U.S.[16]

The study projects CI reductions, applied as credits for crude oil producers or refineries respectively, would be approximately 1.5% by 2020 and 3% by 2025 over the entire lifecycle of petroleum gasoline and diesel. This CI reduction level corresponds to 16% and 32% of the standard in 2020 and 2025 respectively being met in those years from direct petroleum supply measures. We believe the current environment of relatively low oil prices also lends itself to implementation of downstream projects, including refinery energy efficiency and GHG reduction projects, as other capital investments in the upstream and midstream are reduced in the U.S.

When combined, we see opportunities for 4.2MM MT of GHG reduction in 2020 reaching 8.8MM MT in 2025 from these three categories of technologies.

Renewable Diesel – We see opportunities for renewable diesel (R-Diesel) to play an important role in California's biofuel portfolio, based on existing domestic and international plant capacity, reaching 400 MMGY in 2020. This represents almost 50% of the ~850 million gallon global capacity, but is consistent with the estimates by the Air Resources Board staff in their regulatory analysis.[17] To some extent we have concerns with regard to the sustained availability of international supplies (~650 million gallons per year) and the high cost of new capacity. We do believe domestic capacity for hydrotreating waste oils will be constrained. We also believe there will be considerable competition for this capacity with military aviation fuel. Continued uncertainty around the US production tax credit will also inhibit financing capacity expansion.

Biodiesel – Biodiesel is a primary driver of compliance in the Reference Case. In California and the United States there are hundreds of millions of gallons of underutilized biodiesel production capacity. The technology is simple and mature, utilizes low carbon feedstocks and produces a low CI diesel substitute. We see an important opportunity to grow the blend rate beyond the currently anemic 2% levels by volume. Waste grease (used cooking oil),increasing volumes of corn oil biodiesel and soy biodiesel will contribute. We see total biodiesel consumption reaching 265 MMGY in 2020 and more than 500 MMGY in 2025.

[16] NREL (2013), *Biogas Potential in the United States*, NREL/FS-6A20-60178, October 2013, National Renewable Energy Laboratory, Energy Analysis, Golden, CO. Also see EPA Landfill Gas candidate project lists: http://www.epa.gov/lmop/projects-candidates/index.html.
[17] http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm

Availability of corn oil depends primarily on the penetration of necessary unit operations within corn wet mills. Starting from approximately 59% in 2015 we see penetration increasing to ~90% by 2025. We forecast 68 million gallons of inedible corn oil biodiesel reaching California in 2020 out of an estimated US pool of 475 million gallons and greater than 100 million gallons in 2025.

Biodiesel from used cooking oil (waste grease) will continue to make an important contribution to the BD pool. We estimate 51 million gallons will be available to California in 2020 and 77 million gallons in 2025. While the very low CI makes it particularly attractive, community collection by its nature will remain a constraint.

Swing biodiesel feedstock will come in the form of soy oil. While often spurned because of its nominal association with food, soy oil is separated, from soy protein prior to utilization. A healthy LCFS credit value overcomes traditional soy pricing problems, which have mothballed many biodiesel facilities and left many others operating below capacity. With an improving CI profile we predict 51 million gallons of soy biodiesel in the California market in 2020 and 77 million gallons in 2025. We do not see a big role for canola based biodiesel in the US or California.

Natural Gas – We expect natural gas usage in fleets to increase and used to comply with the LCFS. We also assume that an increasing share will come from biomethane captured from landfills and other sources, including anaerobic digestion and waste-treatment facilities. We find approximately 170 million diesel gallon equivalents of liquefied natural gas will be utilized by 2025 and 306 million diesel gallon equivalents of compressed natural gas being utilized. We assume approximately 80% of these volumes will be derived from biomethane sources by 2025, given the increased value for biomethane producers and current levels in California approaching 40%.

Low Case (less than $50 per ton credit value)

Ethanol – In a Low Case scenario, inexpensive corn, wheat, or sorghum based ethanol becomes the primary tool of compliance. Instead of the tapering we saw in the Reference Case, a dramatic increase in these feedstocks occurs, reaching blending level of 2.5 BGY in 2020, together with an additional 140 MMGY of low-CI ethanol. This represents an effective blend rate of 19%-21% in the years 2020-2025.

Electricity and Hydrogen – We find that similar levels of electricity and hydrogen consumption for the transportation sector will occur between the LCFS Reference and Low Case. However, we have not analyzed the use of electricity credits by utilities and the effects on the market, given the lack of current data.

Petroleum Supply Chain Improvements – Lower credit values decrease the incentive for refinery and well head improvements. Significant reductions still occur, reaching 2.1MMT in 2020 and 5 MMT in 2025, but the pace of implementation is slower.

Renewable Diesel – R-Diesel remains relatively expensive from 2015 to 2025 and lower LCFS credit values mean blending remains stuck at circa 2015 levels, approximately 100MMGY.

Natural Gas – While we find that NGV usage and natural gas demand for transportation to remain at similar levels to the Reference Case, we see a significant drop in biomethane use to only double from current levels, growing to only 30 MMGY (diesel equivalent).

Appendix B: Fuel Volumes and Carbon-Intensity Tables

Reference Case ($100 per ton credit value)

Reference Case														
Gasoline Replacements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Corn Ethanol	mm gal	1,220	1,275	1,255	1,200	1,150	1,000	975	850	800	775	725	675	650
Cane Ethanol	mm gal	150	100	100	100	100	200	200	300	300	300	300	300	300
Diversified Ethanol (sorghu	mm gal	150	170	170	190	215	235	235	235	235	235	235	235	235
Cellulosic Ethanol	mm gal	0	0	5	25	35	45	55	65	75	85	95	105	115
Renewable Gasoline	mm gal	0	0	0	0	0	5	15	25	50	75	100	125	150
Hydrogen	mm gal GGE	0	0	2	5	8	11	15	21	25	30	36	44	52
Electricity for LDVs	1000 MWH	200	400	440	596	759	982	1,276	1,629	2,064	2,563	3,127	3,757	4,374
Total Ethanol (MM gal)		1,520	1,545	1,530	1,515	1,500	1,480	1,465	1,450	1,410	1,395	1,355	1,315	1,300
CARBOB (energy adjusted)		12,848	12,950	12,814	12,666	12,519	12,365	12,197	12,021	11,776	11,510	11,256	10,997	10,723
Gasoline As CARFG + E85		14,340	14,495	14,344	14,186	14,034	13,870	13,712	13,546	13,286	13,030	12,761	12,312	12,023
Ethanol (vol %)		10.60%	10.66%	10.67%	10.68%	10.69%	10.67%	10.68%	10.70%	10.61%	10.71%	10.62%	10.68%	10.81%
Diesel Replacements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Soy Biodiesel	mm gal	5	5	5	15	30	85	105	135	175	215	255	285	300
Waste Grease Biodiesel (U(	mm gal	33	35	37	39	41	43	45	47	49	51	53	55	57
Corn Oil Biodiesel	mm gal	11	20	34	48	61	68	68	68	68	82	102	122	142
Tallow Biodiesel	mm gal	4	5	10	10	10	10	10	10	10	10	10	10	10
Canola Biodiesel	mm gal	6	5	5	5	5	5	5	5	5	5	5	5	5
Renewable Diesel	mm gal	118	107	180	260	290	320	360	400	400	400	400	400	400
LNG	mm gal DGE	28	26	30	30	30	30	30	30	30	30	30	30	30
CNG	mm gal DGE	61	70	70	70	70	70	70	70	70	70	70	70	70
Renewable LNG	mm gal DGE	5	5	30	39	51	63	76	90	100	110	120	130	140
Renewable CNG	mm gal DGE	6	11	45	59	77	94	114	136	156	176	196	216	236
Electricity for HDVs/Rail	1000 MWH	-	-	900	900	900	900	900	900	900	900	900	900	900
Total HD NG (DGEs)		100	112	175	198	228	257	290	326	356	386	416	446	476
Total Biodiesel (MM gal.)		59	70	91	117	147	211	233	265	307	363	425	477	514
Diesel (non-adjusted)		3,677	3,732	3,788	3,845	3,903	3,961	4,021	4,081	4,142	4,204	4,267	4,331	4,396
Diesel (energy adjusted)		3,404	3,447	3,324	3,253	3,222	3,162	3,128	3,082	3,074	3,054	3,029	3,014	3,014
Total biodiesel (vol %)		1.65%	1.93%	2.53%	3.21%	4.02%	5.03%	5.94%	6.94%	7.99%	9.01%	10.02%	11.09%	11.94%
Renewable Diesel (vol %)		3.29%	2.95%	5.01%	7.16%	7.92%	8.66%	9.67%	10.67%	10.58%	10.48%	10.38%	10.28%	10.18%

Petroleum Value Chain Reductions

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
MMT Reductions	-	-	-	0.4	0.4	1.3	2.3	3.2	4.2	5.3	6.5	7.6	8.8
CI reduction (g/MJ)	-	-	-	0.2	0.2	0.6	1.1	1.5	2.0	2.5	3.1	3.7	4.3

Low Case (Less than $50 per ton credit value)

Gasoline Replacements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Corn Ethanol	mm gal	1,220	1,500	1,800	1,900	2,200	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
Cane Ethanol	mm gal	150	100	100	100	100	100	100	100	100	100	100	100	100
Diversified Ethanol (sorghu	mm gal	150	170	170	170	170	170	170	170	170	170	170	170	170
Cellulosic Ethanol	mm gal	0	0	5	25	35	35	35	35	35	35	35	35	35
Renewable Gasoline	mm gal	0	0	0	0	0	5	15	25	25	25	25	25	25
Hydrogen	mm gal GGE	0	0	2	5	8	11	15	21	25	30	36	44	52
Electricity for LDVs	1000 MWH	200	400	440	596	759	982	1,276	1,629	2,064	2,563	3,127	3,757	4,374
Total Ethanol (MM gal)		1,520	1,770	2,075	2,195	2,505	2,605	2,605	2,605	2,605	2,605	2,605	2,605	2,605
CARBOB (energy adjusted)		12,848	12,798	12,447	12,208	11,842	11,608	11,429	11,243	10,996	10,745	10,489	10,228	9,969
Gasoline As CARFG + E85		14,340	14,568	14,522	14,408	14,362	14,238	14,059	13,873	13,626	13,375	13,119	12,833	12,574
Ethanol (vol %)		10.60%	12.15%	14.29%	15.23%	17.44%	18.30%	18.53%	18.78%	19.12%	19.48%	19.86%	20.30%	20.72%
Diesel Replacements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Soy Biodiesel	mm gal	5	5	5	5	5	5	5	5	5	5	5	5	5
Waste Grease Biodiesel (U	mm gal	33	35	37	39	41	43	45	45	45	45	45	45	45
Corn Oil Biodiesel	mm gal	11	20	34	48	61	61	61	61	61	61	61	61	61
Tallow Biodiesel	mm gal	4	5	10	10	10	10	10	10	10	10	10	10	10
Canola Biodiesel	mm gal	6	5	5	5	5	5	5	5	5	5	5	5	5
Renewable Diesel	mm gal	118	107	100	100	100	100	100	100	100	100	100	100	100
LNG	mm gal DGE	28	26	30	30	30	30	30	30	30	30	30	30	30
CNG	mm gal DGE	61	70	70	70	70	70	70	70	70	70	70	70	70
Renewable LNG	mm gal DGE	5	5	10	10	10	10	10	10	10	10	10	10	10
Renewable CNG	mm gal DGE	6	11	20	20	20	20	20	20	20	20	20	20	20
Electricity for HDVs/Rail	1000 MWH	-	-	900	900	900	900	900	900	900	900	900	900	900
Total HD NG (DGEs)		100	112	130	130	130	130	130	130	130	130	130	130	130
Total Biodiesel (MM gal.)		59	70	91	107	122	124	126	126	126	126	126	126	126
Diesel (non-adjusted)		3,677	3,732	3,788	3,845	3,903	3,961	4,021	4,081	4,142	4,204	4,267	4,331	4,396
Diesel (energy adjusted)		3,404	3,447	3,449	3,491	3,534	3,591	3,648	3,708	3,770	3,832	3,895	3,959	4,024
Total biodiesel (vol %)		1.65%	1.93%	2.50%	2.88%	3.25%	2.77%	3.13%	3.08%	3.03%	2.99%	2.94%	2.90%	2.85%
Renewable Diesel (vol %)		3.29%	2.95%	2.75%	2.70%	2.66%	2.62%	2.58%	2.54%	2.50%	2.46%	2.43%	2.39%	2.35%

Petroleum Value Chain Reductions

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
MMT	-	-	-	0.2	0.7	1.1	1.6	2.1	2.7	3.2	3.8	4.4	5.0
CI reduction (g/MJ)	-	-	-	0.1	0.3	0.5	0.8	1.0	1.3	1.5	1.8	2.1	2.4

Annual average carbon-intensity (g $CO2_e$/MJ)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Corn Ethanol	82.24	82.24	82.24	70.00	69.30	68.61	67.92	67.24	66.57	65.90	65.24	64.59	63.95
Cane Ethanol	72.5	72.5	72.5	40.0	39.5	39.0	38.5	38.0	37.5	37	36.5	36	35.5
Sorghum/Corn Ethanol	79.1	79.1	79.1	70.0	69.3	68.6	67.9	67.2	66.57	65.9	65.24	64.59	63.95
Misc Corn Ethanol	91.5	91.5	91.5	70.0	69.3	68.6	67.9	67.2	66.57	65.9	65.24	64.59	63.95
Sorghum/Corn/Wheat Ethanol	72.8	72.8	72.8	65.0	64.4	63.7	63.1	62.4	61.81	61.2	60.58	59.98	59.38
Cell. Ethanol[1]	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Molasses Ethanol	22.1	22.1	22.1	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
Renewable Gasoline[2]	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Hydrogen	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9	43.9
Electricity for LDVs	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Soy Biodiesel	83.3	83.3	50.0	49.5	49.0	48.5	48.0	47.5	47	46.5	46	45.5	45
Waste Grease Biodiesel	15.0	15.0	14.0	12.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Corn Oil Biodiesel	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Tallow Biodiesel	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2
Canola Biodiesel	62.6	62.6	62.6	73.2	73.2	73.2	73.2	73.2	73.2	73.2	73.2	73.2	73.2
Renewable Diesel	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
LNG	80.9	80.9	80.9	90.9	90.0	89.1	88.2	87.4	86.5	85.6	84.7	83.8	82.9
CNG	70	70	70	70	70	70	70	70	70	70	70	70	70
Renewable LNG	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Renewable CNG	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Electricity for HDVs/Rail	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9
CARBOB	99.2	99.2	99.2	100.6	100.6	100.6	100.6	100.6	100.6	100.6	100.6	100.6	100.6
CARB Diesel	98.0	98.0	98.0	102.8	102.8	102.8	102.8	102.8	102.8	102.8	102.8	102.8	102.8

8. About Promotum

Promotum is a technology based management consulting firm working at the convergence of fuels, chemicals and biologics. We are a team of standout engineers, scientists and accomplished MBAs, who are as passionate about science and technology as we are about business. By focusing on the convergence of energy, materials, and biology we deal daily with complex issues and disciplines. Promotum is growth focused helping clients enter new markets, evaluate or create them. Our expertise allows us to maximize results for our clients around the world. Promotum is headquartered in Cambridge, Massachusetts.

Functional Practices

- Business Development
- Business Strategy & Planning
- Corporate Development
- Competitive Intelligence
- Due Diligence
- Investment/Financial Analysis
- Licensing
- Market Analysis
- New Venture Creation
- Policy Analysis
- Technology Commercialization

Industrial Practices

- Bio/Pharma
- Biomass to Energy
- Energy Efficiency
- Environmental Sciences
- GHG Life Cycle Analysis
- Green Chemicals
- Green Polymers
- Next Generation Fuels
- Next Generation Vehicles

22_OP_LCFS_NRDC Responses

100. Comment: **LCFS 22-1**

The comment supports the proposed 10 percent by 2020 and a 15 percent by 2025 carbon reduction target.

Agency Response: See response to **LCFS 5-2**.

ARB staff appreciates support for the compliance target in the proposed re-adoption of the LCFS regulation.

This page intentionally left blank.

Comment letter code: 23-OP-LCFS-Tetra

Commenter: Simon Mui

Affiliation: California Vehicles and Fuels Natural Resources Defense Council

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

23_OP_LCFS _Tetra

California Environmental Protection Agency
Air Resources Board

Comment Log Display

BELOW IS THE COMMENT YOU SELECTED TO DISPLAY.
COMMENT 23 FOR LOW CARBON FUEL STANDARD 2015 (LCFS2015) - 45 DAY.

First Name: Simon
Last Name: Mui
Email Address: smui@nrdc.org
Phone Number: 415-875-6120
Affiliation:

Subject: Tetratech/NRDC Study on Five Technologies to Reduce GHGs from Petro Supply Chain
Comment:
Please find attached a joint study by Tetratech and NRDC on several opportunities to reduce GHG emissions and carbon-intensity directly at refineries and crude oil production facilities.

Five approaches to reducing carbon pollution directly from the petroleum supply chain were analyzed. The study's results point to a significant portion of LCFS compliance and credit generation being possible through these technologies. LCFS 23-1

Additional information can be found at:
http://www.nrdc.org/energy/california-petroleum-carbon-reduction.asp

Best regards,
Simon Mui, Ph.D.
Senior Scientist and Director
California Vehicles and Fuels
Natural Resources Defense Council

Attachment: www.arb.ca.gov/lists/com-attach/25-lcfs2015-USUHZFciV3ZVMgh8.zip

Original File Name: Tetratech Study.zip

Date and Time Comment Was Submitted: 2015-02-17 12:32:19

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

OCTOBER 2013
FS:13-10-I

Cleaning Up California's Fuels: Technologies To Reduce The Oil Industry's Carbon Footprint And Meet The Low Carbon Fuel Standard

Since the adoption of the first-in-the-nation Low Carbon Fuel Standard (LCFS) in 2009, California continues to successfully reduce the carbon pollution of transportation fuels. The production and use of petroleum-based fuels are responsible for approximately half of the state's entire carbon emissions.[1] While the substitution of cleaner energy sources for crude oil, like advanced biofuels made from agricultural waste, is a key strategy to reduce carbon pollution, it is also important to employ technologies that can directly reduce the pollution generated from crude oil extraction and refining. A new report from Tetra Tech and NRDC, Carbon Reduction Opportunities in the California Petroleum Industry, looks at significant, concrete steps that the California oil industry can adopt today to curb its carbon emissions. These ready-to-deploy technologies could also go a long way to meeting the industry's responsibility under the LCFS.

The LCFS is a major component of California's Global Warming Solutions Act of 2006, known as A.B. 32, and requires the oil industry and other fuel providers to reduce the carbon footprint of transportation fuels by 10 percent by 2020. As a performance-based standard, the LCFS allows industry flexibility to invest in the most cost-effective technologies to reduce carbon pollution from fuels.

Solar thermal facility developed by BrightSource, Coalinga, California.

Source: tech.fortune.cnn.com/2012/04/17/yergin-gas-solar-wind

EVEN MORE OPPORTUNITIES TO REDUCE CARBON POLLUTION

Five approaches to reducing carbon pollution directly from the petroleum supply chain include:

- Renewable steam generation: using solar power to generate steam for enhanced oil recovery, rather than combusting fossil fuels for that purpose.
- Steam generation with carbon capture and sequestration (CCS): capturing and storing the flue gas emissions from once-through steam generators used in enhanced oil recovery.
- Refinery energy efficiency: enabling refineries to use less energy in their operations.
- Refinery CCS: capturing and storing carbon emissions resulting from the energy-intensive hydrogen processes needed for refining crude oil.
- Renewable refinery feedstocks: displacing part of the refinery's crude oil with renewable-based oils and waste oils.

The new report shows that modest adoption of the five carbon reduction technologies identified above could reduce emissions by nearly 3 million to 6.6 million metric tons annually in 2020. For a reference point, the full potential of these technologies—if adopted across the board—would result in 20 million metric tons of reduction annually, equivalent to the removal of nearly 5 million passenger vehicles from the road. Additional opportunities—such as

For more information, please contact:

Simon Mui
smui@nrdc.org
switchboard.nrdc.org/blogs/smui

www.nrdc.org/policy
www.facebook.com/nrdc.org
www.twitter.com/nrdc

renewable electricity and hydrogen use at refineries, use of other cleaner technologies at oil production operations, and efficiency improvements at crude oil production facilities—could help reduce emissions even further.

MEETING THE LOW CARBON FUEL STANDARD

Even moderate adoption of these technologies could help refiners meet the goals of California's LCFS. The standard requires oil companies to reduce their carbon intensity by 10 percent, or approximately 17 million metric tons, by 2020. Overall, the potential of the oil industry to directly reduce carbon emissions is sizable, and the technologies to do so are available and viable. Moreover, in addition to reducing carbon pollution, many of these technologies can reduce other air pollutants, providing further benefits to public health.

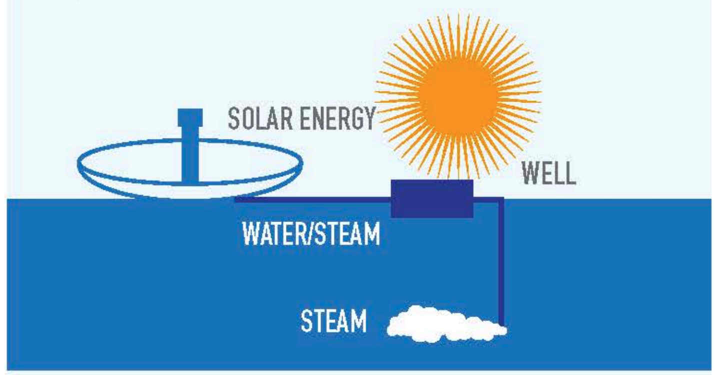
CLEANING UP EXISTING FUEL SUPPLIES

Despite claims to the contrary, there is no shortage of opportunities for the fuel industry to shrink the carbon footprint of transportation fuels. While the use of low carbon, advanced biofuels and the use of cleaner electricity remain key strategies to reduce emissions overall, cutting emissions from the production of petroleum, by far the largest portion of the market, is also important. Ninety five percent of California's transportation fuel supply is derived from crude oil. The oil industry operates more than 50,000 active oil wells and 18 refineries in the state, and the combined carbon emissions from these facilities account for more than 10 percent of the state's emissions, or an estimated 48 million metric tons of carbon dioxide annually.

Fortunately, the LCFS can provide a strong investment signal for existing petroleum facilities to deploy carbon reduction technologies. Meeting the state's air pollution and carbon reduction goals will ultimately require not only that we turn to new, cleaner fuels, but also that our current fuel supplies get cleaner over time. Fortunately, there exist hundreds of ways to accomplish both.

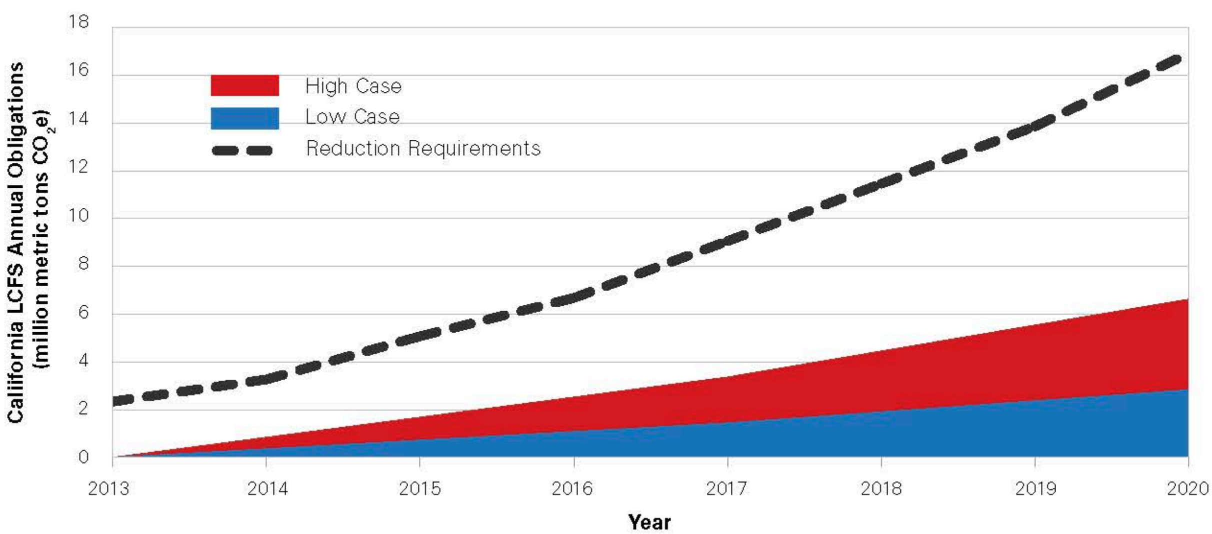
Using Solar Energy to Generate Steam

To generate steam renewably, mirrors and reflective surfaces are arranged to concentrate sunlight. The solar energy is directed at a central tube or tower containing water, which is heated and turned into steam. The steam is injected into oil wells to improve recovery rates



This renewable steam generation technology is currently being deployed commercially by BrightSource in Coalinga, California, and by GlassPoint in McKittrick, California, and Amal, Oman.

By adopting existing carbon reduction technologies and other cost-effective reduction strategies, refiners can meet a significant portion of their LCFS compliance obligations.



1 Estimates based on California's 2011 Greenhouse Gas (GHG) emissions inventory by the California Air Resources Board. Direct combustion emissions in the transportation sector account for approximately 38% of statewide emissions. The inclusion of GHG emissions from upstream crude oil production, refining, and transport increases the total carbon footprint to roughly half of statewide emissions. (www.arb.ca.gov/cc/inventory/inventory.htm)

OCTOBER 2013
IB:13-09-E

Carbon Reduction Opportunities in the California Petroleum Industry

AUTHORS

Karen Law
karen.law@tetratech.com

Michael Chan
michael.chan@tetratech.com

Tetra Tech, Inc.

CONTRIBUTING AUTHOR

Simon Mui, Ph.D.
smui@nrdc.org

Natural Resources Defense Council

SUMMARY

As industry leaders and policymakers seek to reduce the carbon pollution impacts caused by human activity, the petroleum supply chain and the use of petroleum products present numerous and significant opportunities for emission reductions. From crude oil production and refining to gasoline and diesel use in vehicles, each portion of the supply chain contributes to the oil industry's carbon footprint. While substitution of cleaner energy sources for oil is a key strategy to reduce carbon pollution, it is also important to take advantage of the technologies currently available that can directly reduce the carbon footprint of petroleum from production to final use. Opportunities to shrink this footprint include, but are not limited to:

- Renewable steam generation: generating steam for enhanced oil recovery using solar power, rather than combusting fossil fuels in once-through steam generators.
- Steam generation with carbon capture and sequestration (CCS): capturing and storing the flue gas emissions from once-through steam generators used in enhanced oil recovery.
- Refinery energy efficiency: enabling refineries to use less energy in their operations, thereby reducing their carbon emissions.
- Refinery CCS: capturing and storing carbon emissions resulting from the energy-intensive hydrogen processes needed for refining crude oil.
- Renewable refinery feedstocks: displacing part of the refinery's crude oil with natural oils, such as animal fats and waste oils, thereby reducing the full-fuel-cycle carbon intensity of the final refinery products.

The five technologies analyzed here do not encompass the full suite of opportunities to reduce greenhouse gas emissions (GHG, or herein "carbon") in the petroleum supply chain; such an extensive analysis is beyond the scope of this brief. Some of these additional technologies or practices include use of renewable electricity at refineries, use of biomass as an energy input, use of clean distributed generation technologies at oil production operations, renewable hydrogen inputs at refineries, avoidance of lower-quality crude oils that require greater extraction and refining energy, lower-carbon technologies for enhanced oil recovery that utilize gas or chemical injection, and efficiency improvements at crude oil production facilities.[1,2] In addition to these limitations, this brief does not evaluate the costs or cost-effectiveness of the various technologies or the potential reductions in criteria air pollutants.

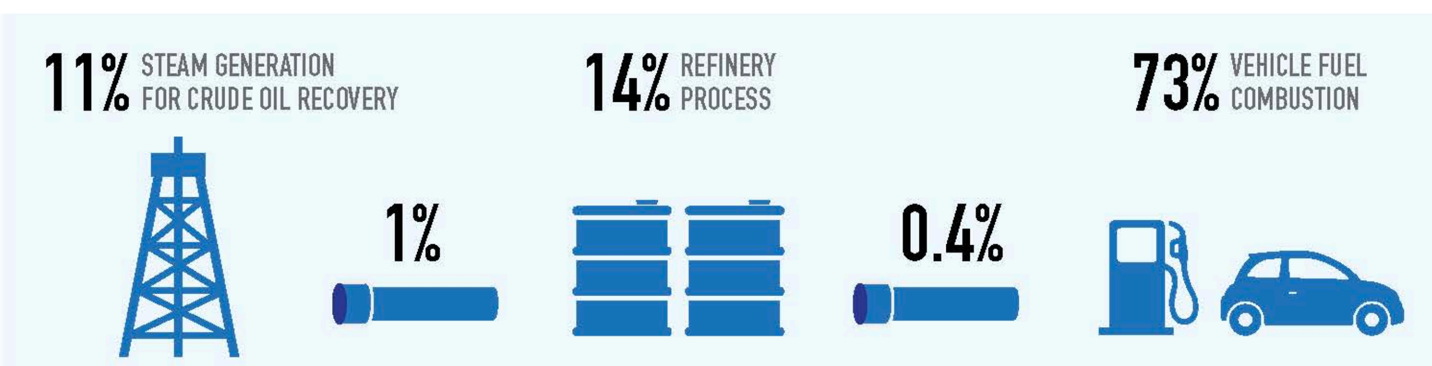
This brief analyzes a low and a high market adoption scenario for the 2014 to 2020 period to illustrate the potential impact of implementing the five carbon reduction technologies identified above. The low case represents a conservative scenario in which the technologies are adopted to a limited degree, whereas the high case represents a scenario in which the technologies are adopted more broadly, though still to a reasonable and achievable degree as discussed further in this brief. These cases are applied to California, which accounts for 11 percent of total U.S. petroleum refining capacity and 8 percent of total U.S. crude oil production.[3] GHG emissions from California petroleum refining and crude oil production are currently estimated to be approximately 31 million metric tons of CO_2e and 17 MMT, respectively, for a total of 48 MMT.[4]

In the low case, the combined GHG emission reductions may be 2.8 million metric tons annually in 2020. In the high case, the combined reductions may be approximately 6.6 million metric tons annually in 2020. As a reference point, the full potential of these technologies—if adopted across the board—would be more than 20 million metric tons of reduction annually.

These carbon reduction technologies can make major contributions to the petroleum industry's obligations under California's Global Warming Solutions Act of 2006 (known as AB32). In addition to carbon pollution reduction, many of these technologies can significantly reduce other air pollutants, providing further benefits to public health. If these technologies were all eligible reduction pathways under California's Low Carbon Fuel Standard (LCFS), part of AB32, even moderate adoption could meet a substantial portion of obligations for refiners under the standard, which requires a reduction of 17 million metric tons in 2020.[5] Overall, the potential to reduce carbon emissions from the petroleum industry is sizeable, and the technologies to achieve these reductions are available and viable. Additional opportunities, such as CCS at the refinery beyond hydrogen applications, and higher levels of renewable refinery feedstock content and inputs can further reduce the carbon footprint of the petroleum industry.

TECHNOLOGIES TO REDUCE CARBON EMISSIONS

The petroleum supply chain consists of multiple stages that, together with vehicle fuel combustion, are responsible for the full-fuel-cycle carbon emissions of the final products, such as gasoline and diesel. From crude oil production through refining to fuel combustion in vehicles, each portion of the supply chain contributes to the total carbon footprint of the petroleum industry. Furthermore, each offers opportunities to reduce this footprint. Three key stages where carbon reduction technologies can significantly impact total emissions are crude oil recovery, refinery processes, and vehicle fuel combustion.



The petroleum supply chain offers at least three key areas where promising technologies can enable significant reductions in carbon emissions. The percentages shown represent the contribution of each stage to total life-cycle emissions. Crude oil transport and finished product transport represent less than 2% of emissions. The totals are less than 100% due to rounding.

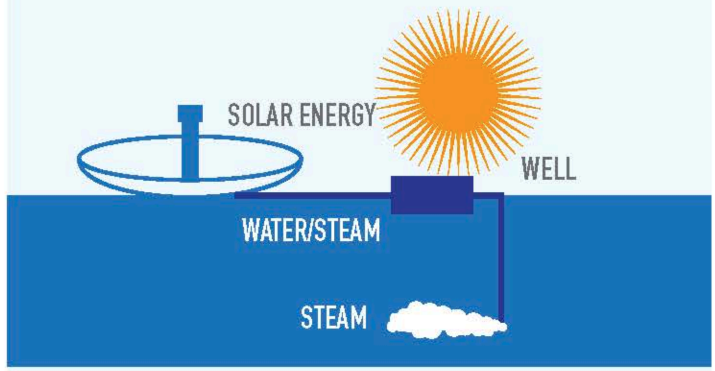
Crude Oil Recovery

The recovery (or extraction) stage may include the use of artificial lift or enhanced recovery methods to push crude oil from underground reservoirs to the surface after the natural reservoir pressure falls to a point where the well cannot produce on its own. In some cases, this process is accomplished by the injection of gas, water, or chemical agents to facilitate recovery. The major greenhouse gas emission sources at this stage are tied to energy use to lift or pump crude oil from the subsurface, production of steam in thermal enhanced oil recovery operations, and potential gas venting, flaring, and fugitive (VFF) emissions.[6]

For some oil fields, steam injection is used to enhance crude oil recovery by decreasing viscosity, causing the oil to swell, and helping sweep the oil out of the reservoir rock.[7],[8] In California, modern steam injection has been utilized since 1960. Today, steam injection is used to produce approximately 70 percent of the 630,000 barrels per day of oil produced in California.[9] Conventionally, fossil fuels such as natural gas are combusted to generate the steam, which is then pumped into injection wells.[10] The process is energy intensive, and the combustion of fossil fuel releases carbon into the atmosphere.[11] Two technologies that can eliminate this carbon release include:

Using Solar Energy to Generate Steam

To generate steam renewably, mirrors and reflective surfaces are arranged to concentrate sunlight. The solar energy is directed at a central tube or tower containing water, which is heated and turned into steam. The steam is injected into oil wells to improve recovery rates



This renewable steam generation technology is currently being deployed commercially by BrightSource in Coalinga, California, and by GlassPoint in McKittrick, California, and Amal, Oman.

- Renewable steam generation. Solar-thermal facilities that concentrate sunlight with mirrors to convert water into steam have been operating since the 1980s, including a pilot project by ARCO Solar utilizing the steam for enhanced oil recovery.[12] Over the past several years, a number of technology companies have been active in commercializing this technology. Because solar energy drives this process, the carbon impact of generating steam using this technology is near zero compared with utilizing natural gas.[13] [see sidebar "Using Solar Energy to Generate Steam"].

- Steam generation with carbon capture and sequestration (CCS). Fossils fuels are still combusted to generate steam, but the carbon from the flue gas emissions is captured and stored. Retrofits using post-combustion capture, which separates CO_2 from the flue gas, can be suitable for existing facilities such as natural gas– based steam generation units.[14] In addition, post-combustion capture can also be used for upgrading facilities, such as those that utilize steam methane reforming units to produce hydrogen.[15] Various subsurface locations exist for permanent disposal of the captured carbon, including deep saline formations, oil fields, and gas fields. Technology to capture, transport, and inject the carbon emissions is commercially available, and there is broad scientific consensus that, provided it is adequately regulated, CCS can be carried out safety and effectively and result in permanent storage in these reservoirs.[16]

Additional recovery-stage reduction opportunities not analyzed in this issue brief include measures to reduce VFF emissions and to improve energy efficiency. Flaring involves intentional burning of the associated gases dissolved in crude oil, which releases CO_2 and potentially other pollutants, depending on combustion efficiency. Venting refers to intentionally releasing the gases, including methane, a gas with a global warming potential 25 times that of CO_2. Fugitive emissions are unintentional or irregular releases of those gases, such as through leaks in valves and seals[17] In general, these emissions can be reduced through industry best practices such as systems to reduce methane loss during the completion of a well (i.e. green completions), better pipeline maintenance and repair, and proactive leakage monitoring and repair.[18] Similarly, improved efficiency through equipment modernization, improved maintenance and repair, and integrated energy management approaches can also lead to reduced emissions.[19]

Refinery Processes

Refineries are a collection of complex chemical process systems that convert crude oil to valuable petroleum products like gasoline, diesel, kerosene, and jet fuel. These typically include distillation, cracking, treating, and reforming. Carbon emissions result from the series of steps required to upgrade the crude oil into its final products. Two technologies that can reduce these emissions are:

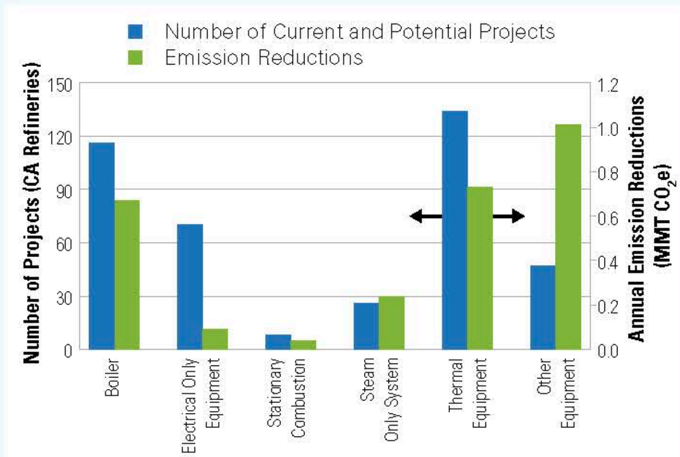
- Refinery energy efficiency. Continual improvements in the efficiency of the refinery enable it to use less energy in its operations, thereby reducing its carbon impact. Measures that increase the energy efficiency of a refinery include improved controls, improved heat recovery, hydrogen and fuel gas management, utilities optimization, and advanced process technologies. McKinsey & Company (2011) found that the U.S. refining industry could reduce its energy use by 13 percent by 2020 through commercially available technologies at an internal rate of return of at least 10 percent; others, such as Energetics Incorporated (2006), found that the technical potential was as high as 26 percent if best practices and state-of-the-art technologies were used.[20]

- Refinery CCS. As with carbon capture and sequestration for steam generation, emissions are not vented into the atmosphere but are instead stored over geological timescales with active measurement, monitoring, and verification protocols. There are many point sources of CO_2 emissions from refinery operations, including hydrogen production, the fluid catalytic cracking (FCC) unit, steam generation, and localized heat requirements. One particular carbon reduction opportunity among refinery processes is hydrogen-related CCS. The production of hydrogen by reforming or gasifying fossil fuels and its use in the refinery both emit carbon dioxide. Hydrogen production usually represents the best capture and sequestration opportunity at the facility, capable of appreciably reducing overall refinery emissions.[21],[22] Other potential CO_2 sources within a refinery are not included in this assessment. [See sidebar on "Opportunities for Refinery Energy Efficiency"]

While not analyzed here, the use of lower-quality crude oils and/or heavier crude oils —including but not limited to tar sands or other extra-heavy crude oils— can also result in greater production and refining emissions due to the additional energy necessary to extract, upgrade, and refine these feedstocks. California refineries utilize a significant mix of heavy crude oils, which is one reason why average refining emissions in California are higher than those in other major U.S. refining regions.[23] Reduced reliance on lower-quality or heavier crude oil feedstocks, through a switch to lighter, higher-quality crude oils and renewable crude oils, can help reduce carbon emissions and yield additional benefits in terms of reduced air pollutants, so long as the switch reduces overall production and refining of lower-quality, heavier crude oil and does not result in shifting those crude oils elsewhere.[24]

Opportunities for Refinery Energy Efficiency

The California Air Resources Board reports that the largest refineries in the state have implemented or are currently implementing efficiency improvement projects whose impact will be equivalent to approximately an 8 percent reduction in refining emissions. These projects involve boilers (cogeneration, steam, and combined cycle plants), electric motors, stationary combustion (gas turbines), steam motors, thermal equipment (furnaces and heat exchangers), and other equipment (including refinery-wide projects and flare systems).



Source: www.arb.ca.gov/cc/energyaudits/publicreports.htm.

Vehicle Fuel Combustion

At the end of the petroleum supply and processing chain, petroleum fuels like diesel are combusted to provide motive power. Examining only the fuel portion of the carbon footprint, most of the carbon content of the feedstocks used to create the fuel is released during vehicle operation and represents 73 percent of the total life cycle, or well-to-wheels, emissions for gasoline.[25] On a full-fuel-cycle basis, combusting fuel from petroleum directly increases atmospheric carbon concentration, whereas renewable feedstocks like biomass are grown using carbon dioxide from the atmosphere and can result in lower net emissions if regrown. The petroleum industry can reduce the direct emissions of fuel use in vehicles by reducing the carbon intensity of the fuel itself through many types of renewable feedstocks.

- Renewable refinery feedstocks. By displacing part of the crude oil with feedstocks from renewable sources, the carbon intensity of the ultimate fuel can be reduced. The use of natural oils, including animal fats, waste grease, and vegetable oils, does not completely eliminate the fuel's carbon impact, as the processing of renewable feedstocks and direct and indirect land conversion also generate emissions, but the full-fuel-cycle carbon intensity of diesel from renewable feedstocks can be 16 to 60 percent less than that of diesel made from crude oil alone. While supply and availability limitations will prevent renewable biomass from entirely replacing crude oil feedstocks, other opportunities, such as renewable electricity use, can also reduce carbon intensity but were not evaluated here.

POTENTIAL TO REDUCE CARBON EMISSIONS

The technologies described above can offer significant reductions in carbon emissions associated with the production of transportation fuels, as shown below. For comparison, the carbon intensities—on a full-life-cycle basis—of petroleum-based gasoline and diesel in California today are 99.18 and 98.03 gCO_2e/MJ, respectively.[26]

The implementation of carbon reduction technologies where applicable can appreciably decrease the overall carbon intensity of petroleum products. The potential carbon reductions are summarized below in the table with assumptions explained in this section.

Technology	Carbon Reduction Potential (gCO_2e/MJ finished product)*	Applicable to:	Estimated Annual Carbon Reduction Potential in California with Full Implementation (million metric tons CO_2e)**
Renewable steam generation	4.8	Finished products of crude oil derived from steam-enhanced oil recovery	7.3
Steam generation with CCS	4.2	Finished products of crude oil derived from steam-enhanced oil recovery	6.4
Refinery energy efficiency	0.5–1.0	Improvements in total refinery efficiency by 5 to 10%	7.3
Refinery CCS***	2.0	Hydrogen-related refinery processes	5.9
Renewable feedstocks	11	Finished products of natural oil	0.8

*See Technical Appendix for calculations of carbon reduction potential.

**Full implementation assumes 100% adoption of renewable steam generation or steam generation with CCS where applicable, 25% efficiency improvement at 100% of refineries, 100% adoption of refinery CCS on hydrogen production units where applicable, and 4% displacement of crude oil with co-processing of mixed renewable or waste/by-product feedstocks at 100% of refineries.

***CCS applied to refinery emissions associated with hydrogen production only. Some hydrogen is produced outside the refinery.

HIGH AND LOW ADOPTION CASES

To illustrate the potential impact of implementing the various carbon reduction technologies within the petroleum industry, two adoption cases between 2013 and 2020 were explored by Tetra Tech, Inc., using assumptions about potential adoption rates and quantitative estimates of emission reductions. The low case represents a conservative market scenario in which the oil producers and refineries adopt technologies to a limited degree, whereas the high case represents a scenario in which adoption is broader, though still to a reasonable and achievable degree. Assumptions for each technology in the low and high cases are described below.

Renewable Steam Generation

Steam generation by concentrating solar energy can replace combusting natural gas expressly for the purpose of generating steam to enhance oil recovery. GlassPoint, a manufacturer of solar steam generators for the oil and gas industry, estimates that as much as 80 percent of natural gas use can be displaced by solar energy, and simulations show that, despite the diurnal and seasonal nature of solar energy, oil recovery from renewable steam generation may be essentially the same as that of combusting natural gas.[27,28]

In the low adoption case, we assume that up to 5 percent of natural gas currently used in once-through steam generators is displaced by renewable steam generation or uses CCS, as described below, by 2020. In the high case, up to 20 percent of the natural gas used in once-through steam generators in California is displaced by renewable steam generation or uses CCS. Other crude oil production facilities globally may also employ this technology, such as the GlassPoint project currently underway in Oman. This study considers only California crude oil sources, making up about 37 percent of the petroleum used in the state.[29] Inclusion of reduction opportunities for foreign sources would increase the emission reduction potential.

Steam Generation with CCS

As an alternative to renewable steam generation, carbon from natural gas steam generation can be generally captured via post-combustion methods and stored. Retrofits using post-combustion capture, which separates CO_2 from the flue gas, can be suitable for existing facilities such as natural gas–based steam generation units.[30] Post-combustion capture can also be utilized for upgrading facilities, such as those that use steam methane units to produce hydrogen.[31] In the low case, we assume that up to 5 percent of carbon emissions from once-through steam generators used in enhanced oil recovery are captured and sequestered or reduced using renewable steam generation, as described above, by 2020. In the high case, up to 20 percent of these carbon emissions from California fields using natural gas steam generation are captured and sequestered or reduce using renewable steam generation. Other out-of-state crude oil production facilities that supply California refineries may also be able to employ this technology, thereby increasing the potential emission reductions. However, this issue paper focuses just on opportunities at California production facilities.

As with refinery CCS, combustion products are sequestered rather than emitted into the atmosphere. CCS is a particularly interesting option for this portion of the petroleum supply chain, as carbon dioxide injection is currently used widely for enhanced oil recovery as well, thereby aligning closely with the original purpose of steam generation. However, additional regulations are necessary for enhanced oil recovery projects to ensure that CO_2 injections into oil fields are sequestered. In fact, in some cases, fields that are amenable to steam recovery may also produce higher yields through the injection of carbon dioxide.[32]

Refinery Energy Efficiency

The opportunities for efficiency improvements in refinery energy consumption are substantial. Technology providers such as Honeywell UOP estimate the potential to be 12 to 25 percent in the United States, attainable through improved operation and control, improved heat recovery, advanced process technology, utilities optimization, and hydrogen and fuel gas management.[33] Lawrence Berkeley National Laboratory suggests that the potential improvement may be greater than 23 percent from energy efficiency measures for refinery boilers and more than 31 percent from energy efficiency measures for steam distribution systems in the United States.[34] Figures from McKinsey & Company indicate that a 13 percent improvement in refinery energy efficiency in the United States can be achieved using only commercially available technologies that offer a positive internal rate of return.[35] The refinery sector public report from the California Air Resources Board, based on self-audits by refineries, indicates that approximately 2.8 million metric tons of CO_2e can be avoided with refinery efficiency improvements, with just over 60 percent of the reductions coming from projects that were completed or were implemented prior to 2010.[36] The avoidance of 2.8 million metric tons is equivalent to an 8 percent reduction in refining emissions. We note that these estimates are likely conservative, given that (1) the information is based on self-audits and (2) the estimates do not include the off-site production of electricity, steam, or hydrogen, which is a potential major source of emissions and would be included in a life-cycle assessment.

The authors evaluate a low and higher case, considering the aforementioned studies that cite up to a 20 to 30 percent energy efficiency improvement while recognizing that some refineries may have already deployed some level of energy efficiency improvements. The cases also account for some conservatism with respect to timescale for planning, permitting, and installation. The low case applies a ramp-up to a very conservative 5 percent improvement in refinery efficiency by 2020 relative to 2010 levels. A 5 percent improvement can be attained, for example, by using advanced process technology, such as new catalysts. The high case applies a ramp-up to a still conservative 10 percent improvement in refinery efficiency by 2020. This level can be attained, for example, using improved heat recovery within and across process units.

Refinery Carbon Capture and Storage (CCS)

In the low case, we assume that 15 percent of the refining capacity in California utilizes CCS by 2020. This adoption rate is roughly equivalent to having just one of the largest refineries in California utilize CCS.[37] We assume that CCS is used to capture and store emissions from the hydrogen production unit. In the high case, up to 30 percent of the refining capacity in California utilizes CCS by 2020. This percentage is equivalent to the two largest refineries in California adopting CCS on hydrogen production.

Because CCS requires significant capital and is technologically intensive, implementation will likely take the form of maximum capture and sequestration at a small fraction of refineries, rather than partial capture and sequestration at all refineries. In addition, CCS is not limited to emissions associated with hydrogen production and may be further applied to other carbon emissions from the refinery. However, we consider only hydrogen-related CCS here since it is generally thought to be a lower-cost option that is comparatively easy to implement.

Renewable Feedstocks

Renewable feedstocks can include first-generation natural oils from vegetable seeds, animal fats, and greases, or second-generation feedstocks including camelina, lignocellulosic biomass, and algal oils.[38] Natural oil from renewable feedstocks is either directly co-processed with the incoming crude oil stream using existing refining equipment or processed in new, stand-alone units. For example, the Paramount Refinery in Paramount, California is currently being retrofitted to produce renewable diesel and jet fuel using Honeywell UOP technology consisting of stand-alone units, while the Valero Refinery in St. Charles, Louisiana, also has a stand-alone unit co-located with the existing refinery. For direct co-processing, there is no technical guidance yet on the maximum allowable renewable fraction that still ensures refinery performance. The level of renewable feedstock acceptable for co-processing in existing refineries depends on the level of contaminants (e.g., nitrogen, sulfur, chlorine, alkali metals), which can negatively affect catalyst performance, as well as the risk tolerance of individual refiners. To date, tests have generally incorporated less than 5 percent renewable feedstocks through co-processing, although up to 30 percent has been proposed.[39] Stand-alone units to produce renewable finished products allow for potentially higher blend levels with petroleum finished products. As more refineries adopt the use of renewables, growing industry experience with this technology will provide greater understanding and better characterization of its carbon reduction potential.

In the low case, we assume that up to 30 percent of refining capacity in California uses 2 percent renewable feedstocks in its refining operations by 2020. In a higher case, up to 60 percent of refineries use 4 percent renewable feedstocks in their refining operations.

Other opportunities to use renewable feedstocks (not analyzed here) include:

- Use of renewable fuels (e.g., biofuels) for refinery process heaters that could partially or fully replace fossil fuels.
- Greater use of renewable-based electricity as an energy input to refineries. Refineries are currently among the largest users of electricity in California.
- Use of renewable hydrogen sources, such as biomass to hydrogen, to displace fossil-based hydrogen sources.

The low and high cases represent modest levels of adoption of carbon reduction technologies by 2020.

Carbon Reduction Opportunity	Low Adoption Case	High Adoption Case
Renewable steam generation or steam generation from natural gas with CCS for oil extraction*	5% of once-through steam generators in CA adopt either solar thermal or CCS	20% of once-through steam generators in CA adopt either solar thermal or CCS
Refinery energy efficiency	Average 5% improvement across all refineries	Average 10% improvement across all refineries
Refinery CCS for hydrogen production**	15% of refining capacity	30% of refining capacity
Renewable feedstocks	30% of refineries using 2% renewable feedstocks in crude oil stream	60% of refineries use 4% renewable feedstocks in crude oil stream

*Renewable steam generation and steam generation from natural gas with CCS are generally mutually exclusive opportunities.

**CCS applied to the entirety of refinery emissions associated with hydrogen production and use as a process fuel.

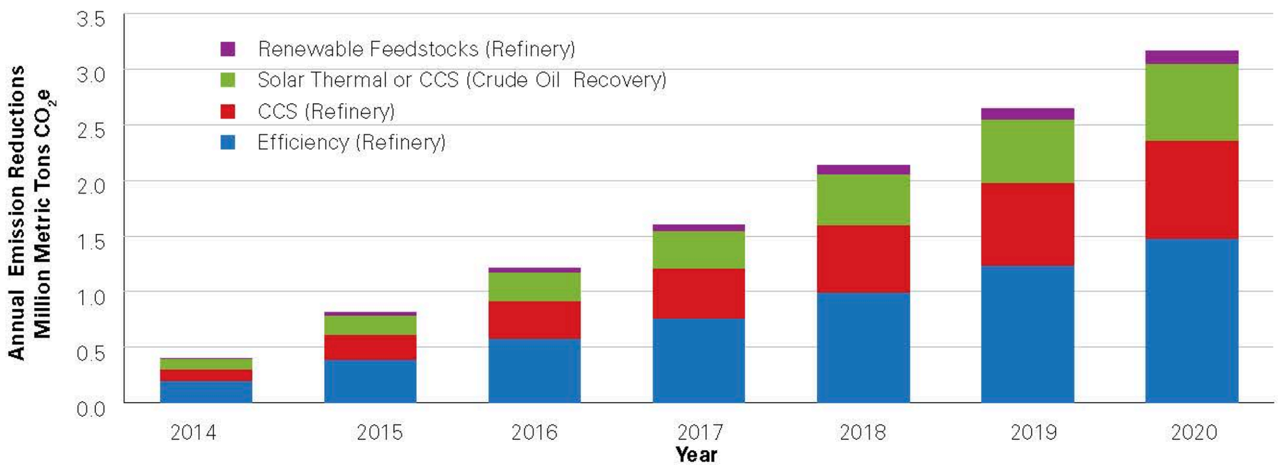
COMBINED CARBON REDUCTION POTENTIAL

The magnitude of potential carbon reductions in the low and high adoption cases is illustrated (in the two figures below) for California between 2014 and 2020. Refining in California represents 15 percent of total U.S. capacity. GHG emissions from California petroleum refining and crude oil production are currently estimated to be approximately 31 million metric tons of CO_2e and 17 MMT, respectively, for a total of 48 MMT.[40]

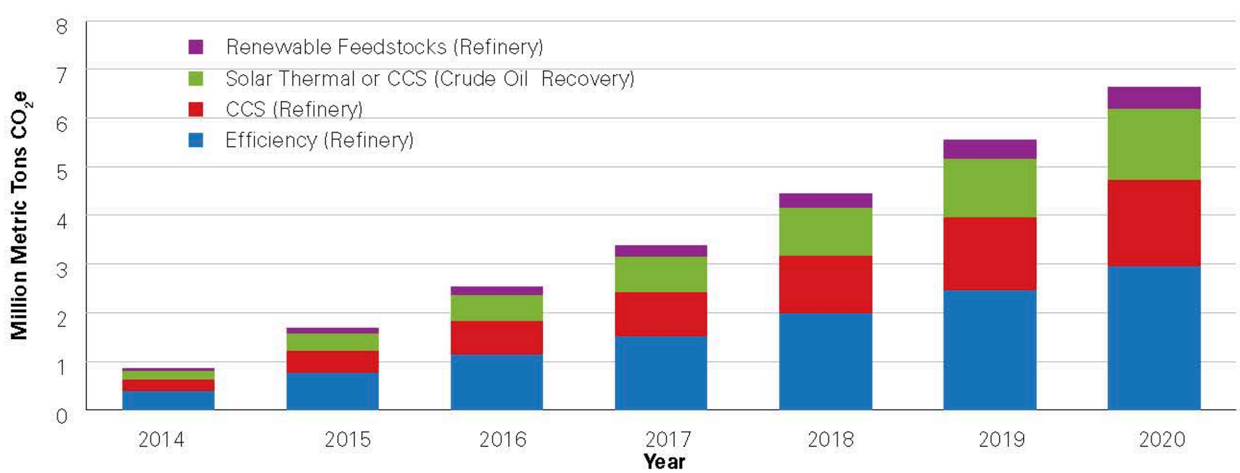
If carbon reduction opportunities for the petroleum industry were adopted to a limited degree (low case), the combined emissions reductions could be 2.8 million metric tons annually by 2020.

If carbon reduction opportunities for the petroleum industry were adopted more broadly to a reasonable and achievable degree (high case), the combined emissions reductions could be approximately 6.6 million metric tons annually by 2020. As a reference, full adoption of these opportunities could reduce carbon emissions by approximately 20 million metric tons annually but would be unlikely to occur by 2020.

Carbon Reduction Potential under a Low Adoption Case: The adoption of carbon reduction technologies to a limited degree is equivalent to reducing total California refining and oil production emissions by 6% by 2020.



Carbon Reduction Potential under a High Adoption Case: The adoption of carbon reduction technologies to a reasonable and achievable degree is equivalent to reducing total California refining and oil production emissions by 14% by 2020.



For oil recovery, renewable steam generation and steam generation utilizing CCS both show similar carbon benefits. Both the low and high cases evaluated here reflect conservative assumptions regarding the adoption of carbon reduction technologies by the petroleum industry. As discussed above, there are numerous technologies and applications not evaluated in this brief that may offer additional reductions. Because many of these technologies, particularly refinery efficiency improvements, also positively impact the economics of the petroleum industry, even higher levels of technology adoption may be feasible.

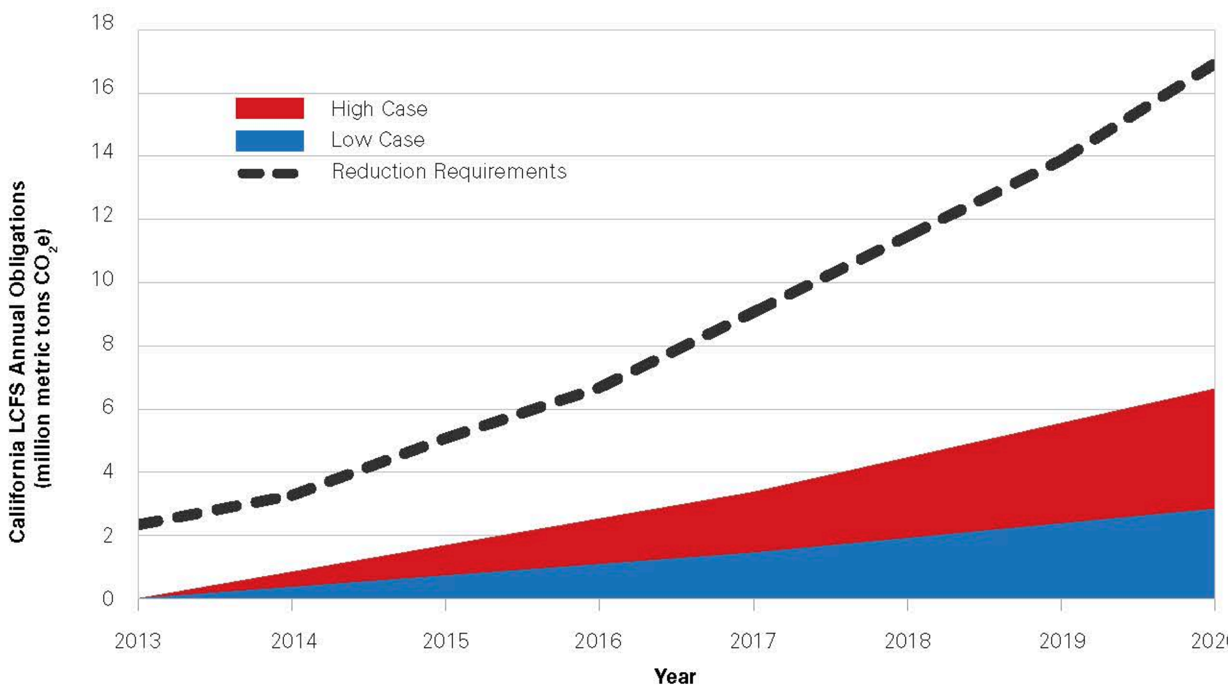
CONTRIBUTING TO CALIFORNIA'S LOW CARBON FUEL STANDARD

These carbon reduction technologies can make major contributions to the petroleum industry's obligations under California's LCFS. Under the standard, refineries must reduce the carbon intensity of their fuels by 10 percent by 2020, relative to 2010 levels. This level of reduction, applied to the projected California gasoline and diesel demand over the next decade, translates to obligations for refiners that reach nearly 17 million metric tons annually in carbon reductions in 2020.[41]

Currently, California's LCFS includes crediting opportunities for innovative technologies to reduce emissions from crude oil recovery, including CCS and solar steam generation. The state's Air Resources Board is currently evaluating refinery-specific measures to require or encourage refining energy efficiency improvements. The LCFS standard currently does not account for reduction opportunities that occur directly at petroleum refineries. Crediting for reductions that go above and beyond requirements could help create additional incentive for refineries to undertake these projects. Many of these technologies can significantly reduce air pollution, resulting in co-benefits in addition to carbon reductions.[42]

The low and high cases described above suggest that approximately 2.8 million to 6.6 million metric tons annually of these obligations can be met in 2020 under conservative assumptions regarding the adoption of the highlighted carbon reduction technologies. Even greater adoption of these technologies, along with other cost-effective reduction strategies, can greatly help refiners to achieve their LCFS obligations if the highlighted carbon reduction technologies are eligible under the program.

California LCFS Annual Compliance Obligations: Adoption of existing carbon reduction technologies and other cost-effective reduction strategies can allow refiners to comply with a significant portion of California's LCFS program.



CONCLUSION

The potential to reduce carbon emissions from the petroleum industry is sizable, and many of the technologies to achieve these reductions are available and viable. Along the supply chain, major opportunities exist in crude oil recovery, refining, and refinery feedstocks to shrink the carbon footprint of petroleum. In California alone, modest adoption of renewable steam generation or steam generation with CCS, refinery efficiency improvements, CCS of hydrogen-related refinery processes, and renewable refinery feedstocks can enable carbon reductions of nearly 3 million to 6.6 million metric tons of reductions annually by 2020. Full adoption of these technologies would result in 20 million metric tons of reduction. If all of these technologies were credited under the LCFS, they could contribute to meeting a significant portion of refiners' annual obligations. Additional opportunities, such as CCS at the refinery beyond hydrogen and additional use of renewable feedstocks and energy inputs, can further reduce the carbon impact of the petroleum industry.

Endnotes

1 California Air Resources Board, *Draft White Paper: Potential GHG Reductions from Clean Distributed Generation Technologies at Oil and Natural Gas Facilities*, March 14, 2012, www.arb.ca.gov/cc/oil-gas/draft_white_paper_oil_DG_March_7.pdf (accessed August 11, 2013).

2 U.S. Department of Energy Office of Fossil Energy, *Enhanced Oil Recovery*, energy.gov/fe/science-innovation/oil-gas/enhanced-oil-recovery (accessed July 12, 2013).

3 Based on U.S. Energy Information Administration crude oil production and refining capacity data for 2012, www.eia.gov/.

4 See Technical Appendix for details on the estimates.

5 Under recent amendments to California's LCFS, innovative carbon reduction technologies used for oil production, such as solar thermal and carbon capture and storage, are eligible for LCFS credit generation, with each credit representing 1 metric ton of reduction. Reductions in petroleum refinery emissions are currently not credited under the LCFS.

6 El-Houjeiri, H.M., S. McNally, and A.R. Brandt, *Oil Production Greenhouse Gas Emissions Estimator*, version 1.1, Appendix C. California Environmental Protection Agency, Air Resources Board, February 23, 2013.

7 According to the National Energy Technology Laboratory, "[i]n steamflooding, high-temperature steam is injected into a reservoir to heat the oil. The oil expands, becomes less viscous and partially vaporizes, making it easier to move to the production wells. Steamflooding is generally used in heavy oil recovery to overcome the high viscosity that inhibits movement of the oil." *See*: www.netl.doe.gov/technologies/oil-gas/publications/eordrawings/Color/coltr.pdf and www.netl.doe.gov/technologies/oil-gas/publications/eordrawings/Color/colsf.pdf.

8 We note that in addition to the thermal (or steam) enhanced oil recovery (EOR) technology evaluated here, gas (including natural gas) and chemical injection are the two other main methods for EOR. In some cases, natural gas injection and repressurization could lead to lower GHG emissions, but only if methane is not vented or leaked and if that natural gas is not later recovered as a primary energy source. Currently, repressurization of oil wells using inert or noncombustible gases like CO_2 and N_2 may be a more economical and stable option than using potentially valuable natural gas feedstocks.

9 California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, *2009 Annual Report of the State Oil & Gas Supervisor*, ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2009/0101summary1_09.pdf.

10 In some applications, coal may be combusted to generate steam.

11 California oil recovery has increased in energy-intensity since the 1960s due to an increasing need for steam injection together with resource depletion. See A.R. Brandt (2011), *Sustainability*, Vol. 3, 1833-1854.

12 www1.eere.energy.gov/solar/pdfs/solar_timeline.pdf; Also see *Implementation of Solar Thermal Technology, edited by Ronal Larson and Ronald West*, 2003, MIT Press (Cambridge, MA).

13 www.brightsourceenergy.com; www.glasspoint.com; www.energymanagertoday.com/glasspoint-solar-steam-generators-to-help-omans-enhanced-oil-recovery-092249/.

14 bellona.org/ccs/?id=37.

15 For example, the Shell Quest project aims to capture 35% of the CO_2 from existing upgraders. *See*: www.zeroco2.no/projects/quest-project.

16 IPCC (2005), *Special Report on Carbon Dioxide Capture and Storage*. Prepared by Working Group III of the Intergovernmental Panel on Climate Change (Cambridge/New York: Cambridge University Press, 2005 442. Environmental Non-Governmental Organisation (ENGO), *Perspectives on Carbon Capture and Storage*, 2012, www.engonetwork.org/engo_perspectives_on_ccs_digital_version.pdf. 2012. Massachusetts Institute of Technology, The Future of Coal: Options for a Carbon-Constrained World (Cambridge, Massachusetts: MIT, 2007), www.climatechange.ca.gov/carbon_capture_review_panel/.

17 IPCC 2006, *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2 "Energy", Chapter 4 "Fugitive Emissions." Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds). Published: IGES, Japan.

18 For more options and information, *see*: Harvey, S., V. Gowrishankar, and T. Singer, Leaking Profits, Natural Resources Defense Council, March 2012, www.nrdc.org/energy/files/Leaking-Profits-Report.pdf.

19 *Carbon Intensity of Crude Oil in Europe*, prepared by Energy-Redefined LLC for the International Council on Clean Transportation, November 2010, www.climateworks.org/download/?id=363969bc-e45a-4434-8ff5-553abff7e451.

20 For references, see the Environmental Defense Fund's fact sheet, "Petroleum Competitiveness," business.edf.org/sites/business.edf.org/files/11210_LCMI-Refineries-Citations.pdf;

business.edf.org/sites/business.edf.org/files/11209_LCMI-Refineries.pdf.

21 Each refinery is different, but overall refinery emissions from hydrogen production range between 5% and 20%. Due to their quantity and high carbon dioxide concentration, these emissions usually represent the best opportunity for CCS at refineries. *See, for example*: Det Norske Veritas, *Global Technology Roadmap for CCS in Industry, Sectoral Assessment: Refineries*, Report No. 12P5TPP-9, Draft Rev. 3, August 25, 2010, cdn.globalccsinstitute.com/sites/default/files/publication_20100825_sector-assess-refineries.pdf.

22 In California and nationwide in the United States, natural gas reforming is the dominant technology, as opposed to coal gasification. See: www.energy.ca.gov/2009_energypolicy/documents/2009-05-18_workshop/presentations/05_Alston_Bird_Vollsaeter_May_18_CCS.pdf.

23 Karras, G., 2011 Oil Refinery CO_2 Performance Measurement, prepared by Communities for a Better Environment (CBE) for the Union of Concerned Scientists, September 2011, www.ucsusa.org/assets/documents/global_warming/oil-refinery-CO2-performance.pdf/. *Also see*: www.ucsusa.org/assets/documents/global_warming/California-Refineries-The-Most-Carbon-Intensive-in-the-Nation.pdf.

24 While in general, reduced demand for these higher-carbon feedstocks can reduce overall production and use, we note that estimating the actual reduction in emissions is nontrivial and requires a market analysis of the reduced overall demand in heavy crude oil as well as accounting for potential feedstock substitution. We note that, in part because of these crediting challenges, the LCFS has remained focused on innovative technologies that require clear additional investments and result in direct, verifiable emission reductions.

25 Omitting carbon reduction technologies on the vehicle itself, e.g., fuel economy improvements and alternative fuels.

26 California Air Resources Board, *Low Carbon Fuel Standard Final Regulation Order*, November 26, 2012, www.arb.ca.gov/fuels/lcfs/CleanFinalRegOrder112612.pdf.

27 Van Heel, A.P.G. et al., "The Impact of Daily and Seasonal Cycles in Solar-Generated Steam on Oil Recovery." Presented at the Society of Petroleum Engineers Enhanced Oil Recovery Conference, Muscat, Oman, April 11–13, 2010, www.glasspoint.com/media/2012/11/SPE-Paper-129225_Solar-Steam_Bentouati.pdf.

28 GlassPoint, "Use Less Gas for EOR," www.glasspoint.com/technology/use-less-gas/ (accessed May 22, 2013).

29 energyalmanac.ca.gov/petroleum/ (accessed August 19, 2013).

30 bellona.org/ccs/?id=37.

31 For example, the Shell Quest project aims to capture 35% of the CO_2 from existing upgraders. *See*: www.zeroco2.no/projects/quest-project

32 See, for example, Melzer, L. Stephen, *Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR): Factors Involved in Adding Carbon Capture, Utilization and Storage (CCUS) to Enhanced Oil Recovery*, February 2012, neori.org/Melzer_CO2EOR_CCUS_Feb2012.pdf. Also see: National Energy Technology Laboratory, U.S. Department of Energy, Improving Domestic Energy Security and Lowering CO_2 Emissions with 'Next Generation' CO_2-Enhanced Oil Recovery (CO_2-EOR), June 1, 2011, DOE/NETL-2011/1504, Activity 04001.420.02.03, www.netl.doe.gov/energy-analyses/pubs/storing%20co2%20w%20eor_final.pdf.

33 "Energy Optimization & CO_2 Reduction Opportunities: A Refining & Petrochemicals Webinar," Honeywell Process Solutions and UOP, 2009.

34 Worrell, E., and C. Galitsky, *Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries: An Energy Star® Guide for Energy and Plant Managers*. Ernest Orlando Lawrence Berkeley National Laboratory, February 2005. The LBNL study doesn't give specific energy use from steam distribution systems, but boiler fuels account for 33% on average of fuel used across the refineries in the U.S.

35 Environmental Defense Fund, "Think U.S. Industry Can't be More Competitive? Think Again" fact sheet citations, August 2010, business.edf.org/sites/business.edf.org/files/11210_LCMI-Refineries-Citations.pdf. Original factsheet, http://business.edf.org/sites/business.edf.org/files/11209_LCMI-Refineries.pdf

36 California Air Resources Board, *Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources: Refinery Sector Public Report*, June 6, 2013, www.arb.ca.gov/cc/energyaudits/eeareports/refinery.pdf.

37 California Air Resources Board, *Mandatory GHG Reporting Data: Emissions Reported for Calendar Year 2010*, March 12, 2012, www.arb.ca.gov/cc/reporting/ghg-rep/reported_data/mandatory_reporting_facility_2010_summary_2012-03-12.xlsx.

38 UOP, Honeywell, presentation by Chris Higby given at Alternative Clean Transportation (ACT) Expo, Washington, D.C., June 26, 2013, www.actexpo.com/pdfs/ACTE2013/presentations/BO3-5/5-Higby-Honeywell.pdf.

39 Egeberg, R.G., N.H. Michaelsen, and L. Skyum, *Novel Hydrotreating Technology for Production of Green Diesel*. Haldor Topsøe, www.topsoe.com/business_areas/refining/~/media/PDF%20files/Refining/novel_hydrotreating_technology_for_production_of_green_diesel.ashx (accessed May 22, 2013).

40 See Technical Appendix for details on the estimates.

41 Based on California Air Resources Board, *LCFS Program Review Advisory Panel: New Illustrative LCFS Scenarios*, www.arb.ca.gov/fuels/lcfs/workgroups/advisorypanel/advisorypanel.htm (accessed June 5, 2013); California Air Resources Board, Low Carbon Fuel Standard Final Regulation Order, www.arb.ca.gov/fuels/lcfs/CleanFinalRegOrder112612.pdf, November 26, 2012.

42 For example, the California Air Resources Board's 2013 public report, Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources Refinery Sector Public Report, shows reductions in particulate matter (PM) and nitrous oxide (NOx) through adoption of energy efficiency technologies. While the report did not include the potential reduction estimates for toxic air pollutants (TACs), co-benefits of TAC reductions would be expected as well. www.arb.ca.gov/cc/energyaudits/energyaudits.htm.

TECHNICAL APPENDIX

This appendix details the methodology, references, assumptions, and calculations used to evaluate carbon reduction opportunities in the petroleum industry.

METHODOLOGY

Tetra Tech Inc. evaluated potential carbon reductions from each technology on the basis of engineering experience and expertise, review of the technical and scientific literature, and discussions with experts. Engineering estimates were made by considering the displaced or avoided energy consumption for the specific energy technology, with baseline energy consumption or emissions data obtained from a number of sources such as the U.S. Department of Energy's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model, developed by the Argonne National Laboratory, as well as publically available data from the California Energy Commission and California Air Resources Board.

Low and High Adoption Cases

Overall technology adoption cases were estimated on the basis of reasonable, conservative what-if scenarios, including consideration of timescales for planning, permitting, and installation. The low and high cases apply linear adoption curves, assuming no technology implementation in 2013, half of scenario implementation by 2017, and full scenario implementation by 2020. The specific adoption percentages for each technology in the two cases are detailed in the issue brief.

Crude Oil Production Emissions

Emissions of direct and indirect GHG emissions from producing crude oil in California were estimated on the basis of field-level carbon-intensity and production data from the California Air Resources Board (2013).[1] We note that ARB estimates are for fields producing more than 10,000 barrels in 2011. Lower heating values were assigned to barrels based on API and utilizing factors in the Oil Production Greenhouse Gas Emission Estimator (OPGEEE), version 1.0.[2] Based on ARB's estimates, total production volume for 2011 was 213,630,418 barrels for fields producing more than 10,000 barrels with a weighted average carbon intensity of 12.4 grams per megajoule (g/MJ). Total emissions were estimated to be 16.8 MMT for California oil production and 0.8 MMT for California Outer Continental Shelf lands.

Steam Generation Emissions

The potential for carbon reductions from steam generation in enhanced oil recovery is assessed on the basis of natural gas consumption in steam flooding and cyclic steam injection for California onshore wells. Based on data from the California Department of Conservation, between January 2011 and June 2012, average natural gas consumption for steam injection was 522,103 million BTU (MMBtu) per day.[3] Of this amount, steam for oil recovery that is not generated through cogeneration is assumed to be generated via once-through steam generators (OTSGs), estimated to be responsible for 58 percent of California steam generation, or 301,330 MMBtu per day. The emissions associated with combustion of natural gas in OTSGs have two components: the emissions of the fuel itself (including natural gas recovery, transportation and distribution, and storage), and the emissions of burning the fuel in a boiler. The emissions profiles from the California version of the GREET model (Table 1) are used to estimate OTSG steam generation emissions.[4] The carbon reduction potential of renewable steam generation is calculated on the basis of the displacement of both natural gas fuel and combustion emissions, while the carbon reduction potential of carbon capture and sequestration (CCS) is based on the displacement of natural gas combustion emissions only. (Upstream emissions associated with the natural gas fuel itself would not be displaced in steam generation with CCS.) Carbon dioxide equivalents are calculated on the basis of the carbon content of the emissions and their global warming potentials utilized in GREET, with the GWP_{CH4} of 25 and a GWP_{N2O} of 298 utilized.

Table 1. Steam Generation Emissions

	Emissions (g/MMBtu)	
	Fuel	**Combustion**
VOC	6.3	1.6
CO	11	16
CH_4	130	1.1
N_20	0.066	0.32
CO_2	5,000	58,000

Refinery Emissions

California refinery greenhouse gas (GHG) emissions are derived from facility reports to the California Air Resources Board for calendar year 2010.[5] The relevant subset of these data, reflecting only the facilities whose primary purpose is petroleum refining, is reproduced in Table 2 below.

Table 2. California Refinery GHG Emissions

Facility ID #	Facility Name	Total Reported CO_2 Equivalent Emissions (metric tons/yr, 2010)
101384	Chevron Products Company—Richmond Refinery, 94802	4,511,882
100914	Shell Oil Products US	4,446,565
101246	BP West Coast Products LLC, Refinery	4,432,662
100138	Chevron Products Company—El Segundo Refinery, 90245	3,452,447
100217	ExxonMobil Torrance Refinery	2,916,147
100372	Valero Refining Company—California, Benicia Refinery and Benicia Asphalt Plant	2,627,977
101331	Tesoro Refining and Marketing Company, 94553	2,028,587
100329	ConocoPhillips Los Angeles Refinery Wilmington Plant	1,660,864
100303	Conoco Phillips Refining Company—SF Refinery	1,638,946
100335	Tesoro Refining and Marketing Company—LAR	1,416,592
101205	Ultramar Inc.—Valero	1,104,741
100913	ConocoPhillips Los Angeles Refinery, Carson Plant	760,577
101226	ConocoPhillips Santa Maria Refinery	240,912
101056	Paramount Petroleum Corporation	209,026
101507	Kern Oil and Refining Company	145,206
101239	San Joaquin Refining Company	84,426
101162	Lunday–Thagard Company	34,040
101320	Edgington Oil Company	20,378
		TOTAL: 31,731,977

Source: CARB

Projections to 2020 of California refinery emissions are based on gasoline and diesel forecasts from the "Low Petroleum Demand Scenario" of the California Energy Commission's 2011 *Integrated Energy Policy Report (IEPR) Transportation Forecasting Report*.[6] Volumes of gasoline and diesel demanded annually are linearly interpolated from IEPR estimates for 2009, 2015, and 2020 (Table 3), and crude oil volume and associated refinery emissions are projected by scaling the demand estimates using 2009 data (Table 4). In 2009, refinery GHG emissions were reported at 31,204,903 metric tons, and 597,132,000 barrels of crude oil were used to produce gasoline and diesel in California.[7]

Table 3. California Gasoline and Diesel Projections

Year	Gasoline (gallons)	Diesel (gallons)
2009	14,804,119,733	3,200,244,414
2010	14,685,955,128	3,265,236,366
2011	14,567,790,522	3,330,228,318
2012	14,449,625,917	3,395,220,270
2013	14,331,461,312	3,460,212,221
2014	14,213,296,706	3,525,204,173
2015	14,095,132,101	3,590,196,125
2016	13,898,190,554	3,641,464,547
2017	13,701,249,006	3,692,732,969
2018	13,504,307,459	3,744,001,392
2019	13,307,365,911	3,795,269,814
2020	13,110,424,364	3,846,538,236

Table 4. Projected California Refinery Volume and Emissions

Year	Total Crude Volume (thousands of barrels)	Total Refinery GHG Emissions (metric tons)
2013	591,388	30,904,714
2014	588,969	30,778,334
2015	586,551	30,651,955
2016	581,719	30,399,476
2017	576,888	30,146,998
2018	572,057	29,894,519
2019	567,225	29,642,041
2020	562,394	29,389,562

Note that refinery emissions were calculated by using crude volume projections to scale current emissions, so the decline in GHG emissions in this table is entirely due to a decline in crude volume. The crude volume decline is projected by the CEC IEPR, presumably accounting for fuel economy improvements and reduced travel demand due to policies that reduce vehicle-miles traveled.

Hydrogen processes make up part of total refinery emissions. As with natural gas used in steam generation, emissions for hydrogen also have two components: those generated during the reforming of natural gas (feed) to produce the hydrogen, and those generated from combustion of natural gas for the energy requirement (process energy) to produce hydrogen, such as a furnace. A more detailed description can be found in NREL (2003).[8]

Utilizing the LBNL "Profile of the Petroleum Refining Industry in California," TetraTech Inc. was able to estimate that 576 standard cubic feet (scf) of hydrogen, or 1.47 kg, is used on average to produce one barrel in California.[9] Utilizing the hydrogen production assumptions embedded in the California GREET model, there is an estimated 10.5 kg CO_2 of emissions per barrel of crude oil (kg/bbl) from H_2 production, with 8.0 kg CO_2 per barrel emitted from steam methane reforming to H_2 and the remaining 2.4 kg CO_2 per barrel from the natural gas utilized as process energy for the H_2 production. The assumptions in the California GREET model are that 0.238 MMBtu of natural gas is used as process energy for each MMBtu of H_2 produced. According to Collodi (2010), CO_2 removal efficiencies for specific streams can be about 90 percent (for tail gas and flue gas) to more than 99 percent (from raw H_2). For simplicity, it is assumed in the calculations that all the CO_2 is removed.[10]

RENEWABLE FEEDSTOCK EMISSIONS

The carbon reduction potential of using renewable feedstocks to displace crude oil is calculated on the basis of the full-fuel-cycle carbon intensity of diesel fuel compared with that of renewable diesel. Carbon intensity values are derived from the California Air Resources Board Low Carbon Fuel Standard (LCFS) regulation.[11] The carbon intensity of renewable diesel is assumed to be the average of fuel produced from soy oil and fuel produced from tallow (Table 5). From these carbon intensity values, the carbon reduction potential is calculated using the California diesel volume projections.

Table 5. Fuel Carbon Intensity Values

Fuel	Carbon Intensity (gCO_2e/MJ)
Diesel	98.03
Renewable diesel:	
From soy oil	82.16
From tallow	39.33
Average	**60.75**

Source: CARB

ANNUAL OBLIGATIONS FOR REFINERS

The annual obligations for refiners imposed by California's LCFS (Table 6) are derived from the California Air Resources Board's illustrative scenarios.[12] Gasoline Scenario 8 and Diesel Scenario 6 were selected as reasonable representations of the future fuel mix, and the carbon intensity values in these illustrative scenarios were modified using updated values from the LCFS final regulation order.[13]

Table 6. California LCFS Annual Obligations for Refiners

Year	LCFS Compliance Schedule for Average Carbon Intensity (gCO_2e/MJ)		Annual Credits Required (million metric tons)		
	Gasoline	Diesel	Gasoline	Diesel	Total
Baseline	99.18	98.03	–	–	–
2013	97.96	97.05	1.9	0.4	2.3
2014	97.47	96.56	2.6	0.6	3.3
2015	96.48	95.58	4.0	1.1	5.1
2016	95.49	94.6	5.3	1.4	6.7
2017	94.00	93.13	7.1	2.0	9.1
2018	92.52	91.66	8.9	2.6	11.5
2019	91.03	90.19	10.6	3.3	13.9
2020	89.06	88.23	12.8	4.2	16.9

Source: CARB

Technical Appendix Endnotes

1 www.arb.ca.gov/fuels/lcfs/regamend13/062013_ca-produced-crude-names_draft-field-allocation-and-ci-estimates.xlsx (accessed August 11, 2013). "Public Workshop for the Refinery-Specific Incremental Deficit Option and Low-Complexity/Low Energy-Use Refinery Provisions," California Air Resources Board June 20, 2013.

2 www.arb.ca.gov/fuels/lcfs/hcico/opgee_v1.0a.xlsx; www.arb.ca.gov/fuels/lcfs/hcico/draft_Inputs_OPGEE_V1%200_preliminary.xlsx, (accessed August 11, 2013). Public Workshop, California Air Resources Board, June 12, 2012.

3 Monthly Production and Injection Database, California Department of Conservation: Division of Oil, Gas, and Geothermal Resources.

4 CA-GREET1.8b, December 2009.

5 California Air Resources Board, *Mandatory GHG Reporting Data: Emissions Reported for Calendar Year 2010*, March 12, 2012, www.arb.ca.gov/cc/reporting/ghg-rep/reported_data/mandatory_reporting_facility_2010_summary_2012-03-12.xlsx.

6 California Energy Commission, *Transportation Energy Forecast and Analyses for the 2011 Integrated Energy Policy Report*, CEC-600-2011-007-SD, August 2011, www.energy.ca.gov/2011publications/CEC-600-2011-007/CEC-600-2011-007-SD.pdf.

7 California Energy Commission, *Energy Almanac*, energyalmanac.ca.gov/ (accessed January 18, 2013).

8 NREL (2003), *Hydrogen from Steam-Methane Reforming with CO_2 Capture*, 20th Annual International Pittsburgh Coal Conference, September 15–19, 2003, Pittsburgh, Pa, published June 30, 2003, www.netl.doe.gov/technologies/hydrogen_clean_fuels/refshelf/papers/pgh/hydrogen%20from%20steam%20methane%20reforming%20for%20carbon%20dioxide%20cap.pdf (accessed September 6, 2013).

9 DOE (2004), *Profile of the Petroleum Refining Industry in California*, Lawrence Berkeley National Laboratory, LBNL-55450, www1.eere.energy.gov/manufacturing/resources/petroleum_refining/pdfs/cpi_profile.pdf (accessed September 5, 2013).

10 Guido Collodi and Foster Wheeler (2009), *Hydrogen Production via Steam Methane Reforming with CO_2 Capture*, 4th International Conference on Safety and Environment in Process Industry, March 14–17, 2010. Florence, Italy, www.aidic.it/CISAP4/webpapers/7Collodi.pdf (accessed September 6, 2013).

11 California Air Resources Board,"Low Carbon Fuel Standard Final Regulation Order, November 26, 2012." http://www.arb.ca.gov/fuels/lcfs/CleanFinalRegOrder112612.pdf. November 26, 2012.

12 Based on California Air Resources Board, *LCFS Program Review Advisory Panel: New Illustrative LCFS Scenarios*, www.arb.ca.gov/fuels/lcfs/workgroups/advisorypanel/advisorypanel.htm (accessed June 5, 2013). California Air Resources Board, Low Carbon Fuel Standard Final Regulation Order, November 26, 2012, www.arb.ca.gov/fuels/lcfs/CleanFinalRegOrder112612.pdf.

13 California Air Resources Board, Low Carbon Fuel Standard Final Regulation Order, November 26, 2012, www.arb.ca.gov/fuels/lcfs/CleanFinalRegOrder112612.pdf.

THE EARTH'S BEST DEFENSE

Natural Resources Defense Council
40 West 20th Street
New York, NY 10011
212 727-2700
Fax 212 727-1773

Beijing

Chicago

Los Angeles

bozeman

San Francisco

Washington

www.nrdc.org

www.nrdc.org/policy
www.facebook.com/nrdc.org
www.twitter.com/nrdc

Printed on recycled paper

FOR IMMEDIATE RELEASE

Press contact:
Christine Keeves, NRDC: ckeeves@nrdc.org / 415-875-6155
Debra Holtz, UCS: debbie.holtz@gmail.com / 510-409-7936
Mina Jung, EDF: mjung@edf.org / 415-293-6111

Report: Pump Primed for Three-Fold Growth in Clean, Alternative Fuels by 2025

California's Low Carbon Fuel Standard Targets are Achievable and Will Drive Growth

SAN FRANCISCO (February 2, 2015) – California is capable of tripling its use of alternative fuels over the next 10 years, according to a new report by the fuels and energy consulting firm Promotum. The study examined the growth potential for cleaner fuels under California's Low Carbon Fuel Standard (LCFS), a program requiring the oil industry to reduce the carbon intensity of fuels through the production and use of cleaner fuels.

"It's time for the oil industry to send the lobbyists and lawyers home and put their engineers to work," said Dr. Simon Mui, director of NRDC's work on clean vehicles and fuels in California. "Despite their protests, this shows once and for all that industry can meet and exceed the standard by diversifying to cleaner fuels like advanced biofuels, renewable natural gas, and clean electricity. A range of cleaner options is there for the taking."

The report's findings show that the oil industry can meet the LCFS reduction target – a 10 percent decrease in carbon emissions by 2020 – through known, existing fuels and refinery technologies. This includes expanding the use of lower-carbon biodiesel and renewable diesel, biomethane, electricity, and ethanol, as well as improving the carbon-intensity of existing alternative fuels. It also found that existing oil refineries and crude oil production facilities could dramatically cut their carbon footprint by integrating renewable energy, utilizing innovative technologies, and investing in greater energy efficiency.

The study analyzed different scenarios in which the program would encourage cleaner fuels by rewarding producers based on their environmental performance, measured in tons of carbon pollution reduced. The strong, performance-based incentive provided by the LCFS – worth potentially more than a dollar per gallon for ultra-low carbon fuel producers of fuels such as ethanol made from agricultural waste or biodiesel made from recycled oils – will enable the market to expand and diversify.

"A growing body of evidence shows that the LCFS will be a critical tool toward achieving Gov. Brown's new goal of cutting petroleum use in cars and trucks in half by 2030 to help California meet its climate goals," said Dr. Jeremy Martin, Senior Scientist and Fuels Lead at the Union of Concerned Scientists.

"By providing a steadily growing market for clean fuels, the LCFS supports investments that will energize clean transportation for decades to come."

At its February 19 hearing, the California Air Resources Board will consider its staff's proposal for re-adoption of the LCFS together with a series of enhancements to the program. Together with other clean transportation policies, the standard will enable California to continue reducing carbon emissions that contribute to global warming and poor air quality

“The LCFS is working to diversify California’s energy mix. Innovation and investments in clean fuels is growing,” said Tim O’Connor, Director of EDF’s California Climate Initiative. “As part of a suite of smart policies under our clean energy law, AB32, we’re seeing more efficient vehicles, more clean fuel options, and better access to transit. Californians will breathe easier, save money at the pump, and reduce their dependence on oil.”

Over the next six years, 70 million tons of carbon pollution will be avoided and 280 million barrels oil will be saved. That’s equivalent to avoiding the pollution from nearly 15 million cars and trucks in one year.

As California considers more ambitious future targets, this report – along with a growing body of research over the last several years – demonstrates that the state can reduce the carbon intensity of fuels beyond its current 10 percent reduction target by 2020 to 15 percent by 2025. Long-term regulatory stability is key and will help enable the alternative fuels market to steadily grow to supply 20 percent of California’s transportation energy, up three-fold by 2025 compared to when the program began in 2011.

The report was commissioned by the Natural Resources Defense Council (NRDC), the Union of Concerned Scientists (UCS), and the Environmental Defense Fund (EDF).

The full report can be found here: http://www.nrdc.org/transportation/california-low-carbon-fuel-standard.asp

Martin’s blog can be found here: http://blog.ucsusa.org/low-carbon-fuels-california-610

O’Connor’s blog can be found here: http://blogs.edf.org/californiadream/2015/02/02/a-possible-antidote-to-the-fossil-fuel-economy

Mui’s blog can be found here: http://switchboard.nrdc.org/blogs/smui/

###

The Natural Resources Defense Council (NRDC) is an international nonprofit environmental organization with more than 1.4 million members and online activists. Since 1970, our lawyers, scientists, and other environmental specialists have worked to protect the world's natural resources, public health, and the environment. NRDC has offices in New York City, Washington, D.C., Los Angeles, San Francisco, Chicago, Bozeman, MT, and Beijing. Visit us at www.nrdc.org and follow us on Twitter @NRDC.

The Union of Concerned Scientists puts rigorous, independent science to work to solve our planet's most pressing problems. Joining with citizens across the country, we combine technical analysis and effective advocacy to create innovative, practical solutions for a healthy, safe, and sustainable future. For more information, visit us at www.ucsusa.org and follow us on Twitter @UCSUSA

Environmental Defense Fund (edf.org), a leading international nonprofit organization, creates transformational solutions to the most serious environmental problems. EDF links science, economics, law and innovative private-sector partnerships. Connect with us on our California Dream 2.0 blog, Twitter and Facebook.

23_OP_LCFS_Tetra Responses

101. Comment: **LCFS 23-1**

The comment lists five potential approaches to reducing carbon pollution directly from the petroleum supply chain.

Agency Response: ARB staff appreciates the analysis included in this comment of potential GHG benefits provided by the innovative crude and refinery investment provisions. Staff agrees that if these technologies are widely adopted by crude oil producers and refiners, they will reduce emissions in the petroleum supply chain and generate significant quantities of credits for LCFS compliance and have been incorporated into the provisions.

This page intentionally left blank.

Comment letter code: 24-OP-LCFS-BIO

Commenter: Brent Erickson

Affiliation: Biotechnology Industry Organization

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

24_OP_LCFS
_BIO

Biotechnology Industry Organization

Biotechnology Industry Organization
Comments to the California Air Resources Board
On the Low Carbon Fuel Standard
Readoption Plan
February 17, 2014

The Biotechnology Industry Organization (BIO) appreciates the opportunity to submit comments to the California Air Resources Board (CARB) on the Low Carbon Fuel Standard (LCFS) readoption plan (the readoption plan, or the plan).

BIO is the world's largest biotechnology organization with more than 1,000 members worldwide. Among its membership, BIO represents over 85 leading technology companies in the production of conventional and advanced biofuels and other sustainable solutions to energy and climate change challenges. BIO also represents the leaders in developing new crop technologies for food, feed, fiber, and fuel. BIO member companies represent many of the low carbon fuel producers that will supply the State of California with the fuels for LCFS compliance.

BIO and its member companies commend CARB for its openness, inclusiveness and transparency throughout the LCFS rulemaking process. In light of its representation on the LCFS advisory panel, BIO has appreciated the opportunity to guide and comment on CARB staff review of the LCFS regulation. BIO and its member companies have reviewed the recent LCFS plan and wish to provide comments. LCFS 24-1

BIO supports California's efforts to reduce the carbon intensity of transportation fuels and believes that biofuels can and must contribute significantly to this important objective. LCFS 24-2 While we are generally supportive of the readoption plan, we do have concerns about certain aspects of it and its potential impact on the production, distribution and availability of low carbon fuels in the State of California. Please see below for our brief comments on these areas of concern.

<u>Compliance Curve</u>

Under the new compliance schedule, the majority of the reductions are set to occur in the last two years, between 2018 and 2020. This new schedule will thus reduce the amount of credits needed between now and 2018. Instead of having a deficit in credits in 2015, which would have likely occurred under the former plan, it now appears that it is not likely that there will be a credit deficit until 2018. Given current and expected low carbon credit prices, BIO is concerned that, despite CARB's apparent projections, the credit price now and over the next four years would not attract fuels generating significant credits. In fact, the new compliance LCFS 24-3

1201 Maryland Avenue SW
Suite 900
Washington DC 20024

202.962.9200 P
202.488.6301 F
bio.org

schedule under the readoption plan may slow down investment in new facilities that would produce the very low carbon fuels that CARB is expecting and which are needed for full LCFS compliance. LCFS 24-3 cont.

Reporting Requirements

BIO and its members are concerned that the intensified reporting requirements under the readoption plan could be particularly burdensome in time and cost to small and new low carbon fuel producers. BIO urges CARB take this concern into account as it works to finalize the readoption plan. CARB should make every effort to ensure that the new reporting (and other) requirements under the plan do not inadvertently discourage small producers or innovation. One way to accomplish this goal could be for the LCFS reporting requirements to be harmonized with other existing programs, including the Quality Assurance Plan under the federal Renewable Fuel Standard. LCFS 24-4

GREET Model

BIO recommends that CARB ensure that the final version of the plan provides for periodic updates to the GREET model to ensure that new feedstocks are added and accounted for in a timely manner. This will help to encourage new and innovative low carbon fuel producers under the program. LCFS 24-5

Denaturant Calculation

BIO opposes the change to the denaturant calculation under the readoption plan and urges CARB to reconsider it as it works toward adopting a final readoption plan. Under the previous LCFS plan, the denaturant calculation was a standard 0.8 in carbon intensity (CI) added. As such, it did not appear to have a significant impact on the overall CI. The new denaturant calculation under the readoption plan would have a significant impact on the overall CI, and it would place a greater disadvantage the lower the CI. For instance, as the CI of an ethanol pathway decreases, the denaturant effect would increase. For ethanol with a CI above that of the CARBOB CI, the effect is such that the denatured ethanol has a lower CI than the anhydrous ethanol. BIO is concerned about the percentage used for ethanol, and the assumption that the non-ethanol components are CARBOB and not already accounted for in the anhydrous ethanol CI. Under the new denaturant calculation, the effect could be as little as <1 or close to 4 CI points, with the greater impact on the lower carbon fuels. LCFS 24-6

Conclusion

BIO is generally supportive of the readoption plan, but has concerns as outlined in this letter with respect to the compliance curve, reporting requirements, GREET model, and denaturant calculation. We respectfully request that CARB consider BIO's comments and recommendations as it works to finalize the readoption plan.

Sincerely,

Brent Erickson
Executive Vice President
Industrial and Environmental Section

This page intentionally left blank.

24_OP_LCFS_BIO Responses

102. Comment: **LCFS 24-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support of our public process.

103. Comment: **LCFS 24-2**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support of the re-adoption of the LCFS regulation.

104. Comment: **LCFS 24-3**

The commenter is concerned that given the new compliance schedule, credit price will not be sufficient to attract fuels generating significant credits.

Agency Response: The adopted compliance curve ramps up the percent reduction more slowly in the 2016 to 2018 period than the original adopted LCFS due to several factors. The first is a lower supply of some low carbon-intensity (CI) biofuels in the 2011 to 2018 period due to much less than originally expected production capacities for cellulosic fuels. The second is the uncertainty created by court suits and the decision of a State court to freeze the compliance level at one percent pending reconsideration of the LCFS. That may have impacted investments and delayed the deployment of production facilities for low CI fuels. Due to these factors, ARB staff's analysis in the Initial Statement of Reasons (ISOR) indicated a substantial possibility of insufficient credit production for full program compliance if the original reduction schedule were to be maintained.

In light of this information, ARB staff concluded that a more gradual implementation schedule was appropriate. Further, staff believes that retention of the ten percent reduction target in 2020 will both increase investment in cleaner fuels and create credit prices high enough to attract the needed fuels to California.

105. Comment: **LCFS 24-4**

The commenter is concerned that reporting requirements are burdensome.

Agency Response: ARB staff has carefully considered the parameters listed in the recordkeeping section. It is a list of what is needed to substantiate each fuel volume claimed within the LCFS Program. Staff has also worked with regulated parties that are currently reporting and workshopped the recordkeeping provision a number of times. We do not believe that the program's reporting requirements are overly burdensome.

ARB staff is aware of the voluntary quality assurance plan provision that the Environmental Protection Agency (U.S. EPA) has adopted in the Renewable Fuel Standard Program. Staff is working with U.S. EPA to better understand how this provision is being implemented at the federal level and to consider adding additional third-party checks to the LCFS system in future rulemakings.

106. Comment: **LCFS 24-5**

The comment recommends that ARB plan for periodic updates to the GREET model.

Agency Response: ARB staff plans to update the analytical models underlying the carbon intensity calculations in the program at regular intervals – possibly every three years. For example, the next update would occur as part of the program review rulemaking concluding prior to January 1st, 2019. Additionally, in the California-modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET)-2.0 model, Tier 2 calculator, staff has included a user-defined fuel option for new types of feedstock and fuel.

107. Comment: **LCFS 24-6**

The comment requests validation of the change to the denaturant calculation under the re-adoption plan.

Agency Response: The existing method of accounting for denaturant added to ethanol does not account for the fact that in each unit (MJ) of denatured ethanol, a portion of the ethanol is displaced by gasoline blendstock (denaturant). The impact of denaturant on carbon intensity (CI) was previously estimated as 0.8 gCO_2e/MJ by assuming an "average" anhydrous ethanol CI of approximately 90 gCO_2e/MJ. Given the development of improved ethanol pathways with reduced carbon intensities, ARB staff finds it necessary to account for the ethanol which is displaced when denaturant is added; thus, a lower CI ethanol results in a higher impact of denaturant CI. Denaturant CIs are now calculated on an ethanol pathway-specific basis, rather than as a constant adder. The formula for denaturant CI is given in CA-GREET 2.0 and a separate stand-alone spreadsheet calculator (http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm) was released to more clearly demonstrate how the calculation works.

See the response to comment **LCFS 8-12**.

This page intentionally left blank.

Comment letter code: 25-OP-LCFS-AofA

Commenter: Alexander Menotti

Affiliation: Airlines for America

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

25_OP_LCFS _AofA

Airlines for America®
We Connect the World

February 17, 2015

Transmitted via LCFS Comment Portal

Mary D. Nichols
Chairman
California Air Resources Board
P.O Box 2815
Sacramento, CA 95812

Re: Comments on Proposed LCFS Readoption

Dear Ms. Nichols,

Airlines for America (A4A) appreciates the opportunity to comment on the Air Resources Board's (ARB) proposed readoption of the Low Carbon Fuel Standard (LCFS).[1] We write to request that ARB include sustainable alternative jet fuel as an eligible credit-generating fuel under the LCFS. The U.S. airline industry has a strong record of fuel efficiency improvements and greenhouse gas (GHG) emissions reductions, and A4A and its members seek to build further on that record through the development and deployment of sustainable alternative jet fuel. There is particularly great interest among A4A members and biofuel producers in producing and utilizing such jet fuel in the California market. Sustainable alternative jet fuel (hereinafter referred to as "bio-jet fuel") is a "drop-in ready" fuel product – fully compatible with and capable of replacing petroleum jet fuels – that can be sustainably produced through the processing of waste oils and other biomass-based feedstocks, thereby resulting in reduced lifecycle GHG emissions relative to petroleum-based jet fuel. Unfortunately, the production of bio-jet fuel is currently *disincentivized* in California because biofuel producers can only generate LCFS credits for biofuel that displaces conventional ground transportation fuels. A4A urges ARB to allow for all low carbon transportation fuels to generate credits under the Clean Fuels Program. Such an approach would eliminate unnecessary distortions in the biofuels market, support the developing California advanced biofuels industry, and provide an additional pool of available credits to contain the costs of the LCFS. LCFS 25-1

For the past several decades, the U.S. airlines have dramatically improved fuel and GHG efficiency by investing billions in fuel-saving aircraft and engines, innovative technologies like winglets (which improve aerodynamics) and cutting-edge route-optimization software. As a result, between 1978 and 2013, the U.S. airline industry improved its fuel efficiency by 120 percent, resulting in 3.6 billion metric tons of CO_2 savings – equivalent to taking 22 million cars off the road on average in each of those years. Further, data from the Bureau of Transportation Statistics confirms that U.S. airlines burned 8 percent less fuel in 2013 than they did in 2000, resulting in an 8 percent reduction in CO_2 emissions, even though they carried 17 percent more passengers and cargo on a revenue-ton-mile basis.

But our airlines are not stopping there. A4A and our members are part of a global aviation coalition that has committed to a 1.5% annual average fuel efficiency improvement through 2020 and carbon neutral

[1] A4A is the principal trade and service organization of the U.S. scheduled airline industry. A4A members and affiliates transport more than 90% of U.S. airline passenger and cargo traffic. The members of the association are: Alaska Airlines, Inc.; American Airlines Group (American Airlines and US Airways); Atlas Air, Inc.; Delta Air Lines, Inc.; Federal Express Corporation.; Hawaiian Airlines; JetBlue Airways Corp.; Southwest Airlines Co.; United Continental Holdings, Inc.; and United Parcel Service Co. Air Canada is an associate member.

1301 Pennsylvania Ave, NW, Suite 1100, Washington, DC 20004-1707 T: 202.626.4000 E: a4a@airlines.org W: airlines.org

growth from 2020, subject to critical aviation infrastructure and technology advances achieved by government and industry. The initiatives our airlines are undertaking to further address GHG emissions are designed to responsibly and effectively limit their fuel consumption, GHG contribution and potential climate change impacts, while allowing commercial aviation to continue to serve as a key contributor to the U.S. economy.

The availability of bio-jet fuel in significant quantities is one key pillar to the achievement of the industry goals, and A4A and its members are working to lay the groundwork for the establishment of a sustainable aviation biofuels industry. A4A is a founding member of the Commercial Aviation Alternative Fuel Initiative® (CAAFI), a public-private partnership with the Federal Aviation Administration (FAA) and other stakeholders that is working to hasten the development and deployment of such fuels. Among other accomplishments, CAAFI helped lead the effort for specifications certifying three alternative jet fuels.

In California, United Airlines has executed an agreement with AltAir Fuels for the purchase of up to 15 million gallons of renewable jet fuel over a three-year period to begin in 2015. AltAir has created 100+ jobs in the Paramount area and added to the tax base considerably by taking over an idled refinery that had no active plans to restart. With appropriate treatment of bio-jet fuel under the LCFS, other facilities would likely follow, making California the undisputed hub of bio-jet fuel production.

Allowing bio-jet fuel producers to generate LCFS credits would significantly improve the economics of new and existing facilities by allowing them to generate credits from all transportation fuels produced, while also creating additional compliance flexibility for regulated parties. The AltAir facility, as well as other potential plants utilizing a similar conversion technology, can necessarily produce both diesel and bio-jet fuel. Given that the LCFS is intended to spur investment in facilities producing low carbon fuels that will enable the standard to be met, ARB should not dilute the investment signal for these facilities by not allowing significant portions of their fuel production to generate credits. Further, it would be inappropriate for ARB to create market distortions by crediting diesel and not bio-jet fuel, thereby creating a financial disincentive for the production of bio-jet fuel even though both fuels deliver similar GHG reductions. Indeed, as a result of the LCFS not crediting bio-jet fuel, AltAir is reducing the total available production of renewable jet fuel for United and others to purchase. Unnecessarily creating such disincentives for producers like AltAir (and thereby suppressing demand from airlines like United) is not only contrary to the GHG reduction goals of the LCFS, but it is particularly inappropriate in light of the critical role the airline industry can play in helping to obtain financing for facilities through dedicated off-take agreements, a role that the airline industry is uniquely situated to fill.

LCFS 25-1 cont.

The proposal's discussion of the future availability of renewable diesel for LCFS compliance cites several facilities that have already contractually committed to producing substantial volumes of bio-jet fuel for the airline industry. These include the above-mentioned AltAir facility, as well as planned facilities from Red Rock Biofuels in Oregon and Fulcrum Bioenergy in Nevada.[2] Instead of relying on the LCFS to incentivize these facilities to devote their production only to renewable diesel, ARB should allow for credit from either renewable diesel or bio-jet fuel and allow the market to determine where the fuel is ultimately allocated. Such an approach would lend more certainty to ARB's fuel availability projections, eliminate concerns that the LCFS may inhibit bio-jet fuel production, and lower compliance costs for regulated parties.

Crediting bio-jet fuel as a cost-containment mechanism is consistent with the direction in ARB Resolution 11-39 to explore "expansion of the LCFS credit trading market" and "incorporation of a flexible compliance

[2] http://www.prnewswire.com/news-releases/united-airlines-and-altair-fuels-to-bring-commercial-scale-cost-competitive-biofuels-to-aviation-industry-210073841.html; http://www.swamedia.com/releases/southwest-airlines-announces-purchase-agreement-with-red-rock-biofuels?l=en-US; http://www.cathaypacific.com/cx/en_HK/about-us/press-room/press-release/2014/Cathay-Pacific-invests-in-sustainable-biojet-fuel-developer.html

mechanism…"[3] While ARB has included several new forms of cost containment in the proposal, the simplest form of cost containment—enlarging the pool of available credits by allowing all low carbon transportation fuels used in California to generate credits—is unnecessarily absent from the proposal. In addition, crediting of bio-jet fuel could contribute to cost containment by providing an additional avenue for low carbon fuel use that is unaffected by ground transportation blending constraints.

We agree with ARB's general exemption of aircraft fuels from California's LCFS mandates.[4] Subjecting aircraft fuels to annual "carbon intensity" standards would raise serious federal preemption issues and would not be appropriate given the rigorous jet fuel specifications that make producing jet fuels a "higher hurdle" than producing ground-based fuels. However, ARB does have the authority to amend the LCFS regulations to create *incentives* to promote the use of low carbon, bio-jet fuels in aircraft by allowing credit for such fuels. By promoting the voluntary production and use of bio-jet fuel, ARB would not, in our view, cross the line into impermissibly regulating aircraft fuels, but rather would simply be creating opportunities for airlines to better support California's GHG objectives.

LCFS 25-1 cont.

Notably, allowing bio-jet fuel to generate LCFS credits would be a measure fully in line with the U.S. Environmental Protection Agency's approach under the Renewable Fuel Standard (RFS) regulations. The RFS explicitly allows for the generation of Renewable Identification Numbers (RINs) for the production of bio-jet fuel, although the RFS appropriately does not mandate the production or use of any volume of aviation biofuel.

A4A strongly urges ARB to adopt a similar approach to expand opportunities for new biofuel production facilities and create additional compliance flexibility for regulated parties. Several stakeholders have previously suggested allowing such a credit for bio-jet fuel under the LCFS. Although ARB declined to include such a provision in the original regulations, it committed to revisiting the issue during the mandatory program review in 2011.[5] While ARB did not address the issue in the 2011 program review, we urge ARB to do so now. Given the strong interest in bio-jet fuel in California, we believe the time is ripe for ARB to include a provision crediting the production of such fuel.

Sincerely yours,

Nancy N Young

Nancy N. Young
Vice President, Environmental Affairs

---

[3] *See* Resolution 11-39, Amendments to the Low Carbon Fuel Standard Regulation, p. 9 (December 16, 2011).

[4] *See* Cal. Code Regs. tit. 17, § 95480.1(d) (2011).

[5] *See* Final Statement of Reasons at 285-286 (December 2009).

This page intentionally left blank.

25_OP_LCFS_AofA Responses

108. Comment: **LCFS 25-1**

The comment requests that ARB staff include sustainable alternative jet fuel as an eligible credit-generating fuel under the LCFS.

Agency Response: Aircraft fuels are exempt because many flights occurring in California airspace originate and terminate at a wide variety of national and international locations. ARB staff has not yet attempted to develop a methodology by which aircraft fuel used by aircraft using California airspace can be allocated to the California transportation fuels market.

This page intentionally left blank.

Comment letter code: 26-OP-LCFS-Aemetis

Commenter: Andy Foster

Affiliation: Aemetis Advanced Fuels Keyes

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

26_OP_LCFS
_Aemetis

AEMETIS

February 17, 2015

Hon. Mary Nichols
Chairman, California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Chairman Nichols,

Aemetis, Inc., a California-based company, owns and operates California's largest ethanol production facility located in Keyes. We believe grain sorghum has an essential role to play in helping California meet the greenhouse gas reduction goals set by the LCFS, and to reduce water usage on water-stressed farm acres in California.

To date, Aemetis has processed approximately 50,000 tons of lower-carbon grain sorghum into liquid transportation fuel, and going forward, we intend to continue processing sorghum. As you know, along with the other California ethanol producers, Aemetis has been awarded a CEC matching grant (#ARV-14-027) to develop the California In-State Sorghum (CISS) program that combines research, market development, and education to support the development of sorghum as a reliable and robust feedstock for the state's low carbon ethanol industry. Under the grant, each of the three California ethanol companies will process approximately 82,000 tons of grain sorghum (~7.9 million gallons of ethanol), eliminating over 15,500 MT of CO2. In short, we are committed to the development and use of grain sorghum as a lower-carbon feedstock as we work to support the LCFS.

As a larger part of our sorghum initiative, we maintain close contact with National Sorghum Producers (NSP) and understand they are submitting comments as well. Along with NSP, we applaud the California Air Resources Board for its update of the LCFS and appreciate special attention given to sorghum ILUC, sorghum fertilizer requirements, and N_2O emissions from sorghum stover. We also recommend that the ARB focus attention on information related to sorghum root-shoot ratios, and as it becomes available, incorporate this information into future versions of CA-GREET. LCFS 26-1

Thank you for the opportunity to comment, and for your strong leadership at the ARB.

Sincerely,

Andrew B. Foster
President
Aemetis Advanced Fuels Keyes, Inc.
andy.foster@aemetis.com
(650) 799-6358

This page intentionally left blank.

26_OP_LCFS_Aemetis Responses

109. Comment: **LCFS 26-1**

The comment recommends that ARB staff stay current on any new information that becomes available regarding root-shoot ratios and incorporate this information into future versions of CA-GREET.

Agency Response: See response to comment **LCFS 9-2.**

This page intentionally left blank.

Comment letter code: 27-OP-LCFS-WE

Commenter: Carol Tjiong

Affiliation: White Energy

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

WHITE ENERGY
CLEAN ENERGY FOR A CLEAN FUTURE.

27_OP_LCFS_WE

February 17, 2015

Chairman Mary Nichols
California Air Resources Board
1001 I Street
Sacramento, CA 95812

RE: 2015 LCFS Readoption

Dear Chairman Nichols,

As stated in prior comments, White Energy is an ethanol producer that has three facilities located in Kansas and Texas. We support the re-adoption of the Low Carbon Fuel Standard (LCFS) and commend California ARB for moving the program forward. We appreciate all of staff's hard work and the openness of the workshops leading up to the issuance of the proposed regulation order, allowing stakeholders to better understand the re-adoption process and development of the proposed regulation order. LCFS 27-1

We would suggest that fuel pathways voluntarily registered under the Biofuel Producer Registration system prior to the effective date of the new proposed regulation order all have the same deactivation schedule under Section 95488(a) regardless of the certification date or application date. Due to the decreased iLUC factor alone, it will be beneficial as an ethanol producer to immediately apply for a new certified pathway under the readopted regulation. However, considering the sheer volume of all new certifications that will need to occur across the program, the uncertainty of being able to obtain the new certifications prior to the effective date is a concern. LCFS 27-2

As stated in prior comments, we feel sorghum plays an important role in helping California meet the greenhouse gas reduction goals set by the LCFS and reducing water usage on irrigated acres. We support the comments of the National Sorghum Producers applauding the ARB for its special attention to sorghum iLUC, sorghum fertilizer requirements and N_2O emissions from sorghum stover. We also recommend that the ARB focus attention on information related to sorghum root:shoot ratios, and as it becomes available, incorporate this information into future versions of CA-GREET. LCFS 27-3

White Energy desires to part of the solution by providing low carbon fuels to help ARB meet its goals to reduce greenhouse gas emissions through the LCFS program.

Thank you for the opportunity to comment.

Sincerely,

Carol Tjiong
Vice President

2745 N. Dallas Parkway, Suite 670, Plano, TX 75093
Telephone 972.715.6490, Fax 214.751.2595
www.white-energy.com

This page intentionally left blank.

27_OP_LCFS_WE Responses

110. Comment: **LCFS 27-1**

The comment expresses appreciation for staffs' openness in the workshops leading up to the proposed regulation.

Agency Response: ARB staff appreciates the support of the re-adoption of the LCFS regulation.

111. Comment: **LCFS 27-2**

The comment suggests that fuels pathways voluntarily registered under the Biofuel Producer Registration system prior to the effective date of the new proposed regulation order all have the same deactivation schedule.

Agency Response: Various holders of fuel pathways under the current regulation have voiced concern that recertifying those pathways under the proposed regulation on a first-in-first-out basis will create inequities in the form of market advantages and disadvantages. Holders with recertified carbon intensities (CIs) that are lower than their existing CIs would have a competitive advantage over their competitors if their pathways are processed first in the recertification queue. In order to minimize this inequity, the ARB Executive Officer will group all similar recertified CIs for activation in the LRT-CBTS system at the same time. All recertified landfill-gas-to-biomethane CIs, for example, will be activated in the LRT-CBTS system at the same time.

112. Comment: **LCFS 27-3**

The comment recommends that ARB staff stay up to date on any new information regarding root-shoot ratios, incorporating the information into future versions of CA-GREET.

Agency Response: See response to comment **LCFS 9-2.**

This page intentionally left blank.

Comment letter code: 28-OP-LCFS-GPS

Commenter: John O'Donnell

Affiliation: Glass Point Solar

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

28_OP_LCFS_GPS

TEL:
+1 (415) 778-2800

FAX:
+1 (415) 762-1966

ADDRESS:
GlassPoint Solar, Inc.
46421 Landing Parkway
Fremont, CA 94538

WEB:
www.glasspoint.com

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

February 17, 2015

Via electronic submittal to: http://www.arb.ca.gov/lispub/comm/bclist.php

Re: Notice of Public Hearing to Consider a Low Carbon Fuel Standard (LCFS)

GlassPoint Solar Inc. (GlassPoint) appreciates and supports ARB's efforts to readopt the Low Carbon Fuel Standard (LCFS) to create a workable regulatory framework. We are pleased to provide these comments on the December 30, 2014 LCFS regulatory adoption package. LCFS 28-1

The proposed regulation is the result of a cooperative rulemaking process that GlassPoint believes has made the regulation better, and specifically the Innovative Crude Provisions. We look forward to the conclusion of the rulemaking in an expeditious manner as possible. GlassPoint is ready to build new low-carbon projects once regulatory standards are set.

GlassPoint is a California company that manufactures solar steam generators for thermal enhanced oil recovery (EOR). Our renewable energy technology has proven reliable, safe and economical in field operations in California and the Middle East. We were pleased to be selected by the U.S. State Department as one of nine finalists for the Secretary of State's prestigious 2014 Award for Corporate Excellence (ACE) for our technology and corporate behavior.

Thermal EOR, or steam injection, extends the value and the life of California's oilfields. Today, thermal EOR accounts for more than 40% of California's oil production and consumes more than 200 MM MMBTU per year of fuel for steam generation. Solar energy can replace a substantial fraction of that existing fuel use, reducing emissions resulting from upstream production.

GlassPoint appreciates ARB's understanding of the potential value of innovative crude production methods. Of the potential innovative methods, the use of solar energy is the lowest-cost, lowest-risk, and largest-scale opportunity to reduce the CI of petroleum fuels produced and used in California. Solar powered oil production technologies can contribute to California's economy while reducing emissions, costs and risks associated with achieving the LCFS targets.[1]

[1] ICF International: The Impact of Solar Powered Oil Production on California's Economy, An economic analysis of Innovative Crude Production Methods under the LCFS. January 2015. Attachment A

ICF has recently completed a study of the economic impact of solar innovative crude production. The study finds that solar EOR in California could deliver over 4.2 million credits per year into the LCFS market while creating up to 44,900 cumulative jobs in California's economy through 2020. In-state solar energy projects can deliver permanent emissions reductions, reduce production costs, and reduce dependence on imported fuels. The results further show that for every job created building and operating solar powered oil production facilities, about 2.5–2.7 jobs are created in supporting industries (indirect) and via spending by employees that are directly or indirectly supported by the industry (induced).[2]

GlassPoint strongly supports the Innovative Crude mechanisms and procedures as provided in the proposed regulation, and believes additional changes are not needed to those specific provisions. We appreciate the staff work that has greatly simplified and clarified the processes associated with project approval and credit monetization. LCFS 27-2

One final reminder on regulatory timing must be noted. This regulatory adoption schedule has been delayed several times and now creates challenges for customers and project developers to harvest the benefits of the Federal solar tax incentives, which expire at the end of 2016. An effective 20% price increase will occur for projects which come online after that date. LCFS 27-3

GlassPoint hopes to establish certainty in the investment community as soon as possible about the longevity of, and the benefits of, this program. That is the easiest way to start in-state investments in lower CI fuel production. We look forward to working with ARB so that projects can capture the Federal benefits and minimize total costs.

Thank you for the opportunity to comment and we look forward to the conclusion of this lengthy rulemaking, and to working on building a lower carbon infrastructure for California.

Sincerely,

John O'Donnell
Vice President, Business Development

[2] Ibid.

The Impact of Solar Powered Oil Production on California's Economy

An economic analysis of Innovative Crude Production Methods under the LCFS

January 2015

Submitted to

CIPA
California Independent Petroleum Association

GlassPoint

Prepared by

ICF International
620 Folsom St, Suite 200
San Francisco, CA 94107

About ICF International

ICF International (NASDAQ:ICFI) provides professional services and technology solutions that deliver benefi ial impact in areas critical to the world's future. ICF is fluent in the language of change, whether driven by markets, technology, or policy. Since 1969, we have combined a passion for our work with deep industry expertise to tackle our clients' most important challenges. We partner with clients around the globe—advising, executing, innovating—to help them define and achieve success. Our more than 4,500 employees serve government and commercial clients from more than 70 offices worldwide. ICF's website is www.icfi.com.

Warranties and Representations

ICF endeavors to provide information and projections consistent with standard practices in a professional manner. ICF MAKES NO WARRANTIES, HOWEVER, EXPRESS OR IMPLIED (INCLUDING WITHOUT LIMITATION ANY WARRANTIES OR MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), AS TO THIS MATERIAL. Specifically but without limitation, ICF makes no warranty or guarantee regarding the accuracy of any forecasts, estimates, or analyses, or that such work products will be accepted by any legal or regulatory body.

Waivers

Those viewing this Material hereby waive any claim at any time, whether now or in the future, against ICF, its officers, directors, employees or agents arising out of or in connection with this Material. In no event whatsoever shall ICF, its officers, directors, employees, or agents be liable to those viewing this Material.

Solar Electric Power Generation

Solar Steam Generation
Central Receiver, Coalinga, CA

Solar Steam Generation
Enclosed Trough, Amal, Oman

Contents

List of Exhibits

Executive Summary

The California Air Resources Board (CARB) staff as proposed to re-adopt the Low Carbon Fuel Standard (LCFS), reaffirming its original target of a 10% reduction in the carbon intensity (CI) of transportation fuels used in California by 2020 and subsequent years. While most of the expected CI reductions will be derived from imported low-CI fuels, the regulation and the re-adoption proposal include provisions to promote innovations in crude oil production methods that reduce the CI of petroleum.

Of the potential innovative methods, the use of solar energy is the lowest-cost, lowest-risk, and largest-scale opportunity to reduce the CI of petroleum fuels produced and used in California. Solar powered oil production technologies—solar steam generation and solar electric power generation—have the potential to contribute to California's economy signifi antly while reducing costs and risks associated with meeting the LCFS. Solar steam generation used in thermal enhanced oil recovery (EOR) displaces imported natural gas that that would have otherwise been combusted. Solar electricity generated on-site at production facilities displaces electricity that would have otherwise been purchased from a utility provider. These solar technologies have the potential to reduce the carbon intensity of California's crude oil, thereby boosting investment in California-based industries, and helping shift LCFS compliance from importing low carbon fuels from out-of-state towards in-state investments and operations of low carbon infrastructure. Investment in these technologies can lead to job growth, increased industry activity, and increased state and local tax revenues. Furthermore, by reducing the carbon intensity of California crude oil, these solar technologies have the potential to preserve California refinery operations while fully meeting the emissions reductions goals of the LCFS.

ICF employed IMPLAN, an input-output model, to calculate the economic impacts of deploying solar steam generation and solar electric power generation technologies. ICF developed *steady* and *accelerated* deployment scenarios for each technology, capturing 5% and 30% of their respective markets (as measured by volume of steam or electricity consumption). ICF also considered the economic impacts of keeping LCFS credits generated by solar steam and solar power in California, rather than having the value of those credits transferred to low carbon fuel providers in other regions. Furthermore, we considered the impacts on refiners as a result of being able to maintain margins that would have otherwise been impacted by reduce crude runs or reduced margins from having to export the refined products.

Exhibit 1. Economic Contributions of Solar Oil Production in California

Cumulative Solar Impact 2015-2020	*Steady*	*Accelerated*
	$25/ton	$150/ton
Total Jobs	**11,000**	**44,900**
Income per Worker	$72,000	$77,900
GSP ($M)	**$1,160**	**$5,090**
Industry Activity ($M)	$2,910	$11,350

In the *accelerated* deployment scenario, where solar energy provides 30% of the state's EOR steam needs or onsite production electricity, ICF concluded:

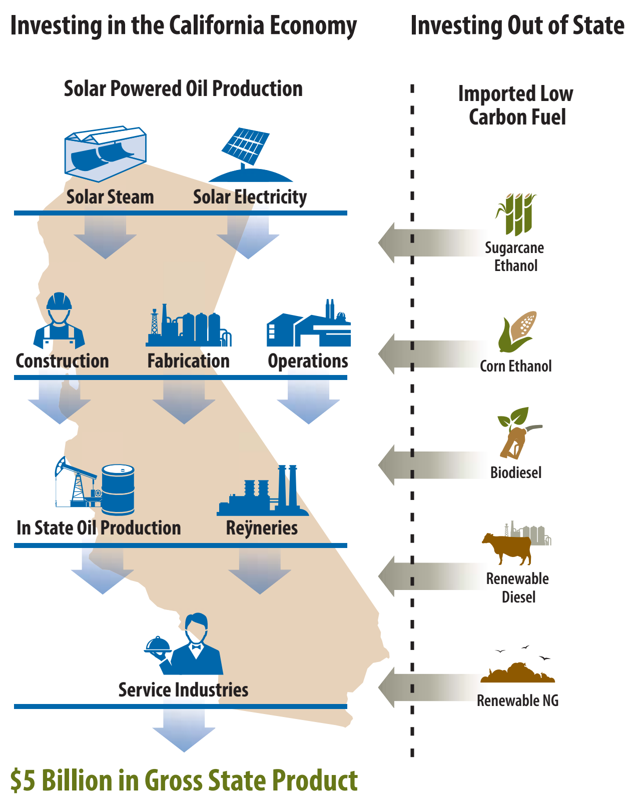
- Innovative crude oil production using solar energy adds 32,100–44,900 cumulative jobs to California's economy from 2015 through 2020, depending on LCFS market conditions.
- These are high value jobs, with labor income per job created in the range of $75,000 per job. Many of the jobs were created in sectors tied to upstream oil production, as well as construction, engineering related services, and fabrication/manufacturing.

- For every job created through investment in solar powered oil production, about 2.5–2.7 jobs are created in supporting industries (indirect) and via spending by employees that are directly or indirectly supported by the industry (induced).
- The deployment of these technologies leads to increased state and local tax revenues in the range of $117–575 million.

Solar steam has greater potential than solar electricity to deliver LCFS credits because 90% of the energy used in California oil production is in the form of steam. In the *accelerated* deployment scenario, solar steam generation has the potential to generate as many credits as some of the most promising low carbon fuel pathways by 2020, including renewable diesel, renewable natural gas, and low carbon intensity biodiesel (e.g., from corn oil). Solar electricity has the potential to generate LCFS credits in line with contributors like electricity and natural gas.

ICF also finds that solar powered oil production technologies may help stabilize the LCFS market in several ways. Firstly, these LCFS credits may help stabilize credit prices by offering a lower cost solution than importing low carbon fuels for compliance. Secondly, we find that these credits may hedge California's exposure to uncertainty in the federal Renewable Fuel Standard market. With the potential for RIN prices to be depressed because of uncertainty in that market, biofuel providers may seek higher LCFS credit prices to pick up the slack in market pricing. However, the deployment of solar powered oil production technologies will provide some buffer against credit price increases. Thirdly, solar powered oil production technologies will provide regulated parties, particularly integrated energy firms with oil production and refining investments, an opportunity to limit their exposure to the LCFS credit market.

Solar powered oil production technologies are commercially available today with low development risk, and unlike some low carbon fuel options, innovative crude methods tap into the existing petroleum supply chain without delay for infrastructure modifi ations or rollouts. The emissions reduction potential of the technologies will deliver credits to the oil producer and reduce the CI of petroleum fuels. Therefore, innovative crude offers the unique advantage of fully complying with the LCFS and achieving the state's GHG reduction goals without hindering the petroleum supply chain. These emissions reductions are available as a "drop in" option using today's fuel production, distribution, and vehicle infrastructure, with minimal infrastructure costs, development risk, and deployment timelines.



ICF's analysis demonstrates that investments in solar powered oil production will yield benefits up to $5 billion in Gross State Product, with jobs created in sectors such as construction, fabrication, oil field operations, and the service industry, while retaining jobs in the refining industry. This contrasts sharply with some of the alternative LCFS compliance pathways, whereby dollars (via commodity pricing and LCFS credits) are exported out of California to pay for low carbon fuels produced elsewhere.

1 Innovative Crude Oil Production

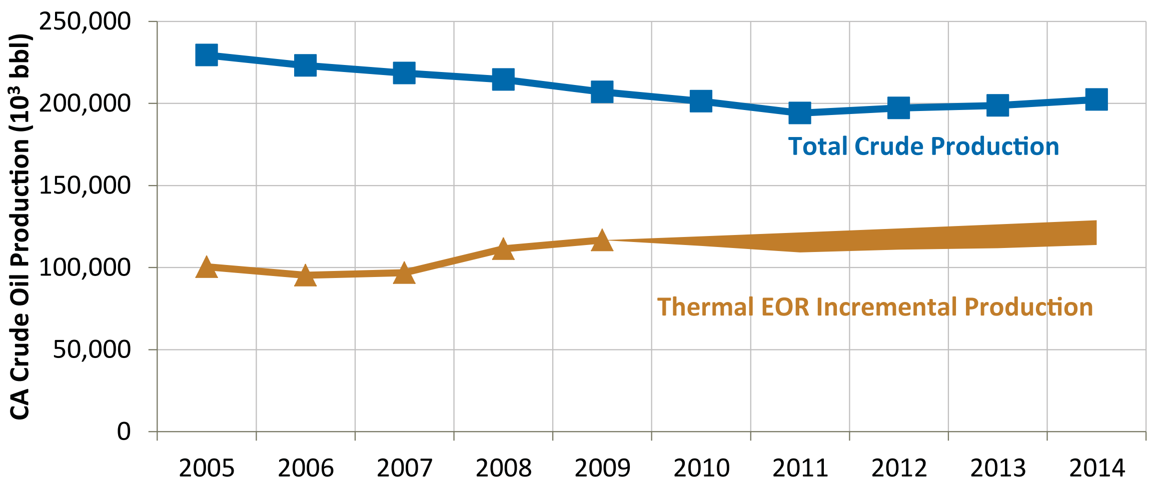
The California Air Resources Board (CARB) staff as proposed to re-adopt the Low Carbon Fuel Standard (LCFS) program in 2015, and to include updates and revisions to the regulation.[1] The regulation and the re-adoption proposal include provisions to promote innovations in crude oil production methods that reduce greenhouse gas (GHG) emissions. In this section, we briefly summarize California's Oil and Gas Sector, its outlook in the near- to mid-term as a result of carbon constraining regulations in the state, and review the relevant innovative crude oil production technologies.

1.1 California's Oil and Gas Sector

Excluding federal offshore areas, California ranks third in the United States in crude oil production. As recently as 2012, nearly 4,700 new wells were drilled in California, bringing the statewide total to 88,500 active wells, operated by 570 companies.[2] A recent report by the Los Angeles Economic Development Corporation (LAEDC) highlights some of the critical parameters characterizing the impact of the Oil and Gas Sector on California's economy, including:[3]

- About 70,000 direct jobs in California are tied to oil and gas production
- Oil and gas production contribute about 0.5% of total California labor income
- The average wage of the component industries in the oil and gas production sectors are considerably higher than the median private industry wage in California

Exhibit 2. Crude Oil Production in California, 2005-2014[4]



1 http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm

2 Division of Oil, Gas and Geothermal Resources of the California Department of Conservation (DOGGR)

3 Oil and Gas in California: The Industry and Its Economic Contribution in 2012, LAEDC, April 2014, http://laedc.org/wp-content/uploads/2014/04/OG_Contribution_20140418.pdf

4 Based on data from EIA and DOGGR. The crude oil production for 2014 is an estimate made by ICF based on data reported through September. Note that production data via TEOR are not yet available past 2009. The shaded range is an estimate based on ICF analysis.

California's Low Carbon Fuel Standard

The LCFS requires a 10 percent reduction in the carbon intensity (CI) of transportation fuels used in California. Carbon intensity is a measure of the lifecycle GHGs of transportation fuels, and includes emissions over the entire fuel supply chain. The LCFS is implemented using a system of credits and defi its: Defi its are generated by fuels that have a carbon intensity greater than the standard and credits are generated by fuels that have a carbon intensity lower than the standard. At the end of each year, defi it-generating parties (generally refiners and fuel importers) must balance their defi its with credits.

Despite several years of reductions in overall crude production since 2005, crude produced from thermal enhanced oil recovery (EOR)[5] or steam injection has been increasing since 2006, as shown in Exhibit 2. Crude Oil Production in California, 2005-2014 above. Steam injection, which reduces the viscosity of oil and increases mobility, has been used commercially in California since the 1960s. Today, more than 40% of California's crude is produced with thermal EOR and is expected to account for half of production in the next few years. As an emitter of GHGs, the oil and gas production industry is impacted by CARB's implementation of the Global Warming Solutions Act of 2006, commonly known as AB 32. The LCFS and light-duty tailpipe GHG standards (originally referred to as Pavley standards) are both part of California's suite of GHG reduction policies under AB 32, and will both lead to reductions in demand for petroleum-based transportation fuels. Although the refinery sector is commonly identifi d and analyzed as one of the primary industry sectors to be impacted by AB 32, upstream oil and gas production sectors will likely experience the effects of the regulation as well.

This report focuses on a potential opportunity included in the proposed re-adoption of the LCFS: "Innovative Crude Production Methods". Operators who produce crude for California's refineries and employ a GHG-reducing "innovative method" in the recovery or extraction process can generate LCFS credits corresponding to the avoided GHG emissions.

1.2 Introduction to Innovative Crude Production Methods

The current proposed LCFS re-adoption regulation identifi s the following technologies as innovative methods for crude production:[6]

Technology	Image	Description	Technology Maturation	LCFS Considerations
Solar steam generation		Uses solar arrays to concentrate the sun's energy to heat water and generate steam for thermal EOR.	Deployed in multiple locations; several vendors.	Steam must be used onsite at the crude oil production facilities.
Carbon capture and storage		Captures CO_2 emissions produced from processing; prevents the CO_2 from entering the atmosphere.	Limited commercial deployment; no commercial deployment at oil field .	Carbon capture must take place onsite at the crude oil production facilities.
Solar or wind electricity generation		Electricity generation from solar technology or wind turbines. Electricity to be used on-site for production-related activities.	Solar PV technology is ubiquitous for non-residential installations. Wind technology is mature, but generally deployed in larger rather than on a smaller scale.	Qualifying electricity must be produced and consumed onsite or be provided directly to the crude oil production facilities from a third-party generator and not through a utility owned transmission or distribution network.
Solar heat generation		Uses solar arrays to concentrate the sun's energy for heat generation.	Concentrating solar technology that can produce process heat (similar to steam generation).	Heat must be used onsite at the crude oil production facilities.

The language also includes provisions regarding year of implementation (no earlier than 2010 for solar steam or CCS; no earlier than 2015 for electricity and heat generation projects), project registration, and minimum GHG reduction thresholds (a carbon intensity reduction of at least 0.10 gCO_2e/MJ or a reduction of at least 5,000 metric tons CO_2e per year).

[5] Thermal EOR is a process whereby heat is introduced to the reservoir in order to reduce the viscosity of the crude, and increase its permeability.

[6] Initial Statement of Reasons, II-17ff. Available online at: http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15isor.pdf

"Solar powered oil production technologies—solar steam generation and solar electric power generation—have the potential to contribute to California's economy significantly while reducing costs and risks associated with meeting the LCFS."

Technologies Selected For Further Analysis

For the purposes of this report, ICF narrowed our consideration of innovative crude methods to *solar steam generation* and *solar electricity generation* based on factors such as commercial availability of the technology, consideration of California oil fi ld characteristics, and industry interest. Other qualifying innovative technologies, including carbon capture and storage (CCS), wind electricity generation, and solar heat generation, were not considered due to limitations or uncertainty in market demand.

- **Solar steam generation.** The technology is commercially available and has been demonstrated by both GlassPoint Solar and BrightSource Energy. These companies have demonstration projects in Kern County and Fresno County, California, respectively. GlassPoint Solar also has deployed its technology in Oman at the Amal West oilfield (in partnership with the national oil company, Petroleum Development Oman, PDO). With about 492 million barrels of steam injected for thermal EOR in California in 2012, there is significant potential for solar steam generation in California. For such thermal EOR projects, steam is the primary energy requirement, with 185 million MMBtu of natural gas required to produce the 492 million barrels of steam injected for thermal EOR. This natural gas is the primary source of GHG emissions associated with oil production. The potential for the technology is limited by factors such as geography and the deployment of efficient combined heat and power (CHP) units at oilfields, which may be difficult to displace depending on when the units were installed and the operators' willingness to displace the technology given the investment. However, ICF anticipates sufficient demand for solar steam generation deployment as part of LCFS compliance.
- **Solar electricity generation.** Solar electric power generation is ubiquitous in California, with more than 8,500 MW of solar energy currently installed, and about 2,750 MW of that installed in 2013. Multiple photovoltaic (PV) technologies have experienced significant declines in installed cost over the last several years, with the average installed system price reported at about \$2.27/W for a non-residential system.[7] The location and electricity demands at oilfields will likely be a good match for solar PV deployment. The regulation restricts credits from potential solar electricity deployment to electricity which is produced and consumed onsite or is directly provided to the facility via third-party generator, not through the utility grid. As oil production operations are generally continuous, there are limits for the fraction of total energy provided by solar PV deployment without concomitant investments in energy storage. Despite these limitations, ICF anticipates that solar PV installations at oil fields will increase substantially between now and 2020 as part of a LCFS compliance strategy based on the cost competitiveness of the technology and the desirable onsite characteristics of oil production fields (e.g., sufficient solar radiation).

[7] US Solar Market Insight: Q3 2014, GTM Research and SEIA, available online: http://www.seia.org/sites/default/files/ esources/iV39f8059N.pdf; assumes a 200-300 kW rooftop installation at a non-residential facility.

2 Economic Impacts of Solar Powered Innovative Crude Production

ICF employed an input-output (I-O) economic model to calculate the economic benefi s of deploying solar steam generation and solar electricity generation in California. We considered several elements associated with the deployment of these technologies, including the following:

- **Capital expenditures.** ICF considered the capital expenditures associated with deploying the technologies in two scenarios (*steady* deployment and *accelerated* deployment). The capital expenditures include the labor and materials associated with building the solar steam installations and solar PV installations.
- **LCFS credit generation.** ICF also considered the value of LCFS credits generated via the deployment of these technologies in California. ICF assumed that the generation of credits would have otherwise been completed outside of California. This is a reasonable assumption given the structure of the LCFS program and a review of CARB's proposed LCFS compliance scenario, which relies heavily on biofuels (e.g., biodiesel, renewable diesel, and renewable natural gas). Given the limited in-state production of low carbon fuels, ICF made the reasonable assumption these innovative crude production technologies will create credits in-state from investments made in-state, versus credit revenues being exported out-of-state for imported low carbon fuels. We valued the credits in two scenarios: a low price of $25/ton and a high price of $150/ton.[8]
- **Refi ery margins.** Depending on the strategy employed, LCFS compliance may lead to significant demand destruction for gasoline and diesel. For instance, CARB's proposed compliance scenario includes about 900 million gallons of diesel replacements being consumed in 2020, representing about 20% of the projected diesel demand. Conversely, CARB's illustrative compliance scenario only projects about 110 million gallons of gasoline replacements being consumed in 2020, in a fuel market with projected demand of about 13.5 billion gallons. Regardless of the compliance strategy, it is highly likely that there will be reduced refinery margins as a result of the LCFS. ICF broadly categorizes these losses into two areas: 1) lost refinery margin and 2) reduced refinery margins as a result from having to export product.

Depending on the chosen means of LCFS compliance, varying levels of decreases occur in gasoline and diesel consumption in California. Although the reduction of petroleum consumption has positive impacts via improved energy security and increased fuel diversity, the decreased consumption of petroleum will also have direct negative impacts on the refining industry—in the same way that the investments in alternative fuels and advanced vehicles will yield positive impacts in the corresponding industries. ICF treated the reduction in gasoline and diesel consumption in the modeling as follows:

- **ICF assumed that there were lost margins on 50% of those crude runs that are assumed to be displaced entirely as a result of the LCFS.** These margins were estimated based on an ICF analysis of the 3-2-1 crack spread for California-based refiners (estimated at about $15/bbl).
- **ICF assumed that the remaining 50% of crude runs representing the reduction in gasoline and diesel consumption in California are exported, rather than displaced entirely.** For these exports, ICF assumed a corresponding decrease in revenue in the export markets because of increased freight costs and competitiveness on pricing (estimated at a combined $5/bbl).

Using CARB's illustrative compliance scenario, each credit generated in 2020 leads to a demand destruction of about 120-130 diesel gallons equivalents.[9]

[8] LCFS credit values traded around $25/ton for all of 2014, and likely are below forward credit prices considering the uncertainty associated with the LCFS program throughout 2014 and rising compliance obligations. The high value of $150/ton was selected for illustrative purposes; the program is capped at $200/ton via a cost compliance mechanism.

[9] The demand destruction is presented as a range because it ultimately depends on the carbon intensity of the low carbon fuels deployed in CARB's illustrative compliance scenario. Available online at http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15appb.pdf

Exhibit 3. Overview of Solar Powered Oil Production Scenarios

Technology Penetration	Solar Steam		Solar Electricity	
	Steady	*Accelerated*	*Steady*	*Accelerated*
Capital Expenditures ($ millions)	$1,900	$5,600	$390	$1,200
LCFS Credits / GHG Emission Reductions	1.4 million	4.3 million	160,000	490,000
LCFS Credit Value ($ millions)	$35–210	$108–645	$4–24	$12–74

Technology penetration notes:

- Solar Steam: About 492 million barrels of steam were injected at California oilfields for thermal EOR in 2012. ICF assumed that solar steam technology providers could capture 5% of the market for steam generation in a *steady* deployment scenario and 30% in an *accelerated* deployment scenario,[10] in accordance with CARB estimates. Note that ICF held the volume of steam injected constant throughout the analysis (2015-2020), despite the very likely possibility that the amount of steam injected into California oilfields will continue to increase over time. The *steady* and *accelerated* levels of solar steam technology deployment amount to about 16 million MMBtu and 49 million MMBtu of steam, respectively, in 2020.
- Solar Electricity: California oil producers purchased about 3.2 terawatt hours (TWh) of electricity as recently as 2012.[11] ICF made the same assumptions for solar PV as were made for solar steam regarding technology penetration: We assumed that solar PV could capture 5% and 30% of the market for electricity purchased by California oil producers by 2020 in *steady* and *accelerated* deployment scenarios, respectively. ICF estimated the deployment of solar PV that would be required to achieve this level using a capacity factor of 20%. In other words, to capture 30% of the market in 2020, ICF assumed that an installed capacity of about 550 MW would be able to provide 0.96 TWh operating at a 20% capacity factor.[12]

Capital expenditure notes:

- Solar Steam: ICF developed estimates for capital expenditures to achieve this level of deployment using data provided by GlassPoint and previous economic assessment of solar steam by Ernst & Young.[13]
- Solar Electricity: We assumed a starting price of $2.33/W[14] with modest decreases over time.[15]

The economic contribution of solar steam and solar electricity deployment are characterized by employment, labor income, value added, and value output.

- **Employment** is reported in terms of annualized job-years. The employment numbers are broken down by direct, indirect, and induced. We also present an employment metric referred to as a **jobs multiplier**, which is the sum of job-years (included direct, indirect, and induced) divided by the direct job-years. This is an indicator of the type of employment activity statewide that is generated by investment in a technology. We also present **labor income** and **labor income per worker**. The latter is a coarse estimate of the value of jobs created by the corresponding investment.
- **Statewide impacts.** We present several metrics measuring the impacts on California's economy, including Gross State Product (GSP), industry activity, output, and taxes.
    - ***Industry activity*** measures the value of goods and services.
    - The ***output multiplier*** mirrors the ***jobs multiplier*** and represents the total industry activity (including direct, indirect, and induced) divided by the direct industry activity. This is an indicator of the type of industry activity statewide that is generated by investment in a technology.
    - The values for ***taxes*** are based on the sum of taxes calculated by IMPLAN, including those associated with employee compensation, proprietor income, tax on production and imports, households, and corporations.

Exhibit 4 below summarizes the results for the *steady* deployment scenarios, with each technology capturing 5% of its respective market (as measured by volume of steam or electricity consumption). Note that for both solar steam and solar electricity, LCFS credits were modeled at values of $25/ton and $150/ton—the results from both LCFS credit pricing scenarios are shown in the table below.

10 Industry discussions and ISOR, II-19 Available online at: http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15isor.pdf

11 Personal communication with CARB staff who que ied the California Energy Consumption Database by county and NAICS code associated with crude petroleum extraction (211111).

12 There are some limitations to these assumptions, considering that crude oil producers are base loading operations. Further, there are no net metering provisions in the proposed language from CARB, and is effectively prohibited because the electricity cannot be purchased from a utility-owned transmission or distribution network. In reality, to capture 30% of the market for electricity consumption by crude oil producers, solar PV technology would have to be deployed in parallel with complementary technologies like solar trackers and energy storage (e.g., batteries) to level out the energy supply with the base loaded demand. To simplify our analysis and the comparison between solar PV and solar steam as innovative crude production technologies, however, we have not considered the expenditures that would likely be required to achieve this level of electricity consumption using solar PV. Rather, we simply quantified the xpenditures that would be required to deploy a given megawatt target of PV.

13 Ernst & Young, "Solar enhanced oil recovery: An in-country value assessment for Oman", 2014, available online: http://tinyurl.com/EY-solar-EOR

14 US Solar Market Insight: Q3 2014, GTM Research and SEIA, available online: http://www.seia.org/sites/default/files/ esources/iV39f8059N.pdf

15 Feldman, D et al., Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections, 2014 Edition, SunShot, US Department of Energy. NREL/PR-6A20-62558

Exhibit 4. Modeling Results for Steady Deployment Scenarios, Cumulative 2015-2020

Economic Parameter	Solar Steam		Solar PV Electricity	
	$25/ton	$150/ton	$25/ton	$150/ton
Employment				
Direct	3,300	4,900	1,100	1,300
Indirect	2,300	2,900	800	800
Induced	2,600	4,200	900	1,100
Total	**8,200**	**12,000**	**2,800**	**3,200**
Jobs Multiplier	2.72	2.56	2.61	2.56
Labor Income ($M)	$590	$930	$200	$240
Income per Worker	$72,000	$77,500	$71,400	$75,000
Statewide Activity ($ millions)				
GSP	$860	$1,360	$300	$350
Industry Activity	$2,260	$3,070	$650	$740
Output Multiplier	1.53	1.59	1.73	1.74
Taxes	$89	$158	$27	$35

The values are shown as cumulative over the analysis period (2015-2020).

ICF notes that by reporting these numbers cumulatively, we may be double-counting jobs i.e., a single person could conceivably account for six job-years assuming that s/he is employed in each year as a result of a particular technology's deployment.

Summary of Economic Contributions

Direct: Impacts of capital expenditures to deploy innovative crude production technologies and the employees hired by the industry itself.

Indirect: Impacts that stem from the employment and business revenues motivated by the purchases made by the industry and any of its suppliers.

Induced: Impacts generated by the spending of employees whose wages are sustained by both direct and indirect spending.

Exhibit 5 summarizes the results for the *accelerated* deployment scenarios, with each technology capturing a 30% of its respective market (as measured by volume of steam or electricity consumption).

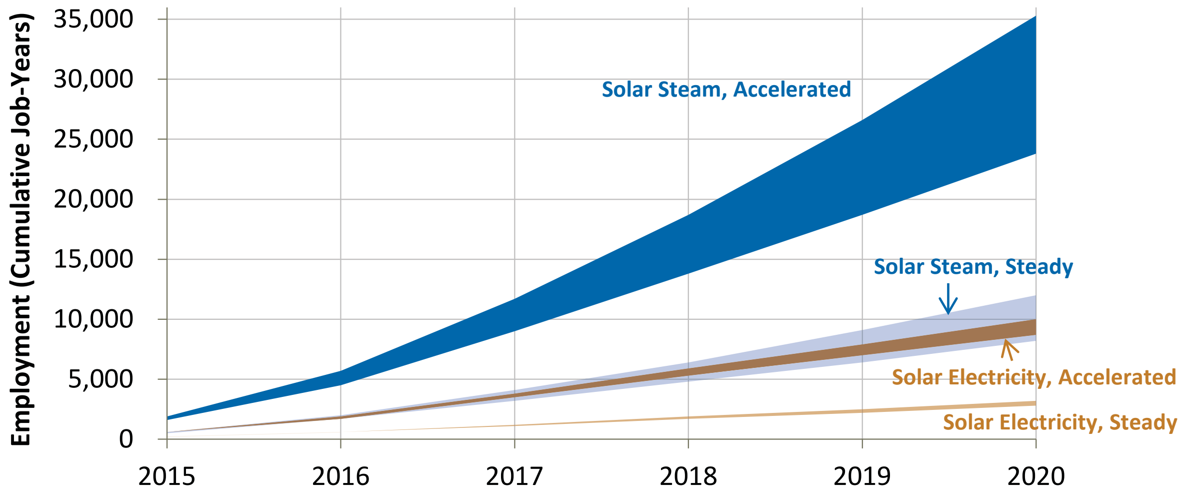
Exhibit 5. Modeling Results for Accelerated Deployment Scenarios, Cumulative 2015-2020

Economic Parameter	Solar Steam		Solar Electricity	
	$25/ton	$150/ton	$25/ton	$150/ton
Employment				
Direct	9,500	14,400	3,300	3,900
Indirect	6,600	8,600	2,300	2,500
Induced	7,700	12,300	2,700	3,200
Total	**23,800**	**35,300**	**8,300**	**9,600**
Jobs Multiplier	2.73	2.56	2.61	2.56
Labor Income ($M)	$1,720	$2,750	$610	$730
Income per Worker	$72,300	$77,900	$73,500	$76,000
Statewide Activity ($ millions)				
GSP	$2,520	$4,030	$890	$1,060
Industry Activity	$6,660	$9,120	$1,950	$2,230
Output Multiplier	1.53	1.59	1.73	1.74
Taxes	$263	$470	$81	$105

The solar steam technology deployment leads to signifi antly higher employment and statewide economic activity, largely as a result of higher capital expenditures associated with capturing the same market share (5% or 30%). The technologies yield similar results in terms of the multipliers for jobs and industry activity / output. In other words, the higher values for solar steam deployment are more of a reflection of the higher overall market opportunity for solar steam rather than something unique about deploying the technology. Solar PV technology has a slightly higher output multiplier, in part because a significant portion (upwards of 55%) of the expenditures associated with solar steam deployment occur outside of California, mainly as imported materials.

Exhibit 6 below shows how the cumulative employment impacts over time for both solar PV and solar steam technologies in the *steady* and *accelerated* scenarios. The range of impacts represents the low and high LCFS credit pricing.

Exhibit 6. Cumulative Employment Impacts in California of Solar Powered Oil Production



The IMPLAN Model

The IMPLAN model is a static input-output framework used to analyze the effects of an economic stimulus on a pre-specifi d economic region; in this study, the State of California. The IMPLAN model tracks economic activity across more than 500 industrial sectors using region-specific ultipliers to trace and calculate the fl w of dollars from the industries that originate the impact to supplier industries. The industrial sectors are based on the North American Industry Classifi ation System (NAICS). The IMPLAN model is one of the most widely used input-output impact models in the United States. For instance, IMPLAN was recently used to estimate the economic contribution of the oil and gas industry in California.

Oil and Gas in California: The Industry and Its Economic Contribution in 2012, LAEDC, April 2014

The IMPLAN model includes more than 500 industry sectors; the table below highlights the sectors that experienced the highest employment impacts. These sectors have been grouped broadly into three categories: oil and gas production industries, solar powered oil production technologies, and indirect and induced sectors. As noted previously, the indirect and induced sectors are those that are impacted by direct investments in the solar powered oil production technologies oil and gas production industries via linkages and increased household incomes. Across both solar steam and solar electricity technology penetration scenarios that were modeled, the construction sector and the drilling oil and gas wells sector captured the highest percentages of employment, accounting for as much as 15-20% of the total employment.

With a larger market penetration, solar steam also has more potential for LCFS credit generation—generating a cumulative 4.4 million and 13.3 million LCFS credits in the *steady* and *accelerated* deployment scenarios compared to just 0.5 million and 1.5 million LCFS credits generated in the *steady* and *accelerated* solar electricity deployment scenarios, respectively.

Exhibit 7. Most Impacted Industry Sectors via Solar Powered Oil Production Technology Deployment

Industry	IMPLAN Sector
Oil and Gas Production Industries	*Drilling oil and gas wells*
	Extraction of natural *gas* and crude petroleum
	Support activities for oil and gas operations
	Wholesale trade
Solar Powered Oil Production Technologies	*Construction of other new nonresidential structures*
	Architectural, engineering, and related services
	Fabricated pipe and pipe fitting manufa turing
	Semiconductor and related device manufacturing
	All other miscellaneous electrical equipment and component manufacturing
Indirect & Induced Sectors	Real estate
	Full-service restaurants
	Limited-service restaurants
	Employment services
	Employment and payroll of state govt, non-education

The higher market potential for solar steam also leads to higher retention of refinery margins attributed to increased refi ery runs and reduced exports of refined products. The retention of these refinery margins manifests itself in the modeling results primarily as increased output and industry activity, and to some extent labor income, rather than employment. Despite not having a significant impact on employment, this is due in part to the nature of the modeling exercise.

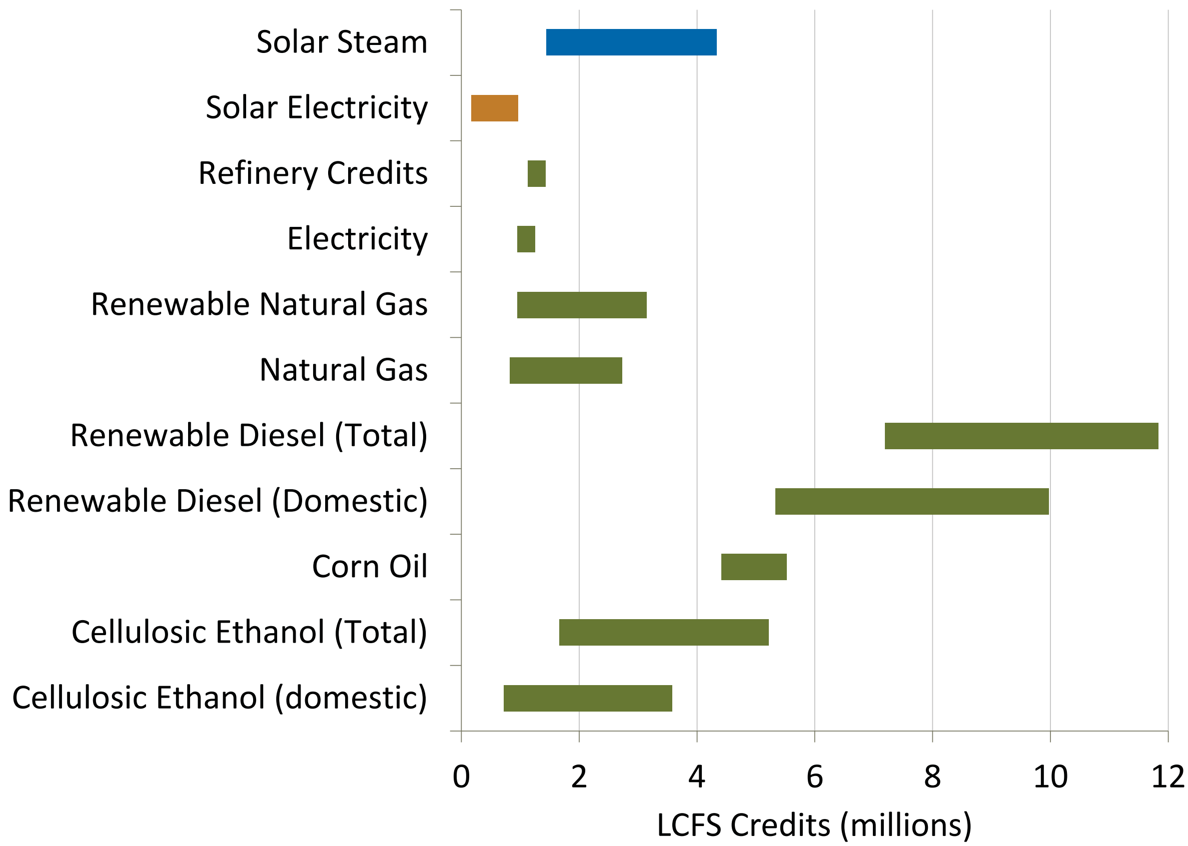
To some extent, the I-O model assumes “full” employment at refineries in the baseline case. In other words, the baseline case—against which the impacts of solar powered oil production technologies are measures—is not assuming that there will be refinery closures as a result of programs like the LCFS or the cap-and-trade program. Furthermore, an increased allocation of expenditures to the refinery sector in the modeling is not going to lead spontaneously to the opening or expansion of an existing refinery in California, thereby generating signifi ant new employment in the sector. Rather, it will lead to enhanced labor income, industry activity, and industry output.

“Solar steam [deployment] leads to higher retention of refinery margins attributed to increased refinery runs and reduced exports of refined products.”

3 Solar Powered Innovative Crude in Context

As part of the re-adoption package, CARB staff eveloped alternative transportation fuel production capacity estimates in various cases (e.g., low, medium, and high).[16] These estimates were used to develop an illustrative LCFS compliance scenario. Exhibit 8 below captures the technical potential for various alternative transportation fuels compared to solar powered oil production technologies in 2020. Note that these values represent the number of LCFS credits that would be generated using the low and high projected estimates published by CARB staff or total fuel volumes available in 2020, not the values assumed for a specific compliance scenario.

Exhibit 8. Total LCFS Credit Potential from Various Compliance Pathways



[16] Available online at http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15appb.pdf

Solar steam has the potential to generate credits comparable with the technical potential of significant pathways that CARB staff se to illustrate compliance, such as domestic cellulosic ethanol. Solar electricity has more limited potential, but is comparable to other contributors to compliance like electricity (used in plug-in electric vehicles) and potential credits generated by energy efficiency improvements at refineries.

While Exhibit 8 focuses on the overall technical potential of various pathways, Exhibit 9 shows the specific deployment potential of solar steam and solar electricity compared to CARB's illustrative compliance scenario for the years 2016-2020.

The potential for innovative crude production technologies is significant: In the *accelerated* deployment scenario, solar steam and solar electricity have the potential to generate 25% and 2%, respectively, of the total cumulative credits required in CARB's illustrative compliance scenario. This puts solar steam on par with pathways such as renewable diesel and renewable natural gas; solar electricity would make a contribution comparable to conventional natural gas. Even in the *steady* deployment scenarios, the LCFS credits generated by solar steam and solar electricity are on par with low carbon fuels like corn oil biodiesel and tallow biodiesel, respectively. Regardless of the deployment scenario, both solar steam and solar electricity have the potential to make material contributions towards LCFS compliance in the 2020 timeframe.

As highlighted in the table above, CARB's illustrative compliance scenario is largely dependent on importing low carbon fuels to California, including corn ethanol (15% of credits), cane-based ethanol (15%), and renewable diesel (22%). To date, nearly all of the renewable natural gas supplied to California for LCFS compliance has been from out-of-state. ICF anticipates that a significant portion of the renewable natural gas will continue to be imported to California from other parts of the United States in the near- to mid-term future (at least through 2018).[17]

Exhibit 9. Estimated LCFS Credit Generation, 2016-2020[18]

Pathway		LCFS Credits (millions) 2016-2020	
Gasoline Substitutes CARB Illustrative Compliance Scenario[17]	Corn Ethanol	9.03	
	Cane Ethanol	7.28	
	Sorghum/Corn Ethanol	1.02	
	Sorghum/Corn/Wheat Slurry Ethanol	0.88	
	Cellulosic Ethanol	1.42	
	Molasses Ethanol	1.49	
	Renewable Gasoline	0.30	
	Hydrogen	0.29	
	Electricity	3.96	
Diesel Substitutes CARB Illustrative Compliance Scenario	Soy Biodiesel	0.43	
	Waste Grease Biodiesel	3.11	
	Corn Oil Biodiesel	5.04	
	Tallow Biodiesel	0.43	
	Canola Biodiesel	0.11	
	Renewable Diesel	13.02	
	Natural Gas	1.39	
	Renewable Natural Gas	7.07	
	Electricity for HDVs and Rail	1.01	
	Refine y Credits	3.16	
	Total	**60.43**	
Solar Powered Oil Production Technologies *Steady* and *Accelerated* Deployment	Solar Steam	4.42	13.28
	Solar Electricity	0.50	1.50

Many of these compliance options are likely to command a significant premium in the market, especially liquid biofuels, thereby pushing credit prices up. California's regulated entities, absent other options, are largely price takers in the low carbon fuel market. In principle, LCFS credit prices will be determined by the marginal abatement cost (assuming a liquid market, and other indicators of a robust market). ICF estimates that the marginal abatement cost associated with the fuel pathways in CARB's illustrative scenario is greater than the abatement cost of the innovative crude production technologies considered here—solar steam and solar PV.

[17] CARB staff estim tes about 50 million diesel gallon equivalents (dge) of RNG consumption in 2014, and used 240 million dge of RNG in 2020 for the illustrative compliance scenario.

[18] Note that these values are calculated by ICF based on our assessment of information presented by CARB, available online at http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15appb.pdf

In other words, ICF believes that in either the *steady* or *accelerated* technology deployment scenarios, innovative crude production technologies have the potential to:

- reduce the marginal abatement cost in the LCFS program in 2020,
- decrease credit prices, and
- reduce California regulated parties' status as a price taker.

ICF estimates that in the *accelerated* deployment case for solar steam, for instance, the credits generated may reduce credit prices by as much as $20-$25/ton in 2020.[19]

Credits from innovative crude production offer a potential hedge against uncertainty in the federal Renewable Fuel Standard (RFS2) market. The RFS2 market has experienced significant volatility. The US Environmental Protection Agency (EPA) sets targets (renewable volume obligations, or RVOs) for the blending of renewable fuels on an annual basis. In November 2014, the EPA announced that they would postpone setting the 2014 RVO targets until 2015, extending a period of regulatory uncertainty in the marketplace. The RFS2 market has also experienced other volatility, such as the availability of federal tax credits. The role of biodiesel, for instance, in the market fluctuates significantly without certainty regarding the availability of a $1.00 per gallon blender's tax credit. This credit has expired and been re-instated retroactively several times in the last five years, creating a difficult investment atmosphere for producers and regulated parties. The uncertainty in the RFS2 market has led to and may continue to lead to volatility of Renewable Identification Numbers (RINs) pricing, the currency of the RFS2 market. For instance, if the RFS2 market is scaled back significantly (via reduced RVOs), it may decrease the price of RINs, and liquid biofuel providers may look to the LCFS program to pick up some of the slack in market pricing. This could lead to an increase in LCFS credit prices.

The credit streams arising from solar powered oil production may provide regulated parties in the LCFS market a buffer against such price volatility. This is dependent, however, on timely deployment of innovative crude production technologies as a compliance diversifi ation strategy.

ICF believes that innovative crude production technologies may provide regulated parties an opportunity to limit their exposure to the LCFS credit market via an integrated investment-based approach. Today, for instance, the majority of LCFS credits are purchased at the point of blending ethanol into gasoline and blending biodiesel or renewable diesel into conventional diesel. In some cases, the LCFS credit value paid is transparent. By and large, however, the LCFS credit market lacks liquidity and transparency in part because some transactions bundle the LCFS credit price paid with fuel price, or refl ct longer-term arrangements. Some market participants have various investments in both refining and low carbon fuels and transfer credits internally. CARB reports, for instance, that one-in-five LCFS credit transactions have $0 credits being transacted.[20] ICF regards this activity as an ordinary part of market participants seeking competitive advantage, and a means to limit their exposure to a potentially volatile LCFS credit market.

The innovative crude provisions of the LCFS allow regulated parties to co-invest in or otherwise source credits from production facilities that reduce the carbon intensity of crude oil, which will durably reduce emissions from upstream crude oil production. These investments will reduce forward uncertainty for all market participants and create economic growth in California, shifting a portion of investment in low-carbon energy facilities from out-of-state to in-state.

"Solar steam has the potential to generate credits comparable with the technical potential of significant pathways that CARB staff use to illustrate compliance, such as domestic cellulosic ethanol."

[19] Note that the economic contributions of such price reductions were not considered under this study's methodology.

[20] CARB, October 27, 2014 LCFS Workshop on Proposed Compliance Curves and Cost Compliance Provision.

Appendix

LCFS Credit Calculations

Solar Steam

The LCFS credits that could be generated for solar steam were calculated using the methodology outlined by CARB in the proposed language:

$$Credits_{innov\_SolarSteam} = 29{,}360 \times V_{steam} \times f_{solar} \times V_{crude\_produced} \times V_{innov\_crude} \times C$$

where $Credits_{innov\_SolarSteam}$ is the amount of LCFS credits generated in metric tons by the volume of crude oil produced and delivered to California refineries for processing; V_{steam} is the volume in barrels of cold water equivalent of steam injected, f_{solar} is the fraction of steam injected that was produced using solar energy; $V_{crude\_produced}$ is the volume (in barrels) of crude oil produced using the innovative method; V_{innov_crude} is the volume (in barrels) of crude oil produced using the innovative method and delivered to California refineries for processing; and C is the constant to convert from metric tons to grams (where 1 MT=106 gCO_2e). The constant at the outset of the equation, 29,360, is the emissions factor associated with the natural gas that would have otherwise been consumed in once through steam generators (OTSGs).21

Solar PV

The LCFS credits that could be generated by solar PV deployment were calculated using the methodology outlined by CARB in the draft language:

$$Credits_{innov\_SolarSteam} = 511 \times \frac{E_{electricity} \times f_{renew}}{V_{crude\_produced}} \times V_{innov\_crude} \times C$$

where $Credits_{innov\_SolarSteam}$ is the amount of LCFS credits generated in metric tons by the solar PV used to produce crude oil and delivered to California refineries for processing; $E_{electricity}$ is the electricity consumption to produce the crude (in units of kWh), and f_{renew} is the fraction of renewable electricity that was produced using solar or wind energy.

Model Description

In this analysis, the economic impacts were calculated using the IMPLAN[22] (IMpact analysis for PLANning), Version 3.0 input-output model. IMPLAN is developed and maintained by the Minnesota IMPLAN Group (MIG). The IMPLAN model is a static input-output framework used to analyze the effects of an economic stimulus on a pre-specified economic region; in this case, the State of California. IMPLAN is considered static because the impacts calculated by any scenario by the model estimate the indirect and induced impacts for one time period (typically on an annual basis).

The modeling framework in IMPLAN consists of two components—the descriptive model and the predictive model.

- The **descriptive model** defines the local economy in the specifi d modeling region, and includes accounting tables that trace the "flow of dollars from purchasers to producers within the region".[23] It also includes the trade flows that describe the movement of goods and services, both within, and outside of the modeling region (i.e., regional exports and imports with the outside world). In addition, it includes the Social Accounting Matrices (SAM) that trace the flow of money between institutions, such as transfer payments from governments to businesses and households, and taxes paid by households and businesses to governments.

---

21 ICF notes that the emissions factor for natural gas is derived from a draft version of the CA-GREET model and is subject to modific tion upon further CARB review.

22 IMPLAN was developed by the Minnesota IMPLAN Group (MIG). There are over 1,500 active users of MIG databases and software in the United State as well as internationally. They have clients in federal and state government, universities, as well as private sector consultants. More information is available at http://www.implan.com.

23 IMPLAN Pro Version 2.0 User Guide.

- The **predictive model** consists of a set of "local-level multipliers" that can then be used to analyze the changes in final demand and their ripple effects throughout the local economy. IMPLAN Version 3.0 uses 2008 data and improves on previous versions of model by implementing a new method for estimating regional imports and exports - a trade model. This new method of estimating imports looks at annual trade fl w information between economic regions; thereby allowing more sophisticated estimation of imports and exports than the traditional econometric RPC estimate used by the previous, Version 2. Additionally, this new modeling method allows for multi-regional modeling functions, in which IMPLAN tracks imports and exports between selected models allowing the users to assess how the impact in one region can impact additional regional economies.

The IMPLAN model is based on the input-output data from the U.S. National Income and Product Accounts (NIPA) from the Bureau of Economic Analysis. The model includes 440 sectors based on the North American Industry Classification System (NAICS). The model uses region-specific multipliers to trace and calculate the flow of dollars from the industries that originate the impact to supplier industries. These multipliers are thus coefficients that "describe the response of the economy to a stimulus (a change in demand or production)."[24] Three types of multipliers are used in IMPLAN:

- Direct—represents the impacts (e.g., employment or output changes) due to the investments that result in final demand changes, such as investments needed for cleanup and/or redevelopment efforts.
- Indirect—represents the impacts due to the industry inter-linkages caused by the iteration of industries purchasing from industries, brought about by the changes in final demands.

Induced—represents the impacts on all local industries due to consumers' consumption expenditures arising from the new household incomes that are generated by the direct and indirect effects of the final demand changes.

[24] Ibid.

The total impact is simply the sum of the multiple rounds of secondary indirect and induced impacts that remain in California (as opposed to "leaking out" to other areas). IMPLAN then uses this total impact to calculate subsequent impacts such as total jobs created and tax impacts. This methodology, and the software used, is consistent with similar studies conducted across the nation.

Inputs and Model Parameters

The direct economic impacts presented in the report are based on: a) investments required to deploy solar steam and solar PV technologies at oilfields in California, b) the value of LCFS credits being generated in-state, rather than exported to low carbon fuel producers outside of California, and c) the value of increased refinery runs and decreased exports that would have otherwise occurred as a result of LCFS compliance. ICF modeled the impacts of the investments for each individual year of the time period (2015-2020).

Output

Whenever new industry activity or income is injected into an economy, it starts a ripple effect that creates a total economic impact that is much larger than the initial input. This is because the recipients of the new income spend some percentage of it and the recipients of that share, in turn, spend some of it, and so on. The total spending impact of the new activity/income is the sum of these progressively smaller rounds of spending within the economy. This total economic impact creates a certain level of value added (GSP), jobs, called the total employment impact, and also tax revenue for state and local governments.

Due to the static nature of the IMPLAN model, the employment impacts must be presented in terms of annual job-years as the model calculates the annual impact of an annual investment. It is likely that once the job is created, it will be sustained, however to ensure that the impact is not overstated; it is conservatively assumed that the job impact is annual. The annualized GSP and tax impacts can be accrued over the program's duration to identify the total impact of the EB-5 program. These dollar values represent the investments that were placed into the economy each year aggregated over time.

Detailed Modeling Results

As noted previously, ICF used the IMPLAN model to calculate the economic impacts of solar powered oil production in California. The data provided in the body of this report have been aggregated into cumulative numbers. The tables below include selected outputs from IMPLAN—employment (in job-years), labor income, industry activity, and GSP—on an annual basis.

Exhibit 10. Changes in Employment, All Scenarios

Solar Technology	Deployment	LCFS	2015	2016	2017	2018	2019	2020
Solar Steam	*Steady*	Low	500	1,100	1,500	1,600	1,700	1,700
		High	600	1,400	2,100	2,400	2,600	2,900
	Accelerated	Low	1,600	3,000	4,500	4,700	4,900	5,100
		High	1,900	3,800	6,100	7,000	7,900	8,700
Solar Electricity	*Steady*	Low	200	400	600	600	500	500
		High	200	400	600	600	700	700
	Accelerated	Low	600	1,200	1,700	1,700	1,600	1,600
		High	600	1,200	1,900	1,900	2,000	2,000

Exhibit 11. Changes in Labor Income, All Scenarios ($ millions)

Solar Technology	Deployment	LCFS	2015	2016	2017	2018	2019	2020
Solar Steam	*Steady*	Low	40	80	110	110	120	130
		High	50	100	150	180	210	240
	Accelerated	Low	100	200	310	340	360	390
		High	130	280	460	550	630	710
Solar Electricity	*Steady*	Low	10	30	40	40	40	40
		High	10	30	50	50	50	50
	Accelerated	Low	40	80	120	120	120	120
		High	50	90	140	150	150	160

Exhibit 12. Changes in Industry Activity, All Scenarios ($ millions)

Solar Technology	Deployment	LCFS	2015	2016	2017	2018	2019	2020
Solar Steam	*Steady*	Low	90	240	380	450	520	580
		High	110	300	490	610	730	830
	Accelerated	Low	270	670	1110	1330	1540	1740
		High	330	850	1450	1820	2170	2490
Solar Electricity	*Steady*	Low	40	80	120	130	130	140
		High	40	90	140	150	160	170
	Accelerated	Low	120	250	370	390	400	420
		High	120	270	410	450	470	500

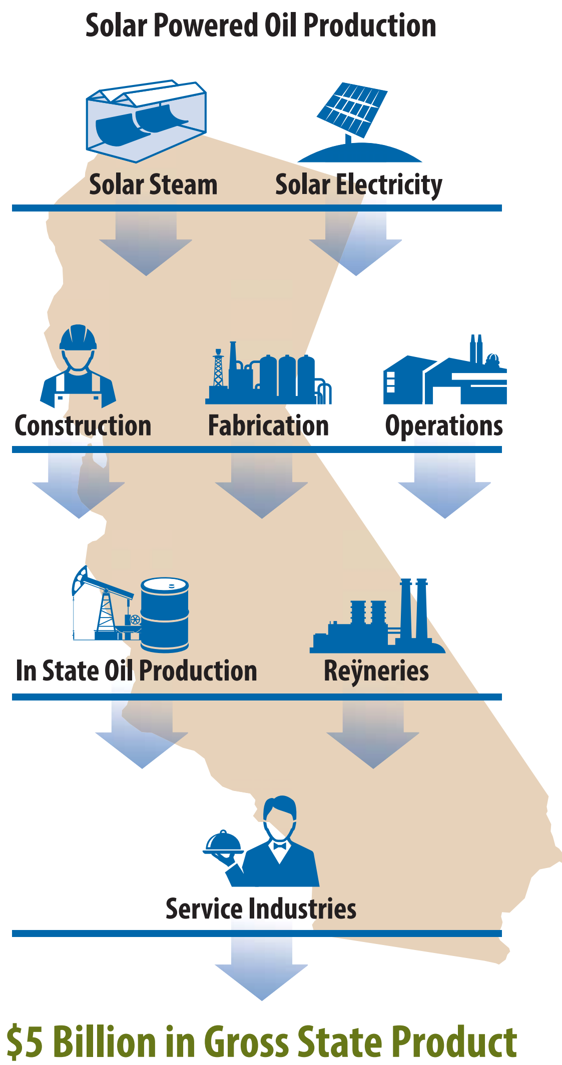
Exhibit 13. Changes in Gross State Product, All Scenarios ($ millions)

Solar Technology	Deployment	LCFS	2015	2016	2017	2018	2019	2020
Solar Steam	*Steady*	Low	50	100	150	170	190	200
		High	60	140	220	270	310	360
	Accelerated	Low	140	280	450	500	550	600
		High	170	390	650	810	940	1070
Solar Electricity	*Steady*	Low	20	40	60	60	60	60
		High	20	40	70	70	70	80
	Accelerated	Low	60	120	180	180	180	180
		High	60	130	200	210	220	230

List of Abbreviations and Acronyms

CARB California Air Resources Board
CCS Carbon Capture and Storage
CI Carbon Intensity
DGE Diesel Gallon Equivalent
EOR Enhanced Oil Recovery
GHG Greenhouse Gas
GSP Gross State Product
I-O Model Input-Output Model
LCFS Low Carbon Fuel Standard
NAICS North American Industry Classifi ation System
OTSG Once Through Steam Generator
PV Photovoltaic
RFS2 Renewable Fuel Standard
RIN Renewable Identifi ation Number
RVO Renewable Volume Obligation (reference to RFS2)

Investing in the California Economy



620 Folsom St, Suite 200, San Francisco, CA 94107 | http://www.icfi. om

Printed on recycled paper.

28_OP_LCFS_GPS Responses

113. Comment: **LCFS 28-1**

The comment expresses appreciation and support for ARB staffs' efforts to readopt the LCFS to create a workable regulatory framework.

Agency Response: ARB staff appreciates the support of the re-adoption of the LCFS regulation.

114. Comment: **LCFS 28-2**

The comment expresses strong support for the Innovative Crude provisions in the LCFS regulation.

Agency Response: ARB staff appreciates the support of the innovative crude oil provision.

115. Comment: **LCFS 28-3**

The commenter expresses concern about regulatory timing.

Agency Response: ARB staff appreciates the commenter's observation regarding regulatory timing and federal solar tax incentives that will expire at the end of 2016. Upon adoption of the regulation during 2015, ARB expects the regulation will be in place at the beginning of 2016.

This page intentionally left blank.

Comment letter code: 29-OP-LCFS-CATF

Commenter: Jonathan Lewis

Affiliation: Clean Air Task Force

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

29_OP_LCFS
_CATF

Comments to the California Air Resources Board by the Clean Air Task Force

CLEANAIR TASK FORCE

On the Proposed Re-Adoption of the Low Carbon Fuel Standard

February 17, 2015

SUMMARY

The Clean Air Task Force (CATF) appreciates this opportunity to comment to the California Air Resources Board on the Low Carbon Fuel Standard (LCFS). CATF is a nonprofit organization that works to help safeguard against the worst impacts of climate change by catalyzing the rapid global development and deployment of low carbon energy and other climate-protecting technologies through research and analysis, public advocacy leadership, and partnership with the private sector.

Our comments focus on the following points:

- ARB should readopt the LCFS through 2020. Achieving compliance with the 2020 target will be difficult, but the LCFS remains the most promising policy tool available for reducing the climate impacts of the transportation sector. LCFS 29-1
- The LCFS's promise is undermined by the proposed adjustment to the lifecycle emissions for corn ethanol, and by the likelihood that regulated entities will increase their reliance on corn ethanol to meet LCFS targets. LCFS 29-2
- The proposed adjustment to corn ethanol's lifecycle emissions score rewards corn for its negative impact on global food security. ARB must acknowledge and address this issue before it erodes the legitimacy of the LCFS program. LCFS 29-3
- The prospects for deep reductions in transportation sector GHG emissions are likely to improve significantly after 2020, particularly if liquid ammonia's potential as an affordable low-carbon fuel is proven out. LCFS 29-4

READOPTION OF THE LCFS

Consistent with an order issued by the California Court of Appeals in *POET, LLC v. California Air Resources Board*, 218 Cal.App.4th 681 (2013), ARB staff has reviewed and revised the LCFS, and is now

> proposing that the Board re-adopt the LCFS, replacing the current LCFS regulation in its entirety. The proposed LCFS regulation will maintain the basic framework of the current LCFS regulation, including: declining carbon intensity targets; use of life cycle analyses; inclusion of indirect land use change effects;

quarterly and annual reporting requirements; and credit generation and trading.[1]

CATF urges the Board to readopt the LCFS. California's LCFS is the country's most promising public policy for bringing low-C fuels into the transportation market. It has several key attributes, all of which positively differentiate it from the federal Renewable Fuel Standard (RFS):

- Dynamic requirements: Increasingly stringent annual reduction requirements dissuade regulated entities from investing in marginally effective compliance strategies.
- Dynamic analyses: There are important ongoing debates about the performance of lifecycle GHG analyses—both with respect to specific technologies and their overall effectiveness. Regular reanalysis of compliance strategies prevents "lock-in" of outdated analyses and ineffectual technologies.
- No grandfathering: Under the LCFS, compliance options are measured according to their performance. Under the RFS, corn ethanol—which is largely exempt from the program's GHG reduction requirements—accounted for 83% of the overall volume mandate finalized by the Environmental Protection Agency (EPA) in 2013, the most recent year in which final renewable volume obligations were issued by EPA.
- Not limited to biofuels: Climate change mitigation depends on strategies that are scalable. That poses a problem for biofuels: the climate benefits of conventional biofuels typically diminish as production scales up, and advanced biofuels tend to be difficult (or impossible) to produce at a large scale.
- Clear focus on GHG reductions: The LCFS cannot blind itself to critically important non-climate impacts, especially the effect that increased consumption of biofuels can have on food prices and global food security. With appropriate safeguards in place, however, ARB can pursue the program's singular goal of GHG reductions without having to accommodate related-but-different objectives like price support for the agricultural sector or energy security.

LCFS 29-2 cont.

A strong, stringent, flexible, intellectually honest LCFS creates a forum in which to consider new, truly low-carbon fuels, and a key market in which to commercialize them. It needs to succeed. However, that success must be achieved in terms of real GHG reductions, not merely on paper. CATF is concerned that a short-term reliance on conventional biofuels—especially corn ethanol—could pull the LCFS in the wrong direction, and imperil its prospects for long term success.

LCFS 29-1 cont.

NET GHG EMISSIONS FROM CORN ETHANOL

When assessing a biofuel's net GHG emissions in the context of a given policy, an important—and complicated—component is the carbon release associated with land use changes. Of particular concern is indirect land use change (ILUC), or the amount of land use change that occurs as agricultural markets accommodate new policy-driven demand for biofuel feedstocks, and the amount of soil and plant-carbon that is released into the atmosphere as a consequence of those changes.

[1] California ARB, *Staff Report-Initial Statement of Reasons* (December 30, 2014) at ES-3.

As supply margins for corn and other crops tighten in the face of competition from policy-driven demand for biofuels, the price of foodstuffs increases. The increase in food prices encourages farmers around the world to cultivate previously unfarmed land—a process that results in substantial losses of soil- and plant-carbon to the atmosphere. Accordingly, a biofuel must "pay back" this "carbon debt" (via CO_2 sequestration by subsequent energy crop growth) before it can be credited with any net climate benefits as compared to petroleum-based fuels (which have comparatively insignificant land use-related carbon impacts).

ARB staff have proposed that the ILUC score for corn ethanol should be reduced from the current score of 30 gCO_2/MJ. Adopting the proposed reduction would be wrong, both as a matter of emissions accounting and as a matter of climate mitigation policy. The proposed reduction would make corn ethanol a more viable LCFS compliance strategy. Heavier reliance on corn ethanol would limit the near- and long-term GHG reductions that can be achieved by the LCFS and would undermine the program's innovation-forcing objective—despite corn ethanol's status as an outmoded technology, the significant uncertainty about whether corn delivers any climate benefits, and the concerns about the non-climate environmental damage associated with its production. LCFS 29-3 cont.

Reducing the ILUC score for corn would be wrong from an emissions accounting perspective because it ignores a host of relevant factors that ARB has not yet been able to effectively quantify in CA GTAP-BIO, but which it knows will raise the ILUC score if/when the factors are correctly incorporated into the model. These factors have been identified by ARB staff[2] and in comments submitted by CATF and other stakeholders.[3] They include:

- The effect of water scarcity constraints on projected crop expansion. Researchers from Purdue University who used GTAP to examine the likely role of water scarcity on crop expansion found that earlier ILUC analyses "likely underestimated induced land use emissions due to ethanol production by more than one quarter."[4] As discussed below, ARB has not yet succeeded in sensitizing CA GTAP-BIO to water constraints, so the effect that such constraints have on LUC patterns and resulting emissions are not fully accounted for. LCFS 29-5
- GTAP's inability to differentiate commercial forest from non-commercial forests, which means that the model wrongly assumes that markets respond to the conversion of both land types in the same way. LCFS 29-6
- The yield improvement assumptions in GTAP overlook important differences among crops and growing regions, they fail to incorporate new research on future corn yields in the Midwest United States, and they do not adequately address the climate impact associated with the increased use of nitrogen-based fertilizers to sustain yield growth. LCFS 29-7

---

2 John Courtis, Anil Prabhu, Farshid Mojaver, and Kamran Adili. iLUC Analysis for the Low Carbon Fuel Standard (Update), California Air Resources Board, (March 11, 2014).
3 CATF, Comments on ARB Proposed ILUC Analysis (May 2014) (http://www.catf.us/resources/filings/biofuels/20140519-CATF%20Comments%20on%20ARB%20Proposed%20ILUC%20Analysis.pdf)
4 Farzad Taheripour, Thomas W. Hertel and Jing Liu. 2013. The Role of Irrigation in Determining the Global Land Use Impacts of Biofuels. ENERGY, SUSTAINABILITY AND SOCIETY.

These issues are described more fully in the appended comments that CATF submitted to ARB in May 2014.

Even if the fundamental concerns described above are put aside for a moment, the proposed ILUC reduction for corn ethanol is problematic because the materials prepared by ARB staff appear to consider two different reduced scores. The first—19.8 gCO_2/MJ—is the unweighted average of the thirty different production scenarios run on CA GTAP-BIO.[5] ARB's potential reliance on this value implies that it believes all thirty scenarios are equally plausible—a position that ARB has not, and cannot, justify. The second score—21.8 gCO_2/MJ—was derived by performing a Monte Carlo simulation (MCS). ARB's Expert Working Group has urged the use of MCS because of its "ability to represent arbitrary input and output distributions, … perform global sensitivity analysis (e.g., contribution to variance) to identify which input parameters contribute most to the variance in the output, and … represent parameter correlations."[6] As between the two scores, the value that was derived from the Monte Carlo simulation—*i.e.*, 21.8 gCO_2/MJ—is superior. LCFS 29-8

A recent paper by Bruce Babcock and Zabid Iqbal of Iowa State University asserts that ILUC models utilized by ARB and EPA have overestimated land use changes by "attribut[ing] all supply response[s] not captured by increased crop yields to land use conversion on the extensive margin."[7] The paper argues for the use of lower ILUC scores by attempting to prove that "the primary land use change response of the world's farmers from 2004 to 2012 has been to use available land resources more efficiently rather than to expand the amount of land brought into production."[8] The paper has several shortcomings, however:

- Babcock and Iqbal only consider intensification techniques such as double cropping rather than analyzing yield increases over this time period.
- The paper dismisses data on extensive land use changes in Africa on the grounds that the linkage between global food prices and those in rural Africa is weak (implying that biofuel policies in the US and EU have little effect on African food prices and land use change)—even though the authors note a correlation between global food prices and food prices in urban Africa.
- The paper makes overly generous assumptions about the extensiveness of double cropping. As Jeremy Martin of the Union of Concerned Scientists wrote in recent comments to ARB, double cropping is not widely used in Southeast Asia where palm oil plantations have moved into formerly uncultivated areas. Nor is double cropping widely adopted in parts of the Midwest where most U.S. biofuels feedstocks—primarily corn and soybeans—are grown. The Babcock and Iqbal paper also fails to account for increased GHG emissions from increased fertilizer usage where it does assume the use of additional double cropping in response to higher crop prices.

---

5 California ARB, *Staff Report-Appendix I: Detailed Analysis for Indirect Land Use Change* (December 30, 2014) at I-25.
6 *Id*. at I-38, I-17.
7 *See* Bruce A. Babcock and Zabid Iqbal, *Using Recent Land Use Changes to Validate Land Use Change Models* (Staff Report 14-SR 109) (http://www.card.iastate.edu/publications/dbs/pdffiles/14sr109.pdf)
8 *Id*.

- Finally, the authors assume the "only net contributor to US cropland from 2007 to 2010 was a reduction in [Conservation Reserve Program (CRP)] land," but this too is an inappropriate assumption, because several studies (from South Dakota State University and even U.S. Department of Agriculture Economic Research Service, Farm Service Agency, and Natural Resources Conservation Service data) show that cropland conversions exceeded acres exiting CRP, with huge impacts on GHG emissions.[9]

Reducing the ILUC score for corn ethanol would also be a mistake in terms of climate mitigation policy. The use of highly complex models like CA GTAP-BIO to determine the net emissions associated with biofuels produces values that have the veneer of objective validity. But the modeling outputs are enormously dependent on the data that are fed into the system and on the system's assumptions about how those data affect physical and economic processes.

LCFS 29-9

A recently published paper examines the extent to which subjective decisions about incorporating different assumptions and data into a lifecycle model can affect the outcome.[10] Plevin *et al*. used a Monte Carlo simulation to characterize the parametric uncertainty associated with the two components of the lifecycle analysis that California used to evaluate biofuels: "an economic modeling component that propagates market-mediated changes in commodity production and land use induced by increased demand for biofuel globally, and a carbon accounting component that calculates the GHG emissions associated with (some) of these induced changes."[11]

The authors found that three parameters have particularly strong influences on the uncertainty importance for ILUC emissions intensity:

- Elasticity of crop yield with respect to price (YDEL) (in the economic model);
- Relative productivity of newly converted cropland (in the economic model); and
- Ratio of emissions from cropland-pasture to cropland, as compared to the ratio from converting standard pasture (in the emissions factor model).[12]

Among these factors, "[b]y far, the greatest contributor to variance in the estimate of ILUC LCFS 29-10

[9] *See* Christopher K. Wright and Michael C. Wimberly. 2013. *Recent land use change in the Western Corn Belt threatens grasslands and wetlands*. PNAS 4134–4139 (doi: 10.1073/pnas.1215404110) (http://www.pnas.org/content/110/10/4134.abstract); Steven Wallander *et al. The Ethanol Decade: An Expansion of U.S. Corn Production, 2000-09*. Economic Information Bulletin No. EIB-79 (August 2011) (http://www.ers.usda.gov/publications/eib-economic-information-bulletin/eib79.aspx); U.S. Department of Agriculture Farm Service Agency. *Cropland Conversion* (July 31, 2013) (http://www.fsa.usda.gov/FSA/webapp?area=newsroom&subject=landing&topic=foi-er-fri-dtc); U.S. Department of Agriculture Natural Resources Conservation Service and Center for Survey Statistics and Methodology, Iowa State University. *Summary Report: 2010 National Resources Inventory* (September 2013) (http://www.nrcs.usda.gov/Internet/FSE_DOCUMENTS/stelprdb1167354.pdf); *see also* Lark, TJ, Salmon, JM, Gibbs, HK. *Cropland expansion outpaces agricultural and biofuel policies in the United States*. ENVIRONMENTAL RESEARCH LETTERS. Expected Spring 2015.

[10] Richard Plevin, *et al*. 2015. Carbon accounting and economic model uncertainty of emissions from biofuels-induced land use change. ENVIRON. SCI. TECHNOL. (doi**:** 10.1021/es505481d)

[11] *Id*.

[12] *Id*.

emissions was YDEL, the elasticity of crop yield to price;" in fact, in ILUC analyses for corn ethanol, YDEL accounts for "nearly 50%"of the variance among possible modeling results.[13] ARB currently uses a YDEL value of 0.25 in GTAP-BIO—a subjective decision that is increasingly difficult to justify in light of separate analyses conducted for ARB by Steven Berry and David Locke. Berry reviewed a collection of studies on yield price elasticity (YPE) and, according to an ARB staff report, "concluded that YPE was mostly zero and the largest value that could be used was 0.1."[14] Locke ran a statistical analysis of a similar set of studies and found "that based on methodologically sound analyses, yield price elasticities are generally small to zero."[15] ARB has nonetheless chosen to include YPE values up 0.35 in its ILUC analyses.[16] [[Id. at Attachment 1-6]]

Developing the relevant data and determining which datasets to use (and which to exclude) are highly subjective exercises, as are the processes of choosing and programming the relational assumptions that drive the model. Viewed in this context, the proposal to reduce the corn ethanol ILUC score can be more appropriately understood as the product of a subjective process—one that reflects the current availability of certain data and analyses that would contribute to a lower ILUC score, but fails to account for a host of countervailing factors that ARB does not yet understand how to model.

LCFS 29-10 cont.

The Board should recognize these limitations, as well as the necessary role that it and ARB staff play in interpreting and acting upon modeling results. The Board should exercise its best judgment in light of the overarching policy objective of the LCFS, which CATF understands to be a meaningful reduction in GHG emissions from the transportation sector. Because corn ethanol's lifecycle GHG emissions are—at best—only slightly lower than those from gasoline, and because increased reliance on corn ethanol would frustrate the development of more innovative and effective compliance options, the proposal to reduce the ILUC score for corn ethanol undermines the objectives of the LCFS. Accordingly, CATF urges the Board to table the proposal.

CORN ETHANOL'S IMPACT ON FOOD SECURITY

Another critically important way in which ILUC estimates are the product of subjective decisions (and not just objective calculations) relates to the treatment of food price increases associated with policy-induced demand for biofuels. As Plevin *et al*. (2015) write, "ILUC emission estimates depend on various modeling choices, such as whether a reduction of food consumption resulting from biofuel expansion is treated as a climate benefit."[17] ARB currently chooses to count GHG reductions that result from reduced food consumption when analyzing the lifecycle emissions of biofuels, but that—again—is a subjective decision. (Moreover, doing

LCFS 29-11

[13] *Id*.
[14] California ARB, *Staff Report-Appendix I: Detailed Analysis for Indirect Land Use Change* (December 30, 2014) at Attachment 1-2.
[15] *Id*. at Attachment 1-5.
[16] *Id*. at Attachment 1-6.
[17] Plevin *et al*. (2015), *supra*.

so implies that ARB assumes that national governments would not subsidize food consumption in the face of rising food prices.)

If instead ARB chose to assume that society would limit the extent to which food consumption would decline (especially taking into consideration a growing world population demanding significantly more calories and protein), its ILUC analysis would produce different results. For example, Thomas Hertel *et al.* (2010) found that if food consumption were held constant in GTAP, the estimated emissions from biofuel expansion would increase by 41%.[18]

LCFS 29-11 cont.

As with the other factors discussed above, the problematic and highly subjective treatment of reduced food consumption reinforces the point that ARB is not obligated to reduce the ILUC score for corn ethanol on the basis of the most recent—but highly incomplete—modeling results.

More generally, CATF urges ARB to reconsider how it accounts for reduced food consumption within the LCFS context, before the issues erodes the legitimacy of the LCFS program.

EMISSION REDUCTION OPPORTUNITIES POST-2020

ARB is appropriately interested in using the LCFS to achieve deep, long-term reductions.

> Although post-2020 goals for the LCFS are not part of this proposed rulemaking, continuing these policies beyond 2020 will ensure that fuel carbon intensity continues to decline and that low-carbon alternatives to petroleum are available in sufficient quantities in the long term. Achieving California's mid and long-term greenhouse gas and air quality goals will require a renewable portfolio of transportation fuels—including electricity and hydrogen—well beyond the current policy trajectories. Accordingly, ARB, in a future rulemaking, will consider extending the LCFS with more aggressive targets for 2030.[19]

LCFS 29-12

An unwarranted reduction to the corn ethanol ILUC score would do more than undermine the actual climate benefits that the LCFS can achieve through 2020; it would lower the ceiling on the long-term effectiveness of the program by extending the period in which marginally beneficial technologies can compete with the far better options that will be available to California after 2020. Chief among these better options may be ammonia, a hydrogen-based energy carrier that CATF has previously discussed with ARB management and staff.

The potential benefits associated with ammonia fuel ammonia are enormous, both for the environment and for the prospects of the LCFS:

LCFS 29-4 cont.

[18] TW Hertel, *et al.* 2010. *Effects of US Maize Ethanol on Global Land Use and Greenhouse Gas Emissions: Estimating Market-Mediated Responses*. BIOSCIENCE. 60:223-231(doi: 10.1525/bio.2010.60.3.8).
[19] California ARB, *Staff Report-Initial Statement of Reasons* (December 30, 2014) at ES-1.

- Zero-carbon ammonia can be produced using air, water, and electricity generated by renewable or nuclear power plants, or by fossil fuel-based generating stations equipped with carbon capture and storage systems.
- A wide range of engines and fuel cells can use ammonia to generate electricity or to power vehicles, and can do so without emitting CO_2.
- Substantial global ammonia production and transport infrastructure is already in place. At 150 million metric tons per year, it is the third largest chemical produced globally.
- At $3.27 per gallon (on an energy equivalent basis to gasoline, at current prices) and $1.78 per gallon (when compared against gasoline's 10-year average price), ammonia is affordable. And as a liquid, it can be more easily transported and stored than hydrogen and natural gas.

The steps that need to be taken before a widespread transition to ammonia fuel can occur are significant—but not insurmountable. These include:

- Building awareness among industry, regulators, and other stakeholders about the economic and environmental advantages of using ammonia fuel for power generation and transportation (especially, at the outset, rail and long-haul truck fleets).
- Helping innovators and investors identify small volume/high profit projects to jumpstart the ammonia energy industry.
- Highlighting opportunities to shift ammonia production to zero-carbon processes (*e.g.*, using stranded or otherwise underutilized wind power assets for ammonia synthesis).
- Detailing ammonia's toxicity risk (which is similar to that of LPG), describing how that risk is managed by farmers globally, and outlining protocols for how it can be managed in the power and transportation sectors.
- Developing a long-term roadmap for building up ammonia production and distribution capacity to the scale of a global energy commodity.

LCFS 29-4 cont.

Since CATF briefed ARB on ammonia in July 2014, research in Texas (on ammonia-gasoline blending in internal combustion engines), Toronto (on the use of ammonia to fuel locomotives), and California have continued to validate the concept and develop demonstration projects.

The California project—which involves the University of California at Los Angeles (UCLA), California Energy Commission, and South Coast Air Quality Management District (SCAQMD)—is among the most interesting efforts to date. UCLA is spearheading a comprehensive program to utilize advanced engines from Sturman Industries for a multifuel (gas and ammonia), low NO_x combined-heat-and-power system. The system will be designed, installed, and optimized at a metals foundry in Los Angeles called California Metal-X (CMX). The project goal is to provide power at $0.097/kwh compared to a current base load cost of $0.18/kwh and peak power costs ranging from $0.20-$0.50/kwh from the grid. These cost savings come along with the potential to prove out an ammonia-based, scalable power source that meets the stringent air quality requirements implemented by SCAQMD.

The system will be designed to run in a wide range of modes including pure ammonia as a peak fuel and a variety of combined heat/power modes depending on power pricing, air quality standards, process efficiency, and power export profitability. UCLA, Sturman Industries, and other project partners will instrument the system to test and optimize ammonia engines, emissions, costs, maintenance, safety and other aspects of these types of operations in the real world. This project is being designed to provide a robust prototype for low cost, clean electricity across the California economy. If successful, the project will provide a technology and engineering basis for installing ammonia power in various markets around the world.

LCFS 29-4 cont.

CONCLUSION

CATF urges ARB to readopt the LCFS through 2020. Although significant challenges remain, the LCFS is the most promising policy tool available for reducing the climate impacts of the transportation sector.

However, that promise is undermined by the proposed adjustment to the lifecycle emissions for corn ethanol, and by the likelihood that regulated entities will increase their reliance on corn ethanol to meet LCFS targets. The proposed adjustment to corn ethanol's lifecycle emissions score rewards corn for its negative impact on global food security. ARB must acknowledge and address this issue before it erodes the legitimacy of the LCFS program.

LCFS 29-3 cont.

An unwarranted reduction to the corn ethanol ILUC score would also lower the ceiling on the long-term effectiveness of the program by extending the period in which marginally beneficial technologies can compete with the far better options that will be available to California after 2020. The prospects for deep reductions in transportation sector GHG emissions are likely to improve significantly after 2020, particularly if liquid ammonia's potential as an affordable low-carbon fuel is proven out.

LCFS 29-11 cont.

LCFS 29-4 cont.

Respectfully submitted,

Jonathan F. Lewis
Senior Counsel
Clean Air Task Force
617.624.0234
jlewis@catf.us
www.catf.us

This page intentionally left blank.

29_OP_LCFS_CATF Responses

116. Comment: **LCFS 29-3, LCFS 29-5 through LCFS 29-7, and LCFS 29-11**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

117. Comment: **LCFS 29-1**

The comment expresses support for re-adoption of the LCFS.

Agency Response: ARB staff appreciates the support for the compliance targets.

118. Comment: **LCFS 29-2**

The comment suggests that the benefits of the LCFS regulation are undermined by the adjustment to the lifecycle emission of corn ethanol.

Agency Response: The use of ethanol as part of the compliance strategy does not undermine the LCFS targets. The ARB staff-proposed carbon intensity (CI) targets and standards for biofuels are designed to be fuel neutral. In other words, all biofuels including corn ethanol, sugarcane ethanol, sorghum ethanol, soy oil biodiesel, canola biodiesel, and palm oil biodiesel have the opportunity to contribute to LCFS and their CI is estimated using the same methodology. In addition to corn ethanol, other biofuels that have made improvements have also received lower CI values than previously estimated. The goal of the LCFS regulation is to evaluate fuels based on their CI scores. As the standard gets stricter, the reliance on lower CI fuels will increase and reliance on higher CI fuels will be limited. The proposed structure of the LCFS regulation is flexible to allow all biofuels to participate, it encourages innovation and recognizes improvements, and by progressively requiring stringent standards provides incentives for low CI fuels to be developed for and used in the California transportation sector.

119. Comment: **LCFS 29-4**

The comment states that prospects for deep reductions in transportation sector GHG emissions are likely to improve significantly after 2020.

Agency Response: ARB staff agrees that further reductions are feasible beyond 2020, and the Board directed the staff to determine what additional reductions can be obtained in the 2020 to 2030 timeframe and to return to the Board with a proposal to further strengthen the LCFS for that time period.

120. Comment: **LCFS 29-8**

The comment states that the proposed iLUC reduction for corn ethanol is problematic.

Agency Response: ARB disagrees with the criticism; we used the unweighted mean in the absence of sufficient information that would have allowed a weighted mean. No evidence clearly suggested that any value deserved more or less weight. Our approach was consistent with the 2009 approach. It should be noted that the mean estimated from the uncertainty analysis is similar to the average calculated from the scenario runs for all of the six biofuels.

121. Comment: **LCFS 29-9**

The comment questions the reduction of the ILUC score for corn ethanol. The comment goes on to add that the assumptions put into the model can have enormous effects on the modeling outputs.

Agency Response: See Response to **LCFS 29-2**.

ARB staff understands that Yield Price Elasticity (YPE)[2], relative productivity of newly converted cropland, and ratio of emissions for land conversion are important elements and have strong influence in the modeling outcome. All of these parameters have been fully accounted for in ARB's modeling approach. Furthermore, ARB staff agrees on the importance of YPE. However, data for YPE are not conclusive to allow assigning a single value for YPE. Since different studies give a range of possible values for YPE, staff used multiple values within this range and created an average of the results. Staff believes that this approach captures the variability in values of YPE from different studies. See also response to **LCFS 8-9**.

[2] YPE is sometimes used interchangeably with YDEL.

122. Comment: **LCFS 29-10**

The comment states that the greatest contributor to variance in the estimate of iLUC emissions was the YDEL.

Agency Response: See Response to **LCFS 8-9**.

123. Comment: **LCFS 29-12**

The comment argues that the reduction to the corn ethanol iLUC score would extend the period in which marginally beneficial technologies can compete with long-term options, including ammonia fuels.

Agency Response: ARB staff disagrees because we believe the revisions to the corn ethanol iLUC value are technically warranted and substantiated. Additionally, the LCFS imposes no barriers to the establishment of fuel pathways for ammonia fuels. Fuel specifications and multimedia analyses must be prepared for all new fuels, but these can be pursued independently from the LCFS fuel pathways.

Producers of ammonia fuel can apply any time for an LCFS pathway. As with any other pathway, the certified carbon intensity (CI) of an ammonia pathway will be based on the results of an ARB staff evaluation of the application submitted.

This page intentionally left blank.

Comment letter code: 30-OP-LCFS-CRF

Commenter: Lyle Schlyer

Affiliation: Calgren Renewable Fuels

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

California Environmental Protection Agency
Air Resources Board

Comment Log Display

BELOW IS THE COMMENT YOU SELECTED TO DISPLAY.
COMMENT 30 FOR LOW CARBON FUEL STANDARD 2015 (LCFS2015) - 45 DAY.

First Name: Lyle
Last Name: Schlyer
Email Address: lschlyer@calgren.com
Phone Number: 5597301154
Affiliation: Calgren Renewable Fuels

Subject: CI Calculations re Fuel Ethanol
Comment:
As with the sorghum issue, Calgren Renewable Fuels applauds the ARB for its handling of the re-authorization of the LCFS. Perhaps the re-authorization was prompted by the lawsuit brought by others in the ethanol industry. If so, we applaud the ARB for its measured and appropriate response. While Calgren did not and does not support the lawsuit, it does support the ARB's attempts to strengthen the LCFS. LCFS 30-1

To be stronger, the LCFS must be based upon good science. Calculation of life-cycle carbon intensities is inherently complicated and a few anomalies are to be expected. We believe our consultant has discovered one such anomaly regarding the CI impact of denaturant. Please review his comments as reflected in the attached summary. Correcting what appear to be inconsistencies and errors regarding the CI impact of denaturant on fuel ethanol will help strengthen the LCFS. LCFS 30-2

On a somewhat related subject, we applaud the ARB for correcting the erroneous 1:1 distillers grain-to-corn displacement ratio that appears in GREET 1.8. But we firmly believe and have previously submitted data showing that the displacement ratio varies somewhat depending upon whether distillers grain is fed to hogs, poultry, feedlot cattle or dairy cows. We urge the ARB to take note of relevant research in this area and apply it where applicable. LCFS 30-3

Thank you for the opportunity to comment.

Attachment: www.arb.ca.gov/lists/com-attach/32-lcfs2015-UDZdLlM3WWYLUgZj.zip

Original File Name: Fuel Ethanol Denaturant Issues.zip

Date and Time Comment Was Submitted: 2015-02-17 14:07:53

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Denaturant Composition and Denatured ethanol Content Changes

Instead of the assumption of 2.5% volume denaturant used by ARB to determine the energy density of ethanol (81.51 MJ/gal), ARB has effectively increased it to 5.4% by assuming the minimum ethanol content, under the ASTM denatured ethanol standard, of 94.6% ethanol and assuming all the other compounds that could be in ethanol are the equivalent of CARBOB in terms of physical properties.

We understand ARB attempts to explain this inconsistency thus: "Denaturant includes CARBOB and "other." According to the California EPA GHG Report, denatured ethanol must contain 94.6% v/v pure ethanol, allowing for up to 2.5% denaturant, 1 percent water, 0.5 percent methanol and 1.4 percent other. Consistent with California's Greenhouse Gas Inventory, the substances potentially contained in the denaturant-ethanol blend are assumed to have the same characteristics as CARBOB for the purpose of estimating emissions."

LCFS 30-2 cont.

<u>ARB's Total "Denaturant Materials" it considers as CARBOB in terms of properties:</u>

Denaturant:	2.5%vol
Water:	1.0% (Note: odd that water is considered to have the energy of CARBOB)
Methanol:	0.5% (Note: at 59.94 MJ/gal is 50% of CARBOB energy density)
<u>Other:</u>	<u>1.4% (Note: often these are the fusel oils produced with the ethanol)</u>
Total:	5.4%vol

Using the energy densities of pure anhydrous ethanol (80.53 MJ/gal) and CARBOB (119.53 MJ/gal) and the assumption that all the non-ethanol compounds have CARBOB properties (and that this is the typical composition of denatured ethanol), the energy density of denatured ethanol would be 82.64 MJ/gal, 1.4% more than the energy density for denatured ethanol (81.51 MJ/gal) codified in the regulations and used by ARB for many other things including carbon credit calculations and in the calculation of the ethanol pathway CI with the revised assumptions on denatured ethanol composition.

From this 5.4%vol CARBOB content of denatured ethanol, using the CARBOB CI of 100.58 gCO2e/MJ, and using ARB's assumption that the energy density of denatured ethanol is 81.51 MJ/gal (note inconsistency, since this is based on 2.5%vol denaturant), the CI of the 5.4% volume non-ethanol portion in a gallon of denatured ethanol, on a gCO2e/MJ of denatured ethanol basis is 7.92 gCO2e/MJ of denatured ethanol. Using the consistent 82.64 MJ/gal basis for denatured ethanol, the denaturant portion of the CI would be only slightly different, 7.86 gCO2e/MJ. This is constant regardless of the pure anhydrous ethanol CI.

Denaturant Displacement of Anhydrous Ethanol

With the current regulations and ethanol pathway CI calculations, a factor of 0.8 gCO2e/MJ is added to the CI calculated with the CA-GREET model to account for denaturant, just as the ILUC factor is added to determine the total pathway CI. Now, ARB is proposing to revise the calculations based on the denaturant displacing anhydrous ethanol such that the CI of the denatured ethanol would be based on the CI of CARBOB and anhydrous ethanol weighted by the energy fraction of each in the resulting denatured ethanol blend. As an example, starting with anhydrous ethanol with a CI of 70 gCO2e/MJ, after multiplying by the anhydrous energy fraction of 92.08%, the CI contribution to the finished blend would be 64.46 gCO2e/MJ. Then the non-ethanol portion of 7.92% of the finished blend energy is multiplied by the CARBOB CI to arrive at 7.97 gCO2e/MJ (which is the same for any E10 blend using ARB's assumptions). The CI of the denatured ethanol is the sum of the two fractions, and is 72.42 gCO2e/MJ. The effect of this method is that the CI is 2.42 gCO2e/MJ higher than the CI of the anhydrous ethanol. LCFS 30-2 cont.

As the CI of the anhydrous ethanol changes, the impact of the denaturant displacement varies as well, with the impact being greater for low CI ethanol and less for higher CI ethanol. For ethanol with a CI above that of the CARBOB CI, the effect is such that the denatured ethanol has a lower CI than the anhydrous ethanol.

There are several issues with this method: the percentage used, and the assumptions that the non-ethanol components are CARBOB and not already accounted for in the anhydrous ethanol CI. Since the CA-GREET model is calculating the direct CI of anhydrous ethanol being produced, and the non-ethanol components before denaturant is added have been produced in the ethanol production process (residual water, methanol as a by-product, and other compounds which are mainly fusel oil also by-products), it seems inconsistent not to assign the same CI to these compounds as the CI of the rest of the anhydrous ethanol. ARB's assumption appears to be that all of the non-ethanol compounds were added to the anhydrous ethanol downstream of the production facility. While this may be true of a portion of the water in the ethanol, since when did water have a CI? The answer is that water has a CI when it is assumed to be CARBOB as CARB has done.

Instead, if denatured ethanol were assumed to be 2.5% denaturant and the remainder anhydrous ethanol without any other compounds, the denaturant would be 3.67% of the energy in denatured ethanol (rather than the 7.92% using the 5.4% CARBOB basis). With this basis, the denaturant portion of the CI would be 3.69 gCO2e/MJ (constant for all ethanol CIs), and the anhydrous ethanol portion of a 70 gCO2e/MJ would be 67.43 gCO2e/MJ (70 x (100% - 3.67%)). The CI of the denatured ethanol would be 71.12 gCO2e/MJ, which is still more than with the old method using 0.8 gCO2e/MJ as the denaturant factor, but is 1.3 gCO2e/MJ less than the 2.42 gCO2e/MJ using the assumption of 5.4% CARBOB in denatured ethanol as proposed by CARB.

LCFS 30-2 cont.

This page intentionally left blank.

30_OP_LCFS_CRF Responses

124. Comment: **LCFS 30-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

125. Comment: **LCFS 30-2**

The comment calls into question the method that is used to calculate the CI impact of denaturant.

Agency Response: Please see response to **LCFS 8-12** and **LCFS 24-6**.

126. Comment: **LCFS 30-3**

The comment requests that ARB staff take note of relevant research that affects the DGS displacement ratio and apply it where applicable.

Agency Response: ARB staff agrees with the commenter that there are studies in the scientific literature that show varying distillers grain with solubles (DGS) credits for specific animals and possibly for specific types of DGS (e.g., wet distillers grain with solubles [WDGS]). But ARB disagrees to the extent the commenter is suggesting that ARB attempt to calculate different credits based on where DGS is sent, and what animal it is fed to – factors that change day to day in commerce. It is not currently possible for staff to know how DGS producers adapt to various market forces over the long-term for selling their DGS. Agricultural products and prices for feed tend to vary over time. It is particularly important to be able to verify the DGS markets for a specific LCFS-approved pathway if a specific credit is to be given for feeding certain animals. Similarly, it is not currently possible for staff to know that individual farmers use a certain amount of agricultural inputs for producing their feedstock over the lifetime of the LCFS fuel pathway. In these and similar cases, staff recommends average values for such inputs until updates are made to the LCA model (CA-GREET 2.0), verification is available, and the science or rigorous multiple-feed market analyses justifies a more specific credit for the duration of specific LCFS fuel pathways.

Similar uncertainty is associated with granting credits for enteric emission reductions from DGS-fed animals. Please see **LCFS 8-13** for further explanation regarding enteric emissions analysis and further discussion on the DGS credit calculation, and LCA boundary not extending to the animals.

ARB staff reviewed the values for DGS credits used in GREET1 2013 and associated peer-reviewed studies, in addition to Argonne National Laboratory technical memorandums. Staff recommends that dry-mill corn (and grain sorghum) ethanol plants use the aggregated displacement ratio for U.S. and export markets proposed in Appendix C of the LCFS Initial Statement of Reasons (ISOR).

ARB staff appreciates the desire of stakeholders to improve the LCA of their fuel through credits or process improvements specific to their fuel pathway. In future iterations of the LCFS, staff hopes to develop a method that considers multiple parameters in the fuel lifecycle to enable applicants to verify the net effects of actual improvements over average default values.

Comment letter code: 31-OP-LCFS-IWP

Commenter: Curtis Wright

Affiliation: Imperial Western Products

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

31_OP_LCFS _IWP

11_OP_ADF _IWP

P.O. Box 1110
Coachella, CA 92236
(760) 398-0815
(760) 398-3515

Imperial Western Products, Inc.

February 16, 2015

Mary D. Nichols
Chair
California Air Resources Board
1001 I Street
PO Box 2815
Sacramento, CA 95812

RE: Proposed Adoption of a Regulation Governing the Commercialization of Motor Vehicle Alternative Diesel Fuels; Proposed Re-Adoption of an Updated Low Carbon Fuel Standard

Dear Ms. Nichols,

Imperial Western Products (IWP) is a biodiesel producer located in Coachella, California. We have been producing biodiesel continuously since 2001, and have made over 54 million gallons of biodiesel. Almost all of the biodiesel we make is made from used cooking oil collected throughout California, and the fuel we sell is sold back into the same areas. In the early years of our biodiesel production, we had to rely on specialty markets, where people who wanted to use biodiesel were willing to go to great lengths to buy it. This resulted in uneven demand, and our business had many wild swings in profitability. We would increase production, then slow production. We would hire and then lay off workers.

Upon the introduction of the federal Renewable Fuel Standard (RFS), and California's Low Carbon Fuel Standard (LCFS), we began to see more and more interest from larger, established fuel providers. These programs, especially the LCFS, resulted in more widespread blending of biodiesel into diesel at the fuel terminals in California, which resulted in steady demand for our biodiesel. Of the 54 million gallons of biodiesel we have made, 30 million gallons have been made since 2011. This demand has allowed us to hire more workers, and keep production steady throughout the year. We currently employ 30 workers directly in the biodiesel production plant. These jobs are good paying manufacturing jobs located in an area where these jobs are scarce. Many of our employees worked in temporary agriculture jobs, or in service jobs in the Coachella valley prior to coming to IWP. In addition to the workers who are employed directly in the biodiesel production plant, we have dozens of employees who work in our used cooking oil collection business. These workers are located throughout the state.

LCFS 31-1

I would like to point out three back stories of some of our employees. Lee Munoz grew up in Coachella, and was working for a television satellite dish installer when we hired

P.O. Box 1110
Coachella, CA 92236
(760) 398-0815
(760) 398-3515

him to work in the biodiesel plant in 2002. Lee began to learn about biodiesel production, became a shift supervisor, and is now Production Manager overseeing 22 plant operators.

Danny Chiang was also raised in the Coachella valley. A mechanical engineer and graduate of UC Berkeley, he was working in a clothing store in Rancho Mirage when we hired him in 2011. Danny quickly learned about biodiesel production, and oversaw installation of a plant-wide control system. Danny programmed all of the plant control system, and not only supervised installation, but actually did a lot of the wiring himself. Danny is now lead plant engineer and supervises another engineer.

Eduardo Zepeda grew up in Coachella and attended the University of California Riverside and studied mechanical engineering. One of his professors, Dr. Wayne Miller, would bring his chemical engineering class to our plant every year on a field trip. I called Dr. Miller in the spring of 2012 and asked him if he had any students who would be interested in a summer internship. He allowed me to post a message to his students, and Eddie responded and was hired. After graduating, we hired him full time. He is now learning the biodiesel production process and has successfully completed several projects, including a water treatment and disposal system.

These are just three of the success stories in our biodiesel plant, and all are possible because of steady demand for biodiesel in California. The LCFS has added value to blending biodiesel in California, and when it gets back on track it will provide additional stability to the market which will allow our company to plan for the future, and continue to provide good paying jobs.

LCFS 31-2

With LCFS back on track, the Alternative Diesel Fuel (ADF) regulations will provide a framework for biodiesel to be blended and prevent any adverse emission impacts until the fleet turnover of new technology diesel engines is achieved. It is important to us that the ADF regulations have a clearly defined sunset, when 90% of the miles travelled are done by new technology diesel engines, and that this end point is reviewed annually so that as soon as this milestone is reached, limits on biodiesel blending are removed. With this provision, hopefully LCFS reductions won't be hindered. We feel strongly that biodiesel, California's advanced biofuel, will be important in helping reach LCFS goals.

ADF 11-1

IWP has been making biodiesel in the Coachella valley since 2001, and with re-adoption of LCFS and implementation of ADF we are confident we can continue to increase biodiesel production to displace petroleum, lower greenhouse gasses, lower criteria air pollutants, and provide jobs in California.

Sincerely,

Curtis Wright

31_OP_LCFS_IWP Responses

127. Comment: **ADF 11-1**

Agency Response: This comment is responded to in the Alternative Diesel Regulation Final Statement of Reasons under Comment Letter **11_OP_ADF_IWP**.

128. Comment: **LCFS 31-1**

The comment supports the job benefits of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

129. Comment: **LCFS 31-2**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

This page intentionally left blank.

Comment letter code: 32-OP-LCFS-BP

Commenter: Ralph Moran

Affiliation: BP America

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

32_OP_LCFS
_BP

BP America, Inc

Ralph J. Moran
1201 K Street, Suite 1990
Sacramento, CA 95814
(916) 554-4504

DATE: February 17, 2015

Via Email
Sam Wade
California Air Resources Board
1001 I Street, Sacramento, CA

Re: BP America Comments on the Proposed Re-Adoption of the LCFS

Dear Sam:

BP appreciates the opportunity to submit comments on the proposed re-adoption of the Low Carbon Fuel Standard (LCFS). As the Board is considering a full re-adoption of the LCFS, we believe it is worthwhile to review why BP continues to have deep concerns about a program that we believe is overly complex, potentially costly and likely infeasible. We also provide comments on specific elements of the revised regulation.

In summary, we believe the LCFS is not a fuel neutral approach, that it picks winners and losers, that it puts a price on carbon emissions from conventional fuels beyond that introduced by a cap and trade system, that it misaligns incentives, rewards and regulated parties, that it shields some pathways from exposure to competition and the market, and that it suffers from a lack of a focused objective. Perhaps most importantly, a LCFS results in <u>no incremental GHG reductions</u> and is not necessary in order to meet the state's GHG reduction goal. LCFS 32-1

The State Should Focus on the Most Cost Effective Approaches

BP continues to believe that a market-based approach (either a well-designed cap and trade or carbon tax) to addressing climate change is not only the most efficient and cost effective – but also the only approach that incorporates a scalable solution recognizing the global nature of the issue of climate change. A market-based approach, such as a cap and trade system, is also the only policy alternative that provides the assurance of meeting a specific emissions reduction target - and does so while delivering this outcome at the lowest cost – ultimately allowing more emission reductions to be achieved. A market-based approach to addressing climate change recognizes that the most efficient emission reduction strategies LCFS 32-2 will change over time as markets and technologies evolve and develop. A market-based approach, such as a cap and trade system, can react quickly to evolving technologies and new approaches in a way that direct measures, or command and control regulatory approaches, simply cannot.

A primary objective of a market-based, GHG-reduction program should be to establish a broad, consistent price for carbon across the widest segment of the economy as is practicable. A broad, consistent carbon price will result in the fairest, most effective and most efficient reduction of GHGs and will best distribute the economic burden and increasing opportunities for low-cost abatement measures. A broader market, including one designed to easily integrate into an eventual regional or federal system, will reduce the impact of leakage and will increase the incentive and marketplace for innovation. That's why the aspiration of such a system should be an economy-wide, market-based program, while recognizing that it may take some time to achieve a fully economy-wide approach.

LCFS 32-2 cont.

BP understands that in certain situations well-designed complementary policies may accelerate commercialization of certain low carbon technologies deemed by regulators to be worthy of support. However, the LCFS is not well designed and in fact may actually discourage investments because of its propensity for picking winners and because of the great uncertainty around feasibility of the targets. While some amount of direct regulation, or command and control regulation, can be justified on a limited basis, going forward the state should acknowledge the transitional nature and shortcomings of the current approach that relies heavily on command and control. A command and control system is not scalable – regionally, nationally or internationally. Because climate change is a global problem that requires a global solution, we need a program that has the potential to be scaled into a large program that will create a common carbon currency.

LCFS 32-3

The LCFS is <u>Not</u> a Market-Based Program

The LCFS is not a market-based approach. It is a direct measure – a command and control regulation with a minor market element. And because the LCFS is a direct measure that regulates GHG emissions on a source (i.e. transportation fuel) that is already covered by the cap and trade program – it is important to acknowledge that the LCFS results in <u>no incremental GHG emission reductions</u>. Every emission reduction that results from the LCFS simply displaces an emission reduction that would otherwise have had to occur in the cap and trade program. In that way, the LCFS doesn't result in any additional or incremental GHG reductions – it simply shifts the reductions from the cap and trade program – to a method prescribed by CARB – in this case to the LCFS. And in doing so, the LCFS forces and shifts emission reductions from an efficient, low cost program where the market chooses how and where the emission reduction is achieved – to a high cost program where the emission reductions occur at multiple times the cost that could be achieved in the cap and trade program.

LCFS 32-1

LCFS 32-4

The LCFS Only Raises Costs – and Does Not Produce Incremental GHG Reductions

How does this work in the real world? Under the California cap and trade program, refiners remain responsible for purchasing allowances to cover emissions from the fuel they refine or import – whether or not a LCFS is in place. The effect of direct regulations

LCFS 32-5

such as the LCFS is that they can lower fuel emissions by either reducing fuel demand or carbon intensity. In the absence of these reductions by the LCFS, the burden on refiners under a cap and trade program is not removed or shifted. Refiners would simply be required to reduce emissions elsewhere, purchase additional allowances (or pay other sectors to make reductions) to cover the emissions that would have been otherwise reduced by these direct measures. The market is able to seek out the lowest cost method of achieving these reductions – rather than being subject to a prescribed (and much more expensive) method of GHG reduction. So when a LCFS is in place, it means refiners simply have fewer obligations in the cap and trade program.

So what is the impact on cost? Given that the demand for cap and trade allowances will be somewhat lower when GHG reductions on sources covered by the cap and trade happen outside of the cap and trade program as the result of a direct regulation such as the LCFS, the price of allowances will likely be reduced some small amount. However, the overall societal cost of the AB32 program will be *much* higher – because in the presence of a direct measure such as a LCFS, GHG reductions are not allowed to occur in the most cost effective manner – but rather in a manner prescribed by policymakers. This might seem paradoxical in a way – but is actually logical. The existence of what most acknowledge is a very expensive regulatory measure in terms of $/tonne CO2e reduced (i.e. the LCFS) will slightly lower the cost of allowances in the cap and trade program – but significantly increase overall societal costs of achieving the GHG reduction target. This is because a direct measure removes the reductions from occurring and being transparently and efficiently priced in the cap and trade system, and masks the costs by imposing them directly and non-transparently on regulated parties.

LCFS 32-5 cont.

Therefore it is incomplete, at best, for the regulation to claim, as it does, that the LCFS will "reduce compliance costs under California's Cap-and-Trade program for regulated entities that are subject to both regulations". The full story is that while the LCFS may result in a minor reduction in the cost of allowances, the overall cost to regulated entities and the overall societal costs of achieving AB32's goals will be <u>much higher</u> in the presence of a LCFS – with no additional, incremental emission reductions occurring from this increased cost and complexity.

Actual Benefits of the LCFS are Unclear

The LCFS was conceived and adopted with a very optimistic view that a robust market for low carbon alternative fuels would exist early in the LCFS program – stimulating supply of large volumes of low cost, low carbon fuels – such as cellulosic ethanol. In fact, the original economic analysis produced by CARB to support the initial adoption of the LCFS estimated that the program would save the state "as much as $11 billion from 2011-2020."

LCFS 32-6

BP believes there will be breakthroughs in alternative fuel technology, including biofuels (driven largely by the federal RFS), and that use of advanced, low carbon biofuels in more efficient conventional engines will provide the bulk of GHG emission reductions in the transportation sector in the mid-term. However, it is clear that this robust, low-cost, alternative fuels industry has not materialized – and may not for many more years. Thus, the LFCS has been premised and designed on fundamentally flawed assumptions that we believe necessitates a complete re-thinking of the program.

Similarly, it is also not clear what role the LCFS is playing in driving innovation in alternative fuels. We believe the federal RFS is the clear and primary driver for innovation in biofuels. With respect to other alternative fuels, we believe that the current price advantage in natural gas (and not the LCFS) is driving renewed consideration of natural gas as a transport fuel, and that a LCFS does not address in any material manner the primary hurdle for use of electricity as a transport fuel – i.e. the cost of electric vehicles. We do believe it is possible to make the case that the LCFS is a driver for bringing biogas, biodiesel, and renewable diesel to California for use in the transportation sector. However, we believe it is difficult to make the case that a LCFS with its expense and complexity, is the appropriate policy choice to drive these outcomes – as opposed to more targeted, less complex and less costly incentives. LCFS 32-6 cont.

A LCFS is Not the Right Long Term Policy for the State

Some have opined that complementary polices, such as a LCFS, are necessary or should be *the* enduring policy for transportation fuels because the price of carbon in a cap and trade system may not rise quickly enough or ever reach the level necessary to bring about material emission reductions in the transport sector. We believe this view demonstrates a misunderstanding of the dynamics of a properly designed cap and trade system. If the cap is properly set, and includes a broad set of emissions sources (including transportation emissions), the carbon price will necessarily rise to deliver the required emission reductions. Furthermore, if it is believed that the public will not accept a carbon price that is necessary for a cap and trade system to deliver emission reductions from the transportation sector, then there is little reason to believe the public would accept the same (or much higher) carbon price imposed on the transportation sector as a result of a complementary policy such as a LCFS. LCFS 32-7

As California looks toward setting longer term climate policy goals, it is more important than ever that the focus be on the most efficient and cost effective means of reducing GHG emissions. Going forward much is at stake in the state's consideration of how to proceed with climate policy post 2020. Reaching post 2020 targets will require nothing less than a fundamental transformation in the way that California produces and uses energy - with significant uncertainty as to the cost and availability of the technology necessary for that transformation to occur.

According to the Scoping Plan Update, achieving post 2020 emission reduction targets that put the state on a path to achieving 2050 goals "will require that the pace of GHG emission reductions in California accelerate significantly. Emissions from 2020 to 2050 will need to decline several times faster than the rate needed to reach the 2020 emissions limit."[1] It has been estimated that the pace of post 2020 emission reductions will need to be <u>five times</u> that of the current program. Governor Brown has said that these future programs will be "far more stringent" and "far more difficult" than current programs. Moreover, these

[1] Proposed First Update to the Climate Change Scoping Plan: Building on the Framework, February, 2014. Page 37 and Figure 6, page 38.

future, much deeper emission cuts will likely (and hopefully) occur during a period of economic growth in the state rather than during the period of economic contraction the state has experienced during much of the current program.

The stakes are therefore much higher, and the potential for significant impact to consumers and the state's economy much more pronounced in a post 2020 GHG reduction program – with the deep emission cuts envisioned. At this important time, with the challenges of deeper, long term emission reductions, and the eyes of the world on California, it is more important than ever that the state focus on the most efficient and cost effective means of reducing GHG emissions. By 2020, California's GHG reduction program- whether it be the program to maintain the 2020 goal or an expanded program - should be far along the way toward relying on a market as the primary mechanism for GHG emission reductions. It is simply not reasonable to expect that current policymakers are equipped today to design a series of command and control policies that determine the exact "recipe" of emission reductions that will meet this century-scale challenge. That should be left to the market. The LCFS is complex, uncertain, expensive and unnecessary to meet the state's long term climate policy goals – and need not be a part of state's climate change policy going forward.

LCFS 32-8 cont.

Cost Containment Proposal

In the development of a cost containment proposal, we appreciate that staff have acknowledged that "some amount of uncertainty will always exist regarding the future supplies of low-CI fuels and the availability and price of LCFS credits". In response, the proposed regulation puts in place a LCFS credit price cap of $200 (with escalation) and a so-called annual credit clearance process.

While we believe the proposed cost containment proposal is not wise or appropriate for a range of reasons, we do believe it represents an important acknowledgement that a) it is very likely that the fuels or vehicles necessary for LCFS compliance won't materialize in required volumes within the timeframe of the regulation and likely for some time after that, b) the original LCFS cost estimates were wildly inaccurate – and rather than saving billions of dollars for fuel consumers, LCFS compliance costs are likely to run into the billions of dollars, and c) emission reductions in the LCFS come at a cost per tonne that are multiple times that of emission reductions in the cap and trade program.

LCFS 32-9

Our internal review of various alternatives to address changes to the LCFS, should the program prove to be infeasible or not cost effective, came to the conclusion that there is no simple, pain-free way to alter the LCFS once it has begun. In fact, the only way to avoid having to make difficult choices about whether or how to alter the program in the future is to set targets from the outset that are demonstrably feasible and cost effective. Credible targets send a consistent market signal to obligated parties and to investors in low carbon fuels. As difficult as these decisions will be around how to alter a LCFS that proves to be infeasible – even more difficult and painful would be to avoid these discussions and later be forced to make last minute, abrupt, arbitrary decisions on how to alter the program.

Cost control, flexible compliance or alternative compliance mechanisms can be useful design features for fundamentally sound programs that have perhaps hit a snag in their implementation. We do not believe the LCFS meets these criteria as it was based on overly optimistic projections about the cost, timing and availability of alternative, low carbon fuels. If, as the evidence suggests, the LCFS is infeasible within its current timeframe, it is the regulation that needs to be changed – or completely reconsidered. If policymakers have miscalculated, then they should go back to the drawing board.

If a LCFS program is to be continued in the short term, we believe CARB should expand its thinking on addressing shortfalls in fuel availability and other LCFS program flaws. The focus should be on solutions that directly address the cause of the problem – not merely reacting to a symptom. Excessive compliance costs that result from the unavailability of alternative fuels is a symptom of a larger problem. Designing cost control measures is a classic example of treating the symptom rather than the disease.

Regarding the specific proposal for a $200/ton price cap on LCFS credits, there are several areas of concern we hope the Board and staff will consider before moving forward. First, it is important to acknowledge that this price cap of $200/ton represents a significant departure from the LCFS compliance cost estimates contained in the 3/5/09 staff report - and which were used to support and adopt the original LCFS.

Conclusions from the 3/5/09 Staff Report include:

LCFS 32-9 cont.

> *"Staff estimated that the displacement of petroleum-based fuels with lower-carbon intensity fuels will result in an overall savings in the State, as much as $11 billion from 2010 -2020" (p.239).*
>
> *"For the five gasoline analyses, the cumulative net cost effectiveness ranged from ($121) to ($142)/MT CO2E reduced, which, for the period of 2010 – 2020, is a cumulative savings of $8 to $9 billion" (p.272).*

If reached, this cost cap would represent billions of dollars per year in additional costs of supplying fuel in the state. In Table ES-4 of the LCFS ISOR, the annual compliance cost in 2020 is estimated at $2.1 billion using a LCFS credit price of $100. The updated regulation contains no analysis as to compliance costs or impact on fuel prices if the $200 cost cap level is achieved. The regulation should model and estimate the cost of the program – and the potential impact on fuel prices should the cost cap level be achieved. The regulation should also analyze the potential market impacts of setting such a price cap. For instance, how could buyers and sellers react to such a price cap and how will this price cap impact the market?

A $200/tonne C02e price cap acknowledges the much higher cost of reducing emissions under the LCFS than could be achieved using a well-designed cap and trade program. This large difference can be seen by investigating both the price cap in the current cap and trade program vs the proposed price cap in the LCFS – and in the current market prices for credits in each of the respective programs. First, regarding current market prices (both which represent the cost of a tonne of C02e), LCFS credits are trading at approximately twice the cost of a cap and trade allowance. Second, comparing the level of the price cap for the respective programs, the LCFS price cap of $200/tonne is approximately 5 times the level of the lowest "price cap" of the state's cap and trade program. These large differences acknowledge the much higher cost of reducing GHG emissions in the LCFS when compared to the cap and trade program. This means the state, and its consumers, are paying a high price in order to allow policymakers to exercise their preference as to how and where GHG emission reductions will occur in meeting the state's GHG goals. California consumers would be much better served by having policymakers set targets and allow the market to choose how the state's GHG targets are met.

Furthermore, the LCFS regulation contains no discussion or analysis about how the cost cap of $200/tonne was arrived at. The regulation could benefit from a discussion as to why the LCFS price cap needs to be set at a level so much higher than cost containment provisions in the cap and trade program. On the other hand, some investors in alternative fuels might argue that $200/tonne cost cap is not sufficient to drive the necessary innovation in alternative fuels. In fact, Board members Dan Sperling and Mary Nichols wrote in a 2012 piece in "Issues in Science and Technology", that a price signal of $.70 per gallon is "not enough to motivate oil companies to switch to alternative fuels". A $0.70 per gallon cost suggests a cost cap much higher than $200/tonne. So while it is clear that GHG reductions under a LCFS will be much more expensive than equivalent reductions under the cap and trade program - it is not clear that the proposed cost cap will allow the LCFS to achieve its intended purpose – that is, innovation in the transport sector. LCFS 32-9 cont.

Moreover, it is not clear that the proposed cost containment mechanism, or the LCFS in general, meets the requirements of AB32 for cost-effectiveness. The language of AB32 requires that GHG reductions in the program are "cost-effective". It is difficult to understand how a LCFS can be considered cost effective when, as shown in previous paragraphs, the cost of a reduction of one tonne of CO2e from the LCFS costs the state multiple times that of equivalent GHG reductions that could be obtained from the cap and trade program. Staff has offered in response to this point that the LCFS is a "transformational" policy, however there appears to be no language in AB32 that provides exemptions from cost effectiveness for transformational policies.

The proposed cost containment mechanism does not facilitate more emission reductions or innovation or change the supply/demand balance of credits - it simply caps costs and allows regulated parties to carry forward unmet compliance obligations. Since this proposal does not result in equivalent emission reductions in the same timeframe (emphasis added) as the regulation, we believe this violates Section 38505 (b) of AB32 which requires:

> *"Alternative compliance mechanism" means an action undertaken by a greenhouse gas emission source that achieves the equivalent reduction of greenhouse gas emissions over the same time period as a direct emission reduction, and that is approved by the state board. "Alternative compliance*

mechanism" includes but is not limited to, a flexible compliance schedule, alternative control technology, a process change, or a product substitution.

For all these reasons, we recommend that the proposed cost containment mechanism, and the LCFS itself, are completely re-evaluated – both for the short and long term. If past assessments of cost and feasibility prove to be so far off from actual costs, what is needed is not an ill-advised cost cap, but rather a re-assessment of the targets, timelines and advisability of the program. If there is a wide-spread inability to comply with the LCFS, what is needed is an acknowledgement of a miscalculation by policymakers.

LCFS 32-9 cont.

We recognize the need for policymakers to address climate change and believe the transportation fuel sector should play a role. However, we don't believe it is reasonable or productive to be wedded to a particular strategy to reach that goal - especially in the face of clear evidence that the program is costly, unachievable, overly complex, unnecessary or otherwise problematic. All options for alternatives should be on the table – both for the current program and post 2020.

Treatment of Crude Oil

It has been and continues to be BP's position that the LCFS should not differentiate between crude oils. We believe strongly that a reasonable evaluation of the effect and impact of differentiating crudes will conclude that there is <u>no environmental benefit</u> from differentiation – only severe unintended consequences to California refiners and fuel suppliers and to the market for transportation fuels. Importantly, a LCFS that does not differentiate crude oils and therefore treats all crudes as equal will maintain the same incentive for innovation and investment in lower carbon fuels.

Before a decision is made to consider differentiation of crudes, we believe it is incumbent on the proponents of differentiation – that they are able to demonstrate, definitively, that there will be material environmental benefits to differentiation of crudes in the California LCFS – and that these benefits will outweigh the consequences of differentiation. We believe the potential unintended consequences are too great to ignore, and that any potential benefits cannot be simply assumed. This important policy decision cannot be justified by the hope that there will be benefits – or by the desire to send a symbolic signal to producers of crude oil. There must be a definitive demonstration of benefits that outweigh risks and consequences. We strongly suggest an evaluation including but not limited to analyzing the following questions:

LCFS 32-10

- Does the differentiation of crude oil in the California LCFS result in a meaningful increase in the volumes of low carbon fuel used in the state?
- Does the differentiation of crude oil in the California LCFS result in meaningful incremental incentive for innovation in low carbon fuels?
- Will the differentiation of crude oil in the California LCFS result in net global GHG reduction?
- Will the differentiation of crude oil in the California LCFS effect what crude is produced globally?

We believe it can be demonstrated that the answer to all of these questions is – no. Further, we believe it can be demonstrated that the likelihood is that differentiation of crude oil in the California LCFS will result in *higher* global GHG emissions. LCFS 32-10 cont.

Electricity Provisions
With regard to the electricity provisions of the draft regulatory changes, we are most troubled by the proposal to remove the requirement that direct metering of electricity usage in electric vehicle charging is necessary to generate credits by 2015. Staff provided little rationale for this proposed change other than that "many EV drivers have elected not to install dedicated EV meters at their residences". In our view, this is precisely why a requirement for metering is necessary. A primary driver of the LCFS is to drive innovation and investment in alternative fuels.

The proposal to eliminate metering brings up many issues including:

1) Verifiability of emission reductions.
An overriding and oft-stated criterion for emission reductions under AB32 is that reductions are real and verifiable. Policymakers, the public and regulated parties who purchase these credits must be able to rely on the fact that these emission reductions are real, that the credits generated are actual and that a ton is a ton. We can think of no other example within the AB32 program where direct generation of a currency within the system is directly and solely generated based on an estimation process – especially where a clear and more reliable method of direct measurement exists.

2) Innovation LCFS 32-11
The LCFS is meant to drive innovation and investment in alternative fuels. It is clear that for electricity in transport, innovation is required for determining and optimizing how, when and why customers recharge their vehicles. This innovation is necessary in order to inform consumer choice, plan for generation needs and load servicing, and to better determine the carbon intensity of actual electricity usage. Because electricity is already ubiquitous as an energy source and the primary hurdle to electrification is in the cost of the vehicle, it is unclear what innovation in electrification would be driven by a LCFS short of that which would come from metering and the information derived from metering. Because of this, it is hard to understand why CARB would backtrack on the requirement that metering be required for electricity generation in the electricity sector.

3) Fairness/Consistency
For most fuels, the LCFS requires considerable investment and innovation in the development and deployment of alternative fuels in order to both generate credits and comply with the CI reductions. Obligated parties, particularly those dealing in liquid fuels, are required to undergo extensive documentation to show the carbon intensity and pathway for their fuel. Metering is required to determine the volume of fuel sold and regulated parties are subject to enforcement and fines if problems with meters arise.

Absent a requirement for metering, it is unclear what investment is required by utilities in order to generate a LCFS credit. Utilities already enjoy a market closed to competition for retail sale of this form of transportation fuel, benefit from an assumption that electricity used is the marginal megawatt – rather than the "conservative default" CI that other fuels have to utilize in the absence of specific data, and now apparently may not even have to actually measure the amount of power that is used by electric vehicles.

4) Taxation
The state of California is already massively underfunded when it comes to funding transportation infrastructure. There are multiple efforts underway by policymakers and stakeholders to find additional sources of revenue. As alternative fuels such as electricity displace petroleum, the transportation funding deficit will only grow. It is likely only a matter of time before transportation fuel taxes are applied to alternative fuels such as electricity. The state Board of Equalization is unlikely to rely on an estimation method to determine tax payment when metering is possible and clearly more accurate.

Researchers who have investigated the role of electricity in a LCFS also agree that metering should be required. UC Davis concluded that: LCFS 32-11 cont.

> *The market for PEV chargers is emerging, so there will be a great deal of innovation in the arena of metering and billing for PEVs in the coming decades…LCFS requirements for metering and reporting for the purposes of credit generation may accelerate these changes".*
>
> *Since PEV chargers are now being built with utility grade meters, it makes sense to tie the generation of LCFS credits to requirements on electricity providers to supply regulators with verifiable, metered data and detailed charging timing profiles that can be used for utility planning and CI calculations.*
>
> *In order to obtain LCFS credits, electricity providers should be required to provide detailed data on charging load, timing and location by a verifiable, utility-grade meter. This information will be used for grid planning and CI calculations and also ensure that PEV charging does not cause or exacerbate grid issues.*[2]

For all these reasons, we urge CARB not to backtrack on the requirement for metering in order to generate LCFS credits from electricity.

GREET Revisions
The proposed regulation contains significant revisions to the carbon intensity values for many alternative fuels pathways as well as for baseline fuels. In some cases, the revisions would increase carbon intensities (CI) by nearly 200%. These contemplated LCFS 32-12

[2] Fuel Electricity and Plug-in Electric Vehicles in a Low Carbon Fuel Standard, Christopher Yang, May 2013

revisions would have significant impacts not only on investments that have been made in good faith reliance on the regulation, but on compliance plans that have incorporated these fuels and pathways, and on the general confidence of the market to rely on the LCFS regulation. We request that CARB adopt a much more deliberative approach to consideration of these changes. This approach would include public workshops held well in advance of any formal rulemaking that review in detail the data upon which the contemplated changes are based, the impact on investments and compliance, the wisdom of making such significant changes to the rules of this regulation at this point and the unintended consequences of these contemplated changes. LCFS 32-12 cont.

Full Data Transparency
At a previous workshop where these CI revisions were discussed, staff did not make available the data or analysis to support the contemplated CI changes. Without seeing the data, it is difficult to provide comment on the validity of the new values. The science of lifecycle analysis as well as understanding of related issues such as methane leakage rates continue to evolve – and are not without controversy.

CARB has a responsibility to ensure that the proposed CA-GREET 2.0 model is based on the most up-to-date, accurate methodologies and data available. Given that the newly proposed CI values are based on evolving science and, if adopted, <u>will</u> have significant impact on investors and compliance entities, it is vital that consideration of any CI revisions – especially changes as significant as these – <u>start</u> with a full and transparent discussion of the data and analysis upon which the changes are based. LCFS 32-13 BP concurs with the following examples of where this transparency and discussion is particularly warranted, as provided by the California Natural Gas Vehicle Coalition and the Coalition for Renewable Natural Gas in their letter of 1/21/15 (summarized here):

1. Tailpipe methane slip factors – concerns have been raised as to the quality and accuracy of the data used to adjust the model's methodology and calculate methane tailpipe emissions factors. Peer reviewed sources of the most up-to-date tailpipe methodology and emissions factors based on actual NGV emissions data, such as the soon-to-be released Argonne National Lab (ANL) Heavy Duty Vehicles Report, calculates methane slip values <u>four to six times lower</u> than those currently being used by CARB staff. LCFS 32-14

2. Methane leakage from RNG production facilities - the current proposed leakage rates are not consistent with New Source Performance Standards which US landfills are subject to for operational and control systems. Concern must be raised as to CARB's reliance on European studies for anaerobic digestion facilities that are not applicable to the US RNG production from landfills. LCFS 32-15

3. Methane leakage from conventional natural gas processes and transport – assumptions currently in CA-GREET 2.0 are based on a national-level EPA methodology, which may not be representative of California's natural gas distribution systems or the primary gas-producing basis supplying natural gas to California. Finalizing these GREET revisions should be delayed to incorporate LCFS 32-16

the release of more up-to-date studies on system leakage which CARB's ISOR (Appendix D) acknowledges is due soon. LCFS 32-16 cont.

We therefore strongly suggest that this portion of the regulatory process is put on hold until the data and analysis upon which the changes are based is presented to the stakeholders and that stakeholders are given ample opportunity to comment on the data and analysis. LCFS 32-17

Impact on Feasibility and Investments
Significantly raising CI values for alternative fuels will have an impact on investments made in reliance on the current LCFS regulation and on the feasibility of what is already a very challenging, possibly infeasible, regulation. For instance, contemplated increases to natural gas and biogas pathways include CI increases ranging from 15% to nearly 200%. For sugar cane ethanol pathways, CI increases are as much as 88%. Companies have made significant, long-term investments in these pathways – and are currently considering future investments. Even at the low end, these changes will impact current investments, significantly altering the economics of these investments - and will put a chill on investments that are being currently considered. At the high end, they make projects uneconomic.

With regard to impact on compliance, to date, natural gas and biogas pathways have contributed a significant amount to compliance. According to the latest UC Davis LCFS Status Review, natural gas and biogas together have accounted for approximately 11% of total LCFS credits – and approximately 90% of non-biofuel LCFS credits[3]. These fuels have provided, and are required to continue to provide, an important compliance bridge while other low carbon fuels such as cellulosic ethanol continue to develop. The contemplated CI increases for these fuels would therefore have a profound effect on regulated entities whose plans have, in good faith, incorporated these pathways into their compliance plans. LCFS 32-18

Grandfathering/Transition
As both the science of lifecycle analysis and related data on fuel pathways – such as methane leakage - continue to evolve - investors and compliance entities cannot and should not be subjected to constant tinkering of CI values – let alone significant, game-changing shifts in carbon intensities during the current timeframe of the regulation.

Even if, after appropriate vetting through a robust public process, the data and analysis support CI changes to existing fuel pathways, there are real public policy questions about whether or how such game-changing revisions are implemented. Staff should consider what will likely be important and unfortunate unintended consequences of increases to the CI of pathways that capture methane that would otherwise be emitted to the atmosphere under business as usual scenarios. By levying a heavy penalty on these pathways, the revised regulation greatly reduces the incentive for projects designed to capture these emissions. LCFS 32-13 cont.

[3] Status Review of California's Low Carbon Fuel Standard, Yeh and Witcover, July, 2014

Moreover, in the recently released pamphlet on Reducing Short-Lived Climate Pollutants in California, CARB states that "The Low Carbon Fuel Standard provides strong financial incentives to use captured methane from landfills and anaerobic digestion facilities as transportation fuels" – and makes similar statements for capture of methane from dairies. If CI revisions on the order of what was presented at the 8/22/14 workshop are adopted, going forward, significantly less incentive will be in place to address methane emissions from both the LCFS and from any market-oriented regulations that may be focused on short-lived climate pollutants.

Any changes that may be justified, after a full vetting of the appropriate data input and assumptions, should go into effect only after a lengthy, well-noticed transition period. Investors and compliance entities must be able to rely on the regulation over an appropriate time period.

LCFS 32-13 cont.

BP Method 2a Pathway Application, Use of GREET and ILUC Revisions
Though BP has concerns with the LCFS, we continue to invest in good faith, both to comply with the regulation and as part of our commitment and contribution toward to a lower carbon transportation sector. These investments include a material business in Brazil to produce efficient, low carbon sugar cane ethanol. Our three sugarcane ethanol mills in Brazil have combined crushing capacity of 10 million tonnes of sugarcane and we are working towards expanding this business further (we recently completed a project to double the capacity of our Tropical mill). Since acquisition, BP has implemented a number of technologies and measures that reduced steam use within the process and improved electricity efficiency of cogeneration. We have also implemented a number of upgrades and installed new-cogeneration capacity at one of the mills. BP supports a sustainable approach to biofuels. We are an active member of Bonsucro – the Better Sugarcane Initiative, and our Tropical mill is already certified under the Bonsucro standard as well as the SA8000 standard for social accountability. We are working to extend certification across our other mills.

BP submitted an LCFS method 2a pathway application for these Brazilian sugar cane ethanol plants in May 2014. Staff has obviously been busy working on the large number of LCFS revisions but has been generous with their time in helping us to work through the many issues around the application. As you might imagine, we are anxious to have our pathway application approved in a timely manner so that the higher efficiency of these plants can be recognized.

In addition to the normal complexities of the 2a process, the approval process has been slowed by the pending adoption of CA-GREET 2.0 and the revisions in ILUC factors. We understand that the science of lifecycle analysis continues to evolve and we want to incorporate the latest science into our application. However, in our most recent discussions with staff, we have been made aware of what we see as troubling inconsistencies in the planned timing of the application of various parts of the pending regulatory revisions. In short, it appears to be CARB's position that the GREET 2.0 revised CIs (which are generally higher for Brazilian cane ethanol) should be modeled into all new pathway applications immediately, while the pending ILUC revisions (which

LCFS 32-19

are generally lower) cannot be used until the effective date of the regulation (approximately 1/1/16).

It is also our understanding, based on a presentation at a 12/17/14 workshop, that because our application was submitted prior to 12/1/14, another option would be for us to utilize GREET 1.8, with certain revisions already implemented in GREET 2.0, for our pending application until one year after the adoption of the revised regulation – at which time we would also adopt the new ILUC factors. This option is sub-optimal for us not only because it will require us to have our application submitted and approved twice, but also because it will put us at a disadvantage with applicants who were allowed to use GREET 1.8 without revisions. This option also increases staff workload by having to evaluate 2a applications multiple times.

LCFS 32-19 cont.

As staff seem willing to allow regulated parties to adopt the most recent science in method 2a application immediately (i.e. GREET 2.0), it seems only fair and consistent to also allow use of the newest ILUC values at the same time – i.e. immediately. This not only makes the application of the regulatory revisions fair and consistent, but also reduces the potential for a large increase in staff workload as applications are submitted now – and then revised after the regulation becomes effective.

Traceability of LCFS Credits
Regulated parties and others have long voiced concerned over CARB's general approach to 'Buyer Liability' within the AB32 program. Buyer Liability provisions increase transaction costs by requiring buyers who have asymmetric access to information and little reasonable capacity to complete their own due diligence, to verify the likely validity of a given credit. The responsibility for ensuring credit validity should sit with those who are in the best position to manage the risk – i.e. credit generators.

Several of the LCFS fuels pathways would require that regulated entities participate in the LCFS credit market in order to attain compliance. Further, in the event of an inability to comply, regulated entities must purchase LCFS credits on the market. The expectation that regulated entities can or will participate in the LCFS credit market, either via a normal compliance approach or via the credit clearance market necessitates a program that allows them to be able to rely on the validity of these credits. In fact, we believe the following language of the current statute requires that CARB ensure the validity of these credits:

LCFS 32-20

> Cal. Health & Safety Code § 38562(d)(1)
> *Any regulation adopted by the state board pursuant to this part or Part 5 [market-based compliance mechanisms] shall ensure all of the following: (1) The greenhouse gas emission reductions achieved are real, permanent, quantifiable,* ***verifiable****, and enforceable by the state board …*

BP urges CARB to act to reduce the risk of invalidation born by market participants by:

1. Limiting the basis for invalidation under proposed section 95495(b)(1) and adding a statute of limitations on the right to commence invalidation procedures, and;

2. Allowing buyers to better access and manage the inherent risk by providing for traceability of LCFS credits. By giving LCFS Credits a unique serial number similar to that applied to offsets generated under the Cap and Trade program or RINs, a buyer would be able to implement their own quality assurance and risk management programs to better evaluate and ensure the integrity of the credits they are purchasing, and in doing so better support the integrity of the program.

LCFS 32-20 cont.

We are happy to discuss these comments and recommendations with you in more detail.

Sincerely,

Ralph J. Moran
BP America, Inc

cc	Richard Corey	Phil Serna
	Mary Nichols	John Eisenhut
	Dan Sperling	Barbara Riordan
	Sandy Berg	John Balmes, M.D.
	Hector De La Torre	Ron Roberts
	Alexander Sherriffs	John Gioia
	Judy Mitchell	

This page intentionally left blank.

32_OP_LCFS_BP Responses

130. Comment: **LCFS 32-1**

This comment is a summary of the commenter's more detailed comments that follow, and responses to those subsequent comments will likewise go into more detail.

Agency Response: In general, the LCFS regulation is fuel neutral in the sense it neither requires nor prohibits the use of any specific transportation fuels in California. Neither does it set volume limitations or goals for any fuels. Instead, it establishes science-based carbon intensity values for all fuels and it requires that the statewide average carbon intensity of transportation fuels be reduced each year through 2020. The reduced-carbon standard can be met through proportionally greater use of lower-carbon fuels, reduction in the carbon intensities of specific fuels sold in California, or, most likely, a combination of the two. While the use of some fuels are expected to grow in California and the use of other fuels is expected to decline as a result of LCFS, these changes are the result of each fuel's ability to contribute to the carbon reduction objectives of the LCFS rather than ARB's desires to designate "winners" and "losers" in the regulation.

While compliance with the LCFS will add to costs that transportation fuel producers would face from compliance with the Cap-and-Trade Program alone, the LCFS regulation will help achieve important California objectives beyond what the Cap-and-Trade Program alone could achieve and is therefore an important part of the state's overall effort to reduce GHG emissions. The LCFS will guarantee that GHG reductions occur in the transportation sector, which the Cap-and-Trade Program alone would not, and will help to achieve greater diversification of the state's fuel portfolio, help reduce dependence on petroleum, and spur greater innovation and development of cleaner fuels.

See responses to **LCFS 32-2** to **LCFS 32-8**.

131. Comment: **LCFS 32-2**

The comment states that only market-based approaches succeed for reducing GHG emissions. The comment adds that the LCFS regulation is a command and control regulatory approach and will be ineffective.

Agency Response: The LCFS is a market-based approach designed to reduce the carbon intensity of transportation fuels by 10 percent by 2020, from a 2010 baseline. It is important to note that the Cap-and-Trade Program and the LCFS program have complementary, but not identical programmatic goals: Cap-and-Trade is designed to reduce greenhouse gasses from multiple sources by setting a firm limit on GHGs; the LCFS is designed to reduce the carbon intensity of transportation fuels. As a market-based, fuel-neutral program, the LCFS provides regulated parties with flexibility to achieve the most cost-effective approach for reducing transportation fuels' carbon intensity.

132. Comment: **LCFS 32-3**

The comment states that the LCFS regulation is not well designed and may discourage investments.

Agency Response: The existing LCFS regulation, in combination with the federal Renewable Fuels Standard and other programs, already has a track record of encouraging investments in lower-carbon fuels, and ARB staff anticipates the proposed regulation will send an even stronger signal to investors in these technologies since it will introduce a revised carbon standard that will require accelerating reductions in transportation fuels' average carbon intensity moving toward 2020. ARB staff disagrees that the proposed LCFS is poorly designed because it picks "winners." As explained in response to **LCFS 32-1**, above, the proposed regulation merely requires that regulated parties find ways to reduce the average carbon content of transportation fuels in succeeding years. To the extent that requirement incentivizes development and greater use of alternative fuels, such development and use will achieve program objectives of reducing GHG emissions from the transportation sector and diversification of the state's transportation fuel pool.

ARB staff does not agree that the proposed LCFS regulation is primarily a "command and control" system; it leaves decisions about how to achieve required fuel carbon intensity reductions up to the transportation fuel market and individual transportation fuel producers and providers. While the proposal is undeniably a complex, technical regulation, this does not mean it cannot be successfully implemented elsewhere. The State of Oregon and the Canadian Province of British Columbia are both implementing low carbon fuel programs. ARB's proposed regulation will include periodic reviews to ensure the program is working as planned and to make adjustments that might be needed.

133. Comment: **LCFS 32-4**

The comment states that the LCFS regulation is a command and control regulatory approach with a minor market element.

Agency Response: ARB staff disagrees that the LCFS is fundamentally a command-and-control system. The LCFS is a fuel-neutral, market-based program that does not give preference to specific transportation fuels and instead bases compliance on a system of credits and deficits based on each fuel's carbon intensity. Carbon intensity (CI) is a measure of the GHG emissions associated with the various production, distribution, and consumption steps in the "life cycle" of a transportation fuel.

It is difficult to respond with depth to this assertion because the commenter provides no specifics to support the claim that the LCFS is not market-based. Notably, the commenter does not describe what components of the program could be considered command-and-control.

134. Comment: **LCFS 32-5**

The comment states that the LCFS regulation raises costs and does not produce incremental GHG reductions.

Agency Response: It is important to note that the primary goal of the LCFS proposal is to achieve a 10 percent reduction in the carbon intensity of California transportation fuels by 2020, from a 2010 baseline. In addition, the LCFS is designed to diversify California's transportation fuel portfolio and to create a durable regulatory framework that can be adopted by other jurisdictions. From these goals flow two important ancillary benefits: long-term reductions in transportation-sector GHG emissions and diversification of the fuel supply by providing consumers with more clean fuel choices.

The LCFS and Cap-and-Trade programs are designed to complement one another – providing a multi-pronged approach to meet the goals of AB 32 for the transportation sector. Fuel suppliers have a compliance obligation under the Cap-and-Trade Program for the GHG emissions that result from the production and use of fuels. This provides an incentive to reduce emissions and sell cleaner fuels in the market, but it does not require cleaner fuels, as fuel suppliers can purchase allowances to cover their emissions if they so choose. The LCFS requires that fuel providers supply cleaner fuels in California. As the LCFS reduces the carbon intensity of fuels, it changes the composition of the state's transportation fuel mix and dependence on traditional petroleum-based fuels. In addition, investments made to comply with one of the programs will generally result in reduced compliance requirements for the other program.

135. Comment: **LCFS 32-6**

The comment states that the original LCFS regulation has not delivered low cost, low carbon fuels or innovation in alternative fuels.

Agency Response: The LCFS is working as designed and intended. Even with the standards frozen at one percent, and continuing legal challenge increasing regulatory risk for producers of low carbon fuels planning investments, tangible results can been seen. For example, as reported in the publicly available LCFS LRT system data, the amount of renewable natural gas used in vehicles in California has increased by over 700 percent since the program started; the amount of biodiesel quadrupled; renewable diesel has grown dramatically to become more than three percent of the total diesel market in California in 2013; and the average crude CI used by California refiners have remained below the 2010 baseline, meaning that the carbon footprint of the crude slate has not increased. Additionally, fuel producers are innovating and achieving material reductions in their fuel pathways' CI, an effect the LCFS regulation is expressly designed to encourage. Credits have been generated from ethanol (60 percent), renewable diesel (15 percent), biodiesel (13 percent), natural gas (ten percent), and electricity (two percent).

136. Comment: **LCFS 32-7**

The comment asserts that the California Air Resources Board (ARB) should not have any regulatory programs, but instead should only rely on the Cap-and-Trade program to achieve GHG reductions and the goals of AB32.

Agency Response: The comment asserts that ARB should not have any regulatory programs, but instead should only rely on the Cap and Trade program to achieve GHG reductions and the goals of AB32. Instead, ARB has chosen to rely on a combination of policies, planning, direct regulations, market approaches, incentives and voluntary efforts. The LCFS is one of the core regulatory foundations.

The Cap and Trade and the LCFS are two complementary programs. While both programs impact transportation fuels, they have different objectives and approaches to emission reductions. These programs work synergistically to achieve the objectives of AB 32 and Executive Order S-01-07. Most importantly, while the focus of the Cap and Trade program is on the reduction of GHG emissions, the objective of the LCFS program is to lower the carbon intensity of transportation fuels – thereby achieving GHG reductions as well as helping transform and diversify transportation fuel in California.

Regarding the cost of the LCFS, the market-based core of the LCFS program along with features such as the cost containment will allow the objectives of the LCFS program to be achieved at the lowest possible cost.

137. Comment: **LCFS 32-8**

The comment states that the LCFS regulation is too prescriptive and expensive to meet the long term climate policy goals of the State of California.

Agency Response: ARB staff disagrees that using the LCFS to drive further reductions beyond 2020 would be inappropriate and therefore should not be studied further. Clearly additional reductions in global warming emissions are needed post 2020 if the State is to continue progress toward its 2050 goals – to such an extent that transportation will need to be revolutionized. The LCFS holds promise for changing the energy and emissions associated with transportation. In recognition of this need the Board directed staff to determine what additional reductions can be obtained in the 2020 to 2030 timeframe and to return to the Board with a proposal to further strengthen the LCFS in that period. The cost and feasibility of additional reductions will be fully considered at that time.

138. Comment: **LCFS 32-9**

The comment questions the use of a cost containment proposal and expands upon a series of concerns related to it.

Agency Response: ARB staff analysis regarding the availability of low carbon intensity (low-CI) fuels indicates that there will be sufficient credit producing fuels available to meet the programs goals through 2020 from existing low-CI fuel technologies and promising low-CI fuels on the horizon. Please see response to **LCFS 40-8.**

Although the overall supply of credits is expected to be adequate to meet the total demand, there may be periods of low market liquidity. For example, parties that possess more credits than they need for near term compliance but have chosen to bank credits for use in future years rather than make them available to others. The cost containment provision was developed to address this possibility. The provision allows regulated parties to achieve compliance with their annual obligations if, for whatever reason, one or more parties is unable to obtain the credits needed for annual compliance due to a lack of liquidity in the ongoing LCFS credit market.

In the event that the demands on the credit market prove to be more than the market can deliver in a given year, the cost containment provision will allow orderly compliance without extreme measures or unacceptable price spikes. The Clearance Market greatly reduces the potential for chaos or extreme volatility in the market should a short term demand for credits exceed supply. The price cap mechanism curbs volatility allowing regulated parties to achieve compliance using a pre-determined mechanism and at a maximum price per credit.

ARB staff proposes the creation of a year-end “credit clearance” process to provide additional compliance options if the LCFS credit market gets tight; to increase market certainty regarding maximum compliance costs; to strengthen incentives to invest in and produce low-CI fuels; and to reduce the probability of credit shortfalls and price spikes. Under this process, regulated parties would be allowed to carry over deficits to the next compliance period, provided that they purchase their pro-rata share of all credits made available for sale during a year-end credit clearance market. This ensures that regulated parties can achieve compliance under all possible credit supply outcomes.

The Clearance Market is not designed as a method of dealing with the situation sometimes describes as “systematic credit shortages”. ARB staff does not believe systematic credit shortages will occur however, as part of the overall LCFS program the ARB will conduct periodic evaluations that would allow for stringency adjustments if they prove to be necessary.

The cost containment provision also significantly increases certainty over how issues related to market liquidity would affect the overall LCFS and thus serves to increase the willingness of investors to pursue low CI fuel technologies and projects. Investment decisions in new fuel supplies will depend on having clarity regarding how the program will manage price volatility or temporary shortfalls in credits from low-CI fuel. Implementing a clear, predictable provision to handle any credit shortage and to limit price spikes without lowering the overall demand for credits reduces the risk of both short-run supply shortages and fuel price spikes. Thus the cost containment provision increases the likelihood of meeting the standard by providing regulatory certainty for investors that the LCFS will continue to provide the needed price premium for low-CI fuels in the future.

The price cap provides an upper bound on the potential cost of credits, and should not be construed as a projection of future credit prices or as a projection of cost of compliance or cost-effectiveness of the regulation. The price cap is set at $200 per credit in 2016 and increase at the rate of inflation in subsequent years. ARB staff's expert judgement indicates that $200 per ton is high enough to provide a sufficient value added to stimulate the investments in and production of low-CI fuels, and sufficiently high to attract these fuels to California if they are produced elsewhere. The price cap at $200 is anticipated to result in multiple, ancillary market benefits, including reduced price uncertainty, and reduced regulatory uncertainty. Reducing both these sources of uncertainty is anticipated to increase the incentives for investment. Potential investors might otherwise be hesitant to invest in low-CI fuel production facilities given conditions of undue uncertainty, particularly because production facilities for low-CI fuels are typically capital-intensive projects with relatively long payback periods.

With respect to the portion of the comment pertaining to the economic impacts of the proposed regulation, see responses to **LCFS 40-13.**

With respect to the portion of the comment pertaining overlap between the Cap-and-Trade Program and the LCFS program, please see response to **LCFS 32-1, 32-2, 32-5 and 32-7.**

139. Comment: **LCFS 32-10**

The commenter recommends that the LCFS not differentiate between crude oils based on carbon intensity and argues that crude differentiation provides no environmental benefit but rather may result in unintended consequences.

Agency Response: There are real, quantifiable, and significant differences between the lifecycle GHG emissions of crude oils. In evaluating the various alternatives for crude oil emissions accounting under the LCFS, ARB staff has used several guiding principles (see page 81 of 2011 ISOR at http://www.arb.ca.gov/regact/2011/lcfs2011/lcfsisor.pdf):

1) *Accurate accounting for emissions from production and transport of crude oil:*

   Since the LCFS regulation takes into account full lifecycle GHG emissions for fuel pathways, including all stages of feedstock production and distribution, the upstream emissions from energy-intensive crude recovery methods need to be accounted for to provide consistent treatment versus other regulated fuels. Establishing an accurate performance-based accounting system will ensure that additional emissions in the carbon intensity of gasoline and diesel fuels from the baseline are captured.

2) *Discouraging potential increases in emissions and ensuring that increases that do occur are mitigated:*

   An incremental deficit for backsliding with respect to the baseline will ensure that the GHG emission contributions from petroleum fuels do not increase over time without being mitigated.

3) *Promoting innovation for emission reduction activities:*

   Providing credits for purchase of crude from production facilities that have implemented innovative methods, such as carbon capture and storage (CCS), to reduce emissions for crude recovery is consistent with the goal of promoting innovation, at the same time accurately accounting for the reduction in upstream emissions. Apart from providing a market signal for cleaner production, credits generated through such activities can provide extra flexibility for meeting LCFS GHG reduction targets.

4) *Avoiding or limiting incentives to use crude shuffling to generate credits, avoid deficits, or transfer GHG emissions to other jurisdictions to avoid regulation under the LCFS:*

   Additionally, a program design that can be exported to other jurisdictions will result in minimizing such GHG emission transfers if other jurisdictions adopt consistent programs.

In addition to meeting the above-mentioned key guiding principles to achieve the intended GHG benefits, the crude oil provision should be designed so as to avoid, as much as possible, adverse environmental and economic impacts. Additionally, considerations for a successful implementation, such as simplicity of methodology, availability of data, and administrative burden, as well as other issues such as fuel supply impacts, etc., should reflect on the decision-making process. Various alternatives for crude oil emissions accounting fall under two broad categories:

1) *Crude Differentiation accounting*:

   Under refinery-specific and California Average approaches, all crudes are differentiated by carbon intensity. Average crude emissions and potential incremental deficits are assessed and assigned annually on a refinery or industry-wide basis. Technologies that reduce emissions from crude production are acknowledged through reduced carbon intensity for crudes and potentially through the innovative crude provision.

2) *No Crude Differentiation accounting*:

   Under the "No Crude Differentiation" or "Crude is Crude" approach, average crude emissions are only determined for the 2010 Baseline and potential increases or decreases in crude production emissions are not evaluated.

Although the No Crude Differentiation approach advocated by the commenter eliminates any incentive for crude shuffling in response to the LCFS, it fails to provide accurate accounting of emissions, to discourage potential increases in emissions, and to promote innovation for emission reduction activities. As discussed on page 84 of the 2011 ISOR, the No Crude Differentiation approach does not account for, track, or mitigate increases in upstream emissions from crudes used by California refineries. This is inconsistent with the life cycle analysis basis of the LCFS and undermines the program's goal to achieve a ten percent emission reduction from the 2010 baseline for transportation. The No Crude Differentiation approach provides no incentive for producers of crude oil that supply California refineries to reduce emissions (e.g., by reducing flaring) since these reductions will have no benefit relative to the compliance with the LCFS. Because the approach provides complete flexibility to purchase worldwide crude supplies irrespective of the emissions associated with producing and transporting the crude, no mitigation would be required if crudes with higher CIs were to be used. Moreover, this approach could result in significantly greater amounts of harder to refine crude oil being used at California refineries because there is no incentive to avoid their use. Consequently, the No Crude Differentiation approach could have adverse environmental impacts for the communities located in the vicinity of the refineries. On the basis of this evaluation, we determined the No Crude Differentiation approach to be inadequate and inconsistent with the key guiding principles for crude oil treatment under the LCFS.

The LCFS is designed to account for all emissions over the lifecycle of a fuel. Although driving innovation in new, low carbon fuels such as biofuels, electricity, hydrogen and natural gas is a priority under the LCFS, the goal of the regulation is to reduce the average carbon intensity of transportation fuels sold in California by ten percent in the year 2020. Ensuring this goal is met is not possible without accurately accounting for emissions associated with the production and transport of crude oil and requiring that increases that do occur are mitigated.

140. Comment: **LCFS 32-11**

The comment questions the reasoning behind the removal of the direct metering of electricity usage requirement in electric vehicle charging to generate credits.

Agency Response: Electricity, unlike almost all other transportation fuels, is primarily distributed directly to residential and commercial users over a shared electrical distribution grid. The transportation electricity shares the existing electrical distribution network with electricity destined for other end-use appliances and applications. The shared electrical distribution network is fundamentally different than other transportation fuel distribution infrastructures. It is technically difficult to segregate the transportation electricity. Due to the unique distribution structure, staff proposed different schemes to calculate the transportation electricity use in different settings.

Installing a separately dedicated meter for residential EV charging was initially viewed to be feasible. However, because separate meters remain costly for EV customers, the majority of EV owners have elected not to install dedicated EV meters at their residences. The percentage of directly metered EV charging residences varies from 5% to 10% in the major California electric utility service territories. Rather than adding a cost barrier to EV adoption by requiring direct metering, staff intends to continuously improve the calculation for retail charging based on the best sources of information about how EVs are charged and driven.

1. *Verifiability of emission reductions*

   ARB staff believes credits for residential EV charging can continue to be real and verifiable even in the absence of direct metering at the residence for all customers. Just as liquid fuels volumes are not measured at individual retail fuel pumps, the amount of electricity used as a vehicle fuel does not need to be monitored at the individual home to be an accurate source of credit in the program.

   In a 15-day change of the regulation, staff added the calculation method for unmetered residential charging, including the determination of the number of non-directly metered residential PEVs, into the LCFS regulation language. In a 15-day change, the proposal was modified to have ARB (rather than the utilities) calculate the generated credits for electricity use from residential charging.

   The EV populations in each service territory are accurately known based on the California Vehicle Rebate Project (CVRP)[3] database, and California Department of Motor Vehicles registration data and other relevant sources. The daily electricity use of PEVs without direct metering will be represented by the best available data regarding daily electricity use of residential PEV in a given compliance period.

   Currently, the best available representative data for unmetered residential charging are likely to continue to be the directly metered data in the same utility service territory. However, this may change with the progress of studies (some external and some directly funded by ARB) focused on evaluating how plug-in electric vehicles are driven, or through potential advances in smart grid technologies coupled with EV on-vehicle technology.

[3] https://energycenter.org/clean-vehicle-rebate-project/rebate-statistics

Currently available data from select, early model year plug-in electric vehicles shows similar electricity consumption across technology type. However, per the direction in Board Resolution 12-11, ARB staff is conducting an evaluation of the charging behavior of both battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV) with an assortment of battery capacities and will report to the Board by 2016 as part of the midterm review for the Advanced Clean Cars program. Additional findings from this assessment will be incorporated into the calculation method per the 15-day changes that provide flexibility to adjust for any future observable differences if future data demonstrates a shift in this area.

The current data collected by California utilities for directly metered customers shows electricity use of about 8kWh per day from home charging. The value is consistent with national level data from U.S. DOE's EV Project, which has been collecting data on Nissan Leaf and Chevrolet Volt vehicles since late 2010.[4] The EV Project shows that the kW hours of daily charging of each major California utility service areas (Los Angeles, San Francisco, and San Diego) are consistent, with values ranging from 8 kWh to 9kWh per day. The data from EV Project consisted of both directly metered charging activities and non-metered charging obtained through on-board data collection system. The EV Project data did not show much variation between metered and non-metered charging activities. Staff will continue to monitor other sources of data for updated information on daily electricity usage of EVs and incorporate those into the calculation method.

Moving forward ARB staff will calculate the generated credits for each utility (after receiving data that are relevant to the calculations submitted by each utility).

2. *Innovation*

Staff agrees that one of the objectives of the proposed Low Carbon Fuel Standard is to foster innovations and investments in the production of the low carbon intensity (CI) fuels. This is one reason that ARB plans to adjust this calculation to account for the progress of technology innovation delivering better data. We note, however, that incentivizing development and use of alternative fuels such as electricity takes precedence over

[4] http://avt.inel.gov/evproject.shtml#ReportsAndMaps

incentivizing innovation in metering. Where a metering requirement could specifically dis-incent use of electricity as a vehicle fuel, such a requirement is inappropriate.

3. *Fairness/Consistency*

   In the proposed regulation, the requirements for application, reporting, and recordkeeping are consistent across all alternative fuel providers. The parameters for credit calculation, however, may differ from one alternative fuel to another, due to the fuel-specific manufacturing, blending, distributing, and marketing processes.

   The credits generated through residential EV charging will be calculated by ARB staff and documented in the Electrical Distribution Utility's LRT-CBTS account. This would reduce burdens on electricity providers, and reduce the probability of miscalculations and subsequent credit invalidation.

4. *Taxation*

   As stated above, the calculation method is sufficiently accurate in calculating the actual electricity use of non-metered residential EV charging for the purpose of the LCFS rule. Staff cannot speak to what methods would or would not be acceptable to other state agencies including State Board of Equalization, should that agency ever be mandated to impose a fuel tax on residential EV charging.

141. Comment: **LCFS 32-12**

The comment questions ARB staffs' revisions to the carbon intensity values for many alternative fuel pathways and baseline fuels.

Agency Response: Based on stakeholder feedback received over last several years and advances in lifecycle analysis, it is imperative that we update our California-modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET) model at this time. These updates were thoroughly vetted through a full and open public process, including workshops and numerous individual meetings with stakeholders.

ARB staff is very sensitive to market stability. In order to preserve stability, staff is attempting to establish a predictable update cycle for these analytical models. The next update is expected in the program review that will conclude prior to January 1, 2019.

Changes will be vetted through the same complete and open public process that ARB employs for all rulemakings.

142. Comment: **LCFS 32-13**

The comment requests that any proposed CI value changes should include a transparent public discussion prior to the change.

Agency Response: The LCFS re-adoption public process, including discussion of CI model changes, was complete and extensive. ARB staff believes that the identification and adoption of new, accurate estimates of GHG emissions from methane are more likely to result in actions to reduce emissions than to suppress the fuel source. For more information about this process please see the response to comment **LCFS 1-12**. With respect to the timing of changes and the impact on investments see response to **LCFS 32-18**.

143. Comment: **LCFS 32-14**

The comment questions the values used in CA-GREET for tailpipe methane slip factors.

Agency Response: See response to comment **LCFS 1-4**.

144. Comment: **LCFS 32-15**

The comment questions the values used in CA-GREET for methane leakage from RNG production facilities.

Agency Response: See response to comment **LCFS 1-5**.

145. Comment: **LCFS 32-16**

The comment questions the values used in CA-GREET for methane leakage from conventional natural gas processes and transport.

Agency Response: See response to comment **LCFS 1-6**.

146. Comment: **LCFS 32-17**

The commenter suggests delaying changes in CI values.

Agency Response: The commenter had made the suggestion to put changes to CI values on hold based on three areas – tailpipe methane slip emissions, methane leakage from RNG production facilities, and methane leakage from natural gas processes and transport. Staff addresses tailpipe emissions in response to

LCFS 1-4, methane leakage from RNG in response to **LCFS 1-5** and **LCFS 32-15**, and methane leakage from natural gas in response to **LCFS 1-6**.

ARB staff is constantly evaluating new data and attempting to strike a balance between accuracy and predictability by transitioning to a regular review and update cycle under the new regulation.

147. Comment: **LCFS 32-18**

The comment questions changes in CI values for specific fuel pathways due to investor expectations based on prior values.

Agency Response: Staff employed the best available science to update the CI value of each fuel in order to be as accurate as possible and encourage the appropriate actions to reduce CI. We understand that changing the CI value for fuels shifts the investment incentives and may impact the economics of existing projects or pathways that were financed assuming a certain value under the prior CI regime. Therefore, we will continue to endeavor to shift CI values in a methodical and transparent way that correctly balances the need to update to the latest science and to provide a stable investment framework. In this iteration, the new 'recertified' CI values will not be applicable until 2016, meaning that the CI incentives in LCFS have remained essentially constant for a five-year period (from 2011-2015). The next scheduled update to the CI calculation models will occur during the program review that will conclude prior to January 1, 2019.

148. Comment: **LCFS 32-19**

The comment expresses concern for the amount of time being taken to approve 2A pathways. The comment also states that revised CIs should be modeled into all new pathway applications immediately while the pending ILUC revisions cannot be used until the effective date of the regulation.

Agency Response: ARB staff acknowledges that the Method 2A LCFS pathway applications submitted by the commenter remain uncertified. With the limited staffing resources available to process pathway applications, a backlog of LCFS pathway applications exists waiting to be processed for certification. To some extent, staff resources were being re-directed to issues related to the re-adoption of the LCFS regulation and to the development of an updated life cycle analysis model for GHG impacts assessments of transportation fuel pathways. Staff sympathizes with the commenter and will process the applications as soon as reasonably possible.

The proposed LCFS regulation will not be used to process applications until January 2016. Thus, the CA-GREET 2.0 model and 2016 LCFS iLUC values cannot be used to evaluate lifecycle GHG emissions of fuel pathways until January 2016. Fuel pathway applications submitted prior to January 2016 for certification must be modeled using the current regulation and the presently-approved CA-GREETv1.8b model, along with iLUC carbon intensity values (land use or other effect) adopted by the Board pursuant to the Final Regulation Order for the Low Carbon Fuel Standard.[5].

149. Comment: **LCFS 32-20**

The comment suggests allowing buyers to better manage their risk by providing traceability of LCFS credits.

Agency Response: ARB staff agrees that monitoring, auditing and enforcement of the LCFS Program are critical to ensure the emission benefits of the program are realized. The ARB's Cap-and-Trade Program currently employs use of third party verifiers and the LCFS staff is interested in adopting such a program for LCFS.

ARB staff is aware of the voluntary quality assurance plan provisions that the U.S. Environmental Protection Agency (U.S. EPA) has adopted in the Renewable Fuel Standard (RFS) Program. The RFS Program requires that all retired credits which are found to be invalid must be offset by honorable credits with real emission benefits. Staff has had discussions with U.S. EPA staff regarding their implementation experience with this recently-adopted provision, as their program uses a similar "buyer-beware" approach.

The ARB staff believes that it would be valuable to add unique serial numbers to the credits generated in the LCFS. Staff is currently exploring the costs and timeframes associated with implementing this change in the LRT-CBTS while efforts are increased to focus resources on the overall quality assurance of LCFS credits.

[5] Title 17, California Code of Regulations (CCR), Subchapter 10. Climate Change, Article 4, Regulations to Achieve Greenhouse Gas Emission Reductions, Subarticle 7. Low Carbon Fuel Standard, § 95486, Determination of Carbon Intensity Values, (b) Method 1 – ARB Lookup Table, Table 6. Carbon Intensity Lookup Table for Gasoline and Fuels that Substitute for Gasoline.

ARB staff does not support limiting the basis for invalidation under proposed section 95495(b)(1); such a limit could diminish the program's ability to accomplish its goals.

This page intentionally left blank.

Comment letter code: 33-OP-LCFS-CIPA

Commenter: Rock Zieman

Affiliation: California Independent Petroleum Assoc.

The following letter was submitted to the LCFS Docket during the 45-day comment period.

33_OP_LCFS _CIPA

CIPA

California Independent Petroleum Association
1001 K Street, 6th Floor
Sacramento, CA 95814
Phone: (916) 447-1177
Fax: (916) 447-1144

Comments of the California Independent Petroleum Association on the Readoption of the Low Carbon Fuel Standard

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

February 17, 2015

Via electronic submittal to: http://www.arb.ca.gov/lispub/comm/bcsubform.php?listname=lcfs2015&comm_period=A

The California Independent Petroleum Association (CIPA) appreciates the opportunity to submit the following comments to the California Air Resources Board (CARB) for its consideration.

The mission of CIPA is to promote greater understanding and awareness of the unique nature of California's independent oil and natural gas producer and the market place in which he or she operates; highlight the economic contributions made by California independents to local, state and national economies; foster the efficient utilization of California's petroleum resources; promote a balanced approach to resource development and environmental protection and improve business conditions for members of our industry.

The members of CIPA believe that domestic petroleum production already plays a meaningful role in helping the state meet its policy goals for reducing greenhouse gas emissions in California. Staff's proposed Innovative Crude Method Provisions enable our members the opportunity to create additional carbon intensity reductions within the program.

CIPA appreciates the staff proposal on Innovative Crude Methods and believes these changes could provide a substantial impetus for California's in-state producers to include more renewable energy in the production of crude. CIPA looks forward to working with CARB on implementing these provisions and lowering the carbon intensity of in-state crude.

CARB's understanding of the potential impact of solar EOR was critical to revising the regulation. To more fully quantify the economic benefits of the proposal, we partnered on a study whose results show that solar EOR in California could deliver over 4.2 million LCFS credits per year while creating between 32,100–44,900 cumulative jobs to California's economy from 2015 through 2020, depending on the LCFS market. Our analysis shows further benefits in that for every job created through investment in solar powered oil production, about 2.5–2.7 jobs are created in supporting industries (indirect) and via

LCFS 33-1

spending by employees that are directly or indirectly supported by the industry (induced).[1] LCFS 33-1 cont.

Thank you for your attention to this important matter. Any questions or follow-up comments can be directed to myself at rock@cipa.org.

Sincerely,

Rock Zierman
CEO

Enc: ICF Report

314043562.1

[1] January 2015, ICF Report: The Impact of Solar Powered Oil Production on California's Economy, An economic analysis of Innovative Crude Production Methods under the LCFS. Attachment A

The Impact of Solar Powered Oil Production on California's Economy

An economic analysis of Innovative Crude Production Methods under the LCFS

January 2015

Submitted to

CIPA
California Independent Petroleum Association

GlassPoint

Prepared by

ICF International
620 Folsom St, Suite 200
San Francisco, CA 94107

About ICF International

ICF International (NASDAQ:ICFI) provides professional services and technology solutions that deliver beneficial impact in areas critical to the world's future. ICF is fluent in the language of change, whether driven by markets, technology, or policy. Since 1969, we have combined a passion for our work with deep industry expertise to tackle our clients' most important challenges. We partner with clients around the globe—advising, executing, innovating—to help them define and achieve success. Our more than 4,500 employees serve government and commercial clients from more than 70 offices worldwide. ICF's website is www.icfi.com.

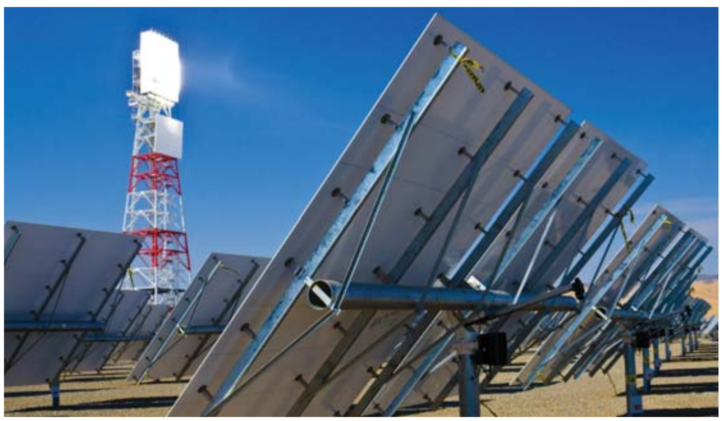
Warranties and Representations

ICF endeavors to provide information and projections consistent with standard practices in a professional manner. ICF MAKES NO WARRANTIES, HOWEVER, EXPRESS OR IMPLIED (INCLUDING WITHOUT LIMITATION ANY WARRANTIES OR MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), AS TO THIS MATERIAL. Specifically but without limitation, ICF makes no warranty or guarantee regarding the accuracy of any forecasts, estimates, or analyses, or that such work products will be accepted by any legal or regulatory body.

Waivers

Those viewing this Material hereby waive any claim at any time, whether now or in the future, against ICF, its officers, directors, employees or agents arising out of or in connection with this Material. In no event whatsoever shall ICF, its officers, directors, employees, or agents be liable to those viewing this Material.

Solar Electric Power Generation



Solar Steam Generation
Central Receiver, Coalinga, CA

Solar Steam Generation
Enclosed Trough, Amal, Oman

Contents

List of Exhibits

Executive Summary

The California Air Resources Board (CARB) staff has proposed to re-adopt the Low Carbon Fuel Standard (LCFS), reaffirming its original target of a 10% reduction in the carbon intensity (CI) of transportation fuels used in California by 2020 and subsequent years. While most of the expected CI reductions will be derived from imported low-CI fuels, the regulation and the re-adoption proposal include provisions to promote innovations in crude oil production methods that reduce the CI of petroleum.

Of the potential innovative methods, the use of solar energy is the lowest-cost, lowest-risk, and largest-scale opportunity to reduce the CI of petroleum fuels produced and used in California. Solar powered oil production technologies—solar steam generation and solar electric power generation—have the potential to contribute to California's economy significantly while reducing costs and risks associated with meeting the LCFS. Solar steam generation used in thermal enhanced oil recovery (EOR) displaces imported natural gas that that would have otherwise been combusted. Solar electricity generated on-site at production facilities displaces electricity that would have otherwise been purchased from a utility provider. These solar technologies have the potential to reduce the carbon intensity of California's crude oil, thereby boosting investment in California-based industries, and helping shift LCFS compliance from importing low carbon fuels from out-of-state towards in-state investments and operations of low carbon infrastructure. Investment in these technologies can lead to job growth, increased industry activity, and increased state and local tax revenues. Furthermore, by reducing the carbon intensity of California crude oil, these solar technologies have the potential to preserve California refinery operations while fully meeting the emissions reductions goals of the LCFS.

ICF employed IMPLAN, an input-output model, to calculate the economic impacts of deploying solar steam generation and solar electric power generation technologies. ICF developed *steady* and *accelerated* deployment scenarios for each technology, capturing 5% and 30% of their respective markets (as measured by volume of steam or electricity consumption). ICF also considered the economic impacts of keeping LCFS credits generated by solar steam and solar power in California, rather than having the value of those credits transferred to low carbon fuel providers in other regions. Furthermore, we considered the impacts on refiners as a result of being able to maintain margins that would have otherwise been impacted by reduce crude runs or reduced margins from having to export the refined products.

Exhibit 1. Economic Contributions of Solar Oil Production in California

Cumulative Solar Impact 2015-2020	*Steady*	*Accelerated*
	$25/ton	$150/ton
Total Jobs	**11,000**	**44,900**
Income per Worker	$72,000	$77,900
GSP ($M)	**$1,160**	**$5,090**
Industry Activity ($M)	$2,910	$11,350

In the *accelerated* deployment scenario, where solar energy provides 30% of the state's EOR steam needs or onsite production electricity, ICF concluded:

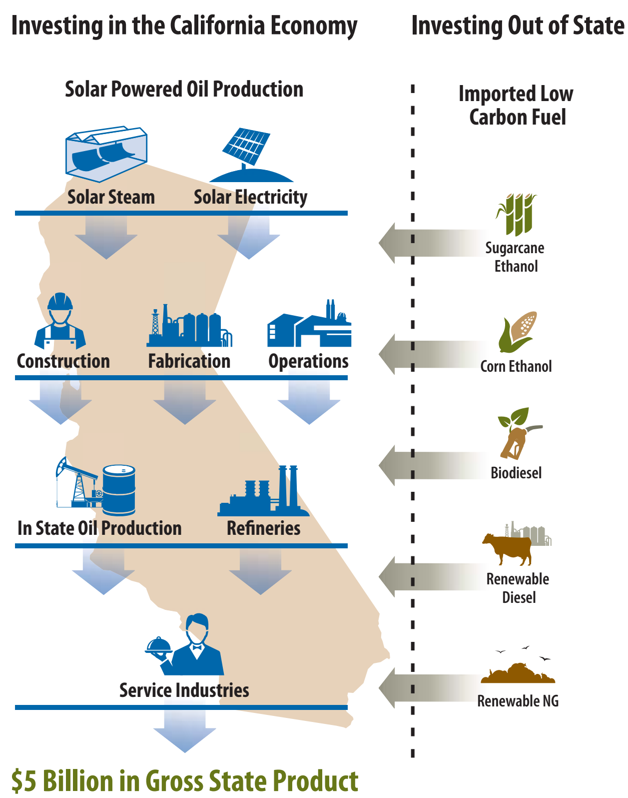
- Innovative crude oil production using solar energy adds 32,100–44,900 cumulative jobs to California's economy from 2015 through 2020, depending on LCFS market conditions.
- These are high value jobs, with labor income per job created in the range of $75,000 per job. Many of the jobs were created in sectors tied to upstream oil production, as well as construction, engineering related services, and fabrication/manufacturing.

- For every job created through investment in solar powered oil production, about 2.5–2.7 jobs are created in supporting industries (indirect) and via spending by employees that are directly or indirectly supported by the industry (induced).
- The deployment of these technologies leads to increased state and local tax revenues in the range of $117–575 million.

Solar steam has greater potential than solar electricity to deliver LCFS credits because 90% of the energy used in California oil production is in the form of steam. In the *accelerated* deployment scenario, solar steam generation has the potential to generate as many credits as some of the most promising low carbon fuel pathways by 2020, including renewable diesel, renewable natural gas, and low carbon intensity biodiesel (e.g., from corn oil). Solar electricity has the potential to generate LCFS credits in line with contributors like electricity and natural gas.

ICF also finds that solar powered oil production technologies may help stabilize the LCFS market in several ways. Firstly, these LCFS credits may help stabilize credit prices by offering a lower cost solution than importing low carbon fuels for compliance. Secondly, we find that these credits may hedge California's exposure to uncertainty in the federal Renewable Fuel Standard market. With the potential for RIN prices to be depressed because of uncertainty in that market, biofuel providers may seek higher LCFS credit prices to pick up the slack in market pricing. However, the deployment of solar powered oil production technologies will provide some buffer against credit price increases. Thirdly, solar powered oil production technologies will provide regulated parties, particularly integrated energy firms with oil production and refining investments, an opportunity to limit their exposure to the LCFS credit market.

Solar powered oil production technologies are commercially available today with low development risk, and unlike some low carbon fuel options, innovative crude methods tap into the existing petroleum supply chain without delay for infrastructure modifications or rollouts. The emissions reduction potential of the technologies will deliver credits to the oil producer and reduce the CI of petroleum fuels. Therefore, innovative crude offers the unique advantage of fully complying with the LCFS and achieving the state's GHG reduction goals without hindering the petroleum supply chain. These emissions reductions are available as a "drop in" option using today's fuel production, distribution, and vehicle infrastructure, with minimal infrastructure costs, development risk, and deployment timelines.



ICF's analysis demonstrates that investments in solar powered oil production will yield benefits up to $5 billion in Gross State Product, with jobs created in sectors such as construction, fabrication, oil field operations, and the service industry, while retaining jobs in the refining industry. This contrasts sharply with some of the alternative LCFS compliance pathways, whereby dollars (via commodity pricing and LCFS credits) are exported out of California to pay for low carbon fuels produced elsewhere.

1 Innovative Crude Oil Production

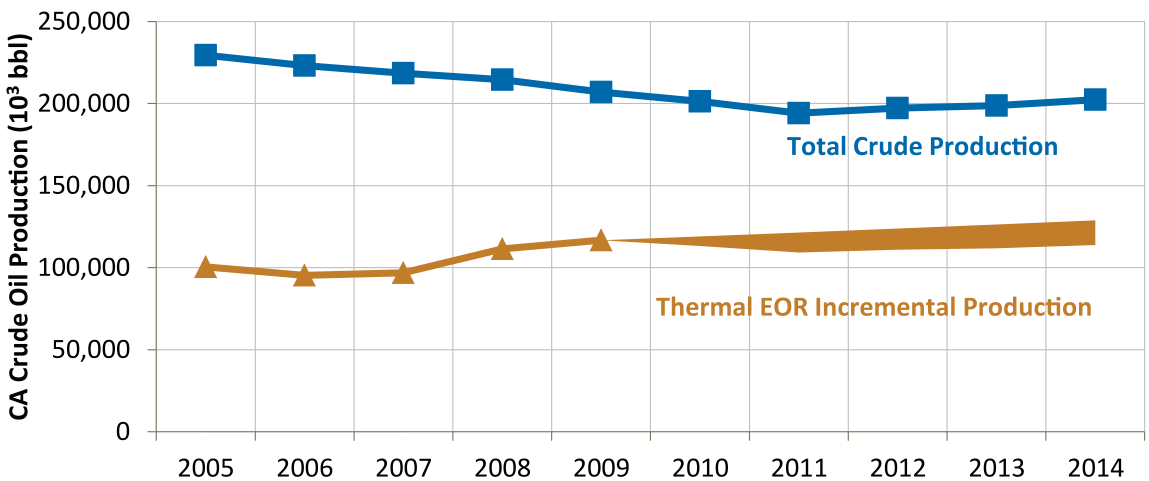
The California Air Resources Board (CARB) staff has proposed to re-adopt the Low Carbon Fuel Standard (LCFS) program in 2015, and to include updates and revisions to the regulation.[1] The regulation and the re-adoption proposal include provisions to promote innovations in crude oil production methods that reduce greenhouse gas (GHG) emissions. In this section, we briefly summarize California's Oil and Gas Sector, its outlook in the near- to mid-term as a result of carbon constraining regulations in the state, and review the relevant innovative crude oil production technologies.

1.1 California's Oil and Gas Sector

Excluding federal offshore areas, California ranks third in the United States in crude oil production. As recently as 2012, nearly 4,700 new wells were drilled in California, bringing the statewide total to 88,500 active wells, operated by 570 companies.[2] A recent report by the Los Angeles Economic Development Corporation (LAEDC) highlights some of the critical parameters characterizing the impact of the Oil and Gas Sector on California's economy, including:[3]

- About 70,000 direct jobs in California are tied to oil and gas production
- Oil and gas production contribute about 0.5% of total California labor income
- The average wage of the component industries in the oil and gas production sectors are considerably higher than the median private industry wage in California

Exhibit 2. Crude Oil Production in California, 2005-2014[4]



[1] http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm

[2] Division of Oil, Gas and Geothermal Resources of the California Department of Conservation (DOGGR)

[3] Oil and Gas in California: The Industry and Its Economic Contribution in 2012, LAEDC, April 2014, http://laedc.org/wp-content/uploads/2014/04/OG_Contribution_20140418.pdf

[4] Based on data from EIA and DOGGR. The crude oil production for 2014 is an estimate made by ICF based on data reported through September. Note that production data via TEOR are not yet available past 2009. The shaded range is an estimate based on ICF analysis.

California's Low Carbon Fuel Standard

The LCFS requires a 10 percent reduction in the carbon intensity (CI) of transportation fuels used in California. Carbon intensity is a measure of the lifecycle GHGs of transportation fuels, and includes emissions over the entire fuel supply chain. The LCFS is implemented using a system of credits and deficits: Deficits are generated by fuels that have a carbon intensity greater than the standard and credits are generated by fuels that have a carbon intensity lower than the standard. At the end of each year, deficit-generating parties (generally refiners and fuel importers) must balance their deficits with credits.

Despite several years of reductions in overall crude production since 2005, crude produced from thermal enhanced oil recovery (EOR)[5] or steam injection has been increasing since 2006, as shown in Exhibit 2. Crude Oil Production in California, 2005-2014 above. Steam injection, which reduces the viscosity of oil and increases mobility, has been used commercially in California since the 1960s. Today, more than 40% of California's crude is produced with thermal EOR and is expected to account for half of production in the next few years. As an emitter of GHGs, the oil and gas production industry is impacted by CARB's implementation of the Global Warming Solutions Act of 2006, commonly known as AB 32. The LCFS and light-duty tailpipe GHG standards (originally referred to as Pavley standards) are both part of California's suite of GHG reduction policies under AB 32, and will both lead to reductions in demand for petroleum-based transportation fuels. Although the refinery sector is commonly identified and analyzed as one of the primary industry sectors to be impacted by AB 32, upstream oil and gas production sectors will likely experience the effects of the regulation as well.

This report focuses on a potential opportunity included in the proposed re-adoption of the LCFS: "Innovative Crude Production Methods". Operators who produce crude for California's refineries and employ a GHG-reducing "innovative method" in the recovery or extraction process can generate LCFS credits corresponding to the avoided GHG emissions.

1.2 Introduction to Innovative Crude Production Methods

The current proposed LCFS re-adoption regulation identifies the following technologies as innovative methods for crude production:[6]

Technology	Image	Description	Technology Maturation	LCFS Considerations
Solar steam generation		Uses solar arrays to concentrate the sun's energy to heat water and generate steam for thermal EOR.	Deployed in multiple locations; several vendors.	Steam must be used onsite at the crude oil production facilities.
Carbon capture and storage		Captures CO_2 emissions produced from processing; prevents the CO_2 from entering the atmosphere.	Limited commercial deployment; no commercial deployment at oil fields.	Carbon capture must take place onsite at the crude oil production facilities.
Solar or wind electricity generation		Electricity generation from solar technology or wind turbines. Electricity to be used on-site for production-related activities.	Solar PV technology is ubiquitous for non-residential installations. Wind technology is mature, but generally deployed in larger rather than on a smaller scale.	Qualifying electricity must be produced and consumed onsite or be provided directly to the crude oil production facilities from a third-party generator and not through a utility owned transmission or distribution network.
Solar heat generation		Uses solar arrays to concentrate the sun's energy for heat generation.	Concentrating solar technology that can produce process heat (similar to steam generation).	Heat must be used onsite at the crude oil production facilities.

The language also includes provisions regarding year of implementation (no earlier than 2010 for solar steam or CCS; no earlier than 2015 for electricity and heat generation projects), project registration, and minimum GHG reduction thresholds (a carbon intensity reduction of at least 0.10 gCO_2e/MJ or a reduction of at least 5,000 metric tons CO_2e per year).

[5] Thermal EOR is a process whereby heat is introduced to the reservoir in order to reduce the viscosity of the crude, and increase its permeability.

[6] Initial Statement of Reasons, II-17ff. Available online at: http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15isor.pdf

"Solar powered oil production technologies—solar steam generation and solar electric power generation—have the potential to contribute to California's economy significantly while reducing costs and risks associated with meeting the LCFS."

Technologies Selected For Further Analysis

For the purposes of this report, ICF narrowed our consideration of innovative crude methods to *solar steam generation* and *solar electricity generation* based on factors such as commercial availability of the technology, consideration of California oil field characteristics, and industry interest. Other qualifying innovative technologies, including carbon capture and storage (CCS), wind electricity generation, and solar heat generation, were not considered due to limitations or uncertainty in market demand.

- **Solar steam generation.** The technology is commercially available and has been demonstrated by both GlassPoint Solar and BrightSource Energy. These companies have demonstration projects in Kern County and Fresno County, California, respectively. GlassPoint Solar also has deployed its technology in Oman at the Amal West oilfield (in partnership with the national oil company, Petroleum Development Oman, PDO). With about 492 million barrels of steam injected for thermal EOR in California in 2012, there is significant potential for solar steam generation in California. For such thermal EOR projects, steam is the primary energy requirement, with 185 million MMBtu of natural gas required to produce the 492 million barrels of steam injected for thermal EOR. This natural gas is the primary source of GHG emissions associated with oil production. The potential for the technology is limited by factors such as geography and the deployment of efficient combined heat and power (CHP) units at oilfields, which may be difficult to displace depending on when the units were installed and the operators' willingness to displace the technology given the investment. However, ICF anticipates sufficient demand for solar steam generation deployment as part of LCFS compliance.
- **Solar electricity generation.** Solar electric power generation is ubiquitous in California, with more than 8,500 MW of solar energy currently installed, and about 2,750 MW of that installed in 2013. Multiple photovoltaic (PV) technologies have experienced significant declines in installed cost over the last several years, with the average installed system price reported at about \$2.27/W for a non-residential system.[7] The location and electricity demands at oilfields will likely be a good match for solar PV deployment. The regulation restricts credits from potential solar electricity deployment to electricity which is produced and consumed onsite or is directly provided to the facility via third-party generator, not through the utility grid. As oil production operations are generally continuous, there are limits for the fraction of total energy provided by solar PV deployment without concomitant investments in energy storage. Despite these limitations, ICF anticipates that solar PV installations at oil fields will increase substantially between now and 2020 as part of a LCFS compliance strategy based on the cost competitiveness of the technology and the desirable onsite characteristics of oil production fields (e.g., sufficient solar radiation).

[7] US Solar Market Insight: Q3 2014, GTM Research and SEIA, available online: http://www.seia.org/sites/default/files/resources/iV39f8059N.pdf; assumes a 200-300 kW rooftop installation at a non-residential facility.

2 Economic Impacts of Solar Powered Innovative Crude Production

ICF employed an input-output (I-O) economic model to calculate the economic benefits of deploying solar steam generation and solar electricity generation in California. We considered several elements associated with the deployment of these technologies, including the following:

- **Capital expenditures.** ICF considered the capital expenditures associated with deploying the technologies in two scenarios (*steady* deployment and *accelerated* deployment). The capital expenditures include the labor and materials associated with building the solar steam installations and solar PV installations.
- **LCFS credit generation.** ICF also considered the value of LCFS credits generated via the deployment of these technologies in California. ICF assumed that the generation of credits would have otherwise been completed outside of California. This is a reasonable assumption given the structure of the LCFS program and a review of CARB's proposed LCFS compliance scenario, which relies heavily on biofuels (e.g., biodiesel, renewable diesel, and renewable natural gas). Given the limited in-state production of low carbon fuels, ICF made the reasonable assumption these innovative crude production technologies will create credits in-state from investments made in-state, versus credit revenues being exported out-of-state for imported low carbon fuels. We valued the credits in two scenarios: a low price of $25/ton and a high price of $150/ton.[8]
- **Refinery margins.** Depending on the strategy employed, LCFS compliance may lead to significant demand destruction for gasoline and diesel. For instance, CARB's proposed compliance scenario includes about 900 million gallons of diesel replacements being consumed in 2020, representing about 20% of the projected diesel demand. Conversely, CARB's illustrative compliance scenario only projects about 110 million gallons of gasoline replacements being consumed in 2020, in a fuel market with projected demand of about 13.5 billion gallons. Regardless of the compliance strategy, it is highly likely that there will be reduced refinery margins as a result of the LCFS. ICF broadly categorizes these losses into two areas: 1) lost refinery margin and 2) reduced refinery margins as a result from having to export product.

Depending on the chosen means of LCFS compliance, varying levels of decreases occur in gasoline and diesel consumption in California. Although the reduction of petroleum consumption has positive impacts via improved energy security and increased fuel diversity, the decreased consumption of petroleum will also have direct negative impacts on the refining industry—in the same way that the investments in alternative fuels and advanced vehicles will yield positive impacts in the corresponding industries. ICF treated the reduction in gasoline and diesel consumption in the modeling as follows:

- **ICF assumed that there were lost margins on 50% of those crude runs that are assumed to be displaced entirely as a result of the LCFS.** These margins were estimated based on an ICF analysis of the 3-2-1 crack spread for California-based refiners (estimated at about $15/bbl).
- **ICF assumed that the remaining 50% of crude runs representing the reduction in gasoline and diesel consumption in California are exported, rather than displaced entirely.** For these exports, ICF assumed a corresponding decrease in revenue in the export markets because of increased freight costs and competitiveness on pricing (estimated at a combined $5/bbl).

Using CARB's illustrative compliance scenario, each credit generated in 2020 leads to a demand destruction of about 120-130 diesel gallons equivalents.[9]

8 LCFS credit values traded around $25/ton for all of 2014, and likely are below forward credit prices considering the uncertainty associated with the LCFS program throughout 2014 and rising compliance obligations. The high value of $150/ton was selected for illustrative purposes; the program is capped at $200/ton via a cost compliance mechanism.

9 The demand destruction is presented as a range because it ultimately depends on the carbon intensity of the low carbon fuels deployed in CARB's illustrative compliance scenario. Available online at http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15appb.pdf

Exhibit 3. Overview of Solar Powered Oil Production Scenarios

Technology Penetration	Solar Steam		Solar Electricity	
	Steady	*Accelerated*	*Steady*	*Accelerated*
Capital Expenditures ($ millions)	$1,900	$5,600	$390	$1,200
LCFS Credits / GHG Emission Reductions	1.4 million	4.3 million	160,000	490,000
LCFS Credit Value ($ millions)	$35–210	$108–645	$4–24	$12–74

Technology penetration notes:

- Solar Steam: About 492 million barrels of steam were injected at California oilfields for thermal EOR in 2012. ICF assumed that solar steam technology providers could capture 5% of the market for steam generation in a *steady* deployment scenario and 30% in an *accelerated* deployment scenario,[10] in accordance with CARB estimates. Note that ICF held the volume of steam injected constant throughout the analysis (2015-2020), despite the very likely possibility that the amount of steam injected into California oilfields will continue to increase over time. The *steady* and *accelerated* levels of solar steam technology deployment amount to about 16 million MMBtu and 49 million MMBtu of steam, respectively, in 2020.
- Solar Electricity: California oil producers purchased about 3.2 terawatt hours (TWh) of electricity as recently as 2012.[11] ICF made the same assumptions for solar PV as were made for solar steam regarding technology penetration: We assumed that solar PV could capture 5% and 30% of the market for electricity purchased by California oil producers by 2020 in *steady* and *accelerated* deployment scenarios, respectively. ICF estimated the deployment of solar PV that would be required to achieve this level using a capacity factor of 20%. In other words, to capture 30% of the market in 2020, ICF assumed that an installed capacity of about 550 MW would be able to provide 0.96 TWh operating at a 20% capacity factor.[12]

Capital expenditure notes:

- Solar Steam: ICF developed estimates for capital expenditures to achieve this level of deployment using data provided by GlassPoint and previous economic assessment of solar steam by Ernst & Young.[13]
- Solar Electricity: We assumed a starting price of $2.33/W[14] with modest decreases over time.[15]

The economic contribution of solar steam and solar electricity deployment are characterized by employment, labor income, value added, and value output.

- **Employment** is reported in terms of annualized job-years. The employment numbers are broken down by direct, indirect, and induced. We also present an employment metric referred to as a **jobs multiplier**, which is the sum of job-years (included direct, indirect, and induced) divided by the direct job-years. This is an indicator of the type of employment activity statewide that is generated by investment in a technology. We also present **labor income** and **labor income per worker**. The latter is a coarse estimate of the value of jobs created by the corresponding investment.
- **Statewide impacts.** We present several metrics measuring the impacts on California's economy, including Gross State Product (GSP), industry activity, output, and taxes.
    - ***Industry activity*** measures the value of goods and services.
    - The ***output multiplier*** mirrors the ***jobs multiplier*** and represents the total industry activity (including direct, indirect, and induced) divided by the direct industry activity. This is an indicator of the type of industry activity statewide that is generated by investment in a technology.
    - The values for ***taxes*** are based on the sum of taxes calculated by IMPLAN, including those associated with employee compensation, proprietor income, tax on production and imports, households, and corporations.

Exhibit 4 below summarizes the results for the *steady* deployment scenarios, with each technology capturing 5% of its respective market (as measured by volume of steam or electricity consumption). Note that for both solar steam and solar electricity, LCFS credits were modeled at values of $25/ton and $150/ton—the results from both LCFS credit pricing scenarios are shown in the table below.

10 Industry discussions and ISOR, II-19 Available online at: http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15isor.pdf

11 Personal communication with CARB staff who queried the California Energy Consumption Database by county and NAICS code associated with crude petroleum extraction (211111).

12 There are some limitations to these assumptions, considering that crude oil producers are base loading operations. Further, there are no net metering provisions in the proposed language from CARB, and is effectively prohibited because the electricity cannot be purchased from a utility-owned transmission or distribution network. In reality, to capture 30% of the market for electricity consumption by crude oil producers, solar PV technology would have to be deployed in parallel with complementary technologies like solar trackers and energy storage (e.g., batteries) to level out the energy supply with the base loaded demand. To simplify our analysis and the comparison between solar PV and solar steam as innovative crude production technologies, however, we have not considered the expenditures that would likely be required to achieve this level of electricity consumption using solar PV. Rather, we simply quantified the expenditures that would be required to deploy a given megawatt target of PV.

13 Ernst & Young, "Solar enhanced oil recovery: An in-country value assessment for Oman", 2014, available online: http://tinyurl.com/EY-solar-EOR

14 US Solar Market Insight: Q3 2014, GTM Research and SEIA, available online: http://www.seia.org/sites/default/files/resources/iV39f8059N.pdf

15 Feldman, D et al., Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections, 2014 Edition, SunShot, US Department of Energy. NREL/PR-6A20-62558

Exhibit 4. Modeling Results for Steady Deployment Scenarios, Cumulative 2015-2020

Economic Parameter	Solar Steam		Solar PV Electricity	
	$25/ton	$150/ton	$25/ton	$150/ton
Employment				
Direct	3,300	4,900	1,100	1,300
Indirect	2,300	2,900	800	800
Induced	2,600	4,200	900	1,100
Total	**8,200**	**12,000**	**2,800**	**3,200**
Jobs Multiplier	2.72	2.56	2.61	2.56
Labor Income ($M)	$590	$930	$200	$240
Income per Worker	$72,000	$77,500	$71,400	$75,000
Statewide Activity ($ millions)				
GSP	$860	$1,360	$300	$350
Industry Activity	$2,260	$3,070	$650	$740
Output Multiplier	1.53	1.59	1.73	1.74
Taxes	$89	$158	$27	$35

The values are shown as cumulative over the analysis period (2015-2020).

ICF notes that by reporting these numbers cumulatively, we may be double-counting jobs i.e., a single person could conceivably account for six job-years assuming that s/he is employed in each year as a result of a particular technology's deployment.

Summary of Economic Contributions

Direct: Impacts of capital expenditures to deploy innovative crude production technologies and the employees hired by the industry itself.

Indirect: Impacts that stem from the employment and business revenues motivated by the purchases made by the industry and any of its suppliers.

Induced: Impacts generated by the spending of employees whose wages are sustained by both direct and indirect spending.

Exhibit 5 summarizes the results for the *accelerated* deployment scenarios, with each technology capturing a 30% of its respective market (as measured by volume of steam or electricity consumption).

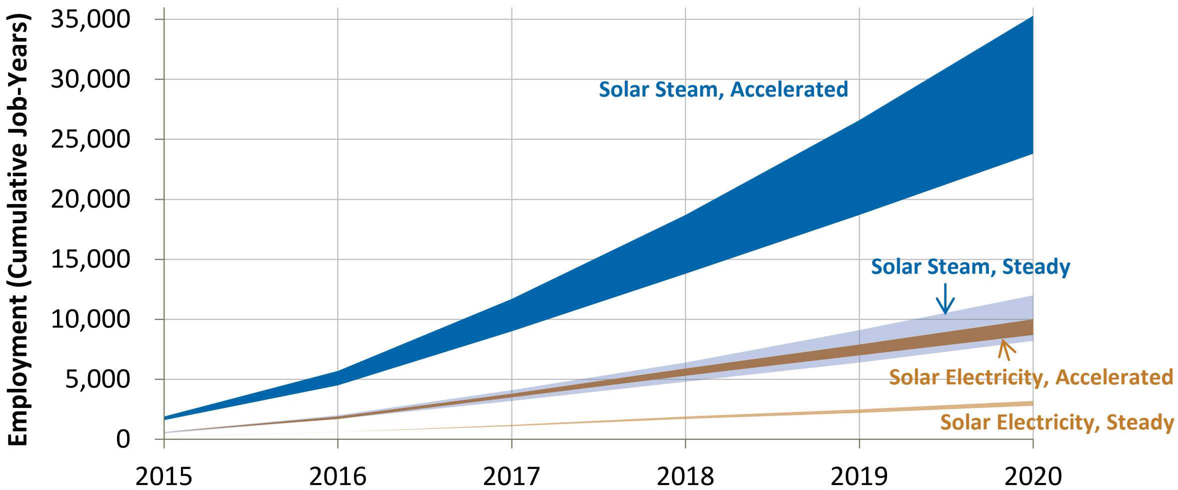
Exhibit 5. Modeling Results for Accelerated Deployment Scenarios, Cumulative 2015-2020

Economic Parameter	Solar Steam		Solar Electricity	
	$25/ton	$150/ton	$25/ton	$150/ton
Employment				
Direct	9,500	14,400	3,300	3,900
Indirect	6,600	8,600	2,300	2,500
Induced	7,700	12,300	2,700	3,200
Total	**23,800**	**35,300**	**8,300**	**9,600**
Jobs Multiplier	2.73	2.56	2.61	2.56
Labor Income ($M)	$1,720	$2,750	$610	$730
Income per Worker	$72,300	$77,900	$73,500	$76,000
Statewide Activity ($ millions)				
GSP	$2,520	$4,030	$890	$1,060
Industry Activity	$6,660	$9,120	$1,950	$2,230
Output Multiplier	1.53	1.59	1.73	1.74
Taxes	$263	$470	$81	$105

The solar steam technology deployment leads to significantly higher employment and statewide economic activity, largely as a result of higher capital expenditures associated with capturing the same market share (5% or 30%). The technologies yield similar results in terms of the multipliers for jobs and industry activity / output. In other words, the higher values for solar steam deployment are more of a reflection of the higher overall market opportunity for solar steam rather than something unique about deploying the technology. Solar PV technology has a slightly higher output multiplier, in part because a significant portion (upwards of 55%) of the expenditures associated with solar steam deployment occur outside of California, mainly as imported materials.

Exhibit 6 below shows how the cumulative employment impacts over time for both solar PV and solar steam technologies in the *steady* and *accelerated* scenarios. The range of impacts represents the low and high LCFS credit pricing.

Exhibit 6. Cumulative Employment Impacts in California of Solar Powered Oil Production



The IMPLAN Model

The IMPLAN model is a static input-output framework used to analyze the effects of an economic stimulus on a pre-specified economic region; in this study, the State of California. The IMPLAN model tracks economic activity across more than 500 industrial sectors using region-specific multipliers to trace and calculate the flow of dollars from the industries that originate the impact to supplier industries. The industrial sectors are based on the North American Industry Classification System (NAICS). The IMPLAN model is one of the most widely used input-output impact models in the United States. For instance, IMPLAN was recently used to estimate the economic contribution of the oil and gas industry in California.

Oil and Gas in California: The Industry and Its Economic Contribution in 2012, LAEDC, April 2014

The IMPLAN model includes more than 500 industry sectors; the table below highlights the sectors that experienced the highest employment impacts. These sectors have been grouped broadly into three categories: oil and gas production industries, solar powered oil production technologies, and indirect and induced sectors. As noted previously, the indirect and induced sectors are those that are impacted by direct investments in the solar powered oil production technologies oil and gas production industries via linkages and increased household incomes. Across both solar steam and solar electricity technology penetration scenarios that were modeled, the construction sector and the drilling oil and gas wells sector captured the highest percentages of employment, accounting for as much as 15-20% of the total employment.

With a larger market penetration, solar steam also has more potential for LCFS credit generation—generating a cumulative 4.4 million and 13.3 million LCFS credits in the *steady* and *accelerated* deployment scenarios compared to just 0.5 million and 1.5 million LCFS credits generated in the *steady* and *accelerated* solar electricity deployment scenarios, respectively.

Exhibit 7. Most Impacted Industry Sectors via Solar Powered Oil Production Technology Deployment

Industry	IMPLAN Sector
Oil and Gas Production Industries	*Drilling oil and gas wells*
	Extraction of natural gas and crude petroleum
	Support activities for oil and gas operations
	Wholesale trade
Solar Powered Oil Production Technologies	*Construction of other new nonresidential structures*
	Architectural, engineering, and related services
	Fabricated pipe and pipe fitting manufacturing
	Semiconductor and related device manufacturing
	All other miscellaneous electrical equipment and component manufacturing
Indirect & Induced Sectors	Real estate
	Full-service restaurants
	Limited-service restaurants
	Employment services
	Employment and payroll of state govt, non-education

The higher market potential for solar steam also leads to higher retention of refinery margins attributed to increased refinery runs and reduced exports of refined products. The retention of these refinery margins manifests itself in the modeling results primarily as increased output and industry activity, and to some extent labor income, rather than employment. Despite not having a significant impact on employment, this is due in part to the nature of the modeling exercise.

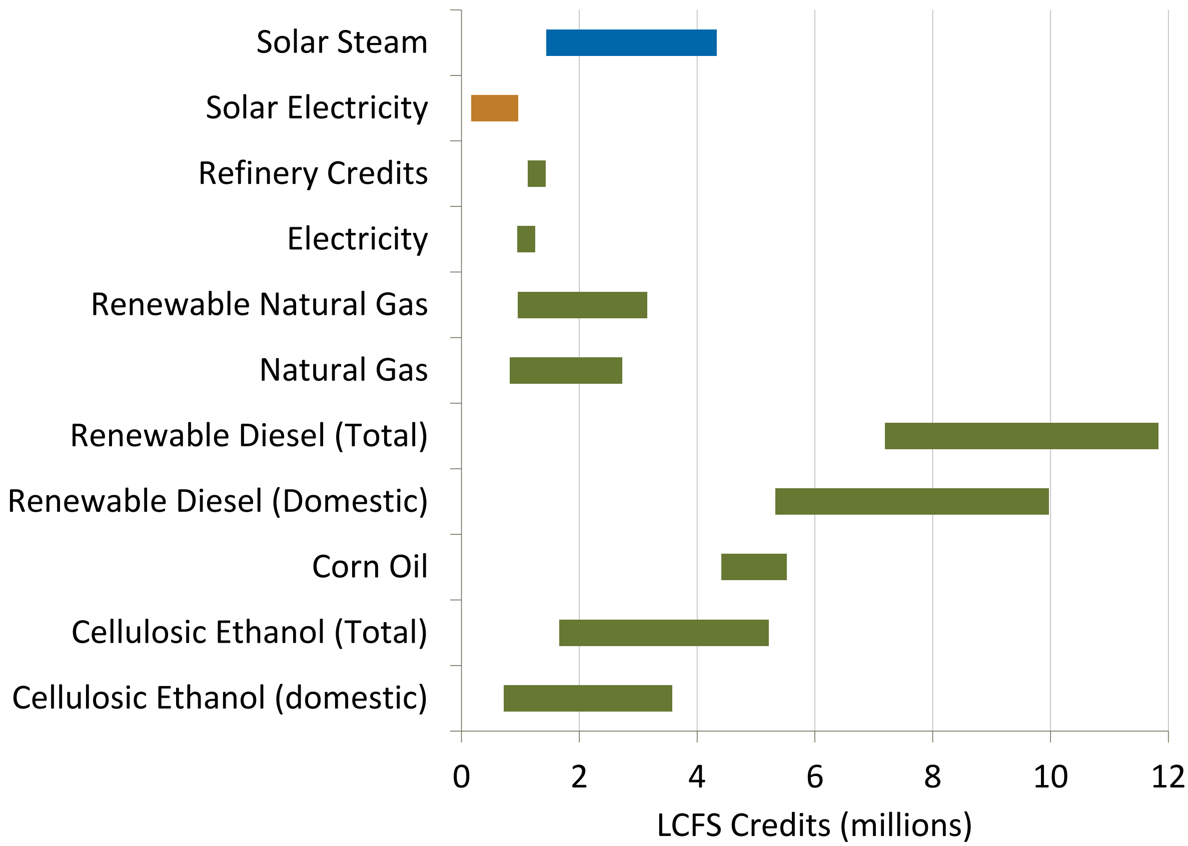
To some extent, the I-O model assumes "full" employment at refineries in the baseline case. In other words, the baseline case—against which the impacts of solar powered oil production technologies are measures—is not assuming that there will be refinery closures as a result of programs like the LCFS or the cap-and-trade program. Furthermore, an increased allocation of expenditures to the refinery sector in the modeling is not going to lead spontaneously to the opening or expansion of an existing refinery in California, thereby generating significant new employment in the sector. Rather, it will lead to enhanced labor income, industry activity, and industry output.

"Solar steam [deployment] leads to higher retention of refinery margins attributed to increased refinery runs and reduced exports of refined products."

3 Solar Powered Innovative Crude in Context

As part of the re-adoption package, CARB staff developed alternative transportation fuel production capacity estimates in various cases (e.g., low, medium, and high).[16] These estimates were used to develop an illustrative LCFS compliance scenario. Exhibit 8 below captures the technical potential for various alternative transportation fuels compared to solar powered oil production technologies in 2020. Note that these values represent the number of LCFS credits that would be generated using the low and high projected estimates published by CARB staff for total fuel volumes available in 2020, not the values assumed for a specific compliance scenario.

Exhibit 8. Total LCFS Credit Potential from Various Compliance Pathways



[16] Available online at http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15appb.pdf

Solar steam has the potential to generate credits comparable with the technical potential of significant pathways that CARB staff use to illustrate compliance, such as domestic cellulosic ethanol. Solar electricity has more limited potential, but is comparable to other contributors to compliance like electricity (used in plug-in electric vehicles) and potential credits generated by energy efficiency improvements at refineries.

While Exhibit 8 focuses on the overall technical potential of various pathways, Exhibit 9 shows the specific deployment potential of solar steam and solar electricity compared to CARB's illustrative compliance scenario for the years 2016-2020.

The potential for innovative crude production technologies is significant: In the *accelerated* deployment scenario, solar steam and solar electricity have the potential to generate 25% and 2%, respectively, of the total cumulative credits required in CARB's illustrative compliance scenario. This puts solar steam on par with pathways such as renewable diesel and renewable natural gas; solar electricity would make a contribution comparable to conventional natural gas. Even in the *steady* deployment scenarios, the LCFS credits generated by solar steam and solar electricity are on par with low carbon fuels like corn oil biodiesel and tallow biodiesel, respectively. Regardless of the deployment scenario, both solar steam and solar electricity have the potential to make material contributions towards LCFS compliance in the 2020 timeframe.

As highlighted in the table above, CARB's illustrative compliance scenario is largely dependent on importing low carbon fuels to California, including corn ethanol (15% of credits), cane-based ethanol (15%), and renewable diesel (22%). To date, nearly all of the renewable natural gas supplied to California for LCFS compliance has been from out-of-state. ICF anticipates that a significant portion of the renewable natural gas will continue to be imported to California from other parts of the United States in the near- to mid-term future (at least through 2018).[17]

Exhibit 9. Estimated LCFS Credit Generation, 2016-2020[18]

Pathway		LCFS Credits (millions) 2016-2020	
Gasoline Substitutes CARB Illustrative Compliance Scenario[17]	Corn Ethanol	9.03	
	Cane Ethanol	7.28	
	Sorghum/Corn Ethanol	1.02	
	Sorghum/Corn/Wheat Slurry Ethanol	0.88	
	Cellulosic Ethanol	1.42	
	Molasses Ethanol	1.49	
	Renewable Gasoline	0.30	
	Hydrogen	0.29	
	Electricity	3.96	
Diesel Substitutes CARB Illustrative Compliance Scenario	Soy Biodiesel	0.43	
	Waste Grease Biodiesel	3.11	
	Corn Oil Biodiesel	5.04	
	Tallow Biodiesel	0.43	
	Canola Biodiesel	0.11	
	Renewable Diesel	13.02	
	Natural Gas	1.39	
	Renewable Natural Gas	7.07	
	Electricity for HDVs and Rail	1.01	
	Refinery Credits	3.16	
	Total	**60.43**	
Solar Powered Oil Production Technologies *Steady* and *Accelerated* Deployment	Solar Steam	4.42	13.28
	Solar Electricity	0.50	1.50

Many of these compliance options are likely to command a significant premium in the market, especially liquid biofuels, thereby pushing credit prices up. California's regulated entities, absent other options, are largely price takers in the low carbon fuel market. In principle, LCFS credit prices will be determined by the marginal abatement cost (assuming a liquid market, and other indicators of a robust market). ICF estimates that the marginal abatement cost associated with the fuel pathways in CARB's illustrative scenario is greater than the abatement cost of the innovative crude production technologies considered here—solar steam and solar PV.

[17] CARB staff estimates about 50 million diesel gallon equivalents (dge) of RNG consumption in 2014, and used 240 million dge of RNG in 2020 for the illustrative compliance scenario.

[18] Note that these values are calculated by ICF based on our assessment of information presented by CARB, available online at http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15appb.pdf

In other words, ICF believes that in either the *steady* or *accelerated* technology deployment scenarios, innovative crude production technologies have the potential to:

- reduce the marginal abatement cost in the LCFS program in 2020,
- decrease credit prices, and
- reduce California regulated parties' status as a price taker.

ICF estimates that in the *accelerated* deployment case for solar steam, for instance, the credits generated may reduce credit prices by as much as $20-$25/ton in 2020.[19]

Credits from innovative crude production offer a potential hedge against uncertainty in the federal Renewable Fuel Standard (RFS2) market. The RFS2 market has experienced significant volatility. The US Environmental Protection Agency (EPA) sets targets (renewable volume obligations, or RVOs) for the blending of renewable fuels on an annual basis. In November 2014, the EPA announced that they would postpone setting the 2014 RVO targets until 2015, extending a period of regulatory uncertainty in the marketplace. The RFS2 market has also experienced other volatility, such as the availability of federal tax credits. The role of biodiesel, for instance, in the market fluctuates significantly without certainty regarding the availability of a $1.00 per gallon blender's tax credit. This credit has expired and been re-instated retroactively several times in the last five years, creating a difficult investment atmosphere for producers and regulated parties. The uncertainty in the RFS2 market has led to and may continue to lead to volatility of Renewable Identification Numbers (RINs) pricing, the currency of the RFS2 market. For instance, if the RFS2 market is scaled back significantly (via reduced RVOs), it may decrease the price of RINs, and liquid biofuel providers may look to the LCFS program to pick up some of the slack in market pricing. This could lead to an increase in LCFS credit prices.

The credit streams arising from solar powered oil production may provide regulated parties in the LCFS market a buffer against such price volatility. This is dependent, however, on timely deployment of innovative crude production technologies as a compliance diversification strategy.

ICF believes that innovative crude production technologies may provide regulated parties an opportunity to limit their exposure to the LCFS credit market via an integrated investment-based approach. Today, for instance, the majority of LCFS credits are purchased at the point of blending ethanol into gasoline and blending biodiesel or renewable diesel into conventional diesel. In some cases, the LCFS credit value paid is transparent. By and large, however, the LCFS credit market lacks liquidity and transparency in part because some transactions bundle the LCFS credit price paid with fuel price, or reflect longer-term arrangements. Some market participants have various investments in both refining and low carbon fuels and transfer credits internally. CARB reports, for instance, that one-in-five LCFS credit transactions have $0 credits being transacted.[20] ICF regards this activity as an ordinary part of market participants seeking competitive advantage, and a means to limit their exposure to a potentially volatile LCFS credit market.

The innovative crude provisions of the LCFS allow regulated parties to co-invest in or otherwise source credits from production facilities that reduce the carbon intensity of crude oil, which will durably reduce emissions from upstream crude oil production. These investments will reduce forward uncertainty for all market participants and create economic growth in California, shifting a portion of investment in low-carbon energy facilities from out-of-state to in-state.

"Solar steam has the potential to generate credits comparable with the technical potential of significant pathways that CARB staff use to illustrate compliance, such as domestic cellulosic ethanol."

[19] Note that the economic contributions of such price reductions were not considered under this study's methodology.

[20] CARB, October 27, 2014 LCFS Workshop on Proposed Compliance Curves and Cost Compliance Provision.

Appendix

LCFS Credit Calculations

Solar Steam

The LCFS credits that could be generated for solar steam were calculated using the methodology outlined by CARB in the proposed language:

$$Credits_{innov\_SolarSteam} = 29{,}360 \times V_{steam} \times f_{solar} \times V_{crude\_produced} \times V_{innov\_crude} \times C$$

where $Credits_{innov\_SolarSteam}$ is the amount of LCFS credits generated in metric tons by the volume of crude oil produced and delivered to California refineries for processing; V_{steam} is the volume in barrels of cold water equivalent of steam injected, f_{solar} is the fraction of steam injected that was produced using solar energy; $V_{crude\_produced}$ is the volume (in barrels) of crude oil produced using the innovative method; V_{innov_crude} is the volume (in barrels) of crude oil produced using the innovative method and delivered to California refineries for processing; and C is the constant to convert from metric tons to grams (where 1 MT=106 gCO_2e). The constant at the outset of the equation, 29,360, is the emissions factor associated with the natural gas that would have otherwise been consumed in once through steam generators (OTSGs).21

Solar PV

The LCFS credits that could be generated by solar PV deployment were calculated using the methodology outlined by CARB in the draft language:

$$Credits_{innov\_SolarSteam} = 511 \times \frac{E_{electricity} \times f_{renew}}{V_{crude\_produced}} \times V_{innov\_crude} \times C$$

where $Credits_{innov\_SolarSteam}$ is the amount of LCFS credits generated in metric tons by the solar PV used to produce crude oil and delivered to California refineries for processing; $E_{electricity}$ is the electricity consumption to produce the crude (in units of kWh), and f_{renew} is the fraction of renewable electricity that was produced using solar or wind energy.

[21] ICF notes that the emissions factor for natural gas is derived from a draft version of the CA-GREET model and is subject to modification upon further CARB review.

Model Description

In this analysis, the economic impacts were calculated using the IMPLAN[22] (IMpact analysis for PLANning), Version 3.0 input-output model. IMPLAN is developed and maintained by the Minnesota IMPLAN Group (MIG). The IMPLAN model is a static input-output framework used to analyze the effects of an economic stimulus on a pre-specified economic region; in this case, the State of California. IMPLAN is considered static because the impacts calculated by any scenario by the model estimate the indirect and induced impacts for one time period (typically on an annual basis).

The modeling framework in IMPLAN consists of two components—the descriptive model and the predictive model.

- The **descriptive model** defines the local economy in the specified modeling region, and includes accounting tables that trace the "flow of dollars from purchasers to producers within the region".[23] It also includes the trade flows that describe the movement of goods and services, both within, and outside of the modeling region (i.e., regional exports and imports with the outside world). In addition, it includes the Social Accounting Matrices (SAM) that trace the flow of money between institutions, such as transfer payments from governments to businesses and households, and taxes paid by households and businesses to governments.

[22] IMPLAN was developed by the Minnesota IMPLAN Group (MIG). There are over 1,500 active users of MIG databases and software in the United State as well as internationally. They have clients in federal and state government, universities, as well as private sector consultants. More information is available at http://www.implan.com.

[23] IMPLAN Pro Version 2.0 User Guide.

- The **predictive model** consists of a set of "local-level multipliers" that can then be used to analyze the changes in final demand and their ripple effects throughout the local economy. IMPLAN Version 3.0 uses 2008 data and improves on previous versions of model by implementing a new method for estimating regional imports and exports - a trade model. This new method of estimating imports looks at annual trade flow information between economic regions; thereby allowing more sophisticated estimation of imports and exports than the traditional econometric RPC estimate used by the previous, Version 2. Additionally, this new modeling method allows for multi-regional modeling functions, in which IMPLAN tracks imports and exports between selected models allowing the users to assess how the impact in one region can impact additional regional economies.

The IMPLAN model is based on the input-output data from the U.S. National Income and Product Accounts (NIPA) from the Bureau of Economic Analysis. The model includes 440 sectors based on the North American Industry Classification System (NAICS). The model uses region-specific multipliers to trace and calculate the flow of dollars from the industries that originate the impact to supplier industries. These multipliers are thus coefficients that "describe the response of the economy to a stimulus (a change in demand or production)."[24] Three types of multipliers are used in IMPLAN:

- Direct—represents the impacts (e.g., employment or output changes) due to the investments that result in final demand changes, such as investments needed for cleanup and/or redevelopment efforts.
- Indirect—represents the impacts due to the industry inter-linkages caused by the iteration of industries purchasing from industries, brought about by the changes in final demands.

Induced—represents the impacts on all local industries due to consumers' consumption expenditures arising from the new household incomes that are generated by the direct and indirect effects of the final demand changes.

[24] Ibid.

The total impact is simply the sum of the multiple rounds of secondary indirect and induced impacts that remain in California (as opposed to "leaking out" to other areas). IMPLAN then uses this total impact to calculate subsequent impacts such as total jobs created and tax impacts. This methodology, and the software used, is consistent with similar studies conducted across the nation.

Inputs and Model Parameters

The direct economic impacts presented in the report are based on: a) investments required to deploy solar steam and solar PV technologies at oilfields in California, b) the value of LCFS credits being generated in-state, rather than exported to low carbon fuel producers outside of California, and c) the value of increased refinery runs and decreased exports that would have otherwise occurred as a result of LCFS compliance. ICF modeled the impacts of the investments for each individual year of the time period (2015-2020).

Output

Whenever new industry activity or income is injected into an economy, it starts a ripple effect that creates a total economic impact that is much larger than the initial input. This is because the recipients of the new income spend some percentage of it and the recipients of that share, in turn, spend some of it, and so on. The total spending impact of the new activity/income is the sum of these progressively smaller rounds of spending within the economy. This total economic impact creates a certain level of value added (GSP), jobs, called the total employment impact, and also tax revenue for state and local governments.

Due to the static nature of the IMPLAN model, the employment impacts must be presented in terms of annual job-years as the model calculates the annual impact of an annual investment. It is likely that once the job is created, it will be sustained, however to ensure that the impact is not overstated; it is conservatively assumed that the job impact is annual. The annualized GSP and tax impacts can be accrued over the program's duration to identify the total impact of the EB-5 program. These dollar values represent the investments that were placed into the economy each year aggregated over time.

Detailed Modeling Results

As noted previously, ICF used the IMPLAN model to calculate the economic impacts of solar powered oil production in California. The data provided in the body of this report have been aggregated into cumulative numbers. The tables below include selected outputs from IMPLAN—employment (in job-years), labor income, industry activity, and GSP—on an annual basis.

Exhibit 10. Changes in Employment, All Scenarios

Solar Technology	Deployment	LCFS	2015	2016	2017	2018	2019	2020
Solar Steam	*Steady*	Low	500	1,100	1,500	1,600	1,700	1,700
		High	600	1,400	2,100	2,400	2,600	2,900
	Accelerated	Low	1,600	3,000	4,500	4,700	4,900	5,100
		High	1,900	3,800	6,100	7,000	7,900	8,700
Solar Electricity	*Steady*	Low	200	400	600	600	500	500
		High	200	400	600	600	700	700
	Accelerated	Low	600	1,200	1,700	1,700	1,600	1,600
		High	600	1,200	1,900	1,900	2,000	2,000

Exhibit 11. Changes in Labor Income, All Scenarios ($ millions)

Solar Technology	Deployment	LCFS	2015	2016	2017	2018	2019	2020
Solar Steam	*Steady*	Low	40	80	110	110	120	130
		High	50	100	150	180	210	240
	Accelerated	Low	100	200	310	340	360	390
		High	130	280	460	550	630	710
Solar Electricity	*Steady*	Low	10	30	40	40	40	40
		High	10	30	50	50	50	50
	Accelerated	Low	40	80	120	120	120	120
		High	50	90	140	150	150	160

Exhibit 12. Changes in Industry Activity, All Scenarios ($ millions)

Solar Technology	Deployment	LCFS	2015	2016	2017	2018	2019	2020
Solar Steam	*Steady*	Low	90	240	380	450	520	580
		High	110	300	490	610	730	830
	Accelerated	Low	270	670	1110	1330	1540	1740
		High	330	850	1450	1820	2170	2490
Solar Electricity	*Steady*	Low	40	80	120	130	130	140
		High	40	90	140	150	160	170
	Accelerated	Low	120	250	370	390	400	420
		High	120	270	410	450	470	500

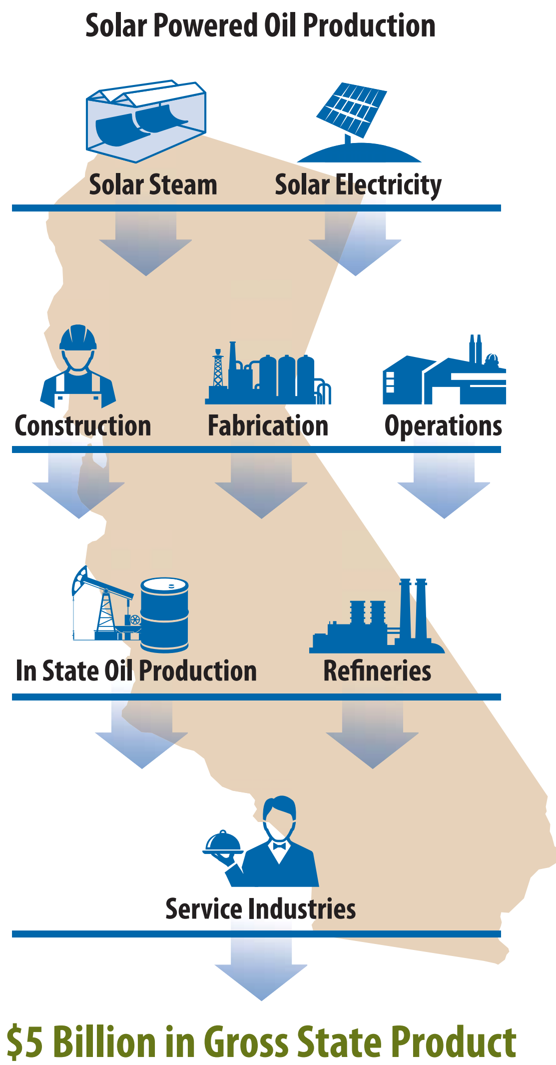
Exhibit 13. Changes in Gross State Product, All Scenarios ($ millions)

Solar Technology	Deployment	LCFS	2015	2016	2017	2018	2019	2020
Solar Steam	*Steady*	Low	50	100	150	170	190	200
		High	60	140	220	270	310	360
	Accelerated	Low	140	280	450	500	550	600
		High	170	390	650	810	940	1070
Solar Electricity	*Steady*	Low	20	40	60	60	60	60
		High	20	40	70	70	70	80
	Accelerated	Low	60	120	180	180	180	180
		High	60	130	200	210	220	230

List of Abbreviations and Acronyms

CARB California Air Resources Board
CCS Carbon Capture and Storage
CI Carbon Intensity
DGE Diesel Gallon Equivalent
EOR Enhanced Oil Recovery
GHG Greenhouse Gas
GSP Gross State Product
I-O Model Input-Output Model
LCFS Low Carbon Fuel Standard
NAICS North American Industry Classification System
OTSG Once Through Steam Generator
PV Photovoltaic
RFS2 Renewable Fuel Standard
RIN Renewable Identification Number
RVO Renewable Volume Obligation (reference to RFS2)

Investing in the California Economy



620 Folsom St, Suite 200, San Francisco, CA 94107 | http://www.icfi.com

Printed on recycled paper.

This page intentionally left blank.

33_OP_LCFS_CIPA Responses

150. Comment: **LCFS 33-1**

The comment suggests that there are significant economic benefits associated with the proposed innovative crude provision.

Agency Response: ARB staff acknowledges the commenter's support of changes to the innovative crude provision and appreciates the contribution of the attached analysis of potential economic benefits provided by the provision. Staff agrees that if solar steam is widely adopted, it will provide significant economic benefits.

This page intentionally left blank.

Comment letter code: 34-OP-LCFS-CBA

Commenter: Celia DuBose

Affiliation: California Biodiesel Alliance

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

34_OP_LCFS _CBA

February 17, 2015

Mary D. Nichols
Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95812

RE: **SUPPORT FOR LCFS READOPTION AND ADF REGULATION ADOPTION** at February 19-20, California Air Resources Board Hearing

Dear Chair Nichols:

Please accept these brief comments from the California Biodiesel Alliance (CBA) in support of both the readoption of the Low Carbon Fuel Standard (LCFS) and the adoption of the Alternative Diesel Fuel (ADF) regulation. CBA is California's not-for-profit biodiesel industry trade association, representing over 50 businesses and stakeholders, including all of the state's biodiesel producers. CBA strives to increase awareness about biodiesel as California's leading and widely available advanced biofuel that delivers significant economic, environmental, and energy diversity benefits throughout the state.

We submit these comments as part of a unified statement from the biodiesel industry, and specifically support the comments of the National Biodiesel Board (NBB) on both program areas, including the technical issues related to ARB's updating of the carbon intensities for biofuels.

First, we wish to thank your California Air Resources Board (ARB) staff for their diligent and inclusive process of seeking and incorporating public comments and specifically for working with our industry over many years as we have endeavored to assure accuracy for biodiesel pathways under LCFS and to finally achieve full legal acceptance for biodiesel. We very much appreciate staff's extraordinary investment of resources and expertise in implementing state law, including California's notable progress in reaching its goals under AB 32, while working to provide the critically needed stable regulatory environment required by the investor community.

In our previous comments on the LCFS, CBA has supported key ARB proposals, including for the Compliance Curve and the Price Cap, and have weighed in on the details of the abundant supply of biodiesel available to help reach program targets. Our industry is happy to have generated a steadily increasing percentage of LCFS credits, up to 13% in Q3 2014. We value our ability to make this contribution to the success of LCFS as the world looks to California for solutions to the dire realities of climate change.

LCFS 34-1

530 Divisadero St., #119, San Francisco, CA 94117
www.californiabiodieselalliance.org

CALIFORNIA BIODIESEL ALLIANCE

34_OP_ADF _CBA

In urging your adoption of the ADF regulation, we wish to express our appreciation for the framework that allows biodiesel to move forward with some time to develop a new NOx mitigation additive and for the exemptions for light and medium duty fleets and for those with 90% NTDEs. We support the 2019 review that will provide for data on actual vehicle miles traveled as fleets turnover to the use of NTDEs. CBA looks forward to continued discussions with ARB staff on ways to address the concerns of some of our member companies, as expressed in their written comments, and to the adoption of the best possible final ADF regulation. ADF 34-1

We appreciated Richard Corey's recent reference to the state's reliance on biodiesel for "future reductions of toxic diesel particulate matter" in his presentation at the California Biodiesel Conference on February 4th in Sacramento. Our industry will continue to bring that and other of biodiesel's many benefits to California, especially to communities that are economically disadvantaged and suffer disproportionately from diesel emissions-related diseases.

Thank you again for your leadership. We applaud your success and look forward to working with you going forward.

Sincerely,

Curtis Wright
Chairman
California Biodiesel Alliance

Cc: California Air Resources Board

530 Divisadero St., #119, San Francisco, CA 94117
www.californiabiodieselalliance.org

34_OP_LCFS_CBA Responses

151. Comment: **LCFS 34-1**

The comment supports the compliance curve and cost containment provisions of the LCFS regulation.

Agency Response: ARB staff appreciates support for the compliance curve and cost containment provisions.

This page intentionally left blank.

Comment letter code: 35-OP-LCFS-AAUSA

Commenter: Kelly Stone

Affiliation: ActionAid USA

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

35_OP_LCFS
_AAUSA

California Environmental Protection Agency
Air Resources Board

Comment Log Display

BELOW IS THE COMMENT YOU SELECTED TO DISPLAY.
COMMENT 35 FOR LOW CARBON FUEL STANDARD 2015 (LCFS2015) - 45 DAY.

First Name: Kelly
Last Name: Stone
Email Address: Kelly.Stone@actionaid.org
Phone Number:
Affiliation: ActionAid USA

Subject: Global Impacts of Rising Biofuel Mandates on Food Security
Comment:
Via Electronic Mail

February 17, 2015

Mary Nichols and Board Members
California Air Resources Board
1001 "I" Street
P.O. Box 2815
Sacramento, CA 95812

Re: Low Carbon Fuel Standard

Dear Chairman Nichols and CARB Board Members:
ActionAid USA, a nonprofit organization working with millions of people around the world and the US to fight the causes of poverty and injustice, applauds the California Air Resources Board's (CARB) proactive approach to climate change mitigation. However, as the Board considers re-adoption of the Low Carbon Fuel Standard (LCFS), we strongly urge it not to lower the indirect land use change (ILUC) score for corn ethanol. Summary

Attached you will find a working paper by Timothy A. Wise and Emily Cole of the Global Development and Environment Institute at Tufts University, "Mandating Food Insecurity: The Global Impacts of Rising Biofuel Mandates and Targets." This paper studies the impact of government biofuel mandates and estimates that mandates will drive a 43% growth in demand for biofuels over the next decade. This level of growth has extremely concerning implications for food security, as well as land and water use. Further incentivizing the use of corn ethanol, which undermines food security and has questionable environmental benefits, would be step in the wrong direction. LCFS 35-1

Crop-based biofuels, particularly corn ethanol, undermine food security around the world by driving up food prices and increasing price volatility.
This not only true for corn products people consume directly; corn is one of the most popular feeds for animals, so an increase in the LCFS 35-2

price of corn also increases the price of meat and dairy products. A 2012 study published by ActionAid estimated that US ethanol expansion cost net corn importing countries $11.6 billion between 2006 and 2011. $6.8 billion of this additional cost was born by developing countries. In fact, during fiscal year 2011, the U.S. spent as much on food aid to Guatemala as the additional money Guatemala paid to import corn at the increased prices.

LCFS 35-2 cont.

Corn ethanol also presents environmental concerns.
In addition to the emissions from direct and indirect land use change, corn ethanol undermines water quality. The nitrogen, phosphorous and other chemicals applied to corn crops are washed from those crops into drainage, local water supplies, rivers and eventually oceans. This poisons the water, and in the case of nitrogen, creates algae blooms that reduce the oxygen levels in the water. The resulting dead zones kill fish and aquatic life or force them to move elsewhere. In 2014, the dead zone in the Gulf of Mexico was 5,052 square miles. The impact of biofuel expansion on water quantity should not be ignored. Corn uses more irrigated water than any other crop in the US, even though the overwhelming majority of corn is currently rain-fed. In recent years, irrigated corn crops increased with the growth in corn production. Perhaps not surprisingly, 87% of irrigated corn crops are grown in areas already showing extremely high water stress. Considering the water demands of growing corn and the strain current corn production is placing on water levels, policy makers should be cautious about policies that encourage further demand.

LCFS 35-3

One other lesson to take from "Mandating Food Insecurity," is that government policies continue to profoundly shape the biofuels industry. Government mandates have and will continue to drive demand growth for first-generation biofuels, such as corn ethanol, that undermine food security and hurt the environment. I strongly urge the Board to ensure that the LCFS does not further incentivize corn ethanol expansion.

LCFS 35-4

Thank you for your consideration and please do not hesitate to contact us should you need additional information.
Sincerely,

Kelly Stone
Biofuels Policy Analyst
ActionAid USA
Kelly.Stone@actionaid.org

"Fueling the Food Crisis: The Cost to Developing Countries of US Corn Ethanol Expansion." ActionAid USA. October 2012.
http://water.epa.gov/type/watersheds/named/msbasin/zone.cfm

http://voices.nationalgeographic.com/2015/02/10/corn-remains-king-in-usda-irrigation-

Attachment: www.arb.ca.gov/lists/com-attach/37-lcfs2015-VjtQNwRrUmUFYgZy.pdf

Original File Name: Mandating Food Insecurity_The GLobal Impacts of Rising Biofuel Mandates and Targets.pdf

Date and Time Comment Was Submitted: 2015-02-17 15:04:28

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

GLOBAL DEVELOPMENT AND ENVIRONMENT INSTITUTE
WORKING PAPER NO. 15-01

Mandating Food Insecurity:

The Global Impacts of Rising Biofuel Mandates and Targets

Timothy A. Wise and Emily Cole
February 2015

Tufts University
Medford MA 02155, USA
http://ase.tufts.edu/gdae

Abstract

Expanding demand for biofuels, fed significantly by government policies mandating rising levels of consumption in transportation fuel, has been strongly implicated in food price increases and food price volatility most recently seen in 2008 and 2011-2012. First-generation biofuels, made from agricultural crops, divert food directly to fuel markets and divert land, water and other food-producing resources from their current or potential uses for production of feed for animals and food for human consumption. A key policy driver of biofuel consumption is government mandates to increase or maintain rates or levels of biofuel blends in transportation fuel, the U.S. Renewable Fuel Standard and the E.U. Renewable Energy Directive being the most prominent cases. In this paper we assess the spread of such mandates and targets, finding that at least 64 countries now have such policies. We estimate the consumption increases implied by full implementation of such mandates in the seven countries/regions with the highest biofuel consumption, suggesting a 43% increase in first-generation biofuel consumption in 2025 over current levels. We compare this to even higher estimates from international agencies. We assess the likelihood of implementation in key countries and regions, which suggests that with reform, particularly in OECD countries, consumption growth could be slowed. We conclude with policy recommendations to reduce the mandate-driven expansion of first-generation biofuels and mitigate their negative social and environmental impacts.

Keywords: biofuels, agriculture, food policy, hunger, land use.

Mandating Food Insecurity:
The Global Impacts of Rising Biofuel Mandates and Targets

Timothy A. Wise and Emily Cole*

Executive Summary

Expanding demand for biofuels, fed significantly by government policies mandating rising levels of consumption in transportation fuel, has been strongly implicated in food price increases and food price volatility most recently seen in 2008 and 2011-2012. First-generation biofuels, made from agricultural crops, divert food directly to fuel markets and divert land, water and other food-producing resources from their current or potential uses for production of feed for animals and food for human consumption.

A wide range of international bodies, including the World Bank, the United Nation's Committee on World Food Security, and a landmark report prepared by G20 countries, has called for reforms to government policies that encourage the continued expansion of first-generation biofuel production. Unlike second-generation biofuels, which are less likely to compete with food crops for land and other resources, first-generation biofuels such as corn ethanol, soy and palm biodiesel, and sugarcane ethanol dominate the current global biofuels market.

In this paper, we document the global spread of the most widespread government support policies for biofuels: consumption mandates, with a particular focus on first-generation biofuels. These policies generally mandate the incorporation over time of a rising share or volume of biofuel into a country's transportation fuel. The U.S. Renewable Fuel Standard (RFS) is one such example, as is the European Union's (EU) Renewable Energy Directive (RED). Sixty-four countries now have biofuel mandates that reflect a wide range of ambition but that all encourage the use and usually the expansion of biofuel use.[1]

We show the current national and regional mandates (focusing on first-generation biofuels mandates) in place at this writing, assess the extent of their implementation based on available data, and estimate to the extent possible the implications of likely implementation. Using a range of projections from international agencies for comparison, we gauge the extent to which current mandates will expand future levels of biofuel consumption and production by 2025.

We find that the projected expansion of biofuels, and the resulting demands on food, land, and water, is indeed worrisome. Today we live in a world where two[2] to three[3] percent of transportation fuel is accounted for by biofuels (depending on the source one uses). Biofuels in the largest biofuel-producing countries, such as the United States and Brazil, comprise approximately 9% and 22% of gasoline and diesel blends consumed in each country, respectively, while most other countries' fuel supplies contain smaller percentages of ethanol and biodiesel.

* Timothy A. Wise is the Director of Policy Research and Emily Cole is a Researcher with the Global Development and Environment Institute at Tufts University. They would like to thank Sheila Karpf for her invaluable editorial assistance. The paper benefited from review by several experts, who remain nameless here. All errors are, of course, the responsibility of the authors.

The most commonly cited scenario from the International Energy Agency (IEA) projects a 150% increase in first-generation biofuel use by 2035. The agency estimates that 8% of transportation fuel (by volume) would come from biofuels,[4] with four-fifths of this expected to come from first-generation sources and just one-fifth from the assumed development of cellulosic ethanol and other second-generation biofuels produced from feedstocks that result in less competition for food and land.[5] IEA thus estimates that roughly 6% of transportation fuel would come from first-generation biofuels in 2035.[6]

Other international agencies estimate lower rates of expansion, and those are more consistent with our estimates based on current mandates and targets. The Organization for Economic Cooperation and Development and the UN Food and Agriculture Organization (OECD/FAO), for example, suggest a 50-60% increase in ethanol and biodiesel consumption over the next ten years.[7]

According to our estimates of global mandates for seven major biofuel-consuming countries (the United States, EU, Brazil, Argentina, China, India, and Indonesia), first-generation biofuel consumption could be expected to grow 43% over its current levels if existing mandates are fully implemented. This means the world would be blending 3-5% of first-generation biofuels into domestic fuel supplies by 2025.

These estimates are indeed worrisome, though they fall well short of the IEA estimates of a world with 8% of transportation fuel being derived from biofuels. This should bring little comfort to those concerned with the food, feed, land, and water demands of continued first-generation biofuel development. A 43% increase over current levels would likely require 13-17 million hectares more land than we are currently already devoting to biofuel production and approximately 145 billion more liters of water (assuming biofuels production requires roughly the same amount as current U.S. corn ethanol production).[8] A more detailed quantitative assessment of these impacts is much-needed to evaluate the specific impacts in different regions and countries under different scenarios.

What's more, the policies (and data) remain uncertain in several large developing countries, most notably China and India. We have good reason to believe that both will experience relatively limited expansion of first-generation biofuel use, but any large-scale commitment to first-generation biofuel development in these countries would have a dramatic and devastating impact, whether the feedstocks or fuel are sourced domestically or imported.

In addition, we find:

Mandates Are Key Drivers

- The number of countries with consumption mandates has risen to 64 and is continuing to grow.
- OECD mandates will continue to be the real drivers of biofuels demand, with the United States and the European Union projected to account for roughly 60% of global biofuel consumption in 2025, and nearly 50% of projected new biofuel consumption.
- Most mandates are based on percentage shares of consumption, rather than volumes as in the United States. The mere growth in demand for transportation fuels, due to economic growth

and the rise in the prevalence of private automobiles, particularly in large, fast-growing developing countries, can be expected to account for a 16% rise in biofuel consumption over current levels.
- An oversupply of palm oil production in supplier countries like Indonesia, partially caused by EU mandates, has contributed to more ambitious consumption mandates in Indonesia.[9] Indonesia shows the most ambitious targets and the most dramatic growth in first-generation biofuel consumption among developing countries, contributing to an already-serious deforestation problem.
- Full implementation of mandates is by no means certain. In India, for example, ethanol targets were recently scaled back from 20% to 5% because the country has lagged in sugar production to provide the necessary feedstock. India is now blending only about 2% ethanol into its transportation fuel supply. India also has a 20% biodiesel target, but there is good reason to doubt it will meet such a goal.[10]

Trade is a Major Driver
- Brazil is a major producer and consumer. Economic growth will drive rises in domestic consumption, but ethanol exports are also expected to increase depending on market and trade conditions. The United States is also seeking to expand its ethanol exports.
- Mandates are driving growing ethanol trade, in perverse ways. Brazilian sugar ethanol is imported by the United States to fulfill its mandates for advanced biofuels, while the United States has sometimes exported corn ethanol to Brazil to make up for losses to the Brazilian domestic market.
- Prior to Dec. 2011 when the U.S. ethanol tax credit and tariff were eliminated, Caribbean Basin Initiative (CBI) countries received preferential treatment in the U.S. ethanol market. The Central American Free Trade Agreement allowed Brazilian ethanol to be dehydrated in CBI countries and then exported to the United States.[11]

Significant Technological and Policy Uncertainty
- China is the biggest wild card in these projections. With a mandate that covers just nine provinces now, China is blending only 1.1% biofuel into its transportation fuels, and that is not expected to grow appreciably. The government has been sensitive to the food-fuel competition in its policies to date, but the country’s demand for transportation fuel is projected to grow dramatically, creating strong incentives for the government to promote consumption. Any expansion of China’s biofuel consumption would have global repercussions, particularly if China relies on imported feedstock or fuel to meet such mandates.
- The emergence of potentially more sustainable non-food-based, second-generation biofuels and implementation of sustainability standards could alter these estimates considerably if the technology and commercial applications proceed more quickly than currently projected. Public research and incentives for second-generation biofuels may help jumpstart the industry beyond its current small scale, but much is still unknown.
- Second-generation biofuels could be no better than first-generation fuels if they displace land or other resources from other productive uses.

Recommendations

Our analysis suggests the need for governments to cease the implementation and expansion of current food-based biofuels consumption mandates and to forgo the creation of new mandates. Mandates prop up demand for biofuels, particularly at times when oil prices are relatively low. Governments and international bodies should also eliminate perverse incentives such as biofuels subsidies for first-generation biofuels that impact the food supply.

Proposed reforms to U.S. and EU mandates are welcome and needed. The EU proposal to limit first-generation biofuels to 7%, within the EU's 10% mandate, would reduce the EU's contribution to global biofuel expansion by 50%.

The United States would do well to consider similar reforms. The United States is expected to remain by far the largest global consumer of first-generation biofuels in 2025, contribute the most to global consumption, and do so using the feedstock – corn – that provides the fewest environmental benefits and most directly competes with food and feed markets. Even a modest reform, such as that proposed by the Environmental Protection Agency in 2013 to scale back the mandate, would reduce projected consumption growth in 2022 by one-third.

Mandates must be scaled back further, and strict sustainability criteria must be applied to mandates for both first and second-generation biofuels. Otherwise, governments are mandating not just biofuel consumption but hunger and unsustainable resource use.

The full paper is available at:
http://www.ase.tufts.edu/gdae/policy_research/BiofuelMandates.html

I. Introduction

Expanded demand for biofuels, fed significantly by government policies mandating rising levels of consumption in transportation fuel, has been strongly implicated in the recent rise and volatility in global food and feed prices.[12] First-generation biofuels, made from agricultural crops, divert food directly to fuel markets and divert land, water and other food-producing resources from their current or potential uses for production of feed for animals and food for human consumption. First-generation biofuels produced from input-intensive and food-based crops have been tied to food and feed price increases, increased greenhouse gas (GHG) emissions for certain fuels, land rights disputes in developing countries, conversion of native grasslands and wetlands to biofuels crops, and other unintended consequences.[13]

Unlike some second-generation biofuels, which are less likely to compete with food crops for land and other resources, first-generation biofuels such as corn ethanol, soy and palm biodiesel, and sugarcane ethanol dominate the current global biofuels market. When the biofuels industry was in its infancy, its proponents promised that second-generation biofuels would come on line in a few years and food versus fuel concerns would wane as perennial grasses, agricultural residues (such as corn stalks or cobs), and wood residues would be used for cellulosic ethanol production.[14] However, cellulosic ethanol production is failing to reach large-scale commercial production, and hence, biofuels produced around the world are failing to meet high levels of GHG emissions reductions that were once promised. New estimates suggest, for instance, that corn ethanol production in the United States may actually contribute to greater carbon emissions than gasoline.[15]

The biofuels industry seeks additional expansion of both first- and second-generation biofuels production. Agribusinesses and biofuels lobbying organizations have pushed for biofuels expansion in countries that currently have large biofuels mandates – most notably Brazil, the European Union (EU), and the United States – and in others where biofuels mandates have yet to be filled or greatly scaled up such as in India and China.[16]

In this paper, we document the global spread of the most widespread government support policies for biofuels, consumption mandates. Sixty-four countries now have biofuel mandates that reflect a wide range of ambition but that all encourage the use and usually the expansion of biofuels.[17] These generally mandate the incorporation over time of a rising share or volume of biofuel into a country's transportation fuel.

The three largest mandates include the U.S. RFS, Brazil's ethanol and biodiesel mandates, and the EU's RED. U.S. demand for ethanol has expanded drastically since 2007, partially a result of subsidies and the RFS mandate but also its use as an oxygenate additive as a replacement for lead. The mandate rose from 11BL a decade ago to nearly 53BL today. Brazil, a country with the oldest global ethanol mandate of 25% ethanol (E25), consumed 24BL of ethanol in 2014.[18] Responding to recent concerns about food vs. fuel, the EU proposed a cap on the amount of biofuels that can be derived from food crops at 7%, out of its 10% biofuels mandate, by 2020. The EU currently consumes about 19BL of biofuels, and most member states will expand consumption further to meet both the 7% proposed food-based biofuels cap and the 10% overall mandate.

We show these and other national and regional mandates in place at this writing, assess the extent of their implementation and likelihood of fulfillment based on available data, and estimate to the extent possible the implications of implementation on global land availability and water use. Using a range of projections from international agencies for comparison, we gauge the extent to which current mandates will expand future levels of biofuel consumption and production by 2025.

Today we live in a world where two[19] to three[20] percent of transportation fuel (depending on the source one uses) is comprised of biofuels. Biofuels in the largest biofuel-producing countries, such as the United States and Brazil, comprise approximately 9% and 22% of gasoline and diesel blends consumed in each country, respectively, while most other countries' fuel supplies contain a smaller percentage of ethanol and biodiesel.

The most widely cited scenario from the International Energy Agency (IEA) suggests a 150% increase in first-generation biofuel use by 2035, with 80% derived from non-cellulosic fuel.[21] This demand increase would mean that the world's transportation fuel supply would be comprised of 8% biofuels in 2035, with 6% from first-generation biofuels.[22]

Other international agencies estimate lower rates of expansion, which are in line with our estimates of demand growth. The Organization for Economic Cooperation and Development and the United Nation's (UN) Food and Agriculture Organization (OECD/FAO), for example, suggest a 50-60% increase in ethanol and biodiesel consumption over the next ten years.[23] Considering current levels of implementation of existing mandates and projections from these and other institutions, it is clear, even with the most conservative estimates, that first-generation biofuels production and consumption will grow significantly over the next one to two decades with significant implications for the environment, food prices, and the livelihoods of people around the world.

II. Background

Biofuels include all fuels made from organic matter. In this paper, we focus on biofuels that can be used for transport, specifically ethanol and biodiesel, and more specifically so-called first-generation biofuels, which are made from food or feed crops. While many of the concerns presented in this paper are equally true of biomass used for electricity production, biomass has not been explicitly included in our estimates and analysis.

A biofuels feedstock is the organic material that is used to make the ethanol or biodiesel. Different countries produce and consume biofuels from different feedstocks with different environmental and social impacts. The principal feedstock in the United States is corn for ethanol. In the EU it is biodiesel made from vegetable oils such as palm oil. Brazil relies on sugar for ethanol. While every feedstock may have an appropriate use, at high volumes they all can have unintended consequences, especially those that are in limited supply. For example, used cooking oil is a feedstock for European biodiesel, which would otherwise go to waste. But heavy demand for used cooking oil is increasing demand for virgin cooking oil such as from African palm, in effect feeding a competition between fuel and food.

Biofuels: Defining Terms

The terms "first- and second-generation biofuels," "conventional ethanol," "advanced biofuels," and "cellulosic ethanol" are used throughout this paper. Below is a definition of each as it is used here:

First-generation biofuels: ethanol and biodiesel produced from crops such as corn and sugarcane (for ethanol) and palm oil, soybean oil, rapeseed oil, used cooking oil, and other vegetable oils (for biodiesel), which are largely also used as food and feed crops. These biofuels have been produced for decades, especially in the case of Brazil with sugarcane ethanol and the United States with corn ethanol.

Second-generation biofuels: ethanol or biodiesel produced from largely non-food feedstocks such as perennial grasses, wood and agricultural residues, algae, etc. While these could potentially result in less competition with the food supply, second-generation biofuels have yet to be produced at large commercial scales so their effects on land use, water supplies, food security, and GHG emissions are still little known.

U.S. Renewable Fuel Standard categories: The U.S. RFS, enacted in 2005 but expanded in 2007, mandates that the U.S. fuel supply contain 138 billion liters (BL) of biofuels from three different biofuels categories by 2022. Note that these categories differ from those of first- and second-generation biofuels listed above, meaning that even though our analysis focuses on first-generation biofuels, the United States considers some first-generation biofuels such as sugarcane ethanol to qualify as an "advanced" biofuel. Terms used in the U.S. case include the following:

- **Conventional ethanol:** the "renewable fuel/conventional ethanol" category in the RFS requires ethanol to meet a 20% GHG reduction threshold although most facilities were grandfathered into this category, meaning they may actually *increase* GHG emissions; conventional ethanol is mostly comprised of corn ethanol.
- **Advanced biofuels:** biofuels that meet a 50% GHG reduction threshold; types of approved advanced biofuels include soy biodiesel, biodiesel from other vegetable oils and animal fats, cellulosic ethanol (see below), and sugarcane ethanol.
- **Cellulosic ethanol:** cellulosic biofuels that meet a 60% GHG reduction threshold and are derived from cellulosic feedstocks such as perennial grasses and wood or agricultural residues.

In 2011, the global biofuels market was worth $83 billion—roughly the size of the world coffee market.[24] The global biofuels market tripled between 2000 and 2007.[25] More recently, between 2009 and 2011 the market doubled again.[26] Today 2-3% of global transportation fuel is from biofuels.[27] A global commodity, biofuels is heavily traded across the globe with some countries both exporting and importing biofuels.

Social and Environmental Costs

Sizeable percentages of food crops are diverted to biofuels production now and will continue to be diverted in the future, with implications for food security. According to FAO-OECD projections, by 2023, 12% of maize and other coarse grains will go to biofuel production, while 14% of global vegetable oils will be used to produce biodiesel; for sugar, 28% will go into the production of transportation fuels.[28] During the recent 2008 food price crisis, 20-40% of the food price increases were attributed to biofuels.[29]

An October 2012 GDAE/ActionAid report found that corn-importing countries paid $11.6 billion in higher corn prices due to U.S. ethanol expansion from 2006 until 2011, $6.6 billion of which was borne by developing nations where much of the population already spends 60-80% of their income on food.[30] A May 2012 GDAE/ActionAid report estimated additional import costs to Mexico in particular, in the form of higher corn prices due to U.S. ethanol expansion, of at least $1.5 billion since 2004. Increased corn prices reduce purchasing power for consumers and can offset international aid dollars sent to developing countries for food and agricultural programs.[31]

Many international agencies have called for reforms to government policies that encourage the continued expansion of first-generation biofuel production. In 2008, the former head of the World Bank, Robert Zoellick, called on countries to reform biofuels mandates due to negative impacts on food security.[32] In 2011, a report commissioned by G20 agricultural ministers, recommended that countries "remove provisions of current national policies that subsidize (or mandate) biofuels production or consumption," acknowledging that biofuels production was a significant factor in increased food prices and food price volatility.[33] And in 2013, the UN Committee on World Food Security's (CFS) High Level Panel of Experts report on biofuels noted that "biofuels and more generally bioenergy compete for land and water with food production"; it recommended an additional set of guidelines be created to evaluate the viability of national biofuels policies based on the impact of said policies on access to land and on international food security.[34]

The environmental benefits of biofuels have also been called into question. Land used to grow biofuels crops is often converted from non-food uses, such as forests, adding to the environmental issues associated with deforestation. In Indonesia, for example, overall forest losses (due partly to palm oil expansion) have been projected as high as 6 million hectares from 2000 to 2012.[35] A recent study from the journal *Nature Climate Change*, estimated that by 2012 Indonesia was losing primary forests at a rate of 840,000 hectares per year, higher than losses in Brazil. (The Indonesian government, however, has reported significantly lower rates of deforestation to the UN – approximately 400,000 hectares annually between 2009 and 2011.)[36] As the World Resources Institute notes, "although the evidence of destruction is mounting, the picture has been muddied by conflicting data, disinformation, claim and counterclaim."[37] The Rainforest Action Network reports that Indonesia is the "third largest emitter of global warming emissions after China and the United States, with 85% of its emissions profile coming from deforestation and drainage of peatlands [of which palm oil is a major driver]."[38]

Two of the original goals for biofuel development in the EU and United States in particular were to increase energy independence and to reduce GHG emissions in the transportation sector. The case for each has gotten weaker over time. As one IEA study puts it, "It is increasingly understood that 1st–generation biofuels (produced primarily from food crops such as grains, sugar beet and oil seeds) are limited in their ability to achieve targets for oil-product substitution, climate change mitigation, and economic growth."[39] In 2011, the National Academies of Science concluded that first-generation biofuels such as corn ethanol are failing to significantly reduce GHG emissions in part due to indirect land use change, and that cellulosic ethanol production in the United States is unlikely to reach a large commercial scale due to technological and economic challenges.[40]

Other first-generation biofuels may result in GHG emission reductions, but figures vary primarily due to different calculations of emissions from indirect land use change. For instance, when corn in the United States is diverted from the feed supply to biofuel production, for instance, additional feed crops must be produced elsewhere which can lead to farmers tearing up native grassland and draining wetlands to create more arable farmland. Cropland dedicated to other food and feed crops (oats, barley, alfalfa, etc.) has decreased in countries such as the United States, Guatemala, and Brazil as demand for corn, sugar, and soybean cropland rose over the past several years.[41]

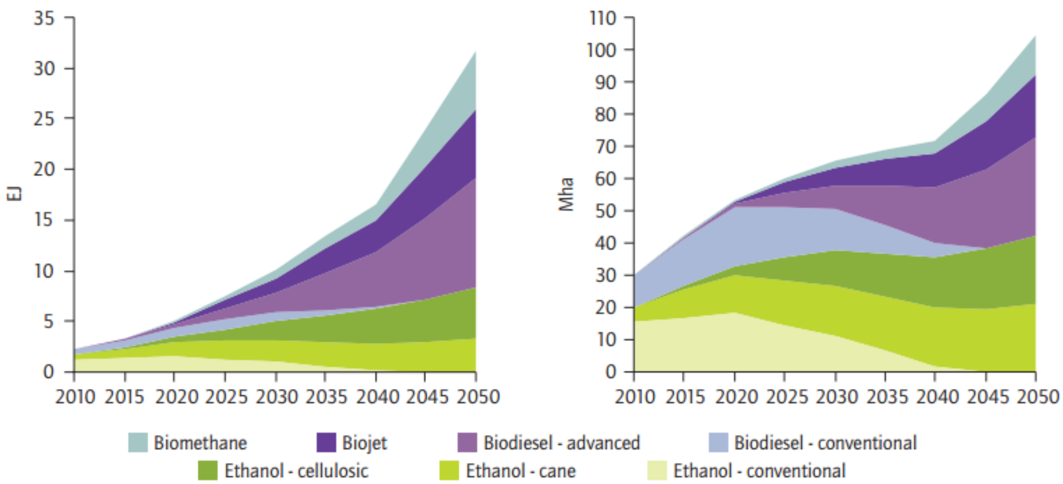
Cellulosic biofuels, a specific type of second generation biofuel, may offer significant GHG benefits and could have more limited impact on land use. Cellulosic biofuels are also expected to lead to fewer food-versus-fuel impacts associated with first-generation biofuels. However, some next-generation biofuels recently proposed in the United States, such as corn biobutanol, would still be produced from food-based crops. Second-generation technologies are under development, and they are not expected to be commercially viable in a significant way by 2025.[42]

Even organizations that are bullish on the use of biofuels, such as the IEA, recognize the land demands for their future biofuels scenarios. Each exajoule (EJ, 10^{18} joules, a unit of energy used at the industrial production level) of energy created requires about 10 million hectares of land. (See Figure 1)[43] It is worth noting that the land-intensity estimates even for second-generation biofuels remains significant (about 3 million ha/EJ), raising questions about their sustainability.

Estimates vary, but according to the FAO, an estimated 2-3% of arable land is devoted to biofuels production.[44] FAO estimates "an equivalent of 20.4 million [hectares (ha)] of sugar cane, or 38.5 million ha of corn, or, if it were biodiesel, 58.8 million ha of rapeseed" are now used in biofuels production worldwide.[45] In the developed world and emerging economies, the energy and land use investments in biofuels vary dramatically. For example, in the United States, 37% of the corn crop is diverted to ethanol production (but one-third of this corn ends up as livestock feed via a by-product called distiller's grain).[46] In the UK in 2011, 1.8% of all farmland was dedicated to growing crops for ethanol,[47] but it also relied upon imported biofuels and biofuel feedstocks from other countries to meet its mandate.

Figure 1[48]

Figure 11: Demand for biofuels (left) and resulting land demand (right) in this roadmap



Note: This is gross land demand excluding land-use reduction potential of biofuel co-products. This assumes 50% of advanced biofuels and biomethane are produced from wastes and residues, requiring 1 Gt of residue biomass. If more residues were used, land demand could be reduced significantly.

Source: IEA analysis based on IEA, 2010c and Table 2 below.

In developed countries and in emerging economies, biofuels production may cause relatively little social disruption, environmental and land use implications aside. In the developing world, however, the demands of biofuels production are much more likely to disrupt the local population and economy.[49] In some countries, such as India and Thailand, there is already great pressure on cropland. Expanding biofuels production in these countries, from any feedstock, would have additional impacts on land use. Countries such as Brazil have systems in place to reduce direct and indirect land use change.[50] However, these systems have not necessarily been effective since soybeans have instead been planted in areas with restrictions on new sugar plantations.

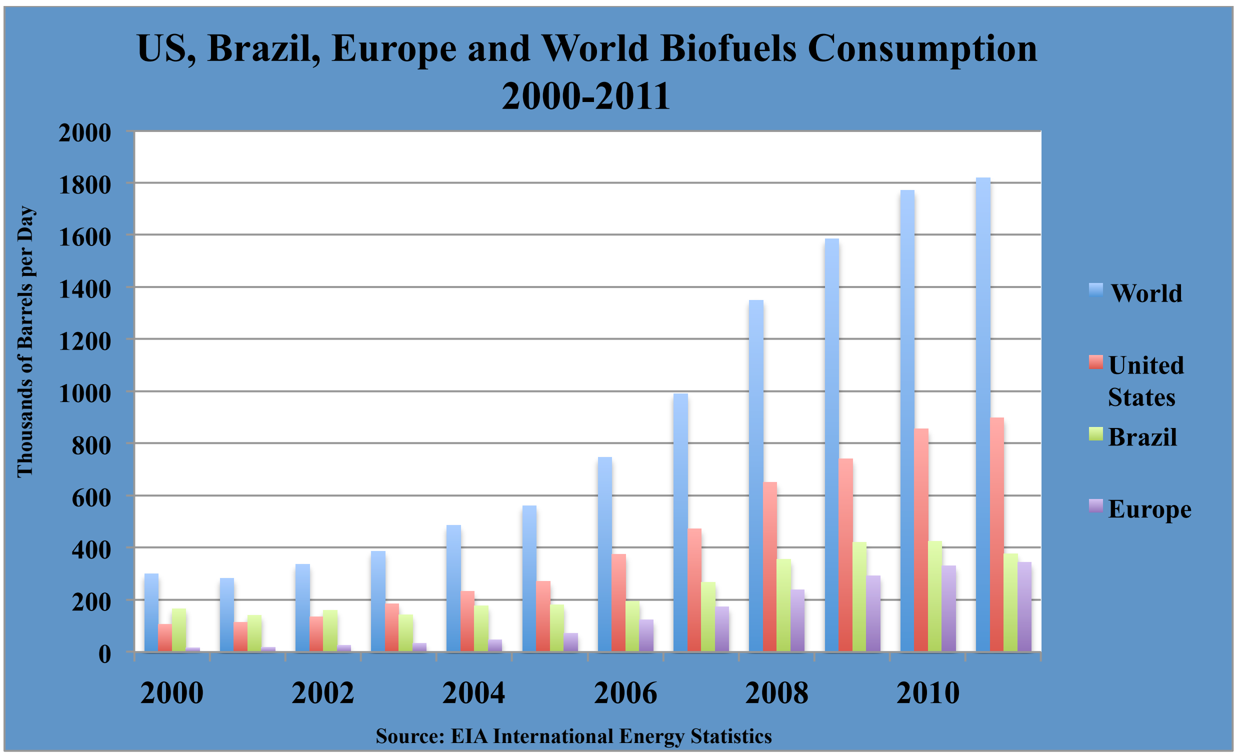
In other countries such as Ethiopia where there are already large-scale land acquisitions and significant displacements of people due to foreign investments in land projects and "villagization," large-scale biofuels projects are yet another threat to rural communities' livelihoods, food security, and human rights. (See Appendix C for list of existing and planned biofuels projects in Ethiopia). In other African countries such as Tanzania, the land rush for biofuels and other agricultural production has resulted in vast tracts of land being sold or leased to commercial interests, many of which are large multinational biofuels companies or agribusinesses aiming to export biofuels to the EU and other countries with large biofuels mandates. Local communities lose land previously used for farming, animal grazing, fishing and gathering wild foods, as well as for wood and water collection, when land deals prioritize investors and outside interests over local livelihoods.

Key Players

While 64 countries have biofuels mandates or targets, global production and consumption of biofuels is driven principally by a few countries. The United States is responsible for 43% of global production of biofuels.[51] Brazil, the second largest producer, provides 26% of global production.[52] Germany (4.9%), France (3.9%), and Spain (2%) round out the top five biofuel producers.[53]

OECD countries are the largest consumers of biofuels and drive biofuels production within their own borders and across the world.[54] As Figure 2 shows, biofuels consumption has increased dramatically since 2000. By 2011, world use had increased 500% with the largest increases coming in the United States.

Figure 2[55]



Focus on Mandates

While subsidies have also played a large part in the development of biofuels industries, the primary focus of this paper is biofuels mandates, as they are the primary government support across countries. Mandates provide security for investors knowing a market for their goods will continue over their investment period, and they drive the development of fuel distribution networks, such as the blending of ethanol into gasoline and its storage and dispensing at fueling stations.

Mandates can take one of two forms. The first, a consumption mandate, requires a certain volume of biofuels to be blended with gasoline and diesel each year. This is the type of mandate that exists in the U.S. RFS.[56] The more common form of mandate requires that a certain percentage of transport fuel consist of ethanol or biodiesel. This is the form of mandate used in the EU[57] and most other countries.

Countries have pursued biofuels policies for many seemingly worthwhile goals:

- Promoting energy security
- Reducing dependence on fossil fuels
- Supporting rural communities, smallholder farmers and rural development
- Reducing GHG emissions and accessing a low-carbon transportation fuel (particularly the EU)
- Improving the nation's trade balance or balance of payments by reducing oil imports
- Promoting national self-sufficiency

In the OECD, these policies were mainly crafted in the early 2000s. In hindsight, mandates were overly optimistic with respect to technical, infrastructure, and market challenges. It is now apparent that biofuels mandates failed to predict future negative impacts on land use, GHG emissions, food security, and rural communities. GHG emissions reductions have been found to be more limited than first thought, indirect land use changes are now understood to be significant, and with high crop prices in 2011-2012 farmers and consumers alike have dealt with higher and more volatile crop and food prices. In the EU and United States in particular, these changes have led to recent proposed policy reforms and ongoing debate over the value of biofuels use.

In other countries, the motivating factors above remain strong. For some countries, such as South Korea, the world's fifth largest oil importer, the pressure to diversify its energy mix for security and economic reasons may outweigh the higher cost and social and environmental impacts of biofuels consumption.[58] Indonesia is a similar story.

Many developing countries have followed the OECD's lead in instituting biofuels mandates. These countries have pursued biofuels policies to show their commitment to fighting climate change and advancing energy security, but also to spur rural development, support the agricultural sector, and move up the agricultural value chain. In addition these policies provide subsidies for particular industries (sugar in India, for example). In Southeast Asia, Malaysia and Indonesia have recently increased domestic biofuels mandates to counteract deteriorating export opportunities as a result of anti-deforestation policies taken by buyers such as the EU. Utilizing more palm oil for biofuels increases demand for the feedstock, increases farm-gate prices, and reduces the amount of diesel that must be imported for consumers. Countries have looked to biofuels both to reduce their dependence on expensive foreign oil but also to create an export industry that could help provide a source of foreign exchange.

The notable exception to this typology is Brazil, the country with the oldest and most fully developed biofuels sector. In the 1970s, Brazil invested heavily in producing ethanol from sugar cane in response to high international oil prices, leading to its position as a leader in the biofuels market, particularly for ethanol.[59]

From biofuels producers to large landholders, every country producing biofuels has much at stake if biofuels mandates are reduced or eliminated, although some biofuels would still be blended (for use as an oxygenate, for instance). This is widely seen as one of the reasons biofuels policies have been so slow to respond to high crop prices and social and environmental concerns.

Government Supports for Biofuels

Major biofuel-producing countries – including Brazil and the United States - have relied on mandates and subsidies to build their biofuels industries. These incentives span the supply chain, from feedstock production to final blending of biofuels with gasoline or diesel. European biodiesel is also subsidized, and cost-competitive because of the significantly higher cost of gasoline in the EU. In France, the estimated cost of biofuels subsidies for 2011 only was between €170 million and €210 million for ethanol and almost three times that amount for biodiesel—between €612 million and €800 million.[60] But it is also the case that in other markets like Indonesia, the drain on national budgets from fossil fuel subsidies makes the mobilization of homegrown feedstocks – in this case, palm oil – a more attractive proposition. Fossil fuel subsidies themselves distort markets, and layering biofuels subsidies on top of them creates large national expenditures and several unintended consequences as certain fuels are prioritized over others.

As the IEA has noted about the rise of biofuels, "The rapid growth of the biofuels industry would not have been possible without government subsidies because many biofuel producers, especially in developed countries, are not cost competitive."[61] The story of biofuels expansion is, therefore, a story of subsidies and mandates. Using the United States as an example, its ethanol and biodiesel industries were propelled by decades of subsidies for production and blending with gasoline and diesel, import tariffs, and the RFS mandate which was enacted in 2005 but greatly expanded in 2007. While the largest tax credits for ethanol and biodiesel have expired, the biodiesel and cellulosic tax credits and other credits such as those for biofuel infrastructure investments are routinely extended, and other smaller supports in various government agency programs continue to prop up the industry.

III. International Biofuels Production and Consumption Estimates

Before presenting our assessment of current mandates and what they would mean for global biofuel demand, we present some of the most important projections from international organizations. They vary in their assumptions, methodologies, and time horizons, but all confirm that we are likely to see significant expansion in biofuel consumption for at least the next ten years. The estimates range from a low of 50-60% growth in demand by 2023, to a high of 150% by 2035. Below, we examine estimates from the International Energy Agency (IEA), the OECD/FAO's Agricultural Outlook, and the U.S. Energy Information Agency (EIA).

Each agency makes assumptions about the key drivers of biofuel demand, both in terms of government policies and market-based factors. All attempt to incorporate announced government policies, though it is difficult to keep up with the ever-changing policy environment. Any projections of 10-20 years into the future will be sensitive to assumed growth rates in key drivers, and such differences in assumptions explain the variation in these estimates.

Transportation fuel demand will be a primary driver of biofuels consumption, especially in fast-growing developing countries such as China and India, but also in areas with mandates for biofuels blending by percentage of transportation fuel. (The blending percentage can stay the same but the effective demand increases with the growth in the market unless fuel efficiency increases, thus reducing the level of fuel demand.) This consumption will be driven by:

- *Population Growth*: with economic growth and economic growth, population growth, especially in emerging markets, will be a key driver of transportation fuel demand.

- *Economic Growth (world, nation, per capita)*: as countries become more affluent, they drive more, demanding more transportation fuel.

- *Number of Miles Driven*: While the United States does not serve as a good model for the rest of the world, recent reductions in number of miles driven show the uncertainty in predicting future patterns of consumption.

- *Fuel Efficiency Standards and Vehicle Technological Change*: changes in transportation technology such as hybrid cars, electric cars, E15- and E85-ready cars and increased fuel efficiency standards will also affect demand. Radical, global change in fuel efficiency could temper demand growth. Consumer uptake of E15, E85, and other higher ethanol blends, stations offering higher blends of ethanol, and availability of flex fuel vehicles also affects consumption, particularly in the United States

- *Broader Energy Markets:* decisions made about broader transportation planning affect demand, including reliance on electrification, commitments to mass transit, and alternative forms of transport.

Other key drivers of biofuels demand include:

- *Oil Prices*: when deciding whether or not to substitute some petroleum consumption with biofuels, the relative prices of these goods is paramount. As petroleum prices are notoriously difficult to predict, oil prices in particular may pose a problem for complex modelers looking several years in the future. In addition, petroleum is an input for first generation biofuel feedstock that is grown with petroleum-based fertilizers. As an input, as oil prices increase, the price of biofuels may also rise. The effect on their relative prices will be a key biofuels demand driver, factoring in subsidies and mandates, which affect prices.

- *Food and Fiber Prices*: like oil prices, the prices of food and fiber will determine whether or not biofuels consumption is economically viable. First generation biofuels are not only competing with food and fiber for land, fertilizer and water, but are produced from food and feed products themselves.

- *GHG Emissions Pricing Schemes*: in the estimates cited here from the IEA, EIA and OECD/FAO, carbon markets and the assumption of a carbon savings from biofuels are key to their continued expansion.

- *Speed of Technological Change in Biofuels*: technological changes and commercial adoption of these technologies are built into IEA and other models projecting increased demand. For years, the biofuels industry promised cellulosic fuels would be commercially viable, but they have been slow to develop due to technological and economic challenges. In the U.S. 2007 energy bill, for instance, policymakers mandated 6.65BL of cellulosic ethanol to be blended with gasoline in 2014, but only 65 million liters (barely 1% of the mandate) are expected to be produced. Whether and how quickly such industries develop will determine a great deal about first-generation biofuel growth.

International Energy Agency Projections

The International Energy Agency (IEA) makes several energy consumption estimates in its *World Energy Outlook* each year. The estimates below are drawn from its 2013 report. The IEA uses three policy scenarios to make its projections.

1. *New Policies Scenario*: this is the most commonly cited set of global projected-demand numbers in research and policy circles. It models "cautious implementation of existing policies," meaning it accounts for policies that are currently in place and assumes the implementation of announced policies. [62] It is the scenario IEA believes reflects the most likely future.

2. *Current Policies Scenario*: this very conservative scenario considers only policies that were in place by mid-2013.

3. *450 Scenario*: the 450 Scenario considers "an energy pathway compatible with a 50% chance of limiting the long-term increase in average global temperature to 2 degrees Celsius."[63]

Biofuels consumption is assumed to increase based on economic and population growth, reductions in fossil fuels subsidies, and a modest increase in petroleum prices. In addition, all three scenarios assume a GHG benefit from biofuels use, although the importance given to GHG reductions as a demand parameter is different in each scenario. In these models, biofuels would have an added economic benefit in carbon trading schemes or with the enactment of a carbon tax making them significantly more price competitive with fossil fuels, although actual GHG emission reductions seen on the ground may differ from projections.

New Policies Scenario

The New Policies Scenario assumes an average rate of GDP growth of 3.6% per year until 2035.[64] It also assumes non-OECD GDP will surpass OECD GDP as early as next year,[65] with strong growth rates for China (5.7%)[66] and India (6.3%)[67] through 2035. Moreover, IEA assumes world population will reach 8.7 billion by 2035 and that 62% of the population will live in urban areas.[68] At the same time, this scenario assumes only modest increases in oil prices from \$110/barrel in 2011, \$113/barrel in 2020 and \$128/barrel in 2035.[69] More than 175 countries currently have fossil fuel subsidies, which the IEA sees declining in the next 20 years, making biofuels more economically competitive.[70] IEA also assumes that China will stick to its goal of reducing its dependence on coal and that India will meet its current 5% ethanol mandate and continue to blend 5% ethanol even as gasoline demand increases.

In line with industry and other academic and governmental predictions, IEA finds "the U.S., Brazil, EU and China make up more than 80% of biofuels demand."[71] By 2035, OECD countries will make up a little under half of biofuels consumption.[72] IEA predicts China will drive growth in biofuels until 2020 when consumption will be driven by India, whose population will be surpassing China and Southeast Asian countries.

The New Policies Scenario assumes an initial increase in energy demand of 1.6% per year, which slows after 2020 to an average of 1%.[73] In this scenario, therefore, there will be a 33% increase in total energy demand by 2035.[74] Energy demanded for "transport grows at an average rate of 1.3% per year over the projection period," with the majority of growth coming from non-OECD countries.[75]

Bioenergy investments are expected to outpace energy demand in aggregate and are thus expected to represent a larger share of total transport-sector demand by 2035. Specifically, IEA predicts a 1.5% annual increase in investments in bioenergy—both biofuels and biomass.[76] This growth is small compared to other renewables (7.3%),[77] but represents a dramatic and persistent increase in production. IEA expects biofuels production to account for only 5% of the increased investment in renewables.[78] However, projections on investment as opposed to production are highly speculative.

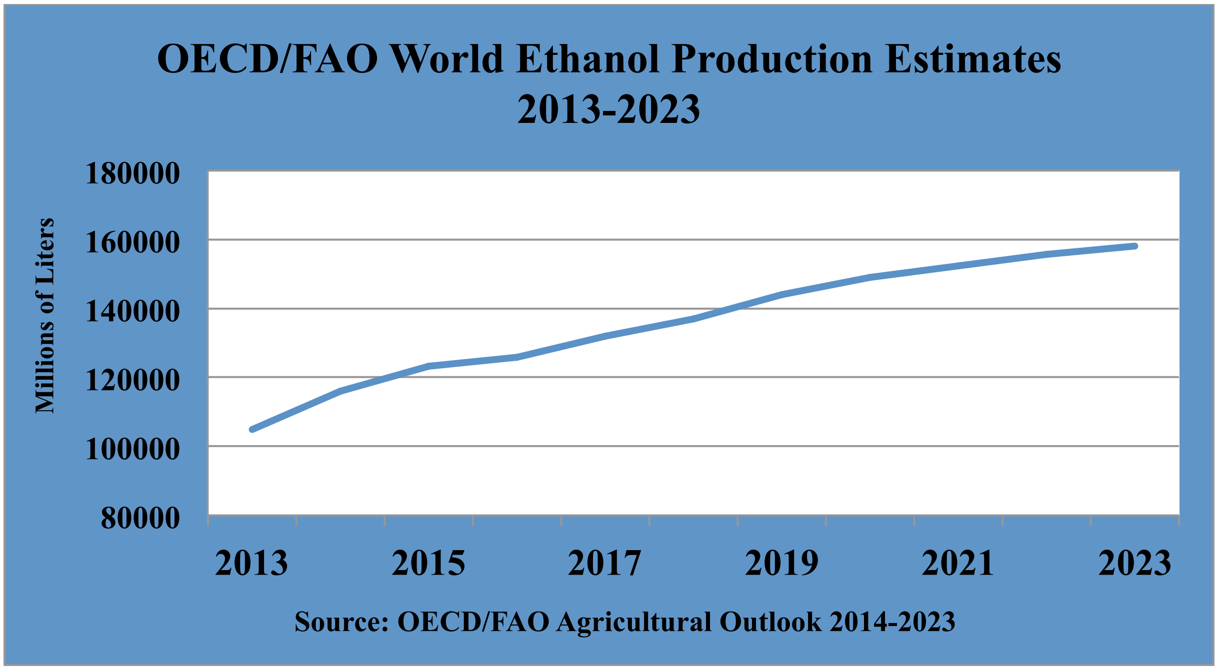
In terms of volumes, IEA predicts consumption of biofuels will increase from 1.3mboe/d in 2011 to 4.1mboe/d in 2035.[79] This aggressive projection predicts 8% of road-transport fuel demand in 2035 will come from biofuels.[80] Yet, they predict that*, even in 2035,* 80% of that fuel will still come from first-generation biofuels, with just 20% coming from cellulosic or other advanced fuels.[81] (Note that the IEA definition of "advanced" may not align with the RFS definition as IEA does not consider sugar ethanol to be advanced).

OECD/FAO Projections

The OECD, established in 1961 to "promote policies that will improve the economic and social well-being of people around the world," predicts an overall increase in global biofuels production but a smaller share in percentage terms represented by demand in OECD countries.[82] OECD countries include the world's richest and the top two biofuels producers in the world – the United States and EU – but also emerging countries like Mexico, Chile and Turkey. The OECD also works closely with emerging economies such as Brazil and those that may greatly influence biofuels markets in the future – China and India.[83]

The OECD, in its annual *Agricultural Outlook* report with the FAO, projects a 50% increase in world ethanol production between 2013 and 2023 with production jumping from 105BL to 158BL.[84] It also finds biodiesel consumption will rise from 26BL in 2013 to 40BL in 2023—a 54% increase over 2013 consumption.[85] The projected expansion in world ethanol production is shown below.

Figure 3[86]



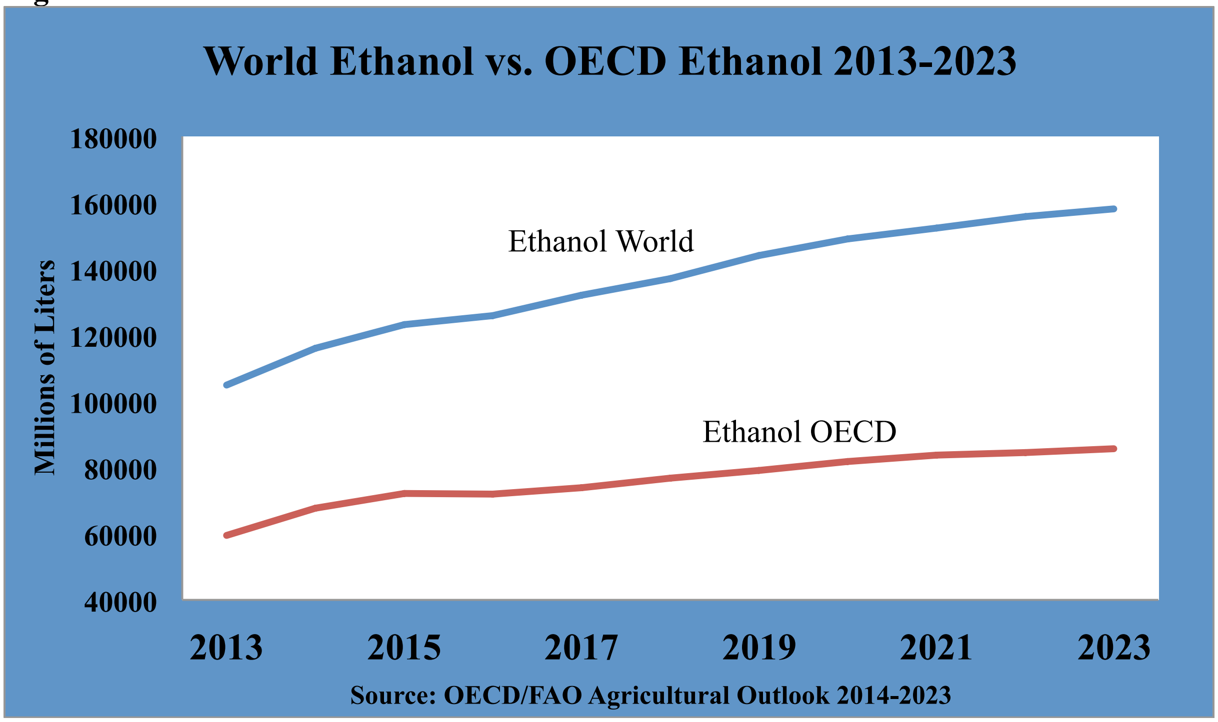
In addition, OECD/FAO predicts, "By 2023, 12%, 28% and 14% of world coarse grains, sugar cane, and vegetable oil production, respectively, are expected to be used to produce biofuels."[87]

While OECD countries dominate biofuels consumption today, the OECD/FAO report finds member states will play a less dominant role in the world biofuels market, as illustrated in the graph below. Brazil currently accounts for most consumption in Latin America, but it is Asia where OECD/FAO predicts biofuels will see the greatest growth, particularly in China and India.[88] Overall, OECD/FAO predicts that growth in ethanol production among developing countries from 45BL in 2013 to 71BL in 2023, will be mostly be driven by Brazil and its 25% ethanol mandate.[89]

OECD/FAO predicts U.S. ethanol use will be significantly restricted by the blend wall and will grow only marginally in terms of percentage consumption.[90] They assume only 12% of the U.S. cellulosic mandate will be implemented by 2023.[91] In addition, OECD/FAO considered political factors in its estimates, including the assumption that the biodiesel blender tax credit will not be renewed.[92] This political analysis is important in bringing predictions in line with political changes instead of assuming a continuation of current policy, although the biodiesel tax credit has typically been renewed.[93]

OECD/FAO's analysis of European demand assumes that current mandates will be fulfilled and carried forward at least through 2023. OECD/FAO finds further that the EU RED fulfillment percentage will be 8.5% accounting for allowable double-counting of GHG-reducing fuels (out of its mandate for 10% of transportation fuels coming from biofuels by 2020).[94]

Figure 4[95]



U.S. Energy Information Agency Projections

The U.S. Energy Information Administration (EIA) has arrived at very different projections from those of the OECD/FAO and IEA. EIA finds that world biofuels production will increase from 1.5 million barrels of oil equivalent per day (Mboe/d) in 2011 to 1.7Mboe/d in 2020, 2.7Mboe/d in 2035 and 3Mboe/d in 2040.[96] Similar to the other models, EIA sees OECD countries dominating production in the short term and non-OECD countries overtaking OECD output in the long term. The timeline for this change is much slower than the other models, however. In 2011 EIA has OECD countries producing 1.0Mboe/d and non-OECD countries producing only 0.5Mboe/d.[97] In this model, OECD and non-OECD countries do not produce equivalent amounts of biofuel (1.2Mboe/d) until 2030, and by 2040 non-OECD countries only lead OECD countries by 1.6Mboe/d to 1.3Mboe/d.[98]

Unlike the other two models, EIA does not see rapid growth in either China or India. While it predicts an annual percent change of 7.8% in India—a significant year over year increase—they find that India will not even produce 0.1Mboe/d by 2040.[99] EIA finds China will produce only 0.1Mboe/d by 2020, 0.3Mboe/d in 2035 and 0.4Mboe/d in 2040, but this growth still translates to a 300% growth rate from 2020 to 2040.[100]

IV. Country Mandates and Main Findings

Sixty-four countries now have biofuels mandates or targets.[101] The level of implementation varies dramatically among these countries, from fully implemented to just announced. Some countries have only begun to create a legal framework for biofuels blending (Mozambique), while others have been producing and consuming biofuels for decades (Brazil). While the background information underlying our analysis is static, our findings show a great deal of movement within biofuels targets and mandates with many countries recently readjusting their mandates or targets both up and down based on price and availability of ethanol and biodiesel in their markets as well as in response to other political, social, and economic objectives.

Mandates and targets range from a high of 25% ethanol blend in Brazil and Paraguay to a low of a 1% biodiesel mandate in Taiwan. The EU's RED has a 10% blending mandate by 2020, but if reforms are approved only 7% is expected to be derived from food-based feedstocks due to recent proposals in the EU to cap the use of crop-based biofuels. The United States has a volume-based mandate that is effectively 10% currently because only up to 10% ethanol can currently be blended into the existing vehicle fleet; the U.S. Environmental Protection Agency (EPA) has approved a 15% ethanol blend (E15) for newer vehicles, but consumers are unlikely to use E15 soon due to due to its incompatibility with older vehicles and small engines, in addition to engine warranty and liability concerns.

In Latin America and East Asia, mandates are much more likely to be tied to levels of production, while mandates in Sub-Saharan Africa and South Asia are largely aspirational. For example, India recently scaled back its 20% ethanol target to 5% and is likely to be at just 2.5% in 2015. India initially hoped to support local sugar production, but faced several hurdles in implementing its plan. An outlier is Zimbabwe, which has invested heavily in biofuels and has a 15% ethanol mandate because it faces economic and trade sanctions, leading to ethanol being more economical than regular gasoline.

With the notable exception of Brazil, countries such as the United States and members of the EU were some of the first countries to implement biofuels mandates. Today, many countries in the developing world, especially biofuels producers, also have biofuels mandates. Our research finds that countries in the developed world are much more likely to have implemented their biofuels mandates or have come close to meeting biofuels targets/mandates (United States, Canada, and Germany) than countries in the developing world (India, Nigeria, and Ethiopia). This reflects both the time countries have had to meet these mandates and secure supply, but also the difficulties of starting a biofuels blending program.

This developed-developing world divide masks, however, the important differences between countries with established and functioning biofuels production and those without. Even in the developing world—especially emerging-market countries—countries where biofuels production has already taken root are consistently meeting their current mandates (Colombia and Ecuador). For countries without the buying power of the OECD, the driving factor behind the implementation of their mandates is the success or failure of domestic production (Panama and Zimbabwe).

In many cases mandates attempt to track biofuels availability and domestic consumption. Indonesia's palm oil biofuels industry is the best example of this trend. It currently has a 5% biofuels mandate, with a target of 15% ethanol and 20% biodiesel by 2025, not only to support domestic production, but also to absorb local demand in part due to the EU proposing to cap food-based biofuels at 7% of volume.[102] In Colombia, the ethanol mandate is explicitly reliant on ethanol stocks and is either 8% or 10% depending on availability. This would also be true from a different angle in the United States if the EPA elected to waive the RFS mandate downward to reflect lower production of cellulosic ethanol.

Overall, there is great variety in mandates, with producers with excess capacity looking to expand their mandates and export biofuels, and importing and OECD countries leveling off their mandates either in terms of volumes or as a percentage of their total consumption due to various food-price, land-use, or environmental concerns.

Methodology

In the summary table below and in the more expansive tables in the appendices, we strive to present the most up-to-date information on whether biofuels volume mandates have been met and the primary feedstock being produced and/or consumed in these countries. As discussed later, there is very good data on biofuels production and consumption in OECD countries, but data are less complete in parts of the developing world and in countries that have recently adopted mandates.

Information has been compiled from industry, international and country reports, and U.S. Department of Agriculture (USDA) country reports. We have privileged the most up-to-date information in our search, but some of this information is a few years old. We have included information we were able to access through regular desk research methods. All of the information below and in the appendices is publically available.

The full list of countries and regions with biofuels mandates can be found in Appendix B. For purposes of analysis we divided the countries in the appendix into several categories, each of which has large consumers in the summary table:

- **OECD**, or developed countries such as the United States and EU, which mostly have 10% ethanol mandates and which mostly are moving toward those goals.

- **High-production countries meeting high mandates**, most notably Brazil and Argentina but also several other countries, such as Colombia and the Philippines.

- **High-production countries failing to meet high mandates or targets,** such as China, India, and Indonesia but also several other Asian countries such as Malaysia, Thailand, and Vietnam.

- Other **countries with aspirational mandates** or targets, with varying degrees of likelihood that they will meet them, such as Chile, Nigeria, and South Africa.

The majority of countries in the world do not have biofuel mandates or targets, and these include several large consumers. Most notable are large petroleum-producing countries such as Russia, Venezuela and the Persian and Arabian Gulf countries, although some of them import biofuels from countries such as Brazil and the United States. The United Arab Emirates is one of the largest importers of U.S. ethanol, for instance.[103] They see little need or value in developing domestic biofuel industries.

As the summary table of selected biofuels consumption mandates shows (Table 1), full implementation of existing mandates and targets would represent a 43% expansion of first-generation biofuels demand over current levels. We present the seven most important biofuels consumers, their mandates and/or targets, their current consumption levels as both volume and as a share of transportation fuel, the additional volume and share implied by full implementation, and the total volume adding in anticipated demand growth for transportation fuels. Added transportation demand contributes significantly (20% of the overall increase in demand) to the total projected biofuels volumes in the countries in which the mandates/targets are a percentage of fuel, but the United States is the notable exception here. (A version of the summary table, with additional notes on sources, can be found in Appendix A.)

Growth pathways could increase further if full mandates/targets are fulfilled, not just those for first-generation biofuels. For instance, we assume: (1) India fails to meet its 20% biodiesel target, which is unlikely in the short-run; and (2) the United States meets mandates for first-generation biofuels but not for cellulosic biofuels, meaning just over half of the mandate is included in this analysis. We assume the United States uses 76BL of first-generation biofuels (such as corn ethanol, soy biodiesel, and sugarcane ethanol) in its fuel supply by 2025, out of a total of 137BL required by the RFS in 2022.[†]

Other assumptions in the summary table analysis include the following:

- EU estimate includes double-counting for advanced fuels, so the effective demand increase from its 10% mandate is 8.6%.[104]
- Consumption numbers for Brazil are calculated based on its 25% ethanol mandate, the latest figures available.
- Argentina's transportation demand is calculated differently because USDA estimates a change in ratio of gasoline to diesel. Separate demand increases were calculated for gasoline and diesel, which have implications for ethanol and biodiesel use.
- China has both a 10% mandate and a 15% target, but only for nine provinces. We assumed China would meet its 15% target because past targets have systematically been met. China's transportation fuel demand growth rate in affected provinces is assumed to be the same as China's overall growth rate. Where uncertainty in current implementation of mandates exists, the midpoint of the range was used for calculations (e.g. China 8-12% current ethanol blend was calculated at 10%).

[†] We assume the U.S. meets its 57BL mandate for corn starch ethanol, 3.8BL mandate for biodiesel (which could be increased by the U.S. EPA), and that the remaining 15BL are met by imported sugarcane ethanol (total of 76BL). We assume the remaining 61BL, mandated to be filled with cellulosic ethanol, a second-generation biofuel, are not produced due to technological and economic challenges, and that EPA waives down this mandate, leaving just 76BL of the mandate to be fulfilled. However, this volume could increase further if the U.S. Congress or EPA alters biofuels mandates to allow more food-based biofuels (such as corn biobutanol and corn oil biodiesel) to count toward its "advanced biofuels" mandate since cellulosic ethanol production has failed to materialize as policymakers projected in 2007.

- We only considered India's 5% ethanol mandate to be binding, so we did not assume the country's 20% ethanol and 20% biodiesel targets would be filled.
- Indonesia currently has a 5% mandate for biofuels, but also has more aggressive targets of 15% ethanol and 20% biodiesel by 2025. The higher targets are used in this analysis.
- All transportation growth is annualized on a linear basis from IEA and USDA growth rates.

Table 1: Selected Biofuel-Consuming Country Mandates through 2025

(in billions of liters)

Country	Mandate/target			Current Consumption		Mandated Increase	Transport Fuel Demand Growth through 2025	Added Volume, Full Mandate+ Demand Growth	Projected Demand 2025	
	Timeframe	Ethanol	Diesel	vol	% fuel supply	%	%	vol	vol	% increase
United States	2022	72 BL	3.8 BL	62.9		21%	N/A	13.1	**76.0**	**21%**
European Union	2020	10.0%		18.7	5.0%	72%	-8%	12.1	**30.8**	**64%**
Brazil	2014	25.0%	7%	29.0	27.5%	0%	36%	12.2	**41.2**	**36%**
Argentina	2014	5%	10%	2.0	7.6%	25%	57%	1.3	**3.2**	**64%**
China*	2020	15%	-	3.6	8-12%	50%	59%	3.9	**7.5**	**109%**
India	2014	5%	-	2.3	2.1%	42%	47%	2.0	**4.3**	**89%**
Indonesia	2025	15%	20%	0.8	3.0%	795%	65%	7.1	**8.0**	**860%**
Total Selected				**119.2**				**51.6**	**170.9**	**43%**

Sources:
All current volumes are taken from the most recent US Department of Agriculture (USDA) GAIN reports unless otherwise noted.
Transport fuel demand growth rates are calculated from IEA's New Policies Scenario except for Indonesia and Argentina.
Ethanol and diesel demand estimates for Argentina, for 2015-2024, are taken from USDA's GAIN Report for Argentina, 2014.
Ethanol and diesel demand estimates for Indonesia, for 2015-2024, are taken from USDA's GAIN Report for Indonesia, 2014.
Diesel consumption for India is derived from USDA's GAIN Report for India, 2013.
Current volumes for the US are the Environmental Protection Agency's (EPA) 2013 mandated biofuels volumes.
*China's mandate is for nine provinces only, representing just 1.1% of current fuel use and a projected 1.3% in 2025.

Full Implementation of Existing Mandates

As the table shows, most large consuming countries with mandates or targets have only partially implemented them, Brazil being the most notable exception. The United States is close to fulfilling its mandate for first-generation ethanol (13BL away from its 76BL mandate of first-generation biofuels). The EU is about 12BL away from its overall 10% mandate, though there is wide variation among member countries in their progress.

OECD countries drive current consumption and account for about half of the growth in projected biofuels demand by 2025. This would be considerably lower if the United States and the EU reformed their mandates. As noted earlier, the EU is currently considering capping the use of crop-based biofuels at 7%. (Here we estimate implementation based on the full 10% mandate, adjusting for double-counting.)

Mandates and targets in key large emerging economies have important implications for future growth in biofuel consumption and production. Information is less reliable, and policy goals are under revision. Still, we present the likely mandates/targets of major biofuel-producing countries and their implications.

Brazil is a large producer and consumer, with high mandates that have been filled. The projected 36% increase in its consumption comes solely from fast-growing demand for transportation fuels, a high percentage of which are biofuels. While the pie may be getting bigger, biofuels' share of the transportation fuel supply is expected to stay relatively flat. Argentina is a much smaller consumer with lower mandates, but increased transportation demand, in addition to increased mandates, are expected to lead to a 64% increase in consumption by 2025.

Two of the least certain mandates include those in China and India. China currently has a 10% mandate in nine provinces only, which it has reached, with a target of 15%, suggesting 50% growth in demand from the target alone. Given anticipated high growth rates in demand for transportation fuels in addition to increased biofuels targets, the projected growth rate is 109% through 2025. This represents an increase of only 3.9BL despite the high percentage increase because the mandate is limited to nine provinces. Future Chinese biofuels policies are expected to continue to be mindful of food vs. fuel concerns (which began after food price spikes in 2008) and future analyses of demand for agricultural commodities. Nationally, biofuels now account for just 1.1% of transportation fuels and that share would grow to just 1.3% in 2025.

India is only halfway to meeting its 5% ethanol mandate, recently scaled back from 20%. Its 20% biodiesel target has not been reduced, but we do not include it here as it is not a binding mandate and, as we explain below, there is good reason to believe India will have to reduce it. Still, even without added biodiesel, we expect India's biofuel production to increase 89% to 4.3BL by 2025.

Indonesia presents the largest planned growth on a percentage basis (860%) as it moves from its current 5% biofuel mandates to aggressive 15% and 20% targets for ethanol and biodiesel, respectively. With high anticipated transportation fuel demand growth, such targets would make Indonesia one of the most significant sources of new demand for biofuels between now and 2025 – 8.0BL – with the bulk of the feedstock expected to come from palm oil.

Overall, these countries account for the large majority of current biofuel production. Assuming they continue to account for such a proportion, the impact of full implementation of their mandates and targets would have huge impacts on land use, water quality and quantity, food prices, and GHG emissions. Our figures suggest a 43% increase in first-generation biofuels consumption over current levels. This world in which 3-5% of the global fuel supply is comprised of first-generation biofuels is close to projections offered by the OECD/FAO scenario. However, growth rates could increase to 115% if second-generation biofuels mandates are met and if other countries such as India meet their lofty biofuels targets. This would result in a world in which 4-7% of the world fuel supply is comprised of biofuels, which is closer to IEA estimates.

For a full list of country mandates please see Appendix B.

Limits to Full Implementation

There is good reason to believe that many countries will be unable to fulfill their current mandates. For some, such as countries in the EU, a likely future 7% cap on food-based biofuels (out of a 10% mandate) leaves a 3% gap to be filled with non-food-based biofuels that have been slow to come to full commercialization. Many countries have yet to meet even the proposed 7% cap. For the United States, the blend wall currently prevents the full implementation of the RFS, and since cellulosic biofuels are required to meet nearly half of the 137BL mandate, policy reforms will be required to bring the mandate more in line with realistic production volumes. For others, such as India, access to feedstock (sugar) is proving difficult to secure.

There are, of course, risks that additional mandates in key countries could add to biofuel demand in ways not anticipated here. As is often the case, China and India are the two most important wild cards for such estimates.

Below we analyze the likelihood of implementation, recent calls for reform, and present the key factors guiding the development of biofuels policies, consumption, and production in selected countries and regions. We find that if recently-proposed policy reforms are implemented (such as in the United States and EU), we can expect lower first-generation biofuel growth, but overall global demand is still expected to increase significantly.

United States

The United States is the world's largest biofuels producer and consumer.[105] The twin pillars of U.S. biofuels policy have included a mandate as well as an intertwined set of subsidies focused at the dominant feedstock (corn), as well as refining and blending facilities (some of which have expired). While the largest tax credit for ethanol production, the Volumetric Ethanol Excise Tax Credit (VEETC), ended in 2011, the biodiesel blenders and cellulosic ethanol production tax credits are routinely extended. State incentives and other federal government programs have also contributed to establishing the required infrastructure to make biofuels production economically viable.

The RFS mandates 137BL of conventional ethanol (mainly corn ethanol), advanced biofuels, and cellulosic biofuels to be blended into the U.S. fuel supply by 2022. In the U.S. mandate, definitions of these different types of biofuels are based primarily on their contributions to reducing life-cycle GHG emissions, as estimated by EPA. In our analysis, we assume the corn ethanol, biodiesel (biomass-based diesel), and a portion of the advanced biofuels mandates will be met (totaling 80BL of the full 137BL mandate), but importantly, we do not assume the 61BL cellulosic ethanol mandate is met since production is just beginning to come on line and experts estimate the mandate will not be filled by 2022. The gap that exists between the advanced biofuels and cellulosic ethanol mandates creates an incentive for additional production/importation of food-based biofuels such as imports of sugarcane ethanol from Brazil and production of other food-based biofuels such as soy biodiesel and corn biobutanol.

U.S. Renewable Fuel Standard Definitions

The RFS mandates increasing levels of the following types of biofuels by 2022:

- **Corn starch ethanol:** the mandate for corn starch ethanol is 57BL by 2015, and this mandated level continues throughout the life of the full RFS. This category is required to meet a 20% GHG reduction threshold (as compared to U.S. gasoline), although several corn ethanol facilities were grandfathered into the law, meaning they were not required to reduce GHG emissions.

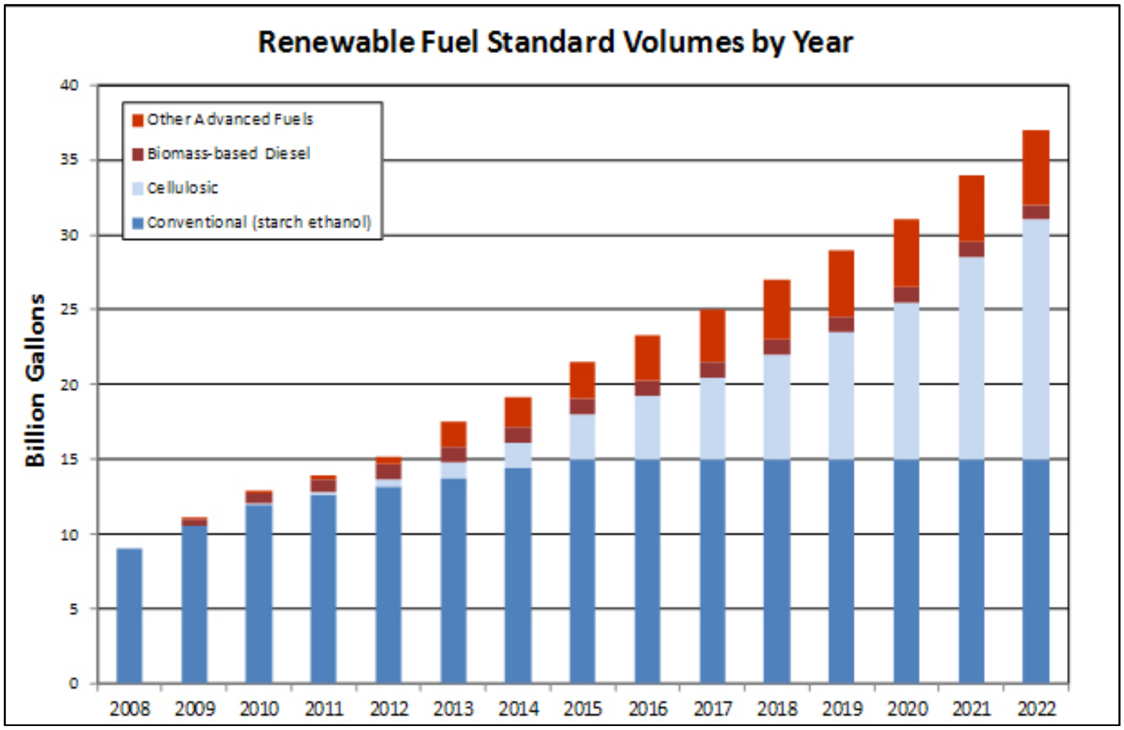
- **Advanced biofuels:** Rising to 80BL by 2022, the advanced biofuel mandate may include biofuels such as sugarcane ethanol, biomass-based diesel (such as biodiesel derived from animal fats, soy, or other vegetable oils), cellulosic ethanol (see below), and other advanced biofuels. These are required to meet a 50% GHG reduction threshold set by the U.S. EPA. The EPA is currently considering whether to treat corn biobutanol, a fuel that does not face the same fueling infrastructure challenges as corn ethanol, as an advanced biofuel, meaning that food-based biofuels may still be considered advanced biofuels in the United States

- **Cellulosic ethanol:** Rising to 61BL by 2022, the cellulosic ethanol mandate may include ethanol derived from cellulosic sources such as perennial grasses and wood and agricultural residues. This category is required to meet a 60% GHG reduction threshold. However, cellulosic ethanol is not produced at a large commercial scale yet, so in our analysis, we do not assume the United States meets its 61BL cellulosic mandate by 2022 (or 2025), leaving a gap of 19BL of advanced biofuels to be filled with fuels such as sugarcane ethanol and soy biodiesel (identified as "other advanced biofuels" in Figure 8).

Figure 5 details the scheduled increase in RFS mandated biofuels volumes, with corn ethanol leveling off at 57BL in 2015 and years thereafter, and cellulosic biofuels mandated to grow steadily after 2010.

Approximately 10% of U.S. gasoline supply currently comes from ethanol—primarily corn ethanol, while biodiesel blends are much lower. Growth projections are relatively flat though, given the issue of the E10 blend wall. The most recent EIA estimates project that biofuels will account for only 11% of U.S. transportation fuel in 2040, although its previous energy projections have estimated significantly higher volumes of biofuels.[106] As a comparison, the RFS mandate requires approximately 25% of the United States fuel supply be comprised of biofuels by 2022, the majority from cellulosic or advanced feedstocks.

Figure 5 [107]



Three key issues have led to the U.S. biofuels market expanding at a significantly slower rate than initially thought. First, Americans are driving less. The Great Recession led to large reductions in driving and this behavior change has not rebounded at the same rate as the economy. The EIA also projects that there will be fewer drivers per capita in the future.[108]

Second, Americans are driving more fuel-efficient cars. Higher Corporate Average Fuel Economy (CAFE) standards are lowering fuel demand. So are American preferences for cars with better fuel economy. Trading large vehicles for smaller cars and hybrids is leading to demand far lower than the EIA anticipated 10 years ago.

Third, the United States has hit the blend wall, or the maximum amount of ethanol deemed safe to blend into the U.S. fuel supply. Gasoline blended with 15% ethanol (E15) is now allowed in cars manufactured after 2001, but it is not available in most areas and issues with engine warranties and negative effects on older vehicles and small engines have prevented its widespread adoption. In addition, for the reasons cited earlier, unlike Brazil there is little indication the United States will significantly increase adoption of flex-fuel vehicles in the near future. If either of those occurred, the U.S. fuel supply could accommodate significantly higher levels of biofuels.

Each year, the Environmental Protection Agency (EPA) is able to revise RFS mandates based on the commercial availability of cellulosic biofuels. In recent years, the EPA has reduced cellulosic ethanol mandates by more than 95% because each year less cellulosic fuel is available than the RFS originally mandated. In 2015, EPA will consider waiving the *entire* RFS downward for calendar year 2014, for the first time in history, due to these lower cellulosic volumes and the ethanol blend wall.[109]

Such reforms can make a large difference in global biofuel demand. If EPA finalized 2014 biofuel volumes in line with those proposed in late 2013 (one way to reform the RFS) and maintained these lower mandates throughout the rest of the RFS, the United States would contribute 4.6BL less to global first-generation biofuel demand, leading to a 14% demand increase instead of a 21% increase by 2022.

EPA is also able to waive RFS mandates downward based on petitions tying biofuels mandates to “severe economic harm.” While several petitions have been submitted to EPA in recent years by U.S. states negatively affected by high crop and food prices, EPA rejected these citing other demand factors playing a larger role in higher food prices. In addition to administrative action, several legislative proposals have been introduced in the U.S. Congress to either eliminate or significantly reform biofuels mandates due to their impacts on food and feed prices and negative effects on the environment. If implemented, reform proposals would bring biofuels mandates more in line with current production volumes.

The arrival of the blend wall and the failure of cellulosic ethanol to come to large commercial production have resulted in numerous unintended consequences of the RFS. Combined with low feedstock (corn) prices, ethanol production in the United States is beginning to exceed the amount of ethanol that can be used in the current domestic vehicle fleet. Hence, U.S. ethanol exports are expected to increase to record levels in 2015 due to this confluence of factors. The RFS has also created a particular market for Brazilian sugarcane ethanol in the United States since cellulosic ethanol has failed to meet advanced biofuels mandates. Hence, in addition to soy biodiesel, sugarcane ethanol from Brazil is a major source of advanced biofuels, with imports of 7.7BL in 2013.[110] OECD projects that by 2023 Brazil could supply up to 38BL to the United States while the United States ships 19BL of corn-based ethanol to Brazil.[111] Others consider this level of bilateral ethanol trade unlikely.

Because Brazil has no restrictions in its own mandates or laws on GHG impacts, corn ethanol can substitute freely in the Brazilian market for some of the sugarcane ethanol exported to the United States The net effect leads to expansion of less beneficial corn-based ethanol fuel beyond its RFS mandate, while the mandate for advanced biofuels is met with additional food-based biofuel. However, these trade flows are highly dependent on volumes that the U.S. EPA finalizes, since the agency can lower advanced and cellulosic biofuels mandates if production is insufficient. Furthermore, the advanced biofuels gap at most is 19BL, with some of this likely being filled with soy biodiesel, so these projections are highly speculative.

The RFS provides a prime example of how domestic mandates interact with existing trade flows and lead to unexpected outcomes, and ones that frequently undermine the political purposes for which a domestic biofuel mandate was originally passed. And since the RFS has primarily been filled with corn ethanol, the RFS has failed to significantly reduce GHG emissions.[112]

European Union

In 2009, the European Commission (EC) established a minimum target of deriving 10% of transportation fuels from biofuels in each member state by 2020. Countries submitted their energy action plans to the Commission by June 2010.[113] During that time, civil society became concerned about both the environmental and social ramifications of this decision. As more evidence became available about indirect land use change due to biofuels, biofuels' effect on food prices, and the human and land rights issues associated with the production of biofuels in some countries around the world, advocates mobilized to change the law. In part, advocates were able to point to the sustainability criteria laid out in Articles 17, 18, and 19 of Directive 2009/28/EC.[114] These GHG and land use sustainability criteria have been in effect since December 2010.

As a result of these intense educational efforts, in October 2012, the EC proposed limiting food-based biofuels to 7% of the 10% renewable energy target in the RED.[115] While it does not go far enough, three-percentage points less in first-generation biofuel represents 11BL in avoided production (assuming the remaining 3% would be difficult to meet with non-food-based feedstocks). This reform would reduce the EU's projected growth rate in first-generation biofuel volume from 64% to 33%, (which also factors in a drop in transportation demand growth through 2025). Because this reform has not yet been implemented, the higher 10% biofuels mandate has been used in our analysis.

OECD/FAO reports 65% of European vegetable oil is being used for biodiesel.[116] In addition, several companies based in EU countries have acquired land in African countries to produce biofuel feedstocks, some of these resulting in land grabs which deprive local communities of land once used for food production, housing, burial grounds, forestry, etc.

The following table shows the origin of biofuels consumed in the EU.

Figure 6[117]

Origin of final biofuels consumed in the EU in 2010[17]

	Biodiesel		Bioethanol		
	Volume (ktoe)	Share		Volume (ktoe)	Share
EU	8,270	83.2%	EU	2,243	80.1%
Argentina	1,003	10.1%	Brazil	234	8.4%
Indonesia	285	2.9%	U.S.	121	4.3%
Malaysia	123	1.2%	Peru	26	0.9%
China	67	0.7%	Kazakhstan	24	0.8%
U.S.	61	0.6%	Bolivia	20	0.7%
Other countries	129	1.3%	Egypt	15	0.5%
			S.Korea	16	0.6%
			Other countries	101	3.6%
Total	9938			2800	

Source: EUROSTAT, COMTRADE.

Figure 7 shows the origin of the feedstocks of biofuels consumed in the EU, showing the EU's dependence on imports of feedstocks.

Figure 7[118]

Origin of all biofuel feedstock consumed in the EU in 2010

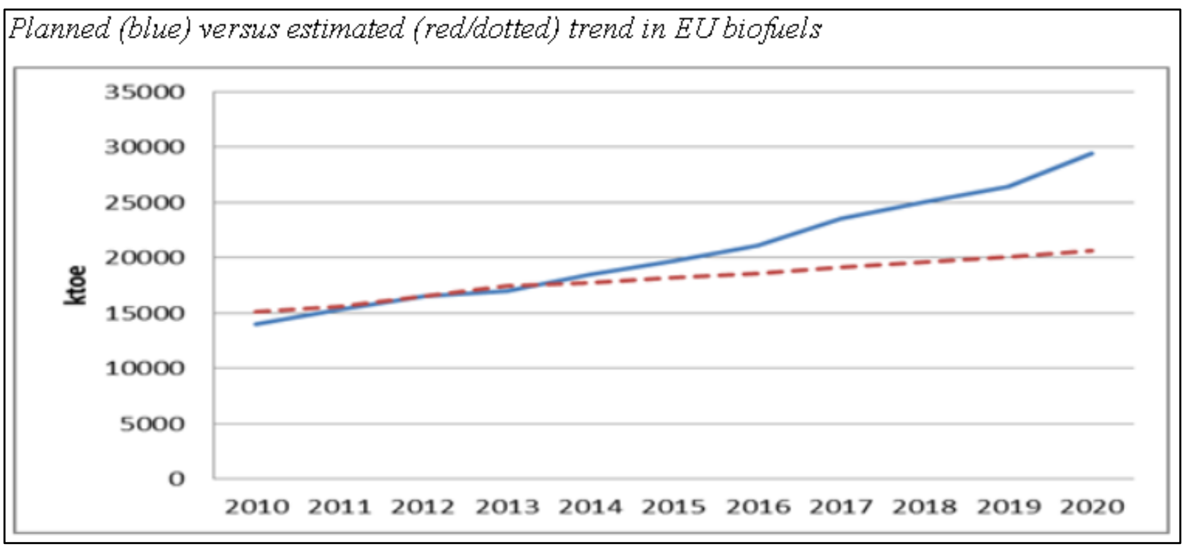
EU	Argentina	Indonesia	Brazil	U.S.	Canada	Ukraine	Malaysia	Paraguay	Other
63.9%	9.7%	6.6%	5.3%	3.0%	2.4%	2.3%	1.7%	1.5%	1.3%

Russia	China	Switzerland	Peru	Bolivia	Peru	Egypt	Guatemala
1.0%	0.5%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%

Overall, progress toward the 10% mandate has been uneven, leaving the EU as a whole unlikely to reach that goal, although added consumption is still projected to be an important driver of global biofuels demand. According to the EC, biofuel use in 2020, the end of the mandate period, is expected to be just two-thirds of the planned total.[119] (See Figure 8.)

Some European countries are already well on their way to meeting the 10% target, with Sweden already blending 10% biofuel into its transportation fuel. However, other countries such as the UK and Spain have yet to meet the newly proposed 7% cap on food-based biofuels, meaning there is still room to expand current blending levels. And since production of non-food-based biofuels has been slow due to technological and economic challenges, meeting the overall 10% targets will be difficult. Despite these constraints, recently proposed reforms, and concerns about biofuels' environmental and social impacts, the EU biofuel market is expected to continue to grow.

Figure 8[120]



Brazil

A dominant force in biofuels markets, Brazil has the longest running biofuels mandates in the world, a large flex-fuel vehicle fleet (which can operate on Brazil's 25% ethanol blend mandate) as well as tax incentives for biofuels production. Brazil's production and consumption of biofuels continue to increase. Ethanol production in 2015 is projected to be up 5% over 2014 at 26.9BL.[121] The Brazilian Senate passed a measure to increase the ethanol mandate to 27.5% from 25% and to cap biodiesel blending at 6%, but the proposal has yet to be approved by the

President.[122] In any case, the mandates in Brazil are seen more as a reflection of the market than a driver, in part because it affects only a small share of ethanol used in the country's vehicle fleet.

In addition to its domestic consumption, Brazil was also the world's largest ethanol exporter in 2013, although exports were down significantly in 2014.[123] In this interconnected market, Brazil exports sugarcane ethanol to the United States while the United States sometimes exports corn ethanol to Brazil to make up for losses. The United States is also its largest importer and accounts for 70% of Brazil's exports of ethanol.[124] Brazil's exports are projected to drop 46% in 2014 to 1.5BL as the United States considers scaling back its mandates for advanced biofuels, although previous estimates from the OECD/FAO projected increased ethanol trade over the next ten years.[125]

Even outside of the U.S.-Brazil relationship, Brazil has been a significant supply-side driver of the global biofuels market. It has used its technical expertise in ethanol as a source of soft power toward other emerging and developing countries to increase biofuels use, although this has leveled off in recent years.[126] For example, Brazil has invested in land, entered into "cooperative agreements," and provided biofuels technology to other countries, including many in Africa and countries in the Western Hemisphere.[127] Brazil and the U.S. signed a Memorandum of Understanding (MOU) in 2007 aimed at increasing agricultural and biofuels investments in developing countries such as Honduras, Nicaragua, Costa Rica, Panama, the Dominican Republic and Haiti, which the governments termed "ethanol diplomacy" at the time.[128] As a Committee on Foreign Relations (CFR) brief wrote in 2007, "Ethanol ha[d] become Lula's [Luiz Inacio Lula da Silva, the former President of Brazil] best diplomatic lever in Latin America…"[129]

Despite its influence, the domestic Brazilian ethanol industry has recently seen setbacks, including a reduction of gasoline taxes resulting in relatively cheaper gasoline and the country's discovery of new oil deposits, which may decrease domestic oil prices – the opposite reason biofuels mandates were first enacted in Brazil.

Argentina

Behind only Brazil in biofuels production and consumption in Latin America, Argentina has invested heavily in both ethanol and biodiesel production. A 10% biodiesel mandate and an ethanol blend rate of 7.6%--even higher than its 5% mandate—are driving Argentina's consumption of biofuels.

Argentina's biofuels production and consumption have expanded rapidly over the last few years. In 2010, Argentina's ethanol blend rate was only 2% but it is expected to rise to 7.5% in 2014.[130] As ethanol demand rises, Argentina is adding additional refining capacity, creating the infrastructure for future production. In the past year a new ethanol plant has brought annual production capacity up to 840 million liters.[131]

Its biodiesel blend rate is expected to double to 8% in 2014, from 4% in 2010. [132] In 2014, its biodiesel consumption and production were projected to be 1.4BL and 2.6BL, respectively, leaving room for biodiesel exports.[133] [134]

Peoples Republic of China

China initially embarked on a biofuels policy to absorb excess grain stores in the early 2000s. It switched course when the 2008 food price spikes led to concerns about shortages if this food was converted to fuel. Since then, China has invested in so-called advanced biofuels that can be grown on marginal land.[135] It has also involved its national oil companies in some biofuels production, showing its interest in developing biofuels for national energy security.[136]

When China makes investments, an entire market can move. The second largest economy in the world and home to one-sixth of the world's people, China has included biofuels in its current five-year energy plan. The U.S. EIA reports China produced 2.6BL of ethanol and 966 million liters of biodiesel in 2013.[137] Compared to the production of the United States or Brazil, these volumes are small. China has mandated 10% ethanol blends in gasoline in nine of its provinces, but this mandate is set to increase to a 15% target in 2020.[138] China is such a large market that these mandates and other infrastructure investments are worth particular attention.

China's investments in biofuels reflect their general approach to energy investing, ensuring the country is investing in all industries and that they are prepared for technological gain in any particular one. If, for example, cellulosic biofuel were to become commercially viable, it is likely China would be an early investor and adopter of this fuel. China is a large net importer of transportation fuel and depends on fuel for its continued economic growth. Considering China's investments in overseas oil fields, its investment in biofuels is modest indeed.

The quick reversal of policy in 2008 demonstrates that China is not wedded to biofuels production for ideological reasons and is likely to be sensitive to biofuels' competition with food crops to the extent that it affects food prices. Without powerful interest groups promoting biofuels, it is better able to adjust quickly to changes in the market either expanding or contracting its production. China has also recently announced it will remove or dial back other policy supports for ethanol. In 2015, it will remove the 17% value-added tax rebate at the same time it is adding a 5% tax on food-based biofuels.[139]

Based on China's stated intentions and recent actions on biofuels, it seems unlikely the government will increase its 15% biofuels target in the near future. Nor is it likely to extend the target to other parts of the country. As demand rises, of course, its consumption of biofuels will rise even with the same target in place. But its limited mandate means that presently only 1.1% of China's transportation fuel comes from biofuels, and even with anticipated growth that percentage would rise to just 1.3%.

If China were to choose to increase dramatically its biofuels production or consumption, it could dwarf production and consumption of many OECD countries. Any move to take the nine-province mandates national would have dramatic impacts, as would policies to import large quantities of biofuels. The environmental and human impacts could be overwhelming. In all models of future biofuels production and consumption, China, and to a lesser extent India, are wild cards, although China has a history of being an innovator in biogas and other homegrown bioenergy sectors.

India

The world's largest democracy embarked on a national biofuels policy in 2009.[140] Like China, India is a major transportation fuel importer and is hoping to improve its trade balance, support local agriculture and agricultural processing, and insulate itself from international oil markets by making non-petroleum energy investments. With a declared non-binding target of a 20% biofuel and biodiesel blend in transport fuels by 2017, India has publicly committed to scaling up biofuels production, but in practice it has done far less.[141]

In 2012, India's Cabinet Committee of Economic Affairs recommended its ethanol *target* be scaled back and changed to a 5% blending *mandate*. The country is currently blending only 2.1% ethanol into its transportation supply.[142] This is mainly due to limited supplies of sugarcane, especially after poor harvests in the past few years. Even with this dramatic reduction in its blending goals, India is projected to produce 2BL of ethanol in 2014.[143]

India's biodiesel target of 20% remains in place, but it is non-binding and it has not been replaced with a binding mandate (as was done with ethanol). The biodiesel industry has also failed to develop, with production in 2013 of just 115 million liters. The primary feedstock was intended to be jatropha, but the government and other countries are now searching for alternatives given its potential to become an invasive feedstock and its high water usage. Meeting the 20% biodiesel target would raise the country's biofuel use to more than 20BL, making it one of the world's largest biofuel consumers.

The Indian government set these initial targets in response to the country's impressive economic growth rate, fluctuating international oil prices, and a desire to be more energy secure.[144] In its own biofuels policy document it makes clear that its policy, unlike those of other countries, will not come into conflict with its food security goals and that biofuels will be derived from non-food feedstocks.[145] India is, however, unlikely to take food security concerns of other countries into consideration in its own biofuels import policies. Moreover, if a fully functioning, large-scale biofuels industry comes online, it is unclear if and how the Indian government would reverse its policy decisions to protect food security.

Despite significant targets and the outsized power of large sugar producers in India, it is unlikely that India will end up blending nearly as much ethanol and/or biodiesel by percentage into its transportation supply as Brazil. India's commitment to food security and its stated goal of prioritizing food security over biofuels development also makes it likely that its program will not grow significantly in the future. These qualifications aside, India's continued economic growth and increased energy demand coupled with its growing population could drive very high biofuels consumption even with its current blend rate. In terms of volume, India's demand could expand dramatically in the coming decade without changing its percentage mandate.

Indonesia

In 2011, Indonesia was the sixth largest producer of biodiesel.[146] Over the past several years, Indonesia has cleared huge tracks of land for its main biodiesel feedstock - palm oil – intended both for export and domestic consumption. Since the EU's adoption of a biofuels mandate, Europe has become a significant consumer of Indonesian palm oil. A new proposal to limit biofuels from food-based feedstocks to 7% in the EU RED, in addition to broader concerns about unsustainable production of palm oil, has slowed exports to Europe.[147]

Indonesia is now using domestic mandates to drive local consumption as it continues to support production for both domestic and export markets through production subsidies and tax incentives.[148] It is too early to say if Indonesia's aggressive 2025 targets—15% for ethanol and 20% for biodiesel—will be met.[149] It currently has a 5% biofuel mandate, but is blending only 4.5% biodiesel and a marginal volume of ethanol.[150] Nevertheless, such dramatic growth in mandates and targets, especially as the country experiences economic growth and increased energy demand, would have huge environmental and social implications unless the government adopts smallholder-led palm oil development strategies and works to close the "productivity gap" with Malaysia.

Indonesia's biofuels expansion and other palm oil demand drivers have resulted in numerous negative impacts, including deforestation, large GHG emissions, and land and human rights issues. Groups such as the Rainforest Alliance, World Wildlife Fund, and Girl Scouts U.S.A. have raised issues of negative consequences of increased palm oil production in Indonesia such as "land-grabbing," forced displacement of communities, poor labor standards, large GHG emissions, and destruction of wildlife habitat. [151]

African Nations

Several African countries have enacted ethanol mandates or targets. Many of these mandates are new and were created in anticipation of domestic biofuels industries. It is too early to tell whether these mandates and targets will drive demand and help support these nascent industries.

South Africa, the most developed of the Sub-Saharan nations, has only begun its biofuels mandate, which is relatively low in any case – 2% ethanol and 5% biodiesel starting in 2015. Significant restrictions on water and land availability in the country make the development of a large domestic biofuels sector unlikely.[152] Moreover, South Africa has excluded maize use for biofuels because of food security concerns, and has also excluded jatropha for fears of it becoming invasive.[153] Despite these restrictions, there were four bioenergy projects operating in 2010 with four more in the pipeline,[154] and South Africa has begun to export ethanol to the EU.[155]

Countries from Senegal in West Africa to Tanzania in East Africa have been the sites of biofuels related land-grabs and failed biofuels projects as international companies seek new land to produce feedstocks in developing countries. Developed country biofuels mandates drive investment in not only biofuel feedstock production (such as sugar) but also biofuel refining facilities. Business setbacks as well as local unrest over forced displacement and other human rights abuses have been raised as reasons why governments should reconsider biofuels mandates, targets, and other incentives and investments in biofuels. Malawi and Zimbabwe are exceptions, being two of the only major producers of ethanol in Southern Africa. Zimbabwe, for instance, is currently blending 15% ethanol.[156]

It is unclear how African countries will approach biofuels moving forward. This is particularly true of countries and regions with recent discoveries of oil and gas. While countries like Angola and Nigeria have put biofuels mandates on the books, it seems unlikely that these large oil producers will follow through on these mandates. The lower domestic price of oil, especially with oil subsidies, makes biofuels particularly uncompetitive in these countries. Like oil producers in Northern Africa where no biofuels mandates exist, Sub-Saharan producers are unlikely sources of high biofuels consumption irrespective of the biofuels mandates they have on the books.

If OECD countries continue to demand biofuels, African production of biofuels is likely to expand in the coming years to meet at least part of this expanded demand. This is especially true in countries such as Ethiopia and Tanzania, which have prioritized large-scale commercial agriculture and foreign direct investment in the sector.

V. Conclusions

Our review of government biofuels mandates suggests consumption of first-generation biofuels in selected major biofuel-producing countries would increase about 43% by 2025 if most of these countries' mandates and targets were fully implemented. This analysis does not include mandates and targets that have little chance of implementation such as India's biodiesel target. The figure would be somewhat lower if existing mandates prove too difficult to achieve, and in some countries that is likely to be the case. First-generation biofuels consumption could be much higher by 2025 if the 64 current governments with mandates/targets continue expanding mandates/targets or if additional countries enact and actively pursue implementation of domestic biofuels mandates or targets.

Over the next ten years, OECD countries will continue to account for nearly two-thirds of first-generation biofuel consumption, and the fulfillment of their mandates would contribute to 50% of added first-generation biofuel use between now and 2025. The United States would be the largest contributor of new biofuels demand, adding 13BL, while the EU would add 12BL by 2025 to meet first-generation biofuel mandates. The United States would remain by far the largest consumer in 2025, with 76BL of first-generation biofuel consumption, which is projected to increase 21% in the coming years barring major policy reforms.

However, if recently proposed EU reforms (to cap food-based biofuels at 7% of the fuel supply) and U.S. EPA reforms (to limit the growth of biofuels expansion) were implemented, the EU and United States would contribute 11BL less to global first-generation biofuels demand in 2025; this would reduce mandate-driven global expansion from 43% to 38%. While these reforms do not go far enough, this demonstrates the impact that short-term policy reforms can have on global biofuels expansion.

Brazil will continue to be a major producer and consumer of biofuels, remaining the second largest consumer in 2025 after the United States with 41BL of consumption. Its consumption is projected to expand 36% if biofuel blending levels are maintained due to increasing demand for transportation fuel as a result of economic growth. The country is expected to continue to be a net exporter, helping other countries fulfill their mandates. This has historically included the export of first-generation biofuel (sugarcane ethanol) to the United States for its advanced biofuel mandate in exchange for the import of another (corn ethanol). However, the economics of fuel blending could change if Brazil expands its oil industry, with the recent discovery of offshore oil, which is expected to increase its proven reserves and double its production capacity by 2020.[157]

China and India present the biggest sources of uncertainty. Any significant moves toward expanded biofuel consumption, over today's comparatively low levels, would have huge impacts for the environment, food prices, and agricultural markets. Based on current mandates and policies, however, the two are projected to contribute an additional 6BL to global consumption, barely half the consumption added by the United States. China's projected blend rate in 2025 is just 1.3%, moderation which keeps the country's large transportation sector from driving biofuel demand to even more unsustainable levels.

Indonesia, on the other hand, has the most aggressive targets, which it is moving to implement. Full implementation would add 7BL to global biofuel demand. This would only deepen the negative environmental and social impacts caused by the country's expanded production. In part, the EU biofuels mandate was responsible for Indonesia's large-scale planting of palm oil, in addition to other demand factors for palm oil and the government's intent to prop up domestic palm oil prices. The government's current mandates have responded to reduced demand by increasing domestic biofuel demand to absorb the excess feedstocks.

Given this increased demand for biofuels, the implications for land and water use and food security are huge. A 43% increase in biofuel production by 2025 would continue to divert food and feed crops into fuel markets. At current land-use rates, it would divert an additional 13-17 million hectares more land than we are currently already devoting to biofuel production and approximately 145 billion more liters of water at rates currently used in corn ethanol production. This is an important area for further research, with the implications depending significantly on the feedstocks used.

If the IEA's projections, which predict full implementation of global biofuels mandates, are accurate, however, our findings would represent only a portion of increased biofuels demand over the next two decades. Importantly, IEA includes second-generation biofuels mandates in addition to those for first-generation biofuels, suggesting that by 2035, the world fuel supply would be comprised of 8% biofuels by volume, with 80% of the biofuels still derived from food crop sources instead of second-generation, non-food feedstocks such as agricultural residues or perennial grasses. Meeting first-generation biofuels estimates would result in consistent growth rates to reach a world with 6% of transportation fuel comprised of biofuels by 2035, in line with our projections if full (first- and second-generation) mandates are met.

Policy Implications

This analysis suggests the need for governments to cease the implementation, expansion, and creation of new food-based biofuels consumption mandates. While recently proposed reforms to U.S. and EU mandates are welcome, even if they are implemented these OECD countries will still account for about one-third of new biofuel demand over the next ten years. Percentage-based mandates, which prevail in most countries, will require additional demand for biofuels as demand for transportation fuels is expected to grow about 16% by 2025; many countries that maintain and enforce such mandates will contribute added demand for biofuels even if they don't increase their mandates.

Governments need to scale back their mandates further, enforce strict sustainability criteria, and ensure that so-called "advanced" biofuel mandates are not feeding further first-generation production or continued production of food-based and land-intensive biofuels.

Other policy recommendations that flow from this analysis include:

- *Remove Food-Based Mandates.* The United States should eliminate food-based biofuels mandates and ensure that future biofuels don't compete heavily with land used for food production.
- *Stop and Do Not Adopt New Food-Based Mandates.* Other countries should eliminate and forgo adoption of food-based and land-intensive biofuels mandates and other incentives working at cross-purposes with food security, biodiversity preservation, land tenure rights, and GHG reduction goals. Governments should work toward international cooperation on these issues in international policymaking venues such as the G7, G20, UN Framework Convention on Climate Change (UNFCCC), UN Committee on Food Security, UN Convention on Biological Diversity, post-2015 development agenda, etc.
- *Continue Research with a Focus on Sustainability.* Research and development of second-generation biofuels should increase but with strong attention to sustainability criteria that can be widely and consistently implemented. Given the volumes required to meet global biofuel demand, even seemingly benign feedstocks can prove unsustainable at large scale.
- *Feedstocks Matter*.[158] As policymakers rethink their biofuels mandates, it is important to pay particular attention to feedstocks and to volumes. If countries are able to produce commercially competitive biofuels from non-food feedstocks in the next ten years, this would transform the current biofuels market; however, as many experts have pointed out, there is a low likelihood of second-generation biofuels being produced in significant quantities soon. Current biofuels production has resulted in large social and environmental externalities, and these will only worsen if first-generation biofuels production continues to increase as expected or if second-generation biofuels result in the same food vs. fuel and other negative impacts as first-generation biofuels. Biofuels are not created equal, and they should not be treated the same.
- *Volumes Are Key*. The United States producing a few billion liters to replace lead in gasoline as an oxygenate may have been warranted, but decades of subsidies and aggressive mandates for approximately 76BL of food-based biofuels continuing on auto-pilot regardless of food or crop prices has led to numerous unintended consequences.

Policymakers now have a choice. Given all we have learned over the past decade about the impacts of biofuels use, it is time to rethink mandates, targets and other subsidies for biofuels, especially those made from crop-based feedstocks or from other sources with large land-use impacts.

Appendix A: Summary Table with Notes

Table 1: Selected Biofuel-Consuming Country Mandates through 2025

(in billions of liters)

Country	Mandate/target			Current Consumption		Mandated Increase	Transport Fuel Demand Growth through 2025	Added Volume, Full Mandate+ Demand Growth	Projected Demand 2025	
	Timeframe	Ethanol	Diesel	vol	% fuel supply	%	%	vol	vol	% increase
United States	2022	72 BL	3.8 BL	62.9		21%	N/A	13.1	**76.0**	**21%**
European Union	2020	10.0%		18.7	5.0%	72%	-8%	12.1	**30.8**	**64%**
Brazil	2014	25.0%	7%	29.0	27.5%	0%	36%	12.2	**41.2**	**36%**
Argentina	2014	5%	10%	2.0	7.6%	25%	57%	1.3	**3.2**	**64%**
China*	2020	15%	-	3.6	8-12%	50%	59%	3.9	**7.5**	**109%**
India	2014	5%	-	2.3	2.1%	42%	47%	2.0	**4.3**	**89%**
Indonesia	2025	15%	20%	0.8	3.0%	795%	65%	7.1	**8.0**	**860%**
Total Selected				**119.2**				**51.6**	**170.9**	**43%**

Sources:

All current volumes are taken from the most recent US Department of Agriculture (USDA) GAIN reports unless otherwise noted.
Transport fuel demand growth rates are calculated from IEA's New Policies Scenario except for Indonesia and Argentina.
Ethanol and diesel demand estimates for Argentina, for 2015-2024, are taken from USDA's GAIN Report for Argentina, 2014.
Ethanol and diesel demand estimates for Indonesia, for 2015-2024, are taken from USDA's GAIN Report for Indonesia, 2014.
Diesel consumption for India is derived from USDA's GAIN Report for India, 2013.
Current volumes for the US are the Environmental Protection Agency's (EPA) 2013 mandated biofuels volumes.
*China's mandate is for nine provinces only, representing just 1.1% of current fuel use and a projected 1.3% in 2025.

Notes/Assumptions:

(1) The US is assumed to meet slightly over half (20 billion gallons) of its 36 billion gallon Renewable Fuel Standard (RFS) mandate by 2022 (and 2025 for this analysis). We assume the US meets its 15 billion gallon mandate for corn starch ethanol, 1 billion gallon mandate for biodiesel (which could be increased by US EPA), and that the remaining 4 billion gallons are met by imported sugarcane ethanol (total of 20 billion gallons). Again, the biodiesel target could be increased by EPA, leading to less imported sugarcane ethanol, but both are considered first-generation biofuels in this analysis. We assume the remaining 16 billion gallons, mandated to be filled with cellulosic ethanol, a second-generation biofuel, are not produced due to technological and economic challenges, and that EPA waives down this mandate, leaving just 20 billion gallons of the mandate to be fulfilled.

(2) EU estimate for "mandated increase" assumes that adjusting for double-counting for advanced fuels the effective mandate would be 8.6%. At this writing,, the proposed reform to 7% from crop-based sources had not been approved.

(3) Consumption numbers for Brazil are calculated based on the 25% ethanol mandate, the latest figures available. Mandate applies to only a small portion of ethanol market, but we estimate total projected demand for all biofuels driven not by mandate but by demand growth including all biofuel types.

(4) Calculated Argentina's transportation demand differently because USDA estimates a change in ratios of gasoline to diesel. Calculated separate demand increases for gasoline and diesel, which has implications for ethanol and biodiesel use.

(5) China has a 10% mandate and a 15% target but for only nine provinces. We assumed China would not expand beyond the nine provinces and would meet its 15% target (and used this as its mandate) because past targets have systematically been met. China's transportation fuel demand growth rate in affected provinces is assumed to be the same as China's overall growth rate. Where uncertainty in current implementation of mandates exists, the midpoint of the range was used for calculations (e.g. China 8-12% current ethanol blend was calculated at 10%).

(6) Only considered India's 5% bioethanol mandate to be binding, so we did not assume the country's 20% bioethanol and 20% biodiesel targets would be filled.

(7) Indonesia currently has a 5% mandate for biofuels, but also has more aggressive targets of E15 and B20 by 2025. The higher targets are used in this analysis.

(8) All transportation growth is annualized on a linear basis from IEA and USDA growth rates.

(9) The growth rate for Chinese transportation fuel demand is for the entire country though the mandate covers only nine provinces.

Appendix B: Global Biofuel Mandates

OECD

Country/ Region	Mandate/Target	Level of Implementation	Anticipated Growth to Reach Mandate (%)	Primary Feedstock
OECD	**Various**	**Implemented, or on track to be fully implemented by target dates.**	**Various**	**Various. Both domestically produced and imported.**
United States	137BL of biofuels by 2022 divided into requirements for first generation, advanced and cellulosic fuels.[159]		21% growth to meet non-cellulosic mandate by 2022. Current production of 58BL of ethanol (corn and sugar) and 5BL of biodiesel.	Corn, soy, animal fat, sugar cane (imported).
Canada	5% national bioethanol mandate; 2% national biodiesel mandate; up to 8.5% bioethanol mandates in four provinces.	Fully implemented.	None.	Corn, wheat, canola oil.[160]
European Union	10% of transportation fuels from renewables by 2020 but proposal for only 7% from food-based feedstocks. Projected volumes for full implementation would be around 30,000ktoe.[161]	In 2012, most countries were on track to meet the 2020 targets. Projections show the EU will fall short of its 2020 goal by approximately 1/3 using around 20,000ktoe in 2020.[162]	92% increase required to meet 10% mandate, which accounts for a drop in transportation demand.	Varies from country to country.
Germany		7-8% of transportation fuel from bioethanol in 2009.[163] 2.6 billion tonnes of biodiesel in 2010; insolvency in companies is leading to lower numbers in recent years.[164]	2-3% from EU 2020 target.	Vegetable oil.[165]
United Kingdom		3.45% of transport fuel from bioethanol.[166]	6.55% from EU 2020 target.	Wheat and sugar beets.[167]

Country/ Region	Mandate/Target	Level of Implementation	Anticipated Growth to Reach Mandate (%)	Primary Feedstock
Spain	Revised targets down to 4.1% for all bioenergy and 3/9% for bioethanol in 2013.[168]	Biodiesel blending has not been enforced since 2010. Revised targets were met in 2013.[169]	6.1% from EU 2020 target.	Domestic oil seeds, imported palm, and animal fat.[170]
France	Current target of 7%.[171]	5.78% from bioethanol and 7.07% from biodiesel.[172]	4.28% from EU 2020 target.	Corn and sugar beets.[173]
Italy		4% of transport fuel from bioethanol in 2009.[174]	6% from EU 2020 target.	Rapeseed, soy, palm, cereal and wine byproducts.[175]
Sweden		Reached target of 10% biofuels in transport fuels.[176]	Met EU 2020 target.	Rapeseed and wood pellets.[177]
Australia	New South Wales 5% ethanol mandate and 2% biodiesel mandate.[178]	Implemented. 6% ethanol mandate adjusted down to 5% until more local supplies are available.[179]	None.	
New Zealand	Biofuel mandate allowed to expire.[180]	The bioethanol excise exemption remains, but other subsidies have been allowed to expire.[181]	N/A.	
South Korea	2% biodiesel mandate.[182]	Since 2010, held production at 400,00kL/year.[183]	None.	
Mexico	2% ethanol mandates in two provinces.	Not fully implemented.	Unclear.	
Chile	5% ethanol and biodiesel target.	Target not met.	Unclear.	Import dependent. No significant domestic production.
Turkey	6% ethanol mandate and 1% biodiesel mandate.[184]	Implemented. Biodiesel blend rate exceeded.[185]	Ethanol usage must double.[186]	Waste cooking oil and sugar beets.[187]

Producers Meeting High Mandates

Country/ Region	Mandate/Target	Level of Implementation	Anticipated Growth to Reach Mandate (%)	Primary Feedstock
	Greater than or equal to 10% ethanol or biodiesel.	**Fully implemented or close to full implementation.**	**Various.**	**Various.**
Argentina	10% biodiesel mandate, 5% ethanol mandate.[188]	Implemented, average national ethanol blend of 7.6% in 2013 (600 million liters).[189]	64% increase to meet current mandates in 2025, which includes increased transport demand.	Soy, sugarcane.[190]
Brazil	25% ethanol blend mandate, 7% biodiesel mandate.[191]	Fully implemented.	36% increase required to maintain current blend level with increased transport demand by 2025.	Sugarcane and soy.
Colombia	8% or 10% ethanol mandate depending on stocks.	Fully implemented.	None.	Sugar cane and palm.[192]
Ecuador	5% biodiesel mandate to increase to 10%; 10% ethanol mandate.[193]	Mandates were being filled as of 2012.[194]	None.	Palm, sugar cane, jatropha.[195]
Paraguay	25% ethanol mandate, but the Senate has passed an increase to 27.5%; 1% biodiesel mandate.[196]	Fully implemented.	None.	Sugarcane.
Peru	7.8% ethanol mandate; 5% biodiesel mandate.[197]	Implemented.	None.	Primarily importing Argentine biodiesel.[198]
Philippines	10% ethanol mandate; 2% biodiesel mandate.[199]	Implemented, but difficulty reaching the 10% ethanol mandate,[200] planned expansion to 5% biodiesel is not yet implemented.	None. 3% for proposed biodiesel expansion.	Palm and coconut oil.
Zimbabwe	15% ethanol mandate (recently up from 5%).[201]	Forced to scale back 20% mandate due to lower production.[202]	None for adjusted mandate.	

Producers Proposing High Mandates

Country/ Region	Mandate/Target	Level of Implementation	Anticipated Growth to Reach Mandate (%)	Primary Feedstock
	Mandates over 5%.	**Not yet fully implemented or level of future implementation is unclear.**	**Various.**	**Various.**
Costa Rica	7% ethanol mandate; 20% biodiesel mandate.[203]	Unclear: seemingly not fully implemented.[204]	Unclear.	Jatropha,[205] palm, sugar cane.[206]
Panama	Currently 5% ethanol mandate to rise to 10% by 2016.	Unlikely to reach 10% by 2016 due to lack of capacity.[207]	5%.	Sugarcane.
China (PRC)	10% biofuels mandate by 2020; 15% biofuels target by 2020.[208]	E10 required and implemented in 9 provinces.[209] Actual blend rate reported between 8 and 12%.[210]	109% increase required to meet 15% biofuels target, which includes expected increased transport demand.	Grain, waste cooking oil, investing in sorghum, cassava and other food crops that can be grown on marginal land.[211]
India	5% ethanol mandate (reduced from 20% target); 20% biodiesel target.[212]	Projected at 2.1% in 2014 and 2.5% in 2015.[213]	89% increase to meet 5% ethanol mandate only by 2025, which includes expected increased transport demand.	Sugarcane, multiple feedstocks for biodiesel moving from jatropha to tree nuts.[214]
Indonesia	5% biofuel mandate; 15% ethanol target and 20% biodiesel target by 2025[215]	4.5% of biodiesel mandate met, but 0% for ethanol.	945% increase to meet full targets and future projected demand for transport fuel.	Palm.
Malaysia	5% biodiesel mandate[216]	Not yet fully implemented throughout the country. Target of this year for implementation in all locations.[217]	Unclear. None if goal is met this year.	Palm.
Thailand	10% biodiesel target by 2019.[218]	Level of implementation depends on palm oil supplies.	Unclear.	Palm.
Vietnam	5% ethanol mandate to go into effect at the end of 2014.[219]	Has not yet begun.	N/A	

Country/ Region	Mandate/Target	Level of Implementation	Anticipated Growth to Reach Mandate (%)	Primary Feedstock
Malawi	10% ethanol mandate.[220]	Only major producer of ethanol in Southern Africa. No readily available data on steps it has taken to meet the mandate.	Unclear.	Jatropha[221] and sugarcane.

All Other Mandates

Country/ Region	Mandate/Target	Level of Implementation	Anticipated Growth to Reach Mandate (%)	Primary Feedstock
Jamaica	10% ethanol mandate[222]	Unclear.	Unclear.	
Uruguay	2% biodiesel mandate from domestic biodiesel; thought will move to 5% ethanol mandate.[223]	Unclear.	Unclear.	Soy, tallow, sugarcane.[224]
Fiji	Voluntary 10% ethanol blend, 5% biodiesel blend.[225]	Unclear.	Unclear.	Unclear.
Taiwan	1% biodiesel mandate.[226]		None.	
Angola	10% ethanol mandate.[227]		Unclear.	Sugar.[228]
Ethiopia	5% ethanol mandate.[229]	Some biofuels plants online, the majority are pre-implementation.[230]	Unclear.	Sugar and jatropha.[231]
Kenya	Kisumu has a 10% ethanol mandate.[232]	Not implemented. Mandate remains a target.	Unclear (close to 10%)	Jatropha.[233]
Mozambique	10% ethanol mandate.[234]	Have created a legal framework, but not fully implemented.[235] 36MnL/year average 2010-2012.[236]	Unclear (close to 10%)	
Nigeria	10% ethanol target.[237]	Not implemented.[238]	Unclear (close to 10%)	
South Africa	Planned 2% ethanol targets and 5% biodiesel targets to begin in 2015.[239]	367MnL/year ethanol production average 2010-2012.[240]	N/A	Sugar cane, sugar beet, sweet sorghum, soybeans, sunflower seed, canola oil and vegetable oil.[241]
Sudan	5% ethanol mandate.[242]	Plans for expanded production. No indication have reached 5%.	Unclear.	Jatropha.

Appendix C: Biofuels Projects in Ethiopia[243]

Table 2: List of biofuel projects in Ethiopia as of December 2012

Feedstock	Project	Investment Type (Public, domestic private, foreign private)	Area (ha)	Location	Current Status of implementation
Sugar cane [3]	Fincha Sugar Factory	Public	21,000	Oromiya	Operational
	Metahara Sugar Factory	Public		Oromiya	Operational
	WONJI / SHOA SUGAR FACTORY	Public	16,000	Oromiya	Operational
	Tendaho Sugar Development Project	Public	50,000	Afar	Implementation
	Wolkaiyt Sugar Development Project	Public	45,000	Tigray	Implementation
	Kuraz Sugar Development Project	Public	175,000	SNNPR	Implementation
	Kessem Sugar Development Project	Public	20,000	Oromiya	Implementation
	Belles Sugar Development Project	Public	75,000	Amhara	Implementation
	BDFC Ethiopia Industry P.L.C	Foreign	18,000	Amhara	Pre - implementation
Castor	Acazis Ethiopia PLC	Foreign	15,000	Oromiya	Operational
	Global Energy Ethiopia	Foreign	2,700	SNNPR	Implementation
	HUSEYIN POLAT	Foreign		Oromiya	Implementation
Jatropha	Sun Biofuels Ethiopia/National Biodiesel Corporation	Foreign	80,000	Benishangul Gumuz	Pre - implementation
	Ambasel Jatropha Project	Domestic	20,000	Benishangul Gumuz	Pre - implementation
	Agro peace bio Ethiopia	Foreign	80,000	Multiregional	Pre - implementation
	African Climate Exchange PLC	Foreign	100,000	Multiregional	Pre - implementation
	Energy seeds Ethiopia PLC	Foreign	2	Multiregional	Pre - implementation
	Africa Ethiopia Biomass Energy PLC	Foreign	NK	SNNPR	Pre - implementation
	Ertale Bio Diesel PLC	Foreign	NK	Multiregional	Pre - implementation
	2H 2S International Business PLC	Domestic	100,000	SNNPR	Pre - implementation
	Ethiopia Bio Power PLC	Domestic	NK	SNNPR	Pre - implementation
	Green Energy plc	Domestic	50,000	SNNPR	Pre - implementation
	National Energy PLC	Foreign	NK	Oromiya	Pre - implementation
	OBM Ethio Renewable Energies PLC	Foreign	50,000	Oromiya	Pre - implementation
	F.E.P.E.Amaro Bio-Oil PLC	Foreign	50,000	SNNPR	Pre - implementation
	J.M.B.O Bio Fuel Production PLC	Foreign	2,000	Oromiya	Pre - implementation
	Paul Morrell	Foreign	1,000	Oromiya	Pre - implementation
	Soubra Abdallah Khalid	Foreign	10,000	Oromiya	Pre - implementation
	The Giving Tree Nursery PLC	Foreign	200	Oromiya	Pre - implementation
	Ardent Energy Group,INC.	Foreign	NK	Multiregional	Pre - implementation
	FB BIODIESEL PLC	Foreign	NK	Amhara	Pre - implementation
	Slishi Atile Dessta	Domestic	NK	Addis Ababa	Pre - implementation
	Sayo Biofuel plc	Domestic	NK	Tigray	Pre - implementation

[3] Note that the primary product from sugarcane production is sugar. Ethanol is a by-product made through processing of the molasses.

Source: EIA and MoA, Jan 2013
Note: NK - not known

Endnotes

[1] Jim Lane, "Biofuels Mandates Around the World: 2014 : Biofuels Digest," December 31, 2013,
[2] Ivetta Gerasimchuk et al., *State of Play on Biofuel Subsidies: Are Policies Ready to Shift?* (International Institute for Sustainable Development, June 2012), 10, http://www.iisd.org/gsi/biofuel-subsidies/biofuels-state-play-2012.
[3] Daryl Brown, "IEA's World Energy Outlook 2013: Renewables and Natural Gas to Surge Through 2035," *Power* 158, no. 1 (January 2014): 204.
[4] Ibid., 197.
[5] Ibid.
[6] Ibid.
[7] *OECD-FAO Agricultural Outlook 2014-2023: Biofuels* (OECD/FAO), accessed August 2, 2014, http://stats.oecd.org/Index.aspx?datasetcode=HIGH_AGLINK_2014. 119.
[8] http://web.extension.illinois.edu/ethanol/wateruse.cfm
[9] R. Thomson Wright and I Edy Wiyono, *Indonesia Biofuels Annual* (USDA Foreign Agricultural Service: Global Agricultural Information Network, July 1, 2014), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Jakarta_Indonesia_6-27-2014.pdf.
[10] Amit Aradhey, *India Biofuels Annual* (USDA Foreign Agricultural Service: Global Agricultural Information Network, July 1, 2013), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_New%20Delhi_India_7-1-2014.pdf.
[11] http://www.iatp.org/files/451_2_73253.pdf
[12] http://www.fao.org/fileadmin/user_upload/hlpe/hlpe_documents/HLPE_Reports/HLPE-Report-5_Biofuels_and_food_security.pdf
[13] http://www.ewg.org/research/going-going-gone; https://www.cbo.gov/publication/41173; http://www.oaklandinstitute.org/land-deals-africa-tanzania
[14] http://smarterfuelfuture.org/resource-center/details/cellulosic-ethanol-just-around-the-corner-since-2007
[15] http://www.nap.edu/catalog.php?record_id=13105
[16] http://www.ethanolrfa.org/exchange/entry/rfa-president-speaks-at-cellulosic-biofuels-summit/
[17] Jim Lane, "Biofuels Mandates Around the World."
[18] Sergio Barros, *Brazil Biofuels Annual* (USDA Foreign Agricultural Service: Global Agricultural Information Network, July 25, 2014), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Sao%20Paulo%20ATO_Brazil_7-25-2014.pdf.
[19] Ivetta Gerasimchuk et al., *State of Play on Biofuel Subsidies: Are Policies Ready to Shift?*, 10.
[20] Brown, "IEA's World Energy Outlook 2013," 204.
[21] Ibid., 197.
[22] Ibid.
[23] *OECD-FAO Agricultural Outlook 2014-2023: Biofuels*. 119.
[24] Ivetta Gerasimchuk et al., *State of Play on Biofuel Subsidies: Are Policies Ready to Shift?*, 6.
[25] Ralph Sims et al., "From 1st to 2nd Generation Biofuels: An Overview of Current Industry and RD&D Activities," 2008, 1, http://www.iea.org/papers/2008/2nd_Biofuel_Gen.pdf.
[26] Brown, "IEA's World Energy Outlook 2013," 197.
[27] Ivetta Gerasimchuk et al., *State of Play on Biofuel Subsidies: Are Policies Ready to Shift?*, 10.
[28] http://www.bmel.de/SharedDocs/Downloads/Landwirtschaft/Welternaehrung/OECD-FAO-AgriculturalOutlook.pdf?__blob=publicationFile
[29] http://www.cbo.gov/publication/45477; http://www.nap.edu/catalog.php?record_id=1310
[30] http://www.ase.tufts.edu/gdae/Pubs/rp/ActionAid_Fueling_Food_Crisis.pdf
[31] http://www.actionaidusa.org/sites/files/actionaid/biofueling_hunger_aausa.pdf
[32] http://www.biofuelsdigest.com/bdigest/2011/04/19/world-bank-chief-calls-for-relaxation-of-biofuels-mandates-to-ease-food-price-pressure/
[33] http://www.actionaidusa.org/eu/2012/07/g20-and-biofuels#sthash.U3oxrEAp.dpuf, http://unctad.org/en/docs/2011_G20_FoodPriceVolatility_en.pdf
[34] http://www.fao.org/fileadmin/user_upload/hlpe/hlpe_documents/HLPE_Reports/HLPE-Report-5_Biofuels_and_food_security.pdf
[35] http://www.nature.com/nclimate/journal/v4/n8/full/nclimate2277.html
[36] http://www.scientificamerican.com/article/deforestation-in-indonesia-is-double-the-government-s-official-rate/

[37] http://www.wri.org/sites/default/files/pdf/indoforest_full.pdf
[38]https://d3n8a8pro7vhmx.cloudfront.net/rainforestactionnetwork/pages/2911/attachments/original/1417555307/BWPT_Investor_Warning_DEC2014.pdf?1417555307
[39] Sims et al., "From 1st to 2nd Generation Biofuels: An Overview of Current Industry and RD&D Activities," 1.
[40] http://www.nap.edu/catalog.php?record_id=13105; http://www.cbo.gov/publication/45477]
[41] http://www.actionaid.org/sites/files/actionaid/biofuels_energy_hunger.pdf
[42] http://www.cbo.gov/publication/45477; http://www.nap.edu/catalog.php?record_id=13105
[43] *Technology Roadmap: Biofuels for Transport* (Paris, France: International Energy Agency, 2011), 27, http://www.iea.org/publications/freepublications/publication/biofuels_roadmap.pdf.
[44] High Level Panel of Experts, *Biofuels and Food Security* (Rome: Committee on World Food Security, June 2013), http://www.fao.org/fileadmin/user_upload/hlpe/hlpe_documents/HLPE_Reports/HLPE-Report-5_Biofuels_and_food_security.pdf.
[45] Ibid.
[46] United States Department of Agriculture Economic Research Service, "Feed Grains Database," July 16, 2014, http://www.ers.usda.gov/data-products/feed-grains-database/feed-grains-custom-query.aspx#ResultsPanel.
[47] Erin Voegele, "DEFRA Releases UK Biofuel Feedstock Production Statistics," *Ethanol Producer Magazine*, February 20, 2013, http://ethanolproducer.com/articles/9588/defra-releases-uk-biofuel-feedstock-production-statistics.
[48] *Ibid.*
[49] Anselm Eisentraut, *Sustainable Production of Second-Generation Biofuels: Potential and Perspectives in Major Economies and Developing Countries* (Paris, France: International Energy Agency, February 2010), 13, http://www.iea.org/publications/freepublications/publication/second_generation_biofuels.pdf.
[50] Ibid., 14.
[51] Ivetta Gerasimchuk et al., *State of Play on Biofuel Subsidies: Are Policies Ready to Shift?*, 6.
[52] Ibid.
[53] Ibid.
[54] Anselm Eisentraut, *Sustainable Production of Second-Generation Biofuels: Potential and Perspectives in Major Economies and Developing Countries*, 17.
[55] *OECD-FAO Agricultural Outlook 2014-2023: Biofuels*.
[56] United States Environmental Protection Agency, "Renewable Fuel Standard (RFS)," *Fuels and Fuel Additives*, December 10, 2013, http://www.epa.gov/otaq/fuels/renewablefuels/.
[57] United States Environmental Protection Agency, "Renewable Fuel Standard (RFS)," *Fuels and Fuel Additives*, December 10, 2013, http://www.epa.gov/otaq/fuels/renewablefuels/.
[58] Gilmar Masiero, *Ethanol and Biodiesel: The Role of Brazil and South Korea in the Emerging Alternative-Energy Market* (Korea Economic Institute, December 2008), 1, http://kki.org/sites/default/files/publications/APSMasiero.pdf.
[59] Ibid.
[60] Chris Charles, Marius Keller, and Tom Moerenhout, *Biofuels--At What Cost?: A Review of Costs and Benefits of France's Biofuel Policies* (Global Subsidies Initiative of the International Institute for Sustainable Development, September 2013), 1, http://www.transportenvironment.org/sites/te/files/publications/bf_costeffectiveness_france.pdf.
[61] Ivetta Gerasimchuk et al., *State of Play on Biofuel Subsidies: Are Policies Ready to Shift?*, 9.
[62] Jack Peckham, "IEA World Energy Outlook to 2035: Diesel Growth Outruns Everything," *Global Refining & Fuels Report* 16, no. 24 (November 27, 2012): 56.
[63] Ibid.
[64] Ibid., 35.
[65] Ibid., 39.
[66] Ibid.
[67] Ibid., 40.
[68] Ibid., 37.
[69] Ibid., 35.
[70] Ibid., 44; http://www.imf.org/external/np/pp/eng/2013/012813.pdf
[71] Peckham, "IEA World Energy Outlook to 2035," 197.
[72] Ibid.
[73] Ibid., 59.
[74] Ibid.

[75] Ibid., 71.
[76] International Energy Agency, *World Energy Investment Report*, Special Report (Paris, France: OECD/IEA, 2014), 24, http://www.iea.org/publications/freepublications/publication/WEIO2014.pdf.
[77] Ibid.
[78] Peckham, "IEA World Energy Outlook to 2035," 197.
[79] Ibid.
[80] Ibid.
[81] Ibid.
[82] "About the OECD," *OECD: Better Policies for Better Lives*, n.d., http://www.oecd.org/about/.
[83] "Members and Partners," *OECD: Better Policies for Better Lives*, accessed November 28, 2014, http://www.oecd.org/about/membersandpartners/#d.en.194378.
[84] *OECD-FAO Agricultural Outlook 2014-2023: Biofuels*. 117.
[85] *Ibid.* 119.
[86] *Ibid.*
[87] *Ibid.* 110.
[88] International Energy Agency, *World Energy Investment Report*, 29.
[89] *OECD-FAO Agricultural Outlook 2014-2023: Biofuels*. 117.
[90] *Ibid.* 110.
[91] *Ibid.* 110.
[92] *Ibid.* 114.
[93] http://dailycaller.com/2013/01/04/biodiesel-tax-credit-extension-will-pay-industry-for-fuels-produced-while-it-was-expired/
[94] *OECD-FAO Agricultural Outlook 2014-2023: Biofuels*. 114.
[95] *Ibid.*
[96] *International Energy Outlook 2014* (Washington, DC: EIA, September 9, 2014), 33, http://www.eia.gov/forecasts/ieo/.
[97] Ibid.
[98] Ibid.
[99] Ibid.
[100] Ibid.
[101] Jim Lane, "Biofuels Mandates Around the World."
[102] R. Thomson Wright and I Edy Wiyono, *Indonesia Biofuels Annual*.
[103] "Petroleum & Other Liquids," *EIA Independent Statistics & Analysis*, November 26, 2014, http://www.eia.gov/dnav/pet/pet_move_expc_a_EPOOXE_EEX_mbbl_a.htm.
[104] Laborde, David, "Assessing the Land Use Change Consequences of European Biofuel Policies," European Commission, 2011. http://www.ifpri.org/sites/default/files/publications/biofuelsreportec2011.pdf
[105] "Major Biofuel Producers by Region," *Biofuels: The Fuel of the Future*, accessed November 28, 2014, http://biofuel.org.uk/major-producers-by-region.html.
[106] *Annual Energy Outlook 2014 with Projections to 2040* (Washington, DC: EIA, April 2014), 15, http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf.
[107] "Renewable Fuel Standard," *Alternative Fuels Data Center, U.S. Department of Energy: Energy Efficiency & Renewable Energy*, accessed November 28, 2014, http://www.afdc.energy.gov/laws/RFS.
[108] *Annual Energy Outlook 2014 with Projections to 2040*, 15.
[109] "Renewable Fuels: Regulations & Standards," *EPA: Fuels and Fuel Additives*, November 21, 2014, http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm.
[110] "Petroleum & Other Liquids."
[111] *OECD-FAO Agricultural Outlook 2014-2023: Biofuels*. 121.
[112] http://www.nap.edu/catalog/13105/renewable-fuel-standard-potential-economic-and-environmental-effects-of-us
[113] European Commission: Energy, "Renewable Energy: Action Plans & Forecasts," accessed July 30, 2014, http://ec.europa.eu/energy/renewables/action_plan_en.htm.
[114] Official Journal of the European Union, *Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the Promotion of the Use of Energy from Renewable Sources and Amending and Subsequently Repealing Directives 2001/77/EC and 2003/30/EC*.
[115] European Commission: Energy, "Renewable Energy: Targets by 2020," accessed July 30, 2014, http://ec.europa.eu/energy/renewables/targets_en.htm.

[116] *OECD-FAO Agricultural Outlook 2014-2023: Biofuels*. 88.
[117] *Report from the Commission to the European Parliament, The Council, The European Economic and Social Committee and the Committee of the Regions: Renewable Energy Progress Report* (Brussels, Belgium: European Commission, March 27, 2013), 11, http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52013DC0175&from=EN.
[118] *Report from the Commission to the European Parliament, The Council, The European Economic and Social Committee and the Committee of the Regions: Renewable Energy Progress Report*, 11.
[119] Ibid., 6.
[120] Ibid.
[121] Sergio Barros, *Brazil Biofuels Annual*.
[122] "Brazil's Senate Approves Bill Raising Biodiesel, Ethanol Blends," *Platss*, September 2, 2014, http://www.platts.com/latest-news/agriculture/riodejaneiro/brazils-senate-approves-bill-raising-biodiesel-21166276.
[123] "U.S. Ethanol Imports from Brazil down in 2013," *EIA Today in Energy*, May 5, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=16131. and Sergio Barros, *Brazil Biofuels Annual*.
[124] Lucia Kassai, "Brazil Ethanol Exports to Drop to 11-Year Low, Dreyfus Unit Says," *Bloomberg*, April 28, 2014, http://www.bloomberg.com/news/2014-04-28/brazil-ethanol-exports-to-drop-to-11-year-low-dreyfus-unit-says.html.
[125] Ibid.
[126] http://pdba.georgetown.edu/CLAS%20RESEARCH/Working%20Papers/WP18.pdf, http://fpc.state.gov/documents/organization/93476.pdf
[127] Kai Thaler, "Brazil, Biofuels, and Food Security in Mozambique," in *Agricultural Development and Food Security in Africa: The Impact of Chinese, Indian and Brazilian Investments* (London: Zed Books, 2013), 145–58, http://scholar.harvard.edu/files/kaithaler/files/chapter_8_thaler-brazil_and_mozambique_revised_draft_0.pdf. and Stephanie Hanson, "Brazil's Ethanol Diplomacy," *Council on Foreign Relations*, July 9, 2007, http://www.cfr.org/renewable-energy/brazils-ethanol-diplomacy/p13721.
[128] Wilson Almeida, *Ethanol Diplomacy: Brazil and U.S. in Search of Renewable Energy* (Georgetown University Center for Latin American Studies, April 15, 2009), http://pdba.georgetown.edu/CLAS%20RESEARCH/Working%20Papers/WP18.pdf., and http://fpc.state.gov/documents/organization/93476.pdf
[129] Hanson, "Brazil's Ethanol Diplomacy."
[130] Ken Joseph, *Argentina: Biofuels Annual 2013* (USDA Foreign Agricultural Service: Global Agricultural Information Network, June 28, 2013), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Buenos%20Aires_Argentina_6-28-2013.pdf.
[131] Ibid.
[132] Ibid.
[133] Ibid., 10.
[134] Ken Joseph, *Argentina: Biofuels Annual 2013*.
[135] Ryan Scott and Jiang Junyang, *Peoples Republic of China Biofuels Annual* (USDA Foreign Agricultural Service: Global Agricultural Information Network, September 9, 2013), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Beijing_China%20-%20Peoples%20Republic%20of_9-9-2013.pdf.
[136] "Global Biofuels-an Overview," *European Biofuels Technology Platform: Accelerating Deployment of Advanced Biofuels in Europe*, July 28, 2014, http://www.biofuelstp.eu/global_overview.html.
[137] Ryan Scott and Jiang Junyang, *Peoples Republic of China Biofuels Annual*.
[138] Ibid.
[139] Ibid.
[140] Aradhey, *India Biofuels Annual*.
[141] "Biofuels Mandates Around the World: 2012," *Biofuels Digest*, accessed November 28, 2014, http://www.biofuelsdigest.com/bdigest/2012/11/22/biofuels-mandates-around-the-world-2012/.
[142] Amit Aradhey, *India Biofuels Annual*.
[143] Ibid.
[144] *National Policy on Biofuels* (New Delhi: Government of India Ministry of New & Renewable Energy), accessed November 28, 2014, http://mnre.gov.in/file-manager/UserFiles/biofuel_policy.pdf.
[145] Ibid., 3.

[146] "International Energy Statistics," *EIA Independent Statistics & Analysis*, accessed November 28, 2014, http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=79&pid=81&aid=1&cid=all,&syid=2007&eyid=2011&unit=TBPD.
[147] Jim Lane, "Biofuels Mandates Around the World."
[148] R. Thomson Wright and I Edy Wiyono, *Indonesia Biofuels Annual*.
[149] Ibid.
[150] Ibid.
[151] "The Rainforest Alliance and Palm Oil," *Rainforest Alliance*, 2015, http://www.rainforest-alliance.org/work/agriculture/palm-oil. Tara Kelly, "Girl Scouts Win U.N. Award For Efforts To Save Orangutans By Eliminating Palm Oil From Cookies," *Huffington Post*, February 9, 2012, http://www.huffingtonpost.com/2012/02/09/girl-scouts-win-award-united-nations_n_1265843.html. "WWF - Palm Oil," *WWF International*, accessed January 12, 2015, http://wwf.panda.org/what_we_do/footprint/agriculture/palm_oil/.
[152] Gisela Prasad, *Bioenergy, Rural Development and Poverty Alleviation in Southern Africa* (Energy Research Centre, University of Cape Town: Global Network on Energy for Sustainable Development, September 2010), http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=2&ved=0CCkQFjAB&url=http%3A%2F%2Fwww.gnesd.org%2F~%2Fmedia%2FSites%2FGNESD%2FPublication%2520pdfs%2FBioenergy_PotentialForDevelopment_SPM.ashx&ei=jTN5VLDLHNTesATsvIHoAg&usg=AFQjCNETKkxjTK4Y754qDibg7Y3R6LfmfQ&sig2=cGOOQFz9hAdVUZK5DQ2tAA&bvm=bv.80642063,d.cWc.
[153] Richard Kunz, "Bioenergy in Water Scarce Countries: Experiences from South Africa," November 25, 2011, http://ieabioenergytask43.org/wp-content/uploads/2013/09/1120-Kunz.pdf.
[154] *South Africa BEFS Country Brief*, Bioenergy and Food Security Projects (FAO, 2013), http://www.fao.org/energy/36348-06e268a674f478f0d7a2f17c362ff140.pdf.
[155] *OECD-FAO Agricultural Outlook 2014-2023: Biofuels*.
[156] Meghan Sapp, "Zimbabwe to Stay With E15," *BiofuelsDigest*, June 23, 2014, http://www.biofuelsdigest.com/bdigest/2014/06/23/zimbabwe-to-stay-with-e15/.
[157] *Sustainable Brazil: An Outlook on the Oil, Ethanol and Gas Markets* (Ernst & Young Terco), accessed November 28, 2014, http://www.ey.com/Publication/vwLUAssets/Sustainable_Brazil_-_Oil_and_Gas/$FILE/Sustainable_Brazil_Oil_and_Gas.pdf.
[158] Pete Harrison et al., *Wasted: Europe's Untapped Resource: An Assessment of Advanced Biofuels from Wastes & Residues* (ECF, February 26, 2014), http://www.theicct.org/sites/default/files/publications/WASTED-final.pdf.
[159] http://www.ewg.org/research/will-real-ethanol-beneficiaries-please-stand
[160] "Plant Locations," *Canadian Renewable Fuels Association*, 2010, http://www.greenfuels.org/en/industry-information/plants.aspx.
[161] *Report from the Commission to the European Parliament, The Council, The European Economic and Social Committee and the Committee of the Regions: Renewable Energy Progress Report*, 6.
[162] Ibid.
[163] Ivetta Gerasimchuk et al., *State of Play on Biofuel Subsidies: Are Policies Ready to Shift?*, 11.
[164] Anna Rauch and Michael Thone, *Biofuels--At What Cost: Mandating Ethanol and Biodiesel Consumption in Germany* (Global Subsidies Initiative and International Institute for Sustainable Development, January 2012), http://www.iisd.org/gsi/sites/default/files/bf_awc_germany.pdf.
[165] Ibid.
[166] *Renewable Transport Fuel Obligation Statistics, Obligation Period 6 2013/14, Report 3* (Department of Transport, May 1, 2014), https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/306399/rtfo-2013-14-year-6-report-3.pdf.
[167] Erin Voegele, "DEFRA Releases UK Biofuel Feedstock Production Statistics."
[168] Marta Guerrero, *Spain Biodiesel Standing Report* (USDA Foreign Agricultural Service: Global Agricultural Information Network, December 10, 2013), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biodiesel%20Standing%20Report_Madrid_Spain_11-26-2013.pdf.
[169] Ibid.
[170] Ibid.
[171] Chris Charles, Marius Keller, and Tom Moerenhout, *Biofuels--At What Cost?: A Review of Costs and Benefits of France's Biofuel Policies*, 4.

[172]Ibid., 2.
[173]Ibid., 3.
[174] Ivetta Gerasimchuk et al., *State of Play on Biofuel Subsidies: Are Policies Ready to Shift?*, 11.
[175]Ornella Bettini, *Italy: Biofuels Overview 2014* (USDA Foreign Agricultural Service: Global Agricultural Information Network, April 9, 2014), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Overview%202014_Rome_Italy_4-9-2014.pdf.
[176] *Energy Policy Highlights* (Paris, France: International Energy Agency, 2014), 20, http://www.iea.org/publications/freepublications/publication/energy_policy_highlights_2013.pdf.
[177]Aziz Elbehri, Anna Segerstedt, and Pascal Liu, *Biofuels and the Sustainability Challenge: A Global Assessment of Sustainability Issues, Trends and Policies for Biofuels and Related Feedstocks* (Rome: FAO, 2013), http://www.fao.org/docrep/017/i3126e/i3126e.pdf.
[178] "Biofuels in NSW," *NSW Government: Trade & Investment Resources & Energy*, accessed November 26, 2014, http://www.resourcesandenergy.nsw.gov.au/energy-consumers/sustainable-energy/office-of-biofuels/biofuels-in-nsw.
[179] Ibid.
[180] Jim Lane, "Biofuels Mandates Around the World."
[181] Ibid.
[182] Ibid.
[183] Task 39 IEA Bioenergy, "Commercializing Liquid Biofuels from Biomass," September 2012, 6, http://task39.org/files/2013/05/IEA-Bioenergy-Task-39-Newsletter-Issue-31-Korea-September-2012.pdf.
[184] Gulden Boluk and A. Ali Koc, "The Implications of Biofuel Policy in Turkey," *International Journal of Energy Economics and Policy* 3 (2013): 14–22.
[185] Ibid., 18.
[186] Ibid.
[187] Ibid., 17.
[188] "Renewable Fuel Standard," *Alternative Fuels Data Center, U.S. Department of Energy: Energy Efficiency & Renewable Energy*, accessed November 28, 2014, http://www.afdc.energy.gov/laws/RFS.
[189] Ken Joseph, *Argentina: Biofuels Annual 2013*.
[190] Ibid.
[191] Sergio Barros, *Brazil Biofuels Annual*.
[192] Leonardo Pinzon, *Colombia Biofuels Annual* (USDA Foreign Agricultural Service: Global Agricultural Information Network, June 26, 2014), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Bogota_Colombia_6-26-2014.pdf.
[193] Jim Lane, "Biofuels Mandates Around the World."
[194] Henry Vega, *Ecuador Biofuel Industry, Ethanol, Biodiesel, Production, Forecast 2012*, Ecuador Biofuels Annual (USDA Foreign Agricultural Service: Global Agricultural Information Network, June 28, 2012), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Quito_Ecuador_6-28-2012.pdf.
[195] Ibid.
[196] Ken Joseph, *Paraguay Biofuels Annual* (USDA Foreign Agricultural Service: Global Agricultural Information Network, July 21, 2014), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Buenos%20Aires_Paraguay_7-21-2014.pdf.
[197] Gaspar E. Nolte and Mariano J. Beillard, *Peru's Ethanol Production Up, Biodiesel However Tumbles* (USDA Foreign Agricultural Service: Global Agricultural Information Network, June 30, 2014), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Lima_Peru_7-1-2014.pdf.
[198] Ibid.
[199] Jim Lane, "Biofuels Mandates Around the World."
[200] http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Manila_Philippines_10-22-2014.pdf
[201] Jim Lane, "Biofuels Mandates Around the World."
[202] Sapp, "Zimbabwe to Stay With E15."
[203] Jim Lane, "Biofuels Mandates Around the World."
[204] "Costa Rica May at Last Implement E10 Policy : Biofuels Digest," accessed August 3, 2014, http://www.biofuelsdigest.com/bdigest/2012/09/11/costa-rica-may-at-last-implement-e10-policy/.

[205] "Alternative Fuels Americas, Inc. (AFAI) Nears Completion of Costa Rican Biofuel Production Infrastructure, Secures 2M Gallons Worth of Feedstock | The Quality Stocks Daily Blog for Micro-Cap and Small-Cap Companies," accessed August 3, 2014, http://blog.qualitystocks.net/stocks-to-watch/alternative-fuels-americas-inc-afai-nears-completion-of-costa-rican-biofuel-production-infrastructure-secures-2m-gallons-worth-of-feedstock/.
[206] Carlos Murillo R., *Biofuels Trade and Sustainable Development: The Case of Costa Rica* (International Institute for Environment and Development, December 2007), http://www.globalbioenergy.org/uploads/media/0712_IIED_-_Biofuels_trade_and_sustainable_development_the_case_of_Costa_Rica.pdf.
[207] Maria Guardia, *Panama Continues Looking for Biofuel Opportunities* (USDA Foreign Agricultural Service: Global Agricultural Information Network, January 22, 2014), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Panama%20Continues%20Looking%20for%20Biofuel%20Opportunities_Panama_Panama_1-22-2014.pdf.
[208] Jim Lane, "Biofuels Mandates Around the World."
[209] Ibid.
[210] Ryan Scott and Jiang Junyang, *Peoples Republic of China Biofuels Annual*.
[211] "Global Biofuels-an Overview."
[212] Aziz Elbehri, Anna Segerstedt, and Pascal Liu, *Biofuels and the Sustainability Challenge: A Global Assessment of Sustainability Issues, Trends and Policies for Biofuels and Related Feedstocks*, 27 and 43.
[213] Amit Aradhey, *India Biofuels Annual*.
[214] Ibid.
[215] R. Thomson Wright and I Edy Wiyono, *Indonesia Biofuels Annual*.
[216] Jim Lane, "Biofuels Mandates Around the World."
[217] Abdul Ghani Wahab, *Malaysia Biofuels Annual 2014* (USDA Foreign Agricultural Service: Global Agricultural Information Network, June 25, 2014), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Kuala%20Lumpur_Malaysia_6-25-2014.pdf.
[218] "Thailand Plans to Raise Biodiesel Output Target to 7.3 Mil Liters/d by 2021: Source," *Platts*, August 13, 2013, http://www.platts.com/latest-news/oil/singapore/thailand-plans-to-raise-biodiesel-output-target-27287876.
[219] Jim Lane, "Biofuels Mandates Around the World."
[220] Ibid.
[221] *Jatropha as Biofuel for Lighting* (NL Agency Ministry of Foreign Affairs, 2011), http://english.rvo.nl/sites/default/files/2013/12/Biofuel%20production%20-%20Malawi%20-%20TNT%20N.V..pdf.
[222] Jim Lane, "Biofuels Mandates Around the World."
[223] Ibid.
[224] Ken Joseph, *Uruguay Biofuels Annual* (USDA Foreign Agricultural Service: Global Agricultural Information Network, June 4, 2009), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/General%20Report_Buenos%20Aires_Uruguay_6-4-2009.pdf.
[225] Jim Lane, "Biofuels Mandates Around the World."
[226] Ibid.
[227] Ibid.
[228] Olatomiwa Bifarin, "Angola's Biocom Project to Begin Ethanol and Sugar Production in 2014," *Advanced Biofuels USA*, July 9, 2014, http://advancedbiofuelsusa.info/angolas-biocom-project-to-begin-ethanol-and-sugar-production-in-2014.
[229] Jim Lane, "Biofuels Mandates Around the World."
[230] Dawit Alemu, *Scoping Report on the Status of Biofuel Development in Ethiopia* (Overseas Development Institute, February 26, 2013), 4–5, http://www.odi.org/sites/odi.org.uk/files/odi-assets/publications-opinion-files/8795.pdf.
[231] Ibid., 2–3.
[232] Jim Lane, "Biofuels Mandates Around the World."
[233] Souleymane Diaby, *Kenya's Draft National Biofuel Policy* (Nairobi, Kenya: USDA Foreign Agricultural Service: Global Agricultural Information Network, March 30, 2011), http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Kenya%E2%80%99s%20Draft%20National%20Biofuel%20Policy_Nairobi_Kenya_3-30-2011.pdf.
[234] Souleymane Diaby, *Kenya's Draft National Biofuel Policy* (Nairobi, Kenya: USDA Foreign Agricultural Service: Global Agricultural Information Network, March 30, 2011),

http://gain.fas.usda.gov/Recent%20GAIN%20Publications/Kenya%E2%80%99s%20Draft%20National%20Biofuel%20Policy_Nairobi_Kenya_3-30-2011.pdf.
[235] *Operationalizing and Implementing the Biofuel Sustainability Framework for Mozambique* (Wageningen University: NL Agency, September 2012), http://english.rvo.nl/sites/default/files/2014/03/Operationaliziog%20Biofuel%20Sustainability%20Framework%20in%20Mozambique%20-%20sept%202012.pdf.
[236] *OECD-FAO Agricultural Outlook 2014-2023: Biofuels*.
[237] Jim Lane, "Biofuels Mandates Around the World."
[238] *Official Gazette of the Nigerian Bio-Fuel Policy and Incentives* (Federal Republi of Nigeria), accessed November 26, 2014, http://www.sunbirdbioenergy.com/docs/Nigeria_E10_POLICY_GAZETTED.pdf.
[239] Jim Lane, "Biofuels Mandates Around the World."
[240] *OECD-FAO Agricultural Outlook 2014-2023: Biofuels*.
[241] *South Africa BEFS Country Brief*.
[242] Jim Lane, "Biofuels Mandates Around the World."
[243] Dawit Alemu, *Scoping Report on the Status of Biofuel Development in Ethiopia*, 5–6.

35_OP_LCFS_AAUSA Responses

152. Comment: **LCFS 35-2 through LCFS 35-3**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

153. Comment: **LCFS 35-1**

The comment states that lowering the iLUC score for corn ethanol will incentivize greater use of corn ethanol which undermines food security and has questionable environmental benefits.

Agency Response: See response to **LCFS 35-2**.

154. Comment: **LCFS 35-4**

The comment states that government mandates will drive demand growth for biofuels, such as corn ethanol.

Agency Response: The adjustments to the carbon intensity (CI) of corn ethanol as well as the adjustments for other biofuels are based on the latest science and improved modeling. The model as currently structured does not allow a detailed evaluation of the impacts of biofuels on global food security. To evaluate such effects ARB staff would need to collect data for calorific content of food and feed production, and the modeling structure would need to be modified accordingly. When these data become available and are collected, future revisions of the model could allow the evaluation of global food security effects and the effect could be incorporated into the indirect Land Use Change (iLUC) analysis.

See also responses to **LCFS 29-2**, **LCFS 29-3**, **LCFS T29-3**, and **LCFS T25-5**.

This page intentionally left blank.

Comment letter code: 36-OP-LCFS-NLB

Commenter: Jennifer Case

Affiliation: New Leaf Biofuels

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

New Leaf Biofuel
2285 Newton Ave
San Diego CA 92113
P: 619-236-8500
F: 619-236-8585
www.newleafbiofuel.com

36_OP_LCFS
_NLB

14_OP_ADF
_NLB

February 17, 2015

Mary D. Nichols, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95812

RE: **SUPPORT FOR LCFS READOPTION AND ADF REGULATION ADOPTION** at February 19-20, California Air Resources Board Hearing

Dear Chair Nichols:

I am writing to express our support of both the re-adoption of the Low Carbon Fuel Standard ("LCFS") and the adoption of the Alternative Diesel Fuel ("ADF") regulation. We want to thank the leadership and staff at the Air Resources Board (ARB) for all of the hard work on these very important issues to Californians, and applaud you on implementing a program that has served as a blueprint for other carbon reduction plans all over the country. LCFS 36-1

My friends and family started New Leaf Biofuel in San Diego in 2006. Our mission was, and is, to convert used cooking oil into biodiesel, which we then sell back to the community in order to create local jobs at our plant and to reduce greenhouse gas emissions caused by the burning of fossil fuels. We chose to locate our production facility in Barrio Logan because we wanted to contribute to an economically disadvantaged community. Our mission has always focused on serving as a model for economic, environmental, and social sustainability.

Over the years, New Leaf, and the biodiesel industry in general, has faced enormous challenges. These include lack of infrastructure, unstable federal policy, and opposition from fossil fuel interests—just to name a few. The Low Carbon Fuel Standard is a critical policy that demonstrates California's commitment to the environment, and provides stability that will spur investment and innovation to further our carbon reduction goals. We, therefore, fully support the re-adoption of the Low Carbon Fuel Standard. LCFS 36-2

I recognize that the process to craft the ADF regulation has been challenging, and I appreciate your efforts to keep the interests of all stakeholders in mind. Importantly for New Leaf and other community-sized businesses that serve smaller diesel markets, we are particularly supportive of the implementation timeline that is designed to allow our industry to certify an ADF 14-1 additive “solution,” improve infrastructure, or otherwise adjust business plans to comply with the ADF regulation. ADF 14-1 cont.

We also look forward to continuing to work with the ARB on the evaluation of options that would allow limited, district-specific exemptions for some fleets to continue use of biodiesel blends up to and including 20 percent (B20). ADF 14-2 We are optimistic that by continuing to work together, we can strike a balance that will address the air quality and public health concerns particular to each part of the state, while achieving the objectives of the Low Carbon Fuel Standard. LCFS 36-2

Again, thank you for your work on this important issue and for your interest in understanding New Leaf’s perspective.

Sincerely,

New Leaf Biofuel, LLC

a California limited liability company

Jennifer Case, President

36_OP_LCFS_NLB Responses

155. Comment: **ADF14-1 and ADF 14-2**

Agency Response: The responses to these comments are in the Alternative Diesel Regulation Final Statement of Reasons under Comment Letter **14_OP_ADF_NLB**.

156. Comment: **LCFS 36-1**

The comment expresses support for the re-adoption of the LCFS regulation and adoption of the ADF regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

157. Comment: **LCFS 36-2**

The comment expresses appreciation for ARB staff's commitment to both the environment and to providing stability that will spur investment and innovation to further carbon reduction goals.

Agency Response: Staff appreciates New Leaf Biodiesel's support of proposed LCFS regulation. Staff agrees with New Leaf Biodiesel that the objectives of the LCFS are achievable, and the air quality and public health concerns can be addressed simultaneously.

This page intentionally left blank.

Comment letter code: 37-OP-LCFS-Alberta

Commenter: Chris Ryan

Affiliation: Government of Alberta

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

Alberta International and Intergovernmental Relations

Deputy Minister
13th Floor, Commerce Pla
10155 - 102 Street NW
Edmonton, Alberta T5J 4G8
Canada
Telephone 780-415-0900
Fax 780-415-6144
www.international.alberta.ca

37_OP_LCFS
_Alberta

February 17, 2015

Ms. Tracy Jansen
Clerk of the Board
California Air Resources Board
1001 I Street
PO Box 2815
Sacramento, California 95812
USA

Dear Ms. Jansen:

On behalf of the Government of Alberta, I would like to provide you with comments on the re-adoption of the updated Low Carbon Fuel Standard (LCFS) being implemented by the California Air Resources Board (CARB).

Albertans, like Californians, understand the importance of carbon management and the need to gradually transition to alternative, less carbon intensive forms of energy. Nevertheless, North America will continue to require secure supplies of oil and gas for decades to come. As Alberta develops its natural resources, environmental stewardship and social responsibility will continue to remain of great importance.

Alberta has a strong desire to collaborate with other jurisdictions to strengthen North America's integrated energy and economic systems as we continue to focus on technology and innovation to address climate change. Alberta has been a strong supporter of long-term efforts to reduce greenhouse gas emissions and continues to support the intent of the LCFS. The Government of Alberta encourages California to consider Alberta's mandatory upstream oil greenhouse gas emissions reduction policies in the development of Alberta's crude oil carbon intensity (CI) values. Under Alberta's greenhouse gas emissions regulatory framework, oil that comes from a regulated facility has a reduction obligation.

In 2007, Alberta passed the Specified Gas Emitters Regulation (SGER), a regulatory framework to reduce greenhouse gas emissions intensity from large industrial emitters and to set up a carbon trading market. Since July 1, 2007, the regulatory framework requires large emitters (facilities releasing 100,000 tonnes or more of greenhouse gas emissions annually) to reduce emissions intensity by 12 per cent.

.../2

There are four choices to comply with reduction targets:

1) make facility improvements to reduce greenhouse gas emissions intensity;
2) use emission performance credits (exceeding 12 per cent target) created in previous years or at other facilities;
3) purchase Alberta-based carbon offset credits; and/or
4) pay $15 per tonne into the Climate Change and Emissions Management Fund (CCEMF).

To date, nearly 51 megatonnes of reductions have been realized relative to business-as-usual projections, and over $503 million has been contributed to the CCEMF, with $249 million invested into clean energy projects.

In the re-proposed LCFS, there does not appear to be recognition of emissions reductions achieved through flexible compliance options, such as Alberta-based carbon offsets, in the development of CI values. A robust analysis of various international crudes should recognize all emissions reductions driven by a jurisdiction's climate change policies. This should include direct emission reductions, as well as greenhouse gas emission reductions that occur through carbon offsets. LCFS 37-1

It would also be of interest to Alberta to understand how marketable crude oils (MCOs) derived from SGER facilities may be incentivized under the re-adopted LCFS. We are pleased to see that the proposed and updated *Crude Oil Carbon Intensity Lookup Table* values now reference a single, non-discriminatory baseline default CI value for all MCOs that comprise the California crude basket, regardless of production method. However, as previously outlined to the CARB in our 2012 submission, updating the LCFS to address issues regarding crude production data quality will be paramount to LCFS's ability to meet regulatory goals. LCFS 37-2

Assumptions made on crude oil production in absence of transparent data may have significant impact on the overall carbon-intensity value of a particular crude oil pathway and how it is categorized. LCFS 37-3

.../3

As drafted, accuracy for LCFS crude estimates is ultimately limited by the data quality reported by an operator. Data quality within North America, and even more significantly from overseas sources, varies considerably from region to region, with key crude production data often remaining undisclosed, such as flaring and venting and produced fluids. As such, data variability and information gaps between jurisdictions have a considerable impact on the uncertainty associated with the estimated carbon-intensity value of their respective crude oils. Relative to Alberta, the availability and reliability of crude production data input into the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model provided to California by other jurisdictions remains an outstanding concern. LCFS 37-3 cont.

During a February 20, 2014 workshop[1] in Brussels, Belgium, Professor Adam Brandt discussed details for current work in areas of model calibration and data uncertainty, and also planned Phase II activities for the OPGEE, including oil sands modelling, tight oil, hydraulic fracturing, CO_2 enhanced oil recovery and solar-thermal technology. Updates for such modules may have considerable impacts on the carbon intensities for current MCOs comprising the California feedstock and warrant regular updates to the re-adopted *Crude Oil CI Lookup Table*. The Alberta government welcomes the opportunity to work with the CARB in its modelling efforts for such Phase II activities, particularly in areas related to oil sands. LCFS 37-4

Alberta continues to make efforts in reducing its environmental footprint and in effectively managing its carbon emissions, illustrated by the use of innovative crude production technologies in existing reserves and improved environmental monitoring technologies that encourage responsible development of Alberta-based crude oils.

It is clear that Alberta and California are both working toward reducing the overall environmental footprint of our energy production and use. We are working toward a clean energy future that includes de-carbonized fossil fuels. Alberta has stringent legislation and measures in place to protect air, land and water during oil and gas development, and we are committed to ongoing environmental improvements that will ensure we remain among the most environmentally responsible energy producers in the world.

.../4

[1] https://circabc.europa.eu/sd/a/e85d829b-2b8a-44dd-974a-552f0e8f478a/Slides%20-%20OPGEE_Feb20_EU_v3.pdf

Alberta welcomes the opportunity to continue to work with California, and I would like to offer our province's key learnings and experiences in crude oil data collection and management. Attached are additional technical comments for your consideration, and we would be happy to further discuss these with you.

Thank you again for providing the opportunity for Alberta to further discuss the LCFS with you.

Best regards,

Gitane De Silva
Deputy Minister

Attachment

cc: Grant Sprague
Deputy Minister of Alberta Energy

Bill Werry
Deputy Minister of Alberta Environment and Sustainable Resource Development

Cassie Doyle
Consul General, Consulate General of Canada in San Francisco

Alberta Government

State of California's Low Carbon Fuel Standards' (LCFS) Rulemaking Proposal

GOVERNMENT OF ALBERTA TECHNICAL SUBMISSION

- Current activities for the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model have been stated to include:
    i. calibration; and
    ii. an uncertainty analysis and examination of models such as PRELIM.
  - Could the California Air Resource Board (CARB) please provide further modelling details and elaborate on the timelines for such activities (i.e. planned, underway, or finalized) for these respective area/modules? LCFS 37-5

- Planned Phase II activities for the OPGEE model have been stated in various CARB workshops to include:
    i. oil sands modelling;
    ii. tight oil; and
    iii. hydraulic fracturing , CO_2 enhanced oil recovery and finally solar-thermal technology.
  - Could CARB please provide further details on potential changes to the OPGEE and elaborate on the timelines for such activities (i.e. planned, underway, or finalized) for these respective area/modules listed, including potential dates? LCFS 37-6
  - Is it foreseen that select Marketable Crude Oils (MCOs) listed in the *Carbon Intensity Values for the Crude Lookup Table* would be subject to regular (i.e. bi-annual or annual) amendments based on future developments for the respective areas/modules? If so, will an impact assessment be conducted annually, or every three years, for the California baseline default value? LCFS 37-7

- Given the OPGEE 1.1 model uses a separate module based on GHGenius, will cited[1] differences be accounted for in overall crude production carbon intensities under the re-adopted LCFS? Could the CARB comment on carbon intensity differences for mining based MCOs? Specifically, are values higher or lower when MCOs are input into the OPGEE, compared to GHGenius? LCFS 37-8

- Some uncertainty exists as to whether OPGEE updates will occur every three years, as outlined in the LCFS rulemaking proposal, or every one to two years, as outlined in the OPGEE 1.1 user's manual. LCFS 37-9

- The preferred compliance curves presented on III-13 (Option 3's 'gradual compliance curve') call for a 50 per cent reduction in fuel carbon intensity in two years. The possibility exists that credit supplies will be exhausted in these more intensive years (or perhaps even beforehand), thereby negating their envisioned use in the 2020-2025 period. LCFS 37-10

[1] O'Connor, D. (2013) OPGEE analysis and comparison to GHGenius. Prepared for Natural Resources Canada, August 19, 2013.

- The LCFS rulemaking proposal outlines that credit prices are not expected to exceed $100/credit. What then is the need for placing a cap on the credit price and can such a control de-incentivize program participants? LCFS 37-11

- Though only presented as being under staff consideration, the rationale behind limiting LCFS eligibility to on-site carbon capture and storage production facilities is not made entirely clear and this proposal's relation to California's Cap and Trade program needs to be more fully clarified. LCFS 37-12

- Proper Tier 2 carbon-pathway validation (third party engineering reports, submissions for Environmental Protection Agency approval, etc.) may require more than 30 days to fulfill. LCFS 37-13 Likewise, submission of evidence for out of state fuel transport modes (or related updates) may also require more than 30 days. LCFS 37-14

37_OP_LCFS_Alberta Responses

158. Comment: **LCFS 37-1**

The commenter recommends that ARB include emission reductions associated with carbon offsets purchased through Alberta's Specified Gas Emitters Regulation in assessing carbon intensities for Alberta crude.

Agency Response: The LCFS is based on the principle that each fuel has "life cycle" GHG emissions that include CO_2, N_2O, and other GHG contributors. This life cycle assessment (LCA) examines the GHG emissions associated with the production, transportation, and use of a given fuel. Therefore, only those activities that directly affect the emissions associated with production, transportation, and use of the fuel will be reflected in the fuel's carbon intensity. Offset credits purchased through climate change programs such as the California Cap and Trade or Alberta's Specified Gas Emitters Regulation (SGER) do not directly affect the life cycle emissions of the fuel and therefore are not acknowledged under the LCFS.

159. Comment: **LCFS 37-2**

The commenter is interested in understanding how crude oil produced in Alberta under the SGER may be incentivized under the re-adopted LCFS.

Agency Response: ARB staff welcomes the opportunity to work with crude oil producers who are willing to provide data to more accurately model the carbon intensity of crudes they produce. Facility improvements designed to lower emissions under Alberta's SGER will lead to lower carbon intensity for the crude under the LCFS. Moreover, crude oil producers may earn LCFS credit on crude sold to California refineries that is produced using innovative production methods.

160. Comment: **LCFS 37-3**

The commenter expresses concern about carbon intensity estimates made for crude oil produced in regions with poor availability of crude production data.

Agency Response: While very good data is available for California, Alaska, western U.S., Alberta oil sands, and some foreign crudes, ARB staff agrees that the lack of accurate data on production parameters for many imported crudes, including conventional light, medium, and cold heavy production from Alberta, is a problem. This lack of data takes two forms: lack of field production data and lack of data that maps field production to marketable crude blends. We have explored options for obtaining this data from several data collection sources and have asked refiners and oil producers to supply this data with very little success. Oil producers are also encouraged to supply data to ARB in order to help maintain a robust database. If crude-specific data cannot be obtained and are not provided by producers, the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) assigns default parameters when estimating the carbon intensity for these crudes. OPGEE defaults are based on available information for a parameter and within the range observed worldwide. Moreover, for some input parameters, OPGEE makes use of "smart defaults." Smart defaults are used by OPGEE for those parameters that can be correlated to other parameters that are often known. For instance, the produced water-to-oil ratio is often unknown, but this parameter can be correlated to field age which is almost always known. We believe that these default parameters generally result in conservatively high carbon intensity (CI) estimates for crudes that are lacking in quality data. Producers who do not believe that these defaults accurately represent their crude production are encouraged to provide ARB with complete and accurate data.

161. Comment: **LCFS 37-4**

The commenter discusses current and future work related to the Oil Production Greenhouse gas Emissions Estimator (OPGEE) and CI values in the crude lookup table.

Agency Response: See responses to **LCFS 37-5**, **LCFS 37-6**, and **LCFS 37-7**.

162. Comment: **LCFS 37-5**

The commenter requests ARB to elaborate on activities involving calibration and uncertainty analysis for the OPGEE model.

Agency Response: ARB staff has not engaged in either calibration or uncertainty analysis for the OPGEE model. However, Adam Brandt at Stanford University has published several papers on the topics of model uncertainty and comparison of OPGEE model results to other LCA models. Citations for these papers include:

1. Vafi, K and A.R. Brandt (2014), Uncertainty of Oil Field GHG Emissions Resulting from Information Gaps: A Monte Carlo

Approach, *Environmental Science and Technology*, 48, 10511-10518, dx.doi.org/10.1021/es502107s.

2. Vafi, K., A.R. Brandt, (2014). Reproducibility of LCA models of crude oil production. *Environmental Science & Technology*. DOI: 10.1021/es501847p

3. Brandt, A.R., Y. Sun, K. Vafi (2014). Uncertainty in regional-average petroleum GHG intensities: Countering information gaps with targeted data gathering. *Environmental Science & Technology*. DOI: 10.1021/es505376t

163. Comment: **LCFS 37-6**

The commenter asks ARB to elaborate on "Phase II" activities involving updates to the OPGEE model.

Agency Response: In mid-2014, ARB staff issued a contact to Adam Brandt of Stanford University. The project scope includes revisions to the treatment of oil sands mining, thermal recovery, and bitumen upgrading and new pathways for tight oil and gas production using hydraulic fracturing and carbon capture with CO_2 enhanced oil recovery. The project is expected to be completed in 2016, at which time the draft model will be posted for public review and one or more workshops will be held to discuss the model changes.

164. Comment: **LCFS 37-7**

The commenter asks ARB to elaborate on the timing of future revisions to the OPGEE model, the crude lookup table CI values, and the 2010 Baseline Crude Average CI.

Agency Response: The regulation language states that "Revisions to the OPGEE model, addition of crudes to Table 8, and updates to all carbon intensity values listed in Table 8 will be considered on a three-year cycle through proposed amendments of the Low Carbon Fuel Standard regulation." If OPGEE model revisions or availability of new oil production data result in changes to the carbon intensity values for 2010 baseline crudes, the 2010 Baseline Crude Average carbon intensity (CI) will be updated as well.

165. Comment: **LCFS 37-8**

The commenter asks ARB to elaborate on differences between the treatment of mined oil sands in the OPGEE and GHGenius models.

Agency Response: The carbon intensity value for "mined and upgraded" synthetic crude oil is slightly higher in OPGEE than in GHGenius. The major differences between the two models are for emissions related to land use change (OPGEE is higher) and transport (GHGenius is higher). OPGEE also includes a small, 0.5 g/MJ assessment for small sources. Emissions estimates for feedstock recovery; upgrading; and venting, flaring, and fugitives are very similar between the two models. Overall, the carbon intensity value for light synthetic crude as estimated by OPGEE is less than 5 percent greater than the value estimated by GHGenius.

166. Comment: **LCFS 37-9**

The commenter asks ARB to clarify the update cycle for the OPGEE model.

Agency Response: See response to **LCFS 37-7**.

167. Comment: **LCFS 37-10**

The comment states that there is a risk that credit supplies will be exhausted in two years.

Agency Response: ARB staff agrees that there will likely be a significant drawdown of banked credits in the 2018 to 2020 period. However, staff's analysis show that there should be a sufficient carry-over of banked credits to maintain a surplus through the post-2020 timeframe when annual credit production, as shown in the illustrative compliance scenario, is expected to begin to exceed the annual rate of deficit incurrence at the 10 percent carbon intensity reduction level. Additionally, given the strong incentives to maintain compliance with the LCFS, ARB staff believes that most, if not all, regulated parties will take steps to ensure they acquire sufficient credits to maintain compliance with the regulation.

168. Comment: **LCFS 37-11**

The comment questions the need for a cap on the credit price. It goes on to add that such a cap may de-incentivize program participants.

Agency Response: The price cap provides an upper bound on the potential cost of credits, and should not be construed as a projection of future credit prices or as a projection of future cost of compliance. Likewise, the $100 illustrative credit price referenced in staff's economic analysis should not be construed as a forecast of future credit prices; ARB does not project future credit prices.

A cost containment mechanism is an essential component of the market rules governing the LCFS fuel market. Investment decisions in new fuel supplies will depend on having clarity regarding how the program will manage price volatility or shortfalls in low CI fuel. Implementing a clear, predictable provision to handle any credit shortage or price spike reduces the risk of supply shortages or price spikes. This means that cost containment actually *increases* the likelihood of meeting the standard by providing regulatory certainty for investors that the LCFS will continue to provide a predictable price premium for low-CI fuels in the future, under all possible outcomes.

See response to **LCFS 32-9**.

169. Comment: **LCFS 37-12**

The commenter asks ARB to clarify the treatment of CCS for credit under the LCFS and particularly the innovative crude provision.

Agency Response: As discussed on pages III-47 and 48 of the Initial Statement of Reasons, ARB staff is proposing to include two revisions restricting the use of carbon capture and storage (CCS) as an innovative crude oil production method. These revisions will help align the treatment of CCS under the innovative crude provision with the treatment under the Cap-and-Trade (C&T) Program. Under the C&T Program, the emission reduction credit for CCS projects is effectively allocated to the facility where carbon capture occurs. In order to be consistent with this allocation methodology, ARB staff is proposing that CCS projects will only qualify for innovative crude provision credit if the carbon capture occurs onsite at the oil production facility. The C&T Program has also delayed credit generation for CCS projects until after ARB has in place an approved quantification methodology for monitoring, reporting, verification, and permanence requirements associated with the carbon storage method. Staff proposes to adopt the same restriction for CCS credit generation under the LCFS.

The most common method of sequestration being considered for carbon capture projects in the United States is through carbon dioxide enhanced oil recovery (CO_2 EOR). Sources of anthropogenic carbon include natural gas, ethanol, synthesis gas, and electrical power production. Therefore, carbon capture with CO_2 EOR projects often involve the production of two fuels, the fuel produced at the capture facility and the crude oil produced using CO_2 EOR. Under the LCFS, the GHG emissions benefits of capture and sequestration for these projects can either be allocated to the fuel produced at the capture facility (i.e., Method 2 pathway application), the oil produced using CO_2 EOR (i.e., innovative crude method provision), or partially allocated to both. ARB staff has decided that emissions benefits of CCS projects are best allocated to the capture facility as this allocation is consistent with:

- Treatment of CCS under the Cap-and-Trade Program and the proposed LCFS refinery investment provision, as well as the U.S. Environmental Protection Agency's (U.S. EPA's) GHG regulations on new power plants. Under all of these programs, credit for emissions reduction due to CCS is allocated to the capture facility.
- The goals of the LCFS, which include reducing the CI of fuels in the transportation sector and promoting the development and use of alternative fuels. By allocating to the capture facility, the capture and sequestration of CO_2 emitted during the production of alternative fuels such as ethanol and hydrogen is promoted as these alternative fuels may be eligible for a much lower CI through the LCFS Method 2 application process.
- The fact that CO_2 EOR is not innovative, as it has been used for decades. However, capturing CO_2 from a steam generator at the oil production facility or from a methane reformer at a bitumen upgrader is considered to be innovative.

Therefore, under the innovative crude provision, ARB staff is proposing that carbon capture must occur onsite at the crude production facility in order for the oil producer to receive innovative crude method credit. Oil producers that simply inject CO2 that has been captured elsewhere are not eligible for innovative method credit.

While ARB staff acknowledges that limiting CCS as an innovative method to only those instances where capture occurs onsite will reduce the potential for generating LCFS credit, staff continues to believe significant credit potential exists for onsite carbon capture and that these proposed changes are appropriate.

170. Comment: **LCFS 37-13**

The comment states that the time allowed to submit evidence for validation of Tier 2 pathways may not be sufficient.

Agency Response: ARB staff believes the deadlines proposed are adequate for processing of Tier 2 applications. Section 95488(e) of the proposed LCFS regulation includes a 90-day period, not the 30-days as the commenter states, for regulated parties to submit the demonstration of a fuel transport mode as follows:

> "*Evidence of Fuel Transport Mode.* A regulated party may not generate credits pursuant to section 95486 unless it has demonstrated to the Executive Officer that a fuel transport mode exists, for each of the transportation fuels for which it is responsible under the LCFS regulation, and that each fuel transport mode has been approved by the Executive Officer pursuant to this section. Transactions associated with fuels for which a fuel transport mode has not yet been approved must be reported using a fuel transport mode code PHY10 in the LRT-CBTS. Electricity used as a transportation fuel is exempt from this requirement. For purposes of this provision, "demonstrated" and "demonstration" includes any combination of either (i) a showing by the regulated party using its own documentation; or (ii) a showing by the regulated party that incorporates by reference documentation voluntarily submitted by another regulated party or a non-regulated party fuel producer that accurately represents the regulated party's transportation fuel.
>
> A regulated party must submit the demonstration of a fuel transport mode to the **Executive Officer within 90 days of** providing a fuel in California unless an initial demonstration of fuel transport mode was previously submitted and approved under the provisions of the previous LCFS regulation order. The Executive Officer shall not approve a fuel transport mode demonstration unless it meets the following requirements:"

If the applicant has previously submitted the physical transport mode information and there are no changes to the fuel transport mode, there is no need for resubmittal. In addition, ARB staff provides flexibility on the submission of out-of-state fuel transport modes by offering two application options: 1) CA-GREET user default, and 2) use of alternative bill of lading for new fuel pathways. Staff will continue to work with the public on a case-by-case basis, upon request, during the application evaluation process.

171. Comment: **LCFS 37-14**

The comment states that the time allowed to submit evidence for out of state fuel transport modes may not be sufficient.

Agency Response: See response to **LCFS 37-13**.

Comment letter code: 38-OP-LCFS-Chevron

Commenter: Don Gilstrap

Affiliation: Chevron

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

Chevron

Rick Powell
General Manager

Chevron Products Comp
1500 Louisiana Street
Houston, TX 77002
Tel 832-854-6541
RDPO@chevron.com

38_OP_LCFS
_Chevron

February 17, 2015

[Submitted Electronically]

Clerk of the Board
Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Low Carbon Fuel Standard Re-Adoption

Dear Madam or Sir:

Chevron appreciates the opportunity to review and comment on the referenced re-adoption proposal.

Chevron is a major refiner and marketer of petroleum products in the state of California and a regulated party under the Low Carbon Fuel Standard (LCFS). We are a member of the Western States Petroleum Association (WSPA) and we support the comments submitted by WSPA in response to this proposed rulemaking. We are providing our separate comments below that highlight the issues of greatest importance to Chevron.

If you have any questions regarding our comments, please contact Nick Economides (925-842-5054) or Rick Powell (832-854-6541).

Thank you for providing this opportunity for Chevron to comment on the re-adoption.

Kind Regards,

Rick Powell
General Manager
Fuels & Product Strategy

Comments of Chevron

Re-Adoption of the California Low Carbon Fuel Standard:
Initial Statement of Reasons

February 17, 2015

Chevron appreciates the opportunity to submit written comments for the record on the above proposed rulemaking. Chevron is a California-based company engaged in oil and gas exploration, petroleum refining and petroleum product marketing. We are a regulated party under the Low Carbon Fuel Standard (LCFS). We are a member of the Western States Petroleum Association (WSPA) and we support the comments submitted by WSPA in response to this proposed rulemaking.

We understand that at the February 19-20 Air Resources Board (ARB) hearing, the Board will consider re-adoption of the Low Carbon Fuel Standard (LCFS) Regulation as well as adoption of the Alternative Diesel Fuel (ADF) regulation. Staff has jointly progressed these two rulemakings and considers them intimately connected as a joint regulatory action “package” to address requirements emanating from the July 15, 2013 State of California Court of Appeal, Fifth Appellate District (Court) opinion in POET LLC *v*. California Air Resources Board (2013) 218 Cal.App.4th 661. The judge’s opinion was that ARB did not adequately address biodiesel NOx emissions that could potentially result from LCFS implementation. The ADF regulation represents staff’s proposed solution to address California Environmental Quality Act deficiencies associated with biodiesel NOx impacts. Chevron’s comments on the ADF proposed rule have been incorporated in those submitted by the Western States Petroleum Association (WSPA), of which Chevron is a member. Our comments below are exclusively devoted to the LCFS rulemaking.

Chevron has worked with ARB over the past few months on the proposed LCFS re-adoption and participated in the series of workshops held by staff on individual segments of the proposed regulations. Chevron was also a member of ARB’s LCFS Advisory Panel and participated in that group’s meetings in 2014. Chevron has provided feedback to ARB through WSPA throughout the rule development process. Finally, Chevron has met with staff individually before and after the issuance of staff’s Statement of Reasons document to outline our concerns regarding the proposed revisions to the program. We appreciate staff’s openness in receiving our input on the large number of issues and considerations involved in this rulemaking and look forward to working with staff on additional refinement of the details of the proposed regulation in the coming months. We are prepared to discuss our comments further with ARB staff, if needed.

Summary

Halfway through the compliance decade (2010-2020), the LCFS program is falling short of meeting its originally envisioned targets and should be adjusted to more accurately reflect the real-world rate of development and market penetration of advanced low carbon intensity fuels. The primary reason is that technology in the cellulosic biofuel space has not emerged as ARB had anticipated. Chevron has first-hand knowledge of this; we embarked on an aggressive program to evaluate and develop promising new technologies and have been largely unsuccessful in this costly endeavor.

Staff implicitly recognizes that the original program targets are overly aggressive; they propose to revise the interim year (2016-2019) CI reduction targets downward in the proposed rule re-adoption. However, staff maintains that the 10% reduction target remains achievable and that "the program is working as intended." Staff's adjustment of the interim year targets, while welcomed, does not go far enough toward establishing the sustainability of the program moving forward. Moreover, claiming that the program's original CI reduction target can be met through the use of massive quantities of accumulated credits in the early years (when over-compliance may be possible), masks the true nature of the challenge the program faces as we head to 2020.

LCFS 38-1

In doing so, staff is not informing California policy makers of the need for immediate adjustment of the program's targets, choosing instead to delay action that will only yield a more severe crisis that must be addressed the next time program progress is reviewed. This decision further propagates the climate of uncertainty that this program has been shrouded in since its inception. It denies all stakeholders the opportunity to formulate concrete compliance strategies and turn their attention to their execution. Instead, affected stakeholders recognize that the program targets will need to be revised once again at some time in the near future. Thus, they remain "on hold" awaiting such revisions, with the delay further casting the program's 2020 goals in doubt. Chevron strongly recommends that staff adopt reasonable, achievable and sustainable CI reduction targets for all years up to and including 2020 as part of the LCFS' re-adoption and has provided staff with its estimates of what such a compliance schedule entails.

Chevron defines program "success" as the achievement of sustainable CI reductions, i.e., targets that can be met largely by the CI reductions generated during the individual compliance year with minimal reliance on an accumulated credit bank to accommodate the expected normal market fluctuations during the year. In that context, Chevron believes that the program's success depends on a dual-pronged strategy involving the setting of reasonable CI reduction targets (the "compliance curve") and maintaining close oversight of the program as it moves forward to ensure it is meeting its forecasted targets. To this end, Chevron recommends that ARB build mandatory biennial comprehensive LCFS program reviews into the re-adoption proposal, with the first one to be completed no later than 1/1/2017.

LCFS 38-2

While we recognize that the actions emanating from such interim LCFS program reviews cannot be predetermined, we expect ARB to consider concrete and specific key indicators (e.g., predicted vs. actual low-CI fuel penetration, predicted vs. actual LCFS credit balances, predicted vs. actual credit prices, overall credit market liquidity, differential of CA gasoline and diesel market prices versus the rest of the nation) as part of these reviews. Chevron also expects staff to include adjustment of the program's outer year targets in the scope of the interim reviews, should evidence of significant and systemic over- or underperformance versus the program targets be established. LCFS 38-2

Chevron is opposed to the Credit Clearance Market (CCM) proposed by staff as a cost control mechanism in the LCFS re-adoption rule. While we appreciate staff's intent in controlling costs to the consumer during short-lived periods when compliance obligations cannot be met and credit availability declines, Chevron believes that the proposed CCM mechanism has serious flaws and could very well result in unintended negative consequences. More specifically, CCM:

- Does not stipulate a mechanism for retiring deficits, if multi-year market shortages persist leaving the regulated community with the prospect of ever-increasing deficit accruals.
- May drive credit costs up, if credits are withheld from the regular market to get a higher CCM price at the end of the year.
- Provides no liability protection against invalid credits secured through the year-end CCM. LCFS 38-3
- Offers no connection between CCM outcome, program off-ramps, and future CI reduction targets.
- Offers refiners no flexibility to voluntarily participate and eliminates their ability to carry-over credits if they do not.

For these reasons, Chevron believes that staff should abandon the proposed CCM and rely instead on the combination of setting achievable targets and frequent interim program reviews outlined earlier. If staff insists on including a cost containment mechanism in the LCFS, Chevron recommends adoption of a simpler program analogous to that employed by EPA in the Renewable Fuels Standard. LCFS 38-4

Chevron believes that staff's forecast of potential CI reductions (and associated targets) in the 2018-2020 time frame are ambitious and unsustainable. Staff's own estimates show that only 7% of the 10% 2020 CI reduction target is sustainable, with the balance (3% CI reduction) attributable to using 7 million metric tons of CO_2e ($MMTCO_2e$) from the forecasted credit bank. Chevron notes that:

- Staff's assumptions on the potential LCFS credit buildup (through 2016) and drawdown (in 2017-2020) are unrealistic. The credit bank, since program inception, stood at slightly under 4 MMT at the end of the 3rd quarter of 2014 (the most recent available actual data). Staff assumes that it will rise to approximately 9MMT by the end of 2015 but offers little in terms of factual support for this aspirational view other than program re-adoption will provide the necessary program certainty for credit generation to begin in earnest. LCFS 38-5

Chevron's view is that the credit bank will likely build at a much slower pace and be exhausted by 2020, as individual year deficits materialize as early as 2017. LCFS 38-5 cont.

- Chevron's projections of relative contributions from most low-CI reduction fuels (e.g., ethanol, biodiesel) and other credit sources (e.g., electric vehicles) over the 2015 to 2020 period are approximately consistent with staff's. However, Chevron disagrees with key staff assumptions of the rate of growth (and associated contribution to meeting LCFS targets) of renewable diesel (RD) and renewable natural gas/biogas (RNG):

    - While renewable diesel is one of the more promising available low carbon intensity fuels for LCFS compliance, ARB's supply projections are optimistic and overly reliant on announced projects and nameplate capacities and downplay inherent feedstock availability concerns that will limit the longer term "upside" of RD. Furthermore, logistical hurdles in the short term (through 2016) involving Federal Trade Commission dispenser pump labeling regulations, superimposed on the fungible nature of the common carrier pipeline system, will be more difficult to overcome than staff assumes in projecting that RD will represent 12% of CARB diesel by 2020. LCFS 38-6

    - Staff's degree of reliance on large-scale production of RNG and diversion to motor fuel applications to generate LCFS credits is questionable. Without RFS and LCFS credit subsidies, RNG for transportation is uneconomic and, in our experience, investors are loath to take on projects where the entire rate of return is based on valuation of regulatory compliance credits. While biogas production is growing steadily, the economics are driving most new production to electricity. RNG projects typically cost twice as much as electricity projects yet offer no additional GHG emission benefits nor do they offer higher non-subsidy revenue to the producer. Furthermore, pipeline injection remains a major barrier due to its high cost, gas quality concerns, and surplus capacity availability.

- Chevron recognizes ARB's efforts to allow credit for refinery investments as an element of LCFS GHG reductions. Chevron is opposed to the concept of stationary source credits being applied to LCFS; we believe that these are covered under ARB's cap and trade program. However, since staff appears to be moving in this direction regardless of our input, we have turned our attention to ensuring the program's efficacy. We recognize that, before considering specific project applications, staff will need to establish the relative efficiency of the applicant refinery versus its peers. Staff's proposed choice of method and tools for efficiency ranking refiners in the state is inappropriate and inequitable toward larger, more efficient refiners. Moreover, the proposed thresholds and restrictions proposed by staff risk eliminating most potential projects. Chevron has conveyed its views of necessary modifications to staff; highlights of our proposed changes in the Refinery Investment Credit segment of the rule are included below: LCFS 38-7

    - The metric used to establish relative refinery efficiency should be the Complexity Weighted Barrel (CWB) as described in the detailed section of our comments. LCFS 38-8

- o Refiners should be allowed to offer offsets of criteria and air toxic pollutants if their efficiency improvement projects indicate a potentially adverse impact in such emissions. LCFS 38-9
- o The 0.1 gCO2e/MJ threshold is too stringent and should be revised consistent with staff's proposed minimum for Innovative Crude Production Technologies. LCFS 38-10
- o Investments should not be limited to capital projects; oftentimes sizeable energy efficiency improvements are funded out of operating expense per established IRS accounting regulations**.** LCFS 38-11
- o The project eligibility cutoff date should be changed to the project's startup date for any project commissioning post 1/1/2015; regardless of when initial project permit applications were filed, the project has not delivered GHG reductions until it starts up. LCFS 38-12
- o The bio-feedstock 10% threshold is too restrictive, even if defined as "percent of total process unit feed." Staff should convert this threshold to a minimum absolute GHG reduction impact. LCFS 38-13

Chevron recognizes that staff is recommending no changes to the crude handling provisions in LCFS as part of the re-adoption rulemaking. Notwithstanding Chevron's concerns with crude differentiation within the LCFS, <u>Chevron supports staff's decision not to recommend conversion from the current three-year CA average crude intensity tracking system to individual refinery baseline crude CI values and agrees with the rationale offered by staff for this decision</u>. Chevron also recognizes ARB's desire to continually improve the accuracy of LCFS data inputs, and recognizes that staff's approach in the re-adoption rulemaking is consistent with that principle. However, <u>we also believe that the degree of crude differentiation built into LCFS, unfairly penalizes indigenous CA crude production and remains unnecessarily excessive and should be reduced</u>. Our reasoning is as follows: LCFS 38-14

LCFS 38-15

- The fundamental reason for these provisions in the rule was to ensure that the average carbon intensity of crudes processed by California refiners did not increase over time. The available crude breakdown data for recent years (2012-1H2014) suggests that this threat has never materialized and that the CA crude average CI has remained relatively stable.
- The revised average indigenous California crude CI values included in the re-adoption package are overwhelmingly higher than corresponding values in the existing rule. Based on first half of 2014 crude volumes, the CI has increased by approximately 19% (comparing "old" vs. "new" Table 8 crude values). Our industry is effectively penalized for its attempts to maintain and increase in-state crude production even though the mix of crudes processed by CA refineries is not changing.
- The worst case scenario these provisions could potentially drive (i.e., exporting heavy California crude to maintain a constant annual average crude CI) yields no tangible greenhouse gas reduction benefits from a global standpoint.

- The ongoing staff effort to maintain and improve crude differentiation inputs and modeling tools in the LCFS is resource-intensive for ARB and equally burdensome for our industry.

In the absence of a valid GHG justification for engaging in such a complex crude differentiation and tracking scheme and in view of the potential adverse impact on indigenous California crude, we believe staff should be moving in the opposite direction than they have been following, i.e., one of simplification and streamlining. We look forward to working with staff on potential improvements to the LCFS crude differentiation provisions following the February Board Hearing. LCFS 38-15 cont.

Chevron does not view the Innovative Crude Production provisions proposed for inclusion in the LFCS re-adoption as yielding meaningful contributions for compliance by 2020 and notes that staff's illustrative compliance scenario does not include contributions from this sector. As mentioned in the Refinery Investment Credit provision discussion above, Chevron does not favor inclusion of credits from stationary sources in LCFS. Should staff choose to proceed, Chevron objects to limiting the application of carbon sequestration (CCS) to those instances where the carbon capture occurs onsite at the crude oil production facilities. CCS has the potential to generate a substantial number of credits under this provision, but many projects (and proposed projects) involve capturing carbon not at the same physical site where the crude is extracted. This restriction could seriously limit the potential for CCS to generate LCFS credits. While the capture of CO_2 from a steam generator or other equipment used in the oil production process may be desirable, the overall cost of doing so is prohibitive compared to capture from other large CO_2 emission sources. LCFS 38-16

Detailed Comments

Following is a series of comments on the various components of ARB's LCFS re-adoption proposal. For each of the topics below, we are providing detailed comments in the subsequent sections.

- **Program Status and Proposed Compliance Targets:** Staff has adjusted the interim year CI reduction compliance targets (2016-2019) lower in the proposed re-adoption rule but has retained the original regulation's 10% reduction target for 2020. The proposed LCFS targets appear to be unsustainable, even by ARB's own analyses.
- **Low-CI Fuel Availability:** Staff's projections of Renewable Diesel use and Biogas market penetration are substantially higher than Chevron's.
- **Cost Containment Mechanism**: Staff proposes a credit clearance market that is overly complicated and predicated on the false premise that any failure to meet the LCFS CI reduction targets will be the result of a lack of credit buyers rather than a lack of credit sellers.
- **Refinery Investment Credit:** ARB proposes to allow refiners to generate credits for GHG reduction projects, but has established restrictions that are likely to prevent many potential projects from qualifying.
- **Electricity Provisions:** The proposals to allow credit generation for electric transportation usage that predates the LCFS and for estimated home vehicle charging

are inappropriate. These artificial credits would have no tie to real GHG reduction, and are inconsistent with proposed rules related to refinery credits.

- **OPGEE:** ARB's continued insistence on crude differentiation serves only to lead to inefficiency, competitive disadvantage for California crude production, and potential "crude shuffling."
- **Indirect Land Use Change:** ARB has refined the ILUC values contained in the proposed regulation based on updated data sources, as well as input from academia and the regulated community. We encourage ARB to keep this process open and transparent.
- **Low Complexity / Low Energy Use Refineries:** ARB is adding unnecessary complication by allowing those refineries who have not invested in the scale needed to meet the high demands of the California fuel market to generate credits and opt out of the state average CI calculations.
- **Innovative Crude Production:** The proposed additions and enhancements to the innovative crude technology options are encouraging, but there is room for improvement.
- **Reporting and Recordkeeping:** We appreciate ARB's efforts to improve accuracy in reporting and the added time for reconciliation with counterparties. We do not, however, agree with some of the other proposed changes.
- **Enforcement:** The proposed per-day violations for reporting errors have the potential to be unduly punitive. We recommend reducing the applicable time period to cover only the time beginning with discovery of the error. Further, there should be an affirmative defense for invalid credits analogous to the RFS.
- **Economic Impact Analysis:** While acknowledging that the LCFS will likely put upward pressure on the cost of fuel in California, ARB understates the expected economic impact by relying on an upper limit of $100/MT for credit prices.

Current Program Status and Proposed Compliance Targets

Since its inception, the LCFS program has aspired to deliver a 10% reduction in California motor fuel carbon intensity (CI) by 2020 versus the 2010 baseline year.
As a result, Chevron engaged in an extensive program to aggressively evaluate promising emerging technologies in this space and invested considerable resources in pursuing those that we believed held the highest potential for success. Unfortunately, five years into the LCFS program, the progress envisioned in cellulosic biofuel development has not materialized, rendering the achievement of the LCFS program's original goals and targets questionable at best. Nevertheless, In the LCFS re-adoption proposal, staff holds on steadfastly to the 10% CI reduction target by 2020. In associated statements, both in California and other jurisdictions considering LCFS programs (e.g., Washington, Oregon), staff holds that "the program is working as intended,"

LCFS 38-1 cont.

Half-way through the 2010-2020 compliance decade, the program is delivering approximately 2% CI reduction (versus an annual target of 1% for 2014 and 2015). Despite a nearly year-long re-examination of the program's components and targets leading up to the re-adoption Board hearing, staff is reluctant to admit that the program faces considerable challenges, even as it proposes to scale back some of the program's targets (e.g., interim-year CI reduction targets – "the compliance schedule") while leaving others (e.g., the 10% 2020 target) in place despite clear evidence that they cannot be met.

ARB's own estimates indicate that the LCFS program as proposed in the re-adoption proposal is not sustainable. Approximately 3% of 10% CI reduction shown for staff's illustrative scenario in 2020 is derived from accumulated credits (from "over-compliance" during previous years) and only 7% is actual, sustainable CI reduction obtained during the year. Annual targets remain unsustainable; staff forecasts a credit bank build up to 9 MMT at the end of 2015 to help satisfy the inherently un-sustainable reductions that the program calls for as we head toward 2020. The reality is that the credit bank stood at just under 4 MMT at the end of the third quarter of 2014 (since program inception) and the expectation it will reach 9MMT over the next 15 months is largely aspirational. ARB's view is that there will be an extraordinary increase in the rate of credit generation over this period as industry will have the benefit of "certainty" following the regulation's re-adoption.

Setting aside the issue of ARB's reliance on an unrealistic initial credit bank starting point at the start of 2016 (to meet the 10% 2020 target), Chevron does not agree that staff's projection of a 7% sustainable reduction in 2020 is accurate. The primary reasons are: staff is using overly aggressive projections in estimating the degree of market penetration of renewable biogas for motor fuel applications and the volumes of renewable diesel that will be incorporated in the CARB diesel pool. Questionable LCFS credit contributions are also forecasted from the Refinery Investment Credit segment of the re-adoption program. The reasons for Chevron's reservations in these areas are outlined further in the detailed comments on these topics.

LCFS 38-1 cont.

Chevron notes the "redirection" of ARBs reliance on different sector contributions to achieve the program's CI reduction goals. There is no significant contribution expectation from advanced cellulosic biofuels that lay at the core of the original program's aggressive goals. This is not surprising given that staff's expectations for growth in that area have not materialized. Going forward, the relative contribution of such low-CI fuels is but a very small fraction of the overall program CI reduction needs. Faced with a substantial reduction in the contribution expected from advanced biofuels, ARB should have reduced LCFS program targets accordingly. We are disappointed that ARB has largely held on to the original program targets (at least for 2020) and looked to fill the cellulosic fuel CI reduction "gap" through aspirational increases in renewable biogas and renewable diesel, as well as arbitrary inclusion of LCFS credits from stationary source segments such the "Refinery Investment Credit" and "Innovative Technologies for Crude Oil Production." In Chevron's view, this "redirection," aspirational CI reduction projections, and over-reliance on banked credits in the 2016-2020 timeframe reflect the magnitude of the challenges that the program is currently facing.

Chevron continues to maintain that there is no certainty in the setting of unrealistic goals and targets that the entire regulated community views as mere placeholders that will have to be ultimately revised. In fact, this approach only serves to prolong the very climate of uncertainty, and sustain deferred action on compliance plans, investments, etc. that ARB should be seeking to promote. In the case of the re-adopted LCFS, once the credit bank status for 2015 is confirmed to be substantially lower than staff's expectations (i.e., roughly within a year's time from re-adoption), the infeasibility of the 2020 CI reduction target will be difficult to dispute and the need for revision will be even more urgent since 2020 will be only four years away at that point.

ARB's ISOR documentation is lacking in terms of detailed data to clearly support the contention that the program is still feasible. A full analysis of the available supply of low-CI fuels; the projected cost of the available fuels; the supply logistics (marine, rail, etc.) which are available to accommodate these alternative fuels; the infrastructure needed to blend, transport and dispense these fuels; the incentives which are needed for consumer acceptance; and other regulatory impediments should all be delineated.

Chevron has developed its own estimates of low-CI fuel volumes which might be available through 2020. We have shared our estimates with ARB, which has also received corresponding input from WSPA based on the work of the Boston Consulting Group (BCG). We have analyzed ARB's assumptions relating to the LCFS compliance curves and are pleased that staff's estimates have been gradually adjusted through this process to more closely reflect our own. In most areas, essential alignment has been reached between our respective viewpoints/estimates with only minor differences remaining. However, key differences remain in:

- The definition of what constitutes a sustainable program. Chevron believes that targets are sustainable if they can be met through the CI reductions accomplished during a particular compliance year with minimum reliance on credit to cover short-term shortfalls.

- The size of the credit bank on 1/1/2016 that will be available to cover future program shortfalls. Chevron's view is that the credit buildup forecasted by ARB is unsubstantiated and is unlikely to materialize.

- Chevron also forecasts that individual credit deficit years will be seen as early as 2017, requiring earlier withdrawals from the credit bank.

- As a combined result of the two previous items (lower credit bank "build" and earlier withdrawals), Chevron expects the credit bank to be essentially exhausted in the 2018 timeframe, leaving no reserves for the large credit drawn necessary to meet the 2020 10% reduction target.

- Chevron's realistic market based outlook indicates substantial differences in our projections of RNG and RD market penetration versus staff's. We also believe that, unless the proposed Refinery Investment Credit provisions are adjusted, there will be no meaningful contributions from that segment in meeting the LCFS targets.

As mentioned earlier, we have met several times with ARB during the re-adoption rule development period and after the ISOR was released, and continue to urge ARB to reset the 2020 target CI reduction level to a more realistic and sustainable level of approximately 4.5%, as

LCFS 38-1 cont.

indicated by our internal projections and those of BCG's most recent study that WSPA has been shared with staff. LCFS 38-1 cont.

Low-CI Fuel Availability

Supply and Blending Limits for Renewable Diesel

Chevron believes that renewable diesel is one of the more promising available low carbon intensity fuels for LCFS compliance. However, ARB's supply projections are optimistic and overly reliant on announced projects and nameplate capacities.

The critical barriers to the market penetration of renewable diesel, however, are not production levels but blending infrastructure and regulatory hurdles. ARB has projected that renewable diesel will make up 12% of the California diesel pool by 2020, but we anticipate it will reach roughly half that level. Logistical hurdles on pump labeling (FTC regulations), superimposed on the fungible nature of the common carrier pipeline system will be difficult to overcome in the 2016-2020 timeframe. We project that the vast majority of diesel in the state will contain 5% renewable diesel by 2020 with higher percentages seen in select centrally-fueled fleet applications, resulting in an overall pool average at 6% renewable diesel.

ARB staff has speculated that regulated parties may pursue several options for getting around the 5% blending limit imposed by FTC labeling rules.

- Segregated grades of diesel at terminals – Staff contends that selling two blend levels (0-5% and 6-20% renewable diesel) would enable higher blend levels. LCFS 38-6 cont.

  This option is problematic as terminals face multiple logistical constraints when it comes to any attempts at additional product segregation (e.g. plot space for additional tankage). Even where it could be considered, it is highly unlikely to occur until LCFS implementation establishes RD supply stability and justifies the investment in expansion of diesel grade infrastructure.

- Moving entire pipeline/terminal systems to higher blend levels – Some terminal position holders could move to 6-20% blends, causing the retailer community served by those terminals to label accordingly.

  Voluntarily industry adoption of an RD6-RD20 specification is equally problematic. The existing fungible pipeline system dictates that industry must move in "lockstep" for any geographic move to higher blends. Such a change would have to be implemented through common carrier pipeline specification change, which would be difficult to achieve short term for competitive reasons. While unlikely before 2020, this is the most likely path forward longer term. It will just take time for the dynamics of the market to make such a dramatic change.

- Large-scale fleet blending – Bypassing the traditional supply system to blend high renewable diesel levels for fleet applications.

  This is a very real possibility. Centrally-fueled fleet blending at higher renewable diesel percentages will likely occur but its impact is small and it has already been comprehended in our estimates.

- Relying on an FTC re-interpretation of the underlying law (2007 EISA) – The FTC may revisit their understanding of Congress' intent and remove the regulatory barriers.

  This is the least likely solution. Several unsuccessful inquiries have already taken place by both fuel providers and renewable diesel producers as expanded blending has been pursued for Renewable Fuel Standard and other blending mandate compliance. The FTC has been unmoved on this point. Congress providing the necessary authority (by reopening EISA) is even more unlikely near term; strong opposition is expected by the biodiesel lobby to any revision attempt.

Given all of this, terminal blending above 5% before 2020 is highly unlikely and fleet blending will have only a marginal impact on the overall market balance, bringing the statewide average to approximately 6% vs. ARB's forecast of 12%.

Biogas Projections

LCFS 38-6 cont.

Reliance on large-scale production of renewable natural gas as a supply of LCFS credits is questionable. Investors will weigh high regulatory risk as they consider such projects. Without RFS and LCFS credit subsidies, renewable natural gas for transportation is uneconomic. Cellulosic RINs are estimated to add three times the commodity value of natural gas and the LCFS may add another one to two times the value. While this may seem like a significant motivator for investment, the possibility that these programs may be modified at any time (based on political and/or regulatory reassessment) represents a significant issue for investors as they consider projects whose returns are based solely on the RFS and/or LCFS credit premiums that they generate.

Typical economics (capital investment, absence of need for gas "cleanup", access to gas pipeline, etc.) of biogas utilization drive the application of such gas to power generation and not motor fuel use. We have cautioned ARB that the GHG reduction benefits associated with "re-purposing" biogas from power generation to CNG/LNG production are not appropriately accounted for in staff's estimates. ARB's carbon intensity assessment of these products ignores this very real possibility, taking full credit for any renewable CNG/LNG production as though it represents green-field landfill gas production. Should it be found that a significant portion of the landfill gas supply used for CNG/LNG production was redirected from electricity production, much of the compliance value of those biogas products will have been lost.

The current version of CA-GREET2.0 estimates the lifecycle CI of CNG from landfill gas to be 17 gCO2e/MJ. If this landfill gas was re-purposed from on-site electricity generation, the amount of electricity displaced from the grid would need to be accounted for as average grid electricity, which has a much higher CI than electricity from landfill gas. CA-GREET2.0 estimates the US-average electricity CI to be 183 gCO2e/MJ, while EPA has estimated the CI of electricity from landfill gas to be 11.4 gCO2e/MJ. EPA also estimated that 3.4 MJ of landfill gas energy is required to produce 1 MJ of electricity[1]. The increase in the landfill gas CNG/LNG CI from displacing landfill gas (LFG) electricity would therefore be:

(1 MJ Elec. / 3.4 MJ LFG) * (183 - 11.4 gCO2e/MJ Elec.) = 50 gCO2e/MJ LFG

For the example above (Landfill Gas CNG), the CI would increase from 17 gCO2e/MJ to 67 gCO2e/MJ if re-purposed from on-site electricity generation, or about the same as fossil natural gas.

Cellulosic Biofuels

ARB staff continues to strongly assert that the LCFS program (and more particularly LCFS credit prices) will drive advanced biofuels production. Evidence that the RFS2 program is struggling in meeting its advanced biofuel objectives does not appear to be materially impacting staff's estimates. Chevron notes that almost all of the advanced biofuel production facilities ARB and others mention are not in California – challenging the notion that the state is really driving the advanced biofuel market and attracting investments. As previously commented by WSPA in its Wood Mackenzie and BCG contractor work in 2012, the LCFS will draw any limited quantities of these fuels that may be available to California via shuffling resulting in sub-optimal costs and often increased emissions.

LCFS 38-6 cont.

When calculating/projecting future biofuels supply, ARB should not rely on press announcements as credible evidence of actual facilities/volumes, since many projects are cancelled after initial press announcements but prior to construction, based on engineering studies that are completed and a more definitive cost estimate becoming available. ARB should count facilities that have started construction for potential facility/volume availability in the next 2 – 3 years. If construction has not started, then a discount factor of at least 50% should be used in projecting future capacity. When using past growth rates and projecting them into the future, ARB should take into account the period of two or so years of essentially no growth.

The ARB documentation is lacking in terms of detailed data to clearly support the contention that the program is still feasible. A full analysis of what supply of low-CI fuels is truly available to California and at what projected cost; what the supply logistics (marine, rail, etc.) are available to accommodate these alternative fuels; what infrastructure is needed to blend, transport and

[1] "Support for Classification of Biofuel Produced from Waste Derived Biogas as Cellulosic Biofuel and Summary of Lifecycle Analysis Assumptions and Calculations for Biofuel Produced from Waste Derived Biofuel," U.S. EPA Office of Transportation and Air Quality Memorandum to Docket EPA-HQ-OAR-2012-0401, July 1, 2014.
Table 6: CI of Electricity from Landfills that Flared Biogas = 12 kg CO2e/mmBTU (= 11.4 gCO2e/MJ)
Table 5: Efficiency of Electricity Generation from Biogas = 11,700 BTU biogas/kWh (= 3.4 MJ biogas/MJ electricity)

dispense these fuels; what incentives are needed for consumer acceptance; and other regulatory impediments should all be delineated. LCFS 38-6 cont.

Cost Containment Mechanism

Staff maintains that sufficient low-CI fuels and credits will be available and, thus, the cost containment mechanism will be seldom (if ever) needed. Staff's stated expectation is that the cost containment mechanism will only be invoked when necessary to respond to some short-lived market "blip" or disturbance that will quickly give way to reestablishment of equilibrium. Staff acknowledges that this tool is not designed to accommodate systemic and prolonged LCFS credit shortages. They consider the ability to carry deficits forward (albeit with interest) for up to five years an "insurance policy" and they see no particular negative aspects to the end-of-year credit clearance market they are proposing (where regulated parties must buy their pro-rata share of pledged credits at a price as high as $200/MT).

We are opposed to the inclusion of such a cost containment mechanism in the LCFS because we believe that it will not accomplish its stated objective (contain prices) and will instead have a number of undesirable (and unintended) consequences. More specifically, the Credit Clearance Market (CCM):

Does not stipulate a mechanism for retiring deficits, if multi-year market shortages persist. If there are inadequate credits available in the year-end auction of credits pledged by suppliers at prices as high as the pre-determined "cap" price, then regulated parties will have to carry a deficit into the following year. As presently designed, carrying over a deficit is an involuntary act by the regulated party – it is not caused by its own failure but by the failure of the market to meet the demand with sufficient supply. Consequently, imposing a 5% deficit interest subjects the regulated party to an unfair and inequitable penalty that only increases the deficit. Our analysis projects that the market will in fact be consistently short credits year after year, and if the annual obligation is not corrected to match actual credit supply, then the regulated community will be facing ever-increasing and interest bearing deficits. LCFS 38-3 cont.

May drive credit costs up (if credits are withheld from the regular market for CCM price). During periods of rising prices (i.e., credit shortages in the open market), the CCM will not keep credit prices in check. In fact, in a credit short year, the CCM is meaningless as there will not be any remaining credits to be brought to the table by sellers. The compounding of "interest" on the carryover/deferred balances will ensure credit buyers soak up the available pool of real LCFS credits in the market during the year and not wait for the CCM. The pool of real LCFS credits available is fixed – it is only their price that remains in question. Staff's setting of the price at $200/MT will serve as the benchmark for credit prices in that environment.

During periods of stable or declining prices (i.e., credit surplus in the open market), the CCM cap price creates an artificial "floor" value below which sellers will be hesitant to offer real LCFS credits for sale to the regulated community at substantially lower prices. This would artificially increase compliance costs – as credit prices will be artificially raised to (or near) the ARB cap and very few transactions will take place before the end-of-year sale. Credit trading would be seriously impaired as the open market would not be allowed to function as it should.

Provides no liability protection against invalid credits secured through the CCM.
Later we identify, in general terms, how the lack of a liability defense available to obligated parties from fraudulent credit sellers is inequitable. However, in the specific context of the CCM provisions, not only is there no liability defense for fraudulent or otherwise invalid credits, there is also no opportunity to conduct due diligence of the sellers. Moreover, ARB's time-table to organize and complete the CCM, suggests that the agency will not be doing any screening of the pledged credits.

Offers no connection between CCM outcome, program off-ramps, future CI reduction targets
The liquidity of the LCFS credit market is not only essential to the program's success. The absence of such liquidity is a clear signal that the program's CI reduction targets are overly aggressive and will render the program infeasible. There is presently no provision in the CCM to conduct a comprehensive program review in the event of repeated credit shortages.

Does not adequately define mechanics of deficit carryover (recordkeeping, reporting, etc.)
Even if all of the above issues were somehow resolved satisfactorily, the CCM proposal in the ISOR and draft regulatory language is sorely lacking in the execution/implementation details that would allow us to understand exactly how it would work. For example: What is the "order" of applying generated credits (through blending or purchases) to the various potential uses for a regulated party on any given year (e.g., meet the current year's obligation, retire previous years' obligations)?

LCFS 38-3 cont.

Finally, the proposal to make public the long and short credit positions of regulated parties undermines the competitiveness of the credit market by disclosing confidential business information. The release of such information would allow competitors and sellers insight into a regulated party's confidential compliance strategy. Using this information and average market pricing, one could estimate the financial impact of LCFS compliance on a regulated party.

Recommended Alternative to the CCM
In lieu of the CCM, Chevron favors a dual approach of setting reasonable, practically achievable CI reduction targets and holding frequent (biennial) program reviews to ensure that the program remains on track and the LCFS credit market is healthy. More specifically, we would like to see staff eliminate the proposed CCM and:

- Provide for biennial mandatory program reviews with the first one completed by 1/1/2017. The initial review should include LCFS credit history including actual credit generation, obligation, and a comparison of actual current credit bank versus staff's projections in the ISOR. As part of the review, staff should include a projection of where the credit bank is expected to be two years later when the next review is due. If overall credit generation is above or below staff's projections (plus/minus a modest estimate allowance/tolerance), CI reduction targets should be adjusted up or down to re-establish an aggressive yet achievable program.

- Establish triggers that would require early program reviews prior to the planned dates outlined above. Specific, measurable thresholds and triggers should be established as part of this process. Some example of such triggers for an early review of subsequent year CI targets include:
  - Monthly credit price exceeds $150
  - Industry credit bank falls below 5 million metric tons (MMT)
  - CA fuel price >70cpg above national average

- Incorporate a simple carryover rule for one-off company imbalances. We would recommend tailoring the provisions of this segment along the lines established for RINs by EPA in the RFS program, with additional enhancements. Key features include:
  - A regulated party may carry over a deficit balance for one year, without penalty
  - Carryover credits must be retired in the following year to completely settle the deficit balance
  - A deficit balance cannot be carried over two years in a row
  - Retirement of any credit shortfall that an obligated party still has at the end of the carryover year, if it is determined that sufficient credits are not available in the market to satisfy the deficit balance (as well as deficits carried over by others). Once again, this situation would force an automatic program review.

LCFS 38-3 cont.

This simple-to-execute approach would satisfy staff's stated goal of addressing short-term tightness in the credit market, while avoiding the market-manipulating aspects of the proposed CCM. Neither this solution nor the CCM can address the very real possibility of a long-term credit shortage. This must be met with the program reviews and schedule adjustments recommended above.

Refinery Investment Credits

It is unlikely that the refinery credits of 1.13 MM MTCO2e in 2020 projected in ARB's compliance curve will be possible. According to the Initial Statement of Reasons, 80% of the 400 refinery efficiency projects identified in the referenced ARB Energy Audit study are now in place, resulting in 2.2 MMT CO2e reductions. Only 0.6 MMT CO2e identified projects remain, just half the amount in ARB's compliance curve. It is not clear that these remaining 20% will proceed given the fact that they have not been pursued already.

LCFS 38-7 cont.

As described below, restrictions on qualifying projects will significantly limit available credits. The proposed 0.1 CI threshold implies that a relatively large emissions reduction of more than 1% of a refinery's emissions per project is required for a project to qualify. Because most, if not all, of the large energy efficiency projects have already been completed ("low-hanging fruit"), a majority of the remaining opportunities are relatively small. However, the cumulative potential of several small projects should not be ignored. Past investments in energy efficiency will limit potential for additional reductions, especially for more efficient refineries, thus remaining improvements are lower than ARB's projections.

The proposed thresholds and restrictions included in the proposed refinery investment credit mechanism risk arbitrarily eliminating most potential emission reduction projects. Changes are necessary to make the proposal viable and equitable. Chevron in particular has a long history of investing in energy efficiency projects and operating with industry-leading efficiency. Due to our prior investments, the proposed limitations and restrictions create arbitrary inequities. We suggest the following modifications to the refinery credits section to address these issues: LCFS 38-7 cont.

- Ensure equity for more efficient refineries by using methodologies that do not discriminate against complex refineries or penalize prior investments.
- Avoid arbitrary restrictions and thresholds, including 0.1 gCO2e/MJ CI and 10% biofeedstock limits, to encourage innovative GHG reductions.
- Eliminate the prohibition on criteria pollutants, as they are adequately regulated by multiple other programs.
- Clarify definitions and language in the rule, for specificity and to increase equity.
- Reduce projections for credit generation to a more realistic level.
- Review refinery carbon intensity gap between GREET and ARB calculations.

Define an equitable industry benchmark

The proposal to handle differences in refinery efficiency (credit varies depending on whether a refinery is above or below the California average carbon intensity for each fuel) is a step in the right direction to ensuring equity. However, emissions per barrel of gasoline and diesel (carbon intensity) are not an appropriate method for comparison due to structural differences in refinery complexity and product mix. The 50% credit for higher-than-average carbon intensity refineries could adversely affect more efficient, but larger and more complex, refineries that produce a range of products.

We propose a Complexity Weighted Barrel (CWB) benchmark, consistent with AB32 cap and trade. Solomon's Complexity Weighted Barrel (CWB), has been implemented for the AB32 cap and trade emissions benchmark to ensure that more complex or diverse product slate refineries are not unfairly penalized. For consistency, we recommend ARB adopt the California average emissions per complexity weighted barrel (4.32 Tonnes Co2(e)/CWB) as the determining threshold for which less efficient refineries qualify for partial (50%) credits. This threshold is consistent with the refinery benchmark of 3.89 allowances/CWB, or 90% of California refinery average. For LCFS, if a refinery has more than 4.32 tons of greenhouse gas per CWB, it should only receive partial credit under the LCFS program, while refineries that have less than the average CWB intensity should receive full credit. LCFS 38-8 cont.

Allow credit for projects implemented since LCFS adoption

The proposed January 1, 2015 permit date limitation for eligibility penalizes early actors contrary to AB 32 provisions 38560.5(b)(1) and (2). We propose that the deadline for project eligibility be the start of the LCFS in 2010, for fairness and consistency. The major investments identified by LCFS 38-12 cont.

the Energy Audit have already implemented over 2.2 MMT CO2e/yr reductions and these projects should be eligible to apply for LCFS credits on a go-forward basis. Should ARB retain the proposed January 1, 2015 cutoff date, Chevron believes ARB should allow refinery greenhouse gas emissions reduction projects to be eligible if implemented (i.e., started up) after that date, regardless of when permits for the project were initially filed. Since permitting can be a multi-year process this will avoid penalizing refineries that are already proceeding with such projects. Moreover, since some projects may not necessitate permit applications this approach would apply a consistent threshold to all projects. LCFS 38-12 cont.

Remove impractical restrictions and thresholds

Several revisions are recommended that may increase success of this new LCFS channel. As it is written the program will not incentivize reductions because it is fatally flawed by the following restrictions and thresholds that could be extremely difficult to achieve:

- Biofeedstock 10% threshold
- 0.1 gCO2e/MJ threshold
- Allow non-capital or offsite investments
- Criteria air pollutants and toxics should remain outside the scope of the LCFS

Biofeedstock percentage of 10% is technically impractical for larger refineries

We recommend ARB reconsider and eliminate the 10% biofeedstock threshold. The threshold is inequitable; the quantity of biofeedstock supply necessary to meet this threshold for larger facilities becomes impractical. A 200,000 BPD refinery would require 20,000 BPD of bio-feedstock, nearly 10 times more than a typical 2000 BPD (i.e., 30 MGY) biodiesel plant. Furthermore, co-processing biofeedstocks is generally technically possible only below 10% due to unsolved process technology constraints. Eliminating this threshold could allow innovation to occur. LCFS 38-13 cont.

CI reduction threshold of 0.1 gCO2e/MJ eliminates many legitimate projects

The threshold of 0.1 gCO2e/MJ is overly restrictive and inequitable; we recommend eliminating it. Especially for larger refineries, which may be 100 times larger than a typical biofuel plant, the absolute quantity of CO2 emissions required to cross this threshold is larger by a similar ratio. Also, with an industry average refinery carbon intensity (excluding tailpipe CO2) of only 7.61 gCO2e/MJ for gasoline and 8.95 gCO2e/MJ for diesel, 0.1 gCO2e/MJ is a relatively large reduction. This threshold is even more challenging for larger, more complex facilities, and for those that are already more efficient than industry average. LCFS 38-10 cont.

If thresholds are included, use absolute rather than percentage emissions impact

Percentage throughput limits are unfair to larger refineries, since the absolute reductions must be larger as facility size increases. This is a perverse outcome, since the larger refineries may be more efficient at the start and therefore should not be precluded from further improvements. Similarly, if CI is calculated based on volume percent of each fuel produced, a refinery's fuel slate will affect its ability to receive LCFS credits for energy efficiency projects. If two refineries have total emissions of 4,000,000 tonnes each, but one produces 10% diesel, while the other produces only 5%, the number of tonnes of emissions reductions necessary to meet the diesel CI target will be different for each refinery (40,000 or 20,000). If thresholds must be included, we LCFS 38-13 cont.

recommend an absolute emission reduction threshold (e.g. 1000 MT/year), rather than a per-unit measure. LCFS 38-13 cont.

Consider including non-capital projects, bundled projects, and offsite portions of projects

Non-capital but sustained improvements should be included since many energy efficiency upgrades are considered non-capital. Also to simplify accounting and increase the success of this pathway, in the same application package ARB could allow bundling of smaller projects. Offsite portions of projects, such as hydrogen plants, could also be made eligible. LCFS 38-11 cont.

Allow de minimis criteria pollutants and overall site offsets

The LCFS should focus on the reduction of GHGs and avoid the additional and unnecessary complexity of regulating emissions that are covered by strict stationary source regulations and CEQA. This is supported by ARB's analysis that concluded that emissions increases at the statewide, regional, or local level are unlikely based on current law and policies that control industrial sources.[2] Furthermore, this provision is inequitable as other credit-generating activities in the LCFS (e.g. alternative fuel pathways, electricity credits, etc.) do not include similar provisions. LCFS 38-9 cont.

At a minimum, Chevron recommends that ARB allow refiners to offset any criteria pollutant and/or toxics health risk impact associated with their submitted efficiency improvement projects. The LCFS should provide refiners the opportunity to offset any criteria pollutant increases related to GHG reduction projects and only require that when de minimis levels are exceeded, using similar thresholds as the Air Pollution Control Districts for criteria pollutants. Adding flexibility to meet such a de minimis criteria pollutant threshold with other offsetting reductions is more practical than the implications of attempting to track second-order criteria pollutant cascading impacts of GHG reduction projects throughout the refinery's operations.

Clarify definitions and language in the rule

Chevron requests that ARB clearly define the following to enable effective implementation of the rule:

- Percent bio-feedstock calculation
- Total volume and energy calculations included in the allocation formula
- Quantification of baseline and reductions
- Harmonization with AB32

Percent bio-feedstock calculation

If the percent biofeedstock restriction is not removed, ARB should clarify whether percent is relative to crude oil feed, intermediate feeds such as VGO or hydrogen, or gasoline and diesel individually, and how this is to be calculated. We also propose that ARB specifically define that these biofeedstock credits apply to both coprocessing bio-oils and coprocessing bio-gas biofeedstocks. LCFS 38-13 cont.

---

[2] *CARB, October 28, 2010, Cap-and -Trade Regulation, Volume VI, Appendix P: Co-Pollutant Emissions Assessment*

Total volume and energy calculations included in the allocation formula

The formula for calculating the total volume and energy of the refinery appears ambiguous. In particular, the basis of the product volumes is not defined. Use of life cycle assessments and other studies to calculate total volume and energy as proposed in this formula is not a technically sound method for allocating energy and emissions to products which fall outside the LCFS. For example, emission allocations between products based on volumes are not representative for refineries that make lubricants or other products besides gasoline and diesel. In order to avoid an arbitrary allocation while still incentivizing projects, a simplified formula could simply allocate the total emission reductions from any given project to that refinery's gasoline and diesel production. LCFS 38-17

Quantification of baseline and reductions

For calculating baselines and reductions, please define type of measurement needed, for instance CEMS, Parametrics, EFs, etc. The LCFS is generally based on a 2010 baseline year but this program seems to be using a 2011-2013 average baseline, the expected baseline year should be clarified. Also the regulatory text is not clear as to how unrelated changes in refinery carbon intensity over time would affect previous refinery credits (such as changes in throughput rates or operational changes such as new units). LCFS 38-18

Harmonization with AB32

For ease of implementation, the proposed definitions of the LCFS should be harmonized with the AB32 requirements such as MRR reporting. LCFS 38-19

Explain apparent inconsistency on petroleum refining Carbon Intensity

According to staff's reported values, there exists a 5 to 7 gCO2e/MJ gap between GREET and ARB calculated industry carbon intensity values for gasoline and diesel. ARB's calculated refinery carbon intensity shown in Initial Statement of Reasons Table III-9 below is 5 gCO2e/MJ below the GREET model for California gasoline, and 7 gCO2e/MJ for diesel. This relatively large difference implies that on average, California refineries have lower actual carbon intensity than modeled by GREET's baseline. These data may indicate a gap in the accuracy of the GREET model, or in the proposed refinery carbon intensity formula. California refineries have been aggressive in implementation of energy efficiency improvements, and petroleum fuels should receive full and fair credit for improved carbon intensity in the LCFS program. LCFS 38-20

Staff investigated the actual carbon intensity of the gasoline and diesel produced by refineries using data from 2011 to 2013 and Equations 14 through 16, above.

Table III-9. Gasoline and Diesel Refinery Carbon Intensities

	CA-GREET (gCO_2e/MJ)	*Industry Average (gCO_2e/MJ)*
Gasoline	13.94	8.95
Diesel	15.33	7.61

Table III-9 lists the average carbon intensity for gasoline and diesel for all refineries. The average gasoline carbon intensity is 8.95 gCO_2e/MJ. Figure III-8 shows the average CI for gasoline for all refineries.

Electricity Provisions

Electricity Credits for Fixed Guideway Transit and Electric Forklifts

Chevron opposes the allowance of LCFS credits for fixed guideway transit and electric forklifts for the following reasons:

- Allowing these credits does nothing to encourage the development of new, low-carbon transportation fuels. Instead, the rule change simply allows the generation of funds from credits sold back to transportation fuel providers and does nothing to further reduce GHG emissions. The value of these credits is estimated by ARB staff to amount to $40 to $100 million for fixed guideway systems and $10 to $25 million for forklifts in the 2015-2020 timeframe.

- Much of the equipment that could generate credits has been in existence for many years – in some cases for decades. As such, only the incremental increase in electricity usage relative to the 2010 baseline should be allowed for credit generation. Staff partly acknowledges this inconsistency by not allowing the use of an Energy Economy Ratio (EER) when calculating the amount of fuel energy displaced for forklifts and only allowing its use for fixed guideway system expansion beyond 2010. LCFS 38-21

- Chevron believes that any credits generated for electric forklifts should be based on metered usage and not calculated based on estimates and assumptions. Staff proposes that electrical distribution utilities (EDUs) would be the regulated party for forklifts and that electricity usage would be estimated based on national shipment data, battery size, assumed annual operating hours, and load factor. Statewide data would be allocated to each service area on the basis of each utility's share of business/commercial accounts. Chevron is strongly opposed to this approach as there is no way to verify that the estimated electricity usage is real. Notwithstanding our opposition on the basis that much of the equipment receiving credits has been in service for many years, if ARB were to go forward with this credit generation scheme, it should be based on metered data that can be directly tied to the vehicles in which the electricity is used.

- Staff has assumed that electric forklift charging will displace diesel fuel in calculating credits. Considering many forklifts are powered by LPG, this is a questionable assumption. ARB has not provided data or information to validate this approach. Therefore, it is not possible to verify that the credits will be accurately generated. LCFS 38-21 cont.

Elimination of Metering Requirement for Residential EV Recharging

The current regulation allows the use of an estimation procedure to approximate residential electric vehicle (EV) recharging electricity usage. However, that provision was to sunset at the end of 2014, and instead electricity used for EV recharging was to be based on direct metering. ARB staff is now proposing to eliminate the requirement for direct metering of electric vehicle (EV) recharging at residences in the post-2014 timeframe. Chevron strongly opposes this proposal for the following reasons:

- All parties participating in the LCFS, both opt-in and required, must be held to the same set of standards with respect to reporting, recordkeeping, validation, etc. Allowing a simple estimation procedure for some fuels and rigorous reporting and recordkeeping for others establishes an uneven playing field among fuel providers.

- Basing credits on an estimation procedure increases the risk of invalid credits. At the very least, credits generated via an estimation procedure are more likely to be open to challenges and invalidation.

Notwithstanding Chevron's opposition to this proposal as noted above, if ARB does go forward with an estimation procedure for determining the amount of electricity used for EV recharging, it needs to be much more rigorous than the current method approved by ARB (see http://www.arb.ca.gov/fuels/lcfs/workgroups/elect/04122013-caletc-letter.pdf). Based on the limited information available in this approval letter, it appears that the method would assume that vehicles within a service area without direct metering would be used in the same fashion as those that do have direct metering. We have a number of concerns and questions about this approach: LCFS 38-22

- Vehicle owners who go to the trouble of installing a separate meter are likely to plug-in more faithfully than those who do not and are therefore not representative of the entire fleet. This is particularly important for PHEV estimates. To justify the estimation methodology, data must be presented to confirm that the results from the metered fleet can be extrapolated to the unmetered fleet.

- The data collected on vehicles with direct metering cannot be applied to the entire fleet of BEVs and PHEVs in an area without also confirming that the distribution of vehicles (by BEV/PHEV and by all-electric range) is the same between those with meters and those without. It is highly unlikely that this distribution would be the same. For example, a PHEV with a 10-mile electric range that was purchased primarily for carpool lane access would likely be under-represented in the sub-set of vehicles with at-home meters.

- A method for avoiding double-counting of electricity usage must be included. If at-home charging for those vehicles without a separate EV meter is accounted for with this method, the method must account for a vehicle owner who only charges at public or work-based charging stations and rarely charges at home. Estimating home usage but then giving full credit to public charging stations has significant potential for double counting.

- At the May 30, 2014, workshop, ARB had proposed to exclude some supplemental information now required in annual reporting. It is unclear from the ISOR whether this change will be implemented. However, if so, Chevron disagrees with this, particularly the exclusion of the number of EVs operating in a service territory. Without this basic piece of information, it will not be possible to cross-check reported electricity usage by EVs for reasonableness. In fact, we suggest that the reporting requirements be enhanced to include not only the number of EVs in a service territory, but also the number of plug-in vehicles in various categories (i.e., pure electric vs. plug-in hybrids by range).

- It is important to distinguish between pure battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV), and within each of those categories, identify the distribution of vehicles by electric range. For example, data collected by the Idaho National Laboratory on in-use driving patterns for the Chevrolet Volt and Nissan Leaf can be found at: http://avt.inl.gov/evproject.shtml#. Dividing the all-electric miles by the number of vehicles reported at that website gives quarterly VMT per vehicle for Oct-Dec 2013. The BEV Leaf (~6000 miles per year if 4Q2013 numbers are forecast to a full year) is accumulating fewer miles on electricity than the PHEV Volt (~8000 miles per year). Clearly, the limited range of the Leaf is resulting in much lower VMT than a typical new car, while the broader utility of the Volt results in greater overall usage and higher VMT on electricity. However, PHEVs with lower range would have fewer miles on electricity, while BEVs with greater range would likely have more miles on electricity. These results reinforce the importance of understanding the make-up of the plug-in fleet in a particular area to generate an accurate estimate of on-road electricity usage. In addition, it is important to continue monitoring recharging and electricity usage of these vehicles as the patterns of usage may change as the vehicles expand beyond "first-adopters."

LCFS 38-22 cont.

Elimination of Public Reporting of Electricity Credit Information

Chevron does not support removal of this requirement from the regulation. The current regulation requires regulated parties for residential and public EV charging to include a public accounting of the number of credits generated, sold, and banked in annual compliance reports. In the ISOR, ARB argues that because public credit accounting is not required of regulated parties of other fuels it is not necessary for electricity. Chevron supports the principle that all fuels and fuel providers should be subject to the same requirements – ARB should not pick "winners and losers." Our positions outlined above with respect to electricity credits for fixed guideway transit/electric forklifts and elimination of metering requirement for residential EV recharging are consistent with that principle. However, if electricity credits are based on estimated

LCFS 38-23

electricity usage rather than direct metering, the public has a right to know precisely how those estimates were prepared and the number of credits generated as a result. LCFS 38-23 cont.

Updates to the OPGEE Model

General Treatment of Crude Oil in the LCFS

Chevron continues to disagree with the crude differentiation approach that ARB has adopted for the LCFS. As several studies have shown, such an approach leads to inefficiencies in the crude market and could potentially lead to "shuffling," with an increase in GHG emissions associated with increased transportation distances. Ultimately, if crudes are valued based on their carbon intensity (CI), there is no evidence to suggest that they will not be produced. In addition, if crudes are valued based on their CI, many crudes produced in California will be at a competitive disadvantage relative to other crudes imported into the state. We encourage ARB to re-think the efficacy of the differentiated crude approach.

"Ground-Truthing" OPGEE

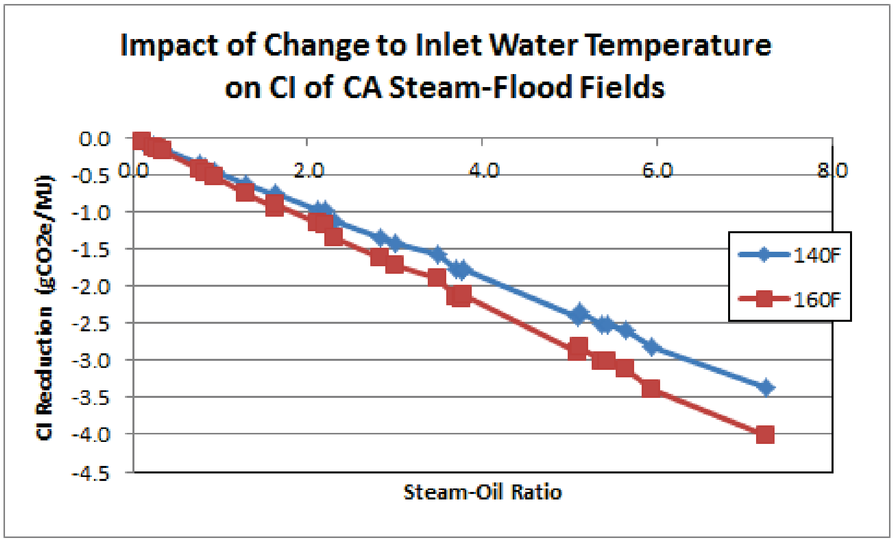
ARB staff, in conjunction with researchers at Stanford University, has continued to make revisions to the OPGEE model over the past several years. The OPGEE model relies on numerous inputs and assumptions about oil field attributes and operational parameters such as field depth, reservoir pressure, number of production wells, number of injection wells, water-oil ratio, gas-oil ratio, steam-oil ratio, API gravity, etc. For many oil fields, little data are available for the input parameters and the model populates the entries with "smart defaults." The CI estimates from OPGEE must be validated against actual data for a given field in California, the U.S., or elsewhere. Given the importance of the crude CI estimates in terms of establishing the 2010 Baseline crude CI and the California-average crude CI for each calendar year, this "ground-truthing" is an important test of the validity of the model approach that should be undertaken. LCFS 38-24

OPGEE Inputs

As noted above, many inputs are required to run the OPGEE model for a particular oil field. For California fields, a number of important parameters, such as water-oil ratio, steam-oil ratio, and production volumes are available or can be calculated from data published by the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources. One such input parameter, the steam-oil ratio (SOR), has a significant influence on the CI calculated by OPGEE for an individual field. The amount of energy required (and therefore the GHG emissions associated) with a given SOR is calculated using a heat balance over the steam generator. A critical input to that calculation is the temperature of the input water to the steam generator. The OPGEE model assumes a default water input temperature of 40°F and provides no rationale for this assumption.

Based on Chevron's experience with steam-flood fields in the San Joaquin Valley, a value of 40°F for inlet water temperature to steam generators is much too low. Because water that is input to steam generators is typically recycled from water produced in the field, its temperature is well above 40°F. For our fields in the San Joaquin Valley, the inlet water temperature typically ranges from 140°F to 160°F, and in some cases is even higher.

The figure below shows the impact on the CI of California steam-flood fields if the inlet water temperature to the steam generators was 140°F and 160°F instead of the assumed default of 40°F. As expected, the influence is greater on fields with the higher SOR values. For SORs in the 5 to 6 range, the CI of the crude would drop by 2.5 to 3.5 gCO2e/MJ by using more realistic estimates of the inlet water temperature. This reflects a CI reduction of 8% to 11% for those fields.



LCFS 38-24 cont.

We encourage ARB staff to revise the OPGEE modeling to reflect a realistic input value for the steam generator feed water temperature, and we will work with ARB staff to provide more specific data on this and other model inputs. As these values will be static for several years once finalized in the regulation, it is important to get them right.

California Crudes are Disadvantaged Under the LCFS

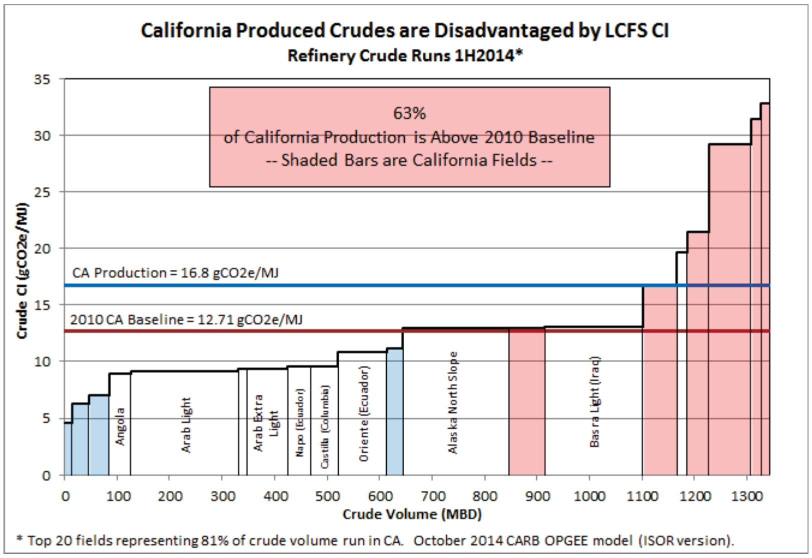
In the 2009 regulation, crudes produced in California were not subject to the high carbon intensity crude oil (HCICO) requirements of the standard as they constituted more than two percent of the 2006 baseline crude mix run in California refineries. The trigger level of two percent was put in place to ensure that ***new crudes*** introduced into the California market with high CI values would have their increased GHG emissions mitigated. This was not intended to punish California producers as their GHG emissions are already regulated under the broader AB32 program.

LCFS 38-25

The current construct of the regulation puts California crudes at a distinct disadvantage. As observed in the figure below, California production averaged 16.8 gCO2e/MJ based on field volumes for the first half of 2014 (see http://www.arb.ca.gov/fuels/lcfs/crude-oil/mid-2014-crude-ave-ci.pdf) and the CI values in Table 8 of the proposed regulation. In addition, 63% of California production has a carbon intensity greater than the 2010 baseline value of 12.71 gCO2e/MJ.

We encourage ARB staff to develop a more equitable treatment of California crudes in the LCFS that recognizes that GHG emissions from the production of those crudes are controlled via AB32. ARB should develop a single CI value for all California crudes without differentiating among the ~150 fields included in the current crude CI lookup table. Changes to that CI value should only be made in the event of a significant change to the average CI of California fields, e.g., +/- 1 to 2 gCO2e/MJ.

LCFS 38-25 cont.



Operator-Specific CI Values

ARB currently evaluates the CI of California oil fields as a single value, although there may be multiple operators within each field with much different operating parameters. If crudes are ultimately valued based on their CI, there should be the ability for individual operators to obtain a separate CI specific to their operation. This would award operators for more efficient operations, similar to what has occurred in the biofuels industry (e.g., there are scores of different CI values for corn ethanol).

LCFS 38-26

De Minimis Level Incremental Crude Deficits

As currently written, incremental deficits are incurred if the California-average crude CI for a particular year is greater than the 2010 Baseline crude CI. In order to avoid increased regulatory and reporting burden for small changes in crude CI, the difference between the California-average crude CI and the Baseline crude CI should exceed a de minimis level (e.g., 0.1 gCO2e/MJ) before an incremental deficit is incurred.

LCFS 38-27

Regulatory Language

Pages 95-96 of the Proposed Regulation Order contains the regulatory language for calculating the incremental deficit if the California-average crude CI for a given year exceeds the 2010 Baseline crude CI. We have the following comments on the proposed regulatory language:

LCFS 38-28

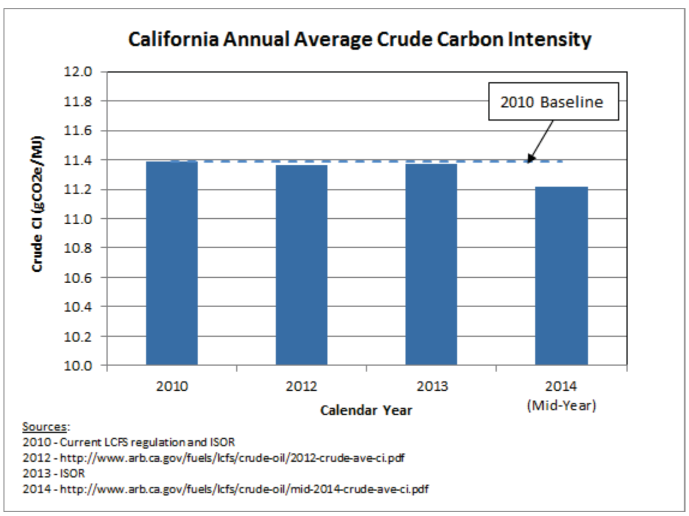
- The language needs to be clear that the parameter E^{XD} (fuel energy, in MJ, for either CARBOB or diesel) is for the calendar year for which the deficit is calculated.
- The language needs to be clear that the parameter E^{XD} is for fuel **supplied** to the California market; the current language refers to fuel "produced in California or imported into California." Fuels produced for export should not be subject to this regulatory requirement.
- The current language appears to calculate debits based on the amount of fuel supplied in the year in which the debits become effective, which is two years after the debits are incurred. Instead, this should be based on the amount of fuel supplied during the year that the debits are incurred.

LCFS 38-28 cont.

Annual Crude CI Calculation

Chevron appreciates ARB's desire to continually improve the accuracy of LCFS data inputs, and recognizes the approach taken by staff in attempting to refine the crude handling provisions as part of the re-adoption rulemaking is consistent with that principle. However, we also believe that the degree of crude differentiation built into LCFS, to comprehend concerns over CA crude CI increasing over time, remains unnecessarily excessive and should be reduced. Our reasoning is as follows:

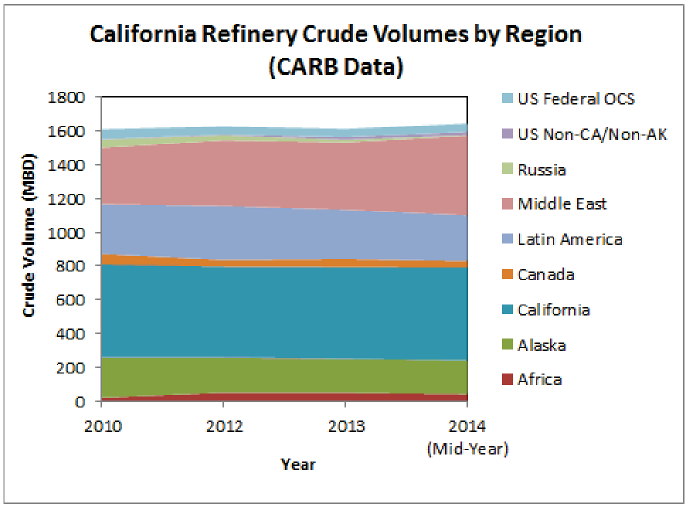
- The fundamental reason for these provisions in the rule was to ensure that the Average carbon intensity of the California crude slate did not increase over time. The available crude breakdown data for recent years (2012-1H2014) suggests that this threat has never materialized and that the CA crude average CI has remained relatively stable.

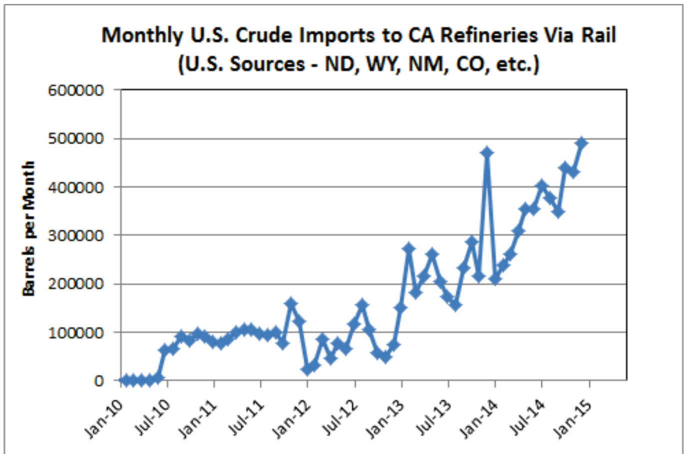


- Moreover, ARB data on crude volumes run in California refineries show a decreasing trend in heavier Canadian crudes, while light Middle Eastern and U.S. mid-continent crudes ("US Non-CA/Non-AK" in the figure below) have trended upwards. Furthermore,

LCFS 38-15 cont.

CEC data on U.S. mid-continent crude imports by rail show strong growth over the past three years that has continued through the second half of 2014. LCFS 38-15 cont.





Source: California Energy Commission
http://energyalmanac.ca.gov/petroleum/statistics/2010_crude_by_rail.html
http://energyalmanac.ca.gov/petroleum/statistics/2011_crude_by_rail.html, etc.

- As a result, we believe that the justification drivers for installing, maintaining and expanding the current LCFS crude differentiation provisions have been greatly diminished since these provisions were implemented.

- Even if ongoing monitoring is necessary to ensure that staff's concerns that a heavier crude CI outlook does not materialize, the worst case scenario (i.e., exporting heavy California crude to maintain a constant annual average crude CI) yields no tangible greenhouse gas reduction benefits from a global standpoint. California's average crude CI may well remain constant, but global GHG emissions are likely to increase as the GHG emissions associated with transporting the crude exported from California (to non-optimal refining centers for processing) will be higher.

- The ongoing staff effort to maintain and improve crude differentiation inputs and modeling tools in LCFS is resource-intensive for the Agency and equally burdensome for our industry in terms of the recordkeeping and reporting requirements it entails. In the absence of a valid GHG justification for engaging in such a complex crude differentiation and tracking scheme, we believe staff should be moving in the opposite direction than they have been following, i.e., one of simplification and streamlining.

We understand that staff does not propose a fundamental change in the California Crude Average approach as part of this re-adoption package. We support staff's decision not to proceed with refinery-specific crude accounting for large, complex refineries and understand the rationale offered for doing so. We agree that there is no practical alternative to facilitate detailed individual crude breakdown in the pipeline crude blends that comprise a large part of refinery crude inputs in the state. We look forward to working with staff in the near future to examine potential options to modify the crude differentiation requirements in LCFS (post re-adoption), toward a less complex alternative that can hopefully satisfy staff's desire to track crude CI trends over time while reducing the compliance burden on our industry.

We note the proposed changes in the methodology for calculating the CA crude average to rely on CA on-shore crude production data (supplied by The Department of Conservation- DOC) and off-shore data (supplied by The Bureau of Safety and Environmental Enforcement- BSEE). This is in lieu of refinery-reported crude volumes that have been used for this purpose heretofore. Staff's rationale is simply that this is essential to improve the accuracy of the crude volumes used in the calculation of the CA Annual Crude Average. There is no backup support or analysis of the impact of the proposed changed in calculation methodology. More specifically, staff does not:

LCFS 38-15 cont.

- Present data to determine how this change will impact the calculated annual volume averages to date. Staff merely indicates that total refinery-reported volumes for 2012 and 2013 closely match the volumes reported by CA field operators. We would recommend a more rigorous side-by-side comparison for 2011-2013 using the CA crude volumes estimated/reported by refineries versus the newly proposed utilization of DOC and BSEE data.

- Elaborate on the methodology that will be used to combine the in-state crude data with out-of-state crude volumes imported into California (both U.S. and foreign) to develop the overall annual CA crude average. Furthermore there is no indication that any potential discrepancies with the refinery-reported volumes will be investigated and reconciled.

- Recognize the difficulty that increased CA exports will entail should this methodology be adopted, dismissing such concerns by simply indicating that production volumes will be adjusted for exported crude volumes (should the need arise). Staff believes their proposal will work as long as all CA-produced crude is processed in CA, which is currently the case. However, staff's proposal appears to be short-sighted and inconsistent with the overall crude handling approach in LCFS which, despite WSPA's input, is designed to drive increased crude exports to prevent CA crude average CI increases. Moreover, the same issues staff outlines in breaking down reported volumes of typical CA pipeline crude blends currently will be in play if/when staff tries to back out exported crude volumes out of the calculated CA annual average. LCFS 38-15 cont.

Indirect Land Use Change

General Comments

Indirect land use change (ILUC) estimates continue to be a source of uncertainty in the overall lifecycle GHG footprint of biofuels, and significant efforts to refine those estimates have continued since ARB initially included ILUC in the LCFS. Although uncertainty in the estimates remains, Chevron agrees that ILUC effects need to be addressed in the context of the LCFS regulation. In principle, the scientific basis for addressing ILUC in the LCFS remains sound, and improvements to methods and models for estimating ILUC values continue to be made.

During the 2009 rulemaking, the Board directed staff to convene a Work Group with experts on both sides of the debate to ensure a balanced and transparent approach to further work on the issue. We applaud ARB for facilitating that effort, as well as the work group participants who devoted considerable time and energy to better define the issues around indirect effects. Although disagreements remained among experts about some key elements of the ILUC calculations (e.g., time accounting), there were other areas of agreement and recommended GTAP model improvements that have been incorporated by Purdue University and ARB (e.g., improved treatment of co-products for corn ethanol and soy biodiesel). LCFS 38-29

Specific Comments on the ILUC Analysis Presented in Appendix I of the ISOR

The detailed analysis of revised ILUC values is summarized in Appendix I of the ISOR. While we believe the inclusion of ILUC is relevant and necessary to a valid assessment of lifecycle impacts, the process for establishing and updating ILUC values should be open and transparent. To that end, we have the following comments and questions on the analysis and the ensuing results. We request that ARB address these questions as they proceed to finalize the modeling updates and rulemaking.

A comparison of the current regulatory ILUC values and the proposed ILUC values is shown in the table below. Also shown are values presented at the November 20, 2014, workshop.

Comparison of Current and Proposed ILUC Values (gCO2e/MJ)			
Fuel Pathway	Current Value (2009 Regulation)	Proposed Value (December 2014 ISOR)	November 2014 Workshop[3]
Corn Ethanol	30	19.8	20.0
Sugarcane Ethanol	46	11.8	19.6
Soy Biodiesel	62	29.1	27.0
Canola Biodiesel	n/a	14.5	14.5
Sorghum Ethanol	n/a	19.4	12.7
Palm Biodiesel	n/a	71.4	46.4

Given the significant changes to both the GTAP model, which estimates the location and amount of land use change for a particular biofuel pathway and a given volume "shock," as well as the emission factors applied to the land use change (via the AEZ-EF model), it would be useful for ARB staff to identify how much of the ILUC changes in the table above are associated with GTAP model revisions versus emission factor revisions. Additionally, what is the basis for the changes between the November 2014 workshop and the December 2014 release of the ISOR?

LCFS 38-30

Table I-1 of Appendix I summarizes the "shocks" used in GTAP to model ILUC emissions. For sugarcane ethanol, the table appears to indicate that 3 billion gallons of Brazilian production and 1 billion gallons of U.S. production were assumed. Is this a correct interpretation of the table, or do those volumes reflect the volumes consumed in Brazil and the U.S.? If the former interpretation is correct, what is the basis for these estimates, as we are not aware of large volumes of sugarcane ethanol being produced in the U.S.? What is the sensitivity of the model to changes in the split between Brazilian production and U.S. production?

LCFS 38-31

The proposed ILUC values are based on an average of 30 model runs which used 5 different values for the yield-price elasticity, 2 sets of values for a yield adjustment for the cropland pasture land category, and 3 sets of values for the elasticity of crop yields with respect to area expansion (5 X 2 X 3 = 30 runs). ARB also prepared a Monte Carlo uncertainty analysis that consisted of up to 1,000 model runs for some pathways. Why were the means of the 30 discrete scenarios used to establish the ILUC values rather than the means of the Monte Carlo simulations?

LCFS 38-32

As noted above, one of the parameters that was varied to establish the 30 model runs for the ILUC analysis was a yield adjustment for the cropland pasture land category, which is a new land category in the GTAP model relative to the 2009 analysis. This yield adjustment is intended to account for potential investments to increase the productivity of this land as it is brought into crop production. The discussion on page I-12 of Appendix I indicates:

LCFS 38-33

[3] See http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/112014presentation.pdf

> *However, Purdue researchers acknowledge that although they believe the effect is real, there is no empirical basis for the elasticity parameter proposed for this endogenous yield adjustment.*

In the absence of empirical evidence to estimate this parameter, staff used two sets of values for the runs employed for each biofuel analyzed here. Given the lack of empirical data with which to estimate this parameter, Chevron requests that staff clarify the basis it used for the elasticities in this analysis. LCFS 38-33 cont.

Land use change effects for cellulosic ethanol are discussed beginning on page I-18 of Appendix I. The discussion indicates that a value of 18 gCO2e/MJ is proposed for cellulosic feedstocks, and that staff is continuing to work on model inputs for cellulosic ethanol from non-food crops and waste. The discussion further indicates that results will be published when the analysis is complete. Will an updated ILUC value be proposed for cellulosic ethanol via a 15-day change notice as part of the current rulemaking, or does staff envision another avenue to formalize this value? In what timeframe does staff expect to have an updated ILUC value for cellulosic feedstocks? Is the 18 gCO2e/MJ value only for farmed trees, miscanthus, and other purpose-grown cellulosic feedstocks, i.e., would waste products used for cellulosic ethanol feedstock be assigned a land use change value of zero? LCFS 38-34

Low Complexity/Low Energy Use Refinery Provisions

Chevron is opposed to ARB's proposal to allow low complexity / low energy use refineries to generate credits equivalent to 5 gCO2e/MJ for their CARBOB and CARB diesel production. The criteria proposed for identifying these refineries is questionable as it ignores energy used per barrel of production in favor of total energy used by the facility. This unfairly penalizes those refiners who have invested in the complex facilities required to meet the demand of the California market at the state's unique specifications. We also oppose this proposal as it adds additional complexity to an already extremely complex program. LCFS 38-35

Refinery-specific crude provisions

The proposal to allow low complexity / low energy use refineries to opt out of the California crude average is also inappropriate. As we and others have stated repeatedly, crude differentiation under the LCFS does not benefit the environment, consumers, or regulated parties and may increase GHG emissions as crude shuffling increasing transportation impacts. Any move to make that differentiation more complicated only serves to compound the problem. There is little benefit to this change to the program or regulated parties and, as ARB states in the ISOR, tracking field-level crude use is extremely complicated. While it may be somewhat easier at the small refinery level, the added complexity of tracking multiple class-level crude CI baselines and usage is not worth the questionable benefit to those choosing to opt out. LCFS 38-36

Innovative crude production

ARB's proposed revisions to the LCFS innovative crude provision, Section 95489(d) are creative and perceptive and address several issues identified as inhibiting the use of innovative crude LCFS 38-37 production methods to reduce GHG emissions. As staff noted in the Initial Statement of Reasons (ISOR) no application has been submitted to date under the current provision. The supported changes include 1) allowing the crude producer to opt in and earn LCFS credit based on the volume of crude supplied to California refineries, 2) reducing the minimum threshold for CI reduction from 1.0 g/MJ to 0.1 g/MJ and allowing projects not meeting the 0.1 g/MJ threshold to be certified if they reduce annual emissions by 5,000 MTCO2e or more, 3) adding solar and wind electrical power generation and solar heat generation to the allowable innovative methods, and 4) the use of simplified, default credit calculations for solar-based steam generation and solar-or wind-based power generation.

However, in keeping with the intent of the innovative crude provision as stated in the ISOR, to promote the development and implementation of innovative crude production methods, additional adjustments to the provision and Staff proposed revisions should also be considered. First, the source and sink of the CO2 used for Carbon Capture and Sequestration (CCS) should not be restricted. LCFS credits should be provided regardless of where capture and storage occurs, not if both are solely onsite at the crude production facilities. This added restriction is contrary to the 2014 First Update to the Climate Change Scoping Plan which promotes innovative strategies such as CCS use to reduce GHG emissions from electricity generation and industrial emitters. Such geographic limitation would further dis-incentivize CCS in California as the overall economics for a third party's carbon capture project would be diminished as most amenable, readily capture volume, carbon capture opportunities are not onsite at the oil production facilities. While the capture of CO2 from a steam generator at the oil production facility may be an admirable objective, the overall cost of actual capture, sufficient volume, gathering and clean-up to a CO2 purity to allow for miscible injection and recovery at a reasonable economic scale is prohibitive as compared to capture from power generation or other industrial emission streams.

LCFS 38-37 cont.

Also, this same limitation requiring onsite generation for solar heat generation and solar or wind electricity generation should be removed. There are no less GHG emission reductions if the oil field operator generates or purchases his power onsite. Greater benefit would be achieved by focusing on regulating emission sources and not emissions footprint. Chevron's solar to steam test project in the Coalinga Field would not qualify for innovative crude consideration under the current definition, although having met the revised emissions reduction threshold, as the mirror field was on adjacent property to the oil operations.

Reducing minimum acceptable steam quality from 65% to 55% for solar steam generation would also be appropriate as several existing oil fields generate steam at a steam quality lower than 65%. This change and increasing the assumed inlet water temperature from 40 F to 140 F and reducing the steam generator pressure from 2000 psi to 700 -1000psi in the crude credit quantity calculation would be more accurate in representing typical oil field operations. Hot produced water is primarily used for steam generation.

While ARB is commended for expanding the list of allowable innovative methods, any new oil recovery method that reduces GHG emissions beyond the required threshold should be allowed to submit their project for Executive Officer consideration as approved innovative technology crude. As an example, the use of polymer flooding in the Wabasca Field in Canada instead of steamflooding for enhanced oil recovery would not qualify for consideration under the current proposed revisions. LCFS 38-37 cont.

Reporting and Recordkeeping

Quarterly Reporting & Reconciliation

Chevron supports and appreciates ARB's proposal to change the quarterly reporting process from a simple 60-day reporting deadline to include a 45-day deadline for reporting, followed by a 45-day reconciliation period. Given the extremely large volume of transactional data involved in compiling these quarterly reports, this structured approach to business partner reconciliation should help to alleviate reporting discrepancies.

Even then, discrepancies are never completely avoidable as billing errors, volume adjustments, and other corrections can occur well after the reporting deadlines. Chevron appreciates that ARB has retained a provision in the regulations for regulated parties to request the reopening of prior quarterly reports for corrections. We support the use of the LRT-CBTS as the vehicle for submitting these requests, as indicated in the proposed regulations. We do not, however, see the need for the accompanying letter on letterhead described in the ISOR. This is an unnecessary manual step that adds no discernable value to the process. LCFS 38-38

Product Transfer Documents

The revised definition of Product Transfer Document (PTD) is problematic. The new definition describes the PTD as a single document that contains "information collective supplied by other fuel transaction documents, including bills of lading, invoices, contracts, meter tickets, rail inventory sheets, Renewable Fuels [sic] Standard (RFS2) product transfer documents, etc." This is in direct contrast with the traditional definition of "product transfer document" under this and other regulatory programs, including the Renewable Fuel Standard and other EPA and state programs. The term is specifically generalized so that required information and messaging can be included on any of the types of documents indicated, without requiring the expense and process burden of generating a new document for every new regulatory program. This definition should be corrected to refer to a document or "collection of documents" that transmits the required information for the LCFS program. LCFS 38-39

Reporting Exports

In the ISOR, ARB proposes to require that a party who sells fuel without obligation report any subsequent export of that fuel by the buyer or any subsequent buyer. This is impractical as there is no way for one party to monitor the movement of fuel owned by another party, particularly in California's fungible supply system and especially if the fuel changes hands again after the initial sale. While ARB proposes to require PTD language stating that any subsequent export of fuel sold without obligation must be reported, this PTD language does not create a legal obligation for the buyer to notify the seller of the export. More importantly, it is inappropriate and unreasonable for ARB to assign the compliance burden related to an export of fuel to anyone other than the actual exporter. The fact that another party at one time held title to that fuel is not sufficient justification for assigning the CI obligation for that fuel to that party for an export LCFS 38-40 decision made by another. It is understandable that ARB wants to track the export of fuels in order to keep the LCFS program whole, but they must assign any associated compliance burden to the actual exporter. This concept has been successfully incorporated into the Renewable Fuel Standard, where an export of renewable fuels results in a renewable volume obligation for the exporter, and there is no reason why the same approach cannot work here. LCFS 38-40 cont.

Enforcement

Violations/Civil Penalties

The LCFS, similar to the federal RFS, imposes liability for the validity of the submitted credit on the submitter. Essentially, this is a "buyer beware" program, where the buyer is expected to conduct due diligence of the credit to establish that it was not fraudulently created and the CI valuation is accurate. The LCFS, as presently drafted, would require the party that submits a credit that was subsequently invalidated to replace those credits, and be potentially subject to civil penalties. As we have seen with the RFS, however, such a system did not prevent extensive fraud which undermined market confidence in small producers. We propose that the LCFS adopt an affirmative defense from civil penalty and credit replacement upon a showing that the invalidity of the credit was caused by a third party and the regulated party neither knew nor should have known of the cause of the invalidity at the time it was submitted for compliance.

Though responsible parties are obligated to exercise diligence and make good faith efforts (and include attestations of accuracy), the volumes of data and the complexity of the reports creates a potential for errors that cannot be eliminated. Since an error may go undetected for months or years, assessing a per day violation for incomplete or inaccurate reports from the date of submittal as proposed in § 95494(b) will produce penalties that are grossly disproportionate to the harm. Therefore, if the error is discovered by the regulated party, it should be afforded an opportunity to cure within 5 business days of discovery without penalty. If the error is discovered by ARB, then penalty should accrue upon the date of notice that the report is incomplete or inaccurate. For un-submitted, incomplete or inaccurate reports, the per-day maximum penalty amount should not exceed $1000 per day. LCFS 38-41

In instances where a civil penalty is to be assessed for an invalid credit, we support ARB's proposal that penalties be assessed on a per credit basis (a maximum of $1000/MT), rather than on a per-day basis. Time- based penalties are often magnified by variables unrelated to the alleged violating act such as by the time required to investigate a suspected violation and obtain the necessary facts to make a determination. Consequently, time based penalties are often disproportionate to the violating conduct.

Authority to Suspend, Revoke, or Modify

ARB should establish an administrative hearing process to allow regulated parties an opportunity to appeal a ARB decision to suspend, revoke or modify a credit or CI valuation. LCFS 38-42

Severability

ARB proposes added a section to the regulations stating that any declaration of one part of the program as invalid would not invalidate the remainder of the program. A general assertion of severability is inappropriate and ignores the interdependence of the LCFS provisions. There are many provisions in the LCFS that significantly impact other provisions, and if declared invalid would render the regulation unworkable. For instance, if the CI values for out-of-state producers were nullified, compliance with LCFS would become impossible in the near term, if not immediately. LCFS 38-43

Economic Impact Analysis

The economic impact analysis presented in the ISOR is based on a number of projections and assertions that we find troubling.

Cost of Credits

ARB applies an upper limit of $100/MT in its economic analysis. This limit naturally has an effect on ARB's assessment of the cost of the program to regulated parties, other business, individuals, and state and local economies. Given ARB's proposal for a Credit Clearance Market with a $200/MT price cap, we believe that $200/MT should be the upper limit used in the economic analysis. Should the market fall short of meeting ARB's credit supply projections, there is a very real possibility that the $200/MT price cap will become a price floor for a significant portion of the available credits. LCFS 38-44

Production Volumes and Price of Low-CI Fuels

We disagree with the assertion that "Since 2010, the production of low-CI fuels has increased in response to the financial incentives provided by the existing LCFS regulation." (p. VII-4) While there has been some incremental reduction in the average CI of corn ethanol supplied to California, sugarcane ethanol imports were at lower levels last year and there still today is no cellulosic biofuel available in large quantities. Also, while biomass-based diesel production levels are up, this could be attributed to the federal blender's tax credit and the federal Renewable Fuel Standard (RFS) rather than the LCFS. LCFS 38-45

Revision of Program Goals

We are surprised with the new *stated* goals of the program (p VII-11) – "To create a durable regulatory framework that can be adopted by other jurisdictions". This is not one of the goals described in Governor Schwarzenegger's executive order establishing the program. LCFS 38-46

Flawed Macroeconomic Analysis

The macroeconomic analysis is flawed based on some faulty assumptions. As stated, the scenario should be run at a maximum credit price of $200, adjusted for inflation, from 2016 through 2020. LCFS 38-47

The macroeconomic analysis assumes that production of conventional fuels in CA remains static due to increasing exports (VII-14). Thus, GHG emissions are not lowered but exported.

Additionally, no impact of lost margin has been taken into account for increased exports, nor have capital effects of exporting been addressed. LCFS 38-47 cont.

Additional Sensitivity Cases Are Needed

ARB needs to include an analysis on the impact to the program if the low-CI products are not available as projected. Also, existing fuel trends which show a decreasing demand in California do not account for low crude oil prices. A scenario should be modeled reflecting a $50/barrel crude oil environment.

Table VII-7 of the ISOR shows ARB's projections related to fuel consumption in 2016 and 2020 under a baseline scenario (no LCFS) and an illustrative compliance scenario (with LCFS). While the table indicates expected growth in renewable diesel and biodiesel, it indicates no growth whatsoever caused by the LCFS in the use of ethanol, electricity or natural gas for transportation. This contrasts directly with ARB's assertion in part VII-E of the ISOR that the LCFS is a necessary complement to the federal RFS because "the potential value of electricity, hydrogen, and natural gas are not considered in an overall program to reduce the carbon intensity of transportation fuels." Yet ARB projects no effect on the consumption of these fuels because of the LCFS. Given the complexity and projected cost of the program and the significant uncertainty regarding ARB's projections regarding the availability of these fuels, it is highly questionable whether the LCFS is worth re-adopting. LCFS 38-48

This page intentionally left blank.

38_OP_LCFS_Chevron Responses

172. Comment: **LCFS 38-1**

The comment questions whether the timetable of reductions is feasible with the current standards of the LCFS program.

Agency Response: ARB staff agrees that the LCFS should be periodically reviewed, and the Board has directed that this be accomplished in 2017 and 2018. However, staff disagrees that, after accounting for these adjustments, there will likely be insufficient credits to achieve the required 10 percent reduction in 2020 and at least maintain that level beyond 2020.

The LCFS compliance curve has been designed to take advantage of the court-mandated slowdown in the program while re-adoption was being considered. As structured, the LCFS compliance curve allows a steady build-up of banked credits through 2018 to facilitate compliance and lower costs through 2020. The combination of banked credits and production of credits in the 2018 to 2020 period was designed to provide sufficient credits for overall compliance with the annual requirements for 2019 and 2020. The staff's analyses indicated that sufficient low carbon intensity (CI) fuels to meet a 10 percent reduction in CI without using banked credits is expected shortly after 2020. Finally, staff recognizes that a number of parties backed off from their previous level of use of low CI fuels in 2014, and that overall credit generation was less than anticipated in the illustrative compliance scenario used in the Initial Statement of Reasons (ISOR). Staff has adjusted the estimates of 2014 credit generation accordingly, and the revised assessment continues to show that there will be sufficient credits to meet the rule's 10 percent requirement in 2020. Given these circumstances, the regulation maintains the 10 percent requirement for 2020.

ARB staff provided extensive information in the ISOR on the potential volumes of low CI fuels that are expected to be available over the next ten years. These included both an upper and lower range of supplies, information on the type of fuels and raw materials needed, and the location of production facilities. The illustrative compliance scenario assumes California would attract relatively minor percent volumes of several low CI fuels (for example in 2020 between 10 to 20 percent of the medium case volumes of cellulosic ethanol and biodiesel) and significantly higher, yet still moderate, percentages of several other low CI fuels (for example in 2020 about one-third of the medium case volumes of renewable diesel and cane ethanol). These somewhat higher percentages are consistent with the history of the LCFS to date. For example, in 2014 virtually all of the renewable diesel (RD) imports into the U.S. came to California for use in the LCFS. Additionally, in 2013, when significant imports of cane ethanol were received in the U.S., California's share was on the order of 35 percent.

The LCFS is a very flexible program that allows regulated parties wide discretion in their choice of compliance paths and fuel choices. The ISOR identifies a wide variety of sources of low-CI fuels that are expected to be available to fuel suppliers in California and which, collectively if they all were to be used in California, have the potential to create far more credits that needed for LCFS compliance in 2020 and beyond.

Finally, staff feels that progress relative to the LCFS targets should be periodically reviewed, and has committed to do so publicly with both a progress report to the Board in mid-2017 and a full program review prior to January 1, 2019.

173. Comment: **LCFS 38-2**

The comment states that there should be a mandatory biennial comprehensive LCFS program review, built into the proposal.

Agency Response: Staff agrees with Chevron that it is important to build a LCFS program review mechanism into the proposed regulation although staff believes a biennial review would create unnecessary market uncertainty and staff workload. Section 95496: Regulation Review addresses the need for program review and allows the Executive Officer and the Board to review the implementation of the LCFS program.

Staff considered Chevron and other stakeholders' recommendations, and incorporated a 15-day change to Section 95496 to further address the timing and minimum scope of the review, and to allow stakeholders to provide input to ARB regarding the implementation of the LCFS program.

174. Comment: **LCFS 38-3**

The commenter is opposed to the Credit Clearance Market and identifies five flaws that they believe will result in unintended negative consequences.

Agency Response: With respect to the general thrust of the comment pertaining to the need for and design of the Credit

Clearance Market, see response to **LCFS 32-9.** With respect to the liability protection portion of the comment see response to **LCFS 40-17**. Relative to the other concerns expressed:

During periods of sufficient credit supply, the price cap is unlikely to act as a floor because competition between low-CI fuel producers to sell their credits will ensure that the credit price is set by the market forces of supply and demand. Implementing a price cap doesn't change the fundamental forces of supply and demand. In the LCFS credit market, low-CI fuel producers compete to sell their credits to regulated parties with compliance obligations; in periods of a credit surplus, competition among credit sellers will prevent the cap price from acting as a floor, and will instead drive down the price of credits to the efficient price based on supply and demand. The California Cap-and-Trade carbon market provides real-world evidence that supports this fundamental economic theory: while the cap-and-trade market has a price cap, allowance prices have historically traded well below the cap.

Moreover, ARB staff has analyzed the potential for the cost containment provision to cause low-CI fuel producers to withhold offering credits for sale in order to manipulate the price of credits upward. Staff's assessment of the market shows that a hoarding situation such as Chevron describes is unlikely because the large number and small size of low-CI fuel producers limits their ability to manipulate the market by hoarding credits. Additionally, the incentive structure of the price cap is designed to address concerns that sellers might hesitate to offer LCFS credits for sale. The cap price increases annually to match the rate of inflation. When the price ceiling is held constant in real terms across all years, low-CI fuel producers have little if any incentive to withhold offering credits for sale, as the maximum credit prices can only decrease in future years, when adjusted for inflation.

The Cost Containment Provision (CCP) is designed to enhance the market signals to encourage investment in low-CI fuels and to provide regulated parties with increased certainty regarding the maximum cost of compliance. Staff analysis and feedback from LCFS market participants has underscored the importance of regulatory consistency in order to facilitate business planning, particularly regarding the stringency of the program's CI reduction targets. Chevron proposes eliminating the CCP and potentially changing the compliance targets annually. Rather than strengthening the market signal provided by the LCFS, Chevron's suggestion of setting CI reduction targets only one year in advance would reduce the incentive for innovation and investments in low-CI fuels, increase administrative burden, weaken the market signal provided by the LCFS, and increase uncertainty for regulated parties. As it can take two to three years to build a new low-CI biofuel facility, for example, investment decisions require greater confidence in the future demand for low-CI fuels than could be provided by CI reduction targets that are known only one year in advance.

ARB staff's analysis indicates that a voluntary cost cap is unlikely to be as effective at containing the cost of compliance and providing certainty on the upward bound for credit prices as a cost cap that applies to all credits in the LCFS market.

Chevron requests that the deficit carry-over provision be reinstated. Regulated parties may still carry deficits from one year to the next if the clearance market is triggered, although any accumulated deficits carried over to subsequent years will be assessed the five percent interest rate. Accumulated deficits are subject to the requirements of Section 95485(c).

175. Comment: **LCFS 38-4**

The comment recommends adoption of a simpler program, analogous to that employed by EPA in the Renewable Fuels Standard.

Agency Response: ARB considered the adoption of a simpler cost containment mechanism but selected the proposed mechanism design for the reasons outlined on pages II-5 through II-9 of the Initial Statement of Reasons. See also the responses to **LCFS 32-9** and **LCFS 38-3**.

176. Comment: **LCFS 38-5**

The comment states that the potential LCFS credit buildup and drawdown are unrealistic.

Agency Response: See response to **LCFS 38-1.**

177. Comment: **LCFS 38-6**

The comment asserts that the issues identified relative to the availability of either Renewable Diesel (RD) or Renewable Natural gas (RNG) will significantly reduce the ability to use these fuels to produce LCFS credits.

Agency Response: ARB staff disagrees that the issues identified relative to the availability of either RD or RNG will significantly reduce the ability to use these fuels to produce LCFS credits. Relative to RD, there are sufficient current and projected production capacities to provide the volumes modeled in the illustrative compliance scenario by California, obtaining between roughly 25 to 45 percent of the 2020 volumes anticipated to be available for use in the U.S. Accommodating this amount of RD in the California fuel distribution system can occur without changes in federal law or regulations. It will require cooperation among the five major refiners that produce virtually all of the State's entire diesel fuel to establish appropriate pipeline specifications and labeling conventions. While not trivial, these steps are well within the abilities of the affected parties, which have accomplished similarly difficult transitions in the efforts to phase out methyl tertiary butyl ether (MTBE) and to modify pipeline specifications to accommodate other changes in California's rules for Cleaner Burning Gasoline. By the commenters own statement, the only thing that would prevent pipeline blending of blends above R5 would be lack of industry support for common carrier pipeline specification changes. Staff therefore believes that the illustrative compliance scenario volumes are reasonable.

Relative to RNG, there has already been significant growth in the displacement of conventional natural gas (NG) with RNG by major suppliers of vehicular NG in California. The development of supplies of RNG has occurred in response to the current LCFS, with supplies increasing by more than 100 percent in both 2013 and 2014, respectively. These producers have indicated their intention to strive to provide 100 percent RNG as a means of maximizing LCFS credit generation and increasing the value of their fuel. It is reasonable to anticipate that these trends will continue as the stringency of the LCFS increases and credit values rise.

Regarding increases in advanced biofuel supply, the LCFS and other incentives, including the federal 2014 Renewable Fuel Standards for the Renewable Fuel Standard Program (RFS2) and tax credits, are expected to increase advanced biofuel supply. ARB staff's experience with the advanced biofuel industry is that some plants have made statements that they were built primarily to supply the California market because of LCFS and some others have made changes to their plant operations specifically to get a lower carbon intensity score in the LCFS program. This experience leads staff to believe that the commenter is incorrect, and that the LCFS, in combination with the other incentives, can lead to supply increases of advanced biofuels.

Regarding discounting certain project or plants when projecting future biofuel supply, staff's methodology is sufficient to yield a conservative range of projected supply potential as described in Appendix B to the Initial Statement of reasons and the responses to comments **LCFS 38-1**, **LCFS 40-8** and **LCFS 40-9**.

178. Comment: **LCFS 38-7**

The commenter is opposed to the concept of stationary source credits being applied to LCFS because they are covered under ARB's cap and trade program. The commenter believes the proposed credit has a number of shortcomings.

Agency Response: ARB staff believes crediting for actions at refiners is a reasonable additional compliance option in LCFS. Staff's analysis has indicated that there are a significant number of projects that could be available for use under the Refinery Investment Credit Provision with the 0.1 gCO_2e/MJ carbon intensity reduction threshold. Specific recommendations proposed by the commenter regarding the method and tools for efficiency ranking of refiners are addressed in **LCFS 38-8** to **LCFS 38-13**.

179. Comment: **LCFS 38-8**

The commenter suggests that the metric used to establish relative refinery efficiency should be the Complexity Weighted Barrel.

Agency Response: The LCFS is based on carbon intensities of transportation fuels. The Refinery Investment Credit Provision was also developed using carbon intensity as the basis for credit generation. By contrast, the Complexity Weighted Barrel (CWB) method evaluates a refinery's efficiency by comparing carbon dioxide emissions for each process unit to a worldwide standard. While there are merits to both methods, the current method of evaluating refineries in the Refinery Investment Credit Provision is more consistent with the design of the LCFS.

180. Comment: **LCFS 38-9**

The comment asserts that refiners should be allowed to offer offsets of criteria and air toxic pollutants if their efficiency improvement projects indicate a potentially adverse impact in such emissions.

Agency Response: ARB staff made a 15-day change to remove the prior language referring to 'no increases in criteria pollutants and toxic emissions' and replaced it with more specific language stating that the project applicant must demonstrate that any net increases in criteria air pollutant or toxic air contaminant emissions from the project must be mitigated in accordance with all local, state and national environmental and health and safety regulations. Some of the applicable regulations do allow offsets.

181. Comment: **LCFS 38-10**

The comment asserts that the 0.1 gCO_2e/MJ threshold is too stringent and should be revised consistent with staff's proposed minimum for Innovative Crude Production Technologies.

Agency Response: Staff's analysis has indicated that there are a significant number of projects that could be available for use under the Refinery Investment Credit Provision with the 0.1 gCO2e/MJ carbon intensity reduction threshold. Further, this threshold is used in other provisions within the program including pathway applications. ARB staff believes this threshold creates an appropriate balance between greenhouse gas reductions and efficient use of current staff resources, but will continue to analyze this threshold for possible modification as projects are submitted and analyzed.

182. Comment: **LCFS 38-11**

The comment suggests that investments should not be limited to capital projects; oftentimes sizeable energy efficiency improvements are funded out of operating expense per established IRS accounting regulations**.**

Agency Response: ARB staff made a 15-day change to allow non-capital energy efficiency projects to be eligible in the Refinery Investment Credit Provision as long as they meet the 0.1 gCO_2e/MJ threshold. Staff included specific exclusions to prevent non-efficiency-related shutdowns and regularly scheduled maintenance from qualifying for this provision.

183. Comment: **LCFS 38-12**

The comment suggests that the project eligibility cutoff date should be changed to the project's startup date for any project commissioning post 1/1/2015.

Agency Response: ARB staff made a 15-day change to make projects eligible that have their authority-to-construct permits approved after January 1, 2016. The purpose of the Refinery

Investment Credit Provision is to incentivize marginal projects that might not have otherwise been economical without the provision. Projects that have undergone permitting to the point of permit approval prior to the existence of this credit have likely already been deemed economical and are not the target of this provision.

184. Comment: **LCFS 38-13**

The comment asserts that the bio-feedstock 10% threshold is too restrictive, even if defined as "percent of total process unit feed."

Agency Response: ARB staff made a 15-day change to the 10 percent renewable feedstock threshold. The renewable feedstock portion of the Refinery Investment Credit Provision is being made into a separate provision, called the Renewable Hydrogen Refinery Credit, and the renewable feedstock threshold is being removed in favor of a threshold based on fossil hydrogen displaced.

185. Comment: **LCFS 38-14**

Agency Response: ARB staff acknowledges the commenter's support of our decision not to recommend refinery-specific incremental deficit accounting for large, complex refineries.

186. Comment: **LCFS 38-15**

In the first part of this comment, the commenter advocates for reducing the extent of crude differentiation within the regulation. The second part of this comment is in regard to ARB staff's proposal to clarify the methodology for calculating the Annual Crude Average CI by specifying that production data from the California Department of Conservation and Bureau of Safety and Environmental Enforcement is to be used in lieu of volumes reported by refineries for California State and Federal Offshore crude.

Agency Response: As the commenter has stated, the Annual Crude Average CI has not exceeded the 2010 Baseline and crude imports by rail from western U.S are increasing. However, the policy decision to differentiate crude based on carbon intensity is still valid going forward, as described in the response to **LCFS 32-10**.

The change in regulation language to clarify the methodology for the Annual Crude Average CI is meant simply to clearly match the regulation language to the calculation methodology already being used for estimating the Annual Crude Average CI (e.g., see 2013 Crude Average CI calculation at http://www.arb.ca.gov/fuels/lcfs/crude-oil/2013-crude-ave-ci.pdf). Staff's justification for this change is further described in the ISOR on pages II-16 and II-17. As stated in the ISOR, the total volume of California crude reported by refineries in 2012 and 2013 very closely matches the total volume of California production reported by oil field operators. During 2012 and 2013, refineries reported a total volume of 432 million barrels while oil field operators reported a total volume of 431 million barrels. Also as stated in the ISOR, staff will continue to validate the assumption that all crude produced in California is refined in California by checking the total California crude volume reported by refineries against the total production volume reported by producers. Exports of California-produced crude can also be checked by consulting with the California Energy Commission, which requires reporting of crude exports as part of the Petroleum Industry Information Reporting Act. If it becomes clearly evident that California crude is being exported, ARB staff will use the best available information to determine the field source(s) of exported crude and reduce the appropriate production volumes used in the Annual Crude Average CI calculation to account for the exported crude.

187. Comment: **LCFS 38-16**

The commenter objects to limiting the application of CCS under the innovative crude provision to only those instances where the carbon capture occurs onsite at the crude oil production facilities.

Agency Response: See response to **LCFS 37-12.**

188. Comment: **LCFS 38-17**

The comment states that the formula for calculating the total volume and energy of the refinery appears ambiguous. In particular, the basis of the product volumes is not defined.

Agency Response: ARB staff agrees and made 15 day changes to clarify. See response to **LCFS 40-115** and **LCFS 40-117.**

189. Comment: **LCFS 38-18**

The comment asks ARB staff to define type of measurement needed for calculating baselines and reductions, to clarify the expected baseline year, and to clarify the regulatory text regarding how unrelated changes in refinery carbon intensity over time would affect previous refinery credits (such as changes in throughput rates or operational changes such as new units).

Agency Response: Data from the Mandatory Reporting Regulation (MRR) was used for calculating baselines and reductions. The first year of complete data for this sector in MRR is 2011. Staff considered using 2011 as the data for the baseline year, but chose a three-year average (2011-2013) to establish a baseline that moderated any single year extreme variances. Amendments have been made in the 15-day package to address the fact that the credits will not be retroactively affected if there are unrelated changes in refinery carbon intensity. However, if the carbon intensity changes the credits going forward would change.

190. Comment: **LCFS 38-19**

The commenter suggests that the proposed definitions of the LCFS should be harmonized with the AB32 requirements such as MRR reporting.

Agency Response: ARB staff has attempted to harmonize definitions across programs where appropriate. The different programs under AB 32 have different purposes and LCFS definitions may necessarily differ from MRR definitions. Staff will continue to review definitions and specific suggestions would be considered in future rulemakings.

191. Comment: **LCFS 38-20**

The comments states that there exists a 5 to 7 gCO2e/MJ gap between GREET and ARB calculated industry carbon intensity values for gasoline and diesel according to staff's reported values.

Agency Response: The Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation (GREET) model is based on Argonne National lab[6] data for refinery emissions, while the average carbon intensities in the Refinery Investment Credit Provision were calculated using MRR data. However, partially due to this discrepancy, ARB staff has decided to remove the portion of the Refinery Investment Credit Provisions in a 15-day change that makes reference to the average carbon intensities. Staff will continue to investigate this discrepancy.

[6] Forman, Grant Stephen, Vincent B. Divita, Jeongwoo Han, Hao Cai, Amgad Elgowainy, and Michael Q. Wang. "US Refinery Efficiency: Impacts Analysis and Implications for Fuel Carbon Policy Implementation." Environmental science & technology (2014).

192. Comment: **LCFS 38-21**

The commenter opposes the allowance of LCFS credits for fixed guideway transit and electric forklifts as well as using non-metered data for forklifts.

Agency Response: With respect to the fixed-guideway transit portions of this comment, the Board directed staff in Resolutions 09-31 and 11-39 to evaluate the feasibility of issuing credits for non-road, electricity-based transportation sources, including mass transit. These vehicles displace gasoline and diesel fuel transportation energy, and use significant and quantifiable electricity for transportation, therefore should be allowed to generate LCFS credits.

The credit calculation adjusts to account for the exclusion of the pre-LCFS off-road electricity applications in 2010 baseline. The LCFS credit formulas for all electric forklifts and existing electric fixed guideways do not include credits for fuel displacement, which substantially reduces the number of credits these electrical applications could generate. In contrast, the LCFS credit formula for new electric fixed guideway system does have the fuel displacement credits. This approach addresses the commenter's concerns related to allowing sources to generate credits without including them in the 2010 baseline.

Staff disagrees with the comment that the proposed electricity provisions create an un-level playing field. Early adopters of lower carbon intensity fuels, such as electricity, should not be penalized by excluding them from LCFS credit generating. Instead, they should be incented to continue and expand such applications.

With respect to metering of electric forklifts, many electric forklifts are charged without the use of a dedicated meter to measure electricity use. Forklift fleet operators often charge batteries used in multiple equipment types using the same charging equipment and meter. In addition, tracking metered data for thousands of forklifts would likely be cost-prohibitive. For these reasons, staff proposes to calculate the amount of electricity used to charge electric forklifts in each utility service area. The calculation method proposed for electric forklift charging is robust. In addition, staff commits to revisit the estimation method as more accurate charging information becomes available.

As indicated in the Initial Statement of Reasons, electric forklifts, including motorized hand trucks, have taken a larger market share nationwide than internal combustion engine (ICE) forklifts powered by gasoline, propane, CNG, or diesel fuel in recent years. An increase in electric forklift use coupled with a decrease in ICE forklift is expected to result in decreased GHG emissions and contribute to meeting the goals of the LCFS program. The commenter is incorrect, staff did not assume that the electric forklifts charging would displace diesel fuel in calculating credits. As stated in the ISOR, because the displacement of diesel fuel cannot be attributed entirely to the LCFS for the forklifts that were already operating in 2010, staff proposes to use a modified credit formula that does not give credit for diesel fuel displacement. For details please refer to III-10 of ISOR.

Staff proposes to estimate the amount of electricity used to charge electric forklifts in each utility service area. The number of forklifts used in California and the amount of electricity used by the fleet can be estimated using national shipment data, battery size, assumed annual operating hours and load factor. Further, each utility's share can be approximated based on their share of the state's non-residential (business/commercial) accounts.

In addition, in the Second 15-Day Modified Regulation Order released on June 23, 2015, staff proposed to allow electrical forklift fleet operators to opt-in to LCFS and generate credits, in order to better encourage technology innovations and foster capital investments to electrical forklifts. Under such a circumstance, the electric forklift fleet operators shall report the directly measured annual electricity use.

193. Comment: **LCFS 38-22**

The comment states objection to the removal of direct metering requirements on electric vehicle recharging at residences. It goes on to add that should staff go forward with an estimate procedure for electric vehicles in residences, then the estimate procedure should be more rigorous than the current method.

Agency Response: With respect to removal of direct metering requirements for residential charging, data on number of EVs in a utility's service territory, and credit invalidation concerns, see responses to **LCFS 32-11** and **LCFS 40-52**. With respect to overlap between public charging and residential charging, see the response to **LCFS 40-61**.

U.S. DOE's EV Project has been collecting extensive data on Nissan Leaf and Chevrolet Volt since late 2010. Although the total

VMTs might be different for BEVs and PHEVs, the EV Project shows that the kW hours of average daily charging for Nissan Leafs (BEVs) and Chevrolet Volts (PHEVs) are similar. Therefore, the daily use data of BEVs and PHEVs are not separated in the proposed calculation method.

194. Comment: **LCFS 38-23**

The comment states that the public reporting requirement of electricity credit information should not be removed from the proposed regulation.

Agency Response: The current LCFS regulation requires regulated parties for residential and public EV charging to include public reporting of certain information. However, public credit accounting is not required for regulated parties of other fuels. Staff revised the rule to make the reporting requirements more consistent among regulated parties. Further, ARB staff will now directly control the calculation of credits for residential charging and will make this calculation as transparent as possible without providing confidential business information.

195. Comment: **LCFS 38-24**

This comment includes three parts: 1) an objection to crude differentiation in the LCFS, 2) a recommendation for ground-truthing the Oil Production Greenhouse Gas Emission Estimator (OPGEE) model, and 3) a recommendation for changing the default value in OPGEE for feed water temperature to steam generators.

Agency Response: In response to part 1 of the comment, see the response to **LCFS 32-10**.

In response to part 2 of the comment, ARB staff agrees that “ground truthing” is an important test of the validity of the model approach that should be undertaken. Unfortunately, staff has yet to find an oil producer who will work closely with us and supply the necessary data to ground truth or calibrate the model against actual GHG emissions. Since the commenter produces about 25 to 30 percent of the oil in California, staff would welcome their participation in such an endeavor. However, Adam Brandt at Stanford University has published several papers on the topics of model uncertainty and comparison of OPGEE model results to other life cycle assessment (LCA) models as described in the response to **LCFS 37-5**

In response to part 3 of the comment, the OPGEE model default for feed water temperature to the steam generator of 40^{o} F was chosen as a very conservative default to be used in the absence of more specific field data. However, ARB staff agrees with the commenter that produced water is logically recycled and enters the steam generator at a higher temperature than the current OPGEE model default value. Therefore, staff has changed the default feed water temperature to 140^{o} F in OPGEEv1.1. This revision to OPGEE affects not only crude CI values in Tables 8 and 9, but also the 2010 Baseline Crude Average CI, the California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB), ultra-low sulfur diesel (ULSD), and California Reformulated Gasoline (CARFG) CI values and the compliance schedule targets, which have also been revised as 15-day changes.

196. Comment: **LCFS 38-25**

The commenter suggests that ARB develop a single CI value for all California crude and not differentiate among the 150 California fields listed in the crude lookup table.

Agency Response: Using the actual specific values better tailors the program to encourage/discourage use of low/high CI crudes. To the extent possible, CI values for crudes are specific to each marketable crude name and the fields that contribute to that crude name. Aggregated CI values or CI values calculated with regional average data are only used when data is unavailable to allow for differentiation.

197. Comment: **LCFS 38-26**

The commenter recommends allowing individual operators within a California oil field to provide operator specific data in order to obtain a separate CI specific to their operation.

Agency Response: ARB staff notes that this comment contradicts the recommendation the commenter made in **LCFS 38-25** that ARB develop a single CI for all California crudes. Calculation of the California annual crude average CI will use California field CI values and volumes as specified in the proposed section 95489(c)(3)(A). When calculating a volume-weighted average CI value such as the California annual crude average CI, there will be little difference between using average field CIs and field volumes versus using individual operator CIs and operator volumes, as all crude produced in California is being refined in California. Therefore, staff does not intend to provide operator-specific CI values at the sub-field level unless the operator is directly supplying crude to a LC/LE refinery that has opted for refinery-specific incremental deficit accounting.

198. Comment: **LCFS 38-27**

The commenter proposes that ARB include a de minimis threshold that must be exceeded prior to assessing an incremental deficit.

Agency Response: ARB staff agrees that the use of a de minimis level that must be exceeded before an incremental deficit is incurred has merit and proposed this revision as a 15-day change for both the California Average incremental deficit determination and the LC/LEU refinery-specific incremental deficit determination. Under the revised language, an incremental deficit will only be triggered if the Three-year California Crude Average CI exceeds the 2010 Baseline Crude Average CI by 0.10 gCO_2e/MJ, but, if an incremental deficit is triggered, the resulting incremental deficit will still be calculated relative to the 2010 Baseline Crude Average CI.

199. Comment: **LCFS 38-28**

The commenter requests clarification on several issues regarding calculating and assessing an incremental deficit.

Agency Response: If the Three-year California Crude Average carbon intensity exceeds the 2010 Baseline Crude Average carbon intensity, incremental deficits for CARBOB and diesel will be added to each affected regulated party's compliance obligation in the year following the year in which the Three-year California Crude Average CI was calculated. For example, the Three-year California Crude Average carbon intensity for years 2013, 2014, and 2015 is calculated in May of 2016. If this value exceeds the 2010 Baseline Crude Average CI, then incremental deficits will be added in the year 2017. These incremental deficits will be based upon the amount of CARBOB and diesel supplied by the regulated party in the year 2017. ARB staff disagrees with the commenter's recommendation that the incremental deficit be based on and applied to the amount of CARBOB and diesel supplied in the year in which the debits are incurred for several reasons. First, the incremental deficit is calculated by comparing a three-year rolling average to the 2010 baseline, and therefore, there is not a single year in which the debits are incurred. Second, it would be extremely difficult and cumbersome to apply incremental deficits retroactively to a year in which the annual compliance reporting has already been completed. Third, applying the incremental deficits to the year following the year in which the deficits are established allows the regulated parties time to plan ahead and ensure that they will have sufficient credits to cover the additional deficits in the following year.

200. Comment: **LCFS 38-29**

The comment states that the scientific basis for addressing iLUC in the LCFS is sound and improvements to methods and models for estimating iLUC values continue to be made.

Agency Response: ARB staff appreciates the commenter's support.

201. Comment: **LCFS 38-30**

The comment requests that ARB staff identify the reasons for adjustments to iLUC values between the original 2009 proposed regulation values, through the 2014 ISOR.

Agency Response: The 2009 analysis used a single model, Global Trade Analysis Project (GTAP), to estimate indirect land use change (iLUC) emissions. Also, in the 2009 analysis, emission factors were embedded within the GTAP model. The current analysis uses two separate models to estimate iLUC emissions. It is not possible to attribute changes in current iLUC values (compared to 2009) specifically to revisions in either the GTAP or Agro-ecological Zone Emission Factor (AEZ-EF) models since the current modeling methodology is different compared to the one used for the 2009 analysis.

As for the changes from the November 2014 workshop results to the proposed values, ARB staff discovered an error in the AEZ-EF model which has been detailed in Appendix I of the ISOR. Fixing the error resulted in a new set of iLUC values for biofuels which were published in the ISOR released in December 2014 (different compared to November 2014). See also response to **LCFS SF8-1**.

202. Comment: **LCFS 38-31**

The comment requests clarification on the basis for sugarcane ethanol production levels in both the U.S. and Brazil.

Agency Response: Since there is no current production of sugarcane ethanol in the United States, ARB staff does not model the production of this biofuel in the United States. Instead, for the iLUC analysis, staff applies a shock of 3 billion gallons of sugarcane ethanol production in Brazil, of which 1 billion gallons is exported to the U.S. The sensitivity of the model to changes in the split between Brazilian production and U.S. production is therefore irrelevant.

203. Comment: **LCFS 38-32**

The comment questions the method used to select iLUC values.

Agency Response: For the Monte Carlo analysis, distributions for many of the parameters were not readily available from published literature. ARB staff therefore had to rely on expert opinion in the development of distributions for many of the parameters. See response to **LCFS 29-8**.

204. Comment: **LCFS 38-33**

The comment requests clarification of the elasticity values used for the yield-price elasticity analysis for the cropland pasture land category.

Agency Response: Cropland Pasture is a new land cover category that was included in the GTAP model in 2010 to enhance the land use analysis. Purdue, in the GTAP model, used a parameter termed cropland pasture elasticity to account for endogenous yield adjustments resulting from changes in crop prices. This is a parameter similar to the Yield Price Elasticity (YPE) parameter for cropland. In the absence of detailed empirical data, researchers at Purdue University developed a value of 0.4 for cropland pasture elasticity based on model calibration. Model calibration adjusts parameter values to produce realistic model outputs. However, when anomalous outputs were observed (i.e., significant reforestation in several regions of the world due to additional cropland change), additional calibration adjustments were made. Using values of 0.1 and 0.2 for cropland pasture elasticity parameter generated model responses without leading to anomalous behavior.

205. Comment: **LCFS 38-34**

The comment questions how future analysis of cellulosic feedstocks will be incorporated into iLUC values.

Agency Response: An updated iLUC value for cellulosic ethanol will require additional data and changes to the model that are not currently available for cellulosic ethanol analysis. Such changes may be included in a future rulemaking. An iLUC value of 18 gCO_2/MJ has been used in the current regulatory framework since the LCFS regulation was adopted in 2009. For the re-adoption, and to be consistent with previous rulemaking, ARB staff proposes to continue using this value for cellulosic feedstocks. Staff is currently working with the California Energy Commission (CEC), Purdue researchers, the U.S. Environmental Protection Agency, and others in determining appropriate inputs, values, etc., for cellulosic ethanol from non-food crops and waste. No timeframe has been established for the completion of this work and the results will be published when the analyses are completed. Staff has not yet determined an iLUC estimate for waste product feedstock.

206. Comment: **LCFS 38-35**

The commenter is opposed to ARB's proposal to allow low complexity / low energy use refineries to generate credits equivalent to 5 gCO_2e/MJ for their CARBOB and CARB diesel production.

Agency Response: The Board directed staff in Resolution 11-39 to consider provisions to the LCFS to address low-energy-use refining processes. This Resolution language was meant to address the lower energy inherently embedded into the transportation fuels from refineries that use simple processes to refine transportation fuel. ARB staff explained our rationale this credit in detail on pages II-14 through II-15 of the Initial Statement of Reasons.

207. Comment: **LCFS 38-36**

The commenter argues that the proposal to allow low complexity, low energy use refineries to opt out of the California Average provision is inappropriate.

Agency Response: See also the response to **LCFS 32-10**.

ARB staff disagrees with commenter's suggestion that the added complexity is not worth the benefit to those choosing refinery-specific accounting. Staff explained our rationale for allowing low complexity, low energy use refineries to opt for refinery-specific incremental deficit accounting in the ISOR on pages II-15 and II-16.

208. Comment: **LCFS 38-37**

The comment includes four recommendations for the innovative crude provision: 1) allow carbon capture to occur offsite of the crude oil production facilities, 2) remove the limitation for onsite solar heat generation and onsite solar and wind electricity generation, 3) reduce the minimum acceptable steam quality from 65 to 55 percent and revise some parameters in the calculation of the default credit value, and 4) allow crude producers to submit any new production method that reduces GHG emissions to the Executive Officer for approval

Agency Response:

1. *Allow carbon capture to occur offsite of the crude oil production facilities*.

   Please see response to Comment **LCFS 37-12**.

2. *Remove the limitation for onsite solar heat generation and onsite solar and wind electricity generation*.

   The commenter is mistaken as the regulation language does not require onsite generation of heat, steam, or electricity. The regulation only requires that the solar heat or steam and solar or wind electricity be consumed onsite. Additionally, offsite electricity must be provided directly to the crude producer from a third party generator and not through a utility owned transmission or distribution network.

3. *Reduce the minimum acceptable steam quality from 65 to 55 percent and revise some parameters in the calculation of the default credit value.*

   ARB staff agrees with this recommendation and has proposed an additional default credit for 55 to 65 percent quality steam. Staff also agrees with the recommendation to change the assumed feed water temperature and steam pressure in calculating the default credit for solar steam generation. Revised default credit values were proposed as a 15-day change.

4. *Allow crude producers to submit any new production method that reduces GHG emissions to the Executive Officer for approval*.

   ARB staff disagrees with this recommendation. While operators may submit data for any new production method that reduces GHG emissions and have these reductions accounted in estimating the CI value for the crude lookup table, staff believes that those categories of projects qualifying for innovative method credit, as well as any limitations specified for those projects, should be subject to a regulatory process in which the public can participate as a way to test the merits of various proposals. Staff encourages crude producers to submit types of projects that they believe should be considered for innovative method credit as part of future amendment cycles.

209. Comment: **LCFS 38-38**

The comment questions the usefulness of submitting an accompanying letter on letterhead in the event a regulated party requests correction of a quarterly report.

Agency Response: Regulated parties are strictly liable for misreporting data in the first instance and may be subject to penalties for each day a quarterly report remains incorrect. The required letter is meant to prevent unauthorized tampering with prior reported information, and to maintain a clear record of which reporting entities have violated the LCFS by misreporting transactions in the LRT-CBTS, as well as a summary of what information was later changed and why the change was needed. If ARB staff finds that enforcement action is necessary based on misreporting, the letter will eliminate confusion and disputes about what took place. The ARB does allow correction requests for multiple quarters to be addressed within a single letter to reduce the workload to regulated parties. Also, the additional time to be provided for report reconciliation is expected to dramatically reduce the number of correction requests.

210. Comment: **LCFS 38-39**

The commenter wishes to return to the earlier Product Transfer Document (PTD) definition.

Agency Response: There have been many cases involving LCFS fuel transactions in the first years of the program where the flexibility associated with a PTD as a "collection of documents" approach has not worked. ARB staff has received input from a number of regulated parties that the "PTD" related information that they receive from their business partners, and which they need for accurate LCFS reporting, is often incomplete, inconsistent, and late. There has been contention between regulated parties over which party has the compliance obligation and confusion regarding the fuel pathway code (CI) transferred. Also, a single PTD provides a simple means for passing alternative fuel production facility information with alternative fuel transactions.

Many of the regulated parties are already passing along the same information as a single record in a document in a consolidated form. It is expected that if a single PTD is transmitted in some format to the recipient of the fuel, there will be less need for reconciliation, and ARB will receive fewer LCFS report correction requests.

211. Comment: **LCFS 38-40**

The comment questions the provision requiring the seller of no-obligation fuel to track the export to any subsequent buyer.

Agency Response: Whenever an obligation is retained by the transferor they are required to notify the downstream transferee in the PTD using a prescribed notice provided in the proposed LCFS regulation. The commenter notes that adding language to the PTD may not impose a legal obligation on the recipient. At a minimum, the warning language puts the recipient on notice of the fuel's regulatory status, which in itself could facilitate enforcement by ARB against the recipient in the event of an unreported export. Moreover, the warning language would improve the transferor's legal position vis-à-vis the transferee in the event of a commercial dispute or indemnification claim based on a transferor's loss of credits caused by the fuel's export. When the fuel obligation is retained, the prescribed notice will be required on the PTD when the fuel is transferred to the recipient buyer.

212. Comment: **LCFS 38-41**

The comment questions making the buyer of credits responsible for verifying that the credits purchased were indeed generated from low carbon fuels.

Agency Response: As stated in this comment, the LCFS is a "buyer-beware" Program. The buyer needs to verify that the credits being purchased were generated from low carbon intensity fuels. Health and Safety Code section 43031 details that the prevention efforts taken by the defendant (i.e., the regulated party) will be taken into consideration when a penalty is assessed. See response to **LCFS 7-3**.

213. Comment: **LCFS 38-42**

The comment asserts that ARB should establish an administrative hearing process to allow regulated parties an opportunity to appeal an ARB decision to suspend, revoke, or modify a credit or CI valuation.

Agency Response: Staff does not agree with having an additional administrative hearing process to allow regulated parties an opportunity to appeal an ARB decision to suspend, revoke or modify a credit or CI valuation. Staff anticipates working with all affected parties after the initial notice is issued; parties can submit information that is considered before the Executive Officer makes his/her final determination. Additionally, the LCFS Program includes a Program Review Process for purposes of evaluating the implementation of the Program. If affected parties find the process detailed in section 95495 inadequate, this is a good public forum to raise these concerns. Staff can consider how best to move forward after having an open dialog with all stakeholders on this topic.

214. Comment: **LCFS 38-43**

The comment suggests deleting the severability provision of the LCFS regulation.

Agency Response: ARB staff recognizes that while some portions of the proposed regulation are interdependent, staff does not believe it is correct to say that every aspect of every provision is integral to the continued functioning of the regulation. In the event a court were to invalidate one provision, it may well be possible to continue implementing the program to the public's benefit. Because of that possibility, staff does not deem it appropriate to delete the severability provision proposed as section 95497.

215. Comment: **LCFS 38-44**

The comment states that ARB should use an upper limit of $200/MT in the economic analysis, like that used for the Credit Clearance Market, rather than $100/MT.

Agency Response: We agree that the $200 price cap provides an upper bound on the potential price of credits, but it should not be construed as a projection of future credit prices or as a projection of the likely future cost of compliance.

ARB staff completed an in-depth economic analysis of the economic impacts of the proposed regulation using what staff believed to be a reasonable range of credit prices (considering multiple potential credit prices but focusing on $100 dollars per credit in some portions of the analysis). The $100 credit price was illustrative and designed to reflect historic prices as indicated on page VII-1 of the ISOR. We note that historical credit prices have remained below the $100 value.

216. Comment: **LCFS 38-45**

The comment disagrees with ARB's assessment that "Since 2010, the production of low-CI fuels has increased in response to the financial incentives provided by the existing LCFS regulation."

Agency Response: Although it is always challenging to tease out the incremental impact of overlapping policy drivers for low-CI fuels, the LCFS unequivocally improves the economics of low carbon fuel production supplied to California, and thus has contributed to the financial incentive for increased production of low-CI fuels worldwide.

As described in the Initial Statement of Reasons, ARB staff has analyzed the historic production of low-CI fuels since the inception of the LCFS in 2010, as well as the potential growth trajectories for low-CI fuels in the Initial Statement of Reasons. This analysis indicates that many innovative, low-CI fuel technologies have moved past the demonstration stage, and have overcome techno-economic challenges that have in recent years limited their supplies.

It is also important to note that neither the federal RFS2 nor the Biodiesel Blenders' Tax Credit specifically incentivize reductions in carbon intensity, which supports the findings of ARB staff's analysis that the carbon intensity reduction goals of the LCFS will not be achieved in full without the LCFS program specifically requiring reductions in carbon intensity.

217. Comment: **LCFS 38-46**

The comment evinces surprise that the regulation's stated goals are not among those outlined by Governor Schwarzenegger in an executive order.

Agency Response: The same goal was mentioned in the 2009 ISOR. More importantly, ARB's authority is not limited to a single executive order; in AB 32 the Legislature stated that when developing measures to reduce emissions, ARB should design its measures to allow harmonizing with market-based measures in other states, regions, nationally, and internationally. It further indicates that this encouragement will "provide an opportunity for the state to take a global economic and technological leadership role in reducing emissions of greenhouse gases."

218. Comment: **LCFS 38-47**

The comment claims that the macroeconomic analysis is flawed and based on faulty assumptions; the commenter believes that continued production and export of petro fuels in California means that emissions will simply be exported.

Agency Response: ARB staff disagrees with both points. The $100 credit price was illustrative and designed to reflect historic prices as indicated on page VII-1 of the ISOR. In addition, the credit price represents the marginal cost of abatement - or the cost of the last ton of emission reductions to comply; most other reductions will be achieved at a lower price. Given the current price of $25, and the average for 2012-2013 was $57, this approach is conservative, as credits can be generated at a lower cost, and the credit price is not known with certainty.

The export assumption does not indicate that the emissions are exported but instead that increasing world demand[7] could be met with California petroleum fuels displaced by lower-carbon fuels used under the LCFS; accordingly there should be less new production (and associated emissions) elsewhere, resulting in a net emissions reduction with an LCFS in place compared to a no-LCFS scenario.[8]

ARB staff used the unadjusted Annual Energy Outlook (AEO) base price, which is lower than the California price to account for the lower value of finished fuels exported.

The increased excess capacity from California refiners is predominantly driven by existing trends that have led to reduced fuel consumption in California that is forecasted to persist in the future.[9] These trends are not exclusively driven by the LCFS; however, the historic trend of the inverse relationship between California demand and exports of finished fuels indicate that the capital effects of exporting are not a barrier. Additionally, the macroeconomic model used considers all aspects of exports including capital and labor costs and economies of scale.

[7] http://www.nytimes.com/2012/03/09/us/oil-exports-have-become-huge-business-in-the-san-francisco-bay-area.html?_r=0
[8] http://www.eia.gov/pressroom/releases/press412.cfm
[9] California Energy Commission (2013) Integrated Energy Policy Report (IEPR) http://www.energy.ca.gov/2013_energypolicy/ accessed 12.15.2014

219. Comment: **LCFS 38-48**

The comment states that the illustrative scenario does not account for the penetration of electric, hydrogen, and natural gas.

Agency Response: ARB staff provided one illustrative scenario of a plausible mix of fuels that would achieve compliance. Because the program is fuel neutral there is flexibility for industry to choose the most cost-effective fuel mix. Alternate scenarios with greater penetration of electric, hydrogen and natural gas use partially incented by the value of LCFS credits are conceivable, especially if the availability of low-cost low-carbon liquid biofuels is limited. See response to **LCFS 32-6**.

This page intentionally left blank.

Comment letter code: 39-OP-LCFS-PGE

Commenter: Matthew Plummer

Affiliation: Pacific Gas & Electric

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

Pacific Gas and Electric Company

Matthew Plummer
Representative
State Agency Relations

77 Beale S
San Fr

(415) 973-3477
(415) 973-7226 Fax

matthew.plummer@pge.com

39_OP_LCFS _PGE

February 17, 2014

Sam Wade
Chief, Transportation Fuels Branch
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Re: Pacific Gas and Electric Company's Comments on the February 19 Board Hearing on Re-Adoption of the Low Carbon Fuel Standard

Dear Mr. Wade,

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to comment on the proposed re-adoption of the Low Carbon Fuel Standard (LCFS), which addresses the State of California Court of Appeals, Fifth Appellate District's (Court) opinion in *POET, LCC vs. California Air Resources Board*. Per the meeting notice, the Board will consider the proposed regulation and provide direction to ARB staff, with adoption occurring at a second hearing in 2015.[1]

Accordingly, PG&E expresses its strong support for the LCFS and asks the Board to instruct staff to move forward with re-adoption. The consumption of transportation fuels is the single largest source of greenhouse gas (GHG) emissions in California and the LCFS is an important program transitioning the state to lower carbon intensity transportation fuels. Re-adoption will provide the regulatory certainty necessary for continued development of alternative fuels. LCFS 39-1

In addition to addressing the Court's ruling, ARB Staff is revising critical technical information and programmatic requirements. Overall, PG&E believes ARB Staff's proposal enhances program integrity and effectiveness, and thanks ARB Staff for an open and collaborative stakeholder process.

LCFS 39-2

PG&E has participated extensively during the re-adoption process, especially with respect to ARB's update to the carbon intensity values for transportation fuels in the LCFS.[2] Given that the LCFS uses a crediting approach to incentivize the lowest carbon transportation fuels, the carbon intensity of each fuel pathway is crucial because it ultimately determines the

---

[1] Air Resources Board. February 19, 2015. Notice of Public Hearing to Consider a Low Carbon Fuel Standard. Website: http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15notice.pdf. Pp. 31.

[2] Carbon intensity values are determined using the California Modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET2.0) in conjunction with the Indirect Land Use Change (iLUC) estimates from the GTAP model.

degree to which each fuel generates credits or deficits, and how transportation fuel providers comply. LCFS 39-2 cont.

PG&E, along with other natural gas and electricity fuel suppliers, provided extensive comments and technical information to ARB Staff during the development of the regulatory package, which is before the Board. While additional changes will be needed prior to re-adoption—like incorporating forthcoming studies on methane emissions—PG&E believes it can continue to work collaboratively with ARB Staff to arrive at carbon intensity values that are based on the best available science and technical information. PG&E looks forward to additional collaboration with ARB Staff on this and other technical issues prior to Board adoption later in 2015. LCFS 39-3

Sincerely,

/s/

Matthew Plummer

39_OP_LCFS_PGE Responses

220. Comment: **LCFS 39-1**

The comment expresses strong support for the LCFS re-adoption because it will reduce GHG emissions and provide certainty for development of alternative fuels.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

221. Comment: **LCFS 39-2**

The comment states that the LCFS proposal changes enhance program integrity and effectiveness and thanks ARB staff for an open and collaborative stakeholder process.

Agency Response: ARB staff concurs with the comment that the proposal enhances program integrity and effectiveness.

222. Comment: **LCFS 39-3**

The comment notes that additional changes may be necessary as new studies and analysis are completed.

Agency Response: ARB staff looks forward to continued collaboration with stakeholders on methane emission studies and other topics. Staff strives to maintain an open public process and will incorporate actionable information made available through that process.

This page intentionally left blank.

Comment letter code: 40-OP-LCFS-WSPA

Commenter: Cathy Reheis-Boyd

Affiliation: Western States Petroleum Assoc.

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

40_OP_LCFS _WSPA

Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

Catherine H. Reheis-Boyd
President

February 17, 2015

Clerk of the Board, Air Resources Board,
1001 I Street,
Sacramento, CA 95814
http://www.arb.ca.gov/lispub/comm/bclist.php

Re: **Public Hearing to Consider a Low Carbon Fuel Standard (LCFS) – Board Agenda Item 15-2-4**

The Western States Petroleum Association (WSPA) appreciates the opportunity to submit written comments for the record on the above proposed rulemaking. WSPA is a non-profit trade association representing twenty-five companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California and four other western states.

WSPA members hold the compliance obligation under the LCFS and are responsible for the challenging job of producing the vast majority of the transportation fuels used daily in California. WSPA has been engaged in the rulemaking process to develop and implement the LCFS since 2007. We have continued to make technical comments on updated regulatory packages and changes to the program despite our concerns about the overall feasibility of the LCFS program.

LCFS 40-1

The fundamental problem with the LCFS remains that it is not good public policy and is incorrectly structured in its reliance on the emergence of a significant low carbon fuels market. We do not see anything in the regulatory package to change our assessment that the LCFS program and compliance schedule will remain infeasible when reauthorized.

A government agency such as ARB should not be setting goals that are aspirational and unrealistic, and then following up with band aid measures that make compliance easier while the market waits for low carbon intensity (CI) fuels to be produced at commercial volumes. The fact that a multitude of credit generation options and a cost containment provision are being proposed for inclusion in the program is a signal reflective of the program's fundamental problems.

In our view, the current 1% CI reduction freeze has given all stakeholders and ARB an opportunity to reflect on what has worked, and particularly what has not worked within the LCFS. As ARB has admitted frequently, the development of commercial–scale low CI fuels, such as cellulosic ethanol, has been much slower than originally envisioned. We must take this re-adoption effort as an opportunity to assess the true status of low CI fuel production, infrastructure, vehicle availability, and consumer acceptance (not aspirational projected or nameplate capacity estimates) and make the changes necessary for an effective program. Additional research and development needs to occur before we can transform to a low CI fuel system. LCFS 40-2

At its core we believe the LCFS, as envisioned by Governor Schwarzenegger in his original Executive Order and as currently designed, is infeasible. Although there will continue to be a slow shift in the transportation fuels market, staying the course with the current design of the program could result in disruptions in the transportation fuels market. There needs to be recognition that California consumers depend on and expect a reliable, useable, and scalable fuel source based on the vehicle population and fuels infrastructure in existence now. LCFS 40-3

A successful climate-oriented fuels policy must protect against fuel supply disruptions, severe job losses in the state's refining industry and unacceptable economic harm to California and its citizens. WSPA and its members are committed to engaging with you to find better, achievable ways of reducing carbon emissions from transportation fuels.

<u>WSPA Requests</u>

WSPA requests two main items of ARB relative to the effort to reauthorize the program. We also have a number of more specific recommendations and requests in our detailed comments that follow. In short:

- WSPA requests program reviews that culminate in staff reports to the Board on an annual basis. LCFS 40-4
- WSPA requests no further efforts to create post-2020 LCFS reduction targets until the pre-2020 program is a proven, feasible program. LCFS 40-5

Sincerely,

1415 L Street, Suite 600, Sacramento, California 95814
(916) 498-7752 ▪ Fax: (916) 444-5745 ▪ Cell: (916) 835-0450
cathy@wspa.org ▪ www.wspa.org

c.c. ARB Board Members – arbboard@arb.ca.gov
Virgil Welch – vwelch@arb.ca.gov
Richard Corey – rcorey@arb.ca.gov
Jack Kitowski – jkitowsk@arb.ca.gov
Samuel Wade – swade@arb.ca.gov
Elizabeth Scheehle – escheehl@arb.ca.gov
Jim Aguila – jaguila@arb.ca.gov
Jim Nyarady – jnyarady@arb.ca.gov
John Courtis – jcourtis@arb.ca.gov
Manisha Singh – mansingh@arb.ca.gov
Wes Ingram – wingram@arb.ca.gov
Kirsten King – kking@arb.ca.gov
Anil Prabhu – aprabhu@arb.ca.gov
Carolyn Lozo – clozo@arb.ca.gov
Stephanie Detwiler – sdetwile@arb.ca.gov
Jim Duffy – jduffy@arb.ca.gov
Hafizur Chowdhury – hchowdhu@arb.ca.gov
Hurshbir Shahi – hshahi@arb.ca.gov
Stephen d'Esterhazy – sdesterh@arb.ca.gov

Western States Petroleum Association Comments on CARB's Public Hearing to Consider a LCFS – February 19, 2015

General Comments

1. **Current Program Status and Proposed Compliance Targets**

Since its inception, the LCFS program has aspired to deliver a 10% reduction in California motor fuel carbon intensity by 2020 versus the 2010 baseline year. Over the same period, WSPA questioned the program's viability pointing out that ARB is relying on as-yet to be developed novel technologies to supply the low CI fuels necessary to meet this goal. WSPA also questioned whether the timetable for the emergence of such technologies (primarily cellulosic fuels) would coincide with ARB's projections. To date, ARB staff has maintained that the LCFS program is working as intended, but WSPA remains concerned about the viability of achieving the targets proposed in the LCFS reauthorization proposal, given the current status of low-CI fuel-producing technologies.

Halfway through the 2010-2020 "compliance" decade, the program is delivering approximately 2% CI reduction (versus an annual target of 1% for 2014 and 2015). ARB maintains the primary reason the program CI reduction targets have not been ratcheted up as originally intended is pending litigation (discussed later in our comments). WSPA is concerned that the program still faces considerable challenges, even as ARB proposes to scale back some of the program's targets, e.g., interim year CI reduction targets, while leaving others such as the 10% 2020 target in place, despite mounting evidence that it cannot be met.

LCFS 40-6

ARB's own estimates indicate the LCFS program as proposed in the reauthorization proposal is not sustainable. Approximately 3% of the 10% CI reduction shown for staff's illustrative scenario for 2020 is derived from accumulated credits (from "over-compliance" during previous years) and only 7% is actual, sustainable CI reductions obtained during the year. While ARB staff forecasts a credit bank build up to 9 MMT at the end of 2015 to help satisfy the otherwise un-sustainable reduction targets, in actuality the credit bank stood at just under 4 MMT at the end of the third quarter of 2014 (since program inception) and, given the rate of credit buildup to date, the assumption that banked credits will reach 9MMT over the next 15 months is aspirational. Even if credit generation sees an increase due to more regulatory certainty, as ARB posits it will, there is unlikely to be enough of a generation increase to meet ARB's projections.

Setting aside the issue of ARB's reliance on an unrealistic initial credit bank at the start of 2016 (to meet the 10% 2020 target), WSPA does not agree that staff's projection of a 7% sustainable reduction in 2020 is accurate. WSPA believes ARB's projections for estimating the degree of market penetration of renewable biogas for motor fuel applications and the volumes of renewable diesel that will be incorporated in the CARB diesel pool are too optimistic. Questionable LCFS credit contributions are also forecasted from the Refinery Investment Credit segment of the re-adoption program. The reasons for WSPA's reservations in these areas are outlined further in the detailed section of our comments.

WSPA notes the "redirection" of ARB's reliance on different sector contributions to achieve the program's CI reduction goals, in particular, the absence of a significant contribution expectation from advanced cellulosic biofuels – an expectation that once provided justification for the original program's ambitious goals. While this appropriately reflects the lack of growth in technologies for advanced cellulosic biofuels, the degree to which such low CI fuels are expected to contribute going forward is now but a fraction of the overall program CI reduction needs. Given ARB's tacit acknowledgment that this area has not grown as initially projected, resulting in a substantial decrease in its potential contribution to program CI reduction, WSPA is surprised that ARB has not reduced program targets accordingly.

Instead, ARB has largely held on to the original program targets (at least for 2020) and looked to fill the CI reduction "gap" created by the lack of development in cellulosic fuels through larger-than-justified increases in reliance on renewable biogas and renewable diesel, and the arbitrary decision to allow the generation of LCFS credits from stationary source segments such the "Refinery Investment Credit" and "Innovative Technologies for Crude Oil Production", and the inclusion of "Pre-LCFS electricity sources (e.g. fixed guideways and electric forklifts)". In WSPA's view, this "redirection" coupled with the overstated focus on credit reliance in the 2016-2020 timeframe without an acknowledgement of the magnitude of sustainable CI reductions, fails to accurately project the true challenges of meeting the program's targets. LCFS 40-6 cont.

WSPA is concerned that if unachievable targets are set at the outset, the regulated community will not receive the benefit of the certainty ARB is seeking to provide with the LCFS because the targets will be viewed as placeholders that will ultimately have to be revised. If overly ambitious targets are promulgated, they may have the unintended consequence of prolonging the climate of uncertainty, sustaining deferred action on compliance plans, investments, etc. that are necessary to the success of the program, and potentially undermining the program's goals. In the case of the readopted LCFS, if the credit bank status for 2015 is confirmed to be substantially lower than staff's expectations (roughly within a year's time from re-adoption), the 2020 CI reduction target will be infeasible and the need for revision will be even more urgent since 2020 will be only four years away at that point.

ARB's ISOR documentation lacks detailed data to clearly support the contention that the program is still feasible. A full analysis of the supply of low CI fuels actually available to California and the projected cost; the supply logistics (marine, rail, etc.) available to accommodate these alternative fuels; the infrastructure needed to blend, transport and dispense these fuels; incentives necessary for consumer acceptance; and other regulatory impediments should all be delineated.

Since the original LCFS adoption package, WSPA has worked with the Boston Consulting Group (BCG) to both analyze ARB's assumptions relating to the LCFS compliance curves but also to provide its own projections of what can sustainably be accomplished by certain timeframes. WSPA and BCG have met several times with ARB during the initial work on the re-authorization in 2014 to compare updated analyses relative to the program's feasibility. WSPA continues to urge ARB to reset the 2020 target CI reduction level to a more realistic and sustainable level of approximately 5%, as indicated in the projections of the Boston Consulting Group's most recent study that has been shared with staff. This WSPA recommendation of the 2020 target factors in staff's proposed lowering of the interim year targets and the associated credit bank impacts it will have.

The attached BCG report (Appendix 1) contains their most recent analysis that compares ARB's and BCG's forecasts and investigates the reasons for the differences. Some of the summary conclusions from the BCG report are:

- A 5.1% reduction in the total fuel pool is sustainable by 2020 based on credits available through blending low-CI fuels (e.g. renewable diesel, biodiesel) and purchasing credits (e.g. electric, natural gas).
- Using the same compliance schedule, BCG forecasts banked credits being exhausted earlier than ARB with annual deficits starting in 2018.
- BCG forecasts a 4.4MMT larger deficit in 2020 versus ARB's scenario
- ARB's near term growth is overestimated [ARB's "illustrative" compliance curves show significantly MORE banked credits in 2014 than are actually going to be available based on projections for the year-end report. While ARB has only published the credit numbers through 3Q2014 as 3.9MMT excess credits, it is highly unlikely this will balloon to 5.5MMT excess credits through 4Q2014.]
- Even ARB's forecast shows only a 6MMT credit bank remaining for 2020, so there is no sustainability anticipated beyond 2020.
- ARB's forecasts of volumes of several low CI fuels through the first three-quarters of 2014 remain excessively aggressive
- The program continues to depend heavily on CI reductions in the diesel/distillate pool.

LCFS 40-7

2. **<u>LCFS Program Feasibility – Low CI Fuel Availability</u>**

   - <u>WSPA requests credible assessment of projections of low CI fuel availability using WSPA criteria, fuel cost competitiveness, plus an assessment of infrastructure and vehicle availability to match with the fuels.</u>

Overall, WSPA's greatest concern continues to be the lack of a credible ARB assessment and forecast of the availability and costs of low carbon fuels and credits that ARB has assumed will be available. We note that multiple caveats are included in ARB's analyses indicating the illustrative scenarios are <u>not forecasts or predictions</u>.

LCFS 40-8

In addition, ARB staff must justify why assumptions that the bulk of the nationwide supply will be delivered to and used in California, are reasonable in light of current and proposed competing programs (i.e., RFS2 and LCFS initiatives in the Pacific Northwest states and B.C.). It is also imperative this analysis include the expected added costs for compliance, including those associated with fuel distribution and refueling infrastructure, and specialized vehicles (e.g., battery electric vehicles).

Although no one can say with any degree of certainty what fuel/credit combinations may be used to attempt to comply with the program, there are a number of assumptions ARB staff has used in the past that are not believable based on EIA projections, historical experience with timing and volumes of new fuel/vehicle introductions, and future market economics.

WSPA has requested several times now that ARB provide an updated analysis based on the technical criteria below, so staff can provide the Board with a realistic update. The technical criteria relate to the three interrelated transportation system components: fuel (availability and cost), infrastructure and vehicles:

Fuel Volumes

The volume analysis should include the following items to assess the capability of the low CI fuel production facilities (current and proposed):

1. Design capacity in gallons per day
2. Date of construction completion
3. Date that feedstock first introduced to process
4. Date that on-specification product first produced
5. Highest utilization demonstrated in a consecutive three month period (utilization is defined as production rate divided by design capacity, inclusive of downtime)
6. Percent of product that was produced on-specification without reprocessing or blending during the period in Question #5.
7. Duration in days of longest continuous period of plant operation
8. Utilization during last calendar year (production rate divided by design capacity, inclusive of downtime)
9. Percent of product that was produced on-specification without reprocessing or blending during the period in Question #8. Qualified biofuels have to be able to replace a certain meaningful percentage of the previous year’s demand for the on- ramp to be triggered.
10. Feedstock availability analysis including what percentage of available feedstock the actual production volume requires. Analysis of feedstock

LCFS 40-8
cont.

availability should be done separately for domestic and foreign supply sources.

Footnote: A definition of "success" could, for example, be once answers to questions #5 and #6 exceed 80%. Or, before a facility is deemed to be viable and included in a consideration of low CI fuels facilities to be in ARB's list of "available fuels" would be the answer to question #5 multiplied by the answer to question #1. Note that typical refinery process utilization ranges between 93 and 98 percent, on an annual basis.

Fuel Cost-competitiveness

Not only is the availability of low CI fuels important, but those fuels must also be cost competitive if the LCFS is to be feasible in a real world market. Accordingly, a cost-competitive analysis must be performed. This analysis should assess how much greater the low CI fuels are in average market costs than petroleum products on a per-gallon basis, and the analysis should also evaluate the role or continued need for subsidies in the cost of the fuels.

LCFS 40-8 cont.

Fuel Infrastructure

This analysis should also consider the capability of the distribution system infrastructure (including retail sites) to handle these volumes and types of fuels and what additional infrastructure would be needed, including costs, to support the assessed volumes.

Vehicle Availability

A mandate for further CI reduction should consider whether commercially produced vehicles are available in sufficient quantity to use the low CI fuels. Further, the compatibility of the existing vehicle fleet to use these higher volumes or types of fuels needs to be analyzed. Barriers like consumer acceptance should also be analyzed in an intellectually honest manner with sensitivity runs to bracket an appropriate range of consumer acceptance.

- <u>Low CI Fuel Availability - Three Fuel Examples</u>:

<u>Renewable Diesel</u>

Renewable diesel is one of the more promising available low carbon intensity fuels for LCFS compliance. However, ARB's supply projections are optimistic and overly reliant on announced projects and nameplate capacities. Announcements regarding new production facilities are frequently optimistic in their projected startup dates and facilities rarely reach nameplate capacities in the first months or even years following completion of construction as they face startup issues. Feedstock availability is of particular concern for a product like renewable diesel that will be competing with established food and industrial product markets for the same lipid feedstocks.

LCFS 40-9

The critical barriers to the market penetration of renewable diesel, however, are not production levels but blending infrastructure and regulatory hurdles. ARB has projected that renewable diesel will make up 12% of the California diesel pool by 2020, but we anticipate it will reach roughly half that level. Logistical hurdles on pump labeling (FTC regulations), superimposed on the fungible nature of the common carrier pipeline system will be difficult to overcome in the 2016-2020 timeframe. BCG projects that the vast majority of diesel in the state will contain 5% renewable diesel by 2020, with higher percentages seen in select centrally fueled fleet applications, resulting in an overall pool average slightly above 5% renewable diesel.

ARB has speculated that regulated parties may pursue several options for getting around the 5% blending limit imposed by FTC labeling rules.

- <u>Segregated grades of diesel at terminals</u> – Staff contends that selling two blend levels (0-5% and 6-20% renewable diesel) would enable higher blend levels.

  This option is problematic as terminals face multiple logistical constraints when it comes to any attempts at additional product segregation (e.g. plot space for additional tankage). Even where it could be considered, it is highly unlikely to occur until LCFS implementation establishes RD supply stability and justifies the investment in expansion of diesel grade infrastructure.

- <u>Moving entire pipeline/terminal systems to higher blend levels</u> – Some terminal position holders could move to 6-20% blends, causing the retailer community served by those terminals to label accordingly.

  Voluntarily industry adoption of an RD6-RD-20 specification is equally problematic. The existing fungible pipeline system dictates that industry must move in "lockstep" for any geographic move to higher blends. Such a change would have to be implemented through a common carrier pipeline specification change, which can take a lot longer than expected.

- <u>Large-scale fleet blending</u> – Bypassing the traditional supply system to blend high renewable diesel levels for fleet applications.

  This is a very real possibility. Centrally-fueled fleet blending at higher renewable diesel percentages will likely occur but its impact is small and it has already been comprehended in BCG's estimates.

- <u>Relying on an FTC re-interpretation of the underlying law (2007 EISA)</u> – The FTC may revisit their understanding of Congress' intent and remove the regulatory barriers.

  This is the least likely solution. Several unsuccessful inquiries have already taken place by both fuel providers and renewable diesel producers as expanded blending has been pursued for Renewable Fuel Standard and other blending mandate compliance. The FTC has been unmoved on this point. Congress providing the necessary authority (by reopening EISA) is even more unlikely near term.

LCFS 40-9 cont.

Furthermore, strong opposition should be expected by the biodiesel lobby to any revision attempt.

In view of the above, terminal blending above 5% (on average) before 2020 is highly unlikely and fleet blending will have only a marginal impact on the overall market balance.

LCFS 40-9 cont.

Renewable Biogas

Reliance on large-scale production of renewable natural gas as a supply of LCFS credits is questionable. Investors will weigh high regulatory risk as they consider such projects. Without RFS and LCFS credit subsidies, renewable natural gas for transportation is uneconomic. Cellulosic RINs are estimated to add three times the commodity value of natural gas, the LCFS may add another one to two times the value. While this may seem like a significant motivator for investment, the possibility that these programs may be modified at any time (based on political and/or regulatory reassessment) represents a significant issue for investors as the consider projects whose returns are based solely on the RFS and/or LCFS credit premiums that they generate.

Typical economics (capital investment, absence of need for gas "cleanup", access to gas pipeline, etc.) of biogas utilization drive the application of such gas to power generation and not motor fuel use. We have cautioned ARB that the GHG reduction benefits associated with "re-purposing" biogas from power generation CNG/LNG production are not appropriately accounted for in staff's estimates. ARB's carbon intensity assessment of these products ignores this very real possibility, taking full credit for any renewable CNG/LNG production as though it represents green-field landfill gas production. Should it be found that a significant portion of the landfill gas supply used for CNG/LNG production was redirected from electricity production, much of the compliance value of those biogas products will have been lost.

LCFS 40-10

The current version of CA-GREET2.0 estimates the lifecycle CI of CNG from landfill gas to be 17gCO2e/MJ. If this landfill gas was re-purposed from on-site electricity generation, the amount of electricity displaced from the grid would need to be accounted for as average grid electricity, which has a much higher CI than electricity from landfill gas. CA-GREET2.0 estimates the US-average electricity CI to be 183gCO2e/MJ, while EPA has estimated the CI of electricity from landfill gas to be 11.4gCO2e/MJ. EPA has also estimated that 3.4MJ of landfill gas energy is required to produce 1MJ of electricity*. The increase in the landfill gas CNG/LNG CI from displacing LFG electricity would therefore be:

(1 MJ Elec. / 3.4 MJ LFG) * (183 - 11.4gCO2e/MJ Elec.) = 50gCO2e/MJ LFG

For the example above (Landfill Gas CNG), the CI would increase from 17gCO2e/MJ to 67gCO2e/MJ if re-purposed from on-site electricity generation, or about the same as fossil natural gas.

*Note: *"Support for Classification of Biofuel Produced from Waste Derived Biogas as Cellulosic Biofuel and Summary of Lifecycle Analysis Assumptions and Calculations for Biofuel Produced from Waste Derived Biofuel," U.S. EPA Office of Transportation and Air Quality Memorandum to Docket EPA-HQ-OAR-2012-0401, July 1, 2014.*

Table 6: CI of Electricity from Landfills that Flared Biogas = 12 kg CO2e/mmBTU (= 11.4 gCO2e/MJ)
Table 5: Efficiency of Electricity Generation from Biogas = 11,700 BTU biogas/kWh (= 3.4 MJ biogas/MJ electricity)

Advanced Biofuels

ARB staff continues to strongly assert that the LCFS program (and more particularly LCFS credit prices) will drive advanced biofuels production. WSPA notes that almost all of the advanced biofuel production facilities ARB and others mention are not in California – challenging the notion that the state is really driving the advanced biofuel market and attracting investments. As previously commented by WSPA in our Wood Mackenzie and BCG contractor work in 2012, the LCFS will draw any limited quantities of these fuels that may be available to California via shuffling resulting in sub-optimal costs and often increased emissions.

LCFS 40-11

When calculating/projecting future biofuels supply, ARB should not rely on press announcements as credible evidence of actual facilities/volumes, since many projects are cancelled after initial press announcements but prior to construction, based on engineering studies that are completed and a more definitive cost estimate becoming available. ARB should count facilities that have started construction for potential facility/volume availability in the next 2 – 3 years. If construction has not started, then a discount factor of at least 50% should be used in projecting future capacity. When using past growth rates and projecting them into the future, ARB should take into account the period of two or so years of essentially no growth.

3. Assessment of LCFS Program – Major Milestone Review

Although ARB has conducted two formal Periodic Reviews of the LCFS program since its inception, WSPA believes ARB needs to conduct a Major Milestone review to inform transportation fuel consumers and state policymakers of the program's progress towards meeting its objectives over the first 5 years of its existence. We note that during the 2014 Advisory Panel meetings there was discussion of the need for a thorough review which provided more definitive data. We urge ARB to conduct such a review where the analysis is focused on quantifiable metrics that should include, at a minimum, the following considerations that are different in scope from the normal Periodic Reviews:

• Actual GHG reductions achieved through the program (in-state and out-of-state reductions quantified separately), and the avenues/means used to drive those reductions.

LCFS 40-12

• GHG reduction achieved solely by the LCFS, exclusive of other programs, (such as the federal RFS2 and CAFÉ standards, or the California ZEV mandate.) To objectively assess LCFS program progress, GHG reduction benefits should be viewed on an incremental basis, i.e. above and beyond what is delivered from these other programs.

• Costs associated with the LCFS program. These should include any subsidies or program expenditures (i.e., total cost for the California taxpayer), and any additional fuel costs.

• Cost-effectiveness of the LCFS program. The analyses should compare the cost-effectiveness of the incremental GHG reduction delivered by the LCFS program (in terms of dollars per ton CO2 reduction) to those of other GHG reduction programs such as the California Cap and Trade Program or and vehicular efficiency programs (CAFÉ).

• Prospects for future successes in terms of GHG reduction which may be attributed to the LCFS program [in the absence of other related regulatory policies], and a reasonable assessment as to their probability of success.

• Assessment of incremental incentives for innovation and in-state employment paid for by state or local dollars. We believe the California public should be apprised as to what their taxes have supported, their incremental fuel and vehicle costs, and be allowed to judge the effectiveness of the LCFS program versus other transportation-related GHG reduction approaches in a transparent, objective manner.

LCFS 40-12 cont.

Economic Impact Analysis Update

To add to the above note on a Major Milestone review, there appears to be a false sense of the degree of updates staff has provided – especially for the economic analysis. There has been minimal effort to update the 2009 economic impact analysis, and during the various 2014 Workshops staff indicated there would not be a comprehensive update to the five year old economic impact analysis.

During the 2011 program updates ARB stated that much of the 2009 analysis remains valid, but acknowledged the need for an entirely new analysis. It was also stated that staff was considering using a contractor to conduct a more comprehensive economic analysis of the LCFS. We were told such an analysis would not be completed until sometime in 2012 or early 2013, but this seems to not have materialized.

LCFS 40-13

4. Cost Containment Mechanism – Credit Clearance

WSPA is concerned that the cost containment mechanism proposed will also act as either a price floor or have the unintended effect of raising LCFS credit prices. Because LCFS credits do not expire, the proposed cost containment mechanism will provide an incentive for those parties that have excess credits to hold on to their credits if they believe that a Clearance Market will occur in the future or to hold out for an offer that is near the Clearance Market price. This negative impact of the cost containment mechanism could be partially mitigated if participation in the Clearance Market was voluntary and if staff re-inserts the deficit carry over provision that was in the previous LCFS reglulations (which WSPA is also suggesting).

In June 2014 WSPA commissioned a paper by Analysis Group, Inc. to review the cost containment mechanisms being proposed by ARB at that point in time.

The Analysis Group pointed out that there "*is a meaningful risk that LCFS compliance costs will increase significantly at some point in the near- to medium-term due to the*

LCFS 40-14

confluence of an increasingly stringent standard, and diminishing opportunities for low-CI fuel substitutions. By virtue of the rate at which the LCFS standard declines, the nature of the transportation systems regulated, and the LCFS design, there is a meaningful risk in the near- to medium-term that compliance with the LCFS could become increasingly difficult. Due to these factors, the cost of actions to generate LCFS credits could rise significantly. Despite the current large bank of surplus credits, the risk of either cumulative deficits or significantly elevated credit costs is high, although the timing and severity of these outcomes is uncertain."

ARB recognized the need for some mechanism to accommodate short-term market disruptions and prevent excessive LCFS cost of compliance during such periods from ultimately impacting fuel prices. WSPA's advice in that regard has been that the setting of realistic goals coupled with frequent program reviews to ensure ample credit availability in a liquid LCFS credit market would obviate the need for a cost containment mechanism such as the Credit Clearance Market that ARB is proposing as part of the re-adoption package.

WSPA agrees with the Analysis Group's finding that, "*While regulated parties are building up a cumulative credit surplus in the early program years, there is a definite risk that these credit surpluses will become exhausted as the standard becomes more stringent, which could lead to very high costs and/or a cumulative credit deficit, which would increase the risk that regulated parties could not achieve compliance. Current ARB proposals that might add limited credits to the market (e.g., Innovative Technologies for Crude Oil Production) would only shift out the date at which these barriers are hit. While there is much technological uncertainty about the timing and severity of these constraints, there is a clear risk that compliance with the LCFS could become increasingly costly and challenging to comply with. Thus, there is justified concern about cost containment*."

LCFS 40-14 cont.

ARB staff maintains that sufficient low CI fuels and credits will be available and, thus, the cost containment mechanism will be seldom (if ever) needed. Staff's vision is that, when it is necessary, it will be in response to some short-lived market "blip" or disturbance that will quickly give way to reestablishment of equilibrium. Staff acknowledges that this tool is not designed to accommodate systemic and prolonged LCFS credit shortages. Staff considers the ability to carry deficits forward (albeit with interest) for up to five years an "insurance policy" and sees no particular negative aspects to the end-of-year credit clearance auction they are proposing (where regulated parties can buy their pro-rata share of pledged credits at a price as high as $200/ton).

WSPA is opposed to the inclusion of such a cost containment mechanism in the LCFS because we believe that it will not accomplish its stated objective (contain costs) and will instead have a number of undesirable (and unintended) consequences. More specifically, the Credit Clearance Market (CCM):

<u>Does not stipulate a mechanism for retiring deficits, if multi-year market shortages persist</u>.
Obligated parties that participate in the year-end auction of credits pledged by suppliers at costs as high as the pre-determined "cap" Maximum Price, have no recourse but to

LCFS 40-15

carry over any remaining deficit into the following year with interest. There is no way to retire deficits if shortages persist year to year. Instead, obligated parties face the prospect of an ever-increasing accrued financial liability that is essentially outside their control. In a market that is consistently short credits year after year, the ability to defer unsatisfied obligation (with interest) offers little comfort to the regulated community staring down the specter of ever-increasing deficits and no method to retire part of the obligation generated by an infeasible standard.

LCFS 40-15 cont.

<u>May drive credit costs up (if credits are withheld from the regular market to get a higher CCM cost)</u>.
During periods of rising costs (i.e., credit shortages in the open market), the CCM will not keep credit costs in check. In fact, the CCM to clear the market at the end of the year is meaningless during a credit-short environment as there will not be any remaining credits to be brought to the table by sellers. The compounding of "interest" on the carryover/deferred balances will ensure credit buyers soak up the available pool of real LCFS credits in the market during the year rather than wait for the CCM. The pool of real LCFS credits available is fixed – it is only their cost that remains in question. Staff's setting of the Maximum Price at $200/ton will serve as the benchmark for credit costs in that environment.

During periods of stable or declining costs (i.e., credit surplus in the open market), the CCM cap Maximum Price creates an artificial "floor" value below which sellers will be hesitant to offer real LCFS credits for sale to the regulated community at substantially lower costs. This would artificially increase compliance costs – as credit costs will be artificially raised to (or near) the ARB cap and very few transactions will take place before the end-of-year sale. Credit trading would be seriously impaired as the open market would not be allowed to function as it should.

LCFS 40-16

<u>Provides no liability protection against invalid credits secured through the CCM.</u>
We reference the issue of lack of an acceptable liability defense provision or protocol in the LCFS to protect obligated parties from potentially fraudulent credit sellers elsewhere in our comments. For the purposes of discussing this topic within the CCM provisions, we emphasize that the only protection we have as buyers of credits is to perform our due diligence and carefully screen the parties we choose to engage as partners in LCFS credit-buying transactions. It appears to WSPA that we will not be afforded this ability with respect to the credits we are obligated to purchase (our pro-rata share) through the CCM. Moreover, the timetable set by ARB to organize and complete the CCM raises concerns that the agency will be undertaking minimal, if any, screening of the credits that are pledged by sellers for the CCM. WSPA objects to the fact that regulated entities may potentially wind up in a position of non-compliance through no fault of their own simply because there is a credit shortage and they are required to participate in a CCM that provides them no control over what credits they buy and from whom.

LCFS 40-17

Offers no connection between CCM outcome, program off-ramps, future CI reduction targets

It stands to reason that LCFS credit market liquidity (measurable potentially through a number of different indicators) is not only essential to the program's success but, also, that the absence of such liquidity should be viewed as a clear signal that the program's CI reduction targets are overly ambitious and that the regulated community is finding it difficult to meet its obligations and remain in compliance. There is no connection or tie-in in the current CCM proposal to initiate a comprehensive program review should the alarming trend of potential credit shortages materialize and become evident through the CCM. LCFS 40-18

Is incomplete in its definition of the mechanics (recordkeeping, reporting, etc.) of deficit carryover

Even if all of the above issues were resolved, the CCM proposal in the ISOR and draft regulatory language is sorely lacking in the execution/implementation details that would allow the regulated community to understand exactly how it would work. For example: What is the "order" of applying generated credits (through blending or purchases) to the various potential uses for a regulated party o on any given year (e.g., meet the current year's obligation, retire previous years' obligations)?

LCFS 40-19

Finally, the proposal to make public the long and short credit positions of regulated parties flies in the face of the principle of confidential business information. A regulated party's competitive position could be seriously compromised by the publication of this information. In addition, this information would give competitors both an understanding of a regulated party's compliance strategy and a view into the regulated party's fuel and credit acquisition activity for the year. Using this information and average market pricing, one could estimate the financial impact of LCFS compliance on a regulated party.

Alternative to the CCM

In lieu of the CCM, a dual approach of setting reasonable, practically achievable CI reduction targets and holding frequent (annual) program reviews to ensure that the program remains on track and the LCFS credit market is healthy should prevent the type of cost excursions that CCM is meant to accommodate. More specifically, staff could eliminate the proposed CCM and:

- Provide for annual mandatory program reviews with the first one due by 1/1/2017. The initial review should include LCFS credit history including actual credit generation, obligation, and a comparison of actual current credit bank versus staff's projections in the ISOR. As part of the review, staff should include a projection of where the credit bank is expected to be in the future. If overall credit generation is above or below staff's projections (plus/minus a modest estimate allowance/tolerance), CI reduction targets should be adjusted up or down to re-establish an aggressive yet achievable program. LCFS 40-20

- Establish triggers that would require early program reviews prior to the planned annual staff report. Specific, measurable thresholds and triggers should be

established as part of this process. Some examples of such triggers for an early review of subsequent year CI targets include:
  - Monthly credit cost exceeds $150
  - Industry credit bank falls below 5 million metric tons (MMT)
  - CA fuel price > "x"cpg above national average

- Incorporate a simple carryover rule for one-off company imbalances. The provisions of this segment could be tailored along the lines established for RINs by EPA in the RFS program, with potential additional enhancements. Key features could include:
  - A regulated party may carry over a deficit balance for one year, without penalty
  - Credits must be retired in the following year to completely settle the deficit balance
  - A deficit balance cannot be carried over two years in a row

LCFS 40-20 cont.

This simple-to-execute approach would satisfy staff's stated goal of addressing short-term tightness in the credit market, while avoiding the market-manipulating aspects of the proposed CCM. Neither this solution nor the CCM can address the very real possibility of a long-term credit shortage. This must be met with the program reviews and schedule adjustments recommended above.

If staff insists on moving forward with a CCM, WSPA recommends that, at a minimum, the following changes should be made:

- Participation in the CCM should be voluntary. In order for ARB to determine whether or not to hold a CCM for a particular year, ARB could issue a "Call For Deficits" similar to the "Call For Credits" already incorporated in staff's proposal.

- Regulated parties that have pledged credits to sell into the Clearance Market, and have not sold or contractually agreed to sell all their pledged credits, cannot reject an offer to purchase pledged credits at the Maximum Price.

- The LCFS credit balance and the individual entity names should be treated as highly confidential because the release of this information could adversely impact business operations. The release of the LCFS credit balance would provide competitors and other LCFS credit market participants with short or long position knowledge.

- The Deficit Carryover provisions should be reinstated. WSPA objects to the removal of the Deficit Carryover provisions in the proposed regulations and request that the current provisions be retained as there may be planning or operational reasons why a regulated party may wish to carry deficits from one year to the next.

LCFS 40-21

On many occasions, WSPA has raised concerns about the interactions between the LCFS and the GHG cap-and-trade program.[1] In general, "quantity-based" programs such as the

LCFS 40-22

LCFS (which relies on averaging across entities to meet a standard) that overlap with a cap-and-trade program do not generate additional emission reductions but do potentially raise costs. Because the LCFS affects sources both under and outside of the GHG cap-and-trade system, these interactions are somewhat more complex. However, this does not affect the conclusion that these interactions create significant concerns for the environmental and economic efficacy of the LCFS.

ARB's cost containment proposal in no way affects these conclusions. The cost containment proposals may mitigate the extent to which the LCFS raises the costs of meeting the AB 32 targets compared to a policy that relies solely on the GHG cap-and-trade program, but does not affect the conclusion that the LCFS raises overall costs.

LCFS 40-22 cont.

WSPA provides additional detailed comments later in this document regarding specific concerns about the cost containment provision as proposed by ARB.

[1.] *see* Schatzki, Todd and Robert Stavins, "Implications of Interactions for California's Climate Policy," Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, August 27, 2012.

Legal Comments:

1. ***ARB has failed to comply with statutory requirements with respect to enacting a fuel specification, including inadequately analyzing fuels impacts through multimedia analysis.***

WSPA strongly disagrees with ARB's characterization of the LCFS as a fuel "standard" rather than a fuel "specification." ARB argues that because the LCFS governs the production process for fuels, rather than imposing "an ARB mandate on a vehicular fuel's particular composition," the LCFS is not a fuel "specification" subject to the Health & Safety Code's requirements for fuel control measures. Initial Statement of Reasons for Proposed Rulemaking, Proposed Re-Adoption of the Low Carbon Fuel Standard ("ISOR"), at III-58 – III-63. ARB argues that a fuel "specification" would be more like a recipe, with quantifiable measurements of components that would make up the fuel; because carbon intensity measurements rely more on how a fuel is made than what is in it, ARB says the LCFS is not a "specification." *See* ISOR at III-61.

LCFS 40-23

But contrary to ARB's assertion, carbon intensity is a criterion or "specification" to which motor vehicle fuels must comply. The Health & Safety Code nowhere requires that a "specification" relate only to the quantity of fuel components. Indeed, the Code recognizes a fuel specification for light-duty vehicle exhaust emission standards—standards that, like the LCFS, are based on overall emissions from fuels as opposed to quantification of their particular components. Cal. Health & Safety Code § 43018(d)(1).

Furthermore, the LCFS will change specifications of California reformulated gasoline and diesel and may require fuel additives to be added to or removed from fuels and new fuels to be used statewide. ARB Draft LCFS Regulation, § 95422

("[T]he transportation gasoline and diesel fuel for which a regulated party is responsible in each calendar year must meet the average carbon intensity standards set forth in this section . . . "). ARB is not permitted to avoid the statutory requirements associated with fuel control measures by simply labeling the LCFS a "standard" as opposed to a "specification."

Furthermore, the Ninth Circuit has already considered the LCFS to be a fuel control measure. *See Rocky Mountain Farmers Union v. Corey*, 730 F.3d 1070 (9th Cir. 2013) (recognizing that the LCFS is "a control respecting a fuel or fuel additive and was enacted for the purpose of emissions control"). In fact, ARB itself has argued that it should have the authority to enact the LCFS precisely because the LCFS is a control on motor vehicle fuels. *See* Defendants' Memorandum in Support of Cross-Motion for Summary Judgment, *Rocky Mountain Farmers Union v. Goldstene*, Case No. 09-CV-02234 (C.D. Cal. Dec. 17, 2010) at 2, 11-18. In its *Rocky Mountain Farmers Union* papers, ARB admitted that "[t]he LCFS controls the carbon intensity of fuels offered for sale in California. It does so by applying a lifecycle analysis." *Id*. at 15. ARB even pointed out that as fuel sources diversify, "differentiating among them on the basis of lifecycle carbon intensity becomes even more critical"— in other words, carbon intensity <u>is</u> a specification of fuels that is controlled by the LCFS with the goal of reducing emissions.

ARB cannot now change its tune in an effort to escape the statutory requirements applicable to fuel control measures. Under the California Health & Safety Code, ARB must assess not only the cost-effectiveness of such controls, but also the technological feasibility of the controls, including, but not limited to, the availability, effectiveness, reliability, and safety of the proposed technology. Cal. Health & Safety Code § 43013(e). ARB's documentation does not adequately assess any of these factors. In addition, as discussed in greater detail below, ARB has failed to undertake the requisite multimedia analysis for the LCFS, also mandated by the Health & Safety Code.

LCFS 40-23 cont.

<u>*Multimedia Analysis Under Health & Safety Code § 43830.8*</u>
One key requirement ARB has attempted to avoid by its improper characterization of the LCFS, is conducting multimedia analyses for fuels that will likely be used to comply with the LCFS, as required under the Health & Safety Code.

Under section 43830.8 of the Health & Safety Code, ARB may not adopt "any regulation that establishes a specification for motor vehicle fuel" unless the regulation, and a multimedia evaluation for the regulation, are reviewed by the California Environmental Policy Council ("Council"). Cal. Health & Safety Code § 43830.8(a). A multimedia evaluation requires ARB to identify and evaluate "any significant adverse impact on public health or the environment, including air, water, or soil, that may result from the production, use, or disposal of the motor vehicle fuel that may be used to meet the state board's motor vehicle fuel specifications." Cal. Health & Safety Code § 43830.8(b).

ARB staff promises they will perform a multimedia analysis later—either if and/or when ARB adopts a new fuel specification (such as the current specification for biodiesel) or if and/or when it amends an existing fuel specification (such as natural gas or E85). ISOR at III-64. Such an approach fails to address upfront any adverse environmental impacts that may be associated with producing fuels that can meet the carbon intensity requirements of the LCFS. Multimedia evaluations are necessary in order to obtain a full and independent assessment of the range of potential environmental impacts of any newly proposed fuel regulations across all media. This assessment should be completed as soon as feasible, not at later dates if and/or when ARB chooses to prepare it.

LCFS 40-23 cont.

In addition, delaying such an evaluation until a later time could hinder the development of the full range of LCFS-compliant fuels due to concerns about allocating any significant resources to the commercialization of a fuel that could ultimately fail a multimedia evaluation.

Nearly six years have passed since ARB stated, during the first LCFS rulemaking, that there was not enough information to conduct a multimedia evaluation for fuels designed to comply with the LCFS. ARB and fuel producers have much better information now regarding the types and blends of fuels that will likely be used under the LCFS. In fact, ARB completed a multimedia analysis for biodiesel in conjunction with the Alternative Diesel Fuel (ADF) rulemaking. ARB should now complete multimedia analyses for all fuels that will likely be used to comply with the LCFS in order to comply with its statutory duty under the Health & Safety Code.

2. ***Combining the ADF and LCFS processes into one CEQA "project" is not procedurally appropriate, and results in an insufficient environmental analysis.***

ARB should analyze the LCFS and the ADF as two separate projects. At the very least, ARB must acknowledge the possibility that the two regulations will not pass concurrently, and should rework the Draft EA to clarify the impacts from each of the regulations, and the specific mitigation measures applicable to each.

LCFS 40-24

The Draft EA published by ARB is the environmental document for both the LCFS and the ADF regulations. While these two rulemakings are being run concurrently, parallel to one another, they are also being run as two separate processes. Because the two regulations are subject to two separate rulemakings, there is the possibility that one regulation could pass but the other could not, or that one regulation could be challenged and its implementation delayed while the other continues to move forward.

ARB has cited CEQA Guidelines § 15378(a) in support of its approach to combine environmental review of the two regulations into one CEQA "project." However, section 15378(a) of the Guidelines simply states that a "project" is "the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment…" While section 15378(c) of the Guidelines clarifies that a "project" can include an activity that requires more than one discretionary approval by one or multiple government agencies, the Guidelines nowhere provide for a "project" that encompasses two separate activities that happen to be related to one another, but are not interdependent. *See* CEQA Guidelines § 15378(c). LCFS 40-25

Interdependence, an element lacking here, is key to including separate actions under the umbrella of one CEQA "project" for purposes of environmental review. *Tuolumne County Citizens for Responsible Growth, Inc. v. City of Sonora* (2007) 155 Cal.App.4th 1214, 1230-1231 [finding a road realignment and construction of a shopping center were part of the same "project" because the shopping center's opening was legally dependent upon the road's realignment]. The LCFS and ADF regulations certainly pertain to related subject matter, but they are not legally dependent upon one another—the LCFS can (and has, in the past) exist without the ADF, and vice versa.

Both statute and regulation recognize the need to analyze separate "projects" in circumstances similar to these. For example, while a real estate developer may request a rezoning of property, as well as a tentative subdivision map, for purposes of effectuating development, those two related but separate actions are recognized as distinct "projects." *See El Dorado Union High School Dist. v. City of Placerville* (1983) 144 Cal.App.3d 123, 129-130; CEQA Guidelines § 15037. Just as with the two related but distinct rulemakings here, each of these two legal actions, which may very well impact the same development, nonetheless may occur without the other and in completely separate processes, and may produce significantly different impacts. LCFS 40-26

Simply put, CEQA does not allow ARB to take two different activities which each have different impacts and require different analyses and pass them off as one "project" to streamline its environmental review process. The process that ARB has adopted here makes it impossible to separate out which impacts stem from the LCFS regulations and which from the ADF regulations, <u>even though the two rules are being considered in separate rulemakings, have distinct impacts as a practical matter, and may not both be adopted, or may be adopted on different schedules</u>. LCFS 40-27

CEQA requires that environmental review documents be "written in a manner that will be meaningful and useful to decision-makers and to the public." Cal. Pub. Res. Code § 21003(b); *see Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal.3d 376, 392. When neither decision- LCFS 40-28 LCFS 40-29 makers nor the public can meaningfully understand the impacts that will arise from each proposal and available mitigation, the usefulness of the Draft EA as a valuable decision-making tool for is significantly undermined, contravening the intent of CEQA. LCFS 40-29 cont.

3. ***The Draft EA does not sufficiently analyze alternatives.***

Under CEQA, an environmental review document "must consider a reasonable range of alternatives to the project" and must "make an in-depth discussion of those alternatives identified as at least potentially feasible." LCFS 40-30 *See Preservation Action Council v. City of San Jose* (2006) 141 Cal.App.4th 1336, 1350; *Sierra Club v. County of Napa* (2004) 121 Cal.App.4th 1490. The purpose of such an analysis is to allow informed decision-making, and the onus for analyzing a sufficient range of alternatives falls squarely on the agency. *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal.3d 376, 405. LCFS 40-31

But ARB's Draft EA falls far short of this requirement. The Draft EA only analyzes a "no project" alternative—LCFS regulations being set aside as a result of the *POET* decision and no adoption of the ADF; a second alternative—re-adopting the existing LCFS without any of the proposed updates and adopting the ADF regulation as proposed; and finally, a "Gasoline-Only Compliance Curve" alternative—an alternative that would remove the diesel standard from the LCFS so that the compliance curves apply only to gasoline and gasoline substitute fuels. LCFS 40-32 Despite the Draft EA's statement that it presents a fourth action alternative—the "No Trading Case Alternative" –ARB never includes a description of that alternative in the Draft EA. Draft EA at 130. LCFS 40-33

Additionally, ARB's description of the alternatives is somewhat misleading. The alternatives that ARB discusses are more accurately described as: (1) no LCFS and no ADF; (2) re-adoption of the existing LCFS and adoption of the proposed ADF as-is; and (3) the "Gasoline-Only Compliance Curve Alternative," which, like the first alternative, would not adopt the proposed ADF, or any rule on diesel fuels. There is no analysis of an alternative that would involve re-adoption of the proposed LCFS with a different ADF regulation, or of a different approach to the LCFS beyond simply dropping diesel fuels from the regulation. In contravention of CEQA, this analysis overlooks potentially less impactful options. *See Citizens of Goleta Valley v. Board of Supervisors* (1990) 53 Cal.3d 553, 566. LCFS 40-34

The mere three alternatives presented by the Draft EA insufficiently represent the broad scope of alternatives, and fail to take into account clearly feasible scenarios—such as an ADF regulation that is substantively different from the one proposed by ARB. In fact, the Draft EA analyzes no alternatives beyond a "no project" alternative for ADF: either the ADF is not adopted at all, or it is adopted exactly as is. ARB cannot limit the alternatives analysis on the ADF without explaining "in meaningful detail" the basis for its conclusion that there are no LCFS 40-35 feasible alternatives to the ADF as proposed. *Laurel Heights Improvement Assn.*, 47 Cal.3d at 405. LCFS 40-35 cont.

CEQA requires that the Draft EA explore more alternatives than the three presented here. ARB has provided an insufficient alternatives analysis in connection with these rulemakings, and therefore the Draft EA should be revised accordingly. LCFS 40-36

4. ***The Draft EA does not sufficiently analyze air quality impacts.***

CEQA requires that reasonably foreseeable impacts of a project must be adequately analyzed and, if necessary, mitigated by the agency. Cal. Pub. Res. Code § 21003(b); *see Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal.3d 376, 392; *Vineyard Area Citizens for Responsible Growth, Inc. v. City of Rancho Cordova* (2007) 40 Cal.4th 412, 431 . But ARB has not adequately analyzed the potential impacts of the interplay between NOx and VOC emissions stemming from the implementation of the LCFS and ADF.

The Draft EA does not attempt to assess the impacts of the LCFS and ADF regulations on ambient ozone and PM concentrations. Instead, ARB staff simply analyzed the impacts of the LCFS in combination with the ADF on the emissions inventory. Table 4-1 of the Draft EA summarizes ARB staff estimates of the NOx emissions impacts of the LCFS and ADF regulations. That table reports a net reduction in NOx emissions of 1.0 tons per day in 2020, growing to 1.3 tons per day in 2023. The Draft EA then asserts that the "long-term impacts on air quality would be **beneficial**." (emphasis in original text) LCFS 40-37

Ozone formation chemistry is highly non-linear and so to assess whether the proposed NOx reduction would bring about discernible reductions in ambient ozone, photochemical modeling is necessary. Because the draft EA does not include the impact of LCFS and ADF on VOC emissions, it is impossible to even qualify the net ozone response due to the regulation.

Air quality impacts of the LCFS are addressed in a recent report prepared by ENVIRON International Corporation for the Coordinating Research Council.[1] Among the findings of that report were:

- The LCFS rule constitutes a potential regional control strategy that has not been specifically studied.
- Reductions in precursor emissions (i.e., NOx, VOC reductions) do not always provide air quality benefits, because ozone chemistry is highly non-linear.

[1] "Low Carbon Fuel Standard Program Air Emissions Effects," Prepared by ENVIRON International Corporation, CRC Project No. A-86, September 24, 2014. http://www.crcao.com/reports/recentstudies2014/A-86%20Low%20Carbon%20Fuel%20Standard%20Program%20Air%20Emissions%20Effects/CRC%20A86%20Final%20Report_%20Sep30_2014.pdf

- In the 2009 rulemaking ARB asserted that due to the relatively small magnitude of emission reductions associated with LCFS it was not practical to expect the air quality model to reasonably predict the cumulative potential benefit on ozone air quality. However, such modeling may be warranted. LCFS 40-37 cont.

5. ***Formulas have changed without the appropriate level of transparency.***

Key elements of the regulation depend on data that are used in calculations that compute indirect land use change and carbon intensity values relevant to the regulation's overall compliance scheme. Changes in the type of data used to compute these values can therefore have a significant effect on the thresholds regulated entities need to meet to come into compliance.

ARB has removed indirect land use change values from the look-up tables that were included in the prior version of the regulation, and now simply describes a credit calculation which requires the incorporation of a land use modifier. The values for such a modifier are not included in the regulation.

Additionally, the carbon intensity calculation process relies on CA-GREET. However, ARB has failed to provide a transparent process to outline bases for changes to the GREET model or allow input for future changes to the model is lacking. ARB acknowledges GREET is used "to provide many emission factors, life cycle inventory data, and fuel cycle emissions values." ARB, LCFS Reauthorization Initial Statement of Reasons, p. II-20. In fact, ARB admits that changes to the GREET model were the impetus for OPGEE revisions—but the GREET changes themselves lacked transparency; even ARB's comparison of the updated model to prior models offers conclusory statements of changes rather than explanations for them. *See, e.g.,* ARB, Comparison of CA-GREET 1.8B, GREET1 2013, and CA-GREET 2.0, pp. C-2-C-3, C-8-C-9. Nothing in the regulations suggests future changes to GREET will be more transparent. LCFS 40-38

Similarly, the sources for data to be used in calculating the Annual Crude Average carbon intensity value have changed, and that data is now to be provided by two different state agencies, with no apparent opportunity for verification or explanation of the data's bases.

Each of these actions opens the door to changes to key formulas outside of the rulemaking process and without opportunity for public comment. When regulations are amended, the California Administrative Procedure Act requires "basic minimum procedural requirements" for rulemaking, including giving interested parties an opportunity to comment on the rulemaking, and a response to public comments. *See Tidewater Marine Western, Inc. v. Bradshaw* (1996) 14 Cal.4th 557, 558; Cal. Gov. Code § 11346. But the proposed regulations attempt to avoid public discourse on potentially significant changes to the implementation of the LCFS by tying key values that are the rule's backbone to calculations and data that could change at any time, with no explanation—essentially a *de facto* amendment of the regulation with no public process.

ARB must explain the bases for relying on the data sources it has chosen, and must provide more certainty that key values and calculations will not change without public input.

LCFS 40-38 cont.

6. ***ARB does not have the authority to compel regulated parties to purchase credits without the capability of verifying those credits.***

The regulations penalize credit holders if they hold invalid credits, even if that is through no fault of their own. Because credits must be verifiable, ARB lacks power to require entities to participate in the credit scheme without providing some level of certainty that credits validly represent the reductions they purport to represent. *See* Cal. Health & Safety Code § 38562(d)(1) ["Any regulation adopted by the state board pursuant to this part or Part 5 [market-based compliance mechanisms] shall ensure all of the following: (1) The greenhouse gas emission reductions achieved are real, permanent, quantifiable, ***verifiable***, and enforceable by the state board …"] [emphasis added].

The statute and regulations do not address independent verification by purchasers of credits, and we have not located any comparable program with such provisions. However, even if buyers were provided the opportunity to verify credits prior to purchase, ARB's authority to suspend, revoke or modify credits under proposed section 95495 would not be limited and, as a result, there is still a risk credits could be invalidated by ARB.

LCFS 40-39

Such a scenario is not without precedent. In 2012, EPA invalidated over 60 million Renewable Identification Numbers (RINs), the tradable credits that are generated as part of the federal Renewable Fuels Standard program, due to criminal fraud perpetrated by certain RIN generators. Because the RFS was set up as a strict buyer liability system, unknowing, good faith obligated parties were left with worthless invalidated RINs and faced enforcement penalties from EPA. ARB should avoid the risk of creating a similar situation under the LCFS regulations.

However, the risk of invalidation could be reduced by limiting the bases for invalidation under proposed section 95495(b)(1) and adding a statute of limitations on ARB's right to commence invalidation procedures.

WSPA therefore requests the following changes be made to the regulations (bold, underlined type):

Section 95495(a)

<u>(1)</u> If the Executive Officer determines that any basis for invalidation set forth in subsection (b)(1) below occurred, in addition to taking any enforcement action, he or she may: suspend, restrict, modify, or revoke an LRT-CBTS account; modify or delete an Approved CI; restrict, suspend, or invalidate credits; or recalculate the deficits in a regulated party's LRT-CBTS account. For purposes of this section, "Approved CI" includes any determination relating to carbon intensity made pursuant to section 95488, or relating to a credit-generating activity approved under section 95489.

<u>**(2) The Executive Officer shall commence enforcement actions under subsections (b)(1)(A)-(F) as follows:**</u>

<u>**(A) The Executive Officer shall commence an action under subsections (b)(1)(A), (C), or (D) within one (1) year from either the date that the subject Approved CI or credit was generated in accordance with section 95486 or the date upon which disputed data was reported in accordance with section 95488, as applicable.**</u>

<u>**(B) The Executive Officer shall commence an action under subsection (b)(1)(B) arising from incorrect material information submitted in connection with an Approved CI or credit transaction within one (1) year from either the date of approval of the CI or the recordation date, as defined by section 95487, of the first transaction wherein incorrect material information was submitted, as applicable.**</u>

LCFS 40-39 cont.

<u>**(C) The Executive Officer shall commence an action arising from a transaction made in violation of applicable laws, statutes and regulations under subsection (b)(1)(E) within one (1) year from the recordation date, as defined by section 95487, of the disputed transaction or from the date the credit was generated in accordance with section 95486, as applicable.**</u>

<u>**(D) The Executive Officer shall commence an action under subsection (b)(1)(F) within six (6) months from the date that a party refused to provide records or failed to produce records within the required time.**</u>

Section 95495(b)(1)

Determination that a Credit, Deficit Calculation, or Approved CI is Invalid.
(1) *Basis for Invalidating.* The Executive Officer may modify or delete an Approved CI and invalidate credits or recalculate deficits based on any of the following:
(A) any of the information used to generate or support the Approved CI was incorrect **for reasons including** <u>**due to**</u> the omission of material information **or changes to the process following submission**;
(B) any material information submitted in connection with any Approved CI or credit transaction was incorrect;

(C) fuel reported under a given pathway was produced or transported in a manner that varies in any way from the methods set forth in any corresponding pathway application documents submitted pursuant to section 95488 (or former section 95486, effective January 1, 2010);
(D) fuel transaction or other data reported into LRT-CBTS and used in calculating credits and deficits was incorrect or omitted material information;
(E) credits or deficits were generated or transferred in violation of any provision of this subarticle or in violation of other laws, statutes or regulations **directly applicable to the credit generation or transfer**; and
(F) a party obligated to provide records under this subarticle refused to provide such records or failed to produce them within the required time.
For purposes of this subsection, "material" means information directly relevant to the generation and calculation of credits under section 95486 or the requirements for credit transactions under section 95487, as applicable.

LCFS 40-39 cont.

7. ***Enforcement provisions with respect to credits and carbon intensities are deficient.***

If invalidation of a credit or CI creates a deficit, the generator and/or holder of the credit will have 60 days to correct the compliance issue by purchasing new credits. *See* proposed section 95495(b)(4) ("If [the Executive Officer's] final determination invalidates credits or deficit calculations, the corresponding credits and deficits will be added to or subtracted from the appropriate LRT-CBTS accounts. Where such action creates a deficit in a past compliance period, the deficit holder has 60 days from the date of the final determination to purchase sufficient credits to eliminate the entire deficit. A return to compliance does not preclude further enforcement actions.").

The proposed regulations do not include an appeals mechanism for challenging the Executive Officer's final determination as to invalidated credits. Although appeals may be brought in Superior Court pursuant to Civil Procedure Code section 1085, it would be preferable for ARB to create a hearing and appeals procedure within its regulations. The 60-day period for correcting deficits should not commence until appeals are exhausted.

LCFS 40-40

WSPA therefore requests the following additions to the regulations (bold, underlined type):

Section 95495(b)(2)

Notice ***and Opportunity for Hearing***. Upon making an initial determination that a credit, deficit calculation, or Approved CI may be subject to modification, deletion, recalculation, or invalidation under subsection (b)(1), above, the Executive Officer will notify all potentially affected parties, including those who hold or generate credits or deficits based on an Approved CI that may be invalid, and may notify any linked program. The notice shall state the reason for the initial determination **<u>and the party's right to request a hearing</u>**, and may be distributed using the LRT-CBTS. Any party receiving such notice may submit, within 20 days, any information that it wants to the Executive Officer to consider **<u>and, if desired, its request for a hearing.</u>** The Executive Officer may request information or documentation from any party likely to have information or records relevant to the validity of a credit, deficit calculation, or Approved CI. Within 20 days of any such request, a regulated party shall make records and personnel available to assist the Executive Officer in determining the validity of the credit, deficit calculation, or Approved CI. **<u>If a party requests a hearing on the Executive Officer's initial determination, the Executive Officer must set a hearing date no later than 60 days from the date of the hearing request.</u>**

Section 95495(b)(4)

Final Determination.

<u>(A)</u> Within 50 days after making an initial determination under sections 95483.3(b)(1) and (2), above, **<u>or holding a hearing, whichever is later,</u>** the Executive Officer shall make a final determination based on available information whether, in his or her judgment, any of the bases listed in subsection (b)(1) exists, and notify affected parties and any linked program. **<u>Affected parties may appeal the Executive Officer's final determination to the Board within 30 days of receiving notice of the Executive Officer's final determination. Such appeals shall be placed on the agenda of the next regularly scheduled Board meeting.</u>**

<u>(B)</u> If the final determination invalidates credits or deficit calculations, the corresponding credits and deficits will be added to or subtracted from the appropriate LRT-CBTS accounts. Where such action creates a deficit in a past compliance period, the deficit holder has 60 days from the date of the final determination **<u>or the disposition of any appeal, whichever is later,</u>** to purchase sufficient credits to eliminate the entire deficit. A return to compliance does not preclude further enforcement actions.

LCFS 40-40 cont.

8. ***ARB's proposed per-day penalties for violations of the LCFS are unnecessary.***

Proposed section 95494 sets penalties for the failure to demonstrate compliance at the end of a compliance period or carry over all deficits; under the proposed regulations, such a failure would constitute a separate violation for each day of the compliance period or, alternatively, ARB could impose a penalty of $1000 per deficit.

LCFS 40-41

WSPA opposes a per day penalty, and proposes that ARB's suggested alternative penalty of $1000 per deficit be employed. While AB 32's enforcement provisions provide for per day penalties when a violation results in the emission of an air contaminant, where, as here, no actual emission of air contaminant is occurring on a per day basis, the imposition of such a penalty would be unnecessary. *See* Cal. Health & Safety Code §§ 42400.1, 42400.3. For example, even if a penalty drew the lowest strict liability level of $10,000 per violation, a failure to demonstrate compliance or carry over deficits could draw a penalty in the range of millions of dollars. Such a penalty is far too severe for an offense that does not signify actual emission of air contaminants beyond a statutory threshold.

Instead, penalties should be assessed on a per deficit basis, an approach which is authorized by the applicable penalty provisions of the Health & Safety Code and which ARB has already suggested. *See* Cal. Health & Safety Code § 38580(b)(3); proposed LCFS regulation § 95494(c). Unlike the extreme per day penalty provision, a per deficit penalty of $1000 is reasonable and more consistent with the nature of the violation.

LCFS 40-41 cont.

WSPA therefore proposes a revision to the text of section 95494(c) as follows:

"~~Failure to demonstrate compliance at the end of a compliance period or carry over all deficits pursuant to section 95485(c) constitutes a separate violation for each day within the compliance period. Alternatively,~~ **E**ach deficit that is not eliminated or carried over **at the end of a compliance period** as required by section 95485(c) constitutes a separate violation of this subarticle for purposes of determining penalties pursuant to Health and Safety Code section 38580(b)(3), subject to a penalty not to exceed $1000 per deficit."

9. ***The requirement that refinery investment credits only be approved for reductions from projects with no increase in criteria or toxic emissions should be eliminated.***

WSPA strongly opposes the additional complex provisions that ARB has added to the refinery investment credit provisions. This added complexity and ambiguity will limit or eliminate legitimate GHG reduction projects from receiving credits. In particular, we oppose the requirement to approve credits only from projects with no increase in criteria or toxic emissions. It is complex, unnecessary, and inequitable when compared to other parties that are participating in the LCFS.

LCFS 40-42

First, while seemingly simple in concept, there are volumes of regulations, guidance documents, and court cases related to air quality permitting where various methodologies are employed for determining what constitutes an increase.

For example, some of the questions that arise are: Is it only operational emissions or construction emissions? Is it only direct emissions from the source or indirect emissions? What if it adds personnel – will their driving trips be included? Should the increase be in terms of mass or concentration at sensitive receptors? What is the baseline for determining an increase? What years are picked for the baseline? What if there is an increase – but it is still within the permitted limit for that source or facility? How is it enforced after-the- fact – when other non-related changes at the refinery may occur that impact emissions year to year? The list can go on and on. This is a regulatory quagmire for ARB since any attempt to address or clarify these issues in the regulation could double the size of the regulation and create substantial litigation risk from various parties.

Second, this limitation is unnecessary because various regulations are in place to make sure emission increases either do not occur or are appropriately mitigated.

Under the California Health & Safety Code and Clean Air Act permitting requirements, there are already ample regulations that reduce the likelihood of an emission increase, and ensure that increases are within regulatory limits. Compliance with these programs is sufficient to ensure that no negative impact would arise from an increase in toxic or criteria air pollutants, should one occur, and thus limiting credits to GHG emission reduction modifications that do not result in <u>any</u> net increase of these pollutants is at best redundant and at worst unnecessarily restricts crediting when sufficient controls on increases are already in place.

For example, pursuant to California Health & Safety Code 39666, California has already adopted airborne toxic control measures to reduce toxic air contaminant emissions from non-vehicular sources such as refineries. Generally, refineries are also subject to Clean Air Act requirements, including permitting, which mandate that their emissions of criteria pollutants remain below a particular emission limitation. *See* 42 U.S.C. 7661c(a).

LCFS 40-42 cont.

Increases of toxic and criteria air pollutants are already sufficiently regulated. ARB's requirement that refinery investment credits only be given when there is no net increase of criteria or toxic air pollutants is unnecessary and should be removed from the regulations.

Finally, this limitation is inequitable. There is no effort by ARB to address contemporaneous criteria and toxic emission impacts for any of the other credit generating parties in the regulation. Is this being addressed for innovative crude projects or modifications at alternative fuel facilities for improving their fuel pathway CI? Is this addressed for the construction of natural gas fueling stations or for receptors near the power plants that generate the electricity for new charging stations?

WSPA therefore requests that, at a minimum, ARB strike proposed section 95489(f)(1)(D) from the proposed regulations. Moreover, we ask that ARB eliminate the capital project requirement, any distinction based on historic refinery efficiency, and the complexity of a CI based on metric and references to petroleum products consistent with prior WSPA comments.

It is WSPA's position that ARB should make this process simple, allowing the applicant to demonstrate that a project or initiative implemented since 2010 will have a decrease in greenhouse gas emissions after 2016. ARB should also work with the applicant on appropriate, on-going monitoring provisions to ensure that the decrease is real, verifiable, quantifiable and sustainable. Refinements can be made to this process based on the applications submitted, but the complexity of the current proposal presents huge barriers to legitimate, creditable projects.

LCFS 40-42 cont.

Policy/Technical Comments:

Section 95481- Definitions and Acronyms

The following terms are in the definition section, but not used in the rule. They should be removed.

- "Aggregation Indicator"
- "Biodiesel Blend"
- "Biofuel Production Facility"
- "Intermediate calculated value"
- "LRT-CBTS Reporting Deadlines"
- "Petroleum Intermediate"

The following terms are in the definition & acronym section, but not used in the rule. They should be removed.

- "AEZ-EF Model"
- "GTAP" or "GTAP Model"

WSPA recommends the following changes to section 95481 definitions (denoted in red):

"B100" – defined in "Biodiesel – does not need to be defined twice. Recommend either:

LCFS 40-43

- ~~(6) "B100" means biodiesel meeting ASTM D6751-14 (2014) (Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels), which is incorporated herein by reference.~~

OR

- (8) "Biodiesel" means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel meeting all the following:
  - (A) Registered as a motor vehicle fuel or fuel additive under 40 Code of Federal Regulations (CFR) part 79;
  - (B) A mono-alkyl ester;
  - (C) Meets ASTM D6751-08 (2014), ~~Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, which is incorporated herein by reference~~;
  - (D) Intended for use in engines that are designed to run on conventional diesel fuel; and

(E) Derived from nonpetroleum renewable resources.

(11) "Biogas" means the raw methane and carbon dioxide derived from the anaerobic decomposition of organic matter in a landfill or ~~artificial~~ manufactured reactor (digester).

(12) "Bio-CNG" means biogas-derived biomethane which has been compressed to CNG. Bio-CNG has equivalent performance characteristics when compared to fossil CNG.

(13) "Bio-LNG" means biogas-derived biomethane which has been compressed and liquefied into LNG. Bio-LNG has equivalent performance characteristics when compared to fossil LNG.

(14) "Bio-L-CNG" means biogas-derived biomethane which has L-CNG. Bio-L-CNG has equivalent or better performance characteristics than fossil L-CNG.

(15) "Biomass" means …

(17) "Biomethane" is the refined end product when carbon dioxide and the impurities present in biogas are separated from the methane in the mixture, resulting in a product ~~about~~ containing approximately 99 percent methane content….

(69) "Producer" means, with respect to any fuel, the entity that made or prepared the fuel. This definition includes "out-of-state" where the production facility is out of the State of California and the entity has opted into the LCFS ~~production as long as~~ pursuant to section 95483.1.

LCFS 40-43 cont.

(70) "Product Transfer Document (PTD)" means a document or set of documents that authenticate(s) the transfer of ownership of fuel from a regulated party to the recipient of the fuel and convey(s) the specific information required by this regulation.

The above correction to the PTD definition is a typographical correction only. WSPA has additional comments regarding this PTD definition below.

(75) "Reporting Party" means any person who, pursuant to section 95483 or 95483.1 is the initial regulated party holding the compliance obligation, and any person to whom the compliance obligation has been transferred ~~directly or indirectly~~ from the initial upstream regulated party.

The following terms are in the Acronyms section, but not used in the rule. They should be removed.

- "FFV"
- "FOA"
- "FPCOA"
- "GREET" (defined in CA-GREET acronym – duplicative)
- "ILUC"
- "TOER"

Section 95481(a)(3)(B) – recommend the following changes *(denoted in red)*:

Transfer of Oxygenate or Biomass-Based Diesel and Retaining Compliance Obligation. Section 95483(a)(3)(A) notwithstanding, a regulated party transferring ownership of oxygenate or Biomass-Based Diesel may elect to remain the regulated party and retain the LCFS compliance obligation for the transferred oxygenate or Biomass-Based Diesel by providing the recipient at the time of transfer with a product transfer document that prominently states the information specified in 95491(c)(1). LCFS 40-44

Section 95481(a)(5) – incorrect reference *(denoted in red)*:

(5) *Effect of Transfer by a Regulated Party of Oxygenate to be Blended with Gasoline.* Where oxygenate is added to gasoline, the regulated party, with respect to the oxygenate, is initially the producer or importer of the oxygenate. Transfers of the oxygenate are subject to section 95483(a)(1)(C). LCFS 40-45

Section 95481(c)(2 & 3) – incorrect reference *(denoted in red)*:

(2) *Transfer of a Blend of Liquid Alternative Fuel and Gasoline or Diesel Fuel and Compliance Obligation.* Except as provided for in section 95483(a)(4)(C), on each occasion that a person transfers ownership of fuel that falls within section 95483(a)(4) ("alternative liquid fuel blend") … LCFS 40-46

(3) *Transfer of a Blend of Liquid Alternative Fuel and Gasoline or Diesel Fuel and Retaining Compliance Obligation.* Section 95483(a)(4)(B) notwithstanding, …

<u>Section 95482 – Fuels Subject to Regulation</u>
No comments.

<u>Section 95483 – Regulated Parties</u>
Section 95483.2 *Establishing a LCFS Reporting tool Account*

This section contains new regulations and establishes registration requirements, account management roles and duties, and an application submittal deadline. The proposed regulations allow for two Account Administrators (primary and secondary). The proposed regulations do not contain a definition for Account Administrator in the definition section but their responsibilities are defined in this section.

WSPA requests ARB include the definition of "Account Administrator" in the definition section (§95481). LCFS 40-47

<u>Q. Regulated Party Miscellaneous Updates</u>

Section 95483(a)(2)(A) - WSPA does not support inclusion of the requirement for the buyer to notify the seller as to whether a company is a producer or importer. The typical LCFS 40-48 transaction is completed entirely with the seller's paperwork and the only buyer response would be to reject a term. No response implies acceptance after a customary 10-day period. This would create a huge burden on a transaction-by-transaction basis. If ARB is presuming this communication is done verbally, then how is it documented in order to show compliance? If the seller's contract passes the obligation on to the buyer, by default, can it be assumed that the buyer communicated their status to them? Can ARB post entity status on the website and enable this to be the communication tool by directing sellers to the website?

LCFS 40-48 cont.

WSPA does not believe the requirement outlined in the first sentence above is necessary and opposes its addition to the regulation. The addition of the language makes a long, complicated regulation even longer and more complicated.

ARB is adding new language to an existing paragraph (§95483(a)(2)(E)) dealing with the transfer of diesel fuel and adding a new section (§95483(d)(3)) dealing with LNG that is re-gasified and then compressed. Here are WSPA's comments:

Section 95483(a)(2)(E) Regulated Parties for Gasoline and Diesel

ARB is proposing to add explicit and clarifying language to what is already allowed in the existing regulation. ARB has added a proposed definition for "Above the Rack" (§95481(a)(1)) and added new language to an existing paragraph dealing with the obligation transfer. The proposed language states:
"… A person, who is neither a producer nor an importer and who acquires ownership of Diesel Fuel or Diesel Fuel Blends from the regulated party above the rack, may become the regulated party for the Diesel Fuel or Diesel Fuel Blends if, by the time ownership is transferred, the two parties agree by written contract that the person acquiring ownership accepts the LCFS compliance obligation as the regulated party…".

LCFS 40-49

WSPA agrees with staff that any party who acquires ownership of Diesel Fuel or Diesel Fuel Blends above the rack may become the regulated party. However, WSPA does not believe the proposed change to the existing regulatory language is necessary.

Section 95483(e) Regulated Parties for Electricity [Note: WSPA has consolidated our comments on the electric portion of the regulation below]

As WSPA has stated numerous times in the past, we strongly oppose ARB's electricity provisions, and continue to propose that electricity NOT be part of the LCFS program. ARB should account for the GHGs from electricity separately and reduce the compliance obligation within the LCFS proportionally based on ARB's anticipated success of the roll-out of EVs.

LCFS 40-50

The electricity provisions should be eliminated from the LCFS since it is a readily available fuel – in fact ubiquitous. Based on ARB's experience, the innovative market signal hoped for from the LCFS is not needed for this fuel. In fact, ARB is proposing to reduce the incentive funding to EVs based on successful consumer acceptance to date.

The applications for incentive funds are chronically over-subscribed; and moreover, this has all been accomplished without any credit generation revenue from the LCFS. Utility reports to ARB in 2012 and 2013 indicate that no revenue has been derived from credit generation; and yet, ARB is touting the popularity of EVs amongst consumers. Clearly, the LCFS credits have not contributed to consumer acceptance to date and should not be needed in the future.

Barring removal from the regulation, there are key issues related to the electricity provisions that need to be addressed include the following:

LCFS 40-50 cont.

Credit Generation For Pre-LCFS Off-Road Electricity Applications: WSPA is opposed to this provision.

1) It is unclear whether ARB has the statutory authority to allow credit generations from sources that pre-date the LCFS.
   - The off-road sources that will generate credits under this provision were in existence prior to the development or implementation of the LCFS.
   - ARB's own projections in the ISOR Appendix B, Table B-19 show that Electricity usage for HDVs/Rail is expected to remain static between 2016 and 2020.
   - The generation of credits for pre-LCFS electric does not meet the intent of the LCFS. These credits do not:
     - o Reduce transportation fuel CI,
     - o Reduce dependence of petroleum,
     - o Reduce GHG emissions.
1) This proposal creates an un-level playing field.
   - "Rewards" status quo activities by allowing them to generate CI credits.
   - Sales of these credits results in a cross-sector subsidy (transportation fuel sector to the electricity sector)
   - Merely allows ARB to justify an infeasible LCFS reduction target.
     - o For example, the ARB estimates HDV/Rail credits will be range from approximately 35 – 59% of the total electricity credits between 2016 and 2020 (from ARB's illustrative mix of fuels, ISOR Appendix B tables B-18 and B-19).

LCFS 40-51

Removal Of Direct Metering Requirement: WSPA opposes the removal of the direct metering requirement.
1) Its removal creates concerns related to credit validity:
   - Due diligence of credits generated from residential charging of EVs is extremely difficult, if not impossible.
   - There is increased probability of credit invalidation.
   - Credit validity is further eroded by:
     - o The proposed CalETC calculation methodology and,
     - o The removal of supplemental reporting by electricity credit generators.

2) This proposal creates an un-level playing field**:**

LCFS 40-52

- ARB is picking "winners and losers" by allowing electricity providers to bypass the detailed application, reporting, and recordkeeping, and rigor required by providers of liquid fuels.

3) Does ARB have the authority to remove the direct metering requirements?
4) Does ARB have the authority to authorize the sale of credits from estimated fuel usage?
5) ARB should, at a minimum, guarantee the validity of such credits and hold transportation fuel providers harmless in the event the credits are invalidated, including not requiring regulated parties to replace invalidated credits used or purchased for compliance.

LCFS 40-52 cont.

Inclusion of new Heavy Duty EERs

1) WSPA does not support the proposal to allow these sources to generate credits without accurately including them in the 2010 baseline.

2) We do not support the proposed EER values for electric buses, and have provided specific comments below. We are concerned there is not sufficient information to establish EER values for electric buses as proposed.

3) If ARB continues to move forward with the proposed electric bus EER, the application should be limited specifically to new electric buses of the type tested and not be extended to existing electric buses (e.g. cantilever buses) in service prior to the implementation of the LCFS.

More detailed comments related to ARB's electricity provisions are outlined below:

LCFS 40-53

Credit Generation for Off-Road pre-LCFS electricity applications:

In ARB's ISOR for the re-adoption of the LCFS, ARB states:

" Providing an opportunity for credit generation for use of use of electricity as a transportation fuel supports the overall purpose of the LCFS to reduce the carbon intensity of the transportation fuel in California, reduce California's dependence on petroleum, create a lasting market for clean transportation technology, and simulate the production and use of alternative, low-carbon fuels."

WSPA argues that while this may be true for new off-road electricity applications, it is certainly not the case for pre-LCFS electrical installations. In addition, the majority (if not all) of the GHG reductions provided by these sources pre-date the LCFS and will not provide any of the opportunities identified above nor reduce GHGs in the road transport sector.

This provision does not reduce the carbon intensity of transportation fuels, but rather "rewards" status quo activities by allowing them to generate CI credits. In addition, the sale of any such credits results in a cross-sector subsidy from the transportation fuel sector to the electricity sector, with no GHG or transportation fuel CI reductions. The

LCFS 40-54

generation of credits by pre-LCFS electrical installation merely allows ARB to justify an infeasible LCFS reduction target.

Allowance of LCFS credits for electricity used in applications in place prior to 2010 will lead to a smaller reduction in transportation fuel CI and GHGs undermining the stated LCFS objectives. WSPA's position continues to be that we are against including credits for fixed guideway systems and electric forklifts unless they are also properly accounted for in the 2010 baseline. Under no circumstances is it appropriate to make credits available for systems and equipment, such as BART, that have been in operation for decades. If ARB insists on pursuing credits for these off-road sources, credits should only be generated for prospective alternative fuel projects that occurred after LCFS adoption. LCFS 40-54 cont.

Direct Metering: §95491(a)(3)(D)(1)(b):

The proposed rule eliminates the requirement that reporting of electricity dispensed to electric vehicles at residences must be based on direct metering. Instead, staff is proposing to allow the use of a "robust estimation method" developed by CalETC.

We continue to emphasize that credit generators should be held to the same set of standards as liquid fuel providers and not be allowed to estimate the fuel supplied for transportation purposes. Eliminating the direct metering requirements also increases the risk of generating invalid credits, which weakens the integrity of the entire LCFS program. In our opinion the credits obtained through the use of estimates are more suspect than credits generated from actual metered electricity usage.

There is also a fairness issue. Considering the minutia of OPGEE inputs, the level of detail required for liquid fuel reporting and the detail involved with obtaining a CI pathway (and the record-keeping requirements for some pathways) simply allowing estimates of electricity used for residential charging is inconsistent. ARB is picking "winners and losers" by not requiring similar degrees of rigor across the program. LCFS 40-55

Further, because credits must be verifiable, ARB lacks power to require entities to participate in the credit scheme without providing some level of certainty that credits validly represent the reductions they purport to represent. *See* Cal. Health & Safety Code § 38562(d)(1) ["Any regulation adopted by the state board pursuant to this part or Part 5 [market-based compliance mechanisms] shall ensure all of the following: (1) The greenhouse gas emission reductions achieved are real, permanent, quantifiable, ***verifiable***, and enforceable by the state board …"] [emphasis added]. ARB should not remove direct metering requirements, which erode the ability to verify and validate credits, and lacks authority to authorize the sale of credits from estimated fuel usage, which cannot be verifiable under California law.

As regulated parties, we are concerned that any credits generated via estimation techniques are more susceptible to challenges and invalidation. ARB should require measures to increase the validity of credits and not erode the validity. Only verified credits should be allowed in the program. WSPA believes the utilities ought to provide enough incentives through LCFS credit revenue or other incentive programs to maximize the amount of direct metering deployed for charging. We continue to oppose the proposal to allow electricity producers to generate credits from unmetered residential EV charging. LCFS 40-55 cont.

Calculation methodology:

Although staff has posted a letter on the ARB website approving this method (dated April 5, 2012), there are insufficient details for us to adequately review and comment upon the methodology. Based on the limited information available, it appears that the method would assume that vehicles within a service area without direct metering would be used in the same fashion as those that do have direct metering. Closer examination of this approval raises many questions/issues as follows:

- The proposal requires the utilities to report data quarterly for EV charging that is metered. The intention is to use this data as a proxy for unmetered EV charging. What is the extent of the metered data? Will this assessment be done only on a regional utility basis because the driving and utilization patterns might vary from region to region? What is the percentage of the metered data relative to unmetered data? What discussions have occurred about the extent necessary to be statistically relevant? For example – one metered customer should not represent hundreds of unmetered customers in the calculation. Is it ARB's intention to post this data in a de-identified or aggregated manner for public review? LCFS 40-56

- The proposal then allows a utility that does not have the ability to compile and report their direct metered data to use a statewide average of the direct metered data that is submitted. This means that a utility can use a statewide average value for direct metering as a proxy for its direct metering information that will be submitted to ARB, which will in turn be used as a proxy for statewide unmetered charging. An embedded approximation like this for use in a broader approximation is hardly robust. Moreover, will ARB report on which utilities have direct metering data and which do not and why? At a minimum, any utility that lacks any directly metered data should be excluded from the estimation technique and the ability to generate credits. There is no guarantee that the usage patterns in one utility's region will be representative of the usage patterns in another region. LCFS 40-57

- To determine numbers of PEV customers, CalETC will obtain 'zip+4' PEV registration data from a data management firm that accesses DMV data, or data from other sources. First, what are the zip+4 data and will this data be posted on the website? Second, who is the data management firm and what controls do they have to ensure the validity of the data? Are they subject to ARB audit and jurisdiction? If DMV data is not used, what are the other sources? How can the data from these other sources be assured? LCFS 40-58

- Is data separately available for PHEVs and BEVs? What is the average and range of the directly-metered data? It would be important to understand the variation potential that exists to understand the potential error band in the unmetered data. Perhaps some safety factor based on a statistically significant lower range should be incorporated into the credit calculation. LCFS 40-59

- Vehicle owners who go to the trouble of installing a separate meter are likely to plug in more faithfully than those who do not and are therefore not representative of the entire fleet. This is particularly important for PHEV estimates. Are there any data with which to confirm that the results from the metered fleet can be extrapolated to the unmetered fleet? LCFS 40-60

- Is ARB accounting for metering in public and work place setting and adjusting the residential estimates as appropriate? Will ARB review the total credits generated by all EV charging and compare it to the DMV records to ensure charging estimates are not "double counting"? LCFS 40-61

- The data collected on vehicles with direct metering cannot be applied to the entire fleet of BEVs and PHEVs in an area without also confirming that the distribution of vehicles (by BEV/PHEV and by all-electric range) is the same between those with meters and those without. It is highly unlikely that this distribution would be the same. For example, a PHEV with a 10-mile electric range that was purchased primarily for carpool lane access would likely be under-represented in the sub-set of vehicles with at-home meters. LCFS 40-62

- How is double-counting of electricity usage prevented? If at-home charging for those vehicles without a separate EV meter is accounted for with this method, is it assumed that all of the public charging stations get full credit for that electricity? What if a vehicle owner only charges at public or work-based charging stations and rarely charges at home? Is that vehicle assigned home-based charging at the same rate as those vehicles with at-home meters? LCFS 40-63

Excluding Supplemental Information:

ARB is proposing to exclude some supplemental information now required in annual reporting. WSPA disagrees with this, particularly the exclusion of the number of EVs operating in a service territory. Without this basic piece of information, ARB will not able to cross-check reported electricity usage by EVs for reasonableness.

In fact, we suggest that the reporting requirements be enhanced to include not only the number of EVs in a service territory, but also the number of plug-in vehicles in various categories (i.e., pure electric vs. plug-in hybrids by range). LCFS 40-64

It is important to distinguish between pure battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV); and within each of those categories, identifying the distribution of vehicles by electric range. For example, data collected by the Idaho

National Laboratory on in-use driving patterns for the Chevrolet Volt and Nissan Leaf can be found at: http://avt.inl.gov/evproject.shtml#.

Dividing the all-electric miles by the number of vehicles reported at that website gives quarterly VMT per vehicle for Oct-Dec 2013. The BEV Leaf (~6000 miles per year if 4Q2013 numbers are forecast to a full year) is accumulating fewer miles on electricity than the PHEV Volt (~8000 miles per year).[1] Clearly, the limited range of the Leaf is resulting in much lower VMT than a typical new car, while the broader utility of the Volt results in greater overall usage and higher VMT on electricity. However, PHEVs with lower range would have fewer miles on electricity, while BEVs with greater range would likely have more miles on electricity. These results reinforce the importance of understanding the make-up of the plug-in fleet in a particular area to generate an accurate estimate of on-road electricity usage. In addition, it is important to continue monitoring recharging and electricity usage of these vehicles as the patterns of usage may change as the vehicles expand beyond "first adopters." LCFS 40-64 cont.

WSPA opposes the proposal to remove the Supplemental Information from electricity providers reporting obligations, including accounting of credits generated, sold, and banked and accounting of number of EVs known to be operating in the service territory.

While WSPA recognizes the confidential nature of credit generation in the LCFS, if electricity credits are based on estimated electricity usage rather than direct metering, the public has a right to know precisely how those estimates were prepared and the number of credits generated as a result.

H.D. EERs: §95490 Table 5

Staff has proposed changes to the heavy-duty EV EER based on electric buses operating in California. Similarly, staff has proposed EERs for heavy rail, light rail and trolley buses, and electric forklifts. WSPA cannot comment on these values without reviewing the data upon which they were based. In general, however, we reiterate our concern about allowing these sources to generate credits without accurately including them in the 2010 baseline.

It is unclear whether ARB has adequate information to establish EER values for electric buses as proposed, and recommend that ARB evaluate whether additional testing or other information is needed prior to publication of EER values. We do not support the use of the proposed EER values. LCFS 40-65

Specific concerns that we would like to raise include the following:

1. There is insufficient evidence available to show that the proposed EERs represent actual in service fuel economies.
    a. The test procedure for electric buses is incomplete. Key information such as the measurement of energy consumption is not adequately described to independently repeat the test.

b. The Altoona Bus Test website does not have a published test procedure for electric buses and the test procedure posted on the website is dated 2006.
c. It is not illustrated that the posted 2006 diesel bus testing procedure is applicable to electric buses.
d. In the posted test results and on the Altoona website, there are caveats presented that indicate that the Fuel Economy tests "will not represent actual "in service" fuel economy but will provide comparative data" (see http://www.altoonabustest.com/bus-tests.htm).

LCFS 40-65 cont.

2. Modifications to the testing protocols have the potential to impact test results, making them non-representative of in-service conditions:
   a. Both an acceleration and deceleration profile should be followed during testing – there is the potential for a biased comparison between buses without a set profile.
   b. Modification of the maximum speed during the commuter cycle testing from 55 miles per hour (mph) to 40 mph may not be representative of real world conditions.
   c. A control vehicle should be used in the testing to account for external factors.

We continue to stress that ARB has not given regulated parties adequate time or information to truly evaluate this proposal. Given the concerns raised and the short comment timeframe, we urge ARB to not include the proposed EER values for electric buses. If ARB continues to move forward with this proposal, the application should be limited specifically to new electric buses of the type tested and not be extended to existing electric buses (e.g. cantilever buses) in service prior to the implementation of the LCFS.

LCFS 40-66

Section 95484 – Average CI Requirements

CaRFG Carbon Intensity
WSPA cannot find a reference to the carbon intensity for CaRFG in the regulation. This is important because it is the baseline against which the reductions are determined. In the existing regulation it is part of the look-up table. Neither can we find any documentation detailing how the CI was derived. WSPA requests that it be included in the regulation.

LCFS 40-67

Section 95485 - Demonstrating Compliance

Credit Clearance 95485(c)(1)(B)2 – we continue to have concerns with the credit clearance proposal as summarized below:

- This provision only serves to 'kick the can down the road' and adds additional complexity to an already complex regulation.
- We question whether any parties will pledge credits to the credit clearance market knowing that parties will have more obligation added the following year.
- The proposal to include a 5% interest rate on carried over credits only exacerbates the issues with infeasibility of LCFS targets in later years of the program.

LCFS 40-68

- This option does not address the infeasibility of the LCFS targets.
- It is not clear how ARB developed the $200 / credit price ceiling.
- We have concerns regarding the ability to perform any due diligence on the Credit Clearance Market credits. ARB should, at a minimum, guarantee the validity of such credits and hold transportation fuel providers harmless in the event the credits are invalidated; including not requiring regulated parties to replace invalidated Credit Clearance Market Credits.

Here are some suggested revisions:

WSPA proposes that participation in the CCM be voluntary. In order for ARB to determine whether or not to hold a CCM for a particular year, ARB could issue a "Call For Deficits" similar to the "Call For Credits" described in §95485(c)(3)(A) in order to inform their decision.

LCFS 40-68 cont.

Section §95485(c)(3)(E)(5) – recommend the following additions *(denoted in red)*:

Regulated parties that have pledged credits to sell into the Clearance Market, and have not sold or contractually agreed to sell all their pledged credits, cannot reject an offer to purchase pledged credits at the Maximum Price.

Deficit Carryover (formerly Section 95488(a)(4))
WSPA objects to the removal of the Deficit Carryover provisions in the proposed regulations. There may be planning or operational reasons why a regulated party may wish to carry deficits from one year to the next. We request that this section remain in the regulation as an option for entities not wishing to participate in the CCM.

This would be accomplished by changing Section 95485 Demonstrating Compliance, (c) *Credit Clearance Market*, (1) by adding the following:

"*(D) Deficit Carryover*. Non-withstanding the above, a regulated party may carry over the deficit to the next compliance period, without penalty and without participating in the Credit Clearance Market, if both of the following conditions are met:

(A) The regulated party fully met its annual compliance obligation or participated in the Credit Clearance Market in the previous compliance period; and
(B) The number of credits retired for the current annual compliance period is at least equal to 90 percent of the current annual compliance obligation."

LCFS 40-69

If this change is made the following changes would also be required to the proposed regulatory language:

Section 95485(c)(4) - Add the following to the first paragraph: "unless the party elected to exercise the Deficit Carryover provision.

And for <u>95485(c)(4) (A)</u> change the definition of "total Deficits" to: "total deficits" refers to the sum of all regulated parties' obligations for the compliance year that have not been met pursuant to section 95485(a) <u>or the Deficit Carryover provision</u>; and
Section 95485(c)(4)(B) The LCFS credit balance and the individual entity names should be treated as highly confidential because the release of this information could adversely impact business operations. The release of the LCFS credit balance would provide competitors and other LCFS credit market participants with short or long position knowledge. While that knowledge would enable the credit clearance market to perform as desired, it would allow for manipulation of the normal LCFS credit market. For example, if a party has to purchase a specified pro rata share of LCFS credits in the credit clearance market and is unable to, then the parties who have credits to sell after the credit clearance market is completed would have a financial incentive not to sell until the next credit clearance market and they would be aware of entities' shortfalls. Rather than have positions posted publicly as noted in 95485(c)(4)(B)1. and 2., regulated parties would prefer to have a designated overseer within the California Air Resources Board to bring buyers and sellers together and preserve confidentiality of individual parties positions.

LCFS 40-69 cont.

Section 95485(c)(5) – WSPA understands ARB is proposing to prohibit entities that have a roll-over deficit under the credit clearance approach from transferring/selling credits to another party until the deficit is "paid back." WSPA understands this prohibition is only intended to apply to "separated" credit transactions and not to the transfer of obligation with physical fuel. We are requesting that ARB confirm this in writing.

LCFS 40-70

Section 95486 – Generating & Calculating Deficits & Credits

Section 95486(a)(4)(A) – recommend the following change – to be consistent with existing regulation & §95486(a)(4)(B)(2) *(denoted in red):*

(A) *Extended Credit Acquisition Period.* A regulated party may acquire, via purchase or transfer, additional credits between January 1st and March 31st ("extended period") to be used for meeting the compliance obligation of the year immediately prior to the extended period. Credits acquired for this purpose are defined as "carryback" credits. All carryback credit transfers must be initiated in the LRT-CBTS by March 31st and completed by April ~~15~~30th to be valid for meeting the compliance obligation of the year immediately prior.

LCFS 40-71

Section 95486(a)(4)(B)(2) – recommend the following change – to be consistent with existing regulation *(denoted in red):*

The additional credit was generated in a compliance year prior to the extended period.

A regulated party electing to use carryback credits must identify the number and source of credits it desires to use as carryback credits in its annual compliance report submitted to the Executive Officer no later than April 30th of the year in which the additional credits were obtained.

LCFS 40-72

A regulated party electing to use carryback credits must acquire and retire a sufficient amount of carryback and other credits to meet 100 percent of its compliance obligation in the prior compliance year. If sufficient credits are not available, a regulated party must minimize its compliance shortfall by retiring all credits purchased during the extended periods that are eligible to be used as carry back credits. LCFS 40-72 cont.

Section 95486(c) - Credit Generation Frequency. Beginning 2011 and every year afterwards, a regulated party may generate credits quarterly after data are reconciled with its business partner.

WSPA believes that the new proposed language is unworkable in its current form. WSPA supports the goals of staff of accurate reporting, and we support the new reporting provisions requiring an initial report followed by a 45 day reconciliation period. Section 95491 Reporting and Recordkeeping (a)(1)(A) calls for reporting parties to "work in good faith with their counter parties to resolve and fuel transaction discrepancies between the parties". WSPA supports this but notes that this does not ensure that there will not be any discrepancies between reporting parties. To be consistent with section 95491, WSPA believes the language of 85486 (c) should be modified to state: LCFS 40-73

(c) Credit Generation Frequency. Beginning 2011 and every year afterwards, a regulated party may generate credits quarterly after its quarterly report has been filed and it has made a good faith effort to ~~after data are~~ reconcile~~d~~ its data with its business partner

Section 95487 – Enhancements to LCFS Credit Provisions

WSPA agrees with the required use of the LRT for initiating and completing all credit transfers. However, WSPA questions whether ARB has a contingency plan for any prolonged outages that the system may experience. It may be appropriate to include a provision empowering ARB to put a temporary manual transaction process in place under such circumstances. LCFS 40-74

Section 95488 - Obtaining and Using Fuel Pathways

(a*)* Applicability-(page 51 – 52 of Appendix A)
Item (1)
WSPA is concerned about the short timeframe for parties to register and obtain a fuel pathway certification for those pathways that do not meet the requirements of 95488 (a)(1) given the two step board adoption process and the possibility of one or more 15-day packages. WSPA suggests a sunset date of one year after the effective date of the LCFS Re-Adoption regulations for **all** fuel pathways. LCFS 40-75

This can be accomplished by deleting the last sentence of the first paragraph 95488 (a) and the following paragraphs (1), (1)(A), (1)(B), (1)(C); and the following to the first paragraph in 95488 (a):

A fuel pathway certification or a registered fuel provider's use of a fuel pathway that was approved under the provisions of the previous LCFS regulation order may remain valid for as long as one year after the effective date of this subsection, and then shall be automatically deactivated.
Item (2)
For clarification purposes, assuming staff makes the above change, WSPA suggests the following phrase "both with approved physical pathways and those with physical pathways pending" be inserted into the revised first sentence of 95488 (a) ~~(1)~~ so it reads as follows: LCFS 40-75 cont.

A fuel pathway certification or a registered fuel provider's use of a fuel pathway both with approved physical pathways and those with physical pathways pending, that was approved under the provisions of the previous LCFS regulation order may remain valid for as long as one year after the effective date of this subsection, and shall then be automatically deactivated.

WSPA believes the above proposed change is consistent with the language in this subsection which uses the terms "in effect", "registered", and "certified"; but does not specifically address the initial demonstration of physical pathway.

(c) Specific Requirements and Procedures.
Item (4)
For increased transparency and because it is used to calculate the CI of denatured ethanol and the CI of CARFG for the 2010 standard, WSPA believes the regulations should contain a specific reference to the California Reformulated Gasoline and Ethanol Denaturant Calculator spreadsheet. LCFS 40-76

This can be accomplished by adding a new paragraph (o) after paragraph 95488 (c) (1) (N) that reads as follows:

(N) A copy of the California Reformulated Gasoline and Ethanol Denaturant Calculator spreadsheet showing the anhydrous and denatured ethanol CI values if the pathway is for ethanol.

California Reformulated Gasoline and Ethanol Denaturant Calculator spreadsheet
Item (5)

WSPA recommends that several changes be made to the spreadsheet that staff has posted that is used to calculate the Carbon Intensity (CI) of CARFG and the incremental CI value that parties are directed to add to their CA-GREET 2.0 Pathway CI Result to account for the denaturant added to anhydrous ethanol. LCFS 40-77

Cell C13 (Line C) should be corrected to contain the correct updated ILUC value for corn ethanol. The proposed new value is 19.8g CO_2e/MJ. Cell C13 currently has a value of

20.00g CO_2e/MJ. The proposed CaRFG baseline number and the 2016+ standards in section 95484 should be updated to reflect this change. LCFS 40-77 cont.

WSPA believes staff is incorrectly characterizing the content of denatured ethanol based on the fuel specification rather than actual industry practice. The denatured ethanol standard allows up to 2.5 vol% denaturant, 1% water, 0.5% methanol and 1.4% other. Ethanol produced at ethanol plants does contain some water and methanol plus higher order alcohols. The reference cited in the spreadsheet only cites the current ethanol specification and gives no justification for treating the water, methanol, and other (which are higher order bio-alcohols) as CARBOB for the CI calculation.

Ethanol producers do not add more than 2.5% denaturant because exceeding this amount would result in having to assign less than 1 RIN per gallon of denatured ethanol (per EPA regulations) and ethanol buyers expect each gallon of ethanol to have 1 RIN attached to it. Thus WSPA agrees that 2.5 vol% should be used for the percent denaturant.

Ethanol producers also typically add water to ethanol up to the 1% standard. This water has no Carbon Intensity (CI) since it is not petroleum based. Theoretically, staff should divide the calculated ethanol vol% of anhydrous ethanol by .99 to account for this.

Ethanol producers do not add anything else to the ethanol. Any methanol contained should be treated as a biofuel (which it is) and not assigned a CI of CARBOB by subtracting the methanol content when calculating the ethanol content of denatured ethanol. The goal is to calculate the biofuel content. The “other” compounds are higher order alcohols which should also be treated as biofuels and not as CARBOB. Their energy content is greater than ethanol which makes up for the lower energy content of methanol. To not over calculate the CI of denatured ethanol staff should set the ethanol content at 96.5% (100% - 2.5% - 1%) or 97.47% (100% - 2.5% - 1%)/0.99 if staff elects to back out the water. Commercial denatured ethanol contains above 96% ethanol if not 97%. LCFS 40-78

To make the changes Cell C33 Line N should be changed to 9.698250% (10.05% times 96.5%). In addition, Cell C49 Line Y should be changed to 96.5% and Cell C50 Line Z should be changed to 3.5% (100% - 96.5%).

Making these changes including the iLUC correction will change the value of CaRFG from 98.18 to 98.14gCO_2e/MJ. More importantly, it will change the 2010 denatured minus anhydrous value Cell 55 to 1.15gCO_2e/MJ from the incorrect high value of 1.78.

Making these changes will also correct the calculated CI impact of denaturant in Cell C62 Line HH which ethanol producers have to use in calculating their new CI values per section 95488 or the regulations. For a 60 CI anhydrous ethanol the denaturant value to add would now be the correct value of 2.03gCO_2/MJ versus the high value (when treating the methanol and other higher order alcohols as CARBOB) of 3.15gCO_2/MJ. This is a decline of 1.12gCO_2/MJ which is significant. If fact, the proposed regulations in this section at 95488(c)(4)(G)(2) Substantiality Requirements, consider 1.0 gCO2e/MJ to be a significant threshold for applying for a new pathway. LCFS 40-78 cont.

Item (6)
WSPA believes that the inclusion of regulated parties reporting CI's in addition to fuel producers, in section 95488(c)(6) *Relationship of Pathway Carbon Intensities to Units of Fuel Sold in California,* is unworkable. Regulated parties that are not fuel producers cannot reasonably be held responsible for the producer's assignment of a CI value. Nor should they be required to determine that the actual CI of the fuel is equal to or less that the CI value reported. This paragraph should just refer to fuel producers. LCFS 40-79

This can be fixed by changing the two references of "regulated parties" to "fuel producers" in paragraph 95488(c)(6)(A).

Evidence of Fuel Transport Mode- (page 84 – 87 of Appendix A)
Item (7)
WSPA suggests that all existing and submitted demonstrations of fuel transport modes be grandfathered into the LCFS Re-Adoption regulations. This could be accomplished by adding a statement to this effect to the second paragraph of 95488(e) Evidence of Fuel Transport Mode so it reads as follows:

A regulated party must submit the demonstration of a fuel transport mode to the Executive Officer within 90 days of providing a fuel in California unless an initial demonstration of fuel transport mode was previously submitted and approved for that facility under the provisions of the previous LCFS regulation order. LCFS 40-80

WSPA cannot see any benefit of having alternative fuel providers re-submit their initial or updated demonstrations of fuel transport modes to ARB. The changes in the LCFS Re-Adoption regulations do not have any impact on the validity of previous initial demonstrations of physical pathways under the existing regulations.

Revised Indirect Land Use Change (iLUC) Values

Indirect land use change (iLUC) estimates continue to be a source of uncertainty in the overall lifecycle GHG footprint of biofuels, and significant efforts to refine those estimates[2] have continued since ARB initially included iLUC in the LCFS. Although uncertainty in the estimates remains, WSPA agrees that iLUC effects for biofuel production need to be addressed in the context of the LCFS regulation, consistent with our comments on the 2009 LCFS rulemaking. In principle, the scientific basis for addressing iLUC in the LCFS remains sound, and improvements to methods and models for estimating iLUC values continue to be made.

In our 2009 comments WSPA also supported convening a Work Group with experts on both sides of the debate to ensure a balanced and transparent approach to further work on

[2] See, for example, proceedings from Coordinating Research Council workshops on life cycle analysis of biofuels/ transportation fuels held in 2009, 2011, and 2013 at http://www.crcao.com/workshops/index.html.

the issue. We applaud ARB for facilitating that effort, as well as the work group participants who devoted considerable time and energy to better define the issues around indirect effects. Although disagreements remained among experts about some key elements of the iLUC calculations (e.g., time accounting), there were other areas of agreement and recommended GTAP model improvements that have been incorporated by Purdue University and ARB (e.g., improved treatment of co-products for corn ethanol and soy biodiesel).

The detailed analysis of revised iLUC values is summarized in Appendix I of the ISOR. We have the following comments and questions on that analysis and the ensuing results.

1. A comparison of the current regulatory iLUC values and the proposed iLUC values is shown in the table below. Also shown are values presented at the November 20, 2014, workshop.

Comparison of Current and Proposed iLUC Values (gCO2e/MJ)			
Fuel Pathway	**Current Value (2009 Regulation)**	**Proposed Value (December 2014 ISOR)**	**November 2014 Workshop[3]**
Corn Ethanol	30	19.8	20.0
Sugarcane Ethanol	46	11.8	19.6
Soy Biodiesel	62	29.1	27.0
Canola Biodiesel	n/a	14.5	14.5
Sorghum Ethanol	n/a	19.4	12.7
Palm Biodiesel	n/a	71.4	46.4

Given the significant changes to both the GTAP model, which estimates the location and amount of land use change for a particular biofuel pathway and a given volume "shock," as well as the emission factors applied to the land use change (via the AEZ-EF model), it would be useful for ARB staff to identify how much of the ILUC changes in the table above are associated with GTAP model revisions versus emission factor revisions. Additionally, what is the basis for the changes between the November 2014 workshop and the December 2014 release of the ISOR?

LCFS 40-81

2. It appears CARB is making a procedural change in how they plan to address iLUC. In the current regulation, iLUC values are part of the regulation (they are specified in the look-up tables). In the proposed regulation, the only mention of iLUC values is in §95486(b)(3)(B) which describes the credit calculation. The calculation requires incorporation of "a land use modifier (if applicable)" but those values are not found in the regulation.

LCFS 40-82

[3] See http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/112014presentation.pdf

This opens the door to changes to key formulas outside of the rulemaking process and without opportunity for public comment. When regulations are amended, the California Administrative Procedure Act requires "basic minimum procedural requirements" for rulemaking, including giving interested parties an opportunity to comment on the rulemaking, and a response to public comments. *See Tidewater Marine Western, Inc. v. Bradshaw* (1996) 14 Cal.4th 557, 558; Cal. Gov. Code § 11346. But the proposed regulations attempt to avoid public discourse on potentially significant changes to the implementation of the LCFS by tying key values that are the rule's backbone to calculations and data that could change at any time, with no explanation—essentially a *de facto* amendment of the regulation with no public process.

ARB must provide more certainty that key values and calculations will not change without public input. A possible remedy would be to add a table of iLUC values to the regulation.

LCFS 40-82 cont.

3. Table I-1 of Appendix I summarizes the "shocks" used in GTAP to model iLUC emissions. For sugarcane ethanol, the table appears to indicate that 3 billion gallons of Brazilian production and 1 billion gallons of U.S. production were assumed. Is this a correct interpretation of the table, or do those volumes reflect the volumes consumed in Brazil and the U.S.? If the former interpretation is correct, what is the basis for these estimates, as we are not aware of large volumes of sugarcane ethanol being produced in the U.S.? What is the sensitivity of the model to changes in the split between Brazilian production and U.S. production?

LCFS 40-83

4. The proposed iLUC values are based on an average of 30 model runs which used 5 different values for the yield-price elasticity, 2 sets of values for a yield adjustment for the cropland pasture land category, and 3 sets of values for the elasticity of crop yields with respect to area expansion (5 X 2 X 3 = 30 runs). ARB also prepared a Monte Carlo uncertainty analysis that consisted of up to 1,000 model runs for some pathways. Why were the means of the 30 discrete scenarios used to establish the iLUC values rather than the means of the Monte Carlo simulations?

LCFS 40-84

5. As noted above, one of the parameters that was varied to establish the 30 model runs for the iLUC analysis was a yield adjustment for the cropland pasture land category, which is a new land category in the GTAP model relative to the 2009 analysis. This yield adjustment is intended to account for potential investments to increase the productivity of this land as it is brought into crop production. The discussion on page I-12 of Appendix I indicates:

> "However, Purdue researchers acknowledge that although they believe the effect is real, there is no empirical basis for the elasticity parameter proposed for this endogenous yield adjustment. In the absence of

LCFS 40-85

> empirical evidence to estimate this parameter, staff used two sets of values for the runs employed for each biofuel analyzed here."

Given the lack of empirical data with which to estimate this parameter, what was the basis for the elasticities used in the analysis?

LCFS 40-85 cont.

6. Land use change effects for cellulosic ethanol are discussed beginning on page I-18 of Appendix I. The discussion indicates that a value of 18gCO2e/MJ is proposed for cellulosic feedstocks, and that staff is continuing to work on model inputs for cellulosic ethanol from non-food crops and waste. The discussion further indicates that results will be published when the analysis is complete. Will an updated iLUC value be proposed for cellulosic ethanol via a 15-day change notice as part of the current rulemaking, or does staff envision another avenue to formalize this value? In what timeframe does staff expect to have an updated iLUC value for cellulosic feedstocks? Is the 18 gCO2e/MJ value only for farmed trees, miscanthus, and other purpose-grown cellulosic feedstocks, i.e., would waste products used for cellulosic ethanol feedstocks be assigned a land use change value of zero?

LCFS 40-86

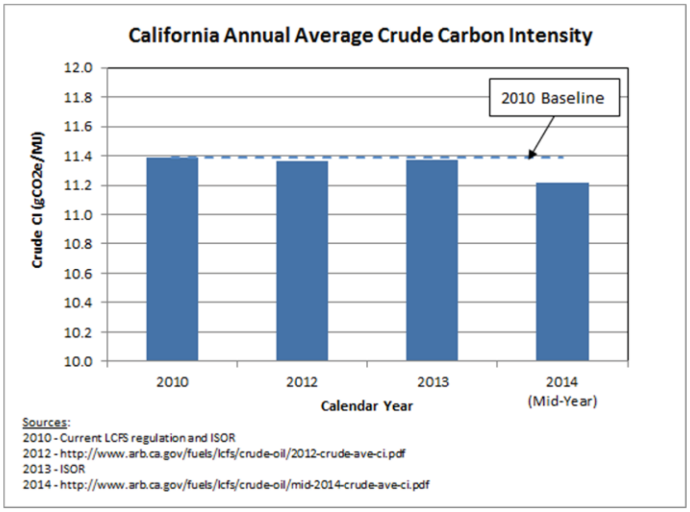
Section 95489- Provisions for Petroleum-Based Fuels

Section (a) – General - Annual Crude CI Calculation

WSPA comprehends ARB's desire to continually improve the accuracy of LCFS data inputs, and recognizes the approach taken by staff in attempting to refine the crude handling provisions as part of the re-adoption rulemaking is consistent with that principle. However, we also believe that the degree of crude differentiation built into LCFS, to comprehend concerns over CA crude CI increasing over time, remains unnecessarily excessive and should be reduced. Our reasoning is as follows:

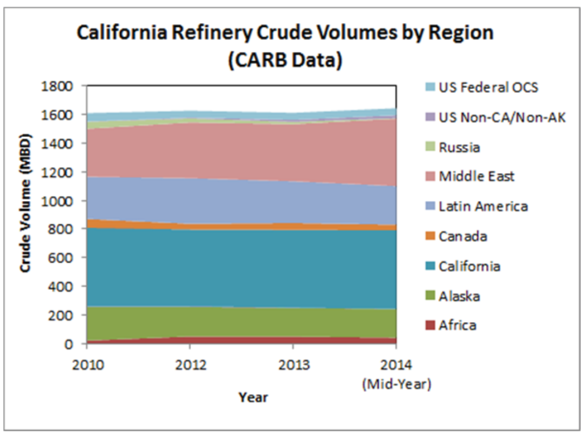
- The fundamental reason for these provisions in the rule was to ensure that the Average carbon intensity of the California crude slate did not increase over time. The available crude breakdown data for recent years (2011-2013) suggests that this threat has never materialized and that the CA crude average CI has remained relatively stable (see plot below).

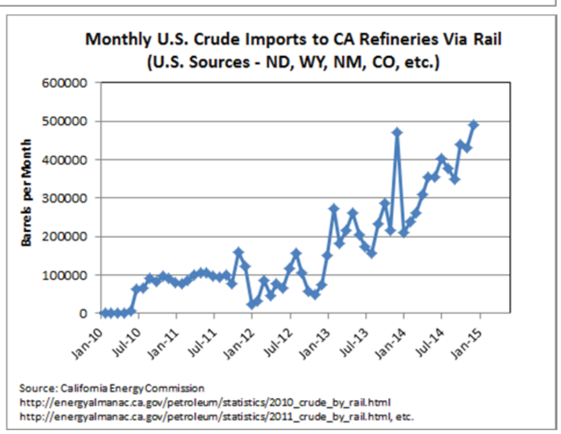
LCFS 40-87



Moreover, ARB data on crude volumes run in California Refineries show a decreasing trend in heavier Canadian crudes, while light Middle Eastern and U.S. mid-continent crudes ("U.S. Non-CA/Non-AK" in the figure below) have trended upwards. Furthermore, CEC data on U.S. mid-continent crude imports by rail show strong growth over the past three years that has continued through the second half of 2014.

LCFS 40-87 cont.





50

- As a result, we believe that the justification drivers for installing, maintaining and expanding the current LCFS crude differentiation provisions have been greatly diminished since these provisions were implemented.
- Even if ongoing monitoring is necessary to ensure that staff's concerns that a heavier crude CI outlook does not materialize, the worst case scenario (i.e., exporting heavy California crude to maintain a constant annual average crude CI) yields no tangible greenhouse gas reduction benefits from a global standpoint. California's average crude CI may well remain constant, but global GHG emissions are likely to increase as the GHG emissions associated with transporting the crude exported from California (to non-optimal refining centers for processing) will be higher.
- The ongoing staff effort to maintain and improve crude differentiation inputs and modeling tools in the LCFS is resource-intensive for the ARB and equally burdensome for our industry in terms of the recordkeeping and reporting requirements it entails. In the absence of a valid GHG justification for engaging in such a complex crude differentiation and tracking scheme, we believe staff should be moving in the opposite direction than they have been following, i.e., one of simplification and streamlining.

LCFS 40-87 cont.

WSPA understands staff does not propose a fundamental change in the California Crude Average approach as part of this re-adoption package. We support staff's decision not to proceed with Refinery-Specific Crude Accounting for large, complex refineries and understand the rationale offered for doing so. We agree that there is no practical alternative to facilitate detailed individual crude breakdown in the pipeline crude blends that comprise a large part of refinery crude inputs in the state. We look forward to working with staff in the near future to examine potential options to modify the crude differentiation requirements in LCFS (post re-adoption), toward a less complex alternative that can hopefully satisfy staff's desire to track crude CI trends over time while reducing the compliance burden on our industry.

LCFS 40-88

We note the proposed changes in the methodology for calculating the CA crude average to rely on CA on-shore crude production data (supplied by The Department of Conservation- DOC) and off-shore data (supplied by The Bureau of Safety and Environmental Enforcement- BSEE). This is in lieu of refinery-reported crude volumes that have been used for this purpose up to this point. Staff's rationale is simply that this is essential to improve the accuracy of the crude volumes used in the calculation of the CA Annual Crude Average. There is no backup support or analysis of the impact of the proposed changed in calculation methodology. More specifically, staff does not:

- Present data to determine how this change will impact the calculated annual volume averages to date. Staff merely indicates that total refinery-reported volumes for 2012 and 2013 closely match the volumes reported by CA field

LCFS 40-89

operators. We would recommend a more rigorous side-by-side comparison for 2011-2013 using the CA crude volumes estimated/reported by refineries versus the newly proposed utilization of DOC and BSEE data.

- Elaborate on the methodology that will be used to combine the in-state crude data with out-of-state crude volumes imported into California (both U.S. and foreign) to develop the overall annual CA crude average. Furthermore there is no indication that any potential discrepancies with the refinery-reported volumes will be investigated and reconciled.
- Recognize the difficulty that increased CA exports will entail should this methodology be adopted, dismissing such concerns by simply indicating that production volumes will be adjusted for exported crude volumes (should the need arise). Staff believes their proposal will work as long as all CA-produced crude is processed in CA, which is currently the case. However, staff's proposal appears to be short-sighted and inconsistent with the overall crude handling approach in the LCFS which, despite WSPA's input, is designed to drive increased crude exports to prevent CA crude average CI increases. Moreover, the same issues staff outlines in breaking down reported volumes of typical CA pipeline crude blends currently will be in play if/when staff tries to back out exported crude volumes out of the calculated CA annual average.

LCFS 40-89 cont.

Many inputs are required to run the OPGEE model for a specific oil field and in particular for California fields, a number of important parameters, such as water-oil ratio, steam-oil ratio, and production volumes are available or are calculated from data published by the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources. We encourage ARB staff to revise the OPGEE modeling to reflect actual realistic input values, such as for the steam generator feed water temperature, and we will work with ARB staff to provide more specific data on this and other model inputs for California crudes. ARB should pursue collecting the same composition, quality, and environmental profile details for other domestic and worldwide crudes as transparency and comprehensive, reliable, comparable data is critical to making effective and sustainable decisions.

LCFS 40-90

Section (c) Addition of Incremental Deficits that Result from Increases in the Carbon Intensity of Crude Oil to a Regulated Party's Compliance Obligation (page 96 – 97 of Appendix A)

Item (1)
95489(c)(3)(B)
WSPA is concerned about the long lag time between the submittal of quarterly crude receipt data to ARB and the regulatory requirement of posting the prior year's Annual Crude Average carbon intensity calculation at the LCFS web site. WSPA requests that in order to facilitate obligated parties compliance planning and execution that ARB be required by the regulations to also post a quarterly Crude Average compliance calculation within 15 days of receiving the 1st, 2nd, and 3rd Quarter Compliance reports. This requirement should be added to paragraph (B) of 95489(c)(3).

LCFS 40-91

Item (2)

95489(c)(3)(C)
The LCFS Regulations have been in a constant state of change since they were adopted by the board. WSPA believes that this uncertainty has and could continue to result in increased LCFS credit prices, compliance issues and difficulty in meeting the goals of the LCFS program. WSPA believes that a three-year cycle for not just updating Table 8 but of the LCFS regulations will have little benefit and add uncertainty to the program. WSPA suggests all LCFS regulatory revisions occur no more frequent than once every 5 years. This should not preclude CARB from adding new crudes to Table 8 on an annual basis. However, overall revisions to Table 8 or the OPGEE model should occur no more frequent than once every 5 years. LCFS 40-92

Section (d) – Credits for Crudes Using Innovative Methods

WSPA notes the revisions to the innovative crude provision, which help resolve several issues with the original provision that rendered it unworkable and thereby inhibited the use of these low-carbon production methods.

Most importantly, reducing the minimum threshold for carbon intensity reduction from 1.0 g/MJ to 0.1 g/MJ, or alternatively achieving annual emissions reductions of 5,000 MTCO2e or more, removes an impossibly high hurdle and might allow for a number of projects to receive approval. Allowing the producer to opt in as a regulated party and generate the credits rather than the refiner generating the credits provides the producer with a stronger incentive than the current regulation to apply to the Executive Officer for approval of the method. WSPA supports replacing the complex formula for calculating credits with default calculations as it will also aid applicants. Finally, WSPA supports the addition of solar and wind electrical power generation and solar heat generation as allowable innovative methods, as this could result in more successful applicants and therefore more available credits for regulated parties. LCFS 40-93

However, WSPA takes issue with limiting CCS as an innovative method to those instances where the carbon capture occurs onsite at the crude oil production facilities. CCS has the potential to generate a substantial number of credits under this provision, but many projects (and proposed projects) involve capturing carbon such as from power generation or other industrial emission streams not at the same physical site where the crude is extracted. This could seriously limit the potential of CCS under this provision and in general and stem the flow of much-needed credits. The capture of CO2 from a steam generator or other equipment at the oil production is desirable, but the overall cost of actual capture, sufficient volume, gathering and clean-up to a CO2 purity to allow for miscible injection and recovery at a reasonable economic scale is prohibitive in/through CCS as compared to capture from other large CO2 emission sources. LCFS 40-94

WSPA also objects to Section 95489 (d)(1)(B), which proposes that credit generation for CCS projects will only be allowed through the use of a Board-approved quantification methodology including monitoring, reporting, verification, and permanence requirements associated with the carbon storage method being proposed for the innovative method." Since applicants are required to be approved by the Executive Officer, WSPA proposes LCFS 40-95 that quantification methodology for CCS projects should only require the approval of the Executive Officer, not the entire Board. WSPA would also encourage ARB to expedite the process for implementing the quantification methodology in order to incentivize applications under this provision. LCFS 40-96

Moreover, the proposal should include an option for Crude Production companies to apply for this credit for other GHG reduction projects above and beyond the four envisioned by ARB and included in the regulations:

- There are other technologies (e.g. solvent extraction) that may result in reduced energy usage and/or GHG from crude oil production.
- Limiting credits to solar and wind eliminates credits for other renewable energy, such as land fill gas, tidal power, etc.
- We feel the use of renewable electricity transmitted through an electricity grid should be eligible for this credit.
- We oppose the requirement that third parties providing either innovative steam or electricity must be co-applicants, especially given that co-applicants are not able to generate credits under the proposal.
    - Any recordkeeping or regulatory requirement would be more appropriately managed through contractual language between third party providers and crude producers.
    - Such a requirement may dis-incent applications for this credit and the use of the technologies ARB is trying promote. LCFS 41-90

LCFS 40-97

Section (e) - Low Complexity/Low Energy Use (LC/LE) Refinery Provisions.

WSPA opposes the LC/LE Refinery provisions. We continue to believe it is inappropriate for ARB to be picking "winners and losers" among the refiners in the state and to effectively place those who have made the investments necessary to generate the volumes of refined product demanded by the market at a competitive disadvantage as far as LCFS compliance is concerned. LCFS 40-98

We oppose the LC/LE Incremental Deficit proposal, as we have consistently opposed crude differentiation in the LCFS program. If crude slate changes are going to be accounted for, WSPA opposes the treatment of individual refinery carbon intensities and particularly when such treatment is separate from, but additive to the statewide average. LCFS 40-99

In general, WSPA has the following concerns about the LC/LE approach to incremental crude oil CI calculation:

- The options are already overly complex for refiners and importers.
- It continues to differentiate between crudes and disadvantage one over the other.
- It could reward a refinery for past high CI crude use while penalizing a refinery with historically low CI crudes. It is not sensitive to energy security concerns.
- Allowing some refiners to opt-out of the industry-wide average approach creates a bifurcated market and introduces the potential for fraud given the chain of custody for crude and feed stocks is immensely complex and there is no uniform,

LCFS 40-100

verifiable certification scheme. ARB's LCFS regulatory requirements should be fraud resistant. LCFS 40-100

If ARB moves forward with the LC/LE provision, we support the proposal to limit the LC/LE Refinery provisions only to transportation fuels produced from crude oil. However, the proposal as outlined raises some specific concerns:

- We believe the definition of "LE refineries" should be based on the lifecycle carbon intensity of the transportation fuels produced. The current proposed definition is based on total energy used at a refinery, and does not take into account life cycle energy use, e.g. whether the energy used per barrel of transportation fuels ***produced from crude oil*** for the LC/LE refiner is high or low compared to other refiners in the state. A LC/LE refiner that uses more energy per gallon of transportation fuel ***produced from crude oil*** should not be granted special treatment. LCFS 40-101
- In the ISOR ARB states that CARBOB and ULSD produced by LC/LE refiners have a CI that is approximately 5gCO2e/MJ less than the CI of other California refiners. However, it is not clear from the ISOR how ARB calculated the LC/LE refiners transportation fuel CI. LCFS 40-102
- Does the calculation of LC/LE overall CI include the transportation fuels produced from all feedstocks to the LC/LE refineries or the transportation fuels produced from crude oil? If the overall CI used to calculate the 5 gCO2e/MJ "adjustment" includes the processing of feedstocks other than crude oil, WSPA believes ARB should modify the adjustment to only take into account the transportation fuels produced from crude oil. LCFS 40-103
- With respect to Low Complexity-Low Energy Use Refineries seeking CI adjustments for the CARBOB and Diesel production from crude oil in 95489 (e), please explain how the volumes of CARBOB and diesel produced from crude oil versus transmix versus "intermediates" in 95489 (e)(2) are calculated? We request that ARB include a methodology for calculation of these different volumes in the regulation. LCFS 40-104
- In the ISOR, ARB staff stated these credits would only be used for compliance obligation by the LC/LE Refinery generating the credit, and would not be eligible to be sold or traded. However the draft regulation does not include any restrictions on how these credits are treated. The regulatory language should indicate that the sale and/or trade of any credits generated under the Low Complexity-Low Energy Use Refinery provisions is prohibited. LCFS 40-105

Section (e)(1) – incorrect reference *(denoted in red)*:

- To be eligible for the credit and deficit calculations in section 95489(e)(3) and the refinery-specific incremental deficit calculation in section 95489(e)(4), a Low-Complexity/Low-Energy-Use Refinery must meet the criteria in section 95481(a)(55~~7~~) using the following equations: LCFS 40-106

Section (e)(2)(C) – if ARB does not remove the definition of "Petroleum Intermediate" recommend the following *(denoted in red)*: LCFS 40-107

- The volume of CARBOB and diesel produced from Petroleum ~~i~~Intermediate feedstocks; and… LCFS 40-107 cont.

Formatting in the refinery-specific incremental deficit equations listed in 95489 (e)(4)(B) contains very little spacing between the individual portions of the "If" and "And" statements. It would be helpful for clarity if a line was inserted to increase the space between the "If" and "and" equations to avoid any confusion about subscripts in the upper equation versus potential superscripts in the lower equation. LCFS 40-108

Section (f) - Refinery Investment Credit

WSPA recognizes ARB's efforts to allow credit for refinery investments as an element of LCFS GHG reductions. However, the proposed thresholds and restrictions risk eliminating most potential projects for arbitrary reasons. California refineries have a long history of investing in energy efficiency and optimization projects. This history is documented in the ARB energy efficiency summary for the refinery sector (http://www.arb.ca.gov/cc/energyaudits/eeareports/refinery.pdf).

WSPA's consultant, PetroTech Consultants, reviewed a recently-released Promotum report entitled, "California's Low Carbon Fuel Standard: Evaluation of the Potential to Meet & Exceed the Standards" dated February 2, 2105, as well as another NRDC-sponsored TetraTech report, "   PetroTech provided comments that are summarized below on the two referenced report's conclusions which were that ARB's refinery investment credit option has significant credits to contribute to the pool.

A relevant subset of PetroTech's comments are:

<u>*Different base years used*</u> LCFS 40-109

Even though the base year for measuring CI reductions under the LCFS is 2010, the currently proposed regulation uses 2011-2013 refinery energy consumption data as the basis for estimating the CI of the petroleum refining process, not 2010. Furthermore, the regulation limits credit generation only to energy efficiency projects that are ***permitted*** *after December 31, 2014. Credit generation is also limited by ARB to capital projects or those using renewable feedstocks that do not increase criteria or toxic pollutants. Capital projects normally take at least one year to implement. Thus, any energy efficiency improvements that were implemented in petroleum refineries between 2010 and 2016 cannot generate credits even though they have reduced the CI of the products.*

<u>*Potential refinery energy efficiency improvements*</u>

Refiners are in the business of transforming and delivering energy. Refinery energy use for the conversion of crude oil to finished products is their second largest cost behind feedstock (crude oil and blendstocks) acquisition. Energy usage and cost is monitored very closely within each refinery and has been for many years. Converting crude oil to *finished products requires energy. There is a theoretical minimum amount of energy required for the conversion that depends on the quality of the crude oil, product specifications and refinery configuration. More complex refineries generally require more energy to operate.*

Two recent studies commissioned by NRDC, one by Promotum[2] and one by Tetratech[3], have greatly overstated the energy efficiency improvements that are still available to the petroleum refineries in California. Both studies use the same 2013 CARB study of California refinery energy efficiency[4] as a basis. In this CARB study, the 12 largest refineries were required to report their 2009 energy usage as well as past and potential energy efficiency projects. This report stated,

> *"The estimated GHG emission reductions are approximately 2.8 MMTCO2e annually. Approximately half of the GHG emission reductions identified were completed before 2010 and are reflected in the 2009 GHG totals shown in Table IS-1. The other half of the GHG emission reductions are from projects that were completed during or after 2010, scheduled, or under investigation and are not reflected in the 2009 GHG values shown in Table IS-1."*

The total emissions reported in Table IS-1 were 31.4 MMTCO$_2$e per year. 50% of the projects were completed prior to 2010, so the remaining potential reductions for 2010 and beyond would be 1.4 MMTCO$_2$e per year. 80% of the projects were listed as competed or ongoing in the report, so the remaining reductions that could potentially be permitted after 2015 would result in a reduction of about 0.5 MMTCO$_2$e per year. The CARB report goes on to state: LCFS 40-109 cont.

> *"However, implementation of some projects may preclude the implementation of other projects that deal with the same equipment or processes. Therefore, these estimated reductions do not necessarily represent readily achievable on-site emission reductions."*

These identified projects with a total reduction of 2.8 MMTCO$_2$e per year were estimated to cost $2,600 million and result in annual savings of $200 for a simple payback of 14 years or a first year rate of return of about 7.7%. The highest rate of return projects would be implemented first, so the rate of return for the remaining projects would be lower.

The Tetratech report estimates that a 5-10 percent reduction in refinery GHG emissions from 2010 levels (1.6 to 3.2 MMTCO$_2$e per year) is easily attainable by 2020. Even their low estimate is higher than the CARB study estimates as a remaining potential. Tetratech justifies their higher estimate as follows:

> *"We note that these estimates [estimates reported in the CARB study] are likely conservative, given that (1) the information is based on self-audits and (2) the estimates do not include the off-site production of electricity, steam, or hydrogen,*

which is a potential major source of emissions and would be included in a life-cycle assessment."

Regarding item (1) in the Tetratech justification, refineries continuously evaluate their energy use and invest in projects to improve energy efficiency. Most of the refining capacity in California is owned by publicly traded corporations. As such, their stockholders (including many public pension funds) expect a minimum rate of return on their investment. Management's fiduciary responsibility limits potential energy efficiency investment to those that meet the minimum return requirements, but also encourages them to invest in projects with good rates of return. The CARB report does state that some of the identified projects will not be implemented but does not state the reasons. There is no logical reason to assume that potential energy efficiency projects would be underreported.

Regarding item (2), refineries do not purchase any significant amount of steam except from co-located cogeneration facilities which are relatively new and efficient. Total electricity usage (both internally generated and purchased) is only 4% of refinery energy usage as identified in the CARB report. Purchased electricity is at grid average GHG levels, so measureable reductions in GHG emissions through purchased electricity are unlikely. The recently issued CARB report on energy efficiency in hydrogen production concludes that the merchant hydrogen plants in California are relatively new and very efficient. Future potential GHG reductions from merchant hydrogen production are only 1-2% of the energy used to produce hydrogen.

LCFS 40-109 cont.

CO2 capture and storage for hydrogen plants is often quoted as an easily implemented GHG reduction technology for refineries. CO2 capture from hydrogen plants will not further the objectives of the current California LCFS. The California oil deposits are too shallow to benefit from CO2 based enhanced oil recovery techniques. Futhermore, the U.S. DOE has recently stated that widespread use of large scale CO2 storage facilities is not expected to be ready for dissemination until 2030[5]*.*

The Promotum report estimates a potential reduction in refinery GHG emissions of 4.3 MMTCO_2e per year by 2025 (~14% reduction from 2010) primarily based on the added value of the emission credit.

"For refinery energy efficiency (EE) investments, it is assumed that at $100/ton, the incentive is sufficient to more than double the payback of EE, such that a reduction of 1.5% per year improvement in GHG emissions at refineries across the industry. We estimate that reductions from EE investments grow linearly from 2017 to 2025, reaching 4.3 MMT in annual reductions by 2025."

According to the 2013 CARB energy efficiency report, 80% of the potential 2.8 MMT of annual CO2e reductions would have been implemented by now, leaving only 0.5 MMT of potential reduction projects that could be permitted in 2015 or beyond and eligible for the credit. The $100/MT of CO_2 credit is about $50 per barrel of crude. Although this *would change the rate of return for energy efficiency projects, the magnitude of this credit would not be sufficient to "more than double the payback of EE."*

Furthermore, there is no technical basis for Promotum's estimated total potential reduction of 4.3 MMT CO_2e per year. There is a theoretical amount of energy required to refine crude oil into saleable products. Neither the Tetratech nor Promotum studies recognize this fact. They both use arbitrary percentage reductions with no theoretical basis for the values.

Allowing full credits for refinery efficiency improvements implemented since 2010 is consistent with the objectives of the LCFS. As stated in the subject document,

> *"The LCFS is performance-based and fuel-neutral, allowing the market to determine how the carbon intensity of California's transportation fuels will be reduced."*

Refinery efficiency improvements since 2010 have reduced the carbon intensity of fuels produced within California relative to the base year of 2010 and should receive full credits under the program. Furthermore, all future projects, not only those that are permitted in 2015 or later should receive full credits. As highlighted by Promotum, the credits raise the rate of return and will cause more projects to be implemented, although not to the extent estimated by Promotum.

LCFS 40-109 cont.

2. Promontum, California's Low Carbon Fuel Standard: Evaluation of the Potential to Meet and Exceed the Standards. http://docs.nrdc.org/energy/files/ene_15012801a.pdf
3. CARB, "Energy Efficiency and Co-benefits Assessment of Large Industrial Sources, Refinery Sector Public Report," June 6, 2013.
4. U.S. DOE, National Energy Technology Laboratory, "Carbon Storage Technology Program Plan," September 2013., http://www.netl.doe.gov/File%20Library/Research/Coal/carbon-storage/Program-Plan-Carbon-Storage.pdf

Therefore, due to our industry's prior investments, the proposed limitations and restrictions staff has developed for the Refinery Investment Credit option are too high, create arbitrary inequities, or are inconsistent with existing programs and law.

We propose modifying the proposed section to address several of the restrictions and thresholds for the following reasons:

a. Limiting onsite increases of criteria air pollutants and toxics unreasonably excludes offsets of criteria and air toxic pollutants
b. 0.1 gCO2e/MJ threshold is too stringent and unfairly penalizes larger, more efficient refineries
c. Investments should not be limited to capital or onsite projects
d. Eligibility cutoff date does not recognize improvements made since program adoption
e. Biofeedstock 10% threshold is too restrictive and unfairly penalizes larger, more efficient refineries.

Incorporating criteria and air toxic pollutant controls in LCFS is misguided

California's long-standing framework of stringent air quality programs must remain the primary tool to regulate local and regional air pollutants rather than grafting co-pollutant measures or requirements onto the LCFS. The proposed limitation in attempt to address criteria and air toxic emissions is complex, unnecessary, and inequitable:

- Complex – there are volumes of regulations, guidance documents, and court cases related to air quality permitting where various methodologies are employed for determining what constitutes an increase. For example, some of the questions that arise are: Is it only direct emissions from the source or indirect emissions? Should the increase be in terms of mass or concentration at sensitive receptors? What is the baseline for determining an increase? What if there is an increase – but it is still within the permitted limit for that source or facility? How is it enforced after-the- fact – when other non-related changes at the refinery may occur that impact emissions year to year? This is a regulatory quagmire for ARB since any attempt to address or clarify these issues in the regulation could double the size of the regulation and create substantial litigation risk from various parties.

- Unnecessary – the CEQA process and robust air quality permitting processes are more than sufficient to reduce the likelihood of an increase, mitigate any increase, or ensure that the increase is within regulatory limits that are protective of the community and the environment. LCFS 40-110

- Inequitable – there is no effort by ARB to address contemporaneous criteria and toxic emission impacts for any of the other credit generating parties/mechanisms in the LCFS regulation (e.g., innovative crude projects or modifications, alternative fuel facilities applying for fuel pathway CI improvement, construction of natural gas fueling stations, or power plants that generate the electricity for new charging stations).

WSPA asks that ARB eliminate the requirement to address criteria pollutant or toxic emissions. ARB could adopt a monitoring approach similar to the approach in their cap and trade program to satisfy itself that its own non AB 32 air programs are effective. At a minimum, ARB should follow its own air pollution policies which provide refiners with the flexibility to offer mitigations offsetting any potential increase in criteria pollutants or toxics.

CI reduction project threshold of 0.1 gCO2e/MJ will unnecessarily eliminate legitimate projects

The threshold for efficiency projects of 0.1 gCO_2e/MJ is overly restrictive and potentially inequitable. For larger refineries, the absolute quantity of emissions reductions required to qualify a project (i.e., satisfy this threshold) will be larger and thus more difficult to meet. Some refineries may be more efficient (from a carbon intensity standpoint). This LCFS 40-111 restriction may preclude such refiners from making further energy efficiency improvements.

Staff's proposed CI calculation in determining project credit also arbitrarily assigns credits based on product slate rather than GHG reduction. If project CI threshold is calculated based on volume percent of gasoline and diesel produced, a refinery's product slate will affect its ability to receive LCFS credits for energy efficiency projects. For example, if two hypothetical refineries have total emissions of 4 MMT each, but one produces 10% diesel, while the other produces only 5%, the number of tons of emissions reductions necessary to meet the minimum diesel CI target will be different for each refinery (40,000 or 20,000 tons).

Furthermore, the 0.1 gCO_2e/MJ reduction represents a substantially higher hurdle (in terms of absolute quantity of CO_2 reductions required) than is expected for other products' pathways in the regulation. This is due to the substantially larger throughput volumes of petroleum refineries and the fact that many petroleum refineries have already implemented energy efficiency improvements to lower their production CI. As a result, the use of a 0.1 gCO_2e/MJ may prevent refiners from making further reductions and, thusly, disadvantage them versus higher carbon intensity manufacturing processes for other products**.**

WSPA proposes eliminating the threshold altogether. If this is not feasible, an absolute value threshold (e.g. 1000 $MTCO_2e$/year) would incentivize reductions in a more equitable manner. In addition, ARB could also allow bundling of smaller projects to further incentivize energy efficiency where there may not be many large projects available.

LCFS 40-111 cont.

Limitations on project type will eliminate valuable GHG reducing projects

The refinery investment mechanism should recognize non-capital but sustained improvements that reduce GHGs in addition to capital projects and co-processing. Many energy efficiency upgrades are considered non-capital. For example, replacement of equipment such as pumps, compressors, seals and blowers may include upgrades with lower greenhouse gas emissions. Insulation projects also may not be considered a capital project. These upgrades may not be considered capital expenses, and individually have relatively low greenhouse gas emission reductions. However, cumulatively, the cost of upgrades and insulation replacement can be significant, and the emissions reductions can add up. Since additional effort may be needed to upgrade rather than replace equipment "in kind", and to undertake insulation replacement, incentives from the LCFS program could help refineries take these actions.

LCFS 40-112

Project eligibility should extend to early actors and at least to new construction.

The time limitation for eligibility of projects penalizes early actors contrary to AB 32 statutory provisions 38560.5(b)(1) and (3). We suggest that the deadline for project eligibility be based on the start of the LCFS program. At a minimum, WSPA believes

LCFS 40-113

that ARB should allow a refinery greenhouse gas emissions reduction project to be eligible if it is implemented (i.e., started up) after January 1, 2015, regardless of when permits for the project were initially filed. LCFS 40-113 cont.

<u>Ensure that biofeedstock co-processing projects have a chance to qualify</u>

Staff should reconsider and remove the proposed 10% biofeedstock threshold as it is inequitable. Percentage throughput limits are unfair to larger refineries, since the absolute volume of biofeedstock must be larger as facility size increases. We do not understand the basis for this threshold and believe that several potentially viable options would become essentially "non-starters" as a result. LCFS 40-114

Co-processing biofeedstocks is generally practical at far lower than 10% refinery throughput, especially for larger refineries. The proposed high thresholds for co-processing will discourage innovation and reduction in greenhouse gas emissions. WSPA recommends that this threshold be removed or that an absolute threshold (such as 1000 $MTCO_2e$/year) reduction should be used.

<u>Other Comments</u>

1) In the proposed section "95489(f) Refinery Investment Credit, the term "$Volume^{Total}$ *= total volume of product output in bbls (bbl).*" could be problematic to define (e.g., does it include only finished fuels or also refinery intermediates requiring further processing at another location? Are sulfur or butane production included?) WSPA would prefer a simple approach and, as an alternative to a potentially complex definition of refinery "products," WSPA recommends that ARB change the denominator in the term, "T = percentage of transportation fuel produced" *from* "total volume of <u>product output</u>…" to the "total volume of <u>crude oil and intermediates supplied to</u> the refinery (bbl)." LCFS 40-115

2) Currently in 95489(f)(1)(D) it states the refinery must annually replace a minimum of 10% of the fossil based feedstock. The regulation should clarify whether the 10% is based on volume of energy. WSPA would like ARB to provide a comparison of the 10% level to the 0.1g/MJ threshold for other projects. The 10% threshold seems to be a high threshold that will not help encourage such projects. LCFS 40-116

3) ARB should consider an option for CI reduction credits to be allocated more specifically to the units and products to which they apply (versus overall for the refinery). LCFS 40-117

Section 95490 – Requirements for Multimedia Evaluation

Please see the Legal comments section.

Section 95491 - Reporting and Recordkeeping

WSPA notes ARB's addition of the 45-day initial reporting deadline and subsequent 45-day reconciliation period. This will enable more immediate reconciliation of discrepancies between reporting parties.

We do not agree that unclear transmission of information on product transfer documents is a key cause of such discrepancies. The primary drivers for reporting discrepancies to date have been confusion regarding changes to regulatory requirements (particularly the nature and timing of the 2011 program amendments), and a steep learning curve for new regulated parties joining the program. LCFS 40-118

We object to the change proposed to the definition of Product Transfer Document (PTD) to refer to a newly created, single document rather than a collection of documents that transmit the required information. The term "PTD" has been used by several regulatory agencies over the years to refer to any document or documents that recognize a transfer of ownership/custody and includes certain required information. The very general nature of this definition has always been intended to allow flexibility in the execution of compliance and cause minimal disruption to operations. Establishing a narrow definition that requires a single, discrete document causes unnecessary additional cost while adding little or no benefit. LCFS 40-119

In the ISOR, ARB states the original transferor of fuel sold without obligation must report any export of that fuel by any subsequent owner or supplier. However, there is no regulatory language on this item in the draft text presented in Appendix A. Assuming that staff will develop language to reflect their intention in this regard and include it in the final regulation order, we have concerns about the practicality and fairness of this requirement. We find it impractical as it will be very difficult for fuel suppliers to ensure that the ultimate exporter communicates their activities backward through the supply chain. It also puts an unfair compliance burden on the original transferor by potentially taking credits away from that transferor because of another party's decision to export. It is understandable that ARB would want to track the export of such fuels, but the compliance cost/benefit of that export should accrue to the exporter and not to another party who has no control over their decision to export. LCFS 40-120

Section (a)(3) – WSPA does not believe the production facility ID and the Company ID should be included in all transaction documents. In many cases, multiple facilities and companies could produce biofuel with the same CI. Once these fuels are introduced into fungible systems where biofuels of the same CI cannot be distinguished, it should no longer be required to be tracked. This information should be included only for the initial transaction in the state of California (either production or importation), but not in further transactions, as the recordkeeping burden and the potential for mistakes and associated non-compliance penalties outweighs the perceived benefit of tracking this information. LCFS 40-121

Section (a)(7) **-** Provision (7) provides for quarterly and annual report corrections with proper substantiation to ARB, but it does not preclude enforcement. WSPA does not agree with this concept related to quarterly progress reports. Entities should be able to make changes to the quarterly reports with enforcement penalties provided the LCFS 40-122 corrections do not material impact a credit transaction relying on the information submitted in the quarterly report. For example, there could be many, non-substantive changes to what is reported with no impact on credit balance – or perhaps the company does not complete any credit transactions between the completion of the quarterly report and when the correction is made. Promoting corrections to these quarterly progress reports is in ARB's best interest and imposing penalties will inhibit such corrections. LCFS 40-122 cont.

Section 95492 – Enforcement Protocols

Section 95493 - Jurisdiction

Section 95494 - Violations

Section 95495 – Authority to Suspend, Revoke or Modify

Section 95496 – Regulation Review

The proposed regulation includes a regulation review and a presentation to the Board by January 1, 2019. WSPA has several concerns with this section:

- The first concern is that this date is too late to effect change in the program. Since the compliance curve accelerates substantially in the final few years prior to the 2020 goal, it is highly likely there will be problems and issues with the program in this time period that will begin to manifest themselves beforehand. By the time the Board meets during 2019 to discuss the E.O. Review and determine if revisions to the regulation are needed, it will be too late. LCFS 40-123
- There is a substantial gap in time between the recent January 1, 2015 review and the January 1, 2019 review. The historical periodicity of regulation review has been more frequent, and as evidenced by several hearings to date held to make changes to the regulation, these more frequent reviews are needed to make changes to the program in a timely way. LCFS 40-124
- The list of issues that are identified as part of the review have been reduced from 13 items to 8. WSPA requests reinstatement of the items that have been proposed for removal from the review list such as:

  (3) Advances in full, fuel lifecycle assessments;
  (4) Advances in fuels and production technologies, including the feasibility and cost-effectiveness of such advances;
  (6) An assessment of supply availabilities and the rates of commercialization of fuels and vehicles; LCFS 40-125
  (8) The LCFS program's impact on state revenues, consumers, and economic growth;
  (9) An analysis of public health impacts of the LCFS at the state and local level, including the impacts of local infrastructure or fuel production facilities in place or under development to deliver low carbon fuels, using an ARB approved

method of analysis developed in consultation with public health experts from academia and other government agencies; LCFS 40-125 cont.

WSPA requests the ARB Board ask staff to revise the regulation to include the review items that were removed, LCFS 40-126 and importantly, that the former Periodic Reviews be replaced with annual staff reports to the Board that provide a detailed synopsis of the health of the program, the challenges, and any need for program changes. LCFS 40-127

Section 95497 - Severability
No comments.

Appendix 1

Boston Consulting Group's Report – "Revised CARB Low Carbon Fuel Standard (LCFS) Illustrative Compliance Scenario," February 12, 2015

CG
NERGY

WSPA
Western States Petroleum Association

vised CARB Low Carbon Fuel Standard FS) Illustrative Compliance Scenario

ary 12, 2015

THE BOSTON CONSULTING GROUP

tive summary

er as part of its Initial Statement of Reasons (ISOR) for LCFS re-adoption, CARB presented ive LCFS compliance schedule (2016-2020)[1] and forecasted volumes of low-carbon ow-CI) fuels allowing regulated parties to comply through 2020.

believes that these volumes and this schedule are overly optimistic and do not reflect a true "P50" ario. It is more likely that volumes will fall short rather than exceed those predicted by CARB.

falls in any of the fuel pathways would hasten the expected shortage of low-CI fuels and create a ion where there are not enough credits available to regulated parties for compliance

tailed methodology from CARB, this document suggests reasonable volumes of low-CI fuels r when using the CARB compliance schedule

ntent is to consider volumes with competing factors in mind:

- Assume healthy growth rates due to technology advances and potential value of LCFS credits
- Retain some conservatism based on high capital costs, uncertainty regarding vehicle availability, and a poor track record of low-CI fuel production versus expectations

iance schedule suggested by CARB using BCG forecasted volumes results in using all edits by 2020; the year 2020 credit deficit is 10.7 MT.

reduction in the total fuel pool is sustainable[2] by 2020 based on credits available through ow-CI fuels (e.g. renewable diesel, biodiesel) and purchasing credits (e.g., elec., natural gas)

onsiders only the recommended "gradual" compliance scenario recommended by CARB in the ISOR. 2. Slowly using up banked credits up until 2020, and retaining the argeted CI reduction in a given year without relying on credits earned in previous years starting in 2020.
R Appendix B, BCG analysis

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

la

ew

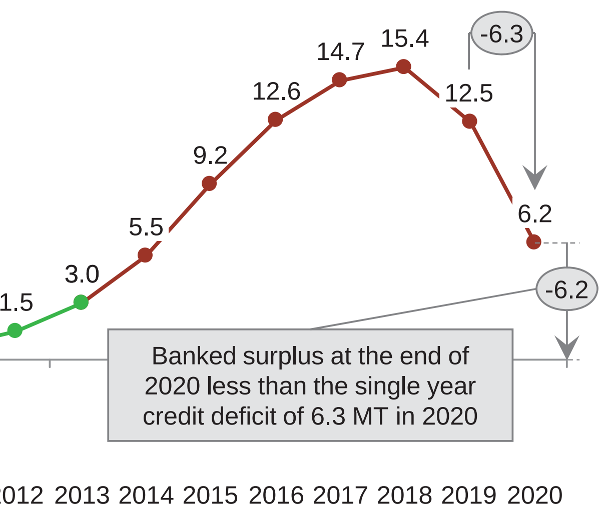
ring BCG and CARB forecasts

ology

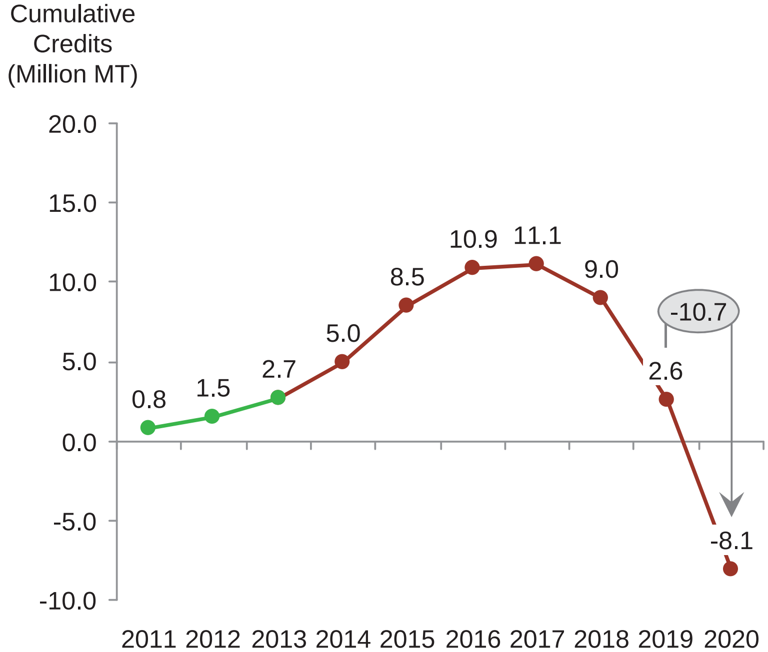
Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

same compliance schedule, BCG forecasts shows d credits being exhausted earlier than CARB

scenarios show banked credits in 20 similar to 2020 annual deficit



BCG scenario shows banked credits gone by 2020, sizable annual deficits starting in 2018



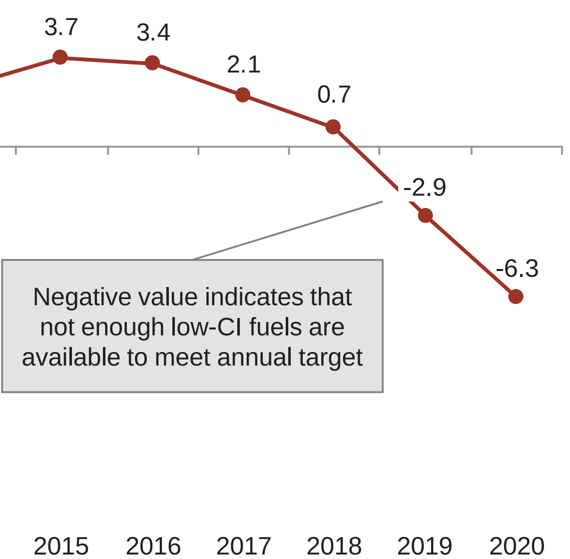
Forecasted   Historical

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

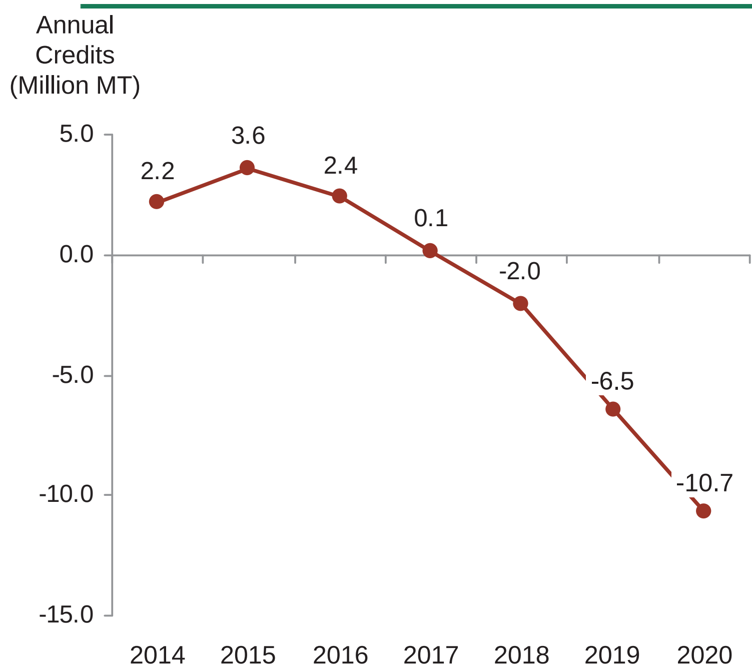
OR Appendix B, BCG analysis

orecasts show 4.4 MT larger deficit[1] in 2020 versus scenario

cenario shows inability to meet rget without banked credits starting in 2019



...while BCG forecasts show even more dramatic annual deficits

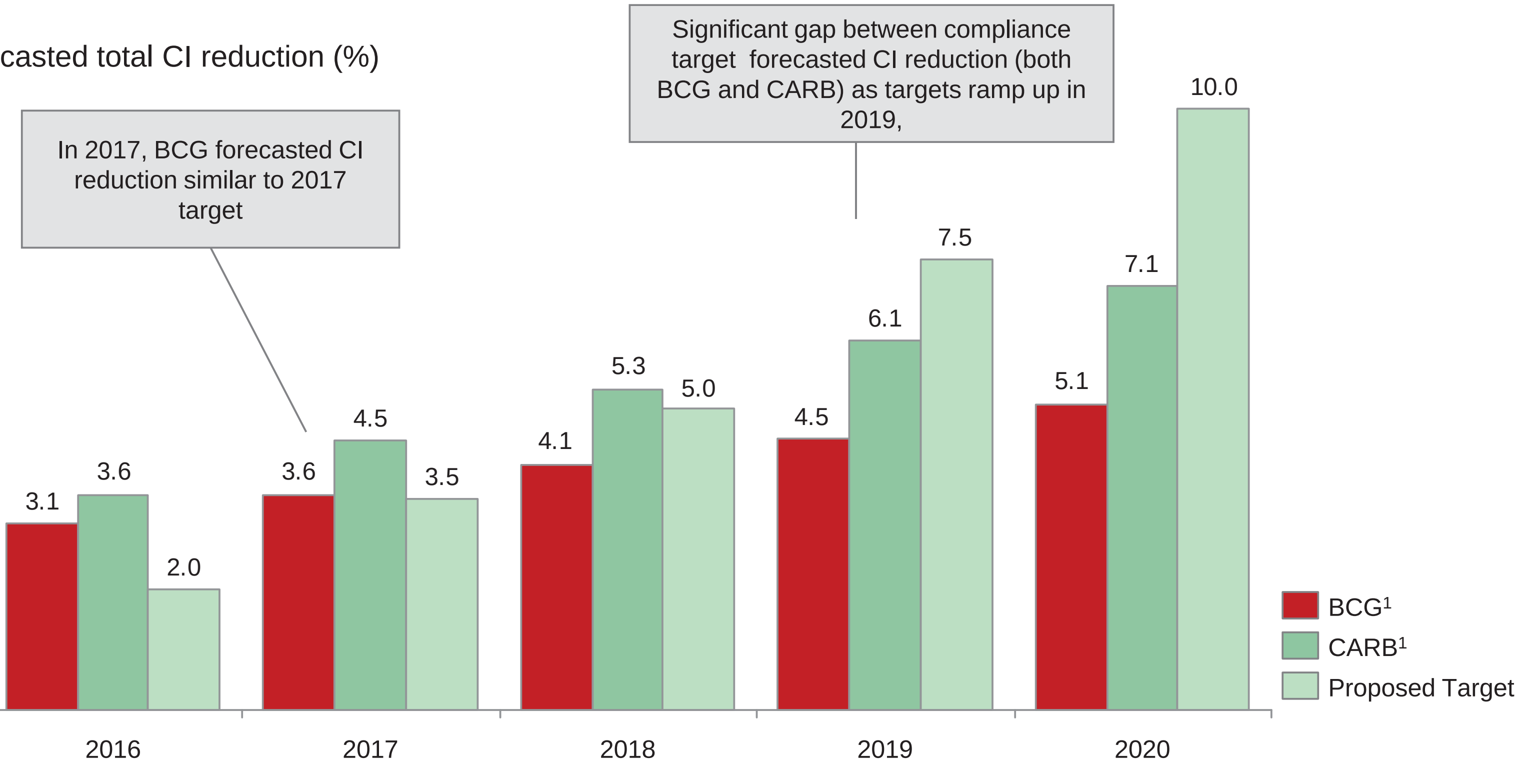


Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

ts generated (from fuels with CIs exceeding target) less credits generated (from fuels lower than CI target) in a given year
DR Appendix B, BCG analysis

scenario results in annual deficits by 2017

casted total CI reduction (%)

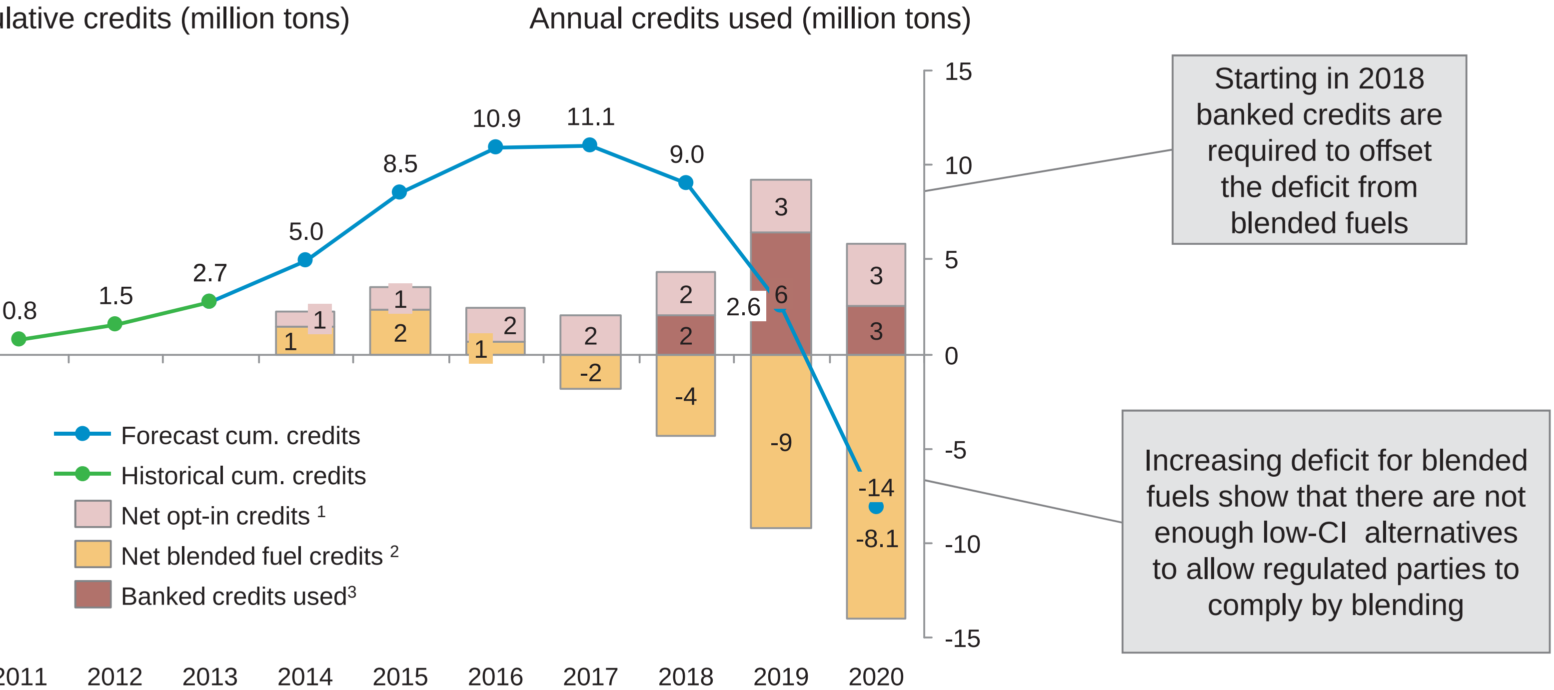


CARB scenarios fall short of CI targets starting in 2019

forecasted CI reductions based on gradual compliance schedule recommended in ISOR Appendix B
OR Appendix B, BCG analysis

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

orecast of compliance outlook relies heavily on d and opt-in[1] credits

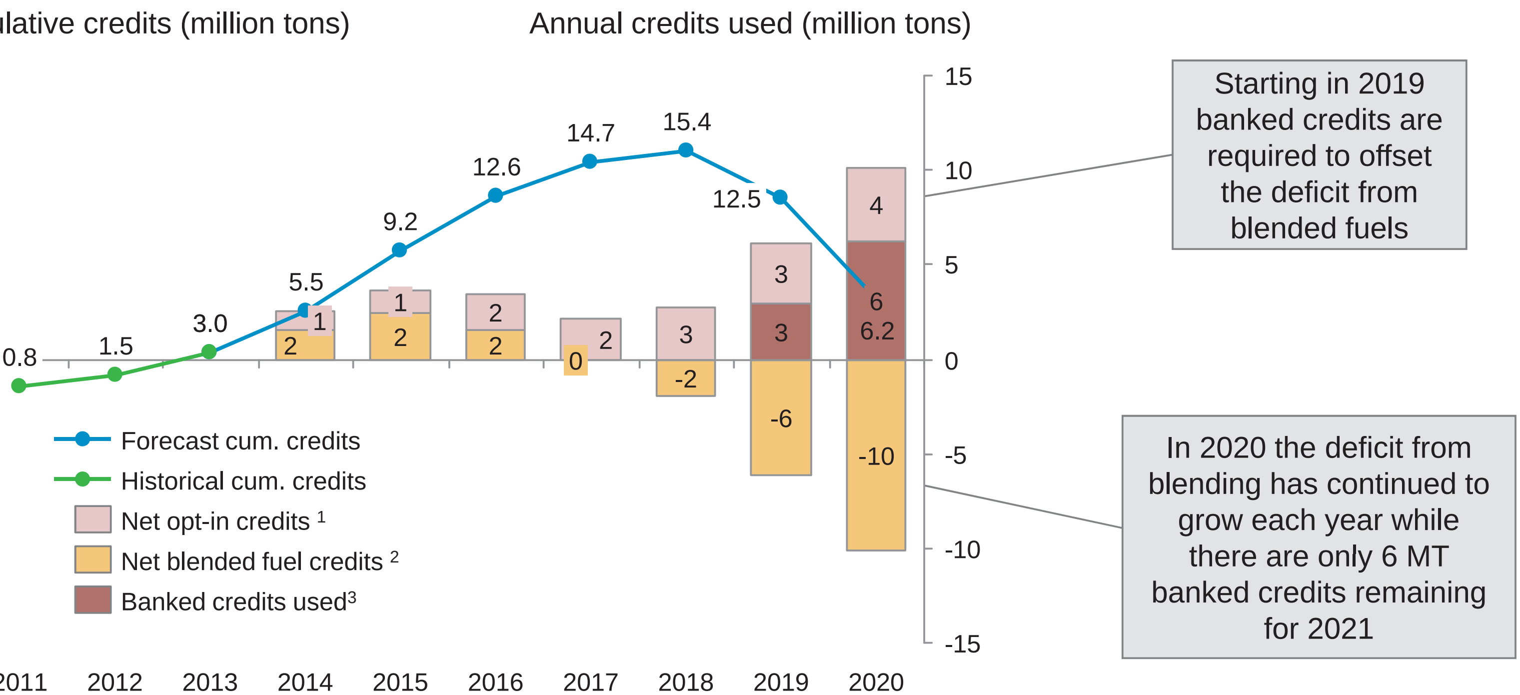


% reduction target	1.0%	1.0%	1.0%	2.0%	3.5%	5.0%	7.5%	10.0%

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

udes natural gas, electricity, and hydrogen 2. Credits minus deficits for blended fuel (e.g. CARBOB, CARB Diesel, ethanol, renew. diesel, biodiesel, etc.)3. Calculated as the the annual deficits and credits generated from all fuels until no banked credits remain (2020 in this example) Assumes that if credits are greater than deficits, credits will be regulated parties to achieve compliance.
ysis

forecast of compliance shows similar outlook for net ed fuel credits by 2020



% reduction target	1.0%	1.0%	1.0%	2.0%	3.5%	5.0%	7.5%	10.0%

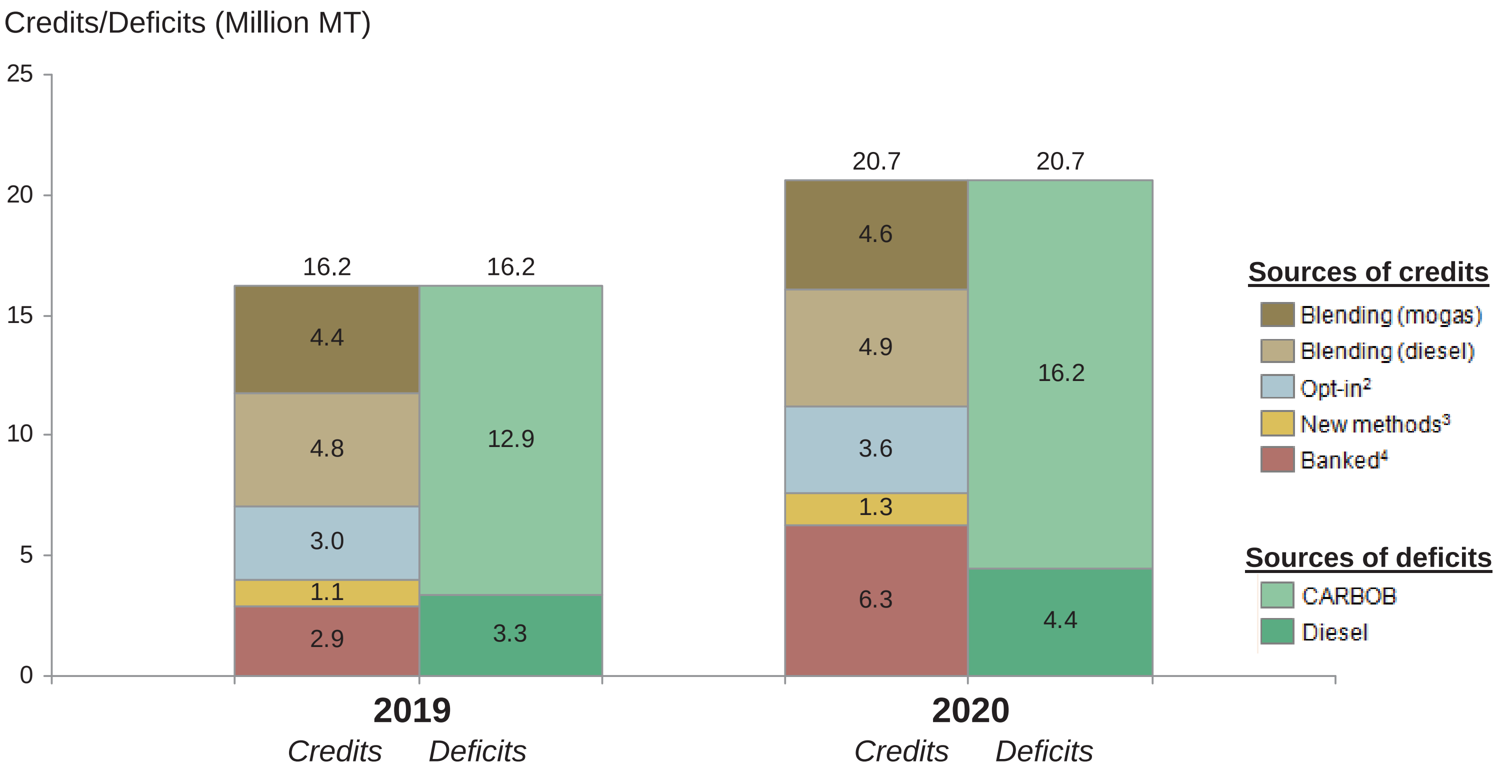
Uncertain whether all parties selling "opt-in" fuels will necessarily opt-in to the LCFS program

udes natural gas, electricity, and hydrogen 2. Credits minus deficits for blended fuel (e.g. CARBOB, CARB Diesel, ethanol, renew. diesel, biodiesel, etc.)3. Calculated as the the annual deficits and credits generated from all fuels until no banked credits remain (2020 in this example) Assumes that if credits are greater than deficits, credits will be regulated parties to achieve compliance.
OR Appendix B, BCG analysis

THE BOSTON CONSULTING GROUP

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

on CARB forecasts, transportation fuel credits[1] only 63% of deficits by 2020

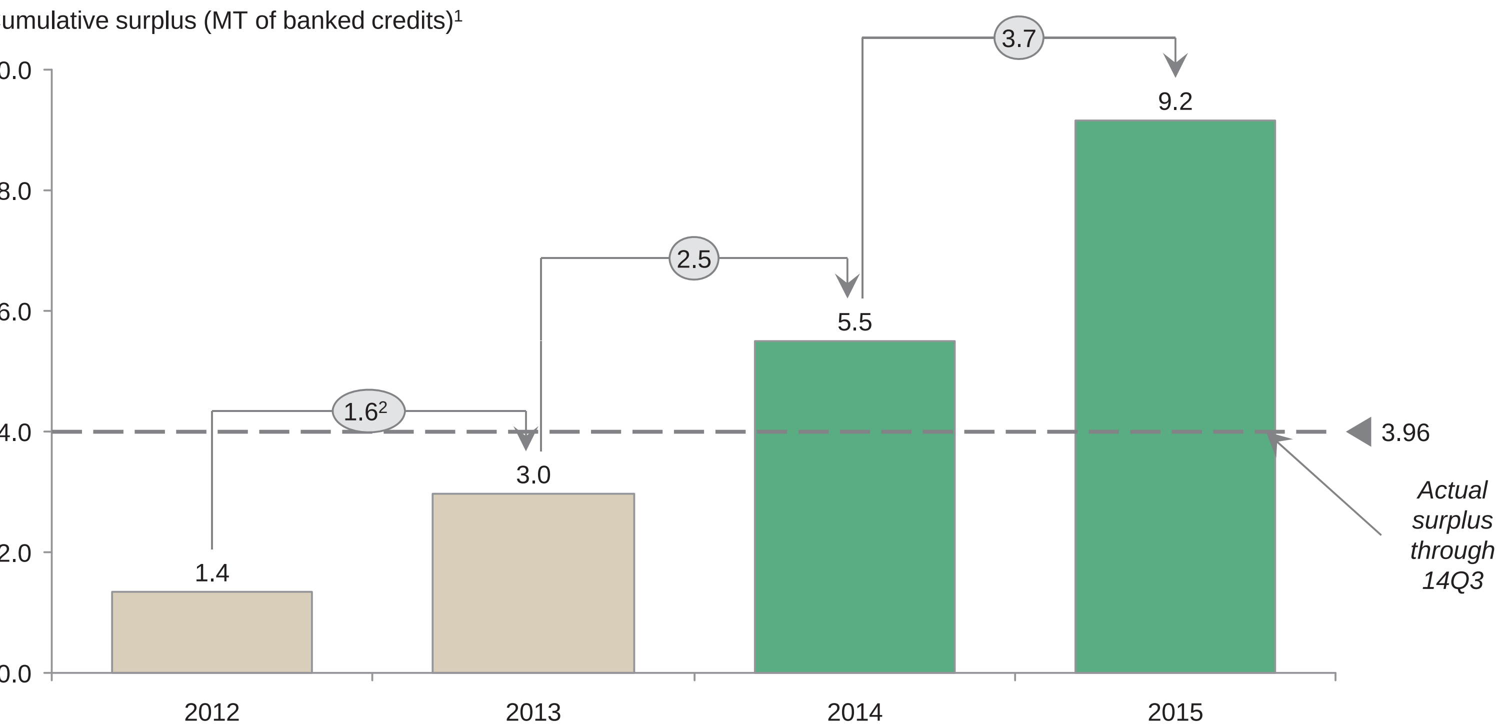


Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

el credits consist of credits generated from blending fuels and from providing alternative fuels (opt-in credits) 2. Opt-in fuels includes natural gas, electricity, and hydrogen 3.
de refinery credits and fixed guideway credits 4 Banked credits required in that year to reach a balance of zero
R Appendix B, BCG analysis

assumes surplus will triple during 2014-15

growth likely overestimated by CARB forecasts

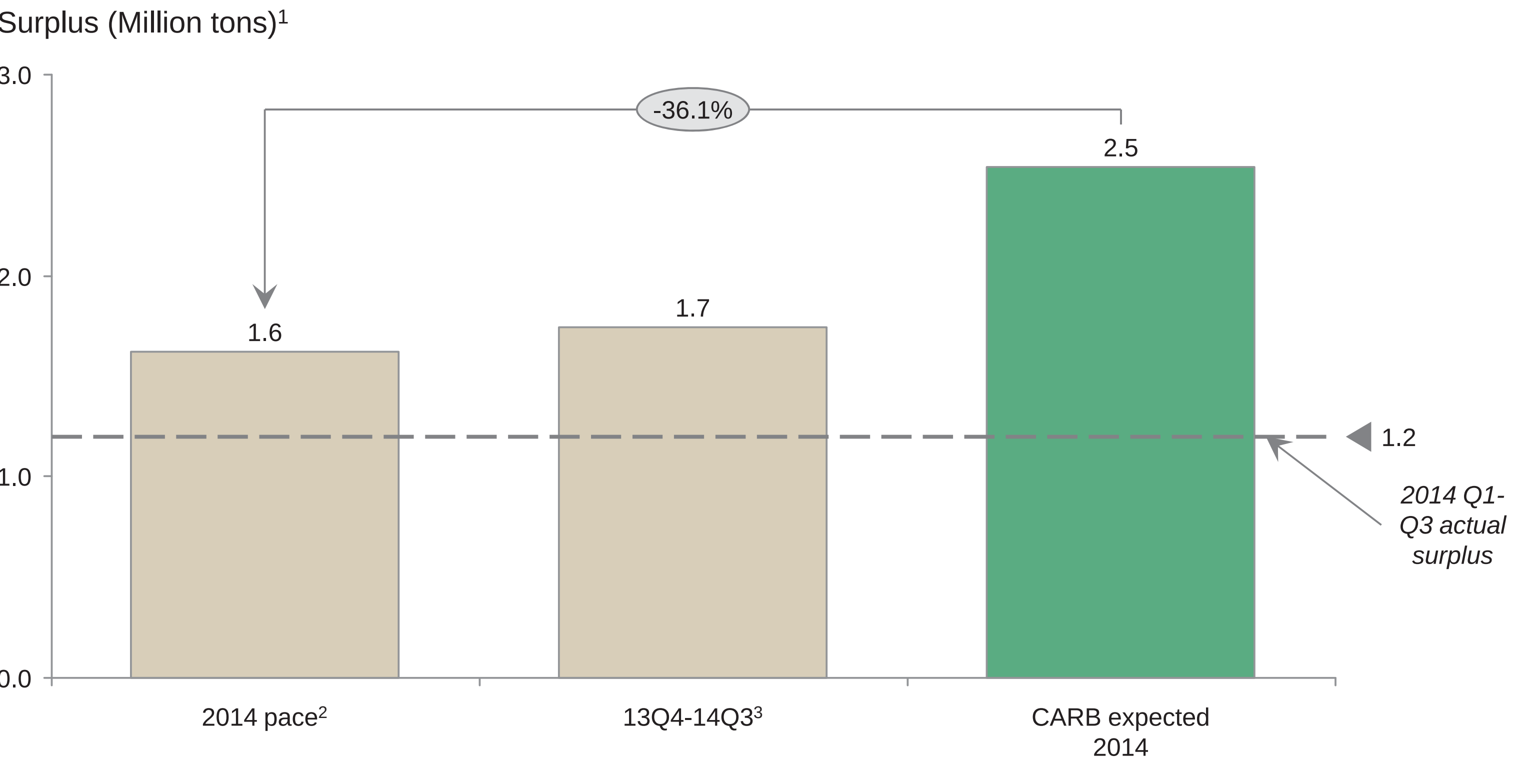


Even with flat CI reduction target (1%), CARB assumes high growth in low-CI fuel volumes over next 15 months

its in CARB "base case" scenario. 2. Surplus in CARB model is 1.7 MM credits even though CARB quarterly data indicates a surplus of 1.3 MM credits.
R Appendix B, CARB quarterly LCFS data (as published January 20, 2015), BCG analysis

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

with three quarters of data available for 2014, credit us on pace to be 36% below CARB forecast



its in CARB compliance scenario. 2. Total surplus for 2014 if 4th quarter surplus is same as average of first three quarters. 3. Surplus for trailing four quarters (13Q4-14Q3)

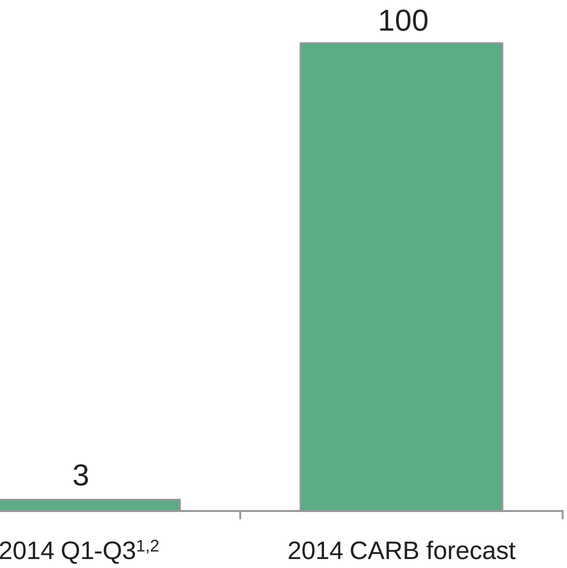
R Appendix B, CARB quarterly LCFS data (as published January 20, 2015), BCG analysis

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

gaps exist between CARB forecasts and volumes gh the first three quarters of 2014

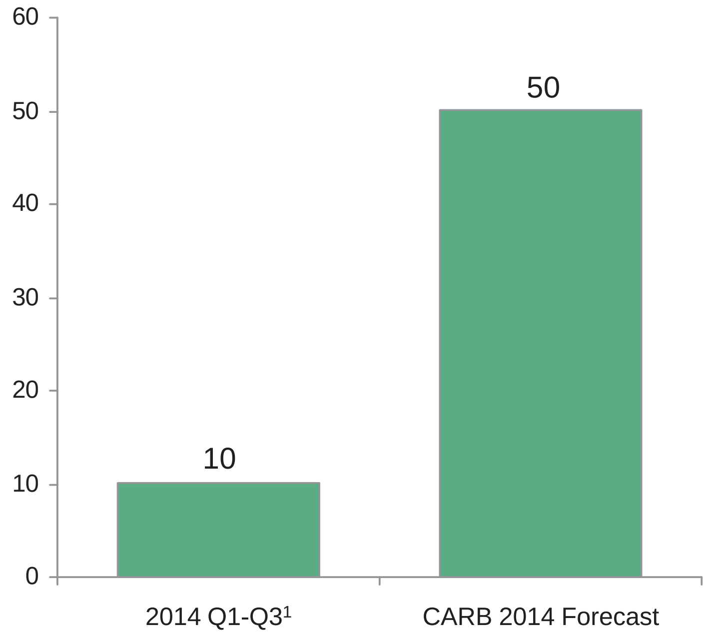
3 continues to predict large cane volumes in 2014 contrary to data

ethanol imports to California (Million gal)



Renewable natural gas another pathway lagging expectations

Renewable NG generating LCFS credits (Million gal DGE)

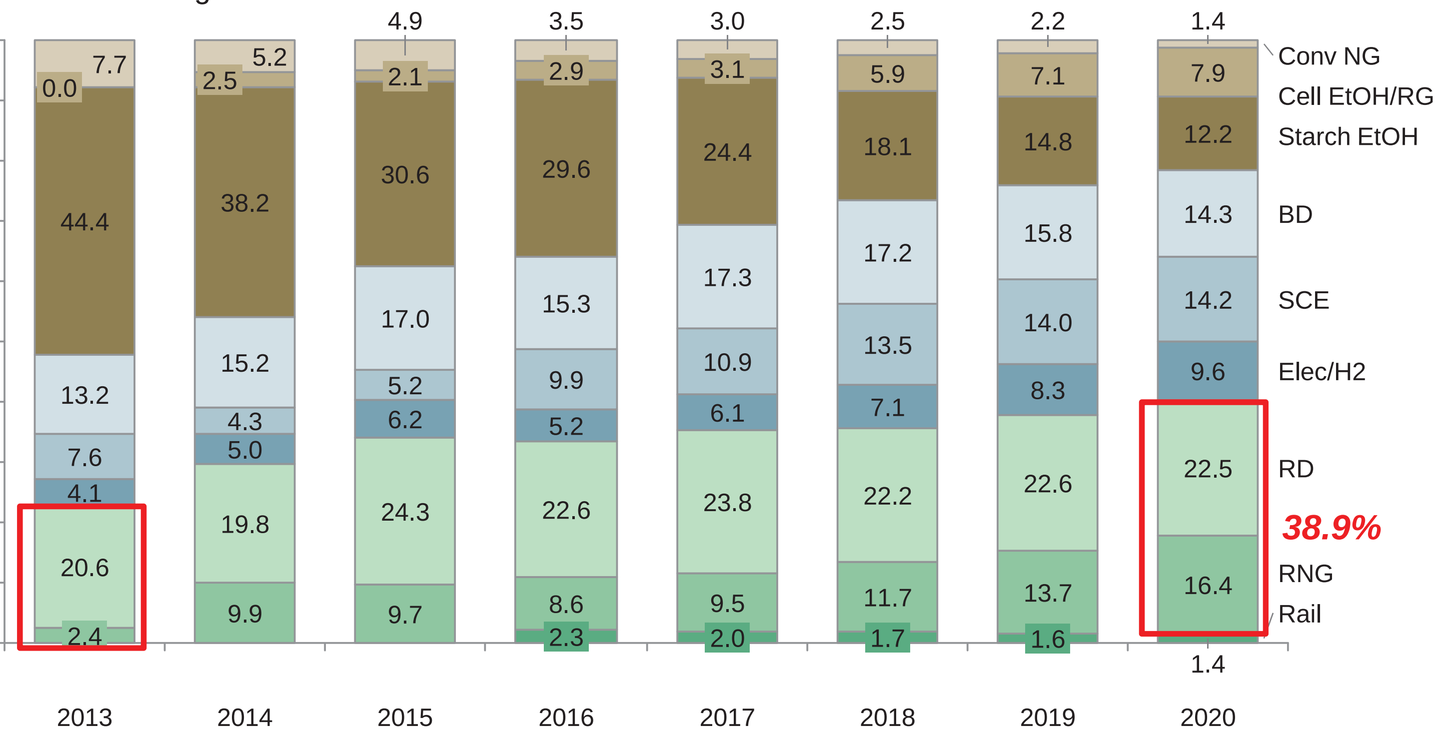


published by CARB as of January 20, 2015). 2. Census data indicates that no volumes have entered California from Brazil since January 2014
R Appendix B, CARB quarterly LCFS data

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

forecasted credits highly dependent on low-CI diesel

f LCFS credits generated



If RD/RNG credits fall below CARB's optimistic expectations, program will quickly become unsustainable

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

pliance scenario workshop

la

ew

ring BCG and CARB forecasts

ology

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

are the differences between the CARB and BCG
sts?

	Reasons for adjusting forecast	BCG 2020	CARB 2020	Cumulative impact by 2020 (MM Tons)[1]
ble diesel (RD) **s**	Renewable diesel volumes to California have grown due to shipments from Singapore. However, blending constraints are expected to keep California volumes near 5% of the blended diesel pool.	**200 MM Gal**	**400 MM Gal**	**(6.0)**
credits	A difficult regulatory environment for new projects and the expected value of these projects for most refiners make it unlikely that any of these credits would be realized through 2020.	**0 MT**	**1.1 MT**	**(3.2)**
ne ethanol **olumes**	Actual volumes from Brazil have declined and industry forecasts of Brazilian sugarcane imports to the US have moderated since 2012. California has not imported sugarcane ethanol since Jan 2014.	**235 MM Gal**	**450 MM Gal**	**(1.9)**
ble natural gas	Without detailed market information, BCG uses CARB's expected growth in RNG usage, but delays the start of the rapid growth from 2014 to 2015	**180 MM DGE**	**240 MM DGE**	**(1.3)**
soline demand	BCG uses the EIA AEO 2014 forecast for the supply of motor gasoline (averages -0.6%) vs. CARB's assumption of an annual 1.1% decline.	**14.0 B Gal**	**13.6 B Gal**	**(1.0)**
vehicle **ity**	After CARB and BCG updated their EV forecasts based on current market information, the differences between the two forecasts are relatively small.	**1,337 GWh for LDVs**	**1,629 GWh for LDVs**	**(0.6)**
			Total impact	***(14.0)***

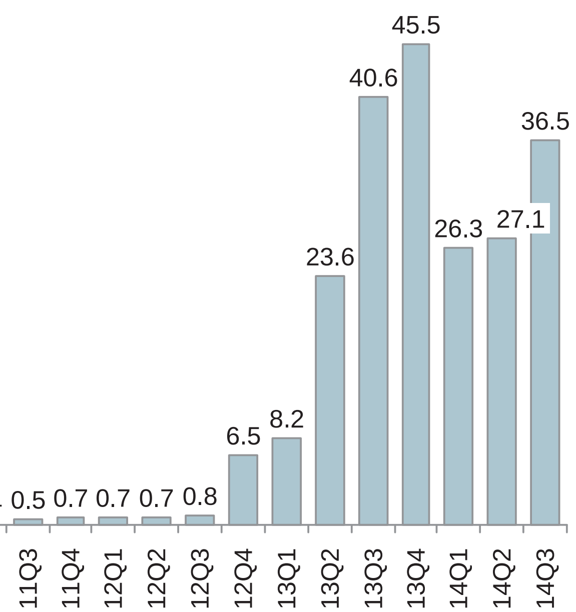
ease if negative) in banked credits through 2020 using the BCG forecasted volumes versus the CARB forecasted volumes 2. Appendix B of the ISOR indicates a median DGE and 61% RNG in the text while the table/model results show 300 MM Gal DGE with 80% RNG.
sis

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

vable diesel volumes in California have increased, but
e limited by blending constraints

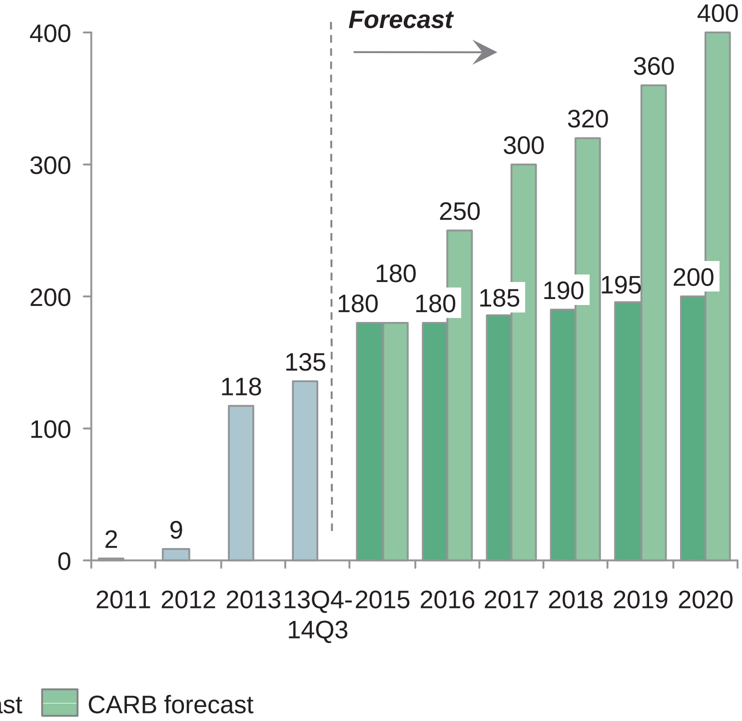
available to California has
ased in the last few quarters

D volumes in California (Million gal)



BCG assumes that regulatory issues will limit RD blends to ~5% through 2020

RD volume generating credits in LCFS (Million gal)



Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

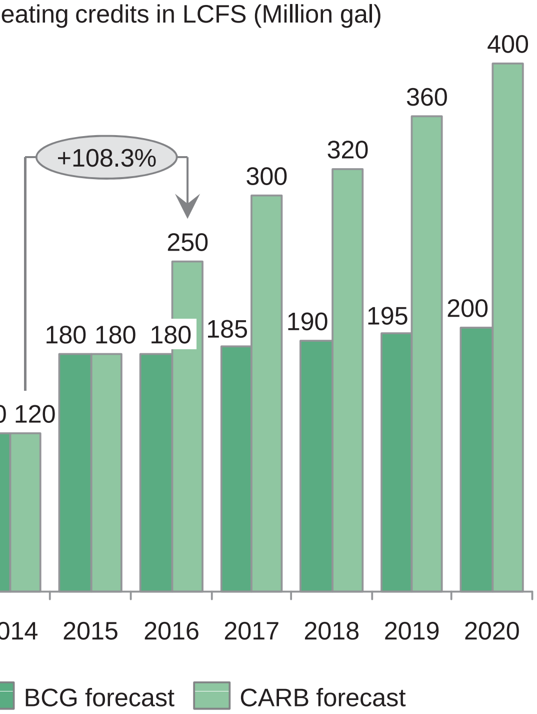
pliance scenario workshop, CARB quarterly LCFS data (as published January 20, 2015), BCG analysis

f blending issues resolved, renewable diesel volumes still be limited due to available RD supply

This is a sensitivity case to evaluate the renewable diesel availability should RD blending logistical issues be resolved

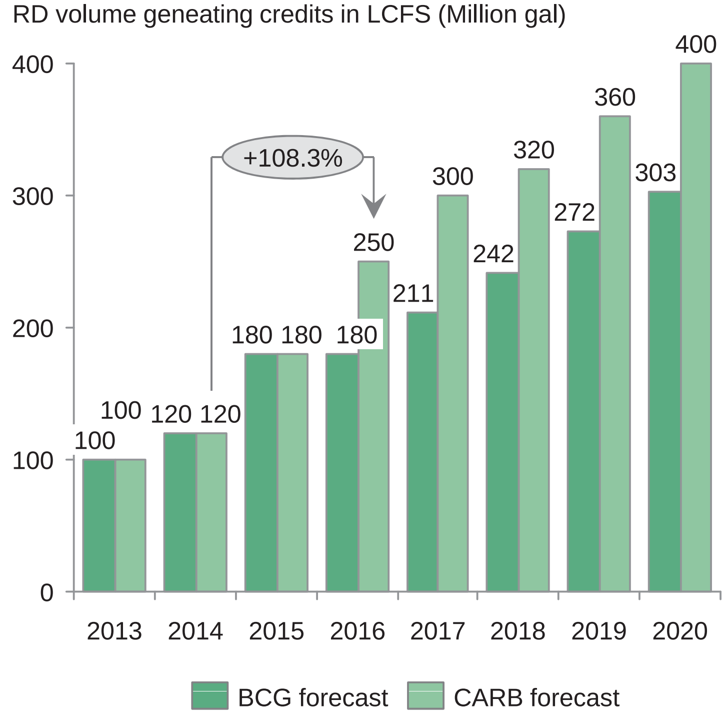
arison of BCG and CARB) volume assumptions

eating credits in LCFS (Million gal)



Comparison if RD blending logistical issues are resolved

RD volume geneating credits in LCFS (Million gal)



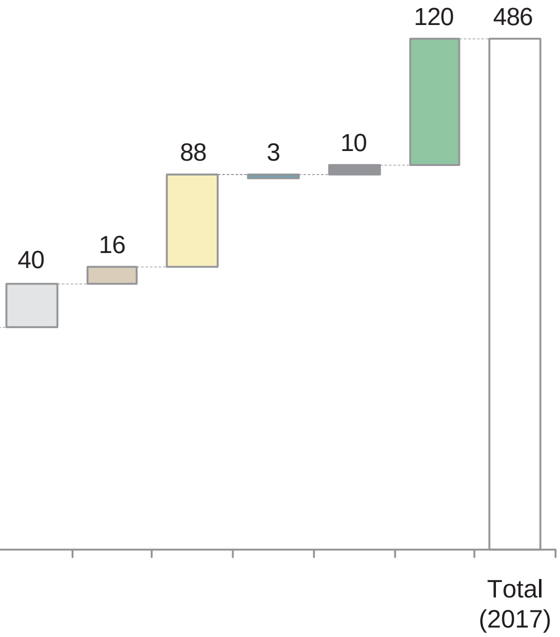
orted in any quarter to date is 45 million gallons
terly LCFS data (as published January 20, 2015), BCG analysis

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

...night available renewable diesel volumes be limited ...gh 2020?

...ounced US renewable diesel projects

...e diesel capacity (MM gal)



Risk factors for RD availability

Projects not being completed

- 25% of potential US capacity by 2017 is a project announced in summer 2014 with few details
- Some projects being funded with government investment, indicating marginal or worse standalone economics

Fuel under contract

- Some facilities have DOD contracts which will probably limit availability to California

Not all production will be diesel fuel

- Some facilities will produce jet as a portion of their fuel production

Logistics not in place for fuels to move to California

- At least one Gulf Coast plant does not have ability to move fuel to California

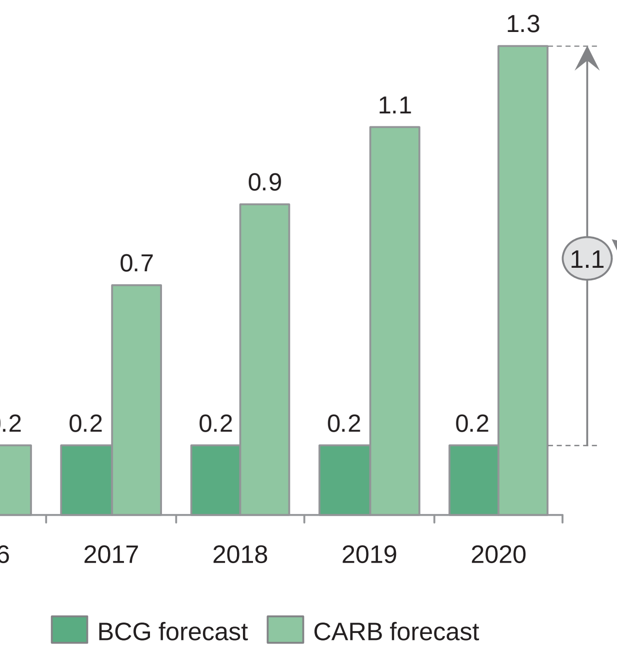
...earch, Biofuels Digest, BCG analysis

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

has introduced new opportunities to generate s; unlikely to see significant usage by 2020

on of CARB and BCG forecasts redits from new provisions

edits (Million MT)



Key difference is outlook for "refinery credits"

Off-road electricity
BCG and CARB both include ~0.2 MT per year for fixed guideway transit systems and some off-road vehicles

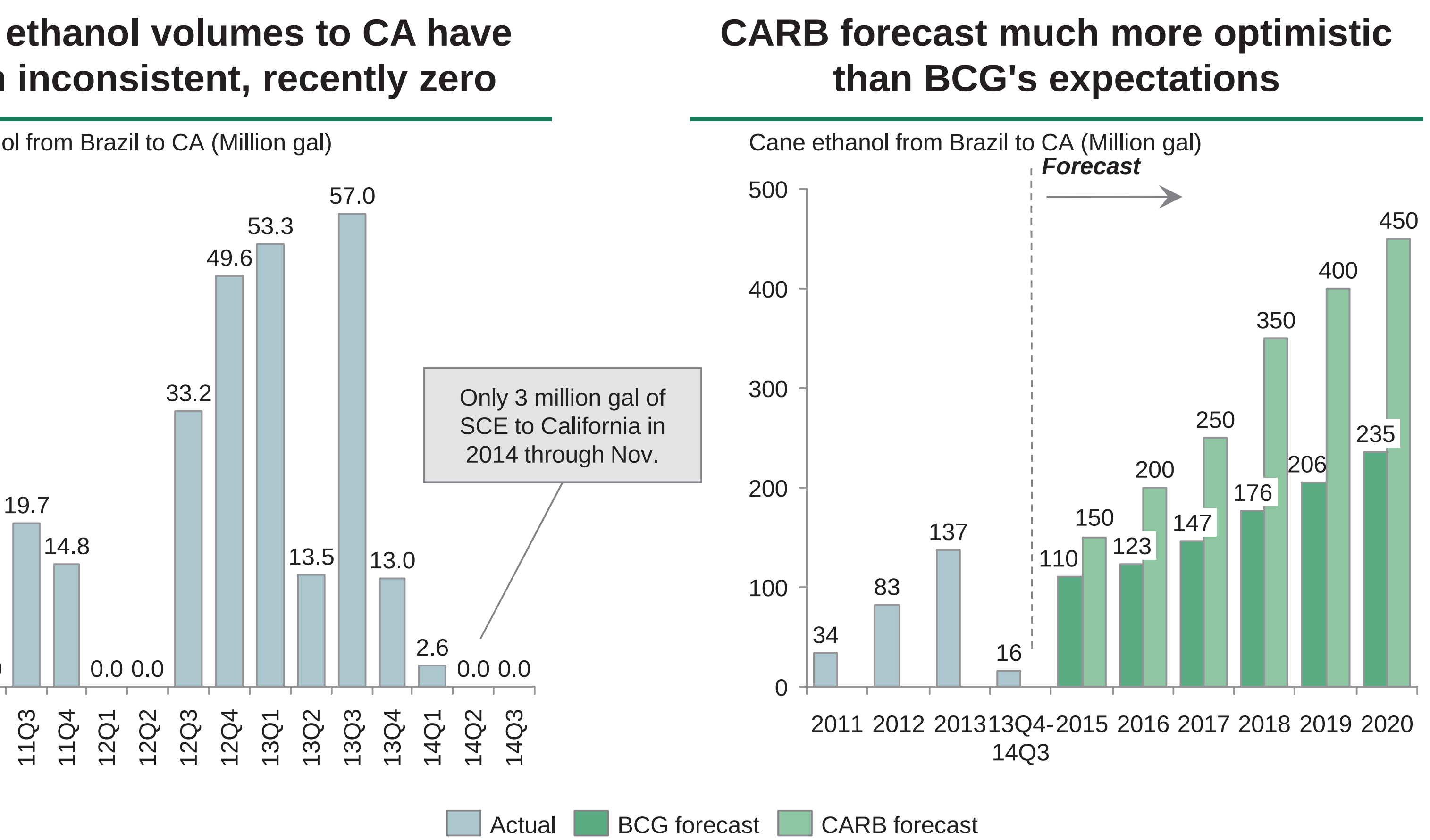
Innovative production methods
Neither BCG nor CARB assume that any of these production methods will generate credits by 2020

Refinery credits
There are significant regulatory hurdles in getting refining projects approved and relatively low returns for these projects. As a result, BCG blieves that refiners will not have a significant number of qualifying, credit-generating projects by 2020.

R Appendix B, BCG analysis

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

forecast for sugarcane ethanol availability optimistic
hough imports have fallen dramatically



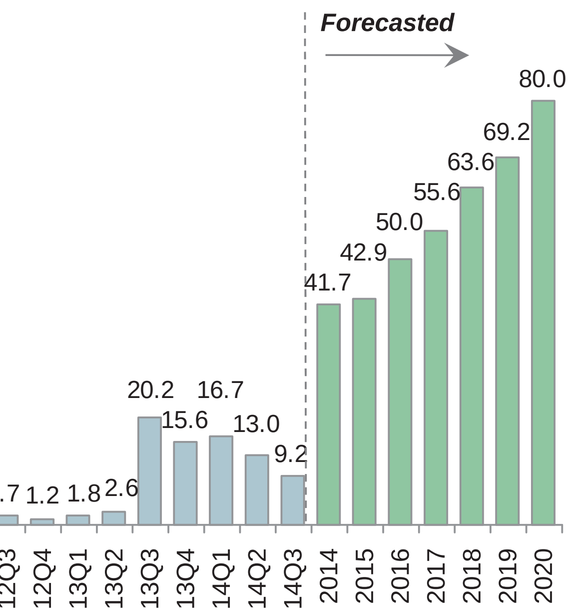
R Appendix B, CARB quarterly LCFS data (as published January 20, 2015), US Census Bureau, BCG analysis

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

renewable natural gas numbers overstated for 2014, optimistic for future years

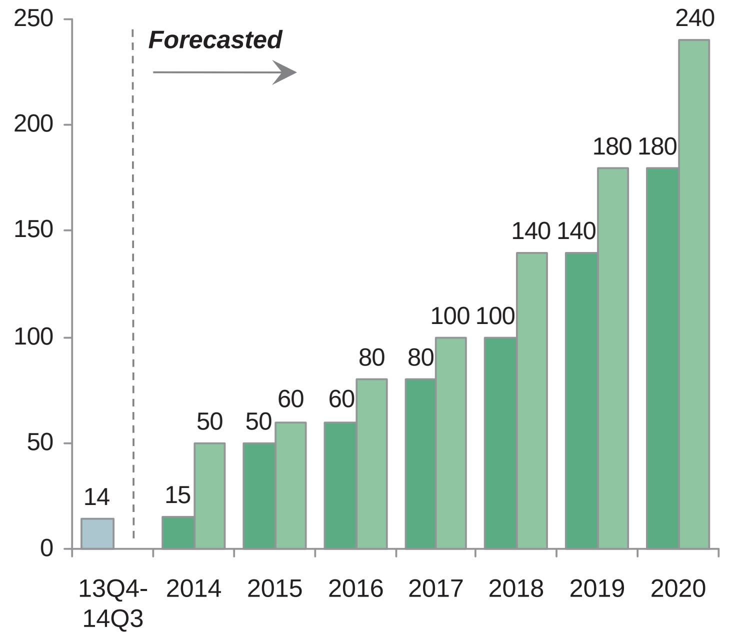
expecting an immediate step change in RNG usage...

e portion of natural gas in LRT[1] (%)



...with 2014-15 volumes 3x that of the last 12 months recorded in LRT

Forecasted NG in LRT (Million dge)



Historical BCG forecast CARB forecast

rting tool
B quarterly LCFS data (as published January 20, 2015)

THE BOSTON CONSULTING GROUP

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

RNG assumptions difficult to assess, pose additional … their estimate of available credits

…odel assumes rapid growth in renewable natural gas usage for transportation

…B assumes the share of renewable natural gas of total natural gas volume increases … 10-15% in 2014 to 80% in 2020

…out access to CARB's market/survey information, BCG has assumed the same growth …cted by CARB

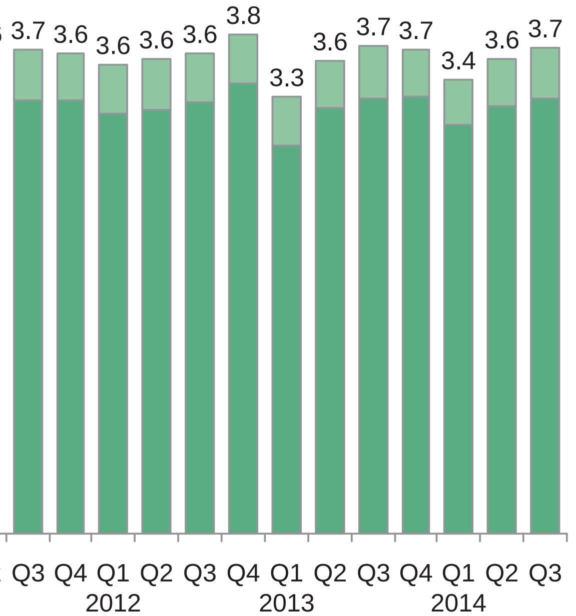
Because 75% of volumes for 2014 have been reported with no evidence of substantial growth, BCG assumes that the rapid growth starts in 2015 (delays growth 1 year)

…able whether LCFS is incenting production of additional renewable NG or …g renewable NG usage from one sector (utility / power generation) to another …tation fuels).

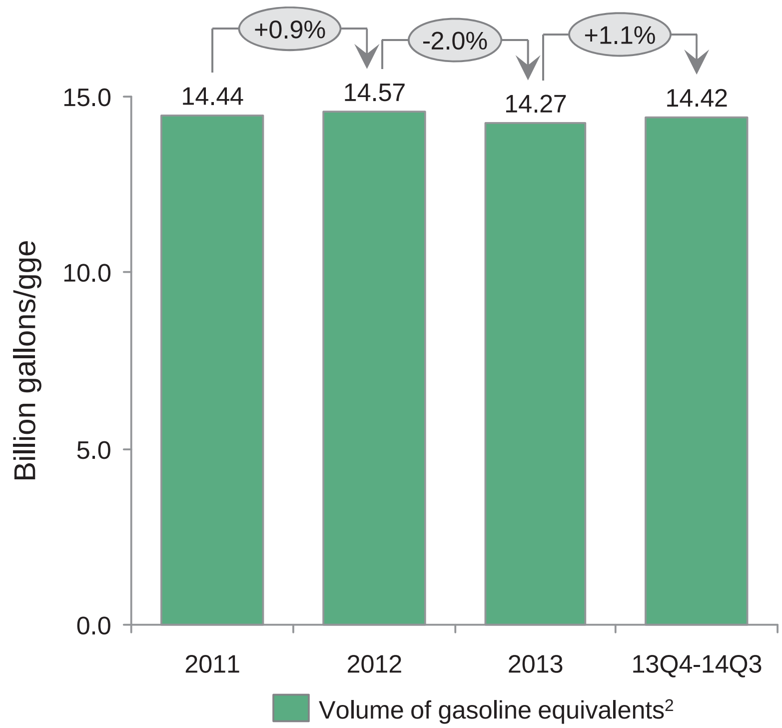
Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

ine (and equivalents) volumes have been consistent
ne first few years of the LCFS

ly volumes of gasoline equivalents
m CARB LCFS reporting tool[1]



Volumes have stayed within a relatively small range since 2011

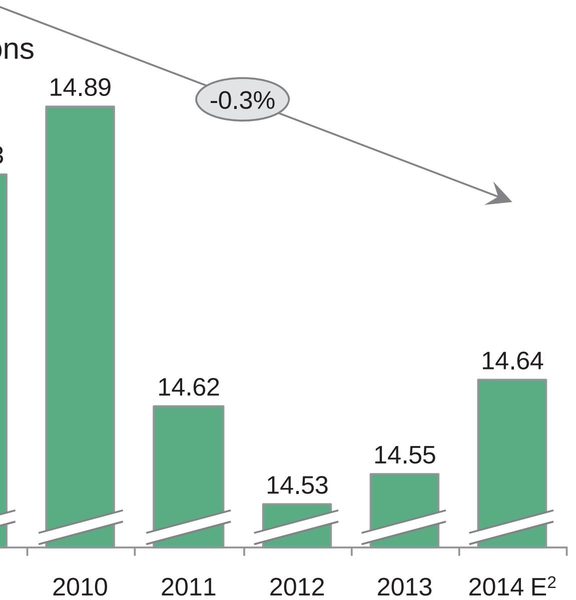


Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

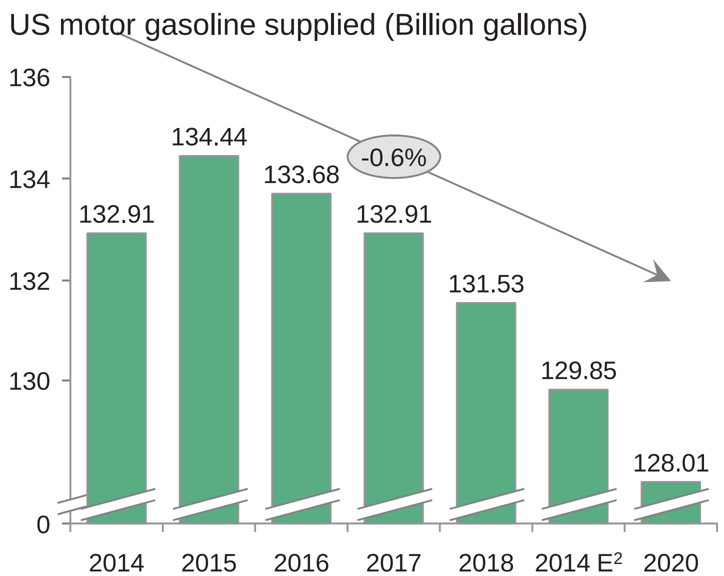
own as it accounts for less than 0.01% of gasoline equivalent volume in each quarter 2. Sum of CARBOB, electricity and ethanol volumes
terly LCFS data (as published January 20, 2015)

ine blend[1] consumption is expected to continue ing moderately through 2020

line blend[1] consumption in ornia has declined ~0.3%/yr



EIA forecasts an average decline in motor gasoline supplied of ~0.6%/yr



BCG assumes an annual decrease of 0.6% in total gasoline equivalent usage

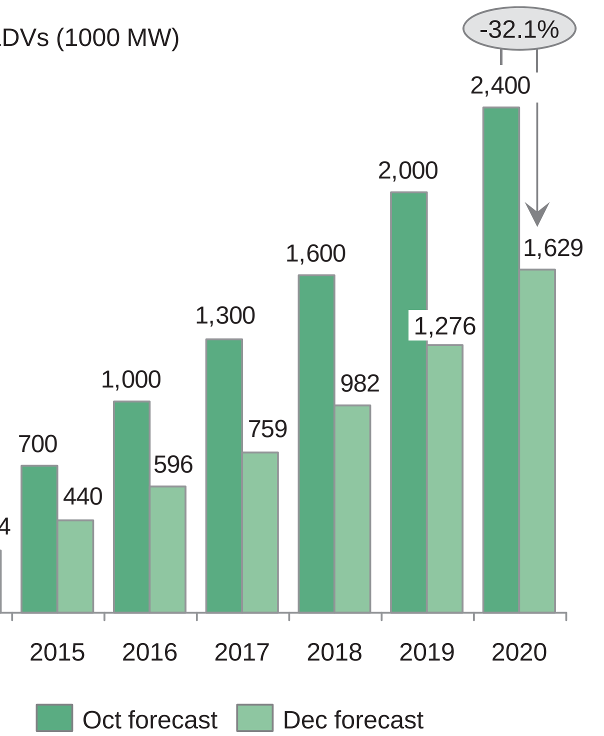
sohol 2. Projected using Jan-Jul 2013 vs. Jan-Jul 2014
d prior to shift in the global crude price may not reflect today's market climate
ghway Administration Motor Fuel Trends

THE BOSTON CONSULTING GROUP

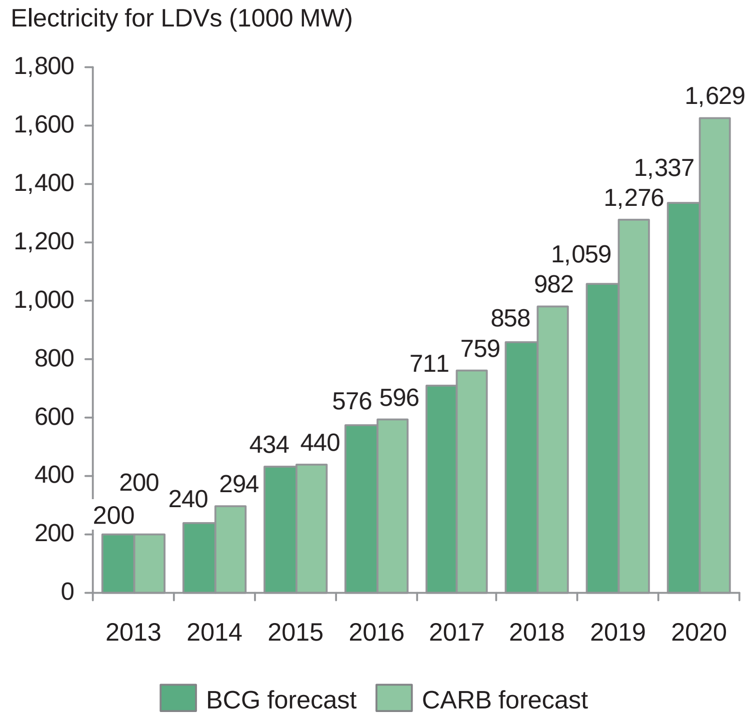
Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

has lowered expectations for EV usage since its
er workshop

October, CARB has tempered tations regarding EV usage...



...making expectations of EV usage close to those projected by BCG



in hybrid electric vehicles (PHEV) as well as battery electric vehicles (BEV)
pliance scenario workshop, CARB ISOR Appendix B

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

la

ew

ring BCG and CARB forecasts

ology

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

dology for BCG sugarcane ethanol and renewable forecast adjustments

Sugarcane Ethanol

ARB volume

ata through June 2014 indicates 2.6 MM gal

nsus data indicates no further imports of
rough November 2014
ed limited imports in Dec 2014 (~3 MM gal)

with optimistic (EIA 2014 AEO) and
stic (FAPRI) projections of sugarcane
imports to the US. Created a blended
on of 50% EIA and 50% FAPRI.
ed that California could get 25% of US
in 2015 with increases of 5% each year up
by 2020.
cent high of US share to the US West Coast
s ~35%

Renewable Diesel

2013-14
- Used CARB volumes/projection

2015-2016
- Assumed that renewable diesel usage would be limited to 5% of the diesel pool due to logistical issues of supplying blends >5% to market + limited availability

2017-2020
- Assumed that the overall percentage would rise above 5%, ramping up to 6% with isolated usage of R100 or other blends

2017-2020 (Sensitivity Case)
- Assumes linear growth in volumes available to California up to a 2020 maximum. This maximum volume includes:
  – 180 million gallons sourced from Singapore
  – California can get 35% of all announced US renewable diesel capacity

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

New Car Dealers Association, CARB quarterly LCFS data (as published January 20, 2015), CARB ISOR Appendix B, US Census Bureau, BCG analysis

dology for BCG EV and RNG forecast adjustments

EVs

ame increases in efficiency in PHEV/BEV as
y CARB in compliance scenario.

n stock

increases of PHEV and BEV stock (more
% for each in 2014)
e continued growth above EIA estimates
gle digit growth in EV stock).
e that stock increases would moderate as
stock increases and tax credits decrease.
sume 25% stock growth 2015-2017
sume 15% stock growth 2018-2020 as
tery costs decline to make EVs marginally
re affordable

Renewable Natural Gas

2014

Given progress to date in 2014, assumed that the CARB forecast of 50 million gallons DGE would not be possible in 2014

2015-2020

Used one year delay from CARB to estimate RNG in BCG forecasts (e.g. 2014 CARB RNG forecast = 2015 BCG RNG forecast)

Copyright © 2014 by The Boston Consulting Group, Inc. All rights reserved.

New Car Dealers Assocation, CARB quarterly LCFS data (as published January 20, 2015), CARB ISOR Appendix B, BCG analysis

BCG

THE BOSTON CONSULTING GROUP

Thank you

bcg.com | bcgperspectives.com

40_OP_LCFS_WSPA Responses

223. Comment: **LCFS 40-23 through 40-37**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

224. Comment: **LCFS 40-1**

The commenter alleges that the LCFS program and compliance schedule is not feasible.

Agency Response: ARB staff disagrees with the comment that the LCFS program and compliance schedule are infeasible. As described in the Initial Statement of Reasons, staff used a step-by-step approach to determine the feasibility of complying with an LCFS CI reduction goal of ten percent by 2020. The Appendix B of the ISOR provides further details of how this evaluation was performed, including an illustrative compliance scenario of how the target can be achieved. See response to **LCFS 38-1**.

225. Comment: **LCFS 40-2**

The comment is primarily an introduction to the more specific comments and suggestions that follow, noting that now is the time to look at what has and has not worked to date, and consider slowing the program down or scaling back its goals pending further research.

Agency Response: The more specific comments are addressed separately below. To the extent that this introduction suggests ARB has proceeded without evaluating what has and has not worked, and to the extent the comment hints that the program is too ambitious, ARB staff disagrees. As extensively set forth in the ISOR and its appendices, the LCFS has been carefully developed based on science, economics, and experience. In ARB's expert judgment innovations in fuel production and type will allow the LCFS to function successfully. We note that the LCFS has built into it review functions as well as self-correcting features, so ARB disagrees that an infeasible and unchangeable program has been developed.

We note that in the subsequent comments, the commenter nowhere claims that its members are not able to produce or cannot purchase the necessary fuels. See the response to **LCFS 38-1 and LCFS 40-1**.

226. Comment: **LCFS 40-3**

The comment states that the current proposal is infeasible because of the slow development progress of low-CI fuels and that staying the course with the current design of the program could result in disruptions to the transportation fuels market.

Agency Response: ARB staff disagrees and believes that the targets are feasible. In addition, we believe the LCFS program in the long-term will provide greater supply reliability due to a diversity of fuels in the market. See response to **LCFS 38-1.**

227. Comment: **LCFS 40-4**

The comment requests program reviews on an annual basis.

Agency Response: Staff understands the desire for a clear schedule for program review but does not believe annual staff reports to the board are needed. In response to the commenter's concerns, staff added a 15-day change that creates a "progress report" to the Board about the program in 2017. A full program review will occur prior to January 1, 2019. For more details see response to **LCFS 38-2.**

228. Comment: **LCFS 40-5**

The comment requests no further efforts to create post-2020 LCFS reduction targets until the pre-2020 program is proven feasible.

Agency Response: See response to **LCFS 40-2** regarding feasibility and continued review. Regarding post-2020 reduction targets, see response to **LCFS 5-2**.

229. Comment: **LCFS 40-6**

The comment states that there will be insufficient credits to achieve the 2020 goals and beyond.

Agency Response: ARB staff disagrees that there will likely be insufficient credits to achieve the required 10 percent reduction in 2020 and at least maintain that level beyond 2020. See the response to comment **LCFS 38-1**.

Staff disagrees that the issues identified relative to the availability of either Renewable Diesel (RD) or Renewable Natural gas (RNG) will significantly reduce the ability to use these fuels to produce LCFS credits. See the response to comment **LCFS 38-6, LCFS 40-9 and LCFS 40-10**.

230. Comment: **LCFS 40-7**

The comment questions the assumptions ARB used in analyzing LCFS compliance curves and presents the results of their own analysis.

Agency Response: See response to **LCFS 40-6**.

231. Comment: **LCFS 40-8**

The comment claims a lack of credible ARB assessment and forecast of the availability and costs of low carbon fuels and credits.

Agency Response: ARB staff provided extensive information in the ISOR on the potential volumes of low CI fuels. See the response to comment **LCFS 38-1**.

ARB staff disagrees that the plant-by-plant detailed assessment of where low-CI fuels might come from requested in the comment is either necessary or feasible. The LCFS is a very flexible program that allows regulated parties wide discretion in their choice of compliance paths and fuel choices and, in fact, is designed to encourage *new* development and production. The ISOR identifies a wide variety of sources of low-CI fuels that are expected to be available to fuel suppliers in California and which, collectively if they all were to be used in California, have the potential to create far more credits that needed for LCFS compliance in 2020 and beyond.

Regarding the concern about competition for low CI fuels from other programs, ARB staff and others have assessed the impact of other Pacific Coast jurisdictions adopting the LCFS. These assessments show that the demand for low-CI fuels by these programs is far less than that in California for two reasons. First, these entities markets combined are significantly smaller than California's. Second, the LCFS phase-in schedules for CI reductions in these jurisdictions are being implemented approximately five years behind California. As a result, the fuel supplies identified in the ISOR are far more than adequate to meet all of the programs' goals well beyond 2020.

232. Comment: **LCFS 40-9**

This comment addresses two main points: 1) supply availability for renewable diesel and 2) availability of renewable diesel blends above 5 percent.

Agency Response: See response to comment **LCFS 38-6**.

233. Comment: **LCFS 40-10**

The comment cautions against reliance on large-scale production of renewable natural gas as a supply of LCFS credits, notes that landfill gas (LFG) to compressed natural gas/liquefied natural gas (CNG/LNG) for transportation fuel is uneconomic without state and federal incentives.

Agency Response: ARB staff agrees that state and federal policies, including LCFS, help drive LFG projects. In fact, the figures mentioned in the comment provide a clear example of the LCFS program improving the economics and incenting low-carbon fuel production. Staff disagree that expecting more projects of this type is unreasonable because of the significant potential LFG waste resource, which is currently unutilized.

Staff acknowledges that investors consider the risk of regulatory change before undertaking LFG projects. This argues for the creation of stable policies that provide consistent investment signals to reduce this regulatory risk. The LCFS endeavors to become such a policy, but has faced uncertainty in the past, primarily due to legal challenges.

The commenter states that repurposing of LFG from onsite electricity generation to transportation fuel is not correctly accounted for in the GHG calculation of the program, and that the fuel pathway should appropriately account for the substitution of average grid electricity generation for the LFG displaced from power production. In consideration of this, LFG pathway applicants must present evidence to ARB staff for the fuel pathway evaluation to demonstrate that the specific source of LFG would likely remain un-utilized in the absence of the proposed project or that the associated processing system was developed for the purpose of providing transportation fuel.

Staff proposes the commenter consider an alternate substitution, where the renewable power previously provided by the landfill project is replaced by renewable power from solar or wind generation (perhaps because these resources are now more competitive in the California Renewable Portfolio Standard program). In this scenario the landfill project may have considered halting cleanup and pipeline injection if not for the LCFS existing as an alternate program incenting the continued use of this low-carbon fuel.

234. Comment: **LCFS 40-11**

This comment addresses two main points: 1) increases in advanced biofuel supply as a result of the LCFS and 2) the methodology for projecting future biofuel supply.

Agency Response: See response to **LCFS 38-6**.

235. Comment: **LCFS 40-12**

The comment states that the LCFS program should undergo a Major Milestone review to inform transportation fuel consumers and state policymakers of the program's progress over the first 5 years of its existence.

Agency Response: This comment does not make a specific suggestion for inclusion in or changes to the proposal, rather it suggests an additional non-regulatory action by an unstated actor. As such, no response is necessary. We do note that in effect, the lengthy public LCFS re-adoption process has served as a major review of the program. Moreover, the re-adopted LCFS calls for review in 2017 and 2018.

236. Comment: **LCFS 40-13**

The comment states that "there appears to be a false sense of the degree of updates staff has provided," that an analysis promised in 2011 "has not materialized," and that the LCFS program 2009 economic analysis is outdated and a new economic analysis should be performed.

Agency Response:

No response is necessary because the comment does not address the proposal. Nor is it clear who holds a "false sense." We note that the December 2014 ISOR contains an economic analysis of the proposed LCFS. For more information on the economic analysis for the regulation, please see Chapter VII of the ISOR and the updated inputs and outputs for macroeconomic modeling found in Appendix F.

237. Comment: **LCFS 40-14**

The comment objects to the use of the credit clearance market and argues that this cost containment mechanism may act as a price floor.

Agency Response: With respect to the general thrust of the comment pertaining to the design of the Credit Clearance Market and the concern that the price cap could act as a floor, see responses to **LCFS 32-9 and 38-3.** Relative to the other concerns expressed:

WSPA suggests that the cost containment provision be voluntary. Staff's analysis indicates that a voluntary cost cap is unlikely to be as effective at containing the cost of compliance and providing certainty on the upward bound for credit prices as a cost cap that applies to all credits in the LCFS market.

ARB staff analysis regarding the availability of low-CI fuels indicates that there will be sufficient credits available through 2025 from existing low-CI fuel technologies and promising low-CI fuels on the horizon. See response to **LCFS 38-1**.

238. Comment: **LCFS 40-15**

The comment asserts that the Credit Clearance Market does not stipulate a mechanism for retiring deficits.

Agency Response: ARB staff analysis regarding the availability of low-CI fuels indicates that there will be sufficient credits available through 2020 from existing low-CI fuel technologies and promising low-CI fuels on the horizon. Please also see responses to **LCFS 32-9 and 38-1**.

In the event that the targets in the program prove to be more than the market can deliver in a given year, the cost containment provision will ensure that orderly compliance is possible without extreme measures. The Clearance Market will allow the market to determine the 'feasibility' of low CI production in an orderly fashion: the Clearance Market greatly reduces the potential for chaos or extreme volatility in the market should a shortfall occur, and the resulting increase in regulatory certainty should produce a corresponding increase in investment in low CI fuel technologies and projects – thereby serving to 'close the gap' on needed fuels.

Given the flexibility of the LCFS, regulated parties may account for compliance in their books differently, as this is a business-specific decision. ARB staff anticipates that most regulated parties will carry accumulated deficits as liabilities, which can be repaid when the market becomes more fully supplied. Typically, market forces respond to increased demand with resultant supply increases in subsequent years. It take approximately two to three years to build a new advanced biofuel facility, which is why staff proposes that regulated parties have up to five years to repay any accumulated deficits.

239. Comment: **LCFS 40-16**

The comment argues that the Credit Clearance Market will drive the credit cost up.

Agency Response: The structure of the clearance market does not require that additional credits are offered for sale during the year-end clearance market in order to contain costs. The cost containment provision (CCP) is designed to provide an effective cap on credit prices in the event of a short supply: if demand for credits outpaces supply in the year-end credit market, regulated parties are able to roll over any remaining deficits to be repaid in future years, preventing a situation in which a shortage of credits might result in regulated parties bidding up the price of credits above the ceiling price.

ARB staff analysis indicates that it is unlikely that the amount of credits pledged to the clearance market will be significantly lower than the amount of credits available for sale because low-CI fuel producers will have incentive to pledge all or most of the credits they are hoping to sell. This is because the credit clearance process would (1) guarantee their credits will be purchased, and (2) that they will receive the best price possible for their credits, because credits are likely to be purchased at or near the maximum price through the CCP. The quantity of credits pledged under the credit clearance process is likely to be a function of how many credits remain available for sale at the end of the year, so the credit price will be primarily determined by the amount of low-CI fuels that have made it to market, rather than the willingness of credit-holders to pledge.

The LCFS contains numerous design features to help minimize the cost of compliance, including the ability for regulated parties to self-generate credits, at costs potentially lower than the market price for credits – for example, by purchasing low-CI fuels for blending with traditional hydrocarbon fuels. As credits and deficits are generated by regulated parties selling transportation fuels in the California market, the quantity of deficits and credits available each year is determined by the actions of regulated parties – namely, the quantity and carbon intensity of fuels sold in the California market. Major regulated parties thus have the ability to greatly influence the quantity of credits provided in future years, for example, by investing in facilities to self-produce low-CI fuels, or by entering into agreements with low-CI fuel producers to ensure their future supplies of credits.

WSPA's comment that the quantity of credits is fixed is predicated on the notion the quantity of low-CI fuels produced is unaffected by both the demand for that fuel and how profitable it is to produce that fuel. Historical data from the LCFS Reporting Tool – and fundamental economic theories of supply – contradict this assertion. The volumes of low-CI fuels consumed in California indicate a strong market response to the regulation stimulating demand for low-CI fuels. A LCFS has been continuously implemented in California since 2010, and regulated parties have generated more credits than needed every year. Since 2010, the production of low-CI fuels has increased in response to the financial incentives provided by the existing LCFS regulation. Many innovative, low-CI fuel technologies have moved past the demonstration stage, and have overcome techno-economic challenges that have in recent years limited the supplies of innovative, very-low CI fuels such as cellulosic ethanol, renewable diesel, and renewable natural gas. Staff analysis indicates that the supplies of low-CI fuels in future years will continue to exhibit the existing trend of increasing production.

For further response to this comment, please see response to Comment **LCFS 38-3**.

240. Comment: **LCFS 40-17**

The comment contends that the Credit Clearance Market provides no liability protection against invalid credits.

Agency Response: ARB disagrees that the government, as opposed to buyers and sellers making commercial arrangements – which could include insurance, bonding or indemnification provisions – needs to protect parties who purchase invalid credits. Parties offering credits for sale in any credit clearance market will have to generate those credits through fuel transactions reported under penalty of perjury through the LCFS reporting tool; this data is subject to ARB staff's process for data review and reconciliation. The penalties for filing false or fraudulent reports (which can include criminal and civil penalties under federal and state law) should also deter false reporting to generate fraudulent credits. ARB cannot guarantee that credits offered through the credit clearance market are valid and will not be invalidated because ARB needs the flexibility to determine, on a case-by-case basis, what party or parties should be required to replace credits that are discovered to be based on inaccurate or fraudulent information. Without replacement of any faulty credits, the goals of the program could be endangered, as compliance with the LCFS would be based in part on low-carbon fuels that were not brought to market in the quantities reported, or with the carbon intensities reported. In most cases, a regulated party will be able to decide for itself whether it will participate in the credit clearance market; if the party believes the clearance market carries unacceptable risks due to more limited opportunity to conduct a review of the credits being offered for purchase, that party can avoid the credit clearance market altogether simply by producing low CI fuels in the compliance period in question, or banking or purchasing enough credits in advance of the compliance deadline.

For further response to this comment, please see response to Comment **LCFS 40-39**.

241. Comment: **LCFS 40-18**

The comment states that the Credit Clearance Market has no connection between its outcome, program off-ramp, and future CI reduction.

Agency Response: ARB staff analysis regarding the availability of low-CI fuels indicates that there will be sufficient credits available through 2025 from existing low-CI fuel technologies and promising low-CI fuels on the horizon. The cost containment provision will ensure that – in the event that the targets in the program prove to be more than the market can deliver in a given year – orderly compliance is possible without extreme measures. Additionally, LCFS staff monitors the demand for and supply of credits in the LCFS Reporting Tool, and will conduct a mid-program review. These activities provide ongoing opportunities to monitor the market and assess whether a sustained shortage is occurring.

242. Comment: **LCFS 40-19**

The comment argues that the Credit Clearance Market proposal is lacking implementation details and will reveal confidential business information.

Agency Response: Additional clarity was provided in a 15-day change through the addition of 95485(c)(5)(C). This new provision explains that repayment of accumulated deficits is permissible only after the regulated party meets 100 percent of its current compliance obligation.

With respect to concerns about confidentiality, see response to **LCFS 40-69**.

243. Comment: **LCFS 40-20**

The comment argues that the Credit Clearance Market should offer annual program review, triggers for early program reviews, and a carryover rule for company imbalances.

Agency Response: The Cost Containment Provision (CCP) is designed to enhance the program's ability to encourage investment in low-CI fuels and to provide regulated parties with increased certainty regarding the maximum cost of compliance. ARB staff analysis and feedback from LCFS market participants has underscored the importance of regulatory consistency in order to facilitate business planning, particularly regarding the stringency of the program's CI reduction targets. The commenter proposes eliminating the CCP and potentially changing the compliance targets annually. Rather than strengthening the market signal provided by the LCFS, the commenter's suggestion of setting CI reduction targets only one year in advance would reduce the incentive for innovation and investments in low-CI fuels, increase administrative burden, weaken the market signal provided by the LCFS, and increase uncertainty and undermine long-term planning for regulated parties. As it can take two to three years to build a new low-CI biofuel facility, for example, investment decisions require greater confidence in the future demand for low-CI fuels than could be provided by CI reduction targets that are known only one year in advance.

Also see response to **LCFS 40-15**.

244. Comment: **LCFS 40-21**

The comment argues that the Credit Clearance Market should offer annual program review, triggers for early program reviews, and a carryover rule for company imbalances.

Agency Response: Regarding the commenter's recommendation that participation in the Credit Clearance Market should be voluntary, see response to LCFS **40-14**.

The commenter recommends that regulated parties who pledged credits to sell into the Clearance Market and have not sold or contractually agreed to sell all their pledged credits be prevented from rejecting an offer to purchase the pledged credits at the maximum price. In the proposed regulation, section 95485(c)(3)(E) Selling in the Clearance Market specifies that, "Regulated parties that have pledged credits to sell into the Clearance Market cannot reject an offer to purchase pledged credits at the Maximum Price."

Regarding the commenter's recommendation that the LCFS credit balance and individual entity names should be treated as confidential, see response to **LCFS 40-68** and **LCFS 40-69**.

The commenter requests that the deficit carry-over provision be reinstated on the basis of planning or operational reasons that may cause regulated parties to wish to carry deficits from one year to another. Regulated parties can still carry deficits from one year to the next if the clearance market is triggered, although any accumulated deficits carried over to subsequent years will be assessed the five percent interest rate. Accumulated deficits are subject to the requirements of Section 95485(c).

245. Comment: **LCFS 40-22**

The comment argues that LCFS overlaps with the cap-and-trade program; and LCFS does not generate additional emission reduction, but may raise costs.

Agency Response: See response to **LCFS 32-7.**

246. Comment: **LCFS 40-38**

The comment argues that key formulas and their data for the regulation have changed without appropriate level of transparency.

Agency Response: ARB's process for explaining anticipated changes to the LCFS regulation, including changes to the values used in its California-modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET), the Oil Production Greenhouse Gas Emissions Estimator (OPGEE), and indirect land use models, has not only met requirements of the Administrative Procedure Act, but has far exceeded the minimum requirements. ARB staff held 20 workshops to share its thinking about planned changes to the LCFS before ARB filed its Notice of Proposed Rulemaking, and held another workshop on CA-GREET prior to a 15-day change. These workshops – most, if not all, of which were attended by representatives of the companies represented by the commenter – included staff presentations describing significant changes contemplated as part of the proposed rulemaking, and attendees were given the opportunity to ask as many questions of staff as they wished in person and on the web. In addition, ARB staff and managers fielded many questions from stakeholders outside of publicly-noticed meetings. Similarly, staff produced documentation to explain these changes in some detail. The document cited by the commenter (Appendix C of the Initial Statement of Reasons) included 78 pages to explain changes that the proposed regulation would make in the model currently being used.

While it is undisputed that the LCFS proposal – just as the existing LCFS regulation – is a highly technical and complex regulation, the parties subject to the LCFS are generally familiar with the scientific and technical underpinnings of the regulation and have provided informative and helpful feedback to ARB staff during the workshops and other informal rulemaking activities that stretched over many months before the filing of the notice with the Office of Administrative Law. Far from lacking transparency, the process used to develop the proposed LCFS regulation has featured long and productive dialog with stakeholders, including both the commenter and the large petroleum companies that are represented by the commenter.

The models used in both the current and proposed LCFS regulations are adapted from models developed elsewhere. For example, the GREET model used in LCFS is an adaptation of the model developed and updated by Argonne National Laboratory. Businesses and individuals with an interest in the LCFS proposal, or more specifically in how carbon intensities are computed, also have an opportunity outside of the rulemaking process to participate in development of the underlying models through other venues.

After the Notice of Proposed Rulemaking was published, ARB staff realized that additional provisions were needed in the regulation to properly adjust carbon intensity values for indirect land use changes that occur during the production of biofuels. These indirect changes are computed through the Global Trade Analysis Project (GTAP) model. Staff consequently revised the proposed regulation to include more detailed provisions governing these adjustments for indirect land use changes. Public comments were taken on these changes during a supplemental 15-day comment period.

The formulas used to compute carbon intensity values and specific carbon intensity values that are available for general use are included in the proposed regulation and will only be changed through amendment of the regulation, once adopted. The commenter appears to believe that these formulas and general carbon intensity values will be amended outside the rulemaking process, but this is not the case. For example, the commenter states that the change in the formula for computing the annual crude average value has changed and takes this as an example of "changes to key formulas outside of the rulemaking process and without the opportunity for public comment." In fact, the referenced change in the annual crude average formula is included in the proposed regulation – not outside the rulemaking process – and is explained in the Initial Statement of Reasons. Furthermore, even though the formula is set forth in the regulation, the regulation also provides that the result of the annual computation will be posted on the internet and subjected to public comment before the value is actually used in computing LCFS compliance obligations. Again, the proposed regulation not only meets the standard of the Administrative Procedure Act, but exceeds it by allowing for public review and comment where it would not otherwise be required.

247. Comment: **LCFS 40-39**

The comment argues that ARB should not compel regulated parties to purchase credits since ARB does not verify the credits; the comment also requests changes to limit the bases for credit invalidation.

Agency Response: ARB disagrees with the commenter's reading of the LCFS. Regulated parties are not compelled to purchase credits; if such parties choose to sell high-CI fuels, they may balance any resulting deficits by producing or buying and blending low-CI fuels. Moreover, if credits are determined to be invalid after they have been sold, the regulation provides ARB staff with the ability to require that various affected parties take corrective action. Whether

ARB staff will require the entity that generated and sold the credits or the entity that currently holds the credits to replace invalid credits will depend on the circumstances of the particular case. However, any credits determined to be invalid – whether after or before sale of the credits – must be replaced to ensure that GHG reductions are achieved and that other LCFS program goals are met, even if that requirement falls to a buyer of credits who failed to determine the validity of credits before purchase.

Health and Safety Code section 38562 does not require ARB to verify LCFS credits; it requires that GHG reductions be *verifiable*. In any event, LCFS credits are verifiable given the fact they are generated through transactions posted by regulated parties in the LCFS Reporting Tool, and ARB staff has the ability to audit or require additional supporting records to verify the reported transactions. Furthermore, the requirement that any credits determined to be invalid must be replaced, even if good-faith purchasers are required to pay for replacement credits, is necessary to ensure that the LCFS program meets its goals as well as AB 32's requirements. Indemnifying credit purchasers from any financial losses associated with the purchase of invalid credits, by contrast, would tend to disincentivize credit buyers from exercising due diligence to ensure the credits they are purchasing are valid, and result in the loss of emissions reductions associated with the invalidated credits.

The commenter is correct that independent (or third-party) verification is not required by the proposed regulation. However, nothing in the regulation prohibits a buyer from voluntarily undertaking verification of credits prior to purchase, or from negotiating contractual terms with the seller to address respective liabilities between the parties if credits are later invalidated. ARB staff notes the commenter's point about the U.S. Environmental Protection Agency's action to invalidate credits under the federal Renewable Fuels Standard, and agrees it is an example – an exceptionally serious example – of the type of situation that can lead to invalidation of credits.

ARB staff's response to the specific changes requested by the commenter to section 95495 of the proposed regulation follows:

1) *Add new* subdivision *(a)(2) to limit ARB enforcement actions to a period of one year or, in the* case *of failure to produce records, six months.*

The balance between the government's ability to address and remedy errors or fraudulent conduct versus private parties' desire for finality and certainty is one that the Legislature has already addressed. The law provides three years in which the People may file an action, dating from the time a violation is discovered or reasonably could have been discovered. (Cal. Civ. Proc. Code §338, subd. (k).) For the reasons described above, ARB believes it is important to the integrity of the program to ensure that flawed or false credits are invalidated and replaced, even if fraud or error comes to light after one year. Establishing a one-year time limit for enforcement action could result in a loss in GHG emissions reductions for problems that are discovered more than one year after the credit is generated or transferred, for example. ARB staff expects that most problems will come to light and be enforced within the time periods proposed in the comment, and ARB staff expects to consider the amount of time that has lapsed as it decides what enforcement action to take in a particular case. However, ARB staff does not agree that all enforcement actions should be confined to these time windows in every case.

2) *For incorrect* information *used to generate or support a carbon intensity value, limit enforcement to the two examples listed in subdivision (b)(1)(A).*

It appears the change urged by the commenter would replace the word "including" with the phrase "due to." The practical effect of this change would be to limit ARB enforcement action for incorrect information supporting a carbon intensity value to situations that either involve the omission of material information or changes to the process following submission of information to obtain a carbon intensity value. ARB staff believes these two circumstances should merely be illustrative of the types of inaccuracies that could lead to invalidation of credits or deletion of an approved carbon intensity value, as the proposed regulation is currently written. Limiting this provision to just those two circumstances could leave ARB without recourse if it determines a carbon intensity is based on faulty information or does not accurately reflect actual processes, so ARB staff declines to make the suggested change.

3) *Under subsection (b)(1)(E), limit enforcement action based on violation of other laws, statutes, and regulations to those laws, statutes, and regulations that are "*directly *applicable to the credit generation or transfer."*

It is not clear what laws the commenter believes are "directly applicable," or indeed whether such a category is sufficiently clear. In any event, by definition no other law could be brought to bear unless it did apply, so adding the word "directly" does not appear to yield a real change. ARB staff believes that the proposed change is unnecessary and would serve no purpose. The existing staff proposal allows enforcement action when "credits or deficits were generated or transferred … in violation of other laws, statutes or regulations..."This requires that the generation or transfer itself has violated such a law, statute, or regulation; in that case, the law, statute, or regulation will always be "directly applicable" to the LCFS transaction that violated it. Moreover, an agency does not have the power by regulation to alter the applicability of federal or state statutes.

4) *Add a definition of "material" to subdivision (b)(1) to include only* information *that is "directly* relevant*" to the generation or calculation of credits.*

The definition as proposed by the commenter is too narrow because information relating to approved carbon intensities, the generation of LCFS deficits, and credit transactions are also relevant to the actions described in this subdivision. But more fundamentally, ARB staff does not believe the term "material" needs to be defined because it is generally understood to include only information that is relevant to the issue being considered.

248. Comment: **LCFS 40-40**

The comment argues that enforcement provisions regarding credits and CI are deficient, and proposes a hearing and appeals procedure within the regulation on them.

Agency Response: ARB staff does not agree that an appeal process is needed. Staff anticipates working with all affected parties after an initial enforcement notice is issued; parties can submit information for consideration before the Executive Officer makes his/her final determination. Moreover, the ARB's procedures and staffing have been developed over recent decades with the Board's quasi-legislative role in mind; assigning the Board a new quasi-judicial role might require adoption of additional procedures as well as hiring new staff or reorganizing existing staff. Additionally, the LCFS Program includes a Program Review Process with the purpose of evaluating the implementation of the Program. If affected parties find the process detailed in section 95495 to be inadequate, the review would be an appropriate public forum to raise those concerns. See response to comment **LCFS 38-42.**

249. Comment: **LCFS 40-41**

The comment recommends the alternative penalties where a party does not show a balanced account at year end – per day or per deficit – be limited to per deficit-penalties only.

Agency Response: ARB accepts that recommendation and revised the regulation's section 95494(c) accordingly to eliminate the per-day alternative. For the type of violation in question, the consequences should relate to the number of deficits.

250. Comment: **LCFS 40-42**

The comment requests that the requirement that refinery investment credits only be approved for reductions from projects with no increase in criteria or toxic emissions be eliminated.

Agency Response: See response to **LCFS 38-9**.

251. Comment: **LCFS 40-43**

The comment proposes changes to some definitions and acronyms in the regulation.

Agency Response: ARB accepts the commenter's recommended changes to the definitions and acronyms in the regulation and circulated amended language in a 15-day change package. With respect to the biodiesel and biodiesel blend definitions, staff modified the regulatory text to align more closely with the alternative diesel fuel regulation. Staff, however, does not agree with the suggested change to the definition of "reporting party." Staff feels the definition already adequately addresses the transfer of obligation.

252. Comment: **LCFS 40-44**

The comment proposes changes to the language in Section 95481(a)(3)(B).

Agency Response: ARB staff acknowledges the recommendation and provided updated language in a 15-day change package.

253. Comment: **LCFS 40-45**

The comment states that there is an incorrect reference in Section 95481(a)(5).

Agency Response: ARB staff acknowledges the referencing error and corrected the reference in a 15-day change package.

254. Comment: **LCFS 40-46**

The comments states that there is an incorrect reference in Section 95481(c)(2&3).

Agency Response: ARB staff acknowledges the referencing error and corrected the reference in a 15-day change package.

255. Comment: **LCFS 40-47**

The comment requests that ARB include the definition of "Account Administrator" in the definition section (95481).

Agency Response: ARB staff accepts the recommendation to include a definition for the Account Administrator and included a definition in a 15-day package.

256. Comment: **LCFS 40-48**

The comment opposes the requirement for buyer to notify the seller as to whether a company is a producer or importer.

Agency Response: ARB staff is proposing to modify the section of concern to the commenter to remove the requirement that the recipient "producer or importer" of a fuel transfer be required to notify the transferor whether the recipient is a producer or importer for purposes of establishing compliance obligation and regulated party. The recipient "producer or importer" of California Reformulated Blendstock for Oxygenate Blending (CARBOB), Diesel Fuel or Diesel Fuel Blends will no longer automatically become the regulated party as indicated in the previous regulation order.

257. Comment: **LCFS 40-49**

The comment opposes the change in regulatory language in Section 95481(a)(1).

Agency Response: ARB staff disagrees that the language is unnecessary as it provides clarity regarding situations where diesel or diesel fuel blends obligation may be passed to downstream entities. This provision would align diesel obligation transfers with the current gasoline provision where end users and retail outlets could not receive an obligation. The obligation would stay above the rack where the wholesale purchaser of the fuel has the capability to blend biomass-based diesel fuels to offset diesel deficits.

258. Comment: **LCFS 40-50**

The comment opposes including electricity as part of the LCFS program.

Agency Response: Staff disagrees with this comment. Although the electric grid is ubiquitous, electricity is hardly a ubiquitous fuel used in the transportation sector at the present time. Currently, less than 0.5% of on-road light-duty vehicles are driven by electricity. The number of heavy-duty trucks fueled by electricity is an even smaller percentage. In fact, as a transportation fuel, the infrastructure needed to charge vehicles, especially in multi-unit dwellings and workplaces, is lacking and lagging.

One of the objectives of the proposed Low Carbon Fuel Standard is to foster investments in the production of the low carbon intensity (CI) fuels. Electricity has the lowest carbon intensities among commonly available fuels and, therefore, should be included in the LCFS provisions as an option to move California toward a low-carbon transportation future.

259. Comment: **LCFS 40-51**

The comment challenges ARB's statutory authority to allow credit from sources that pre-date the LCFS. The comment also argues that LCFS will create an un-level playing field.

Agency Response: See response to **LCFS 38-21**.

260. Comment: **LCFS 40-52**

The comment opposes the removal of the direct metering requirement due to concerns related to credit validity, ARB's authority, and an un-level playing field.

Agency Response: Staff disagrees with this comment. See response to **LCFS 32-11**.

Regarding the authority concern, in the current LCFS regulation, no-direct residential EV metering was required for the period of 2011-2014. Staff simply proposes to continue this current practice and not require separate metering post-2014. The authority to structure the calculation in this way is consistent throughout the various LCFS rulemakings.

The credits generated through EV charging will be calculated by ARB staff using the method laid out in the 15-day changes. This will enhance the credit generation process for electricity providers, and reduce the probability of credit invalidation. If fraud is discovered; the Health and Safety Code and a host of other state and federal statutes may apply, and provide for civil and criminal consequences.

261. Comment: **LCFS 40-53**

The comment opposes the inclusion of new Heavy Duty EERs.

Agency Response: Please see response **LCFS 38-21**. Use of *electricity* for transportation, not use of particular *equipment*, is what LCFS incentivizes. Staff acknowledges that the energy used in heavy duty EVs was not included in the LCFS 2010 baseline. Staff proposes to adjust the credit calculations for existing and new electric heavy duty vehicles to account for the exclusion of the pre-LCFS off-road electricity applications in 2010 baseline. The LCFS credit formulas for existing electric heavy duty vehicles such as electric fixed guideways do not include credits for fuel displacement, which substantially reduce the number of credits these electrical applications generate. In contrast, the LCFS credit formula for new electric fixed guideway system does have the fuel displacement credits. Such approaches address the concerns of allowing these sources to generate credits without including them in the 2010 baseline.

The commenter objects that the EER calculations for heavy-duty electric buses is not adequately explained or documented. ARB has added two studies to the record as part of a 15-day change. The commenter has offered no contrary information, indeed no information at all. ARB disagrees with the commenter's implication that data must be available for every individual bus model before that model can use an EER calculated for the vehicle class. EERs applicable to other fuel/vehicle combinations are not calculated for each individual vehicle, but rather for vehicle classes such as those that are heavy-duty and natural gas fueled.

The proposed EERs for electric buses are necessarily conservative and are based on testing of 3 different buses (including 2 electric buses operating in California: Proterra Electric Bus Model BE-35, and BYD Motors Electric Bus) performed at the Altoona Pennsylvania Transportation Institute (PTI) at Penn State Test Track. The testing was conducted using a Transit Coach Operating Duty Cycle that comprises of 3 Central Business District (CBD) phases, 2 Arterial (ART) phases and 1 Commuter (COM) phase. Testing started on April 25, 2011 and was completed on March 5, 2012. As stated in the reports[10], "The results of the test may not represent actual mileage but will provide objective data that can be used to compare buses tested under this procedure." As such, sufficient testing data were used to establish the EERs for electric buses.

262. Comment: **LCFS 40-54**

The comment opposes credit for off-road pre-LCFS electrical transportation applications.

Agency Response: See response to comment **LCFS 38-21**.

263. Comment: **LCFS 40-55**

The comment opposes the removal of the direct metering requirement due to concerns related to credit validity, fairness issue, and ARB's authority.

Agency Response: See response to comment **LCFS 40-52**.

264. Comment: **LCFS 40-56**

The comment argues that the calculation method problematically allows using the metered EV charging data as a proxy for unmetered charging.

Agency Response: In response to this comment and feedback from other stakeholders, staff included an adjusted calculation method directly in the rule through 15-day changes. The method is robust, since it would be based on best available data for electricity usage and EV populations in each utility's service territory. See the response to comment **LCFS 32-11** and **LCFS 40-52**.

[10] http://www.altoonabustest.com/buses/reports/404.pdf?1340301410

265. Comment: **LCFS 40-57**

The comment argues that any utility that lacks directly metered data for EV charging should be excluded from generating credit.

Agency Response: Across all LCFS life cycle analysis of fuel pathways, if no specific energy use data are available, average values are used. The use of statewide average daily charging data is consistent with such an approach.

Currently, among the utilities that have opted into LCFS, only City of Palo Alto Utilities does not have direct metering data. Considering its small number of EVs, ARB allows it to use the statewide average EV charging data. Staff will continue to monitor other sources of data for updated information on daily electricity usage of EVs and incorporate those into the calculation method.

266. Comment: **LCFS 40-58**

The comment questions the source and validity of data used to determine the numbers of PEV customers.

Agency Response: The estimation methodology referred to in this comment was used in past years by CalETC.

Historically, ARB staff has supplied some of this data to CalETC. To estimate the number of PEVs in each utility service territory, staff uses two databases: the California Vehicle Rebate Project (CVRP) database, and California Department of Motor Vehicle (DMV) registration data. The CVRP database is updated twice monthly, and DMV registration data is provided to ARB in April and October of each year. ARB staff analyzes both databases and consults with staff working on the Zero Emission Vehicle regulation to determine best estimates of PEVs charging in each service area.

In response to this comment and similar comments, in the proposed regulation ARB staff, instead of CalETC or utilities, is responsible for the determination of the final credits to utilities. Specifically, in 15-day change of the regulation, staff proposed to add the entire calculation method, including the determination of the number of non-directly metered residential PEV, into the regulation language.

267. Comment: **LCFS 40-59**

The comment raises questions on separate charging data for PHEVs and BEVs and concerns about the validity of applying metered data to unmetered fleet. Based on the commenter's unfamiliarity with electric vehicle charging, the commenter suggests that ARB reduce any electricity calculations to make them come out lower.

Agency Response: ARB staff disagrees that its calculation method is so uncertain that it should be artificially skewed downward. As the State's (and arguably the nation's) leading regulator focused on automobile emission-reducing technology, ARB is familiar with the electric vehicle use patterns and associated studies. Currently available data from select, early model year plug-in electric vehicles shows similar electricity consumption across technology type. However, per the direction in Board Resolution 12-11, ARB staff is conducting an evaluation of the charging behavior of both battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV) with an assortment of battery capacities and will report to the Board by 2016 as part of the midterm review for the Advanced Clean Cars program. Additional findings from this assessment will be incorporated into the calculation method per the 15-day changes that provide flexibility to adjust for any future observable differences if future data demonstrates a shift in this area. See response to **LCFS 40-52** regarding unmetered charging.

268. Comment: **LCFS 40-60**

The comment raises concerns about the availability of data to confirm the validity of applying the metered PHEVs results to that of the unmetered fleet.

Agency Response: See response **to LCFS 40-59**.

269. Comment: **LCFS 40-61**

The comment raises concerns about "double counting" of credits, especially in the public sector and the work place.

Agency Response: A comparison of the home based charging and non-residential charging is available from the EV Project Infrastructure Reports, which shows that 83% of the electricity use is acquired through residential charging.

Currently public and workplace charging has very little potential to be double counted in the LCFS because: (1) unmetered residential charging is extrapolated from metered residential charging data and (2) almost no workplace or public charging entities have opted in to generate credits. Therefore it is likely that the total amount of electric vehicle credits is underrepresented to date, rather than double counted as the commenter suggests. Staff will consider how to adjust the residential charging estimation method further if needed as significant levels of public and workplace charging entities opt in to the program.

270. Comment: **LCFS 40-62**

The comment raises concerns about the validity of applying the metered BEV and PHEVs data to that of the unmetered fleet.

Agency Response: See response to **LCFS 40-59**.

271. Comment: **LCFS 40-63**

The comment raises concerns about "double counting" of credits, especially in the public sector and the work place.

Agency Response: See the response to **LCFS 40-61**.

272. Comment: **LCFS 40-64**

The comment opposes the removal of report obligations on information such as number of EVs in a service territory and requests adding the reporting obligation to PHEVs.

Agency Response: The current LCFS regulation requires regulated parties for residential and public EV charging to include public accounting of the number of credits generated, sold, and banked in annual compliance reporting. Public credit accounting is not required for regulated parties of other fuels. Staff proposed to remove the requirement of public credit accounting to make the reporting requirements consistent among regulated parties. Since the most important information included in the public credit accounting is already covered in the annual compliance reporting of electricity providers, removing this requirement would not erode credit validity.

In 15-day change of the regulation, staff proposed to add the entire estimation method, including the determination of the number of non-directly metered residential PEV, into the LCFS regulation language, which is subject to public comment. Staff further proposed in the 15-day change that ARB shall calculate the generated credits for estimated electricity use in each utility's service area based on best available data that are relevant to the calculations.

Please also see response to **LCFS 40-59**.

273. Comment: **LCFS 40-65**

The comment expresses concerns about allowing off-road electric applications to generate credit and questions the sufficiency of data for allowing EER values for electric buses.

Agency Response: See response to **LCFS 40-53.**

The proposed EERs for electric buses are based on the testing data of 2 electric buses: Proterra Electric Bus Model BE-35, and BYD Motors Electric Bus. The testing was conducted between 2011 and 2012. The 2 models are actually operated in California now. Therefore it is reasonable to apply the EER to existing electric buses.

274. Comment: **LCFS 40-66**

The comment expresses concerns about allowing off-road electric applications to generate credit and questions the sufficiency of data for allowing EER values for electric buses.

Agency Response: See response to **LCFS 40-65**.

275. Comment: **LCFS 40-67**

The comment requests information on the derivation of CI for CaRFG.

Agency Response: In the past the CI of California Reformulated Gasoline (CaRFG) was not included in the regulation because regulated parties report volumes of California Reformulated Gasoline Blendstocks for Oxygenate Blending (CARBOB) and denatured ethanol that make up CaRFG. Credits and deficits are calculated on the basis of those component fuels, rather than the blend.

Calculation of the "effective" CI of CaRFG is possible through the CA-GREET2.0 model (incorporated by reference into the regulation and fully documented through Appendix C of the Initial Statement of Reasons). To further assist stakeholders on this issue staff released the California Reformulated Gasoline and Ethanol Denaturant Calculator (XLS) which walks through this calculation in a more straightforward fashion.

Further, in response to this comment staff included CaRFG values as a footnote to Table 1 in §95484(b) of the regulation.

276. Comment: **LCFS 40-68**

The comment raises several concerns about the Credit Clearance Market proposal such as complexity and infeasibility of the regulation, and how the $200 credit ceiling is developed. The comment also recommends some revisions.

Agency Response: See response **LCFS 40-15** to **40-17**.

Staff analyzed a range of possible repayment schedules for accumulated deficit accounts. That analysis indicates that a 5% annual interest rate balances concerns that the interest rate be both sufficiently high to incent timely repayment of accumulated deficits when the market is fully supplied and sufficiently low so that it is not punitive.

The price cap is proposed to be set at $200 / credit in 2016 and increase at the rate of inflation in subsequent years. Staff analysis of the price cap indicates that $200/ton is high enough to provide a sufficient value added to stimulate the investments in and production of low-CI fuels, and sufficiently high to attract these fuels to California if they are produced elsewhere. The proposed price cap is anticipated to result in multiple, ancillary market benefits, including reduced price uncertainty, and reduced regulatory uncertainty. Reducing both these sources of uncertainty is anticipated to increase the incentives for investment. Potential investors may be hesitant to invest in low-CI fuel production facilities given conditions of undue uncertainty, particularly because production facilities for low-CI fuels are typically capital-intensive projects with relatively long payback periods.

ARB staff agrees with the commenter's suggestion to add clarifying text to Section 95485(c)(3)(E)(5) of the proposed regulation and proposed in a 15-day change the following addition:

> Section 95485(c)(3)(E)(5)
> Regulated parties that have pledged credits to sell into the Clearance Market cannot reject an offer to purchase pledged

credits at the Maximum Price, provided they have not sold or contractually agreed to sell the pledged credit(s).

277. Comment: **LCFS 40-69**

The comment opposes the removal of the Deficit Carryover provisions and recommends changes to the proposed regulatory language. The commenter also opposes this requirement and states that LCFS credit balance and individual entity names should be treated as confidential because the information could adversely impact business operations

Agency Response: Regarding the deficit carryover provision, see response to **LCFS 40-21**.

Section 95485(c)(4)(B) of the proposed regulation specifies that the Executive Officer will, on or before June 1, post:

- The name of each party that did not meet the requirements of section 95485(a) and the number of credits that each party is obligated to acquire as their pro rata share; and

- The name of each party that has pledged to provide credits for sale in the credit clearance market and the number of credits that each party has agreed to provide.

Publishing the names of regulated parties and their pro-rata share of the credit obligation does not provide the public or competitors with the full position information of regulated parties. The information specified in Section 95485(c)(4)(B) is not sufficient information for the public or competitors to infer an individual entities' compliance strategy and will not compromise a regulated parties' competitive position. Publishing this information ensures that the clearance market functions smoothly by providing the requisite information for regulated parties to conduct transactions, but protects confidentiality by not releasing additional information beyond the minimum information required to conduct transactions in the Clearance Market.

The commenter's rationale for these concerns is that a regulated party may be unable to purchase their pro-rata share of credits in the clearance market, but the Clearance Market is specifically designed to prevent this from occurring by setting the number of credits pledged for sale exactly equal to the total amount of credits that are required to be purchased (i.e., the sum of all pro-rata obligations equals the sum of all credits pledged for sale). As regulated parties are prohibited from purchasing more than their pro-rata share of credits through the Clearance Market, this ensures that regulated parties will have certainty regarding both the availability of credits and the maximum price of credits offered in the Clearance Market.

Given the deliberate structure of the Clearance Market, it is unclear what type of situation would prevent a regulated party acting in good faith from being able to purchase their pro-rata share of credits offered in the clearance market. Nonetheless, even if a regulated party is unable to purchase their pro-rata share of credits through the Clearance Market, there are no clear reasons why ARB providing information regarding a regulated party's pro-rata share would cause regulated parties' to withhold offering their credits for sale during the subsequent year, or to withholding credits until the Clearance Market, as the comment suggests:

- In a year of shortage, demand outpacing supply of credits is likely to result in a credit price that is at or very near that year's price cap. Low-CI fuel producers with excess credits will have incentive to sell as many credits as possible because: (1) they will benefit from increased revenues from selling credits at or near the maximum price; and (2) the price cap is constant in real terms, so low-CI fuel producers' have no incentive to withhold credits to try and sell in subsequent years at a higher price.
- In a year of sufficient supply, low-CI fuel producers with excess credits will have incentive to sell as many credits as possible during the course of normal market operations because it is unlikely that a Clearance Market will occur that year. If the market is fully supplied, there is little rationale for a low-CI fuel producer to withhold their credits for sale, waiting for a Clearance Market that is unlikely to occur.

278. Comment: **LCFS 40-70**

The commenter requests written guidance confirming their understanding of the details of the provision which prohibits transferring/selling credits to another party when they have a deficit themselves.

Agency Response: The prohibition of trading credits does not negate the ability of affected parties for transferring credit generating fuels, by transferring the LCFS obligation at the time title to the fuel is transferred. However, once credits have been separated from a fuel, those credits cannot be transferred so long as the affected party has an outstanding deficit balance.

279. Comment: **LCFS 40-71**

The comment proposes allowing 30 days instead of 15 to record in the LRT-CBTS transactions made during Extended Credit Acquisition Period.

Agency Response: ARB staff disagrees with the proposed change to a 30-day period. Recording transactions promptly in the LRT-CBTS facilitates administration of the program and efficient function of the market for credits. 30 days is not necessary. ARB is not persuaded by commenter's point that an earlier LCFS allowed a lengthy period. Prompt reporting could eventually support more frequent posting by ARB of credit trades to facilitate price transparency. In a 15-day change, trades are required to be completed in 10 days.

280. Comment: **LCFS 40-72**

The comment recommends changes to Section 95486(a)(4)(B)(2).

Agency Response: ARB staff agrees with the commenter and recognizes that regulated parties may not meet their compliance targets for a specified year and therefore would need to retire all credits available to them; this includes any credits that would be available through the credit carry back process. Staff has included a revision that would allow a party to use carryback credits to meet a portion of its compliance shortfall so long as the party minimizes its shortfall by also retiring all credits it possess that are eligible for use in the prior compliance year.

281. Comment: **LCFS 40-73**

The comment proposes changes to the Credit Generation Frequency.

Agency Response: ARB staff disagrees with the recommendation, as regulated parties will have two 45-day periods to submit an accurate quarterly report that aligns with their business partner. The first 45-day reporting period will allow regulated parties to enter their information into the reporting tool while the second 45-day period will allow a regulated party and their business partner(s) to correct any errors in fuel pathway codes, volumes or other information, which was not properly passed along in the product transfer document.

282. Comment: **LCFS 40-74**

The comment requests that ARB include a contingency plan for initiating and completing credit transfers.

Agency Response: ARB staff understands that there is always the concern if an electronic tool goes down for any extended period. Staff already has an old system of credit transfers that was used prior to the development of the LRT-CBTS. Therefore, if the tool were to be under maintenance for longer than a seventy-two hour period, staff could send out a notice and release the manual documentation necessary to complete a trade, which can then be entered into the system at a later date.

283. Comment: **LCFS 40-75**

The comment proposes a sunset date of one year after the regulation effective day for all fuel pathways.

Agency Response: The proposal was modified consistent with the commenter's recommendation.

ARB staff concurs that re-certification should not necessitate re-submission of physical transport mode application material if transport modes and distances have not changed. Provisions that will make this unnecessary were included in the 15-day change package that will go to the Board for approval.

284. Comment: **LCFS 40-76**

The comment states that ARB should include a reference to the denaturant calculator spreadsheet in the regulation.

Agency Response: It is not necessary to include a reference to the denaturant calculator spreadsheet in the regulation. The calculator merely duplicates calculations that are present in CA-GREET-2.0. These calculations were placed into a separate spreadsheet for the convenience of stakeholders.

285. Comment: **LCFS 40-77**

The comment recommends changes to the corn ethanol iLUC value.

Agency Response: The corn indirect land use change (iLUC) value is a topic under consideration of the LCFS and has been revised under the proposed regulation.

286. Comment: **LCFS 40-78**

The comment asserts that the content of denatured ethanol is not characterized based on industry practice.

Agency Response: See response to **LCFS 8-12**.

287. Comment: **LCFS 40-79**

The comment recommends that ARB change the term “regulated parties” in section 95488(c) (6)(A) to “fuel producers.”

Agency Response: The LCFS regulation states:

> LCFS CIs represent the life cycle greenhouse gas emissions, expressed in a per-megajoule of finished-fuel-energy basis, associated with long-term, steady-state fuel production operations. Actual CIs vary over time due to a variety of factors, including but not limited to seasonality, feedstock properties, plant maintenance, and unplanned interruptions and shutdowns. A fuel production operation will not be found to be in violation of its operating conditions unless a CI calculated from production data covering a full year of operations is higher than the certified CI reported for that fuel in the LRT-CBTS system. Fuel producers labeling fuel sold in California with LCFS CIs (in product transfer or similar documents), and regulated parties reporting those CIs in the LRT-CBTS system, must ensure, therefore, that the fuel so labeled and so reported will be found to have a life cycle CI, as calculated from production data covering a year of operations, that is equal to or less than the CIs reported in the LRT-CBTS system and on product transfer documents. Regulated parties shall not report fuel sales under any LCFS CI unless they have determined that the actual CI of that fuel, calculated as described in this section, is equal to or less than the LCFS CI under which sales of that fuel are reported in the LRT-CBTS system. (95488(c)(6)(A))

ARB rejects commenter’s suggestion, because it would significantly diminish the regulation’s enforceability. In many instances only the regulated party reports information to ARB, and the regulated party might be the sole cause of a reporting error. In other instances, a regulated party might report incorrect information provided to that party by a fuel producer, as where the regulated party did not verify the information's accuracy. Finally, there may be instances where it can be said that the fuel producer was solely responsible. In any of the above examples, ARB staff will attempt to take enforcement action against the party primarily responsible for the violation. Regulated parties reporting fuel transactions are nonetheless liable if the CIs they report do not comply with this section. With more parties potentially liable for incorrect information, ARB expects that the accuracy of reports will be improved.

288. Comment: **LCFS 40-80**

The comment opposes the re-submittal of initial or updated demonstrations of fuel transport modes to ARB.

Agency Response: Staff agrees with the commenter and made a change during the 15-day comment period so that if the applicant has previously submitted the physical transport mode information, and there are no changes to the fuel transport mode, there is no need for re-submittal of fuel transport mode information. In addition, ARB staff provides flexibility on the submission of out-of-state fuel transport mode by offering two application options: 1) CA-GREET user default, and 2) use of alternative bill of lading for new fuel pathways. In all such cases, staff will continue to work with the stakeholders on a case-by-case basis, upon request, during the application evaluation process.

289. Comment: **LCFS 40-81**

The comment requests that ARB identify the contributions of changes in the GTAP model and emission factors to changes in iLUC values.

Agency Response: See response to **LCFS 38-30**.

290. Comment: **LCFS 40-82**

The comment questions the removal of ILUC values in the regulation.

Agency Response: In response to this comment, and similar concerns from other stakeholders, a table of the iLUC values was added to the regulation in the 15-day changes.

291. Comment: **LCFS 40-83**

The comment raises questions about how the iLUC emission is calculated for sugarcane ethanol.

Agency Response: See response to **LCFS 38-31**.

292. Comment: **LCFS 40-84**

The comment asks why the means of the Monte Carlo simulations were not used for establishing the iLUC values.

Agency Response: See response to **LCFS 38-32**.

293. Comment: **LCFS 40-85**

The comment questions the use of cropland pasture elasticity to account for endogenous yield adjustments.

Agency Response: See response to **LCFS 38-33**.

294. Comment: **LCFS 40-86**

The comment raises questions about formalizing an iLUC value for cellulosic ethanol.

Agency Response: See response to **LCFS 38-34**.

295. Comment: **LCFS 40-87**

The commenter argues that the degree of crude differentiation within the LCFS should be significantly reduced.

Agency Response: See response to **LCFS 32-10**.

296. Comment: **LCFS 40-88**

The commenter agrees with staff's decision not to propose refinery-specific incremental deficit accounting for large, complex refineries and looks forward to working with ARB on a less complex alternative to crude differentiation.

Agency Response: ARB staff appreciates the commenter's support of our decision not to recommend refinery-specific incremental deficit accounting. Staff remains open to further constructive dialogue on issues of concern to stakeholders.

297. Comment: **LCFS 40-89**

The commenter expresses concerns about the proposed changes to the calculation of the Annual Crude Average CI value.

Agency Response: See response to **LCFS 38-15**.

298. Comment: **LCFS 40-90**

The comment includes two recommendations for modeling of crudes with OPGEE.

Agency Response:

1. *Revise OPGEE using more realistic input values such as for steam generator feed water temperature*.

   See response to **LCFS 38-24**. ARB staff looks forward to working with and receiving data from the commenter to improve the default parameters used in OPGEE as part of future revision cycles.

2. *ARB should pursue collecting the same composition, quality, and environmental profile data for other domestic and imported crudes as is available for California produced crude*.

   See response for **LCFS 37-3**.

299. Comment: **LCFS 40-91**

The commenter recommends that ARB be required to calculate and post quarterly Crude Average CI values.

Agency Response: ARB staff disagrees with this recommendation for mandatory quarterly calculation of crude average CI values as staff believes that the use of the three-year rolling average provides sufficient information for compliance planning and execution. However, staff agreed in 2014 to provide a mid-year, non-regulatory estimate of the crude average CI for the first six months of the compliance period (see http://www.arb.ca.gov/fuels/lcfs/crude-oil/mid-2014-crude-ave-ci.pdf). Staff intends to continue providing this calculation as a service to regulated parties, but do not believe it should be required by the regulation as this mid-year crude average carbon intensity estimate is posted for informational purposes only and provides no regulatory function.

300. Comment: **LCFS 40-92**

The comment suggests all LCFS regulatory revisions should occur no more frequent than once every 5 years and specifically proposes that the frequency of overall revisions to Table 8 or the OPGEE model to be less than every 5 years.

Agency Response: This comment seems at odds with the request to have staff reports to the Board on an annual basis (see **LCFS 40-4**). What would be the purpose of annual reviews of the rule if no changes were ever made? Regardless, the prior changes made to the LCFS regulation have been necessary to ensure a robust market and provide improved program functionality. Further, the historic credit price has been well within expected levels.[11]

As we move forward, we will continue working to refine emission estimates and continue to analyze relevant scientific studies and make appropriate adjustments in the future if deemed necessary. Updating OPGEE and Table 8 on a three-year cycle rather than annually will provide more certainty to refineries for crude purchases as well as allow limited staff resources to be redirected to other LCFS tasks. Updating no more frequently than every three years is consistent with the recordkeeping provisions, and allows for the production of new fuels to be added to the table more frequently than the commenter's proposal of five years, providing up-to-date production information for existing and new fuels to ensure the proper CI values are being used in the market.

301. Comment: **LCFS 40-93**

The commenter expresses support for the revisions to the innovative crude provision.

Agency Response: ARB staff appreciates the commenter's support for the revisions proposed for the innovative crude provision.

[11] From 2012 through 2013, while the LCFS standards for gasoline and diesel were declining, the average credit price reported in the LCFS Reporting Tool (LRT) was $57.70. Weighted average of quarterly LCFS credit prices reported through the LRT available at: http://www.arb.ca.gov/fuels/lcfs/lrtmonthlycreditreports.htm

302. Comment: **LCFS 40-94**

The commenter disagrees with staff's proposal to limit CCS as an innovative crude method to only those instances where the carbon capture occurs onsite at the oil production facility.

Agency Response: See response to **LCFS 37-12**.

303. Comment: **LCFS 40-95**

The commenter objects to staff's proposal to require that CCS projects comply with a Board-approved quantification methodology to qualify for innovative crude production method credit.

Agency Response: ARB staff disagrees with the objection and believes that it is wholly reasonable that a quantification methodology establishing requirements for approving wide ranging and complex carbon capture and storage (CCS) projects under both the Cap-and-Trade and LCFS programs should require a full regulatory process and Board approval. Additionally, the Board approval is already a requirement for the CCS quantification methodology under the Cap-and-Trade Regulation.

Once the CCS quantification methodology is approved by the Board, approval of individual CCS projects under the innovative method provision will occur through the Executive Officer approval process described in the regulation, as long as the project meets the requirements of the quantification methodology.

304. Comment: **LCFS 40-96**

The commenter recommends that the quantification methodology for CCS projects be expedited and only require Executive Officer approval and not the entire Board.

Agency Response: See response to **LCFS 40-95**.

305. Comment: **LCFS 40-97**

This comment includes three objections/recommendations for the innovative crude provision.

Agency Response:

1. *“The proposal should include an option for Crude Production companies to apply for this credit for other GHG reduction projects above and beyond the four envisioned by ARB and included in the regulations. There are other technologies (e.g., solvent extraction) that may result in reduced energy usage and/or GHG from crude oil production. Limiting credits to solar and wind eliminates credits for other renewable energy, such as land fill gas, tidal power, etc*.”

   See response to **LCFS 38-37**. ARB staff believes that fully evaluating a proposed innovative method for inclusion in the regulation requires a deliberate process involving one or more workshops and discussions with stakeholders. Although ARB does not yet have sufficient information on which to evaluate those additional innovative technologies, staff will consider each of these in the next regulatory amendment process.

2. *“We feel the use of renewable electricity transmitted through an electricity grid should be eligible for this credit.*”

   It is our understanding that the commenter is suggesting that the crude producer be able to indirectly purchase offsite renewable electricity that is supplied to a utility distribution system rather than directly consuming the renewably-generated electricity at time of production. Purchase of renewable electricity could be verified and tracked through the generation, transfer, and retirement of renewable energy certificates or RECs. ARB staff has concluded that use of grid electricity together with RECs should not be used to reduce the CI of process electricity under the LCFS or qualify for innovative method credit. The reasons include the following:

   a. RECs are designed to reflect changes in the electricity sector, whereas LCFS is designed to change the transportation sector.

   b. If approved for use, RECs would reduce the CI of the crude and earn innovative credit without in any way changing the pathway itself. Moreover, available RECs can cover generation that occurred many months in the past, at some distance from California, or both. The innovative crude provision is designed to incent CI-reducing innovations in actual crude production pathways. Requiring that the renewable electricity be directly consumed by the crude oil producer at time of production provides a direct link between the crude production and the renewable electricity generation.

c. RECs are tracked in a number of regional systems. The largest and most mature is the Western Renewable Energy Generation Information System (WREGIS), but several others are also in operation. If WREGIS RECs were approved for use in LCFS pathways, requests to use RECs from the other regional tracking systems could be expected. Although these various exchanges have much in common, there are likely important differences that would have to be understood.

ARB staff believes that significant potential exists for renewable electricity generation at or near crude oil production facilities and requiring direct supply of renewably generated electricity does not impose an unreasonable barrier to development and use of this innovative method. Moreover, requiring direct supply of renewably generated electricity helps to ensure that the project was specifically developed for reducing emissions from crude oil production, and therefore represents additional GHG emissions reductions directly attributable to the LCFS program.

3. *"We oppose the requirement that third parties providing either innovative steam or electricity must be co-applicants, especially given that co-applicants are not able to generate credits under the proposal. Any recordkeeping or regulatory requirement would be more appropriately managed through contractual language between third party providers and crude producers*."

ARB staff disagrees with the comment and the recommendation allowing application and recordkeeping to be managed exclusively through contractual language between the third party and the crude producer. Because much of the application and recordkeeping requirements for innovative projects that involve third parties (e.g., producers of steam or electricity or receivers of CO_2) is under the jurisdiction of the third party and not the crude producer, staff believes that the third party should be a co-applicant in order for ARB to have direct regulatory access to the third party.

306. Comment: **LCFS 40-98**

The commenter opposes the LC/LE Refinery provisions.

Agency Response: See response to **LCFS 38-35.**

307. Comment: **LCFS 40-99**

The commenter objects to the refinery-specific incremental deficit option for low-complexity/low-energy-use refineries.

Agency Response: ARB staff disagrees with the commenter's objection. Staff's rationale for including the provision is discussed on pages II-15 and II-16 of the ISOR. Moreover, the inclusion of the refinery-specific option does not affect the California Average provision for the large refineries that the commenter represents. See also the response to **LCFS 32-10**.

308. Comment: **LCFS 40-100**

The commenter expresses several concerns regarding the option for refinery-specific incremental deficit accounting for low complexity, low energy use refineries.

Agency Response: See response to **LCFS 32-10**.

Furthermore, ARB staff see no logical reason why "allowing some refiners to opt-out of the industry-wide average approach creates a bifurcated market and introduces the potential for fraud given the chain of custody for crude and feed stocks is immensely complex and there is no uniform, verifiable certification scheme." The refinery-specific option requires more onerous field-level crude reporting and does not affect the calculation of incremental deficits under the California Average provision.

While staff acknowledges the commenter's objection that the refinery-specific accounting "could reward a refinery for past high CI crude use while penalizing a refinery with historically low CI crudes", staff believes this objection is primarily germane to a refinery-specific accounting scheme that is mandatory for all refineries. Staff disagrees that this presents a significant issue for an optional program that is only available to a limited number of small refineries. Any of the qualifying refineries that believe the refinery-specific accounting would be "penalizing" in any way can simply remain under the California Average provision.

309. Comment: **LCFS 40-101**

The commenter believes the definition of "LE refineries" should be based on the lifecycle carbon intensity of the transportation fuels produced. A LC/LE refiner that uses more energy per gallon of transportation fuel ***produced from crude oil*** [emphasis in original comment] should not be granted special treatment.

Agency Response: Staff was directed by the Board to consider the lower energy inherently embedded into the transportation fuels from refineries that use simple processes to refine transportation fuel. See response to **LCFS 38-35**.

310. Comment: **LCFS 40-102**

The comment states that it is not clear from the ISOR how ARB calculated the LC/LE refiners transportation fuel CI.

Agency Response: ARB staff calculated the carbon intensity of CARBOB and diesel refining from all California refineries using Mandatory Reporting Requirement (MRR) data. Staff then compared the average CARBOB and diesel carbon intensities of complex refineries to those of the LC/LE refineries and found the difference to be about 5 gCO2e/MJ. This calculation was outlined the ISOR and in three workshops: April 18, 2014, July 10, 2014, and September 29, 2014.

311. Comment: **LCFS 40-103**

The comment states that it is not clear if the calculation of LC/LE overall CI includes the transportation fuels produced from all feedstocks to the LC/LE refineries or just the transportation fuels produced from crude oil. If the overall CI used to calculate the 5 gCO_2e/MJ "adjustment" includes the processing of feedstocks other than crude oil, the commenter believes ARB staff should modify the adjustment to only take into account the transportation fuels produced from crude oil.

Agency Response: As outlined in the ISOR, the calculation of LC/LE overall CI does include fuels produced from all feedstocks. There is language in the LC/LE provision that assigns additional deficits for fuels made from sources other than crude oil.

312. Comment: **LCFS 40-104**

The comment requests ARB staff include a methodology for calculation of the volumes of CARBOB, diesel, and transmix in the regulation.

Agency Response: Under section 95483(e)(4)(B) of the regulation states the LC/LE credit is given only to CARBOB and diesel fuel produced from crude oil. As part of the LC/LE provision all applicants must report their volumes of CARBOB and diesel fuel produced from crude, transmix, Petroleum Intermediates, and purchased CARBOB and diesel fuel for blending.

313. Comment: **LCFS 40-105**

The commenter requests that the regulatory language should indicate that the sale and/or trade of any credits generated under the Low Complexity-Low Energy Use Refinery provisions are prohibited.

Agency Response: This language was inadvertently omitted. ARB staff has added 15-day language that prevents the credits from being sold or traded.

314. Comment: **LCFS 40-106**

The comment identifies a typographical error and suggests that 95481(a)(57) should be 95481(a)(55)

Agency Response: This change has been made in the 15-day language.

315. Comment: **LCFS 40-107**

The comment suggest that in 95489(e)(2)(c) intermediate feedstocks should be Petroleum Intermediate feedstocks.

Agency Response: This change has been made in the 15-day language.

316. Comment: **LCFS 40-108**

The comment requests a formatting change.

Agency Response: ARB staff does not see any need for a formatting change in the refinery-specific incremental deficit calculations as staff sees no confusion between subscripts and superscripts in the equations

317. Comment: **LCFS 40-109**

The comment proposes five modifications of the Refinery Investment Provision.

Agency Response:

1) *Limiting onsite increases of criteria air pollutants and toxics unreasonably excludes offsets of criteria and air toxic pollutants.*

See response to **LCFS 38-9.**

2) *The 0.1 gCO_2e/MJ threshold is too stringent and unfairly penalizes larger, more efficient refineries.*

See response to **LCFS 38-10.**

3) *Investments should not be limited to capital or onsite projects.*

See response to **LCFS 38-11**.

4) *The eligibility cutoff date does not recognize improvements made since program adoption*.

See response to **LCFS 38-12**.

5) *The biofeedstock 10% threshold is too restrictive and unfairly penalizes larger, more efficient refineries.*

See response to **LCFS 38-13**.

318. Comment: **LCFS 40-110**

WSPA asks that ARB eliminate the requirement to address criteria pollutant or toxic emissions.

Agency Response: See response to **LCFS 38-9**.

319. Comment: **LCFS 40-111**

The comment asserts that the CI reduction threshold (0.1 gCO_2e/MJ) will unnecessarily eliminate legitimate projects.

Agency Response: See response to **LCFS 38-7** and **LCFS 38-10**.

320. Comment: **LCFS 40-112**

The comment asserts that limitations on project type in the Refinery Investment Credit Provision will eliminate valuable GHG reducing projects

Agency Response: See response to **LCFS 38-11**.

321. Comment: **LCFS 40-113**

The commenter requests that the project eligibility for the Refinery Investment Credit Provision should extend to early actors and new construction.

Agency Response: See response to **LCFS 38-12**.

322. Comment: **LCFS 40-114**

The commenter requests that ARB staff reconsider and remove the proposed 10% biofeedstock threshold as it is inequitable.

Agency Response: See response to **LCFS 38-13**.

323. Comment: **LCFS 40-115**

The commenter recommends that ARB change the denominator in the term, "T = percentage of transportation fuel produced" *from* "total volume of product output…" to the "total volume of crude oil and intermediates supplied to the refinery (bbl).

Agency Response: ARB staff has made a 15-day change to clarify that "$Volume^{Total}$" is the total output of transportation fuels in barrels.

324. Comment: **LCFS 40-116**

The commenter requests that ARB staff provide a comparison of the 10% level to the 0.1g/MJ threshold for other projects. The 10% threshold seems to be a high threshold that will not help encourage such projects.

Agency Response: See response to **LCFS 38-13**.

325. Comment: **LCFS 40-117**

The comment suggests that ARB consider an option for CI reduction credits to be allocated more specifically to the units and products to which they apply (versus overall for the refinery).

Agency Response: ARB staff will consider examining this for the future, but this change would require more analysis and would not be appropriate as a 15-day change. ARB staff did not want to see this provision result in increases elsewhere in the refinery. Any change would need to account for the linked aspect of refinery processes and ensure the project truly reduce GHGs at the refinery as a whole.

326. Comment: **LCFS 40-118**

The comment does not agree that unclear transmission of information on product transfer documents is a key cause of discrepancies.

Agency Response: See response to **LCFS 38-39**.

327. Comment: **LCFS 40-119**

The comment objects to the change proposed that would change the definition of Product Transfer Document (PTD) to refer to a newly created, single document rather than a collection of documents that transmit the required information.

Agency Response: See response to **LCFS 38-39**.

328. Comment: **LCFS 40-120**

The comment expresses concerns about the practicality and fairness of requiring the original transferor of fuel sold without obligation to report any export of that fuel by any subsequent owner or supplier.

Agency Response: See response to **LCFS 38-40**.

329. Comment: **LCFS 40-121**

The comment states that the production facility ID and the Company should not be included in all transaction documents.

Agency Response: Having the Company ID and Facility ID included with each reported transaction where an alternative fuel (e.g., biofuel) is involved is necessary for effective auditing. For example, reporting of Facility ID and volumes would allow ARB staff to detect fraudulent reports totaling 50 million gallons in a given year from Facility X, when Facility X is in fact capable of producing only 20 million gallons per year. Knowing the production facility is also the best way to substantiate the carbon intensity (CI) and volumes of the alternative fuel volumes reported.

Alternative fuel providers maintain Company ID and Facility ID information as part of their business management systems, where it is also available for LCFS reporting. Incorporation of these ID's is readily transferrable to downstream parties via the Product Transfer Document (PTD). It is apparent to ARB staff that the Company ID and Facility ID information is available and can readily remain associated with multiple fuel volume transactions during downstream fuel transactions. The Company ID and Facility ID information is currently being reported in the LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS) as part of fuel transaction reporting in the vast majority of reported transactions (>92 percent) and in 100 percent of all fuel transactions reported by greater than 75 percent of regulated parties.

330. Comment: **LCFS 40-122**

The commenter believes that entities should be able to make changes to the quarterly reports with (*sic*) enforcement penalties, provided the corrections do not materially impact a credit transaction relying on the information submitted in the quarterly report.

Agency Response: ARB staff disagrees. The commenter prefers a reporting-based regulation where its members do not face any liability for misreporting in certain circumstances. Experience at ARB and in regulatory programs elsewhere indicates that complete immunity does little or nothing to deter violations, whether they are caused by accident, neglect or intent; errors are preventable. The crux of the comment goes to how ARB should exercise enforcement discretion based on different circumstances, and the commenter proposes a reasonable distinction between material errors and non-substantive errors. ARB staff has, and regularly employs, discretion to distinguish between such different circumstances in deciding whether to initiate enforcement and if so, what remedy to seek; indeed the regulation at section 95494(a) expressly incorporates specified factors for consideration.

Nevertheless, attempting to codify and completely immunize specified circumstances that sound harmless in the abstract is impossible due to the infinite variety of fact patterns. For example, reporting errors that have "no impact on credit balance" – a category for which the commenter suggests favorable treatment – could in some instances create serious impediments to the overall program's operation. If parties transacting volumes of fuel that collectively generated significant credits or deficits could report the wrong information or simply submit correct information late, significant manipulation or unintended credit market impacts could occur, even if ultimately the reports were corrected or submitted with "no impact" on the party's credit balance.

331. Comment: **LCFS 40-123**

The comment is concerned that the January 1, 2019 date for regulation review and a presentation to the Board is too late to effect change in the program.

Agency Response: ARB staff believes that the review gap is appropriate to maintain stability in the program. Staff will monitor and make public the credit transactions and prices and will report back on volumes. ARB staff has the ability to go back to the board sooner if concern develops.

332. Comment: **LCFS 40-124**

The comment expresses concern that there is a substantial gap in time between the recent January 1, 2015 review and the January 1, 2019 review.

Agency Response: See response to **LCFS 40-123**.

333. Comment: **LCFS 40-125**

The comment requests reinstatement of the items that have been proposed for removal from the review list.

Agency Response: Staff anticipates these topics being considered in the program review conducted prior to January 1, 2019 but does not believe it's necessary to call out all of the items in the rule as the commenter requests. In fact, the request for annual review of some of these items (i.e., advances in fuel lifecycle assessments) seems to conflict with comment **LCFS 40-92,** which indicates frequent changes to CI values (e.g., crude CIs in Table 8) would result in increased LCFS credit prices, compliance issues and difficulty in meeting the goals of the LCFS program and should occur no more frequently than once every five years. See response to **LCFS 38-1**, **LCFS 40-92**, and **LCFS 40-123**.

334. Comment: **LCFS 40-126**

The comment requests the ARB Board to ask staff to revise the regulation to include the review items that were removed.

Agency Response: See response to **LCFS 40-125**.

335. Comment: **LCFS 40-127**

The comment requests that the former Periodic Reviews be replaced with annual staff reports to the Board that provide a detailed synopsis of the health of the program, the challenges, and any need for program changes.

Agency Response: See response to **LCFS 38-1** and **LCFS 40-125**.

Comment letter code: 41-OP-LCFS-Tesoro

Commenter: Miles Heller

Affiliation: Tesoro

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

41_OP_LCFS _Tesoro

TESORO

February 17, 2015

Clerk of the Board
Air Resources Board
1001 I Street
Sacramento, CA 95814

Electronic Submittal

RE: CARB Low Carbon Fuel Standard Re-Adoption, February 19th Hearing

Dear Chairwoman Nichols and Honorable Board Members:

Tesoro appreciates the opportunity to comment on the proposed re-adoption of the Low Carbon fuel Standard (LCFS). Tesoro reliably provides a substantial volume of clean gasoline and diesel to the California market and has a tremendous interest in the implementation of the LCFS and its impacts on that reliable fuel supply.

We understand that the Western States Petroleum Association has provided comments on this re-adoption as well. Tesoro supports those comments, but wishes to focus on a few specific aspects of the proposed regulation.

Refinery Investment Credits

Tesoro appreciates the inclusion of Section 95489 (f) – Refinery Investment Credit that will allow a refinery to receive credit for reducing greenhouse gas (GHG) emissions from its facility. We believe such regulatory incentives will lead to overall statewide GHG emission reductions while concurrently lower carbon intensity of California transportation fuels. Fundamentally, such a provision makes good sense in the context of a performance and life cycle based standard. However, we believe the highly complex qualification criteria added to the proposed regulation will make it very difficult or impossible for emission reduction projects to overcome the hurdles and be qualified for the credits. Tesoro recommends the proposed regulation be modified to address the following concerns:

1. The regulation should be cost neutral related to investment.

   The objective of the proposed provision should be to provide sufficient incentives for refineries to implement emission reduction projects regardless of project costs. Innovations can come in many different forms. Some projects may require physical modification, while other projects may simply require a change in refining process or method of operations. The cost of implementing these projects and air quality permits requirements may vary significantly. We suggest the proposed regulation define capital investment project as a

LCFS 41-1

project to improve energy efficiency, or reduce GHG emissions through physical modification, change in refining process or method of operations at a refinery. LCFS 41-1 cont.

2. <u>At a minimum, projects that demonstrate GHG emission reductions or construction beginning on or after January 1, 2015 should be eligible for credits.</u>

During the workshop process, Tesoro advocated that any projects completed since 2010 achieving real, quantifiable and verifiable reductions should be eligible for credits in years following adoption of such a provision. Because 2010 is the baseline year for the LCFS, Tesoro still believes that such projects result in valid credits utilizing the lifecycle approach promoted by the LCFS.

Because CARB has been reluctant to make this change, Tesoro requests that CARB revisit the requirement that eligible projects must not have submitted permit applications prior to January 1st, 2015. Many emission reduction projects requiring air quality permits may take up to two years to permit due to various regulatory requirements. For this reason, refineries may choose to submit applications for authority to construct early in the process concurrent with internal feasibility evaluation to ensure construction can begin on schedule. Without being able to take advantage of refinery investment credits, some of these projects may not be economically feasible, resulting in missed GHG emission reduction opportunities from projects for which application for authority to construct were submitted prior to January 1, 2015. Tesoro suggests a more appropriate demarcation is a project's construction or implementation date commencing on or after January 1, 2015. LCFS 41-2

3. <u>The regulation should address the issue of criteria and toxic air contaminants by ensuring that the projects comply with applicable regulations administered by the local air pollution control agencies.</u>

Regulating criteria pollutants and toxic air pollutants to ensure no significant net increase is complex. Refineries that may implement GHG reductions under this proposed regulation are located in the jurisdictions of four of the largest air pollution control agencies with the most stringent New Source Review (NSR), Prevention of Significant Deterioration (PSD), and Toxic Air Contaminants Regulation. These regulations must meet the no backsliding requirements under state law and most regulations were reviewed and approved by the Air Resources Board as part of the State Implementation Plan (SIP) or other air toxic programs. We believe compliance with applicable regulations administered by these local air pollution control agencies should be adequate qualification for these projects. LCFS 41-3

4. <u>The carbon intensity threshold for investment project should be at 0.05 gCO2e/MJ level or below.</u>

Depending on the size of the refinery and the product outputs, it may require GHG emission reduction project in the range of 30,000 to 70,000 metric tons to achieve 0.1 gCO2e/MJ reduction in carbon intensity. Consider that the threshold for reporting under this regulation is 10,000 metric tons and the threshold for compliance obligation is 25,000 metric tons, Tesoro suggests the project qualification threshold be eliminated or set at a level below 0.05 LCFS 41-4 gCO2e/MJ reduction in carbon intensity. This level or below is a more reasonable level and will provide better incentives for emission reduction projects. LCFS 41-4 cont.

5. Conduct a survey of California refineries to develop a threshold limit for renewable feedstock that is technologically feasible and cost effective.

   We are not aware that the requirement to replace petroleum feedstock with a minimum 10% of renewable feedstock is technically achievable in the current refinery setting. We would like to suggest that ARB conduct a survey of California refineries to establish a minimum level that can be achieved by refineries within the state. At a minimum, the eligibility threshold should be set no higher than a GHG reduction threshold equivalent to the 0.05 gCO2e/MJ suggested in the prior comment. LCFS 41-5

6. Clarify and Correct Equations in the Proposed Regulation.

   In the equation for credits for diesel and CARBOB on page 119, the term $E^{XD}_{Renewable}$ should be replaced with the term $EC^{XD}_{Renewable}$ as defined on page 121. $Volume^{XD}$ should be clearly defined as the volume of certain products reported to ARB under Subpart Y including coke with a specific conversion rate from ton to barrel. LCFS 41-6

Compliance Schedule

CARB's own compliance scenario demonstrates that the LCFS target of a 10% reduction by 2020 is not feasible. Even in the most back-end loaded schedule proposed by CARB, by 2018 the level of banked credits begins to draw down. This means that by 2018 and in the subsequent years, even with ARB's overly optimistic estimates of low CI fuel availability, there are not enough alternative fuels generating credits to offset the deficits generated by ARB's predicted demand for gasoline and diesel. Based on CARB's data, it appears that only a 7% CI reduction is feasible by 2020. The remaining 3% is made up for by credits banked in the early years of the program. While 3% does not sound like much, it constitutes 30% of overall program compliance towards the 2020 goal and amounts to three times as many credits as have been required on an annual basis to date. The program is simply not feasible in the timeframe contemplated by CARB and not sustainable in the years beyond. This fact necessitates a different approach. LCFS 41-7

One solution to this issue is to understand what is feasible without banked credits and set a 2020 target (and intervening years) that is consistent with the availability of the fuel. The quantities of excess credits accumulated to date from over-compliance in the early years of the program should be viewed as providing compliance flexibility to obligated parties when the reduction obligation increases or when unforeseen incidents occur impacting low CI fuel availability. In fact, this could obviate the need for the Cost Containment Measure CARB has proposed in the amendments.

Coupled with a more feasible compliance schedule, CARB staff should annually review the status of alternative fuel developments, along with all the underlying assumptions to that compliance schedule and provide a report to the board. This way, the board can more frequently assess the volumes of alternative fuels and related credits compared to the projections that were relied upon in setting the schedule and then provide direction to staff regarding program and schedule changes. LCFS 41-7 cont.

Cost Containment Mechanism

Tesoro wants to emphasize that a cost containment mechanism, no matter how well designed, is not a substitute for ensuring a feasible compliance path in the regulation (as discussed above). Such mechanisms have their place to deal with short-term, unforeseen circumstances that can adversely impact fuel availability on consumer cost. With this in mind, Tesoro requests that CARB study the pros and cons of allowing obligated parties in the LCFS program to cover their reduction obligation with allowances and/or offsets from the Cap & Trade program as an additional cost containment option. LCFS 41-8

Tesoro appreciates the opportunity to submit comments on the draft LCFS regulation. Please contact me at (916) 462-5062 if you have any questions.

Sincerely,

Miles Heller
Director, CA Fuels and Regulatory Affairs

41_OP_LCFS_Tesoro Responses

336. Comment: **LCFS 41-1**

The commenter suggests the proposed regulation define a capital investment project as a project to improve energy efficiency, or reduce GHG emissions through physical modification, change in refining process or method of operations at a refinery.

Agency Response: See response to **LCFS 38-11**.

337. Comment: **LCFS 41-2**

The commenter requests that projects that demonstrate GHG emission reductions or constructions beginning on or after January 1, 2015 should be eligible for credits.

Agency Response: See response to **LCFS 38-12**.

338. Comment: **LCFS 41-3**

The commenter requests that the regulation should address the issue of criteria and toxic air contaminants by ensuring that the projects comply with applicable regulations administered by the local air pollution control agencies.

Agency Response: See response to **LCFS 38-9**.

339. Comment: **LCFS 41-4**

The commenter requests that ARB staff reduce the carbon intensity threshold for investment project to 0.05 gCO_2e/MJ or below.

Agency Response: See response to **LCFS 38-10**.

340. Comment: **LCFS 41-5**

The commenter requests ARB staff conduct a survey of California refineries to develop a threshold limit for renewable feedstock that is technologically feasible and cost effective.

Agency Response: See response to **LCFS 38-13**.

341. Comment: **LCFS 41-6**

The commenter requests that in the equation for credits for diesel and CARBOB on page 119, the term $E^{XD}_{renewable}$ should be replaced with the term $EC^{XD}_{renewable}$ as defined on page 121. They also request that the Volume ^{XD} term should be clearly defined as the volume of certain products reported to ARB under Subpart Y including coke with a specific conversion rate from ton to barrel.

Agency Response: ARB staff made 15-day changes to clarify the equations in section 98489(f) of the proposed regulation.

342. Comment: **LCFS 41-7**

The comment asserts that ARB's own compliance scenario demonstrates that the LCFS target of a 10% reduction by 2020 is not feasible, and requests the regulation be reviewed annually.

Agency Response: ARB staff believes there will be sufficient credits to achieve the required 10 percent reduction in 2020 and at least maintain that level beyond 2020. See response to comment **LCFS 38-1**. For a response to the request for more frequent review of the compliance schedule for the program see the response to comment **LCFS 38-2**.

343. Comment: **LCFS 41-8**

The comment requests that ARB study the pros and cons of allowing obligated parties in the LCFS program to cover their reduction obligation with allowances and/or offsets from the Cap & Trade program as an additional cost containment option.

Agency Response: The suggested consideration could take place as part of the LCFS program review in the event the commenter still sees merit in its ideas. We note, however, that ARB has no current plans to implement the suggestion. The Cap-and-Trade program has different goals than does the LCFS, thus importing credits from Cap-and-Trade will not necessarily help achieve the LCFS' goals. Moreover, LCFS already has cost containment measures both in its market-based design and the new measures denominated as cost containment. Finally, ARB staff's analysis regarding the availability of low-CI fuels indicates that there will be sufficient credits available through 2020 from existing low-CI fuel technologies and promising low-CI fuels on the horizon.

Comment letter code: 42-OP-LCFS-NGO

Commenter: Simon Mui

Affiliation: NGO Coalition Supporting LCFS

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

42_OP_LCFS _NGO

25_OP_ADF _NGO

American Lung Association in California • Center for Energy Efficiency and Renewable Technologies • Environmental Defense Fund
National Wildlife Federation • Natural Resources Defense Council
The Nature Conservancy • Union of Concerned Scientists

February 17, 2015

Mary Nichols, Chairman
California Air Resources Board
1001 I Street, PO Box 2815
Sacramento, CA 95812

Dear Chairman Nichols and Members of the Board:

Thank you for your commitment to cleaner, healthier air for all Californians and for your international leadership in protecting current and future generations from the impacts of climate pollution. Our organizations appreciate the work of the Board and staff to develop, implement, and defend a key policy measure under AB 32, the Low Carbon Fuel Standard, and respectfully submit these comments for consideration at your February 19 hearing. Also reflected in these comments is our support for the Alternative Diesel Fuels regulation, which is also before you on the 19th. LCFS 42-1

In January, Gov. Jerry Brown outlined a goal for California to cut in half its petroleum use in cars and trucks by 2030. The LCFS is a critical policy measure to allow the state to achieve this new goal. California remains one of the biggest consumers of petroleum nationally; the state used 14.2 billion gallons of gasoline and 3.8 billion gallons of diesel fuel in 2013.[1] Our state's current dependence on petroleum fuels generates nearly half of our climate pollution, 80 percent of smog-forming NOx emissions, and 95 percent of cancer-causing diesel particulates.[2] The state's dependence on oil is dangerous to public health and is a leading contributor to air pollution. Today, unhealthy air causes more than 9,000 premature deaths and tens of thousands of asthma attacks, emergency room visits, and hospitalizations each year in California.[3] By cutting carbon emissions from transportation fuel, the LCFS is an important piece of California's policy response to the environmental and health crisis caused by our dependence on oil. LCFS 42-2

The LCFS is a critical component of AB 32, California's Global Warming Solutions Act of 2006; it represents one of the state's largest greenhouse gas emission reduction measures. As such, it provides LCFS 42-3

---

[1] ARB December 2014 *Staff Report: Initial Statement of Reasons, Proposed Re-adoption of the Low Carbon Fuel Standard,* Pg ES-1
[2] IBID
[3] ARB *Estimate of Premature Deaths Associated with Fine Particle Pollution (PM2.5) in California Using a U.S. Environmental Protection Agency Methodology* http://www.arb.ca.gov/research/health/pm-mort/pm-report_2010.pdf

the necessary foundation for meeting California's existing health-based air quality and climate goals, and puts the state on a path for meeting its long-term goals with deeper emissions cuts. The program is establishing a direct, long-term regulatory structure to transform our fuel supply in order to: LCFS 42-3 cont.

(1) enable a switch from high-carbon petroleum to ultra-low carbon fuels
(2) ensure continued reductions from all existing fuels, and
(3) protect against crude oil getting even dirtier over time and offsetting progress being made in the transportation sector.

Therefore, the LCFS must remain strong now in order to meet its 10 percent carbon reduction standard in 2020 and be enhanced in the post-2020 time period to ensure that California's 2050 climate goals are met.

1. We strongly support staff's proposal to stay the course on requiring a 10 percent reduction in fuel carbon intensity by 2020.

We strongly support staff's proposal to retain the existing requirement to reduce carbon intensity of diesel and gasoline fuels 10 percent by 2020 and ask the Board to reject long-standing efforts to weaken the standard.

We call on the Board to continue to provide greater regulatory certainty so that the industry stays on track to meet the 10 percent reduction goals. Years of accumulated experience under the LCFS show that the regulated parties continue to make significant progress in achieving the 10 percent in 2020 reduction requirement, with the current requirement being exceeded by nearly 70 percent.[4] More than ever, LCFS regulatory certainty and program stability is needed to support the transition to low-carbon fuels occurring in California and throughout the Pacific Region, where Oregon, Washington, and British Columbia are also working to implement or adopt clean fuel standards.

Furthermore, a growing body of research shows that the oil industry can meet the LCFS targets. A new study conducted by Promotum, a fuels and chemicals consultancy, and commissioned by the Natural Resources Defense Council, the Union of Concerned Scientists, and the Environmental Defense Fund, found that the oil industry can meet the 2020 LCFS standard through known, existing fuels and refinery technologies.[5] (We are also submitting the Promotum study as a separate comment in support of the proposed requirements.) These known strategies include expanding the use of lower-carbon biodiesel and renewable diesel, biomethane, electricity, and ethanol, and improving the carbon intensity of existing alternative fuels. The Promotum study also found that existing oil refineries and crude oil production facilities could dramatically cut their carbon footprint by integrating renewable energy, utilizing innovative technologies, and investing in greater energy efficiency. The Promotum results LCFS 42-4

[4] Air Resources Board (2014), *Low Carbon Fuel Standard Regulation: Initial Statement of Reasons*. December 31, 2014. http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm
[5] Promotum. *California's Low Carbon Fuel Standard: Evaluation of the Potential to Meet and Exceed the Standards*, February 2015

complement a body of technical work, including a compliance and economic study by ICF International (2013), and a regional fuel supply study conducted by ICCT and E4Tech (2014).[6] LCFS 42-4 cont.

2. We support additional reductions and urge ARB to look beyond 2020.

Establishing strong signals now for the post-2020 timeframe is consistent with the transformation process outlined in the First Update to the AB 32 Scoping Plan. California's near-term efforts to establish a strong market for clean, low carbon fuels are critical to make sure the state is on the pathway to the deeper reductions needed to meet the 2050 goals.

Moreover, the growing body of scientific evidence indicates this is possible. Industry can meet more stringent standards and there will be enough alternative fuels available to help industry comply. The aforementioned study by Promotum finds California is capable of reaching a 15 percent reduction target for the LCFS by 2025, representing a tripling in the share of alternative fuels in the next 10 years. The study by ICCT and E4Tech finds that available low carbon fuels could grow to replace up to 400,000 barrels of gasoline and diesel use *per day*, reducing the overall carbon intensity of on-road transportation fuels in California and the Pacific Northwest by 14 percent to 21 percent by 2030.[7] LCFS 42-5

Furthermore, we support the concept of having one regulatory review or report back to the Board prior to 2020 to ensure that the regulation is on track and to incorporate any critical updated scientific data, as ARB is doing with the current regulatory update. However, we ask the Board to reaffirm that any review also be used as a process to enhance long-term regulatory certainty and stability, by including as part of the scope (1) a discussion and evaluation of potential post-2020 requirements beyond the 10 percent carbon-intensity reduction, and (2) an assessment of the LCFS's ongoing contribution and future progress toward meeting both AB 32 goals and the Governor's 2030 climate and petroleum reduction goals. LCFS 42-6

3. We support ARB's proposal to credit refinery pollution reduction improvements and innovative technologies.

We have long held that oil companies can also invest to reduce their own carbon emissions directly at their facilities, thereby lowering their own carbon intensity. A study by TetraTech, a technical consultancy, and NRDC (2013) found that implementation of just a handful of technologies could significantly contribute to meeting the goals of the LCFS.[8] This is largely because even small reductions in carbon intensity, across larger volumes of crude oil or petroleum products, can generate significant carbon reductions.

---

[6] http://www.theicct.org/potential-low-carbon-fuel-supply-pacific-coast-region-north-america; http://www.caletc.com/lcfsreport/ (commissioned by California Electric Transportation Coalition, California Natural Gas Vehicle Coalition, Advanced Biofuels Association, CERES, and Environmental Entrepreneurs.

[7] Malins et al. *Potential Low Carbon Fuel Supply to the Pacific Coast Region of North America*. The International Council on Clean Transportation. Washington, D.C., January 2015

[8] Tetratech and NRDC, *Carbon Reduction Opportunities in the California Petroleum Industry*, October 2013, http://www.nrdc.org/energy/california-petroleum-carbon-reduction.asp

We commend ARB staff for their extensive work and research into the many ways that refineries and crude oil production facilities can reduce their own carbon intensity, and for developing a proposal that allows facilities to obtain LCFS credits for greenhouse gas emissions reductions achieved through their refinery improvement and capital investment projects and through incorporation of renewables. Many of these projects, including solar thermal technologies and energy efficiency at refineries, are expected to have co-benefits in terms of reduced toxics and criteria pollutants. ARB is right to ensure, however, that the additional compliance pathways provided to regulated parties are only for projects that are beyond business-as-usual; that reductions are real and permanent, and verifiable; and that additional co-benefits in terms of reduced toxics and criteria pollutants are maximized. We support ARB staff adopting the above principles as a matter of good policy, and we support ARB's proposal to ensure that that projects represent:

LCFS 42-7

- Actual capital investments or represent increases in renewable energy or feedstock use at refineries. This is to ensure that the program is not rewarding merely shutting down units, rewarding business-as-usual practices, and that actual capital investments or procurement occurs.
- Net carbon-intensity reductions at the refinery. This ensures that only the *net* reductions in carbon intensity at the refinery overall are rewarded (as opposed to only counting emissions from one unit of the refinery). Also, since a carbon-intensity approach is being utilized, the program accounting is robust against annual variations in production (or throughput) at refineries.
- Projects implemented in 2015 or later. Only new refinery carbon-intensity reduction projects, and not past projects that have already been completed, should be rewarded with credits to ensure valuable LCFS credits are not going toward "anyhow" reductions that would have occurred anyways.

Beyond general refinery improvements, ARB appropriately proposes to award credits for innovative technologies that allow crude oil producers to reduce their carbon intensity. A number of technology providers have already expressed interest and have indicated they are attempting to develop projects. The Tetratech/NRDC (2013) study found that existing oil refineries and crude oil production facilities could dramatically cut their carbon footprint by integrating renewable energy inputs, utilizing innovative technologies such as solar thermal, and investing in greater energy efficiency. The study estimated that 3 to 6.6 MMT of CO_2 emission reductions could occur from California facilities alone by 2020, representing 16 percent to 39 percent of the annual requirements that year. We note that the scope of the Tetratech/NRDC study did not incorporate opportunities to replace fossil natural gas at California refineries, which are the single largest industrial user in California.

LCFS 42-8

We note that while many California refineries have publically stated or self-reported that they have pursued all or nearly all cost-effective energy efficiency reduction opportunities, a wide array of literature points to the potential being large and highly dependent on the internal rate of return (IRR) assumed.[9] For example, Booz & Company (2010) estimated that the reduction opportunities at one

[9] Just a few examples include: Kema, Inc., Lawrence Berkeley National Laboratory and Quantum Consulting, *California Industrial Existing Construction Energy Efficiency Potential Study,* for Pacific Gas and Electric Company,

example company increased by more than 3.5 times when going from a high 51 percent IRR to a 14 percent IRR metric for projects. We also note that the carbon reduction value—as monetized by regulatory systems—also greatly affects the cost-effectiveness of projects.[10] In addition, the scopes of both the TetraTech/NRDC (2013) and Promotum (2014) studies only considered a handful of technologies, such that the inclusion of additional technologies utilized by refineries and crude oil producers could result in an even larger reduction potential. LCFS 42-8 cont.

Finally, we applaud the development of the refinery investment provision as a positive incentive to cut greenhouse gases, toxics, and other air pollutants in communities burdened by refinery emissions. While the LCFS is aimed at reducing petroleum consumption, we must also support incentives to clean up local pollution sources and improve community health as the LCFS moves forward. We strongly support ARB precluding refinery investment projects that would cut carbon but increase criteria air pollutants or air toxics from receiving credits. LCFS 42-9

4. We support ARB continuing to account for the carbon intensity of crude oils.

Since its inception, the LCFS has accounted for and protected against potential worsening of petroleum fuels, such as from high carbon-intensity crude oils. We support ARB continuing to ensure the LCFS properly accounts and protects against increases in the carbon-intensity performance of gasoline and diesel above the 2010 baseline, due in particular to increased crude oil production emissions over time. As the modeling work by ARB has shown, the carbon intensity of various crudes can vary as greatly as the carbon intensity of alternative fuels. It makes little sense to ignore those changes from petroleum fuels, which comprise 93 percent of the transportation energy mix, and is consistent with the LCFS program's intent and lifecycle approach. To meet our long-term climate goals, we need to ensure that we simultaneously move to ultra-low carbon fuels *while* preventing current petroleum-based fuels from becoming even dirtier over time. The accounting mechanism for petroleum is a key element of a strong LCFS. LCFS 42-10

5. We support the cost-containment "safety valve" mechanism. The proposed $200/ton cap is reasonable, well-considered, and supported by ample evidence.

Our organizations previously commented that we agree with a broad array of stakeholders that adoption of a well-designed cost-containment mechanism can result in a greater investment certainty and a more robust, resilient program. It can also put to rest extreme cost claims by the oil companies. Some parties, including many serving on the LCFS Advisory Panel in 2011 and the UC Davis Expert Review Panel in 2013, suggested a cost-containment mechanism may provide more price certainty and make the program more resilient in the face of credit price or fuel cost concerns. These suggestions, LCFS 42-11

May 2006.; Worrell, E. and C. Galitsky, *Profile of the Petroleum Refining Industry in California,* Lawrence Berkeley National Lab, LBNL-55450, March 2004; Zhu (2010), "Process Technology: The Key for Industrial Eenrgy/CO_2 Reduction," presentation Petrotech, UOP/Honeywell. McKinsey and Company (2007), "The Untapped Energy Efficiency Opportunity of the U.S. Industrial Sector."

[10] "Profiting from emission reductions in process industries: an oil and gas example," Booz & Company, 2010.

provided both orally and in writing to the agency form a strong record upon which the Board can make a reasoned decision.

At the same time, we noted that a variety of mechanisms built in to the existing regulation, such as credit trading and the life-long use of credits, are already helping ensure market stability in the current program. With new pathways constantly being adopted, additional compliance options provide even more market stability. As asserted in the ARB staff proposal: “The analysis that informed the proposed compliance curves was based on an informed expectation that there will be sufficient credits available through 2020 from existing low-CI fuel technologies and promising low-CI fuels on the horizon.”[11] This statement further supports our belief that a cost-containment mechanism can serve a supporting role, providing even greater market stability.

ARB’s proposed safety valve, a Credit Clearance Market, provides an alternate means to comply with the LCFS in the event that low carbon fuel supplies or pollution reduction opportunities are truly unavailable, or credits exceed $200 per ton in costs. If a regulated party is unable to meet the standard in any year, the provision allows additional time for the company to comply so long as all available credits are purchased during a “clearance period,” with the regulation stipulating the price to be at or below $200/ton. This helps ensure that regulated parties are not sitting on any credits if there is demand for them, the available supply of reductions are truly utilized, and no party would have costs exceeding the ceiling.

LCFS 42-11 cont.

If all available credits at or below $200/ton are utilized, oil companies can make up any shortfalls in emission reductions the following year, for up to five years. To ensure that companies are not simply delaying compliance, there is a 5 percent annual interest applied to any debt. This effectively provides more time to companies, preserves the environmental benefits, and ensures that other companies that invest and fully comply aren’t unfairly penalized by a lower bar provided for others.

ARB has appropriately built in safeguards to ensure that its Credit Clearance Market is transparent, ensures all LCFS credits have been purchased by regulated parties, provides long-term compliance certainty to parties, and stimulates further investment in low-carbon fuels that reduce greenhouse gas emissions.

ARB’s proposed $200/ton cap is reasonable as a “low ceiling” and could even be slightly higher while achieving the above goals. Both the aforementioned Promotum (2015) report and staff ISOR found that compliance to 2020 could be met assuming $100 per credit, providing roughly $1/gallon of gasoline equivalent of incentive for ultra-low carbon fuel providers such as cellulosic ethanol and waste-based biodiesel producers. A $200/ton cap provides a reasonable ceiling in the event of a shortfall of reduction opportunities, equivalent to twice the incentive levels. The staff’s proposal to adjust the price using a Consumer Price Index deflator in all years subsequent to 2016 is well-considered, and ensures that the mechanism keeps pace with inflation and remains at a constant price, in real terms.

[11] ARB December 2014 *Staff Report: Initial Statement of Reasons, Proposed Re-adoption of the Low Carbon Fuel Standard,* Pg ES-4

As noted in past comments, some alternative fuel producers who are interested in starting new low-carbon fuel projects have indicated that a "price floor" would be very valuable to help address uncertainty with the LCFS credit value going forward and would also allow more investors to incorporate the LCFS value when evaluating new projects. We urge ARB to continue working with stakeholders to develop a feasible, implementable, and effective floor option and return to the Board with a floor proposal to complement the cost ceiling mechanism currently being proposed.

LCFS 42-11 cont.

6. We support expanded electric transportation credits.

Our organizations support the expanded role for electrification of transportation in the LCFS. The proposal to allow transit agencies to opt-in to the LCFS for fixed guideway systems (light rail, street cars, trolleys, etc.) encourages cleaner transit that cuts carbon pollution, cleans up neighborhood traffic pollution, and supports sustainable communities as envisioned under Senate Bill 375. We support the provisions to more clearly account for the sustainability benefits of California's growing electric bus fleet. These expanded electric transportation credits provide local air quality benefits, encourage the development of more ultra-low carbon transportation options,[12] and support healthier, sustainable communities.

LCFS 42-12

7. We strongly urge ARB to develop sustainability provisions and independent verification for the LCFS by the end of 2016.

We strongly support the efforts of ARB staff to develop sustainability provisions and an accompanying independent verification process for the LCFS. Both are critical in order to realize the full environmental benefits of the program and for creating a long-term and durable policy that helps avoid negative impacts. Several of the organizations participating in the Sustainability Work Group have recommended that the sustainability provisions establish performance requirements that are equivalent to, if not more stringent than, the standards of the Roundtable on Sustainable Biomaterials (RSB).

Internationally, a large number of biofuel producers, biomass producers, commercial purchasers, government agencies, academics, and NGOs have recognized the need for and value of sustainability certification. Biofuels have tremendous potential to reduce carbon emissions and protect environmental values if developed with caution and appropriate safeguards. However, in the absence of safeguards, some actors may choose to produce biofuels in a manner that has negative environmental or social consequences, raising important questions about the long-term sustainability of the industry.

LCFS 42-13

We have worked in good faith over the past four years with ARB staff and the Board toward voluntary sustainability provisions that help encourage best practices while protecting against potential negative impacts that pose significant risks to the environment and communities. Potential negative impacts include increases in greenhouse gases that can occur if deforestation of native forests occurs for energy crops, loss of critical habitat and biodiversity, increased water consumption, conflicts over land or water

[12] California Air Resources Board LCFS/ADF Draft Environmental Impact Report. The sale of credits generated for could allow transit agencies to reduce fares, expand service or EV bus fleet or upgrade infrastructure. p.23

rights, and reduced food security. Standards such as RSB were developed because a diverse array of stakeholders agreed these impacts should and can be avoided.

Both sustainability provisions and an accompanying independent verification process are critical in order to realize the full environmental benefits of the LCFS and for creating a long-term and durable and policy that helps avoid negative impacts. They serve to:

1) Encourage producers to utilize voluntary third-party certification systems, which allow for on-the-ground measurement and verification of environmental performance (including, but not limited to greenhouse gas emissions).
2) Discourage bad actors engaged in projects resulting in significant environmental harm.
3) Build capacity for ARB to protect against actors producing fuels in a manner that may be environmentally unacceptable.
4) Help provide ARB with additional information and data around production of field, feedstock and facility parameters, which third-parties collect and audit.

LCFS 42-13 cont.

While it is true that it would take additional staff resources to establish sustainability provisions for the LCFS, once developed, existing third-party systems could in theory help reduce workloads going forward. ARB's Sustainability Work Group has made significant progress in developing a science-based definition of sustainability and the specific provisions to be included in the LCFS regulation. But its efforts have stalled, in part due to lack of resources. It is critical to the overall goals and long-term durability of the LCFS that ARB complete this work and formally incorporate sustainability provisions, along with a credible, independent verification process for those provisions, into regulation by end of 2016.

8. We urge ARB to continue reviewing and strengthening existing mechanisms over time to ensure LCFS pathways are verifiable and requirements are enforced.

As the Board considers re-adoption in 2015, we also urge ARB to prioritize its future efforts to review and strengthen verification and enforcement activities over time. In particular, staff should consider how the program could augment verification activities to ensure that in-use production practices reflect the original information submitted to establish the pathway, in order to minimize the risk of unintentional errors or even potential fraud. These comments are also made in light of the fraud that did occur with the Renewable Fuels Standard in 2011, which the U.S. Environmental Protection Agency has now addressed through subsequent requirements and changes.

LCFS 42-14

After the LCFS re-adoption process concludes, ARB should consider potential requirements that could supplement existing enforcement activities, including third-party analysis and verification. Third-party verification, such as by the RSB or an equivalent standard, as mentioned above in Section 7, could provide additional safeguards to ensure that the production methods, feedstocks, and supply chain that can affect greenhouse gas emissions is accurately reported. We also note that some third-party certification systems may also include additional sustainability information that is collected and reported as an added co-benefit. At this time, we are aware that some stakeholders have discussed in previous workshops whether the credit generator or obligated regulated party holds ultimate responsibility for LCFS credits and potential errors. We have not taken a position on this additional matter to date.

As an example of where additional verification and enforcement may be needed, we discuss used cooking oil (UCO), potentially an ultra-low carbon feedstock for the LCFS fuel mix. Converting UCO to biodiesel reuses a "waste" product and avoids displacement effects, such as indirect land use change or adverse effects on availability of food, forage, and fiber crops – if it is indeed "used." There has been some concern that the strong LCFS value may provide a perverse inducement to substitute disguised virgin oils for UCO, depending on the availability of UCO in certain supply chains and cost fluctuations in the various spot markets for oils. This might be the case for palm oil, for example, because the price has seen significant fluctuations in recent years.

Two applications for a Method 2B Fuel Pathway approval (UCO to Biodiesel) that we examined last November did not appear to offer any means of verifying that UCO was used. In fact, the information about the feedstock oil origin and supply was redacted as confidential business information, or otherwise unavailable on the application web site. Going forward, ARB should consider requiring further verification if not done already, including for co-mingling of feedstocks more generally. Thus, to help ensure the GHG benefits of the program and that all parties are utilizing the feedstocks that they are claiming credit for, ARB should consider supplementing current verification activities around feedstocks. LCFS 42-14 cont.

In this example, UCO feedstock verification can be rather simple: There is no need to trace the UCO back to the crops that produced the oil, or to document a full chain of custody farther back than the gathering of the UCO. But it does require that the users and aggregators provide data that allow a verifier to match the volumes collected and the companies collected from. Existing third-party tools, such as the RSB's system for verification and chain of custody related to "End of Life Products and Residues" RSB-STD-01-010-ver.1.6[13], provide the necessary safeguards and are tailored for the essential questions that can verify the "used" status of UCO.

9. We support the current inclusion of a public comment period for fuel pathways and request a longer time period be provided to allow for sufficient review by stakeholders.

We appreciate the opportunity to comment on proposed fuel pathway applications. We would ask, however, that under the re-adopted LCFS, a longer period be instituted for the comments. Some of us experienced difficulties in providing comments for Method 2 B fuel pathways in just the last few months; the current 10-day period is very short to assess a new pathway and gather relevant information. The 10-day period has been interpreted to include the weekend days, which means that some 10-day periods only include five working days. LCFS 42-15

[13] http://rsb.org/pdfs/standards/RSB-STD-01-010%20-%20ver%201.6%20RSB%20Standard%20on%20end-of-life-products,%20residues%20and%20by-products.pdf

10. The Board is on sound footing to adopt updated indirect land use change values.

First, we wish to thank ARB staff for their tireless work to address stakeholder and expert input on indirect land use change analysis. With the dedicated work of ARB staff and many contractors and collaborators, the models used in 2009 have been adapted and updated. They more carefully model animal feed markets, take into consideration irrigation, and adapt the model structure of both GTAP and the associated emissions factor model to take into consideration considerably more detailed information, especially about the United States and Brazil. This process enhanced the technical foundation of the LCFS, and also advanced the state of the art on the study of land use changes associated with expanded biofuels production. The Board is on sound footing to adopt updated emissions values as part of the LCFS re-adoption.

Despite this important progress, there remain areas for continued investigation. The most critical need is related to palm oil. Palm oil is one of the most important drivers of deforestation, and a significant global source of biofuel. The emissions from palm oil are relevant not only for palm biodiesel itself, but for fuels made from other fats, oils or oil byproducts that may substitute for palm oil in the marketplace. The interconnected markets for biodiesel and renewable diesel feedstocks are complicated and the data is imperfect. Moreover, as ARB staff highlighted, there are likely some structural limitations in GTAP that make it difficult to adjust the model to reflect key market dynamics. But this area of inquiry is clearly critically important going forward. Ongoing study is needed to ensure the link between palm and deforestation is understood, and that California fuel regulations do not indirectly contribute to deforestation from palm oil. LCFS 42-16

This is particularly important because forecasts indicate LCFS compliance may lead to a significant increase in the use of fuels made from vegetable oils and animal fats. We urge the ARB to seek expert input on key land use issues raised by palm oil in particular, and large increases in the use of bio-based diesel in general.

This focus on palm oil is important because it is a leading driver of deforestation, and less time has been put into this area than other areas of ARB analysis. But other areas identified are also very important. Forest land cover issues associated with the treatment of unmanaged land in GTAP are very important to ILUC for all fuels, and especially palm oil, and deserve further attention. It is also worth understanding the discrepancy between ARB's irrigation results and those of Taheripour, Hertel and Liu.[14] Analysis of fertilizer, paddy rice, and livestock emissions, and consideration of a dynamic GTAP model is also worthwhile. And, as cellulosic biofuels feedstocks scale up and begin to be significant driver of land use change, it will be important to understand their land use impacts.

Several recent papers continue to challenge ARB's analyses from both directions. One recent white paper argues that ARB's analysis has insufficiently recognized the potential for agricultural intensification, while other reports object to the use of crops to produce fuel instead of food, and

[14] *Energy, Sustainability and Society* 2013, 3:4; http://www.energsustainsoc.com/content/3/1/4

question the accounting framework of biofuels, land use, and carbon sequestration. There is a compelling moral and environmental case to prioritize food production and forest and other ecosystem protection over fossil energy displacement. Going forward it is important for ARB to consider how best to adjust its approach to include new sources of data, modelling approaches, and carbon accounting methodologies. These recent papers do not offer implementable refinements to ARB's methodology in the timeframe of the re-adoption, but suggest areas for inquiry over the longer term (beyond 2020) to ensure that California's low carbon fuels policies remain science-based and broadly sustainable. The work ARB has done to improve the treatment of ILUC over the last five years has certainly reflected a commitment to strong science-based administration of the LCFS, and puts the LCFS on solid footing through 2020.

LCFS 42-16 cont.

11. The Biorefinery Siting Guidance needs an update to incorporate new information on disadvantaged communities.

Given the focus in many AB 32 discussions on the need to protect and improve health and air quality in California's most disadvantaged communities, ARB should provide clear direction to staff on the timing to update the Siting Guidance for Biorefineries in California section on cumulative impacts. Specifically, the guidance document should be updated to reflect the development and widespread use of CalEPA's CalEnviroScreen tool for identifying communities most disadvantaged by local pollution.

LCFS 42-17

12. We support the Alternative Diesel Fuels proposal and encourage ARB to capture and monitor NOx benefits and potential impacts under the rule.

We support the Alternative Diesel Fuels proposal and believe it balances the need to encourage and incentivize alternatives to fossil fuels with the need to ensure that no additional harms are caused by these alternatives.

Because of the potential for biodiesel to increase smog-forming NO_x emissions under certain formulations, engine models, and operating conditions, we support the alternative diesel fuel pathway set forward by ARB staff.[15] To protect against NO_x backsliding under a growing biodiesel market, and as the widespread fleet turnover to NO_x-controlling engines is achieved, ARB must carefully capture the benefits of biodiesel, and monitor the benefits and potential impacts. Fortunately, the proposed ADF regulation looks for ways to maximize these benefits, including offering exemptions for biodiesel fueling stations or fleets using technologies that control NO_x. We strongly encourage ARB to explore additional opportunities to capture NO_x-neutral—and NO_x-reducing—particulate and carbon pollution benefits.

ADF 25-1

Taken together with the LCFS, the ADF will help to avoid nearly 100 deaths per year as cleaner alternatives to diesel are utilized in California.

[15] ARB January 2015 *Staff Report: Initial Statement of Reasons, Proposed Regulation on the Commercialization of Alternative Diesel Fuels*

In closing, we urge ARB to resist attempts to eliminate or weaken AB 32 fuel programs in California. Although the oil industry speaks with a loud voice, it does not speak for average Californians. The LCFS and California climate policies, in general, continue to enjoy broad public support, as evidenced in the annual Public Policy Institute of California poll, *Californians and their Environment*,[16] and other independent third-party research and opinion polls. LCFS 42-18

Climate policy solutions for the transportation sector are needed in California, in other states, across the nation, and around the world. ARB must continue its longstanding leadership role by sending a strong signal that California will not jeopardize the future health and environment of our state, our nation, or our planet for the sake of preserving the status quo. As Oregon, Washington, and other jurisdictions look to adopt and implement similar clean fuel standards, it is critical that ARB continue to build on this transformational policy by maintaining a strong, long-term signal and improving it in the areas identified in this letter. LCFS 42-19

Sincerely,

Bonnie Holmes-Gen and Will Barrett
American Lung Association in California

John Shears
Center for Energy Efficiency and Renewable Technologies

Tim O'Connor
Environmental Defense Fund

Barbara Bramble
National Wildlife Federation

Simon Mui and Debbie Hammel
Natural Resources Defense Council

Michelle Passero
The Nature Conservancy

Jeremy Martin
Union of Concerned Scientists

[16] 76 percent - July 2014 PPIC poll

42_OP_LCFS_NGO Responses

344. Comment: **ADF 25-1**

Agency Response: This comment is responded to in the Alternative Diesel Regulation Final Statement of Reasons under Comment Letter **25_OP_ADF_NGO**.

345. Comment: **LCFS 42-1**

The comment is supportive of the Low Carbon Fuel Standard regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

346. Comment: **LCFS 42-2**

The comment states that, by cutting carbon emissions from transportation fuel, the LCFS is an important piece of California's policy response to the environmental and health crisis caused by our dependence on oil.

Agency Response: ARB staff thanks the commenter for the support of the health benefits of the re-adoption of the LCFS.

347. Comment: **LCFS 42-3**

The comment states that the LCFS regulation is a critical component of AB 32 and represents one of the state's largest greenhouse gas emission reduction measures and provides the necessary foundation for meeting California's existing and future health-based air quality and climate goals.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

348. Comment: **LCFS 42-4**

The comment supports ARB staff's proposal to require a 10 percent reduction in fuel carbon intensity by 2020.

Agency Response: ARB staff appreciates the support for the proposed compliance targets.

349. Comment: **LCFS 42-5**

The comment supports a more aggressive regulatory target in the post 2020 timeframe.

Agency Response: See response to **LCFS 5-2**.

350. Comment: **LCFS 42-6**

The comment supports the concept of having one regulatory review prior to 2020 to ensure that the regulation is on track and to incorporate any critical updated scientific data.

Agency Response: Staff agrees that it is important to build a LCFS regulatory review mechanism into the proposed regulation. Staff included Section 95496: Regulation Review into the proposed LCFS Re-adoption to address the needs of regulatory review.

351. Comment: **LCFS 42-7**

The commenter supports the Refinery Investment Provision.

Agency Response: ARB staff appreciates the support for the refinery investment credit provision.

352. Comment: **LCFS 42-8**

The commenter supports the Refinery Investment Provision and provides information about potential GHG reduction projects at refineries.

Agency Response: ARB staff appreciates the support for the refinery investment credit provision. Staff will review the information the commenter provided about potential GHG reduction projects at refineries.

353. Comment: **LCFS 42-9**

The commenter supports the Refinery Investment Provision.

Agency Response: ARB staff appreciates the support for the refinery investment credit provision.

354. Comment: **LCFS 42-10**

Agency Response: ARB staff acknowledges the commenter's support for differentiating the carbon intensity of crude oil sources and for protecting against increases in carbon intensity of baseline fuels over time.

355. Comment: **LCFS 42-11**

The comment supports the cost-containment "safety valve" mechanism and states that the $200/ton cap is reasonable, well-considered, and supported by ample evidence. The commenter also recommends continued work to develop a price floor.

Agency Response: ARB staff appreciates the support for the cost containment provision and the proposed credit price cap. With respect to a price floor, see response to **LCFS 6-5.**

356. Comment: **LCFS 42-12**

The comment supports expanded electric transportation credits.

Agency Response: ARB staff appreciates the support for the proposed electricity provisions.

357. Comment: **LCFS 42-13**

The comment strongly supports the efforts of ARB staff to develop sustainability provisions and an accompanying independent verification process for the LCFS by the end of 2016.

Agency Response: Staff agrees that it is important to develop sustainability provisions and an accompanying independent verification process for the LCFS. As stated in the Staff Report, staff identified specific areas of the regulation for clarification and improvements in the proposed LCFS Re-adoption. These proposed improvements are expected to improve implementation of the LCFS program. Beyond this proposal, staff will continue to implement and enforce the LCFS program, monitoring its effectiveness, and will consider additional improvements for future iterations of the LCFS regulation, such as independent verification and sustainability provisions. LCFS staff will work with the staff of the verification program for the Mandatory Reporting of Greenhouse Gas Emissions under AB32, and stakeholders to develop a comprehensive, integrated strategy for the LCFS sustainability and verification programs.

358. Comment: **LCFS 42-14**

The comment states that ARB should continue reviewing and strengthening existing mechanisms over time to ensure LCFS pathways are verifiable and requirements are enforced.

Agency Response: Monitoring, auditing and enforcement of the LCFS Program are critical to ensure the emission benefits of the Program are realized. The ARB's Cap-and-Trade Program currently uses of third-party monitors.

The LCFS Program already includes some provisions that address environmental sustainability issues such that the full life-cycle of greenhouse gases is taken into account for each transportation fuel. Each fuel pathway accounts for both direct and indirect land effects in determining the carbon intensity for that fuel. Additionally, ARB has a working group comprised of interested stakeholders, regulated parties, environmental advocates, and other state agencies that work through ideas to recommend which framework (e.g., regulatory, a set of policies, or a combination of the two) would work best for all stakeholders involved. ARB staff that is working on sustainability topics are also working on verification.

ARB staff is aware of the voluntary quality assurance plan provisions that the U.S. Environmental Protection Agency (U.S. EPA) has adopted in the Renewable Fuel Standard (RFS) Program. Staff has had discussions with U.S. EPA on their implementation of this provision, as their program uses a similar "buyer-beware" approach. This approach ensures that all credits retired which are found to be invalid must be offset by honorable credits with real emission benefits. Currently, LCFS market participants can do their own due diligence to ensure the validity of the LCFS credits and these efforts will be taken into consideration if invalid credits are found.

359. Comment: **LCFS 42-15**

The comment supports the current inclusion of a public comment period for fuel pathways and requests a longer time period to be provided to allow for sufficient review by stakeholders.

Agency Response: ARB staff agrees that the comment period is extremely valuable and would like to continue to welcome comments. Staff must, however, maintain a balance between timely pathway certifications and the length of the comment period. To that end, staff will specify that the comment period last for 10-

business days rather than 10-calendar days. In addition, staff will agree to grant commenters time extensions if they can show why they are unable to submit comments within the 10-business day window

360. Comment: **LCFS 42-16**

The comment supports updated indirect land use change values.

Agency Response: Even with limitations related to the structure of the Global Trade Analysis Project (GTAP) model, the efforts by ARB staff have produced the most defensible analysis of indirect effects related to crop-based biofuels. The indirect land use change (iLUC) analysis accounts for potential deforestation and expansion into high carbon peatland in Indonesia and Malaysia. The GTAP model includes in it data from studies and reports that specifically have focused on oil palm expansion in these regions. Staff has also considered data used by the U.S. EPA in their analysis of palm oil for the 2014 Standards for the Renewable Fuel Standard Program (RFS2) program.

The iLUC analysis was subjected to peer-review by experts. ARB staff considered feedback provided by the reviewers, and will continue to consider that feedback (including any for oil palm) in evaluating future updates iLUC analysis.

All fuels including biofuels are scored on their full lifecycle analysis. Lack of data limited the inclusion of emissions from fertilizer, paddy rice, and livestock. Inclusion of unmanaged land and cellulosic biofuels will be considered when data becomes available. When a dynamic version of GTAP suitable for ARB's analysis becomes available, ARB staff is committed to completing comprehensive evaluation and testing of this model prior to considering its use in the regulation.

ARB staff is aware of reports that challenge ARB's analysis on several fronts such as discounting intensification, food issues related to biofuels etc. Many such issues were considered during the current updates but a few could not be included either due to lack of data or due to structural limitations of the model. Staff remains committed to monitoring new data and updates to land use change science and accounting for these limitations when supported by science and data.

361. Comment: **LCFS 42-17**

The comment requests ARB staff to provide clear direction on the timing to update the *Siting Guidance for Biorefineries in California* section.

Agency Response: ARB has no current plans to update the Biorefinery Siting Guidance Document, but will take this comment under consideration.

362. Comment: **LCFS 42-18**

The comment urges ARB to resist attempts to eliminate or weaken AB 32 fuel programs in California.

Agency Response: Staff appreciates the public support of the Low Carbon Fuel Standard and agrees that ARB must continue its longstanding leadership role in climate policy solutions for the transportation sector.

363. Comment: **LCFS 42-19**

The comment urges ARB to continue its longstanding leadership role.

Agency Response: See response to **LCFS 42-18**.

Comment letter code: 43-OP-LCFS-POET

Commenter: Joshua Willter

Affiliation: Poet

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

43_OP_LCFS
_POET

POET

HUMAN + NATURE

O / 605 965 2200 4615 N. LEWIS AVE. SIOUX FALLS, SD 57104

February 17, 2015

By Electronic Mail

Clerk of the Board
California Air Resources Board
1001 I Street, 23rd Floor
Sacramento, CA 95812

Re: Proposed Amendments to the California Low-Carbon Fuel Standards Regulation and the Proposed Regulation of the Commercialization of Alternative Diesel Fuels

Dear Madam:

POET LLC, a member of Growth Energy, concurs in the comments being filed today by Growth Energy, including the environmental analysis under the California Environmental Quality Act offered by Growth Energy, as well as the alternative to the above-captioned proposed amendments and regulations that have been proposed by Growth Energy. Please file this letter in the two separate dockets for the the proposed amendments to the California Low-Carbon Fuel Standards ("LCFS") regulation and the proposed regulation of the commercialization of alternative diesel fuels LCFS 43-1

POET LLC expects to file additional comments prior to the close of the record in the LCFS proceeding.

Thank you for your consideration and assistance.

Sincerely,

Shailesh Sahay
Regulatory Counsel

Revised POET CEQA concurrence 17 feb

This page intentionally left blank.

43_OP_LCFS_Poet Responses

364. Comment: **LCFS 43-1**

Agency Response: The response to this comment is in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

Comment letter code: 44-OP-LCFS-P66

Commenter: Daniel Sinks

Affiliation: Phillips 66

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

PHILLIPS 66

H. Daniel Sinks
Fuels Issues Advisor
3900 Kilroy Airport Way Suite 210
Long Beach, CA. 90806
Phone 562-290-1521
e-mail h.daniel.sinks@p66.com

February 17, 2015

Clerk of the Board, Air Resources Board
1001 I Street
Sacramento, CA 95814

Via electronic submittal to: http://www.arb.ca.gov/lispub/comm/bclist.php

Re: **Notice of Public Hearing to Consider a the Low Carbon Fuel Standard (LCFS) – Phillips 66 Company Comments**

Dear Clerk of the Board,

Phillips 66 Company (Phillips 66) appreciates the opportunity to provide these comments. Phillips 66 will be directly impacted by the by the "re-proposed" Low Carbon Fuel Standard (LCFS) regulations as we are a “regulated party” under the existing regulations and will continue to be a “regulated party” as defined by these proposed regulations. Phillips 66 owns and operates refineries in the State of California. In addition, we have pipeline, terminal, and marketing assets in the State that distribute fuels produced at our refineries. We are a member of the Western States Petroleum Association (WSPA) and fully support the comments submitted by WSPA. LCFS 44-1

Phillips 66 has been engaged with CARB since the inception of the LCFS and throughout this and previous regulatory proceedings. Our staff has participated in the workshop process, participated in the “workgroup” process, held a seat on the LCFS Advisory Panel, participated in trade association (WSPA) meetings with ARB staff, has held individual private meetings with ARB staff, and has provided written comments on every regulatory proceeding.

Based upon our experience as a regulated party under the existing LCFS rules, we focus our comments in this re-adoption proceeding on three main topics:

1) the Compliance Schedule;
2) the Cost Containment Mechanism; and
3) LCFS Credit Generation from Refinery Projects.

Each of the three topics contains a Phillips 66 recommendation that we respectfully ask the Board to consider and subsequently then direct staff to reexamine their current proposals.

Compliance Schedule: Phillips 66 does not believe the compliance schedule proposed by staff is feasible or sustainable. The compliance scenario presented by staff over-estimates the near term credit build and is overly optimistic in the amount of time it will take to bring advanced fuels and vehicles to commercial scale. In the staff’s own scenario, there are not enough annual credits to LCFS 44-2 cover deficits in the 2018/2019 timeframe (and beyond) and compliance is dependent upon a massive credit build in the early years (something that has not materialized).

The downside of adopting staff's unrealistic compliance schedule is that staff will continue to return to the Board every couple of years with amendments that "kick the can down the road" and do not address the fundamental issue of feasibility. Such an approach provides little in the way of regulatory certainty and makes planning business and investment decisions difficult (if not impossible) on the regulated parties. Phillips 66, therefore, respectfully asks the Board to direct staff to develop a realistic compliance schedule that is based upon reasonable forecasts of fuel availability, vehicle penetration rates, needed fuelling infrastructure build-out and is cost-effective.

LCFS 44-2 cont.

Cost Containment – Credit Clearance Market: Phillips 66's believes that a cost containment mechanism is NOT a suitable replacement for a feasible regulation. Staff's proposed cost containment scheme, a Credit Clearance Market, contains an initial price cap on credits of $200 per credit. The staff report lacks sufficient detail regarding how this cap or ceiling price was derived and we request that staff provide a basis and rationale for the $200/crredit.

In addition, under the proposal, participation in the credit clearance market is mandatory for parties who end the year in a deficit situation. Under the existing regulations, regulated parties are allowed to carry over a 10% deficit provided they "pay-back" those deficits the following year. There may be planning or operational reasons why a regulated party may wish to carry deficits from one year to the next. We request this provision remains in the regulation and that participation in the Credit Clearance Market be voluntary for those parties in deficit.

LCFS 44-3

Staff evaluated various cost containment mechanisms before arriving at their recommendation to adopt the Credit Clearance Market. To our knowledge, staff did not evaluate the potential use of Cap & Trade credits for this purpose. Phillips 66 proposes that in lieu of adopting these proposed additional and complex regulations, the Board direct staff to instead allow Cap & Trade credits to be used for LCFS compliance in those circumstances where the Credit Clearance Market would otherwise be triggered.

LCFS Credits for Refinery GHG Reduction Projects Phillips 66 fully supports the ability to generate LCFS credits from refinery greenhouse gas (GHG) reduction projects. However, the proposed thresholds and restrictions risk eliminating many potential projects. We have identified the following elements that make the proposal problematic:

a. Limiting onsite increases of air pollutants unreasonably excludes offsets of criteria and air toxic pollutants.
b. The 0.1 gCO2e/MJ threshold is too stringent: a "tons reduced" threshold should be allowed (this concept is proposed for "innovative crude recovery" so it is only equitable to add a comparable provision here).
c. Investments should not be limited to capital or onsite projects.
d. The biofeedstock 10% threshold is too restrictive and should be eliminated
e. Application of a 50% discount in the number of credits for "less efficient" facilities serves as a dis-incentive. All reduction projects should be allowed full credit.

LCFS 44-4

Phillips 66 respectfully requests the Board to direct staff to work with refiners to streamline the process and eliminate the barriers contained in the proposal.

Thank you for considering our comments. Please feel free to contact me if you have questions regarding our comments.

Sincerely,

<H. Daniel Sinks>

44_OP_LCFS_P66 Responses

365. Comment: **LCFS 44-1**

Agency Response: The response to this comment is in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

366. Comment: **LCFS 44-2**

The commenter does not believe the proposed compliance schedule is feasible or sustainable as the compliance scenario over-estimates the near term credit build and is overly optimistic in the amount of time it will take to bring advanced fuels and vehicles to commercial scale.

Agency Response: Please see response to comment **LCFS 38-1**.

367. Comment: **LCFS 44-3**

The commenter asserts that the cost containment provision is not a suitable substitute for a feasible compliance pathway, and further requests that the cost containment provision should be amended to offer refiners flexibility to voluntarily participate or carry-over deficits

Agency Response: We agree with the comment that a cost containment mechanism is no substitute for a feasible compliance path. However, ARB staff's analysis regarding the availability of low-CI fuels indicates that there will be sufficient credits available through 2020 from existing low-CI fuel technologies and promising low-CI fuels on the horizon.

For a response to the criticism of the cost containment mechanism, and an explanation of why participation in this provision cannot be voluntary, please see the response to comment **LCFS 32-9 and LCFS 38-3, LCFS 40-8** and **LCFS 40-21**.

In response to the request to use Cap-and-Trade allowances or offsets for LCFS compliance, please see the response to comment **LCFS 32-7**.

368. <u>Comment</u>: **LCFS 44-4**

The comment lists six issues with the Refinery Investment Provision.

<u>Agency Response:</u>

1) *Limiting onsite increases of air pollutants unreasonably excludes offsets of criteria and air toxic pollutants*.

See response to **LCFS 38-9**.

2) *The 0.1 gCO_2e/MJ threshold is too stringent: a "tons reduced" threshold should be allowed (this concept is proposed for "innovative crude recovery" so it is only equitable to add a comparable provision here*).

See response to **LCFS 38-10**.

3) *Investments should not be limited to capital or onsite projects*.

See response to **LCFS 38-11**.

4) *The biofeedstock 10% threshold is too restrictive and should be eliminated*.

See response to **LCFS 38-13**.

5) *Application of a 50% discount in the number of credits for "less efficient" facilities serves as a dis-incentive*.

ARB staff is making a 15-day change to remove the 50 percent discount on credits in the Refinery Investment Credit Provision.

6) *All reduction projects should be allowed full credit*.

ARB staff is making a 15-day change to allow all projects that meet the provision's requirements will get full credit.

Comment letter code: 45-OP-LCFS-Dillard

Commenter: Joyce Dillard

Affiliation: Individual

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

Comments ARB Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations
Draft Environmental Assessment due 2.17.2015

You state:

3. Additional Infrastructure Needs

Because credits could be generated through the use of solar-generation of steam, electricity, and heat in oil fields, development of these types of facilities would be incented. Potential compliance responses associated with these methods could result in modifications to ***existing crude production facilities*** *to accommodate solar, and wind electricity, heat, and/or steam generation.* ***These would be located within crude oil production facility sites.***

And

These projects could include the modification of existing or new industrial facilities to capture CO2 emissions, along with construction of new infrastructure, ***such as pipelines, wells, and other surface facilities within or near the emitting facility to enable the transport and injection of CO2 into a geological formation for sequestration.*** *The transport distances and pipeline construction requirements for the captured CO2 would vary depending on the locations of specific industrial sources of the captured CO2 and proposed underground formations, recognizing, however, that pipeline cost could reasonably limit the distance of CO2 transport. CCS would be required to be onsite at locations of oil or gas production facilities to obtain credits through the proposed LCFS.*

Comments:

LCFS ISOR report states:

Revised Annual Crude Average CI Calculation
The crude lookup table lists field-specific CI values for crudes produced in and offshore of California. Regulated parties, however, are often supplied California crude in pipelines carrying crude blended from many fields. ***Because neither staff nor the regulated parties have data that maps crude oil volumes from California fields to pipeline blends, it is not possible to match reported California crude names with CI values from the lookup table.***

Instead of using California crude names and volumes reported by refineries, staff proposes, in calculating the Annual Crude Average CI value, that volume contributions for California State fields will be based on oil production data from the California Department of Conservation, and volume contributions for California Federal Offshore fields will be based on oil production data from the Bureau of Safety and Environmental Enforcement.

LCFS 45-1

> ***Data that maps crude oil volumes from fields to pipeline blends is not available, and therefore, it is not possible to as accurately estimate CI values for California pipeline blends as for fields.***

You have no basis in fact of the Crude Oil Volumes from oil field to pipeline and cannot determine any benefit.

LCFS 45-1 cont.

Sequestration requires an Earthquake Fault Zone and municipal Circulation Elements are a necessity. Land Use Elements are also a consideration due to any proximity to population, housing and schools. The science for migration in rock formations is in the research stage, as we understand it.

LCFS 45-2

There may be no benefit if the risk is too high.

Joyce Dillard
P.O. Box 31377
Los Angeles, CA 90031

45_OP_LCFS_Dillard Responses

369. Comment: **LCFS 45-1 and LCFS 45-2**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

Comment letter code: 46-OP-LCFS-GE

Commenter: Joshua Willter

Affiliation: Growth Energy

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

growth energy
America's Ethanol Producers

777 North Capitol Street, NE, Suite 805, Washington, D.C. 20002
PHONE 202.545.4000 FAX 202.545.4001

Growth

46_OP_LCFS_GE

17_OP_ADF_GE

February 17, 2015

By Electronic Mail

Clerk of the Board
California Air Resources Board
1001 I Street, 23rd Floor
Sacramento, CA 95812

Re: Proposed Amendments to the California Low-Carbon Fuel Standards Regulation and the Proposed Regulation of the Commercialization of Alternative Diesel Fuels

Dear Madam:

Growth Energy, an association of the nation's leading ethanol manufacturers and other companies who serve the nation's need for alternative fuels, is submitting to you the enclosed materials in response to the Executive Officer's notices of proposed amendments to California Low-Carbon Fuel Standards regulation and of the proposal to adopt a regulation for the commercialization of alternative diesel fuels. These materials also include environmental comments being submitted to the Air Resources Board and the Executive Officer pursuant to the California Environmental Quality Act and the Board's implementing regulations.

The Executive Officer has created separate rulemaking files and Board hearing agenda items for these two proposals. In view of the substantial overlap between these two proposals, including in the CARB staff's environmental assessment documentation, I ask that all of these materials, including the appendices and exhibits, be included in each rulemaking file and be considered by the Board in connection with each agenda item.

Growth Energy may file additional materials in one or both rulemaking files for consideration in connection with one or both agenda items at a later time, as permitted by the California Government Code.

If there are logistical questions concerning these submittals, please contact Mr. James M. Lyons of Sierra Research, Inc., at 916-444-6666.

Thank you for your consideration and assistance.

Sincerely,

David Bearden

David Bearden
General Counsel and Secretary

Page 1 of 1

STATE OF CALIFORNIA

AIR RESOURCES BOARD

PROPOSED AMENDMENTS TO THE CALIFORNIA LOW CARBON FUELS STANDARD REGULATION AND THE PROPOSED REGULATION ON THE COMMERCIALIZATION OF ALTERNATIVE DIESEL FUELS

GROWTH ENERGY'S RESPONSE
TO THE NOTICES OF PUBLIC HEARINGS DATED DECEMBER 16, 2014
2015 CAL. REG. NOTICE REG. 13, 45 (JANUARY 2, 2015)

FEBRUARY 17, 2015

For further information contact:
Mr. Chris Bliley
Director of Regulatory Affairs
Growth Energy
CBliley@growthenergy.org
202-545-4000

Executive Summary

On January 2, 2015, the Executive Officer of the California Air Resources Board commenced the formal process of proposing amendments to the California low-carbon fuel standard ("LCFS") regulation and the adoption of a new regulation to govern commercialization of alternative diesel fuels used to comply with the LCFS regulation (the "ADF regulation"). Growth Energy shares CARB's goal of promoting alternative fuels that have lower greenhouse gas impacts than fossil fuels. In fact, promotion of this goal is central to Growth Energy's purpose. Unfortunately, Growth Energy believes that CARB's execution of the LCFS program as proposed would run counter to this goal. The proposal if finalized would promote the wrong fuels based on flawed, incorrect science, and as a result impose significant costs without accompanying greenhouse gas reductions. Thus, Growth Energy opposes adoption of the proposed amendments to the LCFS regulation and the currently proposed ADF regulation. Each regulation is unnecessary to achieve the environmental benefits sought by the California Legislature in the Global Warming Solutions Act of 2006, which is the statute on which the Executive Officer is basing his proposal.

The LCFS regulation is no longer needed to achieve the greenhouse gas reductions sought in the 2009 LCFS regulation, and Growth Energy has proposed a better alternative to the LCFS through the expansion of the existing cap-and-trade program. Since the Board first adopted the LCFS regulation in 2009, much has changed in efforts by the state and federal government to reduce greenhouse gas ("GHG") emissions from motor vehicles. Growth Energy presented a proposed alternative to the LCFS regulation to CARB staff in June 2014. Following review of Growth Energy's proposal, the CARB staff agreed with Growth Energy that Growth Energy's proposal would likely achieve the same level of GHG emissions reductions as the 2009 LCFS regulation through 2020. Growth Energy's proposal had none of the unintended negative environmental consequences of the 2009 LCFS regulation, which have been the subject of litigation, and would have eliminated the need for California businesses and consumers to pay for the LCFS program ─ costs which the CARB staff now says may range up to about 12 cents per gallon by 2020. LCFS 46-1

The new justification for the LCFS regulation ignores the federal renewable fuels program. The CARB staff rejected Growth Energy's proposed alternative to the LCFS regulation in the fall of 2014 because it claimed that by enforcing LCFS requirements now, CARB could prepare the California fuels market for further GHG reductions after 2020. The CARB staff theorized that only an LCFS program can adequately assure the diversification of the sources and methods of producing renewable fuels with low carbon emissions needed to achieve GHG reductions after 2020. When it rejected Growth Energy's proposal last fall, the CARB staff did not properly account for the beneficial effects of the federal renewable fuels standards ("RFS") program in stimulating fuels diversification and in the commercialization of cellulosic renewable fuels. The CARB staff still has not done so.

By disrupting the national market for renewable fuels, the LCFS regulation may increase global greenhouse gas emissions. Under the new LCFS regulation, corn ethanol produced at Midwest biorefineries will likely be displaced in large part by sugarcane ethanol from Brazil. Midwest corn ethanol biorefineries will be forced to choose between curtailing or shutting down production, or finding other markets for the ethanol that can no longer be sold in California. Because external economic factors constrain the output of the Brazilian sugarcane ethanol industry, and may continue to do so, the practical effect of the new LCFS regulation may be the shipment of Brazilian ethanol to California and Midwest ethanol to Brazil. The ethanol would travel on oceangoing tankers powered with fossil fuels. Intercontinental shipments of ethanol in response to California's regulation would have the unintended effect of increasing global GHG emissions. LCFS 46-2

Table of Contents

Page

Comments of Growth Energy on Proposed Amendments to the California Low Carbon Fuels Standard Regulation and the Proposed Regulation on the Commercialization of Alternative Diesel Fuels

Growth Energy respectfully submits these comments on the proposed amendments to the low-carbon fuels standard ("LCFS") regulation and the proposed regulation on the commercialization of alternative diesel fuels. Growth Energy is an association of the leading ethanol producers in the United States and other companies that serve America's need for renewable fuels. As such, Growth Energy shares in a core goal of the LCFS program – the promotion of alternative fuels that lower transportation-sector greenhouse gas emissions, among other benefits. Growth Energy's comments for the California Air Resources Board ("CARB" or "the Board") are contained in this summary document and a number of appendices and exhibits. Growth Energy is combining in these comments its response to the notices of proposed rulemaking published for the LCFS regulation and the alternative diesel fuel ("ADF") regulation, which are both scheduled for a public hearing later this week, as well as its response to the consolidated draft Environmental Assessment ("the draft EA") for the LCFS and ADF proposals.[1]

Part I of these comments outlines some of the key statutory provisions that govern the LCFS and ADF rulemakings and identifies the CARB staff's serious shortcomings in complying with the same. Part II summarizes the analysis contained in the appendices to Growth Energy's comments on the lifecycle emissions analysis used in the LCFS regulatory proposal and the impacts of the LCFS proposal on consumers, businesses, and federal law and policy, as well as related issues. Part III and its accompanying appendices address the draft EA and other issues LCFS 46-3

[1] The public hearing notices dated December 16, 2014, and the draft EA were posted for public review and comment by the Executive Officer on January 30, 2014.

involving the environmental impacts of the two proposals and outline the Board's duties based on the record under the California Environmental Quality Act ("CEQA").[2] Part IV summarizes an alternative to the LCFS regulation that Growth Energy presented to the CARB staff, evaluates the CARB staff's response to Growth Energy's proposal, and describes the Board's legal obligations under the Government Code in light of the current record. Part IV also presents recommendations to facilitate the transparency and external review of the two current regulatory proposals. LCFS 46-3 cont.

I. STATUTORY FRAMEWORK AND BACKGROUND

The Board's consideration of the LCFS amendments and the proposed ADF regulation is governed by the California Government Code, the California Health & Safety Code, and CEQA, as well as the California and federal Constitutions. Pertinent requirements of CEQA and CARB's certified regulatory program to implement CEQA that apply to the draft EA are examined in detail in Part III and Appendix J of these comments. Because they are relevant to every aspect of these two rulemakings, it is important at the outset to identify three key provisions of the Global Warming Solutions Act of 2006 ("AB 32") and the Government Code that apply here. LCFS 46-4

Any regulation adopted by the Board must be consistent with and reasonably necessary to accomplish the purposes of AB 32. *See* Cal. Gov't Code § 11342.2. Three provisions of AB 32 are important to the Board's review of the CARB staff's proposal in order to determine whether the proposal is consistent with AB 32. First, regulations to implement AB 32 must not "interfere with … efforts to achieve and maintain federal and state ambient air quality standards" to the extent feasible, in addition to being adopted in a manner that complies with CEQA. Cal. Health & Safety Code § 38562(b)(4). Second, the emissions reductions that CARB attributes to an AB 32 LCFS 46-5

---

[2] Growth Energy may file additional materials not directly pertinent to the draft EA but relevant to other issues presented in the rulemaking prior to the start of the public hearings this week.

regulation must be "real, permanent, quantifiable, verifiable and enforceable." *Id*. § 38562(d)(1).[3] Third, AB 32 directs that the Board "shall" rely upon "the best available economic and scientific information" when adopting regulations to implement AB 32. *See* Cal. Health & Safety Code § 38562(e). For the reasons explained in these comments and the appendices, the proposed amendments to the LCFS regulation do not comply with those three central provisions of AB 32, and therefore the Board should not adopt them.

LCFS 46-5 cont.

In addition, the Executive Officer cannot demonstrate that the LCFS amendments are "reasonably necessary" to meet the purposes of AB 32, as the Government Code requires. As the CARB staff admitted during the Department of Finance's review of the proposed amendments last fall, the LCFS regulation is likely not necessary in order to reduce greenhouse gas ("GHG") emissions prior to 2020; another, less burdensome alternative identified by Growth Energy would achieve those reductions and would not have the counterproductive impact on the California environment that the LCFS regulation will create.[4] In earlier comments to the CARB staff during development of the new LCFS regulation, Growth Energy explained that the limited purposes of the LCFS regulation were already accomplished by other programs. Having been presented with Growth Energy's alternative to the LCFS regulation, CARB cannot properly claim that no alternative to the LCFS program would be "as effective and less burdensome to affected private persons and equally effective in implementing the statutory purpose or other provision of law" — an averment required by section 11346.5(a)(13) of the Government Code, and which is important in protecting the public from unnecessary regulation. Remarkably, the Executive Officer's

LCFS 46-6

---

3 Notably, the requirements in subsection (d) of section 38562 are not qualified by the limitation in subsection (b), *i.e.*, "to the extent feasible."

4 Regarding those impacts, *see* Part III and Appendix I (Declaration of James M. Lyons).

December 2014 notice proposing the LCFS amendments does not even refer to the alternative measure proposed by Growth Energy, which was presented to the CARB staff in June 2014.[5] LCFS 46-6 cont.

The Legislature heightened the importance of evaluating alternatives to proposed regulations in 2011, when it amended the Government Code in order to require agencies to present their regulatory proposals to the Department of Finance for early review of costs, benefits, and alternative methods of accomplishing an agency's regulatory objectives. The LCFS and ADF rulemakings are among the first to be governed by the 2011 amendments, contained in SB 617. For the LCFS regulation, the CARB staff disabled meaningful stakeholder input into the SB 617 review by severely limiting the time permitted for regulated parties to participate, and by failing to fully disclose all the estimated benefits or costs of the proposed regulation (an omission that continues to this day). LCFS 46-7 The shortfall in the SB 617 process for the ADF rulemaking was even greater: the version of the ADF regulation that the CARB staff submitted to the Department of Finance differed in material ways from the version of the ADF regulation that the CARB staff had under active consideration at the time of its SB 617 submission to Finance. Thus, the agency that the Legislature intended to have an active role in the development of major regulations in California — the Department of Finance — has never formally reviewed the key features of the ADF regulation. Unless the Board itself directs the CARB staff to comply with SB 617, it will be left to another agency (the Office of Administrative Law) to correct this egregious violation of SB 617. ADF 17-1

In addition to mandating early review of regulatory proposals by the Department of Finance, the Legislature requires transparency in the rulemaking process, so that the public can LCFS 46-8 cont.

---

5 *See* Appendix F and related exhibits.

participate effectively in that process. *See, e.g.*, Cal. Gov't Code § 11347.3; Cal. Health & Safety Code § 39601.5. The public rulemaking file required by section 11347.3 of the Government Code is critical to both transparency and public participation. Section 11347.3 requires, in essence, that the public have the same access to all the data and analysis used by an agency in developing regulations, as well as all external input provided to an agency in connection with the adoption or amendment of a regulation.

As indicated in Part IV of these comments, there are substantial questions concerning the Executive Officer's compliance with section 11347.3, in light of the sparseness of the CARB staff's documentation for key parts of its LCFS and ADF proposals. The CARB staff also waited until nearly the last possible moment to open the rulemaking file, which had the effect if not the purpose of limiting public analysis of the empirical and analytical basis for its proposals. While section 11347.3 of the Government Code applies to all California administrative agencies subject to the California Administrative Procedure Act (the "APA"), section 39601.5 of the Health & Safety Code was added to the Board's enabling statute in 2009 by AB 1085, when the Legislature learned of significant shortcomings in transparency in earlier rulemakings. Section 39601.5 compels CARB to provide "all information" on key aspects of its regulatory analysis "before the public comment period for any regulation" commences under the Government Code. It is unclear how the Executive Officer tried to comply with section 39601.5 in these rulemakings. What is clear, however, is that critical information about the assumptions and data on which the LCFS and ADF proposals are based has never been provided to the public.

LCFS 46-8 cont.

II. REGULATORY ANALYSIS

The use of lifecycle analysis ("LCA") in assessing GHG emissions is at the heart of the LCFS regulation. The Legislature has directed that programs like the LCFS regulation rely on the "best available economic and scientific information"; notably, this mandate applies to the carbon

LCFS 46-9

intensity ("CI") values that CARB assigns to the various renewable fuels in the LCFS regulation, as well as to all other parts of the rulemaking.[6] The use of the most scientifically defensive CI values is critical to the rulemaking effort. The CI values provide what the 2009 Initial Statement of Reasons (ISOR") for the LCFS regulation called "signals" to the downstream fuel industry that will direct them to achieve reductions in the CI of the fuels they sell in the most cost-effective manner. Insofar as the intent of the LCFS regulation is to reduce GHG emissions, the regulation must establish "the maximum technologically feasible and cost-effective" method of doing so. Cal. Health & Safety Code § 38561(a). If the CI values send the wrong "signal" to the downstream regulated parties, then the LCFS regulation will result in the use of pathways that may increase GHG emissions above the levels that would result if the best possible CI values had been assigned to various renewable-fuel pathways in the regulation. As one witness affiliated with the University of California stated at the April 2009 Board hearing on the LCFS regulation:

> [I]f we make a mistake in one direction in estimating these numbers, we'll use too much of a biofuel that's actually higher carbon [than] we thought and will therefore increase global warming. And if we use numbers that are too low, then we'll use too little of a biofuel that's lower carbon than we thought and will therefore increase global warming.

Transcript of Public Meeting of the Air Resources Board, April 23, 2009, at 73-74. As explained in Appendices A, B, and C to these comments, and as summarized below, the "signals" that CARB's new California GREET 2.0 and indirect land-use change models provide for corn-starch, corn-stover and sugarcane ethanol do not reflect the best available scientific and economic

LCFS 46-9 cont.

---

[6] *See* Cal. Health & Safety Code § 38562(e). The Legislature has not directed CARB to use carbon intensity as a regulatory mechanism; that is a choice the Board made in the 2009 LCFS regulation and that the CARB staff proposes to continue.

information, and therefore do not provide the accurate "signals" to the downstream industry that are needed to maximize GHG reductions while minimizing costs. To adapt the 2009 formulation of the issue, quoted above: the "numbers" for sugarcane ethanol are "too low" and as a result, "too little" corn-starch and corn-stover ethanol would be used in California gasoline, if the Board adopts the staff's proposal. (*See* Section A.1 & 2 below.)

LCFS 46-9 cont.

In addition, if the currently-proposed regulation were to be adopted, the displacement of corn ethanol that would result will severely interfere – once again as in earlier years of the LCFS program – with the federal renewable fuels standard ("RFS") program, in violation of federal law. No purpose is served by the State's conflict with federal law, because as also explained below, the regulation of CI at Midwest corn-starch ethanol biorefineries serves no beneficial purpose; contrary to the staff's claims in the current rulemaking, those biorefineries cannot and will not attempt to change their production methods solely to achieve lower CI scores in response to the LCFS regulation. In that particular respect the LCFS program violates an important tenet of AB 32, because it does not achieve "real" reductions in GHG emissions,[7] despite claims to the contrary. (*See* Section B below.)

LCFS 46-10

A. The CARB Staff's Lifecycle Emissions Analysis and its Consequences

1. Indirect Land-Use Change

From its inception, one of the most controversial aspects of the LCFS program has been its attempt to incorporate the theory of indirect land-use change ("ILUC") into regulation.[8] The

LCFS 46-11

---

[7] *See* Cal. Health & Safety Code § 38562(d)(1).

[8] It remains Growth Energy's position that the ILUC theory and the methods used to quantify the impacts of biofuel usage on land change, as well as the emissions model used by CARB to estimate emissions from land change, are too unreliable for use in regulation.

concept of ILUC stands at the intersection of environmental science and economics; having made the decision to try to use the ILUC theory in the LCFS program, CARB can be expected to comply with AB 32, and to use the "best available" scientific and economic information. As explained in Appendix A of these comments, the CARB staff has continued to ignore efforts by stakeholders to improve the quality of CARB's ILUC and indirect-emissions models, as well as recommendations of the Expert Working Group ("EWG") that CARB established when it first adopted the LCFS regulation. CARB must now finally address or adopt each of the recommendations presented in Appendix A, and in Growth Energy's other appendices to these comments, or explain fully why it is not doing so. *See* Cal. Gov't Code § 11346.9(a)(3). Insufficient time to address the recommendations in Appendix A is not sufficient justification for rejecting any of them; Growth Energy and other parties offered those recommendations before the staff published its current proposal and, in some instances, *at least four years ago*. (*See* Appendix A at A-2 and Table 1.) In the text below, Growth Energy summarizes some of the key deficiencies in the new ILUC analysis offered by the CARB staff for the Board's review.[9]

LCFS 46-11 cont.

These are among the recommendations in Appendix A:

- *Price-yield response facto*rs. The CARB staff's ILUC analysis for corn-starch ethanol uses a range of price-yield values, despite recommendations from the

LCFS 46-12

---

[9] Each Appendix to the main text of Growth Energy's comments are a fully incorporated part of Growth Energy's comments. The Board must respond fully to each objection and recommendation in the appendices to the main text of these comments, regardless of their placement, or, at a minimum, explain why it believes each of these objectives or recommendations to be "irrelevant." *See* Cal. Gov't Code § 11346.9(a)(3). To ensure compliance with that requirement of the Government Code, California courts will conduct *de novo* review using independent judgment. *Cf. POET LLC v. California Air Resources Bd*. (2013) 218 Cal. App. 4th 681, 747-48. Particularly when the facts concerning CARB's actions in the regulatory process cannot be a subject of genuine dispute, "the independent standard of appellate review" applies. *Id.* at 748.

LCFS 46-13

authors of the model that CARB uses, as well as the EWG, that the most scientifically defensible value is 0.25. In the ISOR for the LCFS regulation, the Executive Officer relies on a non-peer-reviewed data review by a researcher at the University of California-Davis retained by CARB to support a lower price-yield value. In addition to lacking full documentation, the Davis reviewer appears to have made unexplained, selective use of other research, by Dr. J.F.R. Perez at Purdue University. The CARB staff has not supplied critical missing information from the Davis review requested by Growth Energy, and at this juncture, Growth Energy has no choice but to question whether the Davis review used reliable methods. Certainly, the Executive Officer cannot claim that the staff's work on price-yield responses has been transparent, nor that it is based on the "best available" information: information that is not made available to the public during a rulemaking governed by the California APA is akin to having no information at all.[10]

LCFS 46-12 cont.

- *Multiple cropping*. Last year, researchers at Iowa State University ("ISU") published a study that compared the results of ILUC modeling using GTAP (the modeling system used by the CARB staff) with real data. The study showed that over the last 10 to 15 years, there has been no net land conversion from forest and pasture to cropland in many regions of the world. (*See* Appendix A, note 5.) The ISU study confirms that increases in crop prices (a theoretical result of biofuels mandates like the LCFS regulation) will result in multiple cropping. The CARB

LCFS 46-14

[10] If the Board directs the Executive Officer to provide the missing information concerning the Davis review, it must follow the procedures in section 11347.1.

staff has ignored that study in its rulemaking proposal and supporting materials. The CARB staff has also ignored a November 2014 submission by Growth Energy that demonstrated how the ISU work could be adapted to correct the results of GTAP. Since at least 2009, the CARB staff has known about the inability of GTAP to account for multiple cropping; Growth Energy supplied a method to correct that deficiency. If the CARB staff did not agree with Growth Energy's approach, it should have developed and applied its own. Choosing instead to completely ignore the ISU study violates the Legislature's requirement to use the "best available" information. If the staff's position is that it had too little time or resources to include the ISU work in its new proposal, then the solution is simple: the Board should give the staff the resources it needs and direct the staff to return to the Board, before the Board attempts to act on the current LCFS proposal.

LCFS 46-14 cont.

- *CRP Land.* A lack of time or resources to update GTAP is also not a valid reason for the CARB staff's steadfast refusal to include the effects of the Conservation Reserve Program ("CRP") land in mitigating the land-use-related emissions impacts that the CARB staff attributes to corn-starch ethanol. In March 2014, Growth Energy supplied CARB with direct evidence from U.S. Department of Agriculture statistics showing that CRP land conversion has occurred in the last five years. The GTAP system already includes computer code to "access" CRP land, as Appendix A points out. In other words, CARB has a model that can account for CRP land conversion and was provided with CRP conversion data almost a full year ago. But apparently nothing has been done with this issue in the

LCFS 46-15

CARB staff's new proposal, and the reasons why the staff has not done so are not clear in the materials provided to the public. LCFS 46-15 cont.

- *The AEZ-EF and CCLUB models*. The CARB staff's current LCFS proposal uses a model called the "Agro-ecological Zone Emission Factor" model (or "AEZ-EF") to estimate GHG release caused by various theoretical land transitions. In 2013, the researchers at the Argonne National Laboratory ("Argonne") released an updated version of an alternative model that serves the same purpose as AEZ-EF called the "Carbon Calculator for Land Use Change from Biofuels Production" model (or "CCLUB"). The 2013 CCLUB model includes more detailed emissions-related information for the United States than the AEZ-EF model. The land-use change emissions estimated with AEZ-EF and CCLUB differ substantially. (*See* Appendix A, Table 2.) Although the CARB staff has claimed in at least one stakeholder discussion to have evaluated CCLUB, there is no indication of its having done so in the AEZ-EF documentation, the ISOR for the current regulatory proposal, or the staff's accompanying materials. In order to determine whether the CARB staff is using the "best available" science, the Board and stakeholders are entitled to know why the CARB staff has chosen to use AEZ-EF rather than CCLUB. LCFS 46-16

The potential magnitude of the errors in the CARB staff's ILUC analysis, and thus in the "signals" concerning the CI of corn-starch ethanol created by the proposed new LCFS regulation, are large. These false signals threaten to undermine the very purpose of the LCFS by promoting fuels that will not necessarily reduce greenhouse gas emissions and may even increase emissions. Having now been provided with Appendix A to these comments ─ which largely restates various LCFS 46-17 objections to the staff's current approach and corrective recommendations that Growth Energy has previously presented[11] — the Board can and must address these issues. If CARB relies on information not currently in the rulemaking to explain its reasons for not accepting Growth Energy's objections and recommendations, it must place that information in the rulemaking file and allow sufficient time for public review and comment. (*See* note 9 above.) If no such information is forthcoming, then the alternate explanation is that the Board is relying on conjecture and unsupported assumptions, rather than the "best available" information. Alternatively, if the Board is convinced that more time and resources are needed to address the issues presented in Appendix A, it should either suspend the LCFS program or maintain the regulatory status quo until the staff is prepared to bring a new proposal back to the Board. LCFS 46-17 cont.

2. California GREET 2.0

In Appendices B and C, Growth Energy comments on the portions of California GREET 2.0 ("CA GREET 2.0") used in the CARB staff's new LCFS proposal to generate direct-CI values pertaining to corn and sugarcane ethanol. There are several issues identified in Appendices B and C that CARB must address:[12]

- *Impacts of land-use change on methane emissions*. Enteric fermentation, which occurs in the digestive system of ruminant animals, produces methane, which AB 32 treats as a greenhouse gas. The models used in LCA analysis that attribute the creation of additional LCFS 46-18

---

[11] Some of the relevant earlier submissions by Growth Energy are included in Appendix A. Other stakeholders may have advanced similar objections and recommendations, or commented on the same issues. It is impossible to know if that has occurred, however, because the CARB staff has apparently interpreted the Government Code not to require it to have placed all such submissions in the rulemaking file for this proceeding. *See* Part V below. LCFS 46-19

[12] *See* note 8 above.

cropland to biofuel mandates also posit that the increase in cropland will reduce the land area available for grazing animals (unless additional land is cleared for grazing); one result of that reduction in grazing area, or a need to clear more land, will be an increase in livestock prices, a reduction in demand for meat, and smaller herds. As Appendix B notes, EPA's LCA analysis has accounted for this indirect reduction in methane emissions in the RFS program's LCA analysis. The CARB staff, however, has not done so in CA GREET 2.0 or in other parts of its new LCFS proposal, even those this omission has been repeatedly called to the staff's attention. Unless the CARB staff has a sound theoretical or empirical basis for disagreeing with EPA's judgment that a sound LCA-based program should account for the reductions in total methane emissions that will result from any land-use changes predicted from biofuels policies, the CA GREET 2.0 model should be modified to come into line with EPA's approach.

LCFS 46-18 cont.

- *Credit for reductions in methane emissions resulting from the use of DGS*. Livestock fed with a coproduct of corn-starch ethanol production, called distillers grain solubles ("DGS"), experience lower rates of enteric fermentation and therefore release less methane. Accordingly, Argonne's current GREET model (called "GREET 1-2013") gives "credit" to corn-starch ethanol production that includes the production of DGS. By contrast, CA GREET 2.0 does not, ostensibly because the CARB staff does not consider the feeding of animals to fall within the LCA system boundary for corn-starch ethanol. In addition to running counter to the judgment of Argonne's experts, who included a DGS credit for reductions in methane emissions, the CARB staff's approach is arbitrary. The entire ILUC theory is itself based on economic assumptions that are untestable; if the theory itself is

LCFS 46-20

sound enough for inclusion in a regulatory program, then there is no reason to exclude the credits for DGS production recognized by Argonne. LCFS 46-20 cont.

- *Backhaul emissions.* In a regulatory program involving multiple fuel pathways, like the LCFS regulation, the LCA analysis must treat pathways that use different feedstocks in a consistent manner, unless there is sufficient basis to treat them differently. As Appendix C points out, of all the liquid fuels included in CA GREET 2.0, only one (ethanol made from sugarcane) is not charged with so-called "backhaul emissions," which are intended among other purposes to account the GHG emissions attributed to a vessel that has transported liquid fuel to a given destination after it departs for another port. In the case of sugarcane ethanol, which reaches the United States via ocean tankers, the omission of backhaul emissions has a significant impact on its assigned CI value. (*See* Appendix C, section 6.1.[13]) Consistency in the LCA analysis and in the regulatory process generally should require producers of sugarcane ethanol to account for those emissions in their applications, unless they can accurately and affirmatively show for purposes of their pathway application that no such backhaul emissions exist.[14] LCFS 46-21

- *Accuracy of inputs for shipping emissions for Brazilian sugarcane ethanol.* Basic information used in the LCA analysis must be accurate. As Appendix C indicates, CA LCFS 46-22

---

13 A screen-shot of the relevant workbook from CA GREET 2.0 is included as an Exhibit to these comments.

14 If the premise for assigning no backhaul emissions for sugarcane ethanol from Brazill is a belief that vessels that would carry sugarcane ethanol to the United States from Brazil would not leave the United States without a cargo, then (barring some explanation) the same premise should apply to the water transport of renewable diesel from the Far East, corn ethanol produced and used in the United States after barge transport, sugarcane ethanol transported by barge, and other fuels transported by barge that are included in GREET 2.0. LCFS 46-21 cont.

GREET 2.0 assumes that all sugarcane ethanol from Brazil is delivered in 22,000-ton shipments ─ an assumption that is not supported by the available data. (See Appendix C, section 6.2.) CA GREET 2.0's assumption likely understates GHG emissions from inbound ocean transport by 100 percent. CA GREET 2.0 also uses unrealistic, across-the-board assumptions about the relationship between oceangoing vessel power requirements and vessel speed. (*Id.*, section 6.4.) The appropriate course is to modify CA GREET to include default values based on the relevant real-world data (presented in Appendix C), which may be modified for pathways based on verifiable and enforceable certifications by the pathway applicant.

LCFS 46-22 cont.

Appendices B and C identify additional inconsistencies, errors and failures to use the best available information in CA GREET 2.0. Two of the world's leading biofuels experts, Bruce Dale and Seungdo Kim of Michigan State University, have identified additional errors in CA GREET 2.0 for corn ethanol, as documented in Appendix B. Such errors violate the Legislature's mandate for the use of the "best available" information in AB 32 regulations, and those errors were presented and fully documented to the CARB staff in November 2014, shortly after a draft of CA GREET 2.0 was released for public review. The impact on the direct CI emissions factors is significant, especially for corn-stover ethanol, and those errors must be addressed without further delay. Likewise, Appendix C indicates that CA GREET 2.0 does not reflect actual sugarcane farming practices, along with other errors that must also be corrected now, before the rulemaking proceeds further. (See Appendix C, sections 2-5.) Unless those errors are corrected, the new LCFS regulation will provide significantly inaccurate "signals" to downstream regulated parties, and will not maximize the program's goals in a cost-effective manner.

LCFS 46-23

* * *

In sum, the CI values assigned to corn and sugarcane ethanol are not based on reliable data and methodologies, and need to be corrected before CARB tries to move forward with the LCFS "re-adoption" process. Although the CARB staff may believe that some or all the issues identified above cannot be addressed now, given their current regulatory schedule and claimed inadequate level of resources, the Board cannot accept such a position. The Board has discretion in setting the schedule to hear items for approval and to allocate CARB's resources, but under AB 32 it has no discretion to adopt or enforce regulations that are not based on the "best available economic and scientific information." Cal. Health & Safety Code § 38562(e). Again, applying CIs that are not based on the best available economic and scientific information threatens to undermine the very purpose of the LCFS. LCFS 46-24

B. Impacts of the Current LCFS Proposal

The incorrect regulatory "signals" created by the CI values assigned to corn and sugarcane ethanol will skew the California renewable fuels market away from corn-starch ethanol, and toward sugarcane ethanol. Corn-starch ethanol will not be able to compete with sugarcane ethanol using scientifically unreliable CI values. Among other consequences, this means that the potential increase of 13 cents per gallon of liquid fuel in 2020, estimated by the CARB staff if LCFS credits cost $100 per credit, will not be spent to achieve reductions in the CI of California motor fuels in the most cost-effective manner possible and may not lead to GHG reductions at all.[15] LCFS 46-25

---

[15] The CARB staff's 13-cent-per-gallon estimate appears in the Attachment to the Form 399 (Fiscal Impact) report signed on December 15 and 16, 2014, by two CARB staff members, and which Growth Energy located in the rulemaking file at CARB in early January 2015. CARB uses the $100 per credit estimate in the ISOR for the LCFS. *See* LCFS ISOR at VII-1. According to the ISOR, the estimated fuel price increase for gasoline in 2020 using the $100 per credit estimate is 12 cents per gallon. *See id*. at VII-5, Table VII-5. While the CARB staff calls the $100 per credit estimate "conservative," considers the 12-cent-per-gallon estimate to "represent the upper bound of fuel price impacts," and urges that its estimates not be used to "determine the impact of credit prices on the final retail price of transportation fuels," *see id*.,

Despite the lack of corollary benefits, the new LCFS regulation will result in the displacement of corn-starch ethanol produced in the Midwest with other fuels. The staff has published an "illustrative compliance scenario" which projects a reduction in corn ethanol use in California gasoline from the current (2014) level of 1,250 million gallons per year to 700 million gallons per year in 2020, with an increase in consumption of cane ethanol equal to about 64 percent of that reduction. That scenario means a reduction in the use of Midwest corn ethanol in California of about 550 million gallons per year as of 2020, relative to today, equivalent to the entire output of about seven typical-sized ethanol plants.[16]

The CARB staff has based its analysis of the economic impact of the LCFS regulation from 2016 to 2020 — which is an analysis that is mandatory for any rulemaking governed by the APA, and whose reliability must be affirmed by the rulemaking agency before a final rule can be adopted[17] — on estimates of the prices of LCFS credits from 2016 to 2020. The primary case used in CARB's economic impact analysis uses, as indicated above, a $100 per credit price; the staff's analysis also examines economic impacts using lower credit prices. As explained in Appendix D, if sugarcane ethanol pathways achieve CI levels of 40 g/MJ, and corn-starch ethanol pathways achieve CI levels of 70, credit prices as low as $23 would be sufficient to induce a switch from

LCFS 46-25 cont.

---

the staff has not fully explained why it considers the $100 per credit to be "conservative" or why it believes the 12-cent-per-gallon increase to "represent the upper bound."

16 According to data published by the Renewable Fuels Association, the average output of operating corn-starch ethanol biorefineries in the United Sates is about 76 million gallons of ethanol per year. *See* www.ethanolrfa.org/pages/statistics.

17 *See* Cal. Gov't Code § 11346.5(a)(13) (requiring a determination of cost-effectiveness in an initial regulatory proposal); id. § 11346.9(a)(4)(same, in the Final Statement of Reasons for regulatory action). An agency cannot determine the cost-effectiveness of a regulation without estimating the costs of the regulation, as well as its benefits. As for the CARB staff's estimates of the benefits of the proposed new LCFS regulation, see Part IV below.

Midwest corn ethanol to imported sugarcane ethanol, assuming that the latter is available for sale to the downstream market in California. (That is an assumption that the CARB staff has made in its compliance and economic impact analyses.) As Appendix D, prepared by Edgeworth Economics, states, the CARB staff's "scenario indicating a substantial decline in the use of Midwest corn ethanol in California and an increase in the use of imported cane ethanol is therefore not only plausible, but probable if sufficient ethanol is available from Brazil, even at modest credit prices well below CARB's projected level of $100." CARB must explain whether, and if so, why, it considers this dramatic shift in the sourcing of ethanol for the California market (which its own staff's economic impact analysis confirms) to be irrelevant to its statutory mandates or objectives, and to the policies that it pursues as a matter of discretion.

LCFS 46-25 cont.

Much, if not all, of the Midwest corn ethanol eliminated from the California market would be ethanol produced at biorefineries that generate renewable fuel that is certified under the federal Renewable Fuel Standard (RFS) with the specific intent of reducing national greenhouse gas emissions, thereby putting the LCFS program into direct conflict with federal law and policy.[18] In addition to the economic impacts on corn-starch ethanol business operations, the U.S. corn-starch ethanol producers who are currently attempting to finance the development of cellulosic ethanol production capabilities at plants located in the United States may have fewer resources available for those development efforts; in that respect, the LCFS program will further interfere with the goals and purposes of federal biofuels law and policy, which include the commercialization of cellulosic ethanol.

LCFS 46-26

Unless there is a significant expansion in domestic demand for ethanol, the increased imports of Brazilian cane ethanol, combined with the proposed LCFS regulation's

LCFS 46-27

[18] 42 U.S.C. 7545(o)(2)(A)(i)

LCFS 46-26 cont.

generous allowance of credit to California electric utilities,[19] will result in a combination of (i) lost production or even shutdowns at Midwest biorefineries, and (ii) increased logistics costs as those American biorefineries seek foreign markets (potentially, and ironically, in Brazil, where ethanol is not subject to the LCFS regulation). If the Board believes that any other outcome or combinations of outcomes for the Midwest corn ethanol industry from the LCFS regulation will occur, it should explain them and estimate their likelihood of occurrence.[20] LCFS 46-27 cont.

The second outcome ─ corn ethanol export outside the United States to make up volume lost in California ─ will not produce reductions in global GHG emissions.[21] To the extent the first outcome (loss of any commercially practicable way to offset the reductions in California demand) occurs, then the LCFS regulation will have particularly grim consequences for the Midwest corn ethanol industry and those who depend on it. As Appendix D indicates:

> On average, U.S. corn ethanol facilities employ approximately 0.8 employees per million gallons of ethanol produced, or about 61 employees for a typical plant. A reduction in ethanol demand of 550 million gallons per year therefore would result in a direct loss of approximately 440 jobs at ethanol refineries. In addition to these direct effects, the regions that host ethanol production facilities would experience additional reductions in economic activity stemming from reduced purchases of locally-sourced inputs (the "indirect" impact) and reduced spending by facility employees and local vendors (the "induced" impact). These additional economic impacts are generated by the "multiplier" effect, which results from the recycling of business revenues and household income within the local region. Plausible estimates for the overall multiplier effect for employment applicable to the ethanol industry range from about 2 (indicating a total impact on employment equal to two

LCFS 46-28

---

[19] *See* Section C below.

[20] Note that this analysis of potential outcomes from the LCFS regulation assumes for present purposes that corn-starch ethanol pathways achieve the CI levels projected by the CARB staff. As to the realism of those projected reductions in CI levels, see Part III.A below. LCFS 46-27 cont.

[21] In addition to producing no net GHG emissions reductions, the second outcome will impose substantial direct costs on the Midwest corn ethanol industry. Appendix D estimates that the additional logistics costs for the transport of Midwest corn ethanol to a market like Brazil at approximately 10 cents per gallon. LCFS 46-28 cont.

> times the direct employment impact) to about 7. Applying a figure of 4 to the direct employment impacts calculated above implies a loss of approximately 1,760 jobs in ethanol producing regions.

LCFS 46-28 cont.

If CARB disagrees with that assessment or considers those outcomes to be irrelevant to its mission, the Board needs explain why those impacts in the Midwest are overstated, or why those impacts are irrelevant.

III. ENVIRONMENTAL ANALYSIS

LCFS 46-29

Two different statutes ─ AB 32 and CEQA ─ make it critical for the Board to develop a complete understanding of the environmental issues presented by the CARB staff's ADF and LCFS proposals. First and foremost, the purpose of AB 32 is to reduce GHG emissions, *see, e.g.*, Cal. Health & Safety Code § 38562(a); regulations that do not reduce GHG emissions are not "necessary" to meet the purposes of AB 32 and would violate the Government Code.[22] In addition, among other relevant requirements, including the obligation to rely on the "best available" scientific and economic information, *id.* §38562(e), AB 32 directs that to the extent feasible, the Board's GHG regulations not interfere with efforts to meet and maintain federal and state air quality standards. *See id*. § 38562(b)(4). Under CEQA and the Board's implementing regulations, the Board's obligations to protect the environment are, if anything, even more exacting: CARB "shall not" adopt or approve any action "for which significant adverse environmental impacts have been identified during the review process." if there are "feasible mitigation measures or feasible alternatives available which would substantially reduce such adverse impact." 17 C.C.R. § 60006.

LCFS 46-30

As explained below, the CARB staff's two proposals do not meet the criteria of either AB 32, or of CEQA and the Board's implementing regulations. First, the CARB staff's LCFS proposal

LCFS 46-31

[22] *See* Cal. Gov't Code § 11342.2 ("no regulation adopted is valid or effective unless … reasonably necessary to effectuate the purpose of the statute").

assumes that the current LCFS regulations have actually reduced net GHG emissions into the atmosphere; in fact, there is no evidence that the LCFS regulations have done so, to date, and the available evidence demonstrates that there have been no such GHG reductions. Second, and building its first false premise about the efficacy of the current LCFS program, the staff's LCFS proposal invites a further assumption that the new LCFS regulations will achieve further reductions in net GHG emissions, but remarkably, the *staff has offered no definitive quantitative estimate of those GHG reductions.* That proposal also makes unrealistic assumptions about how portions of the affected industries will respond to the new regulation, and fails to account for ways in which the new regulation will increase, rather than decrease, GHG emissions, as well as criteria pollutants. The proposed new LCFS regulation cannot properly be treated as a regulation that meets the purposes of AB 32 because there is no reliable demonstration that the regulation will reduce GHG emissions, and the proposal is therefore not authorized by AB 32 and is invalid under the Government Code. In addition, and in conflict with section 38562(b)(4) of the Health & Safety Code, the CARB staff has ignored alternative, "feasible" methods of obtaining the same GHG reductions that it once attributed to the LCFS regulation through 2020. (*Id.*)

LCFS 46-31 cont.

LCFS 46-32

LCFS 46-33

LCFS 46-34

The staff's two proposals (for the new ADF regulation and for the revised LCFS regulation) also conflict with the requirements of CEQA and cannot be adopted. CARB is obligated to mitigate the significant adverse environmental impacts of the LCFS regulation recognized by the Court of Appeal in *POET v. California Air Resources Bd.* (2013) 218 Cal. App. 4th 681, that will result from the use of biodiesel fuels. As explained in Appendices I and J and as summarized below, the CARB staff's two proposals and the draft EA do not properly mitigate those impacts, or comply in other important respects with CEQA and the Board's implementing regulations.

LCFS 46-35

A. The LCFS Regulation and GHG Emissions

We begin with the facts and analysis that are pertinent to an analysis of the LCFS proposal under AB 32, before turning to the CEQA analysis.

1. Background on Corn-Starch Ethanol Production: Past and Current Practices

The first step in understanding the environmental consequences of the proposed new LCFS regulation relevant to AB 32 is to consider the impacts of the current regulation, first adopted under AB 32 in 2009. The ISOR for the new proposed LCFS regulation claims that "[o]ver the first three years of the LCFS, there has been a steady decline in the average CI of the mix of biofuels used in California. Concurrently, there has been a great expansion of the applications for fuel-pathway CIs." (LCFS ISOR, App. B at B30.) On that basis, the "ARB staff expects these trends to continue and actually accelerate as the stringency of the LCFS increases and credits become more valuable." (*Id.*) The ISOR cites no facts in support of the staff's expectation, and its claim that there has been a "steady decline in the average CI of the mix of biofuels sold in California" is contradicted by the relevant evidence from the corn-starch ethanol industry. These are the pertinent facts: [23] LCFS 46-36

1. Ethanol produced from corn starch is the principal renewable fuel produced in the United States, and has been the primary alternative fuel blended into gasoline in California, both before and after the implementation of the current LCFS regulation. Members of Growth Energy and other producers in the U.S. corn ethanol industry have strong commercial incentives to LCFS 46-37

---

[23] Because Growth Energy does not have access to confidential business information of its members or any other firms in the ethanol industry, it bases these comments on information in the public record. *See* Appendix E (Declaration of Erin Heupel, P.E. (hereinafter "Heupel Decl.").

maximize yield from the feedstock they purchase and to minimize energy usage, and thus to minimize GHG emissions. Next to corn costs, energy costs are the largest variable cost in producing corn ethanol.

2. A corn-starch ethanol plant costs millions of dollars to build. Most corn-starch ethanol is produced in the Midwest, at plants that are carefully sited in order to have ready access to their feedstock, as well as competitively priced natural gas, electricity, or other sources of energy to run the plant. Ethanol plants cannot directly control and document how farmers grow and harvest corn, which the farmers grow not only to sell to ethanol plants, but also to other customers, on the best possible commercial terms for the farmers. The companies that survive and prosper in the corn ethanol industry are those whose plants are designed from the beginning for maximum efficiency in feedstock conversion and minimum energy consumption.

LCFS 46-37 cont.

3. The competitive pressure to reduce energy consumption, and not regulation, is what drives reductions in GHG emissions at corn ethanol biorefineries. For example, the current LCFS regulation has been in full effect since 2011; based on the information in the public record available to Growth Energy, ***no biorefinery*** selling ethanol for blending into gasoline has made ***any*** significant changes in its production methods, feedstocks, methods of transport, or any other factor relevant to GHG emissions, in order to specifically obtain a lower CI value for purposes of the California LCFS regulation. To be sure, as the ISOR claims, numerous plants have obtained approval for plant-specific "pathways" with lower CI values than might have otherwise been assigned to them under the California regulation. Those facilities, however, have obtained approval for those pathways by documenting production methods adopted for competitive reasons and federal policy reasons, completely independent of the California LCFS regulation.

Thus, when the ISOR claims that there has been a "great expansion" in the number of applications for new alternative-fuels pathways, in the case of Midwest corn-starch ethanol plants, it is confusing what are essentially paperwork exercises ─ when applicants are documenting production processes, methods and energy sources that have been adopted for commercial reasons ─ with reductions in CI levels driven by regulation. Because the record of "great expansion" in pathway applications appears to be one of the principal bases for predicting that the new LCFS regulation will result in reductions in the future, it is important for the CARB staff, and ultimately the Board, to identify any evidence that contradicts what Growth Energy has concluded from the information available in the open record.[24] Any such evidence should be then be placed in the rulemaking file pursuant to section 11347.1 of the Government Code for public review and comment. If, on the other hand, the CARB staff has no evidence the current LCFS regulation has driven reductions in the CI levels of corn ethanol plants in the Midwest, and the Board decides to act in reliance on the staff's speculation, then candor should require the Board to admit as much before work is completed on the new regulation.

LCFS 46-37 cont.

Of course, not all corn-starch ethanol plants that were able to participate in the California market before 2011 have been able to remain in that market, because not all such plants have been able to document production processes, methods and energy usage that would qualify them for competitive CI values. When they have been able to remain in the market, they must generally

LCFS 46-38

[24] As Appendix E indicates, Ms. Heupel of POET LLC, for her part, was able to describe the business and regulatory practice at her company in the open record. If the CARB staff believes that it cannot put any information that corroborates its position owing to concerns about business confidentiality, and that contradicts Growth Energy's understanding of how corn starch ethanol biorefineries have gained lower-CI pathways to date, it should so indicate, and include a description of its efforts to obtain permission from the owners of the putatively confidential information in the open record.

LCFS 46-39

sell their product for less than what plants with lower CI values can obtain.[25] The CARB staff has admitted as much.[26] " Some of the plants that could not document the production technologies, processes, methods, and energy inputs that the CARB staff would reward with lower CI values had previously sold a substantial volume of ethanol in California," as one industry participant has stated, and "[t]he LCFS regulation forced some of those plants entirely out of the California market."[27] As the same industry participant has explained:

LCFS 46-38 cont.

> The effect of the LCFS regulation has been to "de-commoditize" the corn ethanol market, for purposes of California -- *i.e.*, ethanol is no longer a fully fungible commodity in California, in which producers can prevail by offering the best commercial terms. Plants that were optimized for shipment of ethanol to California when they were built, but that can no longer sell their ethanol in California, now must find buyers outside California. On an industry-wide basis, the LCFS regulation has led to "fuel shuffling" that has likely increased the number of miles that Midwest corn ethanol had to travel in 2011 in order to get from the production facilities to customer destinations.

LCFS 46-40

Whiteman Decl. ¶ 18. Importantly, as that individual concludes:

> For all the disruptions in the California ethanol market created by the LCFS regulation, there has been no reduction in the overall amount of corn ethanol produced in the United States, or used as a motor fuel in this country or overseas. …. The overall production levels for corn ethanol last year, and for the foreseeable future, depend on macroeconomic factors (including demand for gasoline) that are independent of the LCFS regulation.

---

25 Growth Energy relies here on other public information. *See* Appendix E (Declaration of Robert Whiteman (hereinafter "Whiteman Decl.").

26 *See* Whiteman Decl. ¶ 17. Mr. Whiteman is a senior official in one of the largest ethanol marketing businesses in the United States, and would qualify as an expert on corn-starch ethanol marketing based on his knowledge, skill, experience and training.

27 *Ibid.*

Id. ¶ 20.[28] The CARB staff also agreed, in the 2009 rulemaking, that "fuel shuffling" would be one result of the current LCFS regulation. When taken together, the totality of the evidence thus establishes this important point: ***the current LCFS regulation has not resulted in any reductions in GHG emissions from corn starch ethanol,*** whose use in gasoline has been the downstream fuel industry's principal method of complying with the LCFS regulation.

LCFS 46-40 cont.

In sum, and contrary to what may be the position taken in the ISOR for the new regulatory proposal, there has to date been no "real" reduction, see Cal. Health & Safety Code § 38562(d)(1), in the "average CI in the mix of biofuels used in California," at least with respect to liquid biofuels used in gasoline. Here again, if the CARB staff has any actual evidence contradicting Growth Energy's understanding of how the LCFS regulation has affected the corn-starch ethanol business to date, it must provide that evidence for review under the Government Code, or instead admit that it is asking the Board to rely on unsupported opinion.

LCFS 46-41

2. Prospects for Future Reductions in the Carbon Intensity of Corn-Starch Ethanol

The ISOR also claims that the new LCFS regulation will continue the "trend" towards lower CI levels "as the stringency of the LCFS increases and credits become more valuable." (LCFS ISOR, App. B at B30.) The ISOR continues as follows:

> A two-step process was used to reflect how the trend to lower CI fuels will impact credit generation between 2016 and 2025. First, estimates of "pool-average" CIs for fuels with many different pathways were made based on the range of fuel-pathway CIs (FPCs) approved for use. The fuels studied were corn ethanol (150 FPCs), Cane Ethanol (21 FPCs), and Corn-Sorghum Ethanol (20 FPCs). In each case, the CIs of the lowest 50 percent of FPC CIs were averaged together, and this CI was then assigned (after appropriate adjustments to reflect iLUC changes) as the CI of that fuel category in 2016. Once a starting point for a fuel category's CI was determined for 2016, the CI was further lowered to reflect that higher credit values and continued plant improvements will lead to lower average CI with time. A

LCFS 46-42

[28] Mr. Whiteman prepared his Declaration in 2012.

> conservative adjustment of a one percent decrease in CI values for each category was uniformly applied to at least partially recognize this effect.

Id. at B30-31. As the ISOR adds in a footnote, "For example the average CI of corn-derived ethanol under this method changes from 82.2 grams/MJ to 70.0 grams/MJ." Significantly, the ISOR here concedes that a substantial part of the industry current serving California ─ some or all producers who are in the upper half of the current FPC distribution ─ have no future in the California market. Also significantly, the ISOR offers no technical analysis or informed expert opinion to support the speculation that remaining ethanol production processes will achieve *on average* the first lower-CI level (for corn ethanol, 70.0 grams/MJ), and then year-over-year reductions.

LCFS 46-42 cont.

In addition to lacking any apparent support, other than speculation by the authors of the ISOR, the ISOR's prediction for the future cannot be squared with what is currently known about industry conditions and the requirements of the proposed new LCFS regulation. As noted above (*see* Part II.B) and explained in Appendix D, at relatively modest LCFS credit prices, the LCFS regulation will shift demand for ethanol from corn-starch pathways to sugarcane pathways, and that shift will occur in the first year of the new program (2016). Here are some of the key facts that the ISOR's speculation about future "trends" does not address:

- The U.S. corn ethanol industry currently has enough production capacity to serve the Nation. The most competitive Midwest corn ethanol plants in operation today are built and sited for optimal logistics and energy usage in the first years of production, and not for significant future optimization.[29]

- In addition to energy, the corn feedstock is a major cost factor in corn-starch ethanol production, and corn-starch ethanol plants "cannot directly control and document how

LCFS 46-43

[29] See Appendix E (Heupel Decl.).

farmers grow and harvest corn, which the farmers grow not only to sell to ethanol plants, but also to other customers, on the best possible commercial terms for the farmer."[30]

- Corn-starch ethanol plants are also assigned by the LCFS a large ILUC emissions factor, which they are powerless to change.

- Corn-starch ethanol plants can therefore work with only a fraction of their production processes ─ chiefly, energy, for which they are already likely optimized ─ to achieve lower CI scores.

- Any costs incurred to reduce the CI score of the ethanol that corn ethanol plants would produce would have to be recovered in the California market against competition from sugarcane ethanol and electricity. The deeper the reductions in CI, assuming any such reductions were possible, the greater the costs, and the longer the period needed to remain competitive in California.

Against that backdrop, Growth Energy credits the opinion expressed in Appendix E that in order to remain in the California market, "even a very efficient Midwest corn ethanol plant would have to find and implement further efficiencies or energy reduction opportunities not driven by the nationwide market and recover the costs of the necessary changes, over a very short time frame.… Rather than incur those costs, U.S. corn ethanol plants will try to compete in markets outside California."[31] Here again, if the CARB staff has any basis either to disagree with the prediction of market exist, or to support its belief in the "trend" that the ISOR predicts, it needs to provide the information (be it facts, expert opinion, or any other type of evidence) for public comment. If the CARB staff cannot do so, then as indicated above, candor requires the Board to admit that the predicted future operation of the LCFS regulation in the ISOR is based on unsupported conjecture, at least with respect to corn-starch ethanol.

LCFS 46-43 cont.

---

[30] Heupel Decl. ¶ 10.

[31] *Id.* ¶ 11.

This issue ─ how the new LCFS regulation will affect the supply of cornstarch ethanol to California ─ needs to be addressed clearly, directly, and empirically. Corn starch ethanol remains a part of the CARB staff's compliance scenarios for many years; if corn starch ethanol cannot meet the expectations of the ISOR, then the viability of the new LCFS program as depicted in the ISOR is in serious jeopardy. If the absence of the corn starch ethanol from the California market triggers use of the cost-containment provision, as the costs of LCFS credits skyrockets, then LCFS program will not achieve the GHG reductions that CARB might otherwise attribute to the program.

LCFS 46-43 cont.

3. Greenhouse Gas Emissions and Related Impacts of the New LCFS Regulation

Despite the ejection of corn-starch ethanol from the California renewable fuels market, the new LCFS regulation will not reduce, and will likely increase, net global GHG. As explained above, "fuel shuffling" is one likely outcome of the new LCFS regulation (accompanied by potential shutdowns of biorefineries in the Midwest). To date, the fuel shuffling caused by the LCFS regulation has been confined, in the case of ethanol, to the continental United States. The new LCFS regulation will make fuel shuffling an intercontinental phenomenon, as California begins to draw sugarcane ethanol in large quantities from production sites in Brazil. As explained in Appendix G, one result of the new regulation will be increases in GHG emissions caused by the transport of large volumes of Brazilian sugarcane ethanol to the California market. Looking solely at the GHG emissions increases that should be attributed to oceangoing tankers, fuel shuffling emissions will fall in the range of 385,000 to 735,000 tons of GHG emissions per year, under the assumptions described in Appendix G.[32] If the CARB staff or the Board have any disagreement with those estimated GHG shuffling losses, it should explain them and their basis.

LCFS 46-44

[32] *See* Appendix G. Those estimates are based on necessary corrections to the CA GREET 2.0 model, described in Appendix C. Even if those corrections are not made, GHG emissions from

For its own part, the CARB staff apparently has no current estimate of the net GHG emissions impacts of the LCFS regulation ─ at least, none that it was prepared to publish. The ISOR contains a table (Table IV-2) that contains some estimates of "Projected LCFS GHG Emissions Reductions." The ISOR prefaces that table, however, with this important qualification:

> These estimates do not include a reduction to eliminate the double counting of the Zero Emission Vehicle Mandate, the federal Renewable Fuel Standard Program, the Pavley standards, or the federal Corporate Average Fuel Economy Program. (LCFS ISOR at IV-2)

That is a breathtaking admission. Growth Energy is not aware of any other major regulation that the Board has ever been asked to approve without a net emissions reduction estimate for the pollutant or substance of primary concern (here, GHG emissions). For all that the Board and the public can tell, the programs that the ISOR has failed to include would leave the LCFS program with *de minimus* GHG emissions reduction benefits. Certainly, the current analysis before the Board does not meet the most basic tests for regulatory approval under AB 32; the GHG reductions that the proposed new LCFS regulation are not "quantifiable." Cal. Health & Safety Code § 38562(d)(1). Nor, of course, can the Board claim that the LCFS regulation would be "cost-effective," *see id.* § 38562(a), because there are no quantified GHG emissions reductions benefits to be placed into a ratio with the costs of the proposal. CARB cannot approve the new LCFS program proposed in the ISOR, without contorting the statutory language to allow it to impose costs on the public without first quantifying the GHG reduction benefits for which the public must pay.

LCFS 46-45

LCFS 46-46

---

the transport of sugarcane ethanol by oceangoing tankers will rise by approximately 150,000 tons per year. *Id*. at 1.

There is no escaping the requirements of the rulemaking provisions in AB 32, and certainly none in other parts of the statute. AB 32 begins with legislative findings about the importance of addressing global warming, and urges coordination of California regulatory efforts with those of other jurisdictions. *See* Cal. Health & Safety Code § 38501(a),(b),(c),(f). Yet even if GHG reductions from the new LCFS program could be quantified, those reductions were assumed to be substantial, and they were assumed to extend nationwide ─ in other words, if every goal suggested by the statute's legislative findings were fulfilled ─ the end result would produce no appreciable effect on global warming. As explained in Appendix H, the difference in ambient temperatures could barely be resolved (in the third decimal place) by 2050, using the generally-accepted modelling system developed to assess the impacts of policies on global temperatures, and would be too small to be measured in the real world. In the 2009 LCFS rulemaking the CARB staff acknowledged this point, and suggested that the benefit to the LCFS program as a means of addressing climate change would lie in the export of the regulation outside California. Appendix H demonstrates that even under such an assumption, the LCFS program would not produce changes in the global climate. The LCFS program neither conforms with the rulemaking requirements of AB 32 nor serves the statute's highest aspirations.[33] LCFS 46-47

B. California Environmental Quality Act ("CEQA") Analysis

The core of Growth Energy's CEQA comments on the LCFS and ADF regulations is contained in Appendix I and its attachments, in Appendix J, and the other appendices specifically LCFS 46-48

[33] These observations on the lack of any change in the global climate resulting from the new LCFS program should not be taken to indicate that any regulation adopted under color of AB 32 could ever be exempt from the specific rulemaking requirements in section 38562 and other provisions of AB 32 that limit and specify CARB's authority.

referenced therein. The Board is required to consider detailed responses by the staff to each part of the Growth Energy's CEQA comments.[34] LCFS 46-48 cont.

1. Impacts of the Proposed Regulations on Criteria Pollutants

The ISOR for the ADF regulation estimates that the biodiesel use allowed by the ADF regulation, which will occur as part of efforts to comply with the LCFS regulation, will increase emissions of oxides of nitrogen ("NOx") by 1.35 tons per day in 2014 and according to the ISOR, will drop to 0.01 ton per day by 2023. Here are some of the salient problems in the ISOR for the ADF regulation and in CARB's draft EA, as explained in Appendix I and its attachments: ADF 17-2

- The ISOR and its related documents do not describe the total diesel NOx emissions inventory on which the assessment is based. ADF 17-3

- The CARB staff has erroneously concluded that the use of biodiesel in "New Technology Diesel Engines (NTDEs)" equipped with exhaust aftertreatment devices to lower NOx emissions will not lead to increased NOx emissions. The CARB staff has also incorrectly apply ratios of on-road vehicle travel by NTDEs from the now obsolete EMFAC2011 model to account for the amount of biodiesel used in all NTDEs including those found in non-road equipment. ADF 17-4

- The CARB staff has incorrectly subtracted NOx reductions from the use of "renewable diesel fuel" from increases in NOx increases from biodiesel when assessing the environmental impact of ADF regulation. ADF 17-5

- A conservative but reliable assessment of the NOx emission impacts of biodiesel use under the ADF that uses the latest CARB emissions models and corrects the flaws in the staff analysis has been performed for Growth Energy and is summarized in Appendix I (Lyons). The results of that assessment indicate that NOx increases from biodiesel will be much larger than those estimated by CARB staff and that the magnitude of the impacts will not decline as forecast by CARB staff. ADF 17-6

- In addition, the assessment performed for Growth Energy demonstrates that the ADF regulation will lead to significant increases in NOx emissions in the South Coast and San Joaquin Valley air basins which are already in extreme non-attainment of the federal ozone NAAQS and moderate non-attainment of the federal fine particulate NAAQS. ADF 17-7

---

[34] *See* 17 C.C.R. § 6007(a)

- Inconsistencies and conflicts in the treatment of diesel and biodiesel fuels in the ADF and LCFS regulations create the potential for biodiesel blends to actually contain as much as 5 percent more biodiesel by volume than will be reported to CARB under the ADF regulation. ADF 17-8

- Other errors in the CARB staff's environmental assessment include incorrectly selecting 2014 as the baseline year for the environmental analysis, a lack of documentation and use of unsupported assumption in determination of the NOx control level for biodiesel, and an unnecessary delay in the effective date for the implementation of mitigation requirements under the ADF regulation. ADF 17-9

- Last year, during the development of the ADF and LCFS regulations, the CARB staff declined to adopt a proposed alternative to the ADF regulation submitted by Growth Energy. Given that the Growth Energy alternative was designed to mitigate all potential increases in NOx emissions, it yielded greater and more timely environmental benefits than the staff proposal. The Growth Energy alternative would have required the same mitigation methods as the ADF proposal but simply expanded the circumstances under which those methods must be applied; Growth Energy's proposal had a cost-effectiveness equal to that of ADF proposal. LCFS 46-49 ADF 17-10

2. CARB's Certified CEQA Program

CARB's certified program under CEQA does not excuse it from its obligations to address those serious deficiencies in the ADF proposal and the draft EA. Although "[e]nvironmental review documents prepared by certified programs," such as that adopted by CARB, "may be used instead of environmental documents that CEQA would otherwise require," "[c]ertified regulatory programs remain subject . . . to other CEQA requirements." *City of Arcadia v. SWRCB* (2006) 135 Cal.App.4th 1392, 1421-22. CEQA documents prepared under certified regulatory programs are considered to be the "functional equivalent" of the documents CEQA would otherwise require. *Mountain Lion Found. v. Fish & Game Comm.* (1997) 16 Cal.4th 105, 113. LCFS 46-50

Agencies with qualifying certified regulatory programs are excused only from complying with the requirements found in Chapters 3 and 4 of CEQA (*i.e.*, Pub. Res. Code, §§ 21100-21154) in addition to Public Resources Code § 21167. Pub. Res. Code, § 21080.5, subd. (c). "When conducting its environmental review and preparing its documentation," however, "a certified LCFS 46-51 regulatory program is subject to the broad policy goals and substantive standards of CEQA."[35] The CEQA Guidelines implementing section 21080.5 provide that, "[i]n a certified program, an environmental document used as a substitute for an EIR must include '[a]lternatives to the activity and mitigation measures to avoid or reduce any significant or potentially significant effects that the project might have on the environment.'" (*City of Arcadia, supra*, 135 Cal.App.4th at 1422 [quoting CEQA Guidelines, § 15252(a)(2)(A)]. CARB's functional equivalent document is the "staff report," which "shall be prepared and published by the staff of the state board." 17 C.C.R., § 60005(a).[36] The regulations require the staff report to be "published at least 45 days before the date of the public hearing" on the rulemaking, and to "be available for public review and comment." (*Id.*) Staff reports must be prepared "in a manner consistent" "with the goals and policies of" CEQA, and "shall contain":

LCFS 46-51 cont.

> a description of the proposed action, an assessment of anticipated significant long or short term adverse and beneficial environmental impacts associated with the proposed action and a succinct analysis of those impacts. The analysis shall address feasible mitigation measures and feasible alternatives . . . which would substantially reduce any significant adverse impact identified.

17 C.C.R. § 60005(b).

LCFS 46-52

The regulations also provide that an action "for which significant adverse environmental impacts have been identified during the review process shall ***not*** be approved or adopted as

---

[35] Kostka & Zischke, *Practice Under Cal. Env. Quality Act* (2005) § 21.10] ["Kostka & Zischke"] [citing *City of Arcadia*, *supra*, 135 Cal.App.4th at 1422; *Sierra Club v. State Bd. of Forestry* (1994) 7 Cal.4th 1215; *Californians for Native Salmon & Steelhead Ass'n v. Dept. of Forestry* (1990) 221 Cal.App.3d 1419; *Envt'l Protection Info. Ctr. v. Johnson* (1985) 170 Cal.App.3d 604, 616].)

[36] In this case, CARB's staff report is accompanied by a draft EA.

proposed if there are feasible mitigation measures or feasible alternatives available which would substantially reduce such adverse impact." *Id*. § 60006. "Feasible" means "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors, and consistent with the state board's legislatively mandated responsibilities and duties." *Id*) If CARB receives comments raising "significant environmental issues associated with the proposed action," staff must "summarize and respond to the comments either orally or in a supplemental written report. Prior to taking final action on any proposal for which significant environmental issues have been raised, the decision maker shall approve a written response to each such issue." *Id*. § 60007. LCFS 46-52 cont.

3. CEQA Analysis

Turning to the merits of CARB's current environmental analysis, and as explained in Appendix J, the draft EA does not comply with CEQA in several material respects. LCFS 46-53

First, the draft EA fails to consider the significant environmental effects associated with the version of the LCFS regulation currently in effect. Although the proposed LCFS regulation is nearly identical in structure to the current LCFS regulation, the draft EA fails to describe or identify impacts associated with the whole of the "project" under CEQA by ignoring recognized significant impacts associated with the existing regulation. Ignoring such impacts is inconsistent with the writ issued by the superior court in *POET, LLC v. California Air Resources Board* (2013) 218 LCFS 46-54 Cal.App.4th 681 ("*POET*"), and results in a vague and incomplete project description. The draft EA also fails to state what environmental baseline is being used in its analysis, although the substantive discussions in the EA suggest a baseline of 2014 is being used. A 2014 baseline is inconsistent with Section 15125(a) of the CEQA Guidelines because it does not accurately reflect when CARB commenced its environmental review of the LCFS regulations (2007), and obscures the amount of NOx emissions caused by the increased usage of biodiesel resulting from the LCFS LCFS 46-55 regulation. And even if CARB were able to credibly argue the current LCFS regulation is a different "project" than the nearly identical LCFS regulation proposed for "re-adoption," (1) analysis of pre-2014 impacts would nevertheless be required as "cumulative impacts," and (2) any attempt to ignore prior impacts would constitute impermissible piecemealing or segmentation of environmental review.[37]

LCFS 46-55 cont.

The draft EA's analysis of criteria pollutant emissions caused by the proposed regulations is also incomplete. The draft EA fails to analyze or discuss emissions of any criteria pollutants, other than NOx. But even the discussion of impacts associated with NOx emissions, however, is misleading and fails to consider additional NOx emissions caused by increased biodiesel usage. CARB cannot argue increased renewable diesel fuel usage will offset NOx increases associated with biodiesel. This increase is speculative, and there is no mitigation, legally-binding requirement, or other performance standard to ensure those offsets will occur. The draft EA's analysis of criteria pollutant emissions is also incomplete because fails to analyze known sources of NOx emissions, including emissions associated with biodiesel use in "New Technology Diesel Engines" (NTDEs). Notably, if a more credible analysis of NOx increases using generally accepted techniques is employed, estimated NOx emissions are calculated to be far more severe than that disclosed in the draft EA, and could total as much as 9.73 tons per day statewide in 2020, and 2.39 tons per day (or 872.35 tons per year) in 2020 in the San Joaquin Valley air basin alone. This figure is vastly higher than the 10 tons per year threshold of significant adopted by the San Joaquin Valley Air Pollution Control District for projects under CEQA, and results in emissions

LCFS 46-56

LCFS 46-57

LCFS 46-58

[37] The two regulations under consideration are also internally inconsistent, as Appendix I explains. To avoid an unstable and inaccurate project description, and to avoid additional NOx impacts associated these inconsistencies (including but not limited to the blending of "Alternative diesel fuel" mixed with "CARB diesel"), the regulations must be revised and reconciled.

that directly violate the mandate of AB32. Cal. Health & Safety Code, §§ 38562 (b)(4), 38570 (b).

LCFS 46-58 cont.

The draft EA also recognizes the proposed LCFS regulation would result in the construction of new or modified facilities to meet demand for fuels created by the regulations, including processing plants for agriculture-based ethanol, cellulosic ethanol, and biomethane. The draft EA, however, only generally describes the impacts associated with this increase in develop, although it is feasible to calculate the projected additional emissions associated with such development. Although the draft EA performs no analysis of the impacts associated with these facilities, it finds the impacts to be significant and unavoidable. This is impermissible; a lead agency cannot simply label an impact "significant and unavoidable" without first providing a discussion and analysis. *Berkeley Keep Jets Over the Bay Comm. v. Bd. of Port Comm'rs* (2001) 91 Cal.App.4th 1344, 1370.

LCFS 46-59

The failure to quantify the impacts associated with such new construction also violates CEQA because it forecloses mitigation. If the impacts were quantified, CARB could meaningfully explore ways to develop mitigation to reduce such impacts or modify the regulation to reduce those impacts. Instead, the draft EA merely sets forth "recognized practices" that are "routinely required" to avoid or minimize impacts, without requiring the implementation of any specific measure, or even evaluating whether any such measures – if incorporated – would actually reduce or minimize the impact. This is improper under CEQA because the proposed mitigation measures are not required or otherwise enforceable, there is no discussion as to the efficacy of any measure, there is no quantification of the benefits associated with any measure, and the specific mitigation to be employed is deferred to a later time.

LCFS-46-60

The draft EA also fails to identify and analyze environmental impacts associated with fuel shuffling, which CARB has elsewhere recognized as a reasonably foreseeable consequence of the LCFS regulation. For one component of the LCFS regulation – shuffling of ethanol alone by ship – shuffling would result in at least an additional 150,000 tons per year of CO2 equivalent emissions using CARB's own models, and an additional 385,000-735,000 tons per year using more accurate models. These figures do not even take into account ethanol shuffling by other modes of transportation, or crude oil shuffling. There is likewise no analysis as to whether fuel shuffling would result in increases in criteria pollutants either in-state or out-of-state. LCFS 46-61

The draft EA also fails to adequately analyze project alternatives. For example, the draft EA rejects the Growth Energy alternative, even though the alternative would significantly reduce NOx emissions associated with biodiesel. The draft EA also impermissibly rejects consideration of a Cap & Trade Alternative, even though that alternative would result in none of the numerous impacts the EA found to be significant and unavoidable. The CEQA Guidelines specifically recognize that comments raised by members of the public on an environmental document are particularly helpful if they suggest "additional specific alternatives . . . that would provide better ways to avoid or mitigate the significant environmental effects," CEQA Guidelines, § 15204, and CARB may not limit its project objectives in a way to foreclose consideration of any and all projects, with the exception of the project under consideration. It was exactly this type of pre-judgment that the Court of Appeal warned against in the *POET* decision in its discussion of *post hoc* environmental review, and impermissible delegation of environmental review authority. LCFS 46-62

In sum, CEQA places the burden of environmental investigation on government rather than the public," and the draft EA falls well short of a complete and accurate investigation of the environmental effects of the proposed regulations. *Sundstrom v. County of Mendocino* (1988) 202 LCFS 46-63

Cal.App.3d 296, 311. As a result of these failures, the EA must be revised substantially, and recirculated for public review, prior to CARB's consideration of the proposed regulations for adoption. LCFS 46-63 cont.

IV. THE BOARD'S GOVERNMENT CODE AND RELATED OBLIGATIONS

Addressing the deficiencies in the draft EA and the CARB staff's related environmental materials identified in Part III above and in Appendices I and J will require significant time and resources, if the Board decides to proceed with rulemaking based on the currently proposed regulations. Simultaneously with that effort, the Board also needs to consider whether there are less burdensome alternatives to the current staff proposals, as the Government Code requires, and also address serious problems in the transparency of the current rulemaking process. CARB's tasks under CEQA and the Government Code substantially overlap, because Growth Energy has proposed an alternative to the current LCFS regulation that would eliminate the need for NOx mitigation and thus greatly simplify the CEQA effort, while also reducing the costs and burdens of attaining the identified goals of AB 32. LCFS 46-64

A. The Analysis of Alternatives under the Government Code

The Legislature regularly gives California administrative agencies wide discretion in achieving the purposes of the statutes it enacts, but it also requires that agencies avoid unnecessary or unduly burdensome regulation. Agencies cannot first propose regulations unless they have determined that no alternative to their own proposal would be "as effective and less burdensome to affected private persons and equally effective in implementing the statutory purpose or other provision of law." *See* Cal. Gov't Code § 11346.5(a)(13). Nor can an agency finally adopt its own proposal unless it can properly affirm and explain, with "supporting information," that "no alternative" that it has considered "would be more effective and less burdensome to affected private persons than the adopted regulation, or would be more cost effective to affected private persons and equally effective" in meeting a legislative objective. *Id*. § 11346.9(a)(4).

There is no question that the proposed LCFS and ADF will impose costs on "private persons" and businesses in California, of as much as 13 cents per gallon by 2020, depending on the costs of LCFS credits. (*See* Part II.B above.) Growth Energy responded to the staff's call in the spring and summer of 2014 pursuant to SB 617 for the submission of alternatives to the current LCFS regulation, and what was understood about the developing proposed amendment to the LCFS regulation, as well as the developing proposed ADF regulation.[38] The threshold question that the Board must therefore address is whether it considers itself bound by the Government Code to consider Growth Energy's proposed alternatives to what the CARB staff has now proposed. If the Board believes it has no such obligation, Growth Energy requests that CARB explain its reasons, and specify the deficiencies in Growth Energy's proposed alternatives. LCFS 46-65

1. The Apparent Goals of the LCFS Program

Assuming that the Board agrees that it needs to consider Growth Energy's alternatives under the Government Code, the next task is to determine what benefits the CARB staff is claiming for its LCFS proposal. In that regard, the SB 617 process in 2014 was illuminating. Growth Energy's proposal would have required, depending on the CARB staff's view on the need to control upstream GHG emissions associated with the use of biofuels in California, an amendment to the current AB 32 cap-and-trade regulation applicable to the transportation fuels section.[39] The LCFS 46-66

---

[38] *See* Appendix F.

[39] *Ibid.*

CARB staff responded as follows in the Consolidated Standardized Regulatory Impact Statement ("CSRIA") for the LCFS and ADF proceedings:

> ARB is required to analyze only those alternatives that are reasonable and that meet the goals of the program as required by statute. An initial assessment of the program indicates the goals of the LCFS proposal can be achieved by keeping the program '…separate of the AB 32 Cap-and-Trade system initially (at least first 10 years) in order to stimulate innovation and investment in low-GWI [global warming intensity] fuel (or transportation) technologies.' Due to the strong justifications that the Cap-and-Trade program alone generates neither the CI reductions nor fuel in the transportation sector, this alternative will not be assessed in this document.

CSRIA at 27 (footnote omitted.). Importantly, the CSRIA conceded that Growth Energy's proposed alternative would "likely" achieve the same "estimated GHG emissions reductions" as the current regulation in the period up to 2020. (*Id*. at 26-27.)

The deficiency in the Growth Energy proposal, according to the CSRIA, was not that it created a GHG emissions reduction shortfall at any point prior to the end of the current regulatory horizon; instead, the problem is that the Growth Energy proposal did not rely on the same purported strategy of fuels diversification and achievement of GHG emissions reductions as proposed by CARB. As Appendix A of the CSRIA explained:

LCFS 46-66 cont.

> Transportation in California was powered almost completely by petroleum fuels in 2010. … Transitioning California to alternative, lower-carbon fuels requires a very focused and sustained regulatory program tailored to that goal. … In the absence of such a program, post-2020 emissions reductions would have to come from a transportation sector that would, in all likelihood, have emerged from the 2010-2020 decade relatively unchanged. ***In the absence of an LCFS designed to begin the process of transitioning the California transportation sector to lower-carbon fuels starting in 2010, post-2020 reductions would be difficult and costly to achieve.*** This is why the primary goals of the LCFS are to reduce the carbon intensity of California fuels, and to diversify the fuel pool. A transportation sector that achieves these goals by 2020 will be much better positioned to achieve significant GHG emissions reductions post-2020.

CSRIA at 27 (emphasis added). In essence, the CSRIA claimed that fuels diversification and carbon intensity requirements were necessary in order to make post-2020 greenhouse gas reductions less costly and less difficult to achieve. The text of AB 32 does not itself require the use of a fuels diversification strategy or CI indexes to achieve GHG reductions, and certainly does not mandate the use of regulations intended to reduce the carbon intensity of transportation fuels to achieve greenhouse gas reduction, in order to achieve "the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions." Cal. Health & Safety Code § 38562(a). If the Board believes otherwise, Growth Energy requests that CARB identify the statutory text within AB 32 that requires the creation of a fuels diversification strategy or the use of CI regulations to reduce GHG emissions.[40]

LCFS 46-66 cont.

Assuming the CARB staff's position on the need for a LCFS program now (*i.e.*, from the present time until 2020) must be linked back to the purpose of AB 32 (which is to reduce GHG emissions), the staff's position seems to be that the regulation of the carbon intensity of transportation fuels is necessary now in order to reduce the costs or difficulties of achieving greenhouse gas reductions after 2020. Certainly, the CARB staff cannot defend its current proposal on the basis of any GHG reductions it will achieve: as noted in Part III.A.3 of these comments, the CARB staff has apparently abjured any effort to quantify the GHG reductions that the new LCFS regulation will achieve, either before or after 2020. In other words, the current LCFS program, stripped to its essential purposes, is not a measure to achieve any quantity of GHG

LCFS 46-67

---

[40] The CSRIA identified a white paper published in 2008 by researchers at the University of California (Davis) as support for the CARB staff's position on the need for CI-based regulations. If CARB believes that the 2008 white paper bears on the scope of its authority or discretion under AB 32, it should explain why.

LCFS 46-66 cont.

emissions reductions over an identified time period; it is a measure to prepare California to achieve some unspecified quantity of GHG reductions at some time in the future. LCFS 46-67 cont.

2. The Requirements of Section 11346.9(a)(4)

As also indicated in Part III.A.3 of these comments, absent some "quantifiable" GHG emissions reductions, a regulation adopted under color of AB 32 is not within the scope of CARB's authority; the proposed new LCFS regulation is therefore invalid under section 11342.2 of the Government Code. Even CARB were to take a different view of the scope of its authority under AB 32, the Board would still need, under the California APA, to prove that Growth Energy's alternative does not meet the criteria of section 11346.9(a)(4).[41] The CARB staff has given the Board no basis for claiming to have so proved. Several points are important on this issue. LCFS 46-68

First, as Growth Energy pointed out in its SB 617 proposal last year, the federal renewable fuels program provides for the production and sale of cellulosic and "advanced" biofuels in the same time frame as the LCFS regulation. While the federal program does not require the use of electricity or hydrogen as a transportation fuel, the California motor vehicle emissions control and zero-emission vehicle programs (also noted in Growth Energy's proposal) certainly do.[42] The record in this rulemaking is devoid of any demonstration that the LCFS program will increase fuels diversification more than the federal RFS program and the State's electric-vehicle and related LDFS 46-69

---

[41] The text of the APA makes it clear that the agency has the burden of proving "with supporting information" that no alternative considered by the agency would meet the criteria of section 11346.9(a)(4). If the Board does not agree that it has that burden, it should explain why not. In addition, the Board should articulate the standard that it believes would apply to judicial review of the determination required in section 11346.9(a)(4), and explain its full basis for choosing that standard. LCFS 46-68 cont.

[42] *See* Appendix F (Growth Energy's proposed alternative to the LCFS regulation, describing the programs that will achieve the fuels diversification sought by CARB, in the absence of the LCFS regulation). LCFS 46-69 cont.

programs will. To the contrary, the CARB staff has admitted that it is "unclear to what degree" the LCFS program will require "new production" of "less carbon-intensive fuels … in California or elsewhere."[43] If the record currently contains an analysis that estimates the increase in fuels diversification that the LCFS regulation will achieve compared to the federal RFS program, CARB should identify.

LCFS 46-69 cont.

Second, as should be clear from the ADF ISOR and in the ADF ISOR's accompanying materials, the use of the CI-based regulatory strategy that the CARB staff is recommending will impose costs on the California motoring public, if they bear any costs of the mitigation strategy that the use of the LCFS regulation will require. As Growth Energy has demonstrated in Part III.B and the related Appendices, those costs may be even greater if CARB adheres to its duties under CEQA (though the cost-effectiveness of the mitigation strategy will not change). In addition, the increases in GHG emissions entailed in moving sugarcane ethanol to California (see Part III.A and Appendix G) will likely need to be offset by other types of GHG controls, which will impose additional costs on California consumers and businesses. The CARB staff has not offered any analysis to the Board that explains why those ***present*** costs, along with the direct costs of the LCFS program in the near term, are worth incurring in order to make the ***future*** costs of post-2020 GHG emissions reductions less costly. Conclusory or self-serving statements by businesses who claim that they will construct facilities or produce and market advanced, diversified liquid biofuels are entitled to no weight.

LCFS 46-70

[43] *See* LFCS ISOR Appendix E at E-5.

Third, the long-run, post-2020 plans for GHG reductions developed by CARB call for the phase-out of reliance on liquid biofuels;[44] low-CI liquid fuels, however, are presumably the fuels whose production is in need of diversification, according to the CSRIA. Eventually, the State plans to eliminate gasoline, in particular, from use in California cars and trucks and to fully replace gasoline with electricity. Putting to the side whether CARB's post-2020 strategy is meritorious, the CARB staff has given the Board no basis to explain why CARB should impose costs on California consumers and businesses to foster the use of fuels that (according to CARB) are destined for a diminishing, and no long-term, role in its greenhouse gas reduction strategy. LCFS 46-71

One other important, procedural point must also be noted here. The demonstration required by section 11346.9(a)(4) that there are no superior alternatives to a proposed regulation (as the statute defines superiority) must be based on "supporting information." At present, there is no such "supporting information" in the rulemaking file of which Growth Energy is aware, perhaps because the CARB staff has looked ahead to the Board's obligations under section 11346.9(a)(4) of the Government Code. If the Board intends to add such information to the rulemaking file in order to try to carry its burden under section 11346.9(a)(4), it must comply with section 11347.1 of the Government Code. LCFS 46-72

In sum, with regard to the LCFS proposal, CARB is not currently positioned to proceed with final rulemaking because, among other reasons, it cannot discharge its obligations under section 11346.9(a)(4) of the Government Code. If the Board intends to pursue the staff's proposal, it must address the issues raised here, both substantive and procedural.[45] LCFS 46-73

---

[44] *See* http://www.arb.ca.gov/planning/vision/vision.htm.

[45] If the Board does not agree with Growth Energy's analysis of the obligations of section 11346.9(a)(4), Growth Energy requests that the Board explain its reasons for disagreement.

B. Requirements of Transparency

Section 11347.3 of the Government Code requires CARB to maintain a "file of [the] rulemaking proceeding" for any proposed regulatory action subject to the APA, including the LCFS regulation." The rulemaking file must include, among other items, the following:

> (6) All *data and other factual information***,** any studies or reports, and written comments submitted to the agency in connection with the adoption, amendment, or repeal of the regulation.
>
> (7) All data and other factual information, *technical*, *theoretical*, and *empirical studies or reports*, if any, on which the *agency is relying* in the adoption, amendment, or repeal of a regulation, including any cost impact estimates as required by Section 11346.3.

Gov't Code § 11347.3(b)(5),(6) (emphasis added). The entire rulemaking file, including the foregoing material, must be "available to the public for inspection" from the time when the first notice of the proposed rulemaking is published in the California Regulatory Notice Register, *id.* at § 11347.3(a), which here occurred on January 2, 2015.

As the above-quoted text makes clear, rulemakings at CARB must include the creation of a rulemaking file that includes "***[a]ll*** data and other factual information, any studies or reports, and written comments submitted to the agency" in connection with the proposal. Gov't Code § 11347.3(a),(b)(6) (emphasis added). To assure immediate public access to the supporting materials as soon as the 45-day materials are released, the APA requires that the 45-day notice include a statement that the agency on the date of the notice "has available *all* information upon which [the] proposal is based." *Id*. § 11346.5(a)(16) (emphasis added). A separate provision confirms that the agency must in fact make those records, and any other "public records, including reports, documentation, and other materials, related to the proposed action," available. *Id.* § 11346.5(b).

The "written comments" that must be placed in the record are not simply those submitted to the agency in a particular manner or at a particular time, such as during the period between publication of the notice of a public hearing and public hearing -- an agency must put "all" it receives "in connection with" a regulatory proposal in the rulemaking file. The Legislature's choice of words to describe what comments must be placed in the file -- "in connection with" -- sweep with intentional breadth, and require inclusion of any comments that bear on the subject of the regulatory effort. In addition, the period of public availability must "[c]ommenc[e] *no later than* the date that the notice of the proposed action is published." *Id.* § 11347.3(a) (emphasis added). The use of the term "no later than" makes it clear that the Legislature expected written comments submitted in connection with a proposed regulatory action and received before publication of the required notice to be included in the rulemaking file.

LCFS 46-74

Growth Energy has substantial concerns about the completeness of the rulemaking files for the current LCFS and ADF rulemakings, as it did in the prior LCFS rulemaking in 2009. The Court of Appeal made clear in *POET v. CARB* that neglect to include even a limited number of relevant documents in the rulemaking file would violate the Government Code. To avoid further controversy, Growth Energy requests that the Executive Officer or the CARB legal staff consider and respond to the following questions:

LCFS 46-75
ADF 17-11

1. Does the CARB legal staff agree that the rulemaking file for these two proceedings must include external communications submitted to the staff, the Executive Officer or the Board prior to the date when the rulemaking file is formally opened must be included in the rulemaking file, if those communications were submitted in connection with the adoption or amendment of ADF and/or LCFS regulation? Conversely, does the CARB legal staff believe that no such external communications submitted before the rulemaking file would come within the definition of records

LCFS 46-76

required for inclusion in the file, pursuant to section 11347.3(b)(6)? Are there any written guidelines or instructions used by the CARB staff to determine whether a communication submitted before the file is opened must be included in the file? Are there any written guidelines or instructions that the CARB staff uses in order to determine what constitutes "data … other factual information … studies or reports," or "written comments," that should be included in the rulemaking file? Will any such guidelines or procedures be made available?

LCFS 46-76 cont.

2. The ADF rulemaking was opened in 2013 and then pretermitted in 2014. What steps have been taken to assure that that all external submittals (not within the scope of section 11347.3(b)(7) concerning the 2013-2014 regulatory process were included in the ADF rulemaking file opened in January 2015? If the CARB legal staff believes that no such external submittals before January 2015 were required to be included in the "new" rulemaking file, was there any process by which the public could obtain prompt access to those materials?

ADF 17-12

Turning to the requirements of section 39601.5 of the Health & Safety Code, as noted in Part I, the Legislature in AB 1085 directed CARB to provide "all information" on key aspects of its regulatory analysis "before the public comment period for any regulation" commences under the Government Code. Growth Energy requests that the CARB legal staff explain what steps were taken to provide all the information covered by section 39601.5 in connection with the current LCFS and ADF rulemakings. Growth Energy requests that each document or other file made available to the public under section 39601.5 prior to January 2, 2015, in connection with these two rulemakings be identified, along with the date it was made available and the method by which it was made available.

LCFS 46-77

C. The SB 617 Process

As the correspondence included in Appendix F makes clear, the version of the ADF proposal on which the CARB staff invited comment and responses in the SB 617 process in 2014

ADF 17-13

differed materially from the version of the ADF proposal that the CARB staff was discussing with some stakeholders, and that the CARB staff eventually included in the current rulemaking package. Those differences related to the circumstances under which mitigation would be required, and thus both to the environmental impacts and the costs of ADF regulation. Growth Energy believes that CARB did not substantially comply with SB 617 in connection with the ADF rulemaking, and that the Department of Finance failed to perform a mandatory duty to notify CARB and the public of CARB's noncompliance and to require CARB to comply. Growth Energy therefore requests that the Board reopen the SB 617 process, and allow that process to proceed simultaneously with other work on the ADF regulation. If the Board believes there was substantial compliance with SB 617 in the ADF rulemaking process, Growth Energy requests that CARB explain the basis for that belief.

ADF 17-13 cont.

D. External Peer Review

The Executive Officer has indicated that he has sought external scientific peer review in connection with the LCFS rulemaking. The subjects of that peer review effort, however, are unknown, and it is not clear whether the Executive Officer has sought peer review under section 57004 of the Health & Safety Code for the scientific basis and scientific portions of any part of the currently proposed ADF regulation. If no such peer review has been sought and completed, Growth Energy requests an explanation of the reason why none was sought and completed.

ADF 17-14

V. CONCLUSION

Growth Energy appreciates the opportunity to participate in these rulemakings. Growth Energy believes that the current record does not enable the Board to adopt the regulatory proposals presented by the staff, and hopes that the Board will reconsider the staff's decision not to propose the alternative to the LCFS program that Growth Energy offered in the SB 617 process in 2014. If adopted, the current LCFS proposal will have a devastating impact on Growth Energy's members, who will be forced to exit from the California alternative fuels market. Such an outcome will likely trigger the cost-containment caps in the proposed regulation, and any claimed benefits of the LCFS program will be compromised or lost. By contrast, Growth Energy's alternative proposal will assure the continued supply of reasonably-priced renewable fuel to the California market, and can achieve the same overall GHG reductions as sought by the 2009 LCFS regulation while not creating any increases in criteria pollutants.

Respectfully submitted,

GROWTH ENERGY

February 17, 2015

46_OP_LCFS_GE Responses (Page 1 – 54)

370. Comment: **LCFS 46-1 through LCFS 46-5, LCFS 46-10**, **LCFS 46-29 through LCFS 46-35, LCFS 46-41, LCFS 46-44 through 46-69, and ADF 17-2 through ADF 17-10**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

371. Comment: **ADF 17-1 and ADF 17-11 through ADF 17-14**

Agency Response: These comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under Comment Letter **17_OP_ADF_GE**.

372. Comment: **LCFS 46-6**

The comment states that the Executive Officer cannot demonstrate that the LCFS amendments are reasonably necessary to meet the purposes of AB 32, as the Government Code requires.

Agency Response: As stated within the ISOR, the objective of the LCFS program is to achieve a 10% reduction in the CI of transportation fuel used in California by 2020, thereby providing multiple benefits such as GHG reductions, diversifying the state's fuel portfolio, reducing dependence on petroleum, and decreasing associated prices spikes caused by volatile oil prices. These purposes are clearly identified and are not achieved by other programs or the commenter's alternative. In fact, the comment focuses only on the GHG reduction component and disregards the fundamental objective for CI reductions and the additional benefits that result (which are also recognized or required by AB 32).

However, even focusing on just the GHG emission reductions, ARB staff disagrees with the comment. The LCFS regulation, along with other regulations, policies, planning, market approaches, incentives and voluntary efforts are combining to meet the objectives of AB32. The LCFS regulation is a core component of that, providing almost 20 percent of the emissions benefits.

373. Comment: **LCFS 46-7**

The commenter suggests that they were unable to provide meaningful input on program costs under the SB 617 process due to time constraints and due to ARB's failure to disclose all the estimated benefits or costs.

Agency Response: ARB disagrees that the commenter did not have a meaningful opportunity for input into the economic analysis of the LCFS. SB 617 and the implementing regulations[12] do not mandate a length of time or format by which the agency is required to take public input. However, upon request by Growth Energy, ARB staff extended the deadline for submittal of alternatives by over two weeks (one comment was received late but still addressed) and the merits of the alternatives were considered and analyzed in the Standardized Regulatory Impact Assessment (SRIA).[13,14]

In the response to Growth Energy's request for additional time, ARB staff also noted that failing to submit ideas at that time would not preclude later comments and suggestions from the public. The SRIA itself was posted on October 23, 2014 on the California Department of Finance (DOF) website.[15] Additional opportunities to comment continued through February 17, 2015, at the hearing on February 19, 2015, and with additional comment opportunities until it is formally adopted by the Board in 2015. Staff's approach is within the requirements and spirit of SB 617 and Department of Finance regulations. It is curious that after the passage of so much time, the commenter chose not to identify costs or benefits in any detail, instead preferring to argue that they had no opportunity to do so.

374. Comment: **LCFS 46-8**

The commenter paraphrases a number of provisions of the Government Code, adding its own summary and interpretation in places.

Agency Response: Those observations, regardless whether correct, are not objections or recommendations regarding the proposal. The letter goes on to summarize "Part IV of these comments" (Q64 et seq., below) as raising "questions concerning the Executive Officer's compliance with section" 11347.3 of the Government Code and section 39601.5 of the Health & Safety Code. Those comments are fully responded to in the sequence below.

[12] California Code of Regulations, title 1, sections 20001 (d).
[13] http://www.arb.ca.gov/fuels/lcfs/regamend14/cta_06242014.pdf
[14] http://www.arb.ca.gov/fuels/lcfs/growthenergyresponse_06052014.pdf
[15] http://www.dof.ca.gov/research/economic_research_unit/SB617_regulation/2014_Major_Regulations/documents/Final_ARB_LCFS%20and_ADF_SRIA.pdf

375. Comment: **LCFS 46-9**

The comment states that the "signals" that ARB's new California GREET 2.0 and indirect land-use change models provide for corn-starch, corn-stover and sugarcane ethanol do not reflect the best available scientific and economic information, and therefore do not provide the accurate "signals" to the downstream industry that are needed to maximize GHG reductions while minimizing costs.

Agency Response: ARB staff has relied on the latest scientific information and models to create the LCFS policy framework and the "signals" sent are accurate and reflect the latest science available. The results of the independent peer review confirm, once again, that Staff continues to make every effort to use the best science to assign CI values.

376. Comment: **LCFS 46-11**

The comment states that ARB has not addressed the efforts by stakeholders to improve the quality of ARB's Indirect Land Use Change (ILUC) and indirect-emissions models. The comment also states that ARB has not taken into account recommendations provided by the Expert Working Group that ARB established when it first adopted the LCFS regulation.

Agency Response: See response to **LCFS 8-1** for ARB staff's reasons for including the iLUC analysis.

Since 2009, there have been numerous peer-reviewed literature and scientific reviews of iLUC for biofuels. Empirical data, real-world observations, updated modeling methodology, and improved assessment methods have all been considered in these scientific publications. In preparing the current (2014) proposal, ARB staff has reviewed such articles, recommendations by the Expert Working Group, and comments presented after public workshops, and implemented appropriate modifications to the methodology for the current analysis. Some recommendations that were not considered for the current analysis were either due to lack of detailed data or because modeling structure did not allow for the inclusion of such effects. In the latter situations, ARB concluded that making adjustments outside of the model for a particular feedstock (versus using the same model for all similar feedstocks) created a real danger of unequal treatment.

377. Comment: **LCFS 46-12**

The comment claims that ARB staff has not supplied critical missing information from the Davis review that was requested, that ARB relied on that "non peer-reviewed" report, and that the staff's work on price-yield responses has not been transparent or based on the "best available" information.

Agency Response: The analysis conducted by staff has been provided to stakeholders in the ISOR, and Appendix I thereto. As is clear from the ISOR, although ARB considered the report by U.C. Davis Professor David Rocke, ARB did not adopt his conclusion that the YPE factor should be zero or close to zero. Similarly, although ARB considered a study by Dr. J.F.R. Perez, ARB did not adopt his conclusion that YPE should be 0.29. ARB did not rely on the data that Drs. Rocke and Perez report that they analyzed. In connection with sharing the Perez/Rocke data with one stakeholder interested in iLUC, ARB decided to place that data into the rulemaking record for comment, so that other stakeholders might have an equal chance to consider it. See also response to **LCFS 8-9**.

378. Comment: **LCFS 46-13**

The commenter sets out several abstract legal points in a footnote without tying them to any particular part of the LCFS proposal or the process by which it has been adopted. The comment is phrased as instructions telling ARB what it must do in the future, and telling some future court how to analyze legal challenges in some unstated future litigation.

Agency Response: The comment is not pertinent to the proposal and does not constitute an objection or recommendation regarding how the proposal could be changed. No response is required, but ARB notes that it remains committed to following the law.

379. Comment: **LCFS 46-14**

The comment states that GTAP is unable to account for multiple cropping and that an Iowa State University (ISU) study confirms that increases in crop prices will result in multiple cropping.

Agency Response: A preliminary review of U.S. agricultural data has concluded that double cropping is small and is not expected to contribute significantly to 'intensification effects' as mentioned in the November 2014 submission. As for other regions of the world, significant work has to be completed to collect and disaggregate data to provide accurate information on double cropping. When detailed data become available, ARB staff will consider updates to modeling structure to explicitly account for double cropping in the analysis. It should also be noted that any benefits from double cropping are likely to be offset by increased use of fertilizers and pesticides and these impacts also need to be accounted for in any future analysis (and are not included in the current analysis).

ARB staff has implemented several updates and modifications to the 2009 version of the GTAP model. All of these changes are reflected in the current analysis. New sectors, biofuels, co-products, disaggregation of irrigated/rain-fed cropland, new land transformation structure and elasticities are among some of the updates since 2009. A complete list of all changes is provided in Appendix I of the ISOR. Refinements and modifications to the GTAP model require collection of large data sets, changes to modeling structure, and comprehensive testing to ensure robustness of model outputs. For issues that were not considered for this round of rulemaking, lack of detailed data was a major issue that limited ARB staff's ability to include these in the current analysis.

As described earlier, ARB staff's preliminary review of the November 2014 submission concluded that additional detailed data would be required to evaluate the inclusion of the conclusions of the submission. Lacking detailed data at this time, ARB staff could not complete a comprehensive evaluation of the results presented in the November 2014 submission.

See also response to **LCFS 8-5**.

380. Comment: **LCFS 46-15**

The comment asserts that ARB staff has refused to include the effects of the Conservation Reserve Program (CRP) land in mitigating the land-use-related emissions impacts that ARB staff attributes to corn-starch ethanol.

Agency Response: See response to **LCFS 46-110**.

381. Comment: **LCFS 46-16**

The comment requests to know why the ARB staff has chosen to use the "Agro-ecological Zone Emission Factor" (AEZ-EF) model rather than the "Carbon Calculator for Land Use Change from Biofuels Production" (CCLUB) model to estimate GHG release caused by various theoretical land transitions

Agency Response: The Agro-ecological Zone Emission Factor (AEZ-EF) model is a peer-reviewed carbon emissions model that uses the best available science, data, and methodology to estimate carbon release (or sequester) when land is converted from one use to another. When ARB was made aware of the Carbon Calculator for Land Use Change from Biofuels Production (CCLUB) model developed by Steffen Mueller, a comprehensive review of this model was initiated. The review determined that although the CCLUB uses county-level data and sophisticated biogeochemical modeling, it also involves numerous problematic assumptions in the application of these data. Some of these issues include:

- CCLUB assumes that all cropland-pasture conversion transition only to the biofuel feedstock being examined, when in fact, GTAP more realistically results suggests changes in the harvested area of all crops. Therefore, despite the more complex biogeochemical modeling used in CCLUB, there's no basis for the specific assumption of land transitioning from cropland-pasture to a single biofuel feedstock.

- The Century model, which is used in CCLUB to calculate GHG flows to and from land, requires initialization ("spin-up") to estimate conditions prior to the modeled land conversions. To do this, CCLUB authors assumed that all cropland-pasture land was in crops from 1880-1950, in pasture/hay/grasslands from 1950-2010, and then in corn-corn or miscanthus/switchgrass from 2011-2040, according to which feedstock is being examined. Even if Century models this land-use history perfectly, if the land-use history of the land converted deviates from these assumptions, the Century projection will misrepresent the actual state of the land. The actual land-use history of the converted cropland-pasture strongly determines conversion emissions: land recently in crops will have very low emissions, while lands taken out of crop production long ago will have high emissions when converted. Simply assuming a single land-use history across all land does not address this key information gap. Cropland-pasture is defined as land that transitions between cropland and pasture; assuming it was in pasture/hay/grasslands continuously from 1950-2010 contradicts this definition.

- The CCLUB model cannot be used with GTAP because CCLUB arbitrarily introduces a lower-carbon-density "young forest-shrub" category that is a landcover category that is not part of the GTAP framework; in short CCLUB cannot properly be used with GTAP.

See also response to **LCFS 46-94**.

382. Comment: **LCFS 46-17**

The comment suggests that the Board has not been given the "best available" information regarding iLUC.

Agency Response: ARB staff disagrees that the information presented in the commenter's Appendix A is an improvement over the staff's analysis. ARB staff's analysis has used the latest data and best available science. All information used by ARB staff in the rulemaking process is referenced and appropriately included in the rulemaking file. For the current proposal, ARB staff used a small range of input values for critical parameters to complete 30 scenario runs and the average of the scenario runs is being proposed as an iLUC value for each biofuel. To further validate the scenario estimates, ARB staff completed an uncertainty analysis for which ARB staff reviewed published literature and consulted with experts to develop ranges and corresponding distributions for parameters used in the GTAP and AEZ-EF models. Utilizing the entire range of likely values for the different parameters in the two models, the analysis estimated a mean iLUC value for each of the six biofuels analyzed for the current proposal. The iLUC estimate from the uncertainty analysis is similar to the average iLUC value for each biofuel supporting ARB staff's approach. Therefore, staff does not support the commenter's views that the potential for errors in the iLUC values is large. Also, the LCFS program is designed to evaluate all fuels based on their complete life cycle analysis and not reward fuels that are likely to increase greenhouse gas emissions. The inclusion of iLUC for food-crop-derived biofuels and indirect land use emissions for crude production serve to support ARB staff's approach to accounting for greenhouse gas emissions from all steps starting from feedstock production to final use in a transportation vehicle.

The iLUC analysis is developed using sound scientific principles and the latest data and does not warrant that the Board consider suspending the LCFS program or continue with the regulatory status quo. ARB staff does recognize that the understanding of land use change is constantly evolving, as is the supporting data. ARB staff remains committed to periodically reviewing data and updates in land use science, updating iLUC analysis and presenting new proposals to the Board as warranted.

383. Comment: **LCFS 46-18**

The comment suggests that the Board is relying on conjecture and unsupported assumptions, rather than the "best available" information.

Agency Response: See response to **LCFS 42-16** and **LCFS 46-17**.

384. Comment: **LCFS 46-19**

The commenter states in a footnote that "it is impossible to know" whether other parties submitted comments on the proposal.

Agency Response: The commenter's ignorance on that point does not appear to be an objection or recommendation regarding the proposal. ARB does note, however, that while the Administrative Procedure Act (APA) requires much, it does not require an agency to catalogue tens of thousands of documents for a commenter's convenience. ARB staff notes that over a period of several years there were 21 LCFS public workshops, and 26 ADF public workgroup or workshop meetings as part of developing these two related regulations. Along the way, ARB staff posted, as is its practice, all public comments regarding the proposal received by ARB, including those submitted as part of ARB's many workshops, as well as a wide range of materials on the program web pages ARB maintains. Such materials have long been public.

385. Comment: **LCFS 46-20**

The comment contends that instead of recreating Argonne's work, ARB staff included arbitrary assumptions when creating their CA GREET 2.0 model as it relates to distillers grain solubles (DGS).

Agency Response: See response to **LCFS 8-13**.

386. Comment: **LCFS 46-21**

The comment claims that the omission of "backhaul emissions" for sugarcane ethanol has a significant impact on its assigned CI value and producers of sugarcane ethanol should be required to account for those emissions in their applications.

Agency Response: ARB staff acknowledges that there may be small differences in ethanol transport distance assumptions to the blending terminal between corn ethanol and sugarcane ethanol. These differences arise since corn ethanol arrives primarily from the Midwest by rail car where it is transported from the rail yard to the bulk terminal over an estimated distance of 100 miles. Sugarcane ethanol arrives at a port terminal via ocean tanker. However, the input for this parameter in both pathways is provided for the user to provide, based on actual ethanol transport operations. Therefore, the commenter's suggestion that both transport distances to the blending terminals should be equal is not a concern.

With regard to the comment on estimating a backhaul energy charge for ocean tankers delivering ethanol to California ports, ARB staffs understanding of ethanol transport by ocean has increased significantly since the original assumptions were made in CA-GREETv1.8b. Staff now believes the ocean tanker cargo (ethanol) payloads are much smaller (lowered from 150,000 tons for supertanker to 22,000 tons for medium range tanker), and the tanker energy use (Btu per ton-mile) is substantially higher (from 32 to 145 Btu per ton-mile).

With respect to the back-haul assumption, ARB staff believes that it would be a highly inefficient operation for transport companies to export ethanol from Brazil to California and return the tanker back to Brazil empty. In 2009, UNICA; a consortium of Brazilian sugarcane ethanol producers had contested the validity of the Back-Haul energy charge with the assertion that "UNICA believes that it is highly speculative and arbitrary to assume that the energy consumption and associated emissions of the ocean tanker's round trip be attributed to sugarcane ethanol." UNICA has further responded by saying that "there are no specific data to support the claim that the commenter makes regarding the return trip of the ocean tanker to Brazil after unloading the ethanol. There may be instances where this may happen but verification of such claims across all the shipments is difficult." ARB staff will continue to investigate the onward journey of tanker operations after ethanol is unloaded onto a California port, and propose revisions for considerations as necessary.

387. Comment: **LCFS 46-22**

The comment states that CA GREET 2.0 wrongly assumes that all sugarcane ethanol from Brazil is delivered in 22,000-ton shipments, understates GHG emissions from inbound ocean transport by 100 percent, and uses unrealistic assumptions about the relationship between oceangoing vessel power requirements and vessel speed.

Agency Response: The default cargo payload for ethanol transport from Brazil to California ports via ocean-tanker is 22,000 tons in the draft CA-GREETv2.0 life cycle analysis model being proposed for adoption. The commenter has alleged that this assumption in CA-GREETv2.0 understates GHG emissions from inbound ocean transport by 100 percent. Staff believes the CA-GREET 2.0 estimate to be accurate and may likely be conservative. Staff has determined[16] that the Medium Range tankers are typically employed for ethanol transport from the Port of Santos in Sao Paulo State to a California port. These Medium Range tankers have the capacity to load 10-13 million gallons of ethanol, which implies a cargo payload of at least 33,000 tons. Since larger vessels have more cargo carrying capacity, they can more effectively transport ethanol with fewer GHG emissions per unit-mile. The energy expended to transport ethanol (in Btus/ton-mile) was however conservatively estimated, since increasing the cargo payload only decreases the energy intensity for transport. Therefore, the cargo payload recommended in draft CA-GREETv2.0 may represent, on average, the vessels employed to transport ethanol from Brazil to California. Staff will recommend that the cargo payload parameter be maintained at the proposed value (22,000 tons) until further data and studies become available.

388. Comment: **LCFS 46-23**

The commenter alleges that the draft CA-GREETv2.0 model being proposed for adoption does not reflect accurate parameters for corn ethanol, corn stover ethanol, and sugarcane farming. According to the commenter, these “failures to use the best available information” are described in their report-letter in Appendices B and C.

Agency Response: Staff addresses the comments from these appendices as separate comments, which are listed below for ease of reference.

[16] Pursuant to staff email correspondence received from Chris Hessler on April 1, 2015.

Commenter's Appendix B	Commenter's Appendix C
LCFS 46-115 through **LCFS 46-129**	**LCFS 46-130** through **LCFS 46-162**

389. Comment: **LCFS 46-24**

The commenter asserts that the CI values assigned to corn and sugarcane ethanol are not based on reliable data and methodologies, and need to be corrected before ARB moves forward with the LCFS re-adoption process.

Agency Response: ARB disagrees that the CI values are not based on reliable information. As described in the ISOR, the CA-GREETv2.0 being proposed for adoption incorporates the collective learning of two agencies - namely the ARB and Argonne National Laboratory (ANL), and the best available information on life cycle assessment of fuel pathways, scientific research, and evolution of factors from empirical evidence.

390. Comment: **LCFS 46-25**

The comment asserts that the incorrect regulatory "signals" created by the CI values assigned to corn and sugarcane ethanol will skew the California renewable fuels market away from corn-starch ethanol, and toward sugarcane ethanol.

Agency Response: While ARB agrees that the LCFS is intended to provide a signal away from high-carbon fuels and toward low-carbon fuels, ARB rejects the commenter's suggestion that the signal is "incorrect." The proposed LCFS regulation uses thoroughly reviewed, scientifically credible lifecycle CI values determined from a peer reviewed process and subjected to extensive review and feedback from stakeholders and the public. See responses to **LCFS 46-21** through **LCFS 46-24**.

The LCFS regulation is a market-based program that allows industry to decide the most effective strategy for compliance. However, the credible lifecycle CI calculations ensure that California residents are achieving real CI reductions in the most cost-effective manner.

ARBs illustrative scenario shows a reduction of corn ethanol use by 2020 and an increase in other types of ethanol, primarily sugarcane, to reflect a market response to more favorable CI values.

Note that ARB's illustrative scenario is intended to be just that – illustrative. It demonstrates one plausible path. Different companies will pursue different options based on their business strategies and the availability and price of low carbon fuels (as well as other market factors). Contrary to the comment provided, a scenario that provides a shift to cleaner (lower CI) ethanol (whatever the source) is consistent with ARB's statutory requirements and policies.

With regard to the footnote, the analysis assumes the price of each credit is $100 for every year of the program. From 2012 through 2013, while the LCFS standards for gasoline and diesel were declining, the average credit price reported in the LRT was $57[17]. However, this average price only accounts for the credits purchased on the market. In 2013, California's seven major refineries self-generated a vast majority of their compliance credits through the purchase of low-CI fuels[18]. Thus, if all credits (including those that are self-generated) were purchased in the market, as our analysis assumes, the average price would have been lower than reported. Therefore, ARB assumes an average of $100 per LCFS credit across all years of compliance to be a plausible upper bound.

391. Comment: **LCFS 46-26**

The commenter believes that the LCFS, which rewards and incrementally requires the provision of alternative fuels such as biofuels with lower carbon intensity than petroleum-based fuels, somehow interferes with the federal Renewable Fuels Standard (RFS), which rewards and incrementally requires the provision of biofuels with lower carbon intensity than petroleum-based fuels.

Agency Response: The comment is wrong as a legal and factual matter. Both the RFS and the LCFS can operate in harmony; there is simply no interference. The commenter's theory is also the basis for two lawsuits (one brought by the commenter) that have proceeded for almost six years without success in the United States District Court, and the United States Court of Appeals, before being rejected for further review by the United States Supreme Court. Parts of those lawsuits have yet to be addressed by the courts, but ARB's response to the argument that the Federal RFS somehow preempts or precludes adoption of the LCFS can be found in

[17] Weighted average of quarterly LCFS credit prices reported through the LRT available at: http://www.arb.ca.gov/fuels/lcfs/lrtmonthlycreditreports.htm.

[18] Information obtained through business confidential transactions reported through the LRT.

pleadings and briefs available in the court's public file in *Rocky Mountain Farmers Union v. Corey,* (U.S.D.C., Eastern District) Case 1:09-cv-02234-LJO-BAM. The commenter's attorneys have been directly served with all such pleadings and briefs through an electronic docket maintained by the court.

392. Comment: **LCFS 46-27**

The comment states that the increased imports of Brazilian cane ethanol, combined with the proposed LCFS regulation's generous allowance of credit to the California electric utilities, will result in a combination of lost production or even shutdowns at Midwest biorefineries, and increased logistics costs as those American biorefineries seek foreign markets.

Agency Response: This comment makes assumptions about what may happen in the future under the LCFS and demands that the Board respond to them. These are not objections to or recommendations for the proposal, particularly since the proposed regulation allows the market to decide which fuels will be used to comply with California's carbon intensity standards. As the comment appears to reflect, the LCFS encourages the use of low-carbon fuels in California, regardless of origin and type, which means that the LCFS does not require Midwest biorefineries to shut down or to seek alternative markets (although ARB notes that the ethanol industry has itself been promoting the prospect of increased exports.[19]) The program, in fact, welcomes Midwest biofuel refiners to produce lower carbon intensity fuels for sale in California. A number of Midwest corn ethanol plants have begun to do so, and ARB staff see no reason why such developments would cease. The commenter also notes that Midwest biofuel refiners are investing in the development of cellulosic ethanol, a fuel anticipated to be very low in carbon intensity and therefore highly desirable in the California market under the LCFS.

393. Comment: **LCFS 46-28**

The comment states that possible responses to the LCFS from Midwest corn ethanol facilities are: (1) reduced output and potential plant closures due to loss of any commercially practicable way to continue to serve the California market or (2) export outside the

[19] *Going Global 2015 Ethanol Industry Outlook*, at p. 4, available at http://www.ethanolrfa.org.

United States to make up reduced demand from California that will not produce reductions in global GHG emissions.

Agency Response: The LCFS program is designed to encourage reductions in the average CI of transportation fuels sold for use in California. Corn ethanol plants in particular have been successful in changing their practices to reduce the CI at their facilities. While this comment presents two static alternatives, the world post-regulation is dynamic and will likely yield very different results.

Midwestern corn ethanol plants may continue to lower their CI by using innovative strategies, as illustrated by the Method 2a and 2b applications received under the 2009 LCFS. Such changes would further GHG emissions reductions and assist regulated parties in complying with the LCFS.

394. Comment: **LCFS 46-36**

The comment states that the ISOR does not cite facts in support of ARB staff's claims that there has been a steady decline in the average CI of the mix of biofuels sold in California or the staff's expectation that these trends will continue and actually accelerate as the stringency of the LCFS increases and credits become more valuable. The comment states that Staff's observation of a historic decline in the average CI of the mix of biofuels sold in California is contradicted by the relevant evidence from the corn-starch ethanol industry.

Agency Response: ARB staff disagrees with the commenter's statement "no biorefinery selling ethanol for blending into gasoline has made any significant changes in its production methods, feedstocks, methods of transport or any other factor relevant to GHG emissions, in order to specifically obtain a lower CI value for purposes of the California LCFS regulation."

Staff is aware of these specific actions to reduce CI in part from reviewing applications for CI values under the current regulation, and, in fact, the decline in CI value of the mix of biofuels used in California is readily apparent from the data reported in the LRT. For example, as indicated in the quarterly reports available on ARB's website, the volume of lower-CI ethanol has increased and the volume of higher-CI ethanol decreased since the LCFS went into effect.[20] The expectation that this trend will continue is reasonable,

[20] http://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm.

and is consistent with the ethanol industry's own claims and predictions.[21]

The comment refers to testimony claiming any innovation in the corn ethanol industry is motivated only by competition within the industry to maximize profitability by minimizing operational costs. ARB staff recognizes that fuel producers have multiple incentives to reduce operational costs (including energy costs) and that it is challenging to assign causality for an individual CI improving investment to just one factor. The LCFS, the federal RFS, other state and federal incentives, and the normal competitive pressures that would exist without these programs all contribute to the business case for individual CI reducing projects. To the extent other pre-existing incentives align with the LCFS's incentives to reduce CI, the two sets of incentives reinforce each other to the benefit of the producer and those needing to comply with California's carbon intensity standards. The incentives from the LCFS, of course, will increase as the regulatory standard gets more stringent.

395. Comment: **LCFS 46-37**

The comment states that no biorefinery selling ethanol for blending into gasoline has made any significant changes in its production methods, feedstocks, methods of transport, or any other factor relevant to GHG emissions, in order to specifically obtain a lower CI value for purposes of the California LCFS regulation.

Agency Response: See response **LCFS 46-36**.

396. Comment: **LCFS 46-38**

The comment states that not all corn-starch ethanol plants that were able to participate in the California market before 2011 have been able to remain in that market because not all such plants have been able to document production processes, methods, and energy usage that would qualify them for competitive CI values.

Agency Response: ARB staff encourages any producer who cannot document input values that would qualify for a competitive CI value to work with staff to identify specific pieces of evidence that would be necessary to accurately calculate CI as well as any areas of potential process improvements that could help to reduce the

[21] *E.g.,* http://www.ethanolrfa.org/page/-/rfa-association-site/studies/LCA_Summary.pdf?nocdn=1 (Figure S.1).

carbon intensity of their fuel. Staff also notes that in America's capitalist economy, no existing federal, state or local law, including the prior LCFS, guaranteed any fuel producer a set market share, revenue, or income. The readopted LCFS did not change that reality.

397. Comment: **LCFS 46-39**

The commenter claims that ARB staff may believe that it cannot put any information into the public record that contradicts Growth Energy's understanding of how corn starch ethanol biorefineries have gained lower-CI pathways to date, owing to concerns about business confidentiality.

Agency Response: Although staff does receive confidential business information as part of pathway applications, staff does not need to employ this information to observe that CI improvement opportunities exist at corn starch ethanol facilities. Also, see response to **LCFS 46-27** and **LCFS 46-36**.

398. Comment: **LCFS 46-40**

The comment states that the current LCFS regulation has led to "fuel shuffling" and that the LCFS has not resulted in any reductions in GHG emissions from corn starch ethanol.

Agency Response: The comment addresses a prior regulation, not the proposal, thus needs no response. To the extent the comment is meant to imply that the readopted LCFS will not reduce GHGs, ARB disagrees. The same commenter has made the contradictory complaint that the LCFS will result in high CI corn ethanol being replaced in California by low-CI cellulosic and cane ethanol. Resulting GHG reductions from the program are detailed in the ISOR. Fuel shuffling is not an expected long-term market response to an increased and growing demand for a product. Suppliers will look for more efficient processes to provide lower CI fuels and to the extent any fuel shuffling occurs, it is expected to be limited in amount and duration. See also response to **LCFS 46-36**.

399. Comment: **LCFS 46-42**

The comment states that the ISOR offers no technical analysis or informed expert opinion to support the speculation that remaining ethanol production processes will achieve on average the first lower-CI level, and then year-over-year reductions.

Agency Response: Staff projected the volumes and types of fuels demanded for compliance with the proposed regulations in the illustrative compliance scenario. This scenario represents one of many potential paths to compliance with the LCFS, and reflects staff's analysis of alternative fuel availability and feasible assumptions regarding increased production of low-CI fuels.

Over the first three years of the LCFS, there has been a steady decline in the average CI of the mix of biofuels used in California. Concurrently, there has been a great expansion of the applications for fuel-pathway CIs. These lower CI pathways will provide additional opportunities to produce more credits per unit of fuel used. ARB staff expects these trends to continue and actually accelerate as the stringency of the LCFS increases and credits become more valuable.

However, Midwestern corn ethanol plants could take the example of Poet[22] who put in an application for a facility-specific CI based upon their diversion of methane from a city landfill to power their ethanol plant. The corn ethanol plants that wish to invest in cleaner energy will be able to compete in a changing market and ensure they meet or even exceed the illustrative compliance scenario outlined in the ISOR.

Staff also note that the commenter's own website currently contains a graph projecting that ethanol plants will continue to reduce their lifecycle emissions dramatically through "innovation[s]" such as "alternative energy sources."[23] Also see response to **LCFS 46-36**.

400. Comment: **LCFS 46-43**

The comment makes a number of assertions regarding the method which ARB staff used to calculate CI values for corn ethanol. The comment suggests that cornstarch ethanol producers may struggle to compete in the market.

Agency Response: The comment makes six points about how ARB staff has calculated CI values for corn ethanol.

1. *The commenter states that the Midwest corn ethanol plants are operating optimally, and that they cannot achieve significant future optimization*.

[22] http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/poet-cha-sum-022014.pdf
[23] http://www.growthenergy.org/ethanol-issues-policy/environment/, visited on August 24, 2015.

What may have been optimal prior to the incentives created by the LCFS may no longer be optimal after the value of the LCFS credits is considered (i.e., given the additional credit value certain investments that previously were uneconomic become economic). The higher the LCFS credit price, the higher the value on the low-CI fuels, and the larger the incentive for investment in reducing the CI values for all fuels.

2. *The commenter states that corn-starch ethanol plants are assigned a large ILUC emissions factor, which they are powerless to change.*

   A full life cycle analysis is important to reflect the GHG emissions associated with each fuel's production, transport, storage, and use. The indirect GHGs can often be significant, and therefore ARB considers land use change effects in the determination of CI. Based on the work with land use change academics and researchers, ARB staff concluded that the land use impacts of crop-based biofuels, including corn-starch ethanol, were significant, and must be included in LCFS fuel CIs. Although it is interesting to note that the iLUC value for corn ethanol is lower in the proposed LCFS regulation.

3. *The commenter states that corn-starch ethanol plants can work with only a fraction of their production processes ─ chiefly, energy, for which they are already likely optimized ─ to achieve lower CI scores*.

   According to page ES-6 of the ISOR, the indirect land use value for corn ethanol is 19.8, leaving the direct emissions driving much of the value of the CI (for a corn ethanol plant with a CI of 70, the direct emissions would be 50.2, over 70% of the total CI). The LCFS credit value is designed to incent GHG reductions across the full lifecycle of the fuel—plant changes, agricultural practices and fuel transport choices.

4. *The commenter states that the ISOR does not address what the commenter sees as a key fact that any costs incurred to reduce the CI score of the ethanol that corn ethanol plants would produce would have to be recovered in the California market against competition from sugarcane ethanol and electricity. The deeper the reductions in CI, assuming any such reductions were possible, the greater the costs, and the longer the period needed to remain competitive in California*.

The comment does not relate that asserted "fact" to the proposal, making it difficult to respond. If those facts are true, they do not constitute an objection or recommendation regarding the proposal. Because ARB has chosen to employ a market-based approach, competition is both expected and desired.

5. *The commenter adds a largely unintelligible series of statements that corn ethanol is used in the compliance scenarios, that absent that ethanol, the LCFS credits will trigger the cap, there won't be GHG reductions and asking whether ARB has a basis to "disagree with the prediction of market exist".*

   To the extent that the commenter seems to be predicting an ethanol shortage, no evidence is provided. As discussed elsewhere, ARB believes that fuel providers can supply sufficient transportation fuel to California in a way that allows parties to comply with the LCFS. Please see ISOR and ISOR Appendix B. Carbon intensities are calculated under the LCFS on a full life cycle basis. This means that the CI value assigned to each fuel reflects the GHG emissions associated with that fuel's production, transport, storage, and use. Staff uses the best available science to update the CI value of each fuel in order to be as accurate as possible and account for the entirety of GHG emissions reductions from each low-CI fuel; the LCFS is fuel neutral and cannot give special treatment to one fuel over another. Staff analysis of the price cap suggests that $200/ton is high enough to provide a sufficient value added to stimulate the investments in and production of low-CI fuels and is sufficiently high to overcome any transportation costs incurred.

   To the extent that the commenter fears credit prices will increase to the cap in any year, ARB notes that the higher credit prices, particularly if they are sustained, will increase the incentive to innovate and invest because revenues generated by LCFS credit can be used to increase profit margins or to offset up-front capital costs; these additional revenues will attract investments in low-CI fuels. The commenter suggests that the recovery of the costs to lower direct emissions to compete with other CI fuels will be have to be passed onto California consumers, however, if there is a constraint on the number of credits (or a shortage such that the credit clearance market is necessary), the higher credit prices can help offset the additional investment required to lower CI values, and put Midwest ethanol at an advantage above other higher-CI fuels.

401. Comment: **LCFS 46-70**

The comment highlights the fact that the LCFS regulation will impose present costs on California consumers and businesses, and questions why ARB did not offer an explanation to justify the need for the present costs along with the direct costs of the LCFS program in the near term.

Agency Response: The present costs to the LCFS program are necessary to meet the goals of the LCFS program, which was designed as a discrete early action measure to achieve the long term goals of AB 32, as outlined in S-01-07 (2007). Additionally, in order to meet "a statewide goal… to reduce the carbon intensity of California's transportation fuels by at least 10 percent by 2020" as outlined in the aforementioned Executive Order, the LCFS program is necessary. Staff also notes that the commenter's own description of the purported present costs, which includes words like "if" and "likely," marks those costs as speculative.

402. Comment: **LCFS 46-71**

The comment questions the basis of imposing the present costs on consumers and businesses if liquid biofuels are destined for a diminishing and no long-term role in ARB's GHG reduction strategy.

Agency Response: The basic arguments and conclusions of this comment were based on the findings of ARB's Vision Scenario Planning Projects, not on the LCFS proposal. To the extent the commenter believes that intermediate regulatory steps and associated burdens are not appropriate unless the steps can immediately and completely accomplish all future goals (such as electrification). ARB disagrees. In the agency's experience, progress toward reducing air pollution has been made incrementally. In decades of regulating vehicles and fuels, ARB has never seen evidence suggesting that California's transportation sector, vehicle manufacturers, fuel suppliers and consumers will all be able to abruptly change from the current fuel mix and vehicle population to 100% electric with no intermediate steps. ARB disagrees with the premise that incremental progress and some attendant costs is a poor or unworkable strategy. Commenter has not submitted – and cannot – any examples where more than 38 million people suddenly abandoned all vehicles using one fuel and purchased new ones using another fuel virtually overnight.

403. Comment: **LCFS 46-72**

The comment questions why ARB did not provide supporting information to justify that the proposed regulation is a superior alternative among all the options considered.

Agency Response: The commenter believes that the Notice of Proposed Rulemaking, the ISOR, and the SRIA all fail to provide "supporting information" for the determination that there was no alternative that would be "as effective and less burdensome". ARB clearly outlined the reasons for rejection of alternatives proposed by the commenter in the SRIA analysis that can be found in Appendix E of the ISOR with updated results in Appendix F, and further explained in Chapter VII of the ISOR. These explain in detail why the various alternatives proposed by the commenter and others are not, in fact, "as effective and less burdensome."

404. Comment: **LCFS 46-73**

The comment requests ARB to delay the final rule making until commenter's issues are addressed.

Agency Response: The commenter repeats comments **LCFS 46-34** and **LCFS 46-68**. See responses to those comments.

405. Comment: **LCFS 46-74**

The comment asserts that ARB staff has not included all necessary materials in the rulemaking file, as required by Government Code section 11347.3(a), (b)(6).

Agency Response: ARB staff disagrees, having included all necessary materials in a rulemaking file comprised of over 1,200 pages (ISOR and appendices) and 710 references of varying length.

The commenter assumes that some additional documents in possession of ARB's 11 board members and approximately 1300 employees *also* belonged in the record. The comment is not sufficiently specific to allow a response; what documents are missing? The commenter's repeated quotation in italics of the word "all" suggests that the commenter pictures a collection of documents potentially so broad as to make the rulemaking file too voluminous for the purpose of meaningful public participation. ARB does not favor deluging interested parties in an overload of information or documents.

ARB followed the long-standing practice of administrative agencies in California by (1) assembling the material on which it relied to form a proposal, (2) making a proposal, (3) making items (1) and (2) available to the public, then (4) receiving public comments and making those available, (5) considering those comments, and (6) responding publicly to those comments. That system, which the Legislature set forth in the APA, works reasonably well.

406. Comment: **LCFS 46-75/ADF 17-11**

The commenter expresses its concern about the completeness of the rulemaking files in the ADF and LCFS rulemakings.

Agency Response: The commenter expresses its concern about the completeness of the rulemaking files in the ADF and LCFS rulemakings. Only ARB can determine what ARB did rely upon in creating a proposal, and conversely what information, data or theories ARB did not rely on for any number of reasons. Such is the very essence of the discretion invested in an expert agency charged by the Legislature to address important, complex problems such as air pollution. While the commenter and any other member of the public are entitled to participate in the rulemaking process, it is manifestly ARB's province to determine what constitutes the relevant, credible, necessary foundation for any proposal.

The commenter goes on to propound a series of *questions* that "CARB legal staff" should respond to. Absent knowing what answers the commenter believes to be correct, the questions do not constitute "an objection or recommendation regarding the specific adoption . . . proposed" within the meaning of Government Code section 11346.9(a)(3).

Some of the commenter's questions are not legal in nature, but requests that CARB perform detailed clerical and paralegal tasks to assist the commenter's attorneys in pursuing litigation against CARB. For example, the commenter requests that "CARB legal staff" explain various matters and identify:

> [1] "each document or other file made available to the public under section 39601.5 prior to January 2, 2015, in connection with these two rulemakings;"
>
> [2] provide "the date it was made available;" and
>
> [3] provide "the method by which it was made available."

While the Administrative Procedure Act (APA) requires much, it does not require an agency to catalogue tens of thousands of documents for a commenter's convenience. ARB staff notes that over a period of several years there were 21 LCFS public workshops, and 26 ADF public workgroup or workshop meetings as part of developing these two related regulations. Along the way, ARB staff posted, as is its practice, a wide range of materials on the program web pages ARB maintains. Such materials have long been public.

This comment response is duplicated in the Alternative Diesel Regulation Final Statement of Reasons under Comment Letter **17_OP_ADF_GE**.

407. Comment: **LCFS 46-76**

The comment seeks clarifications on the inclusion of external communications in the rulemaking file.

Agency Response: See response to **LCFS 46-75**.

408. Comment: **LCFS 46-77**

The comment requests ARB staff to identify all information covered by section 39601.5 in connection with the current LCFS and ADF rulemakings.

Agency Response: See response to **LCFS 46-75**.

This page intentionally left blank.

46_OP_LCFS
_GE

17_OP_ADF
_GE

Appendix A

Comments on ARB's Corn Ethanol Land Use Emissions
February 10, 2015
Air Improvement Resource, Inc.

Introduction

ARB presented a new land use emission estimate for corn ethanol in the Initial Statement of Reasons (ISOR). The derivation of this estimate was discussed in Appendix I to the ISOR. ARB developed the corn ethanol estimate from the average of 30 scenarios, where each scenario represented a unique run of the Global Trade and Analysis Project (GTAP) model. The 30-scenario average is 19.8 g CO2 e/MJ. This value is 10.2 gCO2/MJ lower than ARB's current estimate of 30 g CO2e/MJ.

ARB held 3 workshops in developing the new LUC values; one in March 2014, one in September 2014, and a final one in November 2014. AIR participated in all 3 workshops, and submitted comments to the Staff on all 3 workshops. Our previous comments are included as Attachments 1-3 to this document.

Very little changed in ARB's emissions for corn between the November 22 workshop and the ISOR. The value at the November 22 workshop was 20.0 g CO2e/MJ.

Through the workshop process, we have made a number of comments on the Staff's approach and analysis. One comment was adopted, but the remainder were either ignored or shifted to ARB's "Long Term" project list. Table 1 below summarizes the status of comments made. We have divided the recommendations into two categories – GTAP, and AEZ-EF. [1] We have included 3 categories for the status – adopted, ignored, or shifted to long-term.

[1] GTAP determines how much and what type land is needed and where, and the AEZ-EF model determines the emissions of the various land transitions. Both models are needed to estimate LUC for a biofuel.

Table 1. Status of Recommended Items					
Category	AIR Recommendation	Adopted	Ignored	Long-Term	
GTAP	Revise the model land supply structure	X			
	Drop the lower price-yield values		X	X	LCFS 46-79
	Include multiple cropping effects			X	LCFS 46-80
	Evaluate land intensification effects		X	X	
	Include effects of conservation reserve program (CRP)			X	LCFS 46-81
	Include additional effects of fertilizer, livestock, paddy rice emissions			X	LCFS 46-82
	Develop and include cropland-pasture from other regions			X	LCFS 46-84
AEZ-EF	Do a comparison of CCLUB to AEZ-EF		X	X	LCFS 46-85

Table 1 shows that many of the items recommended have simply been shifted for future study. Most of these items were raised by both AIR and the Expert Working Group (EWG) at least 4 years ago (two examples are (1) including CRP in the analysis, and (2) including the effects of livestock and rice paddy emissions). We have listed several items as either being ignored and shifted to the future or just being ignored, because either Staff's response to our input was inadequate, or it was not addressed at all in the ISOR, or both.

For many of the items that have been shifted to further study, we have presented in comments submitted previously, information showing they could be included now (examples are land intensification effects). Some items shifted to further study legitimately require further study, for example, including cropland-pasture from other regions.

Overall, we believe the LUC value of 19.8 gCO2e/MJ for corn ethanol is still too high. The implications of overestimating the LUC value for corn ethanol are that it could lead to shuffling of fuels without any reduction in greenhouse gases and increased costs of compliance with the LCFS. LCFS 46-78

The following section discusses each of the comments above. We skip a discussion of the model structure, since that comment was adopted by the staff.

Price-Yield Values

The ARB analysis uses five price-yield values: 0.05, 0.10, 0.175, 0.25, and 0.35. The average of these 5 values is 0.19. The Purdue recommended value is 0.25, and the EWG recommended 0.25. ARB sponsored research indicating that there was little or no price-yield response (i.e., 0.0). Our comments on price yield were that ARB should drop the lower price yield values (0.05 and 0.10) because the research supporting these lower values was developed over the very short term (1-3 years of price and yield data), and the GTAP model is a longer-term model (5-10 years). [2] ARB utilizes an 11.59 billion gallon per year shock of corn ethanol in its corn ethanol modeling, clearly illustrating that ARB is exercising the model with a medium-term shock, and not a short term shock. Thus, ARB's use of short term price yield responses with the medium or longer term GTAP model is clearly inconsistent.

In the ISOR, ARB references a recent analysis by David Rocke at UC Davis in support of using lower price-yield responses. [3] The Rocke analysis utilized one set of data from a 2012 dissertation by Juan Francisco Rosas Perez. [4] The dissertation indicated that the price-yield response was in the region of 0.29, very close to the Purdue default value. Rocke obtained the data from the dissertation, conducted his own statistical analysis, and concluded that the data did not support the 0.29 price yield value.

LCFS 46-79 cont.

Because of the differences between these two analyses (Perez and Rocke), which are clearly important to understand fully, AIR requested the data Rocke used for his analysis from ARB staff. While staff said they were trying to get the data for AIR, the data was never supplied by staff. Therefore, we were unable to replicate Rocke's analysis of the Perez data. There is not enough information in Rocke's write-up to reject the Perez analysis (the rebuttal is only 3 pages). In addition, this is only one of two sources (according to Rocke) that were used to support the 0.25 price-yield value, Rocke did not attempt to critique the other source. Thus, because we were not able to replicate Rocke's sketchy analysis, and Rocke only critiqued one source, ARB cannot rely on the Rocke analysis for its use of low price-yield values, and should therefore eliminate the lowest value (0.05), or the lowest two values (0.05 and 0.10).

The impacts of eliminating one or both of these values on corn ethanol LUC emissions is shown in Table 1. Without the lowest price yield value of 0.05, the LUC value for corn is 17.62. Without both 0.05 and 0.10, the LUC value is 15.53

[2] "Discussion of the Yield Price Elasticity of GTAP", Taheripour and Tyner, Purdue University, April 2014.

[3] "Statistical issues Related to the Low-Carbon Fuel Standard", October 31, 2014.

[4] "Essays on the Environmental Effects of Agricultural Production", Dissertation, Perez, Juan Francisco Rosas, Iowa State University.

gCO2e/MJ. As before, we recommend that ARB eliminate the lowest two price-yield values. LCFS 46-79 cont.

Table 1. Impact of the Low Price-Yield Values		
Average of ARB Scenarios	Average price-yield	LUC (gCO2e/MJ)
All (ARB value)	0.19	19.84
w/o 0.05 price-yield	0.21	17.62
w/o 0.05, 0.1 price-yield	0.26	15.53

Multiple-Cropping and Land Intensification

GTAP currently does not include any double or multiple cropping. When crop prices increase, producers get more out of the same piece of land by planting second and even third crops. This is particularly true in Brazil, where corn is planted on soybeans, and even in the US, where wheat is planted and corn/soybeans are planted in the same year. This is one process of land "intensification", whereby existing cropland is used to a greater degree before conversion of non-cropland.

In our September 2014 workshop comments (Attachment 2) we pointed out that multiple cropping can be conservatively modeled by increasing the price yield value. We recommended a +0.05 increase in price yield from about the 0.25 Purdue default level to 0.30, other commenters have recommended similar and higher amounts. Ignoring multiple cropping, as ARB is currently doing (or, just deferring including it to some unknown future date) is not technically acceptable or defensible.

LCFS 46-80 cont.

The empirical evidence for intensification globally was developed from data by the Babcock/Iqbal analysis, which we covered in detail in our comments on the November 22 workshop. [5] This analysis showed that over the last 10-15 years of biofuel expansion, there has been no net land conversion from forest and pasture to crops in many regions such as the US, Western Europe, and China. In our November comments (Attachment 3), we developed a filter that could be applied to the ARB results based on GTAP to estimate LUC of biofuels. We showed that application of this filter would reduce LUC from corn ethanol from 20 gCO2/MJ to a range of 6-13 g CO2e/MJ (see Table 2 in Attachment 3).

ARB has known about the inability of GTAP to account for multiple cropping since the last time land use values were adopted in 2009. It is inexcusable that ARB would still be relying on LUC values that do not include multiple cropping or more generally, some accounting for land intensification. We have provided two methods to ARB for accounting for these effects in this version of LUC estimates – either use a somewhat high price-yield factor, or use the filter we developed from the

[5] Using Recent Land Use Changes to Validate Land use Change Models", Babcock and Iqbal, Staff Report 14-SR- 109, Center for Agriculture and Rural Development, Iowa State University, www.card.iastate.edu.

Babcock/Iqbal study. These methods can be applied conservatively to avoid over-accounting for their effects. Of course, this, as well as many other issues, could also be studied further in the future. But some accounting for multiple cropping and land intensification should be included with this LCFS re-adoption. LCFS 46-80 cont.

Conservation Reserve Program

Our comments have also consistently pointed out that ARB should also include the effects of Conservation Reserve Program land (CRP) in mitigating land use emissions. The GTAP model already includes the computer code to access CRP land.[6] We have also presented direct evidence from USDA statistics that conversion of CRP back to crop has already occurred over the last five years (see Table 2 of our comments on the March 11 workshop, Attachment 1). Therefore, we are not discussing a theoretical possibility of this conversion occurring in the future with biofuel expansion. It has already happened, and ARB has ignored it.

Inclusion of US CRP land in estimating LUC of biofuels would clearly lower LUC values. The carbon stored on CRP (above and below ground) reactivated to crops would be similar to ARB's current estimate for pasture. It could even be a little higher than pasture, if shrubs and other plants had started to grow on this land. In some cases, CRP land could even include some young forest. However, it is not likely that forest CRP land would be reactivated back to crops, rather the CRP converted back to crops would be land relatively easy to convert. But the inclusion of CRP land in GTAP modeling would reduce overall the forest estimated to be converted in the US, thereby showing a reduction in GHG emissions from the case of not including CRP land in the analysis. LCFS 46-81 cont.

Include Livestock and Paddy Rice Emission Credits

These are other indirect effects that were identified at the time the last land use values were finalized by the ARB. The biofuel shocks increase crop prices, thereby reducing livestock herds and also reducing the paddy rice crop. Livestock and rice produce prodigious amounts of methane, so the reduction in these two items reduces GHG emissions from biofuels. EPA included these effects in its implementation of the Renewable Fuel Standard in 2010. Given that EPA included these effects several years ago, it is surprising that ARB postponed the inclusion of these effects in their modeling. LCFS 46-82 cont.

Include Fallow Land

---

[6] The AEZ-EF appendix indicates that "GTAP-BIO does not consider conversion of CRP land." This is not exactly true. The computer code for including this land is in the model, and it is easy to activate. AIR has activated this code, and GTAP, along with AEZ-EF (assuming CRP land is similar to pasture) predicts a 1-2 gCO2/MJ reduction for including CRP land in the analysis.

We showed in Table 6 of our comments on the November workshop (Attachment 3) that worldwide there are 193 million hectares of fallow land. The model currently has no capability of accessing this land for increased crop production even though it is probably the most likely land to respond to higher crop demand and is land that could be brought into production without any land use change. LCFS 46-83

Include Cropland-Pasture from other Regions

The GTAP model includes cropland-pasture for the US and Brazil. Cropland-pasture is land that is used alternatively for either cropland or pasture, depending on economics to the producer and other factors. The inclusion of the land type for these two countries reduced LUC emission predictions from GTAP significantly. The US and Brazil are not the only regions with cropland-pasture. Canada, Western Europe, and some other regions also utilize cropland-pasture. LCFS 46-84 cont.

Compare CCLUB to AEZ-EF

ARB uses its AEZ-EF model to estimate the emissions of various land transitions, for example, forest to crop, pasture to crop, crop to pasture and so on. The model was not finalized and released until late November 2014.

AIR has previously commented that ARB should also evaluate LUC emissions with the CCLUB model. [7]CCLUB is used by Argonne to estimate LUC emissions for various biofuels in the GREET model (GREET2013, GREET2014). CCLUB was available in late 2013. CCLUB basically uses the same international emissions that EPA used in the RFS, but has much more detailed emissions for the US. CCLUB is not even referenced by the AEZ-EF documentation. ARB claims to have evaluated CCLUB, but there is no indication of that in either the AEZ-EF documentation, in Appendix I, or in the ISOR. [8] Therefore, due to the fact that ARB released the final AEZ-EF model so late in the process, and that there are no references to CCLUB in any of the ARB documentation, we are not clear on what the advantages there are to AEZ-EF over CCLUB. There was little time for us to perform an in-depth analysis of the differences in these two models that estimate the emissions of various land transitions. LCFS 46-85 cont.

AIR evaluated the impact of using CCLUB instead of AEZ-EF for predicting emissions. The impacts are shown in Table 2. LUC emissions with CCLUB are less than ½ of ARB's AEZ-EF model. AEZ-EF is not superior to CCLUB, certainly the most technically defensible parts of both models should be combined.

---

[7] Dunn, J., Mueller, S, Kwon, H.Y., Wander, M., Wang, M., "Carbon Calculator for Land Use Change from Biofuels Production (CCLUB)", Argonne National Laboratory, ANL/ESD/13-8, September 2013.

[8] In their list of long-term updates to LUC in the ISOR, ARB's number 2 item is to "use improved emission factors, as they become available." However, it appears ARB has not fully evaluated emission factors in CCLUB, which were available long before ARB finalized its AEZ-EF model.

Table 2. Comparison of Corn Ethanol LUC Emissions	
Scenario	LUC (g CO2e/MJ)
ARB Average Inputs with AEZ-EF Emissions	17.14
ARB Average Inputs with CCLUB Emissions	7.77

LCFS 46-85 cont.

Attachment 1

Comments on ARB's March 11 Workshop on
The Low Carbon Fuel Standard
Air Improvement Resource, Inc.
April 6, 2013

These comments are primarily on the workshop presentations provided by CARB, and some of the documentation provided by CARB on the AEZ-EF model shortly after the workshop. The following comments focus on Land Use Change and Facility Registration components of the LCFS.

Land use Change Emissions

There are two models used to estimate the land use change emissions – the Agri-Economic Zone Emission Factor (AEZ-EF) model, and the Global Trade Analysis Project (GTAP). GTAP is a general equilibrium model used to determine land transitions (like pasture to cropland and forest to cropland) in similar agro-economic zones in various regions of the world. The AEZ-EF model is used in conjunction with the GTAP to determine emissions released by the land-use transitions.

We discuss the GTAP model first, followed by the AEZ-EF Model. We then use the ARB-GTAP model and a much more appropriate Purdue GTAP model to estimate the impacts of our recommendations of changes on land use change (LUC) emissions for corn ethanol.

Global Trade Analysis Project (GTAP)

GTAP contains global land pools of cropland, forest, pasture, Conservation Resource Program (CRP) land (in the US), and cropland pasture (in the US and Brazil). The base year for the current model is calendar year 2004. In modeling biofuel increases, the model is "shocked" with the biofuel increase (corn ethanol, for example), and since this requires a significant increase in corn production, the model converts some other cropland to corn production, converts some pasture to crop production, and converts some forest to crop production. The model also contains a price-yield elasticity, such that when the model is shocked for increased corn ethanol, crop prices increase, and yields also increase somewhat on all cropland. Thus, increased production is met through (1) cropland expansion into non-cropland (which creates land use change emissions), and (2) yield increases on existing cropland.

LCFS 46-86

There are other ways in which crop production increases in addition to land expansion and yield increases. A 2013 study by Roy and Foley shows there are three other ways crop production increases: (1) using the existing standing cropland area more frequently by multiple cropping, (2) leaving less land fallow, and (3) having fewer crop failures.[9] None of these 3 ways involves a land use change, or land use change emissions. Furthermore, GTAP does not include these 3 factors: GTAP does not account for double cropping, has no fallow land inventory, and cannot model reduced crop failures. Roy and Foley point out that the influence in these 3 factors on crop production can be estimated by comparing trends in total harvested area to total cropland.

> The growth in annually harvested cropland and standing cropland has been changing in recent decades. Analyzing the 177 crops traced by FAO since 1961 shows that the amount of annually harvested land has increased much faster than the reported total standing cropland on the globe. While standing cropland has increased at the rate of 3.5 mha/year, the annually harvested land increased at a much faster rate of 5.5 mha/yr.

The difference in the above growth rates – 2.0 mha/year – is due to the 3 factors mentioned earlier, which have no land use emissions impact. The authors also examine the potential for the increase in harvested area to continue to increase faster than standing cropland in the future, and find that these trends should continue.

It is difficult to incorporate these factors into the current GTAP model, because these factors require a dynamic GTAP model, and the current model is a static model.[10] However, the analysis of these trends can be used to inform the ranges of input elasticities for the current static GTAP model used by ARB, particularly the price-yield elasticity. Increasing the price yield elasticity in GTAP increases crop production without a land use impact. Thus, the Ray/Foley study argues for a relatively high price-yield elasticity range. ARB, however, has selected a very low price yield elasticity range. This is discussed in more detail in the next section.

LCFS 46-86 cont.

Review of CARB's GTAP Modeling

Price-Yield Elasticity Range

GTAP includes a price-yield elasticity of 0.25 as a default. This level is in part based on extensive research by the GTAP modeling community. [11] The Expert Working Group also recommended this value. The EWG also recommended higher values for regions with significant double cropping, since GTAP does not explicitly include double cropping. GTAP researchers have also pointed out GTAP is a medium-term model, with projections being applicable in the 5-10 year timeframe. CARB appears to concur with this timeframe for GTAP, because CARB describes the model as a

[9] Ray, D.K., and Foley, J.A., *Increasing global harvest frequency: recent trends and future directions,* Environmental Research Letters, (2013), 044041, IOP Publishing.

[10] Purdue is continuing to develop a dynamic GTAP model for these and other reasons.

[11] Keeney and Hertel, "Yield Response to Prices: Implications for Policy Modeling", Working Paper #08-13, August 2008, Department of Agricultural Economics, Purdue University.

"Current" model, meaning, that its estimates are applicable to the 2013/2014 timeframe, even though its primary data is for 2004.[12]

CARB, however, performed sensitivity analyses using price-yield elasticity values from 0.05-0.30 (20%-120% of the default value). CARB's selection of the lower end of the range came from a variety of price-yield studies that were very short term (1-2 years) in nature, and were clearly not appropriate for the GTAP timeframe. All studies on data less than about 4 years should not even be considered in establishing the range of this parameter to use in modeling. Furthermore, CARB did not consider the analysis by Ray and Foley in determining the range of price-yield values to use.

LCFS 46-86 cont.

CARB performed sensitivity analyses on several other parameters. Most of these values were in the range of 80%-120% of the GTAP default level, for example, CARB performed sensitivity modeling of the ETA parameter at the baseline (default), 80% of the baseline, and 120% of the baseline. We support performing sensitivity modeling at different price-yield levels, however, the range should be at least 80%-120% of the Purdue baseline value of 0.25, or 0.20 to 0.30. However even this range is not nearly high enough to properly reflect the increase in crop production that has occurred without land use changes reflected by Ray and Foley analysis referenced earlier.

ETL1 and ETL2 Values

CARB updated the land transformation elasticities (ETL1 and ETL2) in GTAP prior to estimating land use changes. ETL1 governs the transformations between forest, crops, and pasture, and ETL2 governs the transformations between various crops. CARB appears to have used some, but not all, ETL1 and ETL2 values from a 2013 Applied Science paper by Taheripour and Tyner. [13] In the Applied Sciences paper, Taheripour and Tyner indicate

LCFS 46-87

> We tune the regional land transformation elasticities based on actual historical observations on changes in land cover and distribution of cropland among alternative crops during the past two decades. To accomplish this task we use published data on cropland use around the world by the Food and Agriculture Organization (FAO) of the United Nations over the period 1990-2010.

The differences in ETL1 and ETL2 values between the Applied Sciences paper and CARB are shown in Table 1 below.

---

[12] See page 57 of the CARB March 11 Workshop Briefing, iluc_presentation_handouts_031014.pdf.

[13] Taheripour and Tyner, "Biofuels and Land Use Change: Applying Recent Evidence to Model Estimates", Applied Sciences, 2013, 3, 14-38.

Table 1. Differences in ETL1 and ETL2 Values Between CARB and Purdue				
Region	Purdue – Applied Sciences 2013		CARB	
	ETL1	ETL2	ETL1	ETL2
Brazil	-0.30	-0.50	-0.20	-0.75
S_O_Amer	-0.30	-0.25	-0.10	-0.50
R_S_Asia	-0.10	-0.25	-0.10	-0.75
Russia	-0.20	-0.75	-0.02	-0.75
S_S_Afr	-0.30	-0.50	-0.30	-0.25

LCFS 46-87 cont.

It is not clear why CARB chose different ETL1 and ETL2 values than Purdue, and what analysis or data CARB based these values on. An explanation of this should be provided for review, or CARB should use the ETL1 and ETL2 values that were developed by Taheripour and Tyner.

Model Nesting Structure

The Applied Science paper referenced above also included another major improvement in GTAP. According to the paper

> The GTAP-BIO model puts three types of land cover items (forest, pasture, and cropland) into one nest an implicitly assumes that the economic costs of converting one hectare of forest to cropland is similar to the economic cost of converting one hectare of pasture land to cropland and vice versa. This set up another key deficiency of the GTAP-BIO model. Including cropland, forest, and pastureland in the same nest could cause systematic bias in land conversion processes among land cover types due to biofuel production. In general this is not the case and often the opportunity costs of converting forest to cropland is higher than the economic cost of converting pastureland to cropland.

LCFS 46-88

The Expert Working group studying elasticity parameters in GTAP identified this nesting structure as a key deficiency in the model and recommended using a revised nesting structure.

Taheripour and Tyner altered the land cover component of the land supply tree to have forest and pasture land in two different nests. Then they re-evaluated global land use impacts due to the USA ethanol program using the improved model tuned with actual observations. They showed that, compared to the old model

> The new model projects: (1) less expansion in global cropland, (2) lower share for the USA economy in global cropland expansion, (3) and lower forest share in global cropland expansion.

CARB did not include the model nesting structure changes implemented by Taheripour and Tyner, and recommended by the Expert Working Group, even though this revised model was available to CARB in early 2013. CARB should include this critical change in the GTAP model. LCFS 46-88 cont.

Additional Cropland/Pasture Areas in Canada and EU27

GTAP has been updated to include cropland/pasture in the US and Brazil (CARB used the model with these additions). Other regions of the world, such as Canada and the EU27 (and probably many other regions of the world) also have a significant amount of cropland/pasture and idle land. These land areas should be added to GTAP. LCFS 46-89

Conservation Resource Program Impacts

The GTAP model includes the ability to include CRP land in the land inventory for the US. There has been a significant amount of land converted to production from CRP land in the last seven years. Table 2 shows data from the Conservation Resource Program. [14] These data show over 10 million acres of CRP land have gone back into production. These are not forest acres that have gone into production. Over the period from 2007-2011, CRP acreage in wetlands and buffers increased. Clearly, GTAP should be run to access CRP land in the US prior to converting forests or even cropland/pasture. LCFS 46-90

[14] "Annual Summary And Enrollment Statistics", FY2011 for 2007-2011, and December 30 Reports for 2012 and 2013, http://www.fsa.usda.gov/FSA/webapp?area=home&subject=copr&topic=rns-css.

Table 2. CRP Land Enrolled	
Year	Area (million acres)
2007	36.8
2008	34.6
2009	33.8
2010	31.3
2011	31.1
2012	27.1
2013	25.6

AEZ-EF Model

Use of Carbon Data on Accessible and Inaccessible Forests to Determine Emissions from Forest Conversion

The AEZ-EF report indicates

> The carbon data used in AEZ-EF have been aggregated to GTAP-BIO boundaries, but they include both accessible and inaccessible forests, as well as grasslands other than those used for livestock grazing, and thus represent broader resources than those represented in GTAP-BIO.

LCFS 46-91

It is not clear why CARB is including inaccessible forests in developing forest carbon stocks. If forests are inaccessible, then it is highly unlikely they would be converted to pasture or cropland. CARB should instead develop forest carbon from accessible or commercial forests. Detailed carbon data on public, private, and other forests is utilized by EPA in estimating its annual GHG inventories.[15] The carbon in private forests (most likely of forests to be converted to pasture/cropland) is much lower than public or other forests.

Wood Used to Produce Energy

In the new AEZ-EF model, for forest converted to cropland or pasture, CARB is now accounting for carbon stored in hardwood products (HWP). The storage rates are different for different regions, and are based on a 2012 study by Earles, Yeh, and Skog. The HWP fraction ranges between 2-36%.

LCFS 46-92

In addition to accounting for carbon stored in HWP, CARB should also account for wood mass that is used for fuel during forest clearing. Wood that is burned to

[15] USDA Forest Service (2010a), Forest Inventory and Analysis National Program:User Information. U.S. Department of Agriculture Forest Service. Washington, DC. Available online at http://fia.fs.fed.us/tools-data/docs/default.asp.

produce energy (for a sawmill, for example) is replacing fossil-fueled energy, and is renewable. CARB does not count CO_2 emissions from facilities that use waste wood to produce energy for fuel production (CARB does, however, count non-CO_2 GHG emissions, which is appropriate). Heath et al estimate that 35% of carbon from forest clearing is used for energy.[16] In the US, Canada, and the EU27, CARB should not count the CO_2 from wood used to produce energy.

LCFS 46-92 cont.

CCLUB Model

CARB should consider using the Carbon Calculator for Land Use Change from Biofuels Production (CCLUB) model for estimating emissions.[17] Like AEZ-EF, the model was designed to be integrated with GTAP. It has several advantages over AEZ-EF. First, instead of using the Harmonized World Database (HWD) for soil, it uses the CENTURY model, which contains much more specific information on soil carbon for the US than the HWD, on a county-by-county basis. Second, it uses county-by-county carbon data from forest ecosystems for the US from the Carbon Online Estimator (COLE) database, developed by Van Deusen and Heath in 2010 and 2013. [18,19] Third, it allows the user to input HWP fractions, and fourth, it does not count CO_2 from the forest wood used to produce energy. For areas outside of the US, it utilizes Winrock emissions.

CARB has conducted uncertainty analysis of its land use estimates using only AEZ-EF and GTAP. Using the CCLUB model with GTAP to estimate land use change emissions would also provide more information on the uncertainty of CARB's estimates.

LCFS 46-93

---

[16] L. Heath, R. Birdsey, C. Row, and A. Plantinga. "1996 carbon pools and flux in U.S. forest products", Forest Ecosystems, Forest Management, and the Global Carbon Cycle, M. Apps and D. Price, eds. NATO ASI Series I:Global Environment Changes, Volume 40, Springer-Verlag, ppg 271-278.

[17] See reference 7.

[18] Van Duesen, P., and Heath, L., 2010. Weighted Analysis Methods for Mapped Plot Forest Inventory Data: Tables, regressions, maps and graphs. Forest Ecol. Manage. 260:1607-1612.

[19] Van Duesen, P. and Heath, L. 2013. COLE web applications suite. NCASI and USDA Forest Service, Northern Research Station. Available at http://www.ncasi2.org/COLE/

Updated LUC Modeling

AIR downloaded ARB's GTAP model and the AEZ-EF model to determine the impacts of some of our suggestions. ARB did not supply example run results for any particular biofuel shock. ARB ran the models under 1440 different input conditions, for 5 different biofuel shocks, and determined the average emissions for each of the 1440 runs (a total of 7200 runs). The results are shown in Table 3.

Table 3. ARB Land Use Results, March 11 Workshop

Biofuel	LUC Emissions (gCO2e/MJ)
Corn Ethanol	23.2
Sugarcane Ethanol	26.5
Soy Biodiesel	30.2
Canola Biodiesel	41.6
Sorghum Ethanol	17.5

In this analysis we test the impact of three factors that should be changed in the ARB modeling:

- ARB's ETL1 and ETL2 values
- Model Nesting Structure
- Price-Yield Range

LCFS 46-94

It is clearly impractical for us to run the model 1440 times to test the impact of these 3 items. However, it is possible to test the impact with a representative model run. To create the representative model run, we first estimated the average of the ARB inputs. Next, we ran the model with a corn ethanol shock to determine the LUC emissions. Finally, we changed the price yield elasticity, until the model run gave the same answer as corn ethanol in Table 3. The average model inputs are shown in Table 4.

Table 4. Average ARB GTAP Inputs

Input Parameter	Average Value
Price Yield (Ydel)	0.175
PAEL, US	0.3250
PAEL, Brazil	0.1875
ETA	ARB Baseline
ETL1, ETL2	ARB Baseline

When we ran the case in Table 4, we obtained corn ethanol emissions of 21.66 gCO2e/MJ. We then reduced the price yield elasticity from 0.175 to 0.1507, and obtained emissions of 23.22 gCO2e/MJ, which is the same as ARB's corn ethanol estimate. This is our single run that generally represents CARB's 1440 cases.

The impact of the 3 changes on LUC emissions for the corn ethanol shock are shown in Table 5.

Table 5. Impacts of Changes in GTAP Modeling	
Scenario	LUC Emissions (gCO2e/MJ)
AIR "Representative" Case	23.22
Change ETL1 and ETL2 parameters to Purdue "tuned" values	21.20
Implement Purdue GTAP Nesting Structure	19.00
Use Purdue Default Price-Yield Range	14.63
Include CRP Land Conversions	13.75

Table 5 shows likely emissions of 13.75 g CO2e/MJ instead of 23.22 gCO2e/MJ if these changes are implemented and the various runs are repeated. The emissions would be even lower if the model were modified to more properly reflect (1) the Ray and Foley analysis that a major part of crop production has increased without a land use change, and (2) the ARB analysis properly accounted for wood from forest that is used for fuel and replaces fossil fuel during forest clearing.

LCFS 46-94 cont.

2.0 Fuel Pathways and Producer Facility Registration

Growth Energy supports the streamlining of the application process for biofuel production facilities, however, Growth Energy does not support limiting the pathways a facility can apply for, nor does Growth Energy support implementation of CI "bins" that facilities must use when registering the facilities. These changes would both severely limit continued innovation in biofuel facilities.

LCFS 46-95

At the workshop, CARB envisioned bins of either 5, 7, or 9 CI values, with all facilities falling in a bin range getting the same, midpoint value of the bin. For a 7 CI bin case, for example, facilities falling in a bin from 61-67 would all be assigned a value of 64, whether their CI is 61.1 or 66.9. Furthermore, a facility with an actual CI of 65 (assigned value of 64) would not be able to obtain a lower CI value unless it reduced its actual CI to the upper part of the next bin range, or 60.9 (a difference of 4.1 CI). A facility at 61.1, however, with an assigned value of 64 would be able to get into the next lowest bin by reducing its CI to the same value of 60.9, a difference of only 0.2 CI. Clearly, if we are understanding CARB's bin approach correctly, it appears to have significant problems, no matter how the bins are designed.

LCFS 46-96

A second major concern we have with the bin approach is that it is not at all consistent with what ARB is proposing for refineries producing gasoline and diesel. CARB's GHG Emission Reductions for Refineries proposal indicates that CARB is willing to provide credit under the LCFS regulations to refineries, with no minimum CI reduction required. In other words, a refinery that has a project to reduce its CI by 0.1 CI would receive consideration. But under the binning approach for

LCFS 46-97

biorefineries above, there is a much higher minimum threshold for consideration of a lower bin. Thus, gasoline/diesel refineries receive special treatment that biofuel facilities do not.

LCFS 46-97 cont.

Attachment 2

Comments on ARB's September 29th Workshop
On Land Use Change Emissions
Air Improvement Resource, Inc.
October 17, 2014

Introduction

On September 29, 2014 ARB held a workshop on land use change emissions. ARB presented new information on their analysis of LUC emissions for corn ethanol, soybean biodiesel, canola biodiesel, cane ethanol and sorghum ethanol.

We have reviewed the information CARB presented at the workshop and thereafter, and also have obtained the new GTAP model and performed some additional modeling runs. We appreciate the additional time that the staff has provided for us to provide these comments. We will have additional comments later. The comments are presented here are organized into the following sections:

- Irrigated/Rain-Fed Cropland Category
- Land Supply Structure
- ETL11, ETL12, ETL4 and ETL5
- ARB's 30-Scenario Average
- Yield-Price Elasticity
- Cropland Pasture Elasticity
- Corn Ethanol LUC Impacts of our Recommendations

Please add these comments to the page on ARB's website that has been previously established for workshop comments.

Irrigated/Rain-fed Cropland Category

LCFS 46-98

Earlier versions of the GTAP model used an average of irrigated and rain-fed cropland. The expansion of cropland in the model did not differentiate between irrigated or rain-fed areas. Irrigated cropland typically has a higher yield compared to rained cropland in a given Region and AEZ. If cropland expansion occurs on irrigated land, higher yields translate into smaller land requirements. But availability of water for irrigation may limit expansion into irrigated land.

The new version of GTAP developed by Purdue for ARB includes an option to differentiate between irrigated and rainfed cropland. The availability of irrigated land for cropland expansion then can be constrained in certain regions and AEZs, if there is sufficient evidence to constrain expansion of irrigated lands.

ARB used analyses and data from the World Resources Institute (WRI) to determine which regions and AEZs within these regions to constrain expansion into irrigated land.

Figure 1 shows the Regions and AEZs where irrigated land is constrained for the ARB LUC analyses. These regions and AEZs were determined from the WRI reports. [20][21]

LCFS 46-98 cont.

Figure 1

GTAP: Water Constrained Regions/AEZs

AEZ → / Region ↓	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
1 USA							1	1	1				1	1				
2 EU27									1									
3 BRAZIL																		
4 CAN							1	1										
5 JAPAN									1			1						
6 CHIHKG							1	1	1	1			1					
7 INDIA	1	1	1				1	1	1	1					1	1		
8 C_C_Amer	1	1					1	1	1	1	1							
9 S_o_Amer	1	1					1	1	1									
10 E_Asia											1							
11 Mala_Indo				1	1													
12 R_SE_Asia																		
13 R_S_Asia	1		1				1	1	1	1			1					
14 Russia																		
15 Oth_CEE_CIS							1	1					1	1				
16 Oth_Europe																		
17 MEAS_NAfr			1	1			1	1	1	1								
18 S_S_AFR								1										
19 Oceania	1							1	1	1	1							

1 indicates water constrained

We reviewed the WRI reports, but were unable to determine how ARB used the information in these reports to identify the regions and AEZs that should have irrigated land constrained. Because we have been unable to locate the technical documentation that would explain how ARB used the WRI reports to draw the conclusions shown in Figure 1, we request that the staff provide the public with that documentation, and then allow at least five business days for comment.

ARB presented little information at the workshop to evaluate the size of this impact on land use emissions. To evaluate the impact of constraining expansion on irrigated land, AIR ran GTAP with and without the irrigation constraint for corn ethanol, using Purdue and ARB's average elasticity inputs. The results are shown in Table 1.

[20] *Aqueduct Global Maps 2.1: Constructing Decision-Relevant Global Water Risk Indictors*, WRI, April 2014.

[21] *A Weighted Aggregation of Spatially Distinct Hyrdrological Indicators*, WRI, December 2013.

Table 1. LUC Impact of Constraining Crop Expansion on Irrigated Land in Some Areas: Corn Ethanol					
Scenario	Ydel	PAEL	ETA	Irrigation Constrained?	LUC (gCO2e/MJ)
Purdue Best Estimates	0.25	0.4/0.2	Baseline	No	14.23
				Yes	13.32
ARB Average	0.19	0.3/0.15	Baseline	No	17.22
				Yes	16.09

For corn ethanol, constraining expansion on irrigated land adds 0.89 g/MJ for the Purdue default case, and by 1.13 g/MJ for the ARB average. ARB must document how the WRI data was used to develop areas on which cropland cannot be expanded, before including this effect for the various biofuel feedstocks.

LCFS 46-98 cont.

Land Supply Structure

The land supply structure in GTAP was revised in 2013 to include four nesting structures instead of two.[22] Prior to 2013, one nest included the substitution of different types of land – forestland, cropland, and pastureland – and a second nest under cropland that included different types of crops. One elasticity – ETL1 – governed the substitution between forestland, cropland, and pastureland, and a second elasticity – ETL2 – governed the substitution between crop types. A significant concern of ARB's Expert Working Group (EWG) was that forestland, cropland, and pastureland were all in the same nest with one elasticity, which meant that forestland is as readily converted to cropland (and vice versa) as pastureland. Clearly this is not the case – the economics of converting forest to crops must be much different than converting pasture to crops.

In 2013, the land supply structure was modified by Purdue such that the first nest includes only forestland and a second category called cropland+pasture. The second nest under cropland+pasture was divided into cropland and pastureland. The third nest under cropland was divided into irrigated and rain-fed. Finally, both irrigated and rain-fed cropland was divided into different crops. The following new elasticities were defined:

LCFS 46-99 cont.

- ETL11: substitution at the first level between forest and cropland+pasture
- ETL12: substitution at the second level between cropland and pasture
- ETL2: substitution between irrigated and rain-fed
- ETL4: substitution between crops under irrigated land
- ETL5: substitution between crops under rain-fed land

The new land supply structure allows the use of more disaggregated elasticities of transformation between land types.

ARB modeled two approaches in estimating land use emissions – Approach A, which assumes ETL11=ETL12, and Approach B, which provides separate estimates for ETL11

[22] See reference 13.

and ETL12. Approach A is essentially the GTAP model prior to the land supply improvements (i.e., only 1 elasticity which governs conversion of forest, crop, and pasture), while Approach B is the GTAP model with the improvements (expanded nesting supply structure). Elasticity values for Approaches A and B are shown in Attachment 1. In both approaches, the ETL2 values are identical; it is only the ETL11 and ETL12 values that are different between the approaches.

ARB did not implement Approach B in its materials presented at the March 11, 2014 workshop, in spite of the fact that GTAP was updated for land supply structure more than a year ago in January 2013. One of Growth Energy's primary comments on the materials ARB supplied at the March 11 workshop was that ARB should utilize a GTAP model with the updated land supply structure with different elasticities of conversion for forest and pasture. (i.e., Approach B). Approach A must be recognized as unrealistic, and not appropriate for use in the new regulation to set the indirect emissions factor for land use change attributed to biofuel expansion. Approach A is *not* an equally technically appropriate alternative to Approach B. Purdue no longer utilizes Approach A – it is simply now an approach that tries to mimic the old GTAP model prior to the significant improvements made in early 2013. LCFS 46-99 cont.

ETL11, ETL12, ET4, ETL5

ARB's ETL11, ETL12, ETL4, and ETL5 values for Approach B were presented in Slide 24 of the September 29 presentation. Based on the information that is currently available, we believe those values are more appropriate than some alternatives. LCFS 46-100

ARB's 30-Scenario Average LUC Emissions

In the March 11 workshop, ARB modeled 1440 separate scenarios for each biofuel, and averaged the results of these scenarios to estimate LUC for each biofuels. In the September 29 workshop, Staff had reduced this to 30 separate GTAP runs, varying 3 separate input elasticities: the yield price elasticity (YPE, or Ydel), the cropland pasture elasticity (PAEL) for the US and Brazil, and the elasticity of crop yields with respect to area expansion (ETA). There are five values for Ydel, 2 for PAEL, and 3 for ETA (5*3*2 = 30). LCFS 46-101

Growth Energy has commented previously that the number of runs should be reduced (and they have), and further support doing GTAP runs at varying elasticities, since these can affect the results. (See Attachment 2.) However, we believe that ARB has selected the wrong range of values to use for two of the input elasticities.

It is worth noting that Purdue has "best estimates" for each of these inputs. The ARB input values and Purdue best estimates are shown in Table 2.

Table 2. ARB Input Elasticities Compared to Purdue Best Estimates				
Parameter	Description	ARB Values	ARB Average Value	Purdue Best Estimate
YPE	Yield Price Elasticity	0.05, 0.125, 0.175, 0.25, 0.35	0.19	0.25
PAEL	Cropland pasture elasticity*	0.2/0.1, 0.4/0.2	0.3/0.15	0.4/0.2
ETA**	Elasticity of crop yields with respect to area expansion	Baseline, 80% of baseline, 120% of baseline	Baseline	Baseline

*The first value is for the US, the second for Brazil
** ETA varies by region. The baseline values used by ARB are the same as used by Purdue

For YPE, the ARB range is from 0.05 to 0.35, with an average value of 0.19. The range in the March 11 workshop was from 0.05 to 0.30, so ARB has increased the upper end of this range by 0.05. The average value is lower than the Purdue best estimate of 0.25, and lower values yield to higher land use emissions. For PAEL, ARB selected the ARB best estimate and an estimate one-half of that. The average of the two ETA values for Brazil and the US is lower than the Purdue best estimate. Again, lower values lead to higher land use emissions. Finally for ETA, ARB selected the Purdue best estimate as the central value, and values higher and low than the best estimate. The average of the three is at the Purdue best estimate. LCFS 46-101 cont.

For PAEL, ARB seems to have followed the methodology of selecting values higher than and lower than the Purdue best estimate. This approach makes sense to us. However, for YPE and ETA, ARB selected values rather arbitrarily that yield an average value that is significantly different than the Purdue best estimate. ARB has not presented reasons or a rationale why it did this, so it appears they did this for the sole purpose of increasing the land use emissions of crop-based biofuels. We therefore ask that ARB explain those reasons to the public and allow at least five business days for comment. Because ARB must use the best available scientific information when writing its greenhouse gas regulations, we believe that ARB needs to explain why, if it maintains the current approach, it believes that its approach is scientifically superior and uses the best available scientific data.

We present the impacts of this arbitrary decision making process later in these comments.

<u>Yield Price Elasticity (YPE, also Ydel)</u>

In our comments on the previous workshop, we indicated that GTAP is a medium term model, and that YPE values developed over the very short term were not appropriate -- as previously noted, ARB is required to use the best available scientific information under the 2006 law that applies here. The values below 0.15 referenced by ARB were short- LCFS 46-102 term values, therefore, ARB should not be using values below 0.15 (i.e., 0.05 and 0.125), as they are not consistent with GTAP's general timeframe.

In addition, in our previous comments we presented information showing that Purdue's best estimate value of 0.25 does not include double-cropping, conversion of fallow land to cropland in the US, Canada and the EU27 regions, and conversion of Conservation Reserve Program (CRP) land in the United States.[23] We presented significant, substantial and compelling evidence on the conversion of fallow land and CRP land in those comments. CRP land is in the GTAP land supplies and could be utilized directly. We pointed out that both double cropping and fallow land conversion could be simulated with higher Ydel values (i.e., values above 0.25).

LCFS 46-102 cont.

As indicated in the previous section, ARB used two values below 0.15 – 0.05 and 0.15. We believe these should be dropped from the Ydel analysis since they are not consistent with GTAP. Second, we believe ARB should expand the upper limit of Ydel to 0.50. The values we are recommending are 0.15, 0.2, 0.25 (Purdue best estimate), 0.3, and 0.5. The average of these values is 0.28, which is only 0.03 above the Purdue best estimate, and a reasonable conservative average to reflect a small amount of double cropping and/or fallow land conversion. If the staff does not agree, we ask that it explain why in a manner that we and other interested parties can address in a timely manner, and that the staff can consider before it proposes the new regulation.

Cropland Pasture Elasticity (PAEL)

ARB used the Purdue best estimate (0.4/0.2) and one-half of the best estimate (0.2/0.1). There is no information given on why ARB used one-half of the Purdue best estimate without also using something above the Purdue best estimate, for example, 0.6/0.3. The purpose of sensitivity analysis is determine how the model inputs affect the results. Using a sensitivity analysis on only the "low" side of the Purdue best estimate skews the land use values higher, and is not consistent with scientific norms or the requirement to use the best available scientific information. We recommend running three PAEL values, where one is the Purdue best estimate and the other two are higher and lower than the Purdue best estimate. If the staff does not agree with that recommendation, we ask that it fully explain why it is not doing so, in time for the public to comment

LCFS 46-103

Corn Ethanol LUC Impacts of our Recommendations for Elasticity Inputs

The time allowed by the staff to prepare these comments did not permit us to run all of CARB's 30 cases to establish a baseline, but instead, we ran the average of the elasticity inputs, and the high and low. Results are shown in Table 3 compared to ARB's results of

LCFS 46-104

[23] Double cropping refers to the practice of growing two crops on the same land in the same season. For example, often corn or soybeans are grown after winter wheat on the same land in the US. In Brazil, because the growing season is longer, often corn is grown after soybeans. The Conservation Reserve Program is a cost-share and rental payment program under the United States Department of Agriculture (USDA), and is administered by the USDA Farm Service Agency (FSA). The CRP encourages farmers to convert erodible cropland or other environmentally sensitive acreage to vegetative cover.

the 30 runs. As shown in Table 3, values generated by us are lower than ARB's values. The reasons for this are not clear. Our program files have been provided to the staff for these cases for review. For now, we have also constrained expansion on irrigated land, even though we have not had a chance to review the method ARB used to incorporate data and information from the two WRI reports.

Table 3. ARB Average, Low and High LUC Emissions for Corn Ethanol (Approach B with Irrigation Constrained)

Case	Ydel	PAEL	ETA	AIR LUC gCO2e/MJ	ARB LUC gCO2e/MJ
Average of ARB Inputs	0.19	0.3/0.15	Baseline	17.22	21.6
ARB "High"	0.05	0.2/0.1	80% of Baseline	34.49	37.0
ARB "Low"	0.35	0.4/0.2	120% of Baseline	9.68	11.5

Basically, we are recommending that ARB use the Purdue best estimates for elasticity inputs, except for Ydel, which we believe should average about 0.28 or so to reflect some double-cropping which typically takes place in Brazil and also in the US and other areas, and also conversion of some fallow land in the US, Canada, and the EU27, at a minimum. We have estimated emissions by utilizing average input parameters, instead of making 45 runs; but acknowledge that it would be more precise to perform the 45 runs and determine average emissions, since some of the effects are likely not to be linear.[24] Results are shown in Table 4.

LCFS 46-104 cont.

Table 4. ARB Average and Recommended Values for Corn Ethanol (Approach B with Irrigation Constrained)

Case	Ydel	PAEL	ETA	LUC (gCO2e/MJ)
Average of ARB Inputs	0.19	0.3/0.15	Baseline	17.22
Purdue Best Estimate	0.25	0.4/0.2	Baseline	14.23
AIR Recommended*	0.28	0.4/0.2	Baseline	13.23

* We recommend performing the 45 runs and determining the average emissions, which may differ from 13.23 g/MJ.

The LUC with the Purdue best estimate inputs is 14.23 gCO2e/MJ. Our recommendation results in LUC emissions of 13.23 gCO2e/MJ, based on these inputs. Here again, we would like to know if the staff agrees with this recommendation, and, if not, we request an explanation why it does not agree in time for us to provide further input, that the staff can consider as it develops the new regulatory proposal.

[24] 45 = 5 Ydel values (0.15, 0.2, 0.25, 0.3, 0.5), 3 PAEL values (0.2/0.1, 0.4/0.2, 0.6/0.3), and 3 ETA values (baseline, 80%, 120%).

Attachment 3

Comments on November 20 ARB iLUC Workshop
Air Improvement Resource, Inc.
December 4, 2014

Introduction

On November 20 ARB held a third workshop on indirect land use (iLUC) emissions of various biofuels. New land use emission values were presented by the Staff. A summary of the emissions for corn ethanol from the different workshops is shown in Table 1. The emissions of corn ethanol dropped slightly from 21.6 g/MJ to 20 g/MJ.

Table 1. Corn Ethanol iLUC Values (gCO2e/MJ)

Biofuel	Current Regulation	March 2014	September 2014, Approach B	November 2014, Approach B
Corn Ethanol	30.0	23.2	21.6	20.0

Very little new information was presented at this workshop. One decision that ARB made was to use GTAP "Approach B" in estimating land use emissions. Putting to the side numerous other issues related to the iLUC analysis being undertaken by the Staff and stakeholders, the use of "Approach B" is an improvement worthy of support, because it makes the GTAP model ARB is using consistent with the GTAP model developed by Purdue that is described in detail in the January 2013 Applied Science report by Purdue.[25] This approach uses separate elasticities of transformation of Forest-to-Crops and Pasture-to-Crops. LCFS 46-105

ARB made some changes in the AEZ-EF model, but as of November 30 has not released the AEZ-EF model for review and comment. As a consequence, we cannot comment on this model until it is provided for review. In order to permit effective participation in the rulemaking, ARB should make the model fully available without further delay. Waiting until the 45-day process is not appropriate given the complexity and importance of the issues that the AEZ-EF model is supposed to address.

ARB's price-yield elasticity range stayed the same as the previous workshop. According to ARB, this decision was based on a study by UC Davis. However, the UC Davis study was also not made available, so it is impossible to comment on that decision. ARB should provide public access to the relevant study and supporting materials without further delay. Consequently, our comments on price-yield remain the same as they before, i.e., that ARB should disregard th`e two lowest price-yield LCFS 46-106

[25] See reference 13.

elasticities it is currently using, and use somewhat higher price-yield elasticities, so that the average price-yield elasticity is around 0.28 or 0.30, in order to reflect multiple cropping in some countries. Our previous comments on the September 29 workshop that discuss price-yield in more detail are included as Attachment 1 to this document. LCFS 46-106 cont.

This document summarizes our further comments on the workshop and ARB's current land use estimates. It is important to note at the outset that shortly before the workshop, a significant report on using recent land use change data to validate land use change models was released by Iowa State University.[26] The study has important implications for ARB's current land use emission estimates, and thus, important implications for the overall lifecycle emissions of various biofuels as compared to petroleum-derived fuels. In response to a question from a workshop participant, ARB indicated that they had a copy of this study and were reviewing it. We believe that the Staff should address the new study in the ISOR and provide it to the peer reviewers who will be engaged to examine iLUC issues. The ISU report's findings must be used by ARB in conjunction with ARB's GTAP modeling to derive new and updated land use emission estimates for the various biofuels prior to proposing re-adoption of the Low Carbon Fuel Standard (LCFS). Failure to do this would mean that ARB would not be using the latest and best available scientific and economic information to develop its lifecycle emissions for biofuels, which we understand to be required by the governing statute, A.B 32. LCFS 46-107

Our comments are organized in the following sections:

- Summary of the Babcock/Iqbal study
- Impacts on ARB's iLUC estimates for corn ethanol
- Other Comments

<u>Summary of Babcock/Iqbal Study</u>

The study developed new methods of using existing land cover data to evaluate the extent of land transitions in the time period between 2004-2006 and 2012-2014, the time period of fairly rapid expansion of biofuel in the US. These were compared to both the FAPRI and GTAP model estimates. In short, the paper concludes that the models used by EPA and ARB significantly overestimate pasture and forest conversions to crops in many parts of the world (including the US), because they do not include land "intensification", which includes increased double-cropping, reduced fallow land, and reduced land that is planted but not harvested (in other words, increasing the harvested to planted ratio). The authors purposely did not consider crop yield improvements, which is another form of intensification and, which if also included, would further reduce iLUC GHG estimates. [27] LCFS 46-108

[26] See reference 5.

[27] Land "extensification" means conversion of forest and pasture to cropland, whereas "intensification means making existing land (cropland and idle or fallow land) more productive.

The paper first summarizes annual inflation-adjusted price changes in a number of crops from 1965 to 2012, and shows that prices of a number of key crops increased for a number of years from 2004-2012. The paper cites another study by Babcock and others that opines that about one-third of the corn price increase during this time period was due to the biofuel mandate (RFS), other factors such as crop shortfalls and other sources of increased demand account for the rest of the price increase. The reason for showing these price trends was that "the magnitude of these real price increases after such a prolonged and sustained period of flat or falling prices presents a unique opportunity to quantify how world agriculture responds to incentives to produce more." The paper goes on to state that "because indirect land use is a response to higher market prices, model predictions of land use change should be similar whether the higher prices came from increased biofuel production, increased world demand for beef, or from drought that decreased supply. This implies that the pattern of actual land use changes that we have seen since the mid-2000s should be useful to determine the reliability and accuracy of model that have been used to measure indirect land use."

The study then examines changes in "harvested land" between the two periods. The source of this information is the Statistics Division of the Food and Agriculture Organization of the United Nations (FAOSTAT).[28] These data have been widely used to measure the impact of biofuel production on expansion of land used in agriculture and to calibrate the land cover change parameter in the GTAP model used by ARB. [29,30] But the study points out that harvested land is not equal to planted land, and that harvested land will deviate from planted land "when a portion of planted land is not harvested, and when a portion of land is double or triple- cropped." The study examines data from specific countries, and shows that existing land intensification has accounted for 76% of the increase in production in Brazil, and nearly all of the increase in production in India and China.

LCFS 46-108 cont.

An alternative measure of land use is developed, which is the change in FAO's arable land plus permanent crops. Figure 8, which plots the changes in this metric from 2004-2006 to 2012-2014 from the report, is shown below. The report states: "The countries in Figure 8 that either had negligible or negative extensive land use changes should be presumed to not have converted pasture or forest to crops in response to biofuel-induced higher prices. Rather, the presumption should be that any predicted change in land used in agriculture came from cropland that did not go out of production." The regions in Figure 8 with negligible or negative extensive land use changes are: Rest of Asia, the European Union, Canada, Russia, Oceania, China, South Africa, India, Central and Caribbean America, Bangladesh, Japan, Rest

---

[28] http://faostat3.fao.org/home/E

[29] Roberts and Schlenker, "Identifying Supply and Demand Elasticities of Agriculture Commodities: Implications for the US Ethanol Mandate", American Economic Review 103(6): 2265-95

[30] See footnote 1.

of East Asia, Other Europe and Remainder of Former Soviet Union, Ukraine, and the US.

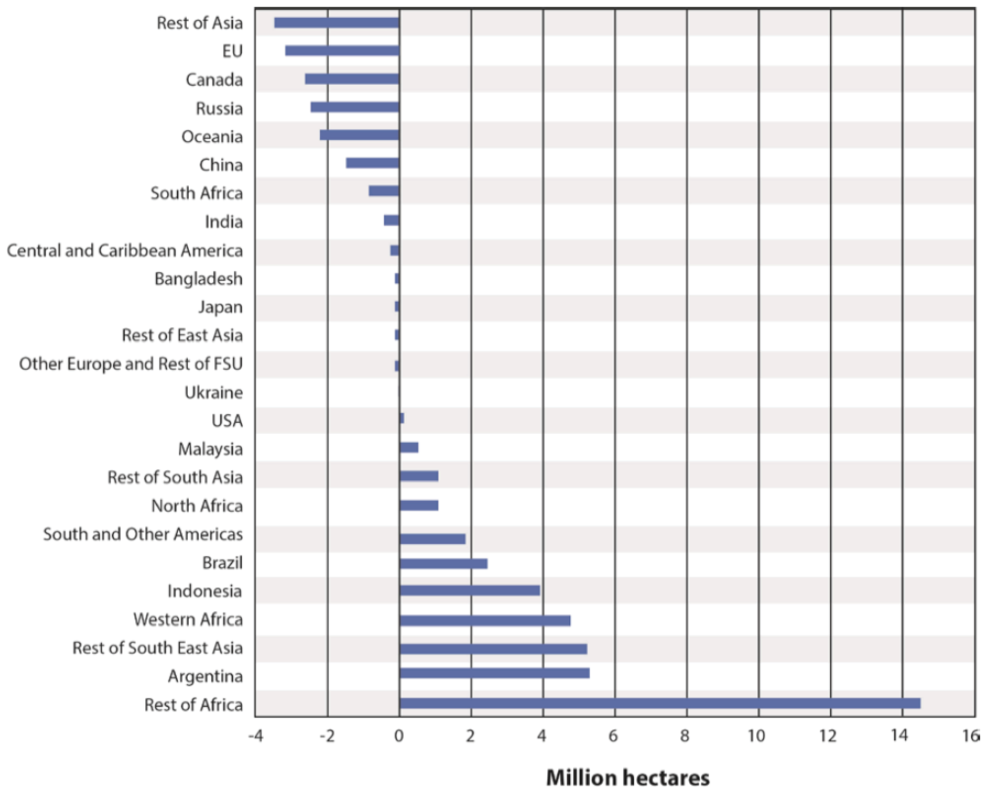


Figure 8. Change in Arable Land Plus Permanent Crops: 2004–2006 to 2010–2012

Figure 8 does show that Western Africa, and the "Rest of Africa", have significant extensive changes in arable land plus permanent crops (see Attachment 2 for countries included in the Africa regions of Figure 8). However, the study indicates that "the extent to which extensive expansion in African countries was caused by high world prices is small for the simple reason that higher world prices were not transmitted to growers in many African countries. Babcock and Iqbal cite a number of studies to support this conclusion.

LCFS 46-108 cont.

Impacts of Babcock/Iqbal Study on ARB's ILUC Estimates for Corn Ethanol

As indicated earlier, we do not have ARB's most recent AEZ-EF model so we cannot replicate ARB's 20 g/MJ value for corn ethanol (the 20 g/MJ value is an average based on 30 individual runs of the GTAP model, coupled with the AEZ-EF model). We can, however, use GTAP runs with the ARB GTAP model and AEZ-EF model ARB released as a part of the September 29th workshop to develop an estimate of the impact of Babcock/Iqbal's recommendations.

The primary conclusion from the Babcock/Iqbal study is that there are regions/countries of the world that had negative or negligible extensive land use changes between 2004-2006 and 2012-2014, and these countries and regions should be presumed not to have any forest or pasture conversion to cropland in response to biofuel expansion. The countries and regions in this category were listed earlier. Other countries not on this list can still be presumed to have some extensive land use conversions (i.e., conversion of forest and pasture to crops). Thus, the Babcock/Iqbal study can be used as a filter on the existing GTAP results.

Table 2 shows our GTAP modeling from our comments on the September 29 workshop (found in Table 4 of that report). We show the iLUC for 3 cases:

LCFS 46-108 cont.

- Average of ARB inputs
- Purdue best estimate
- AIR recommended inputs

Table 2. ARB Average and Recommended Values (Approach B with Irrigation Constrained) for Corn Ethanol

Case	Ydel	PAEL	ETA	AIR Estimated LUC gCO2e/MJ
Average of ARB Inputs	0.19	0.3/0.15	Baseline	17.22
Purdue Best Estimate	0.25	0.4/0.2	Baseline	14.23
AIR Recommended*	0.28	0.4/0.2	Baseline	13.23

The case with the "Average of ARB Inputs" is 17.22 gCO2e/MJ. This is less than ARB obtained with its average of the 30 scenario runs (21.6 gCO2e/MJ), but nonetheless, we can use this case to estimate the impacts of applying the country/region filter from the Babcock/Iqbal analysis.

Table 3 shows emissions from land transitions for the ARB average case. As shown in the table, Forest-to Crop transitions comprise 60% of emissions, and Pasture-to-Crop transitions comprise 21% of emissions.

Table 3. Land Transition Emissions for the ARB Average Case	
Land Transition	ARB Average, Megagrams CO2e
Forest-to-Crop	305,579,609
Pasture-to-Crop	109,196,645
Cropland-pasture to Crop	114,309,541
Crop-to-Forest	0
Crop-to-Pasture	0
Crop-to-Cropland pasture	0
Pasture-to-Forest	-20,801,279
Forest-to-Pasture	124,717
Total	508,409,234

The breakdown of Forest-to-Crop and Pasture-to-Crop emissions by GTAP region for the ARB average case are shown in Table 4. We have not shown areas with less than 1% contribution. We also have bolded the regions that Babcock/Iqbal indicate would not have Forest-to-Cropland or Pasture-to-Cropland transitions. (Our mapping of the Babcock/Iqbal regions which come from FAOSTAT, to the GTAP regions is shown in Attachment 3.)

LCFS 46-108 cont.

We have shaded the sub-Sahara region[31] for several reasons – (1) GTAP predicts it is the largest contributor to emissions for the corn-ethanol expansion, (2) the Babcock/Iqbal analysis shows that the country of South Africa, part of sub-Sahara Africa, should not have forest to crop and pasture to crop transitions, and (3) we are not sure how to separate South Africa from the sub-Sahara region in GTAP, and (4) the Babcock/Iqbal report also indicates that the expansion of cropland from forest and pasture in many African countries is not price-induced.

Thus, on one hand, Babcock/Iqbal are making the case that the extensive land changes in Africa are not price driven, and therefore, not related to biofuel expansion, and so in one case the sub-Saharan region can be omitted from the corn ethanol emissions analysis. On the other hand, if these countries are included in the emissions analysis because they do have extensive land use changes, the emissions will be over-predicted because of our current inability to remove South Africa from the sub-Saharan region. Nonetheless, we will estimate iLUC emissions for these two cases – one without sub-Sahara Africa, and one with.

[31] The sub-Sahara region in GTAP includes Botswana, South Africa, Rest of South African Customs Union, Malawi, Mozambique, Tanzania, Zambia, Zimbabwe, Rest of South African Development Community, Madagascar, Uganda, and rest of sub-Saharan Africa.

Table 4. Regional Forest-Crop Plus Pasture-Crop Transition Emissions for ARB Average		
Region	Megagrams	Percent of Total Forest-to-Crop and Pasture-to-Crop Emissions
USA	**43,316,687**	**10%**
EU27	**15,681,094**	**4%**
Brazil	56,258,521	14%
Canada	**14,911,705**	**4%**
Japan	**3,745,849**	**1%**
China + Hong Kong	**16,121,420**	**4%**
India	**7,732,753**	**2%**
South America (w/o Brazil)	14,930,904	4%
Rest of Southeast Asia	13,248,332	3%
Rest of South Asia	5,810,952	1%
Other CEE_CIS	**7,867,793**	**2%**
Mideast North Africa	**2,629,014**	**1%**
Sub-Sahara Africa	**204,901,423**	**49%**
Oceania	2,628,749	1%

LCFS 46-108 cont.

The results of our analysis of iLUC emissions for the ARB average case, with and without sub-Sahara Africa being included with the other areas without Forest-to-Crop and Pasture-to-Crop transitions, is shown in Table 5. Application of the Babcock/Iqbal analysis reduces iLUC emissions between 21% and 65%, depending on the treatment of emissions in sub-Sahara Africa. The range for corn ethanol for the Purdue Best Estimate (input elasticities) is between 5 and 11 g CO2e/MJ, far lower than ARB's current 20 g CO2e/MJ estimate.

Table 5. Impacts of the Babcock/Iqbal Filter on GTAP Results (g/CO2e/MJ)		
Scenario	ARB Average	Purdue Best Estimate
No Filter (from Table 2)	17.2	14.2
Filter without sub-Sahara impacts	13.3 (-21%)	10.9 (-22%)
Filter with sub-Sahara impacts	6.1 (-64%)	5.0 (-65%)

ARB should revise its iLUC emissions for various biofuels to account for the Babcock/Iqbal analysis. The reasons why emissions are lower with application of their analysis are not new – they are related to multiple cropping in certain regions, the use of idle or fallow land, and the improvement in harvested versus planted land, which are all related to higher prices for commodities. None of these items is currently included in the GTAP model that ARB is using. LCFS 46-108 cont.

Other Comments on the Workshop

Price-Yield Elasticity

As indicated earlier, ARB has stated its intent to use its current price elasticity range, with an average elasticity of 0.19. The Purdue estimate is 0.25, and it does not account for double-cropping or other intensification measures used by the agriculture industry. We have been recommending a price-yield elasticity range of 0.2-0.5, with an average of 0.28, slightly higher than the Purdue best estimate, to account for some multiple cropping. After reviewing the Babcock/Iqbal analysis, we think the best way to account for multiple cropping in the short term is by applying the Babcock/Iqbal filter. Therefore, if ARB were to utilize the Babcock/Iqbal filter on its results, the price-yield range should be modified to have an average of 0.25 at the Purdue best estimate. We do not support ARB's current range, because the lower end of the range is based on very short-term price-yield studies, and GTAP is a medium to long-term model. LCFS 46-109

Conservation Reserve Program Land (CRP) in the US

We have submitted comments showing that a large amount of ex-CRP land appears to have come into production in the US in the last 7 years (see page 5 in Attachment 3).[32] The GTAP model is capable of accessing this land, but in the ARB version of the model the option to access this land within GTAP has been turned off. It is very straightforward to turn this option on. The Babcock/Iqbal study also identifies ex-CRP land as a factor in confirming that there has been no forest or pasture transformations to cropland in the US (see pages 29-30 of the study). Implementation of the CRP land option in GTAP reduces emissions for the ARB average case from 17.22 gCO2/MJ to 16.35 g CO2e/MJ. LCFS 46-110

If ARB decides to use the Babcock/Iqbal study as a filter to determine regions with forest to crop and pasture to crop transitions, then there is no need to modify GTAP to access CRP lands. However, if ARB decides not to use the Babcock/Iqbal study as a filter, then the GTAP modeling used by ARB should allow the model to access CRP land, because that is what has already happened.

Cropland/Pasture Elasticity (PAEL)

In its modeling scenarios, ARB is only examining cropland/pasture elasticity values of 0.2/0.1 (US/Brazil) and 0.4/0.2. The 0.4/0.2 levels are Purdue's default or best LCFS 46-111

[32] "Comments on ARB's March 11 Workshop on The Low Carbon Fuel Standard, Air Improvement Resource Inc., April 6, 2014 (provided in Attachment 4).

estimate. So, ARB is examining the Purdue best estimate and one-half that level (lower levels increase the iLUC emissions).

We indicated in our comments on the September 29 workshop and also in the November 20 workshop, that ARB should estimate emissions for three PAEL levels for the US and Brazil. Two of the levels are the same as the ARB's current levels, the third one is 0.6/0.3. ARB had previously planned on using the 0.6/0.3 values. In response to our question as to why PAEL levels of 0.6/0.3 were dropped from the analysis, ARB indicated that there was a problem with the run, and promised further information on this. To date, we have not seen that information.

LCFS 46-111 cont.

We therefore ran the 0.6/0.3 case using the ARB average price yield elasticity of 0.19 and the baseline ETA value. We encountered no problems with the run, and obtained emissions of 15.55 gCO_2e/MJ (as compared to 17.22 g/MJ for the ARB average case using PAEL levels of 0.3/0.15). We therefore recommend that ARB re-instate the 0.6/0.3 PAEL case in its scenario runs, or explain in detail what its concerns are with this case.

Longer-Term Items

ARB appears to have only 4 items on its agenda for longer-term study (see page 29 of the November 20 workshop handout):

- Address forestry issue in the model
- Account for fertilizer, livestock, and paddy rice emissions
- Include analysis for cellulosic feedstocks
- Develop and validate dynamic GTAP model

Notably absent from this list are all the items which Babcock/Iqbal identify as primary drivers of less Forest-to-Crop and Pasture-to-Crop transitions (and thus the overall iLUC emissions of biofuels) in many regions of the world, such as (1) multiple cropping (double- and even triple-cropping), (2) use of temporary fallow/idle land, (3) less land that is planted and not harvested, and (4) the use of CRP land in the US. In addition, stakeholders reviewing ARB's iLUC estimates have made numerous comments about multiple cropping, the use of CRP, idle land, etc. Many of these items were identified 4-5 years ago by various stakeholders. None should be deferred from action in the current rulemaking, if ARB's intent is to use the best available scientific information and analysis, as A.B. 32 requires.

LCFS 46-112

The amount of temporary or fallow land can actually be computed from the GTAP land cover. In GTAP there are two layers of information on cropland; land cover and harvested area. Any land which has been cultivated in the past is included in the cropland category under the land cover header. This category of land includes all types of cropland (cultivated and idled land such as planted but not harvested, cropland-pasture, CRP, or fallow). The cropland area is generally not divided into different types (except partially

LCFS 46-113

for the US and Brazil). The second layer is harvested area. Harvested area refers to the cropland that is harvested in the base year (i.e. 2004). LCFS 46-113 cont.

The version of GTAP used by CARB has cropland-pasture for the US and Brazil and CRP area for the United States added to the harvested land layer. The model does not allow conversion of CRP land to crop production (the model keeps it under the conservation program). However, cropland-pasture which is used for grassing tasks can be converted back to crop production. Cropland-pasture in the other regions of the world and fallow land (either deliberately not planted or having a harvest failure) are not included in the harvested land layer. The model currently has no capability of accessing this land for increased crop production even though it is probably the most likely land to respond to higher crop demand and is land that could be brought into production without any land use change. LCFS 46-114

In some areas of the world two or more crops can be harvested from the same land in a given year. In these areas, the harvested land may be greater than the cropland area. While some regions may have both fallow land and double-cropped land from this data we can only show the net fallow land (i.e., net cropland not in crops) and the net double-cropped land. A summary of these lands by model region is shown in Table 6.[33]

[33] Darlington, Kahlbaum, O'Connor, and Mueller, "Land Use Change Greenhouse Gas Emissions of European Biofuel Policies Utilizing the Global Trade Analysis Project Model, August 30,2013.

Table 6. GTAP Land Summary (Ha)				
GTAP Region	Cropland	Harvested Area	Net Cropland Not in Crops	Net Double-Cropped
USA	175,807,007	167,059,000	8,748,007	
EU27	124,830,687	115,729,000	9,101,687	
BRAZIL	60,724,257	86,403,000		-25,678,743
CAN	39,573,515	33,514,000	6,059,515	
JAPAN	3,680,435	4,185,000		-504,565
CHIHKG	140,644,611	160,840,000		-20,195,389
INDIA	171,418,998	186,799,000		-15,380,002
C_C_Amer	56,671,461	26,687,000	29,984,461	
S_o_Amer	58,603,527	56,585,000	2,018,527	
E_Asia	5,190,174	4,852,000	338,174	
Mala_Indo	71,571,068	35,999,000	35,572,068	
R_SE_Asia	53,207,433	60,163,000		-6,955,567
R_S_Asia	46,956,517	43,712,000	3,244,517	
Russia	124,542,334	81,229,000	43,313,334	
Oth_CEE_CIS	111,522,274	94,998,000	16,524,274	
Oth_Europe	933,565	1,160,000		-226,435
MEAS_NAfr	53,633,308	49,933,000	3,700,308	
S_S_AFR	211,016,073	175,792,000	35,224,073	
Oceania	33957545	42,181,000		-8,223,455
Total	1,544,484,789	1,427,818,000	193,828,945	-77,164,156

In addition, ARB currently assumes that cropland-pasture that is converted to cropland experiences 50% of the emissions of conversion of permanent pasture. This is strictly an assumption. Purdue currently estimates conversion of cropland-pasture has the same emissions as crop-to-crop conversions. This should also be a focus of future research.

LCFS 46-114 cont.

46_OP_LCFS_GE Responses (Page 55 – 90)

409. Comment: **LCFS 46-78**

The comment contends that the iLUC value for corn ethanol is too high.

Agency Response: ARB staff does not agree with comment that the iLUC value for corn ethanol is too high. The current iLUC values were estimated for all 6 biofuels after the consideration of the best available data and science. (See ISOR and ISOR App. I.) Furthermore, by not accounting for additional emissions from the increased use of fertilizers, staff believes that our approach potentially presents a conservative estimate for iLUC for all the 6 biofuels. See response to **LCFS 8-1**.

Regarding fuel shuffling, see response to **LCFS 46-40**.

410. Comment: **LCFS 46-79**

The comment argues that ARB staff should reevaluate their method for including price-yield values in estimating the iLUC emissions of corn ethanol.

1. Agency Response: The approach used by staff to include a range of YPE values between 0.05 and 0.35 is justified. Justification for this approach is provided in response to **LCFS 8-9**.

2. Notwithstanding the conclusion by Dr. Rocke that the data provided by Juan Francisco Rosas Perez did not support the 0.29 value for YPE, ARB considered this value in the range of YPE values used in the current analysis. This was to account for a range of likely values for YPE based on different published studies (list provided in Appendix I, Attachment 1of the ISOR).

3. The commenter's dismissal of Prof. Rocke's statistical analysis as "sketchy" without further explanation is not a convincing reason for ARB to re-calculate the YPE value.

4. Justification for using the entire range of YPE values has been provided in response **LCFS 8-9**. ARB therefore, does not concur with commenter's suggestion to eliminate the lowest two price-yield values and adjust iLUC values accordingly.

See also response to **LCFS 46-86**.

411. Comment: **LCFS 46-80**

The comment recommends using their suggested values and additional modifications in the GTAP model, to account for multiple cropping.

Agency Response: The methods offered by the commenter to 'adjust' model outputs to reflect effects of double cropping are arbitrary. The GTAP model is a complicated economic model that includes interactions of various sectors in the global economy. Every parameter and input value has the potential to have significant impacts on outputs, many of which may not be substantiated by 'realistic' model behavior. The suggestions offered by the commenter do not conform to accepted principles and procedures used by GTAP modelers in instituting methodologies in such complex general equilibrium models. See responses to **LCFS 8-3**, **LCFS 8-5**, **LCFS 8-9**, and **LCFS 8-10**.

412. Comment: **LCFS 46-81**

The comment makes recommendations for updates to the GTAP model to include the effects of Conservation Reserve Program land.

Agency Response: ARB staff recognizes that Conservation Reserve Program (CRP) land is included in the current GTAP model as an option for future analysis. See response to **LCFS 46-110**.

413. Comment: **LCFS 46-82**

The comment states that the GTAP model does not consider reductions from reduced livestock herds and rice cultivation.

Agency Response: An initial review of fertilizer, livestock, and paddy rice emissions revealed that these impacts could increase iLUC emissions could be higher by up to 10 g/MJ. There was, however, an inconsistency between the approaches used to estimate direct (CA-GREET model) and indirect emissions (GTAP/AEZ-EF models) related to fertilizer, livestock and paddy rice emissions. To eliminate the possibility of double counting such emissions, ARB staff has not yet included these emissions in the present analysis. In the future, when appropriate adjustments can be made to avoid double counting, emissions from these sources will be included.

414. Comment: **LCFS 46-83**

The comment expresses concern that the GTAP model has shortcomings which will affect land use practices.

Agency Response: The GTAP 2004, base data used by ARB, contains all production and economic activities occurring for that year. The claim that idle/fallow land should be accessed by the GTAP land pool is questionable. Stakeholders have not shown any evidence that the trends for fallow or idle land practices have been altered noticeably in recent years. There are reasons why idle/fallow land has remained idle or fallow for many years, perhaps due to lower productivity; degraded soil; salinization; and lack of access to capital, irrigation, or infrastructure.

415. Comment: **LCFS 46-84**

The comment indicates that the GTAP model should include the cropland-pasture land use category.

Agency Response: After review of available data, Purdue and ARB staff updated the GTAP model to include the cropland/pasture land category in the U.S. and Brazil. Since no such data are available for other regions, this category of land cover was not included in the GTAP model for the remaining 17 regions. If data becomes available to inform staff that this land category is active in other regions, appropriate elements could be used to update the model at a future date.

416. Comment: **LCFS 46-85**

The comment argues that the AEZ-EF model is not superior to the CCLUB model.

Agency Response: The AEZ-EF model is a peer-reviewed carbon emissions model that uses the best available science, data, and methodology to estimate carbon release (or sequester) when land is converted from one use to another. CCLUB has numerous problematic assumptions and due to the reasons detailed in **LCFS 46-16**, inconsistencies arise when elements of the CCLUB model are integrated into the GTAP model. Therefore, the potential impacts as presented by the commenter cannot be compared to the iLUC analysis presented by ARB staff.

417. Comment: **LCFS 46-86**

The comment expresses concern about the GTAP model. It goes on to disagree with the low price-yield elasticity range chosen by ARB.

Agency Response: There is no discussion of Yield Price Elasticity (YPE) in Ray and Foley and they have no recommendation in this regard. From this paper, it cannot be concluded that YPE, as a result of multiple cropping, should increase. In fact, Ray and Foley argue that in some cases multiple cropping may lead to lower YPE in the long run. They argue:

> "While increasing the cropland harvesting frequency can, in the short run, increase the net annual production of agricultural crops per hectare of land, it can also lead to the long-term deterioration of soil, water resources, and the agricultural land base itself."[24]

With regard to the commenter's concerns with the GTAP model and the YPE value chosen by ARB staff, see responses to **LCFS 8-2, LCFS 8-3, LCFS 8-5, LCFS 8-9, LCFS 8-10, and 46-9**.

418. Comment: **LCFS 46-87**

The comment seeks an explanation on why ARB staff chose ETL1 and ETL2 values, and what is the basis for choosing them.

Agency Response: The differences in the land transformation elasticities (including ETL1 and ETL2) used by ARB staff and those that appear in the Applied Sciences paper are related to updates in the Applied Sciences paper that was done for the ARB. Taheripour and Tyner developed the elasticity values used in the current analysis. For ARB staff's analysis, Taheripour corrected shortcomings of the Applied Sciences paper where the older model produced results such as reforestation in places where reforestation did not occur.

419. Comment: **LCFS 46-88**

The comment recommends updates for the GTAP.

Agency Response: The Expert Working Group (EWG) recommended "separating the CET nest of forestland from the one

[24] Deepak K Ray and Jonathan A Foley 2013 Increasing global crop harvest frequency: recent trends and future directions *Environ. Res. Lett.* **8** 044041, (Page 6)

for pasture and cropland" and ARB staff has updated the model transformation tree structure accordingly. In the new model tree structure, forestland is in one category and cropland and pasture land in another as recommended by the EWG. Furthermore, cropland is divided into two subcategories of irrigated and rain-fed land, each of which has its own crop categories.

420. Comment: **LCFS 46-89**

The comment recommends that ARB staff include cropland/pasture land use category in the GTAP model.

Agency Response: See response to **LCFS 46-84**.

421. Comment: **LCFS 46-90**

The comment recommends that the GTAP model should be run to access CRP land in the US before converting forests or pastured to cropland.

Agency Response: See response to **LCFS 46-110**.

422. Comment: **LCFS 46-91**

The comment states that AEZ-EF model should include carbon stocks for only accessible forests.

Agency Response: It is true that the carbon data used in the AEZ-EF model includes both accessible and inaccessible forests, and this is broader than those represented in GTAP-BIO model. This would tend to underestimate emissions slightly. The main reason for this is that the GTAP data offer only hectares of managed/accessible forest, not locations, and ARB staff do not have any spatial data distinguishing these. Since the carbon stocks are produced based on spatial data, staff would need to know which areas to include or exclude in our analysis. Also, if GTAP were modified to allow conversion of natural forests, staff would want to assign distinct emission factors to the different forest conversions. Since it does not allow this, all conversion of forest is accompanied by a reduction in timber supply, which incentivizes afforestation elsewhere.

423. Comment: **LCFS 46-92**

The comment recommends that ARB staff account for wood biomass used for fuel during forest clearing as it replaces fossil fuels.

Agency Response: ARB staff does not believe that it is appropriate to account for CO_2 credits from hardwood products (HWP) biomass use since it is our understanding that most of the waste wood is used to produce energy that is used in the processing of the wood itself. Therefore, if the wood weren't harvested, no fossil energy would be needed to be replaced by biomass energy.

In principle, the quantity of biomass energy that displaces fossil energy of the system boundaries should be accounted for. The question isn't answered by looking at the quantity of waste wood combusted for energy; the analysis must determine how much of this energy displaces specific fossil fuels so that the carbon offset can be calculated.

424. Comment: **LCFS 46-93**

The comment recommends that ARB staff use the CCLUB model.

Agency Response: See response to **LCFS 46-16**.

425. Comment: **LCFS 46-94**

The commenter provides quantitative information for the estimated impact of iLUC emissions of corn ethanol if three parameters are changed as discussed previously.

Agency Response: The commenter is providing a quantitative assessment of the impact of changing three parameters; ARB's ETL1 and ETL2 values, the model nesting structure, and the price yield value. As clarified in responses to comments **LCFS 8-9**, **LCFS 46-86**, **LCFS 46-90**, **LCFS 46-92**, and **LCFS 46-110**, ARB staff does not agree with the rationale for the changes. Also, staff notes that the commenter references results and analysis based on an outdated 2013 version of the model. ARB staff has modified the 2013 GTAP model and a new version used to perform the staff's analysis is available to the public. The ETL1 and ETL2 values and the model nesting structures have been changed to reflect the latest Purdue University work. The Ray and Foley study cited does not include any recommendation for changing YPE in the model. For responses to additional comments, see the table below.

Comment	Response
Accounting for CO_2 credits from forest wood	**LCFS 46-92**
Price-Yield Range	**LCFS 8-9** and **LCFS 46-86**
CRP land conversions	**LCFS 46-90** and **LCFS 46-110**

426. Comment: **LCFS 46-95**

The comment states that the use of CI “bins” would severely limit continued innovation in biofuel facilities. The comment also states that the application processes for biofuel facilities should be streamlined and there should be no limits to the number of pathways a facility can apply for.

Agency Response: Staff notes that this comment is counter to their claims (in comment LCFS **46-37**) that past CI improvements due to the LCFS from corn ethanol facilities have not occurred and have all been merely “paperwork exercises”. This commenter goes on to state that significant future optimization opportunities and declines in CIs from corn-starch ethanol is unlikely (see comment **LCFS 46-43**). These prior comments are directly at odds with the request in this comment for continued continuity along the dimension of CI in the program, rather than creation of CI bins, to allow for “*continued* innovation*”* [emphasis added] to be recognized.

Staff agrees that continued innovation and incremental CI reduction is possible from corn ethanol as well as in the lifecycle of other low carbon fuels. Based on this belief, and feedback staff received from the commenter and other stakeholders, staff rejected the proposed bin concept. The bin method was replaced with the two-tiered framework approach described in the Initial Statement of Reasons.

With respect to concerns about limits on the number of pathways a facility can apply for, Staff’s proposal does not include such a limitation.

427. Comment: **LCFS 46-96**

The comment contends that the bin method is problematic no matter how it is designed.

Agency Response: See response to **LCFS 46-95.**

428. Comment: **LCFS 46-97**

The comment contends that the bin method is inconsistent with the proposed method for refineries.

Agency Response: See response to **LCFS 46-95**.

429. Comment: **LCFS 46-98**

The comment requests clarification on how ARB identifies areas with constrained irrigation.

Agency Response: ARB staff utilized two reports developed by the World Resources Institute (WRI) used to generate criteria for water constraints in the GTAP model available at: http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm . Using these reports, WRI generated a matrix of regions/AEZ which identified water-stressed regions/AEZ combinations. The methodology used was discussed in a workshop on September 29, 2014, and the information posted to the LCFS website on December 31, 2014.

The commenter did not provide details of parameter values and modeling constraints used in their analysis and therefore, ARB staff cannot determine the validity of the results shown in Table 1 of the comment and staff cannot comment on the differences detailed between unconstrained and constrained irrigation as presented. However, a review indicates that the results appear to be influenced by Ydel (interchangeably used as YPE), Cropland Pasture Elasticity (PAEL), and elasticity of crop yields with respect to area expansion (ETA) parameters. Discussion on YPE, PAEL, and ETA can be found in Appendix I of the ISOR. Details of identifying water constrained regions is provided in the two reports cited above.

430. Comment: **LCFS 46-99**

The comment requests justification for why ARB staff did not update land supply structure and different land transformation elasticities for forest and pasture, as directed by the commenter.

Agency Response: The document was prepared by the commenter in response to an ARB staff analysis presented in March 2014, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB addresses the comments as follows:

Since the comments are related to an older version of GTAP that is not used in the current analysis, they are irrelevant because the current analysis uses the approach in line with the commenter.

431. Comment: **LCFS 46-100**

The comment recommends that ARB use their recommended land conversion elasticity values.

Agency Response: The document was prepared by commenter in response to ARB analysis presented in March 2014, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

The values used in ARB staff's current analysis correspond to the values suggested by the commenter.

432. Comment: **LCFS 46-101**

The comment seeks justification for values chosen by ARB staff, for yield price elasticity (YPE) and yield elasticity with respect to crop area expansion (ETA).

Agency Response: ARB staff's approach is based on a comprehensive review of literature and a detailed analysis of available studies. ARB staff has used the best scientific approach for YPE. To specifically address YPE, see response to **LCFS 8-9**.

ETA values used by ARB staff are based on the best analysis of productivity of new cropland. Baseline values for ETA, which represents productivity of new cropland relative to existing cropland, were developed by Purdue researchers for each region and AEZ using data from the TEM model. The scenario approach was used to account for the likelihood of variability in values of the critical parameters in the GTAP model. For YPE, published data allowed staff to consider a range between 0.05 and 0.35 (see discussion above). For ETA, however, lack of published data required ARB staff to use values that were 120 percent and 80 percent of baseline as the best estimate to account for variability in ETA.

433. Comment: **LCFS 46-102**

The comment recommends lower values for the yield price elasticity range used by ARB staff. The comment goes on to direct staff to justify their choice.

Agency Response: YPE values used in ARB staff's analysis represent the likely range of values for this parameter and therefore are appropriate. Justification for the selection of the YPE values is provided in responses to **LCFS 8-1**, **LCFS 8-3**, **LCFS 8-5, LCFS 8-9**, **LCFS 46-15**, **LCFS 46-81**, **LCFS 46-83**, and **LCFS 46-86**.

434. Comment: **LCFS 46-103**

The comment recommends running three PAEL values for a sensitivity analysis. The commenter directs ARB staff to justify their choice.

Agency Response: See response to **LCFS 38-33**.

435. Comment: **LCFS 46-104**

The comment recommends a set of values for Ydel, PAEL, and ETA which results in the commenter's preferred iLUC value for corn ethanol. The commenter directs ARB staff to justify their decision.

Agency Response: ARB staff does not agree with the approach suggested by the commenter to use an average of input parameter elasticities to estimate iLUC emissions which is then compared to the average of the 30 scenario runs used in the current analysis. For a given set of elasticities for the three parameters (YPE, ETA, and PAEL), the GTAP output represents a unique solution utilizing complex interactions between various sectors, regions, resources, etc. ARB staff's approach uses 30 different sets of input elasticities (for the three parameters identified above) and uses an average of these runs to estimate iLUC emissions for a biofuel. The average iLUC value estimated by ARB staff is not likely to be the same as the iLUC value estimated by using a single set of elasticity values representing the average of the range used by ARB. This is because the interactions between the various elements within the model are different for each set of input values and is unlikely to be linear. Therefore, values presented in Tables 3 and 4 representing the outputs from 'average' inputs cannot be compared meaningfully to the significantly more rigorous average of the 30 scenario runs. In addition, it is unclear to ARB staff why the commenter refers to 45 runs when the initial comments refer to the 30 scenario runs used in the current analysis. To address the commenter's recommendation to use a value for YPE of 0.28, see responses to **LCFS 8-3**, **LCFS 8-5, LCFS 8-9**, **LCFS 46-15**, and **LCFS 46-101** for ARB staff's justification for YPE values used in the current analysis.

436. Comment: **LCFS 46-105**

The comment lends support to the adoption of Approach B in GTAP modeling by ARB.

Agency Response: ARB staff acknowledges the commenter's support for using Approach B for the current analysis. Staff does not agree with commenter that 'very little new information' was provided at the November 20 workshop. ARB staff provided the following:

- Updates to the AEZ-EF model;
- Indicated that the land transformation parameter would use Approach B;
- Detailed the iLUC value for palm biodiesel; and
- Complete details of the 30 scenario runs that were used to estimate iLUC analysis for the six biofuels.

437. Comment: **LCFS 46-106**

The comment requests that the two lowest price yield values be eliminated.

Agency Response: Justification for using the entire range of YPE values has been provided in response **LCFS 8-9**. ARB staff, therefore, does not concur with the commenter's suggestion to eliminate the lowest two price-yield values and adjust iLUC values accordingly.

See response to **LCFS 46-12** for a discussion of the inclusion of the UC Davis study. See also responses to **LCFS 46-79** and **LCFS 46-86**.

438. Comment: **LCFS 46-107**

The comment requests ARB staff to consider the recent findings in an Iowa State University report on iLUC emissions of biofuels.

Agency Response: See responses to **LCFS 8-3** and **LCFS 8-5**.

439. Comment: **LCFS 46-108**

The comment argues that increases in biofuel crop prices in response to increased biofuel demand do not translate into extensive land conversion. Hence the commenter directs ARB staff to revise its iLUC values for biofuels based on the Babcock and Iqbal analysis.

Agency Response: ARB staff does not agree with the comment that current analysis significantly overestimates pasture and forestland conversion. The database used in the GTAP model includes double cropping data for appropriate regions of the world where double cropping was practiced. Therefore, outputs from the model implicitly include impacts from double cropping though staff does not explicitly disaggregate contributions from such effects. A preliminary review of U.S. agricultural data has concluded that double cropping is small and not expected to contribute significantly to 'intensification effects' as mentioned in the Babcock paper. As for other regions of the world, significant work has to be completed to collect and disaggregate data to provide accurate information on double cropping across the world. Beyond using a baseline that includes double cropping, there is no good methodological approach that would allow model adjustments to account for the evaluation of double cropping. For this, land in different locations needs to be separated into double-cropped vs. non-double cropped land and such data are not currently available. When detailed data becomes available, staff will consider updates to the modeling structure to explicitly account for double cropping in the analysis. It should also be noted that double cropping benefits are offset by increased use of fertilizers and pesticides and these impacts also need to be accounted in the analysis (not included in the current analysis).

ARB staff does not agree with commenter that land conversion as a result of market response to higher prices should be similar for any sector. Land cover changes resulting from increased biofuel production, increased consumption of beef, and decreased supply from drought could be directionally similar but are not expected to be the same for every location/region. The work by Babcock/Iqbal uses the totality of the effect of all factors in the global marketplace to support their conclusions. For ARB's work, however, staff is estimating land cover changes resulting only from the increased production of biofuels, and the results are not expected to mirror the changes from all sectors and all other events in the world.

The GTAP base data used by ARB staff contains all production and economic activities occurring for that year. The claim that idle/fallow land should be accessed by the GTAP land pool is questionable. Stakeholders have not shown any evidence that the trends for fallow or idle land practices have been altered noticeably in recent years especially during the period 2004-2010. There are reasons why idle/fallow land has remained idle or fallow for many years, perhaps due to lower productivity; degraded soil; salinization; and lack of access to capital, irrigation, or infrastructure. Staff will evaluate this land type in its parts, for agronomic and economic viability, yield potential and soil emission estimates, and whether marginal change in land use for this land type occurred since 2004, and will adjust the effects for each AEZ/region together with the resultant changes in yield, agricultural inputs and other relevant factors.

Harvested-to-planted ratio varies from year to year by crop, region, and AEZ. There is no detailed data available for all crops by region and AEZ. When detailed data becomes available, ARB staff will evaluate the potential to include this in the GTAP modeling framework.

ARB staff has not completed a detailed review of the studies provided to support the conclusion that higher world prices are not transmitted to growers in many African countries. It is expected that since the products studied are international commodities, prices will be affected across all markets. As part of the work to consider the inclusion of food security and prices in the iLUC analysis[25], ARB staff reviewed several studies and reports that concluded the biofuel expansion in developed countries was a factor in price increases leading to increased starvation and poverty in developing countries, including African countries. Different conclusions on this issue by various authors and reports led to ARB staff's decision to defer the inclusion of food versus fuel for the current proposal. When additional reports and data become available and a comprehensive analysis has been completed, ARB staff will evaluate the impacts in the future.

The analysis, results, and comparison presented are not relevant since it does not use the current version of the GTAP-AEZ-EF models. For comments related to the inclusion of several issues considered in the Babcock/Iqbal analysis, see responses to **LCFS T25-4**, **LCFS 46-83**, **LCFS 46-102**, **LCFS 46-107**, **LCFS 46-110**, **LCFS 46-113**, **LCFS 8-3**, **LCFS 8-5**, and **LCFS 8-6**.

[25] Since the analysis was not completed at the time of publishing the ISOR, no detailed analysis was available for publication.

440. Comment: **LCFS 46-109**

The comment alleges ARB staff's price yield elasticity values primarily are based on short-term price yield studies.

Agency Response: See response to **LCFS 46-101** and **LCFS 46-102**.

441. Comment: **LCFS 46-110**

The comment suggests ARB staff should run the GTAP model by turning on the option to access CRP land.

Agency Response: ARB staff does not agree with the comment that inclusion of CRP land will necessarily reduce iLUC emissions. Inclusion of a new land cover in the GTAP requires detailed economic data for the conversion to cropland. It also requires information about carbon stock and dynamics to model carbon emissions released when such land is converted to cropland. ARB staff recognizes that CRP land is included in the current GTAP model as an option for future analysis. However, for a type of land to be considered in the GTAP model, a set of data for each region is needed to make that land a viable part of the model's economic decision-making. Unfortunately, detailed data (by AEZ) required to model the economics of conversion and attendant carbon release is currently not available for CRP land. When data for CRP land conversion combined with the economics of conversion are available, ARB staff will include this land cover into the analysis. Also, associated emission factors disaggregated spatially will be included when such data becomes available.

Regarding the comment related to the Babcock study see response to **LCFS 8-5**.

See also responses to **LCFS 46-15**, **LCFS 46-90** and **LCFS 46-118**.

442. Comment: **LCFS 46-111**

The comment recommends that ARB run the GTAP model with higher PAEL.

Agency Response: See responses to **LCFS 38-33** and **LCFS 46-103**.

443. Comment: **LCFS 46-112**

The comment suggests that ARB staff's agenda for longer-term study is limited and should include more items.

Agency Response: The iLUC analysis as currently proposed by ARB staff is based on the latest and best available scientific and economic information. Staff continues to develop greater refinements such that the remaining items to be address represent a smaller and smaller impact.

ARB staff acknowledges that double cropping or multiple cropping is practiced in some regions of the world, but detailed data by region, AEZ, and crop are not available at the present time for inclusion in the analysis. For CRP land and fallow land, detailed economic data and carbon emissions data by region and AEZ are not available. As data becomes available for these topics, staff will consider including them into the modeling framework. See also responses to **LCFS 46-81**, **LCFS 46-108**, **LCFS 46-90**, **LCFS 46-110**, **LCFS 8-5**, and **LCFS 8-10**.

444. Comment: **LCFS 46-113**

The comment points out that the size of temporary or fallow land for biofuel production can be derived from the GTAP land cover.

Agency Response: ARB staff does not agree with the commenter that the amount of temporary or fallow land can be computed from the GTAP land cover data. It is true that the GTAP landcover includes harvested area and total cropland area. Total cropland area includes harvested area, CRP (for U.S. only), planted but not harvested area, land fallowed, etc. It does not disaggregate the amount of fallow land.

The claim that idle/fallow land should be accessed by the GTAP land pool is questionable. Stakeholders have not provided clear evidence that the trends for fallow or idle land practices have been altered noticeably in recent years. There are reasons why idle/fallow land has remained idle or fallow for many years, perhaps due to lower productivity; degraded soil; salinization; and lack of access to capital, irrigation, or infrastructure. When detailed data become available, ARB staff will evaluate this land type for agronomic and economic viability, yield potential and soil emissions estimates, and will consider the inclusion of fallow land into the modeling framework. See also responses to **LCFS 8-5**,

LCFS 46-81, **LCFS 46-83**, **LCFS 46-90**, **LCFS 46-102**, **LCFS 46-110**, and **LCFS 46-114**.

445. Comment: **LCFS 46-114**

The comment suggests that several areas which the commenter wishes to be investigated as part of ARB's future study.

Agency Response: To specifically address comment related to CRP land, see response to **LCFS 46-110**.

After review of available data, Purdue and ARB staff updated the GTAP model to include cropland/pasture land category in the U.S. and Brazil. Since no such data are available for other regions, this category of land cover was not included in the GTAP model for the remaining 17 regions. If data becomes available to inform that this land category is active in other regions, appropriate elements could be used to update the model at a future date. The same approach will be considered for fallow land for which data are currently not available.

The GTAP model uses harvested area to estimate additional land requirements and the base data in 2004 implicitly includes double-cropping information. Therefore, outputs from the model implicitly include impacts from double cropping though ARB staff does not explicitly disaggregate contributions from such effects. Staff recognizes that there are regions in the world which use double cropping. However, significant work has to be completed to collect and disaggregate data to provide accurate information on double cropping for all crops by region and AEZ and to integrate it into the GTAP framework. When detailed data becomes available, staff will consider updates to the modeling structure to explicitly account for double cropping in the analysis. It should also be noted that double cropping benefits are offset by increased use of fertilizers and pesticides and these impacts also need to be accounted in the analysis (not included in the current analysis). The same approach will be considered for fallow land for which data are currently not available.

Cropland pasture refers to land that was previously in cropping but has been fallowed in the recent past. The actual land-use history of the converted cropland-pasture strongly determines conversion emissions: land recently in crops will have very low emissions, while lands taken out of crop production long ago will have high emissions. Since there is no detailed data available for land-use history and corresponding carbon stock in cropland pasture for the

U.S. and Brazil, ARB staff assumed that emissions from conversion of this land cover type are 50 percent of emissions from conversion of pasture. When detailed data becomes available, ARB staff will evaluate carbon emissions from cropland pasture and consider updating the current methodology.

See also responses to **LCFS 8-5**, **LCFS 8-10**, **LCFS 46-81**, **LCFS 46-83**, **LCFS 46-90**, and **LCFS 46-102**.

This page intentionally left blank.

46_OP_LCFS_GE

17_OP_ADF_GE

Appendix B

Comments on the CA-GREET 2.0 Model
February 10, 2014

ARB staff released a draft report comparing GREET1.8b, GREET12013, and CA-GREET 2.0 on October 10. In addition, staff released the GREET 2.0 model for comment. AIR has reviewed some aspects of this model, and offers comments in the following areas:

- GREET2014
- Denaturant Modifications for Ethanol
- DGS Reduced Enteric Emissions Credit

In addition to the above, Professors Bruce Dale and Seungdo Kim reviewed the agricultural chemical and ethanol plant chemical emissions for both corn and cellulose ethanol. Their comments are included in Attachment 1 to this document.

Our combined reviews indicate that ARB has overestimated the direct emissions of both corn ethanol and ethanol made from stover. The implications of overestimating the lifecycle emissions for corn and stover ethanol are that it could lead to shuffling of fuels without any reduction in greenhouse gases and increased costs of compliance with the LCFS. LCFS 46-115

GREET2014

The CA-GREET 2.0 model is based on the GREET1-2013 model from Argonne. GREET2014 was released by Argonne on October 3, 2014. ARB should examine GREET2014 to determine improvements that should be made to CA-GREET 2.0. LCFS 46-116

Denaturant Modifications for Ethanol

The amount of denaturant assumed in CA-GREET1.8b was 2.0%. However, in CA-GREET-2.0 the amount of non-ethanol material in ethanol was increased to 5.4%. The 5.4% is assumed to be 2.4% denaturant, at most 1 percent water, at most 0.5 percent methanol, and at most 1.4 percent "other." The 2.9% combination of water, methanol, and "other", is assumed to have the same carbon intensity of CARBOB, so the net effect of this assumption is the same as assuming 5.4% CARBOB in ethanol. The CI of CARBOB is higher than most ethanol pathways, so increasing the denaturant from 2% to 5.4% in effect raises the CI of ethanol (and doubles the denaturant effect). LCFS 46-117

It is very clear that water does not have the CI of CARBOB. It is also highly unlikely that methanol and "other", whatever the other is, would have the same CI as CARBOB. AIR believes increasing the denaturant to 5.4% is a mistake that unfairly penalizes ethanol. AIR recommends that the denaturant percentage be set to 2.4% in CA-GREET 2.0. LCFS 46-117 cont.

DGS Reduced Enteric Emissions Credit

GREET2013 contains a distiller grains (DGs) credit for the coproduct due to reduced enteric fermentation from livestock from feeding with DGs. Staff is proposing no DGs reduced enteric emissions credit "due to the feeding of animals not being considered in the LCFS pathway LCA system boundary." Staff goes on to say that "...including the feeding of animals in the LCA would require significant analysis and would not only include the enteric emissions or change thereof from business as usual, e.g., other emissions would need to be considered and feed markets would need to be analyzed and updated."

Staff's arguments for not including the enteric emissions credit due to feeding of DGs are weak. First, Staff expands the system boundaries in arbitrary ways already. The Staff has included indirect land use system emissions (iLUC), which cannot be measured, and can only be estimated with a combination of economic modeling and estimates of the carbon released during specific land use changes (i.e., the emission factors of each land use change). Staff has spent a great deal of time and effort on this indirect effect. So, other indirect effects such as reduced enteric fermentation should also be included in Staff's analysis. Second, Argonne has already estimated this effect, and has included it in GREET1-2013. LCFS 46-118

Staff has no specific criticisms of the effect as estimated in GREET1-2013. Staff say, however, that the primary driver of reduced enteric emissions are shortened lifespan of livestock. Staff is concerned that if feeding DGs increases livestock throughput, then enteric emissions could increase. They also cite studies that show feeding defatted DGs compared to grain feeding causes an increase in N2O emissions from finishing beef cattle, which could reduce the enteric credit.

We recommend that Staff include the DG enteric credit in CA-GREET2.0. It is already included in GREET2013. If Staff have concerns with the effect, then they should develop a better estimate of the effect after finalizing CA-GREET2.0 with the current effect, in much the same way as Staff adopted an iLUC effect in 2009 and have spent some effort in the last 1.5 years attempting to improve it.

We note that there is another very significant effect of enteric fermentation. The economic models show that increasing biofuels requires additional cropland, and much additional cropland comes from pasture and cropland/pasture. This raises livestock prices, thereby reducing total livestock herds and total enteric fermentation emissions. The EPA included this effect in the RFS four years ago. We have repeatedly commented to ARB that the Staff should include this effect as well in its analysis, and Staff has pushed this off to the future. Clearly, there are very significant effects of biofuels on enteric fermentation emissions in two areas – the LCFS 46-119

DGs effect and the price effect – and ARB has ignored these effects in this analysis. These are very serious shortcomings in the current ARB analysis. LCFS 46-119 cont.

Additional Comments by Bruce Dale and Seungdo Kim

Attachment 1 contains additional comments by Ca-GREET2.0 by Kim/Dale. These comments cover a number of items for both corn ethanol and ethanol made from corn stover.

Table 1 summarizes the Kim/Dale comments and their impacts on CaGREET emissions for both corn ethanol and corn stover.

Table 1. Impacts of the Kim/Dale Recommendations on CaGREET Corn Ethanol and Stover Ethanol Emissions		
Corrections	Corn dry mill pathway [gCO_2/MJ]	Corn stover pathway [gCO_2/MJ]
Current fertilizer rates	-0.67	
1.2. CO_2 emissions from limestone	-0.83 ~ -2.18	
1.3. Nutrient contents in fertilizers	-0.06	-0.05
1.5. Soil N_2O emissions from corn stover in corn ethanol	-0.21	
1.6. Supplement nutrients in corn stover ethanol		-7.98
2.2. Lifecycle GHG emissions of sulfuric acid	-0.47	-0.92
2.3. Cellulase enzyme loading in corn stover ethanol		-1.32 ~ -1.79
2.4. Marginal electricity in corn stover ethanol		-8.07
Total	-2.24 ~ -3.59	-26.4~ -26.9

Attachment 1

Review of lifecycle GHG calculations for corn ethanol and corn stover ethanol in the

CA-GREET2.0 model

November 6, 2014

Bruce E. Dale and Seungdo Kim

Department of Chemical Engineering and Materials Science

Michigan State University

3815 Technology Boulevard, Lansing, MI 48910

The authors reviewed farming nutrient emission rates and the emission rates of chemicals used in corn ethanol production in the CA-GREET 2.0 model. We have a number of comments, which are detailed in this document.

The table below summarizes the emission impacts of our comments.

Summary of suggested numerical corrections to the CARB values

Corrections	Corn dry mill pathway [gCO_2/MJ]	Corn wet mill pathway [gCO_2/MJ]	Corn stover pathway [gCO_2/MJ]
1.1. Current fertilizer rates	-0.67	-0.66	
1.2. CO_2 emissions from limestone	-0.83 ~ -2.18	-0.82 ~ -2.14	
1.3. Nutrient contents in fertilizers	-0.06	-0.06	-0.05
1.5. Soil N_2O emissions from corn stover in corn ethanol	-0.21	-0.21	
1.6. Supplement nutrients in corn stover ethanol			-7.98
2.2. Lifecycle GHG emissions of sulfuric acid	-0.47	-0.46	-0.92
2.3. Cellulase enzyme loading in corn stover ethanol			-1.32 ~ -1.79
2.4. Marginal electricity in corn stover ethanol			-8.07
Total	-2.24 ~ -3.59	-2.22 ~ -3.57	-26.4~ -26.9

Our comments are presented in the next two sections. The first section details comments on agricultural chemicals, and the second section deals with chemicals used in corn ethanol plants.

1. Feedstock production (corn grain and corn stover)

1.1. Fertilizer rates in corn grain production

The fertilizer application rates per bushel of corn in the CA-GREET2.0 model (in cells: Inputs!F281:F283) do not reflect the current corn culture practices in the US. LCFS 46-120

The CA-GREET2.0 supporting document provides a reference[1] for the fertilizer application rates given in the CA-GREET2.0 model. These values are probably based on available data up to 2005. Unfortunately, the timeframe for the fertilizer application rates was not clearly stated in the reference so we are unable to determine how these California values were generated. Furthermore, newer fertilizer application rates for corn culture practices in 2010 are available and should be used in preference to any earlier values. Thus in this report we have used USDA statistics[2] to estimate the US average 2010 fertilizer application rates per bushel of corn—the most recent time period available. These USDA data are summarized in Table 1. The fertilizer rates in the NASS (USDA study) are slightly lower than those in the CA-GREET2.0 model due to higher corn yields. The NASS fertilizer application rates are 4 – 20% less than the rates in the CA-GREET2.0 model.

LCFS 46-120 cont.

Table 1 Fertilizer application rate per bushel of corn produced [2]

	NASS¶	CA-GREET2.0 (in cells: Inputs!F281:F283)
N (gram per bushel)	400.84	415.33
P_2O_5 (gram per bushel)	138.42	147.77
K_2O (gram per bushel)	143.36	172.11

Fertilizer consumption to produce corn silage is excluded from these data.

[1] Wang, Michael Q., Jeongwoo Han, Zia Haq, Wallace E. Tyner, May Wu, and Amgad Elgowainy. "Energy and greenhouse gas emission effects of corn and cellulosic ethanol with technology improvements and land use changes." Biomass and Bioenergy 35, no. 5 (2011): 1885-1896
[2] National Agricultural Statistics Service. http://www.nass.usda.gov/

Using the current fertilizer application rates per bushel of corn from the NASS data summarized in Table 1 reduces the GHG of corn ethanol by 0.67 (0.66) g/MJ in the dry (wet) mill pathway. The detailed calculations are as follows:

The calculations are done in the CA-GREET2.0 spreadsheet model. Replace the fertilizer rates in the CA-GREET2.0 model (in cells: Inputs!F281:F283) by the NASS values in Table 1. Results are summarized in Table 2.

Table 2 Calculations for fertilizer application rates

	Rates from NASS	CA-GREET2.0
GHG associated with fertilizers [gram/MJ] (EtOH!D429)	14.28	14.81
N_2O emissions [gram/MJ] (EtOH!E429)	14.93	15.32
GHG credit of co-products [gram/MJ] (EtOH!G429)	13.21	13.47
GHG of corn ethanol [gram/MJ] (EtOH!Y429)	76.11	76.78

LCFS 46-120 cont.

The USDA/NASS statistics[2] also show that fertilizer application rates per bushel (i.e., N, P_2O_5, K_2O applied per bushel of corn produced) have been steadily declining with time. (See Figure 1) Even though total amount of fertilizer applied nationally has increased, the application rate per bushel has actually declined due to higher corn yields. Assuming the trends summarized in Figure 1 have continued, even less total fertilizer use per bushel of corn produced is projected after 2010.

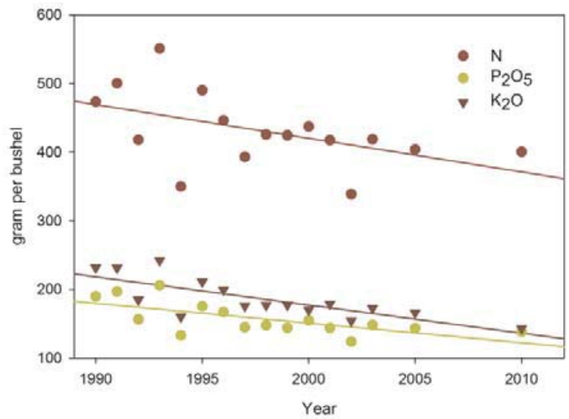


Figure 1 Fertilizer application rates in the US [data source: NASS[2]]

LCFS 46-120 cont.

1.2. CO_2 emissions from limestone

Limestone ($CaCO_3$) is the primary agricultural lime used in the US in 2011[3], accounting for about 93% of the total lime applied. The rest is dolomite ($MgCa(CO_3)_2$). The CA-GREET2.0 model incorrectly assumes that 100% of the carbon in limestone that is applied to soil is released to the air as carbon dioxide and fails to account for various soil, water and atmospheric processes that are very relevant. In contrast, a USDA report[4] based on actual, physical processes occurring in soil, water and the atmosphere finds that two-thirds of the carbon in limestone remains in long-term carbon sinks and only one-third of the carbon in limestone is actually released as carbon dioxide.

LCFS 46-121

[3] United States Environmental Protection Agency (2013) U.S. greenhouse gas inventory report: Inventory of U.S. greenhouse gas emissions and sinks: 1990-2011. United States Environmental Protection Agency, Washington, DC.

[4] USDA (2014) Quantifying Greenhouse Gas Fluxes in Agriculture and Forestry: Methods for Entity-Scale Inventory. , Washington, DC.

For example, dissolved CO_2 resulting from root and microbial respiration exists in equilibrium in soil water with H_2CO_3. This slightly acidic H_2CO_3 reacts with limestone[5] as described below in Equations (1) and (2).

$CO_2 + H_2O \rightarrow H_2CO_3$

(1)

$CaCO_3 + H_2CO_3 \rightarrow Ca^{2+} + 2HCO_3^-$

(2)

Dissolved HCO_3^- is stable and is transported to the ocean by rivers and streams. In the ocean, this carbon is sequestered for time periods of decades to centuries[4].

In a separate study, West and McBride[6] also estimate the carbon dioxide emission factors for limestone applied by accounting for leaching and transport by rivers to the ocean. The carbon dioxide emission factors for limestone applied to agricultural land given in their study are 0.059 kg C/kg limestone applied for limestone and 0.064 kg C/kg dolomite applied for dolomite. These are the emission values currently used in the U.S. National GHG Inventory[3]. However, they do not include the entire range of biophysical processes covered by the USDA report[4].

CA-GREET2.0 should use the most comprehensive, scientifically-valid calculations available to estimate the GHG emissions of agricultural lime application. We believe

LCFS 46-121 cont.

[5] Hamilton, Stephen K., et al. "Evidence for carbon sequestration by agricultural liming." Global Biogeochemical Cycles 21: 1 - 12 (2007).
[6] West TO, McBride AC (2005) The contribution of agricultural lime to carbon dioxide emissions in the United States: dissolution, transport, and net emissions. Agr Ecosyst Environ 108:145–154

those are the values given by the USDA report[4]. The carbon dioxide emission factors for agricultural limestone applied are summarized in Table 3 below.

Table 3 Carbon dioxide emission factors for agricultural limestone application

	Carbon dioxide emission from Limestone [kg CO_2/kg]
CA-GREET2.0	0.44
USDA[4]	-0.15
GREET2014[7] & West and McBride[6]	0.216

LCFS 46-121 cont.

Using the carbon dioxide emission factors from the USDA process-based report[4] and the GREET2014 model[7] reduces the GHG of corn ethanol by 0.83 and 2.18 (0.82 and 2.14) g/MJ in the dry (wet) mill pathway, respectively. The detailed calculations are as follows:

Replace the carbon dioxide emission factors in the CA-GREET2.0 model (in cells: EtOH!F380, 44/100) by the factors in Table 3. Results are summarized in Table 4.

Table 4 Calculations for lime application

	Factor from USDA report[4]	Factor from GREET2014[7]	CA-GREET2.0
CO_2 from $CaCO_3$ use [gram/bushel] (EtOH!F380)	-169	249	506

[7] Argonne National Laboratory (2014) Greenhouse gases, regulated emissions, and energy use in transportation (GREET) computer model 2014.

GHG associated with fertilizers [gram/MJ] (EtOH!D429)	11.81	13.66	14.81	LCFS 46-121 cont.
GHG credit of co-products [gram/MJ] (EtOH!G429)	12.66	13.16	13.47	
GHG of corn ethanol [gram/MJ] (EtOH!Y429)	74.60	75.94	76.78	

1.3. Nutrient contents in N and P_2O_5 fertilizers

The CA-GREET2.0 model assumes that N fertilizer consists of ammonia, urea, ammonium nitrate, urea-ammonium nitrate solution, mono-ammonium phosphate, and di-ammonium phosphate, and P fertilizer consists of mono-ammonium phosphate, and di-ammonium phosphate as summarized in Table 5. However, the nutrient contents in some of these fertilizers are not given correctly in the CA-GREET2.0 model. The nitrogen content in di-ammonium phosphates is 18%[8], not 16% as given in the CA-GREET2.0 model. The P_2O_5 contents in mono- and di-ammonium phosphates are 48 -61% (the most common value is 52%) and 46%[8], respectively.

LCFS 46-122

Table 5 Fraction and nutrient content of N and P_2O_5 fertilizers in CA-GREET2.0 [basis: N for N fertilizer, P_2O_5 for P fertilizer]

N fertilizer	Ammonia	Urea	Ammonium Nitrate	Urea-Ammonium Nitrate Solution	Mono-ammonium Phosphate	Di-ammonium Phosphate
Fraction	0.31	0.23	0.04	0.32	0.04	0.06
N content (%)	82.4%	46.7%	35.0%	-	11.0%	16.0% (Ag_Inputs!AC74)

[8] Penn State Extension, Nitrogen Fertilizers. http://extension.psu.edu/agronomy-guide/cm/tables/table-1-2-11

P_2O_5 fertilizer		Mono-ammonium Phosphate	Di-ammonium Phosphate
Fraction		0.5	0.5
P_2O_5 content (%)		48.0% (Ag_Inputs!AE74)	48.0% (Ag_Inputs!AF74)

Using the correct nutrient contents reduces the GHG of corn ethanol by 0.06 (0.06) g/MJ in the dry (wet) mill pathway and reduces the GHG of corn stover ethanol by 0.05 g/MJ. The detailed calculations are as follows:

Replace the nutrient content in the CA-GREET2.0 model (in cells: Ag_Inputs!AC74, Ag_Inputs!AE74, Ag_Inputs!AF74) by the corrected values (18% for Ag_Inputs!AC74; 52% for Ag_Inputs!AE74; 46% for Ag_Inputs!AF74). Results are summarized in Table 6.

LCFS 46-122 cont.

Table 6 Calculations for nutrient content

	Corrected values	CA-GREET2.0
Corn ethanol in the dry mill pathway		
GHG associated with fertilizers [gram/MJ] (EtOH!D429)	14.72	14.81
N_2O emissions [gram/MJ] (EtOH!E429)	15.32	15.32
GHG credit of co-products [gram/MJ] (EtOH!G429)	13.44	13.47
GHG of corn ethanol [gram/MJ] (EtOH!Y429)	76.72	76.78
Corn stover ethanol		

GHG associated with fertilizers¶ [gram/MJ]	10.06	10.11
GHG of corn stover ethanol§ [gram/MJ]	14.63	14.68

¶ Sum of GHG from cells EtOH!CJ371:EtOH!CN379 divided by ethanol yield (EtOH!G141) and converted to MJ
§ Sum of cells EtOH!AG412:AH412

LCFS 46-122 cont.

1.4. Emissions of N and P_2O_5 fertilizers

Mono- and di-ammonium phosphate fertilizers contain both N and P_2O_5 nutrients. Therefore, the CA-GREET2.0 model probably uses allocation factors to assign emissions to either N or P_2O_5. However, there is no background information given in the CA-GREET2.0 model to describe and define how these putative allocation factors were chosen. The choice of allocation factors should be transparent and readily available through the CA-GREET2.0 model.

The amounts of N and P_2O_5 fertilizers applied based on the fractions of each fertilizer used in agriculture and their respective nutrient contents as given by CA-GREET2.0 are not equal to those of N and P_2O_5 fertilizers used in corn grain production as seen in Table 7. Emissions of N and P_2O_5 fertilizers (in cells: EtOH!D365:E379) are associated with using 439.8 g of N fertilizer and 284.2 g of P_2O_5 fertilizer, not 415.33 g of N fertilizer and 147.77 g of P_2O_5 fertilizer. Therefore, emissions of N and P_2O_5 fertilizers (in cells: EtOH!D365:E379) do not represent emissions associated with the actual amounts of N (415.33 gram/bushel) and P_2O_5

LCFS 46-123

(147.77 gram/bushel) used in corn grain production and should be recalculated to be consistent with current actual corn grain production practice.

LCFS 46-123 cont.

Table 7 Quantities of N and P_2O_5 fertilizers in CA-GREET2.0 [basis: N for N fertilizer, P_2O_5 for P_2O_5 fertilizer]

	N fertilizer		P_2O_5 fertilizer	
	Nutrient [gram/bushel]			
	N	P_2O_5	N	P_2O_5
Ammonia	124.3			
Urea	92.2			
Ammonium Nitrate	16.0			
Urea-Ammonium Nitrate Solution	128.3			
Mono-ammonium Phosphate	16.0	70.0	15.9	69.2
Di-ammonium Phosphate	24.1	72.2	23.1	69.2
Sum	400.8	142.1	38.9	138.4
Total N	400.8 + 38.9 = 439.8			
Total P_2O_5	142.1 + 138.4 =284.2			

1.5. Soil N_2O emissions from corn stover due to corn ethanol production

LCFS 46-124

The CA-GREET2.0 model uses the emission factor (1.325%) for N_2O according to the IPCC guidelines[9], which include direct and indirect N_2O emissions. The CA-GREET2.0 model applies this emission factor to both inorganic fertilizer and corn stover. However, the IPCC guideline[9]

does not include volatile nitrogen loss from crop residues. This volatile nitrogen is lost to the air and is thus not available for soil microbes to convert it to N_2O. Thus, the N_2O emission factor for corn stover should be reduced to 1.225%. The data surrounding this correction to the CA-GREET2.0 calculations are summarized in Table 8. Box 1 below quotes the relevant procedures for calculating indirect N_2O emissions as given in the IPCC guideline[9].

LCFS 46-124 cont.

Table 8 Emission factor

	IPCC[9]	CA-GREET2.0
Fertilizer		
Direct N_2O from fertilizer	0.01	0.01
Indirect N_2O from volatized N from fertilizer	0.001 (=0.1*0.01)	0.001 (=0.1*0.01)
Indirect N_2O from leached N from fertilizer	0.00225 (=0.3*0.075)	0.00225 (=0.3*0.075)
Emission factor for fertilizer	0.01325	0.01325
Crop residues		

[9] Intergovernmental Panel on Climate Change (2006) 2006 IPCC guidelines for national greenhouse gas inventories. http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html.

Direct N_2O from crop residues	0.01	0.01
Indirect N_2O from volatized N from crop residues	-	0.001 (=0.1*0.01)
Indirect N_2O from leached N from crop residues	0.00225 (=0.3*0.075)	0.00225 (=0.3*0.075)
Emission factor for crop residues	0.01225	0.01325

LCFS 46-124 cont.

Box 1. Indirect N_2O calculations (quoted from the IPCC guideline[9])

Volatilization, $N_2O(ATD)$

N_2O FROM ATMOSPHERIC DEPOSITION OF N VOLATILISED FROM MANAGED SOILS (TIER 1)

$$N_2O(ATD)\text{–}N = [(FSN \bullet FracGASF) + ((FON + FPRP) \bullet FracGASM)] \bullet EF4$$

Where:

$N_2O(ATD)$–N = annual amount of N_2O–N produced from atmospheric deposition of N volatilized from managed soils, kg N_2O–N yr^{-1}

FSN = annual amount of synthetic fertilizer N applied to soils, kg N yr^{-1}

FracGASF = fraction of synthetic fertilizer N that volatilizes as NH_3 and NOx, kg N volatilized (kg of N applied) $^{-1}$

FON = annual amount of managed animal manure, compost, sewage sludge and other organic N additions applied to soils, kg N yr^{-1}

FPRP = annual amount of urine and dung N deposited by grazing animals on pasture, range and paddock, kg N yr^{-1}

FracGASM = fraction of applied organic N fertilizer materials (FON) and of urine and dung N deposited by grazing animals (FPRP) that volatilizes as NH_3 and NOx, kg N volatilized (kg of N applied or deposited) $^{-1}$) EF4 = emission factor for N_2O emissions from atmospheric deposition of N on soils and water surfaces, [kg N– N_2O (kg NH_3–N + NOx–N volatilized) $^{-1}$]

This correction reduces the GHG of corn ethanol by 0.21 (0.21) g/MJ in the dry (wet) mill pathway. The detailed calculations are as follows:

Replace the emission factor for corn stover in the CA-GREET2.0 model (in cells: EtOH!D382) by the IPCC emission factor given in Table 8 above. Results are summarized in Table 9.

LCFS 46-124 cont.

Table 9 Calculations for nutrient content

	IPCC value	CA-GREET2.0
Corn ethanol in the dry mill pathway		
N2O from nitrogen fertilizer, and above and below ground biomass [gram/bushel] (EtOH!D382)	11.374	11.596
N_2O emissions [gram/MJ] (EtOH!E429)	15.03	15.32
GHG credit of co-products [gram/MJ] (EtOH!G429)	13.39	13.47
GHG of corn ethanol [gram/MJ] (EtOH!Y429)	76.56	76.78

1.6. Supplemental nutrients in corn stover ethanol production

LCFS 46-125

In the CA-GREET2.0 model, supplemental nutrients (i.e., N, P_2O_5, K_2O) are added in the subsequent growing season to replace nutrients that are assumed to be lost when corn stover is collected to produce corn ethanol. The amount of the supplement nutrients required is assumed to be exactly equal to the nutrient content of the corn stover removed. However, the supplemental nutrients required depend on actual crop management practices used in the subsequent growing season. According to USDA statistics[10], only 33% of cornfields function as cornfields ("corn on corn") in the subsequent growing season, while about 48% of cornfields are used to grow soybeans in the subsequent growing season. Approximately 2.4% of cornfields are converted to developed land, open water or left fallow in the subsequent growing season. This information is summarized in Figure 2.

LCFS 46-125 cont.

Supplemental N nutrients in the following growing season are therefore not necessary for croplands used to produce soybeans even though the nitrogen content in corn stover was removed. Furthermore, supplemental nutrients are not necessary for lands converted to developed land, open water or left fallow. Therefore, supplemental N nutrients are needed in only 49% (=100% - 48% (soybean) - 2.4% (fallow, etc.)) of corn-producing croplands next year, and the supplemental P and K nutrients are needed in only 98 % (100% – 2.4% (fallow, etc.)) of croplands from cornfields next year. By accounting properly for the actual use of corn land in the subsequent growing season, the GHG of corn stover ethanol is reduced by 7.98 g/MJ. The detailed calculations are as follows:

[10] USDA, CropScape - Cropland Data Layer. http://nassgeodata.gmu.edu/CropScape/

Multiply the fertilizer used in the CA-GREET2.0 model (in cells: EtOH!H20:H22) by 0.49 for N, and 0.98 for P_2O_5 and K_2O, respectively. Results are summarized in Table 10 below.

LCFS 46-125 cont.

Table 10 Calculations for supplemental nutrients required for continuous corn

	Corrected values	CA-GREET2.0
GHG associated with fertilizers¶ [gram/MJ]	6.01	10.11
N2O from nitrogen fertilizerΓ [gram/MJ]	-3.87	0
GHG of corn stover ethanol§ [gram/MJ]	6.71	14.68

¶ Sum of GHG from cells EtOH!CJ371:CN379 divided by ethanol yield (EtOH!G141) and converted to MJ
Γ cells EtOH!CJ382 converted to MJ
§ Sum of cells EtOH!AG412:AH412

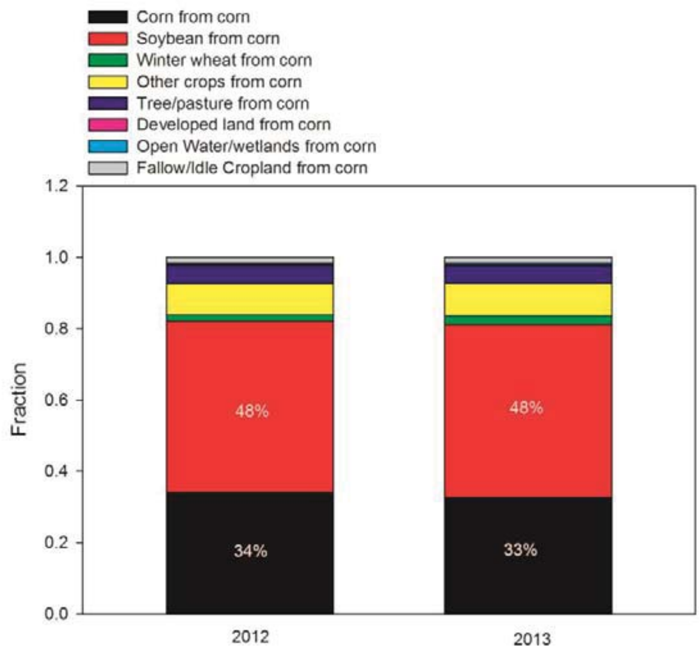


Figure 2 Land use changes in corn cultivation [data source: USDA[10]]

2. Ethanol production (dry mill and cellulosic biorefinery)

2.1. CO_2 emissions from urea displaced by DDGS

Enzymes from bacteria in cattle rumen, specifically urease, break down urea to CO_2 and ammonia, and CO_2 is released. Displacing urea by DDGS avoids those CO_2 emissions. However, the CA-GREET2.0 does not include a credit for CO_2 emissions from urea displaced by DDGS. Even though this value is very small, it should be included in the model for completeness. LCFS 46-126

2.2. Lifecycle GHG emissions of sulfuric acid in corn stover ethanol LCFS 46-127

About 250 grams of sulfuric acid (EtOH!CR361) are used to produce one gallon of corn stover ethanol. A plant producing sulfuric acid generally exports thermal energy (steam) and electricity, and therefore its net energy use is negative[11, 12]. However, the CA-GREET2.0 model does not include the correct energy credits for the exported energy in calculating lifecycle emissions of sulfuric acid. Assuming that 2.1 MMBTU per ton of sulfuric acid[11] is exported from a sulfuric acid plant, the GHG of corn ethanol is reduced by 0.47 (0.46) g/MJ in the dry (wet) mill pathway, and the GHG of corn stover ethanol is reduced by 0.92 g/MJ. The detailed calculations are as follows:

Add an energy credit (2.1 MMBTU/ton) in the cell Ag_Inputs!R26 in the CA-GREET2.0 model. Results are summarized in Table 11. In the CA-GREET2.0 model, sulfuric acid is used to manufacture the phosphorus-containing fertilizers.

The lifecycle GHG of sulfuric acid also affects lifecycle GHG of mono- and di-ammonium phosphates. Correcting the lifecycle GHG of sulfuric acid also changes the GHG of corn ethanol.

LCFS 46-127 cont.

Table 11 Calculations for sulfuric acid

	Corrected values	CA-GREET2.0
Corn ethanol in the dry mill pathway		
GHG associated with fertilizers [gram/MJ] (EtOH!D429)	14.16	14.81

[11] USDOE, Energy and Environmental Profile of the U.S. Chemical Industry, 2000.
[12] National Renewable Energy Laboratory. U.S. Life Cycle Inventory Database.

GHG credit of co-products [gram/MJ] (EtOH!G429)	13.29	13.47
GHG of corn ethanol [gram/MJ] (EtOH!Y429)	76.30	76.78
Corn stover ethanol		
GHG associated with fertilizers¶ [gram/MJ]	9.73	10.11
GHG of biorefineryΓ [gram/MJ]	13.65	14.19
GHG of corn stover ethanol§ [gram/MJ]	13.76	14.68

¶ Sum of GHG from cells EtOH!CJ371:CN379 divided by ethanol yield (EtOH!G141) and converted to MJ
Γ Sum of GHG from cells EtOH!CR371:CR380
§ Sum of cells EtOH!AG412:AH412

LCFS 46-127 cont.

2.3. Cellulase enzyme loading in corn stover ethanol

Recent authoritative studies[13, 14] show that current cellulase enzyme loadings range from 17.5 - 19.9 mg per g of cellulose for dilute acid pretreatment of corn stover followed by enzymatic hydrolysis and fermentation of the sugars to ethanol. This enzyme application rate is equivalent to about 72 – 83 g enzyme per gallon of

LCFS 46-128

[13] Humbird D, Davis R, Tao L, Kinchin C, Hsu D, Aden A, Schoen P et al. Process design and economics for biochemical conversion of lignocellulosic biomass to ethanol: Dilute-acid pretreatment and enzymatic hydrolysis of corn stover. Colorado: National Renewable Energy Laboratory; 2011.
[14] da Costa Sousa L, Jin M, Uppugundla M, Bokade V, Humpula JF, Gunawan C, Foston MB et al. Extractive AFEX™ (E-AFEX™) pretreatment: a unified approach for resolving bottlenecks to efficient cellulosic bioethanol production. New Orleans, LA: 34th Symposium on Biotechnology for Fuels and Chemicals; 2012.

ethanol. However, the enzyme loading used the CA-GREET2.0 model (cells EtOH!CR359) is 113.4 g per gallon of ethanol, which is higher than the current enzyme technologies actually require. Applying current enzyme technologies as summarized in the 2011 National Renewable Energy Laboratory study reduces emissions by 1.32 – 1.79 g/MJ. The detailed calculations are as follows:

Replace the enzyme loading rate in the CA-GREET2.0 model (cells EtOH!CR359) by new enzyme loading values. Results are summarized in Table 12.

LCFS 46-128 cont.

Table 12 Calculations for enzyme loading

	Current technologies		CA-GREET2.0
Enzyme loading [g per gallon]	72	83	113.4
Ethanol yield [gallon/dry ton]	70	79	80
GHG of biorefineryΓ [gram/MJ]	12.39	12.87	14.19
GHG of corn stover ethanol§ [gram/MJ]	12.89	13.37	14.68

Γ Sum of GHG from cells EtOH!CR371:CR380
§ Sum of cells EtOH!AG412:AH412

2.4. Marginal electricity in corn stover ethanol

The CA-GREET2.0 model assumes that excess electricity from a cellulosic biorefinery displaces US average electricity demand. However, it is more reasonable to assume that excess electricity would displace marginal electricity, not US average electricity, which consists of electricity from many different energy sources (i.e.,

LCFS 46-129

fossil fuel, nuclear, renewable energy sources, and hydro). Excess electricity from a cellulosic biorefinery will likely displace electricity from a coal or natural gas-fired power plant, not electricity from nuclear power plant. A nuclear power plant must keep its electricity production level constant at all times. In contrast, marginal electricity is electricity from a power plant which can be brought on line quickly so that the power plant can respond to changing demand for electricity. Nuclear plants and hydroelectric stations are thus ruled out as suppliers of marginal electricity—they can only satisfy base load electricity demand. Electricity from renewable energy sources such as wind and solar are also excluded as sources of marginal electricity because of renewable energy certificates.

Therefore, the marginal electricity replaced by excess electricity from a cellulosic biorefinery would be marginal electricity derived from burning fossil fuels (i.e., coal, petroleum, natural gas). The fuel mix used for marginal electricity production is 64% coal, 34% natural gas and 2% petroleum. These percentages are based on electricity fuel mixes given in the CA-GREET2.0 model. When marginal electricity generated from these fossil fuels is displaced by excess electricity from a cellulosic biorefinery, the GHG of corn stover ethanol is reduced by 8.07 g/MJ. The detailed calculations are as follows:

LCFS 46-129 cont.

Create new sheet for marginal electricity in the CA-GREET2.0 model. The new sheet is named “marginal elec”. Replace the electricity fuel mixes in the cells (marginal elec!C56:C72) by marginal fuel mixes - coal (64%), natural gas (34%), petroleum

(2%), others (0). Replace emissions associated with electricity (EtOH!CS371:CS379) by emissions of marginal electricity. Results are summarized in Table 13.

LCFS 46-129 cont.

Table 13 Calculations for marginal electricity

	Marginal electricity	CA-GREET2.0
GHG creditΓ [gram/MJ]	-27.54	-19.47
GHG of corn stover ethanol§ [gram/MJ]	6.62	14.68

Γ GHG from cells EtOH!CS371:CS379 and converted to MJ
§ Sum of cells EtOH!AG412:AH412

This page intentionally left blank.

46_OP_LCFS_GE Responses (Page 91 – 117)

446. Comment: **LCFS 46-115**

The comment argues that ARB has overestimated the direct emissions of corn ethanol and corn stover ethanol and that this overestimation could lead to shuffling of fuels without any reduction in greenhouse gases and increased costs of compliance with the LCFS.

Agency Response: ARB staff has already addressed many of the comments and questions regarding corn grain and corn stover ethanol CI estimations. Staff believes that GREET1 2013, as the base model for CA-GREET 2.0, provided an adequate starting point for modeling these pathways. Nevertheless, staff, in consultation with Argonne National Laboratory (ANL), further modified many parameters for these pathways and others to be more in-line with many scientific considerations and to work within the LCFS LCA system boundaries. ARB staff made some of these changes prior to the release of the ISOR, but the commenter references the October 10, 2014, CA-GREET 2.0 model and report (supplemental document or ISOR Appendix C), which refers to an earlier version of CA-GREET 2.0. An example of some of the changes made to the corn grain and corn stover pathways is staff's reduction of the nitrous oxide emission factors for feedstocks (corn grain) and agricultural residues (corn stover) from what they are in GREET1 2013 and GREET1 2014 (See "Background:" in response to comment, **LCFS 46-125**, and Appendix C from the ISOR). Another example of how CA-GREET 2.0 was modified from GREET1 2013 is the change of using 100 percent CO_2 emissions from agricultural lime application ($CaCO_3$) to 49 percent, which was updated in GREET1 2014 as well (See response to **LCFS 46-122** and Appendix C from the ISOR). With respect to fuel shuffling see **LCFS 46-40.**

447. Comment: **LCFS 46-116**

The comment argues that the CA-GREET 2.0 model should be updated to reflect the changes made in the GREET2014 model.

Agency Response: The commenter references the October 10, 2014, release of a draft report accompanying CA-GREET 2.0 as an introduction to their comments (**LCFS 46-116** and **LCFS 46-117**), and also references pre-ISOR feedback submitted by Professors Bruce Dale and Segundo Kim, which were included again with Growth Energy's 45-day public comments on the ISOR. The commenter states that the CA-GREET 2.0 model is based on GREET1-2013 from Argonne, and due to Argonne's release of GREET2014, ARB staff should analyze the new model and determine what improvements should be made to CA-GREET 2.0. In actuality, ARB staff did adapt and update many parameters used in CA-GREET 2.0 with GREET1 2014 parameters prior to release of the ISOR. These changes (and the reasons why some parameters were not changed) are explained in the responses to ISOR comments, 15-day change package, and the CA-GREET 2.0 model released with the 15-day changes.

448. Comment: **LCFS 46-117**

The comment recommends that "the denaturant percentage be set to 2.4% in CA-GREET 2.0."

Agency Response: See response to **LCFS 8-12**.

449. Comment: **LCFS 46-118**

The comment encourages ARB to include the credits from enteric methane reductions.

Agency Response: See responses to **LCFS 8-13** and **LCFS 30-3**.

450. Comment: **LCFS 46-119**

The comment argues that the ARB analysis has serious shortcomings in that it allegedly ignores what commenter believes will be a reduction in enteric emissions.

Agency Response: ARB staff disagrees that is it a foregone conclusion that increased biofuel production shifts land use from livestock pasture to cropland, causing a rise in livestock prices, thereby reducing total livestock herds and total enteric fermentation emissions. All of the following would need to be true:

1. Livestock prices increase because of pastureland being used to produce biofuels

2. Rising livestock prices lead to reduced demand for specific livestock (i.e., livestock for the purpose of discussing reduced enteric emissions credit are likely to be feedlot cattle) rather than displacement between various uses of pastureland.

3. Reduced herd sizes result from reduced demand.

4. An overall reduction of emissions occur from reduced heard sizes (see Appendix C: cattle lifetime, N_2O emissions, herd size, etc.)

Additionally, other questions, not limited to the following, would be raised if the price effect above was somehow added to the iLUC modelling. These issues need to be resolved before staff would be comfortable recommending a DGS/enteric fermentation credit to a particular pathway.

1. Where is the DGS going if the livestock market is experiencing reduced demand due to higher costs, but DGS production is not changed for a particular pathway (or is increasing globally with increased biofuel production)?

2. Does DGS production reduce livestock feeding costs and create a counteracting price effect from biofuel production? How should this be treated, for individual pathways or across all pathways with DGS?

For additional information regarding enteric fermentation emissions please see the response to comment **LCFS 8-13**.

451. Comment: **LCFS 46-120**

The comment argues that the CA-GREET 2.0 model does not reflect the current practices for fertilizer use for corn production.

Agency Response: As referenced in Appendix C of the ISOR, ARB staff adopted the agricultural fertilizer input values that Argonne National Laboratory (ANL) used in the release of GREET1 2014. The commenter references a pre-ISOR set of parameters used in CA-GREET 2.0, which were originally used in GREET1 2013 (also cited in Appendix C of the ISOR). When ANL released GREET1 2014, staff reviewed the model and updated CA-GREET 2.0 as applicable. Staff adopted the actual values used in GREET1 2014[26] (as referenced in Appendix C of the ISOR), not the rounded values reported in the ANL report.[21]

Regarding the allocation of agricultural inputs emissions comment: The CA-GREET 2.0 model applies the same allocation factors for these inputs that are used in GREET1 2013 to assign emissions to either N or P_2O_5, which are transparent in CA-GREET 2.0 and

[26] Argonne National Laboratory, GREET 1 2014 spreadsheet, Obtained on 03-OCT-2014 from https://greet.es.anl.gov/greet_1_series

GREET1 2013. The comment states that the incorrect agricultural inputs are used (grams/btu of fertilizer) in CA-GREET 2.0, but this comment, also addressed above, refers to fertilizer application rates that were used in GREET1 2013 and pre-ISOR CA-GREET 2.0 models.

Furthermore, regarding the concentrations of the multi-component fertilizers: Staff is using GREET1 2013 (also GREET1 2014) parameters for nitrogen and phosphorous concentrations in multi-component fertilizers and the resulting emissions. ANL was asked about their choice regarding the nitrogen content of diammonium phosphate (DAP) and the phosphorus content of monoammonium phosphate (MAP) and DAP. In ANL's publication[27] on page 433, section "2.2.2 Ammonium Phosphate", the authors' state, "…referring to the weight percentages of nutrients in the product, N–P_2O_5–K_2O DAP is normally produced as 18–46–0 or 16–48–0, while MAP is 11-51-0, 11-48-0, or 13-52-0 [11]."

ANL communicated to ARB staff that the reason for selecting the 16 percent rather than 18 percent nitrogen content is based upon the more conservative (lower nitrogen content) case.

ANL communicated to ARB staff that the reason for assuming 48 percent P_2O_5 is, "ANL understands that P_2O_5 concentration typically ranges from 46% to 48% for DAP, and from 48% to 52% for MAP for fertilizer application. Without more details on the most common values, ANL is keeping these assumptions." ANL cites, "J. Glauser, Ammonium phosphates, Chemical Economics Handbook, SRI Consulting, Menlo Park, CA, 2010.", which is citation [11] as quoted above regarding MAP and DAP concentrations.

Staff agrees with ANL in selecting the more conservative, lower nitrogen concentration of DAP so all pathways using this fertilizer will not undercount emissions if the lower nitrogen content (DAP) is utilized and therefore requiring greater application than if the higher concentration were used. Similarly, staff agrees with ANL's selection of phosphorous concentrations. In the absence of verified individual producers' agricultural inputs, selecting the more conservative (lower concentration and higher emissions) is appropriate.

[27] Johnson, Michael C., Ignasi Palou-Rivera, and Edward D. Frank. "Energy consumption during the manufacture of nutrients for algae cultivation." *Algal Research* 2, no. 4 (2013): 426-436, http://www.sciencedirect.com/science/article/pii/S2211926413000854

452. Comment: **LCFS 46-121**

The comment suggests replacing the current emission factors for lime application in the CA-GREET 2.0 model with those recommended by the commenter.

Agency Response: ARB staff updated this emission factor from GREET1 2013, based on GREET1 2014 updates, with the release of the ISOR (see CA-GREET 2.0 model and Appendix C from the ISOR). The comment refers to a pre-ISOR CA-GREET 2.0 model, which used the GREET1 2013 parameter. Argonne National Laboratory (ANL) adopted the 2014 U.S. EPA Inventory approach as explained in their technical report.[28] Staff agrees with ANL's selection between the USDA 2014 and U.S. EPA 2014 reports on this matter, as stated in the conclusion of their published technical report quoted as follows:

> "We decided to take the EPA's approach to estimate the CO_2 emission factor from agricultural liming as the EPA has explained in their 2014 GHG emission inventory that the lime dissolution rate was based on liming occurring in the Mississippi River basin, where the vast majority of all U.S. liming takes place. U.S. liming that does not occur in the Mississippi River basin tends to occur under similar soil and rainfall regimes, and thus the emission factor is appropriate for use across the United States (US EPA 2014). On the other hand, the USDA approach lacks resolution at the farm scale, because the method of estimation is based on stream-gauge data that are collected at the watershed scale (U.S. Department of Agriculture 2014). Besides, the USDA does not clarify the scientific basis that supports their assumption on the relative magnitudes of limestone that is acidified to CO_2 emissions to bicarbonate, which has a direct impact on the estimated overall CO_2 emissions from agricultural liming. With the EPA's approach, we updated the CO_2 emission factor from agricultural liming

[28] Hao Cai, Michael Wang, and Jeongwoo Han, Argonne National Laboratory, "Update of the CO2 Emission Factor from Agricultural Liming" October 2014. https://greet.es.anl.gov/publication-co2-lming

from previous 0.44 g CO_2/g $CaCO_3$ to 0.216 g CO_2/g $CaCO_3$ in GREET1_2014[29]."

453. Comment: **LCFS 46-122**

The comment suggests replacing the current nutrient content values of N and P_2O_5 fertilizers in the CA-GREET 2.0 model with those recommended by the commenter.

Agency Response: See response **LCFS 46-120**.

454. Comment: **LCFS 46-123**

The comment argues that emissions from N and P_2O_5 fertilizers in the CA-GREET model 2.0 do not match the amounts of N and P_2O_5 used.

Agency Response: See response **LCFS 46-120**.

455. Comment: **LCFS 46-124**

The comment suggests replacing the current emission factor for N_2O in the CA-GREET 2.0 model with the IPCC emission factor.

Agency Response: ARB staff agrees that N_2O from crop residue should be calculated using the IPCC Tier 1 default emission factor of 1.225 percent rather than the 1.325 percent applied to synthetic nitrogen fertilizer. The CA-GREET 2.0 model has been updated to reflect this change.

Staff concurs with the commenter that N_2O emissions are influenced by soil type, precipitation, topography, temperature, and other factors. Staff further agrees that the CA-GREET model will underestimate the N_2O emissions for some crops and regions of the world, and overestimate the N_2O emissions for others. While there remains a high degree of uncertainty in modeling of N_2O emissions, IPCC Tier 2 methodology should ideally be used to more accurately estimate N_2O emissions; however, until ARB staff is able to develop a robust protocol for verification of applicant-specific agricultural-phase parameters, the IPCC Tier 1 default emission factors will

[29] Hao Cai, Michael Wang, and Jeongwoo Han, Argonne National Laboratory, "Update of the CO2 Emission Factor from Agricultural Liming" October 2014. https://greet.es.anl.gov/publication-co2-lming

continue to be applied uniformly to all feedstocks in the CA-GREET model.

Additional Background: Staff started working with the GREET1 2013 model that uses N in N_2O as percent of N in N fertilizer and biomass for all feedstocks as 1.525 percent, except for sugarcane at 1.220 percent (see comparison in ISOR Appendix C). Staff notes that GREET1 2014 maintains these emission factors except sugarcane is now also 1.525 percent. Staff has discussed the choice of these parameters used in GREET1 2013 and GREET1 2014 with ANL, and the change for CA-GREET 2.0. Staff initially changed all of these factors to the known and widely-accepted IPCC factor of 1.325 percent. Upon subsequent feedback from stakeholders (pre-ISOR), staff again modified CA-GREET 2.0 (post-ISOR, due to time constraints) to more appropriately use the IPCC Tier 1 emission factor for agricultural residues, which is 1.225 percent.

456. Comment: **LCFS 46-125**

The comment recommends that ARB adjust the supplemental nutrients requirements for N, P_2O_5, and K_2O fertilizers since soybean can provide additional nutrients and about 2.4 % of corn fields are converted to developed land or left fallow in the subsequent growing season.

Agency Response: ARB staff agrees with the commenter that actual practices involving stover removal and the next crop after stover harvest influence the amount and types of supplemental nutrients required for a specific field. GREET1 2013, GREET1 2014, and CA-GREET 2.0 rely upon average application rates for any feedstock or make-up application for harvested residue. Staff is not able to review the practices for each field used in a specific pathway, the specific inputs, and subsequent practices going forward annually or for the life of the LCFS pathway. Until better verification and monitoring programs are in-place for LCFS pathways, average input values must be used to prevent undercounting of GHG impacts based upon inputs or removal of residues. Staff recommends this method of analysis for many agricultural practices that cannot be monitored or verified on an ongoing basis.

457. Comment: **LCFS 46-126**

The comment recommends that ARB incorporate CO_2 due to animal waste urea into the CA-GREET 2.0 model.

Agency Response: The comment refers to a pre-ISOR release of the CA-GREET 2.0 model and Appendix C. The release of the ISOR CA-GREET 2.0 model provides a default DGS credit for Tier 1 pathways of 0.781 lb corn, 0.307 lb soybean meal, and 0.023 lb urea for 1 lb DGS. Urea is included as part of the displacement for DGS. These values are based upon Argonne National Laboratory research (referred to in Appendix C), and is the aggregated displacement ratio for U.S. and export markets, which is available in GREET1 2013 and GREET1 2014. The aggregated displacement for U.S. and export markets is the necessary average displacement to use due to staff not being able to monitor the fluctuating U.S. and international DGS markets for the lifetime of LCFS fuel pathways.

458. Comment: **LCFS 46-127**

The comment recommends that ARB consider CO_2 credits associated with excess heat and electricity production in the CA-GREET 2.0 model.

Agency Response: ARB staff reviewed the sulfuric acid production lifecycle assessment (LCA) modeling that Argonne National Laboratory (ANL) used for GREET1 2013, which was used as the base model for CA-GREET 2.0. ANL also employs this same modeling in GREET1 2014. The paper, Johnson, et. al.[30], describes how the sulfuric acid plants energy use is modeled in GREET1 2013. The parameters used in CA-GREET 2.0 and GREET1 2013 are presented in the Johnson paper including a suggested value for net steam export (Johnson et. al., pg. 433, Table 12). However, the steam export credit was not selected for use in GREET1 2013. ANL stated, “ANL is aware that the sulfuric acid plants have an excess heat export of about 3.0 MJ/kg H_2SO_4 (see ANL 2013 paper by Johnson et al.). However, ANL decided not to credit this heat without clear evidence showing that there is always a stable demand from nearby facilities for the excess heat.” Staff agrees with the more conservative approach with modeling sulfuric acid production because there may be sulfuric acid producers that supply sulfuric acid to LCFS pathways, but do not recover the potentially recoverable heat. Staff cannot currently monitor and verify sources of sulfuric acid for all LCFS pathways in order to ensure this heat

[30] Johnson, Michael C., Ignasi Palou-Rivera, and Edward D. Frank. "Energy consumption during the manufacture of nutrients for algae cultivation." Algal Research 2, no. 4 (2013): 426-436. http://www.sciencedirect.com/science/article/pii/S2211926413000854

recovery credit is warranted on an ongoing basis for the lifetime of the LCFS pathway.

459. Comment: **LCFS 46-128**

The comment argues that the current enzyme loading rate in the CA-GREET model is high and suggests ARB to use a lower loading rate.

Agency Response: ARB staff understands the comment to be applicable if enzyme loading were a default parameter in CA-GREET 2.0. However, enzyme loading and many other inputs within the LCFS pathway are user defined, not default. Staff may ask for verification of quantities of enzymes used and receipts documenting these purchases, but the amount of cellulase used is defined by the LCFS fuel pathway applicant based upon the actual use. As such, the enzyme loading cited by the commenter related to the 2011 National Renewable Energy Laboratory (NREL) report is a potential input that an LCFS pathway applicant may claim if that is accurate for their process, but if they use more or less they would report and justify that amount.

460. Comment: **LCFS 46-129**

The comment argues that excess electricity from a cellulosic biorefinery displaces marginal electricity.

Agency Response: ARB staff will require the use of average electricity resource mixes for both grid power consumption and for displacement credit for generated power for pathways submitted under CA-GREET 2.0. See the response to comment **LCFS 18-3.**

This page intentionally left blank.

46_OP_LCFS_GE

17_OP_ADF_GE

Appendix C

REVIEW OF THE SUGAR CANE ETHANOL PATHWAYS IN CA-GREET 2.0

Prepared For:

Growth Energy
777 N. Capitol Street, NE, Suite 805
Washington, DC 20002

Prepared By

(S&T)^2 Consultants Inc.
11657 Summit Crescent
Delta, BC
Canada, V4E 2Z2

Date: February 2, 2015

EXECUTIVE SUMMARY

The California Air Resources Board (Board/ARB) is proposing to re-adopt the Low Carbon Fuel Standard (LCFS) regulation and to include updates and revisions compared to the previous regulation. The ARB staff will bring a new LCFS regulation to the Board for consideration in February 2015. The proposed LCFS regulation will contain revisions to the 2010 LCFS as well as new provisions designed to foster investments in the production of the low-CI fuels, offer additional flexibility to regulated parties, update critical technical information, simplify and streamline program operations, and enhance enforcement.

To address these issues with fuel pathway certifications, staff is proposing a two-tiered system in which conventionally produced first-generation fuels, such as starch- and sugar-based ethanol, would fall into the first tier. Next-generation fuels, such as cellulosic alcohols, would fall into the second tier.

ARB has stated that the Tier 1 process simplifies and expedites the certification process by providing applicants with a streamlined CI calculator that computes pathway CIs using a base set of input parameters needed to determine a Tier 1 pathway CI. This method will use the CA-GREET 2.0 model. This model is a California version of the GREET1 2013 model.

Scope of Work

This work reviews the sugarcane ethanol pathways in the new CA GREET model to ensure that they function properly and utilize the best available science. The review has considered the following questions.

Are the pathways consistent?

It is important that the model uses the same basic approach, including system boundaries and assumptions for all of the ethanol pathways and ideally all of the fuel pathways.

Does the model ask for the key input parameters?

The model will use a combination of default values and user defined inputs to model specific plants. It will be important that all of the important parameters that change from one plant configuration to another are user defined inputs and are not default values.

Does the model reflect the actual practices?

The model must include all of the actual steps in the production process for it to be useful. If it doesn't, some plants will not be able to generate accurate values.

Does the model have the correct background data and are the calculations correct?

Finally it is important that the model contains the best available background data and that the model functions properly. Background data would include the default values, biomass and fuel characteristics, and other inputs.

A significant number of issues were identified. Most of the issues results in the model returning values that are lower than what would be returned if the issues were addressed properly.

Sugar Cane Farming Summary

The CA GREET model does not apply different energy use factors to sugar cane farming even though the two scenarios with mechanical harvesting require almost twice the energy of a manual harvest system. A mechanical harvest system with 100% of the energy supplied by diesel fuel will have GHG emissions of 7.54 g CO_2eq/MJ.

There is evidence that the crop residues that are left on the field are reducing the synthetic nitrogen that is required. The proportion of nitrogen from fertilizer and from crop residue should vary depending on whether or not there is straw burning. The CA GREET model is assuming that there is no difference in nitrogen requirements between burned and unburned fields, an unlikely scenario.

Although there is significant uncertainty regarding the appropriate N_2O emission factor for sugar cane production, the best information in the peer reviewed literature would suggest that the 1% EF1 factor used by CARB is too low. The impact of increasing this to 1.5% is an increase in sugar cane N_2O emissions of 2.83 g CO_2eq/MJ.

Straw Burning Summary

The straw burning emissions appear to be too low by about 4.42 g CO_2eq/MJ as a result of using the IPCC emission factors for Ag residue burning rather than the values for grassland and savanna burning. This increase would be reduced to about 2.5 g CO_2eq/MJ if the nitrogen from the burned straw was not returned to the soil as discussed in the previous section.

Cane Transport Summary

The model should be changed so that the share of the delivery of cane by medium duty trucks and by heavy duty trucks is a user input. The truck energy requirements are the same as for corn ethanol.

Ethanol Production Summary

There are several errors in the CA GREET model related to the transfer of information from the T1 Calculator sheet to the core of the model. These include:

1. Nuclear and biomass power shares of the power generation are transposed when they are transferred to the ETOH sheet.
2. The inputs for sulphuric acid and ammonia are input into the cells for enzymes when they move from the T1 Calculator sheet to the ETOH sheet. Entering non-zero values will produce extremely high and erroneous GHG emissions.

There is also the potential for misinterpretation of the input values. The input for Residual oil is really the quantity of used lubricants that are burned in the plant and not the input of residual oil.

The quantity of biomass that is burned at the plants is hard coded in the model. Not all mills burn all of the bagasse on site; some sell a portion to other local industries. The emissions for these operations will be overestimated. The biomass from the T1 Calculator sheet is transferred to the ETOH sheet, but once it goes there it is not included in any calculations. A proper modelling would require the mills to enter the bagasse consumed and not hard code those quantities. The current model would underestimate the emissions from mills that imported bagasse from another facility or used some straw from the fields to produce more electric power for export.

Transportation Summary

There are issues with the ocean shipping calculations in GREET for many of the fuels, including sugarcane ethanol. The issues for sugar cane ethanol include:

1. The shipment size of 22,000 tons is too high and is not a user input.
2. Ethanol, uniquely of all of the fuels in CA GREET, is not charged with a backhaul.
3. The energy use for ocean shipping is calculated but the calculations underestimate the energy used by a significant amount.
4. Energy use in the model is 145 BTU/ton-mile. Data from the IMO suggests that this should be 335 BTU/ton-mile plus 283 BTU/ton-mile for the backhaul. This would increase the ocean shipping emissions by 17.0 g CO_2eq/MJ, a very significant difference.

Summary

With respect to the four questions that were investigated we find that:

1. There are inconsistencies between some aspects of the sugarcane ethanol pathway and all other pathways.
2. There are key input parameters that should be specified by the user of the model. These would include; the share of cane transported by MD and HD trucks, the ocean shipment size, and confirming that a backhaul is always provided.
3. The model does not reflect actual practice. The lack of change in the farming emissions with the different practices that are employed is problematic. The ocean shipping size is double the typical shipments.
4. The background data in the model is not accurate. Although the biggest issue is with the energy used for ocean shipping, the emission factor applied to cane burning should also be changed.

In addition, there are some programming errors in the calculator that need to be adjusted. The following two tables itemize the changes that should be made to the model.

Table ES- 1 Summary of Changes - Farming

Stage	Manual Harvest			Mechanical Harvest		
	Default	Revised	Change	Default	Revised	Change
All Diesel	4.65	5.39	0.74	4.65	5.39	0.74
Extra Diesel for Mech Harvest					7.54	2.15
Extra N Fert for manual	3.22	4.43	1.21			
N_2O from extra N	2.88	3.96	1.08			
Total			3.03			2.89

Table ES- 2 Changes to Rest of Pathway

Item	Default	Revised	Change
N_2O EF	7.48	10.31	2.83
Residue Leaching		7.13	-0.35
Straw Burning EF	10.06	14.42	4.36
Power Export	-0.72	-0.76	-0.04
Shipping			
Backhaul (default value)	7.16	11.41	4.25
Ship size (default value)		18.88	7.47
Int'l Marine Org. Energy		24.15	5.27
Total			23.79

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION

The California Air Resources Board (Board/ARB) is proposing to re-adopt the Low Carbon Fuel Standard (LCFS) regulation and to include updates and revisions compared to the previous regulation. The ARB staff will bring a new LCFS regulation to the Board for consideration in February 2015. The proposed LCFS regulation will contain revisions to the 2010 LCFS as well as new provisions that the staff claims are designed to foster investments in the production of the low-CI fuels, to offer additional flexibility to regulated parties, to update critical technical information, and to simplify and streamline program operations, and enhance enforcement.

Based on stakeholder comments received in both the original 2009 rulemaking and the 2011 amendments, the Board directed staff in Resolutions 09-31 and 11-39 to consider revisions to the regulation in a number of specific areas, including the approval of additional fuel pathways. Additionally, staff has indicated that it has conducted internal reviews of lessons learned and has been assessing what has changed since the initial implementation of the LCFS. It is evident that evaluating fuel pathways is very resource-intensive.

Furthermore, stakeholders have expressed concerns that many of the Method 2 pathways in the Lookup Table and on the Method 2 web site are not available for wider use by regulated parties.

In order to attempt to address these issues with fuel pathway certifications, staff is proposing a two-tiered system in which conventionally produced first-generation fuels, such as starch- and sugar-based ethanol, would fall into the first tier. Next-generation fuels, such as cellulosic alcohols, would fall into the second tier.

The ARB staff has stated that the Tier 1 process simplifies and expedites the certification process by providing applicants with a streamlined CI calculator that computes pathway CIs using a base set of input parameters needed to determine a Tier 1 pathway CI. This method will use the CA-GREET 2.0 model. This model is a California version of the GREET1 2013 model.

1.1 SCOPE OF WORK

This work reviews the sugarcane ethanol pathways in the new CA GREET model to ensure that they function properly and utilize the best available science. The review has considered the following questions.

Are the pathways consistent?

It is important that the model uses the same basic approach, including system boundaries and assumptions for all of the ethanol pathways and ideally all of the fuel pathways.

Does the model ask for the key input parameters?

The model will use a combination of default values and user defined inputs to model specific plants. It will be important that all of the important parameters that change from one plant configuration to another are user defined inputs and are not default values.

Does the model reflect the actual practices?

The model must include all of the actual steps in the production process for it to be useful. If it doesn't, some plants will not be able to generate accurate values.

Does the model have the correct background data and are the calculations correct?

Finally it is important that the model contains the best available background data and that the model functions properly. Background data would include the default values, biomass and fuel characteristics, and other inputs.

The report follows the structure of the model. The following sections consider the sugarcane farming operations, straw burning, can transportation, ethanol production, and ethanol transport from Brazil to California.

The model contains four basic sugarcane ethanol pathways:

- Sugarcane Ethanol – Base Case
- Sugarcane Ethanol – with Power Export
- Sugarcane Ethanol – Mechanized Harvest
- Sugarcane Ethanol – Mechanized Harvest with Power Export.

The values that are on the T1 Calculator sheet in the user input cells are not necessarily the expected user values for those cells so there are no default values per se for the four pathways. The direct CI values in the following table are therefore indicative of differences between the four pathways. These do not include the denaturant and the ILUC values.

Table 1-1 Sugarcane Ethanol Indicative CI Values

	Base Case	Power Export	Mechanized Harvest	Mechanized Harvest with Power Export
	g CO_2eq/MJ			
Farming energy	4.65	4.65	4.65	4.65
Fertilizers	4.67	4.67	4.67	4.67
N_2O in Soil	7.48	7.48	7.48	7.48
Straw Burning	10.06	10.06	10.06	10.06
Cane Transportation	1.29	1.29	1.29	1.29
Mechanized Harvesting Credit	0.00	0.00	-10.06	-10.06
Filter Cake T&D	0.01	0.01	0.01	0.01
Plant Energy	2.30	2.30	2.30	2.30
Ethanol T&D	7.16	7.16	7.16	7.16
Power Credit	0.00	-0.72	0.00	-0.72
Total	37.62	36.90	27.56	26.84

Not all sugarcane plants will be able to use the calculator as their operations do not fit the four cases. These include fields that are burned and mechanically harvested and mechanically harvested fields that collect some of the residue to supplement the bagasse for power generation. These kinds of plants will have to follow a Tier 2 method.

CARB have also been allowing some plants that produce sugar and ethanol to reduce the sugarcane production emissions through the use of economic allocation between the sugar and the molasses that is used for the ethanol feedstock. The calculator could not be used for those plants. Economic allocation is the least preferred approach under ISO LCA guidelines. The plants that co-produce sugar and ethanol should have the available

LCFS 46-130

data on energy use in distillation and in crystallization to be able to undertake the CI calculation without any allocation.

LCFS 46-130 cont.

2. SUGAR CANE FARMING

The CA GREET model has no user inputs for farming energy, fertilizer, and N_2O emissions. Nor do these values change with the two process modifiers (mechanical harvest and power credit). This is consistent with the other biofuel pathways, where feedstock production values are fixed by the model, but there is a difference in mechanical vs. manual harvest in terms of the fuel energy used and some other parameters.

2.1 ENERGY

Farming energy in the model is supplied by diesel, LPG, gasoline, natural gas, electricity, and renewable natural gas. The default values and their contribution are summarized in the following table. While one can change the default values, they don't go anywhere in the model. The small amount of natural gas on the T1 Calculator sheet is not included in the model.

Table 2-1 Farming Energy

Fuel	Value, BTU/tonne	GHG emissions, g CO_2eq/MJ
Diesel Fuel	36,385	2.061
Gasoline	11,685	0.654
Natural Gas	20,425	0.954
LPG	17,860	0.881
Electricity	8,550	0.092
Renewable Natural gas	95	0.000
Total	95,000	4.642

The sources for the energy use in farming report the energy consumption as diesel fuel per tonne of cane, so it is not clear where the breakdown of fuel use by fuel type came from. If all of the fuel was diesel fuel, then the emissions would increase to 5.39 g CO_2eq/MJ (an increase of 0.75 CO_2eq/MJ). LCFS 46-131

The 95,000 BTU/tonne was introduced in GREET1 2011 and was about twice as high as the previous value, which used data from 2002. It was suggested by Dunn et al (2011) that the reason for the increase could be due to the increase in mechanical harvesting. A recent paper by Wang et al (2014) considered changes in the Brazilian sugarcane industry between 2010 and 2020. The diesel fuel parameters used in that study are shown in the following table.

Table 2-2 Sugar Cane Farming Parameters

	2010	2015	2020
Yield, tonnes/ha	70.5	80.0	84.0
Mechanical Harvest rate, %	50	80	100
Diesel Fuel consumption, l/ha	230	280	314
Diesel, l/tonne	3.26	3.50	3.92
Diesel, BTU/tonne	110,600	118,800	133,000

The energy use is all higher than is found in CA GREET. This data indicate that the farming energy for manual harvesting should be about 2.4 l/tonne (81,000 BTU/tonne) and for 100% mechanical harvest it should be at least 3.9 l/tonne (133,000 BTU/tonne) and not the same for both cases. This difference in farming energy should be very simple to implement in the CA GREET model. LCFS 46-131 cont.

2.2 Fertilizers

The fertilizer parameters are also set in CA GREET and are not to be adjusted by users. The default values and their impact on the GHG emissions from the manufacturing of the fertilizers are shown in the following table. The values on the T1 Calculator tab do not leave the sheet.

Table 2-3 Fertilizer Parameters

Component	Input	GHG Emissions, g CO2eq/MJ
Nitrogen, g/tonne	800.00	3.22
P_2O_5, g/tonne	300.00	0.11
K_2O, g/tonne	1,000.00	0.21
$CaCO_3$, g/tonne	5,200.00	0.71
Herbicide, g/tonne	45.00	0.39
Insecticide, g/tonne	2.50	0.02
Total		4.66

There is a range of fertilizer rates that can be found in the literature. The values used in GREET are within the range and are generally weighted to the more recent data such as the Seabra et al. 2011 report. It is obviously the nitrogen rate that has the largest impact and the earlier version of GREET, such as 1.8d used 1091.7 g/tonne of cane. LCFS 46-132

It is likely that one of the reasons for a trend to lower nitrogen inputs is the increase in mechanical harvesting and the elimination of the straw burning. This increases the nitrogen in the crop residues that are returned to the soil. The nitrogen content of the residues that are not burned during a mechanical harvest were estimated by Fortes et al (2013) to be 41 kg/ha, or 512 g/tonne at an 80 tonne/ha yield. This is consistent with the reduction N fertilizer seen over the past decade and the reduction in straw burning that accompanies the increase in mechanical harvesting.

The conclusion is that, like the farm energy, it is not appropriate to use the same fertilizer parameters for all four scenarios. There should be different parameters for the manual harvest from the mechanized harvest. The manual harvest should have higher nitrogen inputs than the average values in the model and the mechanized harvest should be lower than the current model value.

2.3 N_2O Emissions

The N_2O emissions in the CA GREET model are fixed at 7.48 g CO_2eq/MJ. None of the user inputs have an impact on this value. There are two factors that have an impact on the calculation: the total quantity of nitrogen applied, and the N_2O emission factor applied. These are discussed below. LCFS 46-133

2.3.1 Nitrogen Applied

The nitrogen applied is the sum of the synthetic nitrogen fertilizer, nitrogen applied through amendments such as vinasse application, and the above and below ground crop residues. The values in the CA GREET model are listed below.

Table 2-4 Nitrogen Additions to the System

Source	Quantity, g/tonne	CO_2eq Emissions, g/MJ
Synthetic Fertilizer	800	2.88
Crop Residue	1,036	3.73
Filtercake	36	0.13
Vinasse	205	0.74
Total	2,077	7.48

In the CA GREET model the crop residue value is independent of the type of harvest. The model assumes that the nitrogen in the crop residue is returned to the soil as ash. However the data on the fertilizer that is applied does not appear to support this. If the nitrogen in the burned residue is returned to the soil it is not likely returned to the sugarcane field but at some other land.

The proportion of nitrogen from fertilizer and from crop residue should vary depending on whether or not there is straw burning.

LCFS 46-134

2.3.2 N_2O Emission Factor

The model uses the basic IPCC Tier 1 emission factors for the synthetic nitrogen and the crop residues. This includes the direct emissions of N_2O from nitrogen and crops residues, the emissions from nitrogen that is leached from the site and run-off, and the emissions from volatilization of some of the applied nitrogen. This is a misapplication of the IPCC methodology as there should be a small difference between the emission factor for crop residues, which have no volatilization impact and the synthetic fertilizer which does have a volatilization factor. If the factor for synthetic nitrogen is 1.325%, the value for the crop residue should be 1.225%. The 1.325% is made up of:

- 1% of the nitrogen in the synthetic nitrogen and crop residues is emitted as N_2O (EF1).
- 10% of the synthetic nitrogen is volatilized and 1% of that is emitted as N_2O.
- 30% of the N applied is leached or run-off and 0.75% of that is emitted as N_2O.
- Total is 1% + 0.1*1% + 0.3*.075% = 1.325%

The larger issue is whether or not the IPCC Tier 1 default value for EF1 of 1% is appropriate for this region of the world. N_2O emissions are influenced by soil type, precipitation, topography, temperature, and other factors. The GREET model has applied some different factors for different crops but the CA GREET model has applied the same factors for all crops. This will result in underestimating the emissions for some crops and overestimating the emissions for other crops.

LCFS 46-135

2.3.2.1 *The Scientific Literature*

Sugarcane has a high need for moisture and there is evidence that the N_2O emission factor should be higher due to high levels of precipitation. Renouf et al (2010), in a study of Australian sugarcane production, use an average value of 0.04 for EF1 and report a range of 0.01 to 0.07. Thorburn et al (2010) modeled the N_2O emissions from sugarcane production systems in Australia and determined a range of N_2O emissions form 3-5% of fertilizer applied. Denmard et al (2010) measured N_2O emissions at two sites in Australia and found a range of emissions from 2.8 to 21% of nitrogen in applied fertilizer. The Australian national GHG inventory applies a value of 1.25% for EF1 but it is not clear if this is a Tier 2 value, or simply the Tier 1 value from the 1995 guidelines.

Lisboa et al (2011) looked at this issue for sugarcane production. In addition to the data from Australia they also found data for Hawaii. They determined that the average N_2O emission rate was 3.87%, however while they compare this value to the IPCC EF1 value, they are not comparable. The 3.87% is the total N_2O emissions based just on the nitrogen applied with synthetic fertilizer. It does not include the nitrogen applied from residue or other sources, nor does it include the N_2O from nitrogen leached from the site. Including these would lower the emission factor.

Although information on N_2O emissions for Brazilian sugar cane production is more limited a recent paper by Walter et al. (2014) reported:

> *Experiments in Australia comparing burnt and unburnt harvesting systems indicate that the maintenance of sugarcane straw on the field increases soil N_2O. These results have been recently corroborated by field experiments conducted in Brazil, but with an even more marked increase when vinasse is applied. Because the soil–atmosphere exchange of N_2O depends on complex interactions, more regional and site-specific data are needed to evaluate the impact of this source on the overall GHG balance of biofuels.*

LCFS 46-136

Signor et al (2013) measured the N_2O emissions from sugar cane production at two sites in Brazil. At the first site the proportion of N lost as N_2O ranged from 0.80 to 12.95%. At the second site N_2O emissions varied from 1.22 to 1.53% of added N for ammonium nitrate treatments and from 0.31 to 1.10% for urea.

Experiments reported by da Silva Paredes (2014) found the highest proportions of N emitted as N_2O were registered in the vinasse treatment, which amounted to 15 % of the N applied in the first greenhouse experiment, and 2.5 % in the field experiment, however the N_2O emission rate for just urea were considerably below the Tier 1 default value of 1%.

Vargas et al (2014) investigated the impact of soil moisture and the level of trash retained in the soil and found that N_2O emissions increase with soil moisture and the presence of trash on the soil doubled the impact of increasing soil moisture on N_2O emissions.

Although there is significant uncertainty with respect to the N_2O emission factor for sugar cane production in Brazil, the scientific literature indicates that rates are higher when the fields are not burned and the trash remains on the field. Rates are also higher when vinasse is applied to the field. More work has been done in Australia and corroborated with field experiments in Brazil, and all of that work suggests that the appropriate emission factor is greater than the 1% value for EF1 that has been used by CARB.

2.4 Sugar Cane Farming Summary

The CA GREET model does not apply different energy use factors to sugar cane farming even though the two scenarios with mechanical harvesting require almost twice the energy of a manual harvest system. A mechanical harvest system with 100% of the energy supplied by diesel fuel will have GHG emissions of 7.54 g CO_2eq/MJ.

There is evidence that the crop residues that are left on the field are reducing the synthetic nitrogen that is required. The proportion of nitrogen from fertilizer and from crop residue should vary depending on whether or not there is straw burning. The CA GREET model is assuming that there is no difference in nitrogen requirements between burned and unburned fields, an unlikely scenario. LCFS 46-137

Although there is significant uncertainty regarding the appropriate N_2O emission factor for sugar cane production, the best information in the peer reviewed literature indicates that the 1% EF1 factor used by CARB is too low. The impact of increasing this to 1.5% is an increase in sugar cane N_2O emissions of 2.83 g CO_2eq/MJ.

3. Straw Burning

For fields that are not mechanically harvested the CA GREET model assumes that the fields are burned prior to harvesting. This does result in different values for the manual versus mechanical harvested scenarios, where a credit for the burning emissions is introduced in the mechanical harvesting systems.

In the GREET model all of the nitrogen in the straw is included in the crop residue whether the straw is burned or is left on the soil. This is not likely to be the case but correcting it would result in lower emissions for fields that are burned and no change in the emissions for mechanical harvesting.

Even though the straw is biogenic the methane emissions and the N_2O emissions must still be included in the calculations of GHG emissions. The emission factors used in GREET are shown in the following table. LCFS 46-138

Table 3-1 Straw Emission Factors

	CA GREET	IPCC Grassland	IPCC Ag residue
	g/tonne		
Methane	2,700	2,300	2,700
N_2O	7	21	7

CA GREET also converts the CO and VOC emissions to CO_2eq for straw burning and then provides a credit for the carbon uptake from the atmosphere. This essentially uses the biogenic methane GWP factor of 22.25.

The IPCC values shown above are for grassland burning and for Ag residue burning, as there are no specific emission factors for sugarcane field burning. The source of the IPCC estimates is the paper by Andrea & Merlet (2001). In that paper there are over 40 references to support the grassland estimates and the note beside the Ag residue value is “Value is a best guess”.

The GHG emissions for straw burning would increase to 14.42 g CO_2eq/MJ if the IPCC Grassland values were used rather than the Ag residue values.

3.1 Straw Burning Summary

The straw burning emissions are too low by about 4.43 g CO_2eq/MJ as a result of using the IPCC emission factors for Ag residue burning rather than the values for grassland and savanna burning. This increase would be reduced to about 2.5 g CO_2eq/MJ if the nitrogen from the burned straw was not returned to the soil as discussed in the previous section. LCFS 46-139

4. CANE TRANSPORTATION

The cane transportation distance is a user input to the CA GREET model. They have modelled both a medium duty and a heavy duty truck. This is appropriate because both types of trucks can be used, although they have assigned a 100% share to both types and the share is not a user input. Either one or the other will be used, not both. The share should also be a user input.

LCFS 46-140

The same energy use is used for HD and MD trucks for all pathways in the model. Sugar cane transport it usually at lower speeds than highway travel in North America but the roads are generally dirt, so the assumption of the same energy use is probably reasonable.

The transportation distance is the user input and it is the key parameter in driving the GHG emissions.

4.1 CANE TRANSPORT SUMMARY

The model should be changed so that the share of the delivery of cane by medium duty trucks and by heavy duty trucks is a user input. The truck energy requirements are the same as for corn ethanol.

5. ETHANOL PLANT

The GHG emissions from the ethanol plant stage using the default values in the CA-GREET model amount to 2.30 g CO_2eq/MJ, or less than 10% of the lifecycle emissions for each of the 4 scenarios. The composition of the total is discussed below.

5.1 ENERGY USE

The T1 Calculator sheet asks for total energy use in the mill by type of energy. The calculator as produced only includes some residual oil use and some electric power use. It has zero for biomass use. All of the 2.30 g CO_2eq/J of emissions are energy derived.

Sugar cane mills burn a lot of bagasse to provide the power and the steam for the mills. This biomass is hardcoded into the model and is not adjusted when a user enters biomass energy into the T1 Calculator sheet. It is also not included in the energy consumption values. If a mill imported bagasse or straw to produce more electricity, the model will not produce higher emissions as a result of the higher biomass inputs.

The contribution of the default energy values to the total for this stage is shown in the following table. Even though the bagasse is biogenic the methane and N_2O emissions are still included in the calculations. LCFS 46-141

Table 5-1 Ethanol Plant Energy Related Emissions

Type	Value	Emissions
	BTU/gal	G CO_2eq/MJ
Residual oil (10% loss of lubricants)	300	0.04
Power	24.37	0.00
Bagasse	89,272	2.26
Total	89,596.37	2.30

Most of the emissions are related to methane and N_2O emissions from burning the bagasse. It is not clear on the T1 Calculator sheet that the residual oil use is related to lubricants and users will likely try and zero this value out when they use the calculator.

5.2 CHEMICALS

The two chemicals that are included in the T1 Calculator sheet are sulphuric acid and ammonia. Both are zero in the model. Seabra (2011) reports sulphuric acid consumption in the mills of 0.0074 kg/litre, 28 g/gal. The model is broken as it transfers the 28 g of sulphuric acid to cell DU 357 (Alpha Amylase) on the EtOH sheet rather than to DU 361 (Sulphuric Acid). This results in GHG emissions of 169,460 g CO_2eq/MJ for the ethanol production stage, an obvious error. The ammonia also goes to the wrong cell on the EtOH sheet. LCFS 46-142

The CA GREET model for Tier I applications doesn't apply to mills that produce sugar and ethanol. These need to be done using the Tier 2 methodology, but are still expected to be done using the CA GREET model as the base. These mills use some lime in the production process (Seabra reports 42.6 g/gal). There is no provision in CA GREET for including lime as an input to the ethanol production process. This needs to be added as user input. Lime has GHG emissions of about 1.25 g/g CAO so including this chemical would add about 0.7g CO_2/MJ to the ethanol production emissions.

5.3 POWER EXPORTS

The new CA-GREET model is using the average power mixes rather than trying to estimate the marginal power in all of the different regions that are included in the model. In the case of Brazil, this drastically lowers the credit for power exports. LCFS 46-143

There is an error in the CA-GREET model with respect to the Brazilian power mix. When the data is migrated from the T1 Calculator sheet to the ETOH sheet the values for nuclear and biomass power are transposed. The values in cells Q293 and Q294 on the ETOH sheet are therefore incorrect and lead to a slightly higher credit (~0.1 g/MJ) than should be calculated. LCFS 46-144

A larger issue is the quality of the data being used in the model for Brazil power. The power mix for Brazil that is used in CA-GREET is shown in the following table. The source identified for the data is the US DOE EIA country brief. This brief was updated in December 2014 and the results are also shown in the table. Small amounts from wind, solar, and nuclear made up the rest.

Table 5-2 GREET Brazil Power Mix

	Brazilian Mix in Model	Updated EIA Brief
Resid Oil/Fossil fuels	0.00%	4%
Natural gas	11.00%	11%
Coal	0.00%	0%
Nuclear power	2.00%	0%
Biomass	7.00%	8%
Hydroelectric	55.76%	71%
Geothermal	3.33%	0%
Wind	20.65%	0%
Solar PV	0.26%	0%
Others (purchased)	0.01%	0%
Total	100.01%	94.00%

LCFS 46-145

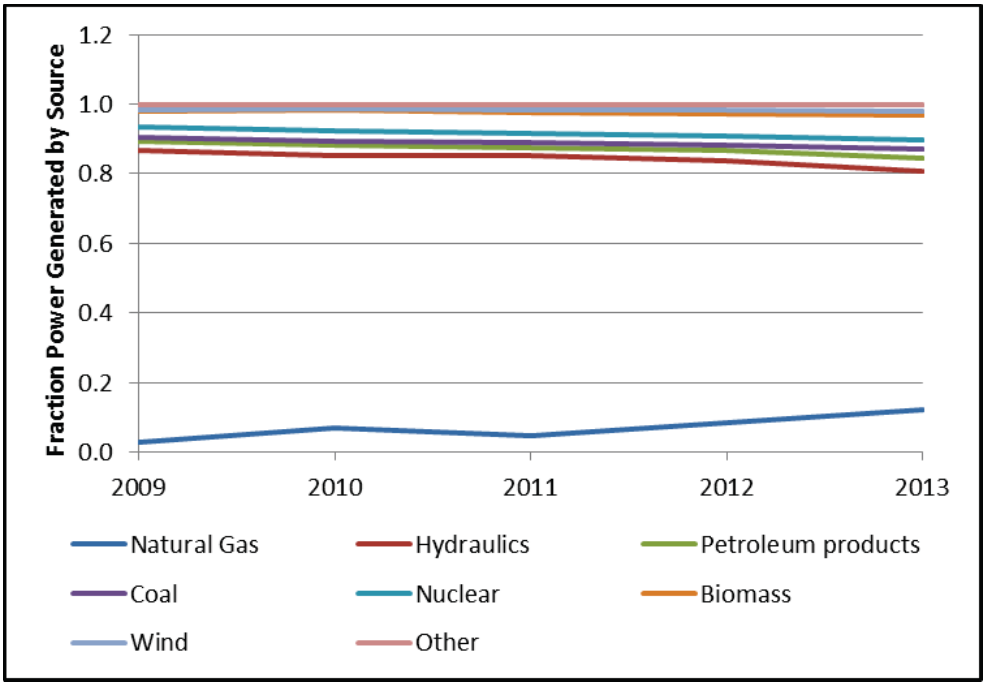
There is a better source of electrical power generation in Brazil. The Energy Research Company - EPE publishes a Statistical Review of the Electric Sector (EPE, 2014). The information from that source is shown below.

Table 5-3 Actual Brazil Power Mix

	2009	2010	2011	2012	2013
Natural Gas	2.86%	7.07%	4.72%	8.46%	12.11%
Hydro	83.87%	78.19%	80.55%	75.18%	68.59%
Petroleum products	2.73%	2.76%	2.30%	2.93%	3.88%
Coal	1.16%	1.36%	1.22%	1.52%	2.60%
Nuclear	2.78%	2.82%	2.94%	2.90%	2.57%
Biomass	4.69%	6.05%	5.95%	6.27%	6.96%
Wind	0.27%	0.42%	0.51%	0.91%	1.15%
Other	1.64%	1.34%	1.81%	1.81%	2.15%
Total	100.00%	100.00%	100.00%	100.00%	100.00%

CARB underestimates the natural gas, coal, and oil used for power generation in Brazil. Furthermore the quantity of gas being used is increasing with time as shown below. The fossil fuel fraction has increased 275% since 2009.

Figure 5-1 Power Generation Trends



Using a more accurate estimate of the Brazilian power mix will slightly increase the base emissions but also increase the power credit available for plants that export power to the grid. LCFS 46-145 cont.

5.4 Ethanol Production Summary

There are several errors in the CA GREET model related to the transfer of information from the T1 Calculator sheet to the core of the model. These include: LCFS 46-146

1. Nuclear and biomass power shares of the power generation are transposed when they are transferred to the ETOH sheet.
2. The inputs for sulphuric acid and ammonia are input into the cells for enzymes when they move from the T1 Calculator sheet to the ETOH sheet. Entering non-zero values will produce extremely high and erroneous GHG emissions.

There is also the potential for misinterpretation of the input values. The input for Residual oil is really the quantity of used lubricants that are burned in the plant and not the input of residual oil. LCFS 46-147

The quantity of biomass that is burned at the plants is hard coded in the model. Not all mills burn all of the bagasse on site; some sell a portion to other local industries. The emissions for these operations will be overestimated. The biomass from the T1 Calculator sheet is transferred to the ETOH sheet, but once it goes there it is not included in any calculations. Proper modelling should require the mills to enter the bagasse consumed and not hard code those quantities. The current model would underestimate the emissions from mills that LCFS 46-148 imported bagasse from another facility or used some straw from the fields to produce more electric power for export.

LCFS 46-148 cont.

6. ETHANOL TRANSPORTATION

Ethanol can be transported from Brazil to California by truck, rail, and pipeline in Brazil, by ocean tanker, and then by truck in California. In CA-GREET the user will select the transportation distances and the distances for each mode on the T1 Calculator sheet. The values in the calculator create emissions of 7.16 g CO_2e/MJ with only the Brazilian truck, ocean freight and the California Port to blending stations being non-zero inputs. The distance from the blending point to the service station is a non-adjustable system input for all types of ethanol; however the distance is different for sugarcane ethanol compared to corn ethanol (50 miles vs. 40 miles). They should be the same. LCFS 46-149

Table 6-1 Transportation Emissions

Mode	Distance	Emissions
Brazil Truck	130	1.01
Ocean Ship	8,758	5.06
US Truck	90	0.70
Truck to Service Station	50	0.39
Total		7.16

The Brazilian trucking distance is short but that will have to be filled in by the applicant for the specific mill.

The issue for modelling is the calculation of the ocean shipping emissions. There are three issues with the calculation which lead to an inaccurate assessment of the emissions. These are described below.

6.1 BACKHAUL

All of the ocean movements in the CA GREET model, ***except Brazilian ethanol***, have an energy charge for the primary movement and the backhaul movement. This backhaul charge is 84% of the energy of the one-way movement. There is no backhaul charge for the Brazilian ethanol. If there was, the emissions would increase by 3.43 g/MJ. The model should be revised to include backhaul as a default value whenever an applicant cannot prove that there will be no backhaul for the relevant pathway. LCFS 46-150

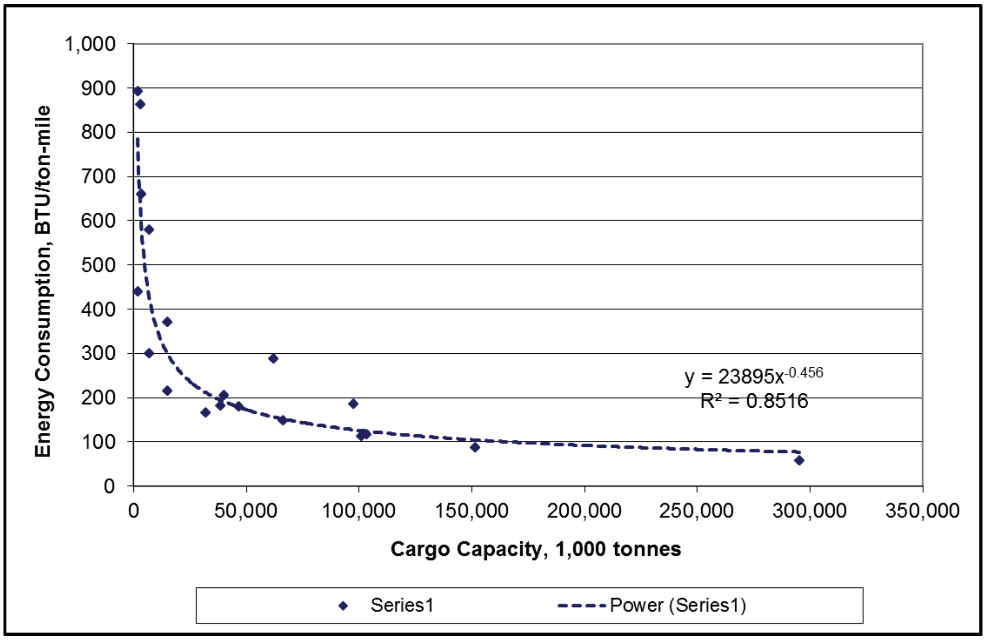
6.2 SHIPMENT SIZE

The CA GREET model assumes that the ethanol is delivered in 22,000 tons shipments. The US DOE EIA reports petroleum product imports on a company level basis. The 2014 data for the first 10 months of the year is currently available. Sugarcane ethanol from Brazil, Guatemala, and Nicaragua has been received in the US. No Brazilian ethanol has been landed in California during this time period. The average size of the shipment was 11,200 tons. This includes shipments that were delivered to more than one port as a single load of the combined capacity. This is only half of the value in the model and it will result in the energy and thus the emissions being underestimated. The model should be revised to require a verifiable shipment size as a user input. LCFS 46-151

6.3 VESSEL ENERGY REQUIREMENTS

The size of the ship has a large impact on the energy expended; larger ships require less energy to move the cargo. The International Maritime Organization (IMO, 2008) published data on the GHG emissions for various sizes of ships. The GHG emissions are easily converted to energy and the relationship for a range of chemical, petroleum product, and crude oil carriers are shown in the following figure. The energy consumption is very sensitive to vessel size, especially for the small vessels, and the energy can increase by 50% of more moving from a 22,000 ton vessel to an 11,000 ton vessel.

Figure 6-1 Energy Requirements vs. Vessel Size



The energy use for the 22,000 ton shipment in GREET is 140 BTU/ton-mile and it excludes the backhaul. The IMO estimate for an 11,000 ton shipment is 343 BTU/ton-mile. To this would be added the 84% for a back haul, for a total energy use of 631 BTU/ton-mile or 4.5 times more than the CA GREET model estimates. This would add about 17.5 g/MJ to the Brazilian sugarcane ethanol carbon intensity for pathways that cannot verify that there is no backhaul.

The calculation of energy consumption in GREET is based on theoretical calculations, includes some erroneous correlations, and underestimates the real world energy use. For example, the faster a ship travels the more power is consumed, but in GREET the energy consumption decreases with faster travel. This is because the power requirements increase as the cube of the velocity in the real world but in GREET the power requirements are independent of the speed. The energy consumed per mile is a function of the square of the speed, or power divided by speed. GREET uses the power/speed equation but doesn't account for the power being a function of the speed, so the end calculated result is incorrect. The model must be revised to correct the errors.

LCFS 46-152

6.4 TRANSPORTATION SUMMARY

There are significant issues with the ocean shipping calculations in GREET for many of the fuels, including sugarcane ethanol. The issues for sugar cane ethanol include:

LCFS 46-151 cont.

1. The shipment size of 22,000 tons is too high and is not a user input.

LCFS 46-150 cont.

2. Sugar cane Ethanol from Brazil, uniquely of all of the fuels in CA GREET, is not charged with a backhaul.

LCFS 46-152 cont.

3. The energy use for ocean shipping is calculated but the calculations underestimate the energy used by a significant amount.
4. Energy use in the model is 145 BTU/ton-mile. Data from the IMO suggests that this should be 335 BTU/ton-mile plus 283 BTU/ton-mile for the backhaul. This would increase the ocean shipping emissions by 17.0 g CO_2eq/MJ, a very significant difference.

7. DISCUSSION

The sugar cane ethanol pathway in the new CA GREET 2.0 model has been thoroughly reviewed. The review has considered the following questions.

- Are the pathways consistent?
- Does the model ask for the key input parameters?
- Does the model reflect the actual practices?
- Does the model have the correct background data and are the calculations correct?

A significant number of issues were identified. Most of the issues results in the model returning values that are lower than what would be returned if the issues were addressed properly.

7.1 SUGAR CANE FARMING SUMMARY

The CA GREET model does not apply different energy use factor to sugar cane farming even though the two scenarios with mechanical harvesting require almost twice the energy of a manual harvest system. A mechanical harvest system with 100% of the energy supplied by diesel fuel will have GHG emissions of 7.54 g CO_2eq/MJ.

There is evidence that the crop residues that are left on the field are reducing the synthetic nitrogen that is required. The proportion of nitrogen from fertilizer and from crop residue should vary depending on whether or not there is straw burning. The CA GREET model is assuming that there is no difference in nitrogen requirements between burned and unburned fields, an unlikely scenario. LCFS 46-153

Although there is significant uncertainty regarding the appropriate N_2O emission factor for sugar cane production, the best information in the peer reviewed literature indicates that the 1% EF1 factor used by CARB is too low. The impact of increasing this to 1.5% is an increase in sugar cane N_2O emissions of 2.83 g CO_2eq/MJ.

7.2 STRAW BURNING SUMMARY

The straw burning emissions are too low by about 4.36 g CO_2eq/MJ as a result of using the IPCC emission factors for Ag residue burning rather than the values for grassland and savanna burning. This increase would be reduced to about 2.5 g CO_2eq/MJ if the nitrogen from the burned straw was not returned to the soil as discussed in the previous section. LCFS 46-154

7.3 CANE TRANSPORT SUMMARY

The model should be changed so that the share of the delivery of cane by medium duty trucks and by heavy duty trucks is a user input. The truck energy requirements are the same as for corn ethanol. LCFS 46-155

7.4 ETHANOL PRODUCTION SUMMARY

There are several errors in the CA GREET model related to the transfer of information from the T1 Calculator sheet to the core of the model. These include: LCFS 46-156

1. Nuclear and biomass power shares of the power generation are transposed when they are transferred to the ETOH sheet.
2. The inputs for sulphuric acid and ammonia are input into the cells for enzymes when they move from the T1 Calculator sheet to the ETOH sheet. Entering non-zero values will produce extremely high and erroneous GHG emissions.

LCFS 46-156 cont.

There is also the potential for misinterpretation of the input values. The input for Residual oil is really the quantity of used lubricants that are burned in the plant and not the input of residual oil.

The quantity of biomass that is burned at the plants is hard coded in the model. Not all mills burn all of the bagasse on site; some sell a portion to other local industries (San Martinho, 2007). The emissions for these operations will be overestimated. The biomass from the T1 Calculator sheet is transferred to the ETOH sheet, but once it goes there it is not included in any calculations. A proper modelling would require the mills to enter the bagasse consumed and not hard code those quantities. The current model would underestimate the emissions from mills that imported bagasse from another facility or used some straw from the fields to produce more electric power for export.

LCFS 46-157

7.5 Transportation Summary

There are issues with the ocean shipping calculations in GREET for many of the fuels, including sugarcane ethanol. The issues for sugar cane ethanol include:

1. The shipment size of 22,000 tons is too high and is not a user input. LCFS 46-151 cont.
2. Ethanol, uniquely of all of the fuels in CA GREET, is not charged with a backhaul. LCFS 46-150 cont.
3. The energy use for ocean shipping is calculated but the calculations underestimate the energy used by a significant amount.
4. Energy use in the model is 145 BTU/ton-mile. Data from the IMO suggests that this should be 335 BTU/ton-mile plus 283 BTU/ton-mile for the backhaul. This would increase the ocean shipping emissions by 17.0 g CO_2eq/MJ, a very significant difference.

LCFS 46-152 cont.

7.6 Summary

With respect to the four questions that were investigated we find that:

1. There are inconsistencies between some aspects of the sugarcane ethanol pathway and all other pathways. LCFS 46-158
2. There are key input parameters that should be included in the model. These would include, the share of cane transported by MD and HD trucks, the ocean shipment size, and confirming that a backhaul is always provided. LCFS 46-159
3. The model does not reflect actual practice. The lack of change in the farming emissions with the different practices that are employed is problematic. The ocean shipping size is double the typical shipments. LCFS 46-160
4. The background data in the model is not accurate. The biggest issue is with the energy used for ocean shipping but the emission factor applied to cane burning should be changed. LCFS 46-161

In addition, there are some programming errors in the calculator that need to be adjusted. Correcting the issues in the model will increase the GHG emissions in the different scenarios. The following two tables itemize the changes that should be made to the model.

LCFS 46-162

Table 7-1 Summary of Changes - Farming

Stage	Manual Harvest			Mechanical Harvest		
	Default	Revised	Change	Default	Revised	Change
All Diesel	4.65	5.39	0.74	4.65	5.39	0.74
Extra Diesel for Mech Harvest					7.54	2.15
Extra N Fert for manual	3.22	4.43	1.21			
N_2O from extra N	2.88	3.96	1.08			
Total			3.03			2.89

Table 7-2 Changes to Rest of Pathway

Item	Default	Revised	Change
N_2O EF	7.48	10.31	2.83
Residue Leaching		7.13	-0.35
Straw Burning EF	10.06	14.42	4.36
Power Export	-0.72	-0.76	-0.04
Shipping			
Backhaul	7.16	11.41	4.25
Ship size		18.88	7.47
IMO Energy		24.15	5.27
Total			23.79

8. REFERENCES

Andreae, M. O. & Merlet, P. 2001. Emission of trace gases and aerosols from biomass burning. Glob. Biogeochem. Cycles 15, 955□966 (2001). http://www.nifc.gov/smoke/documents/Emissions_Trace_Gas_from_Biomass_Burning.pdf

Australian Department of Climate Change and Energy Efficiency. 2011. The Australian Government Submission to the UN Framework Convention on Climate Change. April 2011. http://www.climatechange.gov.au/en/climate-change/emissions.aspx

da Silva Paredes, D., Lessa, A. C. D. R., de Sant'Anna, S. A., Boddey, R. M., Urquiaga, S., & Alves, B. J. 2014. Nitrous oxide emission and ammonia volatilization induced by vinasse and N fertilizer application in a sugarcane crop at Rio de Janeiro, Brazil. Nutrient cycling in agroecosystems. http://link.springer.com/article/10.1007/s10705-013-9594-5

Denmead, O., Macdonald, B., Bryant, G., Naylor, T., Wilson, S., Griffith, D., Wang, W., Salter, B., White, I., Moody, P. 2010. Emissions of methane and nitrous oxide from Australian sugarcane soils. Agricultural and Forest Meteorology (2010) Volume: 150, Issue: 6, Pages: 748-756. http://dx.doi.org/10.1016/j.agrformet.2009.06.018

Dunn, J. Eason, J., Wang, M. 2011. Updated Sugarcane and Switchgrass Parameters in the GREET Model. https://greet.es.anl.gov/files/updated_sugarcane_switchgrass_params

EPE. 2014. Statistical Yearbook of Electricity. http://www.epe.gov.br/AnuarioEstatisticodeEnergiaEletrica/Anu%C3%A1rio%20Estat%C3%ADstico%20de%20Energia%20El%C3%A9trica%202014.xls

FORTES, Caio et al. 2013. Contribution of nitrogen from sugarcane harvest residues and urea for crop nutrition. Sci. agric. (Piracicaba, Braz.), Piracicaba, v. 70, n. 5, Oct. 2013 . http://www.scielo.br/pdf/sa/v70n5/a05v70n5.pdf

Lisboa, C., Butterbach-Bahl, K., Mauder, M., Kiese, R. 2011. Bioethanol production from sugarcane and emissions of greenhouse gases – known and unknowns. GCB Bioenergy. 2011. http://dx.doi.org/10.1111/j.1757-1707.2011.01095.x

Renouf, M., Pagan, R., and Wegener. M. 2010. Life cycle assessment of Australian sugarcane production with a focus on sugarcane growing. The International Journal of Life Cycle Assessment. http://dx.doi.org/10.1007/s11367-010-0226-x

San Martinho. 2007. Offering Memorandum. http://ri.saomartinho.ind.br/saomartinho/web/arquivos/SMTO_OfferimMemorandum_20090810_eng.pdf

Seabra, J.E.A., Macedo, I.C., Chum, H.L., Faroni, C.E., Sarto, C.A., 2011. Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use. Biofuels, Bioproducts and Biorefining 5, 519–532.

Signor, D., Cerri, C., and Conant, R. 2013. N_2O emissions due to nitrogen fertilizer applications in two regions of sugarcane cultivation in Brazil. http://iopscience.iop.org/1748-9326/8/1/015013/pdf/1748-9326_8_1_015013.pdf

Thorburn, P., Biggs, J., Collins, K., Probert, M. 2010. Using the APSIM model to estimate nitrous oxide emissions from diverse Australian sugarcane production systems. Agriculture, Ecosystems & Environment. Volume 136, Issues 3–4, 15 March 2010, Pages 343–350. http://dx.doi.org/10.1016/j.agee.2009.12.014

Vargas, V., Cantarella, H., Martins, A., Soares, J., do Carmo, J., de Andrade, C. 2014. Sugarcane Crop Residue Increases N2O and CO2 Emissions under High Soil Moisture Conditions. http://dx.doi.org/10.1007/s12355 -013-0271-4

Walter, A., Galdos, M., Scarpare, F., Leal, R., Seabra, J., da Cunha, M., Picoli, M., de Oliveira, C. 2014. Brazilian sugarcane ethanol: developments so far and challenges for the future. Wiley Interdisciplinary Reviews: Energy and Environment. Vol. 3 Issue 1. http://dx.doi.org/10.1002/wene.87

Wang, L., Quiceno, R., Price, C., Rick Malpas, R., Woods, J. 2014. Economic and GHG emissions analyses for sugarcane ethanol in Brazil: Looking forward, Renewable and Sustainable Energy Reviews, Volume 40, December 2014, Pages 571-582, ISSN 1364-0321, http://dx.doi.org/10.1016/j.rser.2014.07.212

This page intentionally left blank.

46_OP_LCFS_GE Responses (Page 118 – 148)

461. Comment: **LCFS 46-130**

The comment argues that the Tier 1 calculator is not flexible enough to accommodate all sugar-cane based ethanol pathways in the CA-GREET 2.0 model.

Agency Response: The Tier 1 Calculator may not entirely be used to model complex sugarcane-based ethanol pathways where the sugarcane straw (residue of the mechanical harvesting process) is harvested, brought to the mill, and used as supplemental fuel for the biomass boilers; nor can the Tier 1 Calculator be entirely used to model ethanol fuel derived from sugarcane molasses, a by-product of the sugar production process. Staff further concurs that both of these pathways could be treated as a Tier 2 application and subject to additional scrutiny of an ARB staff person. The Tier 1 Calculator has “express” modules that would enable the applicant to expeditiously determine the GHG impacts from common pathway operations, such as agricultural farming; feedstock transport; finished fuel transport and distribution; straw burning and mechanized harvesting; and electricity cogeneration and surplus power export. These segments are common to most sugarcane-based pathways.

Staff has long since revised the pathway methodology for ethanol derived from sugarcane molasses. The market-based allocation methodology can only be used if the applicant can demonstrate the low economic value of the byproduct molasses produced from the sugar production process. The molasses in this case is a low-quality molasses that is typically sold as a livestock feed supplement. When the applicant can demonstrate that the molasses is a low-value byproduct, the full iLUC value for the crop cannot be designated to the pathway. In this case, the iLUC is apportioned based on a mass allocation of fermentable sugars.

In a recent sugarcane-based molasses-to-ethanol pathway certification,[31] the molasses produced by the sugar and ethanol producer was determined to not be a low-value byproduct, but a

[31] See Raizen Energia, S.A., Method 2B Application for Brazilian Sugarcane Molasses-based Ethanol, Carbon Intensity for Costa Pinto Mill, April 14, 2014. http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/rzn-copi-041414.pdf

feedstock for ethanol production. Therefore, the pathway CI was determined using a mass basis of fermentable sugars allocated between finished sugar and molasses production, and the pathway inherited the full iLUC value designated to the crop.

462. Comment: **LCFS 46-131**

The comment questions the energy use data for sugarcane farming in the CA-GREET 2.0 model.

Agency Response: The Tier 1 calculator was meant to be an "express" calculator with minimal customization of the suggested default parameters of the baseline pathways. The intent was to prevent a change in input parameters (in agricultural chemical and fertilizer use, or agricultural farming fuel shares, for example) where the values cannot be easily corroborated, verified by staff, or usage levels enforced. The Tier 1 Calculator only permits a change in user input "yellow cells".

ARB staff has relied on research provided by ANL to support a higher energy use estimate for sugarcane farming. The higher energy use value of 95,000 Btus per tonne of cane harvested, and the corresponding fuel shares, were derived from the GREET1_2013[32] model. The value was endorsed due the higher levels of mechanized harvesting observed on applicant-owned or leased sugarcane farms, and "green harvest" protocols adopted by local governments in the State of Sao Paulo, for example. In addition, ARB staff has no empirical data yet to support projected sugarcane farming parameters in the future. As data becomes available, staff will consider factors proposed by Wang et al (2014) and stated in Table 2-2 (Appendix C) of the commenter's report.

463. Comment: **LCFS 46-132**

The comment expresses concern that the CA-GREET model 2.0 model does not allow user input values to account for different farming practices

Agency Response: ARB staff depended upon agricultural chemical and fertilizer use input parameters suggested in the GREET1_2013

[32] Argonne National Laboratories, 2013. "Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET Version 1), Systems Assessment Section, Center for Transportation Research, Argonne National Laboratories, October 2013.

model developed by ANL.[33] Those same factors are being proposed for adoption in CA-GREETv2.0. Staff concurs with the commenter that mechanically-harvested farms deposit straw residue on the sugarcane farms. The residue is known to contain N, P, and K nutrients which are retained in the soil to some extent, lowering the amount of fertilizer use for subsequent crop cycles. The commenter's suggestion that different fertilizer application rates for manually- and mechanically-harvested farms be used would be extremely difficult to enforce because the application rates recommended are national averages.

Staff believes that most sugarcane-based ethanol producers procure cane from both mechanically-harvested and manually-harvested farms. The fate of mechanically-harvested sugarcane residue is not exactly clear. In some instances, sugarcane straw from mechanically-harvested farms is collected and burned in a corner field. Alternately, sugarcane straw is also being recognized for its potential to produce additional fuel, either by direct combustion in a biomass boiler or by production of sugars by enzymatic hydrolysis.[34] Therefore, at some point in the future, staff may account for the removal of sugarcane straw and non-availability of nutrients for the next sugarcane crop cycle. Accidental fires, acts of nature, and sabotage also complicate the issue of pre-harvest and residue burning. Lastly, ARB staff has witnessed a tremendous increase in the number of applicants to the LCFS program using mechanized harvesting. Staff believes that this trend is likely to continue during non-drought affected years. Manually-harvested sugarcane is also being phased-out in Brazil. With all these considerations, staff recommends that the fertilizer nutrient application levels be maintained at the present level without making a distinction for manually- or mechanically-harvested sugarcane farms.

[33] Wang, Michael, Jeongwoo Han, Jennifer B. Dunn, Hao Cai, and Amgad Elgowainy. "Well-to-wheels energy use and greenhouse gas emissions of ethanol from corn, sugarcane and cellulosic biomass for US use." *Environmental Research Letters* 7, no. 4 (2012): 045905. http://iopscience.iop.org/1748-9326/7/4/045905

[34] See GranBio BioFlex Plant Method 2B Application for the Production of Cellulosic Ethanol from Brazilian Sugarcane Straw Residue, Sao Miguel dos Campos, Alagoas State, Brazil. http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/gb-102414.pdf

464. Comment: **LCFS 46-133**

The comment points out that the N_2O emission factor is fixed in the CA-GREET 2.0 model.

Agency Response: The commenter's assessment that the nitrous oxide emissions resulting from above ground and below ground biomass and applied nitrogen fertilizer is incorrect. The 7.48 g CO_2e/MJ value presented by the commenter does have fixed aspects as well as a variable aspect that applicants may vary in the T1 Calculator of CA-GREET 2.0. First, the fixed aspects (within the Tier 1 Calculator and application process) are including, but not limited to the nitrogenous fertilizers applied, the IPCC emission factors related to applied nitrogen fertilizer (1.325% nitrogen as N_2O as a percent of nitrogen in nitrogen fertilizer) and above and below ground biomass (1.225% nitrogen as N_2O as a percent of nitrogen in biomass), and the nitrogen content of above and below ground biomass (1,036 g/tonne for sugarcane). The variable portion of this value for all similar crops or agricultural residue based feedstocks is the yield of ethanol, which is typically represented as a volume per mass of feedstock. An increase in the ethanol yield (for example) per feedstock input would decrease this emission for corn, sorghum, sugarcane, corn stover and other similar feedstocks. Conversely, a decrease in fuel yield would result in greater emissions. For example, using the Tier 1 Calculator for sugarcane ethanol and holding all parameters constant except for the ethanol yield, a comparison can be accomplished. The typical yield of sugarcane ethanol is 21.4 gal/wet tonne (metric tons) of sugarcane, results in above ground and below ground biomass and applied nitrogen fertilizer nitrous oxide emissions of 7.20 gCO_2e/MJ. If the yield is changed to 19.0 gal/wet tonne, the emissions are 8.11 gCO_2e/MJ. If the yield is changed to 24.0 gal/wet tonne, the emissions are 6.42 gCO_2e/MJ. Due to increased fuel production per amount of feedstock, less feedstock is required; therefore, less nitrogen fertilizer is required and less above and below ground biomass results, leading to lower emissions. The opposite is true if the ethanol yield is decreased. Additionally, a review of other Tier 1 pathways (corn or sorghum) in the Tier 1 Calculator, should have cleared-up this misunderstanding or calculation error. Staff appreciates the time the commenter took to make staff aware of a potential error (no longer existing) or possibly a typical misunderstanding of how the downstream (ethanol yield) parameter affects upstream (feedstock) requirements and resulting emissions.

465. Comment: **LCFS 46-134**

The comment argues that data on fertilizer application does not support the model assumption that the nitrogen in the crop residue is returned to the soil as ash.

Agency Response: Staff believes that for manually-harvested sugarcane farms, the nitrogen in the sugarcane straw is likely to burn and be emitted as an oxide of nitrogen rather than be returned to the soil in the form of ash. At this point, staff does not have sufficient information to characterize the distinction between fertilizer inputs for manually- and mechanically-harvested sugarcane farms. Staff depended upon the fertilizer input values from ANL (see response to **LCFS 46-132** above). These values represent national averages, and most sugarcane-based ethanol producers procure cane from both mechanically- as well as manually-harvested sugarcane farms. The data represents cases where less fertilizer is applied on harvested farms where straw is left in the field, and cases where more fertilizer is applied because the straw was primarily consumed in pre-harvest burning. With manual or pre-harvest burning being phased-out in predominant sugarcane growing regions in Brazil, staff believes it may be futile to determine fertilizer application rates for each type of harvest. However, staff will continue to monitor research updates and make necessary adjustments if the application rates change significantly.

466. Comment: **LCFS 46-135**

The comment argues that there should be different N_2O emission factors for crop residues and N-fertilizers.

Agency Response: ARB staff agrees that N_2O from crop residue should be calculated using the IPCC Tier 1 default emission factor of 1.225 percent rather than the 1.325 percent applied to synthetic nitrogen fertilizer. The CA-GREET model has been updated to reflect this change.

Staff concurs with the commenter that N_2O emissions are influenced by soil type, precipitation, topography, temperature, and other factors. Staff further agrees that the CA-GREET model will underestimate the N_2O emissions for some crops and regions of the world, and overestimate the N_2O emissions for others. While there remains a high degree of uncertainty in modeling of N_2O emissions, IPCC Tier 2 methodology should ideally be used to more accurately estimate N_2O emissions; however, until ARB staff is able to develop a robust protocol for verification of applicant-specific agricultural-phase parameters, the IPCC Tier 1 default emission factors will continue to be applied uniformly to all feedstocks in the CA-GREET model.

467. Comment: **LCFS 46-136**

The comment argues that N_2O emissions factors for N fertilizers used in sugarcane farming should be high.

Agency Response: ARB staff appreciates the commenter sharing scientific literature with the ARB. Staff does not disagree with the research studies presented advocating higher N_2O emissions rates applicable to sugarcane farming in Brazil. Staff will review the research presented and discuss the merits and impacts of sugarcane straw residue retention on farms. Staff will further consider consensus opinion and derive a conclusion.

While it is important to monitor and evaluate new research, new studies assessing life cycle impacts on transportation fuel pathways, and revisions to peer-reviewed fuel carbon intensities affecting emissions factors, there is public concern over constant changes to the model parameters and a push for more stability regarding certified fuel carbon intensities. At some point, ARB staff must finalize and recommend 'closure' to the best available data. Periodically, staff will undertake an assessment of all currently available science and present an update to the life cycle analysis model, just as staff has done for CA-GREETv1.8b.

468. Comment: **LCFS 46-137**

This comment is a summary of the sugarcane farming-related comments previously made by the commenter

Agency Response: Each of these comments is addressed as follows:

1. *CA-GREET does not apply different energy use factors to sugarcane farming, even though the two scenarios with mechanical harvesting require almost twice the energy of a manual harvest system.*

   The commenter is incorrect that CA-GREET does not differentiate between burned and unburned fields. The burn-area evaluation using MODIS-based satellite imagery suggests decreased levels of pre-harvest burning on LCFS applicant owned or leased sugarcane farms in Brazil year-over-year. This leads staff to believe that manual harvesting is on the decline in pre-dominantly sugarcane growing regions of Brazil. Staff further believes that this practice will be phased-out by public and private initiatives in Brazil. As a result of increased levels of mechanized harvesting, staff did not hesitate to adopt higher farming energy usage numbers suggested by ANL. Those ethanol producers who continue to procure cane from manually harvested regions can avail of lower energy use via the Method 2/Tier 2 pathway LCFS application process.

2. *Evidence suggests crop residues left on the field reduce required synthetic nitrogen, but CA-GREET assumes there is no difference in nitrogen requirements between burned and unburned fields.*

   ARB staff disagrees; CA-GREET assumes that there may be differences between burned and unburned fields, but those differences are sometimes masked by use of national fertilizer application averages. If the national average data, upon which the present CA-GREETv2.0 fertilizer application rates are based, changes in the future, ARB may consider a CA-GREET revision.

3. *While there is significant uncertainty regarding the N_2O emission factor for sugarcane production, the best information indicates that the one percent EF1 factor used by ARB is too low.*

   ARB has chosen not to adjust the N2O emission factor until more detailed information is available.

469. Comment: **LCFS 46-138**

The comment provides the IPCC factors for grassland burning and Ag residue burning. It goes on to points out that the GHG emissions for straw burning would be higher if the IPCC value for grassland burning were used instead of Ag residue burning.

Agency Response: There is no doubt that sugarcane straw is an agricultural residue. The commenter's suggestion that IPCC-based CH_4 and N_2O factors applicable to grasslands be used for sugarcane straw residue lacks any rationale. Staff believes grassland factors are not applicable to sugarcane farm burning, but may be more suitable for indirect land use change emissions associated with land clearing, for example. Staff, however, concurs that straw-burning emissions only be based upon CH_4 and N_2O emissions. All emissions from sugarcane straw burning are determined to be biogenic; however only CH_4 and N_2O emissions will be counted because these pollutants are regulated by the IPCC. CO is assumed to rapidly oxidize to CO_2, and VOCs are assumed to be short-lived in the atmosphere. A correction for biogenic carbon uptake and elimination of VOC and CO equivalent CO_2e emissions from straw burning have been proposed as additional 15-day changes to the Regulation.

470. Comment: **LCFS 46-139**

The comment states that the current straw burning emissions are low.

Agency Response: This comment presents a summary of the sugarcane straw burning emissions presented by the commenter in the previous Comment **LCFS 46-138**. See the response to that comment.

471. Comment: **LCFS 46-140**

The comment supports the use of medium and heavy duty trucks for cane transport.

Agency Response: The commenter states that both medium-duty diesel (MDD), as well as heavy-duty diesel (HDD), trucks are employed to transport cane from the field to sugar and ethanol mills. The fuel share for each mode of transport is 100 percent because the transport modes are unique. Medium-duty diesel trucks are used to transport cane from the harvested location to a central collection location approximately two miles from the field. From the central location, the cane is then loaded onto HDD trucks for transporting the cane to the sugar and ethanol mills on paved roads. Staff, however, disagrees with the commenter that both types of trucks have the same energy intensity. The energy intensity for MDD and HDD trucks is depicted in the table below:

Energy Intensity of MD and HD Diesel Trucks Used for Sugarcane Transport

	HDD Truck	**MDD Truck**
Energy Intensity:	Btu per ton-mile	Btu per ton-mile
Origin to Destination	723	1,544
Back-Haul	723	1,544

Staff suggests that if the commenter desires, the fuel shares for MDD and HDD trucks can be changed to a user-defined input in the "T&D!" worksheet of the draft CA-GREETv2.0 spreadsheet (see Item 9: Energy Consumption and Emissions of Feedstock and Fuel Transportation, Cells GM107:GN107).

472. Comment: **LCFS 46-141**

The comment states that energy provided by bagasse does not appear in energy consumption values.

Agency Response: The yellow input cells in the T1 Calculator for sugarcane-based ethanol apply to additional energy use by the applicant during ethanol production. The GHG emissions from bagasse (the sugarcane residue left behind after the cane is crushed and juice is extracted) combustion are considered biogenic (except for CH4 and N2O emissions), and are counted with a credit for biogenic carbon uptake (see worksheet EtOH! In draft CA-GREETv2.0, Cells DU371:DU380). Additional biomass brought in and used to produce cogenerated electricity is not credited in the pathway. . All surplus cogenerated electricity is verified either by material balance or credited only to the extent supported by the ethanol production. Additionally, see response to **LCFS 46-148**.

473. Comment: **LCFS 46-142**

The comment states that there are errors in the T1 calculator sheet.

Agency Response: ARB staff concurs with the commenter that additional chemicals may be used during ethanol production. These chemicals were not identified in ARB's internal pathway for Brazilian sugarcane-based ethanol.[35] As the commenter points out, staff has confirmed that sulfuric acid is used during fermentation. The reason why it was left out was because the GHG impacts from usage of sulfuric acid were found to be extremely small (less than 0.02 g CO_2e/MJ). Similarly, staff believes that yeast is propagated onsite at most sugarcane ethanol production facilities. A yellow input cell has been provided nevertheless. Staff also concurs that an error exists and has traced the error reported by the commenter back to the GREET1_2013 model developed by ANL. The error was corrected in a 15-day change.

[35] ARB, 2009. "Detailed California-Modified GREET Pathways or Brazilian Sugarcane Ethanol: Average Brazilian Ethanol, With Mechanized Harvesting and Electricity co-Product Credit, With Electricity Co-Product Credit," Stationary Source Division, September 23, 2009, Version 2.3.

Staff also concurs with the research paper[36] cited by the commenter that lime is used in ethanol production. Staff has also assessed that if lime is used (most likely for sugarcane juice pH adjustment), then the impact at usage rates specified by the commenter is 0.66 g CO_2e/MJ to the Brazilian sugarcane-based ethanol pathway. Staff has investigated the use of this chemical and added a lime into to the Tier 1 Calculator, as well as the EtOH! Worksheet in a 15-day change. The corresponding GHG impacts of this chemical use will thus be reflected in the sugarcane-based ethanol pathway CI.

474. Comment: **LCFS 46-143**

The comment states that the use of the average electricity mix results in lower credits for power exports.

Agency Response: The new CA-GREET model uses the average power mixes rather than trying to estimate the marginal power in all the different regions. See the response to comment **LCFS 18-3.**

475. Comment: **LCFS 46-144**

The comment points out an error for the Brazilian power mix in the CA-GREET 2.0 model.

Agency Response: ARB staff concurs with the commenter on the apparent switch between biomass and nuclear energy shares in the Average electrical generating mix for the country of Brazil. The inadvertent error has been fixed in the final version of the CA-GREETv2.0 model recommended for adoption.

476. Comment: **LCFS 46-145**

The comment states that better quality data (EPE, 2014) than currently used in the model exist for the Brazilian power mix.

Agency Response: ARB staff concurs with the commenter regarding the data presented for the average portfolio of electrical generating assets in Brazil. The energy mix for electrical generation being proposed is based on data provided in the annual

[36] Seabra et al. “Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use,” Seabra, J.E.A., Macedo, I.C., Chum, H.L., Faroni, C.E., and Sarto,C.A., Biofuels, Bioproducts, & Biorefining, 5:519-532, March 7, 2011.

Brazilian Energy Balance[37] prepared by the Ministry of Mines and Energy, Government of Brazil. The correction was proposed as a 15-day change to the regulation to consider the re-adoption of an updated Low Carbon Fuel Standard (LCFS), as identified in the table below. Staff thanks the commenter for sharing the average Brazilian mix data.

Proposed 15-day Change to the Average Electrical Generation Mix for Brazil

Electric Generation Mixes: Data Table for Use in GREET (From Annual Energy Outlook 2013)	Brazilian Mix Stationary
Residual oil	3.4%
Natural gas	7.9%
Coal	1.9%
Nuclear power	2.6%
Biomass	7.0%

477. Comment: **LCFS 46-146**

This comment presents a summary of the comments presented on the life cycle impacts of ethanol production from Brazilian sugarcane.

Agency Response: This comment presents a summary of the comments presented on the life cycle impacts of ethanol production from Brazilian sugarcane. Responses to comments on this subject were presented above (see ARB staff response to **LCFS 46-142** and **LCFS 46-145**).

478. Comment: **LCFS 46-147**

The comment alleges that there is the potential for misrepresenting the used lubricant.

Agency Response: The commenter suggests that the input for residual oil under “Ethanol Production” in the T1 Calculator is actually an input being used for lubricants consumed by the ethanol

[37] The average portfolio of electrical generating assets is based upon the Brazilian Energy Balance for years 2010-2012, published by the Empresa de Pesquisa Energetica (EPE) agency of the Ministry of Mines and Energy (http://www.mme.gov.br).

plant. ARB staff concurs that is the correct assumption; it represents lubricant usage at the plant. The only way to simulate lubricant usage is by assuming that lubricants have similar properties to “Residual Oil” in worksheet Fuel_Specs!.

479. Comment: **LCFS 46-148**

The comment asserts that the emissions from bagasse burning can be over- or underestimated if the plant sells or buys some portion of the bagasse to/from other plants.

Agency Response: ARB staff believes that the commenter’s concern regarding the model’s treatment of biomass burned at the plants is largely irrelevant. Bagasse generated by the sugarcane crush is burned in the biomass boilers to produce cogenerated electricity. Most sugarcane-based ethanol plants are self-sufficient for their thermal (process steam) and electricity requirements, and even produce a surplus amount of electricity which is exported to the public grid. This exported electricity is assumed to displace the Brazilian average electricity mix. Regarding the concern that additional biomass may be brought into the facility (for example, sugarcane straw) to produce additional electricity, this should have no impact on the pathway carbon intensity, as only the modeled surplus cogeneration rate per metric tonne of sugarcane processed is credited to the pathway. Staff has relied upon Wang et al,[38] as well as material and energy balances provided by applicants, to estimate the amount of cogenerated electricity produced and surplus exported. Lastly, the bagasse combustion emissions are accounted for in ethanol production (see worksheet EtOH!), with a credit for biogenic uptake of carbon dioxide (CH_4 and N_2O emissions are counted).

480. Comment: **LCFS 46-149**

The comment argues that the transport distance between the blending point and the service station should be the same for sugarcane ethanol and corn ethanol.

Agency Response: There may be small differences in ethanol transport distance assumptions to the blending terminal between corn ethanol and sugarcane ethanol. These differences arise since

[38] Wang, 2007. “WTW Energy Use and GHG Emissions of Brazilian Sugarcane Ethanol Production Simulated by Using the GREET Model,” Wang, M., Wu, M., Huo, H., and Liu, J., Center for Transportation Research, Argonne National Laboratory, July 20, 2007.

corn ethanol arrives primarily from the Midwest by rail car and sugarcane ethanol arrives at a port terminal via ocean tanker. The corn ethanol is transported from the railyard to a bulk terminal over a suggested distance of 100 miles for blending with CARBOB gasoline. The sugarcane ethanol is transported from the port terminal to a bulk terminal over a suggested distance of 90 miles for blending with CARBOB gasoline. However, the input for this parameter in both pathways is provided as a yellow cell for the user to provide, based on actual ethanol transport operations.

481. Comment: **LCFS 46-150**

The comment states that the CA GREET model should be revised to include backhaul as a default, to prevent underestimation of emissions.

Agency Response: See response to comment **LCFS 46-21**.

482. Comment: **LCFS 46-151**

The comment states that the CA-GREET model should be revised to require a verifiable shipment size as a user input to prevent underestimation of emissions.

Agency Response: ARB staff has determined that the typical ethanol ocean tanker vessels currently calling at the Port of Santos in Brazil are Medium Range tankers, which typically carry between (33,000 – 42,700 tons). The commenter believes that shipments are about one-half the ocean tanker capacity. If this is true, then clearly there is more ethanol or other comparable product to be transported during its onward journey from a California port. Hence, a back-haul energy charge must be substantiated with more evidence. Staff will continue to investigate ethanol transport operations from Brazil to California by ocean tanker. However, the CA-GREETv2.0 transport and distribution assumptions are as accurate as possible given currently available information.

483. Comment: **LCFS 46-152**

The comment states that calculation error is introduced to the CA GREET emissions results by not taking into account an appropriate cargo capacity of the vessel and the speed at which the vessel travels.

Agency Response: ARB staff appreciates the commenter sharing their point of view on power requirements and energy use by ocean tankers for transport of ethanol from Brazilian ports to California ports. Staff will continue to investigate the logistics of ethanol transport by ocean tanker. Staff will retain the current ocean transport assumptions (capacity, energy use, and back-haul) in the CA-GREETv2.0 model until further evidence is obtained. For now, staff believes that the parameters are representative, on average, of what an ocean tanker with a cargo payload of 22,000 tons is capable of transporting:

22,000 ton x 2,000 lbs/ton x 453.4 g/lb / 2,988 g/gal Ethanol = 6.7 million gallons of ethanol.

Staff believes shipments of over 10 million gallons of ethanol are not uncommon. It is true that some smaller ethanol producers in Brazil may ship much smaller quantities, but for now the parameters suggested in draft CA-GREET appear to be representative.

484. Comment: **LCFS 46-153**

This comment is a summary of the comment on sugarcane farming emissions.

Agency Response: This comment is a summary of the comment on sugarcane farming emissions. Please see ARB staff responses to **LCFS 46-131** to **LCFS 46-137**.

485. Comment: **LCFS 46-154**

This comment is a summary of the comment on sugarcane straw burning emissions.

Agency Response: This comment is a summary of the comment on sugarcane straw burning emissions. Please see ARB staff responses to **LCFS 46-138** to **LCFS 46-139**.

486. Comment: **LCFS 46-155**

This comment is a summary of the comment on sugarcane transport.

Agency Response: This comment is a summary of the comment on sugarcane transport. Please see ARB staff response to **LCFS 46-140**.

487. Comment: **LCFS 46-156**

This comment is a summary of the comment on sugarcane-based ethanol production in Brazil.

Agency Response: This comment is a summary of the comment on sugarcane-based ethanol production in Brazil. Please see ARB staff responses to **LCFS 46-141** to **LCFS 46-148**.

488. Comment: **LCFS 46-157**

Part of this comment is a summary of the comment on the consumption of residual oil in the sugarcane-based ethanol plant in Brazil. Another part of this comment is a summary of the comment on bagasse burning.

Agency Response: See responses to **LCFS 46-147** and **LCFS 46-148**.

ARB staff would like to add that we know a sugarcane-based ethanol mill in Brazil may sell some of their bagasse to another mill. Most mills (such as Sao Martinho cited by the commenter) are producers of sugar, as well as ethanol, which leads to surplus bagasse accumulation by the mill. Staff, however, only credits bagasse combustion that can be verified by the ethanol production quantities, and the energy and material balances.

489. Comment: **LCFS 46-158**

In summary, the commenter believes that there are inconsistencies between some aspects of the sugarcane ethanol pathway and all other pathways.

Agency Response: The comment does not identify those inconsistencies or state why they should be consistent with different pathways. Accordingly it is not possible to respond. To the extent that the comment is meant merely to summarize comments **LCFS 46-130** through **LCFS 46-157**, those comments are responded to above.

490. Comment: **LCFS 46-159**

The commenter has presented a summary of key parameters that the commenter believes should be modified for sugarcane and sugarcane-based ethanol transport.

Agency Response: Issues related to sugarcane transport and identified by the commenter have previously have been addressed. See responses to **LCFS 46-140** and **LCFS 46-149** to **LCFS 46-151**.

491. Comment: **LCFS 46-160**

The commenter has presented a summary of key issues related to sugarcane farming and ethanol transport by ocean tanker.

Agency Response: See responses to **LCFS 46-131** and **LCFS 46-149** to **LCFS 46-151**.

492. Comment: **LCFS 46-161**

The commenter has presented a summary of key issues related to sugarcane farming and ethanol transport by ocean tanker.

Agency Response: See ARB staff responses to **LCFS 46-13**, and **LCFS 46-149** to **LCFS 46-151**.

493. Comment: **LCFS 46-162**

The commenter recommends the use of different factors for diesel fuel use, farming energy fuel shares, nitrogen fertilizer application rate, and N_2O emissions for manually and mechanically harvested sugarcane farms, as specified in their Table 7.1. In addition, the commenter presents a summary table of GHG impacts assessed for all other issues previously raised with regards to the CI for sugarcane-based ethanol from Brazil. Since staff has provided a response to these concerns above previously, it is not necessary to repeat staff's response here.

Agency Response: Regarding higher diesel fuel use, ARB staff has provided a response to this issue in **LCFS 46-131**. Regarding farming energy fuel shares, the commenter suggests that all fuel energy expended on the sugar farms is diesel fuel energy, whereas the CA-GREET model assumes that in addition to diesel fuel, natural gas, electricity, and LPG are also expended on sugarcane farms in Brazil. This assumption is derived from the original CA-GREETv1.8b model, and is consistent with fuel share values specified in GREET1_2013 and research papers presented on the subject.[39] Lastly, regarding nitrogen fertilizer application and N_2O

[39] Seabra, Joaquim EA, Isaias C. Macedo, Helena L. Chum, Carlos E. Faroni, and Celso A. Sarto. "Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use." *Biofuels, Bioproducts and Biorefining* 5, no. 5 (2011): 519-532.

emissions, the commenter suggests that manually-harvested farms would require more nitrogen than mechanically-harvested farms, as some of the nitrogen nutrient in sugarcane straw is lost during manual harvesting. Staff has addressed this issue in response to **LCFS 46-132**.

http://onlinelibrary.wiley.com/doi/10.1002/bbb.289/abstract;jsessionid=345AEC4393BC8CDBE0C72904DFCC76A6.f01t02?deniedAccessCustomisedMessage=&userIsAuthenticated=false

[39] Jennifer B. Dunn, John Eason, and Michael Q. Wang, Updated Sugarcane and Switchgrass Parameters in the GREET Model, Argonne National Laboratory, 2011. https://greet.es.anl.gov/publication-updated_sugarcane_switchgrass_params

[39] Jeongwoo Han, Jennifer B. Dunn, Hao Cai, Amgad Elgowainy, and Michael Q. Wang, "Updated Sugarcane Parameters in GREET1_2012", December 2012, Second Revision, Argonne National Laboratory. https://greet.es.anl.gov/publication-greet-updated-sugarcane

[39] Wang, Michael, Jeongwoo Han, Jennifer B. Dunn, Hao Cai, and Amgad Elgowainy. "Well-to-wheels energy use and greenhouse gas emissions of ethanol from corn, sugarcane and cellulosic biomass for US use." *Environmental Research Letters* 7, no. 4 (2012): 045905. http://iopscience.iop.org/1748-9326/7/4/045905

This page intentionally left blank.

46_OP_LCFS
_GE

17_OP_ADF
_GE

Appendix D

Appendix D

Compliance with the Revised LCFS Program and Associated Economic Impacts

Prepared by Edgeworth Economics

CARB's proposed changes in the LCFS regulation call for a reduction in the carbon intensity (CI) of gasoline relative to the baseline level of 99.18 by 2 percent in 2016, 5 percent in 2018, and 10 percent in 2020.[1] In theory, the strategies to achieve those reductions could include 1) displacing gasoline usage with other types of fuel with lower CI values (*e.g.*, electricity); 2) changing the current limit on the percentage of ethanol that can be blended into California gasoline below the E85 level (which is E10); 3) reducing the average CI of renewable fuel blended with gasoline under the E10 limit; and 4) deployment of credits generated from the use of renewable fuels prior to 2016 and the use of renewable fuels in diesel after 2016. CARB projects that compliance with the LCFS will rely significantly on the third method through at least 2020.[2] This Appendix to Growth Energy's comments identifies the circumstances under which the LCFS program will shift the supply of ethanol for the California market from the United States to Brazil, as a result of strategies to reduce the average CI of renewable fuels blended into gasoline under the E10 limit.

Through 2020, CARB has projected that compliance with the LCFS could be reached primarily through a shift from corn ethanol, now largely sourced from the Midwest[3] with an average CI value of about 82, to cane ethanol from Brazil, which currently has an average CI value of about 72.[4] CARB developed an "illustrative compliance scenario" which projects a reduction in corn ethanol use in California gasoline from the current (2014) level of 1,250 million gallons per year to 700 million gallons per year in 2020, with an increase in consumption of cane ethanol equal to about 64 percent of that reduction. Thus, CARB's scenario would

[1] CARB, *Staff Report: Initial Statement of Reasons for Proposed Rulemaking*, December 2014 ("ISOR"), p. ES-3.
[2] ISOR, p. B-39.
[3] The Renewable Fuels Association (RFA) lists three operating corn ethanol plants in California, with total capacity of 175 million gallons per year, representing about one percent of total U.S. ethanol production and about 14 percent of consumption in California. [RFA website at www.ethanolrfa.org/bio-refinery-locations]
[4] ISOR, p. B-39.

involve a reduction in consumption of Midwest-sourced corn ethanol of about 550 million gallons per year as of 2020, relative to today, equivalent to the entire output of about seven typical-sized ethanol plants.[5]

CARB presents the foregoing scenario as an example of how compliance could be achieved. CARB bases its analysis of the economic impacts of the LCFS on an assumption that credit prices would equal $100 from 2016 through 2020.[6] CARB also evaluates economic-impact scenarios based on assumed credit prices of $25, the current value as of January 2015, and $57, the average value from 2012 to 2013.[7]

To determine whether credit prices at those levels would, in fact, cause fuel marketers in California to switch from Midwest-based corn ethanol to Brazilian cane ethanol, Edgeworth Economics prepared an analysis of the total, delivered cost of both fuels under various assumptions about the CI for each type. Our analysis uses the following data:

- A CI range for Midwest-based corn ethanol of 81.4 to 92.4, representing a range of ratings for ethanol refineries located in the Iowa/South Dakota/Minnesota area that currently ship product to California, based on CARB's list of "Approved Physical Pathways" and information provided by Growth Energy members.
- A CI range for Brazilian cane ethanol of 72.5 (current) to 40 (as of 2016), as reported in the ISOR at p. B-39.
- Ethanol spot prices at Chicago, IL and Santos, Brazil—2014 average [source: Platts] and 2016 forecast [source: OECD-FAO, *Agricultural Outlook 2014-2023*].
- Rail freight rates from Midwest refinery locations to California, provided by Growth Energy members.
- Maritime freight rates from Brazil to California, including tariff and terminal charge [source: Odin Marine Group, *Ethanol Report*, January 2015 and Growth Energy members].

[5] The average output of operating ethanol facilities is about 76 million gallons of ethanol per year. [RFA website at www.ethanolrfa.org/pages/statistics]
[6] ISOR, p. VII-1.
[7] ISOR, pp. VII-1-2 and "Monthly LCFS Credit Transfer Activity Report for January 2015" [CARB website at www.arb.ca.gov/fuels/lcfs/credit/20150210_jancreditreport.pdf]

- D5 and D6 Renewable Identification Number (RIN) prices—2014 average [source: OPIS].

Because the delivered cost of Brazilian ethanol in California is substantially higher than the cost of Midwest corn ethanol at present, with LCFS credit levels around $25, relatively little cane ethanol is imported into California[8], while Midwest facilities with CI ratings in the low 90s continue to deliver product. At the average ethanol and RIN prices experienced in 2014, the value of an LCFS credit would need to rise to $156 in order to incentivize a switch from the highest-CI-rated Midwest sources to Brazil. The spread between prices for conventional (D6) RINs and advanced biofuel (D5) RINs has recently expanded, which provides additional incentive to import cane ethanol from Brazil. Based on the average spread in January 2015, an LCFS credit price of $105 would incentivize the same switch.

However, based on forecasts for ethanol prices in 2016, which show a narrowing of the price differential between U.S. and Brazilian ethanol, an LCFS credit price of about $36 (based on 2014 RIN spreads) would cause a switch from 92.4-CI corn ethanol to cane ethanol; and a credit price of only $77 would cause a switch from 81.4-CI corn ethanol to cane ethanol. These figures are well below CARB's estimate for LCFS credit prices of $100 in 2016. LCFS 46-163

If Brazilian cane ethanol can receive the CI ratings predicted by CARB, then the switch will occur at even lower credit prices. For example, CARB projects that Brazilian ethanol will have an average CI rating of 40.0 by 2016.[9] At that rating, LCFS credit prices as low as $14 would result in a switch away from the higher-rated facilities in the Midwest, and credit prices as low as $17 would result in a switch away from even the lower-rated Midwest facilities.[10] In this scenario, even Midwest facilities with CI ratings as low as 70, which CARB claims will be the average rating of the Midwest corn facilities still delivering product to California as of 2016[11], would be at risk. Credit prices as low as $23 would be sufficient to induce a switch to imported cane ethanol. CARB's scenario indicating a substantial decline in the use of Midwest corn ethanol in California and an increase in the use of imported cane ethanol is therefore not only

[8] CARB estimates 100 million gallons in 2014. [ISOR, p. B-39]
[9] ISOR, p. B-39.
[10] These figures are calculated using the 2016 forecast for ethanol prices and current RIN spreads.
[11] ISOR, p. B-39.

plausible, but probable if sufficient ethanol is available from Brazil, even at modest credit prices well below CARB's projected level of $100.[12]

The implications for Midwest ethanol producers in this scenario would be severe. Assuming that U.S.-wide demand for ethanol does not increase (the Energy Information Administration projects ethanol consumption will be flat through 2016[13]), then the increased imports of Brazilian ethanol would result in some combination of 1) lost production or shut-down of Midwest facilities—with total lost volumes equivalent to as many as approximately seven typical-sized plants by 2020, as noted above; or, at a minimum, 2) increased logistics costs associated with exporting corn ethanol to the nearest source of demand outside the U.S., which could be Brazil. Obviously, the latter outcome would not result in a decrease in world-wide carbon emissions.

LCFS 46-163 cont.

The economic impact of reduced production levels or complete plant closures in the Midwest can be estimated based on the characteristics of typical ethanol refineries. On average, U.S. corn ethanol facilities employ approximately 0.8 employees per million gallons of ethanol produced, or about 61 employees for a typical plant.[14] A reduction in ethanol demand of 550 million gallons per year therefore would result in a direct loss of approximately 440 jobs at ethanol refineries. In addition to these direct effects, the regions that host ethanol production facilities would experience additional reductions in economic activity stemming from reduced purchases of locally-sourced inputs (the "indirect" impact) and reduced spending by facility employees and local vendors (the "induced" impact). These additional economic impacts are generated by the "multiplier" effect, which results from the recycling of business revenues and household income within the local region. Plausible estimates for the overall multiplier effect for employment applicable to the ethanol industry range from about 2 (indicating a total impact

---

[12] This result holds even if the price differential between U.S. and Brazilian ethanol remains closer to current levels, rather than declining as indicated in the forecast described above.

[13] U.S. Energy Information Administration, *Short-Term Energy Outlook*, February 10, 2015.

[14] Based on various sources, including: John Urbanchuk, "Contribution of the Ethanol Industry to the Economy of the United States," Cardno ENTRIX, prepared for the Renewable Fuels Association, February 2, 2012; David Swenson, "Understanding Biofuels Economic Impact Claims," Iowa State University, April 2007; and various public SEC filings.

on employment equal to two times the direct employment impact) to about 7.[15] Applying a figure of 4 to the direct employment impacts calculated above implies a loss of approximately 1,760 jobs in ethanol producing regions.

Even assuming that the facilities forced out of the California market could find customers outside the U.S., there would still be substantial costs to the industry. For example, transport of ethanol from the Midwest to Brazil would entail increased logistics costs of approximately 10 cents per gallon[16], or $55 million per year, assuming sufficient demand in Brazil for all 550 million gallons of displaced corn ethanol.

LCFS 46-163 cont.

[15] See, for example, Urbanchuk, February 2, 2012, *op. cit.*; Swenson, April 2007, *op. cit.*; Susan Christopherson and Zachary Sivertsen, "Economic Policy Makers Beware: Estimating the Job Impact of Public Investment in Biofuel Plants," working paper, Cornell University, December 12, 2009; and Dave Swenson, "Input-Outrageous: The Economic Impacts of Modern Biofuels Production," Iowa State University, June 2006.
[16] Based on the sources described above.

46_OP_LCFS_GE Responses (Page 149 - 154)

494. Comment: **LCFS 46-163**

The comment discusses the commenter's perspective on a supply shift of Californian ethanol from the United States to Brazil under various assumptions.

Agency Response: See response to **LCFS 46-28**.

This page intentionally left blank.

46_OP_LCFS
_GE

17_OP_ADF
_GE

Appendix E

Nos. 12-15131, 12-15135

UNITED STATES COURT OF APPEALS FOR THE NINTH CIRCUIT

ROCKY MOUNTAIN FARMERS UNION, *et al.*, Plaintiffs-Appellees,

v.

JAMES N. GOLDSTENE, *et al.*,Defendants-Appellants, and ENVIRONMENTAL DEFENSE FUND, *et al*.,Intervenor-Defendants-Appellants.

Appeal from the United States District Court for the Eastern District of California (D.C. Nos. 1:09-cv-02234-LJO-GSA, 1:10-cv-0013-LJO-DLB)

DECLARATION OF ERIN HEUPEL, P.E.

I, Erin Heupel, declare and state as follows:

1. I am the Director of Environment and Technology at POET LLC, a company that constructs and manages ethanol production facilities, headquartered in Sioux Falls, South Dakota. I provide this declaration in support of the opposition by Plaintiffs-Appellees ("Plaintiffs") to the motion filed by Defendants-Appellants ("Defendants") to stay the preliminary injunction and judgments in *Rocky Mountain Farmers Union, et al. v. Goldstene*, Case No. 1:09-cv-02234-

LJO-GSA (E.D. Cal., Dec. 29, 2011).[1] I am a licensed Professional Engineer in the States of Iowa and South Dakota. I make this declaration based on my professional experience and my personal knowledge of the facts set forth herein. I am willing and able to present under oath the facts set forth in this Declaration if called as a witness before the Court.

2. The purpose of this declaration is to respond to statements in the Declaration of Michael Waugh, dated January 20, 2012, and filed in this Court by Defendants on February 10, 2012, on two subjects: (i) the creation of "individualized" pathways for some corn ethanol plants under the California low-carbon fuel standard ("LCFS") regulation, and (ii) the impact of District Court's preliminary injunction on the environmental benefits that Defendants attribute to the LCFS regulation. *See* Declaration of Michael Waugh in Support of Defendants and Defendant-Intervenors' Motion to Stay Preliminary Injunction and Judgments Pending Appeal (Dkt Entry 21-7) ("Waugh Decl.") ¶¶ 5, 39-41, 52-59, *and id.* at 11:9.

3. I am in charge of the efforts of ethanol plants managed by POET LLC, to receive CARB approved individualized carbon intensity "pathways" for

[1] *See* Motion for A Stay of the District Court's Orders and Judgments Pending Appeal (Dkt Entry 22-1) ("Stay Mot.").

the plants managed by POET LLC that can qualify for such pathways.[2] My duties at POET LLC require me to have complete knowledge of the technologies, processes, and methods used for the production of corn ethanol and various co-products by the plants that POET LLC manages, including the production efficiencies and energy requirements of those plants. My responsibilities at POET LLC also require me to have substantial knowledge of the same attributes of corn ethanol plants that compete with the plants that POET LLC manages.

4. At the outset, it is important to understand that companies in the U.S. corn ethanol industry have strong commercial incentives to maximize yield from feedstock and to minimize energy usage, and thus to minimize greenhouse gas ("GHG") emissions. Corn ethanol plants cost millions of dollars to build. Midwest corn ethanol plants are carefully sited in order to have ready access to their feedstock, as well as competitively priced natural gas, electricity, or other sources of energy to run the plant. The companies that survive and prosper in this industry are those whose plants are designed from the beginning for maximum efficiency in feedstock conversion and minimum energy consumption. Next to corn costs, energy costs are the largest variable cost in producing corn ethanol.

LCFS 46-164

[2] *See* Waugh Decl. ¶¶ 52-56. The plants that POET LLC constructs and/or manages are owned by separate investor groups. *See* Declaration of Robert Whiteman (filed March 1, 2012) at note 3.

5. A number of plants managed by POET LLC have received CARB staff approval for 11 different individualized pathways for corn ethanol. I am personally familiar with the attributes of each plant awarded those pathways that the LCFS regulation treats as relevant in determining the carbon intensity of the ethanol that those plants produce. The relevant plants made no changes in production methods, feedstock, methods of transport, or any other factor relevant to the pathway application, in order to reduce the carbon intensity that would be assigned to ethanol produced at those plants. POET LLC obtained the CARB approved CI pathways for these plants by documenting the attributes of production and energy supply relevant under the LCFS regulation that those plants had adopted for commercial reasons, completely independent of the LCFS regulation and the regulation's requirements for the establishment of alternative pathways.

LCFS 46-164 cont.

6. When plants managed by POET LLC make changes in their technologies, production methods, or energy sources, and those changes reduce the carbon intensity, POET LLC seeks changes in the carbon intensity values that apply to those plants to the extent possible under the LCFS regulation. In such instances, however, the motivating factor for the change at the plant is not the LCFS regulation, but the need to remain competitive in production methods and technologies within the Midwest corn ethanol industry. In addition, to my knowledge, none of the Midwest corn ethanol plants that compete with those

managed by POET LLC have made changes in their technologies, production methods, or energy inputs in order to gain a lower carbon intensity value under the LCFS regulation; instead, those plants strive to increase efficiency and reduce energy consumption for the same commercial reasons as the plants managed by POET LLC.

7. The LCFS regulation becomes more stringent in each year after 2011. But, contrary to what appears to be the position taken in Mr. Waugh's declaration, it would not be commercially practicable for Midwest corn ethanol plants to try to keep up with the increases in the stringency of the regulation, simply in order to try to stay in business in California.[3] LCFS 46-165

8. Under the LCFS regulation, all corn ethanol plants, including those in the Midwest, must add an assigned "indirect" carbon intensity emissions factor of 30 gCO_2eq/MJ to their "direct" carbon intensity emissions factor. The "indirect" emissions factor is more than 40 percent of the total carbon intensity level assigned to the corn ethanol pathway that, according to Mr. Waugh's Declaration, has the lowest carbon intensity level recognized by the CARB staff.[4] Nothing that any LCFS 46-166

[3] *See* Waugh Decl. ¶¶ 41, 44.

[4] *See* Waugh Decl., Exh. E at 8 (pathway value of 73.21 gCO_2eq/MJ for Pathway No. ETHC0035). The pathway that Mr. Waugh's declaration identifies as the "lowest carbon intensity value approved for any ethanol," for a plant located in Kansas (Waugh Decl. ¶ 53), is a pathway for a plant that uses the combination of wheat slurry, sorghum, and corn and is not a pathway for an ethanol plant using

single corn ethanol plant or group of corn ethanol plants can do will reduce the "indirect" carbon intensity emissions factor assigned by the LCFS regulation. As a result, the impact of plant changes in improving efficiency or reducing energy consumption do not result in proportional changes in the assigned CI value. For example, the 73.21 gCO_2eq/MJ value above consists of 43.21 gCO_2eq/MJ for the production of feedstock and ethanol as well as ethanol transport and the value of 30 gCO_2eq/MJ for indirect emissions. A 10% reduction in the 43.21 gCO_2eq/MJ value to 38.89 gCO_2eq/MJ yields only a 6% reduction in the overall CI value which becomes 68.89 gCO_2eq/MJ. In addition, within the "direct" emissions factor assigned to a corn ethanol plant, the LCFS regulation attributes a substantial increment to GHG emissions attributed to the cultivation and harvesting of corn (potentially, 35.7 gCO_2eq/MJ). Ethanol plants cannot directly control and document how farmers grow and harvest corn, which the farmers grow not only to

LCFS 46-166 cont.

corn. Sufficient quantities of sorghum feedstock are not available to most corn ethanol plants, including those in the northern Great Plains that were built to serve the California market. Although the yields from converting grain sorghum to ethanol can be similar to corn, the yields of sorghum per acre are lower, making sorghum a generally less desirable crop than corn for fertile or irrigated land. Sorghum tends to be grown where the land is too marginal to support a profitable corn crop, or where moisture availability is scarce. As was the case with the fuel-grade ethanol industry prior to the implementation of the LCFS regulation, grain producers will grow crops that make the most profitable use of their land and agricultural inputs.

sell to ethanol plants, but also to other customers, on the best possible commercial terms for the farmers. LCFS 46-166 cont.

9. As indicated above, the lowest CI value for any Midwest corn ethanol pathway is 73.21 gCO_2eq/MJ and the direct CI value for that pathway is 43.21 gCO_2eq/MJ. Assuming that this lowest CI corn ethanol is blended with a gasoline blendstock assigned a carbon intensity value of 95.86 gCO_2eq/MJ (which is the value assigned to an "average" gasoline blend), LCFS compliance could only be achieved with a 15% ethanol blend ("E15") through 2015. In order for LCFS compliance to be achieved with E15 in 2016, the CI of Midwest corn ethanol would have to be reduced to 64.20, and the direct CI value to 34.20. This represents approximately a 21% reduction in the direct CI value from the lowest CI value currently documented. That same ethanol blended at 15% into the same gasoline feedstock would begin to generate deficits for the blender starting in 2017. LCFS 46-167

10. Experience in 2011 has shown that gasoline blenders in California will quickly try to stop buying and blending ethanol that does not generate a credit against the requirements of the LCFS regulation.[5] Given the "indirect" emissions factor automatically assigned to all corn ethanol plants, and the compliance schedule for LCFS regulation in the near term, even the most efficient Midwest corn ethanol plant currently recognized by the CARB staff would need to reduce LCFS 46-168

[5] *See* Declaration of James M. Lyons ¶¶ 5-7 .

its direct carbon intensity factor by more than 21% and file the necessary documentation with CARB, in order to continue in the California fuel market for one more year past the current limit of 2015. The costs incurred to reduce the carbon intensity of ethanol from the plant would have to be recovered by the end of 2016 before the gasoline blenders stopped buying that plant's ethanol and moved to an alternative fuel with a lower carbon-intensity level, for example, from Brazil or through the use of the "electricity" pathways in the LCFS regulation. LCFS 46-168 cont.

11. The upshot is that even a very efficient Midwest corn ethanol plant would have to find and implement further efficiencies or energy reduction opportunities not driven by the nationwide market and recover the costs of the necessary changes, over a very short time frame. That is not commercially practicable for corn ethanol plants managed by POET LLC or, I believe, for competitor corn ethanol plants. Rather than incur those costs, U.S. corn ethanol plants will try to compete in markets outside California. LCFS 46-169

12. In sum, I am aware of no evidence that the LCFS regulation has had any significant impact on the level of GHG emissions from corn ethanol plants located in the Midwest. A stay of the preliminary injunction will not cause the corn ethanol plants managed by POET LLC, or any competitors to those plants with whose operations I am familiar, to reduce the GHG emissions from their LCFS 46-170

operations relative to current levels. A stay of the preliminary injunction issued by the District Court therefore will not restore or continue any GHG emissions reductions during the pendency of this litigation, simply because the LCFS regulation itself has had no effect on GHG emissions attributable to corn ethanol production, nor would it have any such effect in the near term.

LCFS 46-170 cont.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct. Executed on March 1, 2012 at Sioux Falls, South Dakota.

Erin Heupel, P.E.

Nos. 12-15131, 12-15135

UNITED STATES COURT OF APPEALS FOR THE NINTH CIRCUIT

ROCKY MOUNTAIN FARMERS UNION, *et al.*, Plaintiffs-Appellees,

v.

JAMES N. GOLDSTENE, *et al.*, Defendants-Appellants, and ENVIRONMENTAL DEFENSE FUND, *et al*., Intervenor-Defendants-Appellants.

Appeal from the United States District Court for the Eastern District of California (D.C. Nos. 1:09-cv-02234-LJO-GSA, 1:10-cv-0013-LJO-DLB)

DECLARATION OF ROBERT WHITEMAN

I, Robert Whiteman, declare and state as follows:

1. I am the Chief Financial Officer of POET Ethanol Products, LLC, d/b/a POET Ethanol Products (hereinafter "POET Ethanol Products"), a company based in Wichita, Kansas, that markets ethanol. I provide this declaration in support of the opposition by Plaintiffs-Appellees ("Plaintiffs") to the motion filed by Defendants-Appellants ("Defendants") to stay the preliminary injunction and judgments in *Rocky Mountain Farmers Union, et al. v. Goldstene*, Case No. 1:09-

cv-02234-LJO-GSA (E.D. Cal., Dec. 29, 2011).[1] I am willing and able to present under oath the facts set forth in this declaration if called as a witness before the Court.

Summary

2. In their stay motion, Defendants claim that the low-carbon fuel standard ("LCFS") regulation has had no adverse impact on what Defendants call the "domestic ethanol industry." (Stay Mot. at 31.) As explained below in the main portion of this Declaration, the U.S. corn ethanol "industry" is compromised of numerous separately-owned corn ethanol production plants, mainly located outside California near the sources of corn used to make ethanol. Long before adoption of the LCFS regulation, investors built ethanol plants in the western Great Plains area of the Midwest to serve the California market. They did so in order to obtain the "California premium" - higher prices that prevailed for corn ethanol in California, compared to other large U.S. markets, resulting from specific economic conditions in California. (*See* ¶¶ __-__ below.) The principal impact of the LCFS regulation within what Defendants define as the "domestic ethanol industry" has fallen on those Midwest producers, who served the California market before the LCFS was adopted.

---

[1] *See* Motion for A Stay of the District Court's Orders and Judgments Pending Appeal (Dkt Entry 22-1) ("Stay Mot.").

3. In its first year of implementation, the LCFS regulation forced the exit from the California market of some of those Midwest corn ethanol plants that had been built to serve California. The LCFS regulation also curtailed sales of corn ethanol by some other Midwest plants that had previously had significant sales of ethanol in California. (*See* ¶¶ __-__ below.) The preliminary injunction gives all corn ethanol producers the ability to try to compete again in California as they could before the LCFS regulation took effect.[2]

4. Defendants also claim that the preliminary injunction is jeopardizing reductions in greenhouse gas ("GHG") emissions that were being provided by the LCFS regulation, or that would be provided by the regulation during the pendency of the litigation. (*See*, *e.g.*, Stay Mot. at 28.) That claim ignores the fact that in 2011, and currently and for the foreseeable future, corn ethanol that cannot be sold in California as a result of the LCFS is still being produced and is being sold in other markets. (*See* ¶¶ __-__ below.) The preliminary injunction is not jeopardizing reductions in GHG emissions from the corn ethanol production sector, because there is no evidence that such reductions occurred as a result of the LCFS regulation. Indeed, the LCFS regulation did not affect, and in the near term will

LCFS 46-171

[2] The exclusion of some producers from the California market and those producers' loss of the "California premium" does not mean that the LCFS regulation has lowered ethanol prices in California. *See* ¶ __ below.

not affect, methods of production or output of that sector, which are determined by macroeconomic factors unaffected by the regulation.

LCFS 46-171 cont.

5. This declaration is based on my personal knowledge of the ethanol industry gained in the course of my employment at POET Ethanol Products. I have worked in the transportation fuels industry for more than 17 years, and in the corn ethanol marketing business for more than a decade.[3] My duties at POET Ethanol Products require me to have direct, first-hand knowledge of sales of ethanol by all the production facilities for which we market ethanol. My duties also require me to have a full and current understanding of the methods of ethanol production and delivery throughout the U.S. corn ethanol industry, as well as corn ethanol marketing practices and factors affecting competitive conditions within the

---

[3] POET Ethanol Products currently markets ethanol from 35 ethanol producers, located in Colorado, South Dakota, Nebraska, Kansas, Missouri, Iowa, Minnesota, Indiana, Ohio, and Michigan.

Some of the ethanol plants for which POET Ethanol Products markets ethanol have management contracts with POET LLC, an ethanol plant construction and management firm based in Sioux Falls, South Dakota. The U.S. Environmental Protection Agency has sometimes referred to "POET Biorefining" as a single ethanol production or marketing entity. (*See*, *e.g.*, Renewable Fuels Standard Program (RFS2) Regulatory Impact Analysis (Feb. 2010) 97, *available at* http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=P1006DXP.txt. In point of fact, nearly every ethanol plant having management contracts with POET LLC is owned by a separate group of investors, which typically include a large number of investors from the farming communities near the ethanol plant, who often sell their grain to the local plant managed by POET LLC to make ethanol.

corn ethanol industry, including the impact of regulations like the LCFS regulation on corn ethanol markets.

6. The balance of my declaration is divided into two parts. Part I provides necessary background on the U.S. corn ethanol industry and the California corn ethanol market. Part II explains how the LCFS regulation affected the U.S. corn ethanol industry in 2011, and would continue to affect that industry in the absence of a preliminary injunction.

I. The Corn Ethanol Industry and the California Energy Market

7. Ethanol is used as an additive in gasoline. It has high octane ratings, and can also be used as an oxygenate to help reduce automotive air pollution. Corn ethanol produced at plants located in the Midwest historically provided about 95 percent of California's requirements for oxygenates for blending into gasoline.

8. All ethanol sold in the United States for use in motor fuel has the same physical and chemical composition, regardless of the method of production or the material from which the ethanol is produced (called the "feedstock").[4] Prior to implementation of the LCFS regulation, ethanol for use in gasoline could be sold as a fungible commodity. The market for corn ethanol for use in gasoline was highly competitive. A successful business plan for a corn ethanol plant required

[4] In the case of ethanol made from corn starch, the type of corn used is "No. 2" corn, the hard corn grown as animal feed, and not so-called "sweet corn" sold in grocery stores for human consumption.

proximity to the corn feedstock, access to competitively priced energy needed in the production process, efficient production technology and methods, and good transport logistics to get the ethanol from the plant to the customers' locations.

9. Transport logistics are particularly important for corn ethanol plants that intend to serve distant energy markets, sometimes located more than a thousand miles from the plant. Plants that produce ethanol for shipment over long distances use railways as a mode of transport, preferably in dedicated "unit trains" of tanker cars that can be loaded at sidings within or adjacent to the ethanol plant's fence line.[5]

10. California is the single largest state market for corn ethanol in the United States, historically consuming about ten percent of total U.S. corn ethanol production. Companies that market gasoline in California blend ethanol into base gasoline, called "California Reformulated Gasoline Blendstock for Oxygenate Blending," or "CARBOB." Publicly available price data show that historically, the California gasoline blenders have paid higher prices on average than could be obtained for ethanol sold in other parts of the United States. While many factors can affect the price paid for ethanol, one factor that likely accounts for the higher prices available in California is that the refineries that produce CARBOB tend to

[5] A photograph showing the integration of an ethanol plant with its rail connection is attached as Exhibit 1 to the Declaration of Russ Newman, being filed today by Plaintiffs. (*See* [ECF #], Exh. 1.)

have higher average total production costs than refineries outside California. Even after accounting for the costs of shipping ethanol over the Rocky Mountains, Midwest ethanol producers who could obtain a customer base in California obtained over time a higher "net-back" per gallon (*i.e.*, price per gallon to the customer, net of freight costs) than they could obtain in other markets. For example, in the three years prior to implementation of the LCFS regulation at the end of 2010, for example, the average California "net-back" price for a gallon of ethanol was 3.65 cents per gallon ("cpg") higher than the Chicago market, and 4.17 cpg over prices at New York Harbor.[6]

11. To compete in the California ethanol market, investors in Midwest corn ethanol plants have for many years sited their plants in locations with the best possible rail access to California. Those producers are located west of the Mississippi River, often in North and South Dakota, Minnesota, Iowa, Kansas and Nebraska. Their plants are designed at the outset to be "single line" shippers to California, meaning that they can ship their product on either the BNSF or Union Pacific systems, without changing freight lines and having to pay more than one freight bill.

---

[6] Based on Platts Fuel Price Service daily reports, Jan. 1, 2008 to Dec. 31, 2010, for Chicago spot prices, New York Harbor 5- to 15-day barge prices, and Southern California rail prices, less average estimates of freight from the Midwest.

II. Impacts of the LCFS Regulation

12. The basic features of the LCFS regulation, as it existed in the summer of 2010 prior to implementation, were described in the District Court's decision denying Defendants' motion to dismiss this case. (*See Rocky Mountain Farmers Union, et al. v. Goldstene*, 719 F.Supp. 2d 1170, 1177-79 (E.D. Cal. 2010).) As first adopted, and in its current form, the LCFS regulation assigns to each gallon of ethanol sold in California a "carbon intensity" (or "CI") score based on the "pathway" assigned to the plant where it is produced. The "pathway" for ethanol is in turn defined by the location where the ethanol is produced, the feedstock used (in the case of corn ethanol, No. 2 Corn), the production method, the consumption of ethanol in a vehicle's engine, and other factors. Carbon intensity is quantified in units of grams of carbon-dioxide-equivalent emissions per megajoule ("g/mj") of energy that the LCFS regulation attributes to each pathway. (*See* 719 F.Supp. 2d at 1178-79, 1197.)

13. The stated goal of the LCFS regulation is to produce reductions in the average carbon intensity of transportation fuels sold at the retail level in California, on a year-by-year basis, starting in 2011, until 2020 when that average carbon intensity is required to be 10 percent lower than before the regulation took effect. For example, the LCFS regulation's carbon intensity reduction schedule for gasoline calls for an average carbon intensity in 2011 of 95.61 g/mj (a reduction of

0.25 percent from a 2006 baseline); by 2020, the average carbon intensity level must be 86.27 g/mj. (10 percent below the 2006 baseline). A gasoline blender achieving a lower level of average carbon intensity than 95.61 g/mj in 2011 would generate a credit against the compliance schedule set by the regulation. A gasoline blender whose blended product exceeded 95.61 g/mj in 2011 would generate a deficit. LCFS credits have an indefinite lifetime. Deficits, however, must be made up by the end of the year following the year in which they were created.

14. From a marketing perspective, the simplest example of how the LCFS regulation works is to start with the fact that the LCFS regulation assigns a CI value of 95.85 g/mj for a baseline gasoline and a CI value of 95.86 to CARBOB. In 2011, the LCFS regulation set a target for the average CI of finished gasoline products at 95.61 g/mj -- a value that is 0.25% lower than the baseline gasoline CI value. An oil company blending CARBOB with ethanol having a CI value greater than 95.86 g/mj would increase, not decrease, the carbon intensity of the final gasoline product it is selling -- which is not what the regulation is trying to accomplish. As such, it would generate a deficit, rather than a credit. For ethanol assigned a CI value lower than 95.86 g/mj, the ethanol product will enable, to some extent, a reduction in the carbon intensity of the final, blended gasoline product. The lower the CI value assigned to a given ethanol pathway, the more valuable the

ethanol is to a gasoline blender trying to reduce the carbon intensity of its final product.[7]

15. As first approved by CARB in 2009, the LCFS regulation assigned a CI value of 98.40 g/mj to the Midwest corn ethanol pathway that represented the majority of Midwest plants, including most members of Growth Energy, one of the Plaintiffs in this action. An oil company blending ethanol from that most typical Midwest pathway would therefore have increased, not reduced, the carbon intensity of its finished gasoline product. At POET Ethanol Products, we saw a shift in the buying preferences of our California customers after the LCFS regulation was adopted. A number of our customers would pay a higher price for ethanol that had lower CI values, and to the extent they would buy ethanol with CI values above the CI level assigned to CARBOB, they would only purchase the ethanol at lower prices. That fact is borne out in one of the Declarations signed by Mr. Michael Waugh and filed in support of Defendants' stay motion, which states that "[w]ith the exception of a few isolated days, spot prices for ethanol with a

[7] Federal regulations limit the maximum amount of ethanol that can be blended into gasoline, and commercial gasoline blenders do not always decide to blend the highest levels of ethanol allowed by law. At a blend level of 10 percent, as explained in an accompanying declaration, the blended gasoline could not begin to generate any credit for a gasoline blender against the LCFS regulation in 2011 unless it was assigned a CI value below 95.61 g/mj. *See* Declaration of James M. Lyons ¶ __.

carbon intensity value of 90.1 [g/mj.] were at least $0.01/gal higher than with a carbon intensity of 98.4 [g/mj.], during all of 2011."[8]

16. As Mr. Waugh also notes, a number of Midwest corn ethanol producers were able to obtain adjustments in the CI levels assigned to their ethanol, after the LCFS regulation was first approved. (*See* Waugh Decl. ¶¶ 52-59.) Thus, some plants whose ethanol would have been assigned the 98.4 g/mj. carbon intensity level under the original, 2009 version of the LCFS regulation have been able to obtain lower pathways. As explained in an accompanying Declaration, those plants obtained their specific lower carbon intensity pathways by documenting the production technologies, processes, methods, and energy inputs that were already in place and which they would have used in the absence of the LCFS regulation, which the CARB staff then decided would warrant a lower-CI pathway.[9]

17. Neither Mr. Waugh nor any of Defendants' other declarants addresses the fact that, while some Midwest producers were able to provide documentation to

[8] Declaration of Michael Waugh in Support of Defendants and Defendant-Intervenors' Motion to Stay Preliminary Injunction and Judgments Pending Appeal (Dkt Entry 21-7) ("Waugh Decl.") ¶ 46. Mr. Waugh calls the higher price for lower-CI ethanol a "price premium." *Id*. at 12:19. That higher price for some lower-CI ethanol is not the same as the "California premium" that obtained before the adoption of the LCFS regulation and that is described in Part I of my Declaration.

[9] *See* Declaration of Erin Heupel ¶¶ 5-6.

CARB showing that their ethanol should not be penalized in 2011 with a CI value higher than gasoline, other Midwest plants were unable to do so. Some of the plants that could not document the production technologies, processes, methods, and energy inputs that the CARB staff would reward with lower CI values had previously sold a substantial volume of ethanol in California. The LCFS regulation forced some of those plants entirely out of the California market in 2011. Several of those plants have come forward in this proceeding, and have provided Plaintiffs with declarations that explain the impact of the LCFS regulation on their business.[10] LCFS 46-172

18. The effect of the LCFS regulation has been to "de-commoditize" the corn ethanol market, for purposes of California -- *i.e.*, ethanol is no longer a fully fungible commodity in California, in which producers can prevail by offering the best commercial terms. Plants that were optimized for shipment of ethanol to California when they were built, but that can no longer sell their ethanol in California, now must find buyers outside California. On an industry-wide basis, the LCFS regulation has led to "fuel shuffling" that has likely increased the number of miles that Midwest corn ethanol had to travel in 2011 in order to get from the production facilities to customer destinations. LCFS 46-173

[10] *See* Declaration of Duane Kristensen (impact of LCFS regulation on Nebraska corn ethanol producer); Declaration of Russ Newman (impact on North Dakota producer); Declaration of Delton Strasser (on South Dakota producer).

19. Some of the Midwest plants that were excluded from the California market in 2011, especially those built to serve California, have been required to ship their product using multiple-stage freight movements, which increased the costs of delivery to the customers. Those plants have lost the ability to compete for the lucrative California market, and have also been required to incur higher costs to sell at lower prices elsewhere, as their logistics for delivery have become more complex. Defendants ignore those impacts on the producers who have been excluded from California. The preliminary injunction issued by the District Court is essential to efforts by those producers to try to re-enter the California market and to compete for sales.

LCFS 46-174

20. For all the disruptions in the California ethanol market created by the LCFS regulation, there has been no reduction in the overall amount of corn ethanol produced in the United States, or used as a motor fuel in this country or overseas. (As Mr. Waugh notes, U.S. ethanol producers have recently been shipping some ethanol overseas.) The overall production levels for corn ethanol last year, and for the foreseeable future, depend on macroeconomic factors (including demand for gasoline) that are independent of the LCFS regulation.

21. In conclusion, although Defendants claim that the "LCFS was expected to result in emissions reductions [in California] of almost one million metric tons (MTs) in 2012 and almost two million in 2013," and that "[t]hose

LCFS 46-175

targets would be achieved with a stay" of the preliminary injunction" (Stay Mot. at 28), those claims have no basis in fact. The same amount of corn ethanol would have been produced in the United States in 2011 in the absence of the LCFS regulation, and renewed enforcement of the LCFS regulation cannot be predicted to have any impact on national production of corn ethanol during the pendency of this litigation. The only effect of the LCFS is to cause ethanol "shuffling" by which some lower CI corn ethanol that would have been sold elsewhere is instead shipped to California while the higher CI corn ethanol that would have otherwise been sold in California is sold elsewhere.

LCFS 46-175 cont.

22. Finally, I note that Defendants' claim that any GHG emissions that occurred in 2011 "will be lost" in the absence of a stay. (*Id.*) Buyers in the California ethanol market typically purchase their requirements in multi-month, forward contracts. Even if one were to credit Defendants' claim (which is incorrect, for the reasons explained above) that the LCFS regulation affected production of ethanol in 2011 in a way that reduced GHG emissions, the preliminary injunction issued by the District Court on December 29, 2011, has had no impact on ethanol delivered in California under those contracts..

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct. Executed on March 1, 2012 at Wichita, Kansas.

____

Robert Whiteman

This page intentionally left blank.

46_OP_LCFS_GE Responses (Page 155 - 179)

495. Comment: **LCFS 46-164**

The comment states that corn ethanol producers in the Midwest are incentivized to maximize yield from feedstock and minimize energy usage, and therefore also reduce GHG emissions, due to economics rather than being incentivized to do so by the LCFS regulation.

Agency Response: Staff acknowledges that Midwest corn ethanol producers and for that matter all other fuel producers are economically incentivized to maximize yields from feedstock and to minimize energy usage (and the GHG emissions from energy usage). The LCFS is designed to work in tandem with those incentives to encourage these and other changes that reduce carbon intensity. Where efforts to reduce carbon intensity increase costs, either on a one-time or ongoing basis, additional economic incentives created by the LCFS are valuable. And those incentives will increase over times as the program becomes more stringent. See also response to comment **LCFS 46-36**.

496. Comment: **LCFS 46-165**

The comment states that Midwest corn ethanol plants are unable to keep up with the increases in stringency of the LCFS regulation in order to remain in business in California.

Agency Response: Please see response to **LCFS 46-27**. ARB does not favor one alternative transportation fuel provider over others. The requirements for application, reporting, and recordkeeping are the same across all alternative fuel providers. Staff would like to point out that one of the Midwest corn ethanol plants, POET – Chancellor, made changes to their production technologies and was approved by ARB for its new corn ethanol fuel pathways under Method 2B, with CI values significantly lower than that of conventional corn ethanol.

497. Comment: **LCFS 46-166**

The comment describes the various contributions to the CI factor for corn ethanol pathways.

Agency Response: Please see responses to **PR-27**, **LCFS 8-1**, **LCFS 46-11**, and **LCFS 46-216**.

498. Comment: **LCFS 46-167**

The comment describes changes to CI in order for Midwest corn ethanol pathways to comply with the standards that will be implemented by the LCFS.

Agency Response: Many of the CI values raised in the comment are no longer applicable under the proposed regulation. See response to **LCFS 46-42** and **LCFS 46-43**.

499. Comment: **LCFS 46-168**

The comment describes changes to CI in order for Midwest corn ethanol pathways to comply with the standards that will be implemented by the LCFS, and suggests that in the future it will be difficult to recover associated costs.

Agency Response: The LCFS program is designed to encourage reductions in the overall CI of transportation fuels used in California. Corn ethanol pathway applicants have technologically feasible ways to reduce their CIs. However, to the extent that CI improvements at certain corn ethanol facilities are not the most cost effective way to achieve the LCFS's CI reduction goals, other pathways will provide the desired reductions.

500. Comment: **LCFS 46-169**

The comment states that changes required for corn ethanol plants to meet the requirements under the LCFS program are not commercially practicable.

Agency Response: See response to **LCFS 46-28** and **46-168**.

501. Comment: **LCFS 46-170**

The comment alleges that the LCFS has had no effect on GHG emissions attributable to corn ethanol production, nor would it have any such effect in the near term.

Agency Response: This comment was made in early 2012 during litigation over the original LCFS regulation and is inapplicable here. To the extent this comment repeats the claim that the LCFS's incentives will have no effect on ethanol producers, that claim is addressed in responses to **LCFS 46-36** and **LCFS 46-40**.

502. Comment: **LCFS 46-171**

The comment alleges that the LCFS has had no effect on GHG emissions attributable to corn ethanol production, nor would it have any such effect in the near term.

Agency Response: This item is actually an unsigned declaration apparently prepared in early 2012 during litigation over the original LCFS regulation and is inapplicable here. Because it does not address the 2014 LCFS proposal, no response is necessary. To the extent this comment repeats the claim that the LCFS's incentives will have no effect on ethanol producers, that claim is addressed in responses to **LCFS 46-36** and **LCFS 46-40**.

503. Comment: **LCFS 46-172**

The comment asserts that Midwest ethanol producers should not be penalized in 2011 with CI values higher than gasoline.

Agency Response: This comment was made in early 2012 during litigation over the original LCFS regulation and is inapplicable here.

504. Comment: **LCFS 46-173**

The comment states that the LCFS regulation has de-commoditized the corn ethanol market in California, insofar as ethanol is no longer fully fungible. The comment goes on to speculate that fuel shuffling may have increased transportation distances for Midwest corn ethanol.

Agency Response: This item is actually an unsigned declaration apparently prepared in early 2012 during litigation over the original LCFS regulation and is inapplicable here. Because it does not address the 2014 LCFS proposal, no response is necessary. Nevertheless, we note that ARB agrees that the LCFS differentiates ethanol based on its CI. See response to **LCFS 46-40.**

505. Comment: **LCFS 46-174**

The comment claims that some Midwest ethanol plants have lost the ability to compete in for the lucrative California market and been required to ship their product using more costly methods due to the LCFS program which could exclude them from the California market.

Agency Response: This comment was made in early 2012 during litigation over the original LCFS regulation and is inapplicable here.

Further, a number of Midwest producers have continued to supply fuel to CA post LCFS and most have demonstrated improved production efficiency/CI reductions and reaped benefits from the CA market. See also responses to **LCFS 46-36** and **LCFS 46-40**. No fuel producer was guaranteed a market in California before the LCFS and that remains true with the LCFS in place.

506. Comment: **LCFS 46-175**

The comment asserts that the LCFS program has had no impact on national production of corn ethanol during the pendency of the litigation and the program's only effect was to cause ethanol shuffling.

Agency Response: This comment was made in early 2012 during litigation over the original LCFS regulation and is inapplicable here. To the extent this comment repeats the claim that the LCFS's incentives will have no effect on ethanol producers, that claim is addressed in responses to **LCFS 46-36**, **LCFS 46-40**, **LCFS 46-41**, **and LCFS 46-173**.

46_OP_LCFS_GE

17_OP_ADF_GE

Appendix F

growth energy
America's Ethanol Producers

777 North Capitol Street, NE, Suite 805, Washington, D.C. 20002
PHONE 202.545.4000 FAX 202.545.4001
GrowthEnergy.org

October 31, 2014

By Electronic and U.S. Mail

Dr. Irena Asmundson
Chief Economist
California Department of Finance
915 L Street
Sacramento, CA 95814

Stephen Adams, Esquire
William Brieger, Esquire
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Standardized Regulatory Impact Assessments for the Low-Carbon Fuel Standard and Alternative Diesel Fuel Rulemakings

Dear Dr. Asmundson and Messrs. Adams and Brieger:

Thank you for providing public access to the combined standardized regulatory impact assessments (the "CSRIA") for the low-carbon fuel standard ("LCFS") and alternative diesel fuel ("ADF") rulemakings. I write in order to present some specific questions based on Growth Energy's review of the CSRIA. The first set of questions are intended for the ARB Chief Counsel's Office, and the second set are intended for both the Department of Finance and the ARB Chief Counsel's Office. Let me state at the outset that Growth Energy appreciates the opportunity to participate in the SB 617 process for these two important rulemakings, and the consideration that the ARB staff has given to its submittals. Growth Energy regrets that more information about the goals and the estimated benefits or costs of the LCFS and ADF proposals was not available to stakeholders prior to the time when alternative proposals had to be submitted.

1. Evaluation of ADF Alternatives

Based on some recently-received information (*see* Attachment A), it appears that the ADF portion of the CSRIA does not present ARB's currently proposed regulatory approach to mitigate emissions increases that would be caused by the use of biodiesel fuels in order to comply with the LCFS regulation. As Mr. Adams confirms in Attachment A, ARB does not plan to require mitigation for any biodiesel blends below five percent ("B5"). This is contrary to what the CSRIA describes as ARB's proposal for the ADF regulation, which would require mitigation for some biodiesel blends at concentrations greater than one percent. (*See* CSRIA at 4.) Growth Energy appreciates Mr. Adams' prompt clarification of what the ARB staff is currently planning to consider as part of the ADF regulation.

In light of this clarification, Growth Energy would like to inquire whether the ARB staff plans to revise the portion of the CSRIA that discusses Growth Energy's proposed alternative to the ARB ADF 17-15 proposal. The CSRIA states at one point that the Growth Energy alternative "may achieve more emissions benefits" than ARB's proposal under some circumstances (CSRIA at 22), but then later states that the Growth Energy alternative "does not result in any more emissions reductions than the ADF proposal." (*Id.*) Those two statements appear to contradict one another.

ADF 17-15 cont.

The threshold question is whether the ARB staff intended to state that the Growth Energy proposal would, or would not, result in greater emissions reductions than the ARB proposal (as now clarified). The first quoted portion of the CSRIA refers to possible emissions reduction benefits under the Growth Energy proposal "if biodiesel were to be widely used as an additive under the ADF proposal." (CSRIA at 22.) Based on the ARB staff's projections (and treating biodiesel as "an additive"), biodiesel will certainly be "widely" used in many parts of the State and for many years. If the ARB staff disagrees, or if it meant something different when referring to the use of biodiesel as an "additive," please explain the reason for disagreeing, or clarify what "additive" means in this context.

ADF 17-16

The next question assumes that ARB did, in fact, intend to acknowledge that the Growth Energy proposal would be more protective -- provide more emissions reductions -- than the ARB proposal. On that premise, please advise whether ARB intends to revisit its position that the Growth Energy proposal would only provide "marginally more emissions benefits" than the ARB proposal, now that it is clear that ARB proposes not to require mitigation of any biodiesel blends below B5. In order for Growth Energy and others, including the Department of Finance, to understand the amount of incremental benefit that ARB would assign to the Growth Energy proposal, please also indicate how the staff has quantified that increment, and provide the inputs and assumptions on which that quantification is based.

ADF 17-17

2. Evaluation of LCFS Alternatives

The CSRIA appears to treat Growth Energy's proposed alternative to the LCFS proposal as not requiring complete assessment under the governing statute and regulations. Thus, referring to Growth Energy's proposed alternative ("this alternative") and to the CSRIA itself ("this document"), Appendix A of the CSRIA states as follows:

> ARB is required to analyze only those alternatives that are reasonable and that meet the goals of the program as required by statute. An initial assessment of the program indicates the goals of the LCFS proposal can be achieved by keeping the program '...separate of the AB 32 Cap-and-Trade system initially (at least first 10 years) in order to stimulate innovation and investment in low-GWI [global warming intensity] fuel (or transportation) technologies.' Due to the strong justifications that the Cap-and-Trade program alone generates neither the CI reductions nor fuel in the transportation sector, ***this alternative will not be assessed in this document.***

CSRIA at 27 (footnote omitted; emphasis added). The CSRIA concedes that Growth Energy's proposed alternative would "likely" achieve the same "estimated GHG emissions reductions" as the current regulation in the period up to 2020. (*Id.* at 26-27.)

LCFS 46-176

The deficiency in the Growth Energy proposal, according to the CSRIA, is not that it creates a GHG emissions reduction shortfall at any point prior to the end of the current regulatory horizon; instead, the problem is that the Growth Energy proposal does not rely on the same strategy of fuels diversification

LCFS 46-177

and achievement of GHG emissions reductions as proposed by ARB. As Appendix A of the CSRIA explains: LCFS 46-177 cont.

> Transportation in California was powered almost completely by petroleum fuels in 2010. ... Transitioning California to alternative, lower-carbon fuels requires a very focused and sustained regulatory program tailored to that goal. ... In the absence of such a program, post-2020 emissions reductions would have to come from a transportation sector that would, in all likelihood, have emerged from the 2010-2020 decade relatively unchanged. ***In the absence of an LCFS designed to begin the process of transitioning the California transportation sector to lower-carbon fuels starting in 2010, post-2020 reductions would be difficult and costly to achieve.*** This is why the primary goals of the LCFS are to reduce the carbon intensity of California fuels, and to diversify the fuel pool. A transportation sector that achieves these goals by 2020 will be much better positioned to achieve significant GHG emissions reductions post-2020.

CSRIA at 27 (emphasis added). In essence, the CSRIA is claiming that fuels diversification and carbon intensity requirements are necessary in order to make post-2020 greenhouse gas reductions less costly and less difficult to achieve. Growth Energy would submit, with the greatest respect, that the stated rationale for not providing a complete assessment of its alternative is itself deficient.[1] These are the salient points: LCFS 46-178

- The LCFS regulation does not require, and based on ARB publications is not expected to result in, the production or use of any type of alternative fuel that other regulations do not already either require or cause to be used in California. The federal renewable fuels program is intended to provide for the production and sale of cellulosic and "advanced" biofuels in the same time frame as the LCFS regulation. While the federal program does not require the use of electricity or hydrogen as a transportation fuel, the California motor vehicle emissions control and zero-emission vehicle programs do.[2] LCFS 46-179
- The long-run, post-2020 plans for greenhouse gas reductions developed by ARB calls for the phase-out of reliance on liquid biofuels.[3] Eventually, the State plans to eliminate gasoline, in LCFS 46-180

---

[1] Elsewhere, the CSRIA states that a goal of the LCFS regulation is to "create a durable regulatory framework that can be adopted by other jurisdictions." (CSRIA at 2.) ARB's authorizing legislation directs and permits the Board to adopt regulations to reduce greenhouse gas emissions. The statute does not permit the Board to impose costs on California consumers and businesses in order to export regulations to "other jurisdictions." Notably, the CSRIA does not try to claim that adoption of the LCFS program outside California will reduce costs. To the contrary, adoption of the LCFS program in other jurisdctions is likely to create supply shortages for the lowest-carbon-intensity alternative fuels, and could increase compliance costs for California consumers and businesses. LCFS 46-178 cont.

[2] *See* Attachment B (Growth Energy's proposed alternative to the LCFS regulation) at 8-11 (describing programs that will achieve the fuels diversification sought by ARB, in the absence of the LCFS regulation). LCFS 46-179 cont.

[3] *See* http://www.arb.ca.gov/planning/vision/vision.htm.

777 North Capitol Street, NE, Suite 805, Washington, D.C. 20002
PHONE 202.545.4000 FAX 202.545.4001

particular, from use in California cars and trucks and fully to replace gasoline with electricity. Putting to the side whether ARB's post-2020 strategy is meritorious, the CSRIA does not explain why ARB would seek to impose costs on California consumers and businesses to foster the use of fuels that (according to ARB) are destined for a diminishing, and no long-term, role in its greenhouse gas reduction strategy.

LCFS 46-180 cont.

- ARB's authorizing legislation does not itself require the use of regulations intended to reduce the carbon intensity of transportation fuels to achieve greenhouse gas reduction; it requires that enacted regulations achieve "the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions."[4] If the CSRIA's premise is that regulation of the carbon-intensity of transportation fuels is necessary now in order to reduce the costs or difficulties of achieving greenhouse gas reductions after 2020, as the State transitions away from biofuels, then the CSRIA should have included (i) an identification of the desired reductions in greenhouse gas emissions in the transitional period, and (ii) a sufficient explanation of why the costs of achieving those reductions would be reduced if Californians paid now for compliance with an otherwise unnecessary regulatory program. On a net-present value basis, there is reason to doubt that reliance on the LCFS regulation up to 2020 is the most cost-effective way of reducing greenhouse gas emissions after 2020 -- particularly when ARB would still have authority under its authorizing legislation to adopt and enforce regulations requiring reductions in the carbon-intensity of transportation fuels after 2020.

LCFS 46-181

Appendix A of the CSRIA therefore uses unsupported speculation about future regulatory costs and strategies, and an unspecified target for a future regulation (a regulation to reduce greenhouse gas emissions resulting from the use of liquid biofuels after 2020), as reasons to not provide a complete assessment of the Growth Energy alternative. The question presented is whether the CSRIA is substantially compliant with the Government Code, as amended by SB 617, and with the Department of Finance's implementing regulations.

Section 11346.36 of the Government Code provides that standardized regulatory impact assessments must compare

LCFS 46-182

> [P]roposed regulatory alternatives with an established baseline so agencies can make analytical decisions for the adoption, amendment, or repeal of regulations necessary to determine that the proposed action is the most effective, or equally effective and less burdensome, alternative in carrying out the purpose for which the action is proposed, or the most cost-effective alternative to the economy and to affected private persons that would be equally effective in implementing the statutory policy or other provision of law.

Cal. Gov't Code § 11346.36(b)(2). The Department of Finance's SRIA regulations accordingly require among other things that agencies "should consider" including in their analyses the "assumptions" and "data" used in the evaluation of regulatory alternatives and use "an established baseline" in evaluating "feasible alternatives" to a regulatory proposal. 1 C.C.R. §§ 2003(e), (e)(5). In addition, another portion

[4] Cal. Health & Safety Code § 38562(a).

of those regulations requires agencies to consider "how the effects of the regulation are distributed over time," including costs and benefits. *Id.* at § 2003(e)(4). LCFS 46-182 cont.

The Department's regulations do not specifically provide that agencies may exclude some proposed alternatives from stakeholders from complete analysis. Whether or not the discussion of Growth Energy's proposed alternative to the LCFS proposal in Appendix A is considered as complete as the evaluation of the regulatory alternatives considered in the main text of the CSRIA, ARB's rejection of Growth Energy's alternative does not meet the requirements of the Government Code, as amended by SB 617. LCFS 46-183

The CSRIA concedes that Growth Energy's alternative is likely to achieve the same level of greenhouse gas emissions reductions as the ARB proposal within the time frame for specific emissions reductions (2010-2020) defined by the ARB proposal. The CSRIA does not identify a single alternative fuel that other regulations will not require to be produced and used in California. (*See* note 2 above.) The questions that ARB was therefore required to address are whether the Growth Energy alternative is (i) "equally effective and less burdensome in carrying out the purpose for which the action is proposed," and (ii) would be "the more cost-effective alternative." Cal. Gov't Code § 11346.36(b)(2). ARB's negative answer to those two questions posed in the statute depends on its unsupported notions about how the use of carbon intensity regulations now will ease and reduce the costs of greenhouse gas reductions after 2020. ARB has provided the Department with no basis on which to evaluate, much less to credit, its belief that imposition of the regulatory costs of the LCFS program now will reduce the costs of post-2020 greenhouse gas reductions. Without more, there is no basis to conclude that the ARB proposal is more cost-effective than the Growth Energy alternative. LCFS 46-184

The enactment of SB 617 requires ARB to employ a level of analytical rigor and transparency in the current rulemaking that may not have been required in 2009, when the Board embarked on the regulation of carbon intensity. Likewise, SB 617 requires the Department of Finance to ensure that agencies meet the requirements of SB 617, including what is now section 11346.36 of the Government Code. ARB may contend that the requirements of sections 2002 and 2003 in the Department's regulations are merely precatory, because, for example, section 2003 only lists what an agency "should" consider in the analytical process. That is a question for the Department to consider, as indicated below; regardless, under the text of the Government Code, either the CSRIA does not meet the requirements of the Department's regulations, or those regulations are themselves deficient. LCFS 46-185

Growth Energy therefore suggests that the Department of Finance and the ARB Chief Counsel's Office consider and respond independently to the following questions:

- Whether the requirements for regulatory analysis contained in sections 2002 and 2003 of the Department's regulations are mandatory for all major rulemakings; LCFS 46-186
- Whether the Department's regulations allow an agency to engage in two different levels of review and consideration of regulatory alternatives, in the manner apparently pursued by ARB in the LCFS and ADF rulemakings; LCFS 46-187
- Whether the Department has the authority, or the duty, to refuse to comment upon, or otherwise reject, a standardized regulatory impact analysis that does not contain the information and analysis required by sections 2002 and 2003 of its regulations; LCFS 46-188

- Whether the CSRIA's reliance on speculative and unquantified future (post-2020) estimated cost savings meets the requirements of SB 617 and the Department's regulations, particularly the portions of those regulations that require adequate definition of a baseline, comparative cost-effectiveness assessments, a discussion of "uncertainties associated with … estimates," and attention to how the effects of a regulation (both costs and benefits) may differ in their timing. *See* 1 C.C.R. § 2003(e), (e)(3), (e)(3)(D), (e)(4), (e)(5); and LCFS 46-189

- If the CSRIA meets the requirements of the Department's current regulations, whether those regulations should be amended in order to more effectively permit the evaluation of alternatives required inter alia by section 11346.36(b)(2) of the Government Code. LCFS 46-190

Thank you again for allowing Growth Energy to participate in the SB 617 process for these two regulations. I would appreciate it if you would advise me whether and how the Department and the ARB Chief Counsel's Office plan to respond to the specific questions presented in this letter. In addition, please let me know if you would like to discuss the issues raised here, including the questions that Growth Energy hopes you will consider and address.

Sincerely,

David Bearden

David Bearden
General Counsel and Secretary

cc: Mr. Michael Waugh (by electronic mail)
Mark W. Poole, Esquire (by electronic mail)
Elaine Meckenstock, Esquire (by electronic mail)

This page intentionally left blank.

46_OP_LCFS_GE Responses (Page 180 - 186)

507. Comment: **ADF 17-15 through ADF 17-17**

Agency Response: These comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under Comment Letter **17_OP_ADF_GE**.

508. Comment: **LCFS 46-176**

The comment questions the CSRIA's decision regarding Growth Energy's proposed alternative to the LCFS proposal

Agency Response: See response to **LCFS 46-65**.

509. Comment: **LCFS 46-177**

The comment implies that CSRIA's conclusion that the Growth Energy proposal does not rely on the same strategy of fuels diversification is not adequate reason for not giving the proposal a complete assessment.

Agency Response: See response to **LCFS 46-65**.

510. Comment: **LCFS 46-178**

The comment states that CSRIA's stated rational for not providing a complete assessment of Growth Energy's alternative proposal is deficient.

Agency Response: See response to **LCFS 46-65**.

The SRIA analysis meets all the requirements of SB 617, and the alternative was not analyzed for the reasons listed in response to **LCFS 46-65**. The fuels diversification and carbon intensity requirements are necessary not solely to achieve post-2020 greenhouse gas reductions in a less costly and less difficult manner, but more importantly to achieve California's goals as described in AB 32 and Executive Orders, among other sources. See also response to **LCFS B12-5**.

511. Comment: **LCFS 46-179**

The comment states that the LCFS regulation does not require any type of alternative fuel that other regulations do not already require to be used in California.

Agency Response: The LCFS regulation will require a reduction of the CI of transportation fuels in California and is expected to have positive impacts on GHG emissions and fuel diversity. It works in conjunction with a number of other state and local programs, including the federal RFS program, and ARB's zero-emission vehicle program, as cited in the comment, as well as ARB's Cap-and-Trade Program. See response to **LCFS 46-195**.

512. Comment: **LCFS 46-180**

The comment asks why ARB fosters the use of alternative liquid biofuels when the fuels will phase-out after 2020.

Agency Response: See responses to **LCFS 46-70 and LCFS 46-71**.

513. Comment: **LCFS 46-181**

The comment states that there is reason to doubt the reliance on the LCFS regulation up to 2020 is the most cost-effective way of reducing GHG emissions after 2020.

Agency Response: See response **LCFS 46-66**.

514. Comment: **LCFS 46-182**

The commenter suggests that ARB's cost analysis is incomplete until the analysis determines more precisely the costs of future post-2020 regulations that have not been designed, proposed, subject to public comment, or adopted.

Agency Response: See response to **LCFS 46-65**.

The SRIA approach is within the requirements and spirit of SB 617 and Department of Finance regulations in meeting the goals previously mentioned. The SRIA as analyzed by the Department of Finance for compliance with SB 617, specifically included publically provided alternatives and met the following requirements:

- The data and assumptions of the modeling were clearly identified;
- The baseline was described and used for all analyses (including comparison of alternatives); and
- Outlined how the effects of the regulation, including the costs and benefits are distributed over time for all feasible alternatives.

515. Comment: **LCFS 46-183**

This comment tacitly assumes that every proposed alternative must be fully analyzed, and faults ARB for not performing a more exhaustive analysis of one particular alternative that the commenter had suggested during the SRIA process.

Agency Response: DOF regulations state that agencies must include "identification of each regulatory alternative for addressing the stated need for the proposed major regulation;" alternatives that do not meet the stated need for the proposed major regulation are not required to be analyzed. 2002(c)(8). Additionally, the regulations state that agencies should analyze "feasible alternatives…" while taking into account "an evaluation of the legal and statutory constraints that limit the selection of regulatory alternatives" 2003(e)(1). Section 11342.548 (b)5A provides a description of the alternatives agencies must analyze and Section 11342.548 (b)5C states "an agency is not required to…describe unreasonable alternatives."

516. Comment: **LCFS 46-184**

The comment states that the ARB staff does not have enough evidence to conclude that the LCFS proposal is more cost-effective than the Growth Energy alternative.

Agency Response: For the reasons set out in the SRIA and ISOR, the alternative is not equally effective nor less burdensome, nor is it the most cost-effective alternative to achieve the purpose, because it does not achieve the goals as outlined by the regulation.

517. Comment: **LCFS 46-185**

The comment is in an October 2014 letter addressed to an economist at the "Department of Finance" (DOF) and to two attorneys at the "California Air Resources Board." The paragraph suggests that in the future "ARB may contend" that certain DOF regulations are precatory, in which case "the Department" should consider whether its regulations are deficient.

Agency Response: Having set the stage for a hypothetical future dispute between two state agencies, the commenter "suggests" that DOF and ARB independently consider specific questions and render some type of advisory rulings to the commenter in October 2014. Because the letter was written in October 2014, and because this passage makes no objection or recommendation regarding the specific proposal, no response is necessary. ARB also declines to issue the type of advisory ruling requested. See also response to **LCFS 46-220**.

518. Comment: **LCFS 46-186**

The commenter asks if section 2002 and 2003 are mandatory for all major rulemakings.

Agency Response: **LCFS 46-186** to LCFS **46-190** are not objections or recommendations to the regulatory proposal. Instead, the pre-rulemaking letter "suggests that the Department of Finance and ARB Chief Counsel's Office consider and respond" to five separate legal questions. Many of these questions appear to be targeted at Department of Finance, and, in any event, ARB declines to offer the legal advice or opinions sought by the commenter. See responses to **LCFS 46-75** through **LCFS 46-77** above.

519. Comment: **LCFS 46-187**

The commenter asks if departments can engage in two levels of review for consideration of alternatives.

Agency Response: See response to **LCFS 46-186**.

520. Comment: **LCFS 46-188**

The commenter asks if the Department of Finance has the authority to reject a SRIA.

Agency Response: See response to **LCFS 46-186**.

521. Comment: **LCFS 46-189**

The commenter asks if the requirements of the SRIA process allow for estimation of future costs and benefits.

Agency Response: See response to **LCFS 46-186**.

522. Comment: **LCFS 46-190**

The commenter asks that if the LCFS SRIA meets the requirements of the Department of Finance, should the Department then amend its requirements to satisfy the commenter's agenda?

Agency Response: See response to **LCFS 46-186**.

46_OP_LCFS_GE

17_OP_ADF_GE

Attachment A

Drake, Stuart

From:	Adams, Stephen@ARB <Stephen.Adams@arb.ca.gov>
Sent:	Wednesday, October 29, 2014 2:34 PM
To:	majorregulations@dof.ca.gov
Cc:	Drake, Stuart; Brieger, William@ARB; Elaine Meckenstock (Elaine.Meckenstock@doj.ca.gov)
Subject:	FW: LCFS and ADF rulemakings -- SRIAs

To whom it may concern:

The emails below relate to the SRIA that ARB staff submitted on October 17 for the low-carbon fuel standard regulation and alternative diesel fuel regulation. This copy is being provided for your information.

Stephen Adams
ARB Senior Staff Counsel

From: Adams, Stephen@ARB
Sent: Wednesday, October 29, 2014 11:28 AM
To: 'Drake, Stuart'
Cc: Brieger, William@ARB; Elaine Meckenstock
Subject: RE: LCFS and ADF rulemakings -- SRIAs

Stuart,

The differences you point to between the biodiesel mitigation described in the SRIA and that presented at the Oct. 20 workshop reflects the progression in staff's analysis of the biodiesel NOx issue and mitigation for NOx emissions from biodiesel. You're correct that the SRIA describes a plan to require mitigation for blends from B1 and higher, while the proposal discussed at the workshop would require mitigation beginning at blends of B5 and higher. The reasons behind these changes were described at the workshop, and also on page 2 of the discussion paper that you cite.

Time constraints prevented staff from revising the SRIA to reflect staff's more recent approach. Although the SRIA was submitted to the Department of Finance on the same day that workshop materials were made available, the modeling and analysis work to prepare the SRIA was a weeks-long process. The SRIA as submitted discloses potential economic impacts from the ADF, and the economic impacts from staff's revised approach will likely be lower than stated in the SRIA. I'd also note that the issues of biodiesel NOx emissions and mitigation are still the subject of internal discussion and analysis, and consequently these provisions are subject to further changes prior to filing of the proposed regulation with the Office of Administrative Law.

The economic impact analysis for the ADF will be updated as we move forward. Regulatory concepts and proposals are often revised during their development and public review, especially at this preliminary stage. Given that, changes such as the one involving staff's evaluation of biodiesel emissions are to be expected.

Sincerely,

Steve

From: Drake, Stuart [mailto:sdrake@kirkland.com]
Sent: Tuesday, October 28, 2014 6:30 AM
To: Adams, Stephen@ARB

Cc: Brieger, William@ARB; Elaine Meckenstock
Subject: LCFS and ADF rulemakings -- SRIAs

Steve --

The Department of Finance yesterday provided Growth Energy and other members of the public with access to the October 17, 2014 SRIA that covers the ADF rulemaking. Thank you for helping to make that happen. I'd like to request your Office's further assistance with what appears to be a substantial problem in one portion of the SRIA. That is the portion of the SRIA that describes the staff's proposed mitigation strategy to the Department of Finance and others.

Page four of the SRIA describes the mitigation strategy for the staff's ADF proposal in relevant part as follows (emphasis added):

> "The multimedia evaluation process for biodiesels made from various feedstocks identified a NO_X significance threshold, or blend level, that will result in no significant adverse impacts. The ADF proposal seeks to mitigate NO_X impacts from biodiesel by setting a significance threshold and requiring mitigation of all non-animal biodiesel use at blends above one percent, and all animal biodiesel used at blends above five percent. *The ADF proposal identified one percent for non-animal biodiesel, rather than zero percent, because biodiesel may be used as an essential lubricity additive at one percent or less*."

I am not aware that anyone has called for mitigation when there is zero percent biodiesel in the blend. Growth Energy has proposed mitigation below the five percent level (or "B5") if the blend level was one percent or greater, as the SRIA elsewhere notes. (*See* SRIA at 22.) In any event, a fair reading of the SRIA is that the ARB decided, as of October 17, to require mitigation of all non-animal biodiesel use at blends above one percent.

LCFS 46-191

I believe there may be some material confusion about the ARB staff's position. The confusion arises because the staff appears to be saying different things in its filings with the Department of Finance and in some of its public statements. Appendix A of the ADF regulatory "discussion paper" released by the ARB staff on the same day as the SRIA (October 17) describes the staff's ADF proposal as follows:

> " Recognize biodiesel made from soy feedstocks as low saturation (i.e., B100 with cetane <56) and biodiesel made from animal feedstocks as high saturation (i.e., B100 with cetane ≥56).
>
> " Establish significance thresholds of B5 for low saturation biodiesel, and B10 for high saturation biodiesel to ensure NOx impacts associated with biodiesel use do not increase and steadily decrease. Allow 'Safe Harbor' blending below the significance threshold without the need for additional NOx mitigation."

See http://www.arb.ca.gov/fuels/diesel/altdiesel/20141017_ADF_discussion_paper.pdf. That proposal (mitigation of non-animal based, aka "low saturation" biodiesel, at B5 and higher) was discussed at the ARB staff's workshop on October 20. So, in a nutshell, the SRIA indicates that mitigation will be required for non-animal biodiesel with blend levels above one percent; by contrast, the "discussion paper" and the staff's presentation to the public at its October 20 2014 workshop, indicated that mitigation would only be required for animal-based blends at or above five percent.

LCFS 46-192

If the blend level at which the staff proposal would require mitigation is material enough to have been presented in the SRIA, then this apparent inconsistency in the relevant blend level for mitigation is also material. The SRIA advises the Department of 2inance that the staff's proposal "will result in no significant adverse impacts on public health or the environment." (SRIA at 3.) The Department might reasonably believe that the SRIA's claim in that regard was based on mitigation for animal-based biodiesel blends between one and five percent, based on the portion of the SRIA appearing on page 4 that is quoted above. The likelihood that the Department will be misled -- I assume inadvertently -- about this basic element in the staff's AD2 proposal is sufficient in itself to require correction. In addition, the inconsistency is also relevant to the reasonableness of the staff's claim in the SRIA that the Growth Energy alternative proposal "does not result in any more emissions reductions than the AD2 proposal." (SRIA at 22.) Presumably, in evaluating that claim, the Department would want to know that the staff's proposal does not require mitigation for non-animal based biodiesel at the same level as does the Growth Energy proposal.

LCFS 46-193

If I am missing something that explains why the description of the staff's AD2 proposal in the SRIA does *not* differ materially from the description in the materials that the staff has released to the public on October 17, please let me know. If the staff's proposal really is to require mitigation for non-animal blends higher than one percent (even if less than five percent), please let me know. Otherwise, Growth Energy would like to know how the staff plans to correct the SRIA, so that the Department and others will have an accurate understanding of the staff's proposal. LCFS 46-194

On the assumption that the Department has to provide its evaluation of the SRIA very soon, Growth Energy requests a response to this inquiry by the close of business on Wednesday, October 29.

Please let me know if you would like to discuss these questions, or if you don't believe that the staff will be able to respond by the close of business on October 29. Thanks, Stuart

Stuart Drake | Kirkland & Ellis LLP
655 15th Street, NW | Suite 1200
Washington, DC 20005
202-879-5094 Office | 202-450-0051 Mobile
202-654-9527 Direct Fax
stuart.drake@kirkland.com

****
The information contained in this communication is confidential, may be attorney-client privileged, may constitute inside information, and is intended only for the use of the addressee. It is the property of Kirkland & Ellis LLP or Kirkland & Ellis International LLP. Unauthorized use, disclosure or copying of this communication or any part thereof is strictly prohibited and may be unlawful. If you have received this communication in error, please notify us immediately by return e-mail or by e-mail to postmaster@kirkland.com, and destroy this communication and all copies thereof, including all attachments.
****

46_OP_LCFS_GE Responses (Page 187 - 190)

523. Comment: **LCFS 46-191**

The commenter attaches an email dated October 28, 2014, two months before ARB released the proposed LCFS regulation.

Agency Response: Staff responds to the extent the email makes objections or recommendations that nevertheless pertain to the proposal. The email pointed out what it believed were different statements made by ARB staff.

The commenter suggests that because the ADF proposal changed after ARB's solicitation for alternatives, ARB did not substantially comply with SB 617. ARB fully complied with SB 617.

The ADF proposal as outlined in the SRIA, was not materially different from the final regulation as considered by ARB; SB 617 does not require a new analysis after stakeholder input is considered. After submittal of the SRIA to DOF, ARB staff continued to solicit for and incorporate feedback from stakeholders. As expressly mentioned in the SRIA submitted to DOF, "the final…regulation…to be proposed to the Air Resources Board for consideration of adoption in 2015, will be informed by continued interactions with stakeholders, external researchers, and other regulatory agencies."

Additionally, the timeline as outlined in SB 617 leaves room for additional input and should not be interpreted to indicate that a new analysis be made each time changes are proposed. There is no indication that when enacting SB 617 the legislature intended to preclude public input and the agency from making changes as required under the APA during the subsequent rulemaking process. Clearly the Legislature *added* to the rulemaking process. Preexisting APA requirements were left intact. Finally, the comments received by DOF did not indicate that there were any missing components required by SB 617.

ARB staff notes that over a period of several years there were 21 LCFS public workshops, and 26 ADF public workgroup or workshop meetings as part of developing these two related regulations. All of this work informs an evolving proposal that the public processes are intended to improve. At no point prior to the Board's final adoption of a regulation is any proposal carved in stone. At the time ARB solicited alternative proposals pursuant to SB 617, ARB staff shared its then-current thinking on the form of the proposal which had yet to be formally proposed – and by law could not yet be formally proposed under the terms of SB 617. That solicitation fulfilled the purpose of SB 617, and the input from that solicitation as well as information gathered through other normal rulemaking processes, continued to shape the proposal.

524. Comment: **LCFS 46-192**

The commenter expresses confusion over the SRIA documents and ARB's public process documents.

Agency Response: See response to **LCFS 46-191**.

525. Comment: **LCFS 46-193**

The commenter believes that ARB should resubmit the SRIA to match the current proposal.

Agency Response: See response to **LCFS 46-191**.

526. Comment: **LCFS 46-194**

The commenter asks whether the proposal will require mitigation at different levels than its alternative and when ARB plans to resubmit its SRIA to the Department of Finance.

Agency Response: See response to **LCFS 46-191**.

46_OP_LCFS_GE

17_OP_ADF_GE

Attachment B

STATE OF CALIFORNIA

AIR RESOURCES BOARD

Response to Request for Public Input On Alternatives to the Low- Carbon Fuel Standard Regulation

Growth Energy

June 23, 2014

Executive Summary

The staff of the California Air Resources Board ("CARB") has identified the Low-Carbon Fuel Standard ("LCFS") as a "major regulation" that requires enhanced review for compliance with SB 617 (Calderon and Pavley), a 2011 amendment to the California Administrative Procedure Act (the "APA"). The California Department of Finance ("the Department") has published regulations that implement SB 617. Those regulations require rulemaking agencies like CARB to seek early public input on possible alternatives to the rules being developed by the rulemaking agencies.

Growth Energy, an association of the Nation's leading ethanol producers and other companies that serve America's need for renewable fuels, is submitting to the CARB staff a proposed alternative to the LCFS regulation that would allow the State to eliminate the LCFS program without loss of environmental benefits. Growth Energy's proposal recognizes important changes in the regulatory baseline for the control of greenhouse gas ("GHG") emissions that have occurred since 2009. In particular, the federal renewable fuels standard ("RFS") program, combined with the California cap-and-trade program and a number of California-specific vehicle- and engine-based regulations, now assure that California will receive most if not all of the direct GHG emissions reductions that can be attributed to the LCFS regulation. To the extent that CARB believes that there is still an emissions shortfall from elimination of the LCFS or that it has authority to address lifecycle GHG emissions occurring outside of California under state and federal law (which are issues not addressed in this submittal), Growth Energy proposes that CARB address those remaining issues by modifying the California GHG cap-and-trade regulations, which are now in effect in California and which apply to transportation fuels providers beginning in 2015. LCFS 46-195

Growth Energy's description of its proposed alternative to the LCFS regulation is as detailed as possible, given currently available information. In this submittal, Growth Energy urges the CARB staff to provide the additional information needed to provide further analysis of alternatives to the LCFS regulation.

Table of Contents

Growth Energy's Response to Request for Public Input
On Alternatives to the Low-Carbon Fuel Standard Regulation

Growth Energy respectfully submits this response to the request by the staff of the California Air Resources Board ("CARB") for public input on alternatives to the low-carbon fuel standard ("LCFS") regulation. The CARB staff presented its request for public comment in a notice dated May 23, 2014, and has established today as the deadline for that input.

The CARB staff is seeking public input in connection with its proposal that CARB revise and readopt the LCFS regulation at a public hearing later this year. The purpose of the LCFS regulation, which the Board first adopted in 2009, is to achieve reductions in greenhouse gas ("GHG") emissions from the California transportation sector pursuant to the Global Warming Solutions Act of 2006, commonly called AB 32. Other regulations adopted since 2008 under AB 32 to achieve the same objectives as the LCFS regulation include the "cap and trade" regulation (17 C.C.R. §§ 95801-96022), the GHG emissions standards contained in the Advanced Clean Cars (or "ACC") program (13 C.C.R. §§ 1960.1-1962.2), and a set of regulations to control GHG emissions from heavy-duty vehicles and engines.[1] LCFS 46-196

Overview

Growth Energy has organized its analysis of alternatives to the LCFS regulation in this submission into four parts.

Part I of this submission briefly outlines the statutory and regulatory framework for the CARB staff's request for input on alternatives to the LCFS regulation. As explained in Part I, regulations adopted by the California Department of Finance pursuant to a recent amendment to the APA require CARB to seek and permit effective early public input on rulemaking concerning

[1] These include California's Heavy-Duty GHG regulations now completing the rulemaking process, a second phase of regulations that are under development, and the so-called "Tractor-Trailer" GHG regulation adopted in 2008. *See* http://www.arb.ca.gov/regact/2013/hdghg2013; http://www.arb.ca.gov/cc/hdghg/hdghg.htm.

"major" regulations, including the LCFS. That amendment was contained in SB 617 (Calderon and Pavley). The LCFS rulemaking, and this stage of the LCFS rulemaking, are particularly important, because this rulemaking is one of the first CARB rulemakings governed by SB 617. *See* pp. 4-7 below.

Part II of Growth Energy's submittal addresses some of the important factors that affect a regulatory alternatives analysis undertaken under SB 617. Since 2009, there have been significant changes in the "baseline" conditions for GHG regulation relevant to the LCFS program. As explained in Part II, most of the GHG emissions reductions sought by CARB when it adopted the LCFS regulation in 2009 will be provided by a combination of the federal renewable fuels standard ("RFS") program, along with California's cap-and-trade regulation, ACC program, and regulations limiting GHG emissions from heavy-duty vehicles and engines. Given that most, if not all, of the GHG emissions reductions sought by CARB in 2009 through the LCFS regulation are now assured by those other programs, the LCFS regulation has been rendered largely superfluous from an environmental perspective, even though it imposes huge financial burdens on the regulated community and requires a large commitment of resources by CARB. As a threshold matter, CARB should therefore carefully and fully consider whether, based on regulatory and program developments related to GHG emission control since 2009, there is any continuing need for the LCFS regulation. *See* pp. 8-14 below. LCFS 46-196 cont.

Part III of this submittal explains that, to the extent that the CARB staff finds any continuing need for the LCFS regulation to control GHG emissions, that need could be met instead through a simple modification of the cap-and-trade regulation. Taking that step -- modifying the cap-and-trade regulation -- would fully eliminate any conceivable remaining need for the LCFS regulation, while doing nothing to alter CARB's overall regulatory strategy to LCFS 46-197 address GHG emissions from the California transportation sector. The GHG emissions reductions benefits of the LCFS program would be fully realized from the suite of other GHG regulations adopted federally and in California since 2009, and by the modification of the cap-and-trade program. The direct regulatory costs of the LCFS program are borne primarily by the California motor vehicle fuels marketing industry, which can to some extent pass those costs to its retail customers. Insofar as the LCFS program imposes costs on California businesses and consumers, the alternative presented here (relying on the cap-and-trade program) would not materially alter the allocation of costs and would at the same time reduce regulatory costs by eliminating an entire regulatory program (the LCFS regulation). Judging from the strong concern about the LCFS regulation expressed by oil industry stakeholders, the regulatory relief and reform proposed here warrants full consideration and further development. *See* pp. 14-20 below.

LCFS 46-197 cont.

Part IV of Growth Energy's submittal recommends specific next steps that CARB should consider, including full involvement by the Chief Counsel's Office to ensure compliance with the APA. As will be apparent throughout this submittal, Growth Energy's analysis of regulatory alternatives can be no more detailed than the publicly available information about (i) the new version of the LCFS regulation that the CARB staff is considering for proposal to the Board, and (ii) the information that the CARB staff has provided about the benefits that it is attributing to the LCFS program. Contrary to the position taken in communications to Growth Energy by CARB's Transportation Fuels Section on this subject, very little information on the new version of the LCFS regulation or its estimated benefits -- which are critical to an effective SB 617 process -- has been provided to the public to date. In order to achieve substantial compliance with the APA, the CARB staff needs to provide the public with a full picture of its proposed new

LCFS 46-198

LCFS regulation, and in particular describe any new features of the regulation intended to reduce compliance costs. The CARB staff also needs to completely identify for the public all benefits that it is attributing to the LCFS regulation that would bear on an SB 617 alternatives analysis. Then, after the public has had sufficient time to analyze the relevant information from CARB, the public should be permitted to provide updated regulatory alternative analyses, which the CARB staff should fully consider and address in the Standardized Regulatory Impact Assessment required by 1 C.C.R. § 2002. That approach would ensure compliance with the APA, without conflicting or otherwise undermining any other mandates or obligations applicable to the LCFS regulation. *See* pp. 20-24 below.

LCFS 46-198
cont.

I. The Statutory Framework for the Regulatory Alternatives Analysis under SB 617

The CARB staff is seeking submittals from the public on regulatory alternatives to the LCFS regulation because it has a legal obligation to do so. For many years, section 11346.3 of the APA has provided in part as follows:

> (a) State agencies proposing to adopt, amend, or repeal any administrative regulation shall assess the potential for adverse economic impact on California business enterprises and individuals, avoiding the imposition of unnecessary or unreasonable regulations or reporting, recordkeeping, or compliance requirements. …
>
> (2) The state agency, prior to submitting a proposal to adopt, amend, or repeal a regulation to the office, shall consider the proposal's impact on business, with consideration of industries affected including the ability of California businesses to compete with businesses in other states. For purposes of evaluating the impact on the ability of California businesses to compete with businesses in other states, an agency shall consider, but not be limited to, information supplied by interested parties.

Cal. Gov't Code § 11346.3(a)(2). Based on evidence that rulemaking agencies did not adequately consider the burdens that regulations impose on the public, in SB 617 the Legislature added a requirement that rulemaking agencies prepare a detailed assessment of the costs and benefits of any proposed major regulation, for review by the California Department of Finance ("the Department") ***before*** initiating the traditional informal rulemaking process. *See id.* § 11346.3(c). Those detailed assessments are called Standardized Regulatory Impact Assessments (or "SRIAs."). *See id.* § 11346.36. The Legislature also made it clear in SB 617 that the obligation to consider and use early public input on regulatory impacts could not be met by merely going through the formalities of seeking public input.[2]

The Department completed work on regulations to implement SB 617 in the fall of 2013. The Department's regulations require, among other steps, the following:

> The [rulemaking] agency shall also seek public input regarding alternatives from those who would be subject to or affected by the regulations ... prior to filing a notice of proposed action with OAL unless the agency is required to implement federal law and regulations which the agency has little or no discretion to vary. An agency shall document and include in the SRIA the methods by which it sought public input.

1 C.C.R. § 2001(d). As the rulemaking file for the Department's regulations implementing SB 617 shows, many state regulatory agencies, CARB not excepted, recognized that SB 617 (as implemented by the Department) would mean the end of "business as usual" in the California rulemaking process.[3]

In responding to objections from rulemaking agencies concerning the obligations created by its SB 617 regulations, the Department explained that "[i]nvolving the Department and affected parties early in the [rulemaking] process could result in the discovery of additional and

---

[2] Thus, SB 617 deleted text from section 11346.3(a)(2) of the APA that, up to 2011, had provided that the APA's public-input requirements were not "inten[ded]" to "impose additional criteria on agencies" engaged in rulemaking. *See* Stats. 2011, c.496 (SB 617), subd. (a); Cal. Office of Admin. Law, *California Rulemaking Law under the Administrative Procedure Act* (2012) 57 (legislative history of section 11346.3).

[3] Several rulemaking agencies filed sharp objections to the Department's proposed regulations to implement SB 617 on the ground that the regulations would require major changes in the timing used by the agencies to develop regulations and to obtain public input. *See, e.g.,* Dep't of Finance, *Regulations to Implement SB 617 Re Major Regulations, Responses to 45-day Comment Period (Chart A)* (hereinafter "Chart A"), available at http://www.dof.ca.gov/research/economic_research_unit/SB617_regulation/documents/Response%20to%20Comments%20Chart A.pdf. The Department dealt fully with all those objections and made no material changes in its proposed regulations to implement SB 617.

perhaps more cost-effective alternatives to [a] proposed major regulation, consistent with the intent of SB 617."[4] Similarly, when rulemaking agencies (including CARB) objected to the burdens of preparing the early regulatory analyses of costs and benefits needed for an effective SB 617 process, the Department correctly concluded that the amended APA "clearly contemplates that an agency will have considered [regulatory] alternatives prior to filing a notice of a proposed action" with the Office of Administrative Law and publication of the regulatory notice for further public comment.[5] The Department also made it clear that under the SB 617 process, the "no action" alternative to regulation -- which is an outcome seldom if ever seen in a major California rulemaking -- had to receive full and fair consideration at the beginning of the rulemaking process.[6]

In requiring significant change in the California rulemaking process, the statute and the implementing regulations are salutary. The LCFS regulation in 2009 was typical of major rulemakings affecting the motor vehicle fuels industries in California. Beginning in 2008, CARB had convened a series of public consultation meetings prior to its formal proposal for rulemaking in March 2009. Not until publication of the Initial Statement of Reasons for the LCFS regulation, however, was the public given any opportunity to review the economic analysis of costs and benefits for the proposed regulation; the written comments on economic issues were due a scant 45 days later (in April 2009), and at the Board's April 2009 public hearing, most private-sector speakers were limited to five minutes to make a presentation to

---

4 *See* Chart A at 24.

5 *Id.* at 27.

6 *Id.* at 47-48.

CARB. The public cannot have a significant role in serious economic analysis of a major regulation within such a constrained process.

Unsurprisingly, major economic assumptions and issues were not fully addressed within the time frame for written comments in March to April 2009, nor at the Board hearing. Among the assumptions and factors that could not as a practical matter be "pressure-tested" in the public comment process was the CARB staff's belief that advanced ethanol production methods would eventually drive down gasoline costs at the retail level and make the LCFS program cost-neutral for California consumers or even generate savings of up to $11 billion.[7] That assumption was unsound in 2009, and has since been disproven by experience.[8] Likewise, in the 2009 rulemaking, the CARB staff gave little attention to the ability of the federal RFS program to accomplish the same goals and purposes of the LCFS regulation, and offered largely opaque comparisons between the GHG reductions that the two programs could achieve. Now in its fifth year of implementation, the LCFS regulation has made little or no impact on the supply of lower-GHG fuels in California.[9] SB 617 and the Department's implementing regulations require the Board to improve the quality and depth of the economic analysis for major regulations like the LCFS program.

LCFS 46-199

---

[7] Air Resources Board, *Proposed Regulation to Implement the Low Carbon Fuel Standard -- Staff Report: Initial Statement of Reasons* (hereinafter "ISOR") at ES-26.

[8] As the ISOR itself noted, "Economic factors, such as tight supplies of lower-carbon-intensity fuels ... could result in overall net costs, not savings, for the LCFS." The fact that the cost savings forecast in 2009 proved ephemeral is implicit in the CARB staff's decision, less than two years after the regulation went into effect, to develop "cost reduction" features for the LCFS regulation, which would assist "regulated parties ... unable to meet their compliance obligations ... due to limited supplies of low carbon fuels or LCFS credits in the market." Air Resources Board, *Low Carbon Fuel Standard 2011 Program Review Report* (Dec. 8, 2011) (hereinafter "2011 Program Review") 16.

[9] There have been substantial increases in the efficiency of Midwest corn ethanol production facilities since CARB first embarked on the LCFS rulemaking, and those increases have reduced the lifecycle GHG emissions of those facilities under some analyses; but those reductions in GHG emissions have been caused by market forces (the need to reduce energy consumption in order to remain competitive), not by virtue of the LCFS regulation. *See* note 25 below.

II. Factors Affecting the Regulatory Alternatives Analysis

According to the CARB staff, the goal of the LCFS regulation in 2009 was, and still remains, to "reduce the carbon intensity of transportation fuels used in California by at least 10 percent by 2020 from a 2010 baseline," and also to "support the development of a diversity of cleaner fuels with other attendant co-benefits."[10] Growth Energy sought clarification of the staff's description of the goals of the regulation for purposes of its input in the SB 617 process.[11] Lacking greater specificity or clarification, Growth Energy can only turn to the 2009 rulemaking, in which CARB quantified the "10 percent" target as being a reduction of 16 million metric tons of carbon dioxide equivalent ("MMTCO2eq") GHG emissions associated with combustion of transportation fuels in California, along with a 7 MMTCO2eq reduction in "upstream" emissions, yielding a total 23 MMTCO2eq reduction in worldwide annual GHG emissions in 2020.[12] As explained below, achieving the direct GHG emissions reduction attributed to the LCFS regulation in 2009 -- the 16 MMTCO2eq -- no longer requires the existence of the LCFS regulation. LCFS 46-200

A. Changes in the Regulatory Baseline Since 2009

The most significant development in the regulatory baseline since 2009 has been the adoption and full implementation of the federal renewable fuels standard program under the Energy Independence and Security Act of 2007, pursuant to a Final Rule adopted by the U.S. LCFS 46-201

---

10 The staff identified that goal on June 5, 2014, well after the period for preparation of SB 617 public input had begun, in response to a specific request from Growth Energy. *See* Letter from D. Bearden to K. King, May 30, 2014 (included here as Attachment 1) *and* Letter from M. Waugh to D. Bearden, June 5, 2014 (included here as Attachment 2).

11 *See* Letter from D. Bearden to M. Waugh, June 11, 2014 (included here as Attachment 3). To date, no response to Mr. Bearden's letter of June 11, 2014, has been received.

12 *See* ISOR at VII-1. According to the 2009 ISOR, "These reductions account for a 10 percent reduction of the GHG emissions from the use of transportation fuel." *Id.* That 10 percent target, which the CARB staff also sometimes cites, originates in Executive Order S-01-07 of January 18, 2007. *See* Executive Order S-01-07, § 1, available at http://www.arb.ca.gov/fuels/lcfs/eos0107.pdf.

Environmental Protection Agency in 2010.[13] The federal RFS program assures an adequate supply of low-cost renewable fuel for California, *i.e.*, ethanol produced from corn starch at biorefineries located mainly in the Midwest.[14] Because ethanol produced by any method from any renewable feedstock has the same physical and chemical properties when used in motor fuel, gasoline blended with 10 percent ethanol will achieve the same reduction in exhaust or "tailpipe" GHG emissions regardless of the production process or renewable feedstock used to create the ethanol. Consequently, the portion of the 16 MMTCO2eq reduction in GHG emissions from the California transportation fleet operated on gasoline can and will be obtained by virtue of the federal RFS program.[15] Oil companies will continue to buy and blend ethanol into gasoline sold in California under the federal program even if there were no LCFS program, in order to comply with the federal RFS program. The portion of the California fleet operated on diesel fuel can also achieve its part of the 16 MMTCO2eq reduction in GHG emissions by virtue of the federal RFS

LCFS 46-201 cont.

---

[13] *See* U.S. EPA, *Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Final Rule*, 75 Fed. Reg. 14,669 (Mar. 26, 2010) .

[14] The RFS program, which in its early stages was effectively non-binding on ethanol usage, has begun to cause substantial increases in biofuel production. Total production of biofuels has increased steadily over the last year and a half, reaching approximately 16 billion gallons in the 12 months through April 2014. *See* http://www.epa.gov/otaq/fuels/rfsdata/.

[15] The term "fleet," as used here, includes off-road vehicles and engines in other equipment.

When the CARB staff considered the matter in 2009, it made a number of assumptions about the efficacy of the federal RFS program that need to be reconsidered. The most significant assumption, which was empirically unsupported, was that the federal program (which at the time was still under development) would provide only 30 to 40 percent of the GHG reductions that the staff predicted for the LCFS program. That assumption appears to have been based on a belief that without the LCFS regulation, only 11.3 percent of the advanced or cellulosic biofuels required nationwide by the RFS program would be consumed in California, while a substantially higher amount of those fuels would be drawn from the nationwide fuel pool to California as the result of the LCFS regulation. The advanced biofuels required by the RFS regulation that would be drawn to California by the LCFS program would have been used elsewhere in the absence of the LCFS program, leading to the same reductions in GHG emissions. To the extent that the cellulosic ethanol industry has experienced limits on achieving full commercial launch, those are national and even global economic and technical factors that the existence of the LCFS regulation has not to date, and will not in the future, be able to change or influence.

program, because the federal program results in blending biodiesel and renewable diesel into diesel fuel produced from petroleum.[16]

LCFS 46-201 cont.

As for the portion of the California fleet powered in whole or in part with electricity or hydrogen, there is similarly no continuing need for the LCFS program, owing to other changes in the regulatory baseline since 2009. The Advanced Clean Cars program now assures that electricity and hydrogen will be full participants in the California transportation fuel pool. In 2009, CARB's baseline for the alternatives analysis of the LCFS regulation included the then-current version of the Board's regulations to control GHG emissions from new motor vehicles that had been adopted in 2004, and that set GHG emission standards for 2009 to 2016 model-year new vehicles, sometimes called the "Pavley standards." In addition, the baseline also included the then-current provisions of the agency's Zero Emission Vehicle ("ZEV") standards which require manufacturers offer electric and/or hydrogen fuel cell vehicles for sale in California. CARB has now adopted new-vehicle GHG standards applicable to 2017 to 2025 model-year new vehicles and has made significant revisions to the ZEV standards as part of the ACC rulemaking in 2012.[17]

LCFS 46-202

[16] One reason why California is assured of receiving an adequate supply of ethanol is that ethanol for use in gasoline commands a higher price -- the so-called "California premium" -- in California than in other parts of the United States, as can be readily seen from data available under contract or license from the Oil Price Information Service ("OPIS"). While there are many reasons why the "California premium" exists, one major reason is that refineries producing finished gasoline products for the California retail market tend to have higher production costs than other refineries.

LCFS 46-201 cont.

[17] In its 2009 LCFS alternatives analysis, the CARB staff assumed that manufactures would sell more electric vehicles than required by the ZEV standards, as they existed in 2009. Vehicle manufacturer compliance with the ZEV, new vehicle GHG, and criteria emission standards is determined on a "fleet-average" basis. What this means is that to the extent that manufacturers sell more ZEVs than required, they can in turn sell greater numbers of less fuel efficient or higher emitting vehicles provided that they remain in compliance on average. In addition, manufacturers that over comply can sell "credits" to manufacturers that would not otherwise be in compliance. Therefore, even if the LCFS regulation might lead to greater demand and use of electric vehicles, there would be no net reduction in GHG emissions.

LCFS 46-202 cont.

CARB has also taken and is taking a number of actions to reduce GHG emissions associated with the use of diesel fuel in heavy-duty vehicles which also need to be taken into account in the baseline for the 2014 LCFS analysis. The relevant measures include California's Tractor-Trailer regulation adopted in 2008 which requires use of aerodynamic improvement devices and low-rolling resistance tires, as well as the Phase I and the soon-to-be proposed Phase II heavy-duty GHG regulations that impose specific GHG emission requirements on new heavy-duty vehicles beginning with the 2014 model-year.[18] LCFS 46-203

B. Necessary Information for Development of a Detailed Alternative Program

In addition to properly defining the baseline for the alternatives analysis, it is important to have a clear and complete picture of the revised LCFS program that the CARB staff plans to propose. In addition to full information concerning the estimated benefits of the LCFS program (both in terms of GHG reductions and in any other relevant aspect), the currently unknown elements of that program include the following:

- Updated carbon intensity values for transportation fuels that will be included in the proposed 2014 LCFS regulation. LCFS 46-204
- The detailed form of any proposed "cost-containment" provisions which could allow parties subject to the LCFS regulation to comply with the program's standards, without actually achieving the CI reductions required under the regulation.
- CARB staff's current analysis of the manner in which regulated parties will most likely attempt to comply with the proposed 2014 LCFS.

[18] In addition to ensuring that the GHG emissions reductions associated with those regulations are properly accounted for in the baseline for the 2014 LCFS, CARB staff must also ensure that they properly account for the fact that compliance with the latter regulations is determined on a manufacturer fleet average basis in order to avoid improper assignment of GHG reductions to the 2014 LCFS regulation.

- A full description of any other intended goals of the LCFS regulation, such as stimulating "fundamental" changes in the "transportation fuel pool," along with the metrics to be used to measure progress and success in meeting those other goals.[19] LCFS 46-204 cont.

Contrary to the position taken in the CARB staff's recent correspondence with Growth Energy and in related postings on the CARB website, none of those elements have been disclosed to the public at present. In addition to providing that undisclosed information concerning its analysis, the CARB staff should address the following other pertinent questions, which follow from the foregoing review of changes in the regulatory baseline since 2009: LCFS 46-205

- Does the CARB staff agree that the federal RFS program would, in the absence of an LCFS regulation, assure some level of reductions in GHG exhaust emissions from the California in-use vehicle population that is operated on gasoline? If not, why not; and if so, what would be that level of GHG emissions reductions, on an annual or some other specific basis, if the LCFS program were to be discontinued at the end of 2015? LCFS 46-206
    - Does the staff have any disagreement with the position that the federal RFS program and the "California premium" (*see* note 15 above) would cause Midwest corn ethanol producers to continue preferentially to deliver ethanol to California, and cause the California gasoline marketing sector to blend that Midwest corn ethanol into gasoline up to the current 10 percent limit, even in the absence of the LCFS regulation? If so, what are the specific reasons why the staff disagrees? LCFS 46-207
    - Does the staff believe that the LCFS regulation would result in wider usage of E85 in California than the federal RFS program would cause, and if so, what is the empirical basis for that view? LCFS 46-208
    - Would a possible need for a diesel component to an LCFS program justify an unnecessary gasoline component for an LCFS program, and if so, why? LCFS 46-209
- The 2009 regulatory analysis predicted that ultra-low-CI fuels would be available and would bring the costs of the LCFS program down to the point where the program would be cost-neutral at the consumer level, or would result in savings of up to $11 billion.[20] LCFS 46-210

[19] *See* Air Resources Board, *California's Low Carbon Fuel Standard -- Final Statement of Reasons* (hereinafter "FSOR") 24.

[20] *See* ISOR at ES-26.

Does that remain the CARB staff's position? If not, what will be the consumer costs of the staff's proposed revised LCFS regulation, predicted annually or in some other manner? What uncertainties and assumptions affect those cost estimates?

LCFS 46-210 cont.

- Are the ACC program and other vehicle-based GHG reduction programs adopted to implement AB 32 designed to obtain, and will they obtain, the maximum technologically feasible and cost effective reductions in GHG emissions from the new vehicles that are subject to those standards? (*See, e.g.*, Cal. Health & Safety Code § 38562(a).) If not, why not? With the ACC program and other non-LCFS regulations discussed above in Part II. A. now in place, would the LCFS program actually produce any incremental increase in the displacement of liquid motor vehicle fuels by electricity in ZEVs or hybrid electric vehicles or hydrogen in fuel cell vehicles? If so, what are the relevant increases, and on what assumptions do the predicted increases depend? Why would a vehicle manufacturer that over-achieved the ZEV requirement not use the credit gained from the overachievement by selling a higher-emitting conventional vehicle fleet? To what extent would the staff attribute to the LCFS program any displacement of vehicle miles traveled in conventional vehicles by vehicles powered by fuel cells, and what is the basis for that prediction?

LCFS 46-211

- The CARB staff sometimes refers to Executive Order S-07-01 as a basis for maintaining the LCFS regulation. Should the requirements of Executive Order S-07-01 be reconsidered in the current rulemaking process insofar as the Executive Order called for creation of the LCFS regulation? Does Executive Order S-07-01 limit in any way CARB's discretion in adopting and enforcing measures to implement AB 32? Does AB 32 require adoption and enforcement of the LCFS regulation, if the same GHG reductions that the LCFS regulation can achieve could be achieved by other means?

LCFS 46-212

- To the extent that the LCFS program is still intended to stimulate "fundamental changes in the transportation fuel pool" in California,[21] to what extent had the program succeeded in its first five years? Is achieving that objective consistent with the potential "cost reduction" mechanisms under consideration for a revised LCFS regulation? How should the Department and the public try to weigh that objective against the potential costs for California consumers and businesses in meeting that objective?

LCFS 46-213

Having now presented the above questions to the CARB staff, Growth Energy believes that the staff should address them in the SRIA for the Department, or concurrently in a separate submittal to the Department made available to the public, if the staff does not intend otherwise to respond to those questions. Each question bears on the need for the LCFS regulation, the costs and benefits of the LCFS regulation, or the legal authority that would limit the analysis of regulatory

LCFS 46-214

---

[21] *See* note 19 above.

alternatives. If the CARB staff does not believe that one or more of the above questions are relevant to the evaluation of regulatory alternatives, Growth Energy requests that the CARB staff explain why, with respect to each such question. LCFS 46-214 cont.

III. Regulatory Alternatives

The CARB regulations adopted since 2009 and the federal RFS program adequately provide for full control of the direct GHG emissions from the California vehicle fleet that the LCFS regulation may have been intended to control. In 2009, CARB claimed that the LCFS regulation would provide additional GHG reductions on a lifecycle basis; the "upstream" component of the GHG benefits attributed to the LCFS regulation in 2009 was 7 MMTCO2eq in 2020.[22]

Putting to one side the question whether CARB has legal authority to adopt and enforce a regulation to control GHG emissions occurring outside California, there are several reasons to question whether the LCFS regulation actually achieves any reduction in upstream emissions. As CARB has recognized, the LCFS regulation has to date caused "fuel shuffling" -- ethanol that might have been sold in California prior to the LCFS regulation is still being produced, and is sold somewhere else.[23] Ethanol production processes and pathways that have putatively higher upstream emissions have, at this point, neither terminated nor curtailed operations as a result of the LCFS regulation.[24] In addition, many Midwest corn ethanol biorefineries have qualified for LCFS 46-215

---

22 *See* ISOR at VII-1.

23 *See* FSOR at 477 ("Without the wider adoption of fuel carbon-intensity standards, fuel producers are free to ship lower-carbon-intensity fuels to areas with such standards, while shipping higher-carbon-intensity fuels elsewhere. The end result of this fuel 'shuffling' process is little or no net change in fuel carbon-intensity on a global scale.") The "wider adoption" of LCFS-type standards to which CARB referred in the 2009 FSOR has not occurred.

24 That is not to say, however, that the LCFS regulation is not injurious to the national market in ethanol, nor neutral in its impact on lifecycle GHG emissions. By causing fuel shuffling, the LCFS regulation disrupts the national market in ethanol, imposes costs, and increases transportation-related GHG emissions. Eventually, by effectively banning Midwest corn ethanol from California (if, for example, the LCFS for 2015 established in

lower-carbon-intensity LCFS "pathways" since 2009, on a scale that the CARB staff has admitted was "not expected in 2009."[25] Moreover, the estimates of upstream emissions attributed to Midwest corn ethanol in 2009 were grossly inflated: no one, including CARB, is still prepared to defend the indirect land-use change emissions factors accepted by CARB in 2009, and the current literature demonstrates that the "science" of indirect land-use change is too unreliable to be used as a basis for regulation.[26]

LCFS 46-215 cont.

LCFS 46-216

To the extent there is any remaining basis for attributing upstream GHG emissions reduction benefits to the LCFS regulation, those benefits certainly do not warrant the continuation or re-adoption of the LCFS regulation. The more efficient approach would be to adjust the cap-and-trade regulation in Title 17 of the *California Code of Regulations* to account for whatever increment of GHG emissions reductions would be forgone by eliminating the LCFS regulation.[27] To the extent necessary, modifications to the cap-and-trade regulation would be

LCFS 46-217

2009 were to be enforced), the LCFS regulation will leave California with no commercially viable method of complying with the standard; the staff appears to recognize this problem to some extent, with the currently ill-defined "cost reduction" features that it plans to propose. *See* Air Resources Board, *Low Carbon Fuel Standard Re-Adoption Concept Paper* (March 2014) at 6-7. The reduction in nationwide demand for Midwest corn ethanol will then also impose serious economic harm on the Midwest ethanol industry.

25 *See* 2011 Program Review at 169. The Midwest ethanol production facilities that have qualified for lower-carbon-intensity LCFS pathways have not done so through modifications in their production processes intended to obtain those special LCFS pathways: they have a competitive incentive to increase efficiency, and would have done increased their efficiency in the absence of the LCFS regulation. A Growth Energy member has demonstrated this point in the ongoing *Rocky Mountain* litigation involving some aspects of the LCFS regulation. *See* Declaration of Erin Heupel, P.E. (included here as Attachment 6) ¶¶ 5-6. Notably, in the *Rocky Mountain* litigation, CARB offered no competent evidence to the contrary. As Ms. Heupel also demonstrated, the specific features of the LCFS regulation will eventually force even the highest-efficiency Midwest corn production facilities out of the California market. *See id.* ¶¶ 9-11.

LCFS 46-215 cont.

26 The CARB staff has begun to revise and to reduce the indirect land-use change emission factors that were included in the 2009 LCFS regulation. *See* letter from G. Cooper to K. Sideco, April 9, 2014, available at http://www.arb.ca.gov/fuels/lcfs/regamend14/rfa_04092014.pdf. It remains Growth Energy's position that the modeling methods used by CARB to generate indirect land-use change values are too unreliable for use in a regulation intended to comply with AB 32. *See* Letter from D. Bearden to J. Goldstene, May 10, 2010 (included here as Attachment 4).

LCFS 46-216 cont.

27 In 2009, CARB received substantial comments on the relative inefficiency of the LCFS approach from one of its independent peer reviewers, who urged that CARB consider a cap-and-trade alternative. *See*, e.g., FSOR at 24 (review by Dr. John Reilly); *see also id.* (summarizing Dr. Reilly's review as stating, "The economic analysis

LCFS 46-217 cont.

simple and straightforward. Initially, CARB should determine what, if any, upstream GHG reductions should be attributable to the LCFS regulation, using a scientifically reliable process. CARB would also need an appropriate estimate of the total GHG emissions expected from the use of gasoline and diesel fuel in 2020. A CARB emissions forecast prepared in 2010[28] indicates that total GHG emissions from gasoline and diesel fuel use in California are expected to be approximately 175 million metric tons in 2020 under business as usual conditions. Assuming that the generally required 22 percent reduction in emissions in 2020 under the cap-and-trade program[29] applies to gasoline and diesel fuel use, total 2020 emissions without the LCFS program would be about 135 million metric tons.

Continuing the analysis, and by way of example, suppose that the cap-and-trade regulation had to cover the entire annual 16 MMTCO2eq of GHG emissions that the CARB staff identified as the benefit of the LCFS regulation for 2020. That level of GHG control could be achieved by amending the cap-and-trade regulations to require providers of gasoline and diesel fuel to submit 151 (135+16) million metric tons of allowances – or in other words requiring gasoline and diesel fuel suppliers to surrender 1.11 (151/136) allowances for every ton of GHG emissions they report from the fuels they supply.[30]

LCFS 46-217 cont.

[for the LCFS regulation] was done incorrectly. It does not meet [the] technical standards of economics. The baseline assumptions are mutually inconsistent, and if these assumptions were executed in a proper model it would show that the LCS was unnecessary.") CARB stated in 2009 that it would consider the role of cap-and-trade further in addressing the objectives of the LCFS program once the cap-and-trade regulations were completed. *See* FSOR at 452.

28 *See* Air Resources Board, "California GHG Emissions -- Forecast 2008-2020 (updated Oct. 28, 2010), available at http://www.arb.ca.gov/cc/inventory/data/tables/2020_ghg_emissions_forecast_2010-10-28.pdf

29 This is based on the general percentage reduction requirements established by CARB for total allowances issued. *See* Air Resources Board, "Overview of ARB Emissions Trading Program (October 2011), available at http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf

30 The cap-and-trade regulation already begins to take effect for the gasoline and diesel fuel marketing sector in 2015.

The modifications to the existing text of the cap-and-trade regulation would be minor and limited to section 95852(d) of the regulation.[31] Further, the CARB staff at its discretion could also create a compliance offset program in order to incentivize low- carbon intensity fuels similar to those in place which incentivize other innovative GHG reduction strategies.[32] Insofar as one goal of the APA is to eliminate unnecessary regulation, this approach would well-serve the goals

LCFS 46-218

[31] Thus, the text of section 95852(d), with the modification shown in italics, and assuming that the full 10 percent GHG emission reduction attributed to the LCFS regulation would be covered by cap-and-trade, would provide as follows:

> Suppliers of RBOB and Distillate Fuel Oils. A supplier of petroleum products covered under sections 95811(d) or 95812(d) has a compliance obligation *equal to 1.x allowances* for every metric ton CO_2e of GHG emissions included in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned that would result from full combustion or oxidation of the quantities of the following fuels that are removed from the rack in California, sold to entities not licensed by the California Board of Equalization as a fuel supplier, or imported into California and not directly delivered to the bulk-transfer/terminal system as defined in section 95102 of MRR, except for products for which a final destination outside California can be demonstrated:

(1) RBOB;
(2) Distillate Fuel Oil No. 1; and
(3) Distillate Fuel Oil No. 2.

> *The value of "x" above will be established by Executive Officer by the prior October 31 for each year beginning with 2015 to ensure that actual GHG emissions from the use of RBOB and Distillate Fuel Oil No. 1 and Distillate Fuel Oil No. 2 are reduced to the level that would have been achieved had the Carbon Intensity of those fuels been reduced according to the following schedule relative to 2010.*

Required Carbon Intensity Reduction Relative to 2010	
Year	Reduction
2015	2.7%
2016	3.7%
2017	5.2%
2018	6.7%
2019	8.2%
2020	10.0%

As illustrated above for 2020, the value of "x" would be 0.11 and the compliance obligation for suppliers of gasoline and diesel fuels would be 1.11 times the number of tons of CO2e emissions reported.

[32] *See* Air Resources Board, "Climate Change Programs -- Compliance Offset Program" (updated June 11, 2014), available at http://www.arb.ca.gov/cc/capandtrade/offsets/offsets.htm

of the APA. By eliminating the LCFS regulation, CARB would also free the California transportation fuel sector from continuing uncertainty about the availability and cost of ultra-low-carbon-intensity alternative fuels necessary for future compliance with the LCFS. As the Western States Petroleum Association ("WSPA") has stated:

> The LCFS, as envisioned by Governor Schwarzenegger in his Executive Order and as developed by the ARB, is infeasible. … [S]taying the course now could result in disruptions in the transportation fuels markets. … A successful fuels policy must protect against fuel supply disruptions, severe job losses in the state's refining industry and unacceptable economic harm to California and its citizens.[33]

LCFS 46-219

While Growth Energy believes that its proposal has sufficient merit without endorsement by other organizations, the concerns expressed by WSPA are important. One benefit of the change that Growth Energy is proposing, and a benefit that is particularly important to Growth Energy and the enterprises it represents, is that elimination of the LCFS regulation would eliminate a major conflict between regulations adopted by California and the federal RFS program, a conflict that will only increase if the LCFS regulation is re-adopted.

In considering Growth Energy's proposal, and in addition to the questions presented in Part II of this submittal, the CARB staff should in the SRIA address the following questions:

- The CARB staff's May 23, 2014, notice soliciting public input for the SRIA sought "alternative LCFS approaches." (See Attachment 5.) Does the CARB staff believe the alternatives analysis for the SRIA and public submittals related to the SRIA must be confined to regulatory alternatives that include or would preserve in some form the LCFS regulation? If so, what is the basis for such a limitation?

LCFS 46-220

- Other than emissions created in generating electricity for delivery in California, does AB 32 give CARB the authority to regulate upstream emissions occurring outside California, or to account for upstream emissions occurring outside

LCFS 46-221

[33] The reference is to Executive Order S-01-07, with its "10 percent" by 2020 goal, which according to the CARB staff remains the target for the LCFS regulation. *See* Letter from G. Grey to K. Sideco, June 13, 2014 at 2, available at http://www.arb.ca.gov/fuels/lcfs/regamend14/wspa_06132014.pdf. WSPA has also stated that modification of the LCFS program through "cost reduction" provisions would "simply penalize fuel suppliers for not meeting an infeasible standard." *See* Letter from C. Reheis-Boyd to K. Sideco, April 11, 2014 at 10, available at http://www.arb.ca.gov/fuels/lcfs/regamend14/wspa_04112014.pdf.

LCFS 46-219 cont.

California in adopting regulations to meet the statewide greenhouse gas emissions limit? (*See* Cal. Health & Safety Code § 38505(m), (n); 38562(a).) If AB 32 authorizes CARB to regulate or consider out-of-state GHG emissions attributed to ethanol production, does AB 32 also authorize CARB to address those emissions through the cap-and-trade regulation? LCFS 46-221 cont.

- Can the California cap-and-trade regulations be modified to provide the same numerical reductions in GHG emissions as the LCFS regulation? If not, why not? LCFS 46-222

- If the CARB staff is concerned that the state measures to control GHG emissions and the federal RFS program might not be fully implemented and enforced at some time in the future, would adoption of a revised LCFS regulation as a "backstop" measure, to be implemented only if those other programs are not meeting defined objectives, address that concern? If not, why not? LCFS 46-223

- If the CARB staff believes some regulated parties might prefer to comply with a revised LCFS regulation rather than a modified cap-and-trade regulation, could that issue be addressed by including a revised LCFS as a part of a regulatory alternative (with appropriate opt-in provisions) that would be an option for parties that did not wish to comply with a modified cap-and-trade regulation? LCFS 46-224

- What are the current and expected future levels of resources at CARB, in terms of personnel and other resources, that are allocated to the LCFS regulation? What would be the budgetary impact for CARB if the LCFS program were eliminated? What would be the budgetary impact for CARB caused by the change in the cap-and-trade regulation proposed here? LCFS 46-225

- To the extent the CARB staff would attribute other beneficial impacts, different from GHG emissions reductions, to the LCFS regulation, to whom do those benefits accrue? With regard to those other beneficial impacts, are California consumers benefitted and, if so, how and to what extent? With regard to those other beneficial impacts, are California businesses benefitted and if so, how and to what extent? Do those other beneficial impacts justify or support continuation of the LCFS regulation, and if so, what is the basis for CARB's authority to adopt and enforce the LCFS regulation to obtain those benefits? If those other beneficial impacts include the possibility that sources for alternative fuels will be increased or diversified, are there any peer-reviewed or other studies that support such a proposition? If not, what is the staff's basis for attributing such benefits to the LCFS regulation? Could those benefits be realized through the development of a compliance offset program under the cap-and-trade regulation? LCFS 46-226

As with the questions presented in Part II, the CARB staff's responses to these questions are important in understanding its evaluation of Growth Energy's proposal. If the CARB staff does not believe that one or more of the above questions are relevant to the evaluation of LCFS 46-227 regulatory alternatives, Growth Energy requests that the CARB staff explain why, with respect to each such question. LCFS 46-227 cont.

IV. Next Steps

As noted at the outset of this submittal, Growth Energy's analysis of alternatives to the LCFS regulation can be no more detailed than the available information about the staff's intended revised LCFS regulation. If CARB does nothing further to facilitate the public input into the SB 617 process for use in the SRIA, it will not have substantially complied with the APA as amended by SB 617 and implemented in the Department's regulations. LCFS 46-228

In the CARB staff's first notice that it was ready to receive public input on regulatory alternatives, published on May 23, 2014, the staff set a deadline for that input of June 6, 2014 -- nine business days later. The staff indicated in that notice that the public should, among other things, "submit the quantities of low-CI fuels used each year" in the proposed alternative to the LCFS regulation, "as well as the associated cost and benefit information, and their sources." [34] According to the May 23 notice, that information was needed "to enable comparison of economic impacts."[35] The May 23 notice stated that the objective for public input should be to provide "alternative LCFS approaches," meaning "any approach that may yield the same or greater benefits than those associated with the proposed regulation, or that may achieve the goals at lower cost."[36] LCFS 46-229

The "proposed regulation" to which the May 23 proposal referred (i) had not been provided to the public for review as of May 23, nor (ii) has it been provided at any time since

[34] *See* Attachment 5.

[35] *Id.*

[36] *Id.*

May 23.[37] The May 23 notice was not accompanied by any information that provided the CARB staff's own prediction of "the quantities of low-CI fuels [that would be] used each year" under the CARB staff's proposed regulation, nor the benefits that the CARB staff attributed to the LCFS regulation. Growth Energy requested that the CARB staff give the public the information needed to prepare a complete SB 617 submission and requested that the public be given additional time to prepare SB 617 analyses after the necessary information was released.[38]

The CARB staff responded by extending the deadline for public submittals that would be addressed in the SRIA to June 23, 2014 (31 days after the May 23 notice), but did not provide any of the information requested by Growth Energy and needed to provide the type of input sought in the May 23 notice, and necessary under the Department's SB 617 regulations. Instead, the staff referred to the GHG emissions reductions targeted in the 2009 rulemaking, to a March 2014 "Concept Paper" that discussed the staff's approach to revision of the LCFS regulation, and to material provided to the public in connection with regulatory workshops held in ARB's offices.[39] The March 2014 Concept Paper raises more questions about the staff's approach than it answers: it included, for example, a general description of two different "cost reduction" concepts without indicating how either of them would work, how they would reduce costs, or how they would affect the GHG emissions reduction benefits of the LCFS program. If the March 2014 Concept Paper provided a basis for preparing SB 617 submittals, then there is no reason why the CARB staff should have waited until May 23 to solicit public input under the Department's regulations. Had the staff informed the public when it released the Concept Paper

LCFS 46-229 cont.

[37] The CARB staff has released some draft regulatory text for their proposed revised LCFS, but that partial text does not include, for example, the "cost reduction" feature intended for the new regulation, nor the carbon intensity values to be assigned to each alternative fuel.

[38] *See* Attachment 1.

[39] *See* Attachment 2.

and discussed the Concept Paper at one of its March 2014 regulatory workshops that the Concept Paper was intended to provide a basis for SB 617 input, Growth Energy (and perhaps other stakeholders) would have pointed out at that time that the Concept Paper was inadequate for that purpose; in that event, perhaps the CARB staff would have been able to provide the necessary information for public input into the SRIA.

LCFS 46-229 cont.

The materials provided in connection with the regulatory workshops -- including the partial regulatory text released on May 28, after the staff had launched the public input process -- likewise do not provide the necessary information for detailed public submittals consistent with SB 617 and the Department's regulations. Growth Energy has studied those materials carefully, and with the greatest respect, would challenge the CARB staff to indicate where in those materials the staff identifies GHG emissions reduction targets for a revised LCFS regulation; where the staff identifies any other putative benefits of the LCFS regulation; and where in those materials the staff provides specific and concrete information about the impact of the "cost reduction" concepts on the quantities of alternative fuels that would be used in order to comply with the revised LCFS regulation, or permits a quantification of costs and benefits of a revised LCFS regulation that includes a cost-reduction feature.

LCFS 46-230

Finally, it is important to address comments by the CARB staff at one recent workshop, which suggested that the timing of the current regulatory effort has been affected by the Board's need to comply with the mandate in litigation under the APA and the California Environmental Quality Act ("CEQA").[40] In that litigation, the Superior Court has allowed CARB all the time

LCFS 46-231

[40] The case is *POET LLC et al. v. California Air Resources Board*, Case No. 09 CE CG 04659 (Sup'r Ct., Fresno County). The Writ of Mandate in that proceeding does not require CARB to commence or conclude rulemaking by a particular date, but to proceed in good faith without delay. The Writ of Mandate was issued more than six months ago, by which time CARB presumably knew that it had to comply with the Department's SB 617 regulations.

that the Board has requested in order to comply with the mandate. If CARB needs more time in order to conduct the SB 617 process in a manner that allows sufficient time for effective public input into the preparation of an SRIA, CARB should so inform the Superior Court. (Notably, in its filings with the Superior Court, CARB has not adverted to SB 617 or the Department's implementing regulations.) In addition, the CARB staff would surely agree that even before issuance of the mandate in that litigation, it was aware that it had major program review obligations for the LCFS regulation in 2014.[41] Particularly in light of those program review obligations, the CARB staff's inability to provide more information now to the public, needed to participate fully in the SB 617 process, seems inexcusable.

LCFS 46-231 cont.

Against that backdrop, Growth Energy urges the CARB staff to reconsider its present approach to the SB 617 process, and specifically the staff's approach to obtaining public input for the SRIA. As the staff might expect, if one response to Growth Energy's proposed regulatory

LCFS 46-232

[41] In 2009, when it first adopted the LCFS regulation, the Board directed the CARB staff to conduct and to present by January 1, 2015 a "review of implementation of the LCFS program" that was to "include, at a minimum, consideration of the following areas:

"(1) The LCFS program's progress against LCFS targets;
"(2) Adjustments to the compliance schedule, if needed;
"(3) Advances in full, fuel-lifecycle assessments;
"(4) Advances in fuels and production technologies, including the feasibility and cost-effectiveness of such advances;
"(5) The availability and use of ultralow carbon fuels to achieve the LCFS standards and advisability of establishing additional mechanisms to incentivize higher volumes of these fuels to be used;
"(6) An assessment of supply availabilities and the rates of commercialization of fuels and vehicles;
"(7) The LCFS program's impact on the State's fuel supplies;
"(8) The LCFS program's impact on state revenues, consumers, and economic growth;

. . .

"(12) Significant economic issues; fuel adequacy, reliability, and supply issues; and environmental issues that have arisen; and
"(13) The advisability of harmonizing with international, federal, regional, and state LCFS and lifecycle assessments."

17 C.C.R. § 95489(a).

LCFS 46-231 cont.

alternative is that Growth Energy's proposal lacks a detailed comparison with the costs, benefits, and cost-effectiveness of the staff's proposal in the SRIA, Growth Energy will attribute its lack of specificity to the staff's failure to provide the information needed to offer a more specific regulatory analysis. Because this is one of the first major rulemakings at CARB that is required to comply with SB 617 and the Department's SB 617 regulations, it is also important for the Department to take a proactive role in providing guidance to CARB, the stakeholders, and other members of the public interested in the LCFS program.

LCFS 46-232 cont.

Respectfully submitted,

GROWTH ENERGY

46_OP_LCFS_GE Responses (Page 191 - 218)

527. Comment: **LCFS 46-195**

The comment asserts that equivalent GHG reductions can be achieved without the LCFS proposal.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nevertheless, we note that for several decades, ARB has been "charged with coordinating efforts to attain and maintain ambient air quality standards, to conduct research into the causes and solutions to air pollution, and to systematically attack the serious problem caused by motor vehicles . . ." (Health & Saf. Code §39003) In recent years, greenhouse gases have been recognized as a form of air pollution, and ARB was again charged by the Legislature with developing measures to address GHG emissions. (Health & Saf. Code §38500 et seq.) Based on the agency's experience addressing air pollutants, including decades of regulating motor vehicles and fuels, sole reliance on existing programs will not achieve the carbon-intensity fuel reductions of the LCFS program. For example, California's specific vehicle and engine-based programs will result in an increase in zero-emission (electric and fuel cell) vehicles, but will not ensure the fuel for non-zero emission vehicles is cleaner. The Cap-and-Trade Program is a broad program that achieves GHG reductions across all economic sectors. Therefore, the program could not be counted on to get the same benefits from the transportation fuel sector alone, as the LCFS will.

528. Comment: **LCFS 46-196**

The comment states that other regulations currently in effect already achieve GHG reductions therefore the LCFS proposal is unnecessary.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nevertheless, we note that the submitter has repeatedly mistaken GHG reductions as the sole metric to judge the need for the LCFS program and has minimized the role of the LCFS program in achieving GHG reductions. To the contrary, the LCFS program is necessary to achieve the objectives stated – reducing the CI of transportation fuels by 10 percent, achieving GHG reductions, and transforming and diversifying transportation fuel.

As discussed in response to comments **LCFS 46-179** and **LCFS 46-195**, other regulations have related but ancillary objectives. In addition, and put simply, if California were set to achieve the LCFS objectives through other regulations already adopted, then the additional costs from the LCFS regulation about which the commenter is worried will not materialize.

529. Comment: **LCFS 46-197**

The comment states that other regulations currently in effect already achieve GHG reductions therefore the LCFS proposal is unnecessary.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nevertheless, we note that as explained in the response to comments **LCFS 46-173**, **LCFS 46-179**, **LCFS 46-195**, and **LCFS 46-196** the LCFS program is needed to lower the average CI of transportation fuel.

The Cap-and-Trade Program does not eliminate the need for other policies that are directly focused on promoting new technologies. The reason is that the Cap-and-Trade Program addresses a particular market failure, while technology-promoting policies address others. The Cap-and-Trade Program addresses the failure of market prices to capture the climate-change externality associated with GHG emissions. It remedies this market failure by creating a price signal for avoided emissions. Technology-promoting policies are still needed, however, to address other market failures that impede the development of new technologies. Technology-promoting policies such as California's motor vehicle regulations and the LCFS directly confront these other types of market failures. A Cap-and-Trade system does not obviate the need for such technology policies. To the contrary, it complements technology policies.

530. Comment: **LCFS 46-198**

The commenter expresses concern that the conceptual proposals circulated earlier in the rulemaking process – not the proposed regulation package itself – were not extremely detailed, thus preventing the commenter from suggesting an alternative in detail.

Agency Response: The document was prepared by commenter in June 2014, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows.

ARB staff disagrees because nothing prevented anyone from suggesting an alternative, and making it as detailed as desired. Moreover, at the time of the comment, the LCFS program had been in effect for almost five years, and many workshops and website postings had informed the public about program changes contemplated for inclusion in the eventual re-adoption proposal. As a trade group whose members have participated in and profited from the LCFS over the years, as the party or trade group representing parties who have combined brought no less than three separate lawsuits related to the LCFS, the commenter has demonstrated a deep interest in and familiarity with the program and the proposed re-adoption. ARB staff is not aware of any impediment to commenter's full participation in the pre-rulemaking or rulemaking processes.

Comment 198 goes on to instruct ARB on what it should do after June 2014, to facilitate public participation in the re-adoption process. By following its usual practices, and by complying with the APA, ARB staff successfully facilitated public input, including any economic analyses that any party wished to submit, and as evidenced in the Notice of Proposed Rulemaking and Staff Report dated December 16, 2014, the Notices of 15-day changes, and the two public hearings conducted by the Air Resources Board prior to adopting the proposal.

531. Comment: **LCFS 46-199**

The commenter criticizes ARB's 2009 Staff Report, and claims that the document contained some predictions that were not borne out, but simultaneously acknowledges that these predictions were correct, but according to the commenter happened for reasons other than those advanced in the 2009 Staff Report.

Agency Response: This comment is not pertinent to the proposed re-adoption of the LCFS in 2015, and offers no specific recommendation or objection.

532. Comment: **LCFS 46-200**

The commenter states that the goal of reducing the carbon intensity of transportation fuels by 10 percent equates to a static tonnage of GHGs and as such the LCFS is no longer required.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nevertheless, we note that as the submitter states, the goal of the LCFS program is to “reduce the carbon intensity of transportation fuels used in California by at least 10 percent by, 2020 from a 2010 baseline,” as well as “support the development of a diversity of cleaner fuels with other attendant co-benefits.” That goal is clear and specific, yet the commenter incorrectly re-characterizes the goal solely in terms of the 16 MMTCO2e emission reduction, which is inaccurate. See also response to Comments **LCFS 46-173**, **LCFS 46-179**, and **LCFS 46-195**.

533. Comment: **LCFS 46-201**

The comment implies that equivalent GHG reductions will occur due to the RFS program without the LCFS proposal.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nevertheless, we note that the statement ignores numerous facts and chooses to focus on downstream exhaust GHG emission reductions from 10 percent ethanol blends with gasoline, while discounting the rest of lifecycle emissions. Although tailpipe emissions with ethanol may be the same regardless of the source of the ethanol, a main tenet of the LCFS program is scientifically-based lifecycle emissions. This lifecycle assessment (LCA) examines the GHG emissions associated with the production, transportation, and use of a given fuel. The LCA includes direct emissions associated with producing, transporting, and using the fuels, as well as significant indirect effects on GHG emissions, such as changes in land use for some biofuels. Subjecting this life cycle GHG rating to a declining standard for the transportation fuel pool in California will decrease total life cycle GHG emissions from fuels used in California. The LCFS is designed to encourage the use of cleaner low-carbon fuels in California and encourage the production of those fuels through a performance-based, fuel-neutral structure. Different types of ethanol have different lifecycle emissions and ethanol blended at E10 is not the only source of gasoline credits. Other sources include E85 and advanced cellulosic ethanol, and advanced fuel innovations such as a drop-in gasoline are not referenced. All of these options achieve greater market pull from the LCFS program, thereby increasing production demand and spurring innovation. Please also see response to **LCFS 46-195.**

534. Comment: **LCFS 46-202**

The comment states that the LCFS proposal is not necessary because of the Advanced Clean Cars program.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nevertheless, please see response to LCFS **46-195.** While the zero-emission vehicle (ZEV) portion of the Advanced Clean Cars program will help lower the carbon intensity of transportation fuel, the other portions of the program will not. The ZEV portion of Advanced Clean Cars pre-dates the LCFS. The Air Resources Board determined it is appropriate to have both programs in place to synergistically address emissions. It is commonplace to have complementary policies as part of an overall strategy. For example, the ZEV program also includes state incentives, high occupancy vehicle access, local preferential parking, and a variety of other regulatory and policy incentives to help achieve its goals. The ZEV program promotes electricity and hydrogen in light-duty vehicles, while the LCFS program promotes those fuels, as well as reducing carbon intensity and emissions from fuels used in vehicles that are not ZEVs.

535. Comment: **LCFS 46-203**

The comment states that the LCFS proposal is not necessary because of California's Tractor-Trailer regulation adopted in 2008.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nevertheless, please see response to LCFS **46-195.** The regulations cited by the commenter work synergistically with the LCFS regulation. However, they will not have any impact on the carbon intensity of transportation fuel in California, and therefore will not help ARB achieve the primary objectives of the LCFS program and could not substitute for the LCFS.

536. Comment: **LCFS 46-204**

The commenter requests clarification of four items to establish a baseline for their alternative analysis.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. The commenter asks for information on four elements of the LCFS program, as follows:

1. *Updated carbon intensity values for transportation fuels that will be included in the proposed 2014 LCFS regulation*.

   The updated CI values are contained in sections 95484(b) and 95484(c) of the proposed regulation.

2. *The detailed form of any proposed “cost-containment” provisions which could allow parties subject to the LCFS regulation to comply with the program’s standards, without actually achieving the CI reductions required under the regulation*.

   The specific cost-containment regulatory provisions are contained in section 95485(c) of the proposed regulation. See responses to **LCFS 6-4** and **LCFS 32-9**.

3. *CARB staff’s current analysis of the manner in which regulated parties will most likely attempt to comply with the proposed 2014 LCFS*.

   Being a market-based system, there are multiple options and pathways for LCFS compliance. In fact, ARB staff would expect different companies could have drastically different compliance scenarios. However, staff prepared an illustrative scenario representing one pathway for compliance.

4. *A full description of any other intended goals of the LCFS regulation, such as stimulating “fundamental” changes in the “transportation fuel pool,” along with the metrics to be used to measure progress and success in meeting those other goals*.

   ARB staff has clearly identified the goals of the program throughout the Initial Statement of Reasons (ISOR) staff report. Specific goals include, reducing GHGs and other smog-forming and toxic air pollutants from the transportation sector; decreasing the carbon intensity of California’s transportation fuel pool; providing an increasing range of low-carbon and renewable alternatives; promoting improvements in the fuel supply chain through a full lifecycle accounting of emissions; and diversifying the fuels market in California, thereby reducing petroleum dependency and creating a sustainable and growing market for cleaner fuels.

537. Comment: **LCFS 46-205**

The commenter's June 2014 letter advised ARB to make a specific proposal together with specific analyses and projections regarding how parties are likely to comply with the proposal.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nevertheless, please see response to **LCFS 46-198**. In addition, ARB made a specific proposal in the Notice of Proposed Rulemaking in December 2014, accompanied by a Staff Report analyzing the items that appear to have concerned the commenter in June and much more.

In June 2014, the commenter raised two dozen detailed questions that "CARB staff should address," also requesting an explanation of "why" for each question CARB staff deem irrelevant to alternative evaluations. Those questions do not constitute objections or recommendations regarding the December 2014 proposal. That proposal and the accompanying Staff Report addressed the topics addressed by the questions; they need not be separately addressed again here. To the extent that by re-submitting its June 2014 letter the commenter means to imply that it was improper for ARB not to provide written responses to interrogatories in the midst of a complex rulemaking process, ARB staff disagrees. Such processes are more typically part of litigation.

538. Comment: **LCFS 46-206**

The commenter asks if ARB agrees that the RFS program would assure some GHG reductions in the absence of the LCFS program.

Agency Response: See response **LCFS 46-205**.

This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nonetheless, ARB staff note that it is not uncommon for ARB to adopt synergistic programs that work in partnership with U.S. EPA's regulations – regulation of fuel and fuel additives and rules increasing the fuel economy and decreasing GHG emissions from cars and light-duty trucks are an example. Currently, the federal RFS program provides such synergistic and positive benefits with respect to alternative fuels.

539. Comment: **LCFS 46-207**

The commenter asks if RFS and the "California premium" would ensure delivery of Midwest ethanol to California in the absence of the LCFS.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. See response to **LCFS 46-205**.

540. Comment: **LCFS 46-208**

The comment questions if ARB staff believe that the LCFS regulation would result in wider usage of E85 in California and, if so, why.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nonetheless, ARB staff believes the LCFS regulation could result in wider usage of E85 in California because some ethanols may generate significant credits, though the market participants will ultimately decide which fuels are used to comply with the carbon intensity standards and other factors influence E85 usage.

See response **LCFS 46-205**.

541. Comment: **LCFS 46-209**

The comment questions whether a possible need for a diesel component in the LCFS program justifies an unnecessary gasoline component and, if so, why.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nevertheless, we note that the LCFS program is necessary to achieve the stated objectives. The program provides flexibility and keeps costs down. However, in order to lower the carbon intensity of transportation fuels, achieve significant GHG reductions, and diversify the transportation pool, both a gasoline and diesel component are necessary.

See response to **LCFS 46-205**.

542. Comment: **LCFS 46-210**

The commenter asks if ARB still believes that ultra-low CI fuels will become available and bring down the cost of the program.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. See response to **LCFS 46-205**.

To the extent it pertains to the current regulatory proposal, much of the information the commenter sought in this pre-ISOR feedback was provided in the ISOR. The cost analysis, as presented in the economic chapter in the ISOR is a worst-case scenario that will likely over-estimate the costs, without monetizing many of the benefits.

For instance, the LCFS will help reduce costs associated with petroleum dependency in California, and the health and the climate change impacts of petroleum use in California's transportation sector. These benefits are not quantified in this analysis, but some studies suggest they are significant, potentially several times greater in magnitude than the direct economic costs to regulated parties.

The SRIA outlines one potential scenario of the economic impacts of the regulation using an illustrative $100 average credit price. Table F-2 in the ISOR displays the direct changes in consumer expenditures for this scenario. The consumer expenditures are based on the credit price, and the deficits and credits generated by those volumes (outlined in Table F-1). At different credit prices, volumes of lower CI fuels, and efficiency improvements, among other factors, would likely lead to lower costs to consumers.

543. Comment: **LCFS 46-211**

The commenter asks if ARB believes that the Advanced Clean Car Program and other vehicle-based programs are designed to achieve the maximum technologically feasible GHG reductions.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. See also response to **LCFS 46-205**.

544. Comment: **LCFS 46-212**

The commenter asks if Executive Order S-07-01 need to be reconsidered in the re-adoption of the LCFS.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. As noted above, ARB declines to offer the commenter legal advice or opinions. See response to **LCFS 46-205**.

545. Comment: **LCFS 46-213**

The comment questions the extent to which the LCFS program has succeeded in the last five years and how the potential cost to Californians should be weighed against the success that has been achieved.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nonetheless, staff notes that the LCFS is working as designed and intended. ARB staff notes that the LCFS program has seen real, substantiated changes to the transportation fuel in California as a result of its program – increased volumes of renewable diesel and lower-CI ethanol are two examples. To date, nearly 160 active entities have registered for reporting in the LCFS Reporting Tool, and since the regulation went into effect, regulated parties have successfully operated under the LCFS program. Furthermore, fuel producers are innovating and achieving material reductions in their fuel pathways' carbon intensity, an effect the LCFS regulation is expressly designed to encourage. This is reflected in the large number of applications submitted under the "Method 2A/2B" process. The Method 2A/2B process allows fuel producers to apply for carbon intensity values for their fuels that are lower than the default values found in the LCFS Lookup Tables. To date, more than 230 individual new or modified fuel pathways with substantially lower carbon intensities have been certified. Almost 170 biofuel facilities are registered under the LCFS as supplying low-carbon fuels to California. The fact that some Midwest biorefineries have a low CI and others are adjusting their processes to lower their CI, is a positive sign demonstrating the innovative nature of the market based program.

It is important to remember that the LCFS program is currently at one percent, and has been for a couple of years; in part, due to uncertainty associated with the program as a result of the lawsuits. Even with the standards frozen at one percent, tangible results can been seen. For example, the amount of renewable natural gas used in vehicles in California has increased by over 700 percent since the program started; renewable diesel has grown dramatically to become more than three percent of the total diesel market in California in 2013; and the average crude CI used by California refiners have remained below the 2010 baseline, meaning that the carbon footprint of the crude slate has not increased. Additionally, fuel producers are innovating and achieving material reductions in their fuel pathways' CI, an effect the LCFS regulation is expressly designed to encourage. Moving forward, ARB staff expects that the market signal provided by an increasingly stringent LCFS program will incentivize new cleaner facilities and processes that consider full life cycle emissions.

546. Comment: **LCFS 46-214**

The comment requests that ARB staff submit a new SRIA that includes responses to the series of questions they presented above.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. See also response to **LCFS 46-205.** An additional SRIA is not required, and ARB will not be submitting an additional SRIA for review to DOF. ARB staff notes that the ISOR contains additional economic analysis.

547. Comment: **LCFS 46-215**

The comment questions whether the LCFS regulation actually achieves any reductions in upstream emissions and states that the regulation has caused fuel shuffling.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. See response to **LCFS46-40** and **LCFS 46-213**.

548. Comment: **LCFS 46-216**

The commenter believes the iLUC value used for corn ethanol is too high.

Agency Response: The document was prepared by commenter in response to ARB analysis presented in 2012, and as such does not constitute an objection or recommendation regarding the proposal released in December, 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

All of the iLUC values being proposed to the Board are a result of ARB staff using the latest science and best data to estimate iLUC values for all six biofuels (including ethanol) using a consistent methodology.

See also responses to **LCFS 8-1** and **LCFS 46-165**.

549. Comment: **LCFS 46-217**

The comment states that modification of the Cap-and-Trade Program would be a more efficient way to achieve GHG reductions and makes re-adoption of the LCFS proposal unnecessary.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. See also response to **LCFS 46-205, LCFS 32-2**, **LCFS 32-7**, and **LCFS 46-226**.

550. Comment: **LCFS 46-218**

The commenter suggests that if the Cap-and-Trade Program increased the obligations it already imposed on transportation fuel suppliers, short-term greenhouse gas emission reductions equivalent to those projected to result from the LCFS could be accomplished without need for the LCFS regulation.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nevertheless, please see response to **LCFS 32-2**, **LCFS 32-7**, and **LCFS 46-226**.

551. Comment: **LCFS 46-219**

The comment expresses concerns about the availability and cost of ultra-low-carbon-intensity alternative fuels and that eliminating the LCFS regulation would eliminate a major conflict with the federal RFS.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. See response to **LCFS 46-205.** The LCFS program has made a rigorous assessment of the viability of the new compliance curve (see response to **LCFS 38-1**). In addition, the LCFS program has flexibility provisions and a cost containment mechanism to allow the lowest cost options (see responses to **LCFS 32-9** and **LCFS 38-3**). Finally, for a discussion of the coordination with the RFS program, see responses to **LCFS 38-45** and **LCFS 46-26**.

552. Comment: **LCFS 46-220**

In June 2014, the commenter raised a long list of detailed questions that “CARB staff should address,” together with an explanation of why regarding each response.

Agency Response: Those questions do not constitute objections or recommendations regarding the December 2014 proposal. That proposal and the accompanying Staff Report addressed those topics; they need not be separately addressed again here. To the extent that by re-submitting its June 2014 letter the commenter means to imply that it was improper for ARB not to provide written responses to interrogatories in the midst of a complex rulemaking process, ARB disagrees. Such responses were not required. Staff notes that an unlimited number of questions were allowed, and answered, during the many public workshops ancillary to this rulemaking. The commenter was, of course, free to participate.

553. Comment: **LCFS 46-221**

The commenter asked a series of legal questions for ARB staff to address in the SRIA.

Agency Response: These June 2014 interrogatories and musings are not comments or recommendations regarding the December 30, 2015 LCFS proposal, and need no response.

554. Comment: **LCFS 46-222**

The comment questions whether the Cap-and-Trade Program could be modified to provide the same numerical reductions in GHG emissions as the LCFS.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. See also responses to **LCFS 46-205, LCFS 32-2**, **LCFS 32-7**, **LCFS 46-220**, and **LCFS 46-226**.

555. Comment: **LCFS 46-223**

The comment suggests that adoption of a revised LCFS regulation as a "backstop" measure if the federal RFS Program does not get fully implemented or enforced at some time in the future would be sufficient to meet the State's objectives.

Agency Response:

This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. See also responses to **LCFS 46-205, LCFS 38-45, 46-179, 46-195, 46-201,** and **46-220**.

556. Comment: **LCFS 46-224**

The commenter asks if a modified Cap-and-Trade program will meet the objectives of the LCFS program.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. See also response to **LCFS 46-205.** The premise of the comment is that a modified Cap-and-Trade Program is sufficient to meet the objectives of LCFS program. As explained in the response to comments **LCFS 46-173**, **LCFS 46-179**, **LCFS 46-195**, and **LCFS 46-196**, that option would not meet the objectives.

557. Comment: **LCFS 46-225**

The comment asks what level of resources the ARB has devoted to the LCFS regulation and asks what would be the impact for the ARB if the LCFS program was eliminated.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation. Nevertheless, we note that resources for the LCFS program are approximately 20 staff. If the LCFS program were eliminated, the Cap-and-Trade Program would require fundamental changes to more rigorously incorporate lifecycle emissions (as explained in the response to comments **LCFS 46-195** and **LCFS 46-201**). ARB staff would be needed to incorporate those changes and then oversee the revised program. Staff does not believe the end result would be any significant staff resource changes. Perhaps more importantly, ARB staff does not believe the State's objectives would be met by that approach. Please see responses to **LCFS 32-2**, **LCFS 46-217**, **and LCFS 46-226**.

558. Comment: **LCFS 46-226**

The commenter asks ARB what benefits other than GHG emission reductions can be attributed to the LCFS program.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the regulation proposed in December, 2014. The benefits of the regulation are addressed in the ISOR that post-dates the commenter's question. See response to **LCFS 46-220**. ARB is not obligated to answer the many interrogatories posed by commenter.

559. Comment: **LCFS 46-227**

The commenter asks ARB to explain how the questions posed in **LCFS 46-221** through **LCFS 46-226** affect the evaluation of the commenter's alternative.

Agency Response: This June 2014 submittal is not an objection or recommendation regarding the proposed regulation.

See response to **LCFS 46-220**.

560. Comment: **LCFS 46-228**

In June 2014, the commenter objected that as of that date ARB had not substantially complied with requirements to allow public input into the SB 617/SRIA process.

Agency Response: ARB staff disagrees. ARB staff solicited alternatives from the public in advance of preparing the SRIA, and then analyzed those proposals in the SRIA document. See also response to Comment **LCFS 46-198** regarding public input generally. Moreover, the SRIA process is not the public's sole avenue for participating in and commenting on economic analyses. ARB staff made public its entire proposed regulation and economic analyses in December 2014, and accepted comments for 45 days and again at two public hearings before the Air Resources Board.

561. Comment: **LCFS 46-229**

In June 2014, the commenter objected that in connection with the SB 617/SRIA process, ARB had not provided a sufficiently specific proposal.

Agency Response: ARB staff disagrees. As more fully discussed in responses to comments **LCFS 46-7**, **LCFS 46-72**, and **LCFS 46-198**, by June of 2014, (1) the LCFS program was in its fifth year of actual implementation, (2) numerous workshops related to the re-adoption had been conducted, and (3) a description and some draft language regarding new aspects to be included in the re-adoption had been released. As discussed in response to comments **LCFS 46-195**, **LCFS 46-202**, and **LCFS 46-203**, ARB staff continued to listen to public input and continued its internal research to develop the best possible proposal by the end of 2014.

562. Comment: **LCFS 46-230**

The comment questions whether ARB staff provided all the necessary information consistent with SB 617 and the Department's regulations for public review and input.

Agency Response: See response to **LCFS 46-229**.

563. Comment: **LCFS 46-231**

The comment states that ARB staff's inability to provide more information to the public so they can participate fully in the SB 617 process seems inexcusable.

Agency Response: See response to **LCFS 46-229**.

564. Comment: **LCFS 46-232**

The comment states that Growth Energy's alternative proposal only lacks a detailed comparison of the costs, benefits, and cost-effectiveness because of ARB staff's failure to provide the information needed to offer a more specific analysis.

Agency Response: See response to **LCFS 46-65** and **LCFS 46-72**. We further note that the SRIA and ISOR, including an economic analysis, were made available prior to the comment period on the proposed LCFS; nothing precluded the submitter from reading those documents and submitting comments.

46_OP_LCFS
_GE

17_OP_ADF
_GE

Appendix G

GHG Emissions Impact of Fuel Shuffling Due to California Low Carbon Fuel Standard

AIR, Inc.

February 14, 2015

The California LCFS requires a 10% reduction in carbon intensity between 2010 and 2020 for fuels sold in California. Much of the GHG emission reductions come from biofuels that are mixed with either gasoline or diesel fuel. Biofuel production has increased in the US and elsewhere. There are two possible scenarios for where the biofuels are used. In one scenario, where the LCFS is not in effect, the carbon intensity of biofuels used is approximately the same inside and outside of California. Biofuels are generally used where they are produced, and transportation emissions for biofuels are minimized. For example, ethanol from corn is used in the US, and ethanol from Brazil is used in Brazil. In a second scenario where the LCFS is in effect, the LCFS causes lower carbon intensity biofuels to flow into California for use there. All other biofuel production, which may have slightly higher average carbon intensity than the average in California, is used outside of California. In this second case, global GHG emissions can actually increase, because the same quantity of biofuel is used in either case, but in the second case, transport GHG emissions are higher, because biofuels are not being used where they were produced. This overall concept is referred to as fuel shuffling.

The LCFS requirement causes fuel shuffling, because the regulation is expected to result in increasing amounts of cane ethanol from Brazil to be used in California. This is shown in Table B-18 below, which shows volumes of different types of ethanol that ARB expects under one of the possible compliance scenarios (see Table B-18 of Appendix B to the ISOR). In California corn and related ethanol (sorghum) declines, while other fuels, notably cane ethanol, increases. However, while corn ethanol declines in California, it does not decline elsewhere, but increases with the RFS and with exports. Thus, worldwide there is no change in GHG emissions worldwide just because corn ethanol declines in California. However, the shift from corn ethanol to cane ethanol causes an increase in ethanol transportation and distribution emissions because of the difference in transportation distances between the Midwest to California and Brazil to California.

LCFS 46-233

Table B-18. Illustrative California Reformulated Gasoline Oxygenates and Substitute Fuels through 2020							
Fuel	2014	2015	2016	2017	2018	2019	2020
Corn and related ethanol, mmg	1,400	1,350	1,250	1,175	1,000	925	875
Cane and sugar ethanol, mmg	120	170	240	290	410	460	510
Cellulosic ethanol, mmg	0	0	5	15	50	75	100
Renewable gasoline, mmg	0	0	0	0	5	15	25
Hydrogen, mmgGGE	0.03	0.4	1	2	4	5	7
Electricity for LDVs, mmgGGE	9	14	19	24	31	40	51

We first estimated the GHG emission impact of increased transportation emissions with CaGREET2.0. We used distances and modes of transportation provided in CAGREET2.0. Results are shown in Table 1 below. For this analysis we assume a 390 million gallon per year increase in cane ethanol and a corresponding decrease in corn ethanol, which is the difference in the 2020 cane ethanol value (510 million gallons per year) and the 2014 value (120 million gallons per year) in Table B-18 above. Results show a 145,000 ton per year increase in GHG emissions, which is the fuel shuffling effect, assuming GREET cane ethanol transport emissions are correct.

LCFS 46-233 cont.

Table 1. Extra Transport GHG Emissions from Brazil Sugar Cane Ethanol								
	Emission Factors (grams/MMBTU of Fuel Transported)			Emissions		Emissions, CO2e		
Pollutant	Brazil to LA/Long Beach *	Midwest to CA **	Difference	Billion Grams	GWP	Billion Grams	Short Tons	gCO2e/ MJ
VOC	5.109	1.321	3.788	0.113	3.12	0.351	387	0.0112
CO	12.221	4.428	7.793	0.232	1.57	0.365	402	0.0116
CH4	7.896	3.051	4.845	0.144	25.	3.605	3,974	0.1148
N2O	0.141	0.051	0.090	0.003	298.	0.801	882	0.0255
CO2	6,577.633	2,326.555	4,251.078	126.549	1.	126.549	139,496	4.0292
					Totals:	131.671	145,142	4.1923

*Brazil to LA/Long Beach includes: Pipeline, Rail, Truck, Ocean Tanker, and USTruck.
**Midwest to CA includes: Rail, Truck, and Truck.

LCFS 46-233 cont.

A report by $(S\&T)^2$, however, shows that the CaGREET2.0 transport emissions for cane ethanol could be quite low. [1] We used the same transport distances from Table 1 and information from the $(S\&T)^2$ report to estimate emissions, both with and without a backhaul included. Results are in Table 2 (details shown in Attachment 1) and show that the fuel shuffling emissions are between 375,000 and 716,000 tons of GHG per year.

Table 2. Increase in Fuel Shuffling GHG Emissions	
Case	Extra Fuel Shuffling Emissions (GHG, tpy)
Ca GREET2.0	132,000
$(S\&T)^2$, no backhaul	375,000
$(S\&T)^2$, with backhaul	716,000

[1] *REVIEW OF THE SUGAR CANE ETHANOL PATHWAYS IN CA-GREET 2.0,* $(S\&T)^2$ for Growth Energy, February 2, 2015.

Attachment 1

Details of Fuel Shuffling Estimates for $(S\&T)^2$ Transport Emissions

Without Backhaul

Pollutant	Emission Factors (grams/MMBTU of Fuel Transported) Brazil to LA/Long Beach *	Midwest to CA **	Difference	Emissions Billion Grams	GWP	Emissions, CO2e Billion Grams	Short Tons	gCO2e/MJ
VOC	11.288	1.321	9.967	0.297	3.12	0.925	1,019	0.0294
CO	26.352	4.428	21.924	0.653	1.57	1.026	1,131	0.0327
CH4	15.595	3.051	12.544	0.373	25.	9.336	10,291	0.2972
N2O	0.297	0.051	0.246	0.007	298.	2.181	2,405	0.0695
CO2	13,289.690	2,326.555	10,963.134	326.358	1.	326.358	359,748	10.3910
					Totals:	339.826	374,594	10.8198

*Brazil to LA/Long Beach includes: Pipeline, Rail, Truck, Ocean Tanker, and USTruck.
**Midwest to CA includes: Rail and two Trucks.

With Backhaul

Pollutant	Emission Factors (grams/MMBTU of Fuel Transported) Brazil to LA/Long Beach *	Midwest to CA **	Difference	Emissions Billion Grams	GWP	Emissions, CO2e Billion Grams	Short Tons	gCO2e/MJ
VOC	20.483	1.321	19.162	0.570	3.12	1.778	1,960	0.0566
CO	47.382	4.428	42.953	1.279	1.57	2.009	2,215	0.0640
CH4	27.054	3.051	24.003	0.715	25.	17.863	19,691	0.5688
N2O	0.529	0.051	0.478	0.014	298.	4.236	4,670	0.1349
CO2	23,278.251	2,326.555	20,951.696	623.705	1.	623.705	687,517	19.8584
					Totals:	649.592	716,052	20.6826

*Brazil to LA/Long Beach includes: Pipeline, Rail, Truck, Ocean Tanker, and USTruck.
**Midwest to CA includes: Rail and two Trucks.

LCFS 46-233 cont.

This page intentionally left blank.

46_OP_LCFS_GE Responses (Page 219 - 223)

565. <u>Comment</u>: **LCFS 46-233**

The comment states that the LCFS requirements merely cause fuel "shuffling" and implies that the LCFS regulation will not lead to a reduction in GHG emissions.

<u>Agency Response:</u> See response to **LCFS 46-31**, **46-32, 46-36, 46-40,** and **46-173**.

This page intentionally left blank.

46_OP_LCFS_GE

17_OP_ADF_GE

Appendix H

Appendix H

Impact of the LCFS on Global Climate

A quantitative modeling analysis was conducted to assess the impact of LCFS carbon emission reductions on global climate change.

Climate Model Summary – The effect of the LCFS ISOR estimates of CO_2 emissions reductions attributable to the proposed regulation were modeled using version 5.3 of a coupled, gas-cycle/climate model known as MAGICC (Model to Assess Greenhouse-gas Induced Climate Change). MAGICC has been the primary model used by the Intergovernmental Panel on Climate Change (IPCC) to produce projections of future global-mean temperature and sea level rise. Technical and user manuals explaining the model in more detail are publicly available.[1]

Version 5.3 is the latest version of MAGICC and was updated from version 4.1 to be consistent with the IPCC Fourth Assessment Report, Working Group 1 (AR4).[2] (Version 4.1 uses the earlier IPCC Third Assessment Report, Working Group 1 (TAR) climate couplings.) Updates reflected in MAGICC version 5.3 include: LCFS 46-234

- Climate sensitivity estimates updated based on AR4;
- Revised climate forcing values consistent with AR4;
- Updated carbon cycle modeling and CO_2 concentration stabilization scenarios;
- More realistic sea level rise projection method; and
- Minor "balancing" revision to methane and nitrous oxide budgets.

For purposes of this analysis, the updated climate sensitivity estimate from AR4 is the most noteworthy. The default climate sensitivity for a doubling of CO_2 has been upwardly revised from 2.6°C to 3.0°C in MAGICC version 5.3.

The key parameters for the MAGICC v5.3 modeling were as follows:

a) "mid"-level response for the carbon cycle model,
b) carbon cycle climate feedbacks set to "on,"
c) "mid"-level response for aerosol forcing,
d) 3.0° C sensitivity for doubled CO_2,
e) "variable" thermohaline circulation,
f) vertical oceanic diffusion coefficient set to "2.3 cm^2/s," and
g) "mid"-level ice melt sensitivity.

[1] T.M.L. Wigley, "MAGICC/SCENGEN 5.3: User Manual," National Center for Atmospheric Research, Colorado, September 2008.
[2] The IPCC released its Fifth Assessment Report (AR5), in October 2014. The MAGICC model has not yet been updated to reflect AR5.

Again the 3.0° C sensitivity to doubled CO_2 is consistent with the assumptions used in the IPCC AR4 report, which is based on the assumption that the surface temperature record accurately reflects the effect of greenhouse gas concentrations on ambient temperatures. Explanations of the other parameters are available in the above-referenced user manual.

Emission Inputs – The baseline case assumed a future in which fossil fuels will continue to be consumed in a "business as usual" manner, but with new sources of energy mixing in to supply a balance of non-carbon emitting sources. This baseline emissions case (named A1B-AIM) produces total climate forcing in 2005 that most closely approximates that in IPCC AR4 (A1B=1.596 W/m^2, AR4=1.6 W/m^2). Two different alternative scenarios were run to evaluate the potential effect of the proposed LCFS as summarized below:

1. *LCFS-CA:* This scenario applied the CARB LCFS ISOR estimated reduction in CO_2 emissions from 2020 (20.7 MMT[3] CO_2e). These reductions were held constant on a relative basis from 2020 through 2050.

2. *LCFS-US:* This second scenario assumed the reductions estimated in the LCFS ISOR would be increased by a factor of 8.9 to scale the California reductions to the entire U.S. based on California vs. entire U.S. transportation source CO_2 emission estimates published by the U.S. Energy Information Administration (EIA).

LCFS 46-234 cont.

Table 1 summarizes the baseline global fossil fuel CO_2 emissions by calendar year from the AR4-A1B-AIM reference case contained in the MAGICC v5.3 emissions scenario library. The emission units for fossil CO_2 are petagrams (10^{15} grams) as noted at the bottom of Table 1. As shown in Table 1, baseline emissions under the AR4 A1B-AIM reference case are projected to rise steadily from 1990 through 2050, with 2050 emissions roughly 2.7 times higher than those in 1990.

Table 1
Baseline Scenario
Global Fossil Fuel CO_2 Emissions (Pg C[a])

Calendar Year	Annual Emissions
1990	5.991
2000	6.896
2010	9.680
2020	12.122
2030	14.011
2040	14.945
2050	16.009

[a] Petagrams of carbon; 1 petagram = 10^{15} grams

[3] MMT = million metric tons (1 metric ton = 1,000 kilograms or 1,000,000 grams)

Emissions under the LCFS-CA and LCFS-US scenarios were calculated from these baseline estimates as follows. First, the CARB ISOR LCFS emission reductions in 2020 (20.7 MMT CO_2e) were converted to "petagram carbon" units for input into MAGICC as follows:

$$20.7\ MMTCO2e \times \frac{12.01\ g/mole\ C}{44.01\ g/mole\ CO2} \times \frac{1\ Pg}{10^3\ MMT} = 5.65 \times 10^{-3}\ Pg\ C$$

This reduction in 2020 emissions estimated in the CARB ISOR represents a 0.0047% decrease (5.65×10^{-3}/12.112 Pg C) in global fossil CO_2 emissions relative to the 2020 baseline. Since the ISOR reductions are expressed on a CO_2 equivalent basis, they were applied to the fossil fuel carbon emission estimates in MAGICC (although the model also includes emission estimates for other GHG compounds.)

In applying this LCFS reduction beyond 2020, out to 2050, two approaches were considered: 1) using the same absolute reduction (5.65×10^{-3} Pg C) for each future year; and 2) applying the same relative 2020 reduction (0.0466%) in each future year. The relative reduction approach produced nominally greater reductions (i.e., lower emissions) in future years. Thus, the relative reduction-based emissions were used in the climate modeling.

These California LCFS emission reductions were extrapolated to the second scenario representing nationwide LCFS adoption based on a scaling multiplier developed from EIA estimates of calendar year 2011 transportation sector CO_2 emissions by individual state.[4] EIA estimated 2011 transportation sector emissions of 199.3 and 1,781.9 $MMTCO_2$ in California and the entire U.S., respectively. Thus a scaling factor of 8.94 was developed from this ratio (1781.9÷199.3). This scaling factor was then used to conflate the California LCFS reductions from the ISOR to the entire U.S. For example in 2020, U.S. LCFS reductions were calculated as follows:

LCFS-CA Relative Reduction × Scaling Factor × 2020 Global Emissions, or
0.0466% × 8.94 × 12.122 Pg C = 0.051 Pg C reduction in 2020 CO_2 emissions

Table 2 presents a comparison of the resulting global emission estimates input to the MAGICC model for the baseline case and each of the two LCFS reduction analysis scenarios. Note that these values are emissions, not LCFS reductions (which are represented by the difference between the baseline and scenario emissions in the table).

LCFS 46-234 cont.

[4] U.S. Energy Information Administration (EIA), 2011 State energy-related carbon dioxide emissions by sector, http://www.eia.gov/environment/emissions/state/analysis/.

Table 2 **Comparison of Baseline and LCFS Reduction Scenario Annual Emissions (Pg C) Used in MAGICC Modeling**			
Calendar Year	Baseline (A1B-AIM)	LCFS in California	LCFS in Entire U.S.
1990	5.991	5.991	5.991
2000	6.896	6.896	6.896
2010	9.680	9.680	9.680
2020	12.122	12.116	12.071
2030	14.011	14.004	13.953
2040	14.945	14.938	14.883
2050	16.009	16.002	15.942

The highlighted cells in Table 2 denote those years and emissions that reflect LCFS reductions relative to baseline estimates.

LCFS 46-234 cont.

Climate Modeling Results – Table 3 shows modeled changes in ambient temperature from a 1990 baseline temperature for each case. As shown in the table, the baseline case produces an estimated increase of 0.9952°C in calendar year 2050 over the 1990 baseline. The addition of the LCFS standard is estimated to reduce this temperature increase by two ten-thousandths of a degree (0.0002). Assuming roughly nine times greater reductions to reflect LCFS implementation throughout the U.S., the temperature increase is reduced by 2.0 thousandths of a degree (0.0020).

Table 3 **MAGICC Version 5.3 Model Results (°C) for Calendar Year 2050**		
Scenario	Temperature Change from 1990 Baseline	Change Due to LCFS
Baseline (IPCC Case A1B)	0.9552	n.a.
Low Carbon Fuel Standard in California	0.9550	0.0002
Low Carbon Fuel Standard throughout U.S.	0.9532	0.0020

Appendix I

46_OP_LCFS_GE Responses (Page 224 - 229)

566. Comment: **LCFS 46-234**

This comment is an analysis commissioned by the commenter to evaluate the impact of the LCFS carbon emission reductions on global climate change using the MAGICC model.

Agency Response: This comment does not constitute an objection or suggestion to the proposed regulation. If the commenter's point is that small improvements in the environment are not worthwhile, ARB disagrees. The California Legislature has determined that GHG reductions are worth pursuing.

This page intentionally left blank.

46_OP_LCFS_GE

17_OP_ADF_GE

STATE OF CALIFORNIA

BEFORE THE AIR RESOURCES BOARD

Declaration of James M. Lyons

I, James Michael Lyons, declare as follows:

1. I make this Declaration based upon my own personal knowledge and my familiarity with the matters recited herein. It is based on my experience of nearly 30 years as a regulator, consultant, and professional in the field of emissions and air pollution control. A copy of my résumé can be found in Attachment A.

2. I am a Senior Partner of Sierra Research, Inc., an environmental consulting firm located at 1801 J Street, Sacramento, California owned by Trinity Consultants, Inc. Sierra specializes in research and regulatory matters pertaining to air pollution control, and does work for both governmental and private industry clients. I have been employed at Sierra Research since 1991. I received a B.S. degree in Chemistry from the University of California, Irvine, and a M.S. Degree in Chemical Engineering from the University of California, Los Angeles. Before joining Sierra in 1991, I was employed by the State of California at the Mobile Source Division of the California Air Resources Board (CARB).

3. During my career, I have worked on many projects related to the following areas: 1) the assessment of emissions from on- and non-road mobile sources, 2) assessment of the impacts of changes in fuel composition and alternative fuels on engine emissions including emissions of green-house gases, 3) analyses of the unintended consequences of regulatory actions, and 4) the feasibility of compliance with air quality regulations.

4. I have testified as an expert under state and federal court rules in cases involving CARB regulations for gasoline, Stage II vapor recovery systems and their design, factors affecting emissions from diesel vehicles, evaporative emission control system design and function, as well as combustion chamber system design. While at Sierra I have acted as a consultant on automobile air pollution control matters for CARB and for the United States Environmental Protection Agency. I am a member of the American Chemical Society and the Society of Automotive Engineers and have co-authored nine peer-reviewed monographs concerned with automotive emissions including greenhouse gases and their control. In addition, over the course of my career, I have conducted peer-reviews of numerous papers related to a wide variety of issues associated with pollutant emissions and air quality.

5. This Declaration summarizes the results of analyses I have performed regarding CARB staff's analysis of different aspects of the re-adoption of the Low Carbon Fuel Standard (LCFS) Regulation and Regulation on the Commercialization of Alternative Diesel Fuels (ADFs) as an independent expert for Growth Energy. If called upon to do so, I would testify in accord with the facts and opinions presented here.

6. Based on a review of the Initial Statement of Reasons (ISOR) for the LCFS regulation and the associated appendices, including the draft Environmental Analysis, it is clear that CARB staff failed to quantify the GHG emission reductions associated with the LCFS regulation itself. Rather, staff notes that the GHG reduction estimates provide are inflated as the result of the "double counting" of GHG reductions due to other regulatory programs. LCFS 46-235

7. Further, this review shows that CARB staff failed to perform a complete analysis of the potential air quality impacts associated with the LCFS regulation. More specifically, CARB staff's air quality analysis fails to quantitatively assess the impact of the LCFS and ADF on all emission sources that could be affected nor does it consider all of the pollutants for which emission changes might occur. A summary of the review is Attachment B to this declaration. LCFS 46-236

8. CARB staff rejected a proposed alternative to the LCFS regulation submitted by Growth Energy claiming that it will likely result in the same environmental benefits, but not ensure a transition to lower carbon intensity fuels that CARB staff claims is the main goal of the LCFS regulation. As discussed in detail in Attachment C to this declaration, CARB staff failed to perform any analysis of the Growth Energy Alternative and has provided no support for this finding. Because the Growth Energy Alternative provides greater environmental benefits and is expected to cost less than the LCFS regulation, it must be adopted by CARB instead of the LCFS regulation. LCFS 46-237

9. As part of the development of the ADF regulation, CARB staff examined the impacts of the proposed regulation on emissions of pollutants including oxides of nitrogen (NOx) emitted from heavy-duty diesel engines operating on blends of diesel fuel and biodiesel.

10. NOx emissions directly affect atmospheric levels of nitrogen dioxide, a compound for which a National Ambient Air Quality Standards (NAAQS) has been established. NOx emissions are also precursors to the formation of ozone and particulate matter, which are also pollutants for which NAAQS have been established. Areas of the South Coast and San Joaquin Valley air basins are in extreme and moderate non-attainment of the most recent ozone and fine particulate standards, respectively. LCFS 46-238

11. In the Initial Statement of Reasons (ISOR) for the ADF regulation and its' appendices, CARB staff summarized its analysis of increases in NOx emissions from heavy-duty diesel vehicles over the period from 2014 through 2023. The results of the staff's analysis are most clearly summarized in Table B-1 of Appendix B of the ISOR. This table shows that staff estimate that biodiesel use allowed under the ADF regulation will increase NOx emissions by 1.35 tons per day in 2014 and that the magnitude of this emission increase will drop to 0.01 ton per day by 2023. ADF 17-18

12. I have performed a review of the staff's assessment of the NOx emission impacts of biodiesel use allowed under the ADF regulation presented in ISOR and its' appendices and find it to be fundamentally flawed such that it is not reliable. First, the bases for total diesel NOx emissions inventory is not described in the ISOR or in other ADF 17-19

documents in the record. Second, CARB staff incorrectly assumes that the use of biodiesel in "New Technology Diesel Engines (NTDEs)" equipped with exhaust aftertreatment devices to lower NOx emissions will not lead to increased NOx emissions. Third, CARB staff incorrectly apply ratios of on-road vehicle travel by NTDEs from the now obsolete EMFAC2011 model to account for the amount of biodiesel used in all NTDEs including those found in non-road equipment. Fourth, to assess the overall impact of the ADF regulation on NOx emissions, CARB incorrectly subtracts NOx reductions resulting from the use of "renewable diesel fuel" from increases in NOx emissions resulting from the use of biodiesel.

ADF 17-19 cont.

13. In addition, I have performed a very conservative assessment of the NOx emission impacts of biodiesel use under the ADF that uses the latest CARB emissions models and corrects the flaws in the staff analysis, a summary of which is attached. The results of this assessment indicate that NOx increases from biodiesel will be much larger than those estimated by CARB staff and that the magnitude of the impacts will not decline over time as forecast by CARB staff. In addition, the analysis shows that the ADF regulation will lead to significant increases in NOx emissions in the South Coast and San Joaquin Valley air basins which are already in extreme non-attainment of the federal ozone NAAQS and moderate non-attainment of the federal fine particulate NAAQS. The details of both the review and revised emissions estimates are presented in Attachment D to this declaration.

ADF 17-20

14. In addition to identifying a fundamentally flawed analysis of the increases in NOx emissions from biodiesel use under the ADF, my review indicates that other elements of the staff's air quality and environmental analyses are also fundamentally flawed. These include incorrectly selecting 2014 as the baseline year for the environmental analysis, lacking documentation and using unsupported assumptions in determination of the NOx control level for biodiesel, and unnecessarily delaying the effective date for the implementation of mitigation requirements under the ADF regulation. All of these issues, which are discussed in detail in Attachment E, cause the adverse environmental impacts of the ADF regulation to be greater than purported by CARB staff.

ADF 17-21

15. Another important issue that I have identified with the ADF regulation is that it and the related LCFS and California Diesel regulations contain inconsistent and conflicting definitions and lack provisions requiring the determination, through testing, of the biodiesel content of commercial blendstocks. As a result, there is a clear potential for biodiesel blends to actually contain as much as 5% more biodiesel by volume than will be reported to CARB under the ADF regulation. A detailed discussion of the flaws in the ADF regulation that could allow this to occur is provided in Attachment F. Actual biodiesel levels above those reported under the ADF will lead to larger unmitigated increases in NOx emissions than have been estimated by either CARB staff or me.

ADF 17-22

16. CARB staff has rejected a proposed alternative to the ADF regulation submitted by Growth Energy, claiming that it will result in the same environmental benefits but be more costly than the staff proposal. As discussed in detail in Attachment G to this declaration, this finding is based on the same fundamentally flawed emissions

ADF 17-23

analysis performed by CARB staff that is discussed above. Given that the Growth Energy alternative is designed to mitigate all potential increases in NOx emissions (when assessed in light of a proper emissions analysis) due to biodiesel use under the ADF as soon as the regulation becomes effective, it yields greater and more timely environmental benefits than the staff proposal. In addition, the Growth Energy alternative would require the same mitigation techniques as the ADF regulation, but simply expands the circumstances under which they must be applied, and has an estimated cost-effectiveness equal to that of ADF regulation. Because the Growth Energy Alternative provides greater environmental benefits as cost-effectively as the ADF regulation, it must be adopted by CARB instead of the ADF regulation. ADF 17-23 cont.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 17th day of February, 2015 at Sacramento, California.

JAMES M. LYONS

46_OP_LCFS_GE Responses (Page 230 - 233)

567. Comment: **LCFS 46-235 through LCFS 46-238 and ADF 17-18 through ADF 17-23**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

46_OP_LCFS_GE

17_OP_ADF_GE

sierra research

1801 J Street
Sacramento, CA 95811
Tel: (916) 444-6666
Fax: (916) 444-8373

Ann Arbor, MI
Tel: (734) 761-6666
Fax: (734) 761-6755

Attachment A

Résumé

James Michael Lyons

Education

1985, M.S., Chemical Engineering, University of California, Los Angeles

1983, B.S., Cum Laude, Chemistry, University of California, Irvine

Professional Experience

4/91 to present — Senior Engineer/Partner/Senior Partner
Sierra Research

Primary responsibilities include oversight and execution of complex analyses of the emission benefits, costs, and cost-effectiveness of mobile source air pollution control measures. Mr. Lyons has developed particular expertise with respect to the assessment of control measures involving fuel reformulation, fuel additives, and alternative fuels, as well as accelerated vehicle/engine retirement programs, the deployment of advanced emission control systems for on- and non-road gasoline- and Diesel-powered engines, on-vehicle evaporative and refueling emission control systems, and Stage I and Stage II service station vapor recovery systems. Additional duties include assessments of the activities of federal, state, and local regulatory agencies with respect to motor vehicle emissions and reports to clients regarding those activities. Mr. Lyons has extensive litigation experience related to air quality regulations, product liability, and intellectual property issues.

7/89 to 4/91 — Senior Air Pollution Specialist
California Air Resources Board

Supervised a staff of four professionals responsible for identifying and controlling emissions of toxic air contaminants from mobile sources and determining the effects of compositional changes to gasoline and diesel fuel on emissions of regulated and unregulated pollutants. Other responsibilities included development of new test procedures and emission standards for evaporative and running loss emissions of hydrocarbons from vehicles; overseeing the development of the state plan to control toxic emissions from motor vehicles; and reducing emissions of CFCs from motor vehicles.

4/89 to 7/89 Air Pollution Research Specialist
California Air Resources Board

Responsibilities included identification of motor vehicle research needs; writing requests for proposals; preparation of technical papers and reports; as well as monitoring and overseeing research programs.

9/85 to 4/89 Associate Engineer/Engineer
California Air Resources Board

Duties included analysis of vehicle emissions data for trends and determining the effectiveness of various types of emissions control systems for both regulated and toxic emissions; determining the impact of gasoline and diesel powered vehicles on ambient levels of toxic air contaminants; participation in the development of regulations for "gray market" vehicles; and preparation of technical papers and reports.

Professional Affiliations

American Chemical Society
Society of Automotive Engineers

Selected Publications (Author or Co-Author)

"Development of Vehicle Attribute Forecasts for 2013 IEPR," Sierra Research Report No. SR2014-01-01, prepared for the California Energy Commission, January 2014.

"Assessment of the Emission Benefits of U.S. EPA's Proposed Tier 3 Motor Vehicle Emission and Fuel Standards," Sierra Research Report No. SR2013-06-01, prepared for the American Petroleum Institute, June 2013.

"Development of Inventory and Speciation Inputs for Ethanol Blends," Sierra Research Report No. SR2012-05-01, prepared for the Coordinating Research Council, Inc. (CRC), May 2012.

"Review of CARB Staff Analysis of 'Illustrative' Low Carbon Fuel Standard (LCFS) Compliance Scenarios," Sierra Research Report No. SR2012-02-01, prepared for the Western States Petroleum Association, February 20, 2012.

"Review of CARB On-Road Heavy-Duty Diesel Emissions Inventory," Sierra Research Report No. SR2010-11-01, prepared for The Ad Hoc Working Group, November 2010.

"Identification and Review of State/Federal Legislative and Regulatory Changes Required for the Introduction of New Transportation Fuels," Sierra Research Report No. SR2010-08-01, prepared for the American Petroleum Institute, August 2010.

"Technical Review of EPA Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis for Non-GHG Pollutants," Sierra Research Report No. SR2010-05-01, prepared for the American Petroleum Institute, May 2010.

"Effects of Gas Composition on Emissions from Heavy-Duty Natural Gas Engines," Sierra Research Report No. SR2010-02-01, prepared for the Southern California Gas Company, February 2010.

"Effects of Gas Composition on Emissions from a Light-Duty Natural Gas Vehicle," Sierra Research Report No. SR2009-11-01, prepared for the Southern California Gas Company, November 2009.

"Technical Review of 2009 EPA Draft Regulatory Impact Analysis for Non-GHG Pollutants Due to Changes to the Renewable Fuel Standard," Sierra Research Report No. SR2009-09-01, prepared for the American Petroleum Institute, September 2009.

"Effects of Vapor Pressure, Oxygen Content, and Temperature on CO Exhaust Emissions," Sierra Research Report No. 2009-05-03, prepared for the Coordinating Research Council, May 2009.

"Technical Review of 2007 EPA Regulatory Impact Analysis Methodology for the Renewable Fuels Standard," Sierra Research Report No. 2008-09-02, prepared for the American Petroleum Institute, September 2008.

"Impacts of MMT Use in Unleaded Gasoline on Engines, Emission Control Systems, and Emissions," Sierra Research Report No. 2008-08-01, prepared for McMillan Binch Mendelsohn LLP, Canadian Vehicle Manufacturers' Association, and Association of International Automobile Manufacturers of Canada, August 2008.

"Attachment to Comments Regarding the NHTSA Proposal for Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015, Docket No. NHTSA-2008-0089," Sierra Research Report No. SR2008-06-01, prepared for the Alliance of Automobile Manufacturers, June 2008.

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act – Part 1: Impacts on New Vehicle Fuel Economy," SAE Paper No. 2008-01-1852, Society of Automotive Engineers, 2008.

"Basic Analysis of the Cost and Long-Term Impact of the Energy Independence and Security Act Fuel Economy Standards," Sierra Research Report No. SR 2008-04-01, April 2008.

"The Benefits of Reducing Fuel Consumption and Greenhouse Gas Emissions from Light-Duty Vehicles," SAE Paper No. 2008-01-0684, Society of Automotive Engineers, 2008.

"Assessment of the Need for Long-Term Reduction in Consumer Product Emissions in South Coast Air Basin," Sierra Research Report No. 2007-09-03, prepared for the Consumer Specialty Products Association, September 2007.

“Summary of Federal and California Subsidies for Alternative Fuels,” Sierra Research Report No. SR2007-04-02, prepared for the Western States Petroleum Association, April 2007.

“Analysis of IRTA Report on Water-Based Automotive Products,” Sierra Research Report No. SR2006-08-02, prepared for the Consumer Specialty Projects Association and Automotive Specialty Products Alliance, August 2006.

“Evaluation of Pennsylvania’s Implementation of California’s Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions,” Sierra Research Report No. SR2006-04-01, prepared for Alliance of Automobile Manufacturers, April 12, 2006.

“Evaluation of New Jersey’s Adoption of California’s Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions,” Sierra Research Report No. SR2005-09-03, prepared for the Alliance of Automobile Manufacturers, September 30, 2005.

“Evaluation of Vermont’s Adoption of California’s Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions,” Sierra Research Report No. SR2005-09-02, prepared for the Alliance of Automobile Manufacturers, September 19, 2005.

“Assessment of the Cost-Effectiveness of Compliance Strategies for Selected Eight-Hour Ozone NAAQS Nonattainment Areas,” Sierra Research Report No. SR2005-08-04, prepared for the American Petroleum Institute, August 30, 2005.

“Evaluation of Connecticut’s Adoption of California’s Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions,” Sierra Research Report No. SR2005-08-03, prepared for the Alliance of Automobile Manufacturers, August 26, 2005.

“Evaluation of New York’s Adoption of California’s Greenhouse Gas Regulations On Criteria Pollutants and Precursor Emissions,” Sierra Research Report No. SR2005-07-04, prepared for the Alliance of Automobile Manufacturers, July 14, 2005.

“Review of MOVES2004,” Sierra Research Report No. SR2005-07-01, prepared for the Alliance of Automobile Manufacturers, July 11, 2005.

“Review of Mobile Source Air Toxics (MSAT) Emissions from On-Highway Vehicles: Literature Review, Database, Development, and Recommendations for Future Studies,” Sierra Research Report No. SR2005-03-01, prepared for the American Petroleum Institute, March 4, 2005.

“The Contribution of Diesel Engines to Emissions of ROG, NOx, and PM2.5 in California: Past, Present, and Future,” Sierra Research Report No. SR2005-02-01, prepared for Diesel Technology Forum, February 2005.

“Fuel Effects on Highway Mobile Source Air Toxics (MSAT) Emissions,” Sierra Research Report No. SR2004-12-01, prepared for the American Petroleum Institute, December 23, 2004.

“Review of the August 2004 Proposed CARB Regulations to Control Greenhouse Gas Emissions from Motor Vehicles: Cost Effectiveness for the Vehicle Owner or Operator – Appendix C to the Comments of The Alliance of Automobile Manufacturers,” Sierra Research Report No. SR2004-09-04, prepared for the Alliance of Automobile Manufacturers, September 2004.

“Emission and Economic Impacts of an Electric Forklift Mandate,” Sierra Research Report No. SR2003-12-01, prepared for National Propane Gas Association, December 12, 2003.

“Reducing California’s Energy Dependence,” Sierra Research Report No. SR2003-11-03, prepared for Alliance of Automobile Manufacturers, November 25, 2003.

“Evaluation of Fuel Effects on Nonroad Mobile Source Air Toxics (MSAT) Emissions: Literature Review, Database Development, and Recommendations for Future Studies,” Sierra Research Report No. SR2003-10-01, prepared for American Petroleum Institute, October 3, 2003.

“Review of Current and Future CO Emissions from On-Road Vehicles in Selected Western Areas,” Sierra Research Report No. SR03-01-01, prepared for the Western States Petroleum Association, January 2003.

“Review of CO Compliance Status in Selected Western Areas,” Sierra Research Report No. SR02-09-04, prepared for the Western States Petroleum Association, September 2002.

“Impacts Associated With the Use of MMT as an Octane Enhancing Additive in Gasoline – A Critical Review”, Sierra Research Report No. SR02-07-01, prepared for Canadian Vehicle Manufacturers Association and Association of International Automobile Manufacturers of Canada, July 24, 2002.

“Critical Review of ‘Safety Oversight for Mexico-Domiciled Commercial Motor Carriers, Final Programmatic Environmental Assessment’, Prepared by John A Volpe Transportation Systems Center, January 2002,” Sierra Research Report No. SR02-04-01, April 16, 2002.

“Critical Review of the Method Used by the South Coast Air Quality Management District to Establish the Emissions Equivalency of Heavy-Duty Diesel- and Alternatively Fueled Engines”, Sierra Research Report No. SR01-12-03, prepared for Western States Petroleum Association, December 21, 2001.

“Review of U.S. EPA’s Diesel Fuel Impact Model”, Sierra Research Report No. SR01-10-01, prepared for American Trucking Associations, Inc., October 25, 2001.

“Operation of a Pilot Program for Voluntary Accelerated Retirement of Light-Duty Vehicles in the South Coast Air Basin,” Sierra Research Report No. SR01-05-02, prepared for California Air Resources Board, May 2001.

"Comparison of Emission Characteristics of Advanced Heavy-Duty Diesel and CNG Engines," Sierra Report No. SR01-05-01, prepared for Western States Petroleum Association, May 2001.

"Analysis of Southwest Research Institute Test Data on Inboard and Sterndrive Marine Engines," Sierra Report No. SR01-01-01, prepared for National Marine Manufacturers Association, January 2001.

"Institutional Support Programs for Alternative Fuels and Alternative Fuel Vehicles in Arizona: 2000 Update," Sierra Report No. SR00-12-04, prepared for Western States Petroleum Association, December 2000.

"Real-Time Evaporative Emissions Measurement: Mid-Morning Commute and Partial Diurnal Events," SAE Paper No. 2000-01-2959, October 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," SAE Paper No. 2000-01-2958, October 2000.

"A Comparative Analysis of the Feasibility and Cost of Compliance with Potential Future Emission Standards for Heavy-Duty Vehicles Using Diesel or Natural Gas," Sierra Research Report No. SR00-02-02, prepared for Californians For a Sound Fuel Strategy, February 2000.

"Critical Review of the Report Entitled 'Economic Impacts of On Board Diagnostic Regulations (OBD II)' Prepared by Spectrum Economics," Sierra Research Report No. SR00-01-02, prepared for the Alliance of Automobile Manufacturers, January 2000.

"Potential Evaporative Emission Impacts Associated with the Introduction of Ethanol-Gasoline Blends in California," Sierra Research Report No. SR00-01-01, prepared for the American Methanol Institute, January 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," Sierra Research Report No. SR99-10-03, prepared for the Coordinating Research Council, October 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," SAE Paper No. 1999-01-3676, August 1999.

"Future Diesel-Fueled Engine Emission Control Technologies and Their Implications for Diesel Fuel Properties," Sierra Research Report No. SR99-08-01, prepared for the American Petroleum Institute, August 1999.

"Analysis of Compliance Feasibility under Proposed Tier 2 Emission Standards for Passenger Cars and Light Trucks," Sierra Research Report No. SR99-07-02, July 1999.

"Comparison of the Properties of Jet A and Diesel Fuel," Sierra Research Report No. SR99-02-01, prepared for Pillsbury Madison and Sutro, February 1999.

“Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles,” Sierra Research Report No. SR98-12-02, prepared for the American Petroleum Institute, December 1998.

“Analysis of New Motor Vehicle Issues in the Canadian Government’s Foundation Paper on Climate Change – Transportation Sector,” Sierra Research Report No. SR98-12-01, prepared for the Canadian Vehicle Manufacturers Association, December 1998.

“Investigation of the Relative Emission Sensitivities of LEV Vehicles to Gasoline Sulfur Content - Emission Control System Design and Cost Differences,” Sierra Research Report No. SR98-06-01, prepared for the American Petroleum Institute, June 1998.

“Costs, Benefits, and Cost-Effectiveness of CARB’s Proposed Tier 2 Regulations for Handheld Equipment Engines and a PPEMA Alternative Regulatory Proposal,” Sierra Research Report No. SR98-03-03, prepared for the Portable Power Equipment Manufacturers Association, March 1998.

“Analysis of Diesel Fuel Quality Issues in Maricopa County, Arizona,” Sierra Research Report No. SR97-12-03, prepared for the Western States Petroleum Association, December 1997.

“Potential Impact of Sulfur in Gasoline on Motor Vehicle Pollution Control and Monitoring Technologies,” prepared for Environment Canada, July 1997.

“Analysis of Mid- and Long-Term Ozone Control Measures for Maricopa County,” Sierra Research Report No. SR96-09-02, prepared for the Western States Petroleum Association, September 9, 1996.

“Technical and Policy Issues Associated with the Evaluation of Selected Mobile Source Emission Control Measures in Nevada,” Sierra Research Report No. SR96-03-01, prepared for the Western States Petroleum Association, March 1996.

“Cost-Effectiveness of Stage II Vapor Recovery Systems in the Lower Fraser Valley,” Sierra Research Report No. SR95-10-05, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

“Cost of Stage II Vapor Recovery Systems in the Lower Fraser Valley,” Sierra Research Report No. SR95-10-04, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

“A Comparative Characterization of Gasoline Dispensing Facilities With and Without Vapor Recovery Systems,” Sierra Research Report No. SR95-10-01, prepared for the Province of British Columbia Ministry of Environment Lands and Parks, October 1995.

“Potential Air Quality Impacts from Changes in Gasoline Composition in Arizona,” Sierra Research Report No. SR95-04-01, prepared for Mobil Corporation, April 1995.

"Vehicle Scrappage: An Alternative to More Stringent New Vehicle Standards in California," Sierra Research Report No. SR95-03-02, prepared for Texaco, Inc., March 1995.

"Evaluation of CARB SIP Mobile Source Measures," Sierra Research Report No. SR94-11-02, prepared for Western States Petroleum Association, November 1994.

"Reformulated Gasoline Study," prepared by Turner, Mason & Company, DRI/McGraw-Hill, Inc., and Sierra Research, Inc., for the New York State Energy Research and Development Authority, Energy Authority Report No. 94-18, October 1994.

"Phase II Feasibility Study: Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley," Sierra Research Report No. SR94-09-02, prepared for the Greater Vancouver Regional District, September 1994.

"Cost-Effectiveness of Mobile Source Emission Controls from Accelerated Scrappage to Zero Emission Vehicles," Paper No. 94-TP53.05, presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, OH, June 1994.

"Investigation of MOBILE5a Emission Factors, Assessment of I/M Program and LEV Program Emission Benefits," Sierra Research Report No. SR94-06-05, prepared for American Petroleum Institute, June 1994.

"Cost-Effectiveness of the California Low Emission Vehicle Standards," SAE Paper No. 940471, 1994.

"Meeting ZEV Emission Limits Without ZEVs," Sierra Research Report No. SR94-05-06, prepared for Western States Petroleum Association, May 1994.

"Evaluating the Benefits of Air Pollution Control - Method Development and Application to Refueling and Evaporative Emissions Control," Sierra Research Report No. SR94-03-01, prepared for the American Automobile Manufacturers Association, March 1994.

"The Cost-Effectiveness of Further Regulating Mobile Source Emissions," Sierra Research Report No. SR94-02-04, prepared for the American Automobile Manufacturers Association, February 1994.

"Searles Valley Air Quality Study (SVAQS) Final Report," Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

"A Comparative Study of the Effectiveness of Stage II Refueling Controls and Onboard Refueling Vapor Recovery," Sierra Research Report No. SR93-10-01, prepared for the American Automobile Manufacturers Association, October 1993.

"Evaluation of the Impact of the Proposed Pole Line Road Overcrossing on Ambient Levels of Selected Pollutants at the Calgene Facilities," Sierra Research Report No. SR93-09-01, prepared for the City of Davis, September 1993.

"Leveling the Playing Field for Hybrid Electric Vehicles: Proposed Modifications to CARB's LEV Regulations," Sierra Research Report No. SR93-06-01, prepared for the Hybrid Vehicle Coalition, June 1993.

"Size Distributions of Trace Metals in the Los Angeles Atmosphere," *Atmospheric Environment*, Vol. 27B, No. 2, pp. 237-249, 1993.

"Preliminary Feasibility Study for a Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley Area," Sierra Research Report No. 92-10-01, prepared for the Greater Vancouver Regional District, October 1992.

"Development of Mechanic Qualification Requirements for a Centralized I/M Program," SAE Paper No. 911670, 1991.

"Cost-Effectiveness Analysis of CARB's Proposed Phase 2 Gasoline Regulations," Sierra Research Report No. SR91-11-01, prepared for the Western States Petroleum Association, November 1991.

"Origins and Control of Particulate Air Toxics: Beyond Gas Cleaning," in Proceedings of the Twelfth Conference on Cooperative Advances in Chemical Science and Technology, Washington, D.C., October 1990.

"The Effect of Gasoline Aromatics on Exhaust Emissions: A Cooperative Test Program," SAE Paper No. 902073, 1990.

"Estimation of the Impact of Motor Vehicles on Ambient Asbestos Levels in the South Coast Air Basin," Paper No. 89-34B.7, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"Benzene/Aromatic Measurements and Exhaust Emissions from Gasoline Vehicles," Paper No. 89-34B.4, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"The Impact of Diesel Vehicles on Air Pollution," presented at the 12th North American Motor Vehicle Emissions Control Conference, Louisville, KY, April 1988.

"Exhaust Benzene Emissions from Three-Way Catalyst-Equipped Light-Duty Vehicles," Paper No. 87-1.3, presented at the 80th Annual Meeting of the Air Pollution Control Association, New York, NY, June 1987.

"Trends in Emissions Control Technologies for 1983-1987 Model-Year California-Certified Light-Duty Vehicles," SAE Paper No. 872164, 1987.

This page intentionally left blank.

46_OP_LCFS_GE Responses (Page 234 - 242)

568. Comment: **James Lyons' Resume**

Agency Response: This is submittal one of six of James Lyon's resume. It does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

46_OP_LCFS_GE

17_OP_ADF_GE

Attachment B

Review of CARB Staff's Analysis of the GHG and Air Quality Impacts of the LCFS Regulation

In developing the proposed Low Carbon Fuel Standard (LCFS) regulation for re-adoption, CARB staff purports to have performed an analysis of the impacts that the regulation will have on emissions of both greenhouse gases and air pollutants. However, as is documented below, a review the CARB analysis demonstrates that the staff's analysis is incomplete and unsuitable for use in determining whether or not all adverse impacts have been identified and properly quantified, and all mitigation measures have been appropriately considered.

Summary of the CARB Staff Air Quality Analysis

On December 30, 2014, CARB staff released the proposed LCFS regulation language and the accompanying Initial Statement of Reasons (ISOR), Draft Environmental Analysis, and other supporting documents. Staff's analysis of the impact of the LCFS proposed for re-adoption is contained in Chapter IV of the ISOR as well as in Chapter 4.3. of the Draft Environmental Analysis. LCFS 46-239

In Table IV-2 of Chapter IV of the ISOR, CARB staff provides unsupported estimates of the reduction in GHG emissions associated with the LCFS regulation proposed for re-adoption. However, by CARB staff's own admission, the estimates presented in Table IV-2:

> …*do not include a reduction to eliminate the double counting of the Zero Emission Vehicle mandate, the federal Renewable Fuels Standard program, the Pavley standards, or the federal Corporate Average Fuel Economy program.* LCFS 46-240

Given that CARB staff has failed to estimate and report the GHG reduction benefits of the LCFS regulation proposed for re-adoption separately from other regulations that also seek to reduce GHG emissions from mobile sources, the Board and the public do not know the actual benefits expected to result from the regulation nor can alternatives to the LCFS regulation be properly evaluated by CARB staff.

Turning to the air quality analysis in Chapter IV of the ISOR, CARB staff provides a general discussion of emissions associated with transportation fuel production at California refineries, as well as ethanol, biodiesel, renewable diesel, and potential cellulosic ethanol facilities. Emission factors in, terms of pollutant emissions per year per million gallons of fuel produced, are provided for some facilities. CARB staff also provides an undocumented analysis of NOx and $PM_{2.5}$ emissions associated with "...*the movement of fuel and feedstock in heavy-duty diesel trucks and railcars*" with and LCFS 46-241 without the LCFS and ADF regulations in place. No other assessment of the air quality impacts associated with the LCFS is provided in the LCFS ISOR. LCFS 46-241 cont.

As noted above, the draft Environmental Analysis (EA) for the LCFS and ADF, which is Appendix D to both the LCFS and ADF ISORs, also addresses air quality in Chapter 4.3. Here, short term air quality impacts related to the construction of projects of various types related to the production and distribution of lower carbon intensity fuels under the LCFS are presented. There is, however, no analysis that indicates where these projects will be located within California, nor any quantitative assessment of the emission and environmental impacts beyond the following:

> *Based on typical emission rates and other parameters for abovementioned equipment and activities, construction activities could result in hundreds of pounds of daily NO_x and PM emissions, which may exceed general mass emissions limits of a local or regional air quality management district depending on the location of generation. Thus, implementation of new regulations and/or incentives could generate levels that conflict with applicable air quality plans, exceed or contribute substantially to an existing or projected exceedance of State or national ambient air quality standards, or expose sensitive receptors to substantial pollutant concentrations.*

LCFS 46-242

There is also a general discussion of potential approaches to mitigation, which CARB staff concludes are outside of the agency's authority to adopt. Ultimately, the draft EA concludes that the "short-term construction-related air quality impacts…associated with the proposed LCFS and ADF regulations would be potentially significant and unavoidable." LCFS 46-243

The draft EA also purports to assess the long-term impacts of the LCFS and ADF regulations, but addresses and attempts to quantify only potential increases in NOx emissions due to the use of biodiesel fuels, and concludes with CARB staff ultimately claiming that the long term impacts of the LCFS and ADF on air quality will be "beneficial." LCFS 46-244

Review of the CARB Staff Air Quality Analysis

As summarized above, the air quality related analyses performed by CARB staff regarding the proposed LCFS regulation are both limited and cursory. In order to demonstrate that this is in fact the case, one has to look no further than the air quality analysis CARB staff performed in 2009 to support the original LCFS rulemaking.[1] LCFS 46-245

[1] California Air Resources Board, Proposed Regulation to Implement the Low Carbon Fuel Standard, Volume I: Staff Report: Initial Statement of Reasons, March 5, 2009 and Volume II: Appendices, March 5, 2009. See in particular, Chapter VII of the ISOR and Appendix F.

The first point of note is that in the 2009 ISOR, CARB staff presents quantification of the GHG reductions expected from the LCFS occurring both in California and worldwide in Tables VII-1 and VII-2. While, those estimates have no relevance to the current rulemaking given the differences in the two regulations, fundamental changes in CARB's expectations with respect to how fuel producers will comply with a LCFS regulations, as well as the evolution of methodologies for estimating GHG emissions, provide clear evidence that the GHG emission benefits of the proposed LCFS can and should be explicitly quantified without any "double counting" of the benefits due to other regulatory programs. It should also be noted that in the 2009 ISOR, CARB staff also breaks down the GHG emission benefits expected from specific substitutes for gasoline and diesel fuel. LCFS 46-246

Turning to the air quality analysis itself, the lack of documentation provided precludes any detailed review of the accuracy of the assumptions and methodologies underlying the analysis or any effort to attempt to reproduce the staff's results. Given this lack of documentation, additional information was requested from CARB. As part of this request, Sierra Research pointed out that pursuant to the requirements of AB 1085, the agency had provided far more detailed information for other recent major rulemakings, including the Advanced Clean Cars program, than it released regarding the LCFS and ADF proposals. Unfortunately, CARB staff choose not to provide any additional information related to the analyses underlying the proposed LCFS and ADF regulations. LCFS 46-247

Another striking contrast which highlights the superficiality of the air quality analysis performed for the re-adoption of the LCFS can be seen in the treatment of potential emission impacts associated with the development of biofuel production facilities in California. These impacts are particularly important because the form of the LCFS regulation provides incentives to build biofuel production facilities in areas of California that violate federal National Ambient Air Quality standards, rather than in other states that are in compliance with those standards. The incentive for locating biofuel plants in California is to avoid GHG emissions from fuel and/or feed stock transportation which result in higher carbon intensity values. LCFS 46-248

As noted above, the air quality analysis for the re-adoption of the LCFS presented in section IV of the ISOR provides only estimates for existing California biofuel production facilities and the potential emissions of NO_x, PM_{10}, and volatile organic compounds (VOCs) associated with a hypothetical "northern California" cellulosic ethanol plant. In contrast, in the 2009 ISOR, staff provides a quantitative estimate of the overall number and types of new biofuel production facilities expected to be built in California (Table VII-6 of the 2009 ISOR) as well as a distribution of the number and type of plants expected to be built in eight of the state's air basins and a map showing expected locations. The increases in emissions of not only NO_x, PM_{10}, and VOC, but also carbon monoxide (CO) and $PM_{2.5}$ associated with these biodiesel production facilities were quantified by CARB staff (Table V11-10 of the 2009 ISOR). Again, although the data presented in the 2009 LCFS ISOR are irrelevant with respect to the current re-adoption of the LCFS regulation, the same level of detail and scope of the analysis performed by CARB staff in 2009 should have at a minimum been applied to the current LCFS air quality analysis. LCFS 46-249

Another issue noted with the air quality analysis performed for the re-adoption of the LCFS is related to emission impacts associated with "fuel and feedstock transportation and distribution." LCFS 46-250

The total impact of the LCFS and ADF on NOx and $PM_{2.5}$ emissions from these activities, which constitute a long term operational impact on air quality, are quantified in Table IV-16 of the ISOR. However, the documentation provided describing how the staff's analysis was performed is insufficient to allow one to either review or reproduce it. Further, these emissions are not addressed in the appropriate section of the draft EA. Given that staff estimates that the LCFS/ADF will increase these emissions, they should be identified and assessed as part of the draft EA, particularly given that staff has concluded that the LCFS/ADF impacts on long term air quality are beneficial without considering fuel and feedstock transportation and distribution emissions. The current analysis of these emissions also falls far short of the level of detail shown in the analysis of the same issue performed by CARB staff in the 2009 ISOR, as can be seen in Table VII-11 where impacts on VOC, CO, PM_{10}, and oxides of sulfur (SO_x) were reported by low CI fuel type. LCFS 46-250 cont.

Again, as noted above, the only issue addressed with respect to long term LCFS/ADF air quality impacts in the draft EA are potential NOx emission increases due to the use of biodiesel blends. LCFS 46-251 As discussed in detail elsewhere,[2] the analysis upon which the draft EA and its conclusions are based is fundamentally flawed. However, the air quality analysis in the draft EA is also incomplete in that it fails to address long term changes in motor vehicle emissions beyond those associated with biodiesel and renewable diesel. That such impacts should have been addressed for the current rulemaking can be seen from the CARB staff air quality analysis included in the 2009 ISOR and presentation, which included detailed estimates of motor vehicle impacts on VOC, CO, NOx, SOx, PM_{10}, and $PM_{2.5}$ (rather than just NOx and $PM_{2.5}$) as a function of vehicle and fuel type in Table VII-12. LCFS 46-252

In addition to the above, two other important issues are: 1) CARB staff's failure to even attempt to quantify construction emissions associated with biofuel production facilities in California after finding them to be potentially significant and unavoidable; and 2) to identify and quantify LCFS 46-253 potential emission increases associated with an increase in the number of tanker visits to California ports as the result of the ADF and LCFS regulations. With respect to the former, a California specific tool, CalEEmod,[3] is readily available that could have been used by CARB staff in estimating construction impacts form biofuel plants located in California. LCFS 46-254

With respect to the latter, it should be noted that although CARB staff concluded in the 2009 LCFS air quality analysis that there would be "little to no change to emissions at ports," that analysis predates the current proposal[4] regarding the assignment of CI to crude oil which are likely to encourage crude oil shuffling; as well as CARB staff assumptions regarding increases in assumed volumes of renewable diesel fuel potentially coming to California from production facilities in Asia, and the potential for direct importation of cane ethanol into California from Brazil. These factors will undoubtedly result in increased tanker operations in California waters the emission impacts of which can be estimated using the Emissions Estimation Methodology for Ocean-Going Vessels available on CARB's emission inventory website. According to this source, 1,919 visits by crude oil and petroleum product tankers are forecast for 2015 with roughly 50% percent of those trips involving southern California ports that are part of the South LCFS 46-255

---

[2] Declaration of James M. Lyons filed as comments to the ADF regulation.
[3] California Emissions Estimator Model, Users Guide, Version 2013.2, July 2013.
[4] See proposed section 95489, Title 17 CCR in LCFS ISOR Appendix A.

Coast air basin. The emissions estimated by CARB to be associated with one tanker visit to California are presented in Table 1. As shown, the tanker emissions associated with a single new visit far exceed the NOx, $PM_{2.5}$ and SOx significance thresholds. Given that multiple new tanker visits are likely to result from the LCFS and ADF regulations, these values demonstrate that CARB staff has failed to identify a potentially significant source that will created adverse air quality impacts in its draft EA.

LCFS 46-255 cont.

Table 1
Comparison of Tanker Emissions During A Single Visit to California with South Coast Air Quality Management District Air Quality Significance Thresholds

Pollutant	Significance Threshold (lbs/day)	Tanker Emissions (lbs)
NOx	55	7,700
VOC	55	283
PM_{10}	150	290
$PM_{2.5}$	55	283
SOx	150	1,780
CO	550	629

Attachment B-5

This page intentionally left blank.

46_OP_LCFS_GE Responses (Page 243 - 247)

569. Comment: **LCFS 46-239 through LCFS -46-255**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

46_OP_LCFS_GE

17_OP_ADF_GE

Attachment C

The Growth Energy Alternative to the Proposed LCFS Regulation is the Least-Burdensome Approach that Best Achieves the Project Objectives at the Least Cost That Must be Adopted

As part of the rulemaking process leading to CARB staff's proposed re-adoption of the LCFS regulation, staff was required to solicit and consider alternatives to the proposed regulation. Growth Energy submitted such an alternative. While CARB staff acknowledged that the Growth Energy alternative could provide equivalent reductions in GHG emissions, the agency rejected it from further consideration or analysis by stating only that it was insufficient to transition California to alternative, lower carbon intensity fuels. As discussed below, CARB staff's premise for rejecting the Growth Energy alternative is incorrect. Further, given that the Growth Energy Alternative achieves the same environmental benefits through reductions in GHG emissions as the LCFS regulation, likely at the same or lower cost, it should have been analyzed by CARB staff, in which case it would have to be adopted as the least-burdensome approach the best achieves the project objectives at the least cost. LCFS 46-256

<u>Background</u>

On May 23, 2014, CARB published a "Solicitation of Alternatives for Analysis in the LCFS Standardized Regulatory Impact Assessment" which is attached. On June 5, CARB published a response to a request from Growth Energy extending the deadline for the submission of alternatives from June 5, 2014 to June 23, 2014. On June 23, 2014, Growth Energy submitted an alternative regulatory proposal for the LCFS regulation (which is attached) to CARB in response to the agency's solicitation. On December 30, 2014, CARB staff published both the ISOR for the LCFS regulation as well as a document entitled "Summary of DOF Comments to the Combined LCFS/ADF SRIA and ARB Responses," which is Appendix E to the LCFS ISOR. Appendix E discusses the Growth Energy LCFS alternative and CARB's reason for its rejection.

The staff's assessment of the Growth Energy (GE) Alternative published in Appendix E of the LCFS ISOR is as follows (emphasis added): LCFS 46-257

> *The proposed alternative assumes that the exclusive goal of the LCFS proposal is to achieve GHG emissions reductions without regard to source. If that were the case, this would be a viable alternative to the LCFS and would be assessed in this analysis. It is likely true that the estimated GHG emissions reductions appearing in the 2009 LCFS Initial Statement of Reasons (California Air Resources Board, 2009) could be achieved by the AB 32 Cap-and-Trade Program, along with the other programs cited by Sierra Research and Growth Energy. The LCFS proposal, however, was designed to address the carbon intensity of transportation*

fuels. Transportation in California was powered almost completely by petroleum fuels in 2010. Those fuels were extracted, refined, and distributed through an extensive and mature infrastructure. Transitioning California to alternative, lower-carbon fuels requires a very focused and sustained regulatory program tailored to that goal. The other regulatory schemes the alternative would rely on are comparatively "blunt instruments" less likely to yield the innovations fostered by the LCFS proposal. In the absence of such a program, post-2020 emissions reductions would have to come from a transportation sector that would, in all likelihood, have emerged from the 2010-2020 decade relatively unchanged.

In the absence of an LCFS designed to begin the process of transitioning the California transportation sector to lower-carbon fuels starting in 2010, post-2020 reductions would be difficult and costly to achieve. This is why the primary goals of the LCFS are to reduce the carbon intensity of California fuels, and to diversify the fuel pool. A transportation sector that achieves these goals by 2020 will be much better positioned to achieve significant GHG emissions reductions post 2020.

LCFS 46-257 cont.

ARB is required to analyze only those alternatives that are reasonable and that meet the goals of the program as required by statute. An initial assessment of the program indicates the goals of the LCFS proposal can be achieved by keeping the program "…separate of the AB 32 Cap-and-Trade system initially (at least first 10 years) in order to stimulate innovation and investment in low-GWI [global warming intensity] fuel (or transportation) technologies."[16] Due to the strong justifications that the Cap-and-Trade program alone generates neither the CI reductions nor fuel in the transportation sector, this alternative will not be assessed in this document.

Reference 16 in the above citation is given as:

A Low-Carbon Fuel Standard for California, Part 2: Policy Analysis – FINAL REPORT, University of California Project Managers: Alexander E. Farrell, UC Berkeley; Daniel Sperling, UC Davis. Accessed: 7-15-2015 http://www.energy.ca.gov/low_carbon_fuel_standard/

Discussion

Given that there is no analysis or other support provided by CARB staff for the assertions it makes in rejecting the Growth Energy alternative other than the one reference, which dates to 2007—before either the original LCFS or Cap-and-Trade regulation were adopted was reviewed. The discussion of interactions between a LCFS program with AB32 regulations from the reference is provided below. As can be determined by the reader, the discussion was written before the AB32 regulations were adopted, and the basic concern expressed is that the lower cost of achieving the same GHG reductions from a broader program will be lower than the cost of doing the same from the LCFS

LCFS 46-258

program. Further, the concern expressed regarding lifecycle emission under the LCFS was explicitly addressed in the Growth Energy alternative.

5.2 Interactions with AB32 regulations

RECOMMENDATION 16: The design of both the LCFS and AB32 polices must be coordinated and it is not possible to specify one without the other. However, it is clear that if the AB32 program includes a hard cap, the intensity-based LCFS must be separate or the cap will be meaningless. Including the transport sector in both the AB32 regulatory program and LCFS will provide complementary incentives and is feasible. CARB will soon be developing regulations under AB32 to control GHG emissions broadly across the economy, most likely through a cap-and-trade system plus a set of regulatory policies. Thus, emissions from electricity generation, oil production, refining, and biofuel production are likely to be regulated directly under AB32. These energy production emissions are "upstream" in a fuel's life cycle (while emissions from a vehicle are "downstream"). The recent Market Advisory Committee report recommends including all CO2 emissions from transportation, including tailpipe emissions.

LCFS 46-258

The LCFS regulates consumption emissions—the full life cycle emissions associated with products consumed in California, while it is expected that sector-specific emission caps will be imposed by AB 32 on production emissions—the emissions that are directly emitted within the borders of the state. The different types of boundaries used by these regulations causes certain upstream emissions to be double regulated under the LCFS and AB32. However, the potential for double regulation only applies to fuel production processes in the state of California or other jurisdictions where legislation similar to AB 32 also applies. We agree with the Market Advisory Committee that the LCFS and AB32 regulations will provide complementary incentives and that transportation emissions of GHGs should be included in the AB32 program.

There is no inherent conflict between the LCFS and AB32 caps; both are aimed at reducing GHG emissions and stimulating innovation in low-carbon technologies and processes. However, there are some differences. Most importantly, the LCFS is designed to stimulate technological innovation in the transportation sector specifically, while the broader AB32 program will stimulate technological innovation more broadly. The concerns associated with market failures and other barriers to technological change in the transportation sector (discussed in Section 1.3 of Part 1 and Section 2.3 of Part 2) are the motivation for adopting the sector-specific LCFS. These concerns suggest separating the LCFS from the AB32 emission caps.

The second key difference is that as a product standard using a lifecycle approach, the LCFS includes emissions that occur outside of the state such as *those associated with biofuel feedstock production and the production of imported crude oil. These emissions will not be included in the AB32 regulations.*

The third difference is in expected costs. In the absence of transaction costs and other market imperfections, economic theory suggests that a broader cap-and-trade program will be less costly than a narrower one. By allowing more sectors and more firms to participate in a market for emission reductions, one reduces the cost to achieve a given level of emission reductions -- suggesting that the LCFS be linked to the broader AB 32 regulatory system. In addition, commercially available low-carbon options exist in the electricity and other sectors, but not in transportation fuels (see Part 1 of this study, Section 1.3).

The specific regulations and market mechanisms used to implement AB32 are not yet determined, so it is not possible at this time to specify how the LCFS should interact with them. The ARB should carefully consider the differences in incentives and constraints that the combination of rules will create.

LCFS 46-258 cont.

Returning to the issue of diversification of the transportation fuel sector, CARB concerns are directly refuted by Growth Energy's submission. As noted on pages 9 and 10, ethanol will be added to California gasoline, and renewable diesel and biodiesel will be blended into California diesel fuel as the result of the federal RFS program. The range of fuels and feedstocks from which they are produced under the RFS will be diverse. For example, the following fuel/feedstock pathways, among others, are currently recognized by U.S. EPA under the RFS:[1,2,3,4,5]

- Ethanol from
  - Corn
  - Sugar cane
  - Grain sorghum
  - Celluosic materials
- Biodiesel from
  - Camelina oil
  - Soy bean oil
  - Waste oils, fats and greases
  - Corn oil
  - Canola/rapseed oil
- Renewable diesel from
  - Waste oils, fats and greases

LCFS 46-259

[1] EPA-420-F-13-014
[2] EPA-420-F-14-045
[3] EPA-420-F-12-078
[4] EPA-420-F-11-043
[5] EPA-420-F-10-007

- Renewable gasoline from
  - Crop residue and municipal solid waste

- Renewable natural gas from
  - Landfills
  - Digesters

LCFS 46-259 cont.

As can be seen from Appendix B to the LCFS ISOR, these are many of the fuels that CARB staff also expects to be used in California under the LCFS. Similarly, electricity and hydrogen will be used as transportation fuels in California given the states regulatory mandates for the production of vehicles that operate on these fuels under the Advanced Clean Cars program. Further, in later years these fuels are expected to be required in heavy-duty vehicles as CARB adopts regulations under its proposed Sustainable Freight Transport Initiative, the purpose of which is stated by CARB staff as follows:

> *The purpose of the Strategy is to identify and prioritize actions to move California towards a sustainable freight transport system that is characterized by improved efficiency, zero or near-zero emissions, and increased competitiveness of the logistics system.*

It should also be noted that fuel providers in California will still be incentivized to provide these fuels in California under the Growth Energy alternative in order to reduce the number of GHG credits they will be required to retire under cap-and-trade program. LCFS 46-260

Finally, on pages 15 and 16, Growth Energy's proposal for addressing the loss of upstream emission benefits from the LCFS regulation is explicitly discussed.

Given that the Growth Energy alternative:

1. Provides, as determined by CARB staff, the same GHG reductions as the LCFS regulation; and

2. Is expected to result in lower costs of compliance than the LCFS.

CARB must adopt the Growth Energy alternative as it better achieves the stated project objectives in an equally cost-effective manner.

This page intentionally left blank.

46_OP_LCFS_GE Responses (Page 248 - 252)

570. Comment: **LCFS 46-256**

The commenter alleges that their proposed alternative is a more effective solution than the LCFS regulation.

Agency Response: See response to **LCFS 32-2, LCFS 46-65, LCFS 46-217,** and **LCFS 46-226**.

571. Comment: **LCFS 46-257 through LCFS 46-260**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

46_OP_LCFS_GE

17_OP_ADF_GE

Attachment D

Review of CARB Staff Estimates of NOx Emission Increases Associated with the Use of Biodiesel in California Under the Proposed ADF Regulation

In developing the proposed Alternative Diesel Fuel (ADF) regulation, CARB staff has performed a statewide analysis of the increase in NOx emissions that is currently occurring in California due to the use of biodiesel, as well as the increases in NOx emissions that can be expected in the future due to the continued use of biodiesel in California under the proposed ADF regulation. As documented below, a review of the CARB staff analysis performed by Sierra Research demonstrates that the staff's analysis is fatally flawed and cannot be relied upon. Given this, Sierra Research has performed an analysis, also documented below, that demonstrates there will be substantial increases in NOx emissions if the ADF regulation is implemented as proposed. The significance in the NOx emissions increase associated with the use of biodiesel under the proposed ADF is clear given the dramatic reductions which CARB, the South Coast Air Quality Management District, and the San Joaquin Air Pollution Control District are seeking given their "extreme" non-compliance status with respect to the federal National Ambient Air Quality Standard for ozone.[1] This significance is also reinforced by a comparison of the estimated increase in NOx emissions from biodiesel under the proposed ADF regulation with the benefits of proposed and adopted NOx control measures intended for implementation on a statewide basis as well as in the South Coast and San Joaquin Valley air basins, respectively. ADF 17-24

<u>Review of the CARB Staff Analysis</u>

On December 30, 2014, CARB staff released the proposed ADF regulation language and the accompanying Initial Statement of Reasons (ISOR), technical and economic support information, and draft environmental analysis. Staff's analysis of the impact of the proposed ADF regulation on NOx emissions and supporting information and assumptions are contained in Chapters 6 and 7 of the ISOR, as well as Appendix B entitled "Technical Supporting Information."

The first issue that was identified with the staff's emissions analysis is that the information and data supplied by CARB staff are insufficient to determine exactly how the analysis was performed. Specifically, CARB staff provides no source for the values in Table B-1 labeled "Emission Inventory (Diesel TPD)," which are key to the analysis. As illustrated below, a clear understanding of what diesel sources (e.g., on-road heavy-duty, non-road, marine, locomotives, etc.) are included in the "inventory" is critical to assessing the accuracy of the staff's analysis. ADF 17-25

---

[1] It should be noted that the CARB statewide analysis fails to provide any estimate of the impacts of increased NOx emissions from the ADF regulation in these air basins, where the agency has stated that massive reductions in NOx emissions are required to achieve compliance with federal air quality standards.

Given the lack of documentation regarding the source of the diesel emission inventory values, additional information regarding this analysis as well as other analyses associated with the ADF and Low Carbon Fuel Standard (LCFS) rulemakings was requested. As part of this request, Sierra Research pointed out that pursuant to the requirements of AB 1085, the agency had provided far more detailed information for other recent major rulemakings, including the Advanced Clean Cars program, than it released regarding the LCFS and ADF proposals. Unfortunately, CARB staff choose not to provide any additional information related to the analyses underlying the proposed LCFS and ADF regulations.[2]

Despite the lack of all the information necessary to fully review the CARB staff analysis, it was possible to discern some key assumptions and the general methodology that was applied. The following key assumptions were identified:

1. Actual biodiesel use and the total demand for diesel fuel and substitutes in California will exactly match that forecast by CARB staff in the "illustrative compliance scenarios" developed as part the LCFS rulemaking;[3] ADF 17-26

2. Actual renewable diesel use in California will exactly match that forecast by CARB staff in the "illustrative compliance scenarios" developed as part the LCFS rulemaking;[2]

3. Forty percent of renewable diesel delivered to California will be used directly by refiners to comply with the requirements of CARB's existing diesel fuel regulations[4] while the remaining 60% will be blended into fuel that complies with the diesel fuel regulations downstream of refineries;

4. The use of biodiesel up to the B20 level in New Technology Diesel Engines[5] (NTDEs, which employ exhaust aftertreatment systems to reduce NOx emissions) will not result in any increase in NOx emissions;

5. The use of biodiesel in heavy-duty diesel engines other than NTDEs—which are referred to by CARB staff as "legacy vehicles"—will increase NOx linearly with increasing biodiesel blend content, up to a 20% increase for B100;

---

[2] See attached emails from Jim Lyons of Sierra to Lex Mitchel and other CARB staff from January 2015.
[3] These are presented in Appendix B to the LCFS ISOR.
[4] Sections 2281 to 2284, Title 13, California Code of Regulations.
[5] Proposed section 2293.3 Title 13 CCR (see Appendix A to the LCFS ISOR) defines a New Technology Diesel Engines as:

a diesel engine that meets at least one of the following criteria:

(A) Meets 2010 ARB emission standards for on-road heavy duty diesel engines under section 1956.8.
(B) Meets Tier 4 emission standards for non-road compression ignition engines under sections 2421, 2423, 2424, 2425, 2425.1, 2426, and 2427.
(C) Is equipped with or employs a Diesel Emissions Control Strategy (DECS), verified by ARB pursuant to section 2700 et seq., which uses selective catalytic reduction to control Oxides of Nitrogen (NOx).

6. The blending of renewable diesel downstream of refineries will reduce NOx emissions from legacy vehicles, with each 2.75 gallons of renewable diesel blended offsetting the emissions increase associated with each gallon of biodiesel used; and

7. During the period from 2018 to 2020, 30 million gallons of biodiesel will be blended to the B20 level for use in legacy vehicles each year, and will therefore be subject to the mitigation requirements of the proposed ADF regulation and will not cause an increase in NOx emissions. Furthermore, this volume will increase to 35 million gallons per year from 2021 to 2023.

Based on the above assumptions, CARB staff followed the methodology steps outlined below for estimating biodiesel impacts.

1. The fraction of legacy vehicles in a given year is determined by subtracting the percentage of vehicle miles traveled by on-road heavy-duty vehicles with NTDEs from 100%.

2. The fraction of legacy vehicles from Step 1 is multiplied by the total volume of biodiesel assumed to be consumed in a given year to yield the number of gallons of biodiesel used in legacy vehicles in that year.

3. For years 2018 and later, the amount of biodiesel assumed to be sold as emissions-mitigated B20 in a given year is subtracted from the total volume of biodiesel used in legacy vehicles in that year.

4. The total volume of renewable diesel assumed to be sold in a given year is multiplied by the percentage of legacy vehicles in that year and then multiplied by 0.6 to account for renewable diesel used in refineries to yield the amount of renewable diesel creating reductions in NOx emissions from legacy vehicles in that year.

5. The amount of renewable diesel used in legacy vehicles is then divided by 2.75 to determine the number of gallons of biodiesel for which NOx emissions have been offset for that year.

6. The number of gallons of biodiesel for which NOx emissions have been offset, as determined in Step 5, is then subtracted from the amount of biodiesel used in legacy vehicles, as determined in Step 3, to yield the total number of gallons of biodiesel used in legacy vehicles that cause increased NOx emissions for that given year.

7. The biodiesel volume from Step 6 is multiplied by the assumed NOx increase of 20% for B100 and then divided by the total volume of diesel fuel forecast to be used in that year to get the percentage increase in diesel emissions for that year.

ADF 17-26
cont.

8. The value from Step 7 is multiplied by the assumed Diesel Emissions inventory for that year to yield the final estimate of increased NOx emissions due to biodiesel in units of tons per day for the entire state of California.

ADF 17-26 cont.

Using the above methodology, CARB staff estimates that use of biodiesel in California led to a 1.36 ton per day increase in NOx emissions in 2014, and that the proposed ADF regulation will reduce the magnitude of that increase through 2023 down to 0.01 ton per day.[6]

The review of the staff's emission analysis identified two major issues in addition to the lack of documentation regarding how the diesel "Emission Inventory" values used by staff were developed:

1. Assuming that biodiesel use in NTDEs at levels up to B20 will not increase NOx emissions; and ADF 17-27

2. Assuming that biodiesel NOx emissions are offset by the use of renewable diesel fuel. ADF 17-28

Beginning with NTDEs, it has been demonstrated[7] that the available data indicate not only that NOx emissions from NTDEs will increase with the use of biodiesel in proportion to the amount of biodiesel present in the blend, but also that the magnitude of the increase on a percentage basis will be much greater than that observed for "legacy vehicles." At the B20 level where CARB staff assumed that there will be no NOx increase, the best current estimate is that NTDE NOx emissions will be increased by between 18% and 22%. CARB staff's failure to account for increased NOx emissions from NTDEs renders the staff's emission analysis meaningless in terms of assessing the adverse environmental impacts of the proposed ADF regulation. Another problem with CARB staff's treatment of NTDEs is that they have incorrectly assumed that the penetration of NTDEs into the on-road fleet is equal to that in the non-road fleet. NTDE penetration rates into the non-road fleet will be delayed due to the later effective date of the Tier 4 Final standards, relative to the 2010 on-road standards, and by the fact that while newer trucks dominate on-road heavy-duty vehicle operation, that effect does not occur in the non-road vehicle population.

ADF 17-27 cont.

Similarly, there are fundamental flaws with CARB staff's assumption that the use of renewable diesel will offset increased NOx emissions due to the use of biodiesel. First, it must be noted that there is nothing in either the proposed ADF regulation or the proposed LCFS regulation that mandates the use of any volume of biodiesel in California, much less the use of the exact ratio of renewable diesel to biodiesel assumed by CARB staff in its emissions analysis. Second, based on a review of the ADF and LCFS ISORs and supporting materials, there is no apparent basis for the staff's assumption that 40% of renewable diesel used in California will be used by refiners to aid in compliance with CARB's existing diesel fuel regulations, and that 60% will be blended downstream of refineries. To the extent that fuel producers choose to blend renewable diesel in California, one would expect them to do so by purchasing renewable diesel for use at their

ADF 17-28 cont.

---

[6] Table B-1, Appendix B of the ADF ISOR.
[7] "NOx Emission Impacts of Biodiesel Blends," Rincon Ranch Consulting, February 17, 2015.

refineries where they can benefit from the other desirable properties of this fuel beyond its low carbon intensity (CI) value (e.g., high cetane number and fungibility with diesel fuel at all blend levels), rather than by purchasing LCFS credits generated by downstream blenders of renewable diesel fuel.

ADF 17-28 cont.

To illustrate the magnitude of the significance of CARB's flawed assumptions regarding NTDEs and renewable diesel, if one simply and extremely conservatively assumes that NTDE NOx increases will be the same on a percentage basis as legacy vehicles and eliminates the NOx offsets assumed from renewable diesel, the NOx increases expected from biodiesel increase from 1.35 tons per day statewide in 2014 to approximately 3.44 tons per day—a factor of about 2.65. For 2023, estimated NOx emission increases due to biodiesel rise to about 0.87 tons per day, or about 100 times more than the 0.01 tons per day CARB staff estimated. However, as documented below, a more rigorous analysis indicates that far greater increases in NOx emissions are likely.

ADF 17-29

Detailed Analysis of Increases in NOx Emissions from Biodiesel Use

Given the flawed assumptions and undocumented sources of data associated with CARB staff's analysis of the emission impacts associated with biodiesel under the proposed ADF, Sierra Research undertook a detailed analysis of the same issue. The first step in this analysis was identifying the most current methods and tools for estimating NOx emissions from on- and non-road diesel engines operating in California for which biodiesel use is expected to increase NOx emissions.

ADF 17-30

On-Road Heavy-Duty Diesel Vehicles – On December 30, 2014, CARB officially released the final version of the EMFAC2014 model for estimating on-road emissions in California, which has replaced the now obsolete EMFAC2011 model that CARB staff relied upon for certain elements of its emission analysis. In releasing EMFAC2014, CARB staff noted a number of changes intended to improve the accuracy of the model relative to EMFAC2011. First, EMFAC2014 accounts for CARB's adoption of recent mobile source rules and regulations that lower future NOx emission estimates, including the Advanced Clean Cars program and the 2014 Amendments to the Truck and Bus Regulation. In addition, EMFAC2014 now estimates off-cycle emissions of SCR-equipped vehicles (i.e., NTDEs) by reflecting higher NOx emissions during low speed operation and cold starts.[8]

Given the above, Sierra selected EMFAC2014 for estimating NTDE emissions directly in this assessment. It was used to generate annual average NOx emissions, in tons per day, for the South Coast and San Joaquin Valley Air Basins, and the entire state for the years 2015, 2020, and 2023. Emission estimates were obtained for light-heavy-duty, medium-heavy-duty, and heavy-heavy-duty trucks, as well as school, urban, and transit buses. Output by "model year" was used to differentiate NOx emissions of legacy vehicles from those of NTDEs, which were defined as 2010 and later model-year vehicles consistent with the definition in proposed section 2293.2 Title 13, CCR (see Appendix A to the LCFS ISOR).

[8] Email from ARB EMFAC2014 Team, November 26, 2014.

Off-Road Diesel Equipment and Engines – The process of estimating emissions from off-road equipment and engines in California is much less straightforward than for on-road vehicles, as the most recent CARB models have been separated by equipment type and updated at various points in time as part of the rulemaking process associated with the development of regulations for different source categories.

In addition to having been developed and last updated at different points in time, some of the methodologies do not output data with sufficient detail (e.g., emissions by engine model year) to differentiate between "legacy vehicles" and NTDEs, which, in the case of off-road sources, are defined by CARB staff in proposed section 2293.2 Title 13 CCR as being compliant with Tier 4 final emission standards for non-road compression ignition (i.e., diesel) engines under sections 2421, 2423, 2424, 2425, 2425.1, 2426, and 2427 Title 13 CCR.[9] The effective dates of these standards vary as a function of engine power rating, as shown in Table 1. It should be noted that compliance with the Tier 4 Final standards by engines below 50 horsepower in general does not require the use of the SCR technology[10] that CARB has used to define "NTDEs." Therefore, all engines in this category were assumed to respond to biodiesel in the same way as legacy vehicles, despite the fact that they meet Tier 4 final standards and are technically classified as NTDEs by CARB under the ADF regulation. As discussed below, this again reduced the magnitude of the biodiesel NOx impact.

Table 1
Effective Dates of Tier 4 Final Standards

Horsepower Range	Model Year
50-75	2013
76-175	2015
176-750	2014
Over 751	2015

Table 2 summarizes current state of CARB inventory models and methodologies for off-road diesel emission sources by equipment/engine sector[11] and indicates which outputs have sufficient detail to differentiate between emissions from legacy vehicles and NTDEs. As shown, only the general off-road equipment (construction, industrial, ground support, and oil drilling equipment), cargo handling equipment, and agricultural equipment sectors could be included in the Sierra analyses for the South Coast and San Joaquin Valley Air Basins. For the statewide inventory, it was possible to include transportation refrigeration units (TRUs) as well. Given that all diesel emission categories could not be included in the Sierra analysis, it should be noted that the results of the analysis presented below are conservative in that they do not account for the full magnitude of the increase in NOx emissions related to biodiesel use in California.

[9] See ISOR Appendix A.
[10] See *http://www.arb.ca.gov/diesel/tru/tru.htm#mozTocId341892.*
[11] All models can be downloaded at *http://www.arb.ca.gov/msei/categories.htm* .

The CARB off-road emissions inventory tools were configured to include the impacts of the most recent regulatory actions in each sector, and were executed to provide estimates of annual average day NOx emissions for both legacy and NTDE vehicles for calendar years 2015, 2020, and 2023 occurring in the South Coast and San Joaquin Valley Air Basins, as well as the entire state.

Key Assumptions: The Sierra analysis of the emission impacts of biodiesel use in California relies on the following two key assumptions:

1. B5 will be in use on a statewide basis in 2015, 2020, and 2023;

2. At the B5 level, NOx emissions from legacy vehicles will be increased by 1%, and by 5% from NTDEs.

Table 2
Summary of Current California Off-Road Diesel Emission Inventory Methodologies

Category	CARB Model/Database Tool	Capable of Differentiating Legacy Vehicle and NDTE Emissions
In-Use Off-Road Equipment	2011 Inventory Model	Yes
Cargo Handling Equipment	2011 Inventory Model	Yes
Transportation Refrigeration Units	2011 TRU Emissions Inventory	Yes – but not capable of estimating emissions by air basin
Agricultural Equipment	OFFROAD2007	Yes
Stationary Engines	2010 StaComm Inventory Model	No
Locomotives	NA	No
Commercial Harborcraft	2011 CHC/CA Crew and Supply Vessel/CA Barge and Dredge Inventory Databases	No
Ocean-Going Vessels	2011 Marine Emissions Model	No

The assumption regarding B5 was based on the fact that it represents the highest blend allowed under the ADF without mitigation, at least during the summer months. That this assumption is reasonable can be seen by comparing CARB's current and previous assumptions of biodiesel use: in the current LCFS compliance scenario,[3] the staff assumes a range from about B3 in 2015 to about B4 in 2020; in 2009,[12] the staff assumed approximately B1 in 2015 and B5 in 2020; and

[12] CARB, Proposed Regulation to Implement the Low Carbon Fuel Standard, Volume II, Appendices, March 5, 2009.

in 2011,[13] approximately B10 in 2015 and B20 in 2020 were assumed. Furthermore, the Sierra results can be scaled to reflect lower or higher non-mitigated biodiesel levels by multiplying them by the ratio of the assumed biodiesel level to B5.

The assumptions of a 1% and 5% increase at B5 for legacy vehicles and NTDEs, respectively, are based on the analysis of Rincon Ranch Consulting,[7] where 5% represents the mid-point of the range of estimates.

Diesel Emission Inventory and Biodiesel Impacts

The results of the Sierra analysis for the statewide diesel inventory for 2015, 2020, and 2023 are presented in Table 3 along with the undocumented values published by CARB staff.[6] As shown, the Sierra values are lower than those used by CARB staff. This is expected to some degree given that the Sierra analysis does not include, as explained above, some diesel source categories; however, the difference cannot be reconciled given the lack of information made available by CARB staff regarding its analysis.

Table 3
Statewide Diesel Emissions tons/day

	2015	2020	2023
Sierra Analysis	621	436	277
CARB Table B-1, Appendix B ADF ISOR	863	634	496

Table 4 compares the results of Sierra's analysis with the results of the CARB staff's analysis. As shown, the differences are large and are due primarily to two factors: 1) the staff's assumption regarding biodiesel impacts on NTDE NOx emissions, which is contradicted by the available data; and 2) the differences in the assumed levels of biodiesel use. The impact of the latter difference can also be seen in the results presented in Table 4, where results from the Sierra analysis scaled to reflect the lower biodiesel use rates assumed by CARB staff are presented. Again, even with this adjustment, the results of the Sierra analysis indicate much greater NOx impacts under the proposed ADF. Finally, it should be recalled that because of limitations with CARB's emission inventory methods for off-road sources, not all sources of diesel emissions that could be impacted by biodiesel use under the ADF have been accounted for, and the actual impacts will be greater than those shown in Table 4. ADF 17-31

[13] CARB, Low Carbon Fuel Standard 2011 Program Review Report, December 8, 2011.

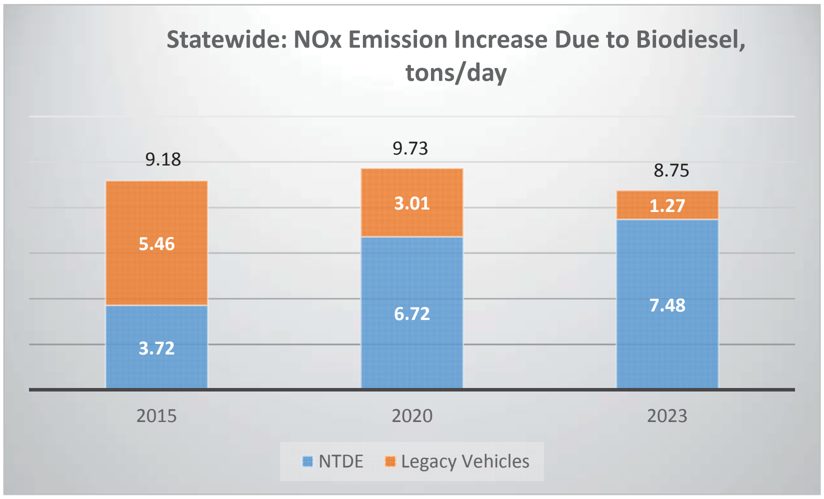
Table 4 Statewide Increase in NOx Emissions Due to Biodiesel tons/day			
	2015	2020	2023
Sierra Analysis – B5	9.18	9.73	8.75
Sierra Analysis at CARB Assumed Biodiesel Levels from Table B-1	4.70	7.15	6.15
CARB Table B-1, Appendix B ADF ISOR	1.29	0.39	0.01

ADF 17-31 cont.

The results of the Sierra analysis are shown graphically in Figures 1a through c for the entire state as well as the South Coast and San Joaquin air basins, respectively. These figures also show the relative contributions of legacy vehicles and NTDEs to the total estimated for each area and year. As shown, the contributions of NTDEs to increased NOx emissions are substantial in 2015, and dominate the impacts in 2020 and 2023. Further data supporting these results are provided in Tables 6 through 8 at the end of this attachment.

ADF 17-32

Figure 1a
Results of Sierra Analysis of Statewide NOx Increases Due to Biodiesel Use under the Proposed ADF Regulation



Attachment D-9

Figure 1b
Results of Sierra Analysis of South Coast Air Basin NOx Increases Due to Biodiesel Use under the Proposed ADF Regulation

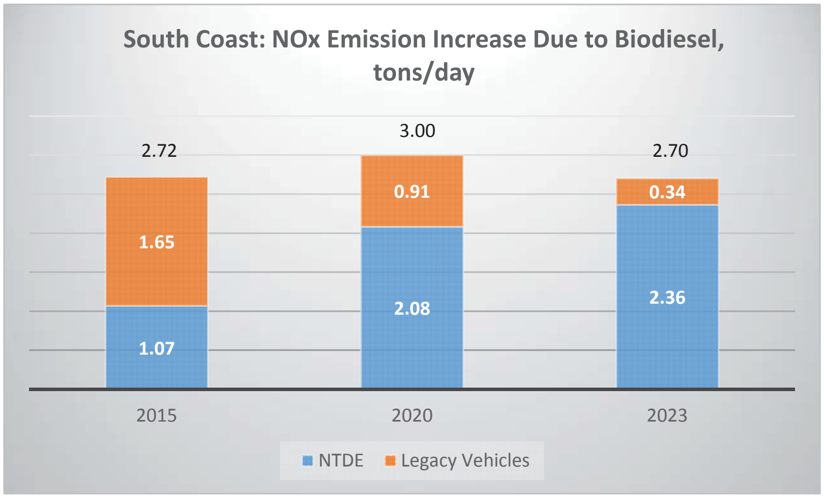
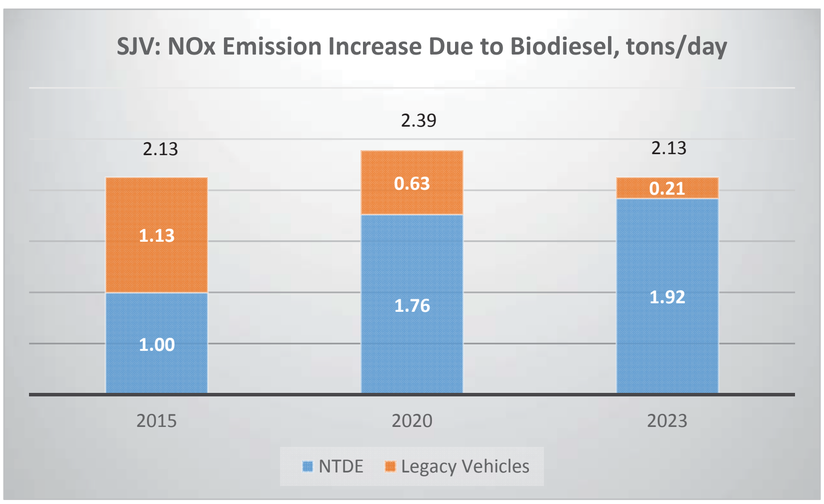


Figure 1c
Results of Sierra Analysis of San Joaquin Valley Air Basin NOx Increases Due to Biodiesel Use under the Proposed ADF Regulation



ADF 17-32 cont.

Attachment D-10

As indicated above, the Sierra analysis uses the results from an assessment of existing data regarding biodiesel impacts on NOx emissions from NTDEs performed by Rincon Ranch Consulting. The key findings of that analysis are shown in Figure 2 (reproduced with permission), which establishes that the available data for biodiesel impacts on NTDE NOx emissions follow a linear relationship just as they do for legacy vehicles.

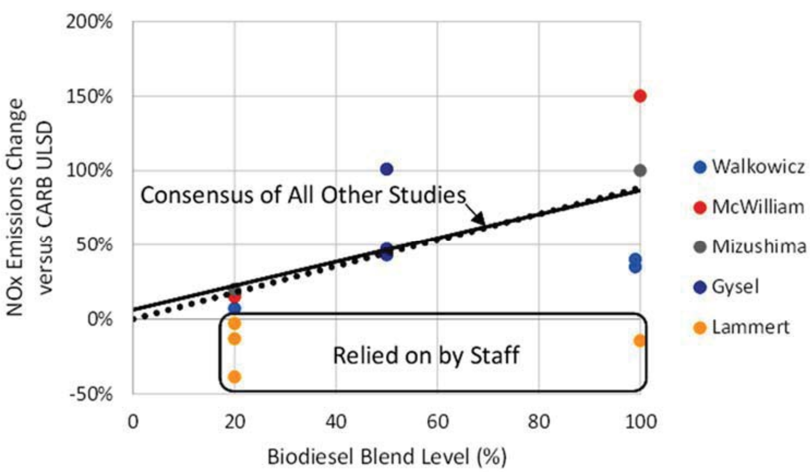
In contrast to the data upon which the Sierra analysis rests, the basis of CARB staff's assumption regarding biodiesel impacts on NTDE emissions rests on the following excerpts from the ADF ISOR:

> *Research also indicates that the use of biodiesel up to blends of B20 in NTDEs results in no detrimental NOx impacts. Therefore, the proposed regulation also includes a process for fleets and fueling stations to become exempted from the in-use requirements for biodiesel blends up to B20 as long as they can demonstrate to the satisfaction of the Executive Officer that they are fueling at least 90 percent light or medium duty vehicles or NTDEs.*
>
> *Staff proposes to take a precautionary approach and in the light of data showing there may be a NOx impact at higher biodiesel blends but not at lower biodiesel blends, staff is limiting the conclusion of no detrimental NOx impacts in NTDEs to blends of B20 and below.*

Clearly, if CARB staff were truly taking a "precautionary approach" to the issue of biodiesel impacts on NTDE NOx emissions, they would also rely on the results of the analysis summarized in Figure 2.

ADF 17-32 cont.

Figure 2
The Impact of Biodiesel on NTDE NOx Emissions



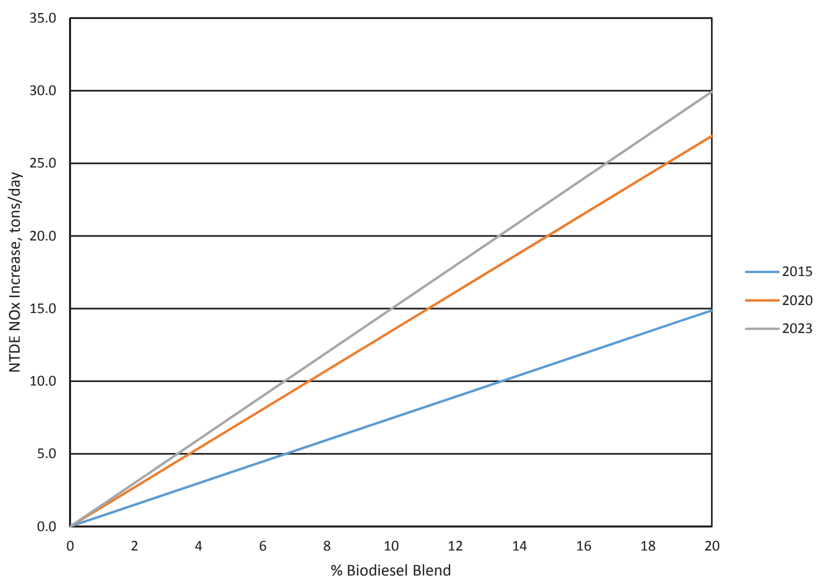
Attachment D-11

The assumption made by CARB staff regarding biodiesel impacts on NDTE NOx emissions has additional ramifications beyond those shown above by the results of the Sierra analysis. As set forth in proposed section 2293.6, Title 13 CCR (see ISOR Appendix A), the mitigation requirements for biodiesel up to the B20 level will be dropped when NTDEs account for 90% of heavy-duty vehicle miles travelled in California (expected by staff to be 2023) and use of B20 without mitigation will be allowed in all fleets of centrally fueled vehicles comprised of more than 90% NTDEs. Given this, use of unmitigated biodiesel blends of up to B20 in NTDEs may be common under the proposed ADF regulation. The potential significance of these provisions of the staff proposal with respect to the potential for NOx increases is shown in Figures 3a through 3c, which illustrate the estimated increases in NDTE NOx emissions as a function of biodiesel content up to B20 for the state, the South Coast air basin, and the San Joaquin Valley air basins, respectively, for the years 2015, 2020, and 2023.

As shown, the potential NOx increases from extensive use of higher level biodiesel blends in NTDEs is quite large. Furthermore, although the results shown in Figures 3a through 3c are maximum potential impacts, they can again be simply scaled for other cases. For example, in order to estimate statewide NOx increases from B20 use in 50% rather than 100% of NTDEs, one would simply multiply the value of 30 tons per day by 0.5 (50/100) to arrive at a 15 ton per day increase. Finally, it should be noted that the values in Figures 3a through 3c reflect both on- and off-road NTDEs as described above for the Sierra analysis of B5 impacts.

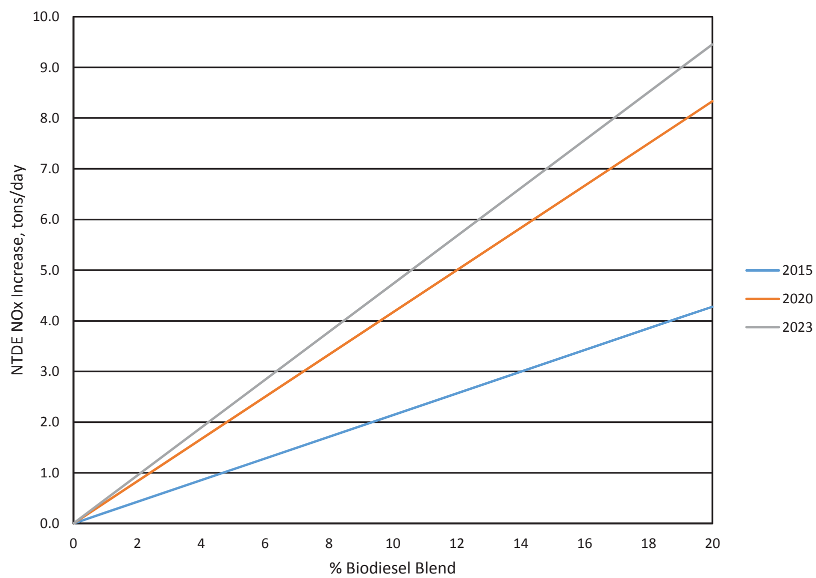
ADF 17-33

Figure 3a
Results of Sierra Analysis of Statewide NOx Increases Due to Biodiesel Use in All NTDEs under the Proposed ADF Regulation



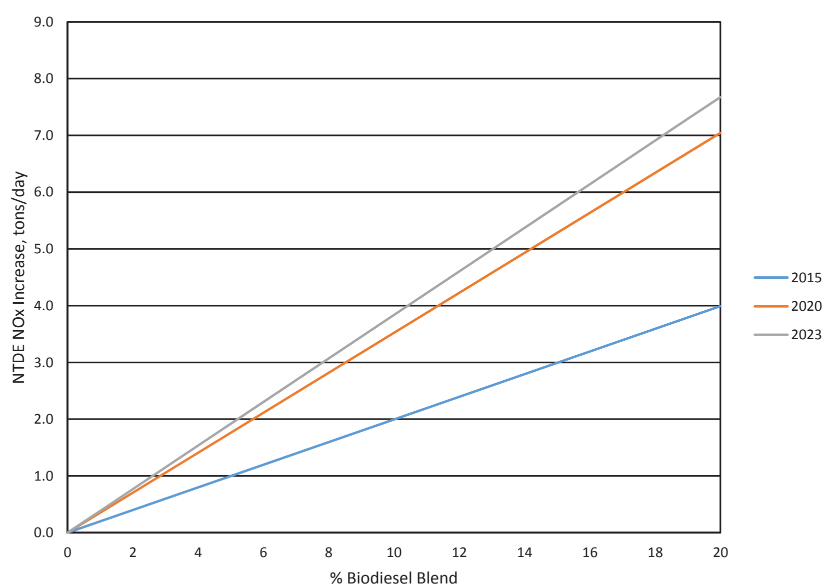
Attachment D-12

Figure 3b
Results of Sierra Analysis of South Coast Air Basin NOx Increases Due to Biodiesel Use in All NTDEs under the Proposed ADF Regulation



ADF 17-33 cont.

Figure 3C
Results of Sierra Analysis of San Joaquin Valley Air Basin NOx Increases Due to Biodiesel Use in All NTDEs Under the Proposed ADF Regulation



Attachment D-13

Significance of Increases in NOx Emissions Caused by Biodiesel

As illustrated above, the proposed ADF regulations are likely to lead to substantial increases in NOx emissions for the state as a whole, as well as in the South Coast and San Joaquin Valley air basins, which are in extreme nonattainment of the federal standard for ozone and experience the state's highest levels of ozone and other pollutants. The significance of the NOx increases from biodiesel can be seen by comparing those increases with air quality planning documents.

Perhaps the best initial point of reference comes from CARB's "Vision for Clean Air"[14] prepared in conjunction with the South Coast Air Quality Management District and the San Joaquin Valley Unified Air Pollution Control District. This report addresses potential control strategies that will be required to bring these extreme ozone nonattainment areas into compliance. According to the Vision report, NOx emissions will have to be reduced by 80% to 90% from 2010 levels in both the South Coast and San Joaquin Valley areas in order to achieve ozone compliance. Furthermore, in working to identify potential control strategies, the three regulatory agencies chose to focus **only** on ways to reduce NOx emissions (and not hydrocarbon emissions) because, in their words, *"NOx is the most critical pollutant for reducing regional ozone and fine particulate matter."* Given this, CARB staff's proposal to allow any NOx emission increases from the use of biodiesel is difficult to understand. ADF 17-34

CARB staff's proposal becomes even more difficult to understand when the emission increases from biodiesel are compared to the emission benefits from adopted and proposed control measures. As an illustration, the NOx reductions expected from transportation control measures in the South Coast Basin that are part of the district's Air Quality Plan[15] are compared in Table 5 to estimated NOx emission increases under the ADF based on Sierra's analysis of B5. As shown, the increases due to biodiesel are far larger than the reductions from transportation control measures and completely offset the benefits of those measures that must be implemented as the result of their being included in the Air Quality Plan. ADF 17-35

Table 5
Comparison of NOx Reductions from South Coast Transportation Control Measures (TCMs) and Estimated NOx Increases from Biodiesel
Under the Proposed ADF Regulation

Calendar Year	NOx Reduction from TCMs, tons/day	NOx Increase due to Biodiesel tons/day
2014/2015	-0.7	2.72
2019/2020	-1.4	3.00
2023	-1.5	2.70

[14] California Air Resources Board, Vision for Clean Air: A Framework for Air Quality and Climate Planning, June 27, 2012.
[15] See South Coast 2012 AQMP. Appendix IV C. *http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2012-air-quality-management-plan/final-2012-aqmp-(february-2013)/appendix-iv-(c)-final-2012.pdf*

Similarly, the approximately two ton per day NOx increase estimated from the use of biodiesel in the San Joaquin Valley under the ADF can be compared to planned and implemented NOx control measures,[16,17] many of which have emission benefits on the order of two tons per day or less. Again, it should also be noted that the potential NOx emission increases allowed under the proposed ADF from extensive use of B20 in NDTEs without mitigation are far greater than the fleetwide impacts associated with the use of B5.

ADF 17-35 cont.

[16] San Joaquin Valley Air Pollution Control District, 2007 Ozone Plan and Appendices and Updates.
[17] San Joaquin Valley Air Pollution Control District, 2010 Ozone Mid-Course Review, June 2010.

Table 6
Results of Sierra Research Statewide Analysis

Statewide Total NOx Emissions Inventory, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	493.3	345.0	204.9
Construction/Mining/Drilling	75.8	56.6	43.6
Cargo Handling Equipment (CHE)	4.02	3.13	2.70
Transportation Refrigiration Units (TRU)	13.33	11.25	12.26
Agricultural Equipment	34.35	19.75	13.44
TOTAL	620.8	435.7	276.9

Statewide NTDE NOx Emissions Inventory, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	73.0	127.2	138.2
Construction/Mining/Drilling	0.8	5.5	9.0
Cargo Handling Equipment (CHE)	0.26	0.89	1.22
Transportation Refrigiration Units (TRU)	0.00	0.00	0.00
Agricultural Equipment	0.21	0.85	1.23
TOTAL	74.4	134.4	149.6

Statewide NOx Emissions Increase Due to B5 , tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	7.8550	8.5374	7.5764
Construction/Mining/Drilling	0.7916	0.7850	0.7962
Cargo Handling Equipment (CHE)	0.0506	0.0668	0.0757
Transportation Refrigiration Units (TRU)	0.1333	0.1125	0.1226
Agricultural Equipment	0.3520	0.2317	0.1837
TOTAL	9.18	9.73	8.75

Statewide NTDE NOx Emission Increase Due to B5, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	3.6523	6.3596	6.9092
Construction/Mining/Drilling	0.0424	0.2735	0.4507
Cargo Handling Equipment (CHE)	0.0131	0.0444	0.0609
Transportation Refrigiration Units (TRU)	0.0000	0.0000	0.0000
Agricultural Equipment	0.0106	0.0427	0.0617
TOTAL	3.72	6.72	7.48

Statewide Legacy Vehicle NOx Emission Increase Due to B5, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	4.2027	2.1778	0.6672
Construction/Mining/Drilling	0.7492	0.5115	0.3454
Cargo Handling Equipment (CHE)	0.0375	0.0224	0.0148
Transportation Refrigiration Units (TRU)	0.1333	0.1125	0.1226
Agricultural Equipment	0.3414	0.1890	0.1220
TOTAL	5.46	3.01	1.27

Table 7
Results of Sierra Research South Coast Air Basin Analysis

South Coast Total NOx Emissions Inventory, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	153.0	107.9	62.3
Construction/Mining/Drilling	28.0	21.5	15.9
Cargo Handling Equipment (CHE)	3.21	2.53	2.20
Agricultural Equipment	2.18	1.23	0.84
TOTAL	186.4	133.1	81.3

South Coast NTDE NOx Emissions Inventory, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	20.8	38.7	42.8
Construction/Mining/Drilling	0.3	2.1	3.3
Cargo Handling Equipment (CHE)	0.24	0.79	1.08
Agricultural Equipment	0.01	0.05	0.07
TOTAL	21.4	41.7	47.3

South Coast NOx Emission Increase Due to B5 , tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	2.3624	2.6270	2.3340
Construction/Mining/Drilling	0.2931	0.2993	0.2929
Cargo Handling Equipment (CHE)	0.0416	0.0568	0.0652
Agricultural Equipment	0.0223	0.0144	0.0113
TOTAL	2.72	3.00	2.70

South Coast NTDE NOx Emission Increase Due to B5, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	1.0410	1.9352	2.1385
Construction/Mining/Drilling	0.0161	0.1056	0.1673
Cargo Handling Equipment (CHE)	0.0118	0.0393	0.0539
Agricultural Equipment	0.0006	0.0026	0.0037
TOTAL	1.07	2.08	2.36

South Coast Legacy Vehicle NOx Emission Increase Due to B5, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	1.3213	0.6918	0.1955
Construction/Mining/Drilling	0.2770	0.1938	0.1256
Cargo Handling Equipment (CHE)	0.0298	0.0175	0.0112
Agricultural Equipment	0.0216	0.0118	0.0076
TOTAL	1.65	0.91	0.34

Table 8
Results of Sierra Research San Joaquin Valley Analysis

San Joaquin Valley Total NOx Emissions Inventory, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	103.9	77.1	43.9
Construction/Mining/Drilling	14.0	12.1	9.4
Cargo Handling Equipment (CHE)	0.09	0.06	0.06
Agricultural Equipment	14.81	8.58	5.82
TOTAL	132.8	97.8	59.2

San Joaquin Valley NTDE NOx Emissions Inventory, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	19.7	33.7	35.9
Construction/Mining/Drilling	0.1	1.1	1.9
Cargo Handling Equipment (CHE)	0.00	0.01	0.01
Agricultural Equipment	0.09	0.36	0.53
TOTAL	20.0	35.2	38.4

San Joaquin Valley NOx Emission Increase Due to B5 , tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	1.8277	2.1196	1.8769
Construction/Mining/Drilling	0.1459	0.1661	0.1696
Cargo Handling Equipment (CHE)	0.0010	0.0011	0.0011
Agricultural Equipment	0.1517	0.1003	0.0793
TOTAL	2.13	2.39	2.13

San Joaquin Valley NTDE NOx Emission Increase Due to B5, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	0.9857	1.6862	1.7973
Construction/Mining/Drilling	0.0075	0.0560	0.0941
Cargo Handling Equipment (CHE)	0.0001	0.0005	0.0007
Agricultural Equipment	0.0046	0.0182	0.0264
TOTAL	1.00	1.76	1.92

San Joaquin Valley Legacy Vehicle NOx Emission Increase Due to B5, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	0.8421	0.4333	0.0796
Construction/Mining/Drilling	0.1384	0.1101	0.0755
Cargo Handling Equipment (CHE)	0.0009	0.0005	0.0004
Agricultural Equipment	0.1471	0.0822	0.0529
TOTAL	1.13	0.63	0.21

46_OP_LCFS_GE Responses (Page 253 - 270)

572. Comment: **ADF 17-24 through ADF 17-35**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

.

This page intentionally left blank.

46_OP_LCFS_GE

17_OP_ADF_GE

Attachment E

Assessment of CARB's Environmental Analysis and ADF Mitigation Requirements

In developing the proposed Alternative Diesel Fuel (ADF) regulation, CARB staff has performed an environmental analysis and included mitigation requirements intended to eliminate the adverse environmental impacts associated with increased NOx emissions resulting from the use of biodiesel under the ADF. ADF 17-36

The environmental analysis is fundamentally flawed in that staff incorrectly selected 2014 as the baseline year and performed the analysis in light of biodiesel usage levels in that year. As documented below, CARB staff has long been aware that biodiesel use leads to increases in NOx emissions, and promised but failed to act to address those emissions through enactment of an ADF regulation as early as 2009. There is no basis for an agency to use its failure to promptly act to address an environmental issue of which it was clearly aware as grounds to change the baseline for assessing its' proposed effort to address that issue. This is even more apparent given that CARB staff acknowledges that a key function of the LCFS regulation is to incent low carbon intensity fuels including biodiesel which has to date generated 13% of all credits issued by CARB under the LCFS.[1] Given this, the proper baseline for assessing the ADF regulation should be 2009 when CARB first stated it would regulate biodiesel use and when, by CARB staff's own admission, little biodiesel was used in California and NOx emissions were minimal. ADF 17-37

The mitigation requirements of the ADF regulation are equally flawed. First, they are based on CARB's staff's fundamentally flawed emission analysis, and second their implementation is unreasonably delayed until 2018—more than ten years after CARB staff was aware that biodiesel use in California would lead to increased NOx emissions. ADF 17-38

History of the ADF Regulation

Although the U.S. Environmental Protection Agency (EPA) published a report in 2002 showing that biodiesel use increases NOx emissions linearly with increasing biodiesel content,[2] the earliest document found on the CARB website indicates that agency discussions regarding the need to adopt regulations addressing NOx began at least as early as February 2004.[3] This led to the first meeting of the Biodiesel Work Group in April 2004.[4] A summary of that discussion

[1] See Page III-2 of the LCFS ISOR.
[2] See EPA, A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions (available at http://www.epa.gov/otaq/models/analysis/biodsl/p02001.pdf).
[3] See CARB, Public Consultation Meeting Regulatory and Non-Regulatory Fuels Activities at 26-29 (Feb. 25, 2004) (available at http://www.arb.ca.gov/fuels/diesel/022504arb.pdf).
[4] See CARB Ltr. (Mar. 18, 2004) (available at http://www.arb.ca.gov/fuels/diesel/altdiesel/041204altdslwsh.pdf).

published at the time[5] it occurred indicates that topics discussed included ways to mitigate NOx emission increases associated with biodiesel use.

In 2006, CARB published a draft guidance document regarding the use of biodiesel in California,[6] at which time the agency simply decided not to address increased NOx emissions until biodiesel use became more widespread.[7] At that time, CARB instead could have ensured that there would be no NOx increases from biodiesel use by simply requiring those interested in selling biodiesel in California to demonstrate that they could formulate biodiesel blends in a way that did not increase NOx emissions, which is one of the approaches CARB is now considering.[8]

The first time CARB was scheduled to adopt regulations addressing this issue was in November 2009; this is indicated on page 12 of CARB's 2009 Rulemaking Calendar,[9] which includes the following summary:

> *Staff will propose motor vehicle fuel specifications for biodiesel and renewable diesel. These specifications are necessary for the implementation of the Low Carbon Fuel Standard regulation (to be considered at the March 2009 Hearing).*

ADF 17-39

No action was taken by CARB in 2009 and the planned adoption date was moved to June 2010; this is evidenced by CARB's 2010 Rulemaking Calendar,[10] which lists the regulatory item on page 11. This time the summary reads:

> *The staff will propose adoption of new motor vehicle fuel specifications for biodiesel and renewable diesel. These specifications are necessary to ensure that the use of these fuels will not increase emissions of criteria and toxic air pollutants when used as a motor vehicle fuel.*

Again, no action was taken by CARB in 2010 and the planned adoption date was moved to November 2011; this is evidenced by CARB's 2011 Rulemaking Calendar,[11] which lists the regulatory item on page 14. This time the summary reads:

---

[5] See *CVS News*, at 27-31 (May 2004) (available at http://www.sierraresearch.com/documents/cvs_news_may_2004.pdf).
[6] See CARB, Draft Advisory on Biodiesel Use (Nov. 14, 2006) (available at http://www.arb.ca.gov/fuels/diesel/altdiesel/111606biodsl_advisory.pdf).
[7] See CARB, Suggested ARB Biodiesel Policy (May 24, 2006) (available at http://www.arb.ca.gov/fuels/diesel/altdiesel/052406arb_prsntn.pdf).
[8] See California Environmental Protection Agency, Discussion of Conceptual Approach to Regulation of Alternative Diesel Fuels (Feb. 15, 2013).
[9] See CARB, 2009 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2009rulemakingcalendar.pdf).
[10] See CARB, 2010 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2010rulemakingcalendar.pdf).
[11] See CARB, 2011 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2011rulemakingcalendar.pdf).

The Low Carbon Fuel Standard incents the use of biodiesel and renewable diesel, for which there are no current emissions–based fuel specifications. Staff will propose fuel specifications for both of these diesel blendstocks.

Yet again, no action was taken by CARB in 2011 and the planned adoption date was moved to November 2012; this is evidenced by CARB's 2012 Rulemaking Calendar,[12] which lists the regulatory item on page 14. This time the summary reads:

Rulemaking to establish commercial fuel specifications for blends of commercial diesel fuel and neat biodiesel in amounts greater than five volume percent.

Yet again, no action was taken by CARB in 2012 and, for the fourth consecutive year, the item was scheduled to be presented to the Board—the CARB Rulemaking Calendar for 2013[13] indicates on page 8 that the Board is currently scheduled to consider adoption of amendments to the agency's Alternative Diesel Fuel Regulations in September 2013. This time the summary reads: ADF 17-39 cont.

Proposed new motor vehicle alternative diesel fuel specifications and commensurate amendments to the diesel fuel regulations.

Unlike the previous years, during 2013 CARB staff did begin to take action to actually develop a regulation that it purported would address increases in NOx emissions resulting from biodiesel use. The hearing notice[14] and Initial Statement of Reasons[15] for the proposed ADF regulation were published in October 2013, in advance of a Board hearing to be held on December 12-13, 2013. However, that hearing was postponed to until March 20, 2014,[16] and then the entire rulemaking was abandoned prior to the March 2014 hearing.[17]

History of Biodiesel Use

Although CARB does not disclose the amounts of biodiesel used in California prior to 72 million gallons estimated in 2014 in the ADF rulemaking documents (see ISOR Appendix B), data for 2005 to 2012 are available from the California Energy Commission.[18] These data are shown in Figure 1 below. As shown, biodiesel use in California increased dramatically in 2006 when CARB staff indicated that it would not regulate biodiesel, and then decreased until the LCFS

[12] See CARB, 20012 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2012rulemakingcalendar.pdf).

[13] See CARB, 2013 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2013rmcal.pdf).

[14] See http://www.arb.ca.gov/regact/2013/adf2013/adf2013notice.pdf

[15] See http://www.arb.ca.gov/regact/2013/adf2013/adf2013isor.pdf

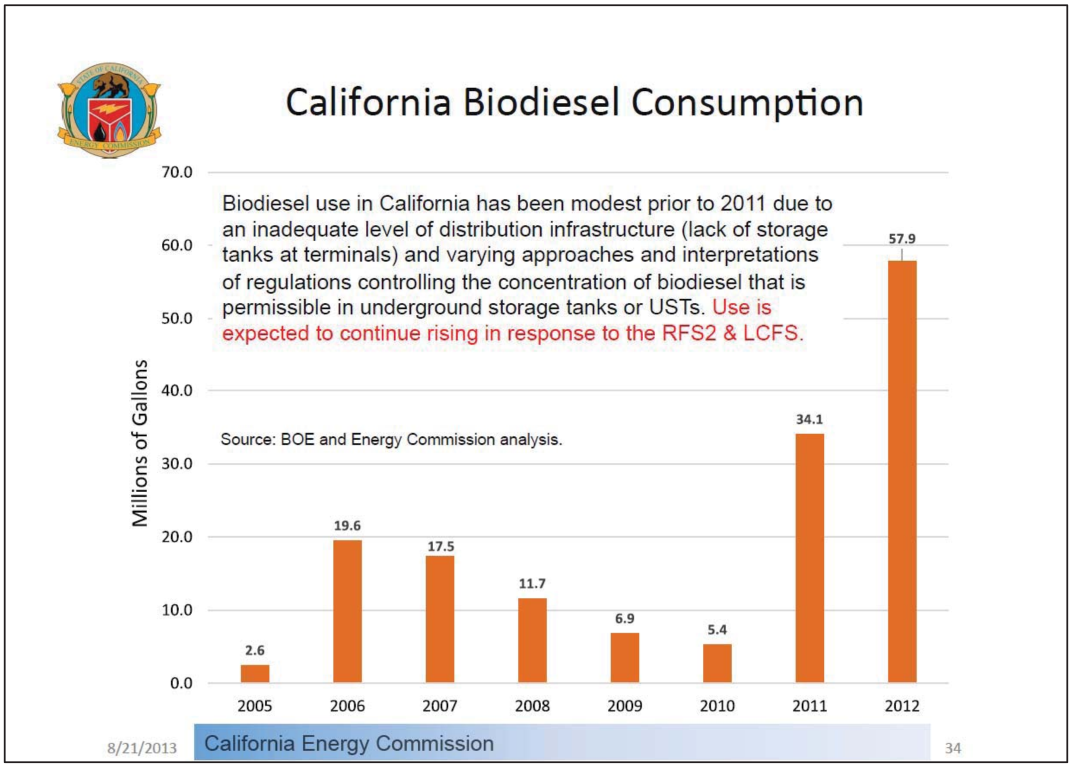
[16] See http://www.arb.ca.gov/regact/2013/adf2013/adf2013postpone.pdf

[17] See http://www.arb.ca.gov/regact/2013/adf2013/NDNPadf2013.pdf

[18] See http://www.energy.ca.gov/2013_energypolicy/documents/2013-08-21_workshop/presentations/06_Schremp_Biofuels.pdf

took effect in 2011 at which point it again increased dramatically. Clearly, the appropriate baseline year for analysis of the ADF regulation is 2009 or 2010 when CARB first committed to adopting a regulation to address biodiesel NOx impacts, not any later year after which substantial increases in biodiesel use occurred in response to the LCFS. ADF 17-40

Figure 1
Biodiesel Consumption in California as Reported by the California Energy Commission



The NOx increases resulting from CARB's failure to regulate biodiesel during the period from 2005 to 2014 are summarized in Table 1. The values presented are approximate and are based on the Sierra Research methodology for 2015 adjusted to account for differences in biodiesel use as well as the absence of NTDE engines in years prior to 2010. Biodiesel use for 2014 is taken from Appendix B of the ADF ISOR, and the estimated use for 2013 assumed linear growth in biodiesel use from 2012 to 2014. Significant increases in NOx emissions from 2011 to 2014 can be seen from a comparison of the values presented in Table 1 with the values presented in Table B-1 of Appendix B to the ADF ISOR. These increased NOx emissions from 2011 to 2014 total 782, 1032, and 3,463 tons for the San Joaquin Valley, South Coast, and entire state, respectively. ADF 17-41

Table 1 Estimated Increases in NOx Emissions Due to Biodiesel Use in California from 2005 to 2014 (tons per year)			
Calendar Year	Statewide	South Coast	San Joaquin Valley
2005	31	9	7
2006	234	70	50
2007	209	63	45
2008	140	42	30
2009	82	25	18
2010	65	19	14
2011	447	134	98
2012	825	246	184
2013	1000	298	227
2014	1191	354	273
Total	4225	1260	945

ADF 17-41 cont.

Proposed ADF Mitigation Requirements

Under the proposed ADF regulation,[19] mitigation is generally required for "low-saturation" biodiesel blends with diesel fuel above B5 (e.g., B6 and higher) during the summer, and above B10 (e.g., B11 and higher) during the winter, unless the fuels are used in vehicles with new technology diesel engines in which case mitigation is not required for levels up to B20. For "high-saturation" biodiesel blends with diesel fuel, mitigation is required year-round above B10 (e.g., B11 and higher) again, unless the fuels are used in vehicles with new technology diesel engines in which case mitigation is not required for levels up to B20. However, no mitigation is required for any biodiesel blend sold in California prior to January 1, 2018.

ADF 17-42

According to the ADF ISOR,[20] CARB staff selected these levels based on an "analysis" for which no detail or documentation has been provided, and that reportedly included consideration of the impacts of new technology diesel engines (NTDEs) and the use of renewable diesel as "offsetting factors." Although it is impossible to thoroughly review an analysis which is not described in detail, in this case it can still be demonstrated to be fundamentally flawed. As discussed elsewhere, CARB incorrectly assumes that NOx emissions from NTDEs are unaffected by biodiesel despite the fact that available data show statistically significant increases in NOx emissions. Further, CARB cannot rely on the use of renewable diesel as mitigation for NOx increases from biodiesel as there is nothing in the ADF or the LCFS regulation that mandates the use of any volume of renewable diesel in California, nor which links the amount of renewable diesel used to the amount of biodiesel used. Further, neither the ADF nor LCFS regulations ensure that fuel producers will use biodiesel in a manner that provides surplus

ADF 17-43

[19] Proposed section 2293.6 Title 13, CCR in ISOR Appendix A.
[20] Chapter 6, Part H.

reductions[21] in NOx emissions. Given that CARB's reliance on "offsetting factors" is fundamentally flawed, the agency's "Determination of NOx Control Level for Biodiesel" is also fundamentally flawed. Another problem with the "determination" is that CARB staff claims to have performed an "analysis" for which no detail or documentation is provided, indicating that the higher blend level threshold for mitigation that applies to "low-saturation" blends during the winter months will not result in adverse air quality impacts. Again, it is not possible to critically review an analysis which is not described in detail; further, the information provided in this analysis is so insufficient that it is not even possible to develop an appropriate set of comments.

ADF 17-43 cont.

In addition to the flaws in CARB staff's analysis of what mitigation should be applied to address the increased NOx emissions associated with biodiesel use, CARB staff is arbitrarily delaying the date on which mitigation is required by two years from the expected effective date of the ADF regulation. According to ADF ISOR, CARB staff claim the reason for this delay is:

> *ARB is also proposing the in-use requirements come into effect on January 1, 2018, as time is needed to overcome logistical and other issues in implementation of in-use requirements. For example, use of the additive Di-tert-butyl peroxide (DTBP) will require replacement of steel tanks with stainless steel tanks, permitting of hazardous substance storage, approval by local fire agencies, additional additization infrastructure, and logistical business changes to acquire the additive. All of this is expected to take around 2 years to complete. Another method of compliance is re-routing higher blends to NTDEs. Research shows that the use of biodiesel in blends up to B20 in NTDEs results in no detrimental NOx impacts. This and other methods of complying with the in-use requirements, such as certification of additional options are also expected to take 2 years or more. Because compliance with the in-use options would be infeasible during initial implementation on January 1, 2016, only recordkeeping and reporting provisions will be implemented initially. The in-use requirements are proposed to come into effect on January 1, 2018.*

ADF 17-44

It is not clear why CARB staff believes that a two year delay in the implementation of mitigation requirements is required under the ADF regulation when the maximum delay in the implementation of new requirements under the LCFS regulation, which will much more dramatically impact fuel producers than the ADF requirements, is only one year, until January 1, 2017. Further, as the biodiesel industry has been on notice that CARB intended to impose NOx mitigation requirements for over ten years, it is not clear why such measures cannot be required from the expected January 1, 2016 effective date of the proposed regulation.

The impact of the failure to immediately require Biodiesel mitigation under the ADF regulation is shown in Table 2. These values are based on the Sierra Research emissions methodology which assumes statewide use of B5. As discussed elsewhere, these impacts

[21] In order to generate surplus reductions in NOx, renewable diesel would have to be blended into diesel fuel downstream of refineries, and although CARB staff has assumed that this will occur they have provided no basis for that assumption.

are significant in that the increases are as large or larger than those sought from emission control measures implemented of under consideration by CARB and local air pollution control agencies in the South Coast and San Joaquin Valley air basins.

Table 2
Potential NOx Increases Due to CARB's Failure to Require Immediate Biodiesel Mitigation Under the ADF
(tons per year)

	Statewide	South Coast	San Joaquin Valley
2016	3405	1013	796
2017	3460	1034	815
Total	6866	2047	1612

ADF 17-44 cont.

Attachment E-7

This page intentionally left blank.

46_OP_LCFS_GE Responses (Page 271 - 277)

573. Comment: **ADF 17-36 through ADF 17-44**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

46_OP_LCFS_GE

17_OP_ADF_GE

Attachment F

Potential for Actual Biodiesel Blend Levels to Exceed Levels Purported Under the Proposed ADF Regulation

In order to properly understand and mitigate the adverse environmental impacts of biodiesel blends sold in California, it is critical that the actual amount of biodiesel present in a blend be accurately known. Despite this, the proposed ADF regulation fails to adequately ensure that the actual biodiesel content of biodiesel blends—and therefore their adverse environmental impacts—will be accurately known or appropriately mitigated. As discussed below, significant changes are required to definitions used in the proposed LCFS and ADF regulations, and new testing, recordkeeping, and reporting requirements need to be added to the ADF regulation to prevent the blending of biodiesel with fuels that already contain undisclosed amounts of biodiesel.

ADF 17-45

Background

CARB regulations at §2281 and §2282, Title 13, California Code of Regulations apply to vehicular diesel fuel sold in California and define "diesel fuel" as follows:

> *"Diesel fuel" means any fuel that is commonly or commercially known, sold or represented as diesel fuel, including any mixture of primarily liquid hydrocarbons – organic compounds consisting exclusively of the elements carbon and hydrogen – that is sold or represented as suitable for use in an internal combustion, compression-ignition engine."*[1]

The proposed LCFS regulation contains the following definitions that are relevant to biodiesel blends (See ISOR Appendix A):[2]

> *"B100" means biodiesel meeting ASTM D6751-14 (2014) (Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels), which is incorporated herein by reference.*
>
> *"Biodiesel" means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel meeting all the following:*

[1] 13 CCR §2281(b)(1) and §2282(b)(3)
[2] See proposed §95481, Title 17, California Code of Regulations

(A) Registered as a motor vehicle fuel or fuel additive under 40 Code of Federal Regulations (CFR) part 79;
(B) A mono-alkyl ester;
(C) Meets ASTM D6751-08 (2014), Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, which is incorporated herein by reference;
(D) Intended for use in engines that are designed to run on conventional diesel fuel; and
(E) Derived from nonpetroleum renewable resources.

"Biodiesel Blend" means a blend of biodiesel and diesel fuel containing 6 percent (B6) to 20 percent (B20) biodiesel and meeting ASTM D7467-13 (2013), Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), which is incorporated herein by reference.

"Diesel Fuel" (also called conventional diesel fuel) has the same meaning as specified in California Code of Regulations, title 13, section 2281(b).

"Diesel Fuel Blend" means a blend of diesel fuel and biodiesel containing no more than 5 percent (B5) biodiesel by weight and meeting ASTM D975-14a, (2014), Standard Specification for Diesel Fuel Oils, which is incorporated herein by reference.

Finally, the proposed ADF regulation contains the following definitions that are relevant to biodiesel blends:[3]

"Alternative diesel fuel" or "ADF" means any fuel used in a compression ignition engine that is not petroleum-based, does not consist solely of hydrocarbons, and is not subject to a specification under subarticle 1 of this article.

"Biodiesel" means a fuel comprised of mono-alkyl esters of long chain fatty acids derived from vegetable oils or animal fats that is 99-100 percent biodiesel by volume (B100 or B99) and meets the specifications set forth by ASTM International in the latest version of Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels D6751 contained in the ASTM publication entitled: Annual Book of ASTM Standards, Section 5, as defined in California Code of Regulations, title 4, section 4140(a), which is hereby incorporated by reference.

"Biodiesel Blend" means biodiesel blended with petroleum-based CARB diesel fuel or non-ester renewable diesel.

[3] See proposed §2293.2(a), Title 13, California Code of Regulations

"Blend Level" means the ratio of an ADF to the CARB diesel it is blended with, expressed as a percent by volume. The blend level may also be expressed as "AXX," where "A" represents the particular ADF and "XX" represents the percent by volume that ADF is present in the blend with CARB diesel (e.g., a 20 percent by volume biodiesel/CARB diesel blend is denoted as "B20").

"B5" means a biodiesel blend containing no more than five percent biodiesel by volume.

"B20" means a biodiesel blend containing more than five and no more than 20 percent biodiesel by volume.

"CARB diesel" means a light or middle distillate fuel that may be comingled with up to five (5) volume percent biodiesel and meets the definition and requirements for "diesel fuel" or "California nonvehicular diesel fuel" as specified in California Code of Regulations, title 13, section 2281 et seq. "CARB diesel" may include: non-ester renewable diesel; gas-to-liquid fuels; Fischer-Tropsch diesel; diesel fuel produced from renewable crude; CARB diesel blended with additives specifically formulated to reduce emissions of one or more criteria or toxic air contaminants relative to reference CARB diesel; and CARB diesel specifically formulated to reduce emissions of one or more criteria or toxic air contaminants relative to reference CARB diesel.

Discussion

The first issue related to the potential for uncertainty and inaccuracy in actual biodiesel content of fuels sold in California involves the different definitions that have been proposed for the term "biodiesel" under the proposed LCFS and ADF regulations. Although the two definitions may be functionally equivalent, they should be made the same under both the LCFS and ADF regulations unless CARB staff can articulate a compelling need for the use of different definitions to describe the same thing.

More importantly, the term "Biodiesel Blend" in the proposed LCFS regulation directly conflicts with the use of the same exact term in the proposed ADF regulation: a "Biodiesel Blend" under the LCFS regulations contains at least 6% biodiesel, while a "Biodiesel Blend" under the ADF is a diesel fuel containing any biodiesel. Furthermore, the LCFS regulation defines "Diesel Fuel Blend" as a blend of diesel fuel and up to 5% biodiesel, while such a fuel would be considered "CARB diesel" under the ADF regulation. Again, this haphazard use of the same term to describe fundamentally different fuels and different terms to describe the same fuel will assuredly lead to confusion in practice regarding the actual content of biodiesel available in California.

Further confusion is created by the definitions of "Biodiesel Blend" and "Blend Level" under the proposed ADF regulation. "Biodiesel Blend" is defined as a mixture of biodiesel and an undefined fuel referred to as "petroleum-based CARB diesel." "Blend

Level" applies to blends of all fuels subject to the ADF regulation, including biodiesel, and is defined as the ratio of an "Alternative diesel fuel" mixed with "CARB diesel." However, as noted above, "CARB diesel" may already contain as much as 5% biodiesel under the proposed ADF regulation. Furthermore, the definition of "Blend Level" includes no reference to the fuel termed "petroleum-based CARB diesel" that appears in the definition of "Biodiesel Blend" under the ADF—instead, it refers to "CARB diesel," which, as noted above, may contain as much as 5% biodiesel. Obviously, the addition of biodiesel to a fuel already containing some amount of biodiesel up to 5% will cause the actual biodiesel content to be higher than the blender expects; this, in turn, will lead to more significant adverse environmental impacts than expected. It is also clear that CARB staff mean for the definition of "Blend Level" to apply to "Biodiesel Blends," as that definition uses an example based on biodiesel (B20) to demonstrate the practical meaning of "Blend Level."

Finally, under the proposed ADF regulation, "B20" is nonsensically defined as a fuel that contains between 6% and 20% biodiesel, which directly contradicts the definition of "Blend Level" in same regulation. There appears to be no need for this definition or the definition of B5 in the proposed ADF regulation.

As outlined above, the proposed CARB LCFS and ADF regulations fail completely in clearly defining the four fuels that are of fundamental importance to ensuring that the biodiesel content of a fuels sold in California—and hence the adverse environmental impacts associated with their use—is accurately known. Instead, the proposed regulations make it likely that biodiesel blenders will unknowingly use fuels that already contain an unknown amount of biodiesel (up to 5%) in blending and that the actual biodiesel content of biodiesel blends may be as much as 5% greater than that represented by the blender and reported to CARB under the ADF regulation. This is significant because, as discussed in other attachments to this declaration, the increases in NOx emissions and associated adverse environmental impacts caused by biodiesel blends become larger in direct proportion to the amount of biodiesel present.

Both the LCFS and the ADF regulation must clearly define the four fuels described below.

1. ***"Diesel fuel"*** **–** This should defined as under 13 CCR §2281(b)(1) and §2282(b)(3).

2. ***"Biodiesel"*** or "***B100"*** – It appears that this could be properly defined through changes to the definitions currently proposed in the LCFS and ADF regulations; this is what should be blended only with "diesel fuel" to create a "Biodiesel Blend."

3. ***"CARB diesel"*** – This is accurately defined under the proposed ADF regulation, but under no circumstances should it be allowed to be blended with biodiesel or any other ADF. It should be renamed to clearly differentiate it from "diesel fuel" such that no reasonable person would understand that it could be legally mixed with any ADF.

ADF 17-45 cont.

4. ***"Biodiesel Blend"*** – This should refer to the "Blend Level" and must correspond to the actual amount of "Biodiesel" or "B100" in terms of percentage by volume in the final blend with "diesel fuel."

ADF 17-45 cont.

In addition to modifying the definitions as described above, the ADF regulation must also be modified to ensure that biodiesel blenders do not intentionally or unintentionally blend biodiesel into fuels that already contain biodiesel. This can easily be achieved by adding requirements to proposed §2293.8 Title 13, CCR, to require that any "diesel fuel" to be used in blending with biodiesel be tested for the presence of biodiesel prior to blending. Similarly, that section should be modified to include reporting and record keeping requirements for biodiesel blenders that document that they have used only biodiesel-free "diesel fuel" in all of their blending operations.

ADF 17-46

This page intentionally left blank.

46_OP_LCFS_GE Responses (Page 278 - 282)

574. Comment: **ADF 17-45 through ADF 17-46**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

46_OP_LCFS_GE

17_OP_ADF_GE

Attachment G

The Growth Energy Alternative to Proposed ADF Regulation is the Least-Burdensome Approach that Best Achieves the Project Objectives at the Least Cost That Must be Adopted

As part of the rulemaking process leading to CARB staff's proposed ADF regulation, staff was required to solicit and consider alternatives to the proposed regulation. Growth Energy submitted such an alternative which CARB staff acknowledged provided equivalent or superior reductions in NOx emissions from biodiesel use but rejected as being more costly. However, as is documented in detail below, CARB staff made fundamental errors in its' assessment of the Growth Energy Alternative, which will in fact provide greater reductions in NOx emissions from biodiesel use than the staff's proposed ADF regulation but do so with equal cost-effectiveness. (Equal cost-effectiveness means that the dollars spent per unit mass of NOx emissions eliminated will be the same.) Given that the Growth Energy alternative provides greater environmental benefits, which in turn substantially lessen the ADF's significant impacts, and is equally cost-effective as the staff's proposed ADF regulation, the Growth Energy Alternative rather than the staff proposal should be adopted by CARB. ADF 17-47

Background

On July 29, 2014, CARB published a "Solicitation of Alternatives for Analysis in the Alternative Diesel Fuel Standardized Regulatory Impact Assessment" which is attached. On August 15, 2014, Growth Energy submitted an alternative regulatory proposal for the ADF regulation (which is attached) to CARB in response to the agency's solicitation. On December 30, 2014, CARB staff published both the ISOR for the ADF regulation as well as a document entitled "Summary of DOF Comments to the Combined LCFS/ADF SRIA and ARB Responses" which is Appendix E to the ADF ISOR, both of which include information related to staff's decision to reject the alternative to the ADF regulation proposed by Growth Energy.

The staff's assessment of the Growth Energy (GE) Alternative published in Appendix E of the ADF ISOR is as follows (emphasis added): ADF 17-48

> ***Benefits:***
>
> ***ARB finds that the GE alternative would meet the emissions goals of the ADF proposal and achieve roughly the same emissions benefits as the ADF proposal. The GE alternative may achieve marginally more emissions benefits if biodiesel were to be widely used as an additive under the ADF proposal. Although the GE alternative is simpler than the ADF proposal, the GE alternative is unnecessarily strict; ARB's analysis of the science does not find that there are NO_X increases with B5 animal biodiesel or biodiesel used in NTDEs, so***

requiring mitigation for these does not achieve any additional emissions benefit versus the ADF proposal.

Costs:

The GE alternative would require mitigation of more fuel than the ADF proposal; regulated parties would incur more costs to mitigate non-animal- and animal-based biodiesel similarly and setting the significance level for both at one percent. Additionally, the NTDE exemption would increase the volumes of fuels to be mitigated, further increasing the direct costs on regulated parties.

Economic Impacts:

The REMI results also indicate that the combined LCFS/ADF proposal has no discernible difference from the GE alternative. Employment, GSP, and output differ only slightly and represent a difference of less than one tenth of one percent. Given that the GE alternative has higher direct costs, the combined LCFS/ADF alternative is preferred.

Cost-Effectiveness:

The GE alternative costs more than the ADF proposal, because it requires mitigation of more biodiesel than the ADF proposal. The GE alternative does not result in any more emissions reductions than the ADF proposal and as such is less cost effective than the ADF proposal.

Reason for Rejection:

ARB rejects the GE alternative because it costs more than the ADF proposal and does not achieve additional emissions benefits*.*

The reason for rejection of the Growth Energy (GE) alternative presented in the ADF ISOR itself is as follows:

This alternative proposal retains the same biodiesel NOx mitigation options as the ADF proposal*. However, under the GE alternative, animal and non-animal biodiesel would be treated equally and require NOx mitigation for all biodiesel blends, including blends below B5.* ***ARB rejects this alternative because the costs are significantly higher than the ADF proposal and do not achieve additional emissions benefits.*** *During the development of this regulation, staff considered alternatives to the proposal and determined that the proposal represents the least-burdensome approach that best achieves the objectives at the least cost.*

Finally, it should be noted that the stated intention of the ADF regulation according to CARB staff in the ADF ISOR is as follows (emphasis added):

ADF 17-49

*The ADF regulation is intended to create a framework for these low carbon diesel fuel substitutes to enter the commercial market in California, **<u>while mitigating any potential environmental or public health impacts</u>**.*

<u>Discussion</u>

As indicated above, the stated reason why CARB staff rejected the Growth Energy alternative to the proposed ADF regulation is because CARB staff believed it would require that actions be taken to mitigate increased NOx emissions from biodiesel under circumstances where CARB staff incorrectly assumed there would no increased emissions due to biodiesel use on under the ADF. However, as is clearly demonstrated in another attachment to the declaration of James M. Lyons,[1] CARB staff's analysis and assumptions of the increases in NOx emissions that will result for the ADF regulation is fatally flawed as is CARB's basis for rejection of the Growth Energy Alternative.

ADF 17-49 cont.

As shown by the Sierra emissions analysis, once the flaws in the CARB emissions analysis are corrected, it becomes clear that the ADF regulation will allow significant and unmitigated increases in NOx emissions to occur throughout California including areas such as the South Coast and San Joaquin air basins which experience the worst air quality in the state. As CARB staff itself admits, the Growth Energy alternative would require mitigation in exactly those areas where CARB staff was lead to believe it was not required based on its flawed emissions analysis. CARB staff also admits the Growth Energy alternative is based on the same mitigation options contained in the ADF regulation, which CARB staff has already determined to be technically feasible and cost-effective. However, the Growth Energy Alternative is superior to the ADF regulation because it expands the conditions under which this mitigation has to be applied in order to eliminate the potential for any increase in NOx emissions due to biodiesel use to a less-than-significant level. The Growth Energy Alternative therefore precludes any adverse environmental impacts due to increased NOx emissions, which is exactly what CARB staff has asserted the ADF regulation is intended to do.

Given that the Growth Energy alternative:

1. Provides complete mitigation of potential NOx emission increases due to biodiesel use under the ADF and any associated adverse environmental impacts; and

2. Relies on the same mitigation strategies proposed by CARB staff which staff has found to be technically feasible and cost-effective,

ADF 17-50

CARB must adopt the Growth Energy alternative as it better achieves the stated project objectives in an equally cost-effective manner.

[1] Review of CARB Staff Estimates of NOx Emission Increases Associated with the Use of Biodiesel in California under the Proposed ADF Regulation.

This page intentionally left blank.

46_OP_LCFS_GE Responses (Page 283 - 285)

575. Comment: **ADF 17-47 through ADF 17-50**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

46_OP_LCFS
_GE

17_OP_ADF
_GE

Appendix J

Appendix J

Additional Analysis Required Under the California Environmental Quality Act

A. <u>CARB May Not Ignore the LCFS Regulation's Pre-2015 Impacts</u>

CARB Staff initiated the environmental review process for the LCFS regulation in 2007, and circulated an Initial Statement of Reasons for the proposed regulation in 2009. As explained by the Court in *POET, LLC v. California Air Resources Board* (2013) 218 Cal.App.4th 681 ("*POET*"), CARB subsequently approved that regulation on April 24, 2009, without completing the environmental review process, and impermissibly delegated authority to complete the environmental review process to the Executive Officer. The Court found that CARB's actions violated CEQA, and directed the superior court to issue a writ enjoining enforcement of the LCFS regulation beyond 2013 levels. The writ issued by the superior court requires CARB, prior to its consideration of the LCFS regulation, to evaluate "the potential adverse environmental effect of increased NOx emissions" associated with the "project" (*i.e.*, the LCFS regulations presently being enforced). (Exhibit "1.") To this day, CARB has never performed a legally compliant review of the environmental effects of CARB's existing LCFS regulation. LCFS 46-261

Although the court in *POET* directed CARB to evaluate the effects of the LCFS regulation, the Environmental Assessment ("EA") for the LCFS regulation and the ADF regulation (the "Proposed Regulations") ignores the impacts of the LCFS regulation presently in effect, as well as any other impacts of the project prior to 2014. As a result, prior to its consideration of the LCFS regulation and the ADF regulation, CARB must substantially revise and recirculate the EA for public review to evaluate the entire project. LCFS 46-262

1. **CARB's Project Description Is Inadequate Because it is Unclear <u>Whether the Existing LCFS Regulation Is Part of the Project</u>**

"An accurate, stable and finite project description is the sine qua non of an informative and legally sufficient" environmental document. (*County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 193.) Additionally, the ***entire project*** being proposed must be described in the EIR, and the project description must not minimize project impacts. (*City of Santee v. County of San Diego* (1989) 214 Cal.App.3d 1438, 1450.) As explained in *County of Inyo*:

> A curtailed or distorted project description may stultify the objectives of the reporting process. Only through an accurate view of the project may affected outsiders and public decision-makers balance the proposal's benefit against the environmental cost, consider mitigation measures, assess the advantage of terminating the proposal (*i.e.*, the "no project" alternative) and weigh other alternatives in the balance. LCFS 46-263

(*County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 192-93.)

The EA violates this mandate. First, the EA is unclear as to whether CARB is treating the "Project" as including the LCFS regulation presently in effect. On the one hand, the EA's project description discusses the existing LCFS regulation; the EA recognizes that the present action is being taken in response to the decision in *POET*; and the "re-adopted" LCFS regulation is structurally nearly identical to the LCFS regulation presently being enforced. On the other hand, however, the EA does not address the environmental effects of the LCFS regulation presently being enforced, and the "carbon intensity" base year has changed from 2010 to 2014. Because it is unclear whether the "project" analyzed in the EA includes the LCFS regulation presently in effect, the project description in the EA is not stable or finite, and is thus inadequate under CEQA. LCFS 46-263 cont.

To the extent CARB intended to omit the current LCFS regulation from the project description, that action would also result in an inadequate project description because it is "inaccurate." CEQA requires the project description to include ***entire project***, not a smaller piece of the project that would have the impact of minimizing project impacts. (*City of Santee*, *supra*, 214 Cal.App.3d at 1450.) Describing only the "re-adopted" portions of the LCFS regulation also runs directly contrary to the writ issued by the superior court, which specifically requires CARB to analyze the effects of the project presently being implemented. (See Exhibit "1.") LCFS 46-264

As a result, CARB must revise the project description in the EA to specifically include the existing LCFS regulation, and analyze the impacts associated with the existing regulation. LCFS 46-265

2. <u>The Baseline Used By CARB Is Unclear</u>

Because the impacts of a project are evaluated against the environmental baseline, determining the proper baseline is critical to a meaningful discussion of the project's environmental impacts. (See *Communities for a Better Environment v. South Coast Air Quality Mgmt. Dist.* (2010) 48 Cal.4th 310, 320.) The EA here obscures the baseline used by CARB for its analysis of the impacts of the regulations because there is no definitive statement explaining what specific baseline is being used in the EA. Rather, the portion of the EA that purportedly sets forth the baseline cites to an appendix to the EA, which discusses the "Environmental and Regulatory Setting" of the Regulations. But even this appendix does not specifically state what date the EA is using as the baseline for environmental review. As a result, the EA should be revised to specifically state what baseline it is using, and recirculated for public review. LCFS 46-266

3. Ignoring Pre-2014 Impacts Results in an Improper Baseline for <u>Environmental Review</u>

Generally, the "environmental baseline" includes the environmental conditions as they exist at the time the lead agency publishes the Notice of Preparation ("NOP") for the project, or, if there is no NOP, as is the case here, "at the time the environmental analysis is commenced." (CEQA Guidelines, § 15125(a).) Although the EA does not specifically state what baseline is being used, the analysis in the EA ignores the LCFS regulation's impacts prior to 2014, and asserts that the analysis in the EA "addresses the potentially significant adverse environmental impacts resulting from implementing the proposed LCFS and ADF regulations LCFS 46-267

compared to existing conditions, **which include existing compliance with the LCFS left in place by the Court at the 2013 regulatory standards**." (EA at 3 [emphasis added].) LCFS 46-267 cont.

Omitting analysis of the project's pre-2014 impacts is improper. Here, the environmental review commenced in 2007, and the initial Staff Report/ISOR for the LCFS regulation was released in 2009. As a result, the proper baseline for environmental review under CEQA is 2007, and certainly no later than 2009. (CEQA Guidelines, § 15125(a).) LCFS 46-268

To the extent CARB intends to use a baseline of 2014, that baseline is also impermissible because it is "misleading" and obscures the impacts of the Regulations. (See, e.g., *Neighbors for Smart Rail v. Exposition Metro Line Construction* (2013) 57 Cal.4th 439.) Specifically, NOx emissions caused by the existing LCFS regulation from 2011 through 2014 from the San Joaquin Valley, the South Coast air basin, and the entire state, respectively, total 782, 1,032, and 3,463 tons per year. (Decl. Lyons at E-4.) Because a 2014 baseline has the effect of essentially sweeping prior NOx emissions under the rug, it is misleading, and a more accurate baseline should be used. LCFS 46-269

The fact that the emissions occurred in the past does not excuse CARB from analyzing the effects of those emissions, as CARB still has the ability to mitigate these emissions, or modify the LCFS regulation in response to its analysis. In *Bakersfield Citizens for Local Control*, for example, the court set aside an EIR for a large commercial development, including a Wal-Mart. The trial court enjoined the construction of the Wal-Mart, but let the remainder of the construction proceed, and those businesses were operating at the time the court of appeal heard the case. The agency asserted the environmental review for the other businesses was moot because those businesses were operational. The Fifth District Court of Appeal disagreed, finding:

> [E]ven at this late juncture full CEQA compliance would not be a meaningless exercise of form over substance. The City possesses discretion to reject either or both of the shopping centers after further environmental study and weighing of the projects' benefits versus their environmental, economic and social costs. As conditions of reapproval, the City may compel additional mitigation measures or require the projects to be modified, reconfigured or reduced. The City can require completed portions of the projects to be modified or removed and it can compel restoration of the project sites to their original condition. LCFS 46-270

(*Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1204.) In other words, "[a]s a matter of public policy and basic equity, developers should not be permitted to effectively defeat a CEQA suit merely by building out a portion of a disputed project during litigation . . . ." (*Id.* at 1203.) By ignoring pre-2014 NOx emissions, CARB is seeking to do just that.[1]

---

[1] CARB also cannot rely upon the rule that the baseline for a previously-reviewed project assumes the previously-approved project exists. (See Remy, Thomas, Moose & Manley, *Guide to CEQA* (11th ed. 2007) at 207.) This is because the Court in *POET, LLC v. California Air Resources Board* invalidated CARB's environmental document for the original LCFS regulation.

Because the EA employs the wrong baseline, the EA should be revised, and recirculated for public review. LCFS 46-271

4. By Failing to Address Pre-2014 NOx Emissions, the EA Is Deficient <u>Because it Does Not Analyze Cumulative Impacts</u>

Even if CARB could argue the existing LCFS regulation was a different "project" under CEQA, CARB in its EA would still need to address the impacts of that regulation as "cumulative impacts." This is because CEQA requires that the environmental document discuss the cumulative effect on the environment of the subject project in conjunction with other closely-related ***past***, present, and reasonably foreseeable probable future projects. (See, e.g., Pub. Resources Code, § 21083, subd. (b).) "The purpose of this requirement is obvious: consideration of the effects of a project or projects as if no others existed would encourage the piecemeal approval of several projects that, taken together, could overwhelm the natural environment and disastrously overburden the man-made infrastructure and vital community services. This would effectively defeat CEQA's mandate to review the actual effect of the projects upon the environment." (*Citizens to Preserve the Ojai v. County of Ventura* (1985) 176 Cal.App.3d 421, 432.) Thus, regardless of whether the original LCFS regulation and the proposed LCFS regulation constituted different projects, CARB cannot avoid analyzing pre-2014 impacts as cumulative impacts. LCFS 46-272

5. CARB's Failure to Analyze Pre-2014 Impacts Constitutes Improper <u>Segmentation/Piecemealing</u>

Ignoring the impacts of the existing regulation also impermissibly piecemeals the analysis of the impacts of the LCFS regulation. CEQA prohibits a lead agency from piecemealing – or segmenting – the environmental review of a project; in other words, a lead agency may not break up an action into several small "projects" that would have the effect of minimizing environmental review. "The requirements of CEQA cannot be avoided by piecemeal review which results from "chopping a large project into many little ones-each with a minimal potential impact on the environment-which cumulatively may have disastrous consequences." (*Lighthouse Field Beach Rescue v. City of Santa Cruz* (2005) 131 Cal.App.4th 1170, 1208-09 [quoting *Bozung v. LAFCo* (1975) 13 Cal.3d 263, 283-84]; see also *Environmental Protection Info. Ctr. v. Calif. Dept. of Forestry & Fire Prot.* (2008) 44 Cal.4th 549, 503.) In other words, where "an individual project is a necessary precedent for action on a larger project," the environmental review performed by the public agency "***must*** address itself to the scope of the larger project." (Cal. Code Regs., § 15165 [emphasis added].) LCFS 46-273

As explained previously, NOx emissions caused by the LCFS regulation from 2011 through 2014 from the San Joaquin Valley, the South Coast air basin, and the entire state, respectively, total 782, 1,032, and 3,463 tons per year. (Decl. Lyons at E-4.) These past emissions – caused directly by the LCFS regulation that remains in effect – are troubling, due to among other things the U.S. EPA's recent redesignation of the San Joaquin Valley as an "extreme" non-attainment area for NOx. (75 Fed. Reg. 24409.) Estimated NOx emissions in the San Joaquin Valley caused by the existing version of the LCFS regulation total approximately 2.39 tons per day (or 872.35 tons per year) in 2020. (Decl. Lyons at D-10 [Figure 1c], F-18 [Table 8].) This is far higher than the San Joaquin Valley Air Pollution Control District's (the "District") adopted threshold of significance for NOx, which explain that a "project" under

CEQA is considered to have a significant impact on air quality if it would cause NOx emissions to exceed 10 tons per year.[2]

LCFS 46-273 cont.

The EA makes no mention of these past increases, despite the fact that under the proposed LCFS regulation considered for "re-adoption" and the ADF regulation, statewide NOx emissions from biodiesel are projected to increase. (ADF ISOR at 42.) To fully consider and evaluate the potential significant impacts of the LCFS regulation and the ADF regulation, CARB may not look at the post-2014 emissions in isolation. Rather, by "chopping" the LCFS regulation into two smaller pieces, and obscuring the environmental impacts of the Regulations in the process, CARB is seeking to impermissibly piecemeal environmental review of the project. (*Lighthouse Field*, *supra*, 131 Cal.App.4th at 1208-09.)

B. The EA's Analysis of Criteria Pollutant Emissions, Including NOx, Is <u>Incomplete</u>

LCFS 46-274

NOx is one of the most important smog-forming emissions from man-made sources in some areas of California, including the San Joaquin Valley. Progress in reducing smog depends largely upon reductions of NOx, or "oxides of nitrogen," which are considered "major contributors to smog formation and acid deposition." (17 C.C.R., § 93118(d)(19).) NOx contributes to the formation of ground-level ozone (smog) in the San Joaquin Valley, particularly during the summer months. (*Calif. Building Indus. Ass'n v. San Joaquin Valley Air Pollution Control Dist.* (2009) 178 Cal.App.4th 120, 126 ["*CBIA*"].) The San Joaquin Valley air basin does not meet the federal ozone standard required under the Clean Air Act; the area has thus been designated by EPA as "extreme non-attainment" for ozone under the federal National Ambient Air Quality standards ("NAAQs"). (75 Fed. Reg. 24409.)

1. The EA Fails to Analyze or Discuss Criteria Pollutants Other than <u>NOx</u>

LCFS 46-275

The EA contains only a minimal discussion of impacts associated with criteria pollutants. (See EA at 51-52.) The EA only quantifies the emissions associated with one criteria pollutant: NOx. There is no discussion of other criteria pollutants, including particulate matter (PM), volatile organic compounds (VOCs), and reactive organic gases (ROG).

Whether CARB believes these impacts are insignificant is irrelevant. CEQA places the burden of environmental investigation on government rather than the public," and a lead agency "should not be allowed to hide behind its own failure to gather data." (See, e.g., *Sundstrom v. County of Mendocino* (1988) 202 Cal.App.3d 296, 311.) By failing to analyze the impacts of the proposed "re-adopted" LCFS regulation and the ADF regulation on criteria pollutants, other than NOx, the EA does not comply with CEQA.

[2] San Joaquin Valley Air Pollution Control Dist., Guide for Assessing and Mitigating Air Quality Impacts (1998; Jan. 2002 rev.) § 4, Table 4-1, p. 26 (the "SJVAPD Guide"), *available at* http://www.valleyair.org/transportation/CEQA%20Rules/GAMAQI%20Jan%202002%20Rev.pdf

2. The Project Will have Significant Impacts Associated With NOx Emissions, Even Using CARB's Own Analyses

Although the EA estimates that NOx emissions will decrease over time, CARB itself estimates that increased use of biodiesel associated with the ADF regulation and the "re-adopted" LCFS regulation will result in additional NOx emissions of 1.29 tons per day [or 470.85 tons per year] in 2015. (ADF ISOR, Table B-1.) Although CARB's estimated increases in NOx are inaccurate, and drastically understate NOx emissions, as explained *infra*, an increase in NOx emissions of 470.85 tons per year is in itself significant, and CARB cannot plausibly claim the Projects' impacts will have "beneficial" impacts on operational criteria pollutant emissions. LCFS 46-276

Any attempt by the EA to offset, or mitigate, biodiesel NOx emissions with the use of renewable diesel fuel is erroneous. There is "nothing in either the proposed ADF regulation or the proposed LCFS regulation that mandates the use of any volume of biodiesel in California, much less the use of the exact ratio of renewable diesel to biodiesel assumed by CARB staff in its emissions analysis." (Decl. Lyons, at D-4.) Despite this, the EA does not include any analysis of the possibility that renewable diesels will not displace biodiesels at the rate contemplated in the ISOR. Thus, any alleged off-set is speculative, and does not excuse CARB's failure to analyze NOx increases associated with biodiesel, or to mitigate the 470.85 tons per year in emissions increased use of biodiesel will generate. LCFS 46-277

Moreover, none of the documents made available for public review by CARB (including the EA, the two ISORs, or the supporting materials) support staff's assertion "that 40% of renewable diesel used in California will be used by refiners to aid in compliance with CARB's existing diesel fuel regulations and that 60% will be blended downstream of refineries." (*Id.*) Indeed, this result defies common sense; to the extent fuel producers choose to blend renewable diesel in California, it would be far more logical for "them to do so by purchasing renewable diesel for use at their refineries where they can benefit from the other desirable properties of this fuel beyond its low carbon intensity (CI) value (e.g., high cetane number and fungibility with diesel fuel at all blend levels)," as opposed to "purchasing LCFS credits generated by downstream blenders of renewable diesel fuel." (*Id.*) LCFS 46-278

The Regulations will have significant impacts resulting from the emission of NOx caused by increase biodiesel usage. As a result, the EA's finding that the Regulations would have a "beneficial" effect to criteria pollutant emissions is erroneous, and not supported by substantial evidence. LCFS 46-279

3. The Analysis of NOx Impacts Is Flawed and Incomplete, and Omits Known Sources of Emissions

The EA's analysis significantly understates the true impacts associated with operational NOx emissions. CARB staff's calculation of NOx emissions associated with increased biodiesel usage was based on the erroneous assumption that biodiesel use in "New Technology Diesel Engines" (NTDEs) at levels up to B20 will not increase NOx emissions. As explained in the Declaration of James M. Lyons, the available data demonstrate "not only that NOx emissions from NTDEs will increase with the use of biodiesel in proportion to the amount LCFS 46-280 of biodiesel present in the blend, but also that the magnitude of the increase on a percentage basis will be much greater than that observed for 'legacy vehicles.'" (Decl. Lyons, at D-4.)

Specifically, "if one simply and extremely conservatively assumes that NTDE NOx increases will be the same on a percentage basis as legacy vehicles and eliminates the NOx offsets assumed from renewable diesel, the NOx increases expected from biodiesel increase from 1.36 tons per day statewide in 2014 to approximately 3.44 tons per day—a factor of about 2.65." (Decl. Lyons, at D-4; see also ADF ISOR, Table B-1.) "For 2023, estimated NOx emission increases due to biodiesel rise to about 0.87 tons per day . . . ." (*Id.* at D-4, D-5.) Thus, accounting for NOx emissions associated with NTDEs alone, projected NOx emissions are far greater than those calculated by CARB staff.

LCFS 46-280 cont.

By performing a detailed and comprehensive – yet conservative – analysis of NOx increases using generally accepted techniques, Sierra Research has concluded that NOx emissions are far more severe, and could total as much as 9.73 tons per day statewide in 2020, and 2.39 tons per day (or 872.35 tons per year) in 2020 in the San Joaquin Valley air basin alone. (Decl. Lyons at D-10 [Figure 1c], D-18 [Table 8].) This figure is vastly higher than the 10 tons per year threshold of significant adopted by the San Joaquin Valley Air Pollution Control District for projects under CEQA. (See SJVAPD Guide, § 4, Table 4-1, p. 26.)

4. The EA Fails to Quantify Impacts Associated With the Construction <u>Of New Facilities</u>

The EA posits that the Regulations would result in the construction of new or modified fuel production facilities to meet demand for fuels created by the Regulations, including processing plants for agriculture-based ethanol, cellulosic ethanol, and biomethane. Without quantifying the potential impacts of these facilities, the EA makes the bare conclusion that several of the impacts associated with these facilities would be "significant and unavoidable."

LCFS 46-281

An environmental document, including a functional equivalent document, however, cannot simply label an impact "significant and unavoidable" without first providing a discussion and analysis. Such a backwards approach "allows the agency to travel the legally impermissible easy road to CEQA compliance." (*Berkeley Keep Jets Over the Bay Comm. v. Bd. of Port Comm'rs* (2001) 91 Cal.App.4th 1344, 1370.) Rather, the lead agency must quantify the impact, and consider feasible mitigation based on that analysis. (See, e.g., *Sundstrom*, *supra*, 202 Cal.App.3d at 311 ["CEQA places the burden of environmental investigation on government rather than the public," and a lead agency "should not be allowed to hide behind its own failure to gather data."].)

The potential impacts associated with the development of new or modified facilities *can* be quantified. As explained in the Declaration of James M. Lyons, CARB attempted to quantify emissions from such facilities in its 2009 rulemaking. (Decl. Lyons at B-3.)

LCFS 46-282

Moreover, by declining to quantify impacts associated with new facilities, the EA essentially forecloses any and all mitigation measures. For example, if potential criteria pollutant emissions were quantified, CARB could modify the proposed regulation, enact another regulation, or otherwise develop mitigation to reduce such impacts. CARB could also reconfigure the Regulations, create performance standards for new California biodiesel facilities, or otherwise create disincentives to develop new facilities within California. Instead, however, the EA merely provides a laundry list of *potential* mitigation measures, without actually requiring that those mitigation measures be implemented, or analyzing whether those mitigation measures would reduce the impacts to a less-than-significant level. LCFS 46-282 cont.

5. The Increased NOx Emissions Under the Regulations Violate AB32

NOx emissions caused by the Regulations also violate AB 32. Health and Safety Code Section 38570, subdivision (b), requires CARB, "***[p]rior to*** the inclusion of any market-based compliance mechanism in the regulations," to "(1) [c]onsider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution," and "(2) [d]esign any market-based compliance mechanism *to* ***prevent any increase*** in the emissions of toxic air contaminants or criteria air pollutants." (Health & Saf. Code § 38570, subd. (b) [emphasis added]. In addition, for any regulation adopted under AB32 like the LCFS regulation, the Board must "***ensure*** . . . activities undertaken pursuant to the regulations do not interfere with . . . efforts to achieve and maintain federal and state ambient air quality standards" (*Id.* § 38562(b)(4); emphasis added)].) Because the Regulations would ***increase*** NOx emissions from biodiesel, the Regulations are unlawful. LCFS 46-283

C. The Mitigation Measures Proposed in the EA Inadequate Under CEQA

The Mitigation Measures specified in the EA are also inadequate under CEQA. The EA finds that several potential impacts of the Regulations would be "significant and unavoidable," resulting from the construction of new or modified facilities to meet demand for fuels created by the Regulations, including processing plants for agriculture-based ethanol, cellulosic ethanol, and biomethane. Rather than including enforceable mitigation, however, the EA merely sets forth "recognized practices" that are "routinely required" to avoid or minimize impacts, without requiring the implementation of any specific measure, or even evaluating whether any such measures – if incorporated – would actually reduce or minimize the impact. This is improper under CEQA for several reasons. LCFS 46-284

First, mitigation must be enforceable. (Pub. Resources Code, § 21081.6, subd. (b); CEQA Guidelines, § 15126.4(a)(2).) The EA, however, does not require any particular measure. Rather, the EA just sets forth a potential mitigation measures that local land use authorities *could* implement if they choose to do so. Because none of the mitigation measures identified in the EA are enforceable, they are inadequate under CEQA. LCFS 46-285

Mitigation must also be effective, and an agency must identify mitigation measures that will minimize the project's significant impacts by reducing or avoiding them. (See, e.g., Pub. Resources Code, §§ 21001, 21100.) The EA, however, does not discuss *how* any of the proposed mitigation measures – if implemented – would reduce or avoid the potential impacts of the Regulation, and if so, to what degree. LCFS 46-286

Nor may CARB permissibly defer the formulation of specific mitigation. To defer mitigation, a lead agency must still (1) "evaluate[] the potentially significant impacts of the LCFS 46-287 project," (2) "identif[y] measures that will mitigate those impacts," (3) "commit[] to the mitigating the significant impacts of the project," and (4) "specify performance standards which would mitigate the significant effect of the project" to govern the subsequent mitigation. (*California Native Plant Soc'y v. City of Rancho Cordova* (2009) 172 Cal.App.4th 603, 621.) Here, in contrast, the EA does not specifically identify the potential impacts, require the mitigation of significant impacts, or "specify performance standards which would mitigate the significant effect of the" Regulations. (See *id.*) LCFS 46-287 cont.

As a result, CARB must revise the EA to further analyze potential mitigation measures, and include enforceable mitigation to minimize the recognized potentially significant impacts of the Regulations, and recirculate the revised EA for public review. LCFS 46-288

D. <u>The EA Fails to Analyze Impacts Associated With Fuel Shuffling</u>

Since its enactment in 2009, the LCFS regulation has led to a phenomenon called "fuel shuffling," in which lower-CI fuels are shipped from around the world to California and higher-CI fuels must be sent for sale elsewhere. (Decl. Lyons at B-4.) CARB has admitted that fuel shuffling will occur. (See, e.g., December 2009, Final Statement of Reasons at 241.) There is no environmental advantage to fuel shuffling, for the same fuels are still produced and consumed, and the same GHGs are still emitted from those processes. Rather, because the LCFS regulation encourages the shipment of fuels to alternative locations that are further from origin facilities, fuel shuffling actually causes emissions of GHGs to increase.[3]

These increases in emissions are potentially significant, but discussed nowhere in the EA. For example, even using CARB's direct emissions model (GREET), GHG emissions associated with shuffling would be significant. For example, the LCFS regulation will likely result in higher amounts of Brazilian cane ethanol being shipped to California, with more traditional fuels being shipped from California to Brazil and other destinations by ship. Additional shipping corn- and sugarcane-based ethanol by ship to and from destinations such as Brazil alone would result in an additional 150,000 tons per year of CO2 equivalent emissions. (Appendix G) Using more accurate direct emission models, increase CO2 equivalent emissions would be between 385,000-735,000 tons per year – or nearly 4.5% of the total emissions benefits CARB assets the Regulations would allegedly cause. (Appendix G) Notably, these figures do not include increases in emissions associated with fuel shuffling of crude oils, or the increases in the transport of ethanol by rail as part of fuel shuffling. (Appendix G) LCFS 46-289

The EA likewise does not evaluate whether fuel shuffling caused by the Regulations would result in additional increases in criteria pollutant emissions. Because transportation of fuels by rail, truck, and sea indisputably create emissions of criteria pollutants, both inside and outside[4] California, the EA must analyze those potential impacts to determine LCFS 46-290

[3] Because the LCFS regulation will not achieve any benefits as to climate change, CARB cannot base any statement of overriding considerations on this assertion.

[4] CARB must analyze both in-state and out-of-state impacts caused by the Regulation. CEQA defines "environment" to include "the physical conditions that exist within the area which will be affected by a proposed project, including land, air, water, minerals, flora, fauna, noise, or objects of historic or aesthetic significance." (Public Resources Code, § 21060.5.) That definition includes no geographic limitation. We also understand CARB has considered out-of-state impacts in previous rulemakings.

whether they are significant. (See, e.g., *Sundstrom*, *supra*, 202 Cal.App.3d at 311 ["CEQA places the burden of environmental investigation on government rather than the public," and a lead agency "should not be allowed to hide behind its own failure to gather data."].) LCFS 46-290 cont.

Thus, to accurately identify and analyze the impacts of the Regulations, the EA must be revised to address impacts associated with fuel shuffling, and recirculate the EA for public review. LCFS 46-291

E. <u>The EA's Discussion of the Growth Energy Alternative Is Insufficient</u>

The requirement that environmental documents identify and discuss alternatives to the project stems from the fundamental statutory policy that public agencies should require the implementation of feasible alternatives or mitigation measures to reduce the project's significant impacts. (See, e.g., Pub. Resources Code, § 21002.) The lead agency must focus on alternatives that can avoid or substantially lessen a project's significant environmental effects. (See *id.*) The EA here impermissibly rejects discussion of the Growth Energy Alternative, and does not include any discussion of a Cap and Trade Alternative. These alternatives are discussed in greater detail below. The CEQA Guidelines specifically recognize that comments raised by members of the public on an environmental document are particularly helpful if they suggest "additional specific alternatives . . . that would provide better ways to avoid or mitigate the significant environmental effects." (CEQA Guidelines, § 15204.) LCFS 46-292

The Growth Energy Alterative contemplates an adjustment to the cap and trade regulation in Title 17 of the California Code of Regulations to account for whatever increment of GHG emissions reductions would be foregone by eliminating the LCFS regulation. CARB concedes the Growth Energy Alternative would achieve the same emissions reductions contemplated under the Regulations. (See Standardized Regulatory Impact Assessment at 26-27.) LCFS 46-293

The Growth Energy Alternative also would not result in fuel shuffling, or the construction of numerous fuel production plants in California. (See Decl. Lyons at B-4.) Because the only impacts found to be "significant and unavoidable" under the EA result from the construction of new and modified fuel production facilities, the Growth Energy Alternative would likely eliminate ***all*** of the Regulations' significant and unavoidable impacts. Because the Growth Energy Alternative would lessen the "significant and unavoidable" effects of the Regulations, it should be included as an alternative in a recirculated EA. (Pub. Resources Code, § 21002.) LCFS 46-294

Despite these benefits, the EA rejects the Growth Energy Alternative to the Regulations because it would allegedly require that actions be taken to mitigate increased NOx emissions from biodiesel under circumstances where CARB staff incorrectly assumed there would be no increased emissions due to biodiesel use under the ADF. These assumptions are flawed. LCFS 46-295

As demonstrated by Sierra Research, the ADF regulation will result in significant and unmitigated increases in NOx emissions throughout California, including significant impacts within the San Joaquin Valley and South Coast air basins. (Decl. Lyons ¶ 15.) The EA concedes the mitigation proposed under the Growth Energy Alternative would require "mitigation in exactly those areas where CARB staff was lead to believe it was not required based on its flawed emissions analysis." (Decl. Lyons at G-3.) Because of this, and the fact that the Growth Energy Alternative expands the conditions under which this mitigation has to be applied in order to eliminate the potential for any increase in NOx emissions due to biodiesel use, the Growth Energy Alternative is environmentally superior to the ADF regulation. (*Id.*) LCFS 46-295 cont.

To the extent CARB argues the Growth Energy Alternative does not meet the objective of "greater innovation and development of cleaner fuels," this is not a valid reason to reject discussion of the alternative. First, as explained in the Declaration of James M. Lyons, the Growth Energy Alternative would also foster greater innovation and development of cleaner fuels in California because most of the same fuels will be blended into California fuels as a result of the federal RFS program. (Decl. Lyons at C-4.)

But even if the Growth Energy Alternative would not meet this project objective, (see ISOR at E-40, E-41), CARB may not simply reject discussion of an alternative simply because it does not meet one of several project objectives. Rather, a feasible alternative that would substantially reduce the project's significant impacts should not be excluded from the analysis simply because it would not fully achieve the project's objectives. (See *Habitat & Watershed Caretakers v. City of Santa Cruz* (2013) 213 Cal.App.4th 1277, 1304.) Here, as discussed above, the Growth Energy Alternative would essentially eliminate all of the "significant and unavoidable" impacts of the Regulations. LCFS 46-296

Further, to the extent CARB relies upon this objective to reject mere analysis of the Growth Energy Alternative, this is improper because it would essentially limit the range of alternatives described to regulations that are nearly identical to the Regulations. Because agencies may not "give a project's purpose an artificially narrow definition," (*In re Bay-Delta Programmatic Envt'l Report Coordinated Proceedings* (2008) 43 Cal.4th 1143, 1166), and CARB has previously demonstrated a pattern of prejudging the LCFS regulation prior to completing the environmental review process, (see *POET, LLC v. California Air Resources Board* (2013) 218 Cal.App.4th 681), CARB should not artificially tailor its objectives to limit the range of alternatives to the LCFS regulation itself. LCFS 46-297

In short, the Growth Energy Alternative better achieves the project objectives than the Regulations, and is environmentally superior to the Regulations. As a result, the EA must analyze the Growth Energy Alternative, and CARB must recirculate the EA for public comment. LCFS 46-298

F. CARB Must Substantially Revise the LCFS Regulation, the ADF Regulation, And the EA, Due to Material Inconsistencies Between the Two Regulations

As explained in detail in the Declaration of James M. Lyons, the LCFS regulation and the ADF regulation "contain inconsistent and conflicting definitions," and lack "provisions requiring the determination, through testing, of the biodiesel content of commercial blendstocks." (Decl. Lyons ¶ 17.) These inconsistencies include that: (1) the Regulations contain different definitions for the term "biodiesel"; (2) the term "Biodiesel Blend" under the LCFS regulations contains at least 6% biodiesel, while a "Biodiesel Blend" under the ADF is a diesel fuel containing any biodiesel; (3) the LCFS regulation defines "Diesel Fuel Blend" as a blend of diesel fuel and up to 5% biodiesel, while such a fuel would be considered "CARB diesel" under the ADF regulation; and (4) under the proposed ADF regulation, "B20" is LCFS 46-299 nonsensically defined as a fuel that contains between 6% and 20% biodiesel, which directly contradicts the definition of "Blend Level" in same regulation. (See Decl. Lyon at H-3, H-4.)

In addition, the term "Biodiesel Blend" is defined in the ADF regulation as a mixture of biodiesel and an undefined fuel referred to as "petroleum-based CARB diesel." "Blend Level" applies to blends of all fuels subject to the ADF regulation, including biodiesel, and is defined as the ratio of an "Alternative diesel fuel" mixed with "CARB diesel." As noted above, however, "CARB diesel" may already contain as much as 5% biodiesel under the proposed ADF regulation. The addition of biodiesel to a fuel already containing some amount of biodiesel up to 5% will cause the actual biodiesel content to be higher than the blender expects, which in turn will result in increased NOx emissions. (See Decl. Lyons at F-3, F-4.) These potential NOx emissions are not discussed in the EA.

LCFS 46-299 cont.

The internal inconsistencies between the LCFS regulation and the ADF regulation also render the project description defective. "An accurate, stable and finite project description is the sine qua non of an informative and legally sufficient EIR." (*County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 193.) Because the LCFS regulation and the ADF regulation contain material, conflicting terms, the project description is not accurate or stable, and must be revised.

Due to these material inconsistencies, the EA is legally flawed. Both the proposed regulations and the EA must be revised significantly, and recirculated for public review.

This page intentionally left blank.

46_OP_LCFS_GE Responses (Page 286 - 298)

576. Comment: **LCFS 46-261 through LCFS 46-298**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

402

46_OP_LCFS_GE

17_OP_ADF_GE

FILED
FEB 10 2014
FRESNO SUPERIOR COURT
By________ DEPT. 402 - DEPUTY

SUPERIOR COURT OF CALIFORNIA, COUNTY OF FRESNO

CENTRAL DIVISION

POET, LLC and JAMES M. LYONS Petitioners and Plaintiffs, vs. CALIFORNIA AIR RESOURCES BOARD; JAMES N. GOLDSTENE, in his official capacity as Executive Officer of the California Air Resources Board; LORI ANDREONI, in her official capacity as a Manager of the California Air Resources Board; and ELLEN PETER, in her official capacity as Chief Counsel of the California Air Resources Board, Respondents and Defendants.	Case No. 09 CE CG 04659 **[redacted] PEREMPTORY WRIT OF MANDATE** Department: 402 Honorable Jeffrey Y. Hamilton, Jr. Action Filed: December 23, 2009

Judgment having been entered in this proceeding, ordering that a peremptory writ of mandate be issued from this Court,

IT IS ORDERED that, immediately on service of this writ:

1. Respondent and Defendant California Air Resources Board ("ARB") set aside its approval of the Low-Carbon Fuel Standard ("LCFS") regulations, including Board Resolution 09-31, dated April 23, 2009; Executive Order R-09-014, dated November 25, 2009; Executive Order R-10-003, dated March 4, 2013; and ARB's decision to defer the formulation of mitigation measures relating to NOx emission from biodiesel.

2. ARB shall (a) select a decision maker, (b) take such action as may be necessary to assure that the decision maker has full authority to approve or disapprove the proposed LCFS regulations and to complete the environmental review, and (c) take such action as may be necessary to assure the decision maker does not approve the proposed LCFS regulations until after the decision maker has completed the environmental review.

3. ARB shall address whether the project will have a significant adverse effect on the environment as a result of increased NOx emissions, make findings (supported by substantial evidence) regarding the potential adverse environmental effect of increased NOx emissions, and adopt mitigation measures in the event the environmental effects are found to be significant.

4. ARB shall allow public comments for a period of at least 45 days on all issues related to the approval of the proposed LCFS regulations (which shall include, without limitation, issues concerning (a) the carbon intensity values attributed to land use changes, (b) the application of the GTAP model, and (c) any new material in any supplemental staff report prepared in connection with the proposed LCFS regulations) and respond to those comments before approving the proposed LCFS regulations.

5. ARB shall [redacted] include in its rulemaking file [redacted] the four emails referenced in the July 15, 2013, Opinion of the Fifth District Court of Appeal, case number F064045, at pages 61 through 80.

6. ARB shall preserve the status quo by continuing to adhere to the LCFS regulations standards in effect for 2013 until the corrective action is completed. Notwithstanding the directive herein that ARB set aside its prior approvals of the LCFS regulations and related resolutions and orders, the LCFS regulations shall remain in operation and shall be enforceable unless its operation is suspended as provided below.

7. Pursuant to Public Resources Code Section 21168.9(c), the Court does not direct ARB to exercise its lawful discretion in any particular way.

8. Pursuant to Public Resources Code Section 21168.9(c), the Court shall retain jurisdiction over ARB's proceedings by way of a return to this peremptory writ of mandate until the Court has determined that ARB has fully complied with the provisions of CEQA.

9. ARB shall file an initial return no later than 30 days after issuance of this writ. The initial return shall explain what action ARB will take to satisfy the writ's requirements; this explanation shall include a schedule and shall identify who will act as the decision maker.

10. Within 15 days of the filing of the initial return, Plaintiffs POET, LLC, and James M. Lyons ("Plaintiffs") may file a response, which shall include Plaintiffs' objections to matter addressed in the initial return. If Plaintiffs file a response, ARB's reply shall be due no later than 15 days after the response.

11. ARB shall proceed in good faith without delay. In the event ARB fails to proceed in good faith with diligence, this Court immediately shall vacate Paragraph 6 of this writ, which preserves the status quo, and shall direct ARB to set aside the LCFS regulations (i.e., suspend the operation and enforcement of the regulations).

IT IS SO ORDERED.

DATED: 2/10/14

Honorable Jeffrey Y. Hamilton, Jr.
Judge of the Superior Court

Submitted on this 23rd day of December 2013, by:

Timothy Jones
John P. Kinsey
Daren A. Stemwedel
Attorneys for Petitioners and Plaintiffs
POET, LLC and James M. Lyons

PROOF OF SERVICE

My business address is 265 E. River Park Circle, Suite 310, Post Office Box 28340, Fresno, California 93720. I am employed in Fresno County, California. I am over the age of 18 years and am not a party to this case.

On the date indicated below, I served the foregoing document(s) described as **[PROPOSED] PEREMPTORY WRIT OF MANDATE** on all interested parties in this action by placing a true copy thereof enclosed in sealed envelopes addressed as follows:

SEE ATTACHED SERVICE LIST

_____ **(BY MAIL)** I am readily familiar with the business' practice for collection and processing of correspondence for mailing, and that correspondence, with postage thereon fully prepaid, will be deposited with the United States Postal Service on the date noted below in the ordinary course of business, at Fresno, California.

_____ (BY PERSONAL SERVICE) I caused delivery of such envelope(s), by hand, to the office(s) of the addressee(s).

_____ (BY ELECTRONIC MAIL) I caused such documents to be scanned into PDF format and sent via electronic mail to the electronic mail addressee(s) of the addressee(s) designated.

_____ (BY FACSIMILE) I caused the above-referenced document to be delivered by facsimile to the facsimile number(s) of the addressee(s).

__X__ (BY OVERNIGHT COURIER) I caused the above-referenced envelope(s) to be delivered to an overnight courier service for delivery to the addressee(s).

EXECUTED ON December 23, 2013, at Fresno, California.

__X__ **(STATE)** I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

[signature]

Lisa Turri Zanoni

{7011/003/00246548.DOC}

SERVICE LIST

VIA ONTRAC-OVERNIGHT
Mark W. Poole, Esq.
Gavin G. McCabe, Esq.
STATE OF CALIFORNIA,
DEPARTMENT OF JUSTICE
455 Golden Gate Avenue, Suite 11000
San Francisco, California 94102-7004
Fax: 415-703-5480
E-mail: mark.poole@doj.ca.gov
E-mail: **gavin.mccabe@doj.ca.gov**

VIA ONTRAC-OVERNIGHT
David R. Pettit, Esq.
NATURAL RESOURCES DEFENSE COUNCIL
1314 2nd Street
Santa Monica, California 90401
Fax: 310-434-2399
E-mail: dpettit@nrdc.org

VIA ONTRAC-OVERNIGHT
CALIFORNIA AIR RESOURCES BOARD
1001 "I" Street
Sacramento, CA 95812

VIA ONTRAC-OVERNIGHT
James N. Goldstene, Executive Officer
CALIFORNIA AIR RESOURCES BOARD
1001 "I" Street
Sacramento, CA 95812

VIA ONTRAC-OVERNIGHT
Lori Andreoni, Manager
CALIFORNIA AIR RESOURCES BOARD
1001 "I" Street
Sacramento, CA 95812

VIA ONTRAC-OVERNIGHT
Ellen Peter, Chief Counsel
CALIFORNIA AIR RESOURCES BOARD
1001 "I" Street
Sacramento, CA 95812

SUPERIOR COURT OF CALIFORNIA • COUNTY OF FRESNO **Civil Department - Non-Limited** 1130 "O" Street Fresno, CA 93724-0002 (559)457-1900	*FOR COURT USE ONLY*
TITLE OF CASE: **Poet, LLC vs California Air Resources Board/CEQA**	
CLERK'S CERTIFICATE OF MAILING	CASE NUMBER: **09CECG04659 JH**

Name and address of person served:

Timothy Jones
Wanger Jones Helsley PC
P.O. Box 28340
Fresno, CA 93729

CLERK'S CERTIFICATE OF MAILING

I certify that I am not a party to this cause and that a true copy of the 02/10/2014 Peremptory Writ of Mandate was mailed first class, postage fully prepaid, in a sealed envelope addressed as shown below, and that the notice was mailed at Fresno, California, on:

Date: **2/10/2014** Clerk, by M Santana, Deputy

M. Santana

Timothy Jones, Wanger Jones Helsley PC, 265 E. River Park Circle, Fresno CA 93729
Mark W. Poole, 455 Golden Gate Avenue, Suite #11000, San Francisco CA 94102
David Pettit, 1314 Second Street, Santa Monica CA 90401

46_OP_LCFS_GE Responses (Page 299 - 304)

577. Comment: **Writ of Mandate**

Agency Response: The Writ of Mandate does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

Comment letter code: 47-OP-LCFS-GE

Commenter: Joshua Willter

Affiliation: Growth Energy

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

47-OP-LCFS-GE Responses

578. Comment: **LCFS 47-1**

The commenter included the following materials with its comment letter.

1. Air Resources Board. (2014). Annual Research Plan: Fiscal Year 2015-2016. **(2.pdf)**

2. Air Resources Board. (2015). Proposed Regulation on the Commercialization of Alternative Diesel Fuels, Staff Report: Initial Statement of Reasons. January 2015. **(1.pdf)**

3. Air Resources Board. (2009). Proposed Regulation to Implement the Low Carbon Fuel Standard. Volume II, Appendices. **(1.pdf)**

4. Andreae, M.O. & Merlet, P. (2001). *Emission of Trace Gases and Aerosols from Biomass Burning*. Global Biogeochemical Cycles, Volume 15, No. 4, pp.955-966. December 2001. **(Emissions_Trace_Gas_from_Biomass_Burning.pdf)**

5. Anuario Estatistico de Energia Electria 2014: ano base 2013, versao “workbook” – dados preliminares. (2014). [Spreadsheet from http://www.epe.gov.br]. **(Anuario Estatistico de Energia Electrica 2014.xlsx)**

6. “Appendix A. Comparison of fuel detail for the State Energy Data System and the Annual and Monthly Energy Review data systems.“ (no date). **(appendixa.pdf)**

7. Australian Government, Department of Climate Change and Energy Efficiency. (2011). *Australian National Greenhouse Accounts*. National Inventory Report 2009, Volume 1. The Australian Government Submission to the UN Framework Convention on Climate Change. April 2011. **(NIR_Volume1.pdf)**

8. Christopherson, S. & Sivertsen, Z. (no date). “Economic Development Policy Makers Beware: Estimating the Job Impact of Public Investment in Bio-fuel Plants.” Working Paper Series, Economic Development: Communities and Regions. **(Chistopherson and Sivertsen 2012.pdf)**

9. Clark, N. N., Atkinson, C. M., Thompson, G. J., & Nine, R. D. (1999). “Transient Emissions Comparisons of Alternative Compression Ignition Fuels.” SAE Technical Papers Series

1999-01-1117, Reprinted from Alternative Fuels for CI Engines. **(2[copyrighted_material].pdf)**

10. Christy, J. R. (2007). “United States District Court for the District of Vermont, Rebuttal Expert Report for the Plaintiffs’ in *Green* Mountain *Chrysler Plymouth Dodge Jeep, et al. v. Crombie, et al.* Case No. 05-cv-302.” University of Alabama in Huntsville. April 18, 2007. **(5.pdf)**

11. Da Silva Paredes, D., Da R. Lessa, A.C., De Sant’ Anna, S.A.C., Boddey, R.M., Urquiaga, S., and Alves, B.J.R. (2013). Nutrient Cycling in Agroecosystems (2014) 98:41-55. December 21, 2013. **(art%3A10.1007%2Fs10705-013-9594-5.pdf)**

12. Dunn, J.B., Eason, J. & Wang, M.Q. (2011). Updated Sugarcane and Switchgrass Parameters in the GREET Model. Center for Transportation Research. Argonne National Laboratory. October 2011. **(feedstock_tech_memo.pdf)**

13. Durbin, T. D., Miller, J. W., Johnson, K.C., Hajbabaei, M., Kado, N. Y., Kobayashi, R., …Cahill, T. (2011). Final Report: CARB Assessment of the Emissions from the Use of Biodiesel as a Motor Vehicle Fuel in California: “Biodiesel Characterization and NOx Mitigation Study.” Prepared for Robert Okamoto and Alexander Mitchell, California Air Resources Board. University of California CE-CERT, Riverside, CA. University of California, Davis, Davis, CA. Arizona State University. October 2011. **(5.pdf)**

14. Durbin, T. D., Karavalakis, G., Johnson, K.C., & Hajbabaei, M., (2013). Final Report: CARB B5 Biodiesel Preliminary and Certification Testing. Prepared for Mr. Alexander Mitchell, California Air Resources Board. University of California CE-CERT, Riverside, CA. April 2013. **(4.pdf)**

15. Durbin, T. D., Karavalakis, G., Johnson, K.C., & Hajbabaei, M., (2013). Final Report: CARB B20 Biodiesel Preliminary and Certification Testing. Prepared for Mr. Alexander Mitchell, California Air Resources Board. University of California CE-CERT, Riverside, CA. July 2013. **(3.pdf)**

16. Eckerle, W. A., Lyford-Pike, E. J., Stanton, D. W., LaPointe, L. A., Whitacre, S. D. & Wall, J. C. (2008). “Effects of Methyl Ester Biodiesel Blends on NOx Emissions.” SAE Int. J. Fuels Lubr., Vol. 1, Issue 1, 2008-01-0078. **(6[copyrighted_material].pdf)**

17. Edgeworth Economics. (no date). Appendix D: Compliance with the Revised LCFS Program and Associated Economic Impacts. **(Appendix D.pdf)**

18. Fortes, C., Vitti. A.C., Otto, R., Ferreira, D.A., Franco, H.C.J., Cesar, P., & Trivelin, O. (2013). *Contribution of Nitrogen from Sugarcane Harvest Residues and Urea for Crop Nutrition*. Scientia Agricola. February 8, 2013. **(a05v70n5.pdf)**

19. Gysel, N., Karavalakis, G., Durbin, T., Schmitz, D., & Cho, A. (2014). "Emissions and Redox Activity of Biodiesel Blends Obtained from Different Feedstocks from a Heavy-Duty Vehicle Equipped with DPF/SCR Aftertreatment and a Heavy-Duty Vehicle without Control Aftertreatment." SAE Technical Paper 2014-01-1400. **(7[copyrighted_material].pdf)**

20. International Maritime Organization. (2008). Prevention of Air Pollution from Ships: Updated 2000 Study on Greenhouse Gas Emissions from Ships, Phase 1 Report. Marine Environment Protection Committee, 58th session, Agenda item 4. September 1, 2008. **(INF-6.pdf)**

21. Karavalakis, G., Durbin, T. D., Johnson, K.C., & Hajbabaei, M., (2014). Final Report: CARB Comprehensive B5/B10 Biodiesel Blends Heavy-Duty Engine Dynamometer Testing. Prepared for Mr. Alexander Mitchell, California Air Resources Board. University of California CE-CERT, Riverside, CA. June 2014. **(8.pdf)**

22. Lammert, M., McCormick, R., Sindler, P. & Williams, A. (2012). "Effect of B20 and Low Aromatic Diesel on Transit Bus NOx Emissions Over Driving Cycles with a Range of Kinetic Intensity." 2012-01-1984, *SAE Int. J. Fuels Lubr.* Vol. 5, Issue 3. **(9[copyrighted_material].pdf)**

23. Lisboa, C.C., Butterbach-Bahl, K., Mauder, M., & Kiese, R. (January 5, 2011). *Bioethanol* Production *from S*ugarcane and Emissions of Greenhouse Gases – Knowns and Unknowns. Global Change Bioenergy (2011), doi: 10.1111/j.1757.1707.2011.02095.x **(1757-1707.2011.pdf)**

24. McCormick, R.L., Alvarez, J.R., Grabosk, M.S., Tyson, K.S., & Vertin, K. (2002). "Fuel Additive and Blending Approaches to Reducing NOx Emissions from Biodiesel." *SAE Technical Paper Series* 2002-01-1658. **(10[copyrighted_material].pdf)**

25. McCormick, R.L., Tennant, C.J., Hayes, R.R., Black, S., Ireland, J.,McDaniel, T., …& Frailey, M. (2005). “Regulated Emissions from Biodiesel Tested in Heavy-Duty Engines Meeting 2004 Emission Standards.” SAE International 2005-01-2200. **(11[copyrighted_material].pdf)**

26. McWilliam, L. & Zimmermann, A. (2010). “Emissions and Performance Implications of Biodiesel Use in an SCR-equipped Caterpillar C6.6.” SAE International 2010-01-2157. **(12[copyrighted_material].pdf)**

27. Mizushima, N., Murata, Y., Suzuki, H., Ishii, H., Goto, Y., & Kawano, D. (2010). “Effect of Biodiesel on NOx Reduction Performance of Urea-SCR System.” SAE International 2010-01-2278. **(13[copyrighted_material].pdf)**

28. Nikanjam, M., Rutherford, J., & Spreen, K. (2010). “Performance and Emissions of Diesel and Alternative Diesel Fuels in a Heavy-duty Industry-Standard Older Engine.” SAE International 2010-01-2281. **(14[copyrighted_material].pdf)**

29. Nuszkowski, J., Tincher, R. R., & Thompson, G.J. (2009). *Evaluation of NOx Emissions from Heavy*-Duty *Diesel Engines with the Addition of Cetane Improvers*. Center for Alternative Fuels, Engines, and Emissions, Department of Mechanical and Aerospace Engineering, West Virginia University, DOI: 10.1243/09544070JAUTO1114. **(15.pdf)**

30. Odin Marine Group. (2015). Ethanol Report, Week 03 & 04. January 26, 2015. **(Odin Ethanol Report Week 03-04 2015.pdf)**

31. OECD-FAO. (2015). [Spreadsheet of Dataset: OECD-FAO Agricultural Outlook 2014-2023]. Data extracted from OECD.Stat. February 10, 2015. **(OECD Ethanol Price Projections.xlsx)**

32. Oil Price Information Service (OPIS). (no date). [Spreadsheet of Dataset from January 1, 2013, to February 5, 2015]. **(OPIS RIN Prices.xlsx)**

33. Platts. (no date). [Spreadsheet of Dataset from January 2, 2012, to January 26, 2015]. **(Platts Spot Prices.xlsx)**

34. Renewable Fuels Association. (2015). Biorefinery Locations. Retrieved from http://www.ethanolrfa.org/bio-refinery-locations .

February 16, 2015. **(Biorefinery Locations_RFA_Renewable Fuels Association.pdf)**

35. Renewable Fuels Association. (2015). Statistics. Retrieved from http://www.ethanolrfa.org/pages/statistics . February 16, 2015. **(Statistics_RFA_Renewable Fuels Association.pdf)**

36. Renouf, M.A., Pagan, R.J., & Wegener, M.K. (2010). *Life Cycle Assessment of Australian* Sugarcane *Products with a Focus on Cane Processing*. The International Journal of Lifecycle Assessment (2011) 16:125-137. DOI 10-1007/s11367-010-0233-y. September 30, 2010. **(Aust sugar cane processing.pdf)**

37. Renouf, M.A. & Wegener, M.K. (2007). “Environmental Life Cycle Assessment (LCA) of Sugarcane Production and Processing in Australia.” Cooperative Research Centre for Sugar Industry Innovation through Biotechnology, School of Geography, Planning and Architecture, School of Natural and Rural Systems Management, University of Queensland, St. Lucia, QLD. **(LCA_sugarcane_Aus.pdf)**

38. Rocke, D. M. (no date). Appendix G: Supplemental Statistical Analysis. Retrieved from http://www.arb.ca.gov/regact/2015/adf2015/adf15appg.pdf **(16.pdf)**

39. $(S\&T)^2$ Consultants Inc. (2015). Review of the Sugar Cane Ethanol Pathways in CA-GREET 2.0. Prepared for: Growth Energy, Washington, DC. February 2, 2015. **(Sugarcane Ethanol Review.doc and Sugarcane Ethanol Review.pdf)**

40. Sao Martinho. (2007). 18,420,870 Common Shares. UBS Investment Bank. February 9, 2007. **(SMTO_OfferimMemorandum_20090810_eng.pdf)**

41. Seabra, J.E.A., Macedo, I.C., Chum, H.L., Faroni, C.E., & Sarto, C.A. (2011). *Modeling and Analysis: Life Cycle Assessment of Brazilian Sugarcane Products: GHG Emissions and Energy Use*. Retrieved from www.wileyonlinelibrary.com. DOI: 10.1002/bbb.289. Biofuels, Bioproducts & Biorefining. 5:519-532. March 7, 2011. **(289_ftp.pdf)**

42. Signor, D., Cerri, C.E.P., & Conant, R. (2013). N2O Emissions due to Nitrogen Fertilizer Applications in Two Regions of Sugarcane Cultivation in Brazil. IOP Publishing. Environmental

Research Letters 8 (2013) 015013, 9 pp. February 12, 2013. **(1748-9326_8_1_015013.pdf)**

43. Swenson, D. (2006). "Input-Outrageous: The Economic Impacts of Modern Biofuels Production." Department of Economics, Iowa State University. June 2006. **(Swenson 2006.pdf)**

44. Swenson, D. (2007). "Understanding Biofuels Economic Impact Claims." Department of Economics, Iowa State University. April 2007. **(Swenson 2007.pdf)**

45. Thompson, G.J. & Nuszkowski, J. (2009). "Neat Fuel Influence on Biodiesel Blend Emissions." Department of Mechanical and Aerospace Engineering, West Virginia University, DOI: 10.1243/14680874JERO4909. **(17.pdf)**

46. Thorburn, P., Biggs, J., & Probert, M. (2010) "Nitrous Oxide Emissions from Soils in Australian Sugarcane Production Systems." 19th World Congress of Soil Science, Soil Solutions for a Changing World. **(1883.pdf)**

47. U.S. Energy Information Administration. (2015). Short-Term Energy Outlook. Retrieved from http://www.eia.gov/forecasts/steo/report/renew_co2.cfm . February 10, 2015. **(Short-Term Energy Outlook - U.S.pdf)**

48. U.S. Energy Information Administration. (no date). "Table 1. State energy-related carbon dioxide emissions by year (2000-2011)." **(table1.pdf)**

49. U.S. Energy Information Administration. (no date). "Table 2. 2011 State energy-related carbon dioxide emissions by fuel." **(table2.pdf)**

50. U.S. Energy Information Administration. (no date). "Table 3. 2011 State energy-related carbon dioxide emissions by sector." **(table3.pdf)**

51. U.S. Energy Information Administration. (no date). "Table 4. 2011 State energy-related carbon dioxide emission shares by sector." **(table4.pdf)**

52. U.S. Energy Information Administration. (no date). "Table 5. Per capita energy-related carbon dioxide emissions by State (2000-2011)." **(table5.pdf)**

53. U.S. Energy Information Administration. (no date). “Table 6. Energy intensity by State (2000-2011).” **(table6.pdf)**

54. U.S. Energy Information Administration. (no date). “Table 7. Carbon intensity of the energy supply by State (2000-2011).” **(table7.pdf)**

55. U.S. Energy Information Administration. (no date). “Table 8. Carbon intensity of the economy by State (2000-2011).” **(table8.pdf)**

56. U.S. Energy Information Administration. (no date). “Table 9. Net electricity trade index and primary electricity source for selected States.” (2000-2011).” **(table9.pdf)**

57. U.S. Environmental Protection Agency. (2003). “The Effect of Cetane Number Increase Due to Additives on NOx Emissions from Heavy-Duty Highway Engines, Final Technical Report.” EPA420-R-03-002. February 2003. **(18.pdf)**

58. Urbanchuk, J. M. (2012). “Contribution of the Ethanol Industry to the Economy of the United States.” Prepared for the Renewable Fuels Association by Cardno Entrix. February 2, 2012. **(Contribution of the Ethanol Industry 2012.pdf)**

59. Vargas, V.P., Cantarella, H., Martins, A.A., Soares, J.R., Braga do Carmo, J., & Alberto de Andrade, C. (2013). *Sugarcane Crop Residue Increases N2O and CO2 Emissions Under High Soil Moisture Conditions*. Research Article. Sugar Tech, Apr-June 2014, 16(2): 174-179, DOI: 10.1007/s12355-013-0271-4. October 8, 2013. **(Sugarcane Crop Residue Increases N2O and CO2 Emissions Under High Soil Moisture Conditions – Springer.pdf)**

60. Walkowicz, K., Na, K., Robertson, W., Sahay, K., Bogdanoff, M., Weaver, C., & Carlson, R. (2009). “On-road and In-Laboratory Testing to Demonstrate Effects of ULSD, B20 and B99 on a Retrofit Urea-SCR Aftertreatment System.” SAE International 2009-01-2733. **(19[copyrighted_material].pdf)**

61. Walter, A., Galdos, M.V., Scarpare, F.V., Verde Leal, M.R.L., Seabra, J.E.A., Pereira da Cunha, M.,…Fernandes de Oliveria, C.O. (2013). *Brazilian Sugarcane* Ethanol*: Developments So Far and Challenges for the Future*. WIREs Energy Environ 2013. DOI: 10.1002/wene.87. **(f-409.pdf)**

62. Wang, L., Quiceno, R., Price, C., Malpas, R., & Woods, J. (2014). *Economic and GHG Emissions* Analyses *for Sugarcane Ethanol in Brazil: Looking Forward*. Renewable and Sustainable Energy Reviews 40 (2014) 571-582. August 2014. **(1-s2.0-S1364032114006728-main.pdf)**

63. Wigley, T. M. L. (2008). MAGICC/SCENGEN 5.3: Operator Instructions. Abbreviated from the MAGICC/SCENGEN 5.3 User Manual. NCAR, Boulder, CO. September 2008. **(3.pdf)**

<u>Agency Response:</u> This comment letter contains 63 references that were cited in Comment Letter **46_OP_LCFS_GE**. None of these materials contain objections to or recommendations concerning ARB's proposed regulation. As such, no response specific to these materials is required. ARB has separately responded to the comments that may rely on these materials.

Comment letter code: 48-OP-LCFS-GE

Commenter: Joshua Willter

Affiliation: Growth Energy

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

48-OP-LCFS-GE Responses

579. Comment: **LCFS 48-1**

The commenter included the following materials with its comment letter.

1. Air Resources Board. (no access date). [Web]. Transport Refrigeration Unit (TRU or Reefer) ATCM. Retrieved from http://www.arb.ca.gov/diesel/tru/tru.htm#mozTocId341892 (#17 in **Draft-ADF-Declaration – References.doc**x)

2. Air Resources Board. (no date). Notice of Decision not to Proceed and Cancellation of March 20, 2014 Hearing to Consider a Proposed Regulation on the Commercialization of New Alternative Diesel Fuels. Retrieved from http://www.arb.ca.gov/regact/2013/adf2013/NDNPadf2013.pdf **(15.pdf)**

3. Air Resources Board. (no date). Notice of Postponement: Public Hearing to Consider a Proposed Regulation on the Commercialization of New Alternative Diesel Fuels. Retrieved from http://www.arb.ca.gov/regact/2013/adf2013/adf2013postpone.pdf **(14.pdf)**

4. Air Resources Board. (2013). Staff Report: Initial Statement of Reasons, Proposed Regulation on the Commercialization of New Alternative Diesel Fuels. Retrieved from http://www.arb.ca.gov/regact/2013/adf2013/adf2013isor.pdf . October 23, 2013. **(13.pdf)**

5. Air Resources Board. (2013). Notice of Public Hearing to Consider the Proposed Regulation on the Commercialization of New Alternative Diesel Fuels. Retrieved from http://www.arb.ca.gov/regact/2013/adf2013/adf2013notice.pdf . October 15, 2013. **(12.pdf)**

6. Air Resources Board (2013). California Air Resources Board 2013 Rulemaking Calendar. Retrieved from http://www.arb.ca.gov/regact/2013rmcal.pdf **(11.pdf)**

7. Air Resources Board (2012). California Air Resources Board 2012 Rulemaking Calendar. Retrieved from http://www.arb.ca.gov/regact/2012rulemakingcalendar.pdf **(10.pdf)**

8. Air Resources Board. (2011). California Air Resources Board 2011 Rulemaking Calendar. Retrieved from http://www.arb.ca.gov/regact/2011rulemakingcalendar.pdf **(9.pdf)**

9. Air Resources Board. (2010). California Air Resources Board 2010 Rulemaking Calendar. Retrieved from http://www.arb.ca.gov/regact/2010rulemakingcalendar.pdf **(8.pdf)**

10. Air Resources Board. (2009). California Air Resources Board 2009 Rulemaking Calendar. Retrieved from http://www.arb.ca.gov/regact/2009rulemakingcalendar.pdf **(7.pdf)**

11. Air Resources Board. (2006). Draft Advisory on Biodiesel Use. Retrieved from http://www.arb.ca.gov/fuels/diesel/altdiesel/111606biodsl_advisory.pdf . November 14, 2006. **(5.pdf)**

12. Air Resources Board. (2006). [Slide presentation]. Suggested ARB Biodiesel Policy. Retrieved from http://www.arb.ca.gov/fuels/diesel/altdiesel/052406arb_prsntn.pdf) . May 24, 2006. **(6.pdf)**

13. Air Resources Board. (2004). [Letter to the public]. Public notice for first meeting of the biodiesel workgroup. Retrieved from http://www.arb.ca.gov/fuels/diesel/altdiesel/041204altdslwsh.pdf . March 18, 2004. **(3.pdf)**

14. Air Resources Board. (2004). [Slide presentation]. Public Consultation Meeting Regulatory and Non-Regulatory Fuels Activities. Retrieved from http://www.arb.ca.gov/fuels/diesel/022504arb.pdf . February 25, 2004. **(2.pdf)**

15. CVS News. (2004). In “CARB Holds Second Workshop on Regulatory and Non-Regulatory Fuels Activities” (pp. 27-31). Retrieved from http://www.sierraresearch.com/documents/cvs_news_may_2004.pdf . May 2004. **(4.pdf)**

16. Lyons, J. “Re: AB 1085 Materials for the Proposed LCFS and ADF regulations.” Message to Alexander (Lex) Mitchell, Jack Kitowski, Katrina Sideco, & Jim Aguila. January 2, 2015, and January 3, 2015. E-mails. **(1085 EMAIL 1.pdf)**

17. Schremp, G. (2013). [Slide presentation]. Biofuel Supply, Feedstock Availability & Infrastructure Issues. California Energy Commission Joint Lead Commissioner Workshop on Transportation Energy Demand Forecasts. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-08-21_workshop/presentations/06_Schremp_Biofuels.pdf . August 21, 2013. **(16.pdf)**

18. South Coast Air Quality Management District. (2013). 2012 Air Quality Management Plan: Regional Transportation Strategy and Control Measures. Appendix IV-C. Retrieved from http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2012-air-quality-management-plan/final-2012-aqmp-(february-2013)/appendix-iv-(c)-final-2012.pdf . February 2013. **(18.pdf)**

19. U.S. Environmental Protection Agency. (2002). A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions: Draft Technical Report. EPA420-P-02-001. Retrieved from http://www.epa.gov/otaq/models/analysis/biodsl/p02001.pdf . October 2002. **(1.pdf)**

Agency Response: This comment letter contains 19 references that were cited in Comment Letter **46_OP_LCFS_GE**. None of these materials contain objections to or recommendations concerning ARB's proposed regulation. As such, no response specific to these materials is required. ARB has separately responded to the comments that may rely on these materials.

This page intentionally left blank.

Comment letter code: 49-OP-LCFS-GE

Commenter: Joshua Willter

Affiliation: Growth Energy

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

49-OP-LCFS-GE Responses

580. Comment: **LCFS 49-1**

The commenter included the following materials with its comment letter.

Intergovernmental Panel on Climate Change (IPCC). (2014). Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, & L.L. White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1132 pp. **(WGIIAR5-PartA_FINAL.pdf)**

Agency Response: This comment letter contains one reference that was cited in Comment Letter **46_OP_LCFS_GE**. None of these materials contain objections to or recommendations concerning ARB's proposed regulation. As such, no response specific to these materials is required. ARB has separately responded to the comments that may rely on these materials.

This page intentionally left blank.

Comment letter code: 50-OP-LCFS-GE

Commenter: Joshua Willter

Affiliation: Growth Energy

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

50-OP-LCFS-GE Responses

581. Comment: **LCFS 50-1**

The commenter included the following materials with its comment letter.

1. "Appendix A. Comparison of fuel detail for the State Energy Data System and the Annual and Monthly Energy Review data systems." (no date). **(appendixa.pdf)**[40]

2. Air Resources Board. (2009). Staff Report: Initial Statement of Reasons, Proposed Regulation to Implement the Low Carbon Fuel Standard. Volume I. March 5, 2009. **(030409lcfs_isor_vol1.pdf)**

3. Air Resources Board. (2014). Annual Research Plan: Fiscal Year 2015-2016. December 2014. **(2015-16_arb_annual_research_plan.pdf)**

4. U.S. Energy Information Administration. (no date). "Table 1. State energy-related carbon dioxide emissions by year (2000-2011)." **(table1.pdf)**[41]

5. U.S. Energy Information Administration. (no date). "2011 Table 2. State energy-related carbon dioxide emissions by fuel." **(table2.pdf)**[42]

6. U.S. Energy Information Administration. (no date). "Table 3. 2011 State energy-related carbon dioxide emissions by sector." **(table3.pdf)**[43]

7. U.S. Energy Information Administration. (no date). "Table 4. 2011 State energy-related carbon dioxide emission shares by sector." **(table4.pdf)**[44]

8. U.S. Energy Information Administration. (no date). "Table 5. Per capita energy-related carbon dioxide emissions by State (2000-2011)." **(table5.pdf)**[45]

[40] Duplicate of reference submitted under Comment #47 – Part 2 of 6.
[41] Duplicate of reference submitted under Comment #47 – Part 2 of 6.
[42] Duplicate of reference submitted under Comment #47 – Part 2 of 6.
[43] Duplicate of reference submitted under Comment #47 – Part 2 of 6.
[44] Duplicate of reference submitted under Comment #47 – Part 2 of 6.
[45] Duplicate of reference submitted under Comment #47 – Part 2 of 6.

9. U.S. Energy Information Administration. (no date). “Table 6. Energy intensity by State (2000-2011).” **(table6.pdf)**[46]

10. U.S. Energy Information Administration. (no date). “Table 7. Carbon intensity of the energy supply by State (2000-2011).” **(table7.pdf)**[47]

11. U.S. Energy Information Administration. (no date). “Table 8. Carbon intensity of the economy by State (2000-2011).” **(table8.pdf)**[48]

12. U.S. Energy Information Administration. (no date). “Table 9. Net electricity trade index and primary electricity source for selected States.” (2000-2011).” **(table9.pdf)**[49]

13. Air Resources Board. (2009). Proposed Regulation to Implement the Low Carbon Fuel Standard. Volume II, Appendices. **(lcfsisor2.pdf)**[50]

14. Christy, J. R. (2007). United States District Court for the District of Vermont, Rebuttal Expert Report for the Plaintiffs’ in *Green Mountain Chrysler Plymouth Dodge Jeep, et al. v. Crombie, et al.* Case No. 05-cv-302. University of Alabama in Huntsville. April 18, 2007. **(5.pdf)**[51]

15. ENVIRON International Corporation and the California Air Districts. (2013). California Emissions Estimator Model (CalEEMod): User’s Guide. Version 2013.2. Prepared for: California Air Pollution Control Officers Association (CAPCOA). July 2013. **(usersguide.pdf)**

16. Intergovernmental Panel on Climate Change (IPCC). (2014). Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, & L.L. White (eds.)]. Cambridge

[46] Duplicate of reference submitted under Comment #47 – Part 2 of 6.
[47] Duplicate of reference submitted under Comment #47 – Part 2 of 6.
[48] Duplicate of reference submitted under Comment #47 – Part 2 of 6.
[49] Duplicate of reference submitted under Comment #47 – Part 2 of 6.
[50] Duplicate of reference submitted under Comment #47 – Part 2 of 6.
[51] Duplicate of reference submitted under Comment #47 – Part 2 of 6.

University Press, Cambridge, United Kingdom and New York, NY, USA, 688 pp. **(WGIIAR5-PartB_FINAL.pdf)**

17. U.S. Environmental Protection Agency. (2014). Regulatory Announcement: EPA Issues Final Rule for Renewable Fuel Standard (RFS) Pathways II and Modifications to the RFS Program, Ultra Low Sulfur Diesel Requirements, and E15 Misfueling Mitigation Requirements. EPA-420-F-14-045. July 2014. **(420f14045.pdf)**

18. U.S. Environmental Protection Agency. (2013). Regulatory Announcement: EPA Issues Final Rule for Additional Qualifying Renewable Fuel Pathways under the RFS2 Program. EPA-420-F-13-014. February 2013. **(420f13014.pdf)**

19. U.S. Environmental Protection Agency. (2012). Regulatory Announcement: EPA Issues Supplemental Determination for Renewable Fuels Produced under the Final RFS2 Program from Grain Sorghum. EPA-420-F-12-078. November 2012. **(420f12078.pdf)**

20. U.S. Environmental Protection Agency. (2011). Regulatory Announcement: EPA Issues Direct Final Rule for Additional Qualifying Renewable Fuel Pathways Under the RFS2 Program. EPA-420-F-11-043. November 2011. **(420f11043.pdf)**

21. U.S. Environmental Protection Agency. (2010). Regulatory Announcement: EPA Finalized Regulations for the National Renewable Fuel Standard Program for 2010 and Beyond. EPA-420-F-10-007. February 2010. **(420f10007.pdf)**

22. Wigley, T. M. L. (2008). MAGICC/SCENGEN 5.3: Operator Instructions. Abbreviated from the MAGICC/SCENGEN 5.3 User Manual. NCAR, Boulder, CO. September 2008. **(3.pdf)**[52]

Agency Response: This comment letter contains 22 references that were cited in Comment Letter **46_OP_LCFS_GE**. None of these materials contain objections to or recommendations concerning ARB's proposed regulation. As such, no response specific to these materials is required. ARB has separately responded to the comments that may rely on these materials.

[52] Duplicate of reference submitted under Comment #47 – Part 2 of 6.

This page intentionally left blank.

Comment letter code: 51-OP-LCFS-GE

Commenter: Joshua Willter

Affiliation: Growth Energy

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

51-OP-LCFS-GE Responses

582. Comment: **LCFS 50-1**

The commenter included the following materials with its comment letter.

1. Argonne National Laboratory. (2014). Carbon Calculator for Land Use Change from Biofuels Production (CCLUB): User's Manual and Technical Documentation. Prepared by Dunn, J.B., Qin, Z., Mueller, S., Kwon, H.Y., Wander, M.M., & Wang, M. ANL/ESD/12-5 Rev. 2. September 2014. **(Ref07.pdf)**

2. Darlington, T., Kahlbaum, D., O'Connor, D., & Mueller, S. (2013). Land Use Change Greenhouse Gas Emissions of European Biofuel Policies Utilizing the Global Trade Analysis Project (GTAP) Model. August 30, 2013. **(Ref33.pdf)**

3. Eve, M., Pape, D., Flugge, M., Steele, R., Man, D., Riley-Gilbert, M., & Biggar, S. (Eds). (2014). *Quantifying Greenhouse Gas Fluxes in Agriculture and Forestry: Methods for Entity-Scale Inventory*. Technical Bulletin Number 1939. Office of the Chief Economist, U.S. Department of Agriculture, Washington, DC. 606 pp. July 2014. **(4.pdf)**

4. Hamilton, S.K., Kurzman, A.L., Arango, C., Jin, L., & Robertson, G.P. (2007). "Evidence for Carbon Sequestration by Agricultural Liming." Global Biogeochemical Cycles, Volume 21, GB2021, doi: 10.1029/2006GB002738. June 5, 2007. **(5.pdf)**

5. Heath, L.S., Birdsey, R.A., Row, C., & Plantinga, A. (no date). 1996 Carbon Pools and Flux in U.S. Forest Products. In: Forest Ecosystems, Forest Management, and the Global Carbon Cycle (M.J. Apps and D.T. Price, eds). NATO ASI Series I: Global Environmental Changes, Volume 40, Springer-Verlag, 271-278 pp. **(Ref16.pdf)**

6. Intergovernmental Panel on Climate Change. (2006). 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Prepared by the National Greenhouse Gas Inventories Programme, Eggleston, H.S., Buendia, L., Miwa, K., Ngara, T., & Tanabe, K. (eds). Published: IGES, Japan. Retrieved from http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html **(V1_0_Cover.pdf; V1_1_Ch1_Introduction.pdf; V1_2_Ch2_DataCollection.pdf; V1_3_Ch3_Uncertainties.pdf; V1_4_Ch4_MethodChoice.pdf; V1_5_Ch5_Timeseries.pdf; V1_6_Ch6_QA_QC.pdf;**

V7_1_Ch7_Precursors_Indirect.pdf; V1_8_Ch8_Reporting_Guidance.pdf; V1_8x_Ch8_An1_Units_Index.pdf; V1_8x_Ch8_ReportingTables.pdf; V2_0_Cover.pdf; V2_2_Ch2_Stationary_Combustion.pdf; V2_3_Ch3_Mobile_Combustion.pdf; V2_4_Ch4_Fugitive_Emissions.pdf; V2_5_Ch5_CCS.pdf; V2_6_Ch6_Reference_Approach.pdf; V2_x_An1_Worksheets.pdf; V3_0_Cover.pdf; V3_1_Ch1_Introduction.pdf; V3_2_Ch2_Mineral_Industry.pdf; V3_3_Ch3_Chemical_Industry.pdf; V3_4_Ch4_Metal_Industry.pdf; V3_5_Ch5_Non_Energy_Products.pdf; V3_6_Ch6_Electronics_Industry.pdf; V3_7_Ch7_ODS_Substitutes.pdf; V3_8_Ch8_Other_Product.pdf; V3_x_An1_Worksheets.pdf; V3_x_An2_Potential_Emissions.pdf; V3_x_An3_Improvements.pdf; V3_x_An4_IPPU_Glossary.pdf; V4_00_Cover.pdf; V4_01_Ch1_Introduction.pdf; V4_02_Ch2_Generic.pdf; V4_03_Ch3_Representation.pdf; V4_04_Ch4_Forest_Land.pdf; V4_05_Ch5_Cropland.pdf; V4_06_Ch6_Grassland.pdf; V4_07_Ch7_Wetlands.pdf; V4_08_Ch8_Settlements.pdf; V4_09_Ch9_Other_Land.pdf; V4_10_Ch10_Livestock.pdf; V4_11_Ch11_N2O&CO2.pdf; V4_12_Ch12_HWP.pdf; V4_13_An1_Worksheets.pdf; V4_13_An1_Worksheets.pdf; V4_14_An2_SumEqua.pdf; V4_p_Ap1_Charcoal.pdf; V4_p_Ap2_WetlandsCO2.pdf; V4_p_Ap3_WetlandsCH4.pdf; V5_0_Cover.pdf; V5_1_Ch1_Introduction.pdf; V5_2_Ch2_Waste_Data.pdf; V5_3_Ch3_SWDS.pdf; V5_4_Ch4_Bio_Treat.pdf; V5_5_Ch5_IOB.pdf; V5_6_Ch6_Wastewater.pdf; V5_x_An1_Worksheet.pdf)

7. Intergovernmental Panel on Climate Change. (2006). [spreadsheet]. IPCC Harvested Wood Products (HWP) Model. To be used in conjunction with Volume 4, Chapter 12, of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. **(V4_12_Ch12_HWP_Worksheet.xls in V4_12_Ch12_HWP_Worksheet.zip)**

8. Intergovernmental Panel on Climate Change. (2006). [spreadsheet]. 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Implements Tier 1 method for estimating

emissions of methane from solid waste disposal sites used in conjunction with Volume 5, Chapter 12, of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. **(IPCC_Waste_Model.xls)**

9. Keeney, R. & Hertel, T.W. (2008). Yield Response to Prices: Implications for Policy Modeling. Working Paper #08-13. Purdue University, West Lafayette, Indiana. August 2008. **(Ref11.pdf)**

10. Ray, D.K. & Foley, J.A. (2013). "Increasing Global Crop Harvest Frequency: Recent Trends and Future Directions." Environmental Research Letters 8, 044041, 10 pp., doi: 10.1088/1748-9326/8/4/044041. IOP Publishing. **(Ref09.pdf)**

11. U.S. Department of Agriculture. (2014). [map]. CropScape - Cropland Data Layer. http://nassgeodata.gmu.edu/CropScape/ **(10.pdf)**

12. U.S. Department of Agriculture. (2011). Conservation Reserve Program: Annual Summary and Enrollment Statistics, FY 2011. Prepared by Barbarika, A. **(Ref14A.pdf)**

13. U.S. Department of Agriculture. (2012). Conservation Reserve Program: Annual Summary and Enrollment Statistics, FY 2012. Prepared by Barbarika, A. **(Ref14B.pdf)**

14. U.S. Department of Agriculture. (2012). Conservation Reserve Program: Monthly Summary – December 2012. **(Ref14C.pdf)**

15. U.S. Department of Agriculture. (2012). Conservation Reserve Program: Status: End of December 2012. **(Ref14D.pdf)**

16. U.S. Department of Agriculture. (2013). Conservation Reserve Program: Monthly Summary – December 2013 (Revised). **(Ref14E.pdf)**

17. U.S. Department of Agriculture. (2013). Conservation Reserve Program: Status – End of December 2013. **(Ref14F.pdf)**

18. U.S. Department of Energy. (May 2000). Energy and Environmental Profile of the U.S. Chemical Industry. Prepared by Energetics Incorporated. Colombia, Maryland. **(11.pdf)**

19. U.S. Environmental Protection Agency. (2013). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011. U.S. Environmental Protection Agency, Washington, DC. EPA 430-R-13-001. April 12, 2013. **(3.pdf)**

20. Van Deusen, P.C. & Heath, L.S. (2010). “Weighted Analysis Methods for Mapped Plot Forest Inventory Data: Tables, Regressions, Maps and Graphs.” Forest Ecology and Management 260, 1607-1612. Journal homepage: www.elsevier.com/locate/foreco . August 5, 2010. **(Ref18.pdf)**

21. Wang, Michael Q., Jeongwoo Han, Zia Haq, Wallace E. Tyner, May Wu, and Amgad Elgowainy. (2011). "Energy and greenhouse gas emission effects of corn and cellulosic ethanol with technology improvements and land use changes." Biomass and Bioenergy 35, no. 5 (2011): 1885-1896. February 2, 2011. **(1.pdf)**

22. West, T.O. & McBride, A.C. (2005). “The Contribution of Agricultural Lime to Carbon Dioxide Emissions in the United States: Dissolution, Transport, and Net Emissions.” Agriculture, Ecosystems & Environment 108:145–154. **(6.pdf)**

Agency Response: This comment letter duplicates pages 56 – 117 of Comment Letter **46_OP_LCFS_GE**. See responses to **LCFS 46-79** through **LCFS 46-129**.

This comment letter also contains 22 references that were cited in Comment Letter **46_OP_LCFS_GE**. None of these materials contain objections to or recommendations concerning ARB’s proposed regulation. As such, no response specific to these materials is required. ARB has separately responded to the comments that may rely on these materials.

Comment letter code: 52-OP-LCFS-Kern

Commenter: Melinda Hicks

Affiliation: Kern Oil & Refining Co.

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

Kern Oil & Refining Co.
7724 E. PANAMA LANE
BAKERSFIELD, CALIFORNIA 93307-9210
(661) 845-0761 FAX (661) 845-0330

February 17, 2015

VIA ELECTRONIC POSTING
Comment List: lcfs2015

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento CA, 95814

Dear Chairman Nichols and Board Members:

Kern Oil & Refining Co. (Kern) is providing comments on the California Air Resources Board's (ARB) Proposed Re-Adoption of the Low Carbon Fuel Standard (LCFS). Specifically, Kern is providing comments in support of the following: (1) Low-Complexity/Low-Energy Use (LC/LU) Refinery Provision; (2) Refinery-specific Incremental Deficit Option; (3) Refinery Investment Credit; and (4) Modification of Compliance Curves for Gasoline and Diesel Standards.

Kern is an independently owned, small refinery located in the Southern San Joaquin Valley, just outside Bakersfield, California. From the inception of LCFS, Kern has been acutely aware of the potential inequalities that result from methodologies adopted to effectuate program goals in a manageable manner for CARB. The loss of granularity and reliance upon averages to effectuate program goals is understandable from a management standpoint; however, it can have detrimental impacts on stakeholders like Kern who do not fit the average mold. In California, the crude oil capacity of transportation fuel producing refineries ranges from approximately 26,000 to 343,800 barrels per day, with a rough average of 142,000.[1] At a crude oil capacity of 26,000 barrels per day, Kern is literally the smallest refinery currently producing transportation fuels. In certain circumstances, specifically the vast discrepancy in facility size and complexity in the refining sector, a more robust/complicated methodology is required to insure the program is being effectuated in a credible and equitable manner. Kern is gratified that the Board has

[1] See California Energy Commission, California Energy Almanac, California Oil Refineries, Information as of November 2014, http://energyalmanac.ca.gov/petroleum/refineries.html and considering Tesoro-Carson / Tesoro Refining & Marketing Company, Wilmington Refinery as a single facility.

previously acknowledged and directed Staff to consider these inequalities and that the LCFS Re-Adoption is incorporating provisions that recognize and take steps to mitigate the inequalities inherent in the broader LCFS "average refinery" implementation methodologies.

Low-Complexity/Low-Energy Use (LC/LU) Refinery Provision

Kern strongly supports ARB's inclusion of a provision issuing a credit for Low-Complexity/Low-Energy Use (LC/LU) refineries in recognition of the inherent lower carbon intensities (CI) of transportation fuels produced at these facilities. The credit helps address the unfair subsidization of higher than average energy-use refiners that results from the current regulation's reliance upon the "average refinery" in determining CI values for finished transportation fuels. Kern greatly appreciates the extensive work performed by CARB staff in calculating the demonstrable lower CI of the transportation fuels produced by LC/LU refineries, which serves as the strong scientific and technical basis for the credit consideration being given to those refineries.

During the initial program adoption during April of 2009, Kern raised concerns regarding the disproportionate impact of the LCFS on low-complexity, lower-energy use refineries like Kern as a result of the program's use of the "average refinery" in calculating CI and emissions targets. On December 16, 2011, the Board formally acknowledged and echoed Kern's concerns – directing the Executive Officer in Resolution 11-39 to consider provisions to the LCFS to address low-energy-use refining processes. As acknowledged in the Staff Report: Initial Statement of Reasons for Proposed Re-Adoption of the Low Carbon Fuel Standard ("ISOR"),[2] Resolution 11-39 was meant to address the lower energy inherently embedded into the transportation fuels from refineries that use simple processes to refine transportation fuels. LCFS 52-1

Over the next three years, staff performed extensive analysis of refinery data submitted through the robust Mandatory Reporting Regulation which unequivocally demonstrated that LC/LU refineries, in fact, embed less carbon intensity into the fuels they produce. In line with the Board's direction, Staff also considered and has adopted clear, justifiable metrics defining LC/LU refineries in relation to a refinery's modified Nelson Complexity and Total Annual Energy Use. Staff's analysis across the refining sector demonstrated a clear break between LC/LU refineries versus their larger, more-complex peers at a Modified Nelson Complexity of less than or equal to 5 and a Total Annual Energy Use of 5 million MMBtu per year.[3] Staff's analysis further demonstrated that the identified LC/LU refineries have demonstrably lower CIs for produced gasoline and diesel – 5.53 gCO2e/MJ below the complex refineries' CI for gasoline and 4.79 gCO2e/MJ below the complex refineries' CI for diesel.[4] After a robust public process, which included multiple workshops, extensive stakeholder collaboration and consideration of no less than seven alternatives,[5] Staff is proposing to credit the LC/LU refineries 5 gCO2e/MJ for

[2] ISOR, December 2014, p. ES-6, III-48.

[3] ISOR, III-39 – III-51; Low Carbon Fuel Standard Re-Adoption Workshop, Staff Presentation, slides 47-49; LCFS Low Complexity / Low-Energy-Use Refinery Provisions Workshop, June 20, 2013, Workshop Presentation, slides 2-4;; see also LCFS Regulatory Amendments Workshop, March 5, 2013, LCFS Amendment Presentation, slide 38.

[4] ISOR, III-53

[5] See LCFS Regulatory Amendments Workshop, March 5, 2013, LCFS Amendment Presentation, slide 39.

CARBOB and diesel. Kern strongly supports the credit proposal and is grateful to staff for the years of work, analysis and stakeholder collaboration that have ultimately culminated in the current proposal. LCFS 52-1 cont.

Refinery-specific Incremental Deficit Option

Kern continues to be encouraged by ARB's acknowledgement that low volume refineries are disadvantaged by the current California Average Approach, in that they can be affected by the incremental deficit but cannot affect the sector-wide annual crude average CI. ARB is proposing a one-time opportunity for Low-Complexity/Low-Energy Use (LC/LU) refineries to opt out of the California Average Approach, and instead have their incremental deficits determined through a comparison of the facility's annual average crude CI and its 2010 baseline crude CI. Kern has some concerns about the potential for LC/LU refineries to be locked into too low of a CI baseline, but is generally supportive of the option proposed.

Kern, however, does believe that ARB should revise the option as relates to the use of a default CI for crude oils that do not have a specific CI assigned in the regulation. As proposed, any crude without a specific assigned CI would get assigned the California average CI of 12.71 gCO_2e/MJ. ARB should assign LC/LU refineries opting into the incremental deficit option their own average default crude CI based on their 2010 baseline CI. Given that LC/LU refiners will likely have 2010 Baseline CIs much lower than the California Average, and that ARB only intends to update the CI lookup table with new crudes on a three year cycle, assigning a California Average default crude CI to all new crudes will unnecessarily limit or even prevent LC/LU refineries from running new crudes without incurring incremental deficits. A LC/LU's default CI for new crudes should also be its individual 2010 Baseline CI as opposed to the California Average because a LC/LU's individual 2010 Baseline CI is more representative of that facility's historic performance as opposed to the State's historic performance. Kern also believes that ARB should consider an implementation schedule for the Refinery-specific Incremental Deficit Option similar to the three-year rolling phase-in approach as proposed in the California Average method for transitioning from the 2010 Crude CI Lookup Table to the 2012 Crude CI Lookup Table. LCFS 52-2

Modification of Compliance Curves for Gasoline and Diesel Standards

Given, the two year delay resulting from the *Poet* decision and the required re-adoption of the LCFS, Kern agrees with ARB that some adjustment must be made to the compliance curves to prevent imposition of a sudden dramatic reduction that would negatively affect the market and regulated parties' ability to comply. Kern understands that ARB has conducted in-depth analyses of projected fuels availabilities and evaluated the impact on compliance goals from separate proposed changes to the LCFS in order to develop the proposed compliance curves. To that end, Kern supports ARB smoothing out the curve to 2020 to ensure that reductions are required in a ratable and smooth manner. LCFS 52-3

GHG Emissions Reductions at Refineries

Kern is cautiously optimistic with regard to ARB's proposal to reward refiners for projects resulting in demonstrable emission reductions at a stationary source facility. As Kern LCFS 52-4 understands it, refiners would earn program credits in consideration of those reductions, consistent with full life cycle analyses demonstrating lower resultant CI of fuels produced. ARB's proposal describes an application process where the refinery's baseline transportation fuel CI would be calculated and compared to the new, post-project calculated transportation fuel CI. Specifically, credits would be generated based on the difference between these two CIs, but only for qualifying projects where a reduction of greater than 0.1 gCO2e/MJ is achieved. Kern understands that Staff's intention is to allow for a project to be implemented in multiple phases over an approved period of time in order to achieve the threshold 0.1 gCO2e/MJ and recommends additional language be added to the proposed regulatory text to clarify Staff's intent. As a small refinery, Kern has limited resources and must utilize its efforts, resources and investments with a high degree of efficiency. Allowing flexibility on the timing of a project is critical because it is not always financially feasible to carry out a substantial project all at once.

LCFS 52-4 cont.

In conclusion, Kern appreciates ARB's consideration of Kern's comments. As always, Kern is committed to working with Staff throughout this regulatory process.

Sincerely,

Melinda L. Hicks
Manager, Environmental Health and Safety
Kern Oil & Refining Co.

cc. Floyd Vergara, ARB
Elizabeth Scheele, ARB
Sam Wade, ARB
Stephanie Detwiler, ARB
Jim Nyarady, ARB
John Courtis, ARB
Jim Duffy, PhD, ARB

52_OP_LCFS_Kern Responses

583. Comment: **LCFS 52-1**

Agency Response: ARB staff appreciates the support for the proposed Low Complexity/Low Energy Use provision.

584. Comment: **LCFS 52-2**

The commenter requests that ARB revise the use of average CIs for crude oils that don't have a specific CI.

Agency Response: ARB staff agrees that refineries opting for refinery-specific incremental deficit accounting should be assigned their refinery 2010 Baseline carbon intensity (CI) as a default for new crudes. Staff included this revision as part of the 15-day change package. Staff disagrees, however, with the suggestion to use a three-year rolling transition into the refinery-specific accounting. The California Average approach was initially implemented in 2012, and therefore a three-year rolling transition is appropriate. If adopted, the refinery-specific option will start in 2016 with assessment of the 2015 refinery crude slate. Refinery crude slates for previous years are not relevant to the refinery-specific option as these were assessed under the California Average approach for years 2013 and 2014.

585. Comment: **LCFS 52-3**

Agency Response: ARB staff appreciates the support for the compliance curves.

586. Comment: **LCFS 52-4**

The commenter requests that ARB staff add additional language to allow for projects to be implemented over multiple phases over an approved period of time.

Agency Response: ARB staff does not agree that additional language is necessary to address the concerns expressed by Kern. A refinery applying for a Refinery Investment Credit may define the length and the scope of the project as it wishes in its application for the Refinery Investment Credit. All portions of the project will be subject to the post-January 1st, 2016 authority-to-construct permit approval deadline. The project shall not start generating credits until it has achieved a reduction of 0.1 gCO_2e/MJ or more from the comparison baseline.

Comment letter code: 53-OP-LCFS-CAHealth

Commenter: Jenny Bard

Affiliation: California Health Group

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

53_OP_LCFS_CAHealth

February 17, 2015

Chairman Mary Nichols
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Public Health Support for Low Carbon Fuel Standard

Dear Chairman Nichols:

On behalf of the undersigned organizations and individuals dedicated to improving the health and medical well-being of Californians, we write in support of the re-adoption of the Low Carbon Fuel Standard (LCFS) to advance California's leadership in moving beyond petroleum and promoting a healthier mix of transportation fuels to keep Californians moving. Since its original adoption, public health and medical groups have supported the LCFS as a key strategy for cleaning our air and ensuring California meets its landmark AB 32 climate targets for 2020. This policy will also be critical to help meet Governor Brown's health-protective goal to cut petroleum usage in California by 50 percent by 2035. LCFS 53-1

California's current dependence on petroleum fuels generates nearly half of our climate pollution, 80 percent of smog-forming NOx emissions and 95 percent of cancer causing diesel particulates[1]. Approximately 40 percent of Californians live close enough to major roadways[2] to experience higher health risks caused by traffic pollution. These pollutants cause billions in health and economic costs and contribute to public health burdens including: respiratory and cardiac illnesses, hospitalizations and deaths as well as the growing health impacts of climate change. California must stay the course with the LCFS regulation to ensure fuels are at least 10% cleaner by 2020, and plan for continued reductions beyond 2020. We appreciate the inclusion of strengthening amendments, such as the provision designed to spur more investment in cleaning up local refinery facilities and produce health and community benefits. We also support the inclusion of safeguards as proposed by staff to ensure that any biofuels used to meet the standard maintain progress toward both criteria air pollution and greenhouse gas reduction goals. LCFS 53-2

Our comments support continuing forward progress with the LCFS to protect the health and well-being of all Californians, and especially those most impacted by dirty fuels, as more alternatives come online to combat climate change. LCFS 53-3

The Low Carbon Fuel Standard promotes a cleaner, healthier fuel mix. The LCFS moves California forward toward the cleanest, most sustainable, low carbon fuels. Each year the LCFS will promote a cleaner mix of fuels and support the implementation of important regulations like the Zero Emission Vehicle Regulation. The CARB analysis demonstrates that the LCFS will provide substantial health benefits by reducing pollution that cuts lives short. In 2020, CARB estimates that nearly 100 lives will be saved by displacing harmful fuels with cleaner, healthier choices.[3] These findings complement recent Lung Association research demonstrating over 400 lives will be saved with the LCFS and Cap and Trade programs' implementation, avoiding over $23 billion in societal damages, including $8.3 billion in respiratory health impacts, by 2025.[4] CARB should move forward to finalize these health-protective policies. LCFS 53-4

CARB should both maintain the 2020 LCFS target and plan additional emission reductions beyond 2020. California's health and medical community strongly support the proposal to re-adopt the LCFS with the original target for a 10 percent carbon reduction by 2020. This goal is vital to cutting the health harms caused by our transportation fuels by incentivizing ever-cleaner choices for Californians. In the first years of the program, the equivalent of taking nearly 2 million vehicles off the road was achieved through the modest requirements to reduce carbon – a number projected to equal removing over 7 million vehicles as the program moves on between 2016 and 2020[5,6]. We believe that after the LCFS is re-adopted, that CARB must turn quickly to the next phase of the program and determine an ambitious course beyond 2020 and evaluate efforts to strengthen the regional programs developing along the West Coast. LCFS 53-5

Refinery Investment provisions support environmental justice and local air quality. We applaud the development of the refinery investment provision as a positive incentive to cut greenhouse LCFS 53-6

---

[1] California Air Resources Board, LCFS ISOR. P.ES-1

[2] Fabio Caiazzo et al., Air pollution and early deaths in the United States, Atmospheric Environment, 2013

[3] California Air Resources Board. Low Carbon Fuel Standard ISOR. "…91 deaths would be avoided for the year 2020 from implementation of the LCFS and ADF regulations." p. IV-9. The Draft Environmental Impact Analysis also found that

[4] American Lung Association in California, Environmental Defense Fund: Driving California Forward. May 2014.

[5] CARB ISOR, p. II-1

[6] United States Environmental Protection Agency, Greenhouse Gas Equivalencies Calculator. http://www.epa.gov/cleanenergy/energy-resources/calculator.html

gases, toxics and other air pollutants in communities burdened by refinery emissions. While this program is aimed at reducing petroleum consumption, we must also support incentives to clean up local pollution sources and improve community health as the LCFS moves forward. We are especially supportive of CARB precluding refinery investment projects that would cut carbon but increase criteria air pollutants or air toxics from receiving credits. LCFS 53-6 cont.

Biorefinery Siting Guidance needs update to incorporate new information on disadvantaged communities. Given the focus in many AB 32 discussions on the need to protect and improve health and air quality in California's most disadvantaged communities, CARB should provide more clear direction to staff on the timing to update the *Siting Guidance for Biorefineries in California* section on cumulative impacts. Specifically, the guidance document should be updated to reflect the development and widespread use of CalEPA's CalEnviroScreen tool for identifying communities most disadvantaged by local pollution. LCFS 53-7

Expanded electric transportation credits support clean air. Our organizations support the expanded role for electrification of transportation in the LCFS. The proposal to allow transit agencies to opt-in to the LCFS for fixed guideway systems (light rail, street cars, trolleys, etc.) encourages cleaner transit that cuts carbon pollution, cleans up neighborhood traffic pollution and supports sustainable communities as envisioned under Senate Bill 375. We support the provisions to more clearly account for the sustainability benefits of California's growing electric bus fleet. These expanded electric transportation credits provide local air quality benefits, encourage the development of more ultra-low carbon transportation options[7] and support healthier, sustainable communities. LCFS 53-8

Ensure low carbon fuels support clean air progress. California needs to continue to focus on promoting the cleanest, most sustainable fuels over the long term. The LCFS regulation must ensure that any alternative fuels used to meet LCFS requirements in the short term contribute to both criteria pollutant and climate benefits without any unintended consequences. We believe that staff's proposal to re-adopt the Low Carbon Fuel Standard along with separate proposals being considered to protect against criteria emissions backsliding is an appropriate pathway forward. LCFS 53-9

In closing, our organizations strongly support the re-adoption of the LCFS to cut petroleum use, air pollution and climate change impacts as California moves forward to a low carbon economy. Further, the LCFS is a crucial component of climate leadership on the West Coast because it provides a strong model for national and international action to clean up transportation fuels and promote improved health and sustainability. We urge the California Air Resources Board to continue its leadership and advance the Low Carbon Fuel Standard to benefit all Californians. LCFS 53-10

Sincerely,

Bonnie Holmes-Gen, Senior Director of Air Quality and Climate Change
American Lung Association in California

Kris Calvin, Presidents & CEO
American Academy of Pediatrics – California

[7] California Air Resources Board LCFS/ADF Draft Environmental Impact Report. The sale of credits generated for could allow transit agencies to reduce fares, expand service or EV bus fleet or upgrade infrastructure. p.23

James K. Knox, Vice President, Advocacy
American Cancer Society Cancer Action Network, California

Alpesh Amin, MD, President
California Service Chapter, American College of Physicians

Francisco Covarrubias, Chair
Asthma Coalition of Los Angeles County

Praveen Buddiga, MD, FAAAAI, CEO
Baz Allergy, Asthma & Sinus Centers

Tom Epstein, VP of Public Affairs
Blue Shield of California

Jeanne Rizzo, RN, President & CEO
Breast Cancer Fund

Matt Read, Director, Statewide Government Relations
Breathe California

Darcel Lee, President & CEO
California Black Health Network

Justin Malan, Executive Director
California Conference of Directors of Environmental Health

Sarah de Guia, JD, Executive Director
California Pan Ethnic Health Network

Adele Amodeo, Executive Director
California Public Health Association – North

Angela, Wang, MD, President
California Thoracic Society

Katelyn Roedner Sutter, Environmental Justice Program Director
Catholic Charities, Diocese of Stockton

Kevin D. Hamilton, RRT, RCP, Chair
Central California Asthma Collaborative

Bill Magavern**,** Policy Director
Coalition for Clean Air

Rachelle Wenger, MPA, Director, Public Policy and Community Advocacy
Dignity Health

Eric Lerner, Executive Director
Health Care Without Harm

Luis Ayala, Executive Director
Los Angeles County Medical Association

Sister Judy Morasci
Vice President of Mission Integration
Mercy Hospitals of Bakersfield

Kevin D. Hamilton, RRT, RCP, Chair
Medical Advocates for Healthy Air (MAHA), Fresno

Martha Dina Argüello, Executive Director
Physicians for Social Responsibility – Los Angeles

Robert M. Gould, MD, President
San Francisco Bay Area Chapter
Physicians for Social Responsibility

Sandra Viera, MPA, Program Manager
Prevention Institute

Linda Rudolph, MD, MPH, Co-Director
Center for Climate Change and Health
Public Health Institute

Joel Ervice, Associate Director
Regional Asthma Management and Prevention (RAMP)

Gloria Thornton, MA, LMFT, Chair
San Francisco Asthma Task Force

Steve Heilig, MPH, Associate Executive Director, Public Health & Education
San Francisco Medical Society

Shan Magnuson, Chair
Sonoma County Asthma Coalition

Jim Mangia, MPH, President and CEO
St. John's Well Child and Family Centers (Los Angeles)

Individual physicians

Karen M. Jakpor, MD, MPH, Riverside
Albert Landucci, DDS, San Mateo

This page intentionally left blank.

53_OP_LCFS_CAHealth Responses

587. Comment: **LCFS 53-1**

The comment expresses support for the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

588. Comment: **LCFS 53-2**

The comment expresses support for the compliance curves and refinery investment provision.

Agency Response: ARB staff appreciates the support for the compliance curves and the proposed refinery investment provision.

589. Comment: **LCFS 53-3**

The comment expresses support for the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

590. Comment: **LCFS 53-4**

The comment expresses support for the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support of the human health benefits of the re-adoption of the LCFS regulation.

591. Comment: **LCFS 53-5**

The comment stresses the importance of maintaining the target of a 10 percent carbon reduction by 2020.

Agency Response: The regulation approved by the Board retains the requirement for a 10 percent carbon intensity reduction in 2020.

592. Comment: **LCFS 53-6**

The comment supports the refinery investment provision and the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the proposed refinery investment provision.

593. Comment: **LCFS 53-7**

The comment requests ARB staff to provide more clear direction on the timing to update the *Siting Guidance for Biorefineries in California* section.

Agency Response: See response to **LCFS 42-17**.

594. Comment: **LCFS 53-8**

The comment expresses support for the expanded electric transportation credits of the LCFS proposal.

Agency Response: ARB staff appreciates the support for the proposed electricity provision.

595. Comment: **LCFS 53-9**

The comment lends support for the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

596. Comment: **LCFS 53-10**

The comment lends support for the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

Comment letter code: 54-OP-LCFS-EFC

Commenter: Reid Detchon

Affiliation: Energy Future Coalition

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

54_OP_LCFS _EFC

California Air Resources Board

Proposed Re-Adoption of the Low Carbon Fuel Standard

Comments Submitted by the Energy Future Coalition and the Urban Air Initiative
February 17, 2015

The Energy Future Coalition and Urban Air Initiative commend CARB for its groundbreaking work in the area of low carbon transportation fuels, and we appreciate this opportunity to comment on ways to further improve on the efficacy of California's Low Carbon Fuel Standard (LCFS). CARB has the opportunity with this rulemaking, in reducing the carbon footprint of the California transportation sector, to take steps that will not only help address the threat of global climate change, but also mitigate serious impacts on public health.

As summarized here and developed more fully in the appendices, these comments argue that:

1. Automakers who continue to use internal combustion engines must increase engine efficiency to meet LCFS standards and reduce GHGs.
2. Displacing aromatics now used for octane in gasoline would produce substantial benefits for public health.
3. Increased use of domestically produced renewable ethanol is essential to both objectives and would have additional co-benefits.
4. The LCFS should fully reflect the latest research on the value of mid-level ethanol blends to reduce GHGs and benefit public health and the environment through the displacement of aromatics. LCFS 54-1

About the Energy Future Coalition and the Urban Air Initiative

The Energy Future Coalition is a broad-based, non-partisan public policy initiative, co-located with the United Nations Foundation in Washington, DC. The Coalition seeks to bridge the differences among stakeholder groups and identify domestic energy policy options that can find broad political support and accelerate the transition to a clean energy economy. Since the Coalition's founding in 2002, one of its principal areas of interest has been the potential of clean renewable fuels to reduce the nation's dependence on oil. This has led to a focus on the public health consequences of the use of aromatic compounds to enhance octane in gasoline. On two occasions, most recently last year, the Coalition co-hosted workshops on this topic with the National Institute of Environmental Health Sciences (NIEHS).

The Urban Air Initiative is a non-profit entity dedicated to research and education in the area of fuel quality and its relationship to mobile source emissions, especially in urban areas. The climate and public health impacts of mobile source (traffic) pollution—in the U.S. and globally—are of great importance to policymakers, industries, and the billions of people that are regularly exposed to harmful pollutants in their homes, schools, and vehicles. Among the most vulnerable are infants and children. The Urban Air Initiative believes that protecting our children's health and well-being is the most important investment society can make to build a better future.

Toward that end, in recent years our two organizations have analyzed dozens if not hundreds of peer-reviewed studies supported and/or conducted by the U.S. Environmental Protection Agency (EPA), the Health Effects Institute (HEI), NIEHS, the U.S. Department of Energy (DOE), the National Oceanographic and Atmospheric Administration (NOAA), numerous federal laboratories (e.g., Argonne, Oak Ridge, NREL, Pacific Northwest, etc.), the California Air Resources Board (CARB), academic institutions, auto companies, and many others.

Context of the LCFS Rulemaking

For many years, California has been a global trend-setter in transportation fuels regulatory policy. The state is one of the world's largest consumers of gasoline, and it has more gasoline-powered light duty vehicles (LDVs) than most nations. Consequently, CARB has led the way in addressing the serious health and climate threats from gasoline combustion by-products. By law, California has special status—relative to other states—in terms of establishing fuel quality standards under the Clean Air Act. CARB's experts recognize that fuel composition is just as important as vehicle control technologies in reducing emissions of carbon and other harmful pollutants.

The December 2014 CARB staff report on the LCFS, "Initial Statement of Reasons for Proposed Rulemaking," notes in the Executive Summary that "the production, transport, and use of traditional fuels are responsible for nearly half of the state's greenhouse gas (GHG) emissions" and states: "The primary goal of the LCFS regulation is to reduce the carbon intensity of transportation fuels used in California by at least ten percent by 2020 from a 2010 baseline." It goes on to say, "The LCFS is a key part of a comprehensive set of programs in California to reduce GHG emissions and other smog-forming and toxic air pollutants from the transportation sector."

These comments are intended to show the link between reducing "GHG emissions and other smog-forming and toxic air pollutants from the transportation sector" and to "encourage the use of cleaner low-carbon fuels in California, encourage the production of those fuels, and, therefore, reduce GHG emissions."

Statement of the Case

1. **Automakers who continue to use internal combustion engines must increase engine efficiency to meet LCFS standards and reduce greenhouse gas emissions.**

Meeting the California LCFS standards by 2020, the EPA's ambitious fuel economy standards of 54.5 miles per gallon by 2025, and the "more aggressive targets for 2030" forecast for California in the current rulemaking will require a fleet-wide transition to light-duty vehicle technologies capable of much greater efficiency. While electric vehicles are gaining traction, they are not expected to achieve substantial market penetration in that time, nor are hydrogen fuel cell vehicles likely to be commercially viable at scale. Even in 2040, according to the U.S. Energy Information Administration, cars with gas- and diesel-powered engines will still represent some 95% of the international car market. Continued evolution of today's internal combustion engines, on the other hand, can achieve the fuel economy targets at an affordable cost. Highly efficient high-compression engines offer the cheapest and most certain path to the GHG and fuel economy standards of the future. The limiting factor is not scalable vehicle technology, but fuel—specifically its octane rating.

The efficiency of an internal combustion engine increases as a factor of its compression ratio – which reflects the amount of fuel burned in a single piston stroke. Higher-octane fuels are needed to enable higher compression ratios – they can withstand a greater rise in temperature during the compression stroke without igniting, thus allowing more power to be extracted. (Uncontrolled combustion, or knock, is harmful to an engine and would render a vehicle unmarketable.)

Thus, to perform adequately, high-compression engines require higher-octane fuel than today's regular-grade gasoline. Premium gasoline can deliver more octane at a higher cost but is currently produced by the addition of a blend of toxic aromatic hydrocarbons, implicated in a range of serious health effects. Clean-burning alcohol fuels such as ethanol, on the other hand, are inherently high in octane. These fuels – which, unlike gasoline, can be produced from a variety of feedstocks, including cellulosic biomass, municipal waste, and even natural gas – can enable greater fuel economy while providing substantial environmental benefits and dramatically reducing oil dependence in the next decade, at a price that mainstream Americans can afford.

Automakers have asked EPA for higher-octane gasoline to comply with the new fuel efficiency-carbon reduction rules.[1] Higher-octane gasoline would enable a compression ratio increase of approximately 2 numbers, significantly increasing fuel efficiency while reducing the most harmful emissions. To do that, automakers need an octane pool of 94 AKI (100 RON) gasoline, as compared with today's U.S. market standard of 87 AKI.

Ethanol has superior octane enhancement properties compared to other alternatives. Technically, economically, and legally (because the Clean Air Act limits the amount of aromatics in reformulated gasoline), the best and perhaps only way to make 94 AKI gasoline available nationwide is with mid-level ethanol blends (discussed here as E30). These blends have been shown in tests by automakers and Oak Ridge National Laboratory to have superior performance and emissions characteristics – mid-level ethanol blends have been called by Oak Ridge a "renewable super premium" fuel.

[1] *See, e.g.*, Cynthia Williams, Ford Motor Company, Comments on Proposed Tier 3 Rule, EPA-HQ-OAR-2011-0135-4349, at 3 (July 1, 2013) ("strongly recommend[ing] that EPA pursue regulations . . . to facilitate the introduction of higher octane rating market fuels," noting that they "offer the potential for the introduction of more efficient vehicles").

Recalling that the "primary goal of the LCFS regulation is to reduce the carbon intensity of transportation fuels used in California," ethanol has the following significant carbon-reducing effects compared to gasoline:

1. Argonne National Laboratory has devoted 20 years of research and analysis to the life-cycle greenhouse gas impacts of transportation fuels. As a 2012 Argonne paper summarized, "advances in technology and the resulting improved productivity in corn and sugarcane farming and ethanol conversion … have increased the energy and greenhouse gas (GHG) benefits of using bioethanol." Compared to regular gasoline, it showed a "well-to-wheels" reduction in GHG emissions from corn-based ethanol of 44% and from cellulosic ethanol of 89-95%.[2]

   To be sure, as agricultural production increases to support ethanol production, concerns about land use and indirect GHG effects must also be considered. A widely circulated and globally influential paper by Timothy Searchinger concluded that those effects are so negative as to overwhelm ethanol's GHG benefits. However, this paper has since been shown to be simplistic in its approach and wrong in its conclusion. Several peer-reviewed analyses have been published, most notably by Argonne, that show the indirect land use impacts hypothesized by Searchinger were overestimated by an order of magnitude. Including the recalculated indirect land use effects in the analysis cited above still results in a <u>reduction of GHG emissions from corn-based ethanol of 34% and from cellulosic ethanol of 88-108% compared to gasoline</u>.

2. That same Argonne research gives no credit for corn's ability to fix carbon in soil permanently. Recent research is showing that modern, high-yield continuous corn grown using conservation or no-till practices is in fact sequestering and rebuilding the carbon content of soil in the Midwest. Argonne is beginning a new study of soil carbon fixation, as well as NOx emissions related to fertilizer use, with regard to its GHG estimates for corn ethanol. Current EPA and CARB life-cycle analysis models similarly underestimate corn's superior ability as a highly efficient C4 plant in sequestering carbon, and should be updated accordingly.[3]

3. Gasoline itself is increasing in carbon intensity as oil from energy-intensive operations, such as heavy crudes from the Alberta tar sands and North Dakota fracking operations in the Bakken field, come to market.

LCFS 54-1 cont.

[2] M. Wang *et al.*, "Well-to-wheels energy use and greenhouse gas emissions of ethanol from corn, sugarcane and cellulosic biomass for US use," 2012 Environ. Res. Lett. 7 045905 (http://iopscience.iop.org/1748-9326/7/4/045905).

[3] See Alverson, "Re-thinking the Carbon Reduction Value of Corn Ethanol Fuel" (attachment).

4. Aromatics require the most energy to produce in the already energy-intensive oil refining process. An E30 blend would reduce refinery CO_2 emissions by 10%.[4]

5. Because of their chemical structure, aromatics are among the most carbon-rich components of gasoline. A recent report by a Health Effects Institute panel noted that aromatics "represent one of the heaviest fractions in gasoline" and said: "The aromatic content of gasoline has a direct effect on tailpipe carbon dioxide emissions. The EPEFE study[5] demonstrated a linear relationship between CO_2 emissions and aromatic content. A reduction of aromatics from 50 to 20% was found to decrease CO_2 emissions by 5%."[6]

LCFS
54-1 cont.

2. Displacing aromatics now used for octane in gasoline would produce substantial benefits for public health.

Aromatic hydrocarbons have been known for a long time to be toxic in their own right. California has limited the amount of aromatics in diesel fuel since 1988, and the Clean Air Act Amendments of 1990 limited the permissible amount of aromatics in reformulated gasoline. Yet the BETX group of chemicals (i.e., benzene, ethylbenzene, toluene, and xylene) still comprises 25-30% of the average gallon of gas. Benzene is a proven human carcinogen that can cause leukemia in exposed persons, and the other aromatics (mainly toluene and xylene) are neurotoxins. Combustion of these aromatics can lead to the formation of benzene in the exhaust gas. According to the HEI report just cited, "It is estimated that about 50% of the benzene produced in the exhaust is the result of decomposition of aromatic hydrocarbons in the fuel." The same report also noted, "Lower levels of aromatics enable a reduction in catalyst light-off time for all vehicles. Research indicates that combustion chamber deposits can form from the heavier hydrocarbon molecules found in the aromatic hydrocarbon portion of the gasoline. These deposits can increase tailpipe emissions, including carbon dioxide, hydrocarbons and NOx."

Of even greater concern, aromatics' emission products are transformed in the atmosphere into secondary organic aerosol (SOA). An important study from the Harvard Center for Risk Analysis, which focused specifically on the public health impacts of secondary particulate formation from aromatic hydrocarbons in gasoline, reported: "Evidence is growing that aromatics in gasoline exhaust are among the most efficient secondary organic matter precursors. … For example, a source apportionment study of SOA formation during a severe photochemical smog event in Los Angeles found that gasoline engines represented the single-

[4] See the 2014 MathPro – GM/Ford/Chrysler linear program study, "Refining Economics of U.S. Gasoline: Octane Ratings and Ethanol Content" (attachment).
[5] The European Programme on Emissions, Fuels and Engine Technologies, 1996
[6] Health Effects Institute Panel on the Health Effects of Traffic-Related Air Pollution, "Appendix B. Fuel Composition Changes Related To Emission Controls" in Special Report 17, "Traffic-Related Air Pollution: A Critical Review of the Literature on Emissions, Exposure, and Health Effects," Chapter 2. Emissions from Motor Vehicles. 2010. http://pubs.healtheffects.org/getfile.php?u=555

largest anthropogenic source of SOA. … Source-specific speciation of total VOC in the 2005 National Emissions Inventory reveals that the U.S. emissions of single-ring aromatic hydrocarbons are 3.6 million tons per year, of which 69% are from gasoline-powered vehicles."[7] The Harvard study predicted 3,800 premature mortalities per year due to aromatics.

Among the toxic SOA emission products from partial combustion of the aromatics in gasoline are polycyclic aromatic hydrocarbons (PAHs). At an EPA Workshop on Ultrafine Particles on February 11, Michael Kleeman of the University of California presented new results from the California Teachers Study by B. Ostro et al., accepted for publication in *Environmental Health Perspectives*. Initial epidemiological results show a hazard ratio of 1.25 for ischemic heart disease from anthropogenic SOA. Research by Verma et al. has found that "photochemical transformations of primary emissions with atmospheric aging enhance the toxicological potency of primary particles in terms of generating oxidative stress and leading to subsequent damage in cells"[8] and that "the oxidative potential was strongly correlated with organic carbon and PAHs."[9]

Delfino et al. strongly linked PAHs with mobile sources: "Indoor and outdoor PAHs (low-, medium-, and high-molecular-weight PAHs), followed by hopanes (vehicle emissions tracer), were positively associated with biomarkers, but other organic components and transition metals were not. … Vehicular emission sources estimated from chemical mass balance models were strongly correlated with PAHs (R = 0.71). … Traffic emission sources of organic chemicals represented by PAHs are associated with increased systemic inflammation and explain associations with quasi-ultrafine particle mass."[10]

How do PAHs created during combustion of aromatic hydrocarbons undergo long-range transport? Zelenyuk et al. found that they are trapped inside highly viscous semisolid OA particles and thus prevented from evaporation and shielded from oxidation. "In contrast, surface-adsorbed PAHs rapidly evaporate leaving no trace. The data show the assumptions of instantaneous reversible gas-particle equilibrium for PAHs and SOA are fundamentally flawed, providing an explanation for the persistent discrepancy between observed and predicted particle-bound PAHs."[11]

[7] K. von Stackelberg et al., "Public health impacts of secondary particulate formation from aromatic hydrocarbons in gasoline," *Environmental Health* 2013, 12:19. http://www.ehjournal.net/content/12/1/19
[8] V. Verma et al., "Redox activity of urban quasi-ultrafine particles from primary and secondary sources," *Atmospheric Environment*, 43(4), December 2009, 6360‑6368. http://www.sciencedirect.com/science/article/pii/S1352231009007857
[9] V. Verma et al., "Physicochemical and oxidative characteristics of semi-volatile components of quasi-ultrafine particles in an urban atmosphere," *Atmospheric Environment*, 45(4), February 2011, 1025‑1033. http://www.sciencedirect.com/science/article/pii/S1352231010009301
[10] R. Delfino et al., "Association of Biomarkers of Systemic Inflammation with Organic Components and Source Tracers in Quasi-Ultrafine Particles," *Environ Health Perspect*. 2010 Jun; 118(6): 756–762. http://www.ncbi.nlm.nih.gov/pmc/articles/PMC2898850/
[11] A. Zelenyuk et al., "Synergy between secondary organic aerosols and long-range transport of polycyclic aromatic hydrocarbons," *Environ Sci Technol*. 2012 Nov 20;46(22):12459-66. http://www.ncbi.nlm.nih.gov/pubmed/23098132

PAHs have been summarized by one leading researcher as: "carcinogenic, immunotoxic, neurotoxic, mutagenic, and endocrine disruptors."[12] Prenatal exposure to low levels of PAHs from ambient air pollution has been associated with multiple adverse effects, including developmental delay at age 3, reduced IQ at age 5 (effects similar to lead), symptoms of anxiety/depression and attention problems at ages 6–7, and ADHD behavior problems in children.[13] At a time when the rising incidence of autism is increasingly linked to disruption by environmental factors, and when the mutagenic effect of PAHs is well established, reducing exposure to PAHs should be a high public health priority.

3. **Increased use of domestically produced renewable ethanol is essential to both objectives and would have additional co-benefits.**

Ethanol's value for octane is not a new discovery. In fact, it was only the competition from tetraethyl lead that knocked ethanol out of that role a century ago. When lead was phased out, however, ethanol was not available in sufficient supply to provide a substitute. That is no longer true today. U.S. ethanol production has risen to roughly 15 billion gallons per year, and almost all gasoline sold today contains 10 percent ethanol. A phased increase to supply an E30 market, sufficient to supply the octane needed for higher-compression engines – reducing aromatics by 60%[14] – is entirely achievable.

Renewable ethanol can be produced from multiple agricultural feedstocks; corn starch has been the principal source in the U.S. and sugar cane in Brazil. Decades of federal investment in research has made possible the conversion of cellulose – widely abundant material that gives plants their structural stability – and major new cellulosic ethanol facilities, representing billions of dollars of private investment, are now going into production from POET-DSM, Abengoa Bioenergy, and DuPont Danisco, using corn stover and other "waste" biomass feedstocks.

The demand for farmland to produce corn for ethanol has been mitigated by continuing increases in yield and by the diversion of the protein in corn to supply animal field. Increased use of conservation tillage has reduced soil erosion and water runoff while saving labor and fuel.

4. **The LCFS should fully reflect the latest research on the value of mid-level ethanol blends to reduce GHGs and benefit public health and the environment through the displacement of aromatics.**

[12] F. Perera et al., "The Relationship Between Prenatal PAH Exposure and Child Neurocognitive and Behavioral Development," PowerPoint presentation, Sept. 2011.
[13] F. Perera et al., "Early-Life Exposure to Polycyclic Aromatic Hydrocarbons and ADHD Behavior Problems," PLOS ONE, November 5, 2014, DOI:10.1371/journal.pone.0111670. http://journals.plos.org/plosone/article?id=10.1371/journal.pone.0111670
[14] See the 2014 MathPro – GM/Ford/Chrysler linear program study, "Refining Economics of U.S. Gasoline: Octane Ratings and Ethanol Content" (attachment).

The Energy Future Coalition and the Urban Air Initiative respectfully urge CARB to consider the role that mid-level ethanol blends could play in delivering a nationwide low carbon, high octane transportation fuels system.

- As a renewable fuel, reflecting its production and land use, ethanol offers substantial GHG reduction benefits relative to gasoline and particularly to aromatics. CARB should incorporate the latest values from Argonne's life-cycle analysis into its calculations. LCFS 54-1 cont.

- In the fall of 2013, the World Health Organization's International Agency for Research on Cancer (IARC) published its findings that traffic-related particulate matter emissions represented a Group 1 carcinogenicity threat to humans. WHO noted that in 2010, 223,000 worldwide deaths from lung cancer alone were attributable to air pollution, and singled out particulate matter and transportation-related pollution as a major source.

- Advanced GDI (gasoline direct injection) systems could make particle number (PN) emissions <u>worse</u> unless fuel composition is improved by reducing aromatic content. Mid-level ethanol blends have been shown to reduce particulate and black carbon emissions by 45 to 80% in direct injection and port fuel injection engines, respectively. Some have argued for the use of particulate filters on gasoline engines; however, the much smaller particles in gasoline exhaust (compared to diesel exhaust) elude capture by such filters, which also will interfere with, possibly even reverse, important fuel efficiency and carbon reduction gains.

The most important fuel quality improvement to achieve reductions in both carbon and particle-borne toxics emissions would be to substantially reduce aromatic hydrocarbons in gasoline. The need for octane can easily be supplied by cleaner-burning ethanol blends. They would:

1. Facilitate automaker compliance with tighter fuel efficiency and carbon reduction requirements.
2. Improve vehicle performance and reduce costs to the consumer.
3. Reduce harmful urban particulate matter, black carbon, and toxics emissions.
4. Provide market-based demand signals to meet national biofuels targets in a cost-effective manner.
5. Provide an alternative to ineffective and costly gasoline particulate filters.
6. Generate billions of dollars annually in carbon reduction and health savings co-benefits.
7. Reduce refinery crude oil usage and diversify the transportation sector away from reliance on crude oil.
8. Stimulate the rural economy and create new jobs.
9. Provide a more stable investment climate for next-generation biofuel technologies.
10. Simplify California's path to low carbon fuels.

54_OP_LCFS_EFC Responses

597. Comment: **LCFS 54-1**

The comment states that the LCFS should fully reflect the latest research on the value of ethanol to reduce GHGs and benefit public health and the environment through the displacement of aromatics. The comment also states that Argonne, EPA and CARB life-cycle analysis models all neglect to account for corn's ability to fix carbon in soil permanently and should be revised.

Agency Response: Staff recognizes that some crops under certain conditions and management practices can incrementally increase soil carbon content over time; however, soil carbon accumulation does not qualify as carbon sequestration under current AB 32 regulations. Once appropriate audit and certification systems are in place for agricultural systems, reduced tillage regimes may yield CI reductions indirectly in the form of reduced on-farm energy use and other such co-benefits of cultivation practices which enhance soil quality, but such systems are not yet in place.

This page intentionally left blank.

Comment letter code: 55-OP-LCFS-EFC

Commenter: Reid Detchon

Affiliation: Energy Future Coalition

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

55_OP_LCFS_EFC

Comments Submitted by the Energy Future Coalition and the Urban Air Initiative

Appendix I: Automakers who continue to use internal combustion engines must increase engine efficiency to meet LCFS standards and reduce GHGs.

1. Automaker studies confirm ethanol's superior octane properties enable substantial reductions in most harmful urban pollutants

This section contains links to auto industry studies on PM/PN, particulate filter technology, and E30 blend emissions and performance results.

- 2012 Ford/Maricq: E30+ blends reduce PM and black carbon by 45%, NOx and HC by 20% in DI engines. http://www.tandfonline.com/doi/pdf/10.1080/02786826.2011.648780

- 2010 CARB/Zhang: E30+ blends reduce PM/PN by 80+% in PFI engines. http://www.calevc.org/carbzhang.pdf

- 2013 Italian PAH emissions: E30+ blends reduce highest potency (HMW) PAHs by 60+%, p. 9, Fig. 17. http://www.sciencedirect.com/science/article/pii/S0306261912006836

- 2010 Honda: high boiler/high DBE aromatics most responsible for increased PN and PAH emissions, fuel quality changes necessary. http://papers.sae.org/2010-01-2115/

- 2013 Ford/Stein SAE: ethanol blends' impacts on SI engine emissions and performance. http://papers.sae.org/2013-01-1635/

- 2013 Oak Ridge/Szybist, Splitter et al.: E30 blends facilitate automaker compliance with fuel efficiency and carbon reduction targets. http://pubs.acs.org/doi/abs/10.1021/ef401575e

- 2009 Ford/Anderson: Energy Security Act targets require orderly introduction of EXX blends. http://papers.sae.org/2009-01-2770/

- 2011 SWRI/Khalek: SIDI engine PM/PN emissions, gasoline particulate filter technologies, and fuel composition discussion. Smaller gasoline PN difficult to capture. http://www.swri.org/3pubs/ttoday/Summer11/PDFs/ParticleEmissions.pdf

2. Vehicle technology advances must be optimized with gasoline quality improvements

On June 3, 2014, in Washington, DC, the Energy Future Coalition held a workshop to bring together leading experts and policymakers to discuss fuel and filter technology options for avoiding or controlling particulate pollution from aromatic hydrocarbons in gasoline and the toxic substances that can accompany them, especially polycyclic aromatic hydrocarbons (PAHs). The event featured a panel of experts from the automobile, clean fuels, and filter technology sectors.

The four excellent presentations can be accessed at the following link:
http://www.energyfuturecoalition.org/What-Were-Doing/Eliminating-Aromatics-Gasoline/Technical-and-Policy-Responses-Health-Risks-Ultrafine
The experts agreed that improvements in gasoline quality were a critically important policy tool for optimizing vehicle technology advances required to meet stricter fuel efficiency and carbon reduction rules.

An important take away from Woebkenberg (Mercedes-Benz), Splitter (Oak Ridge National Labs), and Vander Griend (ICM, Inc.) was that the next generation of vehicles would benefit significantly from higher octane gasoline, preferably in the 94 AKI range. This would allow engine designers to optimize for higher efficiency and reduced emissions, primarily by downsizing and increasing compression ratios. However, the experts all agreed that using aromatic compounds to increase octane to this level would result in substantial increases in PM emissions, especially UFPs and their associated toxics. In contrast, Mercedes confirmed substantial reductions in PN emissions (e.g., 50% or more) with mid-level ethanol blends (AKA E30). In answer to a question about what would happen if E30 were widely available, Woebkenberg replied that the effect would be "magic" in terms of increased engine efficiency accompanied by significant reductions in carbon and particle-borne toxics emissions.

Dr. Derek Splitter of ORNL reported that ethanol's superior octane properties are not fully understood, but involve a combination of octane sensitivity, heat of vaporization, flame speed, pressure sensitivity, and ethanol-specific kinetics. Referring to E30 as "Renewable Super Premium," Splitter said that compared to regular gasoline, it enables much more aggressive downsizing and downspeeding, enabling higher fuel economy despite ethanol's lower energy density. Oak Ridge research has confirmed that ethanol shows diminishing octane returns on blends above E50. He concluded that widespread use of E30 blends would offer a cost effective way to achieve a number of national policies simultaneously: RFS2, GHG – CAFE, and Tier 3.

Steve Vander Griend of ICM provided data to underline the importance of "splash-blending" additional ethanol to E10 to make E30, as opposed to "match-blending", where other components—especially aromatic compounds—are artificially added to shape the blend's distillation curve. Woebkenberg and Splitter agreed that given ethanol's superior octane properties, it makes no sense to add more aromatics when producing an E30, RSP blend.

3. Substantial climate and health co-benefits would be achieved by using ethanol's clean octane to improve gasoline quality

Replacing carbon intensive aromatic compounds with less carbon-intensive ethanol to increase gasoline octane levels has been shown by Oak Ridge and other experts to have the potential of substantially reducing the carbon footprint of the U.S. LDV fleet. E30 "clean octane" would also help reduce the transportation sector's carbon footprint in other ways. LCFS 55-1

In recent years, misinformed sources have contended that the increase in corn ethanol production has contributed to undesirable land use changes, and exacerbated carbon releases to the atmosphere. The empirical evidence shows that this is not true, as farmers have largely shifted some soybean acres to corn, with substantial benefits to soil fertility, carbon sequestration, and feed/food supplies, as explained below.

Shifting soybean acres to corn acres has not reduced the feed ration supplies, but it has increased soil fertility and carbon sequestration and soil organic matter buildup. After processing in an ethanol plant, an acre of corn yields as much protein as an acre of soybeans. Because it is a photo-synthetically superior C4 plant, corn has an extraordinary ability to sequester carbon, and help to move fertilizer nutrients back to the surface for plant growth rather than polluting ground water. Corn's extensive deep root system makes it one of the few plants with this important capability that makes crop production sustainable.

A multi-year USDA research project recently confirmed that no-till corn equaled switch grass in SOC (soil organic carbon) formation, and that over half the increase in SOC was below one foot depth. The researchers estimated that deep soil SOC sequestration benefits of corn have been understated by 60 – 100% in modeling done to date.[1]

Even Michael Pollan, a frequent critic of the current agricultural system, has singled out corn's efficiency compared to other crops. In his book, "Omnivore's Dilemma", Pollan noted: "Few plants can manufacture quite as much organic matter (and calories) from the same quantities of sunlight and water and basic elements as corn." Pollan goes on to praise corn's ability to extract carbon from the air. "The C-4 trick represents an important economy for a plant, giving it an advantage…By recruiting extra atoms of carbon during each instance of photosynthesis, the corn plant is able to limit its loss of

[1] U.S. Department of Agriculture, Agricultural Research Service, "A Surprising Supply of Deep Soil Carbon," February 2014. http://www.ars.usda.gov/is/AR/archive/feb14/soil0214.htm

water and "fix"—that is take from the atmosphere and link in a useful molecule—significantly more carbon than other plants."

98% of U.S. corn is not directly consumed by people (less than one bushel per person per year, out of a 14 billion bushel crop), but instead used as livestock feed and for other purposes. Importantly, when the starch portion of an acre of corn is converted to ethanol, what remains is as much protein and other equivalent high -value feed products as found in an acre of soybeans.

Since corn yields are nearly four times greater than soybean yields, and corn rebuilds SOC much more efficiently than soybeans, the economically and environmentally smart thing to do is to first process the corn to ethanol, and replace the starch with other low-value substitutes. Doing so results in the same amount of protein and feed co-product equivalents offered by an acre of soybeans, increases soil fertility and captured carbon, and offers the added bonus of the corn ethanol industry's job creation, health cost savings, oil import reduction, and environmental (aromatic substitution) benefits.

In the future, as corn yields increase with genetic engineering advances and other improved technologies, corn's ability to simultaneously supply high octane fuel components, feed/food, and carbon sequestration benefits will also increase. As grain output increases, so too does the output of the valuable corn stover residue which has value as a rebuilder of SOC, a feed ration component that can be mixed with ethanol's high protein co-products to replace starch, and a feedstock for cellulosic ethanol production. In summary, more corn, not less, is good for the environment (health and carbon co-benefits), the soil, the food supply, and the economy.

4. Substantial reductions are possible in urban black carbon emissions with clean octane gasoline

Scientists and regulators have identified soot (also known as black carbon, or BC) as a major contributor to climate change and harmful global warming, accountable for as much as 30-40 percent of the rise in global temperatures. Nations are proposing aggressive remediation measures such as installing filters on diesel engines. http://www.nytimes.com/2012/02/18/opinion/a-second-front-in-the-climate-war.html?_r=2&nl=todaysheadlines&emc=tha211

In addition to its global warming effects, press reports have identified BC as "perhaps the most deadly widespread air pollutant".
http://www.washingtonpost.com/national/health-science/epa-to-tighten-national-soot-standards/2012/06/14/gJQABYsPdV_story.html

New real-time measurements suggest that black carbon emissions from light-duty gasoline vehicles are significantly underestimated, as found by Liggio et al:[2]

"Unlike the results for gasoline vehicles, the measured BC emission factor for heavy-duty diesel vehicles was in reasonable agreement with previous measurements. This suggests, the team concluded, that greater attention needs to be paid to black carbon from gasoline engines to obtain a full understanding of the impact of black carbon on air quality and climate and to devise appropriate mitigation strategies.

"The present results also have implications for BC measurements, modeling, and emission regulations. ... The gap between BC mass emissions of HDDV and LDGV is likely to shrink further as regulations for HDDV continue to take effect and alternate technologies for fuel delivery in gasoline vehicles (i.e., gasoline direct injection; GDI) become more popular. BC emissions from GDI engines have been observed to be significantly higher than those from conventional engines. The present results suggest that further dynamometer and on-road measurements of BC from gasoline vehicles are required in order to corroborate our findings and to improve emissions inventories in support of modeling, national and international policies, and estimates of impacts on health, the environment, and climate."

A recent Ford Motor study (2012 Ford/Maricq, cited above) found that gasoline direct injection (GDI) vehicle exhaust PM is dominated by EC/BC, rather than organic carbon (OC), contrary to what EPA concluded in its 2008 Kansas City study, which found that OC accounted for 80% of PM emissions. Ford said this discrepancy stems from the differences between port fuel injection (PFI) and GDI engine technologies. Ford found that GDI vehicles fueled by E0 (gasoline with no ethanol) emit an approximate range of from 8 – 15 x 10^{12} per mile (vs. cubic meter). E30+ blends reduce BC emissions by 45%. Consequently, a nationwide clean octane program could achieve a significant, if not predominant, share of the EPA's targeted emissions of urban BC in a cost-effective, technologically proven, and consumer-friendly manner.

Numerous experts have concluded that spark ignition gasoline-powered engines are a larger source of urban BC emissions than diesel engines (96% of the U.S. vehicle fleet is gasoline powered). In one recent study based upon CalTrans vehicle data, SI gasoline emissions were a factor of 8 to 10 greater than heavy duty diesel emissions. http://aaqr.org/VOL10_No1_February2010/6_AAQR-09-05-IR-0036_43-58.pdf, Table 1, p. 46

[2] J. Liggio et al., "Are Emissions of Black Carbon from Gasoline Vehicles Underestimated? Insights from Near and On-Road Measurements." *Environmental Science & Technology*, 2012. doi: 10.1021/es2033845

In a December 2011 PM study for its LEV III rule, CARB stated that "recent studies show that gasoline engines also play a key role" in PM emissions, and that EC/BC "dominates PM". http://www.arb.ca.gov/regact/2012/leviiighg2012/levappp.pdf, p. 88, p. 11, Fig. 4

"Contrary to the perception diesel vehicles are the main vehicular source of PAHs, light-duty gasoline vehicles have been found to be the most important source of PAH emissions in some urban areas." BC has high porosity and a large surface area, and thus easily adsorbs the carcinogenic and mutagenic PAHs, and transports them to the lungs and organs. http://earthjustice.org/sites/default/files/black-carbon/jiang-et-al-2005-mexico-city.pdf, p. 3378

Honda researchers (2010 Honda study, cited above) noted that gasoline engines are responsible for a significant share of urban particulate emissions. Honda warned that in order to reduce both harmful global warming emissions, as well as health-threatening PN/PAH emissions, gasoline fuel quality must be improved to complement advances in vehicle hardware.

55_OP_LCFS_EFC Responses

598. Comment: **LCFS 55-1**

The comment states that a substantial reduction of the U.S. LDV fleet's carbon footprint can be achieved by using less carbon-intensive ethanol to increase gasoline octane levels.

Agency Response: See response to **LCFS 54-1**.

This page intentionally left blank.

Comment letter code: 56-OP-LCFS-EFC

Commenter: Reid Detchon

Affiliation: Energy Future Coalition

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

56_OP_LCFS
_EFC

Comments Submitted by the Energy Future Coalition and the Urban Air Initiative

Appendix II. Displacing aromatics now used for octane in gasoline would produce substantial benefits for public health.

1. **Gasoline aromatic compounds are a primary cause of the most dangerous urban pollutants**

Aromatic compounds constitute 20-30% of U.S. gasoline, which means that more than 40 billion gallons are combusted each year in U.S. light-duty vehicles. Their physico-chemical properties make them very difficult to combust efficiently. The higher distillation aromatics (high molecular weight, HMW), have higher double-bond equivalents (DBEs), and are particularly important contributors to urban ultrafine particles (UFPs) and polycyclic aromatic hydrocarbon (PAH) emissions. In the 1990 Clean Air Act Amendments, Congress instructed the EPA to achieve the "greatest reduction possible" in gasoline aromatics and the lethal air toxics they produce.

EPA has called ambient particulate matter (PM) one of the nation's greatest health threats, but it regulates only particle mass (vs. particle number), in the form of $PM_{2.5}$ (2.5 to 0.1 micrometers in aerodynamic diameter). Unfortunately, the much smaller UFPs (.1 micrometer, or 100 nanometers and smaller) are the most toxic, most bio-available, and the most effective carriers of the carcinogenic and mutagenic PAHs to the human body.
http://www.particleandfibretoxicology.com/content/6/1/24/ref

PAHs are semi-volatile organic compounds (SVOCs) found in both gaseous and particle form. They comprise the largest mass fraction of UFPs, the primary urban source of which is also gasoline aromatics. Gasoline PAHs are carcinogenic, mutagenic, and genotoxic.
http://aaqr.org/VOL10_No1_February2010/6_AAQR-09-05-IR-0036_43-58.pdf

UFPs have orders of magnitude higher number counts, and much larger surface mass with which to attract and carry the PAHs. For example, PM of 2.0 micrometer per cubic meter ($2\mu/m^3$) would have 2 particles per ml of air, and a surface area of $30\mu/m^2$ per ml of air. In contrast, a UFP of 0.02 μ/m^3 (20 nanometers, or 20 one-billionth of a meter) would have 2,390,000 particles in each ml of air, and a surface area of 3,000 μ/m^2 per ml of air. See slide 4 on link below. https://www.aqmd.gov/tao/ConferencesWorkshops/AircraftForum/FroinesSlides.pdf

Particle-borne PAHs can persist for days in the environment, and can carry long distances after their emission from the tailpipe. SOAs and UFPs insulate and preserve PAHs, which are able to penetrate indoors, and have been found 1.5 miles from congested roadways.
http://www.ph.ucla..edu/pr/newsitem061009.html

Gasoline PAHs are high molecular weight (4 – 6 rings), as opposed to diesel PAHs, which are low molecular weight. HMW PAHs are more toxic, and more persistent than LMW PAHs. In the U.S., approximately 250 million light duty vehicles consume more than 130 billion gallons of gasoline each year, and have historically accounted for more than 90% of transportation sector emissions. Thus, contrary to conventional wisdom, since gasoline PAHs are more abundant and ubiquitous, much smaller than diesel PAHs (extremely difficult and costly to trap), and more toxic, gasoline exhaust poses a much greater health threat to humans than does diesel exhaust. For example, a 2012 University of Colorado – Boulder study found that 80+% of PM2.5 secondary organic aerosols in Los Angeles originated from gasoline, as opposed to diesel, exhaust. http://www.colorado.edu/news/releases/2012/03/02/gasoline-worse-diesel-when-itcomes-

PAHs are considered to be one of the most ubiquitous endocrine disruptor compounds (EDCs) in urban environments. EDCs mimic natural hormones in the body, and experts warn that they are especially damaging to the fetus and young children, and can disrupt genetic structures, causing serious damage that transfers throughout generations. PAHs have been linked to a wide range of disorders, including cancers, heart disease, asthma and other respiratory disorders, premature births, autism, and obesity.
http://ehp03.niehs.nih.gov/article/info%3Adoi%2F10.1289%2Fehp.1104056

The California Office of Environmental Health Hazard Assessment has placed PAHs in Tier 1 on its toxic air contaminants list, in part due to the fact prenatal exposure to PAHs results in "serious and irreversible effects in the fetus".
http://www.oehha.ca.gov/public_info/pdf/GasOEHHA.pdf

Water quality regulators are reporting increasing deposition of PAHs in the nation's waterways, as gasoline exhaust is washed from roadways into rivers, lake, and estuaries. The PAHs are then ingested by fish and other seafood, and can then enter the human food chain.
http://calcium25.com/PAHs-Water-Air-Pollution-0707.pdfhttp://www.greencarcongress.com/2005/08/toxic_metals_de.html

2. **Gasoline aromatic compounds are the predominant precursors to urban secondary organic aerosols (SOAs)**

The Harvard Center for Risk Analysis found that up to $50 billion per year in social costs are attributable to gasoline aromatics. The Harvard study considered only premature mortalities (as opposed to morbidity) caused by PM2.5 secondary organic aerosols (SOAs). In other words, Harvard did not attempt to quantify the even greater health costs associated with particle-borne PAHs, including the increasing evidence of the damage they do to infants and developing children. http://www.ehjournal.net/content/12/1/19/abstract

- Excerpts:

  "Modeled aromatic SOA concentrations from CMAQ fall short of ambient measurements by approximately a factor of two nationwide...Assuming that the contribution of SOA precursors originating from aromatic hydrocarbons in gasoline is higher in urban areas increases these estimates to 5100 predicted premature mortalities nationwide...associated with total social costs of $37.9B".

"...particulates from vehicular emissions of aromatic hydrocarbons demonstrate a sizeable public health burden. The results provide a baseline from which to evaluate potential public health impacts of changes in gasoline composition."

"Evidence is growing that aromatics in gasoline exhaust are among the most efficient secondary organic matter precursors. In general, air quality models do not adequately capture these increased yields or potential interactions, although improvements have been made."

"In the United States, gasoline-powered vehicles are the largest source of aromatic hydrocarbons to the atmosphere...Therefore, it has been suggested that removal of aromatics could reduce SOA concentrations and yield a substantial public health benefit...a number of studies have noted that gas-phase vehicle emissions lead to a substantial fraction of observed SOA. For example, a source apportionment study of SOA formation during a severe photochemical smog event in Los Angeles found that gasoline engines represented the single-largest anthropogenic source of SOA."

"Although CMAQv5.0 contains updated...processes for predicting SOA formation, evidence suggests that the model may still underestimate secondary PM2.5 concentrations."

"Source-specific speciation reveals that the U.S. emissions of aromatic hydrocarbons are 3.6 million tons per year, of which 69% are from gasoline-powered vehicles as shown in Table 3."

"In addition to premature mortality, which dominates monetized estimates of total social cost, exposures to SOA from aromatics in gasoline are associated with other health outcomes, including exacerbation of asthma, upper respiratory symptoms, lost work days, and hospital emergency room visits."

"A recent study in Los Angeles found that gasoline emissions dominated SOA formation, accounting for nearly 90% of total aerosol formation, and the ratio of SOA to primary organic aerosol was approximately a factor of three...Anthropogenic SOA have been shown to enhance biogenic SOA formation."

3. SOAs and PAHs synergistically bind together, enabling long-range transport, increased aging, and greater persistence/penetration indoors

Zelenyuk et al. contend that conventional predictive models of SOAs and PAHs transport and persistence are fundamentally flawed. In its Tier 3 rule, EPA said that PAHs have a half-life of less than an hour, and that they dissipate within 300 feet of emission source. Here, DOE's PNNL confirms that the PAHs undergo LRT and persist for weeks or longer due to their insulation from atmospheric evaporation by the SOAs. This LRT and persistence has enormous implications for the much greater magnitude of the human health threat predicted by EPA assumptions vs. reality. http://www.ncbi.nlm.nih.gov/pubmed/23098132

"[B]ased on current understanding of gas-particle partitioning and atmospheric degradation of PAHs some species, like benzo[α]pyrene and fluoranthene, should not undergo LRT at all yet are found in the Arctic at concentrations similar to those in Europe. In general, existing gas-particle partitioning models severely underpredict observed LRT of particle-bound PAHs, highlighting large knowledge gaps in kinetic partitioning models."

An article describing the PNNL work noted: "The results also show that the particles that envelop pollutants also benefit from this arrangement. The new study shows that the airborne particles last longer with PAHs packed inside." http://www.greencarcongress.com/2012/11/pah-20121117.html#more

As the study put it: "Perhaps the most surprising finding is the observed synergetic relationship between PAHs and SOA. The presence of even a small amount of hydrophobic organics inside SOA significantly decreases the SOA evaporation rate and amplifies the effect of aging, thus creating conditions that ensure efficient LRT of both SOA particles and PAHs, consistent with observations. This synergy between PAHs and SOA particles has important implications not only for human health but also for climate change."

Using advanced instrumentation, PNNL scientists found that the potent PAHs are trapped within the semisolid SOAs (secondary organic aerosols) during particle formation and thus shielded from oxidation and preserved for extended periods of time. This is why CARB and others are now reporting UFP-borne PAHs as far away as 2,500 meters (not 300 feet, as EPA contended in its Tier 3 rule) from their source.

This PNNL research is very important. It helps explain some of the confusion amongst experts about the differences between concentrations of PAHs in gas-phase partitioning (which can be orders of magnitude lower) compared to the much higher concentrations of particle-bound PAHs. The PNNL scientists proved that the SOAs synergistically bond with the PAHs and serve as the "insulation and preservative" for the PAHs that enables their perpetuation and LRT (and vice versa).

4. Gasoline vehicles are the principal source of SOAs and toxics from aromatics

- Excerpts from Bahreini et al. (2012), "Gasoline emissions dominate over diesel in formation of secondary organic aerosol mass", Geophysical Research Letters, Vol. 39: http://onlinelibrary.wiley.com/doi/10.1029/2011GL050718/abstract

  Air-borne and ground-based measurements of OA in Los Angeles Basin indicated that "the contribution from diesel emissions to SOA formation is zero within our certainties. Therefore, substantial reductions of SOA mass on local to global scales will be achieved by reducing gasoline vehicle emissions."

"Consistent with previous studies, this indicates that gasoline vehicles are the dominant source of CO and light, single-ring aromatic VOCs including benzene and toluene."

"Because diesel emissions contribute to POA, but not detectably to SOA, as photochemical processing and SOA formation proceeds, the contribution of diesel emissions to total OA decreases."

"…for more accurate modeling of SOA formation in urban areas, future research should be directed at identifying specific species in the exhaust of gasoline engines that are responsible for SOA formation."

"Assuming that production of SOA relative to POA from gasoline exhaust follows the same trend as in LA…we estimate that within a day of processing, SOA from gasoline exhaust may reach 4 Tg/yr, which is 16% of recent global estimates of biogenic SOA. Our observations suggest that a decrease in the emission of organic species from gasoline engines may significant reduce SOA concentrations on local and global scales."

- Excerpts from Nordin et al. (2013), "Secondary organic aerosol formation from idling gasoline passenger vehicle emissions investigated in a smog chamber," Atmos. Chem. Phys., 13, 1601-6116: http://www.atmos-chem-phys.net/13/6101/2013/acp-13-6101-2013.html

"Gasoline vehicles have recently been pointed out as potentially the main source of anthropogenic secondary organic aerosol (SOA) in megacities."

"Gasoline exhaust readily forms oxidized organic aerosols that commonly dominates the organic aerosol mass spectra downwind of urban areas. … Classical C6 – C9 light aromatic precursors were responsible for up to 60% of the formed SOA, which is significantly higher than for diesel exhaust. Important candidates for additional precursors are higher-order aromatic compounds such as C10 and C11 light aromatics, naphthalene and methyl-napththalenes. We conclude that approaches using only light aromatic precursors given an incomplete picture of the magnitude of SOA formation and the SOA composition from gasoline exhaust."

"Photo-oxidation of gasoline exhaust forms SOA and ammonium nitrate. At the end of the experiments the formed SOA is 9-500 times higher than the emitted POA, which is in sharp contrast to diesel exhaust where the contribution of primary PM often dominates over secondary PM."

"The benzene concentration is strongly elevated in these idling experiments compared to the fuel content (benzene is regulated to less than 1% by volume in gasoline in Europe), most likely due to formation of benzene from other light aromatic compounds in the catalyst. … The enrichment of benzene in the exhaust is also found in road tunnel emission measurements."

"Since gasoline exhaust SOA is a more complex mixture than SOA from pure precursors, it can be expected that gasoline SOA resembles atmospheric observations better than SOA from pure precursors."

"This implies that relatively low concentrations of PAHs can give a significant contribution to SOA formation."

"As shown in this study, gasoline exhaust readily forms secondary organic aerosol with a signature aerosol mass spectrum with similarities to the oxidized organic aerosol that commonly dominates the OA mass spectra in and downwind of urban areas. This substantiates recent claims that gasoline SOA is a dominating source to SOA in and downwind of large metropolitan areas."

- Excerpts from Delfino et al., "Association of biomarkers of systemic inflammation with organic components and source tracers in quasi-ultrafine particles," 2010. Environ Health Perspect 118:756–762: http://www.ncbi.nlm.nih.gov/pmc/articles/PMC2898850/

"Indoor and outdoor PAHs (low-, medium-, and high-molecular-weight PAHs), followed by hopanes (vehicle emissions tracer), were positively associated with biomarkers, but other organic components and transition metals were not. Vehicular emission sources estimated from chemical mass balance models were strongly correlated with PAHs (R = 0.71)".

"Traffic emission sources of organic chemicals represented by PAHs are associated with increased systemic inflammation and explain associations with quasi-ultrafine particle mass."

"To our knowledge, this is the first report from a panel cohort study to show associations of circulating biomarkers of response in human subjects to specific PM organic compound classes. The measured chemicals serve as indicators and tracers for air pollutant sources and for classes of chemicals with the potential for redox activity in the body. In the present analysis, we found the strongest biomarker associations with air pollutant variables for all molecular weight classes of PAHs and specific source markers of vehicular emissions (hopanes) measured in $PM_{0.25}$ with GC/MS. Furthermore, two-pollutant models of the relation between the biomarkers of systemic inflammation and both total PAHs and $PM_{0.25}$ mass showed that mass associations were completely explained by PAHs."

"In the Los Angeles Basin, most outdoor PAHs in $PM_{0.25}$ are expected to be from mobile sources (Schauer et al. 1996), and the CMB exposure correlations are consistent with this expectation. PAHs were also correlated with source markers of vehicular emissions (hopanes). Hopanes are the most unambiguous source marker of traffic emissions."

"Overall, the associations of biomarkers with PAHs and hopanes suggest that our previous findings of positive associations of biomarkers with PM2.5, EC, and primary OC (Delfino et al. 2009) were due to PM of mobile-source origin. PAHs are found in greater concentrations in the quasi-UFP range compared with larger particles (Ntziachristos et al. 2007), and this has been hypothesized to explain enhanced prooxidative and proinflammatory effects of urban UFPs in the lungs and peripheral target organs of rodents (Araujo et al. 2008). The increased biological potency of UFPs may be related to the content of organic chemicals that have the capacity to reduce oxygen, such as quinones and nitro-PAHs, for which PAHs may act, in part, as a surrogate (Ntziachristos et al. 2007) or as a source after biotransformation. From the present results we infer that, although PAHs may have an effect by themselves, they are also likely surrogates for other causal species we did not measure that are emitted from the same (traffic) sources."

"Finding positive associations of biomarkers with both indoor and outdoor PAHs and hopanes along with the indoor/outdoor ratios of these organic components being close to 1.0 suggests that, even though people spend most of their time indoors, indoor air quality and PM exposures are strongly influenced by PM of outdoor origin. These findings are consistent with our previous analysis for the first half of this panel showing that CMB-estimated indoor PM of outdoor origin (particle number, EC, and primary OC) were associated with the biomarkers to a similar degree as outdoor PM (Delfino et al. 2008)."

5. **Heavy molecular weight (HMW) PAHs from gasoline are far more potent than LMW PAHs from diesel**

- California Office of Environmental Health Hazards Assessment report: Gasoline PAHs are heavy molecular weight (HMW), bear many similarities to cigarette smoke PAHs, and are ubiquitous in urban environments, especially adjacent to roadways. http://www.oehha.ca.gov/public_info/pdf/GasOEHHA.pdf.

- Prioritization of Toxic Air Contaminants – Children's Environmental Health Protection Act", October 2001: http://www.oehha.ca.gov/air/toxic_contaminants/pdf_zip/PAHs_Final.pdf

"Prenatal exposure to PAHs results in serious or irreversible effects in the fetus…For instance, PAHs are transplacental carcinogens…There is greater exposure of children to environmental PAHs compared to adults…Biomarkers for direct impacts associated with adverse health outcomes, such as DNA adducts, are increased in children exposed to environmental pollution by PAHs and related POM components. In view of this range of evidence for differential sensitivity of the fetus, infants, and children to health effects induced by POM components such as PAHs, and for greater exposure of children to POM, OEHHA has placed POM in Tier 1 of the priority list."

- Excerpt from Riddle et al., "Large PAHs detected in fine particulate matter emitted from light-duty gasoline vehicles," Atmospheric Environment, Volume 41, Issue 38, December 2007, Pages 8658‑8668: http://www.sciencedirect.com/science/article/pii/S1352231007006553

  "Emission factors of large PAHs with 6–8 aromatic rings with molecular weights (MW) of 300–374 were measured from 16 light-duty gasoline-powered vehicles (LDGV) and one heavy-duty diesel-powered vehicle (HDDV) operated under realistic driving conditions. LDGVs emitted PAH isomers of MW 302, 326, 350, and 374, while the HDDV did not emit these compounds. This suggests that large PAHs may be useful tracers for the source apportionment of gasoline-powered motor vehicle exhaust in the atmosphere. Large PAHs made up 24% of the total LEV PAH emissions and 39% of the TWC PAH emissions released from gasoline-powered motor vehicles. Recent studies have shown certain large PAH isomers have greater toxicity than benzo[a]pyrene. Even though the specific toxicity measurements on PAHs with MW >302 have yet to be performed, the detection of significant amounts of MW 326 and 350 PAHs in motor vehicle exhaust in the current study suggests that these compounds may pose a significant public health risk."

- MW 302+ PAHs are especially toxic, see slides 16 and 17 on Relative Potency Factors, 2012 Simonich/OSU deck. http://www.niehs.nih.gov/research/supported/assets/docs/r_s/what_goes_around_comes_around_chasing_polycyclic_aromatic_hydrocarbons_from_the_beijing_olympics_to_the_us_west_coast.pdf

- Abstract of a study by Y. Jia, "Estimated Reduction in Cancer Risk due to PAH Exposures If Source Control Measures during the 2008 Beijing Olympics Were Sustained," *Environ Health Perspect*. 2011 Jun; 119(6): 815–820: http://www.ncbi.nlm.nih.gov/pmc/articles/PMC3114816/

  "The 2008 Beijing Olympic Games provided a unique case study to investigate the effect of source control measures on the reduction in air pollution, and associated inhalation cancer risk, in a Chinese megacity.

  "We measured 17 carcinogenic polycyclic aromatic hydrocarbons (PAHs) and estimated the lifetime excess inhalation cancer risk during different periods of the Beijing Olympic Games, to assess the effectiveness of source control measures in reducing PAH-induced inhalation cancer risks.

  "We estimated the number of lifetime excess cancer cases due to exposure to the 17 carcinogenic PAHs [12 priority pollutant PAHs and five high-molecular-weight (302 Da) PAHs (MW 302 PAHs)] to range from 6.5 to 518 per million people for the source control period concentrations and from 12.2 to 964 per million people for the nonsource control period concentrations. This would correspond to a 46% reduction in estimated inhalation cancer risk due to source control measures, if these measures were sustained over time. Benzo[b]fluoranthene, dibenz[a,h]anthracene, benzo[a]pyrene, and dibenzo[a,l]pyrene were the most carcinogenic PAH species evaluated. Total excess inhalation cancer risk would be underestimated by 23% if we did not include the five MW 302 PAHs in the risk calculation.

"Source control measures, such as those imposed during the 2008 Beijing Olympics, can significantly reduce the inhalation cancer risk associated with PAH exposure in Chinese megacities similar to Beijing. MW 302 PAHs are a significant contributor to the estimated overall inhalation cancer risk."

6. Particle filters are not an adequate solution

Advanced GDI (gasoline direct injection) systems could make particle number (PN) emissions worse unless fuel composition is improved by reducing aromatic content. Mid-level ethanol blends have been shown to reduce particulate and black carbon emissions by 45 to 80% in direct injection and port fuel injection engines, respectively. Some have argued for the use of particulate filters on gasoline engines; however, the much smaller particles in gasoline exhaust (compared to diesel exhaust) elude capture by such filters, which also will interfere with, possibly even reverse, important fuel efficiency and carbon reduction gains.

This page intentionally left blank.

56_OP_LCFS_EFC Responses

Comment: The letter expresses health concerns associated with aromatic compounds but does not contain any comments related to the rulemaking.

Agency Response: This comment letter does not address the proposed rulemaking.

This page intentionally left blank.

Comment letter code: 57-OP-LCFS-BGA

Commenter: Ross Nakasone

Affiliation: Blue Green Alliance

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

57_OP_LCFS
_BGA

February 17, 2015

Mary Nichols, Chairman
California Air Resources Board
1001 I Street, PO Box 2815
Sacramento, CA 95812

Dear Chairman Nichols and Members of the Board:

The Natural Resources Defense Council and BlueGreen Alliance join to thank you and CARB staff for your efforts to improve and readopt the Low Carbon Fuel Standard (LCFS). We remain strong supporters of AB 32 and the LCFS, which is transforming the fuel industry by reducing the carbon intensity of our transportation fuels.

We share in the mission to address today's environmental challenges in ways that can create, maintain and secure quality jobs and a stronger, fairer economy. We are guided by the principle that Californians deserve both environmental sustainability and economic prosperity. We believe the Low Carbon Fuel Standard advances our mission. To that end, we support efforts in the LCFS that establish a cost containment provision and pathways for refinery improvements.

Over the past three years, the Natural Resources Defense Council and the BlueGreen Alliance, have worked together to meet with ARB and provide recommendations to the California Air Resources Board on the Low Carbon Fuel Standard. On July 10th, 2014, the organizations jointly submitted comments to the agency on ways to enhance the standard. In particular, these include recommendations to add a cost containment mechanism and expand the program's flexibility to encourage GHG emission reduction projects that lower carbon pollution, including energy efficiency and combined heat and power, at both petroleum refineries and crude oil production facilities.

We thank ARB for considering the recommendations, developing the concepts further over the past year, and proposing them for adoption. We support the Board moving forward to adopt those provisions.

By providing a maximum compliance cost or "safety valve," ARB's proposed cost containment provision creates more certainty for all parties while preserving the signal to continue to invest in emission reductions. Allowing regulated parties to make up shortfalls through an additional credit clearance period the following year, providing up to an additional five years to make up credits in the event of a true lack of credits, together with a five percent annual interest applied to deficits will enhance

LCFS 57-1

certainty, encourage future compliance with the LCFS, while maintain the environmental benefits of the standard. LCFS 57-1 cont.

We strongly support credits for GHG emission reductions from refinery improvement projects. Credits for refinery improvements represent a significant opportunity to spur additional investment to improve the environmental performance at refineries and create secure refinery jobs, while reducing the carbon intensity of transportation fuels and fostering additional benefits such as reductions in criteria pollution. To that end, we support the Board adopting staff's proposal for crediting refinery improvements and the provisions that ensure these projects are beyond business as usual. These include the requirements that the projects:

- Represent actual capital investments to reduce carbon emissions (as opposed to simply shutting down units) or expand refineries' use of renewable energy
- Create net reductions in carbon intensity
- Be limited to projects undertaken to help comply with the standards that are not business as usual.
- Demonstrate that associated toxic and criteria air pollutants will not lead to net increases or be lower over the life of the project

LCFS 57-2

We also support awarding LCFS credits to producers and project developers that invest to reduce emissions from crude oil production processes. Implementing innovative technologies, such as carbon capture and storage (CCS), solar thermal and other renewable inputs, can create good, secure jobs and reduce carbon intensity of petroleum directly. In light of petroleum's more than 90% share of the transportation fuels market, improvements such as these could have far reaching positive effects. LCFS 57-3

We believe offering LCFS credits to refineries and producers for these improvements could create significant incentives and make projects that will reduce GHG emissions more attractive while creating, maintaining and securing quality jobs.

Again, we thank ARB staff for their hard work on the LCFS re-adoption and leadership to help address climate change. We look forward to working together on the successful and smooth implementation of the LCFS.

Sincerely,

Simon C. Mui

JB Tengco

Simon Mui
Director, California Vehicles and Fuels
Natural Resources Defense Council

JB Tengco
California Director
BlueGreen Alliance

57_OP_LCFS_BGA Responses

599. Comment: **LCFS 57-1**

The comment shows support for the cost containment provision.

Agency Response: ARB staff appreciates the support for the proposed cost containment provision.

600. Comment: **LCFS 57-2**

The comment supports the refinery investment provision.

Agency Response: ARB staff appreciates the support for the proposed refinery investment provision.

601. Comment: **LCFS 57-3**

The comment supports the innovative crude provision.

Agency Response: ARB staff appreciates the support for the proposed innovative crude provision.

This page intentionally left blank.

Comment letter code: 58-OP-LCFS-EFC

Commenter: Reid Detchon

Affiliation: Energy Future Coalition

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

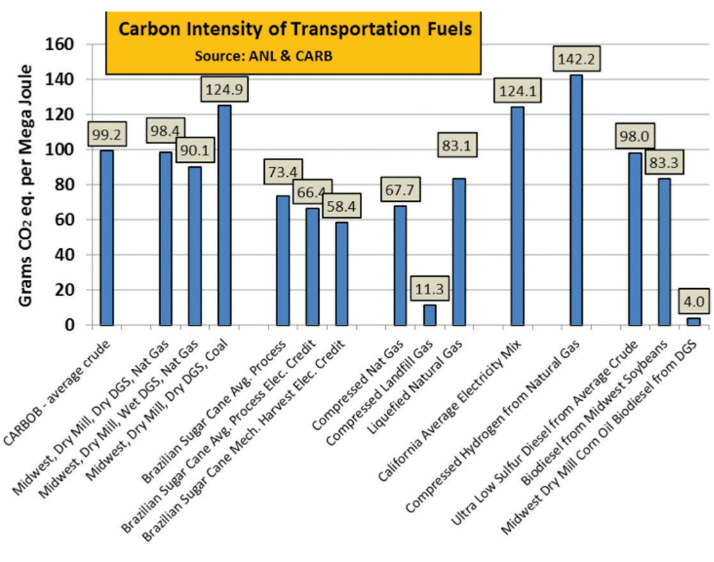
Re-thinking the Carbon Reduction Value of Corn Ethanol Fuel

ETHANOL ACROSS AMERICA

An Ethanol Across America White Paper | Winter 2015

It has been seven years since Argonne National Labs (ANL), as part of the Energy Security and Independence Act requirements, first determined the Life Cycle Carbon Intensity of mid-west corn ethanol fuel. ANL, using their **G**reenhouse gases, **R**egulated **E**missions, and **E**nergy use in **T**ransportation (GREET) model determined that Mid-West average corn ethanol fuel had a CI score of 98 grams CO_2 eq. emissions per mega joule of energy production. In the subsequent years, ANL has provided several updates to this greenhouse gas accounting that have significantly reduced the CI of corn ethanol fuel. However, low carbon fuel market regulators, such as the U.S. EPA and the California Air Resource Board (CARB) have yet to acknowledge these improvements and update their models with this new science. Because fossil fuel CI is trending higher and corn ethanol fuel CI is trending lower, failure to account for and acknowledge these trends erodes public support for biofuels and unfairly penalizes biofuels in low carbon fuel markets. Conversely, recognizing these new realities would provide us with a home grown advanced biofuel that meets a range of health and public policy objectives.

Carbon Intensity Modeling of Transportation Fuels



Using the GREET model, ANL and regulators such as CARB and the U.S. EPA, have determined the CI of all current and potentially significant transportation fuels used in the U.S.

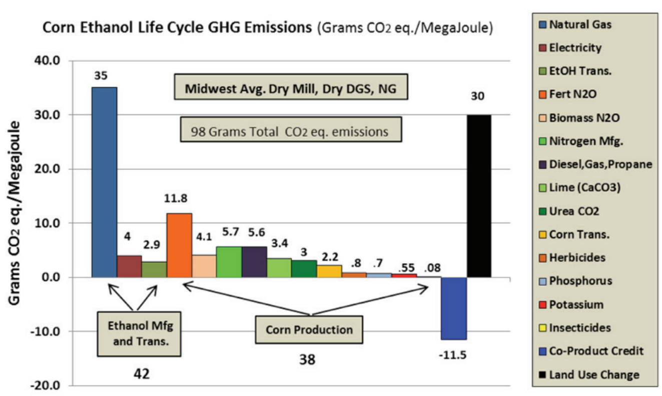
In 2013, California used Corn and Sugar Cane ethanol (62%), Biodiesel (27%), and Natural Gas (9%) for their Low Carbon Fuel Standard (LCFS) compliance.

Ron Alverson

For the past 40 years, Ron, a farmer, has raised corn and soybeans near Chester, South Dakota. Mr. Alverson was a founding member (1987) and past president of the South Dakota Corn Grower's Association, and past board member of the National Corn Grower's Association. Ron was also a founder and is a current board member of Lake Area Corn Processors LLC (Dakota Ethanol), a 60 million gallon per year ethanol production plant at Wentworth, SD, where he is involved with low carbon pathway applications for low carbon fuel markets. He also currently serves as President of the American Coalition for Ethanol's Board of Directors and is a member of the South Dakota State University Foundation Board of Trustees. Ron holds a BS degree in Agronomy/Soil Science from South Dakota State University.

Midwest Average Corn Ethanol Fuel Carbon Intensity

Even though ANL has issued several updates to GREET, CARB Scientists continue to use ANL's GREET 1.8b model (2008) to determine midwest avg. corn ethanol fuel CI. Chart below lists the measurement/modeling points and GHG emissions from corn ethanol fuel.



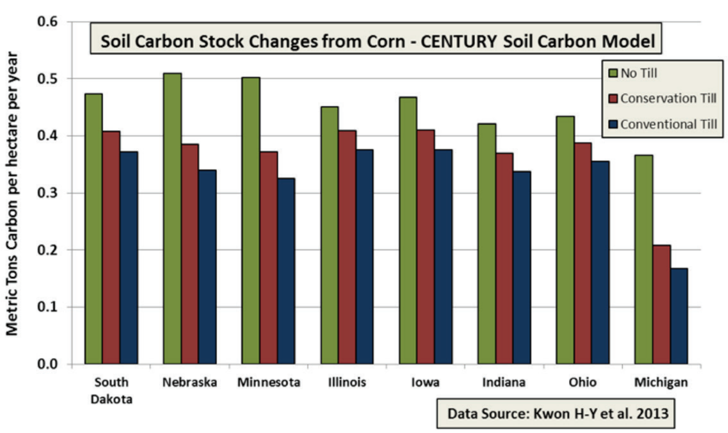
Continued

In addition to the direct GHG emissions from energy used in ethanol mfg. and corn production, modelers adjust total life cycle carbon intensity for co-product credits and soil carbon emissions from estimated **L**and **U**se **C**hanges (LUC).

To their credit, CARB has allowed individual ethanol production facilities to prove reduced carbon pathways. To date more than 100 ethanol production facilities have documented significant reductions in energy use. These production facilities average 86 CI.

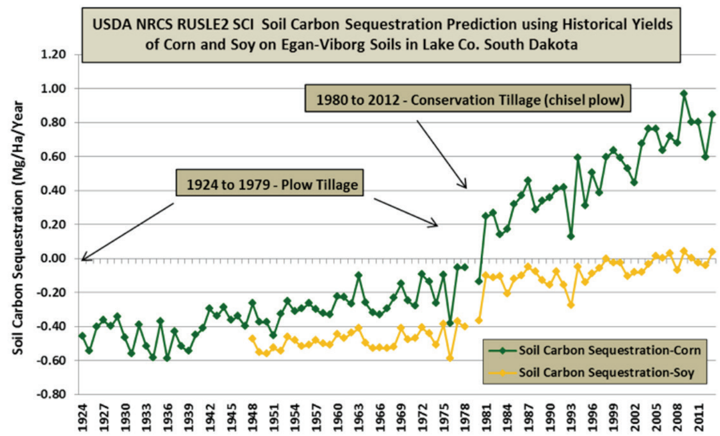
Reductions in Corn Ethanol Fuel Carbon Intensity since 2008

ANL, Agricultural Scientists, Environmental Scientists, and Ethanol Production Companies have documented significant reductions in corn ethanol fuel CI since 2008. ANL Scientists recently determined (GREET version 2.0, 2013) that average ethanol mfg. energy use has decreased 25%, corn farming energy use decreased 24%, corn fertilizer and chemical use decreased by 3%, and that ethanol manufactures are extracting 3% more ethanol from each bushel of corn. ANL affiliated scientists have also updated their Land Use Change calculations (Dunn et al. 2013)[1] with recent data and now estimate that soil carbon emissions from LUC are 7.6 grams CI, a 75% reduction from the widely used estimate of 30 grams CI. A significant portion of this reduction resulted from CENTURY (Kwon H-Y et al. 2013) and CCLUB (**C**arbon **C**alculator for **L**and **U**se Change from **B**iofuels Production) soil carbon modeling that predicts significant soil carbon sequestration from corn. Kwon H-Y et al. results are in the following chart:



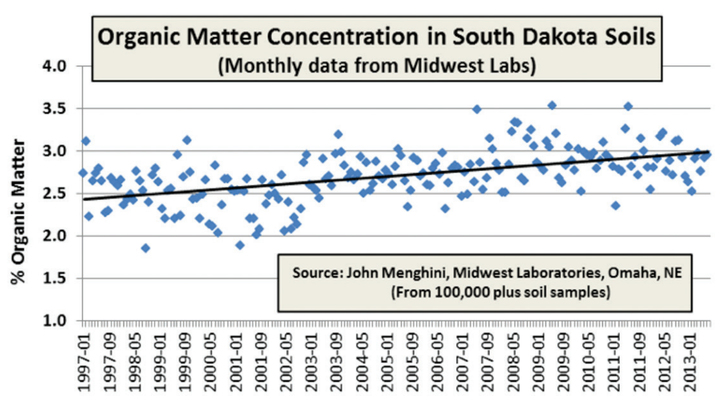
Corn crops that sequester .5 metric tons per hectare of atmospheric carbon annually in soil reduce overall corn ethanol CI by 20 grams.

This modeling is supported by U.S.D.A. National Resource Conservation Service (NRCS) soil carbon modelers. Modelers charted the effect of crop, increasing yield, and reduced tillage practices on soil carbon sequestration. Below are modeling results for Lake County, South Dakota:



The RUSLE2 SCI soil carbon model is calibrated with in-field measurement of actual long term soil carbon stock changes. Calibration data can be found on page 22 of an NRCS publication titled *"Using the Soil Conditioning Index to Assess the Management effects on Soil Carbon"* www.usda.nrcs.gov.

Regional soil testing laboratories (SDSU Soil Testing Laboratory, AGVISE Labs, and Mid-West Labs) have also contributed data indicating gains in soil carbon stocks. Below is a chart generated with soil organic matter data from Mid-West Labs in Omaha, Nebraska:



Organic matter concentration in South Dakota soils has increased about six tenths of 1% in the past fifteen years. Although this may seem like a very small change, this represents significant carbon sequestration in soil and is equivalent to 19 grams CI. The soil samples these data represent came from fields representing all crops grown in South Dakota. Had only corn fields been sampled, soil organic matter increases would very likely have been significantly higher.

1 *Land-use change and greenhouse gas emissions from corn and cellulosic ethanol*. Dunn et al., 2013

2 *Modeling state-level soil carbon emission factors under various scenarios for direct land use change associated with United States biofuel feedstock production.* Kwon H-Y et al., 2013

Dr. David Clay, along with a team of SDSU soil scientists (Clay et al. 2012)[3] merged soil carbon modeling with soil testing lab data to produce a paper titled "Corn Yields and No-tillage Affects Carbon Sequestration and Carbon Footprints"

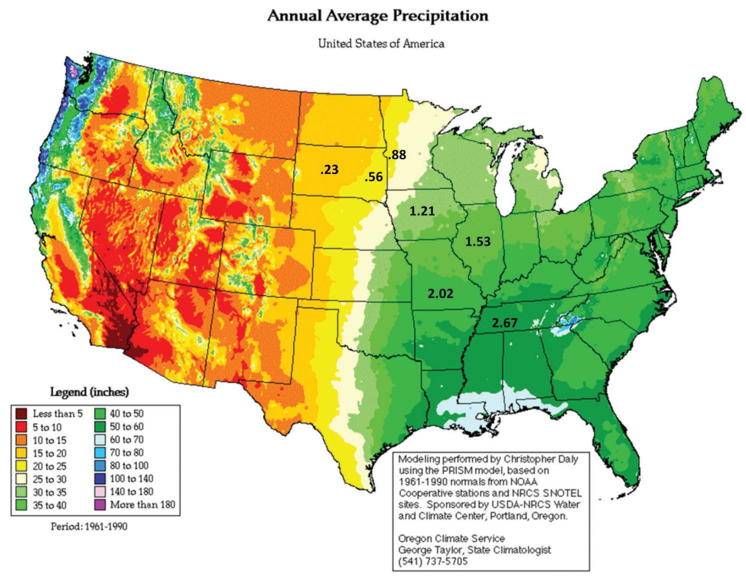
Of equal or greater impact on Land Use Change calculations, is the recently completed work (Babcock and Iqbal., 2014)[4] that tested first generation LUC model assumptions. These scientists have determined that little or no forest land has been converted to cropland in the U.S. as a result of biofuel production. Since 43% of the 30 CI LUC emission penalty is from estimated U.S. forest conversions, LUC is overestimated by more than 13 grams CI. As these and more data are accumulated it appears likely that corn ethanol fuel will eventually receive a LUC emission credit. Indeed, U.S.D.A. Agriculture Research Service Scientists (Follet et al., 2012)[5] have documented annual soil (full rooting profile) carbon sequestration in no-till corn exceeding .9 tons per year. This amount of atmospheric carbon sequestration in soil is equivalent to 80 grams CI! (*http://www.ars.usda.gov/is/AR/archive/feb14/soil0214.htm*)

Corn Production N_2O Emissions

Soil and crop scientists are also re-examining assumptions made in GHG models regarding Nitrous Oxide (N_2O) emissions from Nitrogen (N) fertilizer use and biomass N in corn production. N_2O is by far the largest component of corn production GHG emissions and comprise approximately 50% of all corn production CI.

Current N_2O emission calculations assume that about 1.5% of applied N fertilizer is converted to N_2O. But corn farmers are responding to market signals (N fertilizer prices are up 3–4X over the past 15 years) and have rapidly adopted precision application technology and employed Enhanced Efficiency Fertilizers (EEFs) in order to reduce N application rates, increase N use efficiency and reduce N losses to the air and water. Reviews of Scientific Literature indicate that these actions can reduce N_2O emissions by up to 50%. N losses and N_2O emissions are also greatly impacted by precipitation. Higher rainfall areas have higher N losses and N_2O emissions. European Soil and Environmental Scientists (Lesschen et al., 2012),[6] have developed a "precipitation adjustment factor" to estimate N induced N_2O emissions. These scientists calibrated this factor based on a global review of 352 N_2O emission measurements from fields. Using the Lesschen et al. "precipitation adjustment factor" scientists have estimated N to N2O conversion rates across the U.S. Midwest. See following map.

Precipitation adjusted Fertilizer N-to-N_2O Conversion Rates



As an example, average N_2O emissions from corn produced in Eastern Nebraska are expected to be only 50% of Central Illinois grown corn based on differences in precipitation.

Given the geographic location of U.S. corn ethanol production, these data suggest that using a uniform N-to-N_2O conversion rate across the U.S. Corn Belt does not properly account for the actual N_2O emissions from U.S. corn used for ethanol. A weighted average (ethanol production by precipitation zone) indicates a 10% reduction in Mid-West average N_2O emissions is warranted using this approach. This work is supported by a comparison of the Wang et al. 2012[7] field measurements of N_2O and the Wang et al. data adjusted with the Lesschen et al. precipitation factor. See chart on the following page. N_2O emissions increase when annual precipitation increases.

The GREET model also assumes that the N in corn residues has the same N-to-N_2O conversion rate as fertilizer N. This assumption is not in agreement with Scientific Literature. Research indicates that the N-to-N_2O conversion rate of the N in corn residues is only 20% of fertilizer N conversion rates. Corn residues have a very high carbon to nitrogen ratio, and because of this, N is immobilized by bacteria as this high carbon residue is decomposed. Lesschen et al.[6] discuss this research and support this reduced N-to-N_2O emission factor for corn residue in their research paper. Since 25% (4 CI) of corn ethanol fuel N_2O emissions are the result of corn biomass N, a 3 CI reduction is warranted.

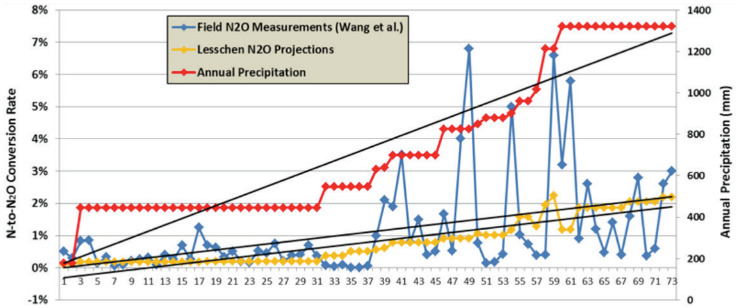
3 *Corn Yields and No-Tillage affects Carbon Sequestration and Carbon Footprints.* Clay et al., 2012.

4 *Using Recent Land Use Changes to Validate Land Use Change Models.* Bruce A. Babcock and Zabid Iqbal, 2014.

5 *Soil Carbon Sequestration by Switch grass and No-Till Maize Grown for Bioenergy.* Follet et al., 2014.

6 *Differentiation of nitrous oxide emission factors for agricultural soils.* Lesschen et al., 2011.

7 *Supporting Information For Well-to-Wheels Energy Use and Greenhouse Gas Emissions of Ethanol from Corn, Sugarcane, and Cellulosic Biomass for U.S. Use*. Wang et al., 2012.



Precision N management practices and increased use of enhanced efficiency N fertilizers have resulted in lower N_2O emissions in corn fields. Acknowledging an ethanol plant location precipitation adjusted weighted average N-to-N_2O conversion factor to determine Mid-West average, and recent science regarding N-to-N_2O conversion factors of fertilizer N and corn biomass N is clearly more scientifically defensible modeling. Corn ethanol N_2O emission factors in GHG models should be adjusted and N_2O emissions should be reduced a minimum of 6 CI. When corn ethanol is produced in areas where precipitation is reasonably balanced with corn crop evapotranspiration, N_2O emissions are likely less than 50% of the current Mid-West average.

Co-Product Credit

For use in the California LCFS, CARB modifies the GREET 1.8b model to reduce the co-product credit for distillers grains and assumes 1 lb. of distillers displaces only 1 lb. of corn in feed markets. Corn ethanol distillers grains are significantly more nutrient dense than corn, containing three times the protein, oil, minerals, and vitamins. None of these high value feed/food components are lost in the corn ethanol fermentation process. Peer reviewed University feeding trials have indicated that distillers grains displace 1.2 to 1.4 lbs of corn in cattle rations. ANL's GREET 1.8b model assumes one pound of distillers grains displace the equivalent of 1.27 lbs. corn. The failure of CARB to acknowledge this science raises corn ethanol CI 2.5 grams in that low carbon fuel market.

When high corn starch diets are used in cattle feed lots and dairies, significant methane emissions occur (enteric fermentation). ANL tabulates a CI credit for a reduction in enteric fermentation because distillers grains has replaced corn in cattle diets. CARB does not acknowledge this science, and has zeroed out this credit in the GREET 1.8b model. This raises corn ethanol CI 3.5 grams in California's LCFS market.

Many dry mill corn ethanol plants have added an additional co-product, corn oil. Each acre of corn produces about 10 gallons. This provides a significant amount of energy in feed rations and or biodiesel markets. Modelers have not accounted for this additional co-product in the same manner as the distillers grain co-product (unlike distillers grains, no feed, food or energy credit has been accrued to the corn ethanol life cycle for corn oil). Rather, modelers have tabulated an exceedingly low life cycle CI for corn oil biodiesel because they have assigned no portion of the GHG emissions from corn production to the corn oil. This distorts the CI of corn oil biodiesel downward at the expense of corn ethanol fuel CI. Corn ethanol gets all the gasses and corn oil biodiesel gets all the glory.

Summary

If greenhouse gas modeling of transportation fuels are to maintain integrity and achieve their desired outcome, it is essential that modeling is done consistently and that modeling assumptions are periodically reviewed and updated with the latest science. U.S. corn ethanol fuel production has experienced significant energy use and greenhouse gas emission reductions over the course of the last few years. Since 2008, innovation in energy use and conversion technology at ethanol production facilities, innovation in enhanced efficiency fertilizers and in corn production management, and improved accuracy of GHG modeling assumptions have reduced current corn ethanol fuel CI by more than 50%. The future is bright for corn ethanol blends to provide significant reductions in U.S. transportation fuel CI. Long term trends are biofuel's friends…fossil fuel CIs are increasing and biofuel CIs are being reduced. Corn provides high per acre production of feed/food, high octane fuel, and low GHGs. The wait is over…the advanced biofuel of tomorrow has arrived!

american coalition for ethanol

Dakota ETHANOL

SOUTH DAKOTA CORN UTILIZATION COUNCIL
A GROWING INVESTMENT

This ***"Re-thinking the Carbon Reduction Value of Corn Ethanol Fuel"* White Paper** was produced and is distributed as part of a continuing series sponsored by the Ethanol Across America education campaign. Support for this paper was provided by the American Coalition for Ethanol, Dakota Ethanol, LLC, and the South Dakota Corn Utilization Council. Interested parties are encouraged to submit papers or ideas to **cfdcinc@aol.com**.

ETHANOL ACROSS AMERICA

Ethanol Across America is a non-profit, non-partisan education campaign of the Clean Fuels Foundation and is sponsored by industry, government, and private interests. For more information, log on to **www.ethanolacrossamerica.net** or contact Douglas A. Durante, Director.

58-OP-LCFS-EFC Responses

602. Comment: **LCFS 58-1**

Agency Response: This comment letter contains one reference that was cited in Comment Letter **54_OP_LCFS_EFC**.

This page intentionally left blank.

Comment letter code: 59-OP-LCFS-EFC

Commenter: Reid Detchon

Affiliation: Energy Future Coalition

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

59_OP_LCFS
_EFC

Environmental Science & Technology

Policy Analysis

pubs.acs.org/est

Refining Economics of U.S. Gasoline: Octane Ratings and Ethanol Content

David S. Hirshfeld* and Jeffrey A. Kolb

MathPro Inc., P.O. Box 34404, Bethesda, Maryland 20827, United States

James E. Anderson*

Ford Motor Company, MD RIC-2122, P.O. Box 2053, Dearborn, Michigan 48121, United States

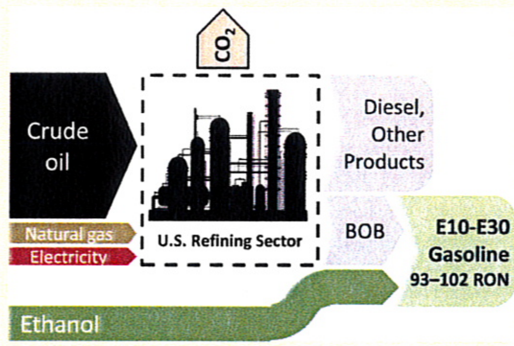
William Studzinski

General Motors Company, 823 Joslyn Avenue, Pontiac, Michigan 48340, United States

James Frusti

Chrysler Group LLC, CIMS 482-00-71, 800 Chrysler Drive, Auburn Hills, Michigan 48326, United States

Supporting Information



ABSTRACT: Increasing the octane rating of the U.S. gasoline pool (currently ~93 Research Octane Number (RON)) would enable higher engine efficiency for light-duty vehicles (e.g., through higher compression ratio), facilitating compliance with federal fuel economy and greenhouse gas (GHG) emissions standards. The federal Renewable Fuels Standard calls for increased renewable fuel use in U.S. gasoline, primarily ethanol, a high-octane gasoline component. Linear programming modeling of the U.S. refining sector was used to assess the effects on refining economics, CO_2 emissions, and crude oil use of increasing average octane rating by increasing (i) the octane rating of refinery-produced hydrocarbon blendstocks for oxygenate blending (BOBs) and (ii) the volume fraction (Exx) of ethanol in finished gasoline. The analysis indicated the refining sector could produce BOBs yielding finished E20 and E30 gasolines with higher octane ratings at modest additional refining cost, for example, ~1¢/gal for 95-RON E20 or 97-RON E30, and 3–5¢/gal for 95-RON E10, 98-RON E20, or 100-RON E30. Reduced BOB volume (from displacement by ethanol) and lower BOB octane could (i) lower refinery CO_2 emissions (e.g., ~ 3% for 98-RON E20, ~ 10% for 100-RON E30) and (ii) reduce crude oil use (e.g., ~ 3% for 98-RON E20, ~ 8% for 100-RON E30).

INTRODUCTION

Octane rating specifications for standard grades of U.S. gasoline (regular, midgrade, and premium) have not changed since the 1970s, when leaded gasoline was phased out, leading to reductions in gasoline antiknock index (AKI) and compression ratios (CR) for naturally aspirated engines. AKI is the average of research octane number (RON) and motor octane number (MON)). But, since the 1970s, there have been great changes in technologies, standards, and regulations applicable to vehicles, oil refining, and fuels.

Auto manufacturers have improved performance and complied with higher fuel economy standards for new U.S. car and light-duty trucks using a variety of design changes, including gradually increasing engine CR. Higher CRs have been enabled by new engine technologies (adaptive spark control, variable valve timing, and fuel injection) and by new combustion chamber designs featuring high turbulence, central spark plug location, and optimized cooling. New vehicle technologies have also contributed (hybridization, turbocharging, downsizing, lightweight materials, and improved aerodynamic drag and rolling resistance).

Over the same time period, refineries have increased energy efficiency, reduced operating costs, met more stringent fuel standards (e.g., low-sulfur gasoline and diesel fuel), accommodated increasing volumes of ethanol in the gasoline pool,

Received: May 2, 2014
Revised: August 20, 2014
Accepted: August 21, 2014
Published: August 21, 2014

and are now reducing the gasoline/distillate ratio of the U.S. refined product slate in response to changes in demand. U.S. gasoline now meets stringent regulations for volatility (as measured by Reid Vapor Pressure (RVP)), sulfur content, and benzene content.

The U.S. Renewable Fuel Standard (RFS2) mandates[1] have triggered large increases in ethanol use; essentially all U.S. gasoline is now E10. RFS2 calls for further annual increases in ethanol use through 2022, although it is not clear how additional ethanol volumes will be accommodated in the gasoline pool, given current regulations governing gasoline and the limited compatibility of the refueling infrastructure and the light-duty vehicle fleet with ethanol content greater than E10.

More change is coming as the automotive industry gears up to meet new federal corporate average fuel economy (CAFE) and GHG standards.[2] The new standards become more stringent each year, reaching a fleet average of 54.5 mpg in 2025 (about double the current standard). Meeting these standards will require advanced vehicle and engine technologies and, possibly, new fuels.

One approach under consideration is to further increase gasoline engine CRs to achieve higher thermal efficiency and therefore higher vehicle fuel economy and lower GHG emissions. For example, increasing the CR from 10:1 to 12:1 could increase efficiency by 5−7%, or by 6−9% for 13:1, depending on attributes of the vehicle, engine, fuel, and drive cycle.[3,4] However, higher CRs require higher-octane fuel to prevent knocking at high load. Increasing CR by 1 number (e.g., from 10:1 to 11:1) requires an increase of 2.5 to 6 RON in the fuel (e.g., from 92 RON to 94.5−98 RON),[3−5] depending on cylinder displacement and geometry and engine technology (e.g., direct injected or port fuel injected, turbocharged or naturally aspirated).

As ethanol use has increased in the past decade, the U.S. refining industry has reduced the average octane rating of the hydrocarbon portion of gasoline (the BOB) by approximately 2−2.5 AKI to take advantage of ethanol's high octane rating while meeting the minimum octane standards for the finished gasoline.[5]

The potential for realizing higher gasoline octane ratings depends on refining techno-economics and federal and state standards on gasoline properties and composition. However, significantly higher gasoline octane ratings can be achieved by (i) increasing the octane rating of hydrocarbon gasoline to the extent feasible (e.g., to values typical 10 years ago) and (ii) increasing ethanol content from the current 10 vol % to 20−30 vol % (assuming federal regulations were modified to allow such fuels). Ethanol has a high volumetric blending octane value in gasoline: ~115−135 RON, depending on the ethanol concentration and BOB RON and composition (Supporting Information (SI) Section 4.6).[6,7]

Ethanol also has a high latent heat of vaporization and high sensitivity (RON minus MON), contributing to improvements in knock resistance in direct-injection and turbo-charged engines, allowing further increases in CR.[3,4] Ethanol can also increase efficiency in part-load operation, regardless of engine architecture.[8,9]

Finally, increasing the ethanol content in gasoline blends could reduce the "well-to-wheels" (WTW), life-cycle GHG emissions from light-duty vehicles, with the magnitude depending on the carbon footprint of ethanol production, fuel properties (e.g., carbon content), and engine efficiency benefits.

The use of high-RON gasolines would contribute to the vehicle industry's ability to meet future CAFE and GHG standards, but the production of such fuels would impose costs on the refining industry. Older WTW studies are outdated, do not consider GHG implications in the U.S. setting, and do not consider ethanol use at present or projected U.S. levels. The 1970s oil embargo and lead phase-out spurred studies[10,11] of optimal octane ratings for unleaded U.S. gasoline, considering both refining sector effects and vehicle efficiency. Reviewing these studies, the U.S. Environmental Protection Agency (EPA) concluded[12] that "the current rating of 91 RON/83 MON for unleaded gasoline does not appear strictly appropriate on a permanent basis." In the 1980s, a European oil industry study[13] evaluated gasoline octane ratings in light of their lead phase-out. In that study, oil consumption was the key metric and neither GHG emissions nor ethanol as a high-octane blending component were considered. A more recent European analysis[14] considered cases with 100-RON gasoline and E20 gasoline, reporting higher refinery CO_2 emissions and cost in the former case and lower CO_2 emissions and cost in the latter. In 2005, a Japanese auto-oil industry research group concluded that increasing the RON of Japanese gasoline from 90 to 95 could provide a WTW CO_2 emissions reduction and that ethanol blending had greater potential than refinery changes.[15] However, that study considered vehicles designed for the Japanese market, Japanese refineries and fuels, and ethanol content was limited to 3 vol %.

A recent paper by Speth et al.[16] addressed economic and GHG implications of increasing U.S. gasoline RON from regular- to premium-grade in the context of future CAFE standards and reported significant associated reductions in WTW CO_2 emissions and cost. Further addressing the lack of relevant analysis, this paper examines the implications for the U.S. refining industry of increasing the octane rating and/or the ethanol content of U.S. gasoline. It assesses the investment requirements, refining cost, and other consequences in the U.S. refining sector of producing a national gasoline pool meeting minimum RON standards from 93.2 (the approximate current average) to 102, with ethanol concentrations from 10 to 30 vol %, both as nationwide midlevel blends (E10 to E30) and as combinations of E85 and E10. Fuel properties are estimated to enable WTW assessments of the associated GHG emissions.

METHODS

The analysis employed regional refinery linear programming (LP) modeling to estimate the effects on the U.S. refining sector of producing a single future national gasoline that (i) meets a uniform minimum octane rating (RON) standard, (ii) contains ≤10 ppm sulfur (the new national Tier 3 standard),[17] and (iii) satisfies existing federal, California, and industry gasoline standards. Linear programming has long been the preferred method for analyzing technical and economic aspects of refining operations.[18,19] A refinery LP model yields an optimal value for an economic objective function, subject to a set of constraints denoting product demands, crude oil availability, refinery process capacities and capabilities, and energy and material balances.

In this study, the objective function to be minimized was total refining cost (the sum of direct operating costs and capital charges for new investments) incurred in producing the same slate of primary refined products with specified properties including octane rating. In this product slate, the volumes of all primary refined products were fixed in all cases (as required for

dx.doi.org/10.1021/es5021668 | Environ. Sci. Technol. 2014, 48, 11064−11071

cost minimization). (See SI Section 4.5.) The methodology for estimating capital charges associated with installing new refining process capacity is discussed in SI Section 4.8 and is similar to that used in the U.S. Department of Energy's Liquid Fuels Market Model.[20]

The analysis assessed refining operations in a future year (2017) for each of three regional refining aggregates, defined in terms of U.S. Petroleum Administration for Defense Districts (PADDs, SI Section 1). PADDs 1−3 were treated together because of their similar refinery characteristics; PADDs 4 and 5 were treated individually because their refining operations and economics differ significantly. Regional results (presented in SI Section 5.3) were aggregated to a national level.

Model Cases. Table 1 shows the scenarios in the analysis, each consisting of a combination of current gasoline octane

Table 1. Modeled Fuel Scenarios

			ethanol blend			
			E10	E10	E20	E30
	sulfur		1 psi RVP waiver			
case	(ppm)	RON	yes	no	no	no
calibration cases (2010)	30	93.2	•	N/A	N/A	N/A
reference cases (2017)	10	93.2	•	•	•	•
study cases (2017)						
E10, E20, E30	10	95	•	•	•	•
	10	98	•	•	•	•
	10	100	•	•	•	•
	10	102	•	•	•	•
E10/E85 combinations	10	93.2[a]	N/A	N/A	•	•

[a]RON of the E10 portion is the same as the Reference cases.

ratings or prospective national RON standard (95 to 102 RON), ethanol concentration (10, 20, or 30 vol %), and RVP waiver assumption. Two additional scenarios representing joint production of E10 and E85 with total ethanol volumes matching that required for national E20 and E30.

Calibration cases validated the regional refining models by demonstrating that their outputs closely match reported data on refining sector performance in 2010, including retail gasoline property data.[21] (See SI Section 4.1).

Reference cases represented production of projected refined product volumes in the study year (2017) assuming nationwide E10, E20, or E30 with *unchanged octane ratings*, and subject to all other fuel regulations and industry standards currently in place or scheduled to be in place by 2017, including the Tier 3 gasoline sulfur limit (10 ppm average).[17] The Reference cases embody octane ratings corresponding to the current average for the U.S. gasoline pool: 87.6 AKI, corresponding to 93.2 RON. For PADD 4, the baseline includes an AKI of 85 (not 87) for Regular-grade gasoline.

Study cases assessed the techno-economic refining sector effects, relative to the corresponding Reference cases, of meeting higher national RON standards with specified ethanol concentrations and blending approaches (as nationwide E10, E20 or E30 or as E10/E85). In the E10/E85 cases, ethanol constituted 20 vol % or 30 vol % of the U.S. gasoline pool, but with the ethanol blended in combinations of E10 and E85 in amounts to provide equal total delivered energy. The ethanol content of E85 was 74 vol %[22] and RVP was 8.0 psi for both winter and summer, with light naphtha as hydrocarbon blendstock.

Model Assumptions. Consistent with federal, state, and industry standards for E10,[23] finished gasoline in all Reference and Study cases also met the following property limits: MON > 82, sulfur <10 ppm average, summer RVP (7 psi in California and federal RFG areas; 9 psi elsewhere), Driveability Index <1250, and benzene <0.62 vol %, average.

Uncertainty in future RVP regulations was considered. Under the federal Clean Air Act,[24] E10 is allowed a 1 psi RVP waiver, relaxing the applicable summer RVP standard by 1 psi, in regions not otherwise subject to lower RVP standards. This waiver reduces refining costs. Higher ethanol blends including E20 and E30 are ineligible for the RVP waiver and were modeled accordingly. The E10 cases were modeled both with and without the RVP waiver; the former to represent current regulations and the latter to avoid conflating the refining cost of summer RVP control with that of producing high-RON fuels.

All Reference and Study cases reflect (i) regional refined product volumes for 2017 estimated from national projections from the U.S. Energy Information Administration (EIA), (ii) an average crude oil price of $96/b, and (iii) an average natural gas price of $5.19/Mcf, all drawn from EIA's Annual Energy Outlook 2011.[22] Reference cases for each refining region maintain approximately constant domestic gasoline output in terms of *energy delivered* (BTU/year) across *all* ethanol concentrations. The total annual volume of finished gasoline increases with increasing ethanol content, reflecting ethanol's lower energy content relative to hydrocarbon gasoline. The Study cases corresponding to each Exx Reference case maintained the same finished gasoline volume.

In all cases, the regional refining models represented refinery production of gasoline blendstocks for oxygenate blending (BOBs). A BOB (SI Section 1) is a gasoline blendstock purpose-produced for blending with ethanol in specified proportions (downstream of the refinery). The resulting finished gasoline meets the specified octane rating standard and all other specifications.

The refinery LP models incorporate ethanol's octane contribution estimated using the molar concentration blending method,[6,7] expressed as volumetric blending octane values that decrease with increasing RON of the finished gasoline blend (SI Table S6). This method provides a conservative representation of ethanol's blending value in typical U.S. gasoline.[7] The blending RVP for ethanol was incorporated as a declining function of ethanol content from E10 to E30[25] (SI Section 4.6).

Model Outputs. The estimated refining sector effects (relative to the appropriate Reference case) for each Study case include the required RON and MON of the BOBs, industry-wide average annual additional refining cost (ARC), per-gallon ARC, refining industry investment, crude oil input to the refining sector, natural gas and electricity use, refining sector CO_2 emissions, average operating severity and total throughput of refinery reformer units, refinery sales of distressed blendstocks, resulting effects on BOB properties (aromatics content, density, energy content), and consumer savings associated with energy density. Reported refining cost and refinery CO_2 emissions results are average national full-year *differences* between values for Study cases and their corresponding Reference cases.

The methodology for computing refining sector CO_2 emissions (described in SI Sections 2 and 3) was as in a

dx.doi.org/10.1021/es5021668 | Environ. Sci. Technol. 2014, 48, 11064−11071

prior study by Hirshfeld and Kolb.[18] The estimated CO_2 emissions apply only to the refining sector; they *do not* represent complete life cycle emissions for fuels (e.g., natural gas) purchased by refineries and used to provide refinery energy.

The estimated changes in refining costs apply only to BOB production and do not depend on the price of ethanol, because ethanol use is constant across the Reference case and Study cases *within* a given ethanol blending scenario (E10, E20, or E30).

The higher ethanol concentration cases assume that implementation barriers are managed; total U.S. ethanol supply (from all sources) increases to support nationwide demand; federal and state regulations governing ethanol/gasoline blends are modified to allow such concentrations; and vehicle fleet and infrastructure capability are in place. Likewise, the E10/E85 cases assume sufficient ethanol supply, numbers of flexible fuel vehicles (FFVs), and E85 fueling stations, and a regulatory framework to support energy parity (or better) retail E85 pricing.

■ RESULTS

Key results, presented here, include refining economics, CO_2 emissions, petroleum consumption, and BOB properties. Additional and more detailed results are given in SI Section 5 and SI Appendix C.

Refining Economics. The estimated average additional refining costs (ARC, ¢/gal of BOB)—*relative to the corresponding Reference case*—of producing gasoline BOBs for each case are shown in Figure 1. These estimated costs are

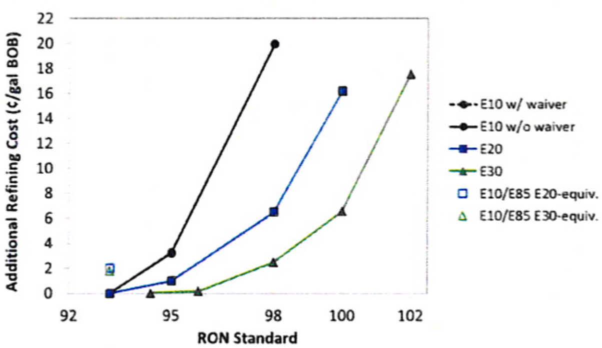


Figure 1. Estimated additional refining cost (¢/gal BOB) for different finished gasoline RON standards, total U.S. year-round average, relative to the respective Reference cases.

independent of ethanol price. They are volume-weighted national averages for the refining regions analyzed and include changes in investment costs and annual operating costs. For a given ethanol content, the refining cost increases with increasing RON standard at an accelerating rate. However, for a given RON standard, the associated ARC decreases with increasing ethanol content. These trends exist for every refining region.

The highest point shown on each curve represents the maximum RON considered feasible for production as the primary gasoline throughout the U.S., using only ethanol and refinery-produced gasoline blendstocks (i.e., with no purchased high-octane blendstocks). These limits come primarily from limitations in U.S. refineries' existing octane-generating capacity needed to produce high-octane BOBs. However, the *maximum* RON standards likely to be attainable nationwide increase with available ethanol content, namely 98-RON E10, 100-RON E20, and 102-RON E30.

The analysis suggests that the refining sector could produce BOBs for national 95-RON E20 or 97-RON E30 gasoline pools at an ARC of approximately 1¢/gal of BOB. This small cost increase reflects the fact that these BOBs have octane ratings similar to that of the BOB currently used for Regular-grade E10. The refining sector could produce national BOB pools for (i) 95-RON E10, 97-RON E20, or 100-RON E30 gasoline pools at ARCs of approximately 5¢/gal, and (ii) 96-RON E10, 99-RON E20, or 101-RON E30 gasoline pools at an ARCs of approximately 10¢/gal.

The cost estimates incorporate both volume and octane rating effects on refining costs. Increasing the *ethanol content* in finished gasoline at constant octane (e.g., E10 95 RON → E20 95 RON) reduces refining costs through two effects. The required octane rating of the BOB declines (Figure 2), reducing

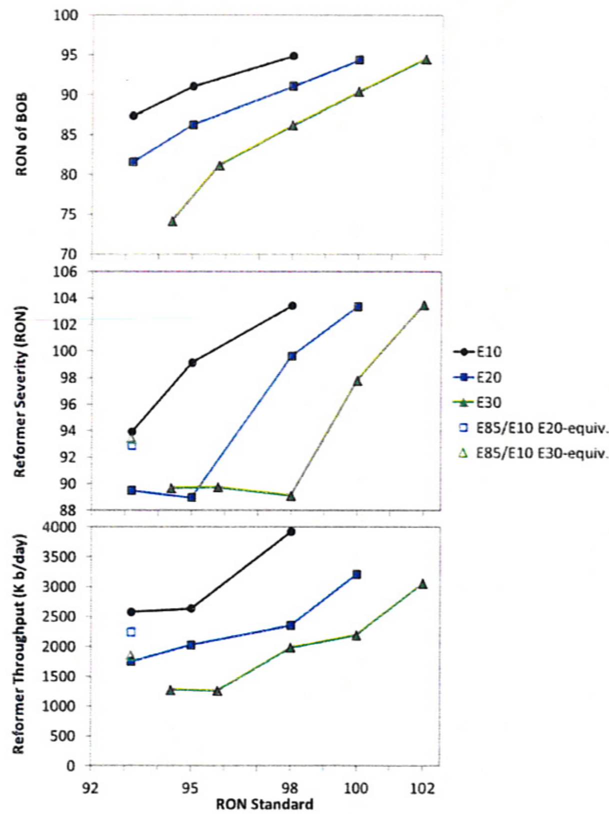


Figure 2. Estimated RON of gasoline BOBs and U.S. total reformer throughput and average severity as functions of RON standard and ethanol content.

the refining cost, and the necessary volume of the gasoline BOB declines (to accommodate the additional ethanol). Increasing the *octane rating* of gasoline at constant ethanol content (e.g., E20 95 RON → E20 98 RON) increases refining costs, likewise through two effects. The required BOB octane rating and associated refining cost increase, while the volume of BOB declines slightly, because its energy density increases with increasing RON. Additional details are provided in SI Section 5.2.

dx.doi.org/10.1021/es5021668 | Environ. Sci. Technol. 2014, 48, 11064−11071

Table 2. Key Results of Refinery Modeling, Year-Round Average, Total U.S

	finished gasoline pool								BOB pool		
study case[a]	RON	volume (MM b/d)	energy density (MM btu/b)	aromatics content (vol %)	Δ refinery invest.[b] ($billion)	Δ refining cost[b] ($billion/y)	Δ ARC[b] (¢/gal)[c]	energy density savings[b] (¢/gal)[c]	RON	MON	crude oil use (MM b/d)
E10	93.2	8.54	5.017	19.0	base	base	base	base	88.8	82.1	14.57
w/RVP waiver	95	8.54	5.025	21.6	4.45	3.84	2.9	0.6	91.1	83.1	14.69
·	98	8.54	5.075	28.6	27.07	23.52	18.0	4.0	94.9	87.1	15.31
E10	93.2	8.54	5.021	19.1	base	base	base	base	88.8	82.1	14.63
·	95	8.54	5.032	21.7	4.36	3.79	2.9	0.8	91.1	83.0	14.75
·	98	8.54	5.082	28.6	25.07	23.49	18.0	4.2	94.9	87.0	15.39
E20	93.2	8.83	4.839	12.5	base	base	base	base	83.3	79.9	13.82
·	95	8.83	4.849	13.8	0.18	1.04	0.8	0.6	86.3	79.4	13.88
·	98	8.83	4.863	18.9	5.92	7.02	5.2	1.7	91.1	83.2	14.13
·	100	8.83	4.904	22.9	17.28	17.51	12.9	4.3	94.4	86.7	14.45
E85/E10 E20eq	n/a[d]	8.82	4.859	15.6	0.79	2.20	1.6	0.9	n/a[d]	n/a[d]	13.95
E30	94.4	9.17	4.671	9.0	base	base	base	base	77.9	78.8	13.08
·	95.8	9.17	4.671	9.0	0.84	0.13	0.1	0.0	81.2	75.7	13.03
·	98	9.17	4.686	11.8	1.04	2.44	1.7	1.0	86.2	79.6	13.16
·	100	9.17	4.694	15.3	4.37	6.42	4.6	1.7	90.4	82.8	13.34
·	102	9.17	4.738	20.1	14.48	17.27	12.3	4.4	94.5	87.0	13.71
E85/E10 E30eq	n/a[d]	9.14	4.686	12.3	1.19	1.73	1.2	0.2	n/a[d]	n/a[d]	13.13

[a]All cases are without RVP waiver unless indicated otherwise. [b]Amounts are relative to the corresponding reference case (~93 RON) with the same ethanol content. [c]Amounts are ¢/gal of finished gasoline. [d]E10 and E10 BOB octane ratings are the same as the E10-only case w/o RVP waiver. The BOB for E85 is assumed to be light naphtha with approximately 71 RON and 70 MON.

Figure 2 shows the estimated BOB RON, average reformer severity, and total reformer throughput as functions of the finished gasoline RON and ethanol content. For a given ethanol content, the BOB octane rating is increased mainly by increasing the concentration of reformate, leading to greater aromatic hydrocarbon content (SI Table S15), higher crude oil consumption, and higher refinery energy use and CO_2 emissions.

(The estimation of BOB RON values using the linear molar blending method,[6] as described in SI Section 4.6, gives a conservative estimate of BOB RON. However, different BOB compositions can have second-order effects yielding higher RON than predicted by this approach.[7,26] Combining the synergistic ethanol blending effects reported by Anderson et al.[7] with the BOB RON values in Figure 2 yields higher finished gasoline RON values for all fuels in the study, with larger effects for E20 and E30 fuels than for E10. A key implication is that higher-octane blends would be more attractive than shown here, because they would require lower-RON BOBs).

The increases in ARC in most of the higher-RON cases are partially offset by the value of the gasoline's increased energy density (Table 2), stemming mainly from increases in aromatic hydrocarbon content. Increased energy density increases vehicle fuel economy and reduces the fuel volume consumed.

Table 2 includes a summary of key refining economics results, reported in terms of annual national values. Costs in Table 2 are incremental changes relative to each Reference case; Reference case costs are provided in SI Table SI−C1.

Estimated refinery investment required increases rapidly with RON standard for each ethanol content but decreases with increasing ethanol content for each RON standard. Most of the indicated investment goes to increase octane-generating capacity, mainly in reforming and pentane/hexane isomerization (the latter an octane-enhancing process that isomerizes *n*-paraffins to *i*-paraffins). Large increases in investments for the highest RON cases—more than $25 billion for E10 and $15 billion for E20 and E30, respectively—indicate that further increases in the RON standard (beyond those shown in Figure 1) would likely be infeasible with existing refining technology.

Estimated annual refining costs are the sum of capital and fixed charges for refinery investments and additional refining operational costs. The latter includes costs from increasing reformer severity and throughput, other octane-yielding refining operations, and loss in revenue associated with rejected low-octane refinery streams sold at a distress price (SI Section 4.5). The estimated annual refining costs and ARCs (¢/gal) exhibit the same trends as refinery investments with respect to RON standard and ethanol content.

Comparison of the refining economics for the E10/E85 Study cases with their corresponding E20 and E30 Reference cases indicates that average U.S. refining costs would be about 1.6¢/gal and 1.2¢/gal (of finished gasoline) higher if ethanol was blended in combinations of E10 and E85 rather than in national E20 or E30, respectively, with the *Reference case octane rating*. These incremental costs are approximately equal to that for producing nationwide 95-RON E20 and 97-RON E30, respectively.

The additional refining costs in the E10/E85 cases stem from "octane give-away" in E85: E85's octane rating is higher than that required by applicable fuel specifications, while it could be fully utilized for E20 or E30. (Current FFVs cannot fully utilize E85's high octane rating, because they must also function well using Regular-grade gasoline. Future vehicles optimized for E85 might realize greater benefit.) Refiners generally take full advantage of ethanol's octane value in the production of suboctane BOBs for E10; in the Reference cases it is assumed that they would follow the same practice in producing E20 or E30.

As a sensitivity analysis, the effect on estimated refining costs of changes in the assumed prices of crude oil and natural gas was determined. As discussed in SI Section 5.5, the ARC would be increased by increasing crude oil price due to increased crude oil demand. In contrast, the ARC would be decreased by increasing natural gas price because of increased production of low-value refinery streams used as refinery fuel instead of natural gas, and increased reformer production of hydrogen, displacing hydrogen produced from natural gas. Also, incremental costs of finished gasoline, assuming a given ethanol price, are provided in SI Table S16. Not surprisingly, higher ethanol price increases the incremental cost of finished gasoline production, in step with increasing ethanol content.

Refining Sector Crude Oil Use. Estimated changes in total refinery crude oil throughput, relative to the E10 Reference case, are shown in Figure 3. The E20 and E30 cases indicate

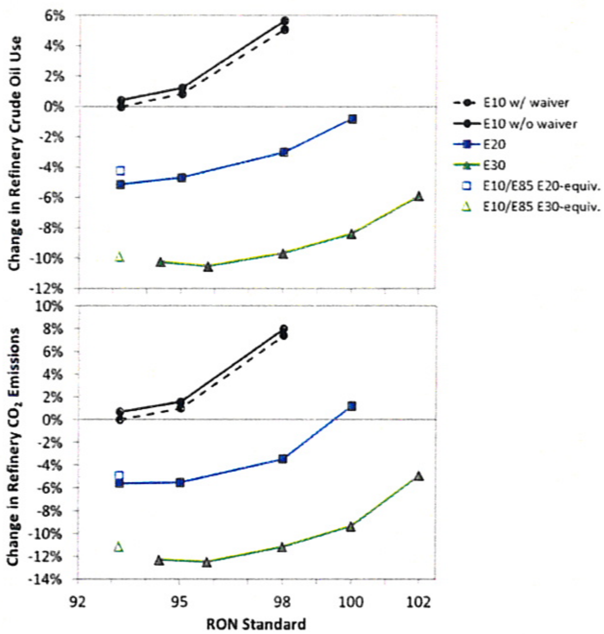


Figure 3. Estimated percent change in total U.S. refinery crude oil use (top) and CO_2 emissions (bottom) relative to E10 Reference case with RVP waiver, year-round average.

reductions of about 5% and 10%, respectively, in crude oil use. Reduced refinery demand for crude oil generally provides a net WTW reduction in oil use, because gasoline production consumes more oil than production of most alternative fuels.[27] These percentage changes are higher if attributed solely to the change in gasoline BOB production (i.e., by a factor of approximately 2, the ratio of total refinery product divided by gasoline BOB quantity).

Crude oil use increases with increasing RON (for a given ethanol content) because this requires higher RON for the corresponding BOBs, typically accomplished through increased reformer throughput and/or severity, both of which increase crude oil consumption. The additional consumption is negligible in Study cases with reformer throughput and severity comparable to their corresponding Reference case (Figure 2). Specifically, 95-RON E20 and 98-RON E30 involve increases in crude oil use of approximately 0.5%, and 1%, respectively, relative to their Reference cases (which have lower RON). Production of higher-RON BOBs calls for larger increases in crude throughput.

Refining Sector CO_2 Emissions. Changes in estimated annual refinery CO_2 emissions relative to the E10 Reference case are shown in Figure 3. Refinery CO_2 emissions decrease with increasing ethanol content in the finished gasoline pool. Conversely, at constant ethanol content, refinery CO_2 emissions increase with increasing RON of the finished gasoline pool, primarily reflecting increased refinery energy use to increase the RON of the BOB pool.

The analysis indicates that the refining sector could produce national BOB pools for 95-RON E10, E20, or E30 finished gasoline with increases in refinery CO_2 emissions $\leq 1\%$ relative to their Reference case octane ratings. Producing national BOB pools for 98-RON E20 or E30 would entail increases in refinery CO_2 emissions of 2.3% and 1.3%, respectively. To yield a net reduction in WTW CO_2 emissions, these increases in refinery CO_2 emissions would have to be more than offset by vehicle CO_2 emissions reductions from higher engine efficiency enabled by these fuels.

Finished Gasoline Pool Properties. To conduct a complete WTW analysis for CO_2 emissions, changes in finished fuel properties are needed, including carbon/hydrogen (C/H) ratio, energy content (lower (net) heating value), and density. Fuel properties were estimated from results returned by the LP models (SI Section 4.7) and are given in SI Table S18 for both gasoline BOB and finished gasoline pools. In general, the C/H ratio and lower heating value of finished gasoline increase with increasing finished gasoline RON (at constant ethanol content) and decrease with increasing ethanol content (at constant finished gasoline RON). Density increases with RON whether accomplished through increased content of aromatic hydrocarbons or ethanol.

Vehicle tailpipe CO_2 emissions (assuming constant engine efficiency) are proportional to a fuel's energy-based carbon content (gC/MJ, Figure 4), calculated from carbon weight

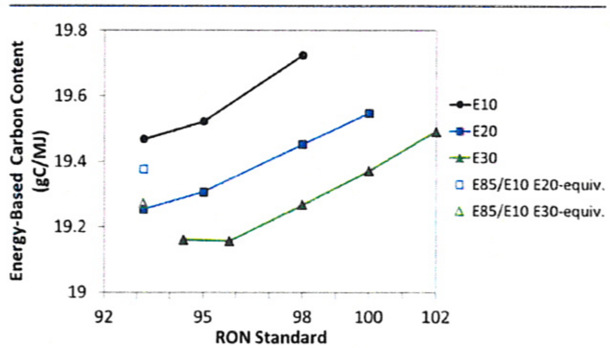


Figure 4. Energy-based carbon content of finished fuel pools (with no RVP waiver), defined as the ratio of carbon weight fraction and energy content on a lower-heating value basis. (Values for E85/E10 scenarios are weighted averages of E10 and E85 in the total fuel pool).

fraction and energy content (MJ/kg). This parameter increases with RON (for a given ethanol content) and decreases with ethanol content (for a given RON). For example, compared with the E10 Reference case, the energy-based carbon content of 98-RON E10 is 1.2% higher and that of 95-RON E30 is 1.6% lower. These differences reflect the greater energy-based carbon content of aromatic hydrocarbons relative to nonaromatic hydrocarbons and ethanol.

DISCUSSION

Increasing the octane rating of U.S. gasoline would enable higher engine efficiency, facilitating compliance with federal fuel economy and greenhouse gas (GHG) emissions standards for light-duty vehicles. It would also have significant implications for the U.S. refining sector, whether the higher octane ratings were achieved through more severe refining operations, increased use of ethanol, or both.

This analysis applied linear programming modeling of the U.S. refining sector to assess the effects on refining economics, crude oil use, CO_2 emissions, and gasoline pool properties of increasing the average octane of the U.S. gasoline pool (currently ~87.5 AKI, corresponding to 93.2 RON) to as high as 102 RON by increasing the octane rating of refinery-produced BOBs and/or the ethanol content in finished gasoline.

This analysis concludes that the U.S. refining sector could produce national BOB pools for 95-RON E20 and 97-RON E30 finished gasoline pools with < $1 billion of investment in additional refining capability and at an ARC of ~1¢/gal (including return on investment). The ARC for these BOBs is low because they would have octane ratings (~92 RON) close to that of the current U.S. E10 BOB pool. Similarly, the U.S. refining sector could produce national BOB pools for 95-RON E10, 98-RON E20, or 100-RON E30 gasoline pools with ~$4–$6 billion of investment and at an ARC of ~3–5¢/gal. Achieving still higher octane ratings for finished gasoline would incur progressively higher investment and ARC until practical limits of refining capability were reached. The price of ethanol relative to gasoline and crude oil are key determinants of the relative costs of the various finished fuels (SI Tables S16 and S17).

Producing E20 and E30 gasoline pools would incur somewhat lower refining costs, petroleum use, and CO_2 emissions than using the corresponding volumes of ethanol in combinations of E10 and E85. The difference stems from the "octane give-away" associated with E85 (whose octane rating is higher than that required by fuel specifications), whereas ethanol's octane can be fully utilized in producing BOBs for E20 or E30.

The study considered higher-RON E10 blends produced with and without the 1 psi waiver for summer RVP currently allowed for most U.S. gasoline (other than reformulated gasoline). Eliminating the RVP waiver would call for a compensating reduction of ~1 psi in the RVP of the affected E10 BOBs. In a given refinery, the ARC of this additional RVP control could be significant. However, on a year-round, national basis, the ARC of this additional RVP control would be small, because (i) it would be required only in the summer gasoline season and (ii) the RVP waiver is not available for federal and California reformulated gasoline (which account for more than one-third of the U.S. gasoline pool).

The analysis showed that, for a given ethanol content, refinery CO_2 emissions and crude oil use increase with finished gasoline RON, reflecting higher refinery energy use and higher reformer severity and throughput needed to produce a BOB pool with higher RON. For a given RON, refinery CO_2 emissions and crude oil use decrease with increasing ethanol content in the gasoline pool, due primarily to the reduction in BOB volume and RON.

The analysis did not include the option to utilize certain high-octane gasoline blendstocks not used now in the U.S., though some have been in the past, including hydrocarbons (iso-octane, iso-octene), alcohols (methanol, iso-butanol), and ethers (MTBE, ETBE, TAME), all with RON of 100 or more.[28,29] A national high-RON gasoline standard (coupled with increased supplies of natural gas liquids resulting from the expansion of U.S. natural gas production) could call out supplies of these high-octane blendstocks, which in turn could improve the economics of the high-RON gasoline standards, with or without additional ethanol use.

The cost estimates for E20 and E30 blends include neither additional costs that would be incurred in the distribution system, refinery to pump, to accommodate higher ethanol content fuels (e.g., replacement of tanks, lines, and pumps at terminals and filling stations) nor savings that might be realized because a national RON standard would reduce the number of gasoline grades in commerce. Nor do these estimates reflect any assessment of market conditions, such as supply/demand balances, that might influence retail gasoline prices in a given period.

Producing national E20 and E30 gasoline pools would require (i) changes in the regulatory framework governing ethanol use to allow such midlevel ethanol blends, (ii) sufficient additional ethanol production to support nation-wide production of these blends, (iii) changes in the distribution infrastructure to handle midlevel ethanol blends, and (iv) a vehicle fleet capable of using these fuels.

For vehicle manufacturers to optimize engine designs to use the combustion advantages of higher-RON, higher-ethanol content fuels, these fuels would have to be readily available nationwide and competitively priced with other liquid fuel alternatives, particularly during a transition to a national high-RON E20 or E30 standard. The transition would require concerted actions by multiple stakeholders, including fuel producers, fuel distributors and retailers, vehicle manufacturers, and government agencies. However, such transitions have been accomplished in the past to realize longer-term, system-wide benefits (e.g., transition to unleaded gasoline).

Understanding the implications for the refining sector is fundamental to assessing the feasibility and potential of future U.S. gasoline with higher octane ratings and/or higher ethanol content. This study provides a techno-economic assessment of this subject to address the lack of such information in the open literature. Higher-octane (95 RON) E10 gasoline was determined to be technically feasible, without considerable additional cost, CO_2 emissions, or petroleum consumption for refineries. Higher ethanol content (E20, E30) could provide a viable path to fuel with still higher octane ratings (98 RON) with reduced petroleum consumption and lower refinery CO_2 emissions. Considering the significant efficiency increases demonstrated for higher-CR engines,[3,4] these results suggest that further consideration (e.g., WTW life-cycle analyses[16]) of higher-octane gasoline in the U.S. is warranted.

ASSOCIATED CONTENT

Supporting Information

Further details on the methodology, detailed regional and national-level results, sensitivity analyses, and discussion. This material is available free of charge via the Internet at http://pubs.acs.org/.

dx.doi.org/10.1021/es5021668 | Environ. Sci. Technol. 2014, 48, 11064–11071

AUTHOR INFORMATION

Corresponding Authors

*Phone: 301-951-9006; e-mail: dave@mathproinc.com.

*Phone: 313-248-6857; e-mail: jander63@ford.com.

Notes

The authors declare no competing financial interest.

ACKNOWLEDGMENTS

This work was funded by the United States Council for Automotive Research (USCAR). While this article is believed to contain correct information, Ford Motor Company (Ford) does not expressly or impliedly warrant, nor assume any responsibility, for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, nor represent that its use would not infringe the rights of third parties. Reference to any commercial product or process does not constitute its endorsement. This article does not provide financial, safety, medical, consumer product, or public policy advice or recommendation. Readers should independently replicate all experiments, calculations, and results. The views and opinions expressed are of the authors and do not necessarily reflect those of Ford. This disclaimer may not be removed, altered, superseded or modified without prior Ford permission.

REFERENCES

(1) Energy Independence and Security Act of 2007. Public Law 110–140, 2007. www.gpo.gov/fdsys/pkg/PLAW-110publ140/html/PLAW-110publ140.htm.

(2) Environmental Protection Administration, Department of Transportation. 2017 and later model year light-duty vehicle greenhouse gas emissions and corporate average fuel economy standards; Final rule. *Fed. Regist.* **2012**, *77* (199), 62623–63200.

(3) Schwaderlapp, M.; Adomeit, P.; Kolbeck, A.; Thewes, M. Ethanol and its potential for downsized engine concepts. *MTZ. Worldwide* **2012**, *23* (2), 24–29.

(4) Leone, T. G.; Olin, E. D.; Anderson, J. E.; Jung, H. H.; Shelby, M. H.; Stein, R. A. Effects of fuel octane rating and ethanol content on knock, fuel economy, and CO_2 for a turbocharged DI engine. *SAE Int. J. Fuels Lubr.* **2014**, *7* (1); DOI 10.4271/2014-01-1228.

(5) Anderson, J. E.; DiCicco, D. M.; Ginder, J. M.; Kramer, U.; Leone, T. G.; Raney-Pablo, H. E.; Wallington, T. J. High octane number ethanol-gasoline blends: quantifying the potential benefits in the United States. *Fuel* **2012**, *97*, 585–594, DOI: 10.1016/j.fuel.2012.03.017.

(6) Anderson, J. E.; Kramer, U.; Mueller, S. A.; Wallington, T. J. Octane numbers of ethanol- and methanol-gasoline blends estimated from molar concentrations. *Energy Fuels* **2010**, *24* (12), 6576–6585, DOI: 10.1021/ef101125c.

(7) Anderson, J. E.; Leone, T. G.; Shelby, M. H.; Wallington, T. J.; Bizub, J. J.; Foster, M.; Lynskey, M. G.; Polovina, D. *Octane Numbers of Ethanol-Gasoline Blends: Measurements and Novel Estimation Method from Molar Composition*, SAE Technical Paper 2012−01−1274, 2012; DOI 10.4271/2012-01-1274.

(8) Marriott, C.; Wiles, M.; Gwidt, J.; Parrish, S. Development of a Naturally aspirated spark ignition direct-injection flex-fuel engine. *SAE Int. J. Eng.* **2009**, *1* (1), 267–295, DOI: 10.4271/2008-01-0319.

(9) Jung, H. H.; Shelby, M. H.; Newman, C. E.; Stein, R. A. Effect of Ethanol on Part Load Thermal Efficiency and CO_2 Emissions of SI Engines. *SAE Int. J. Eng.* **2013**, *6* (1), 456–469, DOI: 10.4271/2013-01-1634.

(10) Wagner, T. O.; Russum, L. W. *Optimum Octane Number for Unleaded Gasoline*, SAE Technical Paper 730552, 1973; DOI: 10.4271/730552

(11) Brown, E. C.; Corner, E. S.; Compton, R. A. New look at auto-fuel economy vs. refining. *Oil Gas J.* **1975**, *29* (9), 125–128.

(12) *Impact of Gasoline Characteristics on Fuel Economy and Its Measurement*, Report No. 76−10 JLB; U.S. Environmental Protection Agency, Office of Mobile Source Air Pollution Control, Emission Control Technology Division, Technology Assessment and Evaluation Branch: Washington, DC, 1976; nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=9100X4N9.TXT.

(13) *The Rational Utilization of Fuels in Private Transport (RUFIT), Extrapolation to Unleaded Gasoline Case*, Report No. 8/80; CONCAWE: Den Haag, 1980; http://rd.springer.com/Chapter/10.1007%2F978-94-009-7197-4_26.

(14) *Oil Refining in the EU in 2020, with Perspectives to 2030*, Report No. 1/13R, 2013; CONCAWE: Den Haag, 2013; https://www.concawe.eu/content/default.asp?PageID=569.

(15) *Study on CO_2 Emissions from Automobiles and Refineries, Report of CO_2*, Emissions Study Working Group; JCAPII, Japan Clean Air Program: June 1, 2005; www.pecj.or.jp/english/jcap/jcap2/pdf/4th/2_3e.pdf.

(16) Speth, R. L.; Chow, E. W.; Malina, R.; Barrett, S. R. H.; Heywood, J. B.; Green, W. H. Economic and environmental benefits of higher-octane gasoline. *Environ. Sci. Technol.* **2014**, *48* (12), 6561–6568, DOI: 10.1021/es405557p.

(17) Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards. *Code of Federal Regulations*, Parts 79, 80, 85, 86, 600, 1036, 1037, 1039, 1042, 1048, 1054, 1065, and 1066, 2014.

(18) Hirshfeld, D. S.; Kolb, J. A. Analysis of energy use and CO_2 emissions in the U.S. refining sector, with projections to 2025. *Environ. Sci. Technol.* **2012**, *46* (7), 3697–3704, DOI: 10.1021/es204411c.

(19) Bredeson, L.; Quiceno-Gonzalez, R.; Riera-Palou, X.; Harrison, A. Factors driving refinery CO_2 Intensity, with allocation into products. *Int. J. Life Cycle Assess.* **2010**, *15* (8), 817–826, DOI: 10.1007/s11367-010-0204-3.

(20) *Liquid Fuels Market Model of the National Energy Modeling System: Model Documentation 2013*; Energy Information Administration; US Department of Energy: Washington, DC, 2013; http://www.eia.gov/forecasts/aeo/nems/documentation/lfmm/pdf/m059%282013%29.pdf.

(21) Alliance of Automobile Manufacturers. *North American Fuel Surveys*; 2009 and 2010.

(22) *Annual Energy Outlook 2011*; Report No. DOE/EIA-0383(2011), Energy Information Agency, US Department of Energy: Washington, DC, 2011; http://www.eia.gov/forecasts/archive/aeo11/index.cfm.

(23) *Standard Specification for Automotive Spark-Ignition Engine Fuel*; ASTM D4814−10b, ASTM International: West Conshohocken, PA, 2010; http://www.astm.org/Standards/D4814.htm.

(24) Controls and Prohibitions on Gasoline Volatility. *Code of Federal Regulations*, Part 80, Title 40, 2010.

(25) Furey, R. *Volatility Characteristics of Gasoline-Alcohol and Gasoline Ether Fuel Blends*, SAE Technical Paper 852116, 1985; DOI 10.4271/852116.

(26) Foong, T. M.; Morganti, K. J.; Brear, M. J.; da Silva, G.; Yang, Y.; Dryer, F. L. The octane numbers of ethanol blended with gasoline and its surrogates. *Fuel* **2014**, *115*, 727–739, DOI: 10.1016/j.fuel.2013.07.105.

(27) Wang, M.; Han, J.; Dunn, J. B.; Cai, H.; Elgowainy, A. Well-to-wheels energy use and greenhouse gas emissions of ethanol from corn, sugarcane, corn stover, switchgrass, and miscanthus. *Environ. Res. Lett.* **2012**, *7* (4), 1–13, DOI: 10.1088/1748-9326/7/4/045905.

(28) Hunwartzen, I. *Modification of CFR Test Engine Unit to Determine Octane Numbers of Pure Alcohols and Gasoline-Alcohol Blends*, SAE Technical Paper 820002, 1982; DOI 10.4271/820002.

(29) American Society for Testing Materials. Knocking Characteristics of Pure Hydrocarbons, Special Technical Publication No. 225, 1958.

59-OP-LCFS-EFC Responses

603. Comment: **LCFS 59-1**

Agency Response: This comment letter contains one reference that was cited in Comment Letter **54_OP_LCFS_EFC**.

This page intentionally left blank.

Comment letter code: 60-OP-LCFS-CBD

Commenter: Brian Nowicki

Affiliation: Center for Biological Diversity

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

60_OP_LCFS _CBD

CENTER for BIOLOGICAL DIVERSITY Because life is good.

February 17, 2015

Via electronic submission

Mary Nichols, Chair
California Air Resources Board
1001 I Street, PO Box 2815
Sacramento, CA 95812

Dear Chair Nichols and Members of the Air Resources Board:

This letter is submitted on behalf of the Center for Biological Diversity ("Center") regarding the California Air Resources Board's ("ARB") proposed adoption of the Low Carbon Fuel Standard, or LCFS, and the associated Draft Environmental Impact Report ("EIR"). The Center for Biological Diversity strongly supports the LCFS as a crucial tool in addressing the large proportion of California's greenhouse gas emissions and other air pollutants that comes from the production, transport, refining, and combustion of transportation fuels.

The Center appreciates ARB's continuing work on the LCFS and other measures to address pollution from transportation fuels. The extraction, refining, transport, and combustion of transportation fuels is the source of nearly half of California's annual greenhouse gas emissions, and the equivalent of more than 217 million metric tons of carbon dioxide (CO2e). This category of greenhouse gas emissions is accompanied by large amounts of nitrogen oxides and ozone pollution: 80 percent of California's total emissions of nitrogen oxides of nitrogen (NOx), and 95 percent of diesel particulate matter (PM) emissions. These pollutants are major contributors to the dangerously poor air quality that affects many communities in our state. Without a doubt, California must pursue every option and opportunity to reduce emissions from transportation fuels.

These comments identify specific opportunities to strengthen the proposed rule with respect to hydraulic fracturing and forest-sourced biofuels, and to strengthen the EIR's treatment of impacts to food prices and availability. Some of the noted issues exist in the previously adopted rule but warrant additional consideration in the proposed rule. In all cases, the Center believes there are real solutions for addressing these issues and enacting a strong LCFS that best serves California.

I. The Carbon Intensities Must Account for Energy Inputs and Greenhouse Gas Emissions Specific to Hydraulic Fracturing and other Carbon-Intensive Oil Recovery Methods.

LCFS 60-1

The LCFS uses carbon intensity values generated via the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) Version 1.1 Draft D, to provide average carbon intensities for

Alaska . Arizona . California . Florida . Minnesota . Nevada . New Mexico . New York . Oregon . Vermont . Washington, DC
P.O. Box 191122 . Sacramento, CA 95819 tel: (916) 201.6938 www.BiologicalDiversity.org

crude supplies by country or U.S. state, often specific to individual oil fields (including more than 150 different crudes in California). However, OPGEE Version 1.1, included by reference in the proposed rule, does not explicitly address fracking as a distinct category of crude production. As a result, it does not account for energy inputs and greenhouse gas emissions associated with many components of fracking and other enhanced oil recovery, such as: the pumping and transport of freshwater used in fracking fluid, manufacture and transport of constituent chemicals and fracking fluids, the manufacture and transport of frac sand, flowback emissions, and disposal of fracking fluids. These omissions are evident in the table of input categories for the OPGEE model, which lists input categories in some detail, and which is extensive for many oil production activities.[1] This oversight is also directly stated in the documentation for the OPGEE model.[2]

> Some techniques are not built in the current version of OPGEE, including CO2 flooding and hydraulic fracturing (also known as "fracking"). These modules will be added in the future.[3]
>
> Because waste treatment emissions only occur sporadically, they are likely to be small when amortized over the producing life of an oil field. For this reason, emissions from waste treatment are considered below the significance cutoff in OPGEE v1.1 Draft D. Possible exceptions could be the treatment and disposal of fracturing fluids and fracturing flow-back water, due to the large volumes produced. Future versions of the model may include these factors.[4]

LCFS 60-1 cont.

The undercounting of emissions and energy inputs specific to fracking raises concerns regarding the impacts associated with high carbon-intensity crudes (addressed in more detail in the next section). In addition, this undercounting undermines the ability of LCFS to effectively achieve its target reductions. Fracking and acidizing are major components of operations in many oil fields in California, North Dakota, and elsewhere. Correctly accounting for the emissions and energy inputs specific to fracking would significantly change both the carbon intensity values for many individual crudes as well as the state average crude carbon intensity used by the large refineries.

Furthermore, the inputs and calculations behind the carbon intensity lookup table indicate heavy use of standard default values instead of field-specific inputs.[5] For example, all California oil fields are given a default flaring-to-oil ratio of 13 scf/bbl oil, and a default pipeline transport distance of 100 miles. Similarly, the three oil fields listed for North Dakota all use the same default inputs for all values, resulting in identical carbon intensities, the relatively low 10.18. In

---

[1] Oil Production Greenhouse Gas Emissions Estimator (OPGEE) Version 1.1 Draft D

[2] http://www.arb.ca.gov/regact/2011/lcfs2011/opgee_userguide.pdf

[3] OPGEE v1.1 Draft D, User Guide & Technical Documentation, page 42.

[4] OPGEE v1.1 Draft D, User Guide & Technical Documentation, page 83.

[5] OPGEE Version 1.1 Draft Lookup Table MCON Inputs, http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/draft_lookup_table_mcon_inputs_opgee_v1_1_102914.xlsx

all of these cases, the LCFS is significantly underestimating carbon intensities for individual oil fields with heavy use of fracking and other high energy-intensity operations. The calculation documentation acknowledges as much with respect to many crudes, including the North Dakota crudes: "OPGEE does not account for emissions from fracking so the CI estimate will likely be low."[6]

We understand that ARB is currently developing these components--water pumping and transport, manufacture and transport of fracking fluid and acid constituents, the manufacture and transport of frac sand, flowback emissions, disposal of fracking fluids and flowback wastewater--to be included in future revisions to the LCFS. In the meantime, these emissions and energy inputs are either being undercounted or not counted at all in the carbon intensity value. Nonetheless, the proposed rule would explicitly include these faulty carbon intensity values, and incorporate the model inputs by reference. While the proposed rule states that ARB intends to update the LCFS at three year intervals, these low carbon intensity values would be in place until the LCFS is amended in the future.

The Center strongly supports ARB's development of a model to assign values to the carbon impacts of fracking and other carbon intensive enhanced oil recovery methods. Correctly accounting for the carbon impacts associated with fracking is critical to demonstrating that the LCFS has successfully reduced fuel carbon intensities by 10% by 2020 and achieved the projected reductions expected from this sector under AB 32. The results of modeling the carbon impacts associated with fracking may lead to retroactive correction of baseline and compliance schedules. One approach, in the interim, would be to apply an additional default value to the standard carbon intensity for crudes produced in oil fields where fracking is common, until the model for estimating emissions associated with fracking is completed and the carbon intensity values can be corrected.

LCFS 60-1 cont.

II. ARB Should Consider Additional Measures to Directly Discourage the Development and Production of High Carbon Intensity Crude Oils Under the LCFS.

In the years since the LCFS was first adopted, the greenhouse gas pollution from the production of transportation fuels has become a much more important and visible issue in California and nationwide. The import of high carbon-intensity crude into California from the expansive hydraulic fracturing operations in the Bakken oil play in North Dakota has increased from essentially zero in 2009, to millions of barrels a year by 2014.[7] This has raised concerns not only over the greenhouse gas impacts but also over the dangers associated with transporting crude by railroad through our state and our communities. Over that same period, California has become increasingly aware of the extensive use and rapid expansion in high-intensity extraction methods such as hydraulic fracturing (fracking) and acidizing. Furthermore, California is now receiving imports of crude from the Alberta tar sands that are the focus of international opposition due to their tremendous damage to the people, land, waters, and wildlife of Alberta and their immense implications for the global climate.

LCFS 60-2

[6] OPGEE v. 1.1 Lookup Table Inputs, USA-North Dakota.

[7] Energy Almanac by CEC, http://energyalmanac.ca.gov/petroleum/statistics/2014_crude_by_rail.html, and the LCFS, Appendix H: 2014 Mid-Year Crude Average CI Estimate.

In 2014, there were five crudes that were not in the 2010 slate, with a production and transport carbon intensity greater than 15 gCO_2e/MJ, for a total of 61.[8] There are 17 crude sources (i.e. oil fields) in California that surpass this carbon intensity, and five with production and transport carbon intensity values greater than 30 gCO_2e/MJ. While some of these high carbon-intensity crudes are relatively small components of the state's domestic crude supply, this still amounts to hundreds of thousands of barrels per field. For example, Placerita crude has a production and transport carbon intensity of 41.72 gCO_2e/MJ and produced 447,209 barrels in the first six months of 2014.

Other high carbon intensity fields are relatively large components of California's domestic crude supply. Coalinga produced 2.9 million barrels in the first half of 2014, with a carbon intensity of 32.82 gCO_2e/MJ; Cymric, 7.6 million at 21.48; Kern Front, 1.5 million at 29.65; McKittrick, 7.6 million at 28.72; Midway-Sunset, 14.4 million at 29.27; Poso Creek, 1.7 million at 32.09; Round Mountain, 2.1 million at 27.77; San Ardo, 3.5 million at 31.48.[9] All of these crudes have production and transport carbon intensity values greater than 15 gCO_2e/MJ even without accounting for many of the greenhouse gas emissions and energy inputs associated with high-intensity production methods such as fracking, an issue raised in the previous section. LCFS 60-2 cont.

The initial LCFS regulation in 2009 included a "bright line" approach to high carbon-intensity crude oil ("HCICO"), in which HCICOs were treated as a distinct category separate from non-HCICO gasoline and diesel; the carbon intensities of the HCICOs were calculated separately and oil suppliers had to report the associated deficits compared to the baseline. The initial LCFS rule also required refinery-specific accounting of crude slates. This approach would have applied penalties specifically to refineries for crude oils that were above a "bright line" of 15 grams CO2 per mega joule and that were not part of the original 2006 crude oil slate.

When ARB amended the LCFS in 2012, the final regulation eliminated the bright line approach to HCICOs and replaced refinery-specific accounting with a statewide average crude carbon intensity. Although the amended rule did include provisions to require reporting of the carbon intensity of fuels by crude source, the current LCFS and the proposed rule were specifically designed to be "fuel-neutral" with respect to all crudes, including HCICOs.[10] Under this approach, an increase in carbon intensity at one refinery is not assigned to the responsible refinery, but is instead spread across the entire sector statewide, and refineries selling higher-carbon products to California will be debited only if the statewide carbon-intensity of all California refineries and importers increases over time. Such a system dilutes both the incentives for parties refining high-intensity crude to change their crude slates and any incentive

[8] Access Western Blend, Canada; Premium Albian Synthetic, Canada; Hamaca, Venezuela; Burrell, California; and Chico-Martinez, California. 2014 Mid-Year Crude Average CI Estimate.

[9] LCFS, Appendix H: 2014 Mid-Year Crude Average CI Estimate.

[10] "The LCFS is designed to encourage the use of cleaner low-carbon fuels in California, encourage the production of those fuels, and, therefore, reduce GHG emissions. The LCFS is performance-based and fuel-neutral, allowing the market to determine how the carbon intensity of California's transportation fuels will be reduced." ISOR at ES-2.

for refineries that may be maintaining or reducing the carbon-intensity of their crude oil slates to avoid higher-carbon crudes.

We urge the Air Resources Board to consider additional measures to directly discourage the development and production of high carbon-intensity crudes, such as the bright line approach to HCICOs and refinery-specific reporting.

LCFS 60-2 cont.

III. The CA-GREET pathway for cellulosic ethanol from "forest waste" does not account for the carbon impacts associated with generating forest-sourced feedstock.

The CA-GREET "Pathway for Cellulosic Ethanol from Forest Waste" does not account for fuels or energy inputs associated with the forest management activities that generate woody biomass feedstock (e.g. harvest, limbing, piling).[11] The "Forest Waste" pathway apparently considers all forest-sourced feedstock to be "residue" from some existing forest management activity, and the CA-GREET model accounts for inputs and emissions starting at the point of collection of the feedstock material, such as from a slash pile. The Forest Waste pathway also does not account for forest carbon impacts (i.e., loss of forest carbon stores and foregone carbon sequestration) from the harvest activities that generate the residue materials.

There is an obvious, if implicit, assumption that all forest-sourced feedstock is waste from forest management activities that had already occurred or would have otherwise occurred. This assumption is not explicated or supported. The Forest Waste pathway defines forest waste generally as " treetops, branches, small-diameter wood, stumps, leaves, dead wood and even poorly-formed whole trees, as well as undergrowth and low-value [tree] species."[12] This definition includes virtually every forest carbon pool other than soil and the boles of large, commercially-valuable saw timber, and there are no criteria with respect to demonstrating that these feedstock materials are the residue of some otherwise occurring forest management activity, rather than the primary driver for a logging project. LCFS 60-3

If forest projects are planned, in whole or in part, in response to economic incentives created by the LCFS (for example, the availability of a nearby biofuels facility that makes forest projects more economically feasible than they would have been in its absence), the CA-GREET life cycle analysis would need to account for the carbon impacts associated with the forest management and harvest of those biofuels feedstocks. Such a scenario is already occurring in

[11] Detailed California-Modified GREET Pathway for Cellulosic Ethanol from Forest Waste, 2009. Available at http://www.arb.ca.gov/fuels/lcfs/022709lcfs_forestw.pdf

[12] "Forest waste typically refer to those parts of trees unsuitable for sawlogs such as treetops, branches, small-diameter wood, stumps, leaves, dead wood and even poorly-formed whole trees, as well as undergrowth and low-value species. Nearly 20 billion cubic feet of wood is removed on an annual basis from lands in the United States. Of that volume, 16 percent is classified as logging waste, according to U.S. Department of Agriculture (USDA). This material is mainly tree tops and small branches that have been considered uneconomical to harvest. The USDA Forest Service Inventory and Analysis program estimates that in 2001, 61 million dry tons of residuals are available annually from harvesting and fuel reduction activities. A recovery system, which would follow behind a conventional logging operation, could recover 60 percent or 40 million dry tons of this waste for potential bioenergy and bio-based product markets." CA-GREET Pathway for Cellulosic Ethanol from Forest Waste, at 2.

the southeastern United States, where the export of wood pellets to Europe to replace coal for electricity generation and residential heating under the European Commission's climate and energy package doubled in 2013, to 3.2 million metric tons annually.[13] Traditionally manufactured from mill waste, wood pellets can also be produced from unprocessed harvested wood, and may constitute a new and growing demand on forest resources.

Because the CA-GREET model does not include emissions and carbon impacts associated with land use and land use change, a separate methodology (the Detailed Analysis of Indirect Land Use Change, or iLUC) was developed to account for indirect land-use change impacts associated with biofuels.[14] This methodology primarily addresses the carbon impacts associated with the conversion of agricultural land from food crops to biofuel feedstocks, and with the clearing of land to plant agricultural feedstock.[15] With respect to forests, the land-use change component addresses only the potential carbon impacts of forest loss to agricultural development. As a result, it does not consider any forest carbon impacts associated with the generation of forest-sourced feedstock in the Forest Waste pathway or elsewhere. These impacts include but are not limited to reduction in forest carbon stocks and lost future sequestration resulting from harvest of trees that otherwise would have continued growing and sequestering carbon, regardless of whether they are considered "poorly-formed" or "low-value." In short, even if forest remains forest, the increased removal of materials for cellulosic ethanol production may affect both terrestrial carbon stocks and atmospheric CO2 concentrations. A model that considers only change from one type of land use to another will not capture these relevant effects.

LCFS 60-3 cont.

In 2009, the ARB Board directed ARB staff to establish a LCFS Sustainability Workgroup charged with developing criteria for each biofuel feedstock category in order to limit the effects of biofuels on carbon stores, GHG emissions, food supplies, and ecological values. However, the Workgroup has not yet proposed any such standards with respect to forest-sourced biofuels, and the LCFS otherwise contains no guidance specific to forest-sourced feedstocks or biofuels.

---

[13] US Energy Information Administration, "U.S. wood pellet exports double in 2013 in response to growing European demand. May 22, 2014. Available at http://www.eia.gov/todayinenergy/detail.cfm?id=16391

[14] LCFS, Appendix I: Detailed Analysis for Indirect Land Use Change.

[15] "Carbon intensities are calculated under the LCFS on a full life cycle basis. This means that the CI value assigned to each fuel reflects the GHG emissions associated with that fuel's production, transport, storage, and use. The CA-GREET model accounts only for such direct effects. In addition to these direct effects, some fuel production processes generate GHGs indirectly, via intermediate market mechanisms. To date, ARB staff has identified an indirect effect that has a measurable impact on GHG emissions: land use change. A land use change effect occurs when demand for a crop-based biofuel brings non-agricultural lands into production. When new land is converted, such conversions release the carbon sequestered in soils and vegetation. The resulting carbon emissions constitute the "indirect" land use change (iLUC) impact of increased biofuel production. For the LCFS, iLUC emissions are attributable to biofuels produced from crops." ISOR, at ES-5.

We urge ARB to ensure that the energy inputs and forest carbon impacts associated with forest-sourced feedstock are fully accounted for before a CA-GREET pathway for cellulosic ethanol from forest waste, or any other biofuel from forest-sourced feedstock, is certified. In addition, we strongly urge ARB to complete the work of the LCFS Sustainability Workgroup, and to adopt standards specific to forest-sourced feedstocks before certifying any related CA-GREET pathways.

LCFS 60-3 cont.

IV. The EIR Fails to Mitigate the Project's Foreseeable Impacts on Food Availability and Hunger among "the World's Poorest People."

The EIR indicates that increasing demand for biofuels can displace production of food crops in favor of biofuel feedstock crops.[16] The Detailed Analysis for the Indirect Land Use Change states that the economic model used to evaluate land use change impacts indicates that the LCFS will result in higher food prices, with some alarming outcomes.

> The LCFS, together with biofuel production mandates in the U.S. and Europe, will result in the diversion of agricultural land from food production to biofuel feedstock production. This diversion of agricultural land to biofuel production will exert an upward pressure on food commodity prices, and potentially lead to food shortages, increasing food price volatility, and inability of the world's poorest people to purchase adequate quantities of food. GTAP analysis predicts that price increases resulting from the additional demand for biofuels will result in reduced crop production, leading to lower food consumption.[17]

LCFS 60-4

In short, the iLUC analysis predicts that the LCFS can exacerbate hunger and food shortages for "the world's poorest people." The Analysis cites Tenenbaum (2008) for references to these impacts.[18] More recently, a Word Resources Institute working paper by Searchinger and Hemilch (2014) found that "bioenergy that entails the dedicated use of land to grow the energy feedstock will undercut efforts to combat climate change and to achieve a sustainable food future."[19] The working paper concludes that "[p]hasing out the dedicated use of land to generate bioenergy, particularly biofuels, would reduce the food gap and, perhaps even more importantly, keep it from greatly expanding."[20]

---

[16] "As discussed above, as demand for biofuel crops increases, it could displace production of food crops, resulting in conversion of both fallow and cultivated lands to biofuel feedstock crop production." Draft EIR, at 33.

[17] Appendix 1: Detailed Analysis for Indirect Land Use Change, at I-21.

[18] D. J. Tenenbaum , "Food vs. Fuel: Diversion of Crops Could Cause More Hunger.", Environmental Perspectives 116(6): A254-257, (2008).

[19] Searchinger, T. and R. Heimlich. 2015. "Avoiding Bioenergy Competition for Food Crops and Land." Working Paper, Installment 9 of *Creating a Sustainable Food Future*. Washington, DC: World Resources Institute, at 1. Available at http://www.worldresourcesreport.org.

[20] Searchinger and Heimlich (2015), at 28.

Currently, the LCFS includes no mechanism, either as part of the carbon intensity value or elsewhere, to account for these impacts. The Detailed Analysis for Indirect Land Use Change determines that the land use change model is incapable of modeling these impacts, and proposes to address the problem "in future updates."[21] Ultimately, the EIR finds that because ARB has no land use authority, it is not within ARB's authority to mitigate these impacts.[22] LCFS 60-5

Exercising land use authority is not the only possible approach to reducing these impacts, and ARB may not point to its lack of land use authority as a reason for implementing no mitigation measures. That is, an agency may not claim that mitigation is infeasible unless that agency truly lacks any authority to implement any feasible mitigation measures. (*See, generally, City of Marina v. Board of Trustees* (2006) 39 Cal.4th 341.) ARB must instead consider all feasible options to mitigate or avoid any significant land use change effects identified. ARB is designing the program that creates the incentives that are producing the impacts, and is thus responsible under CEQA for analyzing and mitigating those impacts. (*Cf. California Unions for Reliable Energy v. Mojave Desert AQMD* (2009) 178 Cal. App. 4th 1225.) Nor may ARB avoid its responsibility to disclose and analyze these impacts by simply declaring that mitigation is infeasible and the impacts unavoidable. "An agency may not "travel the legally impermissible easy route to CEQA compliance" by making a significance determination without fully analyzing a project's effects. (*Berkeley Keep Jets Over the Bay Comm. v. Bd. of Port Comm'rs* (2001) 91 Cal.App.4th 1344, 1371). LCFS 60-6

Accordingly, ARB is responsible not only for providing all the information it reasonably can about these indirect impacts, but also for considering whether there are any possible changes to the program itself (such as limitations on eligibility of particular feedstocks, eligibility requirements for biofuels, including a provision in the life cycle analysis that accounts for the potential of displacing food crops, or verification and certification requirements) that could change the incentives driving land use change and reduce the associated impacts. We urge ARB to take up every option for addressing this important issue. LCFS 60-7

V. Conclusion

The Center for Biological Diversity strongly supports the LCFS as a crucial tool in addressing the large proportion of California's greenhouse gas emissions and other air pollutants LCFS 60-8

---

[21] Some stakeholders maintain that global changes in food consumption are not a direct consequence of biofuel production and staff should not consider food impacts in the modeling of iLUC while others argue that reductions in food consumption would require an assessment of the calorific content of finished food products in the GTAP-BIO model. The model as currently structured, is not capable of modeling any changes in food consumption driven by calorific content. Staff is therefore, proposing to address this issue in future updates. Appendix 1: Detailed analysis for Indirect Land Use Change, at I-21.

[22] "Potential agricultural and forest resource impacts could be reduced to a less-than-significant level by mitigation measures prescribed by local, State, federal, or other land use or permitting agencies (either in the United States or abroad) with approval authority over the particular development projects. However, because ARB has no land use authority, mitigation is not within its purview to reduce potentially significant impacts to less-than-significant levels." Draft EIR, at 47.

that comes from the production, transport, refining, and combustion of transportation fuels. The Center supports ARB's development of a model to assign values to the carbon impacts of fracking and other carbon intensive enhanced oil recovery methods, and the Center encourages the LCFS Sustainability Workgroup's to develop standards specific to forest-sourced feedstocks. LCFS 60-8 cont.

We urge ARB to strengthen the proposed rule with respect to hydraulic fracturing and forest-sourced biofuels, and to strengthen the EIR's treatment of impacts to food prices and availability. For those issues that may take longer than ARB is currently contemplating for adoption of this rule--such as additional measures to directly discourage the development and production of high carbon-intensity crudes, and mitigating impacts to food prices and availability--we urge ARB to initiate the process of developing these measures, in the resolution adopting the revised LCFS. LCFS 60-9

Thank you for your consideration of these comments. Please contact me with any questions or concerns.

Sincerely,

Brian Nowicki

Brian Nowicki
Center for Biological Diversity
(916) 201-6938
bnowicki@biologicaldiversity.org

This page intentionally left blank.

60-OP-LCFS-EFC Responses

604. Comment: **LCFS 60-1 through LCFS 60-9**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

Comment letter code: 61-OP-LCFS-Neste

Commenter: Dayne Delahoussaye

Affiliation: Neste Oil

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

NESTE OIL

61_OP_LCFS
_NESTE

17 February 2015

Clerk of the Board, Air Resources Board
ATTN: Mary Nichols, Chairman
1001 I Street, PO Box 2815
Sacramento, California 95812

Re: Notice of Public Hearing to Consider a Low Carbon Fuel Standard

Dear Chair Nichols and Air Resource Board Members:

Thank you for the opportunity to provide comments to the California Air Resources Board (CARB) regarding its re-adoption of the Low Carbon Fuel Standard (LCFS). Neste Oil US, Inc. respectfully presents the following comments for consideration.

Neste Oil continues its successful strategy of focusing on the production of cleaner traffic fuels and has a long history in providing clean fuels to California that have been refined from traditional petroleum products. Consistent with our vision to be the preferred partner for cleaner traffic fuel solutions, Neste Oil has expanded into the production of transportation fuels from renewable feedstocks and is now the leader and largest producer world-wide of renewable hydrocarbon diesel produced at locations in Porvoo, Finland; Singapore; and Rotterdam, The Netherlands. Neste Oil uses a wide variety of sustainably produced vegetable oil feedstocks including soybean oil, palm oil, rapeseed oil, camelina oil, and various biogenic waste oils and residues including animal tallow, technical corn oil, and other triglyceride oils and free fatty acids usually produced as wastes or residues from various industrial processes.

Neste Oil's renewable hydrocarbon diesel (NEXBTL) meets the ASTM D975 specification for diesel fuel; qualifies as CARB diesel; and is a fully fungible, drop-in fuel that can be used in existing diesel engines without a blend wall and which can utilize existing infrastructure. This renewable hydrocarbon diesel has significantly lower carbon intensity as compared to petroleum diesel and is almost free from aromatics and sulfur, whilst reducing NOx, particulate, and hydrocarbon tailpipe emissions.

Neste Oil supports California's commitment to reducing the greenhouse gas emissions associated with transportation fuel and has incorporated this demand for low-carbon fuels into our business plans. Specifically, Neste Oil has delivered, and plans to continue to deliver, commercial volumes of renewable hydrocarbon diesel (NEXBTL), which qualifies as a low carbon fuel, to numerous customers in California.

Stable Program Necessary to Support Capital Investments LCFS 60-1

LFCS 61-1

Neste Oil, along with many other low-carbon fuel producers, have made significant capital investments in response to the LCFS implementing a demand for renewable or low-carbon transportation fuels. Changing the course or significantly altering the goals of the program at this late stage will have a severe chilling effect on any future potential investments as participants, investors, and capital markets will lose confidence in California's commitment to follow through with its policy goals. Accordingly, re-adoption of a stable LCFS is a necessary next step to fulfil the commitment California made to those producers, to support those investments, and realize true change in the air quality resulting from California's

Neste Oil – Houston

1800 West Loop South, Suite 1700
Houston, Texas 77027
Tel. 713.407.4400 Telefax. 713.407.4480

transportation fuels. Implementation of a stable Low Carbon Fuel Standard in California will send the proper signals to fuel producers like Neste Oil and will provide a significant driver to draw low-carbon fuels to the State in adequate volumes to comply with the target of 10% carbon intensity reduction by 2020.

In addition to stabilization, ARB should use the re-adoption as a springboard to begin to formulate and implement longer-term targets. Producers cannot recoup large capital investments in a short economic cycle. To further support the investments and growth in the production of low-carbon fuels, the market will require signals that the program will remain effective and robust beyond the 2020 timeframe currently at issue. LFCS 61-1 cont.

Proper Implementation is Key to Success

Opponents of the re-adoption efforts may cite concerns about a potential future lack of credit availability. Neste Oil has confidence that a properly implemented Low Carbon Fuel Standard would stabilize the economic drivers and would be an adequate market signal driving continued volumes of low-carbon fuels to California.

Accordingly, proper implementation of the program – both during the re-adoption transition and under the new program – is paramount to the success LCFS. Neste Oil sees staff's inability to timely process and approve otherwise complete pathway applications as an obstacle to additional volumes of low-carbon fuels to be available for consumption in California.

The simple economic model shows that fuels with a lower carbon intensity yield a higher return. However, absent the confirmed CI determination, a producer might reduce fuel production or instead send the fuel to more economical markets outside of California. The removal of those otherwise credit-generating fuels from the California transportation fuel pool could create a shortage – not because of the failure of the market or program design, but as a failure of implementation. LFCS 61-2

With the addition of more approved low-carbon pathways, Neste Oil hopes to significantly increase the volume of low-carbon renewable diesel that it will deliver to its California customers. Neste Oil proposes that the ARB direct staff to implement more robust procedures to ensure that fuel producers are not limited from participation in the California market because of gaps in staff resources.

As a supplement to the pathway application processes proposed, Neste Oil reiterates its recommendation that CARB authorize third-party verifiers, who are unrelated to the applicant, to perform due diligence on the proposed pathway and verify the CI modeling and calculations. The role of CARB staff would then be focused on oversight and verification of Method 1 pathway applications and Tier 1 pathway applications, leaving Tier 2 for more specific staff review, if desired. This methodology is in place in jurisdictions of British Columbia, Alberta, and Ontario and is functioning well. Additionally, the European Union's Renewable Energy Directive (RED) similarly allows producers to calculate actual production values and then be confirmed by an independent third-party verifier.

ILUC Considerations

As a part of the re-adoption proposal, staff has included the use of indirect land use change (ILUC) values for crop-based feedstocks. Staff have made considerable efforts to update the indirect ILUC values of corn ethanol and sugarcane ethanol as well as soy biodiesel, revising these values for all of LFCS 61-3 these pathways downward by 10 to 30 g CO_2/MJ points. These revisions are a result of robust scientific review and stakeholder engagement. However not all of the proposed ILUC values for crop-based fuels have completed the same degree of review to provide adequate confidence. Neste Oil expresses concern regarding some the methodologies used and submits a more detailed analysis and more specific recommendations in the enclosed Attachment A. We look forward to working the staff to refine the ILUC component of the program and modifying the proposal to provide a better result of the indirect land use effects associated with the ever-evolving fuels market. LFCS 61-3 cont.

Renewable Hydrocarbon Diesel Definition

As part of ARB's efforts in the re-adoption of the LCFS regulations, staff identified renewable hydrocarbon diesel as a potential low carbon fuel. The proposed regulation properly describes renewable hydrocarbon diesel as an alternative fuel subject to the LCFS regulations and a biomass-based diesel fuel made from biogenic feedstock sources.

Unfortunately, the proposed definition is less accurate than necessary to describe the various types of fuel available on the market. The proposed LCFS regulation uses the term "renewable diesel". [Of note, staff in the Transportation Fuels Branch have proposed an alternative term and definition for the same product as a part of the Alternative Diesel Fuel Regulation that uses the term "non-ester renewable diesel". At a minimum, we would encourage all programs under ARB to have unified definitions.] While that was a term used in the early commercialization of the fuel, it is not the most accurate term given the wide variety of fuels and different uses of the term. Specifically, some jurisdictions (like Ontario, Canada) use the term "renewable diesel" broadly to include both oxygenated biofuels (fatty acid methyl ester biodiesels or "FAME") along with fungible renewable hydrocarbon diesel (RHD).

Confusion may exist in the market regarding fuels that are not fungible with conventional diesel and are not fully de-oxygenated but are nonetheless called "renewable diesel". As such, that term is not ideal for use by the ARB in its regulations. The commonly understood product available in California and described in the ISOR and proposed regulations is a hydrocarbon oil. The definition should reflect that fuel as accurately as possible. LFCS 61-4

We propose that the term "renewable diesel" be replaced with the term "renewable <u>hydrocarbon</u> diesel" (including references in the definition of "biomass-based diesel" and in section 95486(b)(1) [energy density table]). We further propose that staff consult with the Oil and Gas and GHG Mitigation Branch and with the Department of Measurement Standards to align the nomenclature ("renewable <u>hydrocarbon</u> diesel") within the various regulations that touch and regulate this fuel.

In order to further align the LCFS definition with those in the Proposed ADF Regulations and the LCFS definition of "biomass-based diesel", we propose including language indicating that the fuel is intended for use in a compression ignition engine and that it must comply with ASTM D975-14a (2014). A uniform definition throughout the various ARB regulations will help reinforce a consistent nomenclature and description, accurately describe the fuel with adequate specificity, as well as avoid unnecessary confusion within the agency.

The proposes definition uses "derived from nonpetroleum renewable resources" as descriptive language. This is less useful for the regulations purposes in that is uses the word 'renewable' in the definition of 'renewable diesel' (potentially sloppy drafting), and attempts to define the fuel using a negative by what it is <u>NOT</u> rather than what it <u>IS</u>. A clearer definition would include the phrase "derived from biomass." This is further supported by the fact that the term "biomass" (which is defined in the LCFS regulation) would be clear and adequate.

Accordingly, we propose the following definition (to be used in both ADF and LCFS regulation):

LFCS 61-4 cont.

"Renewable Hydrocarbon Diesel" means:

a) a hydrocarbon oil meant for combustion in compression ignition engines;
b) derived from biomass;
c) not a mono-alkyl ester;
d) registered as a motor vehicle fuel or fuel additive under 40 CFR part 79; and
e) complies with ASTM D975-14a, (2014) *Specification for Diesel Fuel Oils*

CONCLUSION

Neste Oil appreciates the opportunity to comment on the re-adoption proposals. Like California, Neste Oil is proud of its continued leadership in producing clean transportation fuel. While no one producer or type of low-carbon fuel will be able to satisfy the State's carbon reduction and air quality improvement goals in the near term, Neste Oil believes its efforts, along with others like it, can contribute to the continued success of the Low Carbon Fuel Standard.

We look forward to continued participation in the California fuel market and the continued success of the Low Carbon Fuel Standard. Please do not hesitate to contact me if at 713.407.4415 or Dayne.Delahoussaye@nesteoil.com if you have any questions regarding the foregoing.

Respectfully submitted,

NESTE OIL US, INC.

Dayne Delahoussaye

61_OP_LCFS_NESTE Responses

605. Comment: **LCFS 61-1**

The comment states that re-adoption of the LCFS program is needed to fulfil the commitment California made to producers and realize true change in air quality. The comment also states that re-adoption should be used as a springboard to formulate longer-term target goals.

Agency Response: See response to **LCFS 5-2**.

606. Comment: **LCFS 61-2**

The comment expresses concern that untimely processing fuel pathway applications will limit producers' participation in the California market. The comment suggests the use of third-party verifiers to help accommodate the excess workload.

Agency Response: ARB does not agree that implementation cannot succeed without formally adding third-party verification to speed pathway reviews. Prior to the re-adoption effort, ARB staff was able to process full pathway applications in a timely manner. With the diversion of existing staff resources to the re-adoption effort, pathway application processing times increased significantly. If the Board approves the proposed regulation, ARB staff will need to simultaneously process new pathway applications and re-certify existing applications. ARB will devote the necessary resources to these vital functions. Moreover, without changing the LCFS proposal, ARB can develop an improved internal process, in some cases involving a verification step, similar to that proposed by the commenter.

607. Comment: **LCFS 61-3**

The comment states that some of the proposed iLUC values for crop-based fuels have undergone insufficient review.

Agency Response: The update of the iLUC analysis has been a rigorous and transparent process. The scenario runs use the same parameter values and modeling methodology for all six biofuels assigned an iLUC value. All of the iLUC values being proposed to the Board are a result of ARB staff using the latest science and best data available to estimate iLUC values for all six biofuels using a consistent methodology.

See also responses to **LCFS 8-1**.

608. Comment: **LCFS 61-4**

The comment states that the definition for renewable hydrocarbon diesel does not cover all the types that are available on the market. The commenter suggests new definitions.

Agency Response: ARB staff agrees that it is important to have a uniform definition throughout the various ARB regulations to avoid unnecessary confusion. However, different regulations can have different purposes and as such it is sometimes necessary to have definitions which are specific to a regulation. Staff made every effort to make definitions consistent to avoid confusion as long as it did not compromise the intent of each specific regulation.

Staff has responded to the comment by modifying and clarifying the regulation as part of the 15-day changes. Staff replaced the term "*non-ester renewable*" with the term "*renewable hydrocarbon diesel"*.

Comment letter code: 62-OP-LCFS-LCA

Commenter: Stefan Unnasch

Affiliation: Life Cycle Associates

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

Life Cycle Associates

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

62_OP_LCFS_LCA

February 17, 2015

California Air Resources Board
Katrina Sideco
(916) 323-1082
ksideco@arb.ca.gov

Reference: **Comments on the Treatment of Nitrogen Fixation in Soybeans**

Dear Ms. Sideco,

Life Cycle Associates would like to take this opportunity to provide comments and insight to the recently released California GREET2.0 model. The comments herein address the analysis and treatment of N_2O emissions from soybean farming and time impacts on biofuel pathways. These comments are a continuation of comments submitted on 10/28/2014 addressing the same issue, which has not been addressed in the new release. CA_GREET2.0 estimates the releases of N_2O due to fertilizer application, crop residue, volatilization, and the secondary effects from leaching as per the IPCC methods. GREET does not include emissions from nitrogen fixation in legumes. The emissions from the nitrogen fixed in the plants are a major contributor to lifecycle greenhouse gas emissions from soybeans, which affects soy bio- and renewable diesel pathways as well as co-product credits for other pathways. Table 1 shows the impacts of addressing N_2O fixation on the CA_GREET2.0 soy biodiesel and corn ethanol fuel pathways. The effect of the N fixation on the corn ethanol pathway is due to the higher DGS co-product credit obtained for displacing the higher emissions soybean meal animal feed.

Table 1. N_2O fixation Impact on corn ethanol and soy biodiesel fuel pathways.

	GHG Emissions (g CO_2e/MJ_{Fuel})	
Model	**Soy Biodiesel**	**Corn Ethanol**
CA_GREET2.0	1.6	18.3
CA_GREET2.0, N Fixation	6.8	15.3
Difference in Pathway	**5.2**	**-3.0**

LCFS 62-1

GHG Impacts of Nitrogen Fixation in Legumes

The emissions from soybean production have been examined in many fuel LCA models and the latest research from the JRC's GNOC model as well as other studies shows that the emissions from nitrogen fixation are significant. The effect is well described by Venkat, 2010:

> "IPCC (2006) does not include biological nitrogen fixation as a direct source of N_2O, instead relying solely on the nitrogen inputs from crop residues (above and below ground) to account for all legume N_2O emissions. The problem with this is that the IPCC crop residue model does not seem to capture the magnitude of N_2O emissions in the late-growth stages of soybeans (this is the one crop that I have looked at in detail; others may have a similar problem). There is in fact almost an order of magnitude difference between the worst-case (high) N_2O emissions from crop residue and the conservative (low) N_2O emissions in the late-growth stages (crop residue emissions are smaller by a factor of 5 to 10)."

These comments address the N_2O release from soybean farming in GREET and CA_GREET2.0 and compare the results to the EPA RIA analysis, the EU GNOC (Global Nitrous Oxide Calculator) and the 2013 JRC WTT report. Results from these studies suggest that the GREET inputs underestimate the N_2O emissions from soybean production, which affects soy biodiesel, renewable diesel, and corn ethanol pathways with soy displacing corn. Figure 1 shows the N_2O

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

contribution to the total GHG emissions of the finished fuel produced, based on data from GREET and the various leading studies addressed in these comments.

ARB should evaluate these studies and re-examine the GREET methodology and values to ensure that the treatment of corn and soy is commensurate to the N_2O emissions generated.

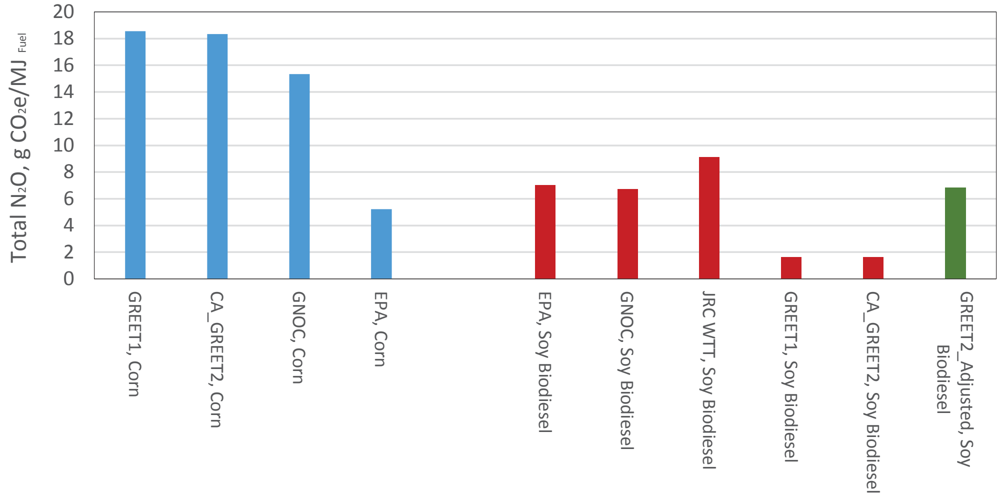


Figure 1. N_2O contribution to GHG emissions from corn and soy crops.
[a] Emissions are calculated from GREET data and data in the EU and EPA studies, crop yields are based on 2014 NASS data for corn and soy.

LCFS 62-1 cont.

EPA RIA N_2O Emissions Analysis

The EPA evaluated the nitrous oxide emissions for soy and corn biomass as part of the RIA analysis (EPA, 2013). Figure 2 shows the N_2O emissions from bioenergy crops in the U.S as presented in the EPA RIA. The N_2O emissions attributed to the crop residue and leaching from soy and corn bioenergy crops account for approximately 40% and 25% of the total N_2O emissions.

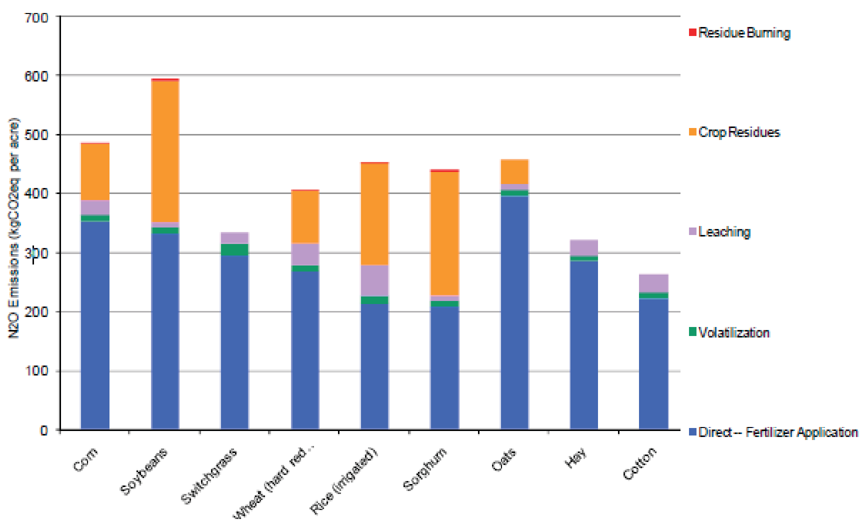


Figure 2. EPA RIA N_2O emissions form bioenergy crops

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

Table 2 shows the N_2O emissions from the biomass fixation and leaching and also the contribution of these emissions to the total GHG emissions of the finished fuel produced, based on the EPA RIA. NASS average crop yields for 2014 is assumed for calculation of the total N_2O emissions (kg/ha).

Table 2. EPA RIA Nitrous Oxide Emissions from Soybean and Corn Farming

EPA RIA Result	Corn	Soybean
Fertilizer and Leaching	2.98	2.82
Crop Residue	0.83	19.9
Total N_2O, g/bu	3.81	22.7
Total N_2O, kg/ha*	1.8	2.2
g CO_2e/MJ_{Fuel}	**5.2**	**7.0**

*NASS 2014 Average crop yield assumed for conversion to kg/ha.

JRC GNOC N_2O Emissions Analysis

The European JRC GNOC (Global Nitrous Oxide Calculator) (Köble, 2014) calculates N_2O emissions based on the 2006 IPCC guidelines (Eggleston, 2006) combining TIER1 and TIER2. The IPCC guidelines distinguishes different pathways (direct, indirect) and different nitrogen sources (e.g. mineral fertilizer, manure, crop residues, and drained organic soils). For the indirect pathways (leaching/runoff and volatilization) the GNOC follows the IPCC TIER1 approach for all nitrogen sources. The same holds for direct emissions from crop residues and drained organic soils.

Table 3 shows the GNOC and the JRC WTT study (CONCAWE, 2013) N_2O emissions from soy and corn farming and also the contribution of these emissions to the total GHG emissions of the finished fuel produced.

LCFS 62-1 cont.

Table 3. JRC GNOC Nitrous Oxide Emissions from Soybean and Corn Farming

N_2O result	GNOC, Corn	GNOC, Soybean	JRC WTT
Region	Iowa	Iowa	EU
Crop	Corn	Soybean	Soybean
Crop Yield, kg/ha	23,827	5,291	--
Chemical N, kg/ha	198	3.05	--
Manure N, kg N/ha	0	0	--
Total N_2O, g/bu	9.16	21.57	29.53
Total N_2O, kg/ha	4.36	2.13	2.92
g CO_2e/MJ_{Fuel}	12.6	6.7	9.1

GREET N_2O Emissions Analysis

Table 4 shows the GREET N_2O emissions from soybean and corn farming and the contribution of these emissions to the total GHG emissions of the finished fuel produced. Table 4 also shows the GREET2 soybean results if a constant for N fixation in the biomass consistent with the GNOC results was applied. A constant for the corn analysis can also be applied (not shown here).

GREET does not include biological nitrogen fixation as a direct source of N_2O, instead relying on the nitrogen inputs from crop residues to account for total N_2O emissions. As previously stated by Venkat, 2010, this analysis does not accurately capture the magnitude of N_2O emissions in the late-growth stages of soybeans. The omission of nitrogen fixation leads to a misrepresentation of

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

the total GHG emissions from soybeans and affects the soy biofuel pathways and other pathways where soybean meal is a substitute co-product.

Table 4. N_2O emissions from soybean and corn pathways.

Case	*GREET1_ Corn	CA_GREET2_ Corn	GNOC, Corn	*GREET1_ Soy	CA_GREET2_ Soy	GNOC, Soy	+Soy, matched GNOC
Chemical N, g/bu	423.3	415.3		49.9	49.9		49.9
Crop Density, lb/bu	56	56		60	60		60
Crop Yield							
bu/acre	158	191		40	40		40
kg/ha	19,506	23,580	19,506	5,291	5,291	5,291	5,291
N Fertilizer, g/acre	165,197	195,926		4,930	4,930		4,930
N in Biomass, g	141.6	142.6		200.7	201.7		200.7
Chemical N, kg/ha	165.2	195.9	165	4.93	4.93	4.93	4.93
Crop Residue N kg/ha	55.26	67.27		19.83	19.93		19.8
N_2O Chemical	1.525%	1.525%		1.325%	1.325%		1.325%
N_2O Crop Residue	1.525%	1.525%		1.325%	1.325%		1.325%
N_2O from fixation, g/bu							17
GREET Result N_2O kg/ha							
Chemical Fertilizer	3.96	4.70		0.10	0.10		0.10
Crop Residue	1.32	1.61		0.41	0.41		0.41
Total N_2O, g/bu	13.5	13.4	11.2	5.2	5.2	21.8	22.1
Total N_2O kg/ha	5.28	6.31	4.36	0.52	0.52	2.16	0.52
g $CO2_e/MJ_{Fuel}$	18.6	18.3	15.3	1.6	1.6	6.7	6.8

*GREET1 cases are determined using GREET1_2014.
+ Soy matched to GNOC include N_2O from legume fixation.

Figure 3 shows a graphical comparison of the GREET N_2O emissions (g/ha) versus the leading studies identified here. The GREET Soybean N_2O emissions (kg/ha) are ~ 5 times lower than the other leading studies.

LCFS 62-1 cont.

Life Cycle Associates

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

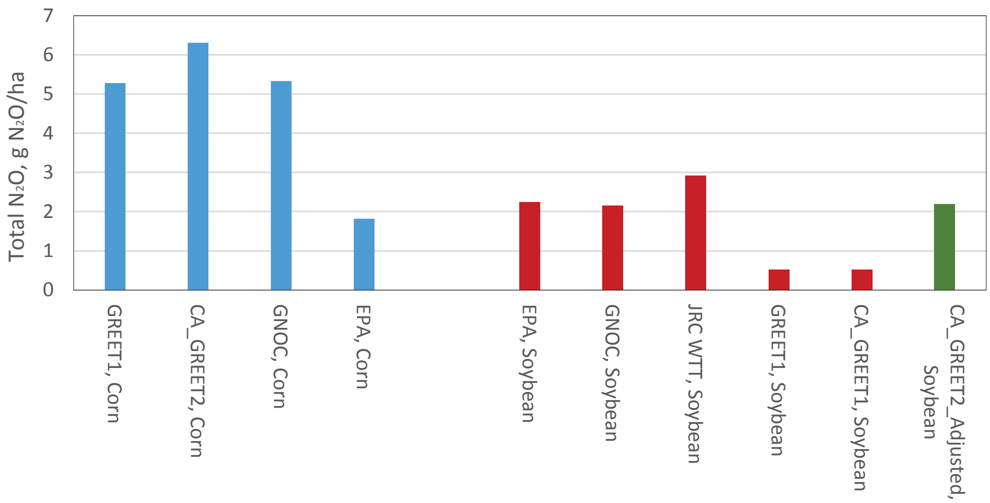


Figure 3. Total N_2O emissions from corn and soybean production.

Figure 4 shows the CA_GREET2 calculation array for soybean farming. An additional term to account for the N_2O from biomass fixation has been added (highlighted in yellow). The WTT results array for the CA_GREET2 adjusted case is shown in Figure 5.

LCFS 62-1 cont.

Life Cycle Associates

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

	Soybeans							
	Soybean Farming	Soybean Farming Fertilizer Use (grams/bushel)				Soybean Farming Herbicide and Pesticide Use (grams/bushel)		Soybean Transportation
Energy consumed: Btu/mmBtu of fuel throughput, except as noted		**Per bushel of soybeans**						
Total energy	20,959	3,024	5,115	3,028	0	5,696	200	5,914
Fossil fuels	20,688	2,987	4,917	2,791	0	5,422	190	5,885
Coal	1,020	138	740	887	0	1,023	37	112
Natural gas	4,277	2,560	3,009	929	0	1,708	61	580
Petroleum	15,392	289	1,168	975	0	2,690	92	5,193
Total emissions: grams/mmBtu of fuel throughput, except as noted		**Per bushel of soybeans**						
VOC	2.013	0.315	0.328	0.042	0.000	0.053	0.002	0.116
CO	33.393	0.376	0.602	0.193	0.000	0.319	0.015	0.444
NOx	14.086	0.433	1.560	0.732	0.000	1.070	0.045	1.071
PM10	0.911	0.075	0.322	0.068	0.000	0.118	0.003	0.029
PM2.5	0.867	0.061	0.253	0.050	0.000	0.074	0.003	0.024
SOx	1.029	1.021	16.790	0.503	0.000	1.520	0.034	0.172
CH4	2.749	0.520	0.772	0.392	0.000	0.704	0.025	0.613
N2O	0.027	0.201	0.008	0.004	0.000	0.008	0.000	0.008
CO2	1,545	159	349	224	0	430	15	465
VOC from bulk terminal	0.000	CO2e from LUC		0.695	NO from nitrogen fertilizer			
VOC from ref. Station		45.386	CO_2 from urea use	5.218	N2O from nitrogen fertilizer			
				17.000	N2O from fixation			

Figure 4. CA_GREET2 soybean farming calculation array.

LCFS 62-1 cont.

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

	Soy Oil-based Biodiesel	
	Feedstock	Fuel
Loss factor		1.000
Unit	per mmBtu	per mmBtu
Total energy	51,578	588,260
Fossi lfuels	50,337	262,702
Coal	4,644	63,780
Natural gas	15,407	170,644
Petroleum	30,286	28,278
VOC	3.369	23.321
CO	41.489	14.717
NOx	23.117	36.254
PM10	1.791	3.390
PM2.5	1.565	2.703
SOx	24.733	21.631
CH4	6.780	39.531
N2O	26.383	0.333
CO2	3,794	18,696.679
CO2 (w/ C in VOC & CO)	3,870	18,789
GHGs	11,901.6	19,877
g CO2e/MJ	**11.28**	**18.84**

LCFS 62-1 cont.

Figure 5. CA_GREET2 soybean biodiesel WTT results array.

We hope that these comments have illustrated that the N_2O emissions in GREET are in need of thorough evaluation. Thank you for taking into account these comments. I look forward to discussing these comments with you in more detail.

Best Regards,

Stefan Unnasch

Stefan Unnasch
Managing Director
Life Cycle Associates, LLC

References

CONCAWE, Edwards, R., 2013. WELL-TO-WHEELS ANALYSIS OF FUTURE AUTOMOTIVE FUELS AND POWERTRAINS IN THE EUROPEAN CONTEXT. JEC/CONCAWE/EUCAR.

Eggleston, H.S., 2006. 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Forestry 5, 1–12.

EPA, 2013. Final Rule - Regulation of Fuels and Fuel Additives: 2013 Renewable Fuel Standards (August 6, 2013) 1–89.

JRC, 2013. User manual for the BioGrace Excel tool. http://www.biograce.net/home

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

Köble, R., 2014. The Global Nitrous Oxide Calculator – GNOC – Online Tool Manual.

Venkat, K. Clean Metrics, September 07, 2010, Modeling soil nitrous oxide emissions for legumes, http://cleanmetrics.typepad.com/green_metrics_clean_metri/2010/09/modeling-soil-nitrous-oxide-emissions-for-legumes.html

62_OP_LCFS_LCA Responses

609. Comment: **LCFS 62-1**

The comment claims that the soil N2O emission factor for soy-based fuels should account for biological nitrogen fixation (BNF).

Agency Response: ARB staff relies on Intergovernmental Panel on Climate Change (IPCC) 2006 GHG Inventory Guidelines to determine Soil N_2O emissions. IPCC specifically reviewed biological nitrogen fixation (BNF) and excluded it as a contributor to N_2O emissions. N_2O emissions from soybeans are accounted for based on the nitrogen content of the residual biomass and the quantity of nitrogen fertilizer applied, using IPCC 2006 Tier 1 default emission factors. Staff recognizes soil N_2O emissions as an evolving and uncertain area of science, and will continue to review emerging studies and monitor progress on this topic.

This page intentionally left blank.

Comment letter code: 63-OP-LCFS-Neste

Commenter: Dayne Delahoussaye

Affiliation: Neste Oil

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

ATTACHMENT A

TECHNICAL COMMENTS RELATING TO CARB CONCERNING DETAILED ANALYSIS FOR INDIRECT LAND USE CHANGE

Steven Gust

Neste Oil Corporation

Senior Associate

Renewable Feedstocks & Processes

P.O. Box 310, 06101 Porvoo, Finland

steven.gust@nesteoil.com

www.nesteoil.com

February 10, 2015

Introduction and Summary

This analysis supports the Comments of Neste Oil concerning the ARB ISOR posted Dec. 30, 2014 and specifically the document Appendix I: Detailed Analysis for Indirect Land Use Change which can be found here: http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15appi.pdf

Neste believes that in many key areas, ARB staff have employed extremely conservative data and analytical approaches that collectively produce a substantial overestimation of the ILUC effect of fuels derived from palm oil.

List of Comments

1. CI comparison. The CI savings of future biofuels is the sum of the direct and indirect emissions compared to the emissions of the appropriate fossil fuel counterpart. This implies that a similar analysis for the fossil fuel counterpart including both the direct and indirect emissions produced in the same period as the biofuel should be conducted. Comparing the emissions for a biofuel produced in the future to that of the fossil fuel counterpart produced today is not valid. The comparison should be for the marginal or new fossil fuel production. The mix of crudes used in refineries is changing and the value for a future "average crude" should be estimated in a similar manner to that of a "future feedstock" for biofuel production. LCFS 63-1

Proposed improvement: That ARB model future marginal oil production and use the fossil fuel counterpart result as the CI comparator for future biofuels.

2. Additional indirect effects. The ISOR states that ARB staff have only identified one indirect effect that has a measurable impact on GHG emissions (Appendix I, paragraph 1, line 8). This statement illustrates the authors have not fully appreciated all of the effects of the biofuels' industry requirement for a GHG reduction in the agricultural as well as other sectors. Other indirect effects as a direct consequence of the biofuel industry are taking place already today. One very clear and important example of this is the indirect effect concerning biogas (methane) capture and avoidance outside of / in addition to what is happening within the biofuel industry. LCFS 63-2

Methane is a powerful greenhouse gas and significant amounts are released during the milling of oil palm fresh fruit bunches into crude palm oil. The capture and use of this biogas is a direct consequence of the biofuels' GHG reduction requirements. As such, when the methane is captured and used, this CI effect is attributed to the oil palm pathway as a direct effect. But in addition to this biofuel sector methane captue, the GHG reduction mechanism is spreading to the agro and oleochemicals sector. GHG reduction is not a requirement in the food or oleochemicals sectors. That the current economic models have failed to capture this effect clearly illustrates an area which should be explored further. (See Annex I for a further description.) LCFS 63-2 cont.

Proposed improvement: ARB model the GHG reduction effects of methane capture in oil palm mills outside of the biofuel sector and include these in the oil palm GHG net emissions reduction calculation

3. Over-simplification of ILUC analysis. ARB staff state:

> *A land use change effect is initially triggered when an increase in demand for a crop-based biofuel begins to drive up prices for the necessary feedstock crop. This price increase causes farmers to devote a larger proportion of their cultivated acreage to that feedstock crop.*

There is in fact a wide range of options and alternatives to farmers and their decisions are much more complex than this simple analysis implies. One of the major considerations is soil suitability as well as weather and climate issues. In addition, farmers consider the cost for additional fertilizers and of switching to new plant varieties etc.

LCFS 63-3

Concerning biofuels and the effect of increased demand on feedstock prices, the facts do not at all coincide with the model. Vegetable oil prices have been decreasing as biofuel volumes have been ramped up. See for example: http://www.nesteoil.com/default.asp?path=1,41,538,2035,14053

There is thus a correlation between biofuel production and decreasing of vegetable oil prices. This should then trigger, by the ARB staff's logic above, that land is taken out of production and by doing this, the biofuels have in fact caused carbon sequestration.

Obviously, there are a number of other factors which come into play when farmers expand or reduce production and it is an over-simplification to focus on commodity prices.

Proposed improvement: ARB continue to work with GTAP modelers in order to validate and calibrate the model to better reflect current reality

4. Peat emissions. On attachment 2-25 of Appendix I, it states:

> *the most robust current estimate of peat CO_2 emissions is 86 Mg CO_{2e} ha^{-1} y^{-1} assuming 50-year annualization; annualized over 30 years, the value is 95 Mg CO_{2e} ha^{-1} y^{-1}. We adopt this 30-year value in AEZ-EF.*

The basis upon which this value has been derived is from a series of papers by Page et al. (*see* list of references at bottom of the page 2-25). That this value is robust is highly questionable. There is in fact a large body of literature and full agreement that the long term emissions from drained peat forest are in the 60 to 70 t CO_2 / hectare / year depending on depth of drainage and peat type. The rule of thumb is that emissions are 1 ton CO2 for each centimeter of drainage with drainage levels of 60 to 70 cm. The depth of peat drainage here is the key issue as a more shallow drain exposes less peat to the air and thus less oxidation (references to this effect can be supplied later). Staff analysis correctly states that of the two techniques used for determining peat loss, that the direct gas flux measurements is subject to difficulties in factoring out respiration of roots but neglects to acknowledge that the subsidence method has major uncertainties with the extent of peat oxidation in the first few years. Page et al repeatedly state that a high subsidence of 75 cm occurs in the first year and that by peat density measurements they attribute a high-level oxidation to occur during this period and further that: LCFS 63-4

> *Bulk density profiles indicate that consolidation contributes only 7 % to total subsidence, in the first year after drainage, and that the role of compaction is also reduced quickly and becomes negligible fter 5 years. Over 18 years after drainage, 92 % of cumulative subsidence was caused by peat oxidation[1].*

This assumption on high levels of oxidation during the first year then increases the time averaged emissions from the lower commonly accepted values of 60 to 70 t CO_2 / hectare / year to the value adopted in the analysis of 95 t CO_2 / hectare / year. Running the GTAP-BIO model with this lower value has a significant effect on the final results.

The only evidence that Page present for the high oxidation rates are the differences in peat density. They do not seem to be aware that during plantation establishment, a deep drain occurs and soil compaction is carried out in order to provide a good base for the palm trees. Obvious examples can

[1] REVIEW OF PEAT SURFACE GREENHOUSE GAS EMISSIONS FROM OIL PALM PLANTATIONS IN SOUTHEAST ASIA Page, S. E., Morrison, R., Malins, C., Hooijer, A., Rieley, J. O. & Jauhiainen, J. www.theicct.org White Paper Number 15 | September 2011

be seen in the region where this practice is not carried out to a sufficiently high degree where palm trees lean over.

LCFS 63-4 cont.

Proposed improvement: ARB use the IPCC value in the model of 73 Mg CO2/hr/yr for peat emissions and solicit expert opinions on the percentage of oxidation during the initial subsidence.

5. Expansion onto peat. ARB states that of the oil palm expansion in Malaysia and Indonesia that one-third (33%) of oil palm expansion in Mala_Indo occurs on peatland (Edwards, Mulligan et al. 2010, Appendix III). It is interesting that ARB has not been able to find a more recent reference. It is highly questionable that the situation concerning expansion has not changed in the past 6 years as the reference to Edwards uses data from 2009. The analysis on expansion by Edwards is given in Appendix III of staff's report. For Malaysia, they state:

> *Tropical Peat Research Institute [TPRI 2009] (quoted in "Status of Peatlands in Malaysia" July 2009 report by Wetland International), displayed a conference poster showing that that the area of oil palm on peatlands in Malaysia increased by roughly 200 kha between 2003 and 2008. The Malaysian Palm Oil Board report that the total area of oil palm in Malaysia increased by roughly 600 kha in the same period. So according to this source, roughly* ***one third*** *of those new plantations are on peat.*

LCFS 63-5

So, for Malaysia, we see that the basis for the data was a conference poster from 2009. Neste Oil strongly suggests that due to the importance of this issue in the ARB ILUC analysis, staff use more than mere conference posters as the source of the basis of the analysis.

With respect to Indonesia, Edwards used the following source:

> *In Indonesia, palm oil is mostly grown in Sumatra, and some in Papua. [Hooijer 2006] superimposed maps of concessions granted for palm oil plantations in these areas, on maps of peatland (table 4 in [Hooijer 2006]), and found that 25% of concessions were on peatland.*
>
> *[Hooijer 2006] argues that the % oil-palm on peat is likely to rise in future, and estimates that probably more than 50% of future palm oil plantations will be on peat.*
>
> ***Conclusion: at least 33% of new plantations in Indonesia and Malaysia are likely to be on peat.***

In this case, a much older reference was used. We understand that Hoojier, who is a peat scientist and is very concerned about peat conversion to estates and the emissions that occur, is not an expert on estate expansion in the region.

In fact other authors reached different conclusions: ***Spatial Modeling of Future Oil Palm Expansion in Indonesia, 2000 to 2022*** *Nancy Harris, Sean Grimland and Timothy Pearson;* Report submitted to EPA July 2011

> *3.4.2 Expansion by Soil Type*
>
> *The area of predicted palm oil expansion between 2000 and 2022 per soil type is important primarily for determining how much expansion occurs on histosols. In both the FAO soil classification and the USA soil taxonomy, a histosol is an organic soil with an organic carbon content by weight of 12 percent or more. Histosols are sometimes referred to as organosols. When palm oil is cultivated on a histosolic soil, the water must be drained as part of site preparation activities and results in significant GHG emissions. Approximately 9% (531,366 ha) of palm oil expansion are predicted to occur in histosol soils with an additional 4,894 ha in the palm only model.*

LCFS 63-5 cont.

The following table illustrates the value that EPA used in their analysis based on a detailed investigation of soil types and land suitability etc.

TABLE II–6—PERCENT OF PALM OIL PLANTATIONS ON PEAT SOIL, HISTORICAL AND PROJECTED

Year	Indonesia %	Malaysia %
2009 (Historical) ...	22	13
2022 (Projected) ...	15	10
2022 (Projected Incremental Expansion)	13	9

RSPO commissioned the following report, which is on the TROPENBOS website: **HISTORICAL CO2 EMISSIONS FROM LAND USE AND LAND USE CHANGE FROM THE OIL PALM INDUSTRY IN INDONESIA, MALAYSIA AND PAPUA NEW GUINEA**[2]

Table 2. Oil palm development in Indonesia and Malaysia on peatland and mineral soils (million hectares).

Country, soil	1990	2000	2005	2010
Indonesia	1.34	3.68	5.16	7.72
Peat	0.27	0.72	1.05	1.70
Mineral	1.07	2.95	4.10	6.02
Malaysia	2.08	3.53	4.59	5.38
Peat	0.15	0.28	0.40	0.72
Mineral	1.93	3.25	4.19	4.66

LCFS 63-5 cont.

Proposed improvement: That ARB use a value in the range 15- 20% expansion onto peat OR alternatively perform a more detailed analysis of the current situation.

6. GTAP-BIO model constraints In the analysis on palm oil, the model has been constrained assuming that all future palm oil would be coming from Malaysia and Indonesia. Neste Oil disagrees with this approach and feels that the constrain is not warranted.

For example, 1.5 million hectares of land have been approved for palm oil development in Liberia, Cameroon and Gabon alone.[3]

LCFS 63-6

[2] http://www.tropenbos.org/publications/historical+co2+emissions+from+land+use+and+land+use+change+from+the+oil+palm+industry+in+indonesia,+malaysia+and+papua+new+guinea

[3] http://www.sustainablepalmoil.org/palm-oil-by-region/africa/#sthash.Q0jnJsao.dpuf

In early 2011, Ghana was the first country in Africa to have its National Interpretation (NI) of the Roundtable on Sustainable Palm Oil (RSPO) Principles and Criteria for sustainable palm oil approved. Ghana has 336,000 hectares planted with oil palm; it is a net importer to meet its demands for palm oil.

Proposed improvement: Neste Oil therefore feels that the constraint of all future palm oil coming from Malaysia and Indonesia is not valid.

LCFS 63-6 cont.

7. AEZEF model YieldTable sheet. All references to palmf have a value of 0. Neste Oil cannot understand what staff have used in the model for the accumulated time averaged biomass for oil palm plantations.

Proposed improvement: Include values for the dry fraction, AGB C- factor etc. for palm trees.

LCFS 63-7

8. AEZEF model forest types for Mala_Indo ARB uses the following forest types for the region

4	Tropical	Sub-humid	Tropical-Sub-humid
5	Tropical	Humid	Tropical-Humid
6	Tropical	Humid (year round)	Tropical-Humid (year round)

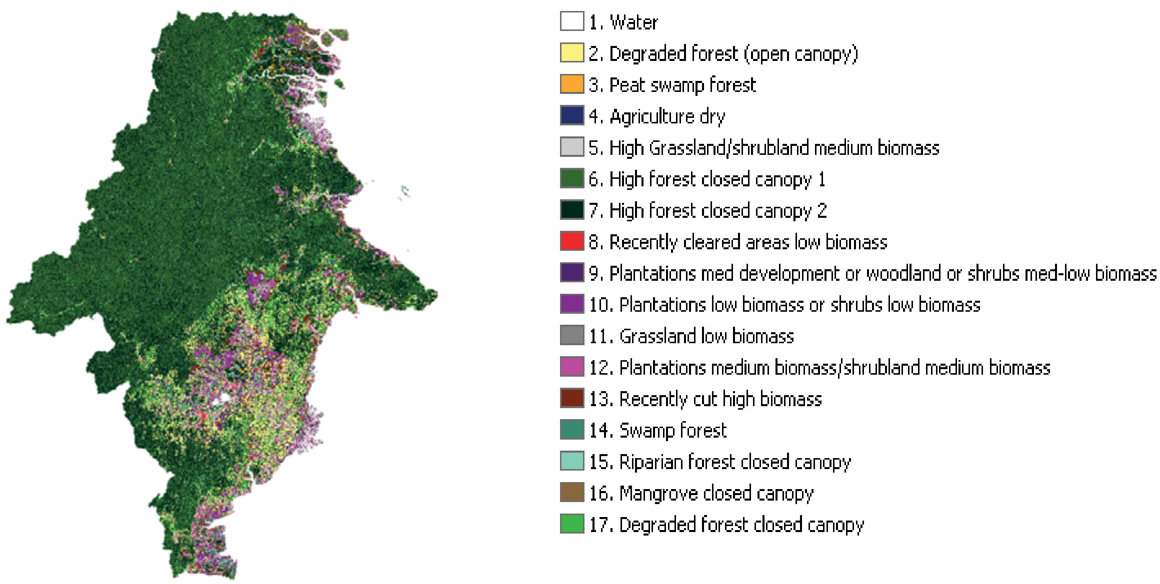
It is unclear from this analysis what classification degraded forests or logged over forests would be given. For example the below map for North-East Kalimantan indicates land cover types. A very large part of the region is covered by degraded forest.

LCFS 63-8

Steven Gust 10 February 2015

Also see this reference for land types:

http://www.isric.org/isric/webdocs/docs/ISRIC_Report_2007_01_web.pdf



LCFS 63-8 cont.

Large areas of grassland and scrub land have also been converted for plantations, especially in Kalimantan. These areas were typically once forested but gave way to scrub and grassland after the large-scale el Niño fires in 1982-1983 and 1997-1998.

According to an article in Geoderma 149 (2009) 76–83*:*

> *… in Indonesia, forests are under increasing pressure of population growth, illegal logging, forest fire, and land use change for agriculture, transmigration and estate crops such as timber and oil palm.*
>
> *Imperata grasslands in Indonesia cover 8.5 million ha, or about 4.5% of Indonesia's total land area. In Kalimantan alone, Imperata grasslands cover an estimated 2.2 million ha (Garrity et al., 1997). Imperata grasslands are seen as a final stage of land degradation and are very difficult recover for more valuable land uses (Murniati, 2002). Regeneration*

of grassland areas is becoming increasingly important, not only to create new secondary forest, but also to recover the original biodiversity. LCFS 63-8 cont.

Conclusions from Neste Oil Analysis

Based on the above comments we suggest that ARB use a 20% peat conversion estimate for the new oil palm estates with a 73 Mg CO2/hr/yr for peat emissions. According to our knowledge, this would produce a value of around 33.6 g CO_2/MJ_{fuel}

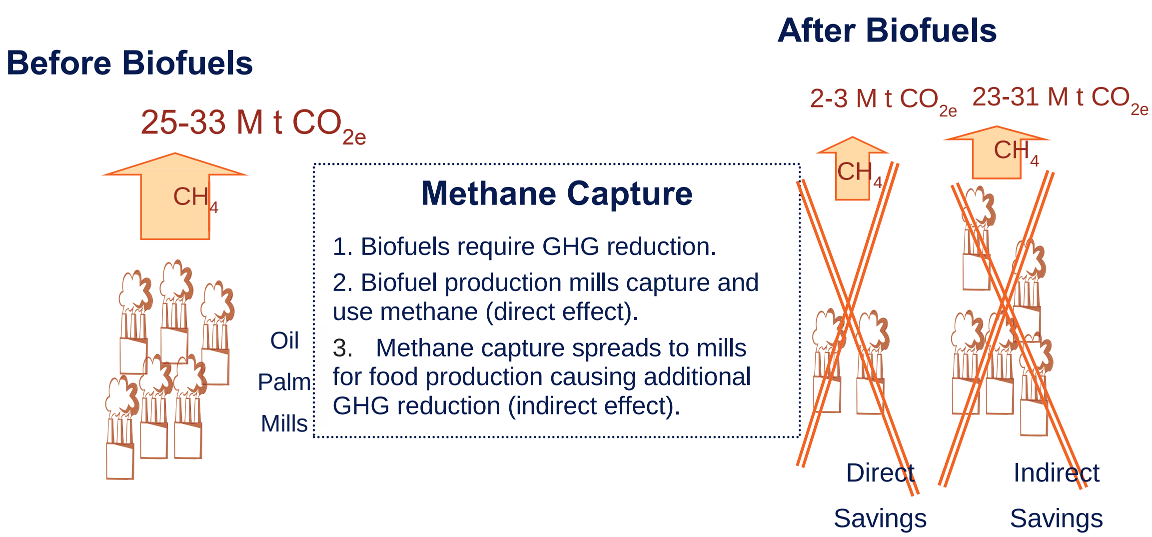
iLUC Emissions for Alternative Scenarios	
Scenario	iLUC, gCO2/MJ
CARB Scenario 8	65.2
20% peat conversion estimate	42.0
73 Mg CO2/hr/yr for peat emissions	51.4
20% peat and 73 Mg CO2/ha/a	33.6

LCFS 63-9

*****

Annex I

At palm oil mills, the GHG reduction strategy with the largest and most immediate beneficial effect is methane capture and utilization. This has long been recognized as a major GHG source in the oil palm pathway but only recently, has there been much progress. There are approximately 1000 palm oil mills in Malaysia and Indonesia. These mills are self-sufficient in energy, using the fiber and shell from the palm oil fruit to produce the electricity and process steam they require. The process generates a wastewater known as POME (palm oil mill effluent), which contains about 5 percent organic materials. For most mills, approximately 3 tons of POME are generated per ton of crude palm oil (CPO). POME is fed into a series of cooling ponds and digestion ponds where the organic material is digested, producing biogas (a 50:50 mixture of methane and carbon dioxide). The digestion proceeds until the discharged water achieves a sufficiently low biological and chemical oxygen demand.



NESTE OIL

Steven Gust 10 February 2015

An example of the indirect savings is:

In the milling process, there is on average 3 $\pm$ 0.2 tons of POME per ton of crude palm oil. Each ton of POME generates 28 cubic meters (varies from 25 to 45) of biogas or about 14-16 cubic meters of methane 14-16 m^3 CH4 x 0.7 kg CH_4 /m^3 = 10 - 11 kg CH_4/t POME. At an CPO yield of 3.7- 4 t CPO/ha x 3 $\pm$ 0.2 t POME/ t CPO x 10-11 kg CH_4/t POME = 110 – 140 kg CH_4/ha. Using a greenhouse gas factor of 21 for methane this becomes 2.3 - 3 t CO_{2e}/ha. In Malaysia and Indonesia there are roughly 11 M ha of mature or producing hectares or 25 -33 M t CO_{2e}.

63_OP_LCFS_NESTE Responses

610. Comment: **LCFS 63-1**

The comment contends that future marginal oil production should use the fossil fuel counterpart result as the CI comparator for future biofuels.

Agency Response: The commenter's request to perform 'marginal' analysis is not relevant since the methodology used for both fossil fuels and biofuels represent an 'average' value for both groups. The LCFS baseline carbon intensity (CI) represents a weighted average of the various crudes used in California and was first established in 2010. This crude CI is updated periodically to reflect the different mix of crudes during each year. In the modeling of indirect effects of biofuels, staff used incremental volumes of biofuels (produced in the period 2004-2010) to estimate indirect Land Use Change (iLUC) values. For biofuels, GHG emissions as they occurred at one time are amortized over 30 years to estimate iLUC values. It is in effect an 'average' iLUC value for the biofuel and is expected to be used over a period of 30 years. Updates to iLUC values represent changes to reflect updated land use science and data for the period 2004-2010. The Global Trade Analysis Project (GTAP)/Agro-Ecological Zone-Emissions Factor (AEZ-EF) models do not calculate new values to reflect changing volumes of biofuels every year.

611. Comment: **LCFS 63-2**

The comment requests ARB staff to model the GHG reductions effects of methane capture in oil palm mills outside of the biofuel sector and include these in the oil palm GHG net emissions reduction calculation.

Agency Response: Currently, only a limited number of mills capture biomethane. For situations where palm mills capture methane and where palm oil is used as a transportation fuel feedstock, an appropriate emissions credit for biomethane capture can be considered under Method 2 of the direct analysis.

612. Comment: **LCFS 63-3**

The comment states that focusing on commodity prices is an over-simplification and requests that ARB continue to work with GTAP modelers to validate and calibrate the model to better reflect current reality.

Agency Response: ARB staff disagrees that the GTAP model is overly simple. In fact, the structure of the GTAP model is complex and includes various elements (i.e., calibrated elasticity parameters, trade relationships, land rents, use of fertilizers, soil quality, new plants and seed varieties, etc.) implicitly designed to account for many of the economic decisions that farmers make when responding to a market demand.

Correlating increases in biofuel availability to lower prices of vegetable oil is not within the scope of the analysis conducted by ARB staff. The adopted modeling methodology only looks at the impacts related to 'additional' production of biofuels and attributes increased demand for biofuels to have a direct relationship to higher prices for the feedstock. Thus, the analysis conducted by staff represents only the effects from increased biofuel production and does not consider all of the global forces that dictate cultivation of oilseeds. In the global marketplace, prices for commodities such as vegetable oils are a result of many complex factors. However, as the commenter suggests, ARB staff will continue to work with GTAP modelers to further validate and calibrate the model.

613. Comment: **LCFS 63-4**

The comment argues for the use of IPCC values for peat emissions.

Agency Response: The ARB emission factor of 95 gCO2e/ha/yr was developed from Page et al. (2011) in their review of studies on peat GHG emissions from palm oil plantations in Southeast Asia. These studies were conducted on deep, organic-rich peatlands with low mineral content typical of peatlands in Southeast Asia that have been converted to palm oil plantations. The GHG emissions estimated are representative of the average peatland emissions in the region. The Page et al. study has been peer reviewed and published in a respected scientific journal. ARB staff believes that this is the most appropriate emissions factor for peatlands for use in our lifecycle analysis of palm oil biodiesel. It should also be noted that the ARB emission factor included the pulse of emissions during the first years following drainage amortized over a 30 year period.

Furthermore, the ARB emission factor may still be a conservative representation of the net effect on GHG emissions from draining peat soils since it does not include emissions due to burning of drained peat during land clearing or via accidental fires. While such emissions are episodic and thus difficult to estimate, peat fires have been estimated to emit around 1,000 tCO_2/ha per event, with very large variability (Couwenberg et al., 2010). The ARB emission factor also does not consider emissions that may occur on inadvertently drained peatlands adjacent to drained palm oil plantations.

The studies reviewed by Page account for emissions from draining and compaction of peat soil prior to palm planting. The commenter has not provided detailed information to identify differences, if any, between the drain and compaction process in representative peat soils and the one cited in the comment.

614. Comment: **LCFS 63-5**

The comment questions the validity of the percentage of oil palm expansion in Malaysia and Indonesia that occurs on peatland.

Agency Response: ARB staff believes that the 33 percent value used for expansion into peatland is appropriate for the following reasons:

- The Edwards study accounted for expansion of land for palm plantations over the period 2003-2008, which matches reasonably well with the 2004-2010 time period considered for the iLUC analysis. In addition, the data was provided by the Malaysian Oil Palm Board, the trade group representing palm oil suppliers.

- The Hoojier paper concluded that greater than 50 percent of expansion was likely on peatland. However, ARB staff used a value of 33 percent as a conservative number to represent expansion on peatland.

- The analysis conducted by Harris et al. for the U.S. Environmental Protection Agency (U.S. EPA) estimated palm expansion through 2022 and does not represent the time period used by ARB staff in the iLUC analysis (i.e., 2004-2010). Utilizing projections for 2022 is therefore not representative of the predicted expansion into peatland in Malaysia and Indonesia for the period 2004-2010.

- Peatland conversion in Malaysia/Indonesia for the period 2005-2010 as reported in Table 2 of the comment is significantly higher than the estimates for such land conversion from the iLUC analysis. Therefore, it appears that the iLUC analysis may have under estimated peatland conversion. ARB staff will review this information and make appropriate revisions in the future.

615. Comment: **LCFS 63-6**

The commenter asserts that the model constraint that all future palm oil will come from Malaysia and Indonesia is not valid.

Agency Response: The modeling timeframe used in the analysis is for the period 2004-2010, and ARB staff used Food and Agriculture Organization of the United Nations (FAO) data for palm oil production and exports for this time period. The FAO data showed that close to 90 percent of palm oil was produced in Malaysia and Indonesia. Only these two countries produced surplus quantities of palm oil that have been exported beyond domestic consumption. All other countries that produced the remaining 10 percent of palm oil were not capable of exporting palm oil in quantities required to produce 400 million gallons of biodiesel.

The commenter cites Ghana, even with 336,000 hectares of palm plantation, is a net importer of palm oil to meet internal demand. Since the ARB analysis is for the time period 2004-2010, export of palm oil by other regions in the future is not applicable for the current analysis.

616. Comment: **LCFS 63-7**

The commenter asserts that the model constraint that all future palm oil will come from Malaysia and Indonesia is not valid.

Agency Response: In the Agro-Ecological Zone–Emissions Factor (AEZ-EF) model, biomass factors for crops are computed based on yield, harvest index (fraction of biomass removed in harvest), moisture content, and carbon fraction. This approach does not apply to Oil Palm whose fruit is harvested. Therefore, in the AEZ-EF sheet, cells that include biomass factors for Oil Palm are set to zero. Biomass factors for Oil Palm have been included in a separate area of the model (rows 69-70 of the Factors Tab in the AEZ-EF model.)

617. Comment: **LCFS 63-8**

The comment states that it is unclear from the model analysis what classification degraded forests or logged over forests would be given.

Agency Response: The model used by ARB staff does not include separate land categories for degraded or logged-over forests. This is because currently there are no data on these land categories (i.e., land rents and other economic data). When data becomes available, staff will consider the inclusion of such transitions into the GTAP modeling framework.

The efforts to create new secondary forests, recover original biodiversity, etc. are not related to the expansion of palm for the production of palm oil and not applicable to the current iLUC analysis. The commenter cites an article from Geoderma 149 (2009) pages 76-83, which concludes that grasslands (e.g., termed Imperata) resulting from destruction of forests by wildfire represent the final stage of land degradation and are not suitable for cultivation (or other useful and valuable purpose). This article does not provide data related to the conversion of grasslands to palm plantations. ARB staff acknowledges that efforts could be directed by governments in these regions to create new secondary forests, recover original biodiversity, etc. but is not applicable to the current analysis.

618. Comment: **LCFS 63-9**

The comment suggests that ARB staff use the commenter's number for peat conversion estimate for new oil palm estates rather than the current model values.

Agency Response: See responses to **LCFS 63-4** and **LCFS 63-5**. Based on responses to these two comments, the consideration of 20 percent peat conversion and the palm emissions factor value of 73 Mg CO_2/ha/yr is not appropriate. Accordingly, any adjustments to the iLUC value for palm oil biodiesel are not justified at this time.

This page intentionally left blank.

Comment letter code: 64-OP-LCFS-FBE

Commenter: Ted Kinesche

Affiliation: Fulcrum BioEnergy

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

64_OP_LCFS
_FBE

Fulcrum BIOENERGY

February 17, 2015

Clerk of the Board
Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: CARB Low Carbon Fuel Standard Re-Adoption

Dear Chairwoman Nichols and Honorable Board Members:

Fulcrum BioEnergy, Inc. ("Fulcrum") strongly supports the California Low Carbon Fuel Standard ("LCFS") and we appreciate the opportunity to provide comments to the California Air Resources Board ("CARB") regarding the implementation of this important policy.

Fulcrum BioEnergy Overview

Fulcrum is a leading developer and owner of low carbon fuel projects that convert post-recycled municipal solid waste ("MSW") into drop-in fuels such as syncrude, diesel and jet fuel. We are entering construction on our first commercial project – the Sierra BioFuels Plant ("Sierra") located near Reno, NV – that will convert approximately 200,000 tons of MSW into nearly 12 million gallons of low carbon fuels. Beyond Sierra, Fulcrum has already contracted for long-term supplies of MSW feedstock that supports the development of several more projects collectively capable of generating nearly 400 million gallons per year of low carbon fuels.

Fulcrum has the capability of producing at least three different fuels for sale into the transportation market. Fulcrum's syncrude is an excellent replacement for crude oil, which can be sold directly to petroleum refineries for further refining into diesel and gasoline. Fulcrum can also further refine its own syncrude to make either diesel or jet fuel. Both Fulcrum's diesel and jet fuels are "drop-in" fuels that meet already established ASTM standards for use in vehicles and aircraft, respectively.

Environmental Benefits of MSW-to-Fuels

Fulcrum's projects reduce greenhouse gas emissions on a lifecycle basis by more than 80% when compared to petroleum-based fuels. Fulcrum has carefully integrated its projects into the waste management hierarchy, such that we only utilize MSW that would otherwise be landfilled, after all available recycling and composting activities. Fulcrum further enhances recycling

fulcrum-bioenergy.com

4900 Hopyard Road, Suite 220 | Pleasanton, CA 94588 | 925.730.0150 PHONE | 925.730.0157 FAX

activities by recovering an additional ten percent of landfilled waste for recycling, which incrementally increases a community's recycling rates. Additionally, Fulcrum converts more than 50% of landfilled waste into low carbon fuels. Between its enhanced recycling activities and the conversion of landfilled MSW into low carbon fuels, Fulcrum will divert a significant portion of waste from landfills.

Moreover, Fulcrum's process does not compete with other waste conversion solutions, such as anaerobic digestion, which are complementary to Fulcrum's efforts because they target wet organics for conversion to biogas.

Credits for Producing Crudes Using Innovative Methods

Fulcrum welcomes CARB's creation of an Innovative Crude pathway that incentivizes the production and sale of lower carbon crudes into California. Fulcrum's projects produce a syncrude, which is an excellent replacement for crude oil and can be refined into transportation fuels at a conventional petroleum refinery. The production of syncrude from waste feedstocks such as post-recycled MSW has several key advantages. It leverages existing infrastructure, reduces the capital costs of emerging biorefineries, minimizes biorefinery emissions and displaces crude oil purchased by a refinery – ultimately reducing the amount of crude oil sold into California.

LCFS 64-1

In reviewing the Innovative Crude requirements in the Proposed Regulation Order, it appears that CARB has focused on several methods to produce conventional crude oil with lower carbon methods (e.g. solar, wind and carbon capture). While these methods have sound GHG benefits, Fulcrum respectfully asks that CARB be open to other forms of innovative crude production – particularly those that directly produce low carbon syncrude and displace actual crude oil. The LCFS program is unique in welcoming innovative and technology-neutral approaches to reducing the carbon intensity of the transportation sector and we hope that the same technology-neutral approach is applied to this section.

Refinery Investment Credit

Fulcrum sees significant opportunity to provide renewable feedstocks directly to a refinery for the production of CARBOB or diesel fuel. As described above, Fulcrum can produce a syncrude from post-recycled MSW feedstock that can be upgraded at a conventional petroleum refinery along with other crude oils. We welcome CARB's inclusion of these renewable feedstocks to generate credit under the Refinery Investment Credit provisions. However, we didn't understand the reason for the 10% minimum requirement to replace fossil based feedstocks. A typical refinery processes well in excess of 100,000 barrels per day and most advanced biofuel refineries will not produce 10,000 to 20,000 barrels of biofuel per day – which would be necessary to meet the minimum threshold for this standard. In fact, many of the advanced biofuel projects that will be built in the coming years will produce 1,000 to 5,000

LCFS 64-2

4900 Hopyard Road, Suite 220 | Pleasanton, CA 94588 | 925.730.0150 PHONE | 925.730.0157 FAX

barrels per day, well short of the proposed 10% displacement requirement. We encourage CARB to focus instead on the overall Carbon Intensity ("CI") benefit that such a renewable feedstock strategy provides the refinery under this Refinery Investment Credit provision, which would be consistent with how other projects are evaluated under this section. If the focus is instead on CI reduction, then this provision will encourage innovative ways to supply refineries with low carbon feedstocks that reduce the overall carbon intensity of a refineries' fuels – consistent with the intent of the LCFS. LCFS 64-2 cont.

In summary, Fulcrum strongly supports the re-adoption of the California LCFS and continues to work every day towards developing and building projects that will serve this important market. We thank CARB Board Members and Staff for their hard work and dedication in addressing GHG emissions in the transportation fuels sector. LCFS 64-3

Respectfully,

FULCRUM BIOENERGY, INC.

Ted Kniesche
Vice President, Business Development

4900 Hopyard Road, Suite 220 | Pleasanton, CA 94588 | 925.730.0150 PHONE | 925.730.0157 FAX

This page intentionally left blank.

64_OP_LCFS_FBE Responses

619. Comment: **LCFS 64-1**

The commenter recommends that technologies that produce low carbon syncrude be included under the innovative crude production method provision.

Agency Response: ARB staff believes that technologies that convert municipal solid waste to finished transportation fuels are most appropriately evaluated under the Method 2 application process for alternative fuels and not under the innovative crude provision, as the emissions benefits of such technologies are only captured through a complete well-to-wheels assessment. Staff encourages the commenter to explore the Method 2 process.

620. Comment: **LCFS 64-2**

The comment asserts that the 10 percent biofuel displacement threshold is too high and should be replaced with a carbon intensity reduction threshold.

Agency Response: See response to **LCFS 38-13**. ARB staff determined that renewable feedstocks are better handled under a Method 2A/2B pathway and thus have removed the renewable feedstock provision from the Refinery Investment Credit Provision.

621. Comment: **LCFS 64-3**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

This page intentionally left blank.

Comment letter code: 65-OP-LCFS-LCA

Commenter: Stefan Unnasch

Affiliation: Life Cycle Associates

The following letter was submitted to the LCFS Docket during the 45-day comment period.

This page intentionally left blank.

Life Cycle Associates

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

65_OP_LCFS_LCA

February 17, 2015

California Air Resources Board
Katrina Sideco
(916) 323-1082
ksideco@arb.ca.gov

Reference: **Electricity Mix in CA GREET**

Dear Ms. Sideco,

Life Cycle Associates would provide insight to the choice of electricity mix in CA_GREET. The choice of electricity mix affects the consumed power for fuel production facilities as well as exported power. Both input power and export power are treated symmetrically in the GREET model. Exported power is treated as a co-product using the substitution method.

The question of electricity mix is most important for fuel pathways using or exporting the most electricity. The pathways involving the most power and the amount of power used/exported are shown below.

Hydrogen, water electrolysis	+ 50 kWh/kg H_2
Electricity	+ 33 kWh/gasoline equivalent gallon
Cellulosic ethanol with power export	- 3 kWh/gal ethanol
Sugarcane ethanol with power export.	- 3 kWh/gal ethanol

These pathways use/export the most power of any fuel pathway. The export power from cellulosic ethanol and sugarcane ethanol represent 13.4% of the output product, while the power is 100% and 150% of the input for the electricity and hydrogen pathways. In contrast, the 0.55 kWh/gal of corn ethanol represents only 2.4% of the energy in this pathway. Consequently, understanding the environmental impact of the power in the above 4 pathways is of the highest priority.

Purpose of LCA

The objective of the LCA for the LCFS is to identify the impact of the change to the use of an alternative fuel on global emissions. ARB has embraced this objective in the analysis of indirect land use. The consequential impact of biofuel use reflects the net global impact of feedstock demand on the agricultural system. ARB calculates the marginal land use for each biofuel.

LCFS 65-1

Similarly, ARB has embraced the marginal approach in the estimation of emissions from alternative fuels, specifically electric vehicles (Unnasch 2001) and hydrogen vehicles (Unnasch, 2005). The analysis conducted as part of ARB fuel cycle studies and the California Hydrogen Highway Blueprint Plan concluded that the marginal resource for electric power corresponds to permanent and sustainable load growth. This concept has the following implications:

- Average emissions are not an appropriate indicator of future emissions
- Minute by minute dispatch does not predict permanent changes in resource mix
- Nuclear power is always base loaded and never on the margin
- Marginal power in California is best represented by a mix of new combined cycle natural gas power plants and non-fossil renewables that correspond to the Renewable Portfolio Standard Requirement.

This approach for marginal emissions was applied to the California Energy Commission's AB1007 Full Fuel Cycle Analysis (Unnasch, 2007), which resulted in the first GREET model used to represent California specific emission impacts. The inputs for this model provided that basis for CA_GREET 1.8b.

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

Marginal Resource Mix

The choice of marginal resource mix has remained challenging. For example the Midwest mix used on CA_GREET 1.8b was based on a Midwest mix without nuclear power. Unfortunately, the changes in the power market with the grown in natural gas is more complicated. ARB has chosen to use and average resource mix for all regions in the US and globally. This approach simplifies the selection of electric resource mix in that the method is well defined. Unfortunately the average resource approach does not accurately reflect the impact on the environment for the fuels with the greatest electric power impacts. These include EV's charged in California as well as cellulosic ethanol and sugarcane ethanol from Brazil. Since these fuel pathways use the most electric power, ARB should develop a marginal approach for these pathways. As more information is understood in other regions, a marginal resource mix could be applied as the analysis progresses.

LCFS 65-1 cont.

Table 1 shows the marginal resource mix for California and Brazil, which are the regions affected most by the power assumption. The prior CA_GREET1.8b assumption on marginal power is appropriate. Alternatively, ARB could revise the marginal assumption to correspond to the prevailing RPS requirement. Similarly, the Brazilian marginal mix can be calculated from the annual resource mix in Table 2. Clearly fossil fuels are growing on the margin and hydroelectric and nuclear power do not correspond to resource growth.

Table 1. Marginal resource mix for fuel pathways involving the most electric power.

Region:	CA Marginal	Brazil Marginal
Residual oil	0.0%	19.7%
Natural gas	78.7%	61.1%
Coal	0.0%	13.1%
Nuclear	0.0%	0.0%
Biomass	0.0%	0.0%
Other (renewables)	21.3%	6%

In the Brazilian situation, bagasse power is derived from the sugarcane ethanol plants, so this power that is being produced by the plant should not be treated as the power that is displaced by the ethanol plant.

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

Table 2. Generation Resources in Brazil

Type	Source	2009	2010	2011	2012	2013	2013 part. % (per source)	2013 part. % (per type)
Hydro	Hydro	390.988	403.290	428.333	415.342	390.992	68,6	68,6
Fossil	Natural gas	13.332	36.476	25.095	46.760	69.003	12,1	18,6
	Petroleum	12.724	14.216	12.239	16.214	22.090	3,9	
	Coal	5.429	6.992	6.485	8.422	14.801	2,6	
Biomass	Bagasse, wood and others	21.851	31.209	31.633	34.662	39.679	7,0	7,0
Nuclear	Uranium	12.957	14.523	15.659	16.038	14.640	2,6	2,6
Wind	Wind	1.238	2.177	2.705	5.050	6.576	1,2	1,2
Others	Recoveries, secondary gases	7.640	6.916	9.609	10.010	12.244	2,1	2,1
Total		466.158	515.799	531.758	552.498	570.025	100,0	100,0

LCFS 65-1 cont.

The choice of average power for California does not accurately affect the criteria pollutant impacts. Criteria pollutants shown in the Appendix include many generation resources that are not on the margin, providing the incorrect impression that EV and hydrogen vehicle emissions are higher than they actually are.

Therefore, the most appropriate resource mix for Brazil and California would be marginal resources defined in here.

Best Regards,

Stefan Unnasch

Stefan Unnasch
Managing Director
Life Cycle Associates, LLC

References

Unnasch, S., L. Browning and E. Kassoy (2001). Refinement of Selected Fuel-Cycle Emissions Analyses. Final Report, ARB Contract 98-338.

Unnasch, S., Kitowski, J., Tutt, E., Bartholomy, B., Blackburn, B., McCarthy, R., Modisette, D., (2005). Societal Benefits Topic Team Report, California 2010 Hydrogen Highway Network for Blueprint Plan. Air Resources Board, Tiax LLC.

Unnasch, S. Pont, J., (2007). Full Fuel Cycle Assessment: Well to Tank Energy Inputs, Emissions and Water Impacts. Tiax LLC, CEC.

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

Appendix

GHG Intensity for CA Average Mix

	Stationary Use: CAMX Mix			
	Total		Urban	
CA_GREET2_CA_MX	Feedstock	Fuel	Feedstock	Fuel
Total energy	143,163	1,923,707		
Fossil fuels	139,731	1,392,232		
Coal	1,590	220,376		
Natural gas	123,396	1,127,998		
Petroleum	14,745	43,858		
VOC	14.125	4.299	0.803	1.999
CO	40.182	72.748	3.632	23.402
NOx	54.401	102.557	4.561	25.927
PM10	2.860	12.759	0.058	1.074
PM2.5	1.134	10.152	0.050	0.997
SOx	16.294	100.468	0.486	2.076
CH_4	268.344	9.666		
N_2O	1.642	1.336		
CO_2	9,119	94,221		
CO_2 (w/ C in VOC & CO)	9,226	94,349		
GHGs	16,424	94,988		
gCO_2e/MJ	15.57	90.03		

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

GHG Intensity for CA Marginal Mix

CA_GREET2.0_CA_Marginal	Stationary Use: California Marginal Mix			
	Total		Urban	
	Feedstock	Fuel	Feedstock	Fuel
Total energy	175,155	1,852,733		
Fossil fuels	174,260	1,624,926		
Coal	3	0		
Natural gas	167,446	1,624,925		
Petroleum	6,810	0		
VOC	17.054	1.556	0.988	0.669
CO	53.437	29.558	4.788	12.710
NOx	66.803	35.326	5.702	15.190
PM10	0.786	0.277	0.022	0.119
PM2.5	0.725	0.277	0.020	0.119
SOx	19.143	0.991	0.264	0.426
CH4	330.951	5.158		
N2O	2.320	0.194		
CO2	11,003	97,479		
CO2 (w/ C in VOC & CO)	11,140	97,530		
GHGs	20,106	97,717		
	19.06	92.62		

65_OP_LCFS_LCA Responses

622. Comment: **LCFS 65-1**

The comment questions using the average electricity resources mixes rather than the marginal resource mix.

Agency Response: Please see the response to comment **LCFS 18-3.**

This page intentionally left blank.

B. COMMENTS SUBMITTED AT THE FEBRUARY 19, 2015 HEARING

Twelve comment letters were received during the February 19 board hearing. Each comment letter is reproduced below with responses following. Comment letter **12_B_LCFS_G**E is 561 pages long and will be reproduced in discrete sections with the responses following each section for readability.

This page intentionally left blank.

Comment letter code: 1-B-LCFS-Unica

Commenter: Leticia Phillips

Affiliation: UNICA

The following letter was submitted to the LCFS Docket during the First Board Hearing.

This page intentionally left blank.

unica

BRAZILIAN SUGARCANE INDUSTRY ASSOCIATION

ETHANOL • SUGAR • ELECTRICITY

15 Leticia

1_B_LCFS _UNICA

February 17, 2015

VIA ELECTRONIC MAIL

John Courtis
Manager, Alternative Fuels Section
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: UNICA's Comments on California Air Resources Board's (CARB) Staff Report: Initial Statement of Reasons.

Dear Mr. Courtis:

The Brazilian Sugarcane Industry Association ("UNICA") appreciates the opportunity to provide comments on the California Air Resources Board's CARB) Staff Report: Initial Statement of Reasons, which was posted for comments on December 31st, 2014.

UNICA is the largest representative of Brazil's sugar, ethanol, and bioelectricity producers. Its members are responsible for more than 50% of Brazil's ethanol production and 60% of Brazil's sugar production. UNICA's priorities include serving as a source for credible scientific data about the competitiveness and sustainability of sugarcane biofuels. UNICA also works to encourage the continuous advancement of sustainability throughout the sugarcane industry and to promote ethanol as a clean, reliable alternative to fossil fuels. Sugarcane ethanol production uses less than 1.5% of Brazil's arable land and reduces lifecycle greenhouse gas (GHG) emissions by up to 90% on average, compared to conventional gasoline. Thanks to our innovative use of ethanol in transportation and biomass for power cogeneration, sugarcane is now a leading source of renewable energy in Brazil, representing over 15% of the country's total energy needs. The industry is expanding existing production of other renewable products, and with the help of innovative companies here in the United States and elsewhere, is beginning to offer bio-based hydrocarbons to replace carbon-intensive fossil fuels and chemicals.

UNICA recognizes the amount of work CARB staff has done throughout 2014 culminating with the issuance of this report, and we continue to support your work LCFS B1-1

Brazilian Sugarcane Industry Association (UNICA) • 1156 15th Street, NW Suite 800 • Washington, DC 20005
Phone +1 (202) 506-5299 • Fax +1 (202) 747-5836 • washington@unica.com.br • www.unica.com.br/EN

improving the Low Carbon Fuel Standard by requesting input and welcoming the cooperation of stakeholders like UNICA. For the purpose of this letter, we would like to comment on two specific appendix of the study: A) Appendix C Comparison of CA-GREET 1.8B, GREET1 2013, and CA-GREET 2.0; and B) Appendix I Detailed Analysis for Indirect Land Use Change. LCFS B1-1 cont.

A) Appendix C: Comparison of CA-GREET 1.8B, GREET1 2013

We were disappointed to see CARB staff's decision to opt for using average electricity mix instead of the marginal mix in Brazil's sugarcane ethanol production for a few reasons. As per your report, the reason for this change is to provide better accuracy for power plants in the U.S. to find their region-specific electricity resource mix and calculate the carbon intensity (CI) of their electricity use. In order to do that, CARB adopted the U.S. Environmental Protection Agency's (EPA) Emissions & Generation Resource Integrated Database (eGRID), 9th edition Version 1.0 for the different regions in the U.S., and included Brazil as the only international eGRID region (Region 29). The more we analyze this proposal, the more it does not make sense for Brazilian industry. Perhaps the average mix approach may make sense for U.S. power plants because the plants take energy from the grid, but this situation is very different compared to the Brazilian model. During the harvest season, sugarcane mills in Brazil are 100% self-sufficient in electricity, so mills consume nothing from the general electricity grid. On the contrary, the electricity unused by the mills is sold into the national grid, contributing as a clean source of power to the grid by displacing the marginal increase of dirtier sources. According to the Brazilian Agriculture Ministry, in December 2013 there were 389 sugarcane mills in Brazil, all of them producing energy for self-consumption and we estimate that about 170 of these mills sell excess electricity into the grid. LCFS B1-2

The Brazilian electrical system (National Interconnected System - SIN) is 98.3% interlinked, so virtually all the production and transmission of electricity in Brazil happens on one main grid closely monitored by the National Electric System Operator (ONS), a federal agency responsible for coordinating and controlling operation of the electricity generation and transmission facilities in the SIN under the supervision and regulation of the National Electric Energy Agency (ANEEL). This unique system adopted by the country creates certainty as to what sources contribute to the marginal generation of power. Sugarcane biomass-based electricity in Brazil receives a fixed income to deliver a "package" of energy per year to the grid. Sugarcane biomass receives this fixed income for the energy it produces and declares its Unit Variable Cost (UVC) equal to zero, since co-generation of sugarcane biomass electricity occurs in order to meet the demand of the sugar and ethanol production in the mill. Wind and solar sources also have a UVC equal to zero. In this way, all the electrical energy these sources produce are made available to the national grid (since the government already paid a fixed income for it).

The process is different for thermo-gas sources. On top of the fixed income they receive to be on stand by, their UVC is greater then zero, meaning if and when the ONS utilizes them, they receive payment for their fuel cost and the operation. In fact, since sugarcane biomass is classified with a unit variable cost equal to zero, the ONS adopts the so-called merit order, where thermal plants from lower to higher operating costs are dispatched in order to meet demand. The ones with lower UVC are the first to be called to meet domestic demand. Since biomass plants have unit variable cost equal to zero, when available (during the sugarcane harvest season), they are the first to be dispached to the system, without the need of an order from the ONS. Differently from sources like coal, diesel, and natural gas, the generation of energy of sugarcane biomass sources is controlled and dictated by the industrial process itself instead of by order of the national operator.

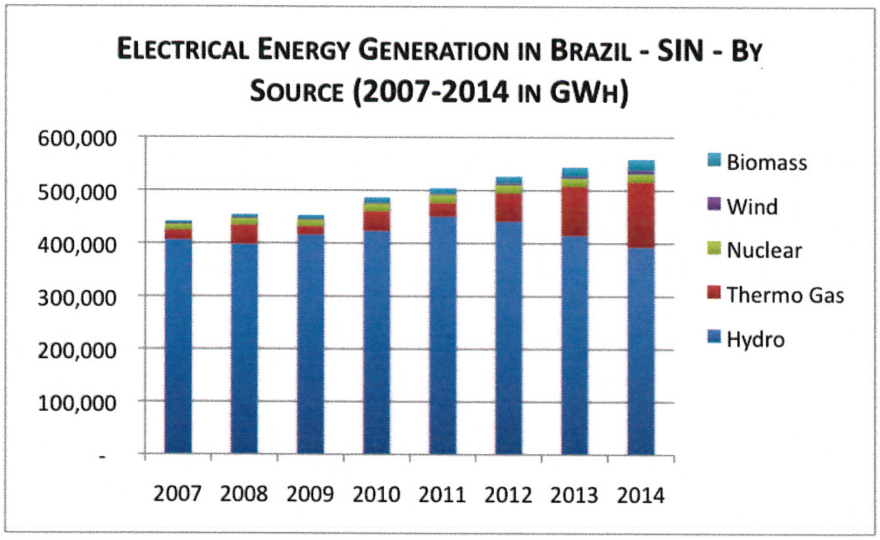
Another important point to remember is during the dry season, when Brazil's reservoirs are at their lowest level, the system is heavily relient on thermo-gas sources, in order to guarantee the security of the system. This is when sugarcane harvesting season and co-generation is at peak, so given the lower operational cost of biomass electricity, this source substitutes for natural gas at the margin.

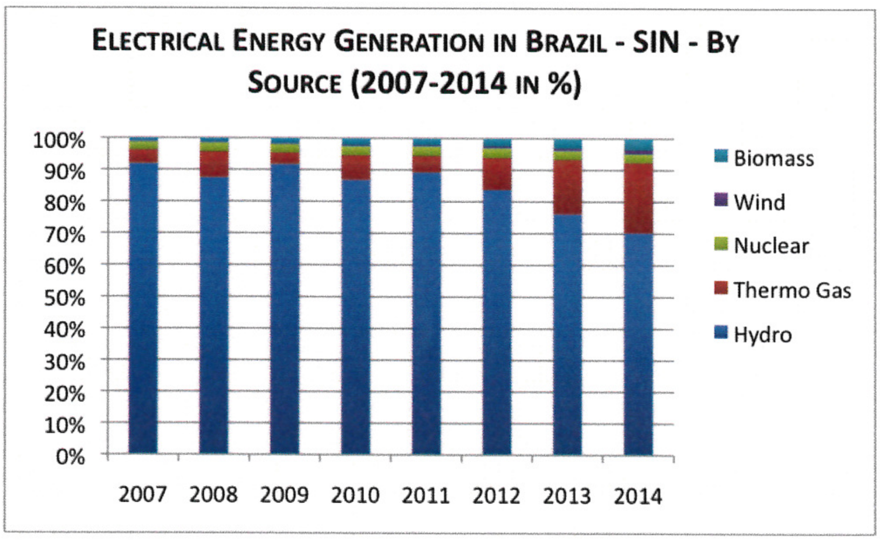
LCFS B1-2 cont.

The graphs below show from 2007 to 2014, the share of hydropower in Brazil decreased significantly, mainly due to droughts that have significantly impacted reservoirs and due to the reduction of the multiannual regulating capacity of the hydroelectric reservoirs, since the most recent hydropower projects in Brazil are composed of "thread-of-water" mills, mills that are only able to hold water for a few hours or days.[1] According to the Brazilian Ministry of Mines and Energy's (MME) 10-year Energy Expansion Plan (PDE 2023), this decreasing trend is predicted to continue, and Brazil has relied (and will rely) especially heavily on thermo-gas sources to provide the marginal power it needs, and to guarantee the security of the electrical system in the country[2]. Since sugarcane mills operate on a fixed revenue basis described above with zero Unit Variable Cost (UVC), we know bagasse-burning electricity cogeneration goes straight into the grid, to substitute the marginal increase of energy. If we look at the marginal sources that have increased over the last few years, we see natural gas has the largest share in the system. Given the operational cost differential between biomass and thermo-gas sources, the seasonality of hydro and biomass energy generation and the fact that hydro mills have a decreased capacity of holding water, we know bagasse electricity cogeneration is displacing fossil fuel sources of power in Brazil, in the daily operation system.

[1] The Brazilian Ministry of Mines and Energy published in 2014 the Brazil 10-year Energy Expansion 2023 Plan (Plano Decenal de Expansão de Energia 2023 –PDE) , available in Portuguese at: http://bit.ly/1F5IlaW, for more information on reservoir capacity see pages 84 and 85.

[2] PDE 2023 page 396.





Notes: Source (Hydro, Wind, Nuclear and Thermo Gas): ONS 2015 available online at http://bit.ly/1zPCNDr
Biomass from 2007-2009: Data from the National Energy Balance for corresponding year – Ministry of Mines and Energy.
Biomass from 2010-2014: Source CCEE (2015) available online at http://bit.ly/1EhnDq0

We urge CARB to continue to adopt the marginal source of electricity for sugarcane pathways. By adopting energy average mix, CARB is not only taking the wrong approach, but is also turning its back on one of the greatest environmental benefits of sugarcane pathways. There is no doubt in our minds that such a position by CARB would discourage carbon mitigation behavior in Brazil and elsewhere.

LCFS B1-2 cont.

Another very important point for consideration is that CARB adopted the U.S. Energy Information Administration's (EIA) data for Brazil's 2011 electricity generation, while the government of Brazil publically displays its data on electricity generation by fuel type on a very up-to-date fashion. As the graphs above show, Brazil's energy matrix includes significantly less hydro today than in 2011, and we believe this decreasing trend will prevail for years to come. The current reality for renewable and fossil sources of energy in the Brazilian energy matrix is very different from the one pictured by EIA, and regardless of the position CARB adopts, this average mix of electricity data should to be updated with the most current numbers available. LCFS B1-2 cont.

B) Appendix I: Detailed Analysis for Indirect Land Use Change

We were glad to see the iLUC penalty number reduced for sugarcane ethanol, as we believe this reflects the effort of CARB staff throughout the years in improving iLUC modeling under the LCFS. We believe some changes adopted by staff, like the new land supply structure for GTAP ("Approach B"), allow us to improve the iLUC analysis by identifying with much more accuracy how pastures and forests respond to cropland expansion, an important improvement for regions with large stocks of pastureland and forests like Brazil.

Despite these positive changes, UNICA would like to once again stress the urgent need for CARB staff to capture crop production expansion based on double-crop systems (soy-corn and soy-cotton, in Brazil's case). During the September 29, 2014 seminar, CARB staff indicated crop and region-specific YPE is the possible solution for representing double cropping within GTAP, but once again CARB ran scenarios of equal values for the different regions of GTAP. We sympathize with CARB staff on the difficulty finding accurate double-cropping data for all regions of the world, however, Brazil has compiled this data for some time and UNICA has provided this information to CARB in previous correspondences. As mentioned in our October 15, 2014 letter, UNICA has run scenarios using a YPE value of 0.35 with encouraging results: less area allocated to crops (due to higher yields) and higher share of cropland expansion in Brazil (cropland expansion is a consequence of the shock on ethanol production). UNICA urges CARB to set a YPE value of 0.35 for soy and corn in Brazil in order to capture the effects of double cropping and improve iLUC analysis even further. We maintain that CARB needs to incorporate this tropical land-saving practice occurring in Brazil in its iLUC analysis. We remain at staff's disposal to provide available data and make necessary introductions to Brazil's government and academia for better explanation and confirmation of this phenomenon to CARB. LCFS B1-3

We appreciate the opportunity to submit these comments, and as we have done in the past, will continue to engage with CARB staff to provide additional input and feedback on the LCFS. We are pleased to see CARB continuing to improve the LCFS and we are glad to be part of this process by cooperating with the agency and serving as a LCFS B1-4 credible source of information about the Brazilian biofuels industry. We remain committed to continue our collaboration with CARB and we look forward to the opportunity to discuss these comments in detail with you. LCFS B1-4 cont.

Respectfully Submitted,

Elizabeth Farina
President & CEO

Leticia Phillips
Representative – North America

Electrical Energy Generation _Brazil - National Interlinked System, by Source, 2007-2014 (in GWh)

Fontes	2007	2008	2009	2010	2011	2012	2013	2014
Hydro	406,084	397,702	415,686	422,893	450,237	441,178	414,556	392,585
Thermo-Gas	18,669	36,489	16,307	37,497	25,982	53,405	93,104	123,621
Thermo-Nuclear	12,307	14,006	12,957	14,515	15,659	16,038	15,450	15,378
Wind	559	557	712	1,472	1,902	3,192	3,957	6,561
Thermo-Biomass	4,008	5,523	7,337	10,414	10,744	12,953	17,148	20,732
Total	441,627	454,277	452,999	486,791	504,524	526,767	544,214	558,877

Obs.:

De 2007 a 2014 para hídrica, térmica convencional, térmica nuclear e eólica: fonte ONS (2015). Disponível online em: http://www.ons.org.br/historico/g

De 2010 a 2014 para térmica a biomassa: fonte CCEE (2015). Disponível online em: http://www.ccee.org.br/portal/faces/pages_publico/quem-somos/in

De 2007 a 2009 para térmica a biomassa: dados obtidos a partir de Balanços Energéticos Nacional - Ministério de Minas e Energia.

Dados de geração das térmicas a biomassa incluem bagaço de cana e outras biomassas. Contabiliza apenas a geração ofertada para o Sistema Interligadc

Electrical Energy Generation _Brazil - National Interlinked System, by Source, 2007-2014 (in %)

Fontes	2007	2008	2009	2010	2011	2012	2013	2014
Hydro	92%	88%	92%	87%	89%	84%	76%	70%
Thermo-Gas	4%	8%	4%	8%	5%	10%	17%	22%
Thermo-Nuclear	3%	3%	3%	3%	3%	3%	3%	3%
Wind	0%	0%	0%	0%	0%	1%	1%	1%
Thermo-Biomass	1%	1%	2%	2%	2%	2%	3%	4%
Total	100%	100%	100%	100%	100%	100%	100%	100%

eracao_energia.aspx
formacoesmercado/info_mercado?_afrLoop=418725877334790

› Nacional.

1_B_LCFS_Unica Responses

623. Comment: **LCFS B1-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

624. Comment: **LCFS B1-2**

The comment urges ARB staff to use the marginal electricity mix when modeling Brazil's sugarcane ethanol production.

Agency Response: With regards to the comment on the incorrect mix of electrical generating assets specified in the draft CA-GREETv2.0 life cycle analysis model, ARB staff concurs with the commenter that the proposed mix had incorrectly grouped several fossil-fueled generating resources with natural gas generation. The table as proposed would have resulted in an applicant using the draft CA-GREETv2.0 model underestimating the GHG impacts as a result of grid-based electrical energy use applicable to a Brazilian fuel pathway. Conversely, the applicant would have also received a lower co-product credit for displacing surplus cogenerated electricity exported to the public electrical grid.

A 15-day change is based on data provided in the annual Brazilian Energy Balance[53] prepared by the Ministry of Mines and Energy, Government of Brazil. Staff thanks the applicant for sharing the average Brazilian mix data.

[53] The average portfolio of electrical generating assets is based upon the Brazilian Energy Balance for years 2010-2012, published by the Empresa de Pesquisa Energetica (EPE) agency of the Ministry of Mines and Energy (http://www.mme.gov.br).

15-day Change to the Average Electrical Generation Mix for Brazil

Electric Generation Mixes: Data Table for Use in GREET (From Annual Energy Outlook 2013)	Brazilian Mix Stationary
Residual oil	3.4%
Natural gas	7.9%
Coal	1.9%
Nuclear power	2.6%
Biomass	7.0%

With respect to the question of marginal vs. average grid emission assumptions, please see response to comment **LCFS 18-3**.

625. Comment: **LCFS B1-3**

The comment requests that ARB staff set a preferred YPE value for soy and corn in Brazil in order to capture the effects of double cropping and improve iLUC analysis.

Agency Response: While ARB staff recognizes that double cropping occurs in Brazil, the structure of the Global Trade Analysis Project (GTAP) model does not allow explicit modeling of double cropping effects. When staff presented the GTAP model with disaggregated Yield Price Elasticity (YPE) by crop and region, it was designed to facilitate the use of crop and region-specific values. However, lack of data did not allow the use of specific values for YPE by crop and region. Academics at Purdue University who developed the GTAP model were also not in favor of using region-specific values until detailed data for each region and crop was available to conduct comprehensive testing of model responses. Given the absence of data, staff did not utilize the crop and region-specific YPE values for the analysis.

Lacking data for all crops and regions, ARB staff used the same value of YPE for all regions and crops for each scenario analysis. The scenario runs used by staff utilized a range of likely values for critical parameters based on literature or expert judgement. A value of 0.35, as suggested by the commenter, was in fact used as one of the values for YPE in the scenario analysis conducted by staff. When region-specific cropping data becomes available for various regions of the world, staff will evaluate the applicability of using these values to test model response. See response to **LCFS 46-14**.

626. Comment: **LCFS B1-4**

The commenter thanks ARB and offers to continue assisting by providing information.

Agency Response: ARB staff appreciates the support.

This page intentionally left blank.

Comment letter code: 2-B-LCFS-Sutherland

Commenter: Susan Lafferty

Affiliation: Sutherland

The following letter was submitted to the LCFS Docket during the First Board Hearing.

This page intentionally left blank.

15 2_B_LCFS _SUTHERLAND

Susan Lafferty

SUTHERLAND

SUTHERLAND ASBILL & BRENNAN LLP
700 Sixth Street, NW, Suite 700
Washington, DC 20001-3980
202.383.0100 Fax 202.637.3593
www.sutherland.com

SUSAN G. LAFFERTY
DIRECT LINE: 202.383.0168
E-mail: susan.lafferty@sutherland.com

February 18, 2015

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, California 95811

Re: Comments on the Re-adoption of the Low Carbon Fuel Standard

Dear Madams and Sirs:

We appreciate this opportunity to comment on the Air Resources Board's ("ARB") proposed re-adoption of and amendments to the Low Carbon Fuel Standard ("LCFS").

Sutherland Asbill & Brennan LLP ("Sutherland") represents various importing, blending, and trading companies in matters related to ARB's LCFS. Among Sutherland's clients are domestic trading companies, fuel suppliers, renewable fuel producers, importers, exporters as well as LCFS credit traders and owners. Many of these companies have participated actively in the regulatory and policy development process underlying ARB's LCFS.

We would like to express our concern over the proposed new requirement in section 95491(c) of the LCFS that would require all product transfer documents ("PTDs") to contain Environmental Protection Agency ("EPA") company and facility identification numbers of the fuel producer as registered under the Renewable Fuel Standard and other EPA fuel regulatory programs.

While requiring this information in PTDs for transfers of biofuels may be reasonable given the diversity of pathways, feedstock, and carbon intensities for such fuels, we believe that the burdens and costs of requiring such information on PTDs for standard carbon intensity ("CI") CARBOB and diesel transfers outweigh the benefits that this requirement would afford.

LCFS B2-1

This requirement would eliminate the possibility of creating a standard PTD for CARBOB and diesel transfers, because each different party transferring such products would have to create its own PTD to provide for its specific company or facility identification numbers. Standardized PTDs for gasoline and diesel are the industry standard at this time, and the time and paperwork necessary to meet this proposed requirement would be substantial.

While providing the specific identification numbers on PTDs for transfers of biofuels may be useful to assist in distinguishing biofuels based on their varying pathways, feedstock, and CIs, this designation for CARBOB and diesel with standard pathways, feedstock, and CIs would provide no additional benefit. Standard gasoline and diesel can be tested so as to ensure that it conforms to applicable ASTM standards and thereby has the standardized CI value. Requiring identification numbers would disrupt automated tracking and inventory systems, resulting in the potential for issues with compliance and tracking the chain of title. Accordingly, requiring facility and company identification numbers on each PTD for standard CI CARBOB and diesel would be burdensome and at the same time would inure few regulatory benefits or value. Furthermore, there are substantially more transfers of CARBOB and diesel than of biofuels, such that this requirement would have a disproportionate impact on CARBOB and diesel transfers.

LCFS B2-1 cont.

We are available to answer any questions that ARB may have on these comments.

Respectfully submitted,

Susan Lafferty (SW)

Susan G. Lafferty
David M. McCullough

2_B_LCFS_Sutherland Responses

627. Comment: **LCFS B2-1**

The commenter requests that the requirement for all product transfer documents to contain EPA company and facility identification numbers of the fuel producer for CARBOB and CARB diesel be eliminated.

Agency Response: ARB staff acknowledges the recommendation and made the necessary regulation amendments as 15-day changes. Staff will propose a revision that will exclude recording U.S. Environmental Protection Agency (U.S. EPA) company and facility identification on product transfer documents (PTDS) for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) and ultra-low sulfur diesel (ULSD) transfers.

This page intentionally left blank.

Comment letter code: 3-B-LCFS-Poet

Commenter: Thomas Darlington

Affiliation: Poet

The following letter was submitted to the LCFS Docket during the First Board Hearing.

This page intentionally left blank.

Thoma

3_B_LCFS
_POET

Status of Recommended Items

Category	Recommendation	Adopted	Ignored	Future
GTAP	Revise model land supply structure	X		
	Drop the lower price-yield values		x	x
	Include multi-cropping			x
	Include idle/fallow land			x
	Include cropland/pasture from other regions			?
AEZ-EF	Compare with CCLUB		x	?
Other Indirect	Include paddy rice and livestock effects			x

LCFS B3-1

3_B_LCFS_POET Responses

628. Comment: **LCFS B3-1**

The comment is a table that lists the commenter's recommended changes and the status of each suggested change.

Agency Response: See response to **LCFS 8-1 and LCFS 8-9** for a discussion of price-yield values, **LCFS 8-5, LCFS 8-9, LCFS 8-10, LCFS 46-108, LCFS 46-83, LCFS 46-102, and LCFS 46-14** for a discussion of multi-cropping and fallow land, **LCFS 42-16 and LCFS 46-82,** for a discussion of paddy rice and livestock, and **LCFS 46-16** for a discussion of CCLUB.

This page intentionally left blank.

Comment letter code: 4-B-LCFS-CU

Commenter: Shannon Baker-Bransletter

Affiliation: Consumers Union & Consumer

The following letter was submitted to the LCFS Docket during the First Board Hearing.

This page intentionally left blank.

4_B_LCFS_CU

15-2-4

Shannon Baker-Branstetter

ConsumerReports
TRUST LIVES HERE

ConsumersUnion
POLICY & ACTION FROM CONSUMER REPORTS

Written comments
Shannon Baker-Branstetter
Policy Counsel
Consumers Union, Advocacy Arm of Consumer Reports

To the California Air Resources Board

At the Public Hearing to Consider
California's Low Carbon Fuel Standard
February 19, 2015

Dear Chairman Nichols and Members of the Board:

Thank you for the opportunity to present Consumers Union's views on California's Low Carbon Fuel Standard (LCFS). We strongly support reauthorization of the LCFS due to its benefits to California's citizens, economy, and environment.

Since our inception in 1936, auto safety and value have been a paramount concern. Consumer Reports tests about 75 new vehicles every year at our test track, where we assess such attributes as fuel economy, ownership costs, reliability, safety, and performance. We do not accept outside advertising, and we have more than 8 million subscribers to all our products and services.

As a national consumer organization with subscribers and activists in every state, we care deeply about the cost of fuel to power our vehicles, and actively promote measures that provide consumers with cleaner, more efficient choices. Working towards this goal, we have supported federal and state fuel economy and greenhouse gas (GHG) emissions standards for vehicles, as well as state initiatives to enhance customer choice for vehicles and fuels.

LCFS B4-1

The California Air Resources Board (CARB) has been successfully implementing the LCFS since it first issued proposed regulations in 2009. CARB's efforts have stimulated the production of alternative fuels. This has increased consumer choice at the pump, and decreased GHG emissions across the state.

Oil prices are volatile. While today gas prices are dramatically low, all forecasts indicate that they will increase again soon. When prices are too low, production slows, demand and supply sync up, and prices increase again. We also recognize that depending on unconventional sources for oil, where production costs are much larger (e.g. hydraulic fracturing and horizontal drilling), will drive prices upward.

So what is the best long-term strategy to hedge our transportation bets and lessen uncertainty at the pump? In two words: competition and diversification. Introducing competition from cleaner fuels will encourage innovation and exert downward pressure on gasoline prices. Diversifying the fuel supply both decreases demand for oil and gives consumers more transportation fuel choices, which are especially valuable when oil prices rise. By increasing consumer choice, the LCFS has helped increase the elasticity of demand, providing protection from fuel price increases.

It is more important now than ever to prepare for our long-term energy future. We don't have to wait for oil prices to go up again to invest in clean fuel technologies. While improvements are being made, oil's near monopoly over transportation infrastructure stymies investment in alternative, and competing, products. The LCFS helps diversify transportation fuels and foster a market for clean fuels by providing greater certainty for bringing these alternatives to market.

LCFS B4-1 cont.

Finally, programs such as LCFS bring numerous other benefits. Burning less fuel, compounded by that fuel being cleaner, improves air quality and progresses public health. These enhancements lead to fewer consumer expenses on health care and missed work days as well.

Consumers Union believes the LCFS will continue to boost fuel choice, incentivize innovation, and decrease consumer costs in the long run. We thank you for your time and support and urge the Board to move forward with this important program.

Sincerely,

Shannon M. Baker-Branstetter

Shannon Baker-Branstetter
Policy Counsel, Consumers Union

4_B_LCFS_CU Responses

629. Comment: **LCFS B4-1**

The comment supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

This page intentionally left blank.

Comment letter code: 5-B-LCFS-Alon

Commenter: Gary Grimes

Affiliation: ALON USA

The following letter was submitted to the LCFS Docket during the First Board Hearing.

This page intentionally left blank.

5_B_LCFS _ALON

Gary Grimes
15-2-4

ALON USA

Hand Delivered at Board Meeting

February 19, 2015

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Comments on the LCLE Provisions in the Proposed LCFS Regulation

Alon USA Energy (Alon) respectfully submits these comments on the proposed regulatory provisions for the readoption of California's Low Carbon Fuel Standard (LCFS or regulation) for Low Complexity – Low Energy Use Refiners (LCLE Refiners). Alon and the Board have been discussing the concept of a LCLE refiner provision since 2011. **Alon strongly supports the LCLE concept as the policy and technical basis for the provision are sound.** But Alon requests ARB also ensure its language includes the entire population of smaller, lower complexity, lower CI refineries located in California for which the policy was intended.

The LCLE provision is an important policy acknowledgment by the Board that there are refineries in California that produce transportation fuels while consuming substantially less energy per finished gallon. These refineries are very limited in numbers, have historically been acknowledged by the regulators that they operate at a market disadvantage, and are by their very design smaller and less complex. Alon owns three such refineries, including one in Bakersfield that seems to be forgotten in this regulatory process. Alon strongly supports the LCLE as policy position, but we have grave concerns over its proposed implementation by staff, specifically the complete omission, or mis-categorization of our Kern County facility.

Though Alon's Bakersfield refinery is currently operating in a very limited mode, and hasn't been in full operation since January 2009, Alon is actively working to bring production back to 2008 levels. The Kern County Board of supervisors have approved an Environmental Impact Report to allow Alon to reconfigure the Refinery and Alon is beginning the engineering work. The impacts of the LCFS and the potential mitigating effects of the LCLE refiner provisions are significant economic considerations for the facility.

Because the CI of the Bakersfield facility is substantially lower than the average California refinery, when operating, the fuels produced by the facility would save approximately 350,000 metric tons of GHG emissions annually over what would otherwise be emitted by an average in-state refinery. The question ARB needs to be asking is "Do we want to encourage or discourage lower CI fuel production in California?". Establishing an appropriate LCLE eligibly criteria is critical to answering this question. This includes addressing LCLE status for the Bakersfield facility. As Attachment A shows, the Bakersfield refinery is most certainly NOT in the group of California's larger, more complex refineries. LCFS B5-1

The Board has an opportunity now to make the LCFS's LCLE provisions work for all refineries in California. Alon cannot wait multiple years for the next scheduled LCFS revision with only the possibility that CARB will amend the LCLE provision. The regulation needs to be adjusted prior to finalizing this package. A summary of Alon's position is a follows:

- Alon supports inclusion of a Low Complexity – Low Energy Use Refinery provision;
- Alon supports the staff proposal of a 5 gCO2e/MJ adjustment, for both gasoline and diesel, at the reporting tool level;
- Alon recommends eligibility metrics for the LCLE refinery category to be at 7 million mmbtu/year and 7 Modified Nelson Index.

Inclusion of the LCLE Refiner provision correctly recognizes that the carbon intensity (CI) associated with the refining portion of a California's fuels is not uniform. Along with other specific refiners, the Bakersfield facility is lower in complexity and energy input than the majority of the in-state fuel producing facilities. The challenge over these past few years has been how to define these separate groups in a manner that is publicly transparent, technically defensible, and provides the necessary eligibility "bright line" between the two. The issue was how to define the eligibility metrics, but it has never been in question that Bakersfield's refinery CI will be significantly lower than the statewide average.

LCFS B5-1 cont.

Alon has demonstrated that the CI of the Bakersfield facility is very low for gasoline and diesel production. This is the metric that should matter the most in the LCFS, the fact that the facility is currently not in full operation, should not impact the eligibility criteria *that will be in effect when the facility comes back into more normal operations.* The fuels produced in Bakersfield will have a lower carbon intensity than the average of the larger, more complex refiners in the state, therefore inclusion into the LCLE category is consistent with the underlying policy and excluding the facility is inconsistent and would lead to increased GHG emissions associated with fuel produced in California.

The proposed eligibility metrics are Total Annual Energy Use and a Modified Nelson Complexity Index. Alon supports the use of these metrics, but rejects the notion that the proposed eligibility levels of 5 million MMBTU/year and a modified Nelson Index complexity below 5 are the right level. This "5/5" level isn't reflective of the entire category of refineries that the LCLE policy is trying to recognize. Alon has been and continues to recommend an eligibility criteria of "7/7". This recommended amendment would not have any ripple impacts throughout the remaining LCFS language, it truly is a stand-alone change. Additionally, this modification would not impact any other refinery in the state, larger or smaller than Alon Bakersfield.

Alon recommends the following actual language amendments:

§ 95481. Definitions and Acronyms.

(55) "Low-Complexity/Low-Energy-Use Refinery" means a refinery that meets both of the following criteria:

(A) A Modified Nelson Complexity Score equal to or less than ~~5~~ 7 as calculated in section 95489(e)(1)(A).

(B) Total annual energy use equal to or less than ~~5~~ 7 million MMBtu as calculated in section 95489(e)(1)(B).

LCFS B5-1 cont.

In summary, the proposed LCLE provisions are technically sound, and convey the right policy, but the LCLE definition (eligibility threshold levels) of "5/5" level isn't reflective of the complete category of refineries that fit its important policy goal. Alon has been and continues to recommend an eligibility criterion of "7/7". Such a level would not allow any existing California refiners to be eligible for the LCLE provisions, but would recognize Alon's lower CI values, assist the facility in producing lower CI fuels while advancing the goals of the LCFS.

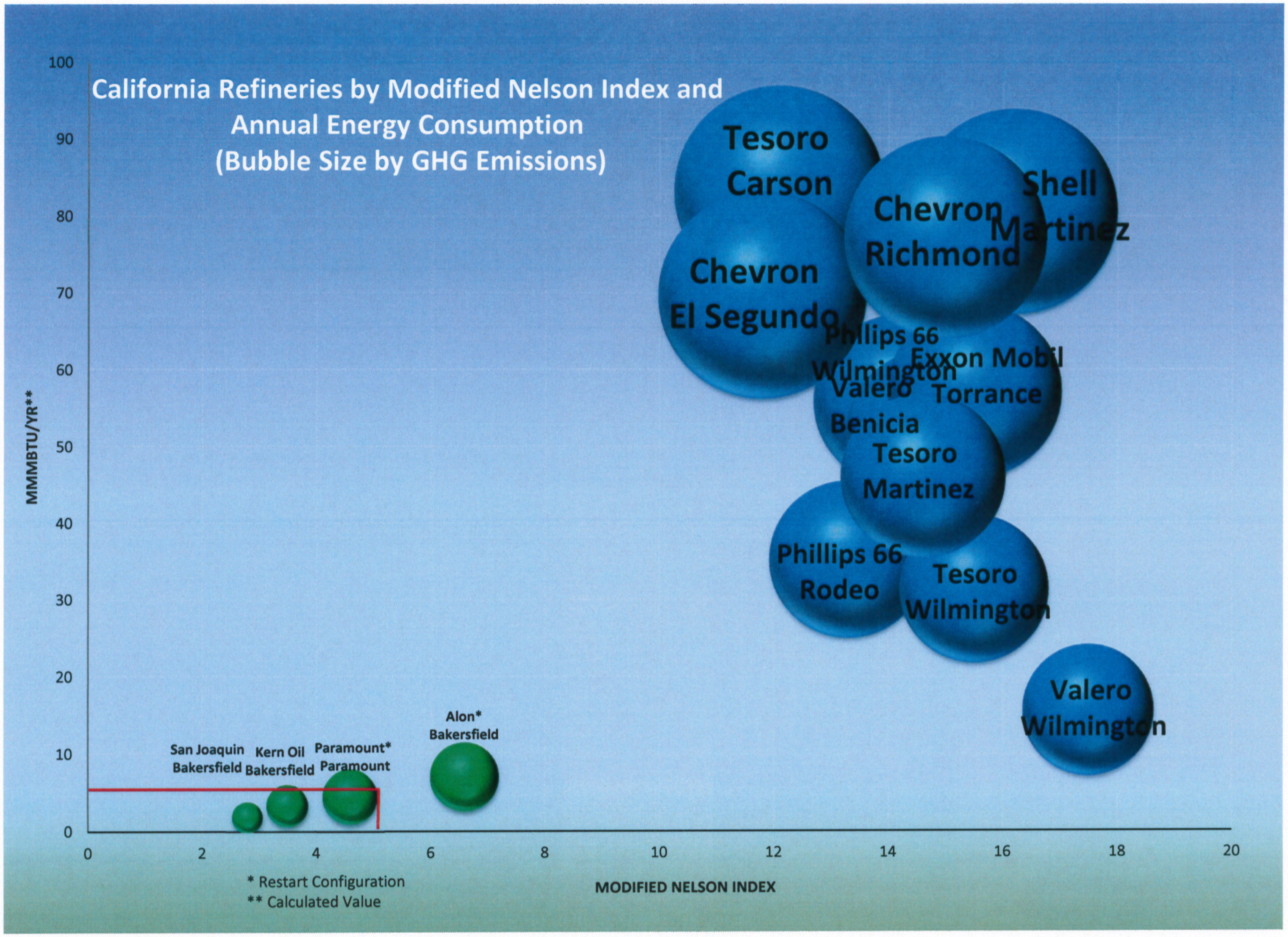
We look forward to working through this issue in the coming months. If you have any questions on these comments please contact Gary Grimes at 562-531-2060 (ggrimes@ppcla.com).

Respectfully submitted,

Glenn Clausen
Vice President, Refining
Paramount Petroleum

Enc: Attachment A

314044930.1



California Refineries by Modified Nelson Index and
Annual Energy Consumption
(Bubble Size by GHG Emissions)
MMMBTU/YR**
100
90
80
70
60
50
40
30
20
10
0
0
2
4
6
8
10
12
14
16
18
20
MODIFIED NELSON INDEX
Tesoro Carson
Chevron El Segundo
Chevron Richmond
Shell Martinez
Phillips 66 Wilmington
Exxon Mobil Torrance
Valero Benicia
Tesoro Martinez
Phillips 66 Rodeo
Tesoro Wilmington
Valero Wilmington
San Joaquin Bakersfield
Kern Oil Bakersfield
Paramount* Paramount
Alon* Bakersfield
* Restart Configuration
** Calculated Value

5_B_LCFS_Alon Responses

630. Comment: **LCFS B5-1**

The commenter recommends that the eligibility metric for the LC/LE provision should be increased to 7 million MMBtu/year and a 7 modified Nelson Index.

Agency Response: ARB staff has analyzed the possibility of changing the Low-Complexity/Low-Energy-Use Refinery (LC/LE refinery) eligibility requirements to total annual energy use equal to or less than 7 million MMBtu and a Modified Nelson Complexity Score equal to or less than 7 (7/7) to accommodate Alon in the LC/LE provisions. Staff has determined that Alon's configuration and expected operation is more similar to other complex refineries than it is to LC/LE refineries. Also, a 7/7 eligibility requirement could potentially allow some of the simpler complex refineries to make modifications and also qualify under the LC/LE provision contrary to the objective of the proposal. In addition, Alon is not currently operational. ARB staff used actual refinery and emission data to design and calculate the LC/LE provision. Alon is asking ARB staff to revise the qualification standards based on projected data provided by Alon. However, it is not appropriate to use projected data to change the qualification standard or recalculate the credit generated. Staff maintains that a 5 million MMBtu per year and 5 Modified Nelson Index score are appropriate eligibility requirements for the LC/LE provision.

This page intentionally left blank.

Comment letter code: 6-B-LCFS-ALA

Commenter: Bonnie Holmes-Gen

Affiliation: American Lung Assoc.

The following letter was submitted to the LCFS Docket during the First Board Hearing.

This page intentionally left blank.

Bonnie Holme
15-2-4

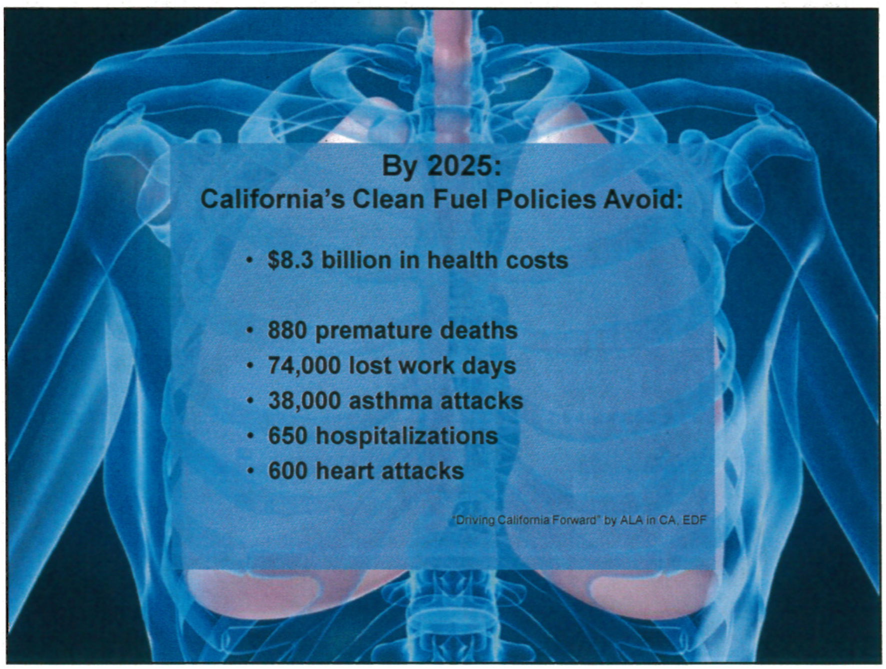
6_B_LCFS
_ALA

Low Carbon Fuel Standard: Health and Medical Support

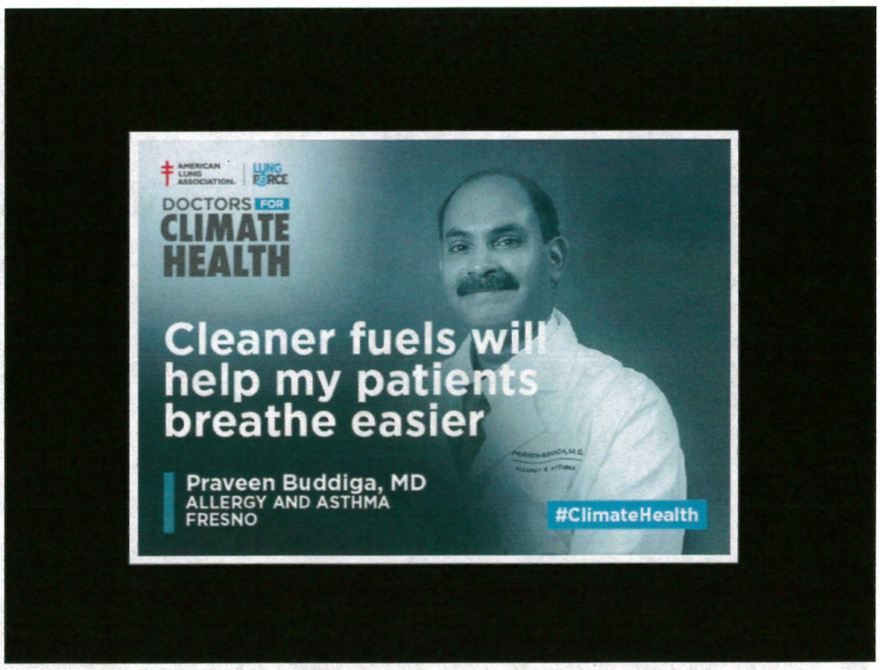
February 19, 2015

Bonnie Holmes-Gen
Senior Director, Air Quality and Climate Change
American Lung Association in California

AMERICAN LUNG ASSOCIATION.
Fighting for Air



LCFS B6-1



LCFS B6-1 cont.

6_B_LCFS_ALA Responses

631. Comment: **LCFS B6-1**

The comment is a series of PowerPoint slides listing some of the health costs and risks that will be avoided with help from the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

This page intentionally left blank.

Comment letter code: 7-B-LCFS-CATF

Commenter: Jonathan Lewis

Affiliation: Clean Air Task Force

The following letter was submitted to the LCFS Docket during the First Board Hearing.

This page intentionally left blank.

15
Jonatha

7_B_LCFS
_CATF

Comments to the California Air Resources Board by the Clean Air Task Force

CLEAN AIR TASK FORCE

On the Proposed Re-Adoption of the Low Carbon Fuel Standard

February 19, 2015

SUMMARY

The Clean Air Task Force (CATF) appreciates this opportunity to comment to the California Air Resources Board on the Low Carbon Fuel Standard (LCFS). CATF is a nonprofit organization that works to help safeguard against the worst impacts of climate change by catalyzing the rapid global development and deployment of low carbon energy and other climate-protecting technologies through research and analysis, public advocacy leadership, and partnership with the private sector.

Our comments focus on the following points:

- ARB should readopt the LCFS through 2020. Achieving compliance with the 2020 target will be difficult, but the LCFS remains the most promising policy tool available for reducing the climate impacts of the transportation sector.
- The LCFS's promise is undermined by the proposed adjustment to the lifecycle emissions for corn ethanol, and by the likelihood that regulated entities will increase their reliance on corn ethanol to meet LCFS targets.
- The proposed adjustment to corn ethanol's lifecycle emissions score rewards corn for its negative impact on global food security. ARB must acknowledge and address this issue before it erodes the legitimacy of the LCFS program.
- The prospects for deep reductions in transportation sector GHG emissions are likely to improve significantly after 2020, particularly if liquid ammonia's potential as an affordable low-carbon fuel is proven out.

READOPTION OF THE LCFS

Consistent with an order issued by the California Court of Appeals in *POET, LLC v. California Air Resources Board*, 218 Cal.App.4th 681 (2013), ARB staff has reviewed and revised the LCFS, and is now

> proposing that the Board re-adopt the LCFS, replacing the current LCFS regulation in its entirety. The proposed LCFS regulation will maintain the basic framework of the current LCFS regulation, including: declining carbon intensity targets; use of life cycle analyses; inclusion of indirect land use change effects; quarterly and annual reporting requirements; and credit generation and trading.[1]

[1] California ARB, *Staff Report-Initial Statement of Reasons* (December 30, 2014) at ES-3.

CATF urges the Board to readopt the LCFS. California's LCFS is the country's most promising public policy for bringing low-C fuels into the transportation market. It has several key attributes, all of which positively differentiate it from the federal Renewable Fuel Standard (RFS):

- Dynamic requirements: Increasingly stringent annual reduction requirements dissuade regulated entities from investing in marginally effective compliance strategies.
- Dynamic analyses: There are important ongoing debates about the performance of lifecycle GHG analyses—both with respect to specific technologies and their overall effectiveness. Regular reanalysis of compliance strategies prevents "lock-in" of outdated analyses and ineffectual technologies.
- No grandfathering: Under the LCFS, compliance options are measured according to their performance. Under the RFS, corn ethanol—which is largely exempt from the program's GHG reduction requirements—accounted for 83% of the overall volume mandate finalized by the Environmental Protection Agency (EPA) in 2013, the most recent year in which final renewable volume obligations were issued by EPA. LCFS B7-1
- Not limited to biofuels: Climate change mitigation depends on strategies that are scalable. That poses a problem for biofuels: the climate benefits of conventional biofuels typically diminish as production scales up, and advanced biofuels tend to be difficult (or impossible) to produce at a large scale.
- Clear focus on GHG reductions: The LCFS cannot blind itself to critically important non-climate impacts, especially the effect that increased consumption of biofuels can have on food prices and global food security. With appropriate safeguards in place, however, ARB can pursue the program's singular goal of GHG reductions without having to accommodate related-but-different objectives like price support for the agricultural sector or energy security.

A strong, stringent, flexible, intellectually honest LCFS creates a forum in which to consider new, truly low-carbon fuels, and a key market in which to commercialize them. It needs to succeed. However, that success must be achieved in terms of real GHG reductions, not merely on paper. CATF is concerned that a short-term reliance on conventional biofuels—especially corn ethanol—could pull the LCFS in the wrong direction, and imperil its prospects for long term success.

NET GHG EMISSIONS FROM CORN ETHANOL

When assessing a biofuel's net GHG emissions in the context of a given policy, an important—and complicated—component is the carbon release associated with land use changes. Of particular concern is indirect land use change (ILUC), or the amount of land use change that occurs as agricultural markets accommodate new policy-driven demand for biofuel feedstocks, and the amount of soil and plant-carbon that is released into the atmosphere as a consequence of those changes. LCFS B7-2

As supply margins for corn and other crops tighten in the face of competition from policy-driven demand for biofuels, the price of foodstuffs increases. The increase in food prices encourages farmers around the world to cultivate previously unfarmed land—a process that results in substantial losses of soil- and plant-carbon to the atmosphere. Accordingly, a biofuel must "pay back" this "carbon debt" (via CO_2 sequestration by subsequent energy crop growth) before it can be credited with any net climate benefits as compared to petroleum-based fuels (which have comparatively insignificant land use-related carbon impacts).

LCFS B7-2 cont.

ARB staff have proposed that the ILUC score for corn ethanol should be reduced from the current score of 30 gCO_2/MJ. Adopting the proposed reduction would be wrong, both as a matter of emissions accounting and as a matter of climate mitigation policy. The proposed reduction would make corn ethanol a more viable LCFS compliance strategy. Heavier reliance on corn ethanol would limit the near- and long-term GHG reductions that can be achieved by the LCFS and would undermine the program's innovation-forcing objective—despite corn ethanol's status as an outmoded technology, the significant uncertainty about whether corn delivers any climate benefits, and the concerns about the non-climate environmental damage associated with its production.

Reducing the ILUC score for corn would be wrong from an emissions accounting perspective because it ignores a host of relevant factors that ARB has not yet been able to effectively quantify in CA GTAP-BIO, but which it knows will raise the ILUC score if/when the factors are correctly incorporated into the model. These factors have been identified by ARB staff[2] and in comments submitted by CATF and other stakeholders.[3] They include:

LCFS B7-3

- The effect of water scarcity constraints on projected crop expansion. Researchers from Purdue University who used GTAP to examine the likely role of water scarcity on crop expansion found that earlier ILUC analyses "likely underestimated induced land use emissions due to ethanol production by more than one quarter."[4] As discussed below, ARB has not yet succeeded in sensitizing CA GTAP-BIO to water constraints, so the effect that such constraints have on LUC patterns and resulting emissions are not fully accounted for.
- GTAP's inability to differentiate commercial forest from non-commercial forests, which means that the model wrongly assumes that markets respond to the conversion of both land types in the same way.
- The yield improvement assumptions in GTAP overlook important differences among crops and growing regions, they fail to incorporate new research on future corn yields in the Midwest United States, and they do not adequately address the climate impact associated with the increased use of nitrogen-based fertilizers to sustain yield growth.

These issues are described more fully in the appended comments that CATF submitted to ARB in May 2014.

---

[2] John Courtis, Anil Prabhu, Farshid Mojaver, and Kamran Adili. iLUC Analysis for the Low Carbon Fuel Standard (Update), California Air Resources Board, (March 11, 2014).
[3] CATF, Comments on ARB Proposed ILUC Analysis (May 2014) (http://www.catf.us/resources/filings/biofuels/20140519-CATF%20Comments%20on%20ARB%20Proposed%20ILUC%20Analysis.pdf)
[4] Farzad Taheripour, Thomas W. Hertel and Jing Liu. 2013. The Role of Irrigation in Determining the Global Land Use Impacts of Biofuels. ENERGY, SUSTAINABILITY AND SOCIETY.

Even if the fundamental concerns described above are put aside for a moment, the proposed ILUC reduction for corn ethanol is problematic because the materials prepared by ARB staff appear to consider two different reduced scores. The first—19.8 gCO_2/MJ—is the unweighted average of the thirty different production scenarios run on CA GTAP-BIO.[5] ARB's potential reliance on this value implies that it believes all thirty scenarios are equally plausible—a position that ARB has not, and cannot, justify. The second score—21.8 gCO_2/MJ—was derived by performing a Monte Carlo simulation (MCS). ARB's Expert Working Group has urged the use of MCS because of its "ability to represent arbitrary input and output distributions, ... perform global sensitivity analysis (e.g., contribution to variance) to identify which input parameters contribute most to the variance in the output, and ... represent parameter correlations."[6] As between the two scores, the value that was derived from the Monte Carlo simulation—*i.e.*, 21.8 gCO_2/MJ—is superior.

A recent paper by Bruce Babcock and Zabid Iqbal of Iowa State University asserts that ILUC models utilized by ARB and EPA have overestimated land use changes by "attribut[ing] all supply response[s] not captured by increased crop yields to land use conversion on the extensive margin."[7] The paper argues for the use of lower ILUC scores by attempting to prove that "the primary land use change response of the world's farmers from 2004 to 2012 has been to use available land resources more efficiently rather than to expand the amount of land brought into production."[8] The paper has several shortcomings, however:

- Babcock and Iqbal only consider intensification techniques such as double cropping rather than analyzing yield increases over this time period.
- The paper dismisses data on extensive land use changes in Africa on the grounds that the linkage between global food prices and those in rural Africa is weak (implying that biofuel policies in the US and EU have little effect on African food prices and land use change)—even though the authors note a correlation between global food prices and food prices in urban Africa.
- The paper makes overly generous assumptions about the extensiveness of double cropping. As Jeremy Martin of the Union of Concerned Scientists wrote in recent comments to ARB, double cropping is not widely used in Southeast Asia where palm oil plantations have moved into formerly uncultivated areas. Nor is double cropping widely adopted in parts of the Midwest where most U.S. biofuels feedstocks—primarily corn and soybeans—are grown. The Babcock and Iqbal paper also fails to account for increased GHG emissions from increased fertilizer usage where it does assume the use of additional double cropping in response to higher crop prices.
- Finally, the authors assume the "only net contributor to US cropland from 2007 to 2010 was a reduction in [Conservation Reserve Program (CRP)] land," but this too is an inappropriate assumption, because several studies (from South Dakota State University and even U.S. Department of Agriculture Economic Research Service, Farm

LCFS B7-4

5 California ARB, *Staff Report-Appendix I: Detailed Analysis for Indirect Land Use Change* (December 30, 2014) at I-25.
6 *Id.* at I-38, I-17.
7 See Bruce A. Babcock and Zabid Iqbal, *Using Recent Land Use Changes to Validate Land Use Change Models* (Staff Report 14-SR 109) (http://www.card.iastate.edu/publications/dbs/pdffiles/14sr109.pdf)
8 *Id.*

Service Agency, and Natural Resources Conservation Service data) show that cropland conversions exceeded acres exiting CRP, with huge impacts on GHG emissions.[9]

Reducing the ILUC score for corn ethanol would also be a mistake in terms of climate mitigation policy. The use of highly complex models like CA GTAP-BIO to determine the net emissions associated with biofuels produces values that have the veneer of objective validity. But the modeling outputs are enormously dependent on the data that are fed into the system and on the system's assumptions about how those data affect physical and economic processes.

A recently published paper examines the extent to which subjective decisions about incorporating different assumptions and data into a lifecycle model can affect the outcome.[10] Plevin *et al.* used a Monte Carlo simulation to characterize the parametric uncertainty associated with the two components of the lifecycle analysis that California used to evaluate biofuels: "an economic modeling component that propagates market-mediated changes in commodity production and land use induced by increased demand for biofuel globally, and a carbon accounting component that calculates the GHG emissions associated with (some) of these induced changes."[11]

LCFS B7-5

The authors found that three parameters have particularly strong influences on the uncertainty importance for ILUC emissions intensity:

- Elasticity of crop yield with respect to price (YDEL) (in the economic model);
- Relative productivity of newly converted cropland (in the economic model); and
- Ratio of emissions from cropland-pasture to cropland, as compared to the ratio from converting standard pasture (in the emissions factor model).[12]

Among these factors, "[b]y far, the greatest contributor to variance in the estimate of ILUC emissions was YDEL, the elasticity of crop yield to price;" in fact, in ILUC analyses for corn ethanol, YDEL accounts for "nearly 50%"of the variance among possible modeling results.[13] ARB currently uses a YDEL value of 0.25 in GTAP-BIO—a subjective decision that is

---

[9] *See* Christopher K. Wright and Michael C. Wimberly. 2013. *Recent land use change in the Western Corn Belt threatens grasslands and wetlands.* PNAS 4134–4139 (doi: 10.1073/pnas.1215404110) (http://www.pnas.org/content/110/10/4134.abstract); Steven Wallander *et al. The Ethanol Decade: An Expansion of U.S. Corn Production, 2000-09*. Economic Information Bulletin No. EIB-79 (August 2011) (http://www.ers.usda.gov/publications/eib-economic-information-bulletin/eib79.aspx); U.S. Department of Agriculture Farm Service Agency. *Cropland Conversion* (July 31, 2013) (http://www.fsa.usda.gov/FSA/webapp?area=newsroom&subject=landing&topic=foi-er-fri-dtc); U.S. Department of Agriculture Natural Resources Conservation Service and Center for Survey Statistics and Methodology, Iowa State University. *Summary Report: 2010 National Resources Inventory* (September 2013) (http://www.nrcs.usda.gov/Internet/FSE_DOCUMENTS/stelprdb1167354.pdf); *see also* Lark, TJ, Salmon, JM, Gibbs, HK. *Cropland expansion outpaces agricultural and biofuel policies in the United States.* ENVIRONMENTAL RESEARCH LETTERS. Expected Spring 2015.

[10] Richard Plevin, *et al.* 2015. Carbon accounting and economic model uncertainty of emissions from biofuels-induced land use change. ENVIRON. SCI. TECHNOL. (doi: 10.1021/es505481d)

[11] *Id.*

[12] *Id.*

[13] *Id.*

increasingly difficult to justify in light of separate analyses conducted for ARB by Steven Berry and David Locke. Berry reviewed a collection of studies on yield price elasticity (YPE) and, according to an ARB staff report, "concluded that YPE was mostly zero and the largest value that could be used was 0.1."[14] Locke ran a statistical analysis of a similar set of studies and found "that based on methodologically sound analyses, yield price elasticities are generally small to zero."[15] ARB has nonetheless chosen to include YPE values up 0.35 in its ILUC analyses.[16] [[Id. at Attachment 1-6]]

Developing the relevant data and determining which datasets to use (and which to exclude) are highly subjective exercises, as are the processes of choosing and programming the relational assumptions that drive the model. Viewed in this context, the proposal to reduce the corn ethanol ILUC score can be more appropriately understood as the product of a subjective process—one that reflects the current availability of certain data and analyses that would contribute to a lower ILUC score, but fails to account for a host of countervailing factors that ARB does not yet understand how to model.

LCFS B7-5 cont.

The Board should recognize these limitations, as well as the necessary role that it and ARB staff play in interpreting and acting upon modeling results. The Board should exercise its best judgment in light of the overarching policy objective of the LCFS, which CATF understands to be a meaningful reduction in GHG emissions from the transportation sector. Because corn ethanol's lifecycle GHG emissions are—at best—only slightly lower than those from gasoline, and because increased reliance on corn ethanol would frustrate the development of more innovative and effective compliance options, the proposal to reduce the ILUC score for corn ethanol undermines the objectives of the LCFS. Accordingly, CATF urges the Board to table the proposal.

CORN ETHANOL'S IMPACT ON FOOD SECURITY

Another critically important way in which ILUC estimates are the product of subjective decisions (and not just objective calculations) relates to the treatment of food price increases associated with policy-induced demand for biofuels. As Plevin *et al.* (2015) write, "ILUC emission estimates depend on various modeling choices, such as whether a reduction of food consumption resulting from biofuel expansion is treated as a climate benefit."[17] ARB currently chooses to count GHG reductions that result from reduced food consumption when analyzing the lifecycle emissions of biofuels, but that—again—is a subjective decision. (Moreover, doing so implies that ARB assumes that national governments would not subsidize food consumption in the face of rising food prices.)

LCFS B7-6

If instead ARB chose to assume that society would limit the extent to which food consumption would decline (especially taking into consideration a growing world population demanding significantly more calories and protein), its ILUC analysis would produce different results. For

[14] California ARB, *Staff Report-Appendix I: Detailed Analysis for Indirect Land Use Change* (December 30, 2014) at Attachment 1-2.
[15] *Id.* at Attachment 1-5.
[16] *Id.* at Attachment 1-6.
[17] Plevin *et al.* (2015), *supra.*

example, Thomas Hertel *et al.* (2010) found that if food consumption were held constant in GTAP, the estimated emissions from biofuel expansion would increase by 41%.[18]

Similarly, Plevin *et al.* (2015) examine the effect of food consumption assumptions by comparing three model outputs for corn ethanol and other biofuels: the ILUC emissions factor; the non-CO_2 emission factor (*i.e.*, methane and nitrous oxide); and the total emission factor, which sums the ILUC factor and the non-CO_2 factor on a trial-by-trial basis.[19] When food consumption is held constant (or fixed) in non-Annex I countries, ILUC emissions for corn ethanol increase by more than 5 gCO_2/MJ as compared to a scenario in which food consumption is not fixed.[20] Total emissions from corn ethanol under a "food fixed" scenario increase by approximately 10 gCO_2/MJ (from roughly 35 gCO_2/MJ to roughly 45 gCO_2/MJ), while the upper limit of the confidence interval for the total emission factor reaches approximately 70 gCO_2/MJ.[21]

LCFS B7-6 cont.

As with the other factors discussed above, the problematic and highly subjective treatment of reduced food consumption reinforces the point that ARB is not obligated to reduce the ILUC score for corn ethanol on the basis of the most recent—but highly incomplete—modeling results.

More generally, CATF urges ARB to reconsider how it accounts for reduced food consumption within the LCFS context, before the issues erodes the legitimacy of the LCFS program.

EMISSION REDUCTION OPPORTUNITIES POST-2020

ARB is appropriately interested in using the LCFS to achieve deep, long-term reductions.

> Although post-2020 goals for the LCFS are not part of this proposed rulemaking, continuing these policies beyond 2020 will ensure that fuel carbon intensity continues to decline and that low-carbon alternatives to petroleum are available in sufficient quantities in the long term. Achieving California's mid and long-term greenhouse gas and air quality goals will require a renewable portfolio of transportation fuels—including electricity and hydrogen—well beyond the current policy trajectories. Accordingly, ARB, in a future rulemaking, will consider extending the LCFS with more aggressive targets for 2030.[22]

An unwarranted reduction to the corn ethanol ILUC score would do more than undermine the actual climate benefits that the LCFS can achieve through 2020; it would lower the ceiling on the long-term effectiveness of the program by extending the period in which marginally beneficial technologies can compete with the far better options that will be available to California after 2020. Chief among these better options may be ammonia, a hydrogen-based energy carrier that CATF has previously discussed with ARB management and staff.

LCFS B7-7

---

18 TW Hertel, *et al.* 2010. *Effects of US Maize Ethanol on Global Land Use and Greenhouse Gas Emissions: Estimating Market-Mediated Responses.* BIOSCIENCE. 60:223-231(doi: 10.1525/bio.2010.60.3.8).
19 Plevin *et al.* (2015), *supra*.
20 *Id.* at Fig. S2.
21 *Id.*
22 California ARB, *Staff Report-Initial Statement of Reasons* (December 30, 2014) at ES-1.

The potential benefits associated with ammonia fuel ammonia are enormous, both for the environment and for the prospects of the LCFS:

- Zero-carbon ammonia can be produced using air, water, and electricity generated by renewable or nuclear power plants, or by fossil fuel-based generating stations equipped with carbon capture and storage systems.
- A wide range of engines and fuel cells can use ammonia to generate electricity or to power vehicles, and can do so without emitting CO_2.
- Substantial global ammonia production and transport infrastructure is already in place. At 150 million metric tons per year, it is the third largest chemical produced globally.
- At $3.27 per gallon (on an energy equivalent basis to gasoline, at current prices) and $1.78 per gallon (when compared against gasoline's 10-year average price), ammonia is affordable. And as a liquid, it can be more easily transported and stored than hydrogen and natural gas.

The steps that need to be taken before a widespread transition to ammonia fuel can occur are significant—but not insurmountable. These include:

- Building awareness among industry, regulators, and other stakeholders about the economic and environmental advantages of using ammonia fuel for power generation and transportation (especially, at the outset, rail and long-haul truck fleets).
- Helping innovators and investors identify small volume/high profit projects to jumpstart the ammonia energy industry.
- Highlighting opportunities to shift ammonia production to zero-carbon processes (e.g., using stranded or otherwise underutilized wind power assets for ammonia synthesis).
- Detailing ammonia's toxicity risk (which is similar to that of LPG), describing how that risk is managed by farmers globally, and outlining protocols for how it can be managed in the power and transportation sectors.
- Developing a long-term roadmap for building up ammonia production and distribution capacity to the scale of a global energy commodity.

LCFS B7-7 cont.

Since CATF briefed ARB on ammonia in July 2014, research in Texas (on ammonia-gasoline blending in internal combustion engines), Toronto (on the use of ammonia to fuel locomotives), and California have continued to validate the concept and develop demonstration projects.

The California project—which involves the University of California at Los Angeles (UCLA), California Energy Commission, and South Coast Air Quality Management District (SCAQMD)—is among the most interesting efforts to date. UCLA is spearheading a comprehensive program to utilize advanced engines from Sturman Industries for a multifuel (gas and ammonia), low NO_x combined-heat-and-power system. The system will be designed, installed, and optimized at a metals foundry in Los Angeles called California Metal-X (CMX). The project goal is to provide power at $0.097/kwh compared to a current base load cost of $0.18/kwh and peak power costs ranging from $0.20-$0.50/kwh from the grid. These cost savings come along with the potential to prove out an ammonia-based, scalable power source that meets the stringent air quality requirements implemented by SCAQMD.

The system will be designed to run in a wide range of modes including pure ammonia as a peak fuel and a variety of combined heat/power modes depending on power pricing, air quality standards, process efficiency, and power export profitability. UCLA, Sturman Industries, and other project partners will instrument the system to test and optimize ammonia engines, emissions, costs, maintenance, safety and other aspects of these types of operations in the real world. This project is being designed to provide a robust prototype for low cost, clean electricity across the California economy. If successful, the project will provide a technology and engineering basis for installing ammonia power in various markets around the world. LCFS B7-7 cont.

CONCLUSION

CATF urges ARB to readopt the LCFS through 2020. Although significant challenges remain, the LCFS is the most promising policy tool available for reducing the climate impacts of the transportation sector. LCFS B7-8

However, that promise is undermined by the proposed adjustment to the lifecycle emissions for corn ethanol, and by the likelihood that regulated entities will increase their reliance on corn ethanol to meet LCFS targets. The proposed adjustment to corn ethanol's lifecycle emissions score rewards corn for its negative impact on global food security. ARB must acknowledge and address this issue before it erodes the legitimacy of the LCFS program. LCFS B7-9

An unwarranted reduction to the corn ethanol ILUC score would also lower the ceiling on the long-term effectiveness of the program by extending the period in which marginally beneficial technologies can compete with the far better options that will be available to California after 2020. The prospects for deep reductions in transportation sector GHG emissions are likely to improve significantly after 2020, particularly if liquid ammonia's potential as an affordable low-carbon fuel is proven out. LCFS B7-10

Respectfully submitted,

Jonathan F. Lewis
Senior Counsel
Clean Air Task Force
617.624.0234
jlewis@catf.us
www.catf.us

Estimating Indirect Land Use Change Emissions from Biofuels

CLEAN AIR TASK FORCE

Comments by Clean Air Task Force to California Air Resources Board

On the ILUC emissions estimate discussed in ARB's presentation "iLUC Analysis for the Low Carbon Fuel Standard (Update)" (March 11, 2014)

May 19, 2014

Overview

The Clean Air Task Force (CATF) is a non-profit environmental organization that works to protect the earth's atmosphere by improving air quality and reducing global climate change through scientific research, public advocacy, technological innovation, and private sector collaboration. CATF is pleased to submit the following comments to the California Air Resources Board concerning ARB's review of the indirect land use change (ILUC) emissions associated with biofuels and how those emissions are accounted for within the state's Low Carbon Fuel Standard (LCFS).

Although research into the effect that biofuels have on climate change is marked by uncertainty and controversy, it is increasingly evident that the production and consumption of some types of biofuels are undermining efforts to reduce greenhouse gas (GHG) emissions. As compared to other policies being used to promote biofuels—most notably, the federal Renewable Fuel Standard—the LCFS represents a significantly better platform for evaluating net GHG emissions and rewarding the fuels with the lowest carbon intensities. CATF is therefore committed to helping ARB ensure that the best and most current research is used to inform its assessments of the carbon intensities of different fuels, especially biofuels. LCFS B7-11

These comments highlight three factors that ARB should take into account as it evaluates the ILUC emissions estimate used to calculate the carbon intensity of biofuels in the LCFS context:

- Studies that supposedly demonstrate a trend toward lower ILUC emissions estimates—including versions of the Global Trade Analysis Project (GTAP) model that ARB relies upon to implement the LCFS—typically ignore how water scarcity constraints will impact crop expansion. A recent analysis that takes water scarcity into account finds that earlier studies "likely underestimated induced land use emissions due to ethanol production by more than one quarter." LCFS B7-12
- GTAP's inability to differentiate commercial forest from non-commercial forests means that the model wrongly assumes that markets respond to the conversion of both land types in the same way. LCFS B7-13
- The yield improvement assumptions in GTAP overlook important differences among crops and growing regions, they fail to incorporate new research on future corn yields LCFS B7-14

in the Midwest United States, and they do not adequately address the climate impact associated with the increased use of nitrogen-based fertilizers to sustain yield growth. LCFS B7-14 cont.

Each of these factors separately suggest that the GTAP model is currently under-counting ILUC emissions. Taken together, they indicate that a reduction to the ILUC emissions estimate discussed in ARB's March 11, 2014, presentation, "iLUC Analysis for the Low Carbon Fuel Standard (Update),"[1] would not be appropriate. CATF therefore urges ARB to keep the ILUC estimate at its current level until ARB can more fully account for the issues raised here and at the March workshop. LCFS B7-15

[I] The "Trend" Toward Lower ILUC Emission Estimates Is Illusory

In California (as in Washington DC), the ethanol industry has aggressively promoted the idea that ILUC emissions estimates for corn ethanol are steadily trending downward as new lifecycle analyses are published. The industry places particularly high value on particular publications by Purdue researchers Wally Tyner and Farzad Taheripour that point toward relatively low estimates of ILUC emissions, e.g., a 2012 paper that reduces the estimated land requirements for US ethanol production by 25%.[2] The cited studies have important shortcomings, however—a problem that is exemplified by the way in which the studies have ignored real-world constraints on the amount of water available for new agriculture.

In fact, more recent work by Taheripour is intended to correct this oversight. In a 2013 study he co-authored by Thomas Hertel and Jing Liu, two other researchers from Purdue, he writes: "[I]n contrast to the recent trend in such studies, incorporating explicit modeling of irrigation, and associated constraints, *significantly raises the land-based emissions associated with biofuel expansion*."[3] LCFS B7-16

Taheripour *et al.* (2013) opens with two key points. First, water availability is essential to understanding the land use impact of biofuel expansion, especially with water availability projected to decrease over the next two decades.

> [T]he question of whether expansion of global cropland cover involves irrigated or rainfed lands make a significant difference in terms of how much new land will be required to provide the additional production called for in the presence of biofuels ... [I]f the expansion of irrigated land is constrained, either due to insufficient water or due to insufficient pumping capacity, then it is likely that more cropland area will be required to meet the additional global demand induced by ethanol production.[4]

The authors cite recent studies that predict large water deficits, including an analysis by McKinsey which estimates that by 2030 water demand will exceed water supply by 40%. "In summary," Taheripour *et al.* write, "it appears that water for agricultural irrigation will become much more expensive in the future – no doubt spurring considerable efficiency gains, but also raising the cost of production and therefore limiting the amount of land on which irrigated crops can be economically grown."[5]

Second, refining land use change models to account for real-world constraints on water availability reveals a greater likelihood that biofuels expansion will drive displaced agricultural LCFS B7-17 production into areas that are rainfed. "These regions tend to be more carbon rich and therefore exhibit higher ILUC emission factors," write Taheripour *et al.* "Therefore, earlier models which ignore the role of irrigation in crop expansion tend to underestimate the ILUC emissions due to biofuel expansion."[6]

LCFS B7-17 cont.

One such model is GTAP-BIO, which Taheripour and Tyner used in the earlier 2012 study to assess the land use impacts of the 2015 ethanol mandate in the US Renewable Fuel Standard.[7] (GTAP-BIO, of course, is used to generate the emissions estimates for biofuels that ARB relies upon to implement the LCFS.) The enhancements that Taherpour *et al.* make to GTAP in the 2013 study allow the model to recognize water scarcity constraints and distinguish between rain-fed and irrigated land. Figures 3 and 6 from Taheripour *et al.* (2013) illustrate the extent to which the intensity of global land use change can differ when models are programmed to distinguish between irrigated crops and rainfed crops, and when constraints on water availability are introduced:

LCFS B7-18

Fig. 3 from Taheripour et al. (2013)

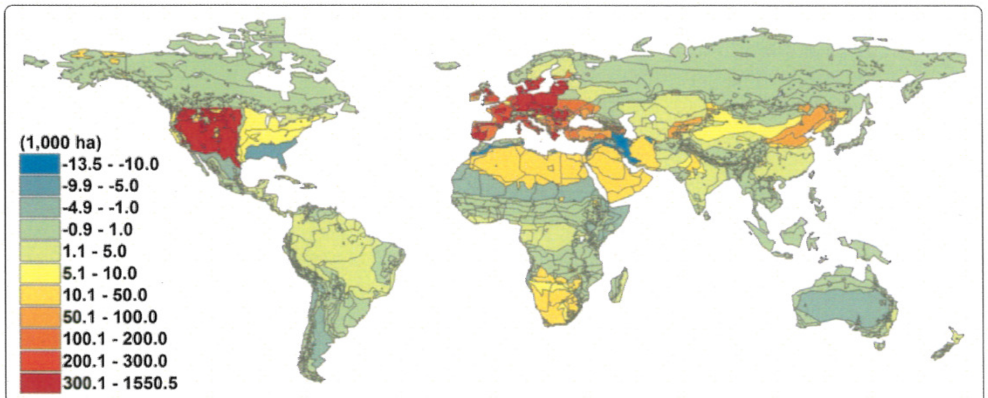


Figure 3 Irrigated cropland cover change, without irrigation constraint.

Fig. 6 from Taheripour et al. (2013)

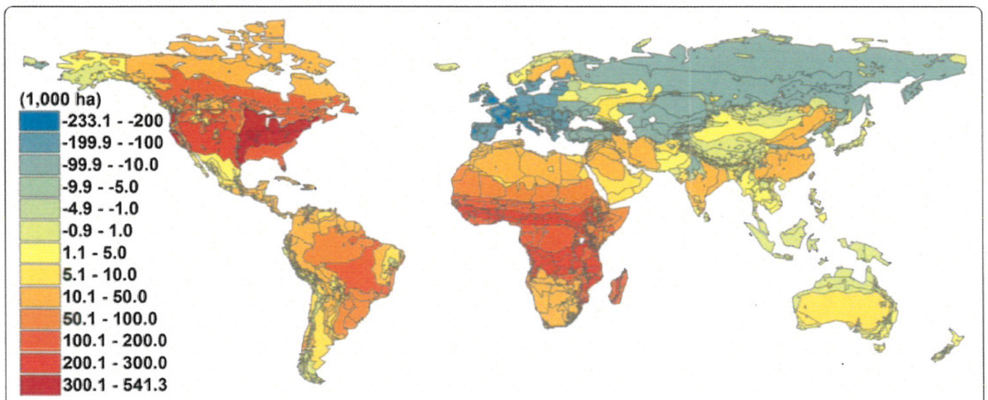


Figure 6 Rainfed cropland cover change, with irrigation constraint. Figures 3, 4, 5, 6 represent change in harvested areas.

By sensitizing the model to these factors, the 2013 study finds that ILUC emissions are likely to be substantially higher than prior estimates:

> [I]ncreasing US ethanol production from its 2001 level to 56.78 billion liters causes about 35.6 g CO2e/MJ emissions if there is no irrigation constraint across the world. Factoring in the physical limitations on irrigation expansion increases the land-based emissions to 45.4 g CO_2e/MJ. This means that the physical water scarcity adds 27.5% to the emissions due to land use changes induced by ethanol expansion. As shown in Table 5 [excerpted below], the constrained case also generates 27.5% more emissions compared to the case wherein we ignore irrigation altogether. This means that earlier studies, which failed to distinguish rainfed from irrigated lands, likely underestimated induced land use emissions due to ethanol production by more than one quarter.[8]

LCFS B7-18 cont.

Table 5 from Taheripour et al. (2013)

Table 5 Land use emissions due to US ethanol production

Simulations	Ethanol production (billion liters)	Annualized ILUC emissions	
		(g CO_2e/MJ)	Deviation from no-irrigation (%)
Unconstrained	50.08	35.6	−0.05
No-irrigation	50.08	35.6	0.0
Constrained	50.08	45.4	27.5

An additional point worth noting in this context is that both of the values cited in the 2013 study for corn ethanol—35.6 and 45.4 g CO_2e/MJ—are higher than the central values that ARB presented at the March 11 workshop (30.0 and 23.2 g CO_2e/MJ).[9]

In its March 2014 presentation, ARB staff notified the Board that the current version of GTAP fails to differentiate between the irrigated and rain-fed land and assumes that the water availability (or, rather, the unavailability of water) does not affect the model's estimates concerning the conversion of new land for crop production. Staff flagged two of the problems connected with this assumption—water is not an unlimited resource, and it cost money to irrigate newly converted cropland—and pointed out that, "Crop expansion and crop switching decisions will require availability of water resource and may change model predictions."[10] According to the presentation, staff plans to collect data on water availability, productivity differences, and land elasticity, and integrate those data into a revised GTAP model within the next few months.[11]

LCFS B7-19

This effort to incorporate water-related restrictions on biofuel demand-driven cropland expansion is likely to materially affect ARB's estimate of the net GHG emissions associated with the LCFS. The 2013 study by Taheripour *et al.* indicates that ignoring the role of irrigation in cropland expansion "introduces systematic biases in the measurement of the size and pattern of global land use changes and therefore the land use emissions due to production of biofuels."[12]

We therefore encourage ARB to ensure that water constraints are accounted for in the lifecycle emissions analyses used to assess the treatment of biofuels within the LCFS.

[II] GTAP's Treatment of Forest Conversion Artificially Suppresses ILUC Emissions

Currently GTAP represents three land-use classes: forestry, pasture, and cropland. These are economic uses of land, however, not land-cover types. That is, GTAP does not represent forests generally; it represents economically productive timberland. As a result, the model assumes that any conversion of forestry land causes a reduction in timber supply, which in turn creates upward pressure on timber prices. This assumption has two effects that are likely to produce lower projected ILUC emissions.

First, the opportunity cost of converting commercial forestry land is greater than the opportunity cost of converting forestland that is not in economic use. The assumption within GTAP that all forestland is commercially managed therefore exaggerates the economic limits on non-commercial forest conversion. Consequently, the model likely projects less overall forest conversion than it would if it differentiated between commercial and non-commercial forests and made both types available for conversion.

Second, once commercial forestland is converted, there is an *afforestation* response elsewhere that makes up some portion of the lost timber supply. GTAP fails to appreciate that the conversion of non-commercial forestland would not produce a similar afforestation response. LCFS B7-20

Notably, other models used to estimate land-use change emissions—including IFPRI's MIRAGE, MIT's EPPA, and PNNL's GCAM—allow for the conversion of non-commercial forestland.

ARB staff referenced these concerns in their presentation for the March 2014 workshop, explaining that GTAP's inability to differentiate between forest categories "creates unrealistic deficit from wood products in the forestry sector."[13] A temporary fix involving adjustments to the Land Transformation Elasticity (ETL) values was proposed, with a completion target of April 2014.[14] It is not clear from ARB's website whether this fix has been executed or how the adjustment impacts the ILUC estimate. CATF cannot specifically comment on the proposed fix until we have reviewed the results of the ETL adjustment, but we are encouraged that ARB has identified this problem and is committed to addressing it. We urge ARB to ensure that its ILUC determination is based on land use modeling that effectively differentiates between commercial and non-commerical forestland.

[III] Aspects of GTAP's Treatment of Yield Problematically Affect ILUC Analysis

Several of the ways in which GTAP treats future crop yields are suppressing the model's ILUC emission projections. These include the model's assumption that price-induced yield improvements for all crops in all regions will match the improvement rate projected for Midwestern US corn, the model's current failure to accommodate new research suggesting that future corn yield improvements in the Midwest US could decelerate, and model's ongoing failure to adequately address the climate impact associated with the increased use of nitrogen-based fertilizers to sustain yield growth. LCFS B7-21

[A] GTAP's Handling of Yield Price Elasticity Suppresses ILUC Estimates

Yield price elasticity is perhaps the most controversial parameter in the GTAP model. GTAP utilizes a single number which determines how much yields—of all crops, in all regions—increase in response to price increases. Most arguments about price-induced yield improvements have focused on the "correct" value for this parameter, while failing to recognize that no such parameter exists in the real world: no single value can properly capture the substantial variability across crop types, climatic conditions, and economic conditions.

In practice, nearly all of the discussion about this parameter is informed by studies of one crop grown in one region—*i.e.*, corn grown in the US Corn Belt. There is little reason to expect that the yield effects measured for corn in the Midwest, a growing region characterized by fertile soil and readily available capital, to be representative of the effect that minor price increases have on, say, rice yield in developing regions. LCFS B7-22

When setting a range of values to consider for yield price elasticity within GTAP, ARB must treat this parameter as representing the *average* yield elasticity for all crops, in all regions, which is likely to be lower than what has been achieved by corn growers in the United States. The high values suggested for the US corn should be treated as the maximum obtainable. If GTAP assumed (appropriately) that not all crops grown around the world will achieve the same level of yield price elasticity as US corn, estimated ILUC emissions would likely increase.

[B] GTAP Does Not Incorporate New Research on Future Corn Yields

The assumptions made in GTAP about future crop yields do not yet take into account important new research by David Lobell and others on the impact that future drought conditions will have on Midwest US corn yields over the next 50 years. According to the study—Lobell *et al.*, "Greater Sensitivity to Drought Accompanies Maize Yield Increase in the U.S. Midwest," SCIENCE (May 2, 2014)—a greater incidence of midsummer drought conditions will slow the steady improvement in corn yields that farmers have historically achieved by increasing their cropping density. Assuming that finding is corroborated, it should be incorporated into GTAP's assumptions about future yield improvement.

According to the study, a handful of factors have allowed farmers to increase the density at which they plant corn and soy—e.g., no-till agricultural, higher ambient CO_2 concentrations, and genetic enhancements. Increased density has contributed to yield improvements, but it also "can be detrimental under drought conditions because of excessive stress exposure for individual plants."[15] The authors examined how corn and soy respond to various environmental stresses to determine "the net effect of recent genetic, agronomic, and environmental changes on drought sensitivity." They find that corn yields are particularly sensitive to increases in daytime vapor pressure deficit (VPD), "a widely used measure of atmospheric water demand that depends on air temperature and humidity." VDP increases appear to be especially impactful when they occur 2-3 months after a corn crop is sowed.[16] As Figure 4(B) from Lobell *et al.* shows, VDP during that timeframe (July, approximately) is expected to climb significantly over the next forty years: LCFS B7-23

Fig. 4 from Lobell et al. (2014)

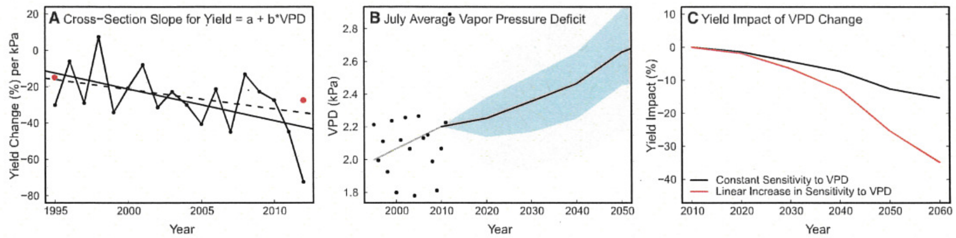


Fig. 4. Changes in vapor pressure deficit and its impacts. **(A)** Estimates of maize yield sensitivity to VPD 61 to 90 days after sowing from a cross-sectional regression for each year in the study period, along with best-fit trend lines with (solid) or without (dashed) including 2012 for computing the trend. Red dots indicate sensitivity estimates from APSIM simulations with sowing densities corresponding to the start and end of the study period. **(B)** Average July VPD in the study region for historical and projected periods. Dots show individual year observations, gray line shows linear trend for 1995 to 2012, black line shows mean VPD projected using 29 climate models, blue shading indicates 25th to 75th percentile of model projections, and gray shading indicates 5th to 95th percentiles. **(C)** Estimated impact of mean VPD projections on average maize yields using either constant yield sensitivity of −27.5% per kPa or a linear increase in sensitivity at the historical rate of 7% per kPa per decade.

The study concludes that if corn-growing regions continue to experience hotter and drier Julys, current projections for corn yield improvements are unlikely to be met: LCFS B7-23 cont.

> One implication is that climate change effects may be more severe than predicted by models that assume current crop genetics and management. Climate model projections indicate that July VPD for this region will become more severe, with an expected increase in average VPD of roughly 20% over the next 50 years (Fig. 4B), driven both by higher temperatures and reduced relative humidity. At current VPD sensitivity, these VPD trends would reduce yields by about 15% over the next 50 years. If maize yields continue to become increasingly sensitive to VPD, then yield losses from VPD trends could be as much as 30% (Fig. 4C).[17]

In addition to casting doubt on long-term yield projections for corn (the feedstock used to produce more than 80% of the biofuel consumed in the United States in 2013), Lobell *et al.*'s findings support the point made above that ARB should not use a yield price elasticity value for corn as a proxy for the elasticity of other crops' yields. Lobell *et al.* demonstrate that there are important physical constraints on corn yields that farmers may not be able to overcome through the commitment of additional resources. Accordingly, the study suggests that GTAP's yield price elasticity value for corn may not be appropriate for corn, much less for other crops.

Consequently, ARB should ensure that the new work by Lobell *et al.* informs future yield projections and the effect those projections have on ILUC estimates.

[C] ARB's Modeling Framework Undercounts N_2O Emissions

The modeling framework used by ARB assumes that yields for a wide range of crops will climb in response to increased demand for biofuel feedstocks, but it does not adequately account for the extra emissions associated with the farming techniques that will be utilized to achieve those higher yields. The likely result of ARB's approach is that ILUC emissions are undercounted. LCFS B7-24

Adding fertilizer, for example, results in additional emissions of nitrous oxide (N_2O), a potent greenhouse gas. ARB's modeling framework currently accounts only for the N_2O emissions that result from fertilization of the feedstock crops used to produce biofuels. This approach ignores the additional use of fertilizer for other crops, even when that additional usage is tied to an overall rise in crop prices brought about by new demand for energy crops. Under the existing modeling framework, therefore, the benefit of price-induced yield increases are counted, while the cost to climate of achieving those increases is not. If ARB accounts for both sides of the equation—*i.e.*, improved yields *and* higher N_2O emissions—as it should, estimated ILUC emissions are likely to increase. LCFS B7-24 cont.

In the March 2014 presentation, ARB staff acknowledged that both crop intensification and crop extensification associated with increased biofuel demand could result in additional N_2O emissions.[18] We urge ARB to fully account for these emissions when estimating ILUC emissions.

[D] GTAP's Treatment of Marginal Crop Yields Increases Uncertainty

One of the recent changes to GTAP that contributed to the proposed reduction in ILUC emissions relates to how the model represents yield on newly converted cropland. GTAP previously relied on a single value of 0.66 to represent the relative productivity of newly converted land,[19] until Taheripour *et al.* (2012) used the Terrestrial Ecosystem Model (TEM) to estimate relative yields on a regional basis.[20] The shift to regionalized estimates is an improvement conceptually, but the implementation of this change creates additional uncertainty—leaving in doubt whether this change produces a better representation of reality.

To implement this change, Taheripour *et al.* estimated the average net primary productivity (NPP) of a single crop—based on corn grown in the US Corn Belt—for land not currently used for crop production in each Region-AEZ combination, and the average NPP of land currently in crop production in that Region-AEZ.[21] The ratio of these NPP values—truncated to a maximum value of 1.0[22]—is used as a proxy for the relative yield of newly converted cropland.[23] This approach implicitly incorporates the following assumptions:

- *That Iowa's 1996 corn season is an appropriate proxy for all crops grown around the world.* (TEM is parameterized using data for corn grown in 1996 in Iowa, one of the world's most productive corn producing regions.) LCFS B7-25
- *That NPP is a good proxy for yield, and the difference in yield between these two land-use classes is best represented as a constant ratio (A/B) rather than, say, a constant difference (A-B).*
- *That TEM's estimate of NPP is correct.* (Pan *et al.* (1996) performed sensitivity analysis on the TEM model (version 4.0), showing that estimated NPP is sensitive to different assumptions about soil texture, temperature, precipitation, and radiation—all of which may vary within a given Region-AEZ.[24])
- *That the average NPP of all land not in crop production is a good approximation of NPP on the land actually converted.* (This assumption holds true only when land selection is random or there is little variability of NPP across land in the Region-AEZ. Neither of these are claimed to be the case in the study.)
- *That truncating some of the NPP ratios to 1.0 produces a valid estimate of marginal yield.* (Taheripour *et al.* make this adjustment in their 2012 study as a way of recognizing the unlikelihood that yields are better on land not being used for production. It remains unclear, however, why this adjustment is necessary if the basic method of computing

NPP and using the ratio is valid. In other words, if the method produces values that are believed to be unrealistically high in some cases, what basis is there to believe that the other values produced by TEM (*i.e.*, those <1.0) are not likewise too high?)

LCFS B7-25 cont.

In principle, regionalized estimates of marginal yield can produce more accurate model results. Whether this is true in practice, however, depends on how the regionalized values are determined. It is unclear whether the present implementation brings GTAP results closer to reality or further from it.

Conclusion

CATF believes that California's LCFS can play a globally important role in identifying and promoting fuels that can meaningfully reduce GHG emissions from transportation. We therefore appreciate the opportunity to help ARB ensure that the best and most current research is used to assess the carbon intensities of different fuels, particularly biofuels.

LCFS B7-26

In order to develop a more reliable ILUC estimate, CATF urges ARB should ensure that its model fully appreciates the extent to which water scarcity will constrain future crop expansion, effectively differentiates commercial forest from non-commercial forests, and utilizes the most comprehensive and up-to-date data on yield improvements.

LCFS B7-27

Sincerely,

Jonathan F. Lewis
Senior Counsel—Climate Policy
Clean Air Task Force
18 Tremont Street, Suite 530
Boston, MA 02108
jlewis@catf.us
617.624.0234

ENDNOTES

[1] John Courtis, Anil Prabhu, Farshid Mojaver, and Kamran Adili. iLUC Analysis for the Low Carbon Fuel Standard (Update), California Air Resources Board, (March 11, 2014) (hereafter "March 2014 Staff Presenation").
[2] Farzad Taheripour, Quinlai Zhuang, Wallace E. Tyner, and Xioliang Lu. Biofuels, Cropland Expansion, and the Extensive Margin. ENERGY, SUSTAINABILITY AND SOCIETY 2012 (hereafter "Taheripour *et al.* (2012)")
[3] Farzad Taheripour, Thomas W. Hertel and Jing Liu. The Role of Irrigation in Determining the Global Land Use Impacts of Biofuels. ENERGY, SUSTAINABILITY AND SOCIETY 2013. 3 (emphasis added) (hereafter "Taheripour *et al.* (2013)").
[4] *Id.* at 1-2.
[5] *Id.* at 2.
[6] *Id.* at 2.
[7] Taheripour *et al.* (2012) at 6.
[8] Taheripour *et al.* (2013) at 9.
[9] March 2014 Staff Presentation at 61.
[10] March 2014 Staff Presentation at 42.
[11] *Id.* at 43.
[12] Taheripour *et al.* (2013) at 1.
[13] *Id.* at 45.
[14] *Id.* at 45.
[15] David B. Lobell *et al.* Greater Sensitivity to Drought Accompanies Maize Yield Increase in the U.S. Midwest. SCIENCE 2014. 516.
[16] *Id.* at 517.
[17] *Id.* at 519.
[18] March 2014 Staff Presentation at 47-48.
[19] *See* Thomas W. Hertel *et al.* Global Land Use and Greenhouse Gas Emissions Impacts of US Maize Ethanol: Estimating Market-Mediated Responses. BIOSCIENCE 2010.
[20] *See* Taheripour *et al.* (2012).
[21] *Id.* at 3.
[22] *Id.* at 8.
[23] *Id.* at 3.
[24] Yude Pan, *et al.* The Importance of Climate and Soils for Estimates of Net Primary Production: A Sensitivity Analysis with the Terrestrial Ecosystem Model. GLOBAL CHANGE BIOLOGY 1996.

7_B_LCFS_CATF Responses

632. Comment: **LCFS B7-2, LCFS B7-3, LCFS B7-6, LCFS B7-9, LCFS B7-10, and LCFS B7-12**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

633. Comment: **LCFS B7-1**

The comment requests that the Board to re-adopt the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

634. Comment: **LCFS B7-4**

The comment expresses concern about the proposed iLUC reduction for corn ethanol.

Agency Response: See response to **LCFS 29-2**, **LCFS 29-3**, and **LCFS 29-5** to **LCFS 29-11**.

635. Comment: **LCFS B7-5**

The comment states that reducing the iLUC score for corn ethanol could be counter to climate mitigation policy.

Agency Response: ARB staff disagrees and believes that we have used the best science. See response to **LCFS 29-2**, **LCFS 29-3**, and **LCFS 29-5** to **LCFS 29-11**.

636. Comment: **LCFS B7-7**

The comment states that the reduced iLUC score for corn ethanol would lower the ceiling on the long-term effectiveness of the program.

Agency Response: See response to **LCFS 29-2**, **LCFS 29-3**, and **LCFS 29-5** to **LCFS 29-11**.

637. Comment: **LCFS B7-8**

The comment supports the re-adoption of the LCFS program through 2020.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS.

638. Comment: **LCFS B7-11**

The comment states that the LCFS program represents a valuable platform for evaluating net GHG emissions and rewarding the fuels with the lowest carbon intensities.

Agency Response: ARB staff welcomes the stakeholders' commitment to offer assistance on lifecycle analyses of transportation fuels.

639. Comment: **LCFS B7-13**

The comment states that GTAP's inability to differentiate commercial forest and non-commercial forests should be taken into account as ARB staff evaluate iLUC emissions estimates.

Agency Response: See response to **LCFS 29-6**.

640. Comment: **LCFS B7-14**

The comment states that the yield improvement assumptions in GTAP overlook several factors.

Agency Response: See response to **LCFS 29-7** and **LCFS 8-9**.

641. Comment: **LCFS B7-15**

The comment states that the GTAP model is currently under-counting iLUC emission.

Agency Response: ARB staff does not agree with commenter that the current analysis under-counts iLUC emissions. The current analysis takes into account updates to data and land use science and represents the best estimate of iLUC emissions. Staff remains committed, however, to monitor new data and updates to land-use change science, and to revise the iLUC analysis when supported by science and data. See also responses to **LCFS 29-5 to LCFS 29-7**.

642. Comment: **LCFS B7-16**

The comment states that past studies have not properly accounted for water availability issues.

Agency Response: ARB staff acknowledges the concern expressed by the commenter related to the need to account for water constraints in agriculture. ARB's Global Trade Analysis Project (GTAP) model was modified in 2014 to disaggregate cropland into rain-fed and irrigated areas to account for the issues highlighted by the commenter. The current ARB GTAP model uses the latest data for irrigation water availability (obtained from the World Resources Institute, WRI) and includes methodology to limit expansion into irrigated cropland if constrained by water scarcity. The McKinsey report cited in the work of Taheripour and Tyner estimates water scarcity for 2030; whereas WRI modeling of water scarcity uses data from 2004-2010 to estimate water scarcity constraints which is the period of interest for the current analysis. See also response to **LCFS 29-5**.

643. Comment: **LCFS B7-17**

This comment states that refining land use change models to account for real-world constraints on water availability reveals a greater likelihood that biofuel expansion will drive displaced agricultural production in areas that are rainfed, and that models which do not account for this tend to underestimate iLUC emissions due to biofuel expansion.

Agency Response: In the current analysis, cropland was disaggregated into rainfed and irrigated areas in the GTAP model. The current ARB GTAP model uses the latest data on irrigation water availability (obtained from the World Resources Institute) and includes methodology to limit expansion into irrigated cropland if constrained by water scarcity. The current ARB analysis allows expansion into rain-fed regions where it is necessary. However, there is no detailed data for carbon stocks by agro-ecological zone (AEZ) and region to distinguish differences in stored carbon between rainfed and irrigated cropland. When data becomes available, ARB staff will include these parameters into the model and update iLUC analysis in the future. See also response to **LCFS 29-5**.

644. Comment: **LCFS B7-18**

The comment presents information that ethanol production emissions are likely to be higher than the LCFS regulation estimates.

Agency Response: Rain-fed and irrigated crop sectors were included in the GTAP model after the March 2014 workshop. In the analysis by Taheripour et al., as reported by the commenter, the authors used an older (2001) database and an older model different than the current ARB model. Also, in their analysis, assumptions related to rainfed and irrigated lands are outdated. Furthermore, the older model used by Taheripour et al. does not include current elasticity structures and does not disaggregate crops. Given that the Taheripour et al. work relies on a model that is different from ARB's version, the iLUC values listed in their work are also different from the iLUC estimates from ARB's model. See also responses to **LCFS B7-16** and **LCFS 29-5**.

645. Comment: **LCFS B7-19**

The comment encourages ARB staff to ensure that water constraints are accounted for in the lifecycle emissions analyses.

Agency Response: ARB staff addressed the concerns expressed by the commenter by including rain-fed and irrigated crop sectors in the GTAP model. The current ARB GTAP model accounts for water availability throughout the biofuels production system and uses the latest water scarcity data from the World Resources Institute. See also responses to **LCFS B7-16**, **LCFS B7-18** and **LCFS 29-5**.

646. Comment: **LCFS B7-20**

The comment urges ARB staff to ensure that the iLUC values are based on land use modeling that differentiates between commercial and non-commercial forestland.

Agency Response: It is true that the current version of the GTAP model does not differentiate between commercially-managed forest and non-commercial forest by region and AEZ. As a result, it is necessary to use the same market response to land conversion both for commercial and non-commercial forests until pertinent data is available because ARB staff cannot predict if inclusion of the non-commercial forest category in the GTAP model leads to higher forest conversion. See also response to **LCFS 29-6**.

ARB staff recognizes the potential for 'afforestation' resulting from deficits in wood products. When additional data differentiating the two categories of forests and the corresponding market responses is available, staff will modify the model to incorporate commercially-managed forest and non-commercial forest by region and AEZ.

Due to the scarcity of data, the current model structure and methodology do not allow for the inclusion of non-commercial forestland into the GTAP model. There is just one forest category in the model. Data will be collected and the methodology adjusted accordingly to account for the conversion of commercial and non-commercial forests in future model updates.

To address the issue related to deficit from wood products in the forestry sector, ARB staff worked collaboratively with researchers at Purdue to calibrate land transformation elasticity values to mitigate such effects. The final set of values for land transformation elasticities are provided in Table I-3 in Appendix I of the ISOR.

647. Comment: **LCFS B7-21**

The commenter states that GTAP's treatment of crop yields fails to accommodate new research that suggests corn yield improvements in the Midwest could decelerate in the future and that the model continues to fail to address the related climate impact from increased use of fertilizers to sustain yield growth.

Agency Response: The commenter states that GTAP's treatment of crop yields fails to accommodate new research that suggests corn yield improvements in the Midwest could decelerate in the future and that the model continues to fail to address the related climate impact from increased use of fertilizers to sustain yield growth. Staff has committed to incorporate data that differentiates yield improvements of different corps for different growing regions in future model updates. Regarding the effects of nitrogen-based fertilizers, current ARB methodology accounts for the increased emissions of nitrogen-based fertilizer in the direct analysis of carbon intensity (CI) for biofuels feedstock. When data becomes available for all other crops, ARB staff will evaluate these impacts in future model updates. See also response to **LCFS 29-7**.

648. Comment: **LCFS B7-22**

The comment questions the current method for determining the yield price elasticity parameter in GTAP.

Agency Response: The GTAP model includes elements that capture critical drivers impacting agricultural and other sectors of the economy. Yield Price Elasticity (YPE) is a parameter in the model to account for price-induced yield changes in agricultural crops. There are other elements in the model such as disaggregation by

AEZ which captures climatic conditions, calibrated parameters to capture economic decisions, etc. See also response to **LCFS 8-9**.

649. Comment: **LCFS B7-23**

The comment requests ARB staff to ensure that the latest work is used to inform future yield projections and the effect those projections has on iLUC estimates.

Agency Response: The commenter's request that ARB staff account for decreases in yields based on the published article by David Lobell is outside the scope of the present analysis. Future work that may consider expanding the LCFS targets beyond 2020 could potentially address the issues related to decreases in yield due to local atmospheric conditions and other factors.

650. Comment: **LCFS B7-24**

The comment requests that ARB staff take into account that crop intensification and crop extensification associated with increased biofuel demand when developing estimated iLUC emissions.

Agency Response: Current ARB methodology accounts for increased N_2O emissions from nitrogen-based fertilizers in the direct analysis of carbon intensity (CI) values for various biofuel feedstocks. ARB staff acknowledges, however, that additional N_2O emissions are likely a result of intensification and extensification associated with increased biofuel demand, but the data for other crops and regions are insufficient to separate the effects of direct analysis from the effects related to land-use changes within the GTAP framework. To avoid the potential for double-counting, ARB staff decided to take a conservative approach and did not include emissions from intensification-extensification. When data becomes available for all crops and regions, staff will evaluate these impacts and include them in future model updates. See also response to **LCFS B7-22**.

651. Comment: **LCFS B7-25**

The comment questions the change from using a single value to represent relative productivity of newly converted land to using the Terrestrial Ecosystem Model (TEM).

Agency Response: ARB staff disagrees that changes to the GTAP model to account for regionalized productivity are less representative of reality. The Terrestrial Ecosystem Model (TEM) approach using average net primary productivity (NPP) as a surrogate for yield estimates for newly converted land provides the best approximation to crop yields on newly converted land in relation to yields on existing cropland. Researchers at Purdue used data for C4 and C3 crops (not exclusively corn as stated by the commenter) to estimate the relative productivity of newly converted land. The following addresses the bulleted list of assumptions regarding NPP that were identified by the commenter:

- The TEM does not use Iowa's 1996 corn season as a proxy for all crops grown around the world. The model, in fact, uses inputs for various crops.

- Taking the difference in yield between land not currently used for production and the average NPP of land currently in crop production does not represent any more meaningful use of these outputs from the TEM model compared to the use of a ratio of the two values. Ratios allow for the consideration of relative productivity of the two types of lands being modeled using the TEM model.

- ARB staff acknowledges that model outputs are sensitive to assumptions about soil texture, temperature, etc. However, if the two sets of runs (i.e., NPP for existing cropland and NPP for newly converted land) use the same inputs, then use of ratios ensures that outputs from both cases are scaled appropriately to ensure ratios remain similar (i.e., varying inputs could generate different inputs but ratios of outputs are likely similar within acceptable variability of input values).

- NPP by AEZ is actually a weighted average of gridded cells used in the modeling and therefore represents a reasonable estimate of average for an AEZ in a region.

Land currently in production usually has the highest productivity among all land available locally. New land that comes into production is expected to have lower productivity. Researchers at Purdue used this reasoning to justify limiting the maximum estimated productivity of new cropland to be no higher than existing cropland (by truncating NPP ratios to 1.0). To assess the impacts of non-truncation for values lower than 1.0, ARB staff conducted a Monte Carlo analysis using a range of potential variables in the NPP values. The Monte Carlo analysis did not indicate that variability in NPP was a significant contributor to the overall variability of iLUC values. ARB staff, however, recognizes that there may be other approaches to improve estimates of new converted land. ARB staff will re-evaluate the productivity of newly converted land when data and new methodologies become available for use in future updates.

652. Comment: **LCFS B7-26**

The comment states appreciation for the opportunity to help ARB staff ensure that the best and most current research is used to assess the carbon intensities of different fuels.

Agency Response: See response to **LCFS B7-11**.

653. Comment: **LCFS B7-27**

The comment requests ARB staff to ensure that its model fully incorporates the effects of water scarcity, effectively differentiates commercial and non-commercial forests, and uses the most up-to-date data on yield improvements.

Agency Response: See responses to **LCFS B7-13**, **LCFS B7-14, LCFS B7-16** to **LCFS B7-18**, and **LCFS B7-23**.

Comment letter code: 8-B-LCFS-NGC

Commenter: Colin Murphy

Affiliation: NextGen Climate

The following letter was submitted to the LCFS Docket during the First Board Hearing.

This page intentionally left blank.

15- Colin Murphy

8_B_LCFS _NGC

NEXTGEN CLIMATE AMERICA

February 18, 2015

NextGen Climate America
111 Sutter St.
San Francisco, CA 94104

Chair Mary Nichols
California Air Resources Board
1001 I St.
Sacramento CA, 95814

Dear Chair Nichols:

On behalf of NextGen Climate, I would like to thank the Air Resources Board for the opportunity to comment on the proposed re-adoption of the Low Carbon Fuel Standard. NextGen Climate America is dedicated to preventing climate disaster and enabling American prosperity. We recognize the critical role transportation plays in climate policy and we strongly support extending California's Low Carbon Fuel Standard (LCFS). Fuel carbon policies, like the LCFS, are a critical element in a comprehensive climate policy and provide an essential incentive for bringing advanced low-carbon technologies into commercial deployment as economies transition to long-term sustainability.

California's s Low Carbon Fuel Standard Shows Leadership on a Key Climate Issue

LCFS B8-1

Transportation accounted for approximately 37% of California's greenhouse gas (GHG) emissions[1]. The share of emissions from transportation is generally expected to go up over the next decade in western U.S. states due to reductions in emissions from non-transportation sectors of the economy. Recognizing the critical need for carbon reduction policies California joined Oregon, Washington and British Columbia in agreeing to groundbreaking climate policy through participation in the Pacific Coast Collaborative (PCC). The success of the PCC efforts towards sustainable fuels policy is a direct result of the leadership the Air Resources Board showed in implementing the first-of-its-kind Low Carbon Fuel Standard. Low carbon fuels policy is necessary element in achieving long term climate sustainability. If the emissions from transportation are not substantially reduced, it is virtually impossible for any state to meet its climate goals. California can set an example the rest of the world can follow by continuing this groundbreaking policy.

Low Carbon Fuel Standards Enable a Smooth Transition to a Sustainable Future

LCFS B8-2

Low carbon fuel policies achieve two goals: direct reduction of carbon emissions and incentivizing commercial deployment of advanced technologies. The latter goal is a niche that few other options in the policy toolkit can address in as direct, efficient and timely a fashion. By creating a market-based incentive structure that provides greater rewards for

[1] CARB (2014) *California's Greenhouse Gas Emission Inventory* http://www.arb.ca.gov/cc/inventory/inventory_current.htm

fuels which yield greater carbon reductions, the Low Carbon Fuel Standard would help the most advanced technologies reach market sooner, so that future, bigger reductions can be attained in a cost effective manner. Without technology-promoting policies like a Low Carbon Fuel Standard, there is a risk that highly efficient technology will not develop quickly enough to meet long term goals. LCFS B8-2 cont.

Recent Research Has Demonstrated that California's Targets Can be Met with Likely Fuel Supplies

Several recent research reports, including the *Pacific Coast Collaborative Low Carbon Fuel Availability Study* from the International Council on Clean Transportation and E4tech, and from Promotum have demonstrated that there are a variety of technological and supply pathways which can meet California's low-carbon fuel demands in a cost-effective manner[2,3]. Already, electric vehicles, including plug-in hybrids, are demonstrating that they are cost-competitive and commercially attractive options in the passenger vehicle market. Existing biofuel production facilities are reducing their carbon emissions through efficiency enhancements and greater use of renewable energy. The first two advanced cellulosic ethanol production facilities in the U.S. came online in the last quarter of 2014, with other projects in various stages of demonstration or commercialization, including in California[4]. There are many combinations of fuels and technologies which would allow California to meet its goals under the proposed Low Carbon Fuel Standard. This flexibility will help minimize cost by allowing fuel markets to find the lowest cost pathways for decarbonization. LCFS B8-3

Cost Containment through a Credit Clearance Market Will Mitigate the Effect of Price Spikes

While there is a growing body of evidence to indicate that the LCFS credit market is appropriately regulated and balanced[5], we recognize that there is value in providing additional levels of cost containment. In order to protect California consumers and businesses, we support the creation of a Credit Clearance Market, to effectively cap the LCFS credit prices in times of excessive demand. LCFS B8-4

A Credit Floor Price Would Give Needed Certainty to Prospective Advanced Low-Carbon Fuel Producers

While the fundamental nature of the LCFS provides a critical incentive for advanced fuels (e.g. cellulosic biofuels, renewable diesel or hydrogen) to enter the market, this incentive often lacks the certainty required for prospective fuel producers to access capital markets LCFS B8-5

---

[2] ICCT & E4Tech (2015) *Potential Low Carbon Fuel Supply to the Pacific Coast Region of North America* http://www.theicct.org/potential-low-carbon-fuel-supply-pacific-coast-region-north-america

[3] Promotum Group (2015) *California's Low Carbon Fuel Standard: Evaluation of the Potential to Meet or Exceed the Standards* http://www.ucsusa.org/sites/default/files/attach/2015/02/California-LCFS-Study.pdf

[4] E2 (2014) *Advanced Biofuel Market Report* https://www.e2.org/ext/doc/E2AdvancedBiofuelMarketReport2014.pdf

[5] UC Davis ITS (2014) *Status Review of California's Low Carbon Fuel Standard* http://www.its.ucdavis.edu/wp-content/themes/ucdavis/pubs/download_pdf.php?id=2253

and build commercial-scale production facilities. Part of this uncertainty revolves around the value of LCFS credits. Credit values have been relatively low for most of the program's history and the best projections indicate an over-supply of credits for the next 2-3 years[6]. This over-supply could risk a decline in credit prices during this period. At the same time, it is critical that advanced, low-carbon fuel producers expand production capacity during this time in order to meet stricter targets in the 2019-2020 timeframe.

Creating a floor price on LCFS credits can help create this certainty and bring more advanced fuel producers into commercial production. This would not only help the LCFS program meet its goals, but would create a more robust and liquid market for low carbon fuels, which would protect California's consumers and businesses from supply-related price increases in the future.

LCFS B8-5 cont.

Carbon Intensities Need to be Regularly Re-Evaluated

Low carbon fuel production is still an emerging field, particularly as it relates to advanced biofuels. Scientific understanding of biofuel production processes is rapidly improving, as are the tools for conducting objective and accurate life cycle analyses. It is very likely that as our understanding of these systems, and our tools for evaluation improve, existing Carbon Intensity (CI) values will be revised. We urge the board to include a regular review process and procedure for modifying existing carbon intensities as better information emerges. We recognize the need to provide long term certainty to fuel providers regarding the value of their fuels and urge the board to find a balanced solution that allows for appropriate revision of CI numbers with a sufficient lead-in or phase-in time to allow producers to compensate for any changes and react appropriately.

LCFS B8-6

Soil Carbon Changes May be Insufficiently Addresses by Current CI Calculations

Agricultural residues are thought to be a critical feedstock for biofuel or bioenergy production[7]. Emerging science is starting to question the assumption that agricultural residues can be removed for biofuel use without impacting soil characteristics, such as stored soil carbon[8,9]. While there is still substantial research ongoing, depleting soil carbon as a result of residue removal can result in fuels which offer limited value towards carbon reduction and may even be worse than the fuels they replace[10]. Given the critical importance of California's LCFS in setting standards for similar policies on the West Coast and beyond, it is absolutely essential that this determination be made with the greatest level of scientific certainty. Please review Attachment 1[11], research which aggregates data from several existing

LCFS B8-7

---

[6] *Ibid.*

[7] U.S. D.O.E. (2011) *Billion Ton Update* http://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update.pdf

[8] Anderson-Teixeira, K. J., Davis, S. C., Masters, M. D., & Delucia, E. H. (2009). Changes in soil organic carbon under biofuel crops. *GCB Bioenergy*, *1*(1), 75–96. doi:10.1111/j.1757-1707.2008.01001.x

[9] Liska, A. J., Yang, H., Milner, M., Goddard, S., Blanco-Canqui, H., Pelton, M. P., ... Suyker, A. E. (2014). Biofuels from crop residue can reduce soil carbon and increase CO2 emissions. *Nature Climate Change*, *4*(5), 398–401. doi:10.1038/nclimate2187

[10] Murphy, C., & Kendall, A. (2014). Life Cycle Analysis of Biochemical Cellulosic Ethanol under Multiple Scenarios. *GCB Bioenergy*, Accepted, in press. doi:10.1111/gcbb.12204

studies of the effect of corn stover removal on soil carbon levels, which finds evidence of significant soil carbon loss even at moderate levels of corn stover removal. This research is not, by itself, definitive on the subject but it indicates that there is a substantial risk here, which has not been adequately addressed by existing models or agricultural practice. We urge the board to exercise extreme caution when determining CI values for residue-derived fuels where the residues would previously have been returned to the soil. We also urge the Board to regularly review research on this subject and revise CI values promptly when sufficient evidence exists to justify such.

LCFS B8-7 cont.

The LCFS is a Strong Policy Which Should be Re-Adopted

The current LCFS has, according to the overwhelming preponderance of evidence, achieved its goals and when the benefits to public health and energy security are considered, it has been a strong investment for the state. Already, tens of thousands of Californians are employed by jobs related to sustainable transportation in the state[12] The California Air Resources Board now has the opportunity to extend this success to 2020 and beyond and cement the state's leadership in this critical area of climate policy.

We would be happy to discuss any of these issues with the Board at your convenience. Please do not hesitate to contact us if there is anything else we can add.

Sincerely,

Colin W. Murphy
Climate Policy Advocate
NextGen Climate America, Inc.
cmurphy@nextgenamerica.org
(415) 802-2405

---

[11] Excerpted from Murphy, C. W. (2013). *Modeling the Environmental Impacts of Cellulosic Biofuel Production in Life Cycle and Spatial Frameworks by*. University of California, Davis.

[12] Advanced Energy Economy (2014) *California Advanced Energy Employment Survey* http://info.aee.net/hs-fs/hub/211732/file-2173902479-pdf/PDF/aeei-california-advanced-energy-employment-survey-fnl.pdf

15-2-4
Colin Murphy

Chapter 4: Analysis of Soil Organic Carbon Changes from Corn Stover Harvest

4.1 Introduction

Biofuels are thought to be a promising technology for reducing greenhouse gas (GHG) emissions from the transportation sector. The U.S. Revised Renewable Fuel Standard (RFS2) calls for a substantial increase in biofuel utilization over the next 10 years. At least 16 billion gallons (61 billion liters) of biofuels made from lignocellulosic feedstocks ("cellulosic biofuels") are specifically mandated by RFS2 (Renewable Fuels Association, 2010). Cellulosic biofuels have the potential to meet RFS2 GHG reduction goals (Bracmort, 2012; Farrell et al., 2006; C. Murphy & Kendall, n.d.; Tao & Aden, 2009; Viikari et al., 2012), but substantial uncertainty remains, particularly surrounding soil organic carbon (SOC) changes from producing and harvesting lignocellulosic feedstocks (Anderson-Teixeira et al., 2009; Lemke et al., 2010; P. Smith, 2007). In fertile soils, organic matter from root growth and above-ground litter is incorporated into the soil over time. Some of this carbon remains in the soil for long periods of time (Humberto Blanco-Canqui & Lal, 2009; J. M.-F. Johnson, Barbour, & Weyers, 2007). When undisturbed, carbon content in soils often reaches equilibrium, where the amount of soil carbon being added approximately equals that being lost (Buyanovsky & Wagner, 1997).

Disturbing these pools of SOC through changes in land coverage or agronomic management, such as removing large amounts of biomass for biofuel production, can alter soil carbon balances. This is of particular interest to biofuel analysts and policy makers, since the magnitude of these changes can be quite significant (Fargione et al., 2008). Cultivating feedstock crops for cellulosic biofuels typically requires a substantial change in management since, at present, virtually no cellulosic biofuel capacity is operating in the U.S. (Advanced Ethanol Council, 2013). Even where specific agronomic practices for biofuel crops are similar to food ones, biomass harvest removes much more biomass from the field than food harvest.

Corn stover, the above-ground, non-grain part of the corn plant, is thought to be a promising feedstock for biofuel production because substantial acreage of corn is already cultivated in the U.S. and stover is typically left on the field as residue (Graham et al., 2007). If harvesting stover causes a loss of soil organic carbon, through oxidation or reduction and volatilization to CO_2 or CH_4, then the life-cycle GHG impact of stover-based biofuels would increase. SOC changes are affected by local soil and climatic conditions as well as the type of organic matter in the soil, some forms, such as lignin, are typically much more recalcitrant than others. Understanding the SOC change is, therefore, an important element in accurate life-cycle assessment of biofuels.

This paper focuses on the following question: Does removing some part of the corn stover from corn fields reduce SOC? If so, under what conditions and by how much is it reduced? To answer this, we collect data from 21 studies of corn stover removal and SOC changes. 17 of these studies were from peer-reviewed publications, two were unpublished data from authors which had published in this field before (and which are intended for publication in the future), one was a M.S. thesis and one a PhD Dissertation.

4.2 Methodology

4.2.1 Data Collection

A literature search was conducted of studies quantifying changes in SOC from the harvest of corn stover. Google Scholar and ISI Web of Science were searched using the keywords "soil carbon" and "corn stover". This returned several hundred results, so a set of criteria was established to limit the inclusion to papers which would most directly reflect the effects of corn stover removal on SOC. These criteria were:

- Inclusion of at least two levels of stover removal, including zero.
- Corn must be grown continuously or must represent at least 50% of any crop rotation.
- Sampling depth must be at least 5 cm.

- Agronomic parameters including soil classification, tillage and nitrogen (N) fertilization must be reported or obtainable through other sources.
- Must be unique data; literature reviews and meta-analyses were used to identify potential studies, though all data in the dataset was copied from the original publication.

Only studies reporting empirical data were selected for this analysis; a comparison between measured and modeled studies is planned for future work. The 5cm sampling depth was picked to minimize the transient effects of surface litter. The crop rotation condition was set to allow corn-soy rotations, which are common. When a paper met these criteria, the relevant data were extracted to a MS-Excel data file (Microsoft, 2006). Additional papers were discovered by examining the works citing and cited by papers which were included in the study, as well as several literature reviews on the subject (Anderson-Teixeira et al., 2009; Humberto Blanco-Canqui, Lal, Post, Izaurralde, & Owens, 2006; Powlson, Glendining, Coleman, & Whitmore, 2011; W W Wilhelm, Johnson, Hatfield, Voorhees, & Linden, 2004; Zanatta, Bayer, Dieckow, Vieira, & Mielniczuk, 2007). When many sampling depths were reported in the same study and field, no more than two were included in this study, to avoid overrepresentation of any single study.

21 suitable studies were identified, which included data from 22 experimental fields (Appendix 8.2). These studies identified several factors thought to impact SOC changes from stover removal: soil clay content, biomass removal rate, initial SOC content, crop rotation practice, N fertilization, tillage practice, sampling depth, soil bulk density and duration of the study. Values for these parameters were extracted from the papers in the study. Where data were not reported, study authors were contacted to attempt to fill in gaps. If this failed, values were estimated from other sources, such as companion studies or earlier or later work from the same research plots. Soil conditions, such as bulk density and clay content were estimated by referencing the soil series and study location in the USDA Web Soil Survey (Soil Survey Staff, 2013).

Residue removal rates were given in the constituent papers, however not all were given as the fraction of above-ground biomass; some were based on surface area measurements or on the percent of mechanically-harvested stover, which excludes a stubble under the cutting height of a harvester. These were converted to mass fractions based on the 1:1 relationship between cut height and stover mass reported in Wilhelm, et al. (2010) and the average "Low-Cut" height for mechanical silage harvesters reported by Wu and Roth (Z. Wu & Roth, n.d.). Where corn height was unavailable, it was assumed to be equal to that of the average in the nearest test field reported in Wilhelm, et al. (Wally W. Wilhelm et al., 2010).

SOC is typically reported in one of two forms, as a mass fraction (g SOC/kg soil, or % SOC) or as a mass-per-area (typically Mg SOC/ha). The mass fraction form was used as the functional unit for our analysis, which reduces covariance between SOC levels and sampling depth. Where mass fractions were not available, the following relationship was used to convert between the two:

$$SOC_m \ \left(\frac{Mg}{ha}\right) = 10{,}000\frac{m^2}{ha} \times SD\ (m) \times BD\left(\frac{Mg}{m^3}\right) \times SOC_f\left(\frac{kg_{SOC}}{kg_{soil}}\right) \qquad (1)$$

where SOC_m is SOC mass per area, SD is sampling depth, BD is soil bulk density and SOC_f is SOC mass fraction.

Tillage practices were grouped into three classes: (1) conventional tillage (CT - which includes continuous tillage using moldboard plow); (2) reduced tillage (RT - which includes conservation tillage; chisel plow; strip tillage; mulch tillage; ridge tillage); and (3) No tillage (NT). Conventional tillage has been widely reported as contributing to SOC loss; several studies find that tillage has a greater affect on SOC than residue removal (Clapp et al., 2000; Dick et al., 1998; Reicosky & Evans, 2002). This effect varies with soil depth, since tillage induces mixing of soils and rapidly moves stover carbon downwards, as well as reducing particle size (Anderson-Teixeira et al., 2009; Dolan, Clapp, Allmaras, Baker, & Molina, 2006). We control for the different tillage classes using indicator variables for which tillage method was used on a field.

Nitrogen fertilization may have an effect on SOC concentrations; this is examined in this study. The effect of nitrogen fertilizer on soil microbial activity and carbon dynamics will depend strongly on biogeochemical conditions, including the amount of available nitrogen in the soil prior to fertilization. Previous literature has been mixed and uncertain regarding the effect of nitrogen on SOC levels (Dolan et al., 2006). There is relatively little variation in nitrogen treatment rates, so it is uncertain whether treating this as a continuous parameter will identify any meaningful effects. Accordingly, two specifications are presented, one with nitrogen treated as a binary qualitative variable and one as a numeric rate (Specifications 4 and 5, respectively).

Soil classes are grouped into 7 categories, corresponding with USDA soil textural classes (Soil Conservation Service, 1987); not every class was observed in this dataset. Indicators for each class and type are included in regressions with appropriate exclusions to avoid perfect multicollinearity.

4.2.2 Analytical Methods and Identification

A reduced form regression approach was used to study the effect of various factors on SOC content in soil. The approach allows for flexible control of a number of factors which may affect SOC. In addition, cluster robust standard errors, clustered at the study level, were used to construct confidence intervals which account for idiosyncratic differences across studies as well as correlation in observations over time within studies (Cameron & Trivedi, 2005). In order to produce results that are relevant for prospective modeling of SOC changes, two types of SOC change are considered. In some cases, the important characteristic is the net gain or loss of SOC after a period of corn stover recovery. This "Within-Field" (WF) change is estimated using a differences-in-differences regression, where the dependent variable is the initial SOC and the initial SOC is controlled for as an explanatory variable.

Sometimes the critical characteristic for models is the difference between SOC in a field in which stover is collected and a hypothetical *status quo*. In the case of corn stover, the *status quo* is assumed to be corn production with stover left on the field, as it is in over 95% of all U.S. corn fields(U.S. EPA, 2013a). This "Between-Field" (BF) change is analyzed using a differences estimation. The basic regression used takes the form

$$y_{it} = h(x'_{it}\beta) + \epsilon_{it} \qquad (2)$$

where y_{it} is the final SOC percentage for field i in time t and x_{it} are explanatory variables including percent biomass removal, initial percent SOC, nitrogen treatment, tillage practice, clay content, sampling depth, and study duration. β is the coefficient estimated by regression, ϵ is the error term and h is the functional form of the parameter, which can be non-linear, such as quadratic or logarithmic. The purpose of the regression is to identify the causal relationship between x_{it} and final SOC. This requires a number of assumptions.

The data collected represent averages across a number of replications such that

$$\overline{y_{it}} = \frac{1}{n_j}\sum_{j=1}^{n_j} y_{ijt} \qquad (3)$$

where j is the number of replications on field i. In order to be able to identify the relationship of interest, the estimates must have linear parameters. To see this, note that the average change in y_i from a change in variable x_i is given by

$$\Delta\,\overline{y_i} = \frac{1}{n_j}\sum_{j=1}^{n_j} \Delta y_{ij} = \frac{1}{n_j}\sum_{j=1}^{n_j} h(\Delta x'_{ij}\beta) \qquad (4)$$

So long as $h(\cdot)$ is linear in the parameters, then

$$\Delta \bar{y}_j = \beta \frac{1}{n_j} \sum_{j=1}^{n_j} h(\Delta x_{ij}) \qquad (5)$$

Note that $h(x_{ij})$ can be a non-linear in the variables x_{ij}, so the assumption is not unduly restrictive.

A second key assumption to identify the causal relationship is that the conditional expectation of the errors is zero. The assumption would be violated if important explanatory variables are omitted, which correlate with an explanatory variable x_{ij} and affect final SOC percent, known as omitted variable bias. The condition may also be violated if the functional form is mis-specified. The robustness of the estimated effects to the inclusion of a number of control variables and specifications is checked to test the sensitivity of our results to potential omitted variable bias.

A last concern relates to the nature of the dependent variable. The SOC content in fields, as a percentage of mass, is constrained to be within the interval (0,1). Linear regressions do not restrict predictions to be between (0,1) and could lead to biased results (Kieschnick & McCullough, 2003). A popular approach to dealing with this is to use a logistic transformation of the dependent variable given by

$$\ln\left(\frac{y_{jt}}{1-y_{jt}}\right) = h(\boldsymbol{x'}_{it}\beta) + e_{jt} \qquad (6)$$

If the errors follow an additive logistic normal distribution, then e_{it} will follow a normal distribution and standard Gaussian statistical inference applies. All proceeding results were run under both a linear model and a logistic model. In general, the logistic model had limited if any advantage over the linear model, and the linear model allowed for more precise estimates because of its assumption of linear marginal effects.

4.3 Results

Variable	Mean	Std. Dev	Min	Max	N
Final Soil Organic Content (kg/kg)	0.0202	0.0064	0.0072	0.0473	251
Initial Soil Organic Content (kg/kg)	0.0233	0.0082	0.0091	0.0544	185
Biomass Removed (fraction of total)	0.4735	0.4187	-0.1800	1	251
Tilling Practice (Categorical Variable)	1.7540	0.6850	1	3	212
Clay Content (kg/kg)	0.2156	0.1002	0.0580	0.4370	251
Sampling Depth (cm)	23.4821	13.4621	5	60	251
Study Duration (years)	10.075	9.99	2	34	251

Table 4-1 - Summary Statistics for Corn Stover Removal Dataset. 81% of plots in the study were treated with nitrogen fertilizer.

Table 4-1 presents the summary statistics of the key variables of interest. As can be seen, final SOC is slightly lower than our initial observed SOC; however, directly comparing differences in means can be misleading for a number of reasons. First, we do not observe initial SOC for 47 of our observations. Second, as can be seen from the summary statistics, there is substantial heterogeneity across studies such as the type of tilling practice, the soil class, sampling depth, soil density and the duration of study.

Direct evaluation of WF and BF changes may lead to incorrect inference if there are other factors which led to changes in SOC in addition to biomass removal. Using a regression approach, we measure WF and BF changes flexibly, controlling for a number of factors which may also determine final SOC percentage. Included in our analysis are nitrogen application rates, duration of the study, clay content, sampling depth, and tillage practices. The effect of different parameters and combinations of parameters are checked in several forms, or "specifications" of the linear regression model.

Study and field effects are also considered, since agronomic practices, as well as local soil and climate conditions would be strongly correlated with the study they are reported in. If different studies are associated with different methodologies which are not captured in the dependent variables of interest, our results may be biased. These are controlled for in the same way as the qualitative variables above. Namely, for some specifications we include indicators for each study, with appropriate exclusion restrictions. In these regressions, identification is based on within-study variation as including indicator variables for each study effectively demeans all variables by their respective within-study or within-field means. By checking for study effects, the effect of variation within a study or field is lost, so this approach can identify whether there are systematic differences between studies, but cannot simultaneously identify the effects of other parameters.

The first three specifications for each model, [1-3] and [6-8], check for the presence of bias introduced by study-specific or field-specific effects. Table 4-2 shows the result for the linear difference estimator (BF SOC changes). Specification [1] presents the basic BF effect with no control variables. If the experiments were properly randomized, the estimated effect should be unbiased. Results including study fixed effects are shown in specification [2]. Control for the effects of the experimental field, rather than the study in which results were reported, was done using the same methods and shown in specification [3]. Similar analyses are done for WF SOC change in specifications 6-8. The relatively similar coefficients generated for each of these specifications, combined with clear statistical significance for all, indicates that there are no significant biases introduced by study or field effects.

Specification	[1]	[2]	[3]	[4]	[5]
Biomass Removed (%)	-0.00113***	-0.00150***	-0.00146***	-0.00126***	-0.00129***
	(0.000382)	(0.000290)	(0.000295)	(0.000374)	(0.000379)
Nitrogen Treatment Indicator				-0.000123	
				(0.000756)	
Nitrogen Rate ('00 kg/ha/year)					0.000726
					(0.000534)
Log Duration (log years)				0.000242	0.000168
				(0.000668)	(0.000634)
Clay Content (%)				0.00348	0.00578
				(0.0102)	(0.0110)
Sampling Depth (cm)				-0.0000763	-0.0000861
				(0.000238)	(0.000229)
Sampling Depth Squared (cm^2)				-0.00000115	-0.000000900
				(0.00000396)	(0.00000380)
Till 1 (CT)				0.0231***	0.0216***
				(0.00387)	(0.00450)
Till 2 (NT)				0.0247***	0.0230***
				(0.00317)	(0.00365)
Till 3 (RT)				0.0250***	0.0237***
				(0.00386)	(0.00412)
Constant	0.0208***	0.0176***	0.0176***	(Omitted)	(Omitted)
	(0.00176)	(0.000139)	(0.000142)		
N	251	251	251	211	207
R Squared	0.006	0.588	0.590	0.958	0.959
AIC	-1824.2	-2047.3	-2042.8	-1651.2	-1623.8
Study Effects?	N	Y	N	N	N
Field Effects?	N	N	Y	N	N

Table 4-2 Difference Estimators (BF SOC changes) for Linear Regression of SOC concentration (%) as dependent variable. Asterisks indicate significance, *: $p<0.1$, **: $p<0.05$, ***: $p<0.01$. Standard errors are in parenthesis.

All of the linear models with more complete sets of parameters, specifications [4], [5], [9] and [10], indicate a very consistent effect of SOC removal; every 1% of additional residue removal leads to a 0.0013% reduction in SOC, with all other factors being held equal. All SOC change values are significant to $p<0.01$. While this SOC reduction appears small, when one considers that the average corn field in this study had 57 Mg/ha at the start of residue removal treatments, this implies a loss of around 50 kg C per hectare for every percent of residue removal. The duration term has a negative sign under both linear (not shown) and logarithmic forms, which indicates that continuing treatment also tends to reduce SOC.

All specifications show a significant negative effect at the 1 percent level of residue removal on SOC. Importantly, this effect does not vary substantially between specifications. The stability in the point estimate indicates that biomass removal treatment was well randomized and was not correlated with other important determinants of final SOC. Few other parameters reach statistical significance in the

Specification	[6]	[7]	[8]	[9]	[10]
Biomass Removed (percent)	-0.00112**	-0.00140***	-0.00135***	-0.00130***	-0.00134***
	(0.000387)	(0.000342)	(0.000344)	(0.000358)	(0.000360)
Initial SOC (%)	0.619***	0.625***	0.639***	0.496***	0.494***
	(0.0948)	(0.0717)	(0.0772)	(0.0734)	(0.0736)
Nitrogen Treatment Indicator				-0.000431	
				(0.000796)	
Nitrogen Rate ('00 kg/ha/year)					0.000324**
					(0.000135)
Log Duration (log years)				-0.000303	-0.000264
				(0.000612)	(0.000616)
Clay Content (%)				0.000411	0.000582
				(0.00707)	(0.00738)
Sampling Depth (cm)				-0.000372	-0.000354
				(0.000272)	(0.000273)
Sampling Depth Squared (cm^2)				0.00000507	0.00000480
				(0.00000440)	(0.00000440)
Till 1 (CT)				0.0170***	0.0159***
				(0.00273)	(0.00274)
Till 2 (NT)				0.0165***	0.0155***
				(0.00238)	(0.00245)
Till 3 (RT)				0.0159***	0.0148***
				(0.00379)	(0.00357)
Constant	0.00731***	0.00903***	0.00518**	(Omitted)	(Omitted)
	(0.00224)	(0.00180)	(0.00211)		
N	185	185	185	165	165
R Squared	0.686	0.829	0.808	0.981	0.981
AIC	-1565.8	-1680.2	-1654.9	-1413.3	-1414.1
Study Effects?	N	Y	N	N	N
Field Effects?	N	N	Y	N	N

Table 4-3 - Difference-in-Difference Estimators (WF SOC changes) for Linear Regression of SOC concentration (%) as dependent variable. Asterisks indicate significance, *: p<0.1, **: p<0.05, ***: p<0.01. Standard errors are in parenthesis.

specifications, however, which generally supports the common impression in literature on the subject: that SOC in corn production systems is variable and uncertain. The signs of most parameters agree with other studies. Sampling depth and study duration are negative, which is to be expected, since both treatment duration and the mass of soil sampled would be expected to correlate with the magnitude of effects noticed; repeated corn cultivation is generally associated with declining SOC (D. L. L. Karlen et al., 1994; W. Smith & Grant, 2012). Clay content has a positive sign, indicating that increasing clay content generally reduces SOC loss, as reported by multiple studies (e.g., 29).

Table 3 shows the difference-in-difference estimator, which controls for initial levels of SOC and describes WF changes If removal treatments were not randomly assigned and there were important differences between treated and untreated fields which affect final SOC levels, the differences regression may lead to biased point estimates. The difference-in-differences estimator is robust for these concerns. Like the difference estimator discussed above, the effect of biomass removal is significant and negative, and does not substantially vary when alternative control variables are included. Unsurprisingly, the parameter with the greatest effect on final SOC concentration is initial SOC concentration. Parameters are generally of similar magnitude, sign and significance as in the BF analysis discussed above, suggesting the studies properly randomized treatment.

For most of the complete specifications (numbers [4], [5], [9], [10]), the results indicate each additional percent of biomass removal results in SOC decreasing an average of 0.0013% with a standard error of approximately 0.0004%, which yields a 95% confidence interval of approximately 0.0005 to 0.002% decrease. We tested for the presence of nonlinear effects using both the logistic model as well as quadratic terms in the linear model; however, the nonlinearities across biomass removal rates were not found to be statistically significant. The result is likely driven by lack of heterogeneity in removal rates across studies. Most studies reported removal rates only for no or near complete removal of biomass, and few had intermediate removal levels. As a result, the estimates are best thought of as an average effect of biomass removal.

Very few parameters besides biomass removal, initial SOC and the model coefficient (which is omitted in favor of tillage practice dummy variables in several specifications) achieve statistical significance, however those parameters are significant to $p<0.01$ certainty. Nitrogen treatment rate is significant on the WF model, but not on the BF model. Several of the non-significant parameters have been identified by other studies, or theoretical understanding of SOC dynamics, as affecting SOC changes. It is uncertain whether the results here are merely artifacts of this experimental design or call into question previous results.

4.4 Discussion

The results demonstrated above show a loss of 0.0005% to 0.002% in SOC per year for every 1% of residue removed. Using equation (1) and assuming a removal rate of 30%, which has been proposed by several sources in literature as a sustainable rate of stover removal (e.g. 41, 42), over a sampling depth of 30 cm and soil density equal to 1.31 (the average found from this dataset), this equates to a loss of 197-786 kg SOC/ha*year, which if emitted entirely as CO_2 yields 0.72 to 2.9 Mg CO_2/ha*year. In the context of life cycle analysis, this CO_2 emission is highly significant. Assuming an approximately 4 dry tonne/ha yield of stover and 292 liter/tonne conversion efficiency, this adds approximately 30 grams of CO_2e per megajoule (MJ) of delivered fuel. The RFS2 requires fuels that achieve the "cellulosic" designation achieve 50% reductions in life cycle GHG intensity compared to the petroleum fuels they displace. This implies targets of around 50 grams CO_2e/MJ for cellulosic biofuels, depending on the fuel being evaluated and the life cycle analysis methodology. The results of this study indicate that for stover based fuels, SOC change alone accounts for most of the allowable GHG emissions.

One area where substantial uncertainty remains is temporal effects. The treatment duration term was highly uncertain (the estimate was much smaller than the standard error) for both linear and logarithmic transformations of duration (Table 4-2 and Table 4-3, specifications 4, 5, 9, 10. Linear parameters were estimated, but not shown). Under commonly accepted models of soil dynamics, SOC concentrations in a field under a positive or negative SOC flux, such as residue removal, will come to an equilibrium over time (Anderson-Teixeira et al., 2013; Buyanovsky & Wagner, 1997). The lack of significance in this parameter may be a result of incorrect model specification, omission of other factors which affect SOC (such as total biomass production on the field), of a misunderstanding regarding the nature of SOC equilibria

SOC changes from stover harvest is a critical issue for determining the life-cycle GHG footprint of biofuels and bioproducts in the U.S. The U.S. grew over 34 million ha (84 million acres) of corn in 2011; which produces over a hundred million tonnes of residue as well. This residue could potentially be used for a wide range of bioprocesses and since it is currently left on the field on over 95% of farms. If SOC decreases from moderate levels of stover harvest are as high as earlier studies predict (Anderson-Teixeira et al., 2009), any bioprocess using corn stover is likely to be a significant net emitter of GHGs.

The results from the regressions above clearly show a significant and robust negative correlation between residue removal and SOC concentration. This matches the expected behavior of systems according to current understanding of SOC dynamics (Anderson-Teixeira et al., 2013; Humberto Blanco-Canqui, Lal, Post, Izaurralde, et al., 2006; Hooker et al., 2005), which strongly implies that the statistical correlation, in fact, reflects a causal relationship. By aggregating the results of many studies, the analysis presented above was able to overcome some of the statistical uncertainty described by previous authors in the field.

Few other parameters achieve statistical significance, which confirms the common conclusion in literature that SOC dynamics are highly uncertain. For WF changes, initial SOC was significantly correlated with final SOC, which is to be expected, since SOC changes are incremental increases or decreases upon previously existing SOC pools. The WF analysis also showed a significant relationship between nitrogen fertilization rate and SOC change. Previous research has been divided on the subject of the relationship between N fertilization and SOC (Dolan et al., 2006; Pikul, Johnson, Schumacher, Vigil, & Riedell, 2008).

One finding of this analysis contradicts well-established opinion in this field. For both WF and BF changes, SOC did not significantly differ between different tillage practices (CT, RT and NT were within a range less than any of their standard errors). Multiple previous studies have concluded that tillage, particularly conventional tillage (CT in this study), are strongly associated with reductions in SOC (e.g. 27, 38, 39). Further analysis is required to determine whether this is an artifact of the regression parameters used in this study, or whether tillage effects are more uncertain than previous literature indicated.

It is possible that the current model does not effectively capture differences in biomass production between fields. Of the parameters considered, only nitrogen fertilization is strongly associated with more biomass being produced. Changes in SOC levels are determined by the balance between inputs to soil, largely from plant matter, and flows out, from erosion and microbial metabolism. Rapid plant growth can increase SOC in two ways, by facilitating rapid root growth and creating a larger pool of above ground biomass, some of which may be incorporated into the soil. If the model, as currently formulated, is insensitive to the total biomass production of corn plants, then the categorical variables for tillage may be absorbing some unintended effects. Additionally, in areas with very high biomass production, tillage is sometimes required to minimize the insulating effects of surface residue, which can slow soil warming in spring and retard germination (Nielsen, 2010). This may imply an interaction between biomass production effects and tillage which is not captured in the current model.

Understanding SOC changes within the framework of life cycle analysis is complicated because accurate estimation of these changes is typically based on a consequential assessment framework. That is to say, the characteristic of interest is what changes a proposed production system would cause on the world. So, for a stover based production system the absolute magnitude of emissions from SOC change must be evaluated in a context which also considers any emissions from SOC change that would occur had the stover not been removed. This is usually done by a comparison between systems in which stover is harvested and the *status quo* in which it is generally not harvested. The analysis presented in this paper can help future analysts by presenting models for WF and BF changes. In general, the BF case better matches the needs of consequential LCA. BF comparison evaluates the difference between fields in which stover is removed and those in which it is retained on the soil. The WF comparison, on the other hand, may be less vulnerable to uncertainty stemming from soil conditions or measurement practices. BF comparisons in this study implicitly assume that all fields in a study have approximately equal SOC concentrations at the start of the study, which is not always the case, as is demonstrated by some of the studies in this review (Clapp et al., 2000; Wilts, Reicosky, Allmaras, & Clapp, 2004). Since initial SOC levels clearly affect SOC dynamics under residue removal, this means that BF comparisons suffer from at least one source of uncertainty that WF would likely avoid.

There are several areas of uncertainty which may affect the conclusions of this analysis. Climate conditions and the cultivars grown substantially affect total biomass production, which is the maximum amount of biomass that could be returned to the soil. Not all studies quantify total biomass returned, future work will attempt to evaluate whether mass of carbon entering the soil is more strongly correlated with maintaining SOC levels than residue removal rates.

While many studies have reviewed the impact of crop residue removal on SOC (Anderson-Teixeira et al., 2009; Humberto Blanco-Canqui, Lal, Post, Izaurralde, et al., 2006; Powlson et al., 2011; W W Wilhelm et al., 2004; Zanatta et al., 2007) most have not looked at agricultural management strategies that can help offset SOC lost due to crop residue removal. Blanco-Canqui (2013) recently reviewed the potential of several agricultural practices to counteract the SOC lost due to residue removal. No-till cover crops or applying C-rich substances such as manure, compost or the solid byproduct of cellulosic ethanol production (e.g. lignin cake or biochar) can all have beneficial impacts on SOC levels in soils from which lignocellulosic biomass is harvested.

The substantial uncertainty surrounding the SOC effects of sustained stover collection clearly demonstrate the need for further research in this area. LCA of biofuel production shows the critical importance of providing relatively low-GHG feedstocks for biofuel production systems. Likely near-term technology can achieve the goals of climate change mitigation policies, like RFS2, but they do not clear the GHG target thresholds for advanced biofuels by much; if feedstock production results in SOC loss at the higher end of its uncertainty range, there is virtually no chance for biofuels to achieve their GHG reduction targets and, in fact, at the high ranges of SOC loss, biofuels may be worse than the petroleum fuels they hope to replace.

Further study is needed to answer these critical questions. Most pressingly, there needs to be more empirical studies of SOC change under a variety of management conditions. Already, there is a multi-center research effort, coordinated by the USDA under the Sungrant program to directly address this research need (D. L. Karlen, Varvel, et al., 2011; Stott, Jin, & Ducey, n.d.). Additionally, better guidance regarding the most relevant methods for quantifying SOC change and measurement standards would help facilitate meaningful comparisons between studies.

8_B_LCFS_NGC Responses

654. Comment: **LCFS B8-1**

The comment states that the LCFS regulation is a necessary element in achieving long-term climate sustainability.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

655. Comment: **LCFS B8-2**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

656. Comment: **LCFS B8-3**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

657. Comment: **LCFS B8-4**

The comment supports the re-adoption of the LCFS regulation and the cost containment provision.

Agency Response: ARB staff appreciates the support for the proposed cost containment provision.

658. Comment: **LCFS B8-5**

The comment suggests the creation of a price floor for LCFS credits.

Agency Response: See response to **LCFS 6-5**.

659. Comment: **LCFS B8-6**

The comment requests that the Board to include a regular review process and procedure for modifying existing carbon intensities as better information emerges.

Agency Response: ARB staff agrees that the scientific understanding of biofuel production processes is continuing to improve, as are the tools for conducting life cycle analyses. See response to **LCFS 24-5**.

660. Comment: **LCFS B8-7**

ARB staff appreciates the commenter's concern regarding the use of harvested agricultural residues as biofuel feedstock and its net effect on stored soil carbon.

Agency Response: ARB staff appreciates the commenter's concern regarding the use of harvested agricultural residues as biofuel feedstock and its net effect on stored soil carbon. Staff acknowledges the importance of sustainable harvesting practices and the complex nature of soil organic carbon modeling and empirical analysis.

Staff agrees that soil carbon is affected by many parameters and these variables should be evaluated for specific regions, conditions, and practices for individual and specific LCFS fuel pathways. Furthermore, because soil organic carbon levels are dynamic, verification and monitoring for fuel pathways is critical to ensure LCFS credit market integrity. Staff has already gained some experience processing and approving agricultural residue feedstocks for biofuel production in the LCFS program. The fuel pathway reviews conducted to date include operating conditions that require sustainable harvesting and collecting of agricultural residues. Staff is committed to track new developments in research on soil carbon changes from use of agricultural residues for biofuel production. Staff will continue to review research on this subject and propose revisions to CI values when sufficient evidence exists to justify a change. Staff appreciates the ongoing feedback, comments, and other useful information provided by stakeholders on soil organic carbon changes from agricultural residue harvesting, which is an evolving and complex area of study.

Comment letter code: 9-B-LCFS-LCFC

Commenter: Graham Noyes

Affiliation: Low Carbon Fuels Coalition

The following letter was submitted to the LCFS Docket during the First Board Hearing.

This page intentionally left blank.

Graham
15-

9_B_LCFS
_LCFC

LOW CARBON
FUELS COALITION
980 Ninth Street, 16th Floor
Sacramento, CA 95814
(916)668-4636
www.lcfcoalition.com

February 19, 2015

Clerk of the Board
Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Comment of Low Carbon Fuels Coalition Regarding the Proposed Re-adoption of an Updated Low Carbon Fuel Standard

Dear Chairwoman Mary Nichols and Members of the Board,

Thank you for the opportunity to provide comments regarding the proposed re-adoption of California's Low Carbon Fuel Standard ("LCFS"). This letter provides the comments of the Low Carbon Fuels Coalition. The Coalition represents a broad range of low carbon fuel providers including producers and developers of biodiesel, ethanol, renewable natural gas, waste-derived fuels, and retail low carbon fuel providers. The Low Carbon Fuels Coalition tracks regulations and legislation, advocates for policies that benefit the entire low carbon fuels industry, and facilitates industry success through consensus and coalition building.

We strongly support the re-adoption of the Updated LCFS as proposed. We applaud the Air Resources Board's continued work to implement and improve the LCFS. As a direct result of the LCFS, California is leading the world in reducing greenhouse gas ("GHG") emissions from vehicles, and diversifying the transportation sector. We look forward to the LCFS program's continued success and are committed to assisting you in this endeavor.

California's first three years of LCFS experience have strengthened rather than weakened the state's economy and accelerated the growth of California's Clean Economy. The LCFS is driving tangible and valuable business activities by incentivizing technological innovations that reduce carbon intensity ("CI"). Companies are developing new CI fuels and technologies, investing in infrastructure to expand the availability of low CI fuels and

LOW CARBON
FUELS COALITION
980 Ninth Street, 16th Floor
Sacramento, CA 95814
(916)668-4636
www.lcfcoalition.com

technologies, and making investments to reduce the CI of conventional petroleum fuels and biofuels.

The LCFS is also providing the collateral benefit of reducing the US trade deficit. While domestic production has expanded substantially in recent years, the US still imports approximately half of its crude oil requirements, resulting in a net export of about $500 million per day to foreign coffers.[1] By diversifying the California transportation market, the LCFS enables the expansion of low CI fuels derived from US biomass and waste materials, as well as other US based low carbon fuel technologies. It has been determined that ethanol production in 2013 added more than 87,000 direct jobs across the country, increased the gross domestic product by $44 billion, and contributed $30.7 billion in new household income.[2] By 2022, the advanced biofuels industry is expected to produce $150 billion of economic output and support 800,000 jobs in the U.S.[3]

While we support the program as a whole, we would like to highlight several key aspects of the proposed regulation that have received significant attention and emphasize our support for these program components.

1. Compliance Curve- We strongly support ARB's proposal to maintain the original LCFS CI reduction at 10% by 2020. The entire US fuels market is watching California's progress and will benefit from California's aggressive leadership given the increasing severity of climate change. The low carbon fuels industry is committed to supplying California's low carbon fuel requirements and confident that it can produce more than sufficient quantities of fuel. LCFS B9-1

---

[1] The US is a massive net importer of crude oil at a monthly value that ranged from 20-25 billion dollars per month during 2013. A small portion of this trade deficit is offset by finished petroleum product exports which ranged from 1-7 billion dollars per month during the same period. See US Energy Information Administration, Monthly Crude Oil Trade and Monthly Petroleum Products Trade, http://www.eia.gov/todayinenergy/detail.cfm?id=15151#tabs_SpotPriceSlider-2 (last viewed November 1, 2014).

[2] See 2014 Ethanol Industry Outlook, Renewable Fuels Association, http://ethanolrfa.3cdn.net/2704ddcafa38cadd54_mlblcbx7o.pdf (last viewed February 11, 2015).

[3] See Energy Fact Check, American Council on Renewable Energy, http://www.energyfactcheck.org/featured-fact-checks/ (last viewed February 11, 2015.)

LOW CARBON
FUELS COALITION
980 Ninth Street, 16th Floor
Sacramento, CA 95814
(916)668-4636
www.lcfcoalition.com

2. Price Cap- We support the transparent and predictable market rules in the Updated LCFS to ensure that temporary shortages in the supply of low CI fuels or LCFS credits do not disrupt the market. Adoption of a Credit Clearance Market will protect markets in the event of a lack of liquidity. We support the proposed figure of $200/ton as the price that triggers the credit clearance mechanism. LCFS B9-2

3. Enforcement provisions- We support the expanded and clarified enforcement provisions that ARB has proposed to respond to fraudulent credit trades or other invalid activities are discovered in the market. The clearly defined rules dictating culpable parties and penalties will help market participants to behave within acceptable compliance boundaries. Due to the complex and novel nature of environmental attribute markets, regulators and enforcement officials must exert concerted efforts to maintain the integrity of credits and respect for the overall program. We support ARB's vesting of the Executive Officer with discretionary authority to intervene in the market to investigate suspect credits as well as the provisions providing interested parties the opportunity to respond and to submit evidence in the proceedings. LCFS B9-3

We look forward to working with you as you continue to strengthen and improve the LCFS. Please let me know if any clarification of these comments would be helpful. LCFS B8-1

Sincerely,

Graham Noyes
Acting Executive Director
Low Carbon Fuels Coalition

9_B_LCFS_LCFC Responses

661. Comment: **LCFS B9-1**

The comment supports the compliance curves and the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the proposed compliance curves.

662. Comment: **LCFS B9-2**

The comment supports the transparent and predictable market rules in the updated LCFS proposal.

Agency Response: ARB staff appreciates the support for the proposed cost containment provision.

663. Comment: **LCFS B9-3**

The comment supports the transparent and predictable market rules in the updated LCFS proposal.

Agency Response: ARB staff appreciates the support for the proposed enforcement provisions.

This page intentionally left blank.

Comment letter code: 10-B-LCFS-BIV

Commenter: Joe Gershen

Affiliation: Individual

The following letter was submitted to the LCFS Docket during the First Board Hearing.

This page intentionally left blank.

Joe Gershen
15-2-3 & 15-2-4

February 19, 2014

10_B_LCFS
_BIV

Mary D. Nichols, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95812

Re: SUPPORT FOR LCFS READOPTION AND ADF REGULATION ADOPTION at February 19-20, California Air Resources Board Hearing – Items: 15-2-3 & 15-2-4

Dear Chair Nichols,

I am very supportive of both the re-adoption of the Low Carbon Fuel Standard ("LCFS") and the adoption of the Alternative Diesel Fuel ("ADF") regulation. I would like to thank ARB leadership and staff for all their hard work on these issues, which are vitally important to Californians. I would also like to commend you on implementing a program that has inspired other carbon reduction plans on the west coast and around the country and North America. LCFS B10-1

Driven by my intense concern over global climate change, I've spent nearly 15 years committed to education, fleet transition and implementation of biodiesel in California, and have watched it grow from a fledgling idea of a few pioneering environmentalists, scientists and engineers into a robust and growing industry that has created hundreds of high paying green California jobs in some of the most disadvantaged communities around the state.

Today the California biodiesel industry is capable of reducing over 610,000 metric tons of carbon emissions from our atmosphere, which is equivalent to removing almost 140,000 cars from California roads. But these metrics took on important and measurable meaning when ARB put them into the context of the Low Carbon Fuel Standard. This groundbreaking, critical policy demonstrates California's commitment to environmental and energy sustainability while simultaneously sending a strong and stable signal to the business community that will encourage investment and innovation, which will, in turn, help to further the state's carbon reduction goals.

The development of the ADF regulation has been a challenging process but ARB has been very mindful of all stakeholder interests and I am very appreciative of that effort. The California biodiesel industry is made up of independent producers, marketers, feedstock suppliers and other interested companies of all sizes. The challenge has been to be inclusive and ARB staff has been attentive to our needs and demonstrated their willingness to work with our industry to help develop a variety of compliance options.

I am confident that working together with ARB, the California biodiesel industry can build on its success. Last year biodiesel was responsible for generating 16% of all LCFS credits while contributing approximately $350 million in economic activity to California's economy. We look forward to doing even more to reduce carbon, lower emissions, displace petroleum and create good, high paying jobs in disadvantaged California communities.

Respectfully submitted,

Joe Gershen
Biodiesel industry veteran
CBA Vice-Chair

10_B_LCFS_BIV Responses

664. Comment: **LCFS B10-1**

The comment supports the re-adoption of the LCFS regulation and the adoption of the ADF regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

This page intentionally left blank.

Comment letter code: 11-B-LCFS-CF

Commenter: Lisa Mortenson

Affiliation: Community Fuels

The following letter was submitted to the LCFS Docket during the First Board Hearing.

This page intentionally left blank.

15-2-3
Lisa Mortenson

11_B_LCFS _CF

COMMUNITY FUELS™ It makes sense.

February 11, 2015

The Honorable Chairwoman Mary Nichols
California Air Resources Board
PO Box 2815
Sacramento, CA 95812

RE: Low Carbon Fuel Standard Re-adoption

The Honorable Chairwoman Nichols:

The California Low Carbon Fuel Standard (LCFS) has made a positive impact by reducing harmful emissions and stimulating the California economy. Community Fuels designed, built and operates an advanced biorefinery at the Port of Stockton. When I co-founded the company 10 years ago, our team was confident that the public would continue to support clean, renewable energy and that state and federal policies would be implemented to incentivize the further development and integration of clean fuels.

Community Fuels produces biodiesel, an advanced biofuel as defined by the U.S. EPA. **Biodiesel is the nation's first commercially-available advanced biofuel**; U.S. production has exceeded 1 billion gallons per year for the past three years. Biodiesel is an important component to the Low Carbon Fuel Standard because it is a proven, reliable, and commercially-available low carbon fuel that can be integrated into the existing diesel infrastructure (i.e. tanks, pumps and engines).

Biodiesel continues to have strong public and bipartisan support due to its many benefits.

1. **Performance Benefits**
   - Biodiesel is a superior diesel fuel with high lubricity and detergent properties. This results in smoother and cleaner running engines and contributes to reduced wear and tear and lower maintenance costs.
   - Biodiesel (used in a 5% or lower blend ratio) may be used in all diesel engines; diesel engines are 20 to 30% more efficient than gasoline engines.

2. **Environmental & Health Benefits**
   - Biodiesel is nontoxic, biodegradable and reduces harmful emissions including carbon dioxide, particulate matter, carbon monoxide, hydrocarbons, sulfates, and PAH; reducing these emissions improves human health.
   - Biodiesel is produced from a wide variety of fats and oils that are co-products of other industries; fats and oils are plentiful due to the high global demand for proteins.
   - Biodiesel has a strong energy balance; for every unit of fossil energy it takes to produce biodiesel on a lifecycle basis, over 5.5 units of renewable energy are returned.

3. **Economic Benefits**
   - When biodiesel is produced in California, it generates significant economic benefits including jobs, revenues and taxes.
   - In-state biodiesel production creates new advanced manufacturing jobs; manufacturing jobs have the highest multiplier effect of all the industries surveyed by the U.S. Bureau of Economic Analysis.
   - Biodiesel diversifies our State's energy sources which increases energy security and reduces price and supply volatility.

The U.S. biodiesel industry has over 3 billion gallons of production capacity registered with the EPA. This existing production capacity is over 5 times higher than the entire biomass based diesel (biodiesel and renewable diesel) categories included in the 2020 illustrative compliance scenario published by the California Air Resources Board (CARB). Californians do not need to rely on fuels imported from other countries - the U.S. biodiesel industry is ready to deliver. Also, when Californians import energy, we give up many of the economic opportunities associated with the LCFS program. **Let's keep the economic opportunities within California by minimizing imported energy and maximizing in-state production.**

Community Fuels biodiesel is primarily sold to regulated parties, which include petroleum refiners, pipeline shippers and importers. Regulated parties purchase our fuel in order to meet compliance obligations under the U.S. Renewable Fuel Standard, the CA LCFS, and the CA Cap and Trade program. Every gallon of biodiesel that is purchased displaces a gallon of diesel fuel and therefore reduces the market share of regulated parties. **Without strong and stable policies requiring the use of clean, renewable fuels, regulated parties would not purchase our fuel.**

We appreciate the efforts made by CARB staff to further improve the LCFS program by reducing indirect land use change penalties, improving the integrity of fuel pathways, and strengthening the reporting and enforcement provisions to reduce fraud risk. We request that CARB staff sunset the alternative diesel fuel rulemaking at the earliest possible date in order to remove obstacles to broader use of biodiesel throughout the state. **Community Fuels strongly supports the re-adoption of the California Low Carbon Fuel Standard.** The continued success of this regulation is critical to the viability of our California business. Please contact me with any questions at (760)942-9306 or lisa@communityfuels.com. LCFS B11-1

With enthusiastic support of renewable fuels, clean air and a strong economy,

Lisa Mortenson
Co-Founder and Chief Executive Officer
American Biodiesel, Inc. dba Community Fuels

Cc: Board Members of the California Air Resources Board
The Honorable Governor Edmund G. Brown, Jr.

COMMUNITY FUELS™

Community Fuels. A proven advanced biofuel producer.

- **Empowering Communities**
with regional production of cost-effective renewable energy.
- **Supporting Regional Economies**
by enabling easier access to clean energy and developing diversified feedstock supplies.
- **Producing High Performance Fuels**
that improve lubricity and reduce engine wear.
- **Supplying Advanced Biofuels**
that help clean the air and meet the requirements of the US Renewable Fuel Standard.
- **Meeting Market Demand**
efficiently with our proprietary process technology.
- **Supplying Western Markets**
with a renewable fuel that meets the rigorous quality requirements of multiple major oil companies.

Why Community Fuels?

- **Proven:** Community Fuels is a proven producer - We have been in continuous operation since 2008 and have fulfilled over 5000 bulk orders of fuel.
- **Low Risk:** Our fuel exceeds the ASTM standard and meets the requirements of multiple major oil companies and pipeline operators. We perform proactive testing on all fuel to ensure high quality.
- **Marketable Credits:** The marketplace is comfortable with Community Fuels' product, our RINS, and our CI credits - it takes years to build market confidence.
- **Operational Excellence:** Our rigorous operational procedures in production, quality assurance, and accounting makes our customers' jobs easier. We provide comprehensive documentation and proof of compliance with every load.

Contact Community Fuels now to establish a relationship for reliable supply of high quality biodiesel fuels. **Call (760)942-9306 or email sales@communityfuels.com now!**

www.communityfuels.com

National Biodiesel Accreditation Commission
BQ-9000
PRODUCER

11_B_LCFS_CF Responses

665. Comment: **LCFS B11-1**

The comment strongly supports re-adoption of the LCFS program and states that the continued success of this regulation is critical to the viability of their California business.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

This page intentionally left blank.

Comment letter code: 12-B-LCFS-GE

Commenter: Joshua Willter

Affiliation: Growth Energy

The following letter was submitted to the LCFS Docket during the First Board Hearing.

This page intentionally left blank.

12_B_LCFS _GE

3_B_ADF _GE

STATE OF CALIFORNIA

AIR RESOURCES BOARD

PROPOSED AMENDMENTS TO THE CALIFORNIA LOW CARBON FUELS STANDARD REGULATION AND THE PROPOSED REGULATION ON THE COMMERCIALIZATION OF ALTERNATIVE DIESEL FUELS

GROWTH ENERGY'S RESPONSE
TO THE NOTICES OF PUBLIC HEARINGS DATED DECEMBER 16, 2014
2015 CAL. REG. NOTICE REG. 13, 45 (JANUARY 2, 2015)

ADDITIONAL EXHIBITS TO COMMENTS FILED FEBRUARY 17, 2015

FEBRUARY 19, 2015

Exhibit Cover Sheet

growth energy™
America's Ethanol Producers

777 North Capitol Street, NE, Suite 805, Washington, D.C. 20002
PHONE 202.545.4000 FAX 202.545.4001 GrowthEnergy.org

May 10, 2010

Mr. James N. Goldstene
Executive Officer, California Air Resources Board
1001 I Street, 23rd Floor
Sacramento, California 95812

By Hand and Electronic Mail

Re: Petition to Amend the Low-Carbon Fuel Standard Regulation Pursuant to Cal. Gov't Code § 11340.6

Dear Mr. Goldstene:

On behalf of Growth Energy, an association of the nation's leading ethanol manufacturers and other companies who serve the nation's need for alternative fuels, I respectfully petition for amendments to the California low-carbon fuel standard ("LCFS") regulation published in title 17 of the *California Code of Regulations* at 17 C.C.R. §§ 9548-95490. That regulation was approved by the California Air Resources Board ("CARB" or "the Board") in April 2009, and you took final action with respect to the relevant provisions of the LCFS regulation in November 2009. This petition is submitted pursuant to section 11340.6 of the California Government Code. It is based upon data and analysis that has become available to Growth Energy within the last two weeks.[1]

The specific amendments to the LCFS regulation proposed by Growth Energy are as follows:

1. An amendment to the LCFS regulation that would take effect no later than December 31, 2010, that would eliminate the "Land Use or Other Indirect Effect" carbon intensity values assigned to the corn ethanol pathways in Table 6 in section 95486 ("Table 6") for corn ethanol used to comply with the LCFS regulation in 2011 and 2012. LCFS B12-1

[1] The relevant new developments are also discussed in a letter to ARB from the Renewable Fuels Association ("RFA") dated April 28, 2010, which, while not formally requesting action under the Government Code, also recommends an immediate change in the LCFS regulation. The RFA letter is included as an attachment to this petition.

2. As an alternative to the amendment presented above in paragraph 1, an amendment to the LCFS regulation that would take effect no later than December 31, 2010, and that would replace the 30 gram of carbon dioxide-equivalent emissions per megajoule ("g/mj") value in Table 6 for corn ethanol pathways with 15.1 or 13.9 g/mj, for corn ethanol used to comply with the LCFS regulation in 2011 and 2012. LCFS B12-2

3. If the amendment presented in paragraph 1 is not adopted, then in addition to the amendment presented in paragraph 2, an amendment to the LCFS regulation that would take effect no later than September 30, 2010, and that would require the Executive Officer to take final action on a Method 2A or Method 2B submittal under section 95486 within 90 days of his receipt of a complete submittal pursuant to Method 2A or Method 2B. LCFS B12-3

The change in paragraph 1 above would be effected by replacing "30" in the indirect emissions values for corn ethanol in Table 6 with "0." Changes in regulatory text sought in paragraphs 2 and 3 of the petition are shown in Exhibit 1. The balance of this letter and the attached exhibits provide the rest of the information required by section 11340.6 of the Government Code. LCFS B12-4

I. Authority to Amend the LCFS Regulation and Requirements of the Government Code

Sections 39600-39601 of the Health & Safety Code empower the Board to adopt regulations in accordance with the California Administrative Procedure Act ("the APA"). The power to adopt regulations brings with it the power to amend regulations. Except when the right to do so is otherwise restricted, section 11340.6 of the Government Code permits any interested person to seek amendment to rules adopted by the Board. There is no statutory impediment to consideration of this petition on its merits. A response is therefore required in the manner described in your recent response to another petition under section 11340.6 of the Government Code, in which you stated as follows:

> Under Government Code section 11340.7, the State agency within 30 days may grant or deny the petition in part, and may grant any other relief or take any other action as it may determine to be warranted by the petition. It must also indicate why the agency has reached its decision in writing and if it grants the petition, it must schedule the matter for public hearing in accordance with the notice and hearing requirements of the APA.

Letter to M. Steele from J. Goldstene, Feb. 11, 2010 at 1 n.1 (*see* Exhibit 2). If you determine that you lack authority under sections 39515 and 39516 to consider and to grant any aspect of this petition, Growth Energy requests that (i) you refer this petition to the Board, and (ii) the Board grant this petition. LCFS B12-5

II. Grounds for Amendment of the LCFS Regulation.

The Board adopted the LCFS regulation as an early-action measure to implement the Global Warming Solutions Act of 2006, codified at sections 38500-38599 of the Health & Safety Code (the "2006 Act"). The Legislature directed ARB to use the "best available economic and scientific information" when adopting regulations to implement the 2006 Act. Health & Safety Code § 38652 (e).

During the LCFS rulemaking, ARB selected models developed by the Global Trade Analysis Project ("GTAP") to estimate the indirect emissions impact of the use of corn ethanol to comply with the LCFS regulation. As you explained in announcing the use of GTAP at the start of the LCFS rulemaking:

> To assess the emissions from land use changes, staff used the Global Trade Analysis Project (GTAP) [model] to estimate [greenhouse gas, or "GHG"] emissions impact. ... In general, the [GTAP] model evaluates the worldwide land use conversion associated with the production of crops for fuel production. Different types of land use have different rates of storing carbon. In general, multiplying the changes in land use times an emission factor per land conversion type results in an estimate of the GHG emissions impacts of land conversions.

Notice of Public Hearing to Consider Adoption of a Proposed Regulation to Implement the Low Carbon Fuel Standard (dated Feb. 24, 2009) at 8. The suite of the GTAP models used in last year's LCFS regulation is specified in the regulation at 17 C.C.R. §95481(a)(20.5), and is called in the regulation the "February 2009" version of GTAP.

LCFS B12-6

The GTAP modeling system was developed by the faculty and staff of the Department of Agricultural Economics at Purdue University. It should be noted in this regard that at least one GTAP expert at Purdue (Dr. Thomas Hertel) advised the Board at the inception of the regulatory process that the use of GTAP to select single-point carbon intensity values might be less defensible than other uses of the GTAP system and could be considered arbitrary. Last month researchers at Purdue led by Professor Wallace E. Tyner reported the development of a new and, in their opinion, improved version of the GTAP modeling system, called GTAP-BIO-ADV. Their research was partially funded by the Argonne National Laboratory. A final report summarizing the changes made in the GTAP modeling system has been prepared and is attached to this petition as Exhibit 3. Consistent with Dr. Hertel's advice during the rulemaking process, the new GTAP report presents a range of indirect land-use emissions values for corn ethanol, and invites the reader to evaluate the range of outputs and the assumptions that produce the different outputs.[2]

As indicated in the new report from the GTAP researchers at Purdue, the indirect emissions impact that Table 6 attributes to corn ethanol (which is based on the February 2009 version of GTAP) is significantly overstated, based on the results of GTAP-BIO-ADV. Table 6 assigns an indirect carbon intensity value to corn ethanol of **30 g/mj**. Based on certain assumptions about growth in yield and population, the average indirect land-use emissions that can properly be attributed to corn ethanol using the updated GTAP modeling system is **13.9 g/mj**, or less than half the level used in Table 6, measured in g/mj of carbon intensity. The marginal carbon intensity value that the new analysis based on GTAP-BIO-ADV would attribute to corn ethanol's indirect effects under those same assumptions about yield and

LCFS B12-7

[2] It should be noted that Growth Energy does not agree with some of the fundamental assumptions made in indirect land-use change ("ILUC") theory applied in the LCFS rulemaking, and that Growth Energy believes that the final LCFS regulation failed to comply with the 2006 Act and other legal requirements, even before publication of the new work on GTAP discussed in this petition.

LCFS B12-6 cont.

population growth is **15.1 g/mj.** The Board should not overlook this important change in the results that are produced by the GTAP modeling system using updated data, which was not available to the Board when it approved the LCFS regulation, nor available to the public during the post-hearing review process last summer and fall. LCFS B12-7 cont.

Growth Energy does not believe that the economic and scientific bases for attribution of indirect emissions impacts to corn ethanol usage are adequate, as explained in comments submitted to ARB last year. Putting that disagreement with the Board's overall approach to the side, however, it should be clear that ARB must reconsider Table 6 before the LCFS regulation takes full effect at the start of 2011. Discussing the carbon intensity values developed last year, one consultant for ARB testified as follows at the April 2009 Board hearing:

> [I]f we make a mistake in one direction in estimating these numbers, we'll use too much of a biofuel that's actually higher carbon [than] we thought and will therefore increase global warming. And if we use numbers that are too low, then we'll use too little of a biofuel that's lower carbon than we thought and will therefore increase global warming.

See April 2009 Hearing Transcript, *available at* http://www.arb.ca.gov/board/mt/2009/mt042309.pdf, at 73-74. As the same witness pointed out, "the cost to the world of being wrong in both directions is fairly symmetrical," and "there's no obvious conservative direction" to take in order to minimize the risks and costs of error. *Id.* at 74. LCFS B12-8

There is debate today about how to conduct a full lifecycle emissions analysis of transportation fuels. At this point, however, it should be clear that the GTAP modeling framework as adapted to a lifecycle analysis for corn ethanol has changed significantly since 2009. Moreover, the results produced by the GTAP systems are highly dependant on some assumptions that (in the latest report from Purdue) are not fully documented or explained. For example, it is far from clear whether what the new report calls the "yield effect" on food consumption is consistent with historical data. The selection of a population growth rate in the new iteration of the model is also not fully explained, and the new model appears to continue the assumption in the old model that forest land is converted in roughly the same proportion to all other land types. The new model is therefore likely to overstate the impact of corn ethanol usage on greenhouse gas emissions, accepting all other assumptions made in the ILUC theory. The new GTAP system may be an improvement over the February 2009 version, but the risk of error that punishes corn ethanol without a proper scientific basis remains great. LCFS B12-9

Given the risk of error, Growth Energy believes that the best course would be to eliminate any indirect emissions penalty for ethanol, and perhaps for all other biofuels, for at least the first two years of the LCFS compliance period (2011 and 2012), so that the science can catch up with regulatory process. Such a deferral of indirect emissions assessments will give the Board's external expert working groups time to formulate and present recommendations for full lifecycle analysis to the Board. A decision to defer ILUC-based emissions penalties in Table 6 for a full two years should be made now, so that the regulated parties can develop initial compliance plans with the LCFS regulation that are not based on clearly mistaken ILUC-based penalties. Assuming that the expert working groups can report to the Board by the end of the current year and recommend appropriate reforms in lifecycle emissions assessments at LCFS B12-10 that time, and that the Board can act on those recommendations in early 2011, then revised carbon intensity values could be included in Table 6 in early 2011 to take effect in 2013. LCFS B12-10 cont.

Even if ARB maintains the view (not shared by Growth Energy) that there is surely some indirect emissions impact from corn ethanol use, and that the indirect emissions value must be "greater than zero," there should be no disagreement that the February 2009 verison of the GTAP modeling system on which the LCFS regulation is currently based is now obsolete. When the GTAP modeling system is updated with what the new Purdue report calls "model improvements" and with a 2006 data base, there is a substantial reduction in the carbon intensity values that the Purdue team believes can credibly be assigned to corn ethanol. (*See, e.g.*, Exhibit 3, Table 20 at p. 46.) The use of a 2006 data base seems itself to be questionable, but the availability of that data set certainly shows that the older data set used in the February 2009 version of the GTAP modeling system is no longer the "best available economic and scientific information." Health & Safety Code § 38652 (e). Surely, those who believe that some "non-zero" value needs to be assigned to indirect emissions from the use of biofuels would agree that the 30 g/mj value in Table 6 is not the correct or most reliable "non-zero" value, and must be changed in order to avoid a serious mistake. LCFS B12-11

Based on the new work at Purdue (but without agreeing with the premise that corn ethanol must be assigned some indirect land-use change emissions impact), if the Board believes that a "non-zero" value for indirect emissions must remain in Table 6, Growth Energy believes that consistency with the "best available" science requirement of the 2006 Act mandates the replacement of the 30 g/mj value with either 13.9 or 15.1 g/mj, depending on whether ARB decides to use average or marginal emissions values. Such a change should be made now, with the expectation that the expert working group and the Board will be able to revisit the issue in time to make any necessary further changes for biofuels usage after 2012. If such a change is not made now, the LCFS regulation will take full effect in a few months' time using carbon intensity values that are simply no longer credible.[3] LCFS B12-12

In the event that ARB decides not to establish a two-year moratorium on the use of indirect emissions impacts for corn ethanol, Growth Energy requests two further regulatory changes in addition to the reduction in the indirect emissions values assigned to corn ethanol in 2011 and 2012. First, given the importance of prompt action on revisions to the carbon intensity values assigned to alternative fuels, LCFS B12-13 Growth Energy also requests that section 95486 be revised to include a 90-day deadline for action on Method 2A and Method 2B applications. Second, in light of the rapid pace of developments in the GTAP modeling structure, Growth Energy believes it would be appropriate to amend the LCFS regulation to make it clear that the Executive Officer should permit the use of updated versions of the GTAP models in the Method 2A and Method 2B procedures for determining carbon intensity. LCFS B12-14

---

[3] During the rulemaking process that Growth Energy seeks, it is possible that other interested parties could come forward with data and analysis to support changes in the indirect land-use change values assigned to ethanol produced from sugar cane. To avoid proliferation of proceedings, Growth Energy recommends that any such changes sought in the indirect emissions values assigned to ethanol produced from sugar cane be presented without delay pursuant to Government Code § 11340.6. Growth Energy would vigorously oppose any action with respect to such a petition concerning sugar cane ethanol that might result in a delay in consideration of amendments sought in this petition. LCFS B12-12 cont.

The dates specified for final action to amend the current regulation presented on pages one and two of this letter (by December 31, 2010, for the amendments to Table 6, and by September 20, 2010 for the Method 2A/2B amendments) are critical to the objectives of this petition. Any delay from those dates will therefore mean effective denial of the petition. ARB should proceed with the publication of a notice for a public hearing to consider the changes requested here as soon as possible, and certainly no later than the 30-day period allowed by the Government Code for action on petitions of this type. LCFS B12-15

* * * *

Thank you for considering this petition. Please contact me at 605-965-2375 if you have any questions, or if further steps are required for consideration of this petition by you or by the Board.

Sincerely,

David Bearden

David Bearden
General Counsel

cc: Ellen Peter, Esquire

12_B_LCFS_GE Responses (Page 1 – 8)

666. Comment: **LCFS B12-1**

The comment suggests eliminating the "Land Use or Other Indirect Effect" carbon intensity values assigned to corn ethanol pathways.

Agency Response: Eliminating the "land-uses or other indirect effect" carbon intensity values would be inconsistent with a key objection of the LCFS program; to lower the CI of transportation fuels through an accurate lifecycle assessment. See also responses to **LCFS 8-1**, **LCFS 8-4**, **LCFS 46-166**, **LCFS 46-216**, **LCFS T25-1**, and **LCFS B12-4**.

667. Comment: **LCFS B12-2**

The comment suggests an amendment to the LCFS program that would impose a different iLUC value for corn ethanol.

Agency Response: This document was prepared by the commenter in response to ARB analysis presented in 2009 where the value of 30.0 g/MJ appears, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

The comments are not relevant since it requested reductions in the iLUC value for corn ethanol for 2011 and 2012. The current analysis has updated the iLUC value for corn ethanol to 19.8 g/MJ, and this value will be used starting in 2016 upon Board approval in 2015.

668. Comment: **LCFS B12-3**

The comment suggested a 2010 amendment to the LCFS regulation to require the Executive Officer to take final action on a Method 2A or Method 2B submittal within 90 days of submittal of the complete package.

Agency Response: The 2010 document is not directed at the current LCFS proposal. Staff responds to the extent the 2010 letter makes objections or recommendations that nevertheless could pertain to the proposal. ARB does not think it is wise to require an absolute time limit for processing applications, given that every application is different in terms of complexity, and given the fact that available staff resources fluctuate depending on the State's annual budget. In approving the LCFS regulation, the Board considered the need for an expeditious process for reviewing a Method 2A or 2B submittal and weighed that need against the public interest in being able to review the submittal in an open process. While ARB staff expects most submittals to be reviewed relatively quickly, in some cases, the complexity of a submittal may warrant a staff review that exceeds 90 days. Therefore, the Board determined that the most appropriate balance of these considerations is reflected in the public review and final action provisions contained in section 95486(f). Staff believes the existing-process in the regulation provides a necessary and appropriate balance between these two considerations and has therefore determined that commenter-requested amendment would be inappropriate.

669. Comment: **LCFS B12-4**

Agency Response: This document was prepared by the commenter in response to an ARB analysis presented in 2009, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

ARB staff disagrees with the commenter's proposal to amend the LCFS regulation to eliminate "Land Use or Other Indirect Effect" carbon intensity values assigned to corn ethanol by replacing the proposed iLUC value with "0". See response to **LCFS B12-1**.

670. Comment: **LCFS B12-5**

The commenter argues that "any regulation adopted by the Board must be consistent with and reasonably necessary to accomplish the purposes of AB 32."

Agency Response: The commenter asserts that the proposal falls short of that standard for three separate reasons, addressed as (1), (2), and (3) below.

Before addressing those points, ARB staff notes that the commenter has made an implicit – and incorrect – assumption, namely that the LCFS is founded solely on AB 32. Before AB 32 was enacted in 2006, ARB promulgated regulations under other authority for almost 40 years. During those decades, ARB's authority grew steadily. The LCFS proposal is based in part on ARB's pre-AB 32 authority, and need not serve only AB 32 goals. For example, ARB relied upon its broad authority to regulate motor vehicles, motor vehicle fuels, and to attack the problem caused by motor vehicle emissions systematically. (See, e.g., Health & Saf. Code §§39003, 39600, 39601.) Moreover, it is the policy of the State of California to reduce the State's dependence on petroleum. (Pub. Res. Code §25000.5) ARB has also been charged with reducing toxic air contaminants. (Health & Saf. Code §39650 et seq.)

Insofar as AB 32 also authorizes ARB to adopt an LCFS, the proposal, by stimulating innovative fuels and incentivizing the use of existing low-carbon fuels such as electricity, will help accomplish the purposes of AB 32.

1. *The commenter points out that AB 32 implementation measures "must not 'interfere with . . . efforts to achieve and maintain federal and state ambient air quality standards' to the extent feasible.*"

   The LCFS does not interfere, and in fact furthers California's systematic efforts to reduce motor vehicle pollution. The LCFS incentivizes fuels that are currently understood to be cleaner than gasoline and diesel, such as low carbon ethanol, electricity, hydrogen, biodiesel, and renewable diesel.

2. *GHG reductions must be "real, permanent, quantifiable, verifiable, and enforceable."*

   Based on quarterly and annual reports showing what fuels have been provided for use in California, ARB will be able to demonstrate the applicability of those five objectives.

3. *The Board is required to rely on the best available economic and scientific information available when adopting AB 32 regulations*.

   As set forth in the Initial Statement of Reasons, and its appendices and references, ARB staff has relied on the best available economic and scientific.

671. Comment: **LCFS B12-6**

The comment questions whether the GTAP model provides accurate estimates for the indirect emissions impact of corn ethanol pathways.

Agency Response: The document was prepared by the commenter in response to ARB analysis presented in 2009, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

1. ARB staff disagrees with the commenter that the use of a point estimate value for carbon intensity is arbitrary. Although the regulation adopted in 2009 requires the use of a point value for iLUC emissions, it reflects the average of iLUC estimates from several scenarios for each biofuel. The scenarios were designed to capture variability in parameters that impact the model outputs. To improve upon the analysis completed in 2009, ARB staff developed a Monte Carlo framework with assistance from UC Berkeley. The Monte Carlo analysis uses outputs from hundreds of simulations and is able to isolate parameters in the GTAP and AEZ-EF models that have the largest impact on model outputs. These parameters were used to develop a set of 30 scenarios by utilizing a range of discrete values for each of the parameters (variations were based on literature review and expert opinion) identified from the Monte Carlo screening analysis. For the proposed regulation, the iLUC estimate, a single point estimate for each biofuel reflects the average of the 30 scenario runs. Furthermore, the mean value estimated from the hundreds of Monte Carlo simulations was used to corroborate the average value calculated from the scenario runs. To be noted is that the mean estimated from the uncertainty analysis is similar to the average calculated from the scenario runs for all of the six biofuels. See also response to **LCFS 38-32**.

2. The updates to the model being referenced are for the time period 2010-2012. All applicable updates to the GTAP database, methodology, and structure have been included in the current version of the GTAP model. Only areas for which there was lack of data were not included in the current analysis.

3. Commenter's footnote (written in 2010 about the adoption of an earlier regulation) are not objections or recommendations regarding the current proposal and do not need a response. As to comments related to the incorporation of iLUC emissions into the regulation, the ISOR describes support below for the inclusion of iLUC estimates for biofuels.

The analysis conducted in 2009 used available data and understanding of land use science to develop the best estimate of iLUC emissions. The current analysis has refined the 2009 iLUC analysis to account for the latest data and updated land use change science. All of the iLUC values being proposed to the Board are a result of ARB staff using the latest science and best data to estimate iLUC values for all six biofuels.

See also responses to **LCFS 8-1**, **LCFS 46-166** and **LCFS 46-216**.

672. Comment: **LCFS B12-7**

The comment states that the indirect emissions impact attributed to corn ethanol is significantly overstated based on the results of GTAP-BIO-ADV.

Agency Response: The document prepared by the commenter is dated May 10, 2010, and is in response to ARB analysis presented in 2009, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014.

See also responses to **LCFS 46-216** and **LCFS B12-13**.

673. Comment: **LCFS B12-8**

The comment states that the economic and scientific basis for determining the value for indirect emission impacts of corn ethanol usage are inadequate.

Agency Response: The document was prepared by commenter in response to ARB analysis presented in 2009 where the value of 30.0 g/MJ appears, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

ARB staff does not agree with comments that the economic and scientific bases for attribution of indirect emissions to corn ethanol are inadequate. ARB staff used GTAP, which is an economic model that captures the most significant economic effects related to modeling the impacts of biofuel expansion. The GTAP model is also a peer-reviewed model based on sound scientific principles. A peer review of iLUC emissions in 2009 concluded that the model was scientifically appropriate to estimate iLUC emissions.

The 2010 letter is irrelevant because it refers to updates to the GTAP model implemented by Purdue after the Board Hearing in 2009. ARB staff, per the Board's directive, had committed to update the iLUC analysis only after completing a comprehensive review of the science of land use change. Between 2009 and December 2014, ARB staff utilized published information by Purdue and other researchers and available data to refine the 2009 version of the model. Empirical data, real-world observations, updated modeling methodology, and improved assessment methods have all been considered in the current methodology to estimate iLUC emissions. Many of the suggestions presented by the commenter have been incorporated into the current analysis. Some recommendations that were not considered for the current analysis were either due to lack of detailed data or because the modeling structure did not allow for the inclusion of such effects. In the future, when data becomes available, staff will incorporate appropriate modeling structures and parameters to account for other effects not considered for the current rulemaking

Details of the 30 scenario runs and the uncertainty analysis using the Monte Carlo approach are provided in Appendix I of the ISOR. The uncertainty analysis concluded that the mean of the likely values was not significantly different from the average of the 30 scenario runs. ARB staff's approach therefore limits the likelihood of risks and costs related to erroneous values for iLUC emissions. See response to **LCFS 8-1** for support using the Monte Carlo. See also responses to **LCFS B12-6** and **LCFS B12-19**.

674. Comment: **LCFS B12-9**

The comment expresses concern that the GTAP model needs further improvement and currently runs the risk of error that punishes corn ethanol without a proper scientific basis.

Agency Response: The 2010 letter is irrelevant because it refers to updates to the older version of the GTAP model implemented by Purdue after the Board Hearing in 2009. See responses to **LCFS B12-8** and **LCFS B12-27**.

675. Comment: **LCFS B12-10**

The comment suggests eliminating any indirect emissions penalty for ethanol, and possibly all other biofuels, for at least the first two years of the LCFS compliance period.

Agency Response: The document was prepared by the commenter in response to ARB analysis presented in 2009 and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

ARB staff does not agree with the commenter that the iLUC values as should be eliminated for the first two years of the program. Although it should be noted that those first two years (2011 and 2012) have passed with no adverse impact identified to the ethanol industry.

See also responses to **LCFS 8-1**, **LCFS 8-4**, **LCFS 46-166**, **LCFS 46-216**, **LCFS B12-4**, **LCFS T25-1**, and **LCFS B12-16**.

676. Comment: **LCFS B12-11**

The comment states that the 2009 version of GTAP is obsolete.

Agency Response: See response to **LCFS B12-7**.

677. Comment: **LCFS B12-12**

The comment states that the indirect land-use change emissions impact for corn ethanol should be changed.

Agency Response: The document was prepared by the commenter in response to ARB analysis presented in 2009 where the value of 30.0 g/MJ appears, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

The current ARB proposal is a significant change from the 2009 proposal and includes results based on the latest data and improved version of GTAP modeling and the latest information on parameters influencing the model and emission factors. ARB staff, per the Board's directive, had committed to update the iLUC analysis only after completing a comprehensive review of the science of land use change.

See also responses to **LCFS B12-8**, **LCFS B12-9, LCFS B12-1**, **LCFS B12-4**, **LCFS B12-17**, **LCFS B12-26**, and **LCFS B12-27**.

678. Comment: **LCFS B12-13**

The comment implies that a two-year moratorium should be placed on the use of indirect emissions impact for corn ethanol.

Agency Response: This document was prepared by the commenter in response to ARB analysis presented in 2009, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments in responses to **LCFS 46-216**, **LCFS B12-7**, and **LCFS B12-10**.

679. Comment: **LCFS B12-14**

The comment requests a 90 day deadline for action on the Method 2A and Method 2B applications and an amendment to the LCFS regulation to make it clear that the Executive Officer should permit the use of updated versions of the GTAP models in the Method 2A and Method 2B procedures.

Agency Response: Please see response **LCFS B12-3**. With regard to the suggestion to use an updated version of GTAP, we note that such an updated version is part of the readopted LCFS.

680. Comment: **LCFS B12-15**

In 2010, the commenter believed that there was available evidence of certain land changes that were not accounted for in the GTAP model incorporated into the 2009 proposal.

Agency Response: The comment is not directed at the 2014 LCFS proposal and does not need a response.

Exhibit 1

Table 6. Carbon Intensity Lookup Table for Gasoline and Fuels that Substitute for Gasoline.

Fuel	Pathway Description	Carbon Intensity Values (gCO2e/MJ)		
		Direct Emissions	Land Use or Other Indirect Effect	Total
Gasoline	CARBOB – based on the average crude oil delivered to California refineries and average California refinery efficiencies	95.86	0	95.86
Ethanol from Corn	Midwest average; 80% Dry Mill; 20% Wet Mill; Dry DGS	69.40	~~30~~ 15.1 or 13.9	~~99.40~~ 84.5 or 83.3
	California average; 80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG	65.66	~~30~~ 15.1 or 13.9	~~95.66~~ 80.76 or 79.56
	California; Dry Mill; Wet DGS; NG	50.70	~~30~~ 15.1 or 13.9	~~80.70~~ 65.8 or 64.6
	Midwest; Dry Mill; Dry DGS, NG	68.40	~~30~~ 15.1 or 13.9	~~98.40~~ 83.5 or 82.3
	Midwest; Wet Mill, 60% NG, 40% coal	75.10	~~30~~ 15.1 or 13.9	~~105.10~~ 90.2 or 89.0
	Midwest; Wet Mill, 100% NG	64.52	~~30~~ 15.1 or 13.9	~~94.52~~ 79.62 or 78.42
	Midwest; Wet Mill, 100% coal	90.99	~~30~~ 15.1 or 13.9	~~120.99~~ 106.09 or 104.89
	Midwest; Dry Mill; Wet, DGS	60.10	~~30~~ 15.1 or 13.9	~~90.10~~ 75.2 or 74.0

	California; Dry Mill; Dry DGS, NG	58.90	~~30~~ 15.1 or 13.9	~~88.90~~ 74.0 or 72.8
	Midwest; Dry Mill; Dry DGS; 80% NG; 20% Biomass	63.60	~~30~~ 15.1 or 13.9	~~93.60~~ 78.7 or 77.5
	Midwest; Dry Mill; Wet DGS; 80% NG; 20% Biomass	56.80	~~30~~ 15.1 or 13.9	~~86.80~~ 71.9 or 70.7
	California; Dry Mill; Dry DGS; 80% NG; 20% Biomass	54.20	~~30~~ 15.1 or 13.9	~~84.20~~ 69.3 or 68.1
	California; Dry Mill; Wet DGS; 80% NG; 20% Biomass	47.44	~~30~~ 15.1 or 13.9	~~77.44~~ 62.54 or 61.34
Ethanol from Sugarcane	Brazilian sugarcane using average production processes	27.40	46	73.40
	Brazilian sugarcane with average production process,mechanized harvesting and electricity co-product credit	12.40	46	58.40
	Brazilian sugarcane with average production processand electricity co-product credit	20.40	46	66.40
Compressed Natural Gas	California NG via pipeline; compressed in CA	67.70	0	67.70
	North American NG delivered via pipeline; compressedin CA	68.00	0	68.00
	Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in CA	11.26	0	11.26
	Dairy Digester Biogas to CNG	13.45	0	13.45
Liquefied Natural Gas	North American NG delivered via pipeline; liquefied in CA using liquefaction with 80% efficiency	83.13	0	83.13
	North American NG delivered via pipeline; liquefied inCA using liquefaction with 90% efficiency	72.38	0	72.38

	Overseas-sourced LNG delivered as LNG to Baja;re-gasified then re-liquefied in CA using liquefactionwith 80% efficiency	93.37	0	93.37
	Overseas-sourced LNG delivered as LNG to CA;re-gasified then re-liquefied in CA using liquefaction with 90% efficiency	82.62	0	82.62
	Overseas-sourced LNG delivered as LNG to CA;no re-gasification or re-liquefaction in CA	77.50	0	77.50
	Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 80% efficiency	26.31	0	26.31
	Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 90% efficiency	15.56	0	15.56
	Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 80% efficiency	28.53	0	28.53
	Dairy Digester Biogas to LNG liquefied in CA usingliquefaction with 90% efficiency	17.78	0	17.78
Electricity	California average electricity mix	124.10	0	124.10
	California marginal electricity mix of natural gas andrenewable energy sources	104.71	0	104.71
Hydrogen	Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps)	142.20	0	142.20
	Liquid H2 from central reforming of NG	133.00	0	133.00
	Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps)	98.80	0	98.80
	Compressed H2 from on-site reforming of NG	98.30	0	98.30
	Compressed H2 from on-site reforming with renewable feedstocks	76.10	0	76.10

(c) *Method 2A – Customized Lookup Table Values (Modified Method 1).*

Under Method 2A, the regulated party may propose, for the Executive Officer's written approval pursuant to section 95486(f), modifications to the GTAP Model or to one or more inputs to the CA-GREET model used to generate the carbon intensity values in the Method 1 Lookup Table.

For any of its transportation fuels subject to the LCFS regulation, a regulated party may propose the use of Method 2A to determine the fuel's carbon intensity, as provided in this section 95486(c). For each fuel subject to a proposed Method 2A, the regulated party must obtain written approval from the Executive Officer for its proposed Method 2A before the regulated party may use Method 2A for determining the carbon intensity of the fuel. The Executive Officer's written approval may include more than one of a regulated party's fuels under Method 2A.

The Executive Officer may not approve a proposed Method 2A unless the regulated party and its proposed Method 2A meet the scientific defensibility, "5-10" substantiality, and data submittal requirements specified in section 95486(e)(1) through (3) and the following requirements:

(1) The proposed modified GTAP Model or CA-GREET inputs must accurately reflect the conditions specific to the regulated party's production and distribution process;

(2) The proposed Method 2A uses only the inputs that are already incorporated in CA-GREET and does not add any new inputs (e.g., refinery efficiency); and

(3) In lieu of use of the GTAP Model or a modified GTAP Model, the ~~The~~ regulated party ~~must~~ may request the Executive Officer to conduct an analysis or modeling to determine the new pathway's impact on total carbon intensity due to indirect effects, including land-use changes, as the Executive Officer deems appropriate. ~~The Executive Officer will use the GTAP Model (February 2009), which is incorporated by reference, or other model determined by the Executive Officer to be at least equivalent to the GTAP Model (February 2009).~~

(d) *Method 2B – New Pathway Generated by California-Modified GREET (v.1.8b).* Under Method 2B, the regulated party proposes for the Executive Officer's written approval the generation of a new pathway using the CA-GREET model as provided for in this provision and the GTAP Model or a modified GTAP model. The Executive Officer's approval is subject to the requirements as specified in section 95486(f) and the following requirements:

(1) For purposes of this provision, "new pathway" means the proposed full fuel-cycle (well-to-wheel) pathway is not already in the ARB Lookup

Table specified in section 95486(b)(1), as determined by the Executive Officer;

(2) The regulated party must demonstrate to the Executive Officer's satisfaction that the CA-GREET can be modified successfully to generate the proposed new pathway. If the Executive Officer determines that the CA-GREET model cannot successfully generate the proposed new pathway, the proponent-regulated party must use either Method 1 or Method 2A to determine its fuel's carbon intensity;

(3) The regulated party must identify all modified parameters for use in the CA-GREET for generating the new pathway;

(4) The CA-GREET inputs used to generate the new pathway must accurately reflect the conditions specific to the regulated party's production and marketing process; and

(5) In lieu of use of the GTAP Model or a modified GTAP Model, the ~~The~~ regulated party ~~must~~ may request the Executive Officer to conduct an analysis or modeling to determine the new pathway's impact on total carbon intensity due to indirect effects, including land-use changes, as the Executive Officer deems appropriate. ~~The Executive Officer will use the GTAP Model (February 2009), which is incorporated by reference, or other model determined by the Executive Officer to be at least equivalent to the GTAP Model (February 2009).~~

(e) *Scientific Defensibility, Burden of Proof, Substantiality, and Data Submittal Requirements and Procedure for Approval of Method 2A or 2B.* For a proposed Method 2A or 2B to be approved by the Executive Officer, the regulated party must demonstrate that the method is both scientifically defensible and, for Method 2A, meets the substantiality requirement, as specified below:

(1) *Scientific Defensibility and Burden of Proof.* This requirement applies to both Method 2A and 2B. A regulated party that proposes to use Method 2A or 2B bears the sole burden of demonstrating to the Executive Officer's satisfaction, that the proposed method is scientifically defensible.

(A) For purposes of this regulation, "scientifically defensible" means the method has been demonstrated to the Executive Officer as being at least as valid and robust as Method 1 for calculating the fuel's carbon intensity.

(B) Proof that a proposed method is scientifically defensible may rely on, but is not limited to, publication of the proposed Method 2A or 2B in a major, well-established and peer-reviewed scientific journal (e.g., Science, Nature, Journal of the Air and Waste Management Association, Proceedings of the National Academies of Science).

(2) *"5-10" Substantiality Requirement.* This requirement applies only to a proposed use of Method 2A, as provided in section 95486(c). For each of its transportation fuels for which a regulated party is proposing to use Method 2A, the regulated party must demonstrate, to the Executive Officer's satisfaction, that the proposed Method 2A meets both of the following substantiality requirements:

(A) The source-to-tank carbon intensity for the fuel under the proposed Method 2A is at least 5.00 grams CO2-eq/MJ less than the source to-tank carbon intensity for the fuel as calculated under Method 1. "Source-to-tank" means all the steps involved in the growing/extraction, production and transport of the fuel to California, but it does not include the carbon intensity due to the vehicle's use of the fuel; "source-to-tank" may also be referred to as "well-to-tank" or "field-to-tank."

(B) The regulated party can and is expected to provide in California more than 10 million gasoline gallon equivalents per year (1,156 MJ) of the regulated fuel. This requirement applies to a transportation fuel only if the total amount of the fuel sold in California from all providers of that fuel exceeds 10 million gasoline gallon equivalents per year.

(3) *Data Submittal.* This requirement applies to both Method 2A and 2B. A regulated party proposing Method 2A or 2B for a fuel's carbon intensity value must meet all the following requirements:

(A) Submit to the Executive Officer all supporting data, calculations, and other documentation, including but not limited to, flow diagrams, flow rates, CA-GREET calculations, equipment description, maps, and other information that the Executive Officer determines is necessary to verify the proposed fuel pathway and how the carbon intensity value proposed for that pathway was derived;

(B) All relevant data, calculations, and other documentation in (A) above must be submitted electronically, such as via email or an online web-based interface, whenever possible;

(C) The regulated party must specifically identify all information submitted pursuant to this provision that is a trade secret; "trade secret" has the same meaning as defined in Government Code section 6254.7; and

<u>(D)</u> The regulated party must not convert spreadsheets in CA-GREET containing formulas into other file formats.

~~(D)~~ (f) The Executive Officer shall take final action a request for modification of a fuel's carbon intensity value using Method 2A or Method 2B within 90 days of a complete submittal of such a request. The Executive Officer shall notify a party making a submittal using Method 2A or Method 2B within 15 days of receipt of such a submittal whether he has found the submittal to be complete.

12_B_LCFS_GE Responses (Page 9 – 16)

681. Comment: **Exhibit 1**

Agency Response: These pages are proposed regulatory changes associated with comment **LCFS B12-4.** As such, see the response to **LCFS B12-4**.

This page intentionally left blank.

Exhibit 2

Air Resources Board

Mary D. Nichols, Chairman
1001 I Street • P.O. Box 2815
Sacramento, California 95812 • www.arb.ca.gov

Linda S. Adams
Secretary for Environmental Protection

Arnold Schwarzenegger
Governor

(Via email and U.S. Mail)

February 11, 2010

Mr. Michael J. Steel, Esq.
Morrison Foerster
425 Market Street
San Francisco, California, 94105-2482
msteel@mofo.com

Re: Response to January 11, 2010, Petition Filed by Associated General Contractors of America

Dear Mr. Steel:

I am writing in response to the petition filed pursuant to the Administrative Procedure Act (APA), Government Code section 11340.6, by the Associated General Contractors of America (AGC or petitioner) dated January 11, 2010.[1] The petition requests that the Air Resources Board (ARB or Board) adopt an emergency amendment to delay the fleet average target dates of the In-Use Off-Road Diesel-Fueled Fleets Regulation (regulation)[2] for two years. The petition also requests that ARB ask the United States Environmental Protection Agency (U.S. EPA) to postpone consideration of California's request for authorization of the regulation that ARB submitted pursuant to section 209(e)(2) of the federal Clean Air Act (CAA) until such time that ARB has resolved the issues underlying the petition.

After careful consideration of all of the facts associated with the petitioner's request, pursuant to Government Code section 11340.7(b), I am granting the following relief and finding that the following actions are warranted:

---

[1] The petition is available from ARB upon request. Under the APA, any interested person may petition a State agency requesting the adoption, amendment, or repeal of a regulation as provided in Government Code section 11340.6. The petition must clearly and concisely state the substance or nature of the regulation, the requested amendment or repeal, the reason for the request, and the reference to the authority of the State agency to take the action requested. Under Government Code section 11340.7, the State agency within 30 days may grant or deny the petition in part, and may grant any other relief or take any other action as it may determine to be warranted by the petition. It must also indicate why the agency has reached its decision in writing and if it grants the petition, it must schedule the matter for public hearing in accordance with the notice and hearing requirements of the APA.

[2] Title 13, California Code of Regulations, sections 2449 through 2449.3.

The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption For a list of simple ways you can reduce demand and cut your energy costs, see our website: http://www.arb.ca.gov

California Environmental Protection Agency

Printed on Recycled Paper

(1) ARB will issue an advisory notifying all stakeholders subject to the regulation that ARB will take no enforcement action regarding compliance with the regulation's emission standards or other emission related requirements before ARB receives authorization from U.S. EPA; and

(2) a hearing will be held in Sacramento on March 11, 2010, before the Executive Officer to take testimony and other relevant information on the need for further amendments to the regulation to address the economic recession confronting the State and the adverse impacts that the recession has caused to the construction and other industries that operate off-road vehicles. As the Board has already directed staff to provide an update on the regulation at its April 2010 meeting, any information and testimony collected at this hearing shall be compiled and included as part of that update.

This relief, coupled with statutory and regulatory relief already provided by Assembly Bill 8 2X (AB 8 2X or bill), will ensure no stakeholders will be in violation with the regulation's March 1, 2010 emission standards or other emission related requirements. Therefore, I have concluded that an emergency does not exist. I am also taking no action on the petitioner's request that ARB request U.S. EPA to delay issuance of the authorization, because the request is outside the scope of the APA petition process.

Summary of January 11, 2010 Petition

The petitioner's request that ARB delay implementation of the regulation can be summarized as follows: since the Board's approval and adoption of the regulation in 2007-2008, changed circumstances in the economy and its impact on construction activity in California have affected the financial ability of construction fleets to comply with the regulation's requirements while concurrently resulting in fewer emissions from construction vehicles. In claiming that a two-year moratorium in implementing the initial compliance requirements is urgently necessary, the petition argues that, without such immediate relief, California construction contractors will suffer immediate and irreparable harm because the regulation as it currently exists will force fleets to either downsize or have to purchase and install expensive and unreliable emission control devices or repower their equipment in order to meet the 2010 and 2011 fleet average requirements.[3] In making this claim, AGC asserts that the relief provided by AB 8 2X signed by the Governor on February 20, 2009, provides insufficient relief with "some relief to some contractors, but not to others, and certainly not to all [a]nd even those relieved of the initial burdens will find that that [sic] their relief is fleeting. . . ."[4]

[3] Petition at p. 6.
[4] *Id.*

AGC further argues that current economic conditions in the construction industry will not improve over the next two years,[5] and that reduced emissions resulting from the current economy gives the Board flexibility to delay the regulation and thereby reduce the financial burdens that it will impose, while still meeting the goals of the State Implementation Plan.[6]

<u>Background of the Regulation</u>

The Board approved the regulation for adoption on July 26, 2007, and formally adopted it on April 4, 2008. In adopting the regulation the Board specifically found that the regulation was necessary, technically feasible, and cost effective.[7] In finding that the regulations were necessary, the Board determined that in-use off-road diesel-fueled vehicles are significant contributors of emissions of oxides of nitrogen (NOx), particulate matter (PM), including PM2.5, and diesel exhaust, the last of which has been identified as a toxic air contaminant. The Board further found that the regulation would result in reductions in emissions that would prevent approximately 4,000 premature deaths and other harmful health impacts and would help California meet National Ambient Air Quality Standards (NAAQS) for ozone and PM2.5.

Subsequently, California, the nation, and the international community, in general, experienced a serious economic recession that has undisputedly impacted California businesses, including the State's construction industry. In response, as part of the 2009-2010 State budget, the California Legislature passed, and the Governor signed, AB 8 2X. Codified in Health and Safety Code section 43018.2, ARB was directed to amend the regulation to provide specified relief to affected stakeholders who have been negatively impacted by the State recession. Specifically, the legislation directed the Board to modify the NOx and PM credit provisions of the regulation to reflect vehicle retirements that reduce total fleet horsepower between March 1, 2006 and March 1, 2010, and reduced fleet activity between March 1, 2007, and March 1, 2010. It further directed the Board to amend the total cumulative NOx turnover and PM retrofit requirements for the years 2011 through 2013, to provide fleets with greater compliance flexibility with the regulation's requirements over the next three years.

Pursuant to the legislation's directives, the Board approved amendments to the regulation on July 23, 2009, with the amendments formally adopted and operative on December 3, 2009.

After adoption of the regulation in 2008, but before the enactment of AB 8 2X, AGC filed on December 15, 2008, the first of its two petitions, and requested that ARB amend and/or repeal the regulation. ARB and AGC agreed on February 4, 2009, to hold the

---

[5] *Id.*, at p. 7.
[6] *Id*, at p. 5.
[7] Resolution 07-19, a copy of which is attached as Attachment 1.

petition in abeyance as the parties evaluate data to determine the recession's impacts on construction fleets. With notice from either party, the petition could once again be activated and require an ARB response. To date, neither party has sought to activate the first petition.

On December 3, 2009, AGC presented ARB staff with its 2009 emissions inventory modeling analysis using the Diesel Off-Road On-Line Reporting System (DOORS)[8] data collected by ARB staff. The analysis was subsequently sent to the Board and made a part of the record of the December 11, 2009, Board hearing. At the hearing, the Board directed staff to return at its April and July 2010 Board hearings with an assessment of how the recession has impacted stakeholders subject to the regulation, using such information that is available, including the most recent fleet data that fleets are required to report no later than April 1, 2010.

<u>Response to Petition</u>

A. Actions Warranted by the Petition

Pursuant to the authority provided under Government Code section 11340.7, I am granting the following relief and finding the actions described below to be warranted.

1. Enforcement Advisory

I have determined that issuance of an enforcement advisory is warranted. The advisory will notify all stakeholders affected by the regulation that ARB will not take any enforcement action for noncompliance with the regulation's emission standards or other emission related requirements before ARB receives authorization from U.S. EPA.

2. Hearing before the Executive Officer to Determine Need for Further Relief from the Impacts of the Recession

I am scheduling a hearing to be held on March 11, 2010 before the Executive Officer for the purpose of receiving testimony and other relevant information on the question of whether the regulation needs to be further amended to provide additional mitigation for stakeholders that have been adversely impacted by the recession and for whom the compliance relief provided by the AB 8 2X amendments has not been adequate. At the hearing, the petitioner and affected stakeholders will be provided the opportunity to fully present information on the effects of the recession on the construction industry and other industrial sectors of the economy, in general, and off-road fleets in particular. They will also be able to present testimony and information on how the recession has

[8] DOORS is an online reporting tool designed to help fleet owners report their off-road diesel vehicle inventories and actions taken to reduce vehicle emissions to ARB, as required by the regulation.

affected emissions in the State, and why further delay of the regulation's compliance schedule is necessary and will not affect California's continuing efforts to improve air quality within its borders. I am also requesting that AGC and other stakeholders provide concrete and verifiable information to support any claims that the economy, in general, and the construction industry, specifically, will not have sufficiently rebounded from the recession by 2013.[9] The collected information will assist ARB staff in determining whether additional amendments to the regulation beyond those already adopted should be proposed to the Board.

In holding the hearing, I recognize that the present recession is the deepest recession since the Great Depression of the 1930s, that it has adversely impacted many fleets covered by the regulation, and that recovery from this recession is taking longer than many expected. I also recognize that the recession has resulted in reduced activity for many fleets and that, as a consequence, emissions are lower than forecasted in 2007, when the regulation was initially approved. However, what must be determined is the adequacy of the amendments already in place. The Executive Officer hearing will provide the best means of collecting information to make that determination.

In directing that an Executive Officer hearing be held, I have determined immediate Board action is not necessary since no emergency exists. The petition argues that the regulation must be immediately delayed by two years to prevent immediate and irreparable harm to fleets, in large part because the fleets have been adversely impacted by the current severe recession.[10] There is no dispute that a severe recession exists and that fleets have been negatively impacted. However, the AB 8 2X amendments, which became operative on December 3, 2009, have averted the need for immediate emergency action. The amendments adopted by the Board address the petition's concerns by providing a two-year delay, except for the largest fleets that were able to sustain revenues at pre-recession 2007 levels. Any fleet that has reduced its horsepower through retirement of vehicles between March 1, 2006 and March 1, 2010 will receive compliance credit for that horsepower reduction. Similarly, any fleet that has reduced its operational activity over the last several years (i.e., the difference in fleet activity between calendar year 2007 and the 12-month period bounded by March 1, 2009 to February 28, 2010) will also receive compliance credit. This effectively provides immediate compliance relief in the first years of the regulation's implementation for most fleets that have been adversely affected by the recession. For example, any fleet that has reduced its horsepower through retirements or reduced the amount that it operates by 32 percent or more will be COMPLETELY exempt from any compliance actions in 2010 or 2011 (i.e., will not be required to turn over any vehicles or install any retrofits). Fleets that have been more modestly impacted by the recession will be able to offset some of their 2010 and 2011 compliance requirements.

---

[9] See Petition at pages 4 and 6
[10] Petition at page 6

The AB 8 2X amendments also allow all fleets, even those unaffected by the recession, to postpone much of the compliance actions originally required for 2011 and 2012 until 2013. Fleets whose business has not been adversely impacted should financially be in position to meet the regulation's immediate 2010 requirements.[11] Moreover, it is reasonable to assume that at least some of these fleets will take advantage of the regulation's early action credit provisions.[12] This relief along with the compliance relief provided in the above-referenced advisory preclude my finding that an emergency exists. For these reasons, I cannot accept AGC's characterization that most, if not all, fleets need immediate further relief to avoid irreparable harm.[13]

Immediate action is also not required even though the AB 8 2X amendments do not address the fleet average requirements of the regulation. The petition essentially argues that the remedy provided in AB 8 2X is insufficient in that it does not address the fleet average requirements of the regulation.[14] The argument is unsupportable because AB 8 2X specifically provides relief to fleets from the regulation's best available control technology (BACT) requirements, which are a compliance alternative to the fleet average requirements. Thus, to the extent that fleets achieve compliance by meeting the regulation's BACT requirements through credits for vehicle retirements and fleet inactivity, they are under no obligation to meet the fleet average requirements. Consequently, the AB 8 2X relief effectively addresses all of the regulation's performance requirements.

B. No Action is Warranted for ARB to Request that U.S. EPA Delay Issuing California an Authorization for the Regulation

The petition requests that ARB inform U.S. EPA that it should not issue the authorization that California has requested for the regulation. I have determined that such a request is outside of the scope of the APA petitioning process, which is directed at requests for adoption, amendment, or repeal of a regulation.[15] Accordingly, no action on the request is warranted.

C. Conclusion

In conclusion, for the foregoing reasons, I am granting the following relief: ARB will issue an advisory no later than February 28, 2010, notifying stakeholders that ARB will not take any enforcement action for noncompliance with the regulation's March 1, 2010 emission standards or other emission related requirements before it receives authorization from U.S. EPA. I have further determined that an Executive Officer

[11] See e.g., title 13, Cal. Code Regs., §§ 2449(d)(1), 2449.1(a)(2)(A)2., and 2449.2(a)(2)(A)2.
[12] Title 13, Cal Code Regs , § 2449(g)(1)(G).
[13] Petition at page 4.
[14] Petition at pages 1 and 4.
[15] Govt. Code § 11340.7.

hearing to take testimony and receive information on the question of whether further amendments to the regulation, beyond those that have been adopted to date, is warranted. At the hearing, AGC and other stakeholders will have the opportunity to present testimony and documentation on the recession's impact and what additional relief stakeholders need to address those impacts.

If you have questions regarding the decision on this petition or would like to discuss the regulation, please contact Mr. Erik White, Chief, Heavy-duty Diesel In-Use Strategies Branch, at (916) 322-1017 or ewhite@arb.ca.gov or Mr. Michael Terris, Senior Staff Counsel, Office of Legal Affairs, at (916) 445-9815 or mterris@arb.ca.gov.

Sincerely,

James N. Goldstene
Executive Officer

Attachment

cc: Tom Cackette,
Chief Deputy Executive Officer

Ellen M. Peter
Chief Counsel

Bob Cross, Chief
Mobile Source Control Davison

Erik White, Chief
Heavy-Duty Diesel In-Use Strategies Branch

Michael Terris
Senior Staff Counsel
Office of Legal Affairs

12_B_LCFS_GE Responses (Page 17 – 24)

682. Comment: **Exhibit 2**

Agency Response: This exhibit is an email from Executive Officer James Goldstene and is referred to in comment **LCFS B12-5**. As such, see the response to **LCFS B12-5**.

This page intentionally left blank.

Exhibit 3

Land Use Changes and Consequent CO_2 Emissions due to US Corn Ethanol Production: A Comprehensive Analysis*

By

Wallace E. Tyner
Farzad Taheripour
Qianlai Zhuang
Dileep Birur
Uris Baldos

April 2010

Department of Agricultural Economics
Purdue University

FINAL REPORT

* The research underlying this report was partially funded by Argonne National Laboratory. We are deeply indebted to Dr. Michael Wang for his many contributions to this research. Throughout the process, he has consistently posed excellent questions that have stimulated more thinking and modifications on our part. Also, for this final paper, he provided an excellent set of insightful suggestions and comments that have improved the paper significantly. Of course, the authors are solely responsible for the content of and any errors in the report.

Executive Summary

The basic objective of this research was to estimate land use changes associated with US corn ethanol production up to the 15 billion gallon Renewable Fuel Standard level implied by the Energy Independence and Security Act of 2007. We also used the estimated land use changes to calculate Greenhouse Gas Emissions associated with the corn ethanol production.

The main model that was used for the analysis is a special version of the Global Trade Analysis Project (GTAP) model. It is a computable general equilibrium model that is global in scope. The version used for this analysis has up to 87 world regions and 57 economic sectors plus the biofuel sectors that were added for this analysis. There are many different versions of the GTAP model. It is used by thousands of economists around the world for analysis of trade, energy, climate change, and environmental policy issues. The model is publically available with documentation of the model and data base at www.gtap.org. The version used in this analysis contains energy and GHG emissions (GTAP-E) and also has land use (GTAP-AEZ). The name for the special version created for this work is GTAP-BIO-ADV and encompasses many changes to improve the analysis of corn ethanol:

- The three major biofuels have been incorporated into the model: corn ethanol, sugarcane ethanol, and biodiesel.
- Cropland pasture in the US and Brazil and Conservation Reserve Program lands have been added to the model.
- The energy sector demand and supply elasticities have been re-estimated and calibrated to the 2006 reality. Current demand responses are more inelastic than previously.
- Corn ethanol co-product (DDGS) has been added to the model. The treatment of production, consumption, and trade of DDGS is significantly improved.
- The structure of the livestock sector has been modified to better reflect the functioning of this important sector.
- Corn yield response to higher corn prices has been estimated econometrically and included in the model.
- The method of treating the productivity of marginal cropland has been changed so that it is now based on the ratio of net primary productivity of new cropland to existing cropland in each country and AEZ.

There are many other changes both in data and model structure, which are detailed in the report, but these are the major model and data modifications.

To evaluate the land use implications of US ethanol production we develop three groups of simulations. In the first group we calculate the land use implications of US ethanol production off of the 2001 database. This approach isolates impacts of US ethanol production from other changes which shape the world economy. In the second group of simulations, we first construct a baseline which represents changes in the world economy during the time period of 2001-2006. Then we calculate the land use impact of the US ethanol production off of the updated 2006 database, while we follow the principles of the first group of simulations for the time period of 2006-20015. Finally, in the third group of simulations we use the updated 2006 database obtained from the second group of simulations but we assume that during the time period of 2006-2015 population and crop yields will continue to grow.

In this summary, we will first report the land use changes for the third group of simulations. Then we present emissions obtained for the three groups of simulations. Tables 1 and 2 provide the estimated land use changes broken down by US and rest of world (Table.1) and the forest pasture split (Table 2). On average 28% of the land use change occurs in the US, and 72% in the rest of the world. Forest reduction accounts for 35% of the change and pasture 65%. On average 0.12 hectares of land are needed to produce 1000 gallons of ethanol.

Table1. Simulated global land use changes due to the US ethanol production: with yield and population growth after 2006

Changes in US corn ethanol production	Land use changes (hectares)			Distribution of Land Use changes (%)			Hectares per 1000 Gallons
	Within US	Other Regions	World	Within US	Other Regions	World	
3.085 BG (2001 to 2006)	119281	320068	439349	27.1	72.9	100.0	0.14
2.145 BG (2006 to 7 BG)	58799	150754	209553	28.1	71.9	100.0	0.10
2.000 BG (7 to 9 BG)	58167	134225	192392	30.2	69.8	100.0	0.10
2.000 BG (9 to 11 BG)	60919	141118	202038	30.2	69.8	100.0	0.10
2.000 BG (11 to 13 BG)	64529	167511	232040	27.8	72.2	100.0	0.12
2.000 BG (13 to 15 BG)	69848	196148	265996	26.3	73.7	100.0	0.13
13.23 BG (2001 to 15 BG)	431544	1109824	1541368	28.0	72.0	100.0	0.12

Table 2. Simulated global land use changes due to the US ethanol production: With yield and population growth after 2006

Changes in US corn ethanol output	Land use changes (hectares)			Distribution of land use changes (%)		
	Forest	Grassland	Crop*	Forest	Grassland	Total*
3.085 BG (2001 to 2006)	-155414	-283921	439349	35.4	64.6	100.0
2.145 BG (2006 to 7 BG)	-71830	-137724	209553	34.3	65.7	100.0
2.000 BG (7 BG to 9 BG)	-67347	-125070	192392	35.0	65.0	100.0
2.000 BG (9 BG to 11 BG)	-70376	-131670	202038	34.8	65.2	100.0
2.000 BG (11 BG to 13 BG)	-79832	-152216	232040	34.4	65.6	100.0
2.000 BG (13 BG to 15 BG)	-93949	-172051	265996	35.3	64.7	100.0
13.23 BG (2001 to 15 BG)	-538749	-1002651	1541368	35.0	65.0	100.0

*The difference between the changes in cropland and the sum of forest and grassland is due to rounding

We now consider estimated emissions induced by US ethanol production. Table 3 summarizes the emissions results from the three sets of simulations, and Table 4 provides the estimated ethanol and gasoline emissions in grams per gallon of gasoline equivalent.

Table 3. Estimated land use change emissions due to U.S. ethanol production (Figures are annual CO_2 emissions in grams per gallon of ethanol)

GTAP results off of 2001 database	Average emissions	1676
	Marginal emissions	1846
GTAP results off of 2006 database	Average emissions	1407
	Marginal emissions	1446
GTAP results off of 2006 plus population & yield growth	Average emissions	1116
	Marginal emissions	1217

Table 4. Estimated well-to-wheel ethanol and gasoline emissions for average land use changes (emissions are in grams per gallon of gasoline equivalent)

Description	Ethanol Emissions	Gasoline Emissions	Ethanol GHGs vs Gasoline (percent)
Simulations Off of 2001	10342	11428	90.5
Simulations Off of 2006	9933	11428	86.9
Simulations Off of 2006 Plus population & yield growth	9490	11428	83.0

Land use change and the associated GHG emissions is a very controversial topic. Some argue it is impossible to measure such changes. Others argue that failure to measure the land use changes and the consequent GHG emissions would lead us to incorrect policy conclusions. After working on this topic for over two years, we come out between these extremes. First, with almost a third of the US corn crop today going to ethanol, it is simply not credible to argue that there are no land use change implications of corn ethanol. The valid question to ask is to what extent land use changes would occur. Second, our experience with modeling, data, and parameter estimation and assumptions leads us to conclude that one cannot escape the conclusion that modeling land use change is quite uncertain. Of course, all economic modeling is uncertain, but it is important to point out that we are dealing with a relatively wide range of estimation differences.

In some cases, the results are fairly stable regardless of the simulation. For example, the percentage of land that comes from forest ranges between 25 and 35 percent depending on the model and assumptions being used. Similarly, the fraction of land use change that occurs in the U.S. ranges between 25 and 34 percent. However, the land needed to meet the ethanol mandate ranges between 0.12 and 0.22 hectares/1000 gallons, which is a fairly wide range. The land use ethanol CO_2 emissions per gallon range between 1116 and 1676, also a fairly large range. Total ethanol CO_2 emissions due to production and consumption of gasoline (including land use) range between 77.5 g/MJ and 84.4 g/MJ. Ethanol emissions as a fraction of gasoline emissions range between 83.0 and 90.5 percent. From these results, we feel confident that corn ethanol would meet a 10 percent savings standard. On the other hand the results suggest that corn ethanol would not meet a 20 percent emissions reduction standard. However, we cannot say that corn ethanol would not meet a 20 percent standard given the inherent uncertainty in the analysis, and potential improvement in direct emissions associated with corn farming and ethanol production.

Analysis such as that undertaken here is very complex and is limited by data availability, validity of parameters, and other modeling constraints. Economic models, like other models, are abstractions from reality. They can never perfectly depict all the forces and drivers of changes in an economy. However, the basic model used for this analysis, GTAP, has withstood the test of time and peer review. Hundreds of peer reviewed articles have been published using the GTAP data base and analytical framework. In this project, we have made many changes in the model and data base to improve its usefulness for evaluating the land use change impacts of large scale biofuels programs. Yet, uncertainties remain. In this paper, we have described the evolution of the modeling and analysis and present openly the evolution of the results. We believe quite strongly that analysis of this type must be done with models and data bases that are available to others. Replicability and innovation are critical factors for progress in science. They also are important for credibility in policy analysis.

Table of Contents

List of Tables

List of Figures

1. Introduction

US ethanol production has increased sharply from 1.7 billion gallons (BGs) in 2001 to about 10 BGs in 2009. According to the Renewable Fuel Standard (RFS) in the US Energy Independence and Security Act of 2007 (CRS RL34294), 2007, US corn ethanol production will reach 15 BGs in 2015. This level of ethanol production will affect agricultural activities within the US and around the world. In particular, it can cause land use changes anywhere in the world, and the implications of land use changes are complex and controversial. A sizeable ethanol production program has the potential to increase corn price, corn yield per unit of land, affect corn consumption, change corn trade, and encourage livestock producers to use byproducts of ethanol production in their animal feed rations. Land use changes associated with increased corn ethanol production are important because the land use changes can affect the CO_2 emissions associated with ethanol production and consumption.

Argonne National Laboratory (ANL) (Wang 1999, Wang et al. 1999, and 2005) has developed a life cycle model (GREET) which estimates the emissions of greenhouse gases (GHGs, including CO2, CH4, and N2O) of corn ethanol production. The GREET model classifies GHG emissions into three categories: 1) feedstock production; 2) fuel production - corn to ethanol in this case; and 3) vehicle operation. The total emissions associated with the ethanol supply chain are then compared with the analogous calculations for gasoline. At present, there is limited data on GHG emissions from direct land use changes due to biofuel production included in the GREET model. The land use consequences of biofuel production and their corresponding emissions were highlighted in the literature. The early papers published in this area show that biofuel production could have extraordinary land use implications (Searchinger et al. 2008[1], Fargione et al. 2008). Because the land use emissions were claimed to be so large, it was deemed important to get different assessments of the possible land use changes and associated emissions. Argonne and Purdue agreed that Purdue would conduct such an analysis using the Global Trade Analysis Project (GTAP) modeling framework and data base. In order to do this analysis with GTAP, several model and data base modifications were required, and these are described in this report.

This report aims to evaluate land use changes and CO_2 emissions induced by US corn ethanol production for several alternative configurations and assumptions. The results of this paper provide information on land use related emissions due to ethanol production that can be combined with the emissions calculated in GREET to produce total green house gas (GHG) emissions associated with corn ethanol production and use. This total can then be compared with gasoline to determine the net gain/loss for corn ethanol production and use compared with gasoline.

To achieve this goal we use three major components. First, we use a computational general equilibrium (CGE) model to assess the economic impacts of ethanol production and its land use implications for the world under alternative sets of assumptions. The CGE model is a special version of the Global Trade Analysis Project (GTAP) model (Hertel, 1997) of the global economy which was recently developed by Taheripour, Hertel, and Tyner (2009) to evaluate impacts of biofuel production for the global livestock industry.

The second component consists of a module which converts land use changes estimated in GTAP to the associated CO_2 emissions. This module generates CO_2 emissions factors which we use to convert land use changes into CO_2 emissions based on the Woods Hole Research Center data set on the soil and land cover carbon profiles. The Woods Hole data set divides the

[1] We will henceforth refer to this paper as SEA

whole world into 10 regions and provides data on the soil and land cover carbon profiles for each region[2].

Finally, we convert the land use related emissions calculated in module two to emissions per gallon of 100% ethanol and add those emissions to those calculated in GREET to get total emissions. This can be done either within the GREET model or by direct calculations. For this paper we have done the calculations directly.

In this report rather than using the terms direct and indirect emissions, as is commonly reported in the literature, we categorize the emissions as those calculated in GREET and associated with use of corn for producing and consuming ethanol and emissions associated with land use changes. By some definitions of the term indirect, these would be labeled indirect emissions, but to avoid confusion we label them emissions associated with induced land use changes.

We should from the outset acknowledge that land use change is a complicated process. It is driven by many factors and varies through time. There are social as well as economic factors involved in the complicated process of evolving land use. The factors vary by culture, region, and economy.[3] Obviously neither this analysis nor any analysis can capture all the factors involved in land use change. What we have attempted to do is to isolate the impacts of a substantial increase in US corn based biofuels production. Since corn is a globally produced and consumed commodity, these impacts will be of necessity global. The impacts will be driven to a

---

[2] In our earlier report (Tyner, Taheripour, and Baldos, 2009) we applied the IPCC data set as well. The IPCC data set provides data on the soil and land cover carbon profiles at a global scale with no specification of geographical distribution. The IPCC land use emissions factors are much larger than the regional emissions factors derived from the Woods Hole data set. In this report we only apply the land use emissions factors obtained from the Woods Hole data set. The IPCC data set is too aggregate to be useful in this analysis. Since our results are down to the AEZ and country level, we took advantage of the greater disaggregation in the Woods Hole data.

[3] We are indebted to Gbadebo Oladosu and Keith Kline of Oak Ridge National Laboratory for providing data and useful perspectives on the land use change process.

significant degree by changes in global supply and demand of feed grains. Thus, we have used a global general equilibrium model which can capture many of these market mediated effects.

The rest of this paper is organized as follows. We first introduce the GTAP model and modifications which are made in this model to make it suitable for analyzing economic and environmental consequences of biofuels. Then we explain our simulations and assumptions behind them along with the land use results from these simulations. After that we introduce the land use CO_2 emission factors which we use to convert land use changes into CO_2 emissions. Finally, we present CO_2 emissions induced by US ethanol production due to land use changes and compare these results with results from other studies.

2. Land use changes due to US ethanol production: GTAP model

To evaluate the impacts of the US corn ethanol production on global land use we need a model which is global in scope, and which links global production, consumption and trade. In addition, the model should properly link energy, biofuel, and agricultural markets. Since biofuel, crop, and livestock industries compete through the land market, the model should link these activities through the land market as well. Furthermore, biofuels byproducts, which can be used in animal feedstuffs, bridge these industries through a triangular relationship which alters the nature of competition among these industries. All of this has led us to use a special purpose version of the Global Trade Analysis Project (GTAP) model and its database. GTAP is a computable general equilibrium (CGE) model which considers production, consumption, and trade of goods and services by region and at a global scale. Figure 1 represents an illustrative overview of the GTAP model.

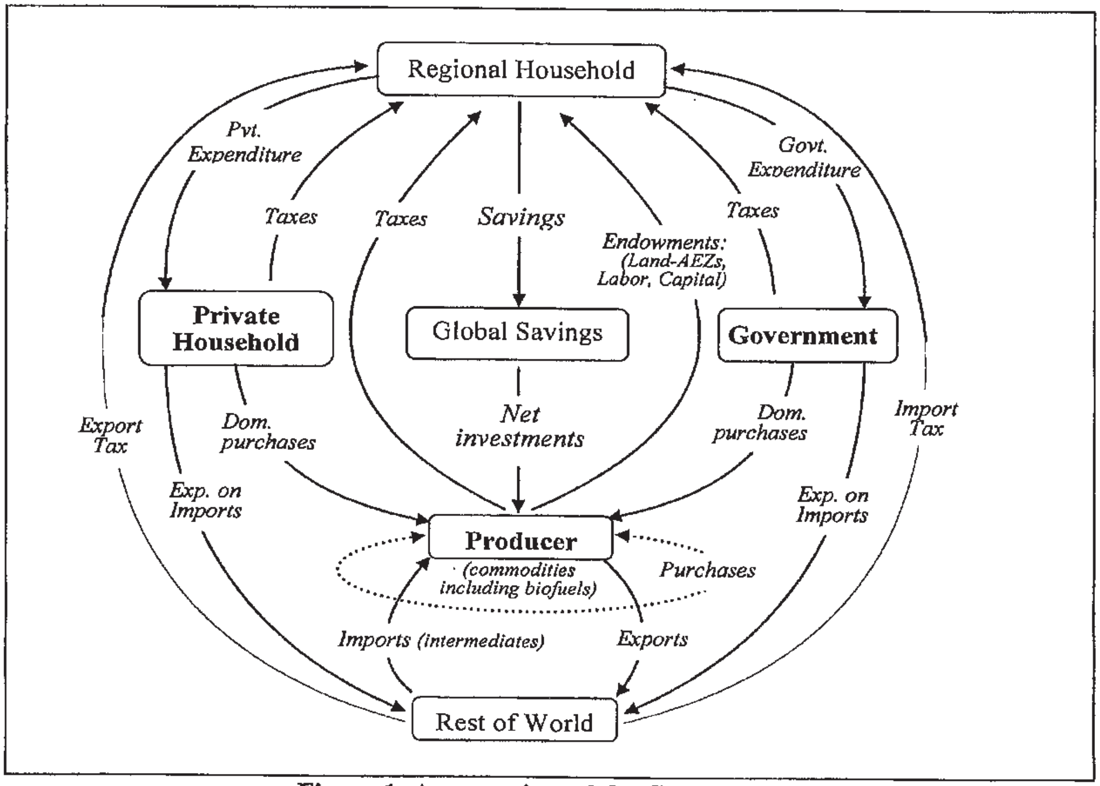
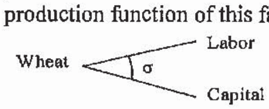


Figure 1. An overview of the GTAP model

In GTAP each country or composite region is represented by a regional household which collects all incomes generated by the economy and allocates them among three components of the final demand: Private Household, Government, and Savings (for details see Brockmeier (1996)). In this model households (consumers) maximize their utilities according to their budget constraints and producers minimize their production costs subject to resource constraints. The model determines demands for and supplies of goods and services according to consumer and producer behaviors. Resources are labor, capital, land, and natural resources, and they owned by consumers. In GTAP, markets are competitive, consumers and producers are price takers, and utility and production functions usually follow the constant elasticity of substitution (CES) functional forms[4]. We will introduce the production and consumption structures of GTAP later in this report.

The GTAP model simulates the world economy using a global database which contains input-output tables for almost all countries. These tables provide detailed information on production and consumption of commodities and services along with investment and bilateral trade among regions. This database also includes payments to labor, capital, and land (for details see Dimaranan (2006)). GTAP data come from a multitude of sources. The country input-output tables are generally provided by contributors in the countries who have access to national statistics data. Trade data come from UN sources and USDA. Protection data come from several sources, but CEPII in France is the major source. Energy data come from the IEA in Paris. There are other sources as well. The GTAP staff at Purdue set the standards for data and assure quality and consistency. The database also includes the most updated global land cover and land uses database by region disaggregated into 18 Agro Ecological Zones (AEZs). These AEZs share common climate, precipitation and moisture conditions. The land cover and land use database is based on the Center for Sustainability and Global Environment (SAGE) database (for more information on the land use database see Lee et al. (2005)). The land use data base provides information on global crop yields as well. Note that the land use database excludes inaccessible forests. The version 6 of the GTAP data base covers 57 groups of commodities and services for

[4] Here, we use a simple graphical example to explain a constant elasticity of substitution functional form. Consider a producer which can use labor (L) and capital (k) to produce wheat (W). The following simple figure depicts the production function of this farmer:



In this graph σ represent the elasticity of substitution between labor and capital. If the farmer can only use labor and capital in a fixed proportion, then $\sigma=0$. However, if the farmer can reduce number of work hours and increase the amount of capital (say due to an increase in wage rate) to achieve its production goal, then σ is a number greater than zero. In general, σ can take any number between zero and infinity when we consider substitution among inputs or among consumption of goods and services.

87 countries and regions. Version 6 is based on 2001 data, and was the starting point for the biofuels analysis reported in this paper.

The GTAP model and its data base have been frequently modified and improved in the past three years to develop an improved tool for examining the economic and environmental consequences of the global biofuel production. In this process Taheripour et al. (2007) have explicitly introduced three biofuel commodities (including ethanol from food grains, ethanol from sugarcane, and biodiesel from oilseeds) into the GTAP data base version 6.

Birur, Hertel, and Tyner (2008) have incorporated biofuels into the GTAP-E model[5]. They augment the model by adding the possibility for substitutability between biofuels and petroleum products. We will henceforth refer to this model as GTAP-BIO-ADV (advanced GTAP-BIO model). Figures 2 and 3 represent the structure of consumption and production sides of this model. In these figures CES means constant elasticity of substitution (as explained in footnote 4 above) and CDE stands for constant difference elasticity and is the means of expressing household preferences in GTAP.

[5] GTAP-E was originally developed by Burniaux and Truong (2002) to incorporate energy into the GTAP framework, and recently modified by McDougall and Golub (2007).

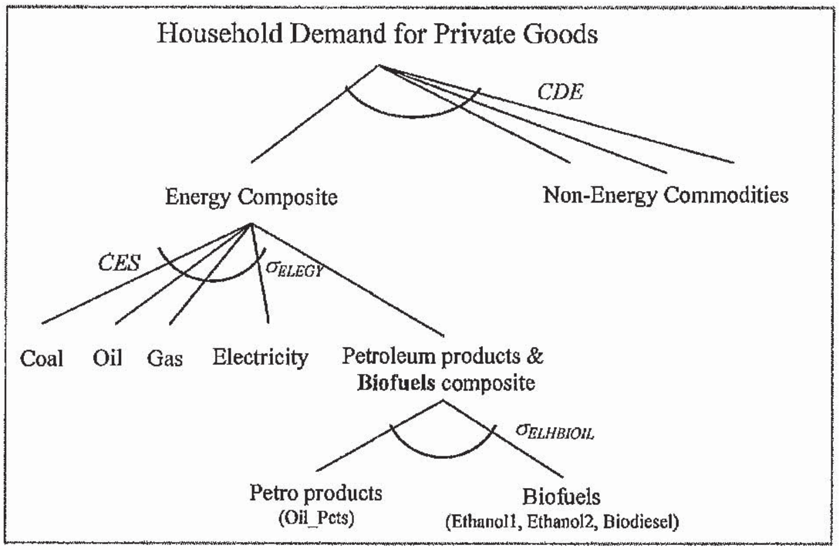


Figure 2. Structure of consumption side of the GTAP-BIO-ADV model

Figure 2 indicates that households could use biofuel as a substitute for petroleum products in GTAP-BIO-ADV. On the other hand, Figure 3 shows that at the bottom-most level of the production side biofuels are a compliment to petroleum products in the production process. It should be noted here that in a general equilibrium model like GTAP, all the equations are solved simultaneously, so it is not a stepwise solution process.

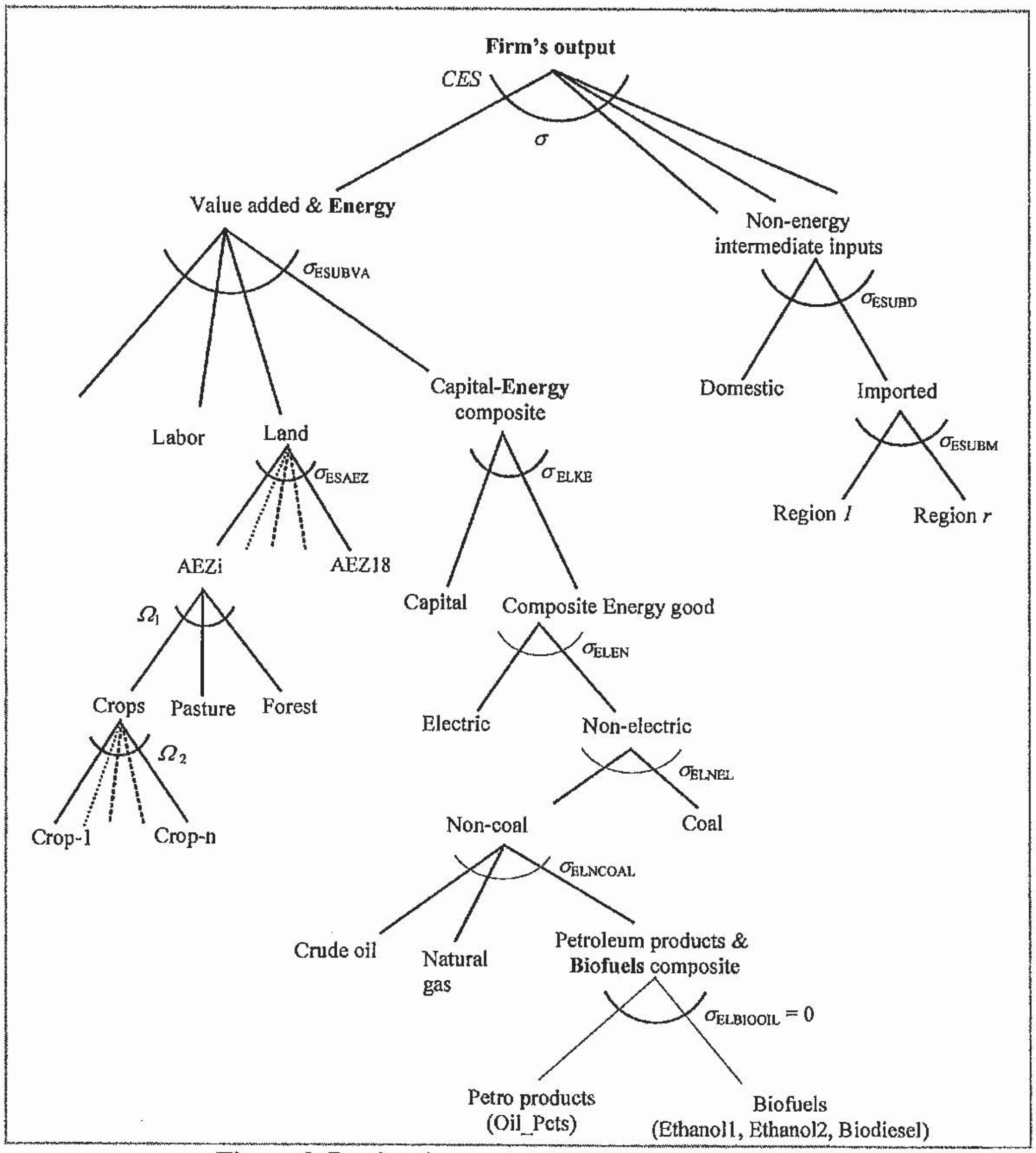
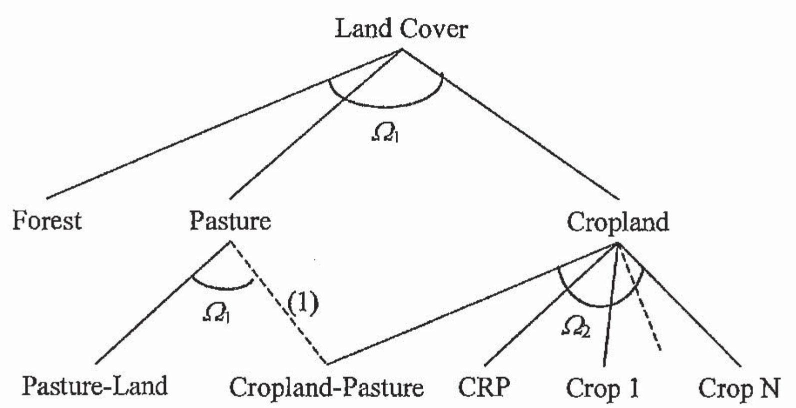


Figure 3. Production structure of GTAP-BIO-ADV

Hertel, Tyner, and Birur (2008) have recently augmented this model with a land use module to better depict the global competition for land among land use sectors. The land use module traces changes in the demand for land across the world at the AEZ level and thereby captures the potential for real competition between alternative land uses. In this module land does not move across AEZs. However, distribution of land across its alternative uses can change within each AEZ. Alternative uses of land are: forest, grassland, and cropland. In this module livestock producers compete to use grassland, and there is competition among agricultural activities to use croplands. Corn is in the coarse grains category along with sorghum, oats, and barley. However, in the US, that grouping is mostly corn. For example, in 2009, corn constituted 95.4% of the coarse grains production (by weight). Most of the rest was sorghum, which also could be used for biofuels. There is no need to separate corn from the other coarse grains.

Recently, Birur (2010) has added two new land categories of cropland-pasture and unused cropland (e.g. retired cropland under the US Conservation Reserve Program (CRP)) into supply of land. Figure 4 represents the new structure of land supply in the modified model.



(1) To create this link we introduced an industry into the GTAP framework which uses only cropland-pasture as an input and sells its output (land) to the livestock industry.

Figure 4. Land cover and land use activities in the GTAP-BIO-ADV

In the new land supply tree cropland pasture and unused cropland (mainly CRP) are explicitly defined as components of cropland. CRP land mainly generates environmental benefits. Hence, this type of land is introduced as an input into the sector which provides these services (i.e. Oth_Ind_Se). Cropland-pasture is an input into livestock industry. To facilitate transition of cropland-pasture from livestock industry to crop production and vice versa, an industry is added to the model which uses cropland-pasture as an input and sells its output (cropland-pasture) to the livestock industry. This industry competes in the land market with crops. Finally, the livestock industry combines cropland-pasture with pasture land in its production function as shown in Figure 5. This figure indicates that the livestock industry combines pasture land with cropland-pasture in the value added nest and uses feed and non-feed inputs in its production function.

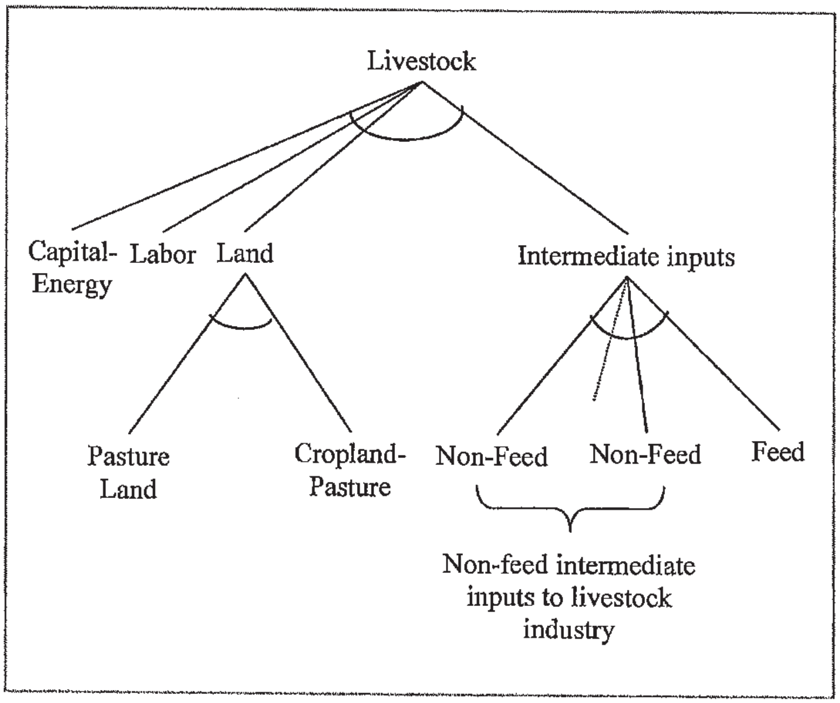


Figure 5. Production structure of the livestock industry

The land use module determines expansion of cropland and its distribution among agricultural activities according to two important parameters: price elasticity of yield and ratio of productivities of marginal and average lands. The price elasticity of yield measures changes in crop yield due to the changes in crop price. In the simulations reported in this report we assumed that the price elasticity of yield is equal to 0.25. Keeney and Hertel (2008) have provided a detailed discussion on this parameter along with econometric evidence behind it.

The ratio of marginal and average productivities measures the productivity of new cropland versus the productivity of existing cropland. We will henceforth refer to this ratio as ETA. In our earlier work we were assumed that ETA=0.66 all across the world. In this report we use a set of regional ETAs at the AEZ level which is obtained from a bio-process-based biogeochemistry model (Terrestrial Ecosystem Model (TEM): Zhuang et al., 2003) along with spatially referenced information on climate, elevation, soils, and vegetation land use data. The new regional ETAs vary across the world and among AEZs. Appendix A represents these ETAs along with more details on their calculation processes. The new estimated ETA values are now included in the model by country and AEZ.

A major attempt has been made to introduce production, consumption, and trade of biofuel byproducts into the GTAP modeling framework. Taheripour et al. (2010) and Taheripour, Hertel, and Tyner (2009) represent the latest modifications in this area. These papers extend the original GTAP-BIO database (Taheripour et al. 2007) in several directions to properly trace the links among biofuel, vegetable oil, food, feed, and livestock industries. Unlike the initial database these papers distinguish between feedstock of the US and EU ethanol industries. In the modified GTAP-BIO database, the US uses corn and EU uses wheat in ethanol production. Following the original work, the ethanol industry also produces distillers dried grains with solubles (DDGS). They also split the "other food products" industry into two distinct industries: processed food and processed feed. In addition, they split the vegetable oil sector into two distinct industries: crude vegetable oil and refined vegetable oil. The crude vegetable oil sector uses oilseeds and produces crude vegetable oil (as the main product) and oilseed meal (as the byproduct). Unlike the original GTAP-BIO database which directly converts oilseeds to biodiesel, they introduce a biodiesel production technology which uses crude vegetable oil and other inputs to produce biodiesel.

In addition, the latter paper uses a three level nesting structure for the demand for animal feedstuffs in the livestock industry which brings more flexibility into this part of the model. Figure 6 depicts this nesting structure. At the lower level of this nesting structure DDGS and coarse grains are combined to create an energy feed. At this level oilseeds and oilseed meals are combined to create a protein feed as well for countries that use oilseeds directly as feed. At a higher level the protein and energy feed ingredients are combined. At this level other crops also are bundled together. The livestock industry receives some inputs from processed livestock industry as well, and these materials are bundled together at the second level too. Finally, all feed ingredients are combined to create the feed composite.

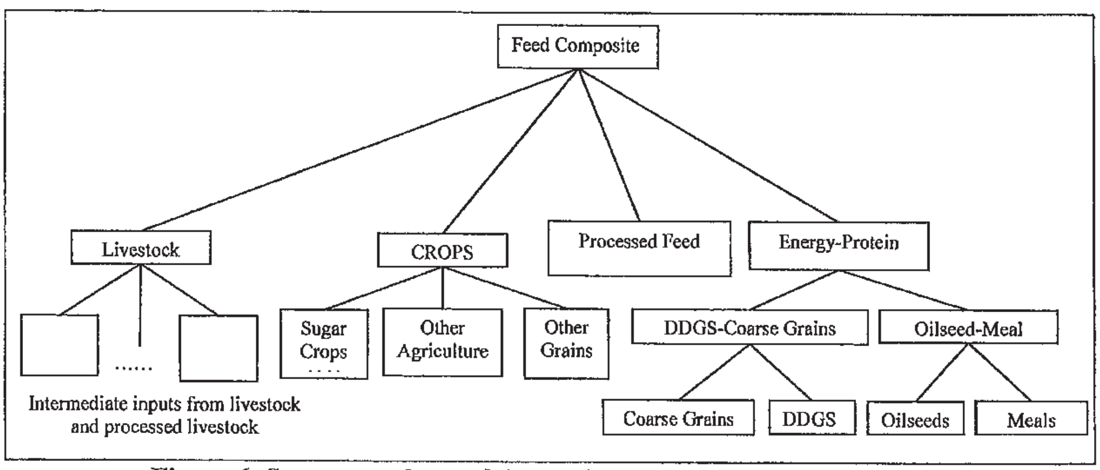


Figure 6. Structure of nested demand for feed in livestock industry

They assigned elasticities of substitution to the different components of the demand for feed to replicate changes in the prices of DDGS and meals in the US and EU during the time period of 2001-2006. In addition, they did several experimental simulations and sensitivity tests to reach displacement ratios between DDGS, grains, oilseeds, and oilseed meals according to the literature in this area. Since oilseeds and oilseed meals are good substitutes in some regions, they applied a relatively high elasticity of substitution, 20, between these two feed materials for all types of animal species. Following the literature, they used values of 25, 30, and 20 for the elasticities of substitution between coarse grains and DDGS in the dairy farms, other ruminant, and non-ruminant feed structure, respectively. They also applied a non zero and small value, 0.3, for the elasticity of substitution between the energy and protein feedstuffs because DDGS could displace a portion of meals in some feed rations, as shown in Arora, Wu, and Wang (2008) and Fabiosa (2009). In the composite of other crops and composite of processed livestock inputs they applied elasticities of substitution of 1.5 for all types of livestock industry. Finally, following Keeney and Hertel (2005) they used 0.9 for the elasticity of substitution at the higher level of the feed demand nest.

Here we use some GTAP simulation results to show how these elasticities shape the cost structure of the livestock industry. To accomplish this task we use the results obtained from the simulations introduced in the next section of this report. In particular, we use the results of the first simulation of the second group of experiments. This particular simulation replicates transition of the global economy from 2001 to 2006. The results of this simulation predict that the cost shares of coarse grain, other crops, and meals in the US livestock industries declined during the time period of 2001-2006, while the cost share of DDGS increased. The largest substitution is DDGS for coarse grains, but there is also substitution for other crops and oilseed meals, depending on the livestock species. Note that we dropped processed feed from the list of animal feeds to highlight the changes in the shares of crops, DDGS, and meals in this time period (Table 1).

Table 1. Cost shares of major feed items in the US livestock industries in 2001 and 2006*

Feed Items	2001			2006		
	Dairy	Meat Ruminant	Non-Ruminant	Dairy	Meat Ruminant	Non-Ruminant
Coarse Grains	67.6	68.4	82.9	64.9	63.8	83.0
Other crops	6.4	10.4	2.9	6.0	9.7	2.7
DDGS	5.6	6.4	1.1	9.2	11.5	1.6
Oilseeds meals	20.3	14.9	13.1	19.9	14.9	12.6

*Processed feed is dropped from this table to highlight shares of items listed in the table.

To evaluate the land use implications of US ethanol production we use a new model which includes all modifications and improvements which have been made in the GTAP-BIO-ADV model and its data base described above and in the associated references. In short this model has the following specifications:

1) It covers production, consumption, and trade of three types of biofuels: ethanol from crops, ethanol from sugarcane, and biodiesel from crude vegetable oil.
2) By products are DDGS and oilseeds meals.
3) The crude vegetable oil industry uses oilseeds and produces crude vegetable oil and oilseed meals.
4) The biodiesel industry uses crude vegetable oil to produce biodiesel.
5) The demand for feedstuffs follows a three level nesting structure.
6) The land module handles two new land categories of unused cropland and cropland pasture. While the model could trace changes in these two groups of land across the world, we have data on cropland pasture for the US and Brazil and data on CRP only for the US.

7) We have calibrated ETA for each AEZ and region instead of using the globally fixed ETA parameter as in the past.
8) Energy demand and supply elasticities have been re-calibrated for this version.
9) In this report we divide the world economy into 19 regions, 34 groups of commodities and services, 32 industries, and 5 groups of endowments. The list of regions, commodities, industries and endowments are shown in Appendix B.
10) In this report when we shock US ethanol, we hold production of other biofuels constant.

3. GTAP simulations and their results

To evaluate the land use implications of US ethanol production we develop three groups of simulations. In the first group we follow the approach that we used in our earlier report (Tyner, Taheripour, and Baldos, 2009). In this approach, we calculate the land use implications of US ethanol production off of the 2001 database. This approach isolates impacts of US ethanol production from other changes which shape the world economy. This method assumes that other factors such as population growth, yield improvement, and economic growth do not affect the land use implications of producing more ethanol from agricultural resources. Hertel et al. (2010) provide more insights on this approach. While this approach uses the 2001 starting point, it is different from our January 2009 draft results in that all the model changes described above have been included in this first set of simulations.

In the second group of simulations, we first construct a baseline which represents changes in the world economy during the time period of 2001-2006. Then we calculate the land use impact of the US ethanol production off of the updated 2006 database, while we follow the principles of the first group of simulations for the time period of 2006-2015. Finally, in the third group of simulations we use the updated 2006 database obtained from the second group of simulations, but we assume that during the time period of 2006-2015 population and crop yields will continue to grow. These are two important factors which could alter the land use impacts of ethanol production in the future. These three groups of simulations and their results are described in the rest of this section.

Group 1: Simulations with no economic and yield growth and 2001 base

We calculate the land use implications of the US ethanol production for the following 6 time segments:

- Ethanol production from 2001 to 2006 level.
- Ethanol production from 2006 level to 7 B gallons,
- Ethanol production from 7 B to 15 B gallons by increments of 2 B gallons.

The global biofuel industry has followed a rapid growth path during the time period of 2001-2006. The historical observations from this time period have been used to calibrate the biofuel-parameters of the model (Hertel, Tyner, and Birur, 2008). Then we consider gradual increases in the production of US ethanol after 2006 to evaluate marginal impacts of ethanol production. For this purpose we first increase the US ethanol production from its 2006 level (4.855 BG) to 7 B gallons. Thereafter we increase ethanol production by increments of 2 B gallons to achieve the goal of 15 B gallons of ethanol in 2015.

The detailed global land use changes obtained from the first group of simulations are shown in Appendix C. Table 2 summarizes these results. These results indicate that producing 13.23 BGs of ethanol (from the 2001 production level to 15 BGs) requires about 2.96 million hectares of additional land, of which 1.01 million hectares (34%) are expected to be in the US, with the reminder (1.95 million hectares) in other regions (66%). This result suggests that the land use changes due to US ethanol production will mainly take place outside the US. Results from this group of simulations also indicate that the size of required land to achieve the 15 BGs ethanol production is much smaller than the land use changes suggested by a simple calculation which ignores important factors that could mitigate land use impacts of ethanol production[6]. Several factors mitigate the land use consequences of ethanol production. Among them are: less corn consumption in the livestock industry due to using more DDGS in the livestock industry, reductions in output of the livestock industry, reallocation of croplands across the world among alternative crops, and higher yields in crop production due to higher prices. Hertel et al. 2010 have decomposed contributions of these factors in mitigating the land use impacts of ethanol production.

Table 2. Global land use changes due to the US ethanol production: Off of 2001 database

Changes in US corn ethanol production	Land use changes (hectares)			Distribution of land use changes (%)			Hectares per 1000 gallons
	Within US	Other Regions	World	Within US	Other Regions	World	
3.085 BG (2001 to 2006)	227982	382394	610376	37.4	62.6	100.0	0.20
2.145 BG (2006 to 7 BG)	162558	297766	460324	35.3	64.7	100.0	0.21
2.000 BG (7 to 9 BG)	152990	295051	448041	34.1	65.9	100.0	0.22
2.000 BG (9 to 11 BG)	154018	310639	464657	33.1	66.9	100.0	0.23
2.000 BG (11 to 13 BG)	154706	325639	480345	32.2	67.8	100.0	0.24
2.000 BG (13 to 15 BG)	155000	340311	495311	31.3	68.7	100.0	0.25
13.23 BG (2001 to 15 BG)	1007253	1951800	2959053	34.0	66.0	100.0	0.22

The magnitude of land requirement to increase US ethanol production from its 2001 level to 15 BG obtained from these simulations is smaller than its corresponding value in our earlier report (Tyner, Taheripour, and Baldos, 2009) by about 16.7% (i.e. 2.96 million hectares versus 3.55 million hectares). Two major modifications in the GTAP model contribute to this reduction.

[6] One can determine land use changes due to the US ethanol production by multiplying corn yield (370 bushels per hectare of land) by a corn to ethanol conversion factor (e.g. 2.7 gallons per bushel of corn). This simple approach leads to 1000 gallons of ethanol per hectare of land. Hence, based on this simple calculation, increasing ethanol production from its 2001 level (1.77 BG) to 15 BG needs about 13 million hectares of land.

A portion of this reduction is associated with the land conversion factors. As noted earlier in this report we apply a set of regional land conversion factors at the AEZ level. These land conversion factors in several AEZs are higher than the single conversion factor of 0.66 which we used in our earlier work (see Appendix A).

Introducing the new land categories (cropland pasture and unused land[7]) into the model also contributes to the reduction in land requirement. In particular, in the US and Brazil in the presence of cropland pasture farmers convert a portion of this type of land to crop production. For example, an increase in US ethanol production from its 2001 level to 15 BG brings about 1.2 million hectares of cropland pastures into crop production, but not only to corn production. Indeed, a portion of this land conversion prevents sharp reductions in production of other crops. It is important to note that the competition between crop and livestock industry prevents full conversion of cropland pasture to crop production.

These two modifications not only reduce the land requirement of ethanol production. They also alleviate the adverse impact of ethanol production on the prices and consumption of crops.

Table 2 also indicates that the required land for producing 1000 gallons of ethanol grows as we move to higher levels of ethanol production. For example, for the 2001 to 2006 simulation, an additional 3.085 B gallons of ethanol triggers global land use changes of roughly 610,376 hectares. This is equal to 0.20 hectares per 1000 gallons of ethanol. However, for the 13 BGs to the 15 BGs simulation, an additional 1000 gallons of ethanol requires 0.25 hectares of land. To increase ethanol production from the 2001 level to 15 BGs, we need an average of 0.22 hectares of land per 1000 gallons of ethanol. The marginal level (0.25) is higher than the average (0.22),

[7] In these simulations we hold the area of US CRP land constant.

which would be expected because as more land comes into production, the yields on the incremental area would be lower.

Table 3 depicts another aspect of the land use implications of US ethanol production. This table shows the distribution of land use changes between forest and grassland. About 24.7% of the required croplands which are needed to increase ethanol production from its 2001 level to 15 BGs come from forest, and the rest (75.3%) come from grasslands. Table 3 also indicates that as we move to higher levels of ethanol production the portion of forests in the converted land into crop production increases very slightly (from 23.5 % in 2001 to 25.1% at the 15 BGs ethanol production.

Table 3. Global land use changes due to the US ethanol production: Off of 2001 database

Changes in US corn ethanol output	Land use changes (hectares)			Distribution of land use changes (%)		
	Forest	Grassland	Crop*	Forest	Grassland	Total*
3.085 BG (2001 to 2006)	-143716	-466652	610376	23.5	76.5	100.0
2.145 BG (2006 to 7 BG)	-114409	-345912	460324	24.9	75.1	100.0
2.000 BG (7 BG to 9 BG)	-112330	-335712	448041	25.1	74.9	100.0
2.000 BG (9 BG to 11 BG)	-116795	-347864	464657	25.1	74.9	100.0
2.000 BG (11 BG to 13 BG)	-120688	-359650	480345	25.1	74.9	100.0
2.000 BG (13 BG to 15 BG)	-124151	-371156	495311	25.1	74.9	100.0
13.23 BG (2001 to 15 BG)	-732089	-2226946	2959053	24.7	75.3	100.0

*The difference between the changes in cropland and the sum of forest and grassland is due to rounding. Cropland pasture is included in cropland.

In the absence of crop yield growth, the increasing global land use change given equal increments of US ethanol production is explained by the differences in the productivity of available lands. Productive lands are employed first before marginal lands, which have lower productivity and lower yields. At low levels of production, more productive lands are available; hence, less land is required to produce additional ethanol. However, at high levels of production, most of the productive land is already being used, and only marginal land is available. Given this, more marginal land is required to produce the same increment of US corn ethanol production.

Group 2: Simulations with updated baseline for the time period of 2001-2006

The global economy changed significantly over the 2001-2006 period. Countries followed different economic growth paths, population increased everywhere at different rates, land productivity rapidly increased in many regions (with some exceptions), and technology has improved in many areas. These are important factors which could alter the land use implications of biofuels. In the second group of simulations we take these factors into account.

To accomplish this task we developed a database which includes data on: crop production, harvested area, forest areas, gross capital formation, labor force (skilled and unskilled), gross domestic product, and population for the whole world at the country level. Then we used this data set to generate a baseline which replicates transition of the global economy from 2001 to 2006, while we targeted global biofuel production during this time period in the presence of population, income, and yield growths. In building the baseline we guide the model to replicate the historical paths of changes in harvested area across the world as well. Furthermore, we trace changes in global forest area to match our land use results with the historical changes in forest areas during the time period of 2001-2006. We adjusted rates of technological improvements to trace changes in cropland and forest areas.

Data sources

To construct the baseline the following data items were collected:

1- Population: World population figures by country were obtained from the UN website for 2001-2006. Then the population figures by region were calculated for our GTAP aggregation[8]. Finally, the percentage change in population between 2001 and 2006 was calculated for each region (see table 4).

2- GDP: Real GDP figures by country were obtained from the World Development Index (WDI) database for 2001-2006. Then the GDP figures by region were calculated for our GTAP aggregation. Finally, the percentage change in GDP between 2001 and 2006 was calculated for each region (see table 4).

3- Capital: Real capital formation figures by country were obtained from the WDI database for 2001-2006. Then the capital formation figures by region were calculated for our GTAP aggregation. Finally, the percentage change in capital formation between 2001 and 2006 was calculated for each region (see table 4).

4- Labor: Labor force figures by country were obtained from the WDI database for 2001-2006. Then the labor force figures by region were calculated for our GTAP aggregation. Finally, the percentage change in labor force between 2001 and 2006 was calculated for each region (see table 4). We followed Walmsley, Dimaranan, and McDougall (2000) to split labor force into groups of skilled labor and unskilled labor.

5- Crop production: Crop production figures by crop type and by country were obtained from the FAO website for 2001-2006. Then crop production figures by region were calculated for our GTAP aggregation for 2001-2006.

6- Harvested Area: Harvested areas by crop type and by country were obtained from the FAO website for 2001-2006. Then the harvested areas by region were calculated for our GTAP aggregation for 2001-2006.

[8] The aggregation schedule is shown in Appendix B, Table B-2.

7- Yield: Yields were calculated by region and by crop using items 5 and 6 introduced above. Since yield fluctuates over time, annual percentage changes in yields were calculated. Then we obtained the average of percentage changes in yield over the time period of 2001-2006 for each crop within each region. Table 5 reports the cumulative yield change for each region and crop category over the five years. Thus these percentages are roughly five times the annual growth rates.

8- Global forest export price - Values and quantities of exports of forestry products were obtained from the FAO website for 2001-2006. These figures were used in defining a global price index for forest products to shape technological progress in forest industry.

9- Finally, we used the FAO assessment of changes in global forest areas to track changes in the global forest areas (FAO, 2006). The FAO assessment covers the time period of 2000-2005, while we need changes in 2001-2006. So we assumed that changes in forest areas within the period of 2000-2005 are similar to the changes in the time period of 2001-2006.

Table 4. Percentage changes in macro economic variables (2001-2006)

Regions	Population	GDP	Skilled labor	Unskilled labor	Capital
1 USA	5.2	15.0	5.7	5.2	18.9
2 EU27	1.82	10.2	7.4	-1.1	13.1
3 BRAZIL	6.88	17.2	24.4	8.5	11.1
4 CAN	5.31	14.6	9.1	8.3	34.0
5 JAPAN	0.59	8.8	0.2	-4.1	0.7
6 CHIHKG	3.59	59.0	17.5	4.7	83.6
7 INDIA	8.51	45.9	27.5	8.7	94.8
8 C_C_Amer	6.41	16.8	33.7	6.8	25.4
9 S_o_Amer	7.19	24.4	50.2	10.1	54.4
10 E_Asia	2.75	25.9	15.1	5.3	21.6
11 Mala_Indo	7.18	29.1	56.5	9.0	30.1
12 R_SE_Asia	7.2	33.7	26.6	9.3	43.0
13 R_S_Asia	10.8	32.5	34.4	15.5	39.0
14 Russia	-2.38	37.7	2.2	1.2	69.6
15 Oth_CEE_CIS	2.27	25.5	14.9	-2.2	40.0
16 Oth_Europe	2.27	25.5	14.9	-2.2	40.0
17 MEAS_NAfr	10.18	26.7	30.7	19.1	47.8
18 S_S_AFR	13.47	27.5	17.3	13.6	45.2
19 Oceania	7.79	17.4	11.1	8.5	54.8

Table 5. Percentage change in yield (accumulation of growth rates 2001-2006)

Region\Crop	Wheat and Paddy Rice	Coarse Grains	Oilseeds	Sugarcane	Other Agriculture
1 USA	-2.3	11.0	11.6	1.8	-7.3
2 EU27	4.0	7.3	13.5	7.8	-1.8
3 BRAZIL	12.4	22.8	3.5	8.1	9.3
4 CAN	10.8	10.2	14.4	33.3	18.1
5 JAPAN	-4.1	-18.4	-8.6	5.1	-0.5
6 CHIHKG	6.3	17.0	5.6	42.6	5.2
7 INDIA	5.3	16.4	15.6	-4.1	-2.4
8 C_C_Amer	4.0	13.2	28.6	13.2	5.4
9 S_o_Amer	10.0	9.0	-0.7	6.4	3.5
10 E_Asia	5.6	48.3	3.6	0.0	5.6
11 Mala_Indo	4.3	19.4	27.4	9.3	19.8
12 R_SE_Asia	10.1	18.1	10.8	-4.6	15.6
13 R_S_Asia	6.8	37.8	-5.1	4.4	11.5
14 Russia	20.8	17.2	22.2	48.8	15.0
15 Oth_CEE_CIS	15.1	26.0	16.7	22.6	13.5
16 Oth_Europe	15.1	26.0	16.7	22.6	13.5
17 MEAS_NAfr	20.3	25.3	46.6	4.3	1.7
18 S_S_AFR	6.4	9.8	10.2	-5.7	3.4
19 Oceania	10.9	-9.6	0.7	2.2	17.3

To generate the 2006 baseline, we shock major macroeconomic variables according to the historical observations for the time period of 2001-2006. In particular, we shocked GDP, gross capital formation, labor force, and population at the regional level. We also introduced shocks to increase global biofuels outputs according to actual observations for the same time period. In addition to these shocks, we guide the model to replicate observed improvement in yield over the time period of 2001 to 2006 by crop and by region. Finally, we introduced technological changes in input output ratios to replicate regional changes in harvested area during the time period of 2001-2006. Furthermore we guide the model to trace changes in forest area during the baseline time period. Appendix D shows the list of implemented shocks. This experiment provides us a new database which represents the world economy in 2006 in the presence of changes in the major derivers of the world economy. To separate out the impacts of the US ethanol program from other derivers of the world economy we repeat this experiment without the US ethanol shock. The difference between the land use implications of these two simulations gives us the impact of the US ethanol program for the time period of 2001-2006.

Then we used the updated 2006 database to evaluate the land use impacts of increasing US ethanol from its 2006 level to 15 BG incrementally. The global land use implications obtained from the second group of simulations are shown in Appendix C. Table 6 summarizes these results.

Table 6. Simulated global land use changes due to the US ethanol production: Off of updated baseline

Changes in US corn ethanol production	Land use changes (hectares)			Distribution of Land Use changes (%)			Hectares per 1000 gallons
	Within US	Other Regions	World	Within US	Other Regions	World	
3.085 BG (2001 to 2006)	119281	320068	439349	27.1	72.9	100.0	0.14
2.145 BG (2006 to 7 BG)	76003	225500	301503	25.2	74.8	100.0	0.14
2.000 BG (7 to 9 BG)	71207	217720	288927	24.6	75.4	100.0	0.14
2.000 BG (9 to 11 BG)	71783	223877	295660	24.3	75.7	100.0	0.15
2.000 BG (11 to 13 BG)	72547	228732	301279	24.1	75.9	100.0	0.15
2.000 BG (13 to 15 BG)	73459	233064	306524	24.0	76.0	100.0	0.15
13.23 BG (2001 to 15 BG)	484280	1448962	1933242	25.1	74.9	100.0	0.15

The results obtained from the second group of simulations indicate that we need 1.93 million hectares of cropland to increase ethanol production from the 2001 level to 15 BGs. This figure is smaller than its corresponding figure obtained from the first group of simulations by 34.7%. Two main factors contribute to this reduction. During the time period of 2001-2006 crop yields are growing faster than the demands for crops globally. This reduces the size of land use changes in this period. Then when we calculate the land use implications of US ethanol for the time period of 2006-2015 from the updated database of 2006, we get smaller land use changes because crop yields are higher in the updated database.

In the second group of simulations cropland pasture moves to crop production faster than in the first group of the simulations as well. In the presence of economic growth about 3.9 million hectares of cropland pasture will move to crop production.

Table 7 represents distributions of land use changes between forest and pasture for the second group of simulations. In this group of simulations on average about 34.8% of required land for ethanol production comes from forest land. This figure is higher than the corresponding figure of the first group of simulations (i.e. 24.7%).

Table 7. Simulated global land use changes due to the US ethanol production: Off of updated baseline

Changes in US corn ethanol output	Land use changes (hectares)			Distribution of land use changes (%)		
	Forest	Grassland	Crop*	Forest	Grassland	Total*
3.085 BG (2001 to 2006)	-155414	-283921	439349	35.4	64.6	100.0
2.145 BG (2006 to 7 BG)	-107215	-194290	301503	35.6	64.4	100.0
2.000 BG (7 BG to 9 BG)	-98360	-190567	288927	34.0	66.0	100.0
2.000 BG (9 BG to 11 BG)	-102124	-193538	295660	34.5	65.5	100.0
2.000 BG (11 BG to 13 BG)	-104305	-196978	301279	34.6	65.4	100.0
2.000 BG (13 BG to 15 BG)	-105540	-200984	306524	34.4	65.6	100.0
13.23 BG (2001 to 15 BG)	-672959	-1260277	1933242	34.8	65.2	100.0

*The difference between the changes in cropland and the sum of forest and grassland is due to rounding

Group 3: Simulations with crop yield and population growth for the time period of 2006-20015

Some advocates of the US corn ethanol program argue that crop yields will increase in the future such that this increase could eliminate the land use implications of ethanol production. This argument neglects the impacts of the future changes in the demand for crops. Demands for crops could increase in the future due to several factors such as changes in population and income, dietary transition as poorer countries consume more meat, or technological progress. In other words, one cannot examine yield (supply) increases alone; we must also include assumptions about increases in crop demand as well. In the third group of simulations we examine impacts of changes in crop yields and demand as important items which could determine demand and supply for crops and food products.

For our model simulations we use population growth as a proxy for food demand increase. We assume that population will continue to grow globally during the time period of 2006-2015 after 2006 at the annual growth rate of 2001-2006. We also assume that crop yield will increase uniformly at 1% annually after 2006 in all regions and across all types of crops. While 1% might seem small, it is actually a large number as it is applied in all regions and for all crops. We also assume that the regional demands for forest products will increase according to their annual rates of 2001-2006. We made the latter assumption to maintain the long run pattern in forest products outputs. These simulations also include all the changes incorporated in the baseline simulation of the second group of simulations.

To find the land use impacts of US ethanol program under these assumptions we did simulations with and without US ethanol production off of the updated data base for 2006 (obtained in the second group of simulations) for the time period of 2006-2015 in the presence of population and yield shocks. The global land use implications of the US ethanol plan under these assumptions are shown in appendix C. To understand the land use implications of the US ethanol program under these assumptions we first analyze the land use implications with no US ethanol production. Table 8 indicates land use changes due to the yield and population growth for US, EU, Brazil, and other regions.

Table 8 indicates that after 2006 the cropland areas of US, EU, Brazil, and other regions would fall due to the simultaneous shocks in yield and population growth. This means that yield growth would dominant the demand growth for crops, and therefore the demand for cropland decreases everywhere. In addition to that, the yield growth contributes to higher levels of food consumption everywhere.

Table 8. Simulated global land use changes due to population and yield growth after 2006 (figures are in 1000 hectares)

Period	Land cover	US	EU	Brazil	Others	World
2006-2007	Forestry	142.8	194.8	430.5	2141.4	2909.5
	Cropland	-162.1	-217.5	-97.3	-2382.6	-2859.5
	Pastureland	19.4	22.7	-333.2	241.2	-50.0
2007-2009	Forestry	380.0	512.8	917.6	6070.3	7880.6
	Cropland	-363.6	-513.7	-232.3	-5940.4	-7050.0
	Pastureland	-16.3	0.9	-685.3	-129.9	-830.6
2009-2011	Forestry	548.3	713.7	1077.5	9085.8	11425.3
	Cropland	-406.4	-623.6	-268.0	-7764.1	-9062.2
	Pastureland	-141.9	-90.1	-809.5	-1321.7	-2363.2
2011-2013	Forestry	736.4	929.7	1287.0	12422.1	15375.2
	Cropland	-452.2	-737.3	-298.5	-9776.0	-11264.0
	Pastureland	-284.2	-192.4	-988.5	-2646.1	-4111.2
2013-2015	Forestry	997.5	1243.9	1610.3	15745.7	19597.5
	Cropland	-522.7	-886.0	-340.6	-11626.9	-13376.2
	Pastureland	-474.8	-358.0	-1269.7	-4118.8	-6221.4

The simulation results indicate that consumption of crops and food products grow faster than population everywhere across the world. This indicates that the yield effect works through two channels: 1) reduction in crop land area needed to satisfy demand, and 2) higher per capita consumption of food. This means that one percent yield improvement will not end with one percent reduction in cropland, even if there is no population growth.

The released croplands are going to forest to support the long run growth in forest products. Note that as mentioned earlier in this group of simulations we assume the global forest sector will continue to grow according to its 2001-2006 growth rate.

With this discussion we now examine impacts of adding biofuel shocks into this picture. In general, the US ethanol program in this group of simulations generate smaller land use changes compared the results of the second group of simulations. Table 9 shows that under the assumptions of this group of simulations we need 1.5 million hectares of cropland to increase ethanol production from the 2001 level to 15 BGs. This figure is smaller than the corresponding figure obtained from the second group of simulations by 20%. For the earlier time segments after 2006 the size of land requirement is significantly smaller than what we observed in the second group of simulations. For example, in this group of simulations we need only 0.1 hectares of cropland to produce 1000 gallons of ethanol in the time segment of 2006-2007, while the corresponding number obtained from the second group of simulations is about 0.14.

As we move forward towards 2015, the population growth dominants the yield growth in some regions, and the land requirement grows. Table 9 shows that the share of US in land requirement grows at the beginning but it decreases when we move towards 2015.

Table 9. Simulated global land use changes due to the US ethanol production: with yield and population growth after 2006

Changes in US corn ethanol production	Land use changes (hectares)			Distribution of Land Use changes (%)			Hectares per 1000 gallons
	Within US	Other Regions	World	Within US	Other Regions	World	
3.085 BG (2001 to 2006)	119281	320068	439349	27.1	72.9	100.0	0.14
2.145 BG (2006 to 7 BG)	58799	150754	209553	28.1	71.9	100.0	0.10
2.000 BG (7 to 9 BG)	58167	134225	192392	30.2	69.8	100.0	0.10
2.000 BG (9 to 11 BG)	60919	141118	202038	30.2	69.8	100.0	0.10
2.000 BG (11 to 13 BG)	64529	167511	232040	27.8	72.2	100.0	0.12
2.000 BG (13 to 15 BG)	69848	196148	265996	26.3	73.7	100.0	0.13
13.23 BG (2001 to 15 BG)	431544	1109824	1541368	28.0	72.0	100.0	0.12

The distribution of land use changes between forest and pasture land are similar to the second group of simulations. Our assumption on the regional demands for forest products derives this result. It is very important to note that adding income growth or changes in other economic factors into this picture may change the geographical distribution of land use changes or the distribution of the land requirement for ethanol production between forest and grassland. (Table 10)

Table 10. Simulated global land use changes due to the US ethanol production: With yield and population growth after 2006

Changes in US corn ethanol output	Land use changes (hectares)			Distribution of land use changes (%)		
	Forest	Grassland	Crop*	Forest	Grassland	Total*
3.085 BG (2001 to 2006)	-155414	-283921	439349	35.4	64.6	100.0
2.145 BG (2006 to 7 BG)	-71830	-137724	209553	34.3	65.7	100.0
2.000 BG (7 BG to 9 BG)	-67347	-125070	192392	35.0	65.0	100.0
2.000 BG (9 BG to 11 BG)	-70376	-131670	202038	34.8	65.2	100.0
2.000 BG (11 BG to 13 BG)	-79832	-152216	232040	34.4	65.6	100.0
2.000 BG (13 BG to 15 BG)	-93949	-172051	265996	35.3	64.7	100.0
13.23 BG (2001 to 15 BG)	-538749	-1002651	1541368	35.0	65.0	100.0

*The difference between the changes in cropland and the sum of forest and grassland is due to rounding

4. Land use CO_2 emission factors

We use emissions factors to convert land use changes into the land use CO_2 emissions (LUCE). Land conversions of forest and grassland into crop production releases CO_2 emissions from two sources: 1) direct CO_2 emissions from land conversion and 2) foregone CO_2 sequestration by forests. The direct CO_2 emissions consist of carbon stored in the vegetation and in the soil, which are released when forests or grasslands are cleared and converted into croplands. The forgone carbon sequestration accounts for the amount of carbon that could have been stored from annual forest growth, if land had remained forested. This is the opportunity costs of cleared land in terms of its potential to store carbon.

As mentioned earlier in this report we use the Woods Hole data set[9]. This data set divides the world into 10 homogenous regions, determines distributions of forests and grasslands within each region across different types of vegetation cover, and provides detailed information on the carbon stored in the vegetation and in the soil of forests and grasslands within each region.

[9] This data set, which is taken from the supporting documents of SEA

The Woods Hole data set provides two key carbon figures for each type of land according to its natural vegetation. These figures are carbon stored in the soil and carbon stored in the vegetation. We assume that when a natural vegetation area (either forest or grassland) is converted to cropland, about 25% of the carbon stored in its soil will be released into the atmosphere. In addition, we assume 75% of carbon stored in the forest type vegetation and 100% percent of carbon stored in the grassland vegetation will be released into the atmosphere at the time of land conversion[10]. If more than one type of vegetation is available in an area we calculate the weighted average emissions for that area, where weights are shares of vegetation areas. We calculate emissions factors for forest areas and grasslands, separately. Sensitivity analysis can be conducted on any of the data and assumptions used in this analysis.

Regarding the forgone carbon sequestration we assumed when a natural vegetation area is converted to cropland, it loses its carbon sequestration capacity as long as it is under crop production. Again, if more than one type of land is available we use weighted average of forgone carbon sequestration. We simply add the direct and forgone sequestration in each region. Hence, in each area we have two groups of emissions factors: forest and grassland emission factors. The Woods Hole data set along with emissions factors obtained from this data set are presented in Appendix E. Data in this appendix are calculated based on the assumption that the converted land to crop production will remain under crop production for 30 years[11]. We recognize that the 30 year period is somewhat arbitrary, and we have not considered what changes might occur after that period. Thirty years is about the life of a biofuels facility, so it seems as reasonable an assumption as any.

[10] In essence, we are assuming that 25% of the carbon in wood is stored in buildings, furniture, etc.

[11] To test the sensitivity of carbon emissions factors with respect to the time period of ethanol production, we calculated the land use emissions factors for 50, 80, and 100 years from the Woods Hole data in our earlier report (Tyner, Taheripour, and Baldos, 2009).

At this point it is important to note that some research indicates that conservation tillage practices and enhanced rotation programs can increase carbon sequestration ability of croplands. This means that using advanced technologies in corn production can increase carbon stored in soil (West and Post, 2002). In this paper we ignore impacts of advanced tillage methods on the carbon sequestration ability of cropland.

As we mentioned earlier the Woods Hole data set divides the world into 10 regions. On the other hand this version of the GTAP model divides the world into 19 regions. Table 11 relates each region of GTAP to one of the regions of the Woods Hole data set.

Table 11. GTAP and Woods Hole regions

GTAP Regions	Woods Hole Regions
United States	United States
Canada	Canada
Sub Saharan Africa	Africa
European Union 27 East Europe and Rest of Former Soviet Union Rest of European Countries	Europe
Russia	Former Soviet Union
Brazil Central and Caribbean Americas South and Other Americas	Latin America
Middle Eastern and North Africa	North Africa and Middle East
East Asia Oceania Japan	Pacific Developed
China and Hong Kong India	China/India/Pakistan
Rest of South East Asia Rest of South Asia Malaysia and Indonesia	South and Southeast Asia

We now present regional forest[12] and grassland emissions factors derived from the Woods Hole data set in Table 12. Converting forest areas to cropland in South and South East

[12] Searchinger et al. 2008 calculated forest forgone emissions from carbon uptake by growing forest. Indeed they divided growing forest uptake by the area of total area forest in each ecosystem to determine forgone carbon emissions. We followed this approach to make our results comparable with Searchinger et al. 2008 results.

Asia, China, and India generates the highest CO_2 emissions per hectare of land compared to the rest of the world in the Wood's Hole data. For example, the forest emissions factor in these regions is equal to 23 metric tons of CO_2 per hectare of forest per year, when the duration of ethanol production is 30 years. The lowest emissions factor among forest areas is in Sub Saharan Africa. In this region the forest annual emissions factor is equal to 10.4 metric tons of CO_2 per hectare of forest.

Table 12. GTAP regions and their corresponding CO_2 emissions factors for forest and grassland areas (figures are in annual metric ton CO_2 equivalent per hectare for 30 years corn production time horizon)

Regions	Forest emissions factors	Grassland emission factors
United States	19.6	3.7
Canada	15.3	5.7
Sub Saharan Africa	10.4	1.5
European Union 27 East Europe and Rest of Former Soviet Union Rest of European Countries	18.6	6.6
Russia	14.1	7.0
Brazil Central and Caribbean Americas South and Other Americas	16.1	2.5
Middle Eastern and North Africa	12.2	2.2
East Asia Oceania Japan	13.2	3.5
China and Hong Kong India	23.0	6.6
Rest of South East Asia Rest of South Asia Malaysia and Indonesia	23.0	6.6

The third column of Table 12 shows annual emissions factors for grassland areas derived from the Woods Hole. Figures of this table illustrate that converting grasslands to crop

However, this approach underestimates the magnitude of forgone forest emissions. Growing forest update should be divided by the area of growing forest - not the total area in forest. In addition, for many ecosystem types the Woods Hole database shows zeros for growing forest.

production releases smaller CO_2 emissions compared to deforestation. The highest regional grassland annual emissions factor, derived from the Woods Hole data set, is Russia (with 7 metric tons CO_2 per hectare per year), and the lowest is Sub Saharan Africa (with 2.2 metric tons CO_2 per hectare per year).

5. Estimated land use CO_2 emissions due to the US ethanol production

We now combine simulated land use changes due to US ethanol production with the CO_2 release emissions factors. This is a straight forward process. Suppose ΔLF_{rj} (see Tables 2, 6, 9) is the size of change in land type j (for j = forest and grassland) in region r due to X gallons of increase in the US ethanol production. In addition, suppose that the annual CO_2 emissions factor for land type j in region r for a 30 year ethanol production is about Frj (see Table 12). Then the global annual CO_2 emissions due to producing x gallons of ethanol per year in the US will be equal to:

$$(1)\quad LUE_W = \sum_r \sum_j \Delta LF_{rj} \cdot F_{rj} \quad .$$

Using this approach we calculated CO_2 emissions for all land use simulation scenarios (Three groups of simulations and 6 time segments) and for all emissions factors derived from the Woods Hole data sets. Once we have emissions, we can calculate the marginal and average land use emissions due to production of each gallon of pure ethanol (E100) for all groups of simulations examined in this paper. For example, Table 13 shows how we calculated the marginal land use emissions due to producing each gallon of E100 for the 13 to 15 BGs for the first group of our simulations.

Table 13. Estimated marginal land use emissions per gallon of E100 for 13 to 15 billion gallons simulation (30 year pay off method)

Total 30 year emissions from land use changes (million metric tons)	110.77
Change in ethanol production (million gallons) per year	2000
Emissions (metric tons per gallon-year of ethanol)	0.0554
Emissions (grams per gallon-year of ethanol)	55386
One year marginal emissions (grams per gallon of ethanol)	1846

The value of 110.77 million metric tons of emissions presented in this table is obtained by multiplying regional forest and grassland changes due to an increase in ethanol production from 13 to 15 BGs (see appendix C) by their corresponding Woods Hole annual emissions factors presented in the second and third columns of Table 12 and then summed over regions. The result of this calculation is multiplied by 30 to present the magnitude of total emissions over 30 years. One can follow the rest of example through table 13. We now present land use emissions for all groups of simulations discussed earlier in this report.

Land use emissions for the first group of simulations

Table 14 represents marginal and average land use emissions obtained from simulations off of the 2001 database. This table indicates that marginal emissions are increasing in ethanol production. For example, while an increase in ethanol production from 7 BGs to 9 BGs generates 1687 grams CO_2 emissions per gallon of ethanol, moving from 9 BGs to 11BG causes 1745 grams CO_2 per gallon. When ethanol production reaches 15 BGs, then each additional gallon of ethanol generates 1846 grams of CO_2. Table 14 indicates that average emissions are increasing in ethanol production as well. This table shows that during the time period of 2001-6 on average each gallon of US ethanol was generating 1477 grams CO_2. However, if ethanol production reaches 15 BGs, then on average each gallon of ethanol generates 1676 grams of emissions. It is important to note that in this group of simulations about 61% of emissions come from deforestation and 39% come from converting grasslands into crop production.

Table 14. Annual marginal and average estimated land use emissions due to the US ethanol production: Obtained from the simulations off of the 2001 database

Time Segment	Marginal Emissions (grams CO_2 per gallon of ethanol)				Average emissions (grams CO_2 per gallon of ethanol)			
	Changes in ethanol production	**Forest**	**Grasslands**	**TOTAL**	**Total ethanol production**	**Forests**	**Grasslands**	**TOTAL**
2001-6	3.085	886	590	1477	3.085	886	590	1477
2006-7	2.145	990	628	1619	5.23	929	606	1535
2007-9	2.000	1033	654	1687	7.23	958	619	1577
2009-11	2.000	1067	677	1745	9.23	982	632	1613
2011-13	2.000	1097	701	1797	11.23	1002	644	1646
2013-15	2.000	1122	724	1846	13.23	1020	656	1676

Note that in this paper we ignored impacts of the first 1.77 billion gallons of ethanol on the average land use changes per gallon of ethanol production. Incorporating land uses changes due to the first 1.77 billion gallons of ethanol will moderately reduce the average emissions per gallon of ethanol.

Land use emissions obtained from this group of simulations are smaller than our earlier estimates for land use emissions. For example, as shown in table 14, on average each gallon of US generates 1676 grams emissions. The corresponding number in our earlier report was about 2210 grams emissions. This shows about 16.5% reduction emissions per gallon of ethanol. This is due to using the new regional ETAs and incorporating cropland pasture into the picture.

Land use emissions for the second group of simulations

Table 15 presents the marginal and average emissions for the second group of simulations, where we calculate land use changes according to the updated baseline for 2001-6.

Emissions obtained from second group of simulations follow the pattern of the first group. However, their magnitudes are smaller than the first group.

Table 15. Annual marginal and average estimated land use emissions due to the US ethanol production: Obtained from the simulations off of the updated 2006 database

Time Segment	Marginal emissions (grams CO_2 per gallon of ethanol)				Average emissions (grams CO_2 per gallon of ethanol)			
	Changes in ethanol production	Forest	Grasslands	TOTAL	Total ethanol production	Forests	Grasslands	TOTAL
2001-6	3.085	1003	412	1414	3.085	1003	412	1414
2006-7	2.145	1026	349	1376	5.23	1012	386	1399
2007-9	2.000	1002	370	1372	7.23	1009	382	1391
2009-11	2.000	1028	377	1406	9.23	1014	381	1394
2011-13	2.000	1043	385	1429	11.23	1019	382	1400
2013-15	2.000	1052	395	1446	13.23	1024	384	1407

As shown in table 15, when the US ethanol production reaches to 15 BGs of ethanol each additional gallon of ethanol generates about 1446 grams of emissions. At this level of ethanol production, on average each gallon of ethanol causes 1407 grams of CO_2 emissions. These figures are smaller than the corresponding figures of the first group of simulations by 21.7% and 16%. These reductions are due to yield improvement during the time period of 2001-2006. As noted earlier in this time period yield has improved in many regions faster than the demand for crops for food. It is important to note that in this group of simulations more than 70% of emissions come from deforestation and the rest comes from converting grasslands into crop production.

Land use emissions for the third group of simulations

Table 16 shows the marginal and average land use emission for the third group of simulations, where we calculate land use changes according to the simulations with the updated 2001-06 database and population, yield, and forest product growth.

Table 16. Annual marginal and average estimated land use emissions due to the US ethanol production: Obtained from the simulations off of the updated 2006 database and with population and yield growth after 2006

Time Segment	Marginal emissions (grams CO_2 per gallon of ethanol)				Average emissions (grams CO_2 per gallon of ethanol)			
	Changes in ethanol production	Forest	Grasslands	TOTAL	Total ethanol production	Forests	Grasslands	TOTAL
2001-6	3.085	1003	412	1414	3.085	1003	412	1414
2006-7	2.145	674	305	978	5.23	868	368	1236
2007-9	2.000	565	372	937	7.23	784	369	1153
2009-11	2.000	469	477	946	9.23	716	392	1108
2011-13	2.000	433	619	1051	11.23	665	433	1098
2013-15	2.000	480	736	1217	13.23	637	479	1116

As shown in table 16, in this case during the time period of 2006-2015 the marginal emissions grow when the population growth dominates the yield growth. For example, an additional gallon of ethanol produces about 978 grams emissions in the time segment of 2006-7, while each gallon of additional ethanol causes 1217 grams emissions in the time segment of 2013-15. In this group of simulations on average each gallon of ethanol generates about 1116 grams emissions. This figure is smaller than the corresponding figure obtained from the second group of simulations by about 21 percent.

6. Final analysis

We now compare the land use emissions obtained from the three groups of simulations with the results of SEA. Table 17 shows lower emissions due to indirect land use change when we incorporate all economic and demographic and yield growth into account in the third group of simulations. The average value of the third group of simulations is about 13% of the original SEA result. The results of the first and the second groups of simulations are about 21% and 16.4% of SEA.

Table 17. Estimated land use change emissions due to U.S. ethanol production (Comparing GTAP and Searchinger et al. (2008) results)

Searchinger et al. (2008)	Total Emissions for 30 years (million metric tons)	3801
	Change in ethanol production (billion liters of ethanol)	55.92
	Total emissions for 30 years (grams per liter)	67972
	Liters per gallon	3.785
	Total emissions for 30 years (grams per gallon of ethanol)	257302
	One year emissions (grams per gallon of ethanol)	8577
GTAP results off of 2001 database	One year average emissions (gram per gallon of ethanol)	1676
	One year marginal emissions (gram per gallon of ethanol)	1846
GTAP results off of 2006 database	One year average emissions (gram per gallon of ethanol)	1407
	One year marginal emissions (gram per gallon of ethanol)	1446
GTAP results off of 2006 plus population & yield growth	One year average emissions (gram per gallon of ethanol)	1116
	One year marginal emissions (gram per gallon of ethanol)	1217

Total emissions from production and consumption of ethanol

Table 18 contains the estimated well-to-wheel ethanol emissions for the marginal and average land use changes for the three groups of simulations[13]. For the first group of simulations production and consumption of each gallon of ethanol (E100) on average generates about 6800 grams of GHGs emissions. In this case about 24.6% of released emissions are related to land use changes. When we incorporate changes in population and other factors, each gallon of ethanol (E100) on average causes about 6531 grams of GHGs emissions. In this case about 21.5% of released emissions are related to land use changes. Finally, in the third group, when we take into account the population and yield growth after 2006, then production and consumption of each

[13] In this report the direct marginal GHG emissions (i.e. non-land emissions) of ethanol for the post 2006 are taken from 100% dry mill.

gallon of ethanol (E100) generates about 6240 grams of emissions. In the third case, about 17.9% of released emissions are related to land use change.

Table 18 indicates well to wheel ethanol emissions expressed as grams/gal of ethanol and in grams per Megajoule (MJ). For the first, second, and third groups of simulations production and consumption of each gallon of ethanol (E100) on average generates about 84.4 g/MJ, 81.1 g/MJ, 77.5 g/MJ emissions, respectively.

Table 18. Estimated annual well-to wheel ethanol emissions for marginal and average land use changes

Description		Land use emissions (grams/gal)	Land use emissions (grams/MJ)	Well-to-wheel emissions without land use[a] (grams/gal)	Well-to-wheel emissions plus land use (grams/gal)	Well-to-wheel emissions plus land use (grams/MJ)[b]
Simulations Off of 2001	Marginal	1846	22.9	5100	6946	86.3
	Average	1676	20.8	5124	6800	84.4
Simulations Off of 2006	Marginal	1446	18.0	5100	6546	81.3
	Average	1407	17.5	5124	6531	81.1
Simulations Off of 2006 Plus population & yield growth	Marginal	1217	15.1	5100	6317	78.4
	Average	1116	13.9	5124	6240	77.5

[a]From GREET simulations. We used the default values in GREET version 1.3c for 2015 for the simulations. The marginal and average differ for ethanol direct emissions because the fraction that is wet versus dry milling decreases over time yielding slightly lower direct emissions for the marginal case.
[b]Low heating values of gasoline and ethanol are: 116090 BTU/gal and 76330 BTU/gal.

Finally, Table 19 compares total emissions of E100 obtained from the three groups of simulations with the emissions of conventional gasoline. This table indicates that ethanol production induces lower emissions compared to conventional gasoline for all groups of simulations. For example, total GHGs emissions due to production and consumption of E100 (including land use emissions) obtained from the first group of simulations are about 10342 grams per gallon of gasoline equivalent for the average land use changes. This figure is about

90.4% of the emissions due to production and consumption of conventional gasoline. When we use the updated 2006 database, total estimated GHGs emissions due to production and consumption of E100 are about 9933 grams per gallon of gasoline equivalent for the average land use changes. This figure is 86.9% of the emissions due to production and consumption of conventional gasoline. Finally, when we use the updated data base, and we assume population and yield increase after 2006, then total estimated emissions for E100 are 9490 grams per gallon of gasoline equivalent for the average land use changes. In this case the E100 emission estimate is about 83.0% of emissions associated with conventional gasoline. Table 19 presents emissions of ethanol and gasoline in grams per gallon of gasoline equivalent and per MJ.

Table 19. Estimated well-to-wheel ethanol and gasoline emissions for average land use changes

Description		Emissions in grams per gallon of gasoline equivalent			Emissions in grams/MJ		
		Ethanol	Gasoline	Ethanol vs gasoline (percent)	Ethanol	Gasoline	Ethanol vs gasoline (percent)
Simulations Off of 2001	Marginal	10564	11428	92.4	86.3	93.3	92.2
	Average	10342	11428	90.5	84.4	93.3	90.5
Simulations Off of 2006	Marginal	9956	11428	87.1	81.3	93.3	87.1
	Average	9933	11428	86.9	81.1	93.3	86.9
Simulations Off of 2006	Marginal	9608	11428	84.1	78.4	93.3	84.1
	Average	9490	11428	83.0	77.5	93.3	83.0

Since the third group simulations takes into account changes in population, crop yields, economic growth, and growth in primary inputs during the time period of 2001-2006 and after that assumes that population and yield growth will continue, the emissions obtained from this group of simulations are lower than the other cases. However, the results are derived from our assumptions, in particular for the time period of 2006-2015. Any change in these assumptions could alter the results. In other words, we have assumed 1 percent global growth in yields for all crops and 2001-06 population growth through 2015. Changes in these assumptions would alter the numerical results.

7. Conclusions

The overarching objective of this research has been to estimate the global land use changes induced by US corn ethanol programs and in doing so to closely examine some of the critical issues that have been overlooked in some prior studies. It is a very controversial topic. Some argue it is impossible to measure such changes. Others argue that failure to measure the land use changes and the consequent GHG emissions would lead us to incorrect policy conclusions. After working on this topic for over two years, we come out between these extremes. First, with almost a third of the US corn crop today going to ethanol, it is simply not credible to argue that there are no land use change implications of corn ethanol. The valid question to ask is to what extent land use changes would occur. Second, our experience with modeling, data, and parameter estimation and assumptions leads us to conclude that one cannot escape the conclusion that modeling land use change is quite uncertain. Of course, all economic modeling is uncertain, but it is important to point out that we are dealing with a relatively wide range of estimation differences. The estimation range depends on what is being simulated, as will be seen below.

Over the two plus years we have working on this topic, we have made numerous improvements in the models used for the analysis. These improvements are spelled out in the text above and in the appendices. We have better data on land productivity and on cropland pasture and CRP lands, and these data and associated parameters are now in the model. We have improved the treatment of the livestock and livestock feed sectors. Similarly, these changes are reflected in the current version of the model. We have amassed data on crop yields and many other variables for every region of the world and used much of that data in our analysis and model calibration. These data and model improvements have significantly improved the analysis and model results.

Table 20 provides a convenient summary of the evolution of some of our results over the different versions of the model and data. The third column replicates the summary results from our January 2009 draft paper before all the model changes described were implemented. The January 2009 results are provided only for reference, so our comparisons will be based on the three simulations reported in this paper. The fourth column is with all the model improvements and the 2001 data base. The fifth column is with the baseline updated to 2006 as described above. The last column is both with the updated baseline to 2006 and the assumed growth in demand and supply as described above.

Table 20. Summary of the different modeling results

Result	Units	Original Jan. 09 estimates	Model improvements with 2001 data base	Baseline updated to 2006	Updated baseline and growth in demand and yield
Land needed for ethanol	Ha./1000 gal.	0.27	0.22	0.15	0.12
Distribution of land use change between forest and pasture	%forest/%pasture	23/77	25/75	35/65	35/65
Distribution of land use change between U.S. and rest of world	%US/%Others	35/65	34/66	25/75	28/72
Average emissions of 15 bil. gal. program	Grams CO_2/gal. of ethanol	1931	1676	1407	1116
% of Searchinger, et al.	%	22.5	19.5	16.4	13.0
Emissions per gallon gasoline eq.	Grams CO_2/gal.	10564	10342	9933	9490
Emissions per MJ	Grams $C0_2$/MJ	86.3	84.4	81.1	77.5
Total ethanol emissions as % of gasoline	%	92.4	90.5	86.9	83.0

In some cases, the results are fairly stable regardless of the simulation. For example, the percentage of land that comes from forest ranges between 25 and 35 percent depending on the model and assumptions being used. Similarly, the fraction of land use change that occurs in the U.S. ranges between 25 and 34 percent. However, the land needed to meet the ethanol mandate ranges between 0.12 and 0.22 hectares/1000 gallons, which is a fairly wide range. The ethanol CO_2 emissions per gallon range between 1116 and 1676, also a fairly large range. However, the total emissions per MJ range between 77.5 g/MJ and 84.4 g/MJ, a small range. The reason for the small range in this case is that the direct ethanol emissions are assumed to be constant, so the land use emissions are being added to a constant level of direct emissions making the variability in total emissions per mile smaller.

Ethanol emissions as a fraction of gasoline emissions range between 83.0 and 90.5 percent. From these results, we feel confident that corn ethanol would meet a 10 percent savings standard. On the other hand, the results suggest that corn ethanol would not meet a 20 percent emissions reduction standard. However, we cannot conclude that corn ethanol would not meet a 20 percent standard given the inherent uncertainty in the analysis, and potential improvement in direct emissions associated with corn farming and ethanol production. In a recent analysis including uncertainty in GHG estimation using an earlier version of GTAP-BIO, Hertel et al. (2010) concluded that the corn ethanol induced emissions from land use change range between 2 and 51 g/MJ. Our estimate for the last case is 14 g/MJ. This large range taken from another study using similar approaches clearly illustrates the uncertainty inherent in this analysis. It also concludes that zero is not within the error bounds. In other words, we know land use change induced emissions are not zero, but measuring them with high precision is not yet possible.

8. Limitations and future research

As indicated above, analysis such as that undertaken here is very complex and is limited by data availability, validity of parameters, and other modeling constraints. Economic models, like other models, are abstractions from reality. They can never perfectly depict all the forces and drivers of changes in an economy. However, the basic model used for this analysis, GTAP, has withstood the test of time and peer review. Hundreds of peer reviewed articles have been published using the GTAP data base and analytical framework. In this project, we have made many changes in the model and data base to improve its usefulness for evaluating the land use change impacts of large scale biofuels programs. Yet, uncertainties remain. In this paper, we have described the evolution of the modeling and analysis and present openly the evolution of the results. Like other GTAP model versions, once it has been subjected to peer review, this model version will be available to others in the GTAP community to use in their analyses. We believe quite strongly that analysis of this type must be done with models and data bases that are available to others. Replicability and innovation are critical factors for progress in science. They also are important for credibility in policy analysis.

Some of the important topics for future research are as follows:

- More sensitivity on prospective growth in crop demand and supply by region and AEZ. The future growth in demand and supply of agricultural commodities, particularly coarse grains, are critical determinants of the impacts of biofuel programs. If global income and population growth and dietary transition lead to greater growth in demand for coarse grains than in supply, the impacts of biofuels mandates would be greater. On the other hand, if new technologies and broader adoption of these technologies lead to greater growth in supply, then the impacts of biofuels mandates would be reduced.

- Research is needed on the impacts on food and feed systems induced by biofuels under real world conditions of weather variability. Under binding mandates such as the Renewable Fuel Standard, demand is quite inelastic, which would lead to greater commodity price variability in the event of weather shocks such as drought.
- Improved data and information on land use and land cover change could be used in the future to improve model parameters and perhaps the model structure. We are certainly open to considering new information in this domain in the future.
- In this version of the model, substantial improvements in modeling and parameters for livestock production and use of feedstuffs including DDGS have been made. Nonetheless, as the markets evolve we will learn more about the functioning of these markets as feed users adapt to the new animal feeding realities.
- In general, we will need to update the model in many ways as new versions of the GTAP data base are released. This is an on-going process for GTAP. The new version of the GTAP data base is version 7, so constant quality improvement has been part of business as usual since the launch of GTAP in 1994.
- In this research we relied on Woods Hole data set to derive land use carbon emissions. This data set provides limited information on forgone carbon sequestration due to deforestation. This is a major deficiency. We have developed a set of land use emissions using the TEM model at the AEZ for all GTAP regions. However, they have not yet been verified and subjected to peer review, so they are not used in this analysis.

Our primary focus now is to incorporate cellulosic feedstocks into GTAP and to find better ways of getting greater sub-regional specificity in our analysis. We are now working with partners, including Argonne, to accomplish these objectives.

References

Arora S., M. Wu, and M. Wand. 2008. "Updated of Distiller Grains Displacement Rations for Corn Ethanol Life-Cycle Analysis." Center for Transportation Research, Energy System Division, Argonne National Laboratory.

Balshi M.S., A.D.McGuire, Q. Zhuang, J.M.Melillo, D.W. Kicklighter, E.Kasischke, C. Wirth, M. Flannigan, J.Harden, J.S.Clein, T.J. Burnside, J.McAllister, W.A.Kurz, M.Apps, and A. Shvidenko. 2007. "The role of historical fire disturbance in the carbon dynamics of the pan-boreal region: A process-based analysis." J. Geophys. Res., 112.

Birur, D.K., T.W. Hertel, and W.E. Tyner 2008. "Impact of Biofuel Production on World Agricultural Markets: A Computable General Equilibrium Analysis." GTAP Working Paper No 53, Center for Global Trade Analysis, Purdue University, West Lafayette, IN.

Birur, D,K, 2010. "Global Impacts of Biofuels on Agriculture, Trade, and Environment: A Computable General Equilibrium Analysis," Ph.D. Dissertation, Purdue University (forthcoming).

Brockmeier M., 2010. "A Graphical Exposition of the GTAP Model," GTAP Technical Paper No. 8, Center for Global Trade Analysis, Purdue University, West Lafayette, IN.

Burniaux, J., and T. Truong. 2002. "GTAP-E: An Energy-Environmental Version of the GTAP Model." GTAP Technical Paper No. 16, Center for Global Trade Analysis, Purdue University, West Lafayette, IN.

CRS RL34294, 2007. "Energy Independence and Security Act of 2007: A Summary of Major Provisions." Congressional Research Service.

Dimaranan, B.V. Edt. 2006. "Global Trade, Assistance, and Production: The GTAP 6 Data Base." Center for Global Trade Analysis, Purdue University, West Lafayette, IN 47907, USA.

Euskirchen, E.S., A.D. McGuire, D.W. Kicklighter, Q. Zhuang, J.S. Clein, R.J. Dargaville, D.G. Dye, J.S. Kimball, K.C. McDonald, J.M. Melillo, V.E. Romanovsky, N.V. Smith. 2006. "Importance of recent shifts in soil thermal dynamics on growing season length, productivity, and carbon sequestration in terrestrial high-latitude ecosystem" Global Change Biology, 12, 731-750.

Fabiosa, J.F., 2009. Land-Use Credits to Corn Ethanol: Accounting for Distillers Dried Grains with Solubles as a Feed Substitute in Swine Rations. Working paper 09-WP 489, Center for Agricultural and Rural Development , Iowa State University.

Fargione, J., J. Hill, D. Tilman, S. Polasky, and P. Hawthorne. 2008. "Land Clearing and the Biofuel Carbon Debt" Science 319:1235–1238.

Hertel, T. W. 1997. "Global Trade Analysis, Modeling and Applications." Cambridge University Press, Cambridge.

Hertel, T. W., C. E. Ludena and A. Golub. 2009. "Economic Growth, Technological Change and Patterns of Food and Agricultural Trade in Asia", Chapter 6 (pp. 175-210) in: From Growth to Convergence: Asia's Next Two Decades, edited by Fan Zhai, UK: Palgrave MacMillan.

Hertel, T., Tyner W., Birur, D., 2010. "The Global Impacts of Biofuels Mandates." *The Energy Journal* 31(1):75-100.

Hertel, T., Golub A., Jones A., O"hare M., Plevin R., Kammen D., 2010. "Effects of US Maize Ethanol on Global Land Use and Greenhouse Gas Emissions: Estimating Market-mediated Responses." *Bioscience* 60 (3).

Keeney, R., and T. W. Hertel. 2008. "The Indirect Land Use Impacts of U.S. Biofuel Policies: The Importance of Acreage, Yield, and Bilateral Trade Responses." GTAP Working Paper No. 52, Center for Global Trade Analysis, Purdue University, West Lafayette, IN.

Lee, H.-L., T. W. Hertel, B. Sohngen, and N. Ramankutty. 2005. "Towards and Integrated Land Use Data Base for Assessing the Potential for Greenhouse Gas Mitigation." GTAP Technical Paper # 25, Center for Global Trade Analysis, Purdue University.

Lubowski, R.N., M. Vesterby, S. Bucholtz, A. Baez, and M. Roberts. *Major Uses of Land in the United States, 2002*. USDA Economic Information Bulletin Number 14, May 2005.

McDougall, R., and A. Golub. 2007. "GTAP-E Release 6: A Revised Energy-Environmental Version of the GTAP Model." GTAP Technical Paper, forthcoming.

McGuire A. D., Melillo J. M., Joyce L. A., Kicklighter D. W., Grace A. L., Moore III B., Vorosmarty CJ (1992) Interactions between carbon and nitrogen dynamics in estimating net primary productivity for potential vegetation in North America. *Global Biogeochemical Cycles* 6, 101-124.

McGuire, A.D., Sitch, S., Clein, J.S., Dargaville, R., Esser, G., Foley, J., Heimann, M., Joos, F., Kaplan, J., Kicklighter, D.W., Meier, R.A., Melillo, J.M., Moore, B., Prentice, I.C., Ramankutty, N., Reichenau, T., Schloss, A., Tian, H., Williams, L.J., and Wittenberg, U. 2001. "Carbon balance of the terrestrial biosphere in the twentieth century: Analyses of CO2, climate and land use effects with four process-based ecosystem models." *Global Biogeochemical Cycles*, *15*, 183-206.

Melillo, J. M., A. D. McGuire, D. W. Kicklighter, B. Moore III, C. J. Vorosmarty and A. L. Schloss (1993). "Global climate change and terrestrial net primary production." *Nature* 363, 234-240.

Raich J.W., Rastetter E.B., Melillo J.M., Kicklighter D.W., Steudler P.A., Peterson B.J., Grace A.L., Moore III.B., Vorosmarty C.J. 1991. "Potential net primary productivity in South America: application of a global model." *Ecological Applications* 1, 399-429.

Searchinger, T., R. Heimlich, R. Houghton, F. Dong, A. Elobeid, J. Fabiosa, S. Tokgoz, D. Hayes, and T. Yu. 2008. "Use of U.S. croplands for biofuels increases greenhouse gases through emissions from land use change." *Science* 319:1238–1240.

Taheripour, F., T.W. Hertel, W.E. Tyner, J.F. Beckman, and D. K. Birur. 2010. "Biofuels and their By-Products: Global Economic and Environmental Implications." *Biomass and Bioenergy 34* , pp.278-89.

Taheripour, F., T. Hertel, and W. Tyner. 2009. "Implications of the Biofuels Boom for the Global Livestock Industry: A Computable General Equilibrium Analysis," An earlier version used for the background paper for the 2009 *State of Food and Agriculture (SOFA) From the Food and Agriculture Organization of the UN (FAO), a revised version is also presented at2009 Applied and Agricultural Economics Association meeting in Milwaukee Wisconsin,* Center for Global Trade Analysis, Purdue University.

Taheripour, F., D. Birur, T. Hertel, and W. Tyner. 2007. "Introducing Liquid Biofuel into the GTAP Database." GTAP Research Memorandum No. 11. Center for Global Trade Analysis, Purdue University, West Lafayette, IN, USA.

Tyner, W. E., F. Taheripour, and U. Baldos. "Land Use Change Carbon Emissions due to U.S. Ethanol Production, Draft Report to Argonne National Lab, January 2009. http://www.agecon.purdue.edu/papers/biofuels/Argonne-GTAP_Revision%204a.pdf

Walmsley, T.L., B.V. Dimaranan, and R.A. McDougall, 2000. "A Base Case Scenario for the Dynamic GTAP Model." Center for Global Trade Analysis, Purdue University, West Lafayette, IN, USA.

West, T., and W. Post. 2002. "Soil Organic Carbon Sequestration Rates by Tillage and Crop Rotation: A Global Data Analysis." Soil Sci. Soc. Am. J. 66:1930–1946.

Wang, M. 2005. "Updated Energy and Greenhouse Gas Emission Results of Fuel Ethanol". Presented on the 15th International Symposium on Alcohol Fuels, Sept. 26-28, 2005, San Diego, CA, USA.

Wang, M. 1999. "GREET 1.5 — Transportation Fuel-Cycle Model Volume 1: Methodology, Development, Use, and Results." Center for Transportation Research, Energy Systems Division, Argonne National Laboratory, Argonne, Illinois.

Zhuang, Q., A. D. McGuire, J. M. Melillo, J. S. Clein, R. J. Dargaville, D. W. Kicklighter, R. B. Myneni, J. Dong, V. E. Romanovsky, J. Harden, and J. E. Hobbie. 2003. "Carbon cycling in extratropical terrestrial ecosystems of the Northern Hemisphere during the 20th Century: A modeling analysis of the influences of soil thermal dynamics," *Tellus, 55(B).*

Appendix A

Regional Land Conversion Factors (ETA parameters)
Productivity of new cropland versus productivity of existing cropland

Appendix A: Land Conversion Factors

In the GTAP-BIO-ADV model the parameter ETA, which shows productivity of new cropland versus productivity of exiting cropland, plays an important role in determining the land use impacts of biofuel production. In our past simulations for biofuel analyses we usually assumed that ETA=0.66 for all regions across the world. Indeed, with this setup we assumed that productivity of one unit (let say one acre) of new croplands is equal to 2/3 of the productivity of one acre of existing croplands, all across the world. In this report we leave this assumption and we apply regional ETAs at the AEZ level. The regional ETAs are obtained from a process-based biogeochemistry model (Terrestrial Ecosystem Model (TEM)) along with spatially referenced information on climate, elevation, soils, and vegetation land use data. The new regional ETAs are varying across the world and among AEZs. In this appendix, we first explain the role of ETA in the GTAP-BIO-ADV model. Then we briefly introduce the TEM model and its data sources. Finally we explain derivations of the regional ETA parameters along with the results.

Role of ETA in the land use module

As we mentioned above ETA measures the productivity of the new cropland versus the productivity of existing cropland. To avoid confusion we define these two types of land:

Existing cropland: Is defined as a land which has been cultivated and used for crop production in the past. GTAP classifies these lands under the title of crop cover.

New cropland: Is defined as natural land (could be either forest or pasture land) that will be converted to cropland due to the need for expansion in the demand for crops.

We now use an example to explain the role of ETA in the GTAP-BIO-ADV model. Suppose that we want to expand production of corn in region *A* by 600 bushels and also suppose that this region only produces corn. In addition, suppose that the corn yield of the existing cropland is about 150 bushels/acre. So the question is how much land we need to produce 600 more bushels of corn? The answer is that it depends on the productivity of land that we want to bring into crop production. Suppose that region *A* has a piece of forest which can be converted to crop production and that ETA=2/3=0.66. With these assumptions the GTAP-BIO-ADV model will calculate that in region *A* we need 6 acres of land to meet the target. Because it assumes that the yield of the new cropland is about 100 bushels per acre. Now if we assume that ETA=1, (i.e. the productivity of the new and existing cropland are equal) then we need only 4 acres to satisfy the target for corn production. This example highlights the role of ETA in GATP-BIO-ADV model.

In fact, in GTAP we have a solid and reliable database which provides productivity measures for existing croplands for all regions across the world by AEZ. However, we do not have information on the productivity of new cropland, and there are large uncertainties in predicting future productivity of existing cropland in different parts of the world. So far we used parameter ETA=0.66, based on empirical evidence from US land use and consulting experts on the productivity of the new cropland. In this report we use the TEM model along with spatially referenced information on climate, elevation, soils, and vegetation land use data to determine productivity of new cropland versus the existing cropland at the AEZ level in each region. To accomplish this task using the TEM model we calculate the Net Primary Production, as a proxy for productivity, at 0.5° x 0.5° (latitude by longitude) spatial resolution for all grid cells across the world. In this calculation we assume that all grid cells are producing a generic C4 crop. Then we use this information to derive the land conversion factors at the AEZ level for each region of

GTAP. The next section introduces the TEM model and its calculation steps along with the data used in calculating NPPs. Then we discuss the conversion of NPPs to the land conversion factor.

TEM model

We use a process-based biogeochemistry model, the TEM (Zhuang et al., 2003) to estimate NPP for each 0.5° x 0.5° (longitude and latitude) of the global terrestrial ecosystems. TEM uses spatially referenced information on climate, elevation, soils, and vegetation to make monthly estimates of C and N fluxes and pool sizes of the terrestrial biosphere. In TEM, the net ecosystem exchange of CO_2 between the land ecosystems and atmosphere is calculated as the difference between the uptake of atmospheric CO_2 associated with photosynthesis (i.e., gross primary production or GPP) and the release of CO_2 through autotrophic respiration (R_A), heterotrophic respiration (R_H) associated with decomposition of organic matter. The fluxes GPP, R_A and R_H are influenced by changes in atmospheric CO_2, climate variability and change, and the freeze-thaw status of the soil. The following figure represents this model and its major components.

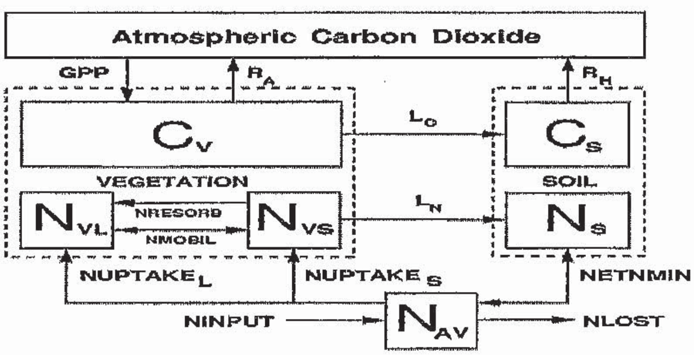


Figure A1. The Terrestrial Ecosystem Model

The model has been extensively used to evaluate C dynamics in northern high latitudes and the globe (e.g., Euskirchen *et al* 2006, Balshi *et al* 2007; Zhuang et al., 2003; Melillo et al., 1993; McGuire et al., 2001). Its structure, algorithm, parameterization, calibration and performance have been well documented.

Parameters in TEM may be specific to different vegetation types, specific to different soil textures, or constant for all vegetation types and soil textures. Most of the parameters in TEM are assigned values derived from the literature, but some parameters are calibrated to the carbon and nitrogen pools and fluxes of intensively studied sites (see Raich et al., 1991 and McGuire et al., 1992 for details). In this paper the model is calibrated for generic C4 crops. The pools and fluxes of ecosystem carbon and nitrogen of these crop ecosystems are shown in table A1.

Table A1. Carbon and nitrogen pools and fluxes used for a generic parameterization

Variable	Values* for C4	Source and Comments
C_v	649	Evrendilek[2004]
N_v	9.9	Evrendilek[2004]
C_s	3071.5	Evrendilek[2004]
N_s	307.1	Evrendilek[2004]
N_{av}	2.64	Based on 0.86%, the mean N_{av}:N_s ratio
GPP	649	Evrendilek[2004]
NPP	296.6	Evrendilek[2004]
NPPSAT	296.6	Evrendilek[2004]
NUPTAKE	3.98	Calculated from NPP_n, 75%NPP_n=NUPTAKE.

*Units for annual gross primary production (GPP), net primary production (NPP), and NPPSAT are g C $m^{-2}yr^{-1}$. Units for vegetation C (C_v) and soil C (C_s) are g C m^{-2}. Units for vegetation N (N_v), soil N (N_s), and inorganic N (N_{av}) are g N m^{-2}. Units for annual N uptake by vegetation (NUPTAKE) are g N m^{-2} yr^{-1}.

Input data sets

To apply TEM to make spatially and temporally explicit estimates of ecosystem carbon storage and net primary production in this study, we use the same input data sets as were used in Zhuang et al., (2003). These input data sets are important for directly affecting processes in the model (e.g., the effects of soil temperature on heterotrophic respiration) and for defining the parameters that are specific to vegetation types and soil textures. We use a potential vegetation data set similar to that described in Melillo et al. (1993) to run the model to equilibrium prior to driving the model with transient changes in atmospheric CO_2 and climate. Soil texture and elevation do not vary in our simulations. The transient historical atmospheric CO_2 concentrations are used. The data sets describing historical changes in monthly air temperature and precipitation are gridded at 0.5° x 0.5° spatial resolution for our simulations (Zhuang et al., 2003).

Global simulations

To run TEM for the globe, we use the data of atmosphere, vegetation, soil texture, and elevation at 0.5° latitude x 0.5° longitude resolution from 1900 to 2000. For the simulations of C4 crops, we assume that each grid cell was replaced with the generic C4 crop and keep the information of soils, elevation and climate as the same as the simulation for natural ecosystems. For each grid cell, we first run TEM to equilibrium for an undisturbed ecosystem using the long-term averaged monthly climate and CO_2 concentrations from 1900 to 2000. We then run the model for 150 years with the climate from 1900 to 1949 to account for the influence of inter-annual climate variability on the initial conditions of the undisturbed ecosystem. We then run the model with transient monthly climate data from 1900 to 2000. The simulated NPP for C4 crop simulations of the year 2000 are used for this analysis.

Using NPP data to obtain ETA

We use the NPP data as a proxy for yield to calculate the regional land conversion factors by AEZ. In this process first we matched the results from TEM with our land database to assign AEZs to all grid cells across the world. Then we imposed several restrictions to drop lands which are not good for crop production. In particular, we dropped the grid cells with the following types of land cover:

- ALPINE_TUNDRA_&_POLAR_DESERT
- FORESTED_BOREAL_WETLANDS
- NON-FORESTED_BOREAL_WETLANDS
- TEMPERATE_FORESTED_WETLANDS
- XERIC_SHRUBLANDS
- TROPICAL_FORESTED_WETLANDS
- DESERTS
- TROPICAL_NON-FORESTED_WETLANDS
- TROPICAL_NON-FORESTED_FLOODPL
- TEMPERATE_NON-FORESTED_WETLAND
- TEMPERATE_FORESTED_FLOODPLAINS
- TEMPERATE_NON-FORESTED_FLOODPL

In addition we dropped all grid cells with cells with median of terrain slopes greater than or equal 5%. We dropped these because they are not appropriate for crop production. Then we used the cleaned database to derive the land conversion factors.

To explain the derivation process first we analyze our data for two sample regions: US AEZ10 and Brazil AEZ4. The following two graphs (figures A2 and A3) represent the shares of available and converted natural grasslands in these two sample areas. In each graph we classified the land into 6 groups of productivities (NPPs). Figure A2 indicates that in this AEZ a big portion of the natural grass land is already converted to crop production. A small amount of grassland is available to be converted to crop production in this AEZ. However, the available land is distributed across all productivity groups. Note that the AEZ10 of the US covers a large area with relatively different land qualities, weather conditions and length of growing periods between 180 to 240 days.

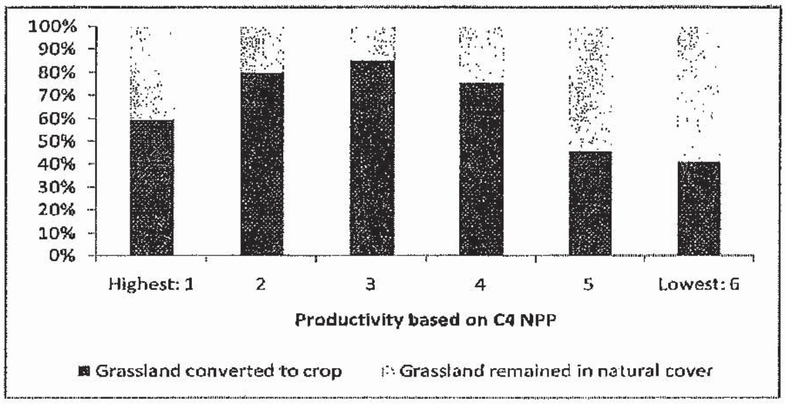


Figure A2. Availability of grassland suitable for crop production in US-AEZ10

Now consider figure A3 which indicates that in the Brazil AEZ4 there are lots of grassland remained in natural cover and only a small portion of grassland in this AEZ has been converted to crop production. In this AEZ available land is distributed across all productivity groups as well.

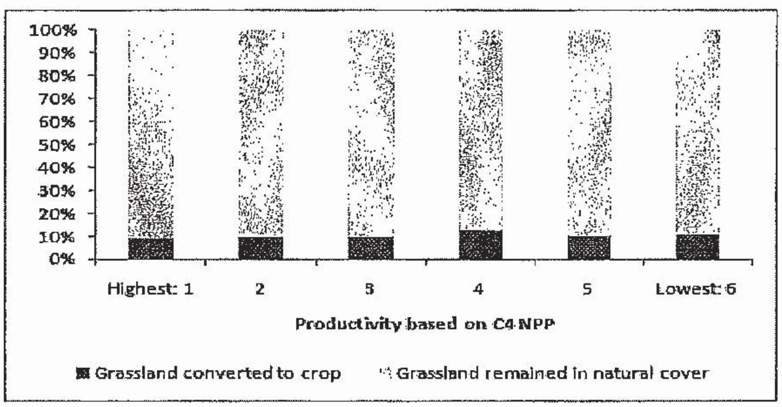


Figure A3. Availability of grassland suitable for crop production in Brazil-AEZ4

Now consider another aspect of the NPP data in these two AEZs. Figure A4 compares the average productivity of grassland converted to crop production in the past with the productivities of all grassland parcels that remained in natural cover in US AEZ10. In this figure grid cells are sorted according to their productivity. So when we move from left side to the right side of the horizontal axis, we move from grid cells with higher productivities to the grid cells with lower productivities.

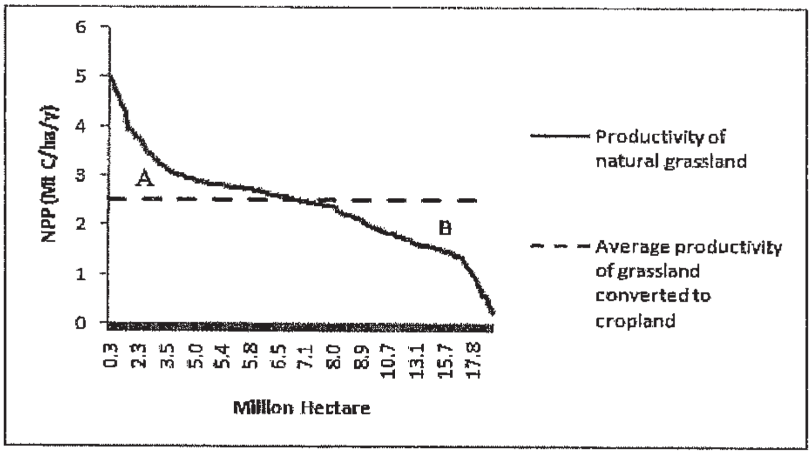


Figure A4. Average and marginal productivities in US AEZ10 for grassland

The ratio of the area A in this graph (area below the productivity of grassland curve and above the average productivity of grassland converted to cropland horizontal line) over the area B (area above the blue curve and below the red line) provides us a land conversion factor for this type of land in this AEZ. All of the land pixels in area A represent pixels with productivity (for C4) higher than the average productivity of existing cropland (the straight line). All of the pixels in B have productivity less than the average cropland. So area A over area B shows average productivity of new land versus average productivity of existing cropland. The assumption then is that the marginal unit of land has this productivity. Figure A5 provides the same information for Brazil AEZ4.

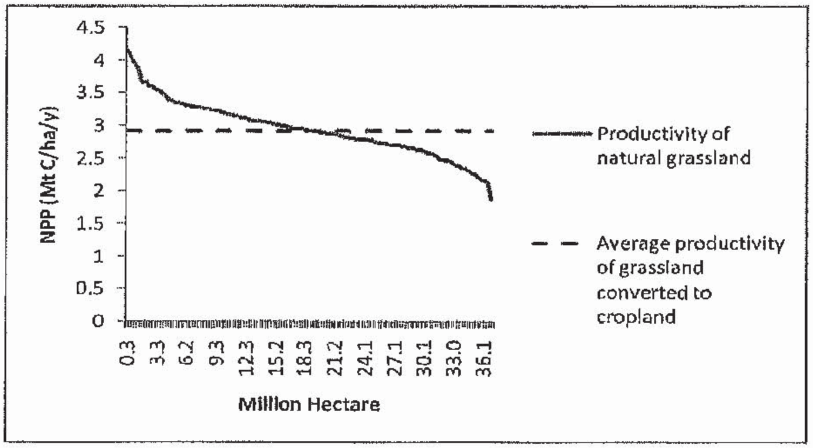


Figure A5. Average and marginal productivities in Brazil AEZ4 for grassland

While we are able to derive the conversion factors for all types of land cover we pooled all land types in each AEZ in each region and we defined the geographical land conversion factors at the AEZ level. It is important to point out that the model does not take into account irrigation. However, in real world in some areas lands are under crop production with irrigation. For this reason we dropped the productivity of all natural land by 10% and we assumed no land conversion factor greater than 1. The results of these calculations are shown in table A2. In this table zero means no land is available and 1 shows that the marginal and average productivities are equal. Table A2 indicates that the US land conversion factors range from 0.51 to 1, depending on the AEZ. Our earlier value for the land conversion factor (i.e. ETA=0.66) falls within this range. However, Table A2 shows that the Brazil land conversion factors range from 0.89 to 1, and most of them are around 0.9. This means that our earlier land conversion factor was underestimating the marginal productivity of land in Brazil. While we apply these land conversion factors in this report we will continue to improve our results in the future.

Table A2. Regional land conversion factors obtained from NPP data for a generic C4 crop[1]

AEZ[2]\Region[3]	R1	R2	R3	R4	R5	R6	R7	R8	R9	R10	R11	R12	R13	R14	R15	R16	R17	R18	R19
1	0.00	0.00	0.91	0.00	0.00	0.00	0.93	1.00	0.95	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.68	0.61	1.00
2	0.00	0.00	0.92	0.00	0.00	0.00	0.89	1.00	0.81	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.59	1.00	1.00
3	0.00	0.00	0.93	0.00	0.00	0.00	0.86	1.00	0.90	0.00	0.00	0.00	1.00	0.00	0.00	0.00	1.00	0.89	0.74
4	0.00	1.00	0.89	0.00	0.00	1.00	0.93	1.00	0.88	0.00	0.88	0.89	1.00	0.00	0.00	0.00	0.86	0.92	0.92
5	0.00	0.00	0.93	0.00	0.00	0.90	0.98	0.88	0.90	0.00	0.90	0.91	0.98	0.00	0.00	0.00	0.00	1.00	0.96
6	0.00	0.00	0.91	0.00	0.00	0.88	0.98	0.97	0.85	0.00	0.88	0.95	0.78	0.00	0.00	0.00	0.00	1.00	0.88
7	0.73	0.00	0.00	0.89	0.00	0.80	0.90	0.59	1.00	1.00	0.00	0.00	0.43	1.00	0.98	0.00	0.46	0.80	0.65
8	0.71	0.90	0.00	0.91	0.00	1.00	0.71	0.72	0.90	1.00	0.00	0.00	0.60	0.84	0.84	0.00	0.71	0.79	0.86
9	1.00	1.00	0.00	0.85	1.00	0.98	0.88	1.00	0.91	1.00	0.00	0.00	1.00	0.94	0.82	0.00	0.77	0.84	0.93
10	0.93	0.96	0.88	0.88	0.96	0.84	1.00	0.89	1.00	0.93	0.00	1.00	0.92	0.89	0.89	0.87	0.98	0.88	0.92
11	0.96	0.83	1.00	1.00	0.94	0.95	0.90	1.00	0.87	0.84	0.00	1.00	0.79	0.89	1.00	0.00	0.00	0.77	0.96
12	0.89	0.86	0.91	0.00	0.95	0.92	0.90	1.00	0.84	0.00	0.00	1.00	1.00	0.00	0.89	0.00	0.00	1.00	0.98
13	0.92	1.00	0.00	0.55	0.00	1.00	1.00	0.00	1.00	1.00	0.00	0.00	1.00	0.63	0.97	0.00	0.00	0.00	0.00
14	0.51	0.89	0.00	0.80	0.00	0.92	1.00	0.00	1.00	1.00	0.00	0.00	1.00	0.90	1.00	0.95	0.00	0.00	0.00
15	0.71	0.90	0.00	0.83	1.00	1.00	1.00	0.00	0.64	1.00	0.00	1.00	1.00	0.90	1.00	0.87	0.00	0.00	1.00
16	1.00	0.89	0.00	1.00	0.00	1.00	1.00	0.00	0.92	0.00	0.00	1.00	1.00	0.85	1.00	1.00	0.00	0.00	1.00
17	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

1 In this table zero means no land is available and 1 means that the marginal and average productivities are equal.
2 Rows are AEZs from AEZ1 to AEZ18.
3 Columns are regions and regions are listed in Appendix B.

Appendix B
Lists of Commodities, Industries, and Regions

Table B 1. List of industries and commodities in the new model

Industry	Commodity	Description	Name in the GTAP_BIOB
Paddy_Rice	Paddy_Rice	Paddy rice	Pdr
Wheat	Wheat	Wheat	Wht
CrGrains	CrGrains	Cereal grains	Gro
Oilseeds	Oilseeds	Oil seeds	Osd
OthAgri	OthAgri	Other agriculture goods	ocr, pfb, v_f
Sugarcane	Sugarcane	Sugar cane and sugar beet	c-b
DairyFarms	DairyFarms	Dairy Products	Rmk
Ruminant	Ruminant	Cattle & ruminant meat production and	Ctl, wol
NonRum	Non-Rum	Non-ruminant meat production	oapl
ProcDairy	ProcDairy	Processed dairy products	Mil
ProcRum	ProcRum	Processed ruminant meat production	Cmt
ProcNonRum	ProcNonRum	Processed non-ruminant meat production	Omt
Forestry	Forestry	Forestry	Frs
Cveg_Oil	Cveg_Oil	Crude vegetable oil	A portion of vol
	VOBP	Oil meals	A portion of vol
Rveg_Oil	Rveg_Oil	Refined vegetable oil	A portion of vol
Proc_Rice	Proc_Rice	Processed rice	Pcr
Bev_Sug	Bev_Sug	Beverages, tobacco, and sugar	b_t, sgr
Proc_Food	Proc_Food	Processed food products	A portion of ofd
Proc_Feed	Proc_Feed	Processed animal feed products	A portion of ofd
OthPrimSect	OthPrimSect	Other Primary products	fsh, omn
Coal	Coal	Coal	Coa
Oil	Oil	Crude Oil	Oil
Gas	Gas	Natural gas	gas, gdt
Oil_Pcts	Oil_Pcts	Petroleum and coal products	p-c
Electricity	Electricity	Electricity	Ely
En_Int_Ind	En_Int_Ind	Energy intensive Industries	crpn, i_s, nfm, fmp
Oth_Ind_Se	Oth_Ind_Se	Other industry and services	atp, cmn, cns, ele, isr, lea, lum, mvh, nmm, obs, ofi, ome, omf, otn, otp, ppp, ros, tex, trd, wap, wtp
NTrdServices	BTrdServices	Services generating Non-C02 Emissions	wtr, osg, dwe
EthanolC	Ethanol1	Ethanol produced from grains	
	DDGS	Dried Distillers Grains with Solubles	
Ethanol2	Ethanol2	Ethanol produced from sugarcane	
Biodiesel	Biodiesel	Biodiesel produced from vegetable oil	

Table B 2. Regions and their members

Region	Description	Corresponding Countries in GTAP
USA	United States	Usa
EU27	European Union 27	aut, bel, bgr, cyp, cze, deu, dnk, esp, est, fin, fra, gbr, grc, hun, irl, ita, ltu, lux, lva, mlt, nld, pol, prt, rom, svk, svn, swe
BRAZIL	Brazil	Bra
CAN	Canada	Can
JAPAN	Japan	Jpn
CHIHKG	China and Hong Kong	chn, hkg
INDIA	India	Ind
C_C_Amer	Central and Caribbean Americas	mex, xna, xca, xfa, xcb
S_o_Amer	South and Other Americas	col, per, ven, xap, arg, chl, ury, xsm
E_Asia	East Asia	kor, twn, xea
Mala_Indo	Malaysia and Indonesia	ind, mys
R_SE_Asia	Rest of South East Asia	phl, sgp, tha, vnm, xse
R_S_Asia	Rest of South Asia	bgd, lka, xsa
Russia	Russia	Rus
Oth_CEE_CIS	Other East Europe and Rest of Former Soviet Union	xer, alb, hrv, xsu, tur
R_Europe	Rest of European Countries	che, xef
MEAS_NAfr	Middle Eastern and North Africa	xme,mar, tun, xnf
S_S_AFR	Sub Saharan Africa	Bwa, zaf, xsc, mwi, moz, tza, zmb, zwe, xsd, mdg, uga, xss
Oceania	Oceania countries	aus, nzl, xoc

Appendix C
Land Use Changes Due to Ethanol Production

Table C1. Global land use changes due to US ethanol production: Off of 2001 database (1000 hectares)

Region	2001-2006			2006-2007			2007-2009			2009-2011			2011-2013			2013-2015		
	F	C	P	F	C	P	F	C	P	F	C	P	F	C	P	F	C	P
USA	-111	228	-117	-79	163	-84	-74	153	-79	-74	154	-80	-75	155	-80	-75	155	-80
EU27	-33	52	-19	-28	43	-15	-28	43	-15	-30	45	-15	-31	47	-16	-33	49	-17
BRAZIL	-24	35	-11	-20	28	-9	-19	28	-8	-20	29	-9	-21	30	-9	-21	31	-10
CAN	-38	64	-26	-28	47	-19	-27	46	-19	-28	48	-20	-30	51	-21	-31	53	-22
JAPAN	-1	1	0	-1	1	0	-1	1	0	-1	1	0	-1	1	0	-1	1	0
CHIHKG	11	7	-18	9	5	-14	9	5	-14	10	5	-15	10	6	-16	11	6	-17
INDIA	-4	9	-5	-4	8	-4	-4	8	-5	-4	9	-5	-4	10	-5	-5	10	-6
C_C_Amer	-4	12	-8	-3	10	-7	-2	10	-7	-2	10	-8	-2	11	-9	-2	12	-9
S_o_Amer	18	21	-39	13	16	-29	12	16	-28	12	17	-29	13	17	-30	13	18	-31
E_Asia	2	0	-2	1	0	-2	1	0	-1	1	0	-2	1	0	-2	2	0	-2
Mala_Indo	2	-1	-1	1	0	-1	1	0	-1	1	0	-1	1	0	-1	1	0	-1
R_SE_Asia	1	0	-1	1	0	-1	1	0	-1	1	0	-1	1	0	-1	1	0	-1
R_S_Asia	-1	4	-3	-1	4	-3	-1	4	-3	-1	4	-3	-1	4	-3	-1	4	-3
Russia	51	-3	-49	35	-2	-34	33	-1	-32	34	-1	-33	35	-1	-33	35	-1	-34
Oth_CEE_CIS	-2	26	-25	-1	20	-19	-1	20	-19	-1	21	-20	-1	21	-20	-1	22	-21
Oth_Europe	0	1	0	0	1	0	0	1	0	0	1	0	0	1	0	0	1	0
MEAS_NAfr	0	18	-18	0	15	-15	0	15	-15	0	15	-15	0	16	-16	0	17	-17
S_S_AFR	-11	115	-104	-12	89	-77	-13	88	-75	-14	92	-78	-16	97	-81	-17	101	-84
Oceania	0	19	-18	0	14	-14	0	14	-13	0	14	-14	0	15	-14	0	15	-15
TOTAL	-144	610	-467	-114	460	-346	-112	448	-336	-117	465	-348	-121	480	-360	-124	495	-371

F, C, and P are stand for Forest, Cropland, and Pastureland, respectively

Table C2. Global land use changes due to US ethanol production: Off of 2006 updated database (1000 hectares)

Region	2001-2006			2006-2007			2007-2009			2009-2011			2011-2013			2013-2015		
	F	C	P	F	C	P	F	C	P	F	C	P	F	C	P	F	C	P
USA	-71	119	-48	-39	76	-37	-35	71	-36	-35	72	-37	-35	73	-38	-35	73	-39
EU27	-13	21	-7	-16	20	-3	-16	20	-4	-18	22	-4	-18	22	-4	-19	23	-4
BRAZIL	-33	23	10	-20	14	6	-17	13	4	-17	14	3	-17	14	3	-17	14	2
CAN	-11	20	-9	-9	11	-2	-8	10	-2	-8	11	-3	-8	11	-3	-8	11	-4
JAPAN	-1	1	0	0	1	0	0	1	0	0	1	0	0	1	0	0	1	0
CHIHKG	3	15	-18	-8	16	-8	-6	15	-9	-5	15	-9	-5	15	-10	-5	15	-10
INDIA	-14	29	-15	-8	13	-5	-8	13	-5	-8	14	-5	-8	14	-6	-9	14	-6
C_C_Amer	-6	20	-14	-4	9	-6	-3	9	-6	-3	9	-7	-2	10	-7	-2	10	-7
S_o_Amer	6	23	-29	2	15	-17	2	14	-16	1	15	-16	1	15	-16	1	15	-16
E_Asia	2	2	-4	1	1	-2	1	1	-2	1	1	-2	1	1	-2	1	1	-2
Mala_Indo	-9	10	-1	-7	7	-1	-6	7	-1	-6	7	-1	-6	7	-1	-7	7	-1
R_SE_Asia	-6	6	-1	-5	5	0	-4	4	0	-4	4	0	-4	4	0	-4	4	0
R_S_Asia	-4	18	-14	-2	9	-6	-2	9	-6	-2	9	-7	-2	9	-7	-3	9	-7
Russia	2	21	-23	12	14	-26	11	13	-23	9	13	-23	9	13	-22	8	13	-22
Oth_CEE_CIS	-12	50	-38	-11	24	-12	-10	23	-13	-10	24	-14	-10	24	-14	-10	25	-15
Oth_Europe	-1	1	0	-1	1	0	0	1	0	0	1	0	0	1	0	0	1	0
MEAS_NAfr	0	15	-15	0	7	-8	0	7	-7	0	7	-7	0	7	-7	0	7	-8
S_S_AFR	13	26	-39	8	50	-58	6	49	-54	4	50	-54	3	50	-54	2	51	-53
Oceania	-1	17	-16	-1	10	-9	-1	9	-9	-1	10	-9	-1	10	-9	-1	10	-9
TOTAL	-155	439	-284	-107	302	-194	-98	289	-191	-102	296	-194	-104	301	-197	-106	307	-201

F, C, and P are stand for Forest, Cropland, and Pastureland, respectively

Table C3. Global land use changes due to US ethanol production: Off of 2006 updated database with yield and population growth after 2006 (1000 hectares)

Region	2001-2006			2006-2007			2007-2009			2009-2011			2011-2013			2013-2015		
	F	C	P	F	C	P	F	C	P	F	C	P	F	C	P	F	C	P
USA	-71	119	-48	-44	59	-15	-54	58	-4	-62	61	1	-67	65	3	-72	70	2
EU27	-13	21	-7	-33	26	7	-39	34	5	-45	44	1	-49	56	-7	-53	68	-15
BRAZIL	-33	23	10	-37	12	25	-38	15	22	-40	19	21	-39	21	18	-37	23	14
CAN	-11	20	-9	-3	10	-7	-5	11	-6	-7	12	-6	-6	13	-7	-4	12	-9
JAPAN	-1	1	0	-1	1	0	-1	1	0	-2	2	0	-2	2	0	-3	3	0
CHIHKG	3	15	-18	-9	-4	13	-17	-9	26	-22	-15	37	-20	-22	42	-12	-28	41
INDIA	-14	29	-15	20	-19	-1	33	-36	3	41	-49	9	42	-55	13	43	-58	15
C_C_Amer	-6	20	-14	-12	13	-1	-20	15	5	-28	19	9	-34	22	12	-40	25	15
S_o_Amer	6	23	-29	1	13	-13	-6	11	-6	-9	10	-1	-11	9	2	-14	8	5
E_Asia	2	2	-4	1	1	-2	1	1	-1	1	0	-1	1	0	-1	1	0	-1
Mala_Indo	-9	10	-1	-1	1	0	1	-1	0	4	-4	0	7	-7	0	9	-9	0
R_SE_Asia	-6	6	-1	-3	2	1	-1	0	1	2	-3	0	5	-5	0	6	-7	0
R_S_Asia	-4	18	-14	-1	2	-2	-1	0	1	-1	-3	4	-1	-5	6	1	-8	8
Russia	2	21	-23	34	6	-41	32	4	-36	36	1	-37	42	-2	-40	50	-6	-43
Oth_CEE_CIS	-12	50	-38	8	41	-49	58	44	-102	93	65	-159	111	98	-210	107	133	-239
Oth_Europe	-1	1	0	-1	1	0	0	1	0	0	1	0	0	1	-1	0	1	-1
MEAS_NAfr	0	15	-15	1	3	-4	1	2	-3	0	1	-1	1	-1	1	1	-4	4
S_S_AFR	13	26	-39	9	36	-45	-8	37	-29	-31	40	-8	-59	45	14	-76	47	30
Oceania	-1	17	-16	-1	6	-4	-2	4	-2	-2	2	0	-1	0	2	-1	-2	3
TOTAL	-155	439	-284	-72	210	-138	-67	192	-125	-70	202	-132	-80	232	-152	-94	266	-172

F, C, and P are stand for Forest, Cropland, and Pastureland, respectively

Appendix D
Experiments Used in Simulations

Introduction

In this appendix first we briefly explain few basic concepts that we use in defining an experiment in GTAP for non professional readers. Then we introduce experiments which we defined for the simulations we introduced in this paper. As we mentioned earlier, GTAP is a computable general equilibrium (CGE) model. This model consists of equations, identities, a database, a set of parameters or elasticities, and several types of variables. Variables in this model are either endogenous (determined within the model) or exogenous (determined outside the model). For example, in GTAP population and tax rates are exogenous variables, but the household demands for goods and services are endogenous variables. The values of the exogenous variables are given to the model but the system determines the values of the endogenous variables using the equations defined in the model.

In GTAP, an experiment consists of a set of commands that guide the system to move the world economy from an existing equilibrium condition to a new equilibrium. The experiment could be simple or complicated. For example, here we introduce two simple experiments.

Suppose that you would like to examine consequences of a 2% increase in the US population for the world economy, assuming no changes in other exogenous variables. For this simple experiment since population is an exogenous variable, we can directly increase (or shock) it by 2% and ask the system to determine consequences of this increase for the world economy. This experiment is simply can be defined by the following command:

Shock pop("US") = 2;

The system starts with the initial equilibrium condition for the world economy (base data), numerically calculates impacts of this shock on the endogenous variables through the equations of the model, and determines a new equilibrium for the world economy.

Now look at another simple experiment. In this experiment we would like to examine impacts of 2% increase in the US demand for meat, while we assume no changes in other exogenous variables. In this case, since the demand for meat is an endogenous variable we cannot directly shock it. Instead, we should shock an exogenous variable which could affect the demand for meat. In this case subsidy is an appropriate exogenous variable. The subsidy on meat consumption could encourage consumers to buy more meat. Now the question is: How much subsidy should be paid to induce the desired increase in the demand for meat? We do not need to answer this question. The system can answer the question through the following swap and shock:

Swap qpd("meat", "US") = tpd("meat", "US");

Shock qpd("meat", "US") = 2;

Here *qpd* and *tpd* represent percentage changes in the demand for meat and its subsidy/tax rate for the US economy. The first command endogenizes the rate of subsidy on meat for the US economy and exogenizes the US demand for this commodity. The second command shocks the US demand for meat, which is now an exogenous variable. The system starts with the initial equilibrium, uses the equations of the system, increases the US subsidy rate on meat to reach 2% increase in the US private demand for meat, and determines a new equilibrium for the world economy through the simulation process. With this introduction we now present the experiments that we used in our simulations. In what follows we present only the main swaps and shocks that derive the results, and we do not present those which we used to fix data problems or avoid minor technical issues.

Experiments of Group 1: Simulations with no economic and yield growth and 2001 base

The experiments used for this group of simulations contain simple shocks and swaps. For the first time period (i.e. 2001-2006) we used the following experiment:

To fix the CRP land of the US

***Swap** tf(AEZ_COMM,"Oth_Ind_Se","USA") =*

p_HARVSTAREA_L(AEZ_COMM,"Oth_Ind_Se","USA");

This swap keeps the area of CRP land unchanged. It swaps changes in CRP land with changes in tax rate on land endowment.

To boost ethanol production

***Swap** qo("Ethanol1","USA") = tpd("Ethanol1","USA");*

***Shock** qo("Ethanol1","USA") = 174.29379;*

Here the swap endogenizes subsidy on ethanol consumption and exogenizes ethanol production and then the shock boosts ethanol production according to its expansion for the time period of 2001-2006 (i.e. 174.3%).

This swap and shock jointly subsidize ethanol production. However, they cause an increase in government subsidies. To offset the impacts of this subsidy we use the following swap to finance the policy through an increase in taxes on biofuel consumption.

To Make the RFS revenue neutral

***Swap** del_taxrpcbio("USA") = tpbio("USA");*

Then we repeated the same experiment for other time slices with appropriate percentage changes in ethanol production.

Experiments of Group 2: Simulations with updated baseline for the time period of 2001-2006

For the first time period of this group of simulations we used more complicated shocks and swaps.

To control CRP land of the USA

Swap tf(AEZ_COMM,"Oth_Ind_Se","USA")=qoes(AEZ_COMM,"Oth_Ind_Se","USA");

This swap controls changes in the US CRP land.

To simulate biofuel economy

swap aosec("oil") = pxwcom("oil");

Shock pxwcom("oil") = 136;

Shock afall("ethanol1","Oil_pcts","USA") = -49;

Shock to("Ethanol1","USA") = -10.93;

Shock to("biodiesel","USA") = -7.00;

Shock to("Ethanol1","EU27") = 50.77;

Shock to("biodiesel","EU27") = 81.18;

Swap qo("ethanol1","USA") = tpd("ethanol1","USA");

Swap tms("ethanol2","Brazil","USA") = qxs("ethanol2","Brazil","USA");

Swap qo("biodiesel","USA") = tpd("biodiesel","USA");

Swap qo("ethanol1","EU27") = tpd("ethanol1","EU27");

Swap qo("biodiesel","EU27") = tpd("biodiesel","EU27");

Swap qo("ethanol2","Brazil") = tpd("ethanol2" ,"Brazil");

Shock qo("ethanol1","USA") = 174.29;

Shock qxs("ethanol2","Brazil","USA") = 591.8636;

Shock qo("biodiesel","USA") = 2823.3992;

Shock qo("ethanol1","EU27") = 3444.0395;

Shock qo("biodiesel","EU27") = 409.5644;

Shock qo("ethanol2","Brazil") = 47.39088;

These swaps and shocks jointly introduce changes in the crude oil price and define the US, EU, and Brazil biofuel performances and their supporting policies in this area for the time period of 2001-2006.

To shock population

Shock POP(REG) = file default.prm header "PO16";

This shock reads the regional population growth rates for the time period of 2001-2006 from the parameter file of the system and introduces them to the model.

To shock GDP

Swap afereg(REG) = qgdp(REG);

Shock qgdp(REG) = file default.prm header "IN16";

This shock and swap read percentage changes in the regional GDPs for the time period of 2001-2006 from the parameter file of the system and introduces them to the model.

To shock skilled and unskilled labor

Shock qo("sklab",REG)= file default.prm header "LS16";

Shock qo("Unsklab",REG)=file default.prm header "LU16";

Supplies of skilled and unskilled labor are two important endowments in GTAP. These shocks read percentage changes in labor force for the time period of 2001-2006 from the parameter file of the system and introduce them to the labor market of each region. The GTAP-BIO does not consider labor movement across regions, meaning that there is no migration.

To shock capital stock

Shock qo("Capital",REG)=file default.prm header "CA16";

Capital stock is a major deriver of economic growth. Unlike the GTAP dynamic, capital stock is an exogenous endowment in the GTAP static model. The above shock introduces changes in the regional capital stocks during the time period of 2001-2006 to the system.

To introduce technological progress

Shock aoall(ALL_INDS,REG) = file default.prm header "PRNE";

Technological progress is another source for economic growth. The above shock introduces technological progress in all industries except for crop industries. Note that the header PRNE contains zero values for crop sectors. The next commands define the technological progress for crop industries. Note that values for technological progress are obtained based on Hertel, Ludena, and Golub (2009) for non-agricultural industries and service.

To shock crop yields

Swap p_YIELD(CROP_INDS,REG) = afall("land",CROP_INDS,REG);

Shock p_YIELD(CROP_INDS,REG) = file default.prm header "YD16";

In GTAP-BIO-ADV crop yields are endogenous variables and they respond to the prices of crops. In this simulation, we use the above swap to make them exogenous. Then we shock them to simulate the historical observation on yield growth for the time period of 2001-2006.

To control forest and pasture land prices

Swap aosec("forestry") = pxwcom("forestry");

Shock pxwcom("forestry") = 21;

Shock aosec("Dairy_Farms")=1;

Shock aosec("Ruminant")=1;

These commands define technological progress for forestry, ruminant, and non ruminant industries according to the observed changes in the world price index of forestry product (21%) during the time period of 2001-2006. It is also necessary to introduce the technology shocks for the dairy and ruminant industries in order to reproduce changes in forest areas.

Finally, for the time slices after 2006 we followed the simple experiments that we introduced for the first group of simulations.

Experiments of Group 3: Simulations with crop yield and population growth for the time period of 2006-20015

The experiment used for the first time slice of this group is similar to the first experiment of the second group of simulations. For the rest of time slices we just shocked population and yield according the assumptions we explained in the text along with shocks for ethanol production.

Appendix E

Woods Hole land use CO_2 emission data set

Definitions:

We used the same Woods Hole emissions data that was used in the Searchinger, et al. paper (2008). The specific source for that data is not given in the paper, but Richard Haughton, one of the authors, is affiliated with Woods Hole.

In this appendix we used the following abbreviations:

FAE_MH: Forest area by ecosystem in million hectares

FAE%: Forest area by ecosystem in percent

CINV_MT/H: Carbon in vegetation in metric ton per hectare

CINS_MT/H: Carbon in soil in metric ton per hectare

DCEFLC_MT/H: Direct carbon emissions from land conversion in metric tons per ha

RGFA_MH: Re-growing forest area in million hectares

GCUBRGF_MMTC/yr: Gross carbon uptake by re-growing forests in million metric tons carbon per year

CUBF_MTC/H/yr: Carbon uptake by forest area in metric ton carbon per hectare per year

FCS30 _MTC/H: Foregone Carbon Sequestration in 30 years in metric ton per hectare

WACE_MT/H: Weighted average carbon emissions in metric ton per hectare

WACO2E_MT/H: Weighted average CO2 emissions in metric ton per hectare

Table C 1. Woods Hole Land use CO_2 emission data-United States

Description	Broad leaf forest	Mixed forest	Wood land	Coniferous / Mountain Forest	Coniferous Pacific Forest	Chaparral	Total Forest	Grassland	Total Grassland
FAE_MH	54.60	88.20	38.50	24.10	29.20	6.20	240.80	0.00	
FAE%	22.67	36.63	15.99	10.01	12.13	2.57	100.00	0.00	0.00
CINV_MT/H	150.00	170.00	90.00	150.00	200.00	40.00		10.00	
CINS_MT/H	150.00	160.00	90.00	100.00	160.00	80.00		80.00	
25% of CINS_MT/H	37.50	40.00	22.50	25.00	40.00	20.00		20.00	
DCEFLC_MTH	150.00	167.50	90.00	137.50	190.00	50.00		30.00	
RGFA_MH	38.00	47.00	47.00	1.00	15.00	0.00		0.00	
GCUBRGF_MMTC/yr	-34.70	-36.40	-2.10	0.00	-23.60	0.00		0.00	
CUBF_MTC/H/yr	-0.64	-0.41	-0.05	0.00	-0.81	0.00			
FCS30_MTC/H	19.07	12.38	1.64	0.00	24.25	0.00		0.00	
WACE_MT/H	38.33	65.89	14.65	13.76	25.98	1.29	159.90	30.00	30.00
WACO2E_MT/H	140.69	241.80	53.77	50.50	95.35	4.72	586.84	110.10	110.10

Table C 2. Woods Hole Land use CO_2 emission data- North Africa and Middle East

Description	Temperate Evergreen Forest	Tropical Moist Forest	Tropical Woodland	Total Forest	Tropical Grassland	Desert Scrub	Total Grassland
FAE_MH	6.80	2.10	18.50	27.40	44.20	793.10	837.30
FAE%	24.82	7.66	67.52	100.00	5.28	94.72	100.00
CINV_MT/H	160.00	200.00	27.00		18.00	3.00	
CINS_MT/H	134.00	117.00	69.00		42.00	58.00	
25% of CINS_MT/H	33.50	29.25	17.25		10.50	14.50	
DCEFLC_MTH	153.50	179.25	37.50		28.50	17.50	
RGFA_MH	5.00	1.40	0.00		0.00	0.00	
GCUBRGF_MMTC/yr	-14.50	-6.10	0.00		0.00	0.00	
CUBF_MTC/H/yr	-2.13	-2.90	0.00		0.00	0.00	
FCS30_MTC/H	63.97	87.14	0.00		0.00	0.00	
WACE_MT/H	53.97	20.42	25.32	99.71	1.50	16.58	18.08
WACO2E_MT/H	198.07	74.93	92.92	365.93	5.52	60.83	66.36

Table C 3. Woods Hole Land use CO_2 emission data- Canada

Description	Temperate Evergreen Forest	Temperate Deciduous Forest	Boreal Forest	Total Forest	Temperate Grassland	Tundra	Total Grassland
FAE_MH	37.30	46.10	461.00	544.40	10.90	322.70	333.60
FAE%	6.85	8.47	84.68	100.00	3.27	96.73	100.00
CINV_MT/H	160.00	135.00	90.00		7.00	5.00	0.00
CINS_MT/H	134.00	134.00	206.00		189.00	165.00	0.00
25% of CINS_MT/H	33.50	33.50	51.50		47.25	41.25	0.00
DCEFLC_MTH	153.50	134.75	119.00		54.25	46.25	0.00
RGFA_MH	7.80	1.70	13.00		0.00	0.00	0.00
GCUBRGF_MMTC/yr	-18.50	-3.00	-17.70		0.00	0.00	0.00
CUBF_MTC/H/yr	-0.50	-0.07	-0.04		0.00	0.00	0.00
FCS30_MTC/H	14.88	1.95	1.15		0.00	0.00	0.00
WACE_MT/H	11.54	11.58	101.75	124.86	1.77	44.74	46.51
WACO2E_MT/H	42.34	42.48	373.40	458.23	6.51	164.19	170.70

Table C 4. Woods Hole Land use CO_2 emission data-Latin America

Description	Tropical Evergreen Forest	Tropical Seasonal Forest	Tropical Open Forest	Temperate Evergreen Forest	Temperate Seasonal Forest	Total Forest	Grassland	Desert	Total Grassland
FAE_MH	296.30	537.30	252.50	53.60	55.40	1195.10	6.90	30.70	
FAE%	24.79	44.96	21.13	4.48	4.64	100.00	18.35	81.65	0.00
CINV_MT/H	200.00	140.00	55.00	168.00	100.00		10.00	6.00	
CINS_MT/H	98.00	98.00	69.00	134.00	134.00		42.00	58.00	
25% of CINS_MT/H	24.50	24.50	17.25	33.50	33.50		10.50	14.50	
DCEFLC_MTH	174.50	129.50	58.50	159.50	108.50		20.50	20.50	
RGFA_MH	0.00	45.60	0.00	14.68	0.00		0.00	0.00	
GCUBRGF_MMTC/yr	0.00	-164.20	0.00	-48.90	0.00		0.00	0.00	
CUBF_MTC/H/yr	0.00	-0.31	0.00	-0.91	0.00		0.00	0.00	
FCS30_MTC/H	0.00	9.17	0.00	27.37	0.00		0.00	0.00	
WACE_MT/H	43.26	62.34	12.36	8.38	5.03	131.38	3.76	16.74	20.50
WACO2E_MT/H	158.78	228.80	45.36	30.76	18.46	482.15	13.81	61.43	75.24

Table C 5. Woods Hole Land use CO_2 emission data-Pacific Developed

Description	Temperate Evergreen Forest	Temperate Deciduous Forest	Tropical Moist Forest	Tropical Woodland	Total Forest	Tropical Grassland
FAE_MH	14.00	14.00	63.60	106.10	197.70	70.50
FAE%	7.08	7.08	32.17	53.67	100.00	0.00
CINV_MT/H	160.00	135.00	200.00	27.00		18.00
CINS_MT/H	134.00	134.00	117.00	69.00		42.00
25% of CINS_MT/H	33.50	33.50	29.25	17.25		10.50
DCEFLC_MTH	153.50	134.75	179.25	37.50		28.50
RGFA_MH	13.90	13.30	1.90	0.00		0.00
GCUBRGF_MMTC/yr	-33.30	-26.50	-6.00	0.00		0.00
CUBF_MTC/H/yr	-2.38	-1.89	-0.09	0.00		0.00
FCS30_MTC/H	71.36	56.79	2.83	0.00		0.00
WACE_MT/H	15.92	13.56	58.58	20.13	108.19	28.50
WACO2E_MT/H	58.44	49.78	214.97	73.86	397.05	104.60

Table C 6. Woods Hole Land use CO_2 emission data- South and Southeast Asia

Description	Tropical Moist forest	Tropical Seasonal Forest	Open forest	Total Forest	Temperate Grassland*	Total Grassland
FAE_MH	159.40	137.60	44.90	341.90		
FAE%	46.62	40.25	13.13	100.00		
CINV_MT/H	250.00	150.00	60.00	0.00	7.00	
CINS_MT/H	120.00	80.00	50.00	0.00	189.00	
25% of CINS_MT/H	30.00	20.00	12.50	0.00	47.25	
DCEFLC_MTH	217.50	132.50	57.50	0.00	54.25	
RGFA_MH	70.88	52.39	18.43	0.00		
GCUBRGF_MMTC/yr	-171.10	-108.00	-16.00	0.00		
CUBF_MTC/H/yr	-1.07	-0.78	-0.36	0.00		
FCS30_MTC/H	32.20	23.55	10.69	0.00		
WACE_MT/H	116.42	62.80	8.96	188.17	54.25	54.25
WACO2E_MT/H	427.25	230.48	32.87	690.59	199.10	199.10

* Figures are belong to China, India, and Pakistan

Table C 7. Woods Hole Land use CO_2 emission data-Africa

Description	Tropical Rain Forest	Tropical Moist Forest	Tropical Dry Forest	Montane Forest	Total Forest	Shrub Land	Total Grassland
FAE_MH	222.00	190.20	200.10	27.70	640.00	47.10	
FAE%	34.69	29.72	31.27	4.33	100.00	100.00	0.00
CINV_MT/H	126.70	60.20	12.60	79.90		4.60	
CINS_MT/H	190.00	115.00	70.00	100.00		30.00	
25% of CINS_MT/H	47.50	28.75	17.50	25.00		7.50	
DCEFLC_MTH	142.53	73.90	26.95	84.93		12.10	
RGFA_MH	21.29	23.73	6.44	0.86		0.67	
GCUBRGF_MMTC/yr	-20.20	-19.90	0.00	0.00		0.00	
CUBF_MTC/H/yr	-0.09	-0.10	0.00	0.00		0.00	
FCS30 _MTC/H	2.73	3.14	0.00	0.00		0.00	
WACE_MT/H	50.39	22.89	8.43	3.68	85.38	12.10	12.10
WACO2E_MT/H	184.91	84.02	30.92	13.49	313.35	44.41	44.41

Table C 8. Woods Hole Land use CO_2 emission data-Europe

Description	Temperate Evergreen Forest	Temperate Deciduous Forest	Boreal Forest	Temperate Woodland	Total Forest	Temperate Grassland	Total Grassland
FAE_MH	71.90	55.50	27.50	45.00	199.90	26.70	
FAE%	35.97	27.76	13.76	22.51	100.00	100.00	0.00
CINV_MT/H	160.00	120.00	90.00	27.00		7.00	
CINS_MT/H	134.00	134.00	206.00	69.00		189.00	
25% of CINS_MT/H	33.50	33.50	51.50	17.25		47.25	
DCEFLC_MTH	153.50	123.50	119.00	37.50		54.25	
RGFA_MH	66.00	43.20	27.20	0.00		0.00	
GCUBRGF_MMTC/yr	-137.50	-80.00	-33.10	0.00		0.00	
CUBF_MTC/H/yr	-1.91	-1.44	-1.20	0.00		0.00	
FCS30 _MTC/H	57.37	43.24	36.11	0.00		0.00	
WACE_MT/H	75.85	46.29	21.34	8.44	151.92	54.25	54.25
WACO2E_MT/H	278.36	169.90	78.31	30.98	557.55	199.10	199.10

Table C 9. Woods Hole Land use CO_2 emission data- Former Soviet Union

Description	Temperate Evergreen Forest	Temperate Deciduous Forest	Boreal Forest	Temperate Woodland	Total Forest	Temperate Grassland	Total Grassland
FAE_MH	88.30	53.60	612.90	186.00	940.80	31.20	
FAE%	9.39	5.70	65.15	19.77	100.00	100.00	0.00
CINV_MT/H	160.00	135.00	90.00	27.00		10.00	
CINS_MT/H	134.00	134.00	206.00	69.00		189.00	
25% of CINS_MT/H	33.50	33.50	51.50	17.25		47.25	
DCEFLC_MTH	153.50	134.75	119.00	37.50		57.25	
RGFA_MH	0.00	0.00	0.00	0.00		0.00	
GCUBRGF_MMTC/yr	-137.50	-80.00	-33.10	0.00		0.00	
CUBF_MTC/H/yr	-1.56	-1.49	-0.05	0.00		0.00	
FCS30 _MTC/H	46.72	44.78	1.62	0.00		0.00	
WACE_MT/H	18.79	10.23	78.58	7.41	115.01	57.25	57.25
WACO2E_MT/H	68.96	37.54	288.39	27.21	422.10	210.11	210.11

12_B_LCFS_GE Responses (Page 25 – 118)

683. Comment: **Exhibit 3**

Agency Response: This exhibit is a report from Purdue University and is referred to in comment **LCFS B12-6** through **LCFS B12-11**. As such, see the responses to **LCFS B12-6** through **LCFS B12-11**.

This page intentionally left blank.

Exhibit 4

RFA RENEWABLE FUELS ASSOCIATION

April 28, 2010

Mary D. Nichols, Chairwoman
California Air Resources Board
Headquarters Building
1001 "I" Street
Sacramento, CA 95812

Dear Chairwoman Nichols,

I am writing to inform you and the Board of an important advancement in the science of indirect land use change (ILUC) that has major implications for California's recently adopted Low Carbon Fuels Standard (LCFS). New research conducted and published by Purdue University using the Global Trade Analysis Project model (GTAP) concludes that land use change emissions potentially associated with corn ethanol expansion are likely *less than half* of the level estimated by the California Air Resources Board (ARB) staff for the LCFS. While we continue to have grave concerns about including highly uncertain and prescriptive indirect emissions penalties in the LCFS (for instance, we do not believe ARB has the authority to account for ILUC consistent with the Commerce Clause of the U.S. Constitution), we write to point out the new Purdue findings because we believe ARB has committed itself to consider and respond to critical developments like these. LCFS B12-16

ARB has repeatedly stated that its ILUC analysis for the LCFS was based on the "best available" science and analytical tools, and that the Board is committed to evaluating and adopting advances in the science that would improve the accuracy of its analysis. Indeed, ARB states, "...the GTAP is the best available tool for estimating the global land use change impacts associated with expanded biofuel production. *When and if the Board is made aware of a better estimation tool, it can direct staff to utilize that tool* (emphasis added)."[1] To be sure, Purdue's recent enhancement of the GTAP model and its new ILUC results represent a "better estimation tool" than was used by ARB for the LCFS. Accordingly, we believe that the Board, given its commitments, must direct the staff to adopt the new Purdue results and use the new, improved GTAP model from this point forward until such time that even better tools are available. Because regulated parties under the LCFS will imminently be making decisions about 2011 fuel purchases and related logistics, the Purdue ILUC value should be adopted in the LCFS look-up table *immediately* so that regulated parties have the certainty they need to make purchasing and logistical decisions for the upcoming 2011 LCFS compliance cycle. LCFS B12-17

The new Purdue University research, which was funded in part by the U.S. Department of Energy (DOE), clearly shows that ARB significantly overestimated corn ethanol indirect land use change emissions under the LCFS. In simulations where the most recent available global economic database (2006) was employed and future crop yield increases and population growth were considered, Purdue economists estimated average corn ethanol land use emissions at 13.9 grams LCFS B12-18

[1] Calif. Air Resources Board, California's Low Carbon Fuels Standard: Final Statement of Reasons (December 2009), 633.

CO2-equivalent per mega joule (g/MJ). These results are less than half of the ILUC value of 30 g/MJ adopted by ARB for the LCFS. Presumably to test the sensitivity of ARB's results to model enhancements excluding the use of the 2006 database, the Purdue researchers also examined a case that mirrored exactly the approach taken by ARB for the LCFS analysis (i.e., the old 2001 GTAP database was used, and crop yield growth and population growth was ignored). Even in this case, Purdue found average corn ethanol land use change emissions to be 20.8 g/MJ, or 31% lower than ARB's estimate of 30 g/MJ. Purdue recently finalized and published these results and shared them with stakeholders, including staff at ARB.[2] LCFS B12-18 cont.

The new results obtained by Purdue can be compared in an apples-to-apples manner to the ARB LCFS results because in both cases: 1.) the exact same economic model (Purdue's GTAP) was used; 2.) the same corn ethanol production scenario (15 billion gallons by 2015) was examined; and 3.) the same department at the same university conducted the simulations and many of the same researchers were involved. To be clear, the differences between the new Purdue results and ARB's LCFS results stem from the many major improvements that Purdue has made to the GTAP model, not from any discrepancies in the analytical objectives or underlying scenarios. Many of these enhancements were made in response to comments and questions submitted to ARB and Purdue in recent years by stakeholders and other users of the GTAP model. The following are among the major improvements that were made to GTAP: LCFS B12-19

- *The model's global economic database was updated from 2001 to 2006.* ARB's analysis for the LCFS used the old (2001) GTAP database, while the new Purdue research draws from a recently integrated 2006 database. The authors of the new Purdue paper state, "The global economy changed significantly over the 2001-2006 period..." and there were changes to "...important factors which could alter the land use implications of biofuels." LCFS B12-20

- *Cropland pasture in the U.S. and Brazil and Conservation Reserve Program (CRP) lands have been added to the model.* These important land types were absent from the model when it was used by ARB and its contractors for the LCFS analysis. Excluding these lands from the model, as ARB did, constrains the amounts and types of land that are available for conversion to crops, which ultimately results in artificially inflated ILUC estimates. LCFS B12-21

- *According to the Purdue authors, the model's treatment of corn ethanol animal feed co-products (called distillers dried grains, or DDG) is "significantly improved" over the version of model used by ARB for the LCFS.* Despite real world data and information to the contrary, ARB simply assumed for the LCFS analysis that DDG replaces only corn in animal feed rations and only on a pound-for-pound basis. LCFS B12-22

---

[2] Purdue economists presented their results at an April 23, 2010, workshop at the University of Chicago. The April 2010 final report was distributed electronically to stakeholders, including ARB staffer John Courtis, on April 15, 2010. The report is available online at http://www.transportation.anl.gov/pdfs/MC/625.PDF.

- *The model's method for estimating crop yields on newly converted(i.e., marginal) lands is much more sophisticated and detailed than previous versions of the model, including the version used by ARB for the LCFS.* The model now estimates crop yields on newly converted lands with regional specificity, rather than applying one generic estimate to all marginal croplands around the world, as ARB did for the LCFS. LCFS B12-23

- *For the new analysis, Purdue took into account crop yield growth and population growth over the period of the simulation.* The new model conservatively assumed growth in crop yields of 1% annually from 2006 to 2015. To account for increased food demand, the Purdue authors also assumed global population will grow at a rate consistent with recent trends. In contrast, ARB ignored both effects for the LCFS analysis and did not assume crop yields would grow at all beyond the period of 2006-2008. LCFS B12-24

- *The new Purdue analysis also assumes that some portion of the carbon stored in trees is not immediately released into the atmosphere when the forest is converted to cropland.* Rather, it is assumed in the new version of the model that a fraction of the carbon in harvested trees will be stored long term in furniture, buildings and other wood products. For the LCFS analysis, ARB assumed 100% of the carbon in trees is immediately released into the atmosphere when the forest is converted (despite the agency's clear statement in the ISOR that it meant to assume that 10% of the carbon would be stored in wood products).[3] LCFS B12-25

In many instances in the LCFS public record, ARB acknowledged that these improvements to the model were necessary. As one example, in regard to the exclusion of cropland pasture and CRP lands, ARB stated that the precision of the GTAP model could be increased by "...expand[ing] the types of land areas available for conversion to agricultural uses. Former Conservation Reserve Program lands could be added in the U.S. Idle croplands that are not currently available could be added worldwide."[4] In regard to this issue, ARB further stated, "There are efforts currently by many institutions and GTAP researchers to include these types of lands in the GTAP database. *Once such a database becomes available, we will evaluate it for possible adoption* (emphasis added)."[5] As another example, ARB also recognized that using the old GTAP database (2001) was a weakness of the analysis. According to ARB, "Staff was aware at the outset of the modeling effort that using 2001 as the baseline year was a limitation. The reason that GTAP employed the 2001 world economic database as the analytical baseline is that this was the most recent year for which a complete global land use database existed as of the time of analysis."[6] Fortunately, a more current world economic database (2006) now exists within GTAP. LCFS B12-26

---

[3] In its Initial Statement of Reasons, ARB stated that it "...assumed that 90 percent of the above-ground...carbon is emitted over the fuel production period," meaning 10 percent is sequestered in building products. However, this assumption was not reflected in ARB's final ILUC results. When ARB was questioned about why this assumption was not reflected in final calculations, it responded in the FSOR that, "A miscommunication between ARB, UC Berkeley, and Purdue resulted in a discrepancy between the emission factors discussed in the Staff Report (and presented on the ARB website) and the emission factors actually used in the land use change modeling for the regulation." ARB suggested that, "Instead of '90 percent,' the actual assumption was '100 percent.'" A correction was made in errata to fix the "mistake." (FSOR, 651-653)
[4] Calif. Air Resources Board, California's Low Carbon Fuels Standard: Final Statement of Reasons (December 2009), 635.
[5] Ibid., 659
[6] Ibid., 693.

Even after these enhancements were made to GTAP, many uncertainties remain. Still, the new Purdue results are being received by the scientific community as the state-of-the-art in terms of land use change modeling. While the Purdue authors acknowledge that "...modeling land use change is quite uncertain..." and that their analysis is "...limited by data availability, validity of parameters, and other modeling constraints...", the new Purdue study undoubtedly represents the cutting edge and best available science on the issue of land use change and biofuels. Without question, the new Purdue results are superior to the results obtained by ARB in terms of robustness, data currency, and detail. Throughout the LCFS process, ARB has repeatedly stated its intent to integrate modeling improvements and new data as they become available. Indeed, in the LCFS Initial Statement of Reasons, the agency writes, "...ARB has committed to determining the total direct and indirect emissions associated with production, distribution, and use of all fuels through conducting complete lifecycle analyses *based on the best available science* (emphasis added)."[7] Further, ARB suggests, "The Board agrees that the issue of land use change impact estimation must be subject to ongoing evaluation and analysis..."[8] and, "The Board has also committed to an ongoing inquiry into the best indirect land use change estimation methodologies."[9]

LCFS B12-26 cont.

In keeping with ARB's stated commitment to using the best available science and data, the Board should move *immediately* to adopt the value of 13.9 g/MJ for the corn ethanol ILUC penalty in lieu of the current 30 g/MJ estimate. ARB has vociferously committed to adopting advancements in the science of the indirect effects as it becomes available. Integrating the new Purdue value would represent a directional shift in the fuels that would be viewed as viable compliance options, i.e. the current carbon intensity scores prevent most corn ethanol from being used beyond 2011, while adjusting the carbon intensity scores to reflect the new Purdue ILUC value would allow many corn ethanol pathways to serve as viable compliance options for several years under the LCFS. As noted above, <u>any delay in considering and adopting the new Purdue results will seriously hamper the ability of regulated parties to comply with 2011 LCFS obligations</u>. Time is of the essence. The California fuels market simply can't afford to wait for possible modifications to the regulation that may result from the expert work group recommendations (which aren't expected until December 2010). Adopting the Purdue ILUC value immediately would greatly enhance the ability of regulated parties to meet their greenhouse gas reduction obligations in the early years of the LCFS, ultimately minimizing fuel cost impacts to the state's consumers.

LCFS B12-27

Further, there is very recent precedent for ARB making material changes to adopted regulations and adjusting implementation deadlines when new information and better data are presented. Just last week at its April Board meeting, ARB staff acknowledged that its previous estimates of off-road diesel emissions related to the off-highway diesel rule were "too high."[10] New analyses from third parties and ARB itself showed the original off-road emissions inventory may have been overestimated by ARB by 140-400%. At last week's meeting, ARB members stated that

LCFS B12-28

[7] California Air Resources Board, Staff Report: Initial Statement of Reasons, Proposed Regulation to Implement the Low Carbon Fuels Standard: Vol. I (March 5, 2009), Page IV-48
[8] Calif. Air Resources Board, California's Low Carbon Fuels Standard: Final Statement of Reasons (December 2009), 638.
[9] Ibid., 642
[10] Calif. Air Resources Board, Staff Presentation at April 2010 Board meeting (April 22, 2010), slide 10.

additional analysis needs to be conducted and affected parties must be given more time to comply with the rules. Similarly, new analyses presented to ARB in December 2009 led the Board to direct staff to re-evaluate the science behind the pending on-road diesel rules for trucks and buses. One Board member stated the staff report upon which the rule is based is "not acceptable" and proposed that ARB "...set aside the rule until this report be redone."[11] In a similar way, we are urging the Board to re-evaluate the science behind ILUC and consider the new evidence presented in the Purdue paper.

LCFS B12-28 cont.

We appreciate your consideration of this new information and your commitment to ensuring the best available science is appropriately integrated into the LCFS regulation. While we view the new Purdue analysis as being the best available to date, we believe much more research and analysis is needed on the issue of land use change. There is still much room for improvement in the GTAP model and the scientific community still has a great deal to learn, in general, on the topic of biofuels and land use change. We would greatly appreciate the opportunity to meet with you and your staff to discuss the new Purdue results in more detail.

Sincerely,

Bob Dinneen

Bob Dinneen
President & CEO

Cc:

Monica Vehar, Clerk of the Board
John R. Balmes, M.D., Board member
Sandra Berg, Board member
Dorene D'Adamo, Board member
Lydia H. Kennard, Board member
Ronald O. Loveridge, Board member
Barbara Riordan, Board member
Ron Roberts, Board member
Daniel Sperling, Board member
John G. Telles, Board member
Ken Yeager, Board member

[11] Calif. Air Resources Board, Transcript of December 2009 Board meeting (December 9, 2009), 80.

12_B_LCFS_GE Responses (Page 119 – 124)

684. Comment: **LCFS B12-16**

The 2010 letter states that a recent study by Purdue concludes that land use change emissions potentially associated with corn ethanol expansion are likely less than half of the level estimated in the 2009 LCFS proposal.

Agency Response: The document was prepared by the commenter in response to ARB analysis presented in 2009 where the value of 30.0 g/MJ appears, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments in responses to **LCFS 8-1**, **LCFS 8-4**, **LCFS 46-166**, **LCFS 46-216**, **LCFS T25-1**, **LCFS B12-1**, and **LCFS B12-4**.

685. Comment: **LCFS B12-17**

The 2010 letter states that the Purdue iLUC value should be adopted in the LCFS look-up table immediately so that regulated parties have the certainty they need.

Agency Response: The document was prepared by the commenter in response to ARB analysis presented in 2009 where the value of 30.0 g/MJ appears, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments in responses to **LCFS 8-1** and **LCFS 46-216**.

686. Comment: **LCFS B12-18**

The 2010 letter states that the LCFS regulation significantly overestimated corn ethanol indirect land use change emissions.

Agency Response: The document was prepared by the commenter in response to ARB analysis presented in 2009 where the value of 30.0 g/MJ appears, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments in responses to **LCFS 8-1**, **LCFS 8-4**,

LCFS 46-166, **LCFS 46-216**, **LCFS B12-1**, **LCFS B12-2**, and **LCFS B12-13.**

687. Comment: **LCFS B12-19**

The 2010 letter states that the updated GTAP model data is the same, and differences can be accounted for in model enhancements.

Agency Response: The document was prepared by the commenter in response to ARB analysis presented in 2009 and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments in response to **LCFS B12-17**.

688. Comment: **LCFS B12-20**

The 2010 letter alleges that ARB staff's original analysis for the LCFS regulation used outdated data.

Agency Response: This document was prepared by the commenter in response to ARB analysis presented in 2009, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the 2010 letter pertains to the later proposal or the process by which the LCFS was proposed and adopted, ARB addresses the comments as follows:

ARB's version of GTAP uses a 2004 baseline for which data is available for all the elements incorporated into the current version of the model. Consideration of this baseline was related to available data for all elements incorporated into the current version and completing comprehensive testing of all the elements of the GTAP model.

689. Comment: **LCFS B12-21**

The 2010 letter claims that ARB staff did not incorporate the new GTAP model.

Agency Response: This document was prepared by the commenter in response to ARB analysis presented in 2009, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the 2010 letter pertains to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

Cropland Pasture is a new land cover category that was included in the GTAP model in 2010 to enhance the land use analysis. After review of available data, Purdue and ARB updated the GTAP model to include a cropland/pasture land category in the U.S. and Brazil. Inclusion of this land category in the current analysis lowered iLUC emissions for all six biofuels. See response to **LCFS 38-33**.

For a discussion of CRP lands, see also responses to **LCFS 46-15** and **LCFS 46-110**.

690. Comment: **LCFS B12-22**

The 2010 letter states that, according to the Purdue authors, the new GTAP model's treatment of corn ethanol animal feed co-products is significantly improved over the model used in the LCFS regulation.

Agency Response: This document was prepared by the commenter in response to ARB analysis presented in 2009, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. The comment is not relevant since the version of the GTAP model used for the proposed regulation includes updates to the treatment of animal feed co-products.

691. Comment: **LCFS B12-23**

The 2010 letter claims that the Purdue GTAP model crop-yield estimate is preferable to the version used in the LCFS regulation.

Agency Response: This document was prepared by the commenter in response to ARB analysis presented in 2009, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the 2010 letter pertains to the later proposal, or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

The comments are not relevant since ARB staff has included the updates to estimate crop yields on newly-converted land. Data to include updated productivity were derived from published work by

Taheripour et al.[54] The new productivity values by region and AEZ is provided in Appendix I Table I-2 of the ISOR.

692. Comment: **LCFS B12-24**

The 2010 letter states that the ARB staff analysis does not account for growth in crop yields.

Agency Response: The document was prepared by the commenter in response to ARB analysis presented in 2009 and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the 2010 letter pertains to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

The 2010 letter is irrelevant because it refers to updates to the GTAP model implemented by Purdue after the Board Hearing in 2009. The analysis in 2009 and the current analysis (2014) account for the impacts on yields from price changes and technological advances. Changes in population are not relevant to either the 2009 or the current analyses since the modeling exercise estimates impacts from increased biofuel production on various sectors of the global economy. The current version of the Purdue/ARB model is static and is not capable of estimating impacts of population change.

693. Comment: **LCFS B12-25**

The 2010 letter alleges that ARB staff used incorrect values for forest to cropland conversion.

Agency Response: This document was prepared by the commenter in response to ARB analysis presented in 2009, and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the 2010 letter pertains to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

The comments are not relevant to the current analysis. In the current analysis, using published data, ARB staff has updated the analysis and accounts for carbon sequestered in wood products.

[54] F. Taheripour, Q. Zhuang, W. Tyner, and X. Lu, Biofuels, Cropland Expansion, and the Extensive Margin, Energy, Sustainability, and Society, 2:25, 2012, http://www.energsustainsoc.com/content/2/1/25

Details of the analysis are provided in Appendix I, Attachment 2, Section 3.1.4 of the ISOR.

694. Comment: **LCFS B12-26**

The 2010 letter directs ARB staff to incorporate the Purdue analysis using the 2006 database information for GTAP.

Agency Response: The document was prepared by the commenter in response to ARB analysis presented in 2009 and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

After 2009, ARB staff has reviewed not only the research published by Purdue but also other advances in the science of land use change. The current analysis has refined the 2009 iLUC analysis to account for the latest data and updated land use change science. See also responses to **LCFS B12-16**, **LCFS B12-17**, and **LCFS 46-81**.

695. Comment: **LCFS B12-27**

The 2010 letter directs the Board to adopt the commenter's preferred iLUC value for corn ethanol.

Agency Response: The document was prepared by the commenter in response to ARB analysis presented in 2009 and as such does not constitute an objection or recommendation regarding the proposal released in December 2014. To the extent the comments pertain to the later proposal or the process by which the LCFS was proposed and adopted, ARB staff addresses the comments as follows:

In the current proposal, ARB staff has already modified the 30.0 g/MJ value to 19.8 g/MJ for corn ethanol to reflect the latest work. The comments are not relevant since the updates they refer to were implemented by Purdue after the Board Hearing in 2009. It is worth noting that for the period 2011-2014, fuels used under the LCFS have over-complied with the standards and do not support the commenter's view point that delays in modifying iLUC values for corn ethanol could seriously hamper the ability of regulated parties to comply with 2011 obligations.

See also responses to **LCFS B12-8**, **LCFS B12-9**, and **LCFS B12-16**.

696. Comment: **LCFS B12-28**

The 2010 letter requests the Board re-evaluate the science behind the iLUC estimates and consider the Purdue paper.

Agency Response: This document was prepared by the commenter in response to ARB analysis presented in 2009, and as such does not constitute an objection or recommendation regarding the proposal released in December2014. See also response to **LCFS 46-216**.

Air Resources Board

Mary D. Nichols, Chairman
1001 I Street • P.O. Box 2815
Sacramento, California 95812 • www arb ca.gov

Linda S. Adams
Secretary for Environmental Protection

Arnold Schwarzenegger
Governor

June 9, 2010

Mr. David Bearden
General Counsel
Renewable Fuels Association
One Massachusetts Avenue, N.W., Suite 820
Washington, D.C. 20001

Re: Petition for Rulemaking

Dear Mr. Bearden:

Thank you for your letter to Chairman Mary D. Nichols dated May 10, 2010. Chairman Nichols has asked that I respond on her behalf. In your letter, you petitioned, pursuant to Government Code section 11340.6, on behalf of Growth Energy for the Air Resources Board (ARB or Board) to amend the Low Carbon Fuel Standard (LCFS) regulation, codified in title 17, California Code of Regulations (CCR), sections 95480-95490. Specifically, you petitioned for amendments to section 95486.

After careful consideration of the facts associated with your request, pursuant to Government Code section 11340.7(b), I am denying your petition to amend the LCFS regulation at this time. However, pursuant to Board Resolution 09-31,[1] I will consider recommending possible changes to the regulation in the future based upon the work being done in conjunction with the Expert Workgroup we convened to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. Below I provide further details on our denial of your petition.

Your requested "amendment 1" would take effect no later than December 31, 2010, and would eliminate the land use change carbon intensity of corn ethanol for two years, 2011 and 2012. With respect to this requested amendment, the Board has previously found that crop-based biofuel production does entail land use change impacts, and that those impacts do result in significant greenhouse gas emissions. See Board Resolution 09-31. In light of those findings, the Board determined that it would be remiss if it did not account for land-use change effects in the carbon intensities of crop-based biofuels. Moreover, in the April 2010 report released by Purdue for Argonne

[1] Resolution 09-31, April 23, 2009: See: http://www.arb.ca.gov/regact/2009/lcfs09/res0931.pdf

National Laboratories that you cited, the authors also conclude that "it is simply not credible to argue that there are no land use change implications of corn ethanol." Your petition does not refute the Board's finding that the land use change impacts result in significant greenhouse gas emissions, nor does it refute the study authors' conclusion noted above. Thus, your petition presents an insufficient basis for eliminating the land-use change carbon intensity value for corn ethanol.

Alternatively, "amendment 2" of your petition would lower the indirect land-use carbon intensity value for corn ethanol to one of two values. This requested change is based on the Purdue study you cited in your petition, which we are currently reviewing. As discussed below, it is premature to make changes to the LCFS regulation based on this study. Our initial observation is that the Purdue model used for this study is not publicly available; as a result, a more detailed evaluation is not currently feasible at this time.

As part of the Purdue study, the authors varied a number of parameters which resulted in a range of land use carbon intensity values that are 1/3 to 1/2 lower than ARB's published average value. However, the values are generally within the range of results that we found in running various sensitivities. ARB believes that this is important work and is being considered by the Expert Workgroup as part of its comprehensive evaluation.

As noted, the Expert Workgroup was established at the direction of the Board in Resolution 09-31 upon the Board's approval of the LCFS regulation. The Expert Workgroup is charged with refining and improving the land use and indirect effect analysis of transportation fuels. The Expert Workgroup includes individuals from diverse stakeholder groups such as government agencies, academic institutes (including Purdue University), national laboratories, the biofuel and oil industries, and environmental groups. The Expert Workgroup has formed eight (and potentially nine) subgroups that are actively evaluating all facets of the modeling, including comparative models. For more information on the Expert Workgroup, see the following link: http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/expertworkgroup.htm.

At the next Expert Workgroup meeting on June 17, 2010, Purdue University representatives will make a presentation on their work so that the Expert Workgroup members will have an understanding of the study, including the key assumptions. We have asked Purdue and Argonne National Laboratories to make the updated Global Trade Analysis Project version publically available for inspection and evaluation. When it becomes available, it is likely that ARB will use Purdue's new work as one of the two baselines for evaluating the impact of inputs and assumptions. The assessment of the Expert Workgroup will be reflected in a report, including recommendations, that the Board will consider at the end of the year.

Because the Expert Workgroup will be assisting ARB staff in evaluating the Purdue study and that work has not yet commenced, it is premature to adopt Purdue's recent work. And, as indicated, our understanding is that the model and the underlying details which will need to be considered for a full evaluation are not yet available. However, as mentioned above, we believe that assessing this study is an important part of our effort to evaluate developments regarding the indirect effects issue as directed by the Board.

Finally, you also requested an amendment that would take effect no later than September 30, 2010 and would require the Executive Officer to take final action on a Method 2A or 2B submittal under section 95486 within 90 days of his receipt of a complete submittal pursuant to Method 2A or 2B. In approving the LCFS regulation, the Board considered the need for an expeditious process for reviewing a Method 2A or 2B submittal and weighed that need against the public interest in being able to review the submittal in an open process. While we expect most submittals to be reviewed relatively quickly, in some cases, the complexity of a submittal may warrant a staff review that exceeds 90 days. Therefore, the Board determined that the most appropriate balance of these considerations is reflected in the public review and final action provisions contained in section 95486(f). We believe the existing process in the regulation provides a necessary and appropriate balance between these two considerations and have therefore determined that your requested amendment would be inappropriate.

Based on the reasons discussed above, ARB believes that granting the requested changes specified in your petition would be inappropriate at this time. However, as noted, we are continuing to evaluate the ongoing developments in the field of land use and indirect effect analysis of transportation fuels. ARB will consider revisiting the need for updating the indirect effects carbon intensity value for corn ethanol when the Expert Workgroup completes its analysis.

In accordance with Government Code section 11340.7(d), a copy of this letter is being transmitted to the Office of Administrative Law for publication in the California Regulatory Notice Register. The agency contact person on this matter is Ms. Claudia Nagy, Staff Counsel, Office of Legal Affairs, at (916) 445-5501 or cnagy@arb.ca.gov. Any person who is interested in obtaining a copy of the petition may obtain it from her.

Sincerely,

James N. Goldstene
Executive Officer

cc: Ms. Claudia Nagy
Staff Counsel
Office of Legal Affairs

12_B_LCFS_GE Responses (Page 125 – 127)

697. Comment: **ARB Letter**

Agency Response: This exhibit is a letter from Executive Officer James Goldstene responding to David Beardon's Petition. See responses to **LCFS B12-1** through **LCFS B12-15**.

This page intentionally left blank.

October 14, 2014

Mr. Richard W. Corey, Ph.D.
Executive Officer
California Air Resources Board
1001 I Street
Sacramento, CA 95814

VIA Electronic and Postal Mail

Dear Dr. Corey:

Thank you for the opportunity to participate in the September 29, 2014 workshop on land use change (LUC) emissions. Thank you also for agreeing to provide the updated GTAP model to aid in our evaluation of your latest work in estimating LUC emissions from various feedstocks, and for agreeing to provide the two WRI reports used to evaluate irrigated versus rain-fed cropland.

While some progress in estimating land use emissions has perhaps been made, we have a number of concerns with ARB's presentation and some of the statements made by Staff at the workshop. We summarize each of these concerns below. This letter does not constitute our full comments on the information presented at the workshop, these comments will be submitted by our organizations on or before the due date. However, we thought it was important to highlight these concerns now.

1. AEZ-EF Model

Little has been done to address comments raised on the March 2014 workshop material with respect to the AEZ-EF model. Staff cited contractual reasons for not making progress in this area. However, this now puts ARB in the position of having very little time to address very significant concerns raised by the industry and others. At the same time, while Staff has not made progress in this area, the Staff presentation at page 7 indicates that "minor changes will be made in October 2014", and that the "impacts on ILUC are expected to be negligible." If Staff has not done this work yet, how does Staff know that the impacts on ILUC are expected to be negligible? The comments that were submitted to the Staff following the March workshop, if implemented properly, would not have negligible effects on the emissions. We are therefore disappointed that (1) Staff had not made any progress in this area since March, (2) Staff feel they must now rush to make progress because of deadlines, and (3) Staff are already discounting any impacts these changes may have. This is not a good approach to improving the science of land use change emissions, as it applies to a newly adopted LCFS.

LCFS B12-29

2. Irrigated/Rain-Fed Cropland

Working with Purdue, Staff developed separate rain-fed and irrigated cropland categories in GTAP, so that Staff could evaluate the LUC impact of limiting the growth of irrigated cropland where there appears to be evidence that this growth is limited. Since yields are higher on irrigated farmland, this has the effect of lowering the overall new land converted to crops. Staff indicated that the effect of including these new land categories was "small", however, it appears that this comment was based on what would happen between a scenario where some land has irrigated cropland with limitations to a scenario where all land has irrigated cropland with limitations. This is not the correct comparison. The comparison should have been between some irrigated cropland with limitations and no irrigated cropland with limitations (i.e., the baseline model without this change). Staff indicated this latter effect could be up to 5 g/MJ. Given that the new LUC for corn ethanol is 21.6 g/MJ from ARB's most recent modeling, 5 g/MJ, if it applies to corn ethanol, is hardly "small." We will be evaluating this impact in more detail prior to submitting comments on October 15, including the underlying data and rationale developed by WRI for limiting irrigated land expansion in the various AEZs. LCFS B12-30

3. Effect of Double-Cropping

Double-cropping is not an uncommon practice in many parts of the world when commodity prices are high. Double-cropping directly reduces the pressure to convert pasture, cropland pasture, and forest to crops. There are numerous examples of this. It has been well known that GTAP does not yet account for double-cropping, and since the LCFS was first adopted, comments have been submitted to ARB that ARB should evaluate the LUC impacts of double-cropping. The Expert Work Group elasticities sub-group suggested that if GTAP cannot be modified to directly address double-cropping, the yield-price elasticity could be used to simulate double-cropping effects. And yet, ARB has done nothing in this area. ARB has not even run "what-if" scenarios to determine what kind of impact double cropping would have on the results in countries like the US and Brazil, especially now ARB has apparently modified the model to allow the use of different yield-price elasticities for different crops in different AEZ regions. ARB's lack of progress in this area is unacceptable in improving LUC estimates. LCFS B12-31

4. Yield-Price Elasticity

ARB attempted to show 2 charts (pages 27 and 28 of the presentation) to support its claim that it the price-yield elasticity could be zero or very close to zero. The first chart plotted yield vs price for US corn from FAO data from 1990-2013. The chart appeared to show no relationship. However, one would never really use this kind of approach to develop a relationship between yield and price; there are simply too many factors changing from year-to-year to develop such a relationship. The second chart was a trend plot of corn yield and price from 1990-2013 (using the same data as the first chart). Since the second chart was a different way of presenting the same data as in the first chart, the same comment applies: there are too many things changing to develop any relationship of yield versus price in these data. ARB made no attempt to isolate just the impact of price changes on yields. Therefore, these two charts prove nothing. Purdue's estimated price yield value is 0.25. ARB evaluated a range from 0.05 to 0.35 (minus 0.2 from Purdue's estimate, and plus 0.1 from the Purdue default). The average from ARB's range is 0.19, 24 percent lower than the value recommend by Purdue. We support analyzing a range of price-yield elasticities, but this range should be from LCFS B12-32

0.15 to 0.50 with an average somewhat above 0.25 to simulate some double cropping (as recommended in the RFA comments on the March 11 workshop), not 0.15 to 0.35 (which has an average below the value recommended by Purdue without any double cropping). LCFS B12-32 cont.

5. Cropland Pasture Elasticity

Staff estimated two cropland/pasture elasticitiy scenarios – 0.4/0.2 for US/Brazil, and 0.2/0.1 for US/Brazil. The 0.4/0.2 is the Purdue-estimated set of inputs. Staff has presented no support for its 0.2/0.1 set of inputs, it is simply less than the Purdue-estimated values. Again, if a range is to be used, unless there is specific evidence otherwise to show that the Purdue-estimated values are too high, then the range should be on either side of the Purdue-estimated inputs. LCFS B12-33

6. Comparison of GTAP Outputs With World Data

ARB has received comments from stakeholders that it should compare GTAP's land use changes to real data. ARB rejects this type of comparison as "not productive", because GTAP is evaluating a single factor (increase in biofuel demand) while factors affecting land use changes in the real world are multiple. ARB then showed charts that compared world forest changes from 2000-2012 with GTAP-estimated changes for several feedstocks. The forest changes for the biofuels were very small in comparison with total forest changes from 2000-2012.

We find ARB's excuses on making no attempt to calibrate land use changes to real world data troubling. The expansion of corn ethanol in the US is predicted by GTAP to have converted 75,000 ha of forest in the US. GTAP also knows where in the US that forest is getting converted. If 75,000 ha of managed forestland have been converted to crops in the last 10 years due to biofuel expansion, then it should be apparent from satellite or other data. ARB should have attempted to validate forest conversions, at least in the US, if not in other major countries with predicted forest conversion. LCFS B12-34

We find it troubling that ARB apparently does not believe it is productive to validate model predictions by examining real-world empirical data and trends. The principles of sound, science-based policymaking and regulation dictate that model predictions should be validated when possible. Given that ARB's GTAP shock is meant to simulate impacts from 2001-2015, we now have real-world data for the majority of that period.

7. Effect of Fertilizer, Livestock, and Paddy Rice Emissions

The industry first made comments that ARB should evaluate these 3 effects several years ago. ARB has failed to do anything about these issues. EPA evaluated these in 2010 as a part of the RFS. They had a significant impact on EPA's LUC estimates. ARB cites a concern with double counting emissions between GTAP and GREET. EPA, however, also used GREET for direct emissions, and did not have a concern with double counting. ARB has completely failed to explain why it cannot include factors at this time in this update to LUC emissions that EPA successfully included in its analysis 4 years ago as a part of the RFS. LCFS B12-35

Summary

ARB has perhaps made some progress in updating LUC emissions as part of the LCFS. However, we have serious concerns with the lack of progress in these other areas. There are far too many items that Staff is pushing off to some future update of LUC emissions. LCFS B12-36

Respectfully,

Geoff Cooper

Geoff Cooper
Renewable Fuels Association

Chris Bliley

Chris Bliley
Growth Energy

cc:
Mary D. Nichols, Esquire, Chair, California Air Resources Board
Mr. Michael Waugh, Chief, Transportation Fuels Section
Mr. John Courtis, manager, Alternative Fuels Section
Mr. Anil Prabhu, Ph.D. Alternative Fuels Section

12_B_LCFS_GE Responses (Page 128 – 131)

698. Comment: **LCFS B12-29**

The comment alleges that ARB staff did not update the AEZ-EF model.

Agency Response: ARB staff notes that this document was submitted in October 2014, and as such does not constitute an objection or recommendation on the current proposal. The current analysis includes all relevant updates to the Agro-Ecological Zone Emissions Factor (AEZ-EF) model based on available data. The comments submitted were evaluated at first by staff and later by the contractor. Appropriate refinements were made to the model when supported by available data and methodology. For responses to the comments, see responses to **LCFS 46-16**, **LCFS 46-85**, **LCFS 46-92**, and **LCFS 46-93**. At this time, all of the iLUC values being proposed to the Board are a result of ARB staff using the latest science and best available data.

699. Comment: **LCFS B12-30**

The comment argues that ARB staff's conclusion that including the impact of areas with limited growth of irrigated cropland, results in a small effect is not accurate.

Agency Response: The comments related to scenarios where some land has irrigated cropland with limitations to a scenario where all land has irrigated cropland with limitations' are not relevant based on the development of the GTAP model. The GTAP model accounts for all categories of cropland and disaggregates cropland into irrigated and rain-fed types. There is no version of the model which includes all land being irrigated. The "5 g/MJ" difference indicated at the workshop on September 29, 2014, is the difference from an older version of a Purdue model with no separation of irrigated/rain-fed lands and the version which includes the disaggregation. The current ARB analysis uses an updated version of the model. Furthermore, this was an average difference from a few illustrative scenario runs and not the entire 30 runs as is used in the current analysis. The comments related to the 5 g/MJ are therefore not relevant since it does not apply to the current version of the model.

700. Comment: **LCFS B12-31**

The comment directs ARB staff to account for double-cropping in the GTAP model for more accurate results.

Agency Response: See responses to **LCFS 8-4** and **LCFS 8-5**.

701. Comment: **LCFS B12-32**

The comment supports a range of price-yield elasticities but suggests that the range should be changed to the commenter's preferred value.

Agency Response: Please see responses to **LCFS 8-9**, **LCFS 46-79**, **LCFS 46-86**, and **LCFS 46-98**.

702. Comment: **LCFS B12-33**

The comment contends that the Purdue analysis for cropland/pasture elasticity ratio is preferable to the ratio ARB staff used and directs staff to use the preferred value or justify their original value.

Agency Response: See responses to **LCFS 38-33** and **LCFS 46-103**.

703. Comment: **LCFS B12-34**

The comment directs ARB staff to validate the GTAP model predictions with real-world empirical data and trends.

Agency Response: ARB staff disagrees with the commenter that the current analysis should consider real-world data in assessing model outputs. See responses to **LCFS 8-4** and **LCFS 8-5**.

704. Comment: **LCFS B12-35**

The comment argues that ARB staff must explain why the effects of fertilizer, livestock, and paddy rice emissions are not included in the iLUC emissions updates.

Agency Response: See response to **LCFS 42-16** and **LCFS 46-82**.

705. <u>Comment</u>: **LCFS B12-36**

The comment contends that, while some progress has been made in updating iLUC emission estimates, more work is needed.

<u>Agency Response:</u> The current approach used by ARB staff is appropriate since it used the most current data and the latest modeling structure. Any specific issues that were not considered for the current analysis were either due to lack of detailed data or because modeling structure did not allow for the inclusion of a particular effect. See also responses to **LCFS 8-1** and **LCFS T25-1**.

This page intentionally left blank.

12_B_LCFS_GE

3_B_ADF_GE

Comments of Growth Energy on the Air Resources Board Staff Presentations at a Public Consultation Meeting on Regulations for Commercialization of Alternative Diesel Fuels

These comments respond to the CARB staff's request for comments on the staff's presentations at the November 21, 2014 public consultation meeting on the proposed adoption of regulations to govern commercialization of alternative diesel fuels, including as part of compliance strategies for the California Low Carbon Fuel Standard ("LCFS") regulation.

1. Methodology for Assessing Impact of Biodiesel Use on NOx Emissions

As Growth Energy has commented previously, CARB staff's approach to assessing the NOx emission impacts of biodiesel and biodiesel blends in heavy-duty diesel engines is flawed.[1] The staff's approach does not adequately protect the environment, in part because it ignores the fact that the existing emissions test data indicate that there are statistically significant increases in emissions of oxides of nitrogen (NOx) at biodiesel blend levels below B5, the lowest level at which CARB staff has chosen to perform testing. As fully explained in an expert report prepared for Growth Energy by Mr. Robert Crawford of Rincon-Ranch Consulting,[2] any sound statistical analysis of the available data indicates that statistically significant increases in NOx emissions occur at biodiesel blend levels below B5. ADF B3-1

In light of the recent release of biodiesel emissions data by CARB staff, Mr. Crawford has updated his work to include all of that data. The results of this updated analysis were summarized by Jim Lyons of Sierra Research during a presentation made at the October 20, 2014 ADF workshop, and detailed documentation regarding the updated analysis was provided to CARB staff ADF B3-2

1 See Attachments A – D.

2 See Crawford, R., "NOx Emission Impact of Soy- and Animal-based Biodiesel Fuels: A Re-Analysis," December 10, 2013.

by Mr. Lyons via email on October 24, 2014,[3] along with a request that it be posted on agency's ADF website.

As CARB staff has been advised, inclusion of the newly released biodiesel emission test data does not alter Mr. Crawford's previous findings. Likewise, the CARB staff's decision to characterize biodiesels as "low saturation" or "high saturation," instead of "soy" or "animal" based," does nothing to alter Mr. Crawford's findings or protect against increases in NOx emissions resulting from biodiesel use in California. CARB staff has not posted Mr. Crawford's updated analysis on the agency's ADF webpage; has never discussed or explained why it has not adopted Mr. Crawford's approach; and did not discuss Mr. Crawford's revised analysis in any way during the November 21, 2014 workshop. CARB staff appears determined to avoid full public review of the available data, in violation of its environmental protection regulations and the statutes that apply to this rulemaking, including the California Environmental Quality Act ("CEQA") and the Global Warming Solutions Act of 2006 ("AB 32").

ADF B3-2 cont.

2. Proposed Biodiesel Control Levels

For what it treats as low saturation biodiesel blends, CARB staff is proposing a control level of B5 from April 1 to October 31 of each year and a control level of B10 throughout California during the rest of the year. What this means, based on the proposed regulatory language[4] released by CARB staff, is that during the summer, mitigation of increased NOx emissions is not required until low saturation biodiesel blend levels exceed B5 (e.g., B6)—despite the fact that ***CARB staff acknowledges that statistically significant impacts occur at the B5***

ADF B3-3

---

3 Although these were already provided to CARB staff, materials related to Mr. Crawford's most recent analysis are attached to these comments.

4 Proposed Section 2293.6(a)(2).

level.[5] Given this, there can be no dispute that the staff proposal will result in increases in NOx emissions in California. Such an outcome, however, is not permitted under CEQA and AB 32. ADF B3-3 cont.

During the winter the control level for low saturation biodiesel blends increases from B5 to B10, meaning that NOx mitigation is not required until the biodiesel blend level reaches B11. As a result, CARB staff is allowing unmitigated increases in NOx emissions in California to as much as double during the winter. Further, Growth Energy is not aware of, nor has CARB staff identified, any other NOx control measure affecting stationary, area, or mobile sources that is allowed to be relaxed during the winter months anywhere in California. Such an inconsistency cannot be squared with CARB's CEQA obligations or the requirements of AB 32, which include the avoidance of controls that would have the effect of increasing regulated emissions (such as NOx) or hampering compliance with state and federal ambient air quality regulations. ADF B3-4

For high saturation biodiesel blends, CARB staff is proposing a year-round control level of B10, meaning that NOx mitigation is not required until the B11 level. Again, this is above the B10 level at which even CARB staff has determined that statistically significant increases in NOx emissions will occur; therefore, it will allow unmitigated increases in NOx emissions to occur throughout California.

Growth Energy again urges CARB staff to revise its proposal to ensure that it is protective of California air quality by requiring mitigation of potential NOx emission increases from all levels of biodiesel blends, the need for which is indicated by Mr. Crawford's work. CARB cannot risk increases in NOx emissions by failing to require year-round NOx mitigation for low saturation

---

[5] This was acknowledged by CARB staff at the October 20th workshop. See *http://www.arb.ca.gov/fuels/diesel/altdiesel/20141017_ADF_statistical_analysis.pdf* and *http://www.arb.ca.gov/fuels/diesel/altdiesel/20141017_ADF_discussion_paper.pdf*

biodiesel blends beginning at the B5 level, and for high saturation biodiesel blends beginning at the B10 level. ADF B3-4 cont.

3. New Technology Diesel Engines and the Sunset and Exemption Provisions

CARB staff claims, currently without empirical support or any other explanation, that the use of biodiesel blends in so-called "new technology diesel engines" (NTDEs) will not result in increased NOx emissions regardless of the type of biodiesel used or the blend level up to at least B20. Based on that claim, CARB staff is proposing to eliminate the requirements for mitigation of biodiesel-related NOx emission increases when the population of vehicles equipped with NTDEs in the California truck fleet reaches a certain level and for biodiesel blends used by centrally fueled truck fleets that are composed of at least 90% of vehicles equipped with NTDEs. The available studies in the peer-reviewed literature, which have been previously identified by Growth Energy for CARB staff,[6] contradict the staff's claim. The proposed exemptions for fleets of vehicles comprised mainly of vehicles equipped with NTDEs and the sunset provisions are therefore not permitted under the governing statutes because they would permit an unmitigated risk of increased NOx emissions, and adverse impacts on air quality. ADF B3-5

4. Definitions of CARB Diesel and Blend Level

At present, CARB staff is proposing to define "CARB diesel" to which biodiesel will be allowed to be blended under the ADF regulation as follows:[7]

> *...a light or middle distillate fuel that may be comingled with up to five (5) volume percent biodiesel and meets the definition and requirements for "diesel fuel" or "California nonvehicular diesel fuel" as specified in 13 CCR 2281, et seq. "CARB diesel" may include: renewable diesel; gas-to-liquid fuels; Fischer-Tropsch diesel; CARB diesel blended with additives specifically formulated to reduce emissions of one or more criteria or toxic air contaminants relative to reference CARB diesel;*

ADF B3-6

[6] See Attachment D

[7] Proposed Section 2293.2(a)(9)

and CARB diesel specifically formulated to reduce emissions of one or more criteria or toxic air contaminants relative to reference CARB diesel.

The "blend level" of a biodiesel blend or blend of another ADF would be defined[8] as follows:

> *...the ratio of an ADF to the CARB diesel it is blended with, expressed as a percent by volume. The blend level may also be expressed as "AXX," where "A" represents the particular ADF and "XX" represents the percent by volume that ADF is present in the blend with CARB diesel (e.g., a 20 percent by volume biodiesel/CARB diesel blend is denoted as "B20").*

Because "CARB diesel" can contain up to 5% biodiesel and the control levels proposed by CARB staff above which NOx mitigation is required are defined in terms of "blend levels," the actual biodiesel content of a biodiesel blend under the staff proposal could be as much as 5% greater than the "blend level" used to determine if NOx mitigation is required. Thus, for example, under the staff proposal NOx mitigation of a summer blend of "low saturation" biodiesel blend would not be required even though it contains 10% biodiesel and the unmitigated NOx emissions would be as much as twice those assumed by CARB staff.

ADF B3-6 cont.

There are at least two ways by which CARB staff could easily address this issue. The first would be to require biodiesel blenders to test the CARB diesel fuels they use in order to determine the biodiesel content and type of biodiesel present in a given CARB diesel before blending occurs. The second would be to require that biodiesel blenders use only CARB diesel fuels that have been certified as containing no biodiesel. In any case, CARB staff must modify its proposal to ensure that the actual biodiesel content of blends is accurately known and that appropriate NOx mitigation requirements are imposed. Failure by CARB staff to require accurate measurement and reporting of the biodiesel content of biodiesel blends will lead to unmitigated increases in NOx emissions

---

[8] Proposed Section 2293.2(a)(4)

along with other potential issues, including violations of pump labeling and vehicle manufacturer warranty requirements.

ADF B3-6 cont.

5. Phase-In Requirements and Program Review

Under the current staff proposal, although the ADF regulation would become effective on January 1, 2016, ***mitigation of increased NOx emissions from the use of biodiesel blends would not be required until 2018.***[9] In addition, CARB staff is proposing to perform a "review" of efficacy of the NOx mitigation requirements of the biodiesel provisions of the ADF regulation by December 31, 2019.[10] As in other respects, the CARB staff proposal fails to adequately protect against adverse air quality impacts and violates the statutes governing this rulemaking. To comply with CEQA and AB 32, the Board must mandate in the ADF rulemaking that mitigation of NOx increases commences as soon as the amended LCFS regulation becomes effective. CARB staff has not explained and cannot explain why California air quality should be exposed for an additional two years to adverse effects from the impacts of increased NOx emissions owing to biodiesel use (which CARB staff itself has estimated to be currently 1.3 tons per day statewide,[11] even after incorrectly assuming that there is no NOx increase from use of biodiesel in NTDEs).

ADF B3-7

Similarly, with respect to the program review, instead of acting to ensure that there are no adverse air quality impacts associated with biodiesel use by proposing mitigation requirements for all biodiesel blends of B1 and above, CARB staff is proposing to wait three years after the implementation of the ADF regulation before making an effort to "determine the efficacy" of the proposed NOx mitigation provisions. As pointed out numerous times in these and previous

ADF B3-8

[9] Proposed Section 2293.6(a)(1)

[10] Proposed Section 2293.6(a)(6)(A)

[11] See *http://www.arb.ca.gov/fuels/diesel/altdiesel/20141017_ADF_discussion_paper.pdf*

Growth Energy comments on the proposed ADF,[12] the currently proposed NOx mitigation provisions are inadequate and will result in increases in NOx emissions and associated adverse impacts on air quality in California. There is no legal basis for waiting until the end of 2019 for CARB staff to make that determination.

ADF B3-8 cont.

6. Authority Granted to the Executive Officer

Under the staff proposal, the Executive Officer, rather than the Board, would be authorized to make findings regarding the potential adverse environmental impacts of potential alternative diesel fuels other than biodiesel.[13] Under CEQA and the Board's implementing regulations, the duty to consider and assess, and to mitigate, potential adverse environmental impacts lies with the Board, not the Executive Officer. In the current rulemaking regarding biodiesel blends, CARB staff is establishing the precedent for the Board, rather than the Executive Officer, to make decisions regarding adverse environment impacts, and the same process must be followed for any future alternative diesel fuel.

ADF B3-9

7. Unfair Competitive Advantages

At present, producers and blenders of biodiesel used in California are allowed to profit from the sale of that fuel under the Low Carbon Fuel Standard (LCFS) regulation through the generation of LCFS credits, despite the fact that use of that fuel results in unmitigated increases in NOx emissions and adverse air quality impacts. Under the proposed ADF regulation, producers and blenders of other alternative diesel fuels would similarly be allowed to profit via the LCFS regulation during Stages 1, 2, and 3a, despite the fact that their products lead to adverse environmental impacts. Such an approach is unexplained and anticompetitive—CARB staff

ADF B3-10

---

[12] See Attachments A – D.

[13] See for example, proposed Sections 2293.5(b)(3), 2293.5(b)(6) 2293.5(c) and 2293.5(d).

should ensure that no ADF for which adverse environmental impacts have been established can generate LCFS credits ***before the producers of that ADF are required to mitigate those impacts***. For example, if CARB adopts the staff proposal that mitigation of biodiesel NOx impacts is not required until January 1, 2018, then no biodiesel sold in California before that time should be allowed to generate LCFS credits. If this issue is not addressed by CARB staff, producers and blenders of low carbon intensity fuels, such as ethanol, for which mitigation measures must be implemented will be disadvantaged, and producers and blenders of fuels such as biodiesel that are not required to mitigate adverse environmental impacts will be undeservedly rewarded.

ADF B3-10 cont.

Respectfully submitted,

GROWTH ENERGY

12_B_LCFS_GE Responses (Page 132 – 140)

706. Comment: **ADF B3-1 through ADF B3-2**

Agency Response: This comment is responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

707. Comment: **ADF B3-3 through ADF B3-10**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

ATTACHMENT A

growth energy™
America's Ethanol Supporters

777 North Capitol Street, NE, Suite 805, Washington, D.C. 20002
PHONE 202.545.4000 FAX 202.545.4001 GrowthEnergy.org

December 12, 2013

By Electronic Mail

Clerk of the Board
California Air Resources Board
1001 I Street, 23rd Floor
Sacramento, California 95812

Re: Proposed Regulation to Govern Commercialization of New Alternative Diesel Fuels (2103 Cal. Reg. Notice Register 1646 (October 25, 2013)

Dear Madam:

Growth Energy, an association of the nation's leading ethanol manufacturers and other companies who serve the nation's need for alternative fuels, is submitting to you the enclosed materials in response to the October 15, 2013, notice of proposed regulatory action to establish rules to govern the commercialization of new alternative diesel fuels.

Growth Energy is a strong supporter of biodiesel fuels, which continue to play an important part in our nation's efforts to achieve energy independence with renewable sources and to address environmental concerns. While we applaud the effort to incentivize greater use of all renewable fuels, including biodiesel, we have several significant concerns about the CARB staff's current regulatory proposal and the regulatory process.

Growth Energy believes that significant but feasible changes must be made to the CARB staff's proposed regulations, because the staff's current proposal does not include all reasonable and feasible methods of mitigating potential increases in emissions of oxides of nitrogen ("NOx"), among other reasons. The required changes to the staff's proposal are explained in the enclosed comment and will facilitate the lawful commercialization and use of biodiesel in California in a manner that fully protects the environment. In addition, the CARB staff has not yet publicly released all the test data and analysis on which it is basing its proposal. The decision to postpone the public hearing until March 2014 affords time for the staff to make full disclosure of all the data and analysis. ADF B3-11

Please contact me or David Bearden, our General Counsel, at 605-965-2375 if you have any questions concerning this submission.

Sincerely,

Tom Buis

Tom Buis
CEO, Growth Energy

STATE OF CALIFORNIA

AIR RESOURCES BOARD

PROPOSED REGULATION TO GOVERN THE COMMERCIALIZATION OF NEW ALTERNATIVE DIESEL FUELS

GROWTH ENERGY'S RESPONSE
TO THE NOTICE OF PUBLIC HEARING DATED OCTOBER 15, 2013
2013 CAL. REG. NOTICE REG. 1646 (OCTOBER 25, 2013)

DECEMBER 12, 2013

Executive Summary

These Comments by Growth Energy on the proposed regulation to govern the commercialization of alternative diesel fuels address two main issues: (1) the duty of the Air Resources Board to mitigate potential increases in exhaust emissions of oxides of nitrogen ("NOx") from engines operated on biodiesel fuels, and (2) the analytical and procedural obligations for this rulemaking under the governing statutes.

Growth Energy strongly supports the use of biodiesel to achieve the Nation's environmental and energy independence objectives. As with other elements of California's effort to participate in those national strategies, however, the proposed alternative diesel fuel regulation must avoid having unintended negative environmental consequences, and must be considered carefully and in a manner that permits full and effective public participation. The flaws in the current regulatory proposal for alternative diesel fuels can be readily addressed through feasible mitigation measures, which would put biodiesel in parity with other alternative fuels for which the Board has for many years required risk mitigation through regulation. ADF B3-12

As explained in these Comments, a detailed review of the Air Resources Board staff's analysis of the impacts of biodiesel use on NOx emissions, and a reanalysis of the data used by the staff made available to the public, shows that statistically significant increases in NOx emissions must be expected from the use of biodiesel blends of less than ten percent including blends of five percent and lower amounts of biodiesel. Applying the Board's normal precautionary principles, and consistent with the obligations of the California Environmental Quality Act and the Global Warming Solutions Act, the staff's proposed "Significance Level" of ten percent for biodiesel blends should instead be reduced to zero, because the use of biodiesel at any level can be expected to result in increased NOx emissions if not mitigated using reasonable and feasible measures. ADF B3-13

These Comments also show that the potential increases in NOx emissions caused by biodiesel use under the proposed regulation are far larger than the NOx levels considered significant enough to require costly mitigation or control measures in the State's two "extreme" areas for ozone nonattainment -- the South Coast Air Basin and the San Joaquin Valley Air Pollution Control District. It would counterproductive, and not consistent with the governing statutes, for the Board to commit itself to measures that will result in NOx emissions increases in order to implement the low-carbon fuel standard under the Global Warming Solutions Act, especially when those increases greatly exceed the levels for which the State's air quality districts currently require mitigation or control of those emissions when they come from other sources. ADF B3-14

These Comments also urge the Board to ensure that all comments and data received by the staff in connection with this rulemaking effort, or relied upon in formulating the proposed regulation, be placed in the public rulemaking file, and that sufficient time be allowed to review those materials before the Board considers regulatory action. If the Board directs the staff to address these important issues of public access and transparency -- which are governed by the Administrative Procedure Act -- this regulatory item can be completed in a timely manner. ADF B3-15

Table of Contents

Page

Comments of Growth Energy on the Proposed Regulation To Govern the Commercialization of New Alternative Diesel Fuels

Growth Energy respectfully submits these comments on the California Air Resources Board's proposed regulation to govern the commercialization of new alternative diesel fuels (the "proposed ADF regulation"). As explained below, Growth Energy believes that the Board should direct the staff to make revisions in the proposed ADF regulation and cannot adopt the proposed ADF regulation in its current form. The proposed ADF regulation does not require the use of feasible measures that are necessary to mitigate adequately the potential adverse environmental impacts of increased use of biodiesel blends in California. ADF B3-16

I. INTRODUCTION AND OVERVIEW

CARB's obligation to examine the impacts of widespread biodiesel usage, and to address potential adverse environmental impacts, have recently been clarified by the California Court of Appeal in *POET LLC, et al. v. California Air Resources Board*, (2013) 218 Cal. App. 4th 681. In that litigation, ARB claimed that it intended to "ensure" that there would be "no" increase in regulated pollutants from Diesel-powered engines in California as a result of the LCFS regulation, and in particular that there would be no increase in exhaust emissions of oxides of nitrogen ("NOx") resulting from the use of biodiesel fuel. 218 Cal. App. 4th at 732. ADF B3-17

The CARB staff's proposed approach to the task of NOx mitigation in the proposed ADF regulation falls far short of the claimed metric: whatever the benefits of the proposed ADF regulation for other purposes, the staff's approach will not ***ensure*** that the implementation of the LCFS regulation can cause ***no*** increase in NOx emissions. These comments briefly outline, and the accompanying materials fully explain, the unnecessary environmental risks to the State's efforts to control NOx emissions that the proposed ADF regulation fails to address.[1] Those risks are not based on unqualified speculation, or merely the opinion of Growth Energy; the risks can be demonstrated from the emissions data that the CARB staff has placed in the docket, when those data are evaluated using simple but appropriate statistical tools and methods.[2] Moreover, the increases in NOx emissions, which the CARB staff's data establish, are significant by any contemporary measure: the increases in NOx emissions that the increased use of biodiesel will cause as a result of the LCFS regulation are many times larger than the NOx increases that CARB and regional air quality authorities require to be mitigated. (*See* pp. 18-19 below.)

ADF B3-17 cont.

Addressing the problem of increased NOx emissions is a feasible task, as the Staff Report that accompanies the proposed ADF regulation concedes. Once the risk is established, and the methods of mitigation are determined to be feasible, CARB's task is clear: under the California Environmental Quality Act ("CEQA"), it must require mitigation before it can proceed with regulation.[3]

In this instance, mitigation may impose direct costs on the firms that choose to use biodiesel to comply with the LCFS regulation, and indirect costs on the operators of Diesel engines, but CARB decided nearly five years ago that the benefits of the LCFS regulation overall were worth the costs. In that respect, biodiesel should be treated no differently than the

[1] In addition to the materials cited below in notes 2 and 4, Growth Energy is also attaching to these comments for inclusion in the rulemaking file -- and for analysis and response by the Board -- its earlier comments on the CARB staff's ADF regulatory proposal, submitted on September 16, 2013. Those comments, and likely many other comments from other parties, were not placed in the rulemaking file when CARB issued its 45-day notice. *See* pp. 13-14 below (requirements of the California Administrative Procedure Act).

[2] *See* R. Crawford, "NOx Emissions Impact of Soy- and Animal-Based Biodiesel Fuels: A Re-Analysis" (Dec. 2013) (hereinafter "Crawford Report"), attached to these Comments as Exhibit A.

[3] *See POET*, 218 Cal. App. 4th at 731-742.

alternative fuels that the LCFS regulation requires for gasoline, which are ethanol, natural gas and electricity. ADF B3-17 cont.

Instead of requiring the Diesel sector to bear its fair share of the costs of the LCFS regulation through proper environmental mitigation, however, the CARB staff's proposed approach deploys what the Staff Report calls an "Effective Blend Level" concept to exempt biodiesel fuel from any meaningful mitigation requirement.[4] Rather than following the precautionary principles that have constantly guided CARB rulemaking -- which in other contexts sometimes have inclined the Board to require extreme regulatory stringency based on scant evidence of actual harm -- in this one instance, the CARB staff appears intent on risking air quality rather than requiring feasible, if costly to some, mitigation measures. The CARB Staff Report suggests in one place that this deviation from the Board's longstanding regulatory strategy may be necessary to protect the growth of the biodiesel "market."[5] But the CARB staff cites no evidence to support its speculation that the biodiesel "market" is at risk, and there is no evidence of such a risk in the public rulemaking file. Even if such a private market risk existed, however, neither the California Global Warming Solutions Act nor the California Government Code allow CARB to consider factors extrinsic to the statutes in meeting the clean-air goals established by law.[6] The California statutes protect California citizens and air quality, not market entrepreneurs and arbitragers. It is not the proper purpose of any California regulation to ADF B3-18

[4] *See* Declaration of James M. Lyons (hereinafter "Lyons Decl."), attached to these Comments as Exhibit B.

[5] *See* Staff Report at 63 (rejecting "immediate" mitigation because "this option has the potential to disrupt or even collapse the burgeoning ADF market by unnecessarily placing overly restrictive requirements that are not warranted by emissions testing"). Tellingly, that portion of the Staff Report has no citations to support the claim.

[6] In its current proposal, the CARB staff is engrafting onto the Global Warming Solutions Act a provision allowing it to avoid mitigation of environmental harm, in order to encourage particular industries or based on general economic preferences. CARB cannot proceed in that fashion. *Cf. Clean Air Constituency v. CARB*, (1974) 11 Cal.3d 801 (CARB lacks authority to establish criteria to govern its actions that are not found in its enabling statutes).

pick "winners" and "losers:" all fuels, including all alternative fuels, must have their environmental risks properly assessed, and when feasible mitigated in full. ADF B3-18 cont.

The balance of these Comments is divided into two parts. The first part, in Section II below, summarizes the technical analyses contained in the accompanying report of Robert Crawford, a statistician with expertise in evaluation of emissions data, and in the Declaration of James M. Lyons, an expert in automotive air pollution who evaluates the "Effective Blend Level" concept as a method of addressing the risks of increased NOx emissions. Section II also summarizes the relevant portions of the Staff Report dealing with the available mitigation methods and their feasibility. The second part, in Section III below, explains the Board's legal obligations to mitigate the risks of increased NOx emissions presented by biodiesel fuel usage.

II. ENVIRONMENTAL ASSESSMENT OF THE PROPOSED REGULATION

Were the matter ever in any doubt, the Court of Appeal's *POET* decision, which the California Supreme Court has recently declined to review, makes it clear that the Board must take seriously the issue of NOx emissions increases from the increased use of biodiesel in order to comply with the LCFS regulation. CARB has recognized, first in the LCFS regulatory process and more recently in court, that the LCFS regulation will increase the use of biodiesel. The CARB staff now claims in the current ADF rulemaking, however, that emissions testing proves that the use of biodiesel blends containing less than 10 percent biodiesel will not increase NOx emissions. That claim is demonstrably wrong, as Mr. Crawford establishes in his analysis of the available emissions data. (*See* Exhibit A and Section A below.) Because the data do not support the CARB staff's claims that operation of engines on blends below 10 percent biodiesel will not increase NOx emissions, and in fact show the opposite, CARB has a duty to mitigate. The CARB staff's environmental analysis is also unsound in other respects as well, as demonstrated in Mr. Lyons' Declaration. (*See* Exhibit B and Section B below.) ADF B3-19

A. Impact of the Proposed Regulation on Exhaust Emissions of Oxides of Nitrogen

Mr. Crawford's report carefully reviews each of the six studies cited in the CARB staff's literature review on biodiesel NOx emissions, as well as CARB's biodiesel characterization study ("Durbin 2011") and the data available from that study. It is important to note at the outset that not all the data from the CARB study has been made available to the public. CARB should publish all of the testing presented in Durbin 2011[7] and any future testing that it sponsors in a complete format that allows for reanalysis, and an opportunity to evaluate those materials prior to the deadline for submission of public comments or CARB's hearing on the approval of the proposed ADF regulation. ADF B3-20

Putting aside the CARB staff's failure to make a complete disclosure of the data reflected in Durbin 2011, it is clear that the data from Durbin and the other six studies do not support the CARB staff's conclusion and, indeed, the data refute the staff's conclusion in some instances. These are the salient points from Mr. Crawford's analysis:

- There is ***no evidence*** supporting the staff conclusion that NOx emissions do not increase until the B10 level is reached. Instead, there is consistent and strong evidence that biodiesel increases NOx emissions in proportion to the biodiesel blending percent. ADF B3-21

- There is ***clear and statistically significant evidence*** that biodiesel increases NOx emissions at the B5 level in at least some engines for both soy- and animal-based biodiesels. ADF B3-22

None of the six studies in the literature measured the NOx emissions impact from biodiesel at blending levels below B10. Only two studies tested a fuel at the B10 level. All

[7] The data should be published in a useable format, and should include (a) the measured emission values for each individual test replication; or (b) averages across all test replications, along with the number of replications and the standard error of the individual tests. The first format (individual test replications) is preferable because that would permit a full examination of the data including effects such as test cell drift over time.

other testing was at the B20 level or higher. Because none tested a B5 (or similar) fuel, the studies do not constitute substantial evidence that NOx emissions are not increased at B5 or other blending levels below B10. Those six studies therefore provide no data or evidence supporting the validity of the staff's claim that biodiesel below B10 does not increase NOx emissions. To the contrary, all of the studies are consistent with the contention that biodiesel increases NOx emissions in proportion to the blending percent. Indeed, two of those six studies present evidence and data that the NOx impact from biodiesel is a continuous effect that is present even at very low blending levels and will increase at higher levels in proportion to the blending percentage. ADF B3-22 cont.

With regard to the CARB biodiesel characterization report, Mr. Crawford has uncovered the fact that for the three engines for which the CARB staff has published the emission values measured in engine dynamometer testing, all of the data demonstrate that biodiesel fuels significantly increase NOx emissions for both soy- and animal-based fuels by amounts that are proportional to the blending percent. That is true for on-road and off-road engines and for a range of test cycles. When B5 fuels were tested for those engines, NOx emissions were observed to increase. NOx emission increases are smaller at B5 than at higher blending levels and the observed increases for two engines were not statistically significant by themselves based on the pair-wise t-test employed in Durbin 2011. However, the testing for one of the engines (the 2007 MBE4000) showed statistically significant NOx emission increases at the B5 level for both soy- and animal-based blends. The data are sufficient to disprove the staff's contention that biodiesel blends at the B5 level will not increase NOx emissions. ADF B3-23

In sum, based on examination of all of the studies cited by CARB as the basis for its proposal to exempt biodiesels below B10 from mitigation, it is clear that the available research ADF B3-24 points to a very substantial risk, if not a certainty, that both soy- and animal-based biodiesel blends will increase NOx emissions in proportion to their biodiesel content, including at the B5 level. Based on data in the CARB Biodiesel Characterization Report, soy-based biodiesels will increase NOx emissions by about 1% at B5 and 2% at B10, while animal-based biodiesels will increase NOx emissions by about one-half as much: 0.45% at B5 and 0.9% at B10. All of the available research shows that the NOx increases are real and implementation of mitigation measures will be required to prevent increases in NOx emissions due to biodiesel use at blending levels below B10. The available research likewise demonstrates that, to the extent CARB is identifying B10 as a "threshold of significance" under CEQA, (1) the utilization of this threshold is unsupported by the evidence in the record. For the same reasons, and for the reasons discussed in Section III.B below, the utilization of B10 as a "threshold" is contrary to the Legislature's mandate that the regulations should "not interfere with ... efforts to achieve and maintain federal and state ambient air quality standards." Cal Health & Safety Code § 38562(b)(4).

ADF B3-24 cont.

ADF B3-25

B. The "Effective Blend Level" Concept

Mr. Lyons' Declaration builds on the analysis performed by Mr. Crawford and demonstrates that the CARB staff's "effective blend level" concept will operate to exempt biodiesel from any meaningful mitigation, even if biodiesel is causing real-world increases in NOx exhaust emissions from Diesel engines operated in California. Mr. Lyons demonstrates, in particular, that "despite the forecast nine-fold increase in biodiesel use in California from 50 million to 450 million gallons from 2013 to 2023 ... the forecast Effective Blend Level of biodiesel decreases to less than zero over virtually all of the period in question." (Lyons Decl. ¶ 14.)

ADF B3-26

If the fractional coefficients being applied in the "effective blend level" equation (*see* Lyons Decl. ¶¶ 11-12) are incorrect to any significant extent, the environment will not be protected. The CARB staff has apparently selected those coefficients without allowing for the possibility of errors that could understate NOx impacts -- a clear violation of CARB's precautionary norms. The adverse effects will be severe if there is error in the coefficients, because the CARB staff itself recites evidence that the biodiesel market will be concentrated in low-blend biodiesel. (*See* Lyons Decl. ¶¶ 15, 17.) Growth Energy is aware of no other regulatory concept in any CARB program in which mitigation measures required by CEQA depend on a formula that could err as easily as the "effective blend level" equation could. ADF B3-27

The mischief in the "effective blend level" coefficients lies in their complexity and the risk of quantitative error. A much simpler but equally fatal analytical flaw, which also violates both sound regulatory policy and the requirements of CEQA, is the failure of the effective blend level calculation to ensure that any NOx increases that require mitigation will be addressed by the use of a mitigation measure in the ***same*** relevant location, and at the ***same*** time, as the NOx increases are occurring. If NOx mitigation does not occur in the same area and at the same time as biodiesel use that increases NOx emissions, the environmental harm presented by those increased NOx emissions will go unmitigated; the adverse impacts of NOx increases are defined by their location, and their severity is greatest at the time when the emissions occur. ADF B3-28

As Mr. Lyons points out, the "effective blend level" concept does not fully protect, for example, Los Angeles residents, if NOx increases experienced in the summertime in Los Angeles can be offset by the biodiesel "market" in whole or part by practices that mitigate those emissions in a different season and in another place. (*See* Lyons Decl. ¶¶ 19-20.) The regulation, as proposed by the CARB staff, does nothing even to incentivize, much less require, ADF B3-29 the biodiesel "market" to deliver mitigation at the time and place it is needed. That may be a result of the CARB staff's conclusion that, as they have written the mitigation rule, it is unlikely that mitigation will ever be required; if so, that simply underscores the weakness of the mitigation rule itself (*see*, *e.g.*, Lyons Decl. ¶¶ 8-10, 15-18). CEQA and its implementing guidelines must be read to require mitigation where and when the adverse effect would otherwise occur. By not accounting for that requirement, the "effective blend level" concept violates CEQA. ADF B3-29 cont.

Mr. Lyons' Declaration identifies other flaws in the staff proposal that must be addressed. As his Declaration establishes, the data on which CARB relies for its assumption that "new-technology" diesel engines will have lower NOx emissions when operated on biodiesel is inadequate to support the weight it is given by the CARB staff (*see* Lyons Decl. ¶¶ 21-23); that data cannot be treated as substantial evidence to support a regulation that posits lower emissions from such engines. Each of the issues raised in Mr. Lyons' Declaration must be addressed by the Board. ADF B3-30

C. Available Mitigation Measures

Mitigation of the risks of NOx increases from biodiesel usage is entirely feasible. The proposed ADF regulation can easily be modified to ensure that the use of biodiesel will not result in increased NOx emissions by setting the "Significance Level" for biodiesel blends at zero -- which is the level that the available data require -- so that mitigation would occur whenever and wherever it should. In addition, CARB must eliminate the use of annual statewide averages for determining the "effective blend levels" and instead use actual blend levels at the batch level. These two changes would require that mitigation be applied to all biodiesel blends in light of the actual amount of biodiesel present in each specific blend. ADF B3-31

Appendix 1 to proposed Section 2293.5(c) specifies the three mitigation measures that CARB staff has identified for mitigation of increases in NOx emissions due to biodiesel use. They include (i) addition of di-tert-butyl peroxide to biodiesel blends at a level that varies with the amount of biodiesel in the blend and (ii) blending of low-NOx diesel fuel along with biodiesel into biodiesel blends. Under the staff's proposal, parties responsible for mitigation of increased NOx emissions from biodiesel can choose either of those approaches. They all could be easily applied to any blend containing ten percent or less biodiesel, as well as blends of more than ten percent, if appropriately modified to ensure that there would be no increase in NOx emissions associated with the use of biodiesel. The Staff Report and the rulemaking file contain no significant evidence that such approaches could not be applied at the batch level. ADF B3-32

In addition to conceding the feasibility of the three identified mitigation measures by including them in the proposed ADF regulation, the Staff Report also provides cost estimates for the application of each measure.[8] Absorption of those estimated costs by entities or individuals choosing to use biodiesel is in no way inconsistent with the types of costs that have been imposed by CARB on other California businesses and residents in other regulatory programs. Indeed, the Global Warming Solutions Act gives CARB no choice but to require the regulated parties and their downstream customers to absorb those costs: the Legislature has specifically directed that CARB is to "ensure" that "activities undertaken pursuant to the regulations" adopted to implement the Act -- including the use of biodiesel to comply with the LCFS regulation -- "do not interfere with … efforts to achieve and maintain federal and state ambient air quality standards." Cal. Health & Safety Code § 38562(b)(4). ADF B3-33

[8] Those costs are $0.25 per gallon of biodiesel blended for di-tert-butyl peroxide, $1.20 per gallon of biodiesel blended for low-NOx diesel and a one-time expense of between $100,000 and $200,000 for the certification of a biodiesel blend that could then be sold in California in any volume. *See* Staff Report at 59 and *id.* App. C.

In addition to being technically feasible, consistent with costs required by other CARB regulations, the mitigation measures outlined in the Staff Report can be implemented. In some instances, regulated parties would simply have to ensure that steps have been taken to ensure their final blends meet the fuel property specifications associated with the certified blend. Mitigation using di-tert-butyl peroxide or low NOx diesel requires only knowing the amount of biodiesel in the blend and ensuring that the entity performing the blending also be responsible for adding di-tert-butyl peroxide or low NOx diesel to the blend. ADF B3-34

The Staff Report claims that "[i]t would be impractical to determine the individual blend level for each gallon of biodiesel blend being sold across the State." The Staff Report continues: "To do so would require the retailers and marketers of biodiesel blends (i.e., the diesel dispensing facilities) to continuously test and determine the biodiesel blend level for each of the approximately 3 billion gallons of on-road diesel fuel sold in California each year."[9] The Staff Report offers no support for that claim, however, and it is contradicted by the overall regulatory experience under the LCFS regulation as well as the data necessary to actually to employ the Effective Blend concept. The LCFS regulation already requires producers of biodiesel sold in California or other entities to which the fuel is transferred to report the volumes of biodiesel to CARB via the Low Carbon Fuel Standard Reporting Tool ("LRT") in order to receive greenhouse gas emission reduction credits. (*See* 17 C.C.R. § 95484(b)(B)(2).) Moreover, in order to employ the Effective Blend concept, data regarding the amount of biodiesel used in blends of five percent or less, as well as the type and volumes of biodiesel used in blends of more than five percent, would be required. Presumably, this data will also be derived from the LRT. The LRT is currently treated by CARB as an accurate source of data regarding biodiesel use in ADF B3-35

[9] Staff Report at 23.

California.[10] The CARB staff regularly publishes quarterly summaries of greenhouse gas credits generated from biodiesel and other fuels under the LCFS.[11]

ADF B3-35 cont.

Given that biodiesel producers must report both their production volumes and production pathways (*e.g.*, soy-based, animal-based, or other) to CARB via the LRT in order to generate greenhouse gas credits under the LCFS regulation, the implementation of NOx mitigation measures involving use of di-tert-butyl peroxide or low NOx diesel under the ADF regulation would be simple and straightforward. All that CARB would have to do is to require entities earning greenhouse gas credits under the LCFS for non-certified biodiesel blends to also report to CARB via the LRT how, when, and where mitigation of the NOx emissions associated with the use of that biodiesel via di-tert-butyl peroxide or low NOx diesel was achieved. Recordkeeping requirements analogous to those that already apply to data reported via the LRT would also apply to mitigation of biodiesel NOx impacts.

ADF B3-36

By following that approach, CARB staff can both ensure that there are no NOx increases associated with the use of biodiesel in California while simultaneously avoiding any need to involve retailers and marketers of biodiesel in the "impractical" activity described in the Staff Report unless those same retailers and marketers of biodiesel were earning greenhouse gas reduction credits from biodiesel under the LCFS. If the CARB Executive Officer or the staff disagrees with Growth Energy on this point, it is incumbent upon them to explain why and for the Board to give the public an opportunity to respond before CARB weighs the evidence and arguments, because this is an issue involving available and practical mitigation measures under CEQA.

ADF B3-37

---

[10] *See, e.g.*, Staff Report at 30.

[11] The most recent summary for the second quarter of 2013 is available at http://www.arb.ca.gov/fuels/lcfs/20130930_q2datasummary.pdf.

III. THE BOARD'S LEGAL OBLIGATIONS

The Court of Appeal clarified in *POET* that CARB is subject, among other provisions, to sections 15004 and 15352 of the CEQA Guidelines. The Court of Appeal also gave clear instructions about the need to comply with the rulemaking-file requirements of the Administrative Procedure Act. Perhaps most importantly, the Court of Appeal made plain the Board's duty to mitigate, in particular with respect to the subject of NOx exhaust emissions from engines operated on biodiesel. This final section of Growth Energy's comments summarizes the steps that CARB must take to meet its obligations under the governing statutes as clarified by the Court in *POET*, with primary emphasis on the duty to mitigate under CEQA.

A. Procedural and Structural Rulemaking Requirements

CARB must recognize that *any* communications it has received of a factual nature, or data that it has acquired in connection with regulatory action, are not exempt from the requirement to disclose those communications in the public rulemaking file under Gov't Code § 11347.3 (absent a valid and complete demonstration of privilege). *See POET*, 218 Cal. App. 4th at 741-754. At present, the rulemaking file for the ADF proposal cannot possibly be claimed to include all material required for the rulemaking file: Growth Energy knows this, because its own comments of September 16, 2013 (*see* Exhibit C) have not been placed in that file. As noted above, CARB has apparently not made full disclosure of all data relevant to the Durbin emissions study. (*See* p. 5 above.) Likewise, the Staff Report claims that the proposed ADF regulation "is based upon feedback from nearly every corner of the regulated industry as well as other impacted organizations and individuals that are impacted by actions concerning or that regulate the fuels industry."[12] The rulemaking file, when last checked in the week of

ADF B3-38

ADF B3-39

[12] Staff Report at 3-4.

December 2, 2013, did not contain any written comments reflecting that "feedback;" those materials should have been in the rulemaking file no later than October 15, 2013, when the public hearing on the proposed ADF regulation was announced. *See* Cal. Gov't Code § 11347.3(a), (b)(6), (7). ADF B3-39 cont.

Accordingly, one of the first steps that CARB must take in the current proceeding is to ensure compliance with section 11347.3 of the Government Code, and re-issue a notice of proposed rulemaking to allow 45 days of comment prior to a public hearing at which it would take action on a proposed ADF regulation. If CARB takes this action quickly, there will be no delay in program objections, including reconsideration of the LCFS standards during 2014. ADF B3-40

It is also clear from *POET* that, as CEQA and the guidelines direct, there are other reasons why CARB cannot take action with respect to the proposed ADF regulation. *See POET*, 218 Cal. App. 4th at 717-731. If CARB is the decision-maker with respect to the proposed ADF regulation, it must evaluate the environmental issues presented by the staff proposal for itself, and complete the environmental review process required under CEQA and CARB regulations, *before* the Board commits CARB to the proposed ADF regulation. Likewise, the opportunity to participate in the environmental analysis must be adequate -- which in this instance, it is not, in part because not all the relevant data has been publicly released. A comment deadline scarcely 45 days after the staff analysis has been released, when all relevant data have not been provided, will not permit an adequate environmental assessment. ADF B3-41

To comply with the procedural requirements of CEQA as confirmed in *POET*, CARB should direct the staff to complete the environmental review process (including full disclosure of the basis for its proposal); prepare a complete rulemaking file; respond to public comment; and publish a Final Statement of Reasons, before considering the proposed ADF regulation on its ADF B3-42 merits at a subsequent hearing. At that hearing, interested parties should be allowed all the time required to present and to respond to legitimate technical, empirically-based analysis of the environmental issues presented by the proposed ADF regulation. CARB can neither approve the proposed ADF regulation with the record in its current status and at the type of hearing planned for this week, nor defer the environmental assessment to a point after it has committed itself to the proposed regulation, nor delegate any of its CEQA responsibilities identified by the Court of Appeal in *POET*.

ADF B3-42 cont.

B. The Duty to Analyze Potential Impacts and Mitigate Significant Impacts

The importance of NOx emissions control for California air quality is well known and is illustrated, for example, by a June 2012 CARB Report entitled "Vision for Clean Air: A Framework for Air Quality and Climate Planning," prepared in conjunction with the South Coast Air Quality Management District and the San Joaquin Valley Unified Air Pollution Control District.[13] That report addressed potential control strategies that will be required to bring the only two areas of the country designated as being in extreme nonattainment of the National Ambient Air Quality Standard ("NAAQS") for ozone[14] into attainment. In working to identify potential control strategies, these three agencies chose to focus on ways to reduce NOx emissions (and not hydrocarbon emissions) because "NOx is the most critical pollutant for reducing regional ozone and fine particulate matter."[15] The report also identifies diesel-powered heavy-duty vehicles as the largest source of NOx emissions in California, and classifies diesel-powered

ADF B3-43

---

[13] *See* CARB, Vision for Clean Air: A Framework for Air Quality and Climate Planning (June 27, 2012) (available at http://www.arb.ca.gov/planning/vision/docs/vision_for_clean_air_public_review_draft.pdf).

[14] *See* http://www.epa.gov/airquality/ozonepollution/designations/2008standards/final/region9f.htm.

[15] *See* Vision for Clean Air at 10.

construction, mining and agricultural equipment as other significant sources of NOx emissions in California. ADF B3-43 cont.

As indicated above, CEQA requires that mitigation measures must be implemented locally and must be contemporaneous with the emissions events of concern; the type of statewide mitigation concept contained in the Staff Report, unbounded to relevant time intervals, does not comply with CEQA. It is therefore relevant to consider, by way of example, the heavy-duty diesel vehicle NOx emissions inventory for the South Coast and San Joaquin Valley areas during calendar years 2015 and 2020. On-road heavy-duty diesel emission estimates were developed using CARB's latest emission factor modeling software EMFAC2011.[16] The model estimates regional emissions, in tons/day, by vehicle class and model year. Emission estimates were computed for both older vehicles as well as vehicles using what CARB would consider to be NTDEs -- which in this case were assumed to be 2010 and later model-year vehicles. Emissions from off-road construction equipment were estimated using CARB's 2011 In-Use Inventory model.[17] Emissions from agricultural equipment were developed using CARB's OFFROAD2007 model because CARB's regulatory in-use inventory model is still under development for this sector.[18] For construction and agricultural equipment, NTDE vehicles were assumed to be those with engines certified to Tier 4 emission standards. It was assumed Tier 4 engines are used in 2013-and-later model year engines rated at or below 50 HP, 2014-and-later model year engines between 51 and 750 HP, and to 2015-and-later model years for engines ADF B3-44 cont.

[16] For more information on EMFAC2011 and to download modeling materials, *see* http://www.arb.ca.gov/msei/modeling.htm.

[17] For more information on CARB's off-road model, *see* http://www.arb.ca.gov/msei/categories.htm#offroad_motor_vehicles.

[18] Information about OFFROAD2007 and the pending in-use agricultural sector model can also be found at http://www.arb.ca.gov/msei/categories.htm#offroad_motor_vehicles.

above 750 HP. The resulting inventories are presented in Tables 1 and 2 for calendar years 2015 and 2020, respectively.

Table 1

2015 Heavy-Duty NOx Emission Inventories for the South Coast and San Joaquin Valley Air Basins (tons per day)

Air Basin	On-Road		Construction		Agricultural		Total
	Older	NTDE	Older	NTDE	Older	NTDE	
South Coast	117.27	14.91	24.04	0.42	3.92	0.26	160.82
San Joaquin	83.07	15.44	11.85	0.21	26.73	1.86	139.16

Table 2

2020 Heavy-Duty NOx Emission Inventories for the South Coast and San Joaquin Valley Air Basins (tons per day)

Air Basin	On-Road		Construction		Agricultural		Total
	Older	NTDE	Older	NTDE	Older	NTDE	
South Coast	66.53	28.44	20.0	1.8	2.2	0.5	119.47
San Joaquin	32.13	30.33	11.5	1.0	15.0	3.8	93.76

Tables 1 and 2 show that vehicles with NTDEs account for only about 10% of NOx emissions in 2015 and between 25% and 40% of NOx emissions in 2020. Therefore, even if the CARB staff's assertion that biodiesel does not increase emissions from NTDEs were correct, the majority of NOx emissions would still be coming from older engines where, it has been clearly demonstrated, NOx emissions increase with the use of higher biodiesel blends. Applying the estimated NOx increases developed from the available emissions data analyzed by CARB staff (*see* Lyons Decl. ¶ 9, Table 1), and assuming more realistically and conservatively (as CEQA requires) that NTDEs will be affected by biodiesel in the same way as other engines, the overall increases in NOx emissions caused by biodiesel use will be (i) between 0.7 and 1.6 tons per day

ADF B3-44 cont.

in 2015 and between 0.5 and 1.2 tons per day in 2020 in the South Coast, and (ii) between 0.6 and 1.4 tons per day in 2015 and between 0.4 and 0.9 tons per day in 2020 in the San Joaquin Valley. ADF B3-44 cont.

One way to put the magnitude of these potential increases in NOx emissions into context is to compare them with the air quality significance thresholds applied by the South Coast Air Quality Management District[19] and the San Joaquin Valley Air Pollution Control District[20] when evaluating the potential emission impacts of proposed projects in their jurisdictions. In the San Joaquin Valley Air Pollution Control District, the threshold is 10 tons per year while in the South Coast basin, the threshold is 0.0275 tons per day which equals 10 tons per year if daily emissions occurring over the course of the year are equal. The potential 2015 emission increases from the use of five percent biodiesel blends in the South Coast and the San Joaquin Valley are ***25 to 60 times higher*** than the 10-ton-per-year threshold. Even with reductions in diesel NOx emissions by 2020, the potential NOx increases due to biodiesel remains ***15 to 40 times higher*** than the 10-ton-per-year threshold. Potential increases of NOx emissions on such a scale require mitigation at the time and in the place where they will occur. *See POET*, 218 Cal. App. 4th at 740 (under CEQA, "ARB must adopt mitigation measures that minimize the adverse impact" of a potential increase in NOx emissions). Moreover, despite the fact that increases of NOx emissions resulting from the proposed ADF regulation would significantly exceed thresholds adopted by the South Coast Air Quality Management District and the San Joaquin Valley Air Pollution Control District, the ISOR fails to analyze whether the proposed ADF regulation has the potential to conflict with, or obstruct, applicable air quality plans. ADF B3-45

---

[19] *See* http://www.aqmd.gov/ceqa/handbook/signthres.pdf.

[20] *See* http://www.valleyair.org/transportation/CEQA%20Rules/GAMAQI%20Jan%202002%20Rev.pdf.

There is no question that an increase in biodiesel usage will occur as a result of the LCFS regulation, a measure adopted under the Global Warming Solutions Act. *See POET*, 218 Cal. App. 4th at 700-01. Consequently, under not only CEQA, but also the Global Warming Solutions Act, CARB cannot permit emissions increases from biodiesel of such a magnitude when both the South Coast Air Quality Management District's 2012 Air Quality Management Plan[21] and the San Joaquin Valley's 2013 One Hour Ozone Plan[22] contain control measures intended to reduce NOx emissions by amounts of about the same magnitude as the potential emission increases resulting from biodiesel use at the five percent level. *See* Cal Health & Safety Code § 38562(b)(4) (greenhouse gas control measures such as the LCFS regulation are not to "interfere with ... efforts to achieve and maintain federal and state ambient air quality standards."). ADF B3-45

IV. CONCLUSION

For the reasons explained above and in the reports and analyses accompanying these Comments, CARB cannot lawfully approve the proposed ADF regulation at this week's public hearing. CARB cannot commit itself now to the proposed ADF regulation and adjourn the important task of environmental assessment to a post hoc process. The available emissions data do not support, and indeed refute, the CARB staff's claim that low-level biodiesel blends are benign. Mitigation is required, and is required at the time and in the places where the NOx emissions increases can be expected to occur. If CARB directs the staff to make straightforward changes in the proposed ADF regulation in a timely manner that will require feasible mitigation ADF B3-46

[21] *See* South Coast Air Quality Management District, 2012 Air Quality Management Plan, 2012 AQMP CARB/EPA/SIP Submittal (Dec. 2012) (available at http://www.aqmd.gov/aqmp/2012aqmp/Final/index.html).

[22] *See* http://www.valleyair.org/Air_Quality_Plans/Ozone-OneHourPlan-2013.htm.

measures, there will be no jeopardy to any program objective of the Global Warming Solutions Act or any other CARB project.

Respectfully submitted,

GROWTH ENERGY

12_B_LCFS_GE Responses (Page 141 – 166)

708. Comment: **ADF B3-11 through ADF B3-13, ADF B3-15, ADF B3-18, ADF B3-19, ADF B3-25 through ADF B3-30, and ADF B3-35 through ADF B3-42**

Agency Response: This comment is responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

709. Comment: **ADF B3-3 through ADF B3-10, B3-14, ADF B3-16, B3-17, ADF B3-20 through ADF B3-24, ADF B3-31 through ADF B3-34, and ADF B3-43 through ADF B3-46**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

EXHIBIT A

NOx Emissions Impact of Soy- and Animal-based Biodiesel Fuels: A Re-Analysis

December 10, 2013

Prepared for:

Sierra Research
1801 J Street
Sacramento, CA 95811

Prepared by:

Robert Crawford
Rincon Ranch Consulting
2853 South Quail Trail
Tucson, AZ 85730-5627
Tel 520-546-1490

NOX EMISSIONS IMPACT OF SOY- AND ANIMAL-BASED BIODIESEL FUELS: A RE-ANALYSIS

prepared for:

Sierra Research, Inc.

December 10, 2013

prepared by:

Robert Crawford
Rincon Ranch Consulting
2853 South Quail Trail
Tucson, AZ 85730-5627
Tel 520-546-1490

NOX IMPACT OF SOY- AND ANIMAL-BASED BIODIESEL FUELS: A RE-ANALYSIS

Table of Contents

List of Tables

List of Figures

1. EXECUTIVE SUMMARY

1.1 Background on the Proposed Rule

The California Air Resources Board (CARB) has proposed regulations on the commercialization of alternative diesel fuel (ADF) that were to be heard at the December 2013 meeting of the Board. The proposed regulations seek to "... create a streamlined legal framework that protects California's residents and environment while allowing innovative ADFs to enter the commercial market as efficiently is possible."[1] In this context ADF refers to biodiesel fuel blends. Biodiesel fuels are generally recognized to have the potential to decrease emissions of several pollutants, including hydrocarbons (HC), carbon monoxide (CO), and particulate matter (PM), but are also recognized to have the potential to increase oxides of nitrogen (NOx) unless mitigated in some way. NOx emissions are an important precursor to smog and have historically been subject to stringent emission standards and mitigation programs to prevent growth in emissions over time. A crucial issue with respect to biodiesel is how to "... safeguard against potential increases in oxides of nitrogen (NOx) emissions."[2]

The proposed regulations are presented in the Staff Report: Initial Statement of Reasons (ISOR) for the Proposed Regulation on the Commercialization of New Alternative Diesel Fuels[3] (referenced as ISOR). Chapter 5 of the document describes the proposed regulations, which exempt diesel blends with less than 10 percent biodiesel (B10) from requirements to mitigate NOx emissions:

> There are two distinct blend levels relative to biodiesel that have been identified as important for this analysis. Based on our analysis to date, we have found that diesel blends with less than 10 percent biodiesel by volume (<B10) have no significant increase in any of the pollutants of concern and therefore will be regulated at Stage 3B (Commercial Sales not Subject to Mitigation). However, we have found that biodiesel blends of 10 percent and above (≥B10) have potentially significant increases in NOx emissions, in the absence of any mitigating factors, and therefore those higher blend levels will be regulated under Stage 3A (Commercial Sales Subject to Mitigation).[4]

---

[1] "Notice of Public Hearing to Consider Proposed Regulation on the Commercialization of New Alternative Diesel Fuels." California Air Resources Board, p. 3. http://www.arb.ca.gov/regact/2013/adf2013/adf2013notice.pdf.

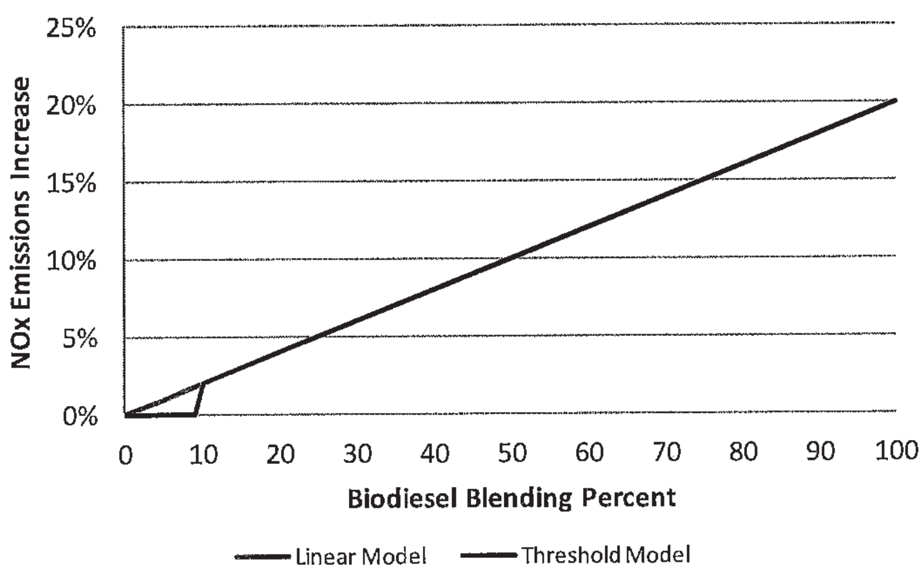
[2] Ibid. p. 3.

[3] "Proposed Regulation on the Commercialization of New Alternative Diesel Fuels. Staff Report: Initial Statement of Reason." California Air Resources Board, Stationary Source Division, Alternative Fuels Branch. October 23, 2013. http://www.arb.ca.gov/regact/2013/adf2013/adf2013isor.pdf.

[4] Ibid, p. 22.

Existing research on the NOx emission effects of biodiesel has consistently been conducted under the hypothesis that the emission effect will be linearly proportional to the blending percent of neat biodiesel (B100) with the base diesel fuel. The Linear Model that has been accepted by researchers is shown as the blue line in Figure 1-1. The Staff position cited above is that biodiesel fuels do not increase NOx emissions until the fuel blend reaches 10% biodiesel. This so-called Staff Threshold Model departs from the Linear Model that underlies past and current biodiesel research by claiming that NOx emissions do not increase until the biodiesel content reaches 10 percent. ADF B3-46 cont.

Figure 1-1
Linear and Staff Threshold Models for Biodiesel NOx Impacts



The Staff Threshold model is justified by the statement: "Based on our analysis to date, we have found that diesel blends with less than 10 percent biodiesel by volume (<B10) have no significant increase in any of the pollutants of concern." Other portions of the ISOR state that Staff will track "... the effective blend level on an annual statewide average basis until the effective blend level reaches 9.5 percent. At that point, the biodiesel producers, importers, blenders, and other suppliers are put on notice that the effective blend-level trigger of 9.5 percent is approaching and mitigation measures will be required once the trigger is reached."[5] Until such time, NOx emission increases from biodiesel blends below B10 will not require mitigation.

Section 6 of the ISOR presents a Technology Assessment that includes a literature search the Staff conducted to obtain past studies on the NOx impact of biodiesel in heavy-duty ADF B3-47

[5] Ibid, p. 24.

engines using California diesel (or other high-cetane diesel) as a base fuel. Section 6.d presents the results of the literature search with additional technical information provided in Appendix B. The past studies include the Biodiesel Characterization and NOx Mitigation Study[6] sponsored by CARB (referenced as Durbin 2011).

The results of the Staff literature search are summarized in Table 1-1, which has been reproduced from Table 6.1 of the ISOR. For B5 and B20, the data represent averages for a mix of soy- and animal-based biodiesels, which tend to have different impacts on NOx emissions (animal-based biodiesels increase NOx to a lesser extent). For B10, the data represent an average for soy-based biodiesels only. Staff uses the +0.3% average NOx increase at B5 in comparison to the 1.3% standard deviation to conclude:

> Overall, the testing indicates different NOx impacts at different biodiesel percentages. Staff analysis shows there is a wide statistical variance in NOx emissions at biodiesel levels of B5, providing no demonstrable NOxemissions impact at this level and below. Atbiodiesel levels of B10 and above, multiple studies demonstrate statistically significant NOx increases, without additional mitigation.[7]

Table 1-1
Results of Literature Search Analysis

Biodiesel Blend Level	NOx Difference	Standard Deviation
B5	0.3%	1.3%
B10[a]	2.7%	0.2%
B20	3.2%	2.3%

Source: Table 6.1 of Durbin 2011
Notes:
[a] Represents data using biodiesel from soy feedstocks.

ADF B3-47 cont.

The Staff conclusion is erroneous because it relies upon an apples-to-oranges comparison among the blending levels. Each of the B5, B10, and B20 levels include data from a different mix of studies, involving different fuels (soy- and/or animal-based), different test engines, and different test cycles. The B5 values come solely from the CARB Biodiesel Characterization study, while the B10 values come solely from other studies. The B20 values are a mix of data from the CARB and other studies. The results seen in the table above are the product of the uncontrolled aggregation of different studies that produces incomparable estimates of the NOx emission impact at the three blending levels.

[6] "CARB Assessment of the Emissions from the Use of Biodiesel as a Motor Vehicle Fuel in California: Biodiesel Characterization and NOx Mitigation Study." Prepared by Thomas D. Durbin, J. Wayne Miller and others. Prepared for Robert Okamoto and Alexander Mitchell, California Air Resources Board. October 2011.
[7] ISOR, p. 32.

As will be demonstrated in this report, the Staff conclusion drawn from the data in Table 1-1 is not supported by past or current biodiesel research, including the recent testing program sponsored by CARB. In fact, past and current studies indicate that biodiesel blends at any level will increase NOx emissions in proportion to the blending percent unless specifically mitigated by additives or other measures. ADF B3-47 cont.

1.2 Summary and Conclusions

The following sections of this report examine the studies cited by CARB one-by-one. As evidenced from this review, it is clear that the data do not support the Staff conclusion and, indeed, the data refute the Staff conclusion in some instances. Specifically:

- There is no evidence supporting the Staff conclusion that NOx emissions do not increase until the B10 level is reached. Instead, there is consistent and strong evidence that biodiesel increases NOx emissions in proportion to the biodiesel blending percent. ADF B3-48

- There is clear and statistically significant evidence that biodiesel increases NOx emissions at the B5 level in at least some engines for both soy- and animal-based biodiesels. ADF B3-49

Considering each of the six past studies obtained from the technical literature and their data on high-cetane biodiesels comparable to California fuels, we find the following:

1. None of the six studies measured the NOx emissions impact from biodiesel at blending levels below B10. Only two studies tested a fuel at the B10 level. All other testing was at the B20 level or higher. Because none tested a B5 (or similar) fuel, none of them can provide direct evidence that NOx emissions are not increased at B5 or other blending levels below B10. ADF B3-50

2. These studies provide no data or evidence supporting the validity of the Staff's Threshold Model that biodiesel below B10 does not increase NOx emissions. In fact, all of the studies are consistent with the contention that biodiesel increases NOx emissions in proportion to the blending percent. ADF B3-51

3. Two of the studies present evidence and arguments that the NOx impact from biodiesel is a continuous effect that is present even at very low blending levels and will increase at higher levels in proportion to the blending percentage. ADF B3-52

Considering the CARB Biodiesel Characterization report, we find that:

4. For the three engines where CARB has published the emission values measured in engine dynamometer testing, all of the data demonstrate that biodiesel fuels significantly increase NOx emissions for both soy- and animal-based fuels by amounts that are proportional to the blending percent. This is true for on-road and off-road engines and for a range of test cycles. ADF B3-53

5. Where B5 fuels were tested for these engines, NOx emissions were observed to increase. NOx emission increases are smaller at B5 than at higher blending levels and the observed increases for two engines were not statistically significant by themselves based on the pair-wise t-test employed in Durbin 2011.[8] However, the testing for one of the engines (the 2007 MBE4000) showed statistically significant NOx emission increases at the B5 level for <u>both</u> soy- and animal-based blends. ADF B3-54

By itself, <u>the latter result is sufficient to disprove the Staff's contention that biodiesel blends at the B5 level will not increase NOx emissions</u>.

Based on examination of all of the studies cited by CARB as the basis for its proposal to exempt biodiesels below B10 from mitigation, it is clear that the available research points to the expectation that both soy- and animal-based biodiesel blends will increase NOx emissions in proportion to their biodiesel content, including at the B5 level. <u>CARB's own test data demonstrate that B5 will significantly increase NOx emissions in at least some engines</u>. ADF B3-55

Based on data in the CARB Biodiesel Characterization report, soy-based biodiesels will increase NOx emissions by about 1% at B5 (and 2% at B10), while animal-based biodiesels will increase NOx emissions by about one-half as much: 0.45% at B5 (and 0.9% at B10). <u>All of the available research says that the NOx increases are real and implementation of mitigation measures will be required to prevent increases in NOx emissions due to biodiesel use at blending levels below B10</u>. ADF B3-56

Finally, we note that CARB has not published fully the biodiesel testing data that it relied on in support of the Proposed Rule and thereby has failed to adequately serve the interest of full public disclosure in this matter. The CARB-sponsored testing reported in Durbin 2011 is the sole source of B5 testing cited by CARB as support for the Proposed Rule. Durbin 2011 publishes only portions of the measured emissions data in a form that permits re-analysis; it does not publish any of the B5 data in such a form. It has not been possible to obtain the remaining data through a personal request to Durbin or an official public records request to CARB and, to the best of our knowledge, the data are not otherwise available online or through another source. ADF B3-57

CARB should publish all of the testing presented in Durbin 2011 and any future testing that it sponsors in a complete format that allows for re-analysis. Such a format would be (a) the measured emission values for each individual test replication; or (b) averages across all test replications, along with the number of replications and the standard error of the individual tests. The first format (individual test replications) is preferable because that would permit a full examination of the data including effects such as test cell drift over time. Such publication is necessary to assure that full public disclosure is achieved and that future proposed rules are fully and adequately informed by the data. ADF B3-58

---

[8]As discussed in Section 3.3, the pair-wise t-test is not the preferred method for demonstrating statistical significance.

1.3 Review of 2013 CARB B5 Emission Testing

In December 2013, after the release of the ISOR and in response to an earlier Public Records Act request, CARB released a copy of new CARB-sponsored emission testing conducted by Durbin and others at the University of California CE-CERT[9]. The purpose of the study was "... to evaluate different B5 blends as potential emissions equivalent biodiesel fuel formulations for California."[10] Three B5 blends derived from soy, waste vegetable oil (WVO), and animal biodiesel stocks were tested on one 2006 Cummins ISM 370 engine using the hot-start EPA heavy-duty engine dynamometer cycle. A preliminary round of testing was conducted for all three fuels followed by emissions-equivalent certification testing per 13 CCR 2282(g) for two of the fuels. As noted by Durbin: "[t]he emissions equivalent diesel certification procedure is robust in that it requires at least twenty replicate tests on the reference and candidate fuels, providing the ability to differentiate small differences in emissions."[11]

Soy and WVO B5 Biodiesel

The B5-soy and B5-WVO fuels were blended from biodiesel stocks that were generally similar to the soy-based stock used in the earlier CARB Biodiesel Characterization Study (Durbin 2011) with respect to API gravity and cetane number. In the preliminary testing, the two fuels "...showed 1.2-1.3% statistically significant [NOx emissions] increases with the B5-soy and B5-WVO biodiesel blends compared to the CARB reference fuel."[12] The B5-WVO fuel caused the smaller NOx increase (1.2%) and was selected for the certification phase of the testing. There, it "... showed a statistically significant 1.0% increase in NOx compared to the CARB reference fuel"[13] and failed the emissions-equivalent certification due to NOx emissions. ADF B3-59

Animal B5 Biodiesel

The B5-animal derived fuel was blended from an animal tallow derived biodiesel that was substantially different from the animal based biodiesel used in the earlier Durbin study, and was higher in both API gravity and cetane number. The blending response for cetane number was also surprising, in that blending 5 percent by volume of a B100 stock (cetane number 61.1) with 95% of CARB ULSD (cetane number 53.1) produced a B5 fuel blend with cetane number 61. ADF B3-60

In preliminary testing, the B5-animal fuel showed a small NOx increase which was not statistically significant, causing it to be judged the best candidate for emissions-equivalent certification. In the certification testing, it "...showed a statistically ADF B3-61

[9] "CARBB5 Biodiesel Preliminary and Certification Testing." Prepared by Thomas D. Durbin, G. Karavalakis and others. Prepared for Alexander Mitchell, California Air Resources Board. July 2013. This study is not referenced in the ISOR, nor was it included in the rule making file when the hearing notice for the ADF regulation was published in October 2013.
[10] Ibid, p. vi.
[11] Ibid, p. viii.
[12] Ibid, p. 8.
[13] Ibid, p. 9.

significant 0.5% reduction in NOx compared to the CARB reference fuel"[13] and passed the emissions-equivalent certification. The NOx emission reduction for this fuel blend appears to be real for this engine, but given the differences between the blendstock and the animal based biodiesel blendstock used in the earlier Durbin study it is unclear that it is representative for animal-based biodiesels in general.. ADF B3-61 cont.

Summary

The conclusions drawn in the preceding section are not changed by the consideration of these new emission testing results. For plant-based biodiesels (soy- and WVO-based), the new testing provides additional and statistically significant evidence that B5 blends will increase NOx emissions at the B5 level. The result of decreased NOx for the B5 animal-based blend stands out from the general trend of research results reviewed in this report. However:

- The same result – reduced NOx emissions for some fuels and engines – has sometimes been observed in past research, as evidenced by the emissions data considered by CARB staff in ISOR Figure B.3 (reproduced in Figure 2.1 below). As shown, some animal-based B5 and B20 fuels reduced NOx emissions while others increased NOx emissions with the overall conclusion being that NOx emissions increase in direct proportion to biodiesel content of the blends and that there is no emissions threshold. ADF B3-62 cont.

- Increasing cetane is known to generally reduce NOx emissions and has already been proposed by CARB as a mitigation strategy for increased NOx emissions from biodiesel[14]. The unusual cetane number response in the blending and the high cetane number of the B5-animal fuel may account for the results presented in the recently released study.

Considering the broad range of plant- and animal-based biodiesel stocks that will be used in biodiesel fuels, we conclude that the available research (including the recently released CARB test results) indicates that unrestricted biodiesel use at the B5 level will cause real increases in NOx emissions and that countermeasures may be required to prevent increases in NOx emissions due to biodiesel use at blending levels below B10.

###

[14] For example, see Durbin 2011 Section 7.0 for a discussion of NOx mitigation results through blending of cetane improvers and other measures.

2. CARB LITERA TURE REVIEW

The Staff ISOR explains that the Appendix B Technology Assessment is the basis for CARB's conclusion that biodiesels below B10 have no significant impact on NOx emissions. The assessment is based on data from seven studies (identified in Table 2-1) that tested high-cetane diesel fuels. The first study (Durbin 2011) is the Biodiesel Characterization Study that was conducted for CARB, while the others were obtained through a literature search.

Table 2-1
List of Studies from High-Cetane Literature Search

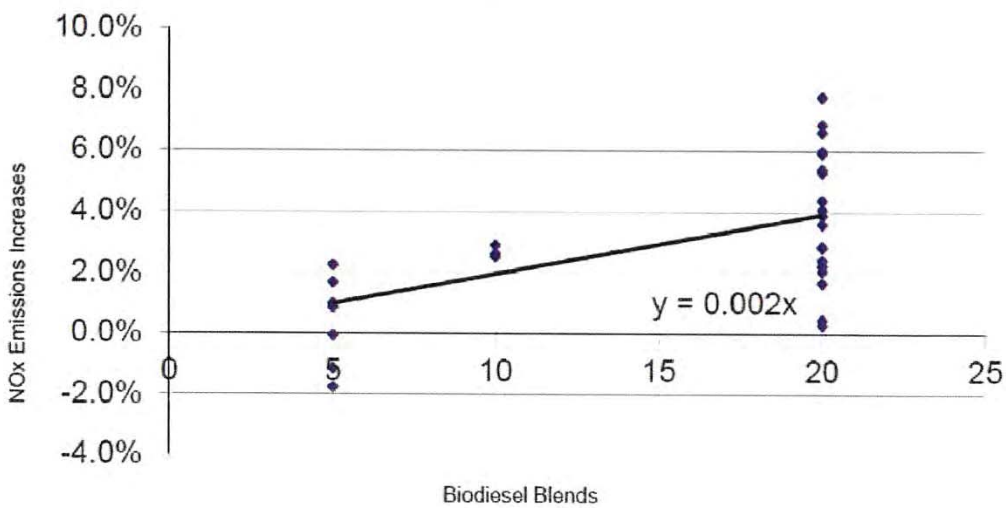
Primary Author	Title	Published	Year
Durbin	Biodiesel Mitigation Study	Final Report Prepared for Robert Okamoto, M.S. and Alexander Mitchell, CARB	2011
Clark	Transient Emissions Comparisons of Alternative Compression Ignition Fuel	SAE 1999-01-1117	1999
Eckerle	Effects of Methyl Ester Biodiesel Blends on NOx Emissions	SAE 2008-01-0078	2008
McCormick	Fuel Additive and Blending Approaches to Reducing NOx Emissions from Biodiesel	SAE 2002-01-1658	2002
McCormick	Regulated Emissions from Biodiesel Tested in Heavy-Duty Engines Meeting 2004 Emissions	SAE 2005-01-2200	2005
Nuszkowski	Evaluation of the NOx emissions from heavy duty diesel engines with the addition of cetane improvers	Proc. I Mech E Vol. 223 Part D: J. Automobile Engineering, 223, 1049-1060	2009
Thompson	Neat fuel influence on biodiesel blend emissions	Int J Engine Res Vol. 11, 61-77.	2010

Source: Table B.2 of Durbin 2011

Figure 2-1 reproduces two exhibits from Appendix B that show increasing trends for NOx emissions with the biodiesel blending level. Based on the slopes of the trend lines,

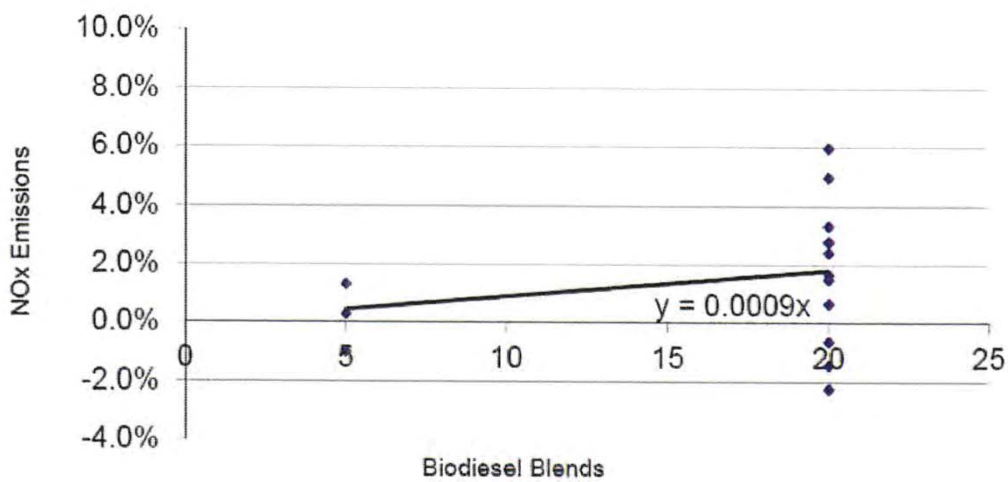
Figure 2-1
NOx Emission Increases Observed in Biodiesel Research Cited in Staff ISOR

Figure B.2: NOx Impact of Soy Biodiesel Blended in High Cetane Base Fuel



ADF B3-63

Figure B.3: NOx Impact of Animal Biodiesel Blended in High Cetane Base Fuel



Source: Figures B.2 and B.3 of Appendix B: Technology Assessment soy-based biodiesels are shown to increase NOx emissions by approximately 1% at B5, 2% at B10, and 4% at B20. Animal-based biodiesels are shown to increase NOx emissions by about one-half as much: 0.45% at B5, 0.9% at B10, and 1.8% at B20. Although there is substantial scatter in the results, these data do not appear to support the Staff Threshold Model that biodiesel does not increase NOx emissions at B5 but does so at B10. ADF B3-63 cont.

We will examine the Durbin 2011 study at some length in Section 3. In this section, we look at each of the other studies cited by the Staff to find out what the studies say about NOx emissions impacts at and below B10.

2.1 Review of Literature Cited in the ISOR

The Staff literature search sought and selected testing that used fuels with cetane levels comparable to California diesel fuels; the Staff does not, however, list those fuels or provide the data that support the tables and figures in Appendix B of the ISOR. Therefore, we have necessarily made our own selection of high-cetane fuels in the course of reviewing the studies. The key testing and findings of each study are summarized below, with a specific focus on what they tell us about NOx emission impacts at B10 and below.

2.1.1 Clark 1999

This study tested a variety of fuels on a 1994 7.3L Navistar T444E engine. Of the high-cetane base fuels, one base fuel (Diesel A, off-road LSD) was blended and tested at levels of B20, B50, and B100. NOx emissions were significantly increased for all of the blends. The other base fuel (CA Diesel) was tested only as a base fuel. Its NOx emissions were 12% below that of Diesel A, making it is unclear whether Diesel A is representative of fuels in CA. This study conducted no testing of the NOx emissions impact from biodiesels at the B10 level or below.

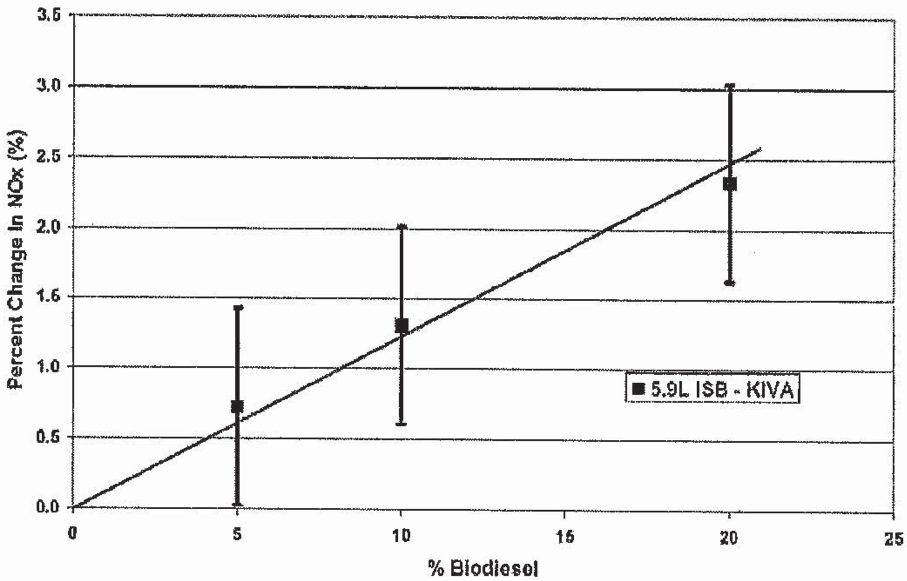
2.1.2 Eckerle 2008

This study tested low and mid/high-cetane base fuels alone and blended with soy-based biodiesel at the B20 level. The Cummins single-cylinder test engine facility was used in a configuration representative of modern diesel technology, including cooled EGR. Testing was conducted under a variety of engine speed and load conditions. FTP cycle emissions were then calculated from the speed/load data points. The test results show that B20 blends increase NOx emissions compared to both low- and high-cetane base fuels. This study conducted no testing of the NOx emissions impact from biodiesels at the B10 level or below. ADF B3-64

The study notes that two other studies "show that NOx emissions increase nearly linearly with the increase in the percentage of biodiesel added to diesel fuel." Eckerle's Figure 21 (reproduced below as Figure 2-2) indicates a NOx emissions increase at B5, which is the basis for the statement in the abstract that "Results also show that for biodiesel blends containing less than 20% biodiesel, the NOx impact over the FTP cycle is proportional to

the blend percentage of biodiesel." The authors clearly believe that biodiesel fuels have NOx emission impacts proportional to the blending percent at all levels including B5.

Figure 2-2
Impact of Biodiesel Blends on Percent NOx Change for the 5.9L ISB Engine Operation Over the FTP Cycle



Source: Figure 21 of Eckerle 2008

ADF B3-64 cont.

2.1.3 <u>McCormick 2002</u>

This study tested low- and mid-cetane base fuels alone and blended with soy- and animal-based biodiesel at the B20 level. The testing was conducted on a 1991 DDC Series 60 engine using the hot-start U.S. heavy-duty FTP. NOx emission increases were observed for both fuels at the B20 level. Mitigation of NOx impacts was investigated by blending a Fisher-Tropsch fuel, a 10% aromatics fuel and fuel additives. <u>This study conducted no testing of the NOx emissions impact from commercial biodiesels at the B10 level or below.</u>

ADF B3-65

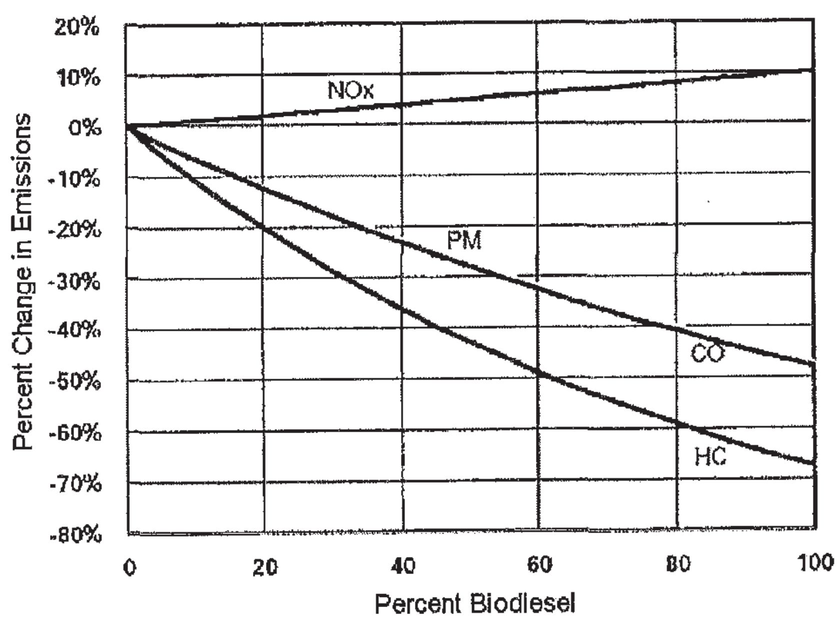
This study also tested a Fisher-Tropsch (FT) base fuel blended at the B1, B20, and B80 levels. Although the very high cetane number ($\geq$75) takes it out of the range of commercial diesel fuels, it is interesting to note that the study measured higher NOx emissions at the B1 level than it did on the FT base fuel and substantially higher NOx emissions at the B20 and B80 levels. While the B1 increase was not statistically significant given the uncertainties in the emission measurements (averages of three test runs), <u>it is clear that increased NOx emissions have been observed at very low blending levels.</u>

2.1.4 McCormick 2005

This study tested blends of soy- and animal-based biodiesels with a high-cetane ULSD base fuel at B10 levels and higher. Two engines were tested -- a 2002 Cummins ISB and a 2003 DDC Series 60, both with cooled EGR. The hot-start U.S. heavy-duty FTP test cycle was used. The majority of testing was at the B20 level with additional testing at the B50 and B100 levels. One soy-based fuel was tested at B10. The study showed NOx emission increases at B10, B20, and higher levels. The study also investigated mitigation of NOx increases. This study conducted no testing of the NOx emissions impact from biodiesels below the B10 level.

The authors present a figure (reproduced as Figure 2-3) in their introduction that shows their summary of biodiesel emission impacts based on an EPA review of heavy-duty engine testing. It shows NOx emissions increasing linearly with the biodiesel blend percentage.

Figure 2-3
Trend in HC, CO, NOx and PM Emissions with Biodiesel Percent



Source: McCormick 2005

ADF B3-66

2.1.5 Nuszkowski 2009

This study tested five different diesel engines: one 1991 DDC Series 60, two 1992 DDC Series 60, one 1999 Cummins ISM, and one 2004 Cummins ISM. Only the 2004 Cummins ISM was equipped with EGR. All testing was done using the hot-start U.S. heavy-duty FTP test cycle. The testing was designed to test emissions from fuels with and without cetane-improving additives. Although a total of five engines were tested, the base diesel and B20 fuels were tested on only two engines (one Cummins and one DDC Series 60) because there was a limited supply of fuel available. NOx emissions increased on the B20 fuel for both engines. A third engine (Cummins) was tested on B20 and B20 blended with cetane improvers to examine mitigation of NOx emissions. This study conducted no testing of the NOx emissions impact from biodiesels at the B10 level or below. ADF B3-67

2.1.6 Thompson 2010

This study examined the emissions impacts of soy-based biodiesel at the B10 and B20 levels relative to low-cetane (42), mid-cetane (49), and high-cetane (63) base fuels using one 1992 DDC Series 60 engine. The emissions results were measured on the hot-start U.S. heavy-duty FTP cycle. The study found that NOx emissions were unchanged (observed differences were not statistically significant) at B10 and B20 levels for the low- and mid-cetane fuels. NOx emissions increased significantly at B10 and B20 levels for the high-cetane fuels. This study conducted no testing of the NOx emissions impact from biodiesels at levels below B10. ADF B3-68

2.2 Conclusions Based on Studies Obtained in Literature Search

From the foregoing summary of the studies cited by Staff, we reach the conclusions given below.

1. None of the six studies measured the NOx emissions impact from commercial-grade biodiesel at blending levels below B10, and only two studies tested a fuel at the B10 level. All other testing was at the B20 level or higher. Because none tested a B5 (or similar) fuel, none is capable of providing direct evidence regarding NOx emissions at B5 or other blending levels below B10. ADF B3-69

2. These studies provide no data or evidence supporting the validity of Staff's Threshold Model that biodiesel below B10 does not increase NOx emissions. In fact, all of the studies are consistent with the contention that biodiesel increases NOx emissions in proportion to the blending percent. ADF B3-70

3. Two of the studies present evidence and arguments that the NOx impact from biodiesel is a continuous effect that is present even at very low blending levels and will increase at higher levels in proportion to the blending percentage. One study tested a Fischer-Tropsch biodiesel blend at B1 and observed NOx emissions to increase (but not by a statistically significant amount). ADF B3-71

###

3. CARB BIODIESEL CHARACTERIZATION STUDY

3.1 Background

CARB sponsored a comprehensive study of biodiesel and other alternative diesel blends in order "... to better characterize the emissions impacts of renewable fuels under a variety of conditions."[15] The study was designed to test eight different heavy- duty engines or vehicles, including both highway and off-road engines using engine or chassis dynamometer testing. Five different test cycles were used: the Urban Dynamometer Driving Schedule (UDDS), the Federal Test Procedure (FTP), and 40 mph and 50 mph CARB heavy-heavy-duty diesel truck (HHDDT) cruise cycles, and the ISO 8178 (8 mode) cycle. Table 3-1 (reproduced from Table ES-1 of Durbin 2011) documents the scope of the test program. Because the Staff relied only on engine dynamometer testing in its Technology Assessment, only the data for the first four engines (shaded) are considered here.

Table 3-1
A Breakdown of the Test Engines for the Different Categories of Testing

2006 Cummins ISM[a]	Heavy-duty on-highway	Engine dynamometer	
2007 MBE4000	Heavy-duty on-highway	Engine dynamometer	
1998, 2.2 liter, Kubota V2203-DIB	Off-road	Engine dynamometer	
2009 John Deere 4.5 L	Off-road	Engine dynamometer	
2000 Caterpillar C-15	Heavy-duty on-highway	Chassis dynamometer	Freightliner chassis
2006 Cummins ISM	Heavy-duty on-highway	Chassis dynamometer	International chassis
2007 BME4000	Heavy-duty on-highway	Chassis dynamometer	Freightliner chassis
2010 Cummins ISX15	Heavy-duty on-highway	Chassis dynamometer	Kenworth chassis

Source: Table ES-1 of Durbin 2011, page xxvi
Notes:
[a] Data for the first four engines (shaded) are considered in this report.

[15] Durbin 2011, p. xxiv.

The original goal of this report was to subject all of the NOx emission testing in Durbin 2011 to a fresh re-analysis. However, it was discovered that Durbin 2011 did not report all of the data that were obtained during the program and are discussed in the report. The chassis dynamometer testing was conducted at the CARB Los Angeles facility. Emission results for the chassis dynamometer testing are presented in tabular and graphical form, but the report does not contain the actual emissions test data. For the engine dynamometer testing, some of the measured emission values are not reported even though the emission results are reported in tabulated or graphical form. Requests for the missing data were directed to Durbin in a personal request and to CARB through an official records request. No information has been provided in response and we have not been able to obtain the missing data from online or other sources. ADF B3-72

For this report, we have worked with the data in the forms that are provided in Durbin 2011 as being the best-available record of the results of the CARB study. Because Staff used only data obtained in engine dynamometer testing, the analysis presented in this report has done the same. Nevertheless, the results of the chassis dynamometer testing are generally supportive of the results and conclusions presented here. Durbin 2011 notes:

> "... The NOx emissions showed a consistent trend of increasing emissions with increasing biodiesel blend level. These differences were statistically significant or marginall y significant for nearly all of the test sequences for the B50 and B100 fuels, and for a subset of the tests on the B20 blends."[16]

Durbin notes that emissions variability was greater in the chassis dynamometer testing, which leads to the sometimes lower levels of statistical significance. There was also a noticeable drift over time in NOx emissions that complicated the results for one engine.

3.2 Data and Methodology

Table 3-2 compiles descriptive information on the engine dynamometer testing performed in Durbin 2011. The experimental matrix involves four engines, two types of biodiesel fuels (soy- and animal-based), and up to four test cycles per engine. However, the matrix is not completely filled with all fuels tested on all engines on all applicable test cycles. The most complete testing is for the ULSD base fuel and B20, B50, and B100 blends. There is less testing for the B5 blend, and B5 is tested using only a subset of cycles. For this reason, we first examine the testing for ULSD, B20, B50, and B100 fuels to determine the overall impact of biodiesels on NOx emissions. We then examine the more limited testing for B5 to determine the extent to which it impacts NOx emissions.

This examination is limited by the form in which emissions test information is reported in Durbin 2011. A complete statistical analysis can be conducted only for the two on-road engines for which Appendices G and H of Durbin 2011 provide measured emissions, and for a portion of the testing of the Kubota off-road engine for which Appendix I provides

[16] Durbin 2011, p. 126.

Table 3-2 Experimental Matrix for Heavy-Duty Engine Dynamometer Testing Reported in Durbin 2011				
Engine	Biodiesel Type	Fuels Tested	Test Cycles	Notes
On-Road Engines				
2006 Cummins ISM	Soy	ULSD, B20, B50, B100, B5	UDDS, FTP, 40 mph, 50 mph	B5 tested on 40 mph and 50 mph cruise cycles
	Animal	ULSD, B20, B50, B100, B5	UDDS, FTP, 50 mph	B5 tested only on FTP.
2007 MBE4000	Soy	ULSD, B20, B50, B100, B5	UDDS, FTP, 50 mph	B5 tested only on FTP.
	Animal	ULSD, B20, B50, B100, B5		B5 tested only on FTP.
Off-Road Engines				
1998 Kubota V2203-DIB	Soy	ULSD, B20, B50, B100, B5	ISO 8178 (8 Mode)	none
	Animal	Not tested		
2009 John Deere	Soy	ULSD, B20, B50, B100	ISO 8178 (8 Mode)	B5 not tested
	Animal	ULSD, B20, B5		none

measured emissions. The data needed to support a full re-analysis consist of measured emissions on each fuel in gm/hp-hr terms, which are stated in Durbin 2011 as averages across all test replications along with the number of replications and the standard error of the individual tests. With this information, the dependence of NOx emissions on biodiesel blending percent can be determined as accurately as if the individual test values had been reported and the appropriate statistical tests for the significance of results can be performed.

Regression analysis is used as the primary method of analysis. For each engine and test cycle, the emission averages for each fuel are regressed against the biodiesel blending percent to determine a straight line. The regression weights each data point in inverse proportion to the square of its standard error to account for differences in the number and reliability of emission measurements that make up each average. The resulting regression line will pass through the mean value estimated from the data (i.e., the average NOx emission level at the average blending percent), while the emission averages for each fuel may scatter above and below the regression line due to uncertainties in their measurement. The slope of the line estimates the dependence of NOx emissions on the blending percentage.

Where the data points closely follow a straight line and the slope is determined to be statistically significant, one can conclude that blending biodiesel with a base fuel will increase NOx emissions in proportion to the blending percent. The regression line can then be used to estimate the predicted emissions increase for a given blending percent. The predicted emissions increase is the value one would expect on average over many measurements and is comparable to the average emissions increase one would expect in a fleet of vehicles.

The same level of analysis is not possible for the testing on B5 fuel, which is reported as a simple average for the on-road engines and is not reported at all for the off-road engines. For the B5 fuel, Durbin 2011 presents emission test results in a tabulated form where the percentage change in NOx emissions has been computed compared to ULSD base fuel. This form supports the presentation of results graphically, but it does not permit a proper statistical analysis to be performed. Specifically, the computation of percentage emission changes will perturb the error distribution of the data, by mixing the uncertainty in measured emissions on the base fuel with the uncertainties in measured emissions on each biodiesel blend, and it can introduce bias as a result of the mixing. Further statistical analysis of the computed percent values should be avoided because of these problems. Therefore, a more limited trend analysis of the NOx emissions data for B5 and the John Deere engine is conducted.

3.3 2006 Cummins Engine (Engine Dynamometer Testing)

Table 3-3 shows the NOx emission results for the 2006 model-year Cummins heavy-duty diesel engine based on a re-analysis of the data for this report. As indicated by highlighting in the table, the relationship between increasing biodiesel content and increased NOx emissions for soy-based biodiesel is statistically significant at >95% confidence level[17] in all cases. For the animal-based biodiesel, the relationship is statistically significant at the 92% confidence level for the UDDS cycle, the 94% confidence level for the 50 mph cruise, and the >99% confidence level for the FTP cycle.

For the soy-based fuels, the R^2 statistics show that the emissions effect of biodiesel is almost perfectly linear with increasing biodiesel content over the range B20, B50, and B100. Although not as high for the animal-based fuels (because the emissions effect is smaller and measurement errors are relatively larger in comparison to the trend), the R^2 statistics nevertheless establish a linear increase in NOx emissions with increasing biodiesel content over the same range. The linearity of the response with blending percent is well supported by the many NOx emissions graphs contained in Durbin 2011.

The table also gives the estimated NOx emission increases for B5 and B10 as predicted by the regression lines. For soy-based fuels, the values are 1% for B5 (range 0.8% to 1.3% depending on the cycle) and 2% for B10 (range 1.6% to 2.6% depending on cycle).

[17] A result is said to be statistically significant at the 95% confidence level when the p value is reported as $p \leq 0.05$. At the $p \leq 0.01$ level, a result is said to be statistically significant at the 99% confidence level, and so forth.

Table 3-3 Re-Analysis for 2006 Cummins Engine (Engine Dynamometer Testing) Model: NOx = A + B · BioPct Using ULSD, B20, B50, and B100 fuels							
Biodiesel Type	Test Cycle	R^2	Intercept A	BioPct Slope B		Predicted NOx Increase for B5	Predicted NOx Increase for B10
			Value	Value	p value	Pct Change	Pct Change
Soy-based							
	UDDS	0.997	5.896	0.0100 [a]	0.001	0.8%	1.7%
	FTP	0.995	2.024	0.0052	0.003	1.3%	2.6%
	40 mph	1.000	2.030	0.0037	<0.0001	0.9%	1.8%
	50 mph	0.969	1.733	0.0028	0.016	0.8%	1.6%
Animal-based							
	UDDS	0.847	5.911	0.0021 [b]	0.080	0.2%	0.4%
	FTP	0.981	2.067	0.0031	0.001	0.7%	1.4%
	50 mph	0.887	1.768	0.0011	0.058	0.3%	0.6%

Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better.
[b] Orange highlight indicates result is statistically significant at the 90% confidence level or better.

For animal-based fuels, the values are approximately one-half as large: 0.4% for B5 (range 0.2% to 0.7%) and 0.8% for B10 (range 0.4% to 1.4%). These predicted increases are statistically significant to the same degree as the slope of the regression line from which they are estimated. That is, the NOx increases predicted by the regression line for soy-based fuels are statistically significant at the 95% confidence level (or better) on all cycles and the predicted NOx increases for animal-based fuels are statistically significant at the 90% confidence level (or better) on all cycles and at the >99% confidence level for the FTP.

Because the limited data on B5 were not used to develop the regression lines for each cycle, and no test data on B10 are available, use of the lines to make predictions for B5 and B10 depends on their linearity over the range between ULSD and B20. Based on the R^2 statistics and the graphs in Durbin 2011, the slopes observed between ULSD and B20 are the same as the slopes observed between B20 and B100 for each of the test cycles. We believe that the linearity of the response with blending percent for values over the range ULSD to B100 would be accepted by the large majority of researchers in the field, as would the use of regression analysis to make predictions for B5 and B10. ADF B3-73

The Durbin 2011 report takes a different approach for determining the statistical significance of NOx emission increases for each fuel. For each fuel tested, it computes a percentage change in emissions for NOx (and other pollutants) relative to the ULSD base fuel. It then determines the statistical significance of each observed change using a conventional t-test for the difference of two mean values (2-tailed, 2 sample equal

variance t-test). The t-test is conducted on the measured emission values before the percentage emission change is computed.

The t-test would be the appropriate approach for determining statistical significance if only two fuels were tested. However, it is a simplistic approach when three or more fuels are tested because it is applied on a pair-wise basis (B5 vs. ULSD, B20 vs. ULSD, etc.) and does not make use of all of the data that is available. It will have less power than the regression approach to detect emission changes that are real. This limitation is in one direction, however, in that the test is too weak when 3 or more data points are available, but a finding of statistical significance is valid when it occurs. As long as the linear hypothesis is valid, the regression approach should be the preferred method for analysis and for the determination of whether biodiesel blending significantly increases NOx emissions. ADF B3-74

Because emission changes will be smallest for B5 (because of the low blending volume), the pair-wise t-test is most likely to fail to find statistical significance at the B5 level. In cases where the pair-wise t-test for B5 says that the emission change vs. ULSD is not statistically significant – but slope of the regression line <u>is</u> statistically significant – the proper conclusion is that additional B5 testing (to improve the precision of the emission averages) would likely lead to the detection of a statistically significant B5 emissions change using the t-test. In this case, <u>the failure to find statistical significance using the t-test is not evidence that B5 does not increase NOx emissions</u>.

For this engine, soy-based B5 was tested on the 40 mph and 50 mph cruise cycles and animal-based B5 was tested on the FTP. To examine this matter further, Table 3-4 reproduces NOx emission results reported in Tables ES-2 and ES-3 of Durbin 2011. Soy-based B5 was shown to increase NOx emissions on the 40 mph cruise cycle, but not on the 50 mph cruise cycle. Animal-based B5 was shown to increase NOx emissions on the FTP. Durbin 2011 noted (p. xxxii) that "[t]he 50 mph cruise results were obscured, however, by changes in the engine operation and control strategy that occurred over a segment of this cycle." Therefore, we discount the 50 mph cruise results and do not consider them further. Neither of the remaining B5 NOx emission increases (for the 40 mph Cruise and FTP cycles) were found to be statistically significant using the t-test, although the 40 mph cruise result for soy-based fuels comes close to being marginally significant (it would be statistically significant at an 86.5% level). The NOx emission increases at higher blending levels were found have high statistical significance (>99% confidence level). ADF B3-75

This format, used throughout Durbin 2011 to report emission test data and to show the effect of biodiesel on emissions, is subject to an important statistical caveat. The percent changes are computed by dividing the biodiesel emission values by the emissions measured for the ULSD base fuel. Therefore, measurement errors in the ULSD measurement are blended with the measurement errors for each of the biodiesel fuels. The blending of errors in each computed percent change can bias the apparent trend of emissions with increasing biodiesel content. As will be shown in Section 3.3.2, we can see this problem in the animal-based B5 test data for this engine.

Table 3-4 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 2006 Cummins Engine (Engine Dynamometer Testing)						
	Soy-based Biodiesel				Animal-based Biodiesel	
	40 mph Cruise		50 mph Cruise		FTP	
	NOx % Diff	p value	NOx % Diff	p value	NOx % Diff	p value
B5	1.7%	0.135	-1.1%	0.588	0.3%	0.298
B20	3.9% [a]	0.000	0.5%	0.800	1.5%	0.000
B50	9.1%	0.000	6.3%	0.001	6.4%	0.000
B100	20.9%	0.000	18.3%	0.000	14.1%	0.000

Source: Table ES-2 and ES-3 of Durbin 2011, p. xxviii
Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on the pair-wise t-test.

3.3.1 NOx Impact of Soy-based Biodiesel at the B5 Level

Figures 3-1a and 3-1b display the trend of NOx emissions with blending percent for the soy-based biodiesel on the 40 mph cruise cycle. Figure 3-1a plots the percentage increases as reported by Durbin 2011 in contrast to two different analytical models for the relationship:

- The Linear Model shown by the blue line; and
- The Staff Threshold model (black line), in which the NOx emission change is zero through B9 and then increases abruptly to join the linear model.

In Figure 3-1a, the linear model is an Excel trendline for the computed percent changes. While the data violate a key assumption for the proper use of regression analysis, this approach is the only way to establish a trendline given the form in which Durbin 2011 tabulates the data and presents the results of its testing.

Figure 3-1b plots the actual measured emission values in g/bhp-hr terms in contrast to the same two analytical models. Here, the linear model line is determined through a proper use of regression analysis, in which each emission average in g/bhp-hr terms is weighted inversely by the square of its standard error, using the data for ULSD, B20, B50 and B100 (i.e., excluding the B5 data point). In the case of this engine and biodiesel fuel, both forms of assessment show generally the same trend for NOx emissions as a function of blending percent. Although the NOx emission increases for B5 may fail the t-test for significance, emissions are increased at B5 and the B5 data point is fully consistent with the Linear Model. The Threshold model is clearly a less-satisfactory representation of the test data. ADF B3-76

Figure 3-1a
Durbin 2011 Assessment: 40 mph Cruise Cycle NOx Emissions Increases for Soy-Biodiesel Blends (2006 Cummins Engine)

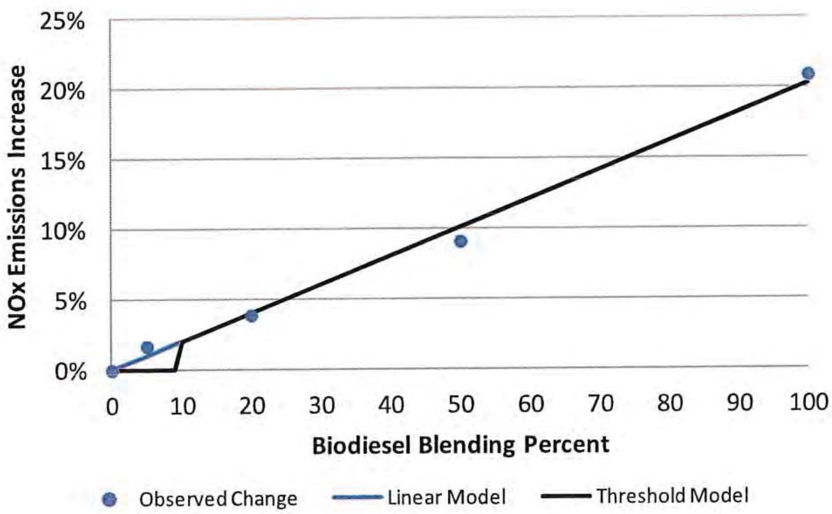
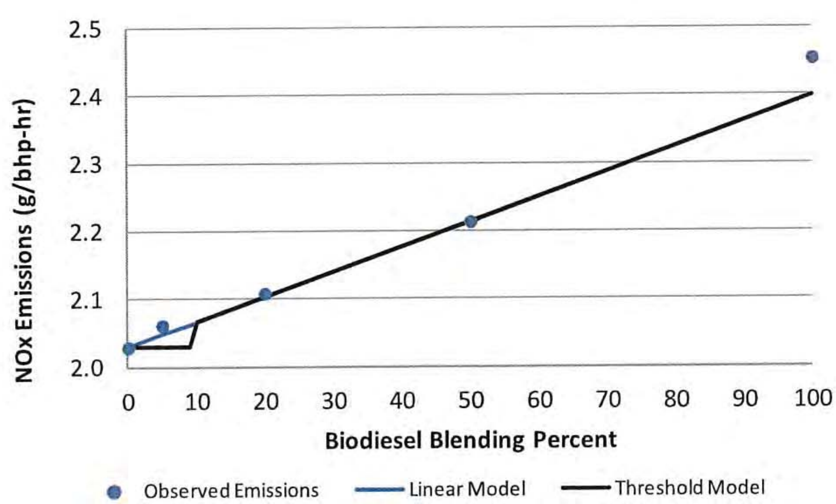


Figure 3-1b
Re-assessment of 40 mph Cruise Cycle NOx Emissions Increases for Soy-Biodiesel Blends (2006 Cummins Engine)



Note that the slope of the trendline (Figure 3-1a) is greater than the slope of the regression line (Figure 3-1b). In the latter figure, the B100 data point stands above the regression line, which passes below it. The regression line (but not the trendline) is fit in

a manner that accounts for the uncertainties in each data point, so that the line will pass closer to points that have smaller uncertainties and farther from points that have greater uncertainties. For these data, the B100 data point has the largest uncertainty (±0.026 g/bhp-hr) followed by the B20 data point (±0.025 g/bhp-hr). The other three data points (ULSD, B5, and B50) have uncertainties less than ±0.001 g/bhp-hr. The B20 data point happens to fall on the line, but the B100 data point is found to diverge above. Because the regression analysis can account for the relative uncertainties of the data points, it provides a more accurate and reliable assessment of the impact on NOx emissions. ADF B3-77

3.3.2 NOx Impact of Animal-based Biodiesel at the B5 level

Figures 3-2a and 3-2b display the trend of NOx emissions with blending percent for the animal-based biodiesel on the FTP test cycle as reported by Durbin 2011 and as re-assessed in this report using regression analysis, respectively. As Figure 3-2a shows, the NOx percent change values reported by Durbin 2011 appear to follow the Staff Threshold model in that NOx emissions are not materially increased at B5, but are increased significantly at B20 and above. As a result, the blue trendline in the figure (fit from the B20, B50 and B100 data points) has a negative intercept.

Figure 3-2b paints a very different picture from the data. Here, the ULSD and B5 data points stand above the weighted regression line (blue) developed from the data for ULSD, B20, B50 and B100. In the data used to fit the regression line, the ULSD data point has the largest uncertainty (±0.013 g/bhp-hr) while the other three data points (B20, B50, and B100) have uncertainties of ±0.002 g/bhp-hr (one case) and ±0.001 g/bhp-hr (two cases). Considering all of the data, the B5 data point has the second highest uncertainty (±0.007 g/bhp-hr). The regression line closely follows a linear model with a high R^2 (0.981) considering the weighted errors, while the ULSD and B5 points lie above it. ADF B3-78

Because the ULSD data point is subject to more uncertainty and appears to be biased high compared to the regression line, the NOx percent changes computed by Durbin 2011 are themselves biased. The trendline result in Figure 3-2a that appeared to be supportive of the Staff Threshold model now appears to be the result of biases in the ULSD and B5 emission averages.

Two important conclusions can be drawn from the foregoing:

1. Accurate and reliable conclusions regarding the impact of B5 on NOx emissions cannot be drawn from the computed percent changes that are reported in Durbin 2011. Nor can accurate and reliable conclusions be drawn from visual inspection of graphs that present such data. Weighted regression analysis of the measured emission values (g/bhp-hr terms) must be performed so that the uncertainties in emissions measurements can be fully accounted for. ADF B3-79

2. When a weighted regression analysis is performed using the testing for this engine, there is no evidence that supports the conclusion that B5 blends will not increase NOx emissions. In fact, the data are consistent with the conclusion that biodiesel increases NOx emissions in proportion to the blending percent. ADF B3-80

Figure 3-2a
Durbin 2011 Assessment: FTP NOx Emissions Increases for Animal-based Biodiesel Blends (2006 Cummins Engine)

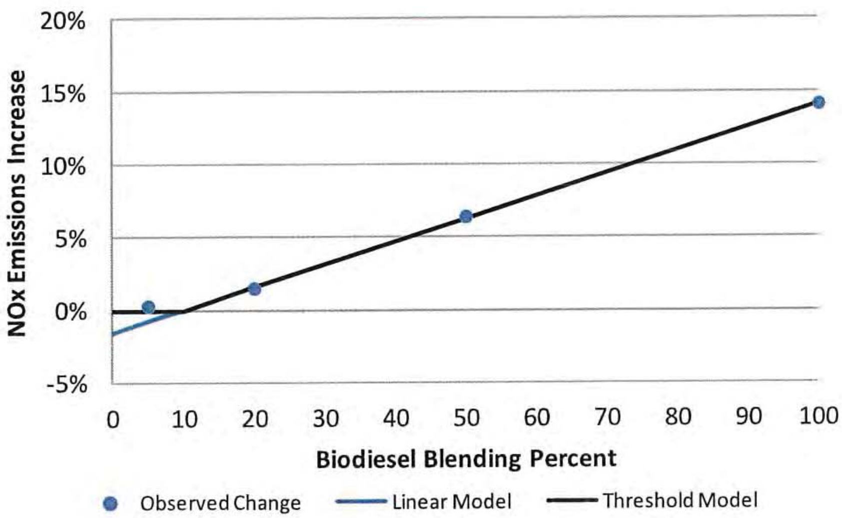
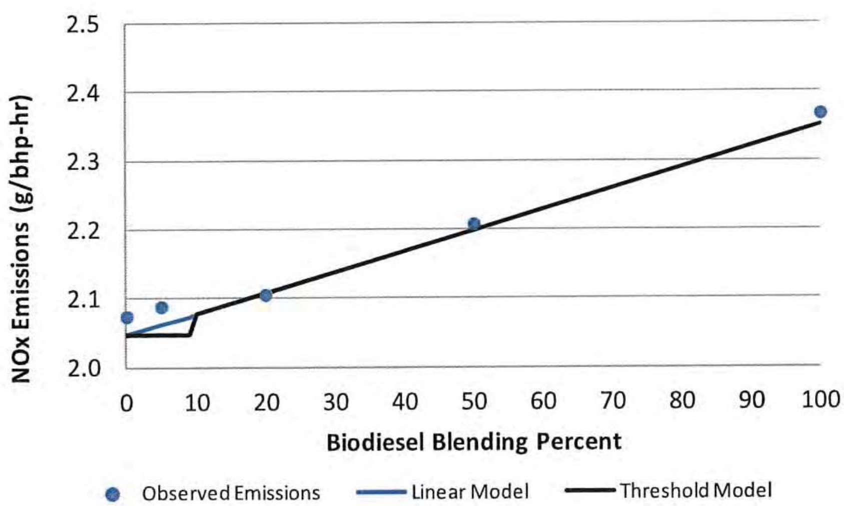


Figure 3-2b
Re-assessment of FTP NOx Emissions Increases for Animal-based Biodiesel Blends (2006 Cummins Engine)



3.4 2007 MBE4000 Engine (Engine Dynamometer Testing)

To analyze the data for the 2007 MBE4000 engine, it has proved necessary to remove two data points, one for the soy-based B20 fuel on the 50 mpg cruise cycle and one for the animal-based B50 fuel on the FTP test cycle:

- Appendix H reports the 50 mph cruise emission average for soy-based B20 to be 0.014 ± 0.020 g/bhp-hr. This value is implausible and wholly inconsistent with the NOx emission change of +6.9% reported in Table ES-4 of Durbin 2011, which would imply a NOx emission average of 1.21*1.069 = 1.30 g/bhp-hr.

- Appendix H reports the FTP emission average for the animal-based B50 fuel to be 2.592 ± 0.028 g/bhp-hr, which stands well above the other test data on animal-based biodiesel. This value is also inconsistent with the NOx emission change of +12.1% reported in Table ES-4 of Durbin 2011, which would imply a NOx emission average of 1.29*1.121 = 1.45 g/bhp-hr.

We believe these reported values are affected by typographical errors and have deleted them from the dataset used here.

With these corrections, Table 3-5 shows the results of the NOx emissions analysis for the 2007 model-year MBE4000 heavy-duty diesel engine. As indicated by highlighting in the table, the relationship between increasing biodiesel content and increased NOx emissions is statistically significant at >99% confidence level in two cases for soy-based biodiesel (the UDDS and FTP cycles) and at the 90% confidence level in one case (the 50 mph cycle). For the animal-based biodiesel, the relationship is statistically significant at the 96% confidence level for the UDDS cycle, the 98% confidence level for the FTP cycle, and >99% confidence level for the 50 mph cycle. ADF B3-81

Durbin 2011 again notes a problem with the 50 mph cruise test results, saying (p. xxxii) that "[the NOx] trend was obscured, however, by the differences in engine operation that were observed for the 50 mph cruise cycle." Therefore, we will focus the discussion on the UDDS and FTP results.

For the soy-based fuels, the R^2 statistics show that the emissions effect of biodiesel is almost perfectly linear with increasing biodiesel content over the range from ULSD to B20, B50, and B100 for all cycles (including the 50 mph cruise). That is, the NOx emissions increase between ULSD and B20 shares the same slope as the NOx emissions increase between B20 and B100. For the animal-based biodiesel, the R^2 statistics also establish a linear increase in NOx emissions with increasing biodiesel content over the same range. The linearity of the response with blending percent is also well supported by the many NOx emissions graphs contained in Durbin 2011.

Table 3-5 Re-Analysis for 2007 MBE4000 Engine (Engine Dynamometer Testing) Model: NOx = A + B · BioPct Using ULSD, B20, B50, and B100 fuels							
Biodiesel Type	Test Cycle	R^2	Intercept A	BioPct Slope B		Predicted NOx Increase for B5	Predicted NOx Increase for B10
			Value	Value	p value	Pct Change	Pct Change
Soy-based							
	UDDS	0.989	2.319	0.0090 [a]	0.005	4.6%	9.1%
	FTP	0.998	1.268	0.0049	0.006	2.5%	5.0%
	50 mph	0.979	1.198	0.0054 [b]	0.092	2.7%	5.5%
Animal-based							
	UDDS	0.913	2.441	0.0036	0.044	2.0%	4.0%
	FTP	0.999	1.288	0.0038	0.020	2.5%	5.0%
	50 mph	0.994	1.205	0.0049	0.003	2.5%	5.0%

Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better.
[b] Orange highlight indicates result is statistically significant at the 90% confidence level or better.

The table also gives the estimated NOx emission increases for B5 and B10 as predicted by the regression lines. For soy-based fuels, the values are ~3.5% for B5 (range 2.5% to 4.6% depending on the cycle) and ~7.5% for B10 (range 5.0% to 9.1% depending on cycle). For animal-based fuels, the values are approximately two-thirds as large: ~2.3% for B5 (range 2.0% to 2.5%) and ~4.5% for B10 (range 4.0% to 5.0%). The predicted increases are statistically significant to the same degree as the slope of the regression line from which they are estimated. That is, the predicted NOx increases are statistically significant at the >99% confidence level for soy-based fuels on the UDDS and FTP cycles and at the >95% confidence level for animal-based fuels on all cycles. The predicted NOx increase is statistically significant at the 90% confidence level for soy-based fuels on the 50 mph cruise cycle.

ADF B3-82

For this engine, soy- and animal-based B5 were tested on the FTP. Table 3-6 reproduces the NOx emission results reported in Tables ES-4 and ES-5 of Durbin 2011. While there are caveats on use of the pair-wise t-test, the FTP test data for this engine show NOx emissions at the B5 level for both soy- and animal-based fuels that are statistically significant at the 99% confidence level (or better) in this case. That is, the test data for this engine as reported by Durbin 2011 refute the Staff Threshold Model that biodiesel blends below B10 do not increase NOx emissions.

Table 3-6 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 2007 MBE4000 Engine (Engine Dynamometer Testing)				
	Soy-Based Biodiesel FTP		Animal-Based Biodiesel FTP	
	NOx % Diff	p value	NOx % Diff	p value
B5	0.9% [a]	0.007	1.3%	0.000
B20	5.9%	0.000	5%	0.000
B50	15.3%	0.000	12.1	0.000
B100	38.1%	0.000	29%	0.000

Source: Table ES-4/5 of Durbin 2011, p. xxix
Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on pair-wise t-test.

Figures 3-3a and 3-3b below compare the FTP data for this engine to the regression line representing the linear model (blue) and the Staff Threshold model (black) for both soy- and animal-based biodiesel. In both cases, the regression line was developed using the data for ULSD, B20, B50, and B100 (i.e., excluding the B5 data point). For both soy- and animal-based biodiesels, the data point for B5 falls on the established line, while the Staff Threshold model is inconsistent with the data. For this engine, it is clear that soy- and animal-based biodiesels increase NOx emissions at all blending levels. ADF B3-83

Figure 3-3a
Re-assessment of FTP Cycle NOx Emissions Increases for Soy-based Biodiesel Blends (2007 MBE4000 Engine)

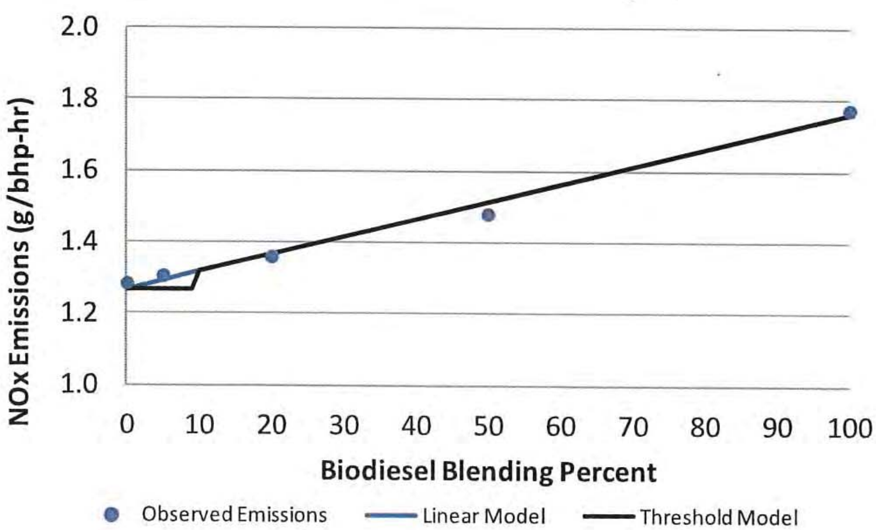
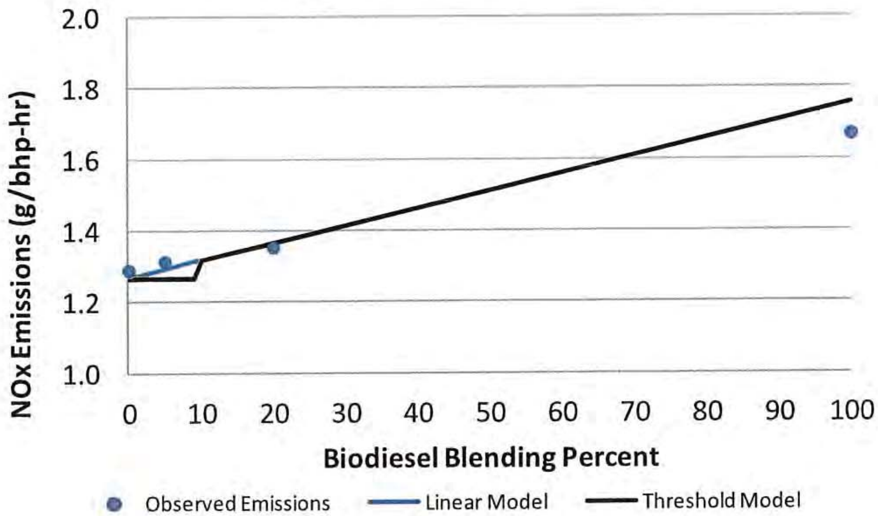


Figure 3-3b
Re-assessment of FTP Cycle NOx Emissions Increases for Animal-based Biodiesel Blends (2007 MBE4000 Engine)



3.5 1998 Kubota TRU Engine (Engine Dynamometer Testing)

The 1998 Kubota V2203-DIB off-road engine was tested on the base fuel (ULSD) and soy-based biodiesel at four blending levels (B5, B20, B50, B100) in two different series using the ISO 8178 (8-mode) test cycle. Appendix I reports the measured emissions data only for the first series (ULSD, B50, B100). Using this subset of data, Table 3-7 summarizes the results of the re-analysis for this engine.

As for the other engines, the results of the analysis demonstrate the following:

- The high R^2 statistic shows that the emissions effect of biodiesel is almost perfectly linear over the range B50 and B100. That is, the slope from ULSD to B50 is the same as the slope from B50 to B100. The slope of the regression line is statistically significant at the 99% confidence level.

- NOx emissions are estimated to increase by 1.0% at the B5 level and by 2.1% at the B10 level. These estimated NOx emission increases are statistically significant to the same high degree as the regression slope on which they are based.

ADF B3-84

Table 3-7 Re-Analysis for 1998 Kubota V2203-DIB Engine (Engine Dynamometer Testing) Model: NOx = A + B · BioPct Using ULSD, B50, and B100 fuels							
Biodiesel Type	Test Cycle	R^2	Intercept A	BioPct Slope B		Predicted NOx Increase for B5	Predicted NOx Increase for B10
			Value	Value	p value	Pct Change	Pct Change
Soy-based	ISO 8178	0.999	12.19	0.0256 [a]	0.01	1.0%	2.1%

Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better.

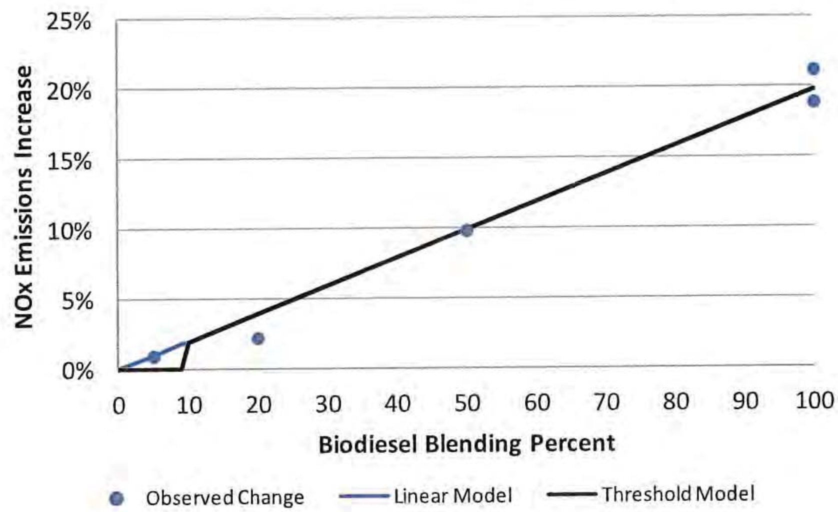
The second test series involved ULSD, B5, B20, and B100 fuels. Measured emissions data are not given in Appendix I, so we must work with the calculated percent changes in NOx emissions tabulated in Durbin 2011. Table 3-8 reproduces the NOx emission results reported in Table ES-8 of Durbin 2011 for the two test series. For the second test series, biodiesel at the B5 level increased NOx emissions, but the result fails the pair-wise t-test for statistical significance. The NOx emission increase at the B20 level was statistically significant at the 90% confidence level, and the increase at the B100 level was statistically significant at the >99% confidence level. The significance determinations use the pair-wise t-test, which is subject to caveats, but this is the only method available to gauge significance because re-analysis of the computed percentage changes is not possible. ADF B3-85

Table 3-8 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 1998 Kubota TRU Engine (Engine Dynamometer Testing)				
	Soy-Based Biodiesel Series 1 ISO 8178		Soy-Based Biodiesel Series 2 ISO 8178	
	NOx % Diff	p value	NOx % Diff	p value
B5	Not tested		0.97%	0.412
B20	Not tested		2.25% [a]	0.086
B50	7.63% [b]	0.000	Not tested	
B100	13.76%	0.000	18.89%	0.000

Source: Table ES-8 of Durbin 2011, p. xxxviii
Notes:
[a] Orange highlight indicates result is statistically significant at the 90% confidence level or better based on pair-wise t-test.
[b] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on pair-wise t-test

Figure 3-4 displays the trend of NOx emissions with blending percent for the first and second test series combined. As the figure shows, the available data points scatter around the trendline determined from the emission change percentages (not from regression analysis). The B20 data point falls below the trend line while the two B100 data points bracket the trend line. It is not possible to explain the divergence of the B20 data point

Figure 3-4
Durbin 2011 Assessment: ISO 8178 Cycle NOx Emissions Increases for Soy-based Biodiesel Blends (1998 Kubota Engine, Test Series 1 and 2 Combined)



because the emissions data for the second test series are not published in Durbin 2011. The B5 data point clearly supports the Linear Model and is inconsistent with the Staff Threshold Model. ADF B3-86

3.6 2009 John Deere Off-Road Engine (Engine Dynamometer Testing)

The only information on the 2009 John Deere off-road engine comes from the tabulation of calculated percentage emission changes. Table 3-9 reproduces these data from Table ES-7 of Durbin 2011. For the soy-based biodiesel, NOx emissions are significantly increased at the B20 and higher blend levels. The increase for B20 is statistically significant at the 90% confidence level and the increases for B50 and B100 are statistically significant at the >99% confidence level based on the pair-wise t-test. A soy-based B5 fuel was not tested. ADF B3-87

Table 3-9 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 2009 John Deere Engine (Engine Dynamometer Testing)				
	Soy-Based Biodiesel ISO 8178		Animal-Based Biodiesel ISO 8178	
	NOx % Diff	p value	NOx % Diff	p value
B5	Not tested		-3.82	0.318
B20	2.82%[a]	0.021	-2.20	0.528
B50	7.63%	0.000	Not tested	
B100	13.76%	0.000	4.57	0.000

Source: Table ES-7 of Durbin 2011, p. xxxviii
Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on pair-wise t-test.

For animal-based biodiesel, the testing shows the unusual result that B5 and B20 appear to decrease NOx emissions, while B100 increases NOx. The B5 and B20 decreases are not statistically significant, while the B100 increase is statistically significant at the >99% confidence level. Durbin 2011 concludes:

> The animal-based biodiesel also did not show as great a tendency to increase NOx emissions compared to the soy-based biodiesel for the John Deere engine, with only the B100 animal-based biodiesel showing statistically significant increases in NOx emissions.[18]

Durbin 2011 does not discuss these results further and does not note any problems in the testing, making further interpretation of the results difficult. Figure 8-1 of Durbin 2011 presents the NOx results for this engine with error bars. First, we note that the figure appears to suggest that NOx emissions were increased on the B20 fuel in contradiction to the table above. Second, it is clear that the error bars are large enough that no difference in NOx emissions can be detected among ULSD, B5, and B20 fuels. Overall, this result could be consistent with the Staff Threshold Model through B5, but the failure to detect a NOx emission increase at B20 is not. Without further information, it is not possible to determine whether the result seen here is a unique response of the John Deere engine to animal-based biodiesel or is the result of a statistical fluctuation or an artifact in the emissions data.

ADF B3-87 cont.

3.7 Conclusions

The Biodiesel Characterization report prepared by Durbin et al. for CARB is an important source of information on the NOx emissions impact of biodiesel fuels in heavy-duty engines. It is the sole source of information on the NOx impact of B5 blends cited in the ISOR. When the engine dynamometer test data are examined for

ADF B3-88 cont.

[18] Durbin 2011, p. xx.

the three engines for which emissions test data have been published, we find clear evidence that biodiesel increases NOx emissions in proportion to the blending percent. Where B5 fuels were tested for these engines, NOx emissions are found to increase above ULSD for both soy- and animal-based blends in all three engines and by statistically significant amounts in one engine.

ADF B3-88 cont.

Specifically, a re-analysis of the NOx emissions test data demonstrates the following:

1. For the 2006 Cummins engine, biodiesel fuels are found to significantly increase NOx emissions for both soy- and animal-based blends by amounts that are proportional to the blending percent. This result indicates that biodiesels will increase NOx emissions at blending levels below B10. When B5 fuels were tested, NOx emissions were observed to increase but by amounts that fail to reach statistical significance according to the pair-wise test.[19] Graphical analysis demonstrates that NOx emissions measured for B5 fuels are consistent with the Linear Model, but not the Staff Threshold Model.

ADF B3-89

2. For the 2007 MBD4000 engine, biodiesel fuels are found to significantly increase NOx emissions for both soy- and animal-based blends by amounts that are proportional to the blending percent. This result indicates that biodiesels will increase NOx emissions at blending levels below B10. When B5 fuels were tested, NOx emissions were observed to increase and by amounts that are found to be statistically significant using the pair-wise t-test.[13] This result alone is sufficient to disprove the Staff Threshold Model. Graphical analysis demonstrates that NOx emissions measured for B5 fuels are consistent with the Linear Model, but not the Staff Threshold Model.

ADF B3-90

3. For the 1998 Kubota TRU (off-road) engine, soy-based biodiesel fuels are found to significantly increase NOx missions. Animal-based biodiesel was not tested. When a soy-based B5 fuel was tested, NOx emissions were observed to increase but by amounts that fail to reach statistical significance according to the pair-wise test.[13] Graphical analysis demonstrates that NOx emissions measured for B5 fuels are consistent with the Linear Model, but not the Staff Threshold Model.

ADF B3-91

The measured emissions test data for the other off-road engine (2009 John Deere) are not contained in the Durbin 2011 report and CARB has not made them publicly available. Thus, a re-analysis was not possible. Based on the tables and figures in Durbin 2011, soy-based biodiesel fuels were shown to significantly increase NOx emissions at B20 levels and higher, but B5 was not tested. Testing of animal-based blends shows no change in NOx emissions at B5 and B20 levels, but B100 is shown to significantly increase NOx emissions. Durbin 2011 discusses this result only briefly, and it is unclear what conclusions can be drawn from it.

ADF B3-92

###

[19] As discussed in Section 3.3, the pair-wise t-test is not the preferred method for demonstrating statistical significance.

12_B_LCFS_GE Responses (Page 167 – 204)

710. Comment: **ADF B3-57 through ADF B3-63, ADF B3-69 through ADF B3-71, ADF B3-73, ADF B3-75, ADF B3-81 through ADF B3-87, ADF B3-89 through ADF B3-92**

Agency Response: This comment is responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

711. Comment: **ADF B3-46 (continued) through ADF B3-56, ADF B3-64 through ADF B3-68, ADF B3-72, ADF B3-74, ADF B3-76 through ADF B3-80, and ADF B3-88**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

APPENDIX A

RESUME OF ROBERT W. CRAWFORD

Education

1978 Doctoral Candidate, ScM. Physics, Brown University, Providence, Rhode Island
1976 B.A. Physics, Pomona College, Claremont, California

Professional Experience

1998-Present Independent Consultant

Individual consulting practice emphasizing the statistical analysis of environment and energy data with an emphasis on how data and statistics are properly used to make scientific inferences. Mr. Crawford provides support on statistical, data analysis, and modeling problems related to ambient air quality data and emissions from mobile and stationary sources.

Ambient Air Quality and Mobile Source Emissions – Mr. Crawford has worked with Sierra Research on elevated ambient CO and PM concentrations in Fairbanks AK and Phoenix AZ, including the effect of meteorological conditions on ambient concentrations, the relationship of concentrations to source inventories, and the use of non-parametric techniques to infer source location from wind speed and direction data. Ongoing work is employing Principal Components Analysis to elucidate the relationship between meteorology and $PM_{2.5}$ concentrations in Fairbanks. In the past year, this work led to creation of the AQ Alert System, a tool used by air quality staff to track $PM_{2.5}$ monitor concentrations during the day and to prepare AQ alerts over the next 3 days based on the meteorological forecast.

In past work for Sierra, he has also conducted studies of fuel effects on motor vehicle emissions for Sierra. For CRC, he determined the relationship between gasoline volatility and oxygen content on tailpipe emissions of late model vehicles at FTP and cold-ambient temperatures. For SEMPRA, he determined the relationship between CNG formulation and tailpipe emissions of criteria pollutants and a range of air toxics. Other work has included the design of vehicle surveillance surveys and determination of sample sizes, development of screening techniques similar to discriminant functions to improve the efficiency of vehicle recruitment, the analysis of vehicle failure rates measured in inspection & maintenance programs, and the statistical evaluation of data collected on freeway speeds using automated sensors.

Stationary Source Emissions – Over the past 5 years, Mr. Crawford has worked with AEMS, LLC on EPA's MACT and CISWI rulemakings for Portland Cement plants, in which significant issues related to data quality, data reliability, and emissions variability are evident. Key issues include the need to properly account for uncertainty and emissions variability in setting emission standards. He also supported AEMS in the

current EPA rulemaking on reporting of greenhouse gas emissions from semiconductor facilities, where the proper characterization of emission control device performance was a key issue. He is currently supporting AEMS in a regulatory process to re-determine emission standards for an industrial facility where the new standard will be enforced by continuous emissions monitoring (CEMS). At issue is how to set the standard in such a way that there will be no more than a small, defined risk that 30-day emission averages will exceed the limitations while emissions remain well-controlled .

Advanced Combustion Research – In recent work for Oak Ridge National Laboratory, Mr. Crawford conducted a series of statistical studies on the fuel consumption and emissions performance of Homogenous Charge Compression Ignition (HCCI) engines. One of these studies was for CRC, in which fuel chemistry impacts were examined in gasoline HCCI. In HCCI, the fuel is atomized and fully-mixed with the intake air charge outside the cylinder, inducted during the intake stroke, and then compressed to the point of spontaneous combustion. The timing of combustion is controlled by heating of the intake air. If R&D work can demonstrate a sufficient understanding of how fuel properties influence engine performance, the HCCI combustion strategy potentially offers the fuel economy benefit of a diesel engine with inherently lower emissions.

1979-1997 Energy and Environmental Analysis, Inc., Arlington, VA. Director & Partner (from 1989).

Primary work areas: Studies of U.S. energy industries for private and institutional clients emphasizing statistical analysis, business planning and computer modeling/forecasting. Responsible for the EEA practice area that provided strategic planning and forecasting services to major energy companies. Primary topical areas included: U.S. energy market analysis and strategic planning; gas utility operations; and natural gas supply planning.

U.S. Energy Market Analysis

During 1995-1997, Mr. Crawford directed EEA's program to provide comprehensive energy supply and demand forecasting for the Gas Research Institute (GRI) in its annual Baseline Projection of U.S. Energy Supply and Demand. Services included: development of U.S. energy supply, demand, and price forecasts; sector-specific analyses covering energy end-use (residential, commercial, industrial, transportation), electricity supply, and natural gas supply and transportation; and the preparation of a range of publications on the forecasts and energy sector trends.

From 1989 through 1997, he directed the use of EEA's Energy Overview Model in strategic planning and long-term market analysis for a client base of major energy producers, pipelines, and distributors in both the United States and Canada. The Energy Overview Model was used under his direction as the primary analytical basis for the 1992 National Petroleum Council study The Potential for Natural Gas in the United States. Mr. Crawford also provided analysis for clients on a wide range of other energy market issues, including negotiations related to an LNG import project intended to serve U.S. East Coast markets. This work assessed the utilization and economic value of seasonal

gas deliverability in order to develop LNG pricing formulas and evaluate the project's viability.

Other topical areas of work during his period of employment with EEA include:

Gas Load Analysis and Utility Operations – Principal investigator in a multi-year research program for the Gas Research Institute (GRI) that examined seasonal gas loads, utility operations, and the implications for transmission and storage system reliability and capacity planning.

Gas Transmission and Storage – Principal investigator for a study of industry plans for expansion of underground gas storage capacity in the post-Order 636 environment, including additions of depleted-reservoir and salt-formation storage, an engineering analysis of capital and operating costs for the projects, and unbundled rates for new storage services.

Natural Gas Supply Planning – Mr. Crawford was EEA's senior manager and lead analyst on gas supply planning issues for both pipeline and distribution companies, which included technical and analytic support in development and justification of gas supply strategies; and identification of optimal seasonal supply portfolios for Integrated Resource Planning proceedings.

Transportation Systems Research

Mr. Crawford also had extensive experience in motor vehicle fuel economy and emissions while at EEA. He participated for five years in a DOE research program on fuel economy, with emphasis on the evaluation of differences between laboratory and on-road fuel economy. His work included analysis of vehicle use databases to understand how driving patterns and ambient (environmental) conditions influence actual on-road fuel economy. He also developed a software system to link vehicle certification data systems to vehicle inspection and testing programs and participated in a range of studies on vehicle technology, fuel economy, and emissions for DOE, EPA, and other governmental agencies.

SELECTED PUBLICATIONS (emissions and motor vehicle-related topics)

Statistical Assessment of $PM_{2.5}$ and Meteorology in Fairbanks, Alaska: 2013 Update. Crawford and Dulla. Prepared for the Alaska Department of Environmental Conservation. (forthcoming).

Statistical Assessment of $PM_{2.5}$ and Meteorology in Fairbanks, Alaska. Crawford and Dulla. Prepared for the Alaska Department of Environmental Conservation. March 2012.

Principal Component Analysis: Inventory Insights and Speciated $PM_{2.5}$ Estimates. Crawford. Presentation at Air Quality Symposium 2011, Fairbanks and North Star Borough, Fairbanks, AK. January 2011.

Influence of Meteorology on $PM_{2.5}$ Concentrations in Fairbanks Alaska: Winter 2008-2009. Crawford. Presentation at Air Quality Symposium 2009, Fairbanks and North Star Borough, Fairbanks, AK. July 2009.

Analysis of the Effect of Fuel Chemistry and Properties on HCCI Engine Operation: A Re-Analysis Using a PCA Representation of Fuels. Bunting and Crawford. 2009. Draft Report (CRC Project AFVL13C)

The Chemistry, Properties, and HCCI Combustion Behavior of Refinery Streams Derived from Canadian Oil Sands Crude. Bunting, Fairbridge, Mitchell, Crawford, et al. 2008. (SAE 08FFL 28)

The Relationships of Diesel Fuel Properties, Chemistry, and HCCI Engine Performance as Determined by Principal Components Analysis. Bunting and Crawford. 2007. (SAE 07FFL 64).

Review and Critique of Data and Methodologies used in EPA Proposed Utility Mercury MACT Rulemaking, prepared by AEMS and RWCrawford Energy Systems for the National Mining Association. April 2004.

PCR+ in Diesel Fuels and Emissions Research. McAdams, Crawford, Hadder. March 2002. ORNL/TM-2002/16.

A Vector Approach to Regression Analysis and its Application to Heavy-duty Diesel Emissions. McAdams, Crawford, Hadder. November 2000. ORNL/TM-2000/5.

A Vector Approach to Regression Analysis and its Application to Heavy-duty Diesel Emissions. McAdams, Crawford, Hadder. June 2000. (SAE 2000-01-1961).

Reconciliation of Differences in the Results of Published Shortfall Analyses of 1981 Model Year Cars. Prepared by Energy and Environmental Analysis, Inc. for the U.S. Department of Energy under Contract DE-AC01-79PE-70045. October 1985

Short Test Results on 1980-1981 Passenger Cars from the Arizona Inspection and Maintenance Program. Darlington, Crawford, Sashihara. August 1984.

Seasonal and Regional MPG as Influenced by Environmental Conditions and Travel Patterns. Prepared by Energy and Environmental Analysis, Inc. for the U.S. Department of Energy under Contract DE-AC01-79PE-70045. March 1983.

Comparison of EPA and On-Road Fuel Economy – Analysis Approaches, Trends, and Impacts. McNutt, Dulla, Crawford, McAdams, Morse. June 1982. (SAE 820788)

Regionalization of In-Use Fuel Economy Effects. Prepared by Energy and Environmental Analysis, Inc. for the U.S. Department of Energy under Contract DE-AC01-79PE-70032. April 1982.

1985 Light-Duty Truck Fuel Economy. Duleep, Kuhn, Crawford. October 1980. (SAE 801387)

PROFESSIONAL AFFILIATIONS

Member, Society of Automotive Engineers.

HONORS AND AWARDS

2006 Barr y D. McNutt Award for Excellence in Automotive Policy Analysis. Society of Automotive Engineers.

US Patent 7018524 (McAdams, Crawford, Hadder, McNutt). Reformulated diesel fuels for automotive diesel engines which meet the requirements of ASTM 975-02 and provide significantly reduced emissions of nitrogen oxides (NO_x) and particulate matter (PM) relative to commercially available diesel fuels.

US Patent 7096123 (McAdams, Crawford, Hadder, McNutt). A method for mathematically identifying at least one diesel fuel suitable for combustion in an automotive diesel engine with significantly reduced emissions and producible from known petroleum blend stocks using known refining processes, including the use of cetane additives (ignition improvers) and oxygenated compounds.

###

12_B_LCFS_GE Responses (Page 205 – 210)

712. Comment: **Robert Crawford's Resume**

Agency Response: This is submittal one of four of Robert Crawford's resume. It does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

EXHIBIT B

BEFORE THE
CALIFORNIA AIR RESOURCES BOARD

In re:	)
	)
Proposed Regulation on the Commercialization of Alternative Diesel Fuels (Public Hearing Scheduled for March 20, 2014)	)
	)

Declaration of James M. Lyons

I, James M. Lyons, declare and state as follows:

1. I am an engineer with training and expertise in motor vehicle fuels, automotive emissions control, and automotive air pollution. I am a Senior Partner of Sierra Research, Inc. ("Sierra"), an environmental consulting firm located at 1801 J Street, Sacramento, California. Sierra specializes in research and regulatory matters pertaining to air pollution control, and does work for both governmental and private sector clients. I have been employed at Sierra Research since 1991. I received a B.S. degree in Chemistry from the University of California, Irvine, and a M.S. Degree in Chemical Engineering from the University of California, Los Angeles. Before joining Sierra in 1991, I was employed by the State of California in the Mobile Source Division of the California Air Resources Board ("CARB").

I. Introduction, Qualifications, and Materials Considered

2. I have prepared this Declaration and the analysis it contains for Growth Energy. I hold the opinions expressed in this Declaration with a reasonable degree of engineering and scientific certainty. I plan to request an opportunity to testify before CARB at the public hearing scheduled for this matter, so that I may answer any questions concerning my opinions and the analysis and sources on which I have based those opinions. I also request that CARB review and

respond to each part of the analysis and opinions presented in this Declaration before deciding what action to take on the CARB staff's proposed alternative diesel fuel ("ADF") regulation.

3. During my career, I have worked on many projects related to the following areas: (1) the assessment of emissions from on- and non-road mobile sources, including ships and locomotives; (2) analyses of the unintended consequences of regulatory actions; and (3) the feasibility of compliance with air quality regulations. I have also studied how the use of biodiesel fuels can influence exhaust emissions of oxides of nitrogen ("NOx") when used in vehicles and engines operated in California, and I have prepared and filed declarations regarding that issue in *POET LLC et al. v. California Air Resources Board*, an action in which I was a co-petitioner.

4. I have testified as an expert under state and federal court rules in cases involving CARB regulations for gasoline, Stage II vapor recovery systems and their design, combustion chamber system design, and issues related to emissions from heavy-duty vehicles and engines. While at Sierra I have acted as a consultant on automobile air pollution control matters for CARB and other governmental organizations. I am a member of the American Chemical Society and the Society of Automotive Engineers and have co-authored nine peer-reviewed monographs concerned with automotive emissions, including greenhouse gases and their control. In addition, over the course of my career, I have conducted peer-reviews of numerous papers related to a wide variety of issues associated with pollutant emissions and air quality. My résumé is attached as Attachment A.

5. I have reviewed a report being filed along with this Declaration by Growth Energy that has been prepared by Mr. Robert Crawford of Rincon Ranch Consulting, entitled *NOx Emissions Impact of Soy- and Animal-based Biodiesel Fuels: A Re-Analysis* (December

2013). I have also studied the CARB Initial Statement of Reasons ("ISOR" or "Staff Report") released to support the proposed ADF regulation, and the studies cited in the ISOR that are pertinent to Mr. Crawford's analysis. The additional materials I have considered to prepare this Declaration are identified as references.

6. Mr. Crawford's report examines the empirical basis for the CARB staff's claims that the use of biodiesel in California is unlikely to warrant environmental mitigation, and that the use of biodiesel blends below the ten percent blend level (B10) in California pursuant to the proposed ADF regulation will not result in increases in NOx emissions.

7. Mr. Crawford's report applies generally accepted methods of data analysis and demonstrates expertise in the subject-matter of the report; Mr. Crawford is an expert in the field in which he opines in his report; and his report is the type of analysis on which experts in the field of automotive emissions control rely.

II. Analysis and Opinions

A. Increases in NOx Emissions from Biodiesel Blends Below B10

8. As explained in detail in Mr. Crawford's report, a proper statistical analysis of the available emissions data relied upon by CARB staff in developing the proposed ADF regulation demonstrates that statistically significant increases in NOx emissions will result from biodiesel blends that contain less than ten percent biodiesel, including at the five percent level (B5) and below. In addition, Mr. Crawford's report demonstrates that NOx emissions increase in direct proportion of the amount of biodiesel in a blend and there is not, as CARB staff claims, a "threshold" below which biodiesel use in a blend will not increase NOx emissions. Given this, as I explain below in more detail, CARB staff should be proposing a Significance Level of zero, rather than ten percent, for biodiesel. Given the issues identified with the CARB staff analysis of

ADF B3-93

biodiesel impacts on NOx emissions by Mr. Crawford, CARB has no credible scientific basis upon which to adopt the ADF regulation as proposed with the biodiesel Significance Level set at ten percent.

ADF B3-93 cont.

9. CARB staff presents, in Figures B.2 and B.3 of the ISOR, regressions of all the available emissions data considered by CARB staff in developing the proposed ADF regulation. Based on Mr. Crawford's findings, the slopes of these regression lines can be used to calculate the increases in NOx emissions expected from the use of soy- and animal-based biodiesel as a function of biodiesel content in the blend. The values calculated for soy- and animal-based biodiesel at selected blends levels over the range from one percent to twenty percent are shown in Table 1.

Table 1
Expected Increases In NOx Emissions from Biodiesel Use Based on Available Emissions Data Considered by CARB Staff

Biodiesel Blend Level %	Percentage Increase in NOx Emissions	
	Soy-Based	Animal-Based
1	0.2	0.09
2	0.4	0.18
3	0.6	0.27
4	0.8	0.36
5	1	0.45
10	2	0.90
20	4	1.80

ADF B3-94

10. As shown in Table 1, the magnitude of the NOx increase for animal-based biodiesel is approximately half that observed for soy-based biodiesel. As also shown in Table 1, the emissions data considered by CARB show that increases in NOx emissions between about one and two percent occur at the proposed B10 significance threshold.

ADF B3-95

B. The "Effective Blend Level" Concept Provides No Assurance Against Increases in NOx Emissions Due to Biodiesel Use

11. The proposed ADF regulation relies on a concept called the "Effective Blend Level" (EB) for biodiesel to determine when mitigation would be required. The formula proposed by CARB staff for calculating the Effective Blend Level for biodiesel is found in proposed Section 2293.6(a) and is reproduced below.

$$EB = 100 \times \left[\frac{NBV - 0.5LN - 0.73RD - VM - 0.55AB}{TCV}\right]$$

As specified in Section 2293.6(a), the above formula is to be used to compute an annual average statewide value for the Effective Blend Level relative to the total volume of fuel used in compression ignition engines excluding alternative fuels such as natural gas and liquefied petroleum gas ("TCV") in the state during that year.

12. The calculation begins with establishing the net volume of biodiesel of all types used in California *excluding biodiesel used in blends of five percent or less* (NBV) — a step that has no scientific basis, as demonstrated by Mr. Crawford's analysis, and that, on its own, completely invalidates the use of the EB metric for the intended purpose. The NBV value is then further reduced by subtracting 50% of the volume of low NOx Diesel (LN) used statewide and 73% of the volume of renewable Diesel used statewide. The remainder is then further reduced by subtracting the volume of biodiesel of all types used in blends where steps have been taken to voluntarily mitigate NOx increases (VM) and then again by subtracting 55% of the volume of animal-based biodiesel (AB) to account for the smaller magnitude of the NOx emission increases observed with that fuel.[1] The final value is then divided by TCV (i.e., the total volume of fuel

1 Those voluntary mitigation measures are assumed to have been taken before the so-called "Significance Level" is reached and mitigation would be required under the staff's proposal. *See* ¶ 13.

used in compression ignition engines excluding alternative fuels such as natural gas and liquefied petroleum gas in the state during that year) and multiplied by 100 to yield the Effective Blend Level on a percentage basis.

13. As specified in proposed Section 2293.5(c)(4), mitigation of NOx increases associated with biodiesel would be required only when the value of EB reaches 9.5 percent, which is 95% of the 10% Significance Level proposed for biodiesel.

14. There are a number of specific problems with the concept and calculation of the predicted Effective Blend Level that create the potential for significant increases in NOx emissions to result from the use of biodiesel in California; these are explained in detail below and should be addressed by CARB. As an initial matter, however, the overall problem with the EB concept will allow massive increases in the amount of biodiesel used in California without requiring any mitigation of the associated increase in NOx emissions. This can be seen readily by comparing CARB staff's projections of biodiesel use in California (Figure 6.2 of the ISOR) with CARB staff's projections regarding the Effective Blend Level for biodiesel (Figure 6.5 of the ISOR). Those two figures are reproduced below in Figure 1. As can been seen, despite the forecast nine-fold increase in annual biodiesel use in California from 50 million to 450 million gallons from 2013 to 2023 shown in Figure 6.2 of the ISOR, the forecast Effective Blend Level of biodiesel **decreases** to less than zero over virtually all of the period in question — meaning that, under the CARB staff's proposal, no mitigation of the increase in NOx emissions in California from biodiesel use will ever occur. CARB needs to confront and eliminate the EB concept from the staff's proposal, in light of this very simple demonstration of why the EB concept will not protect the environment against increases in NOx emissions. ADF B3-96

Figure 1. CARB Biodiesel Forecasts

Figure 6.2: Statewide Biodiesel Volume

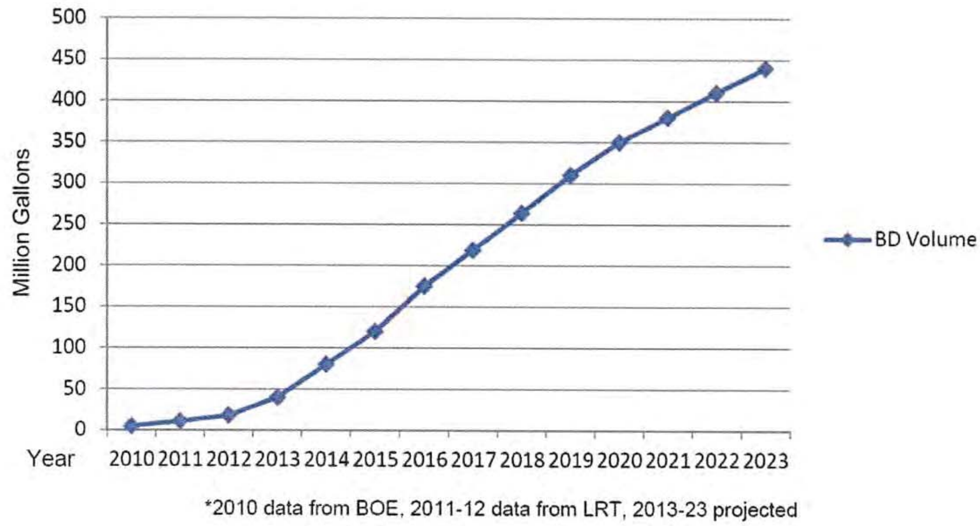
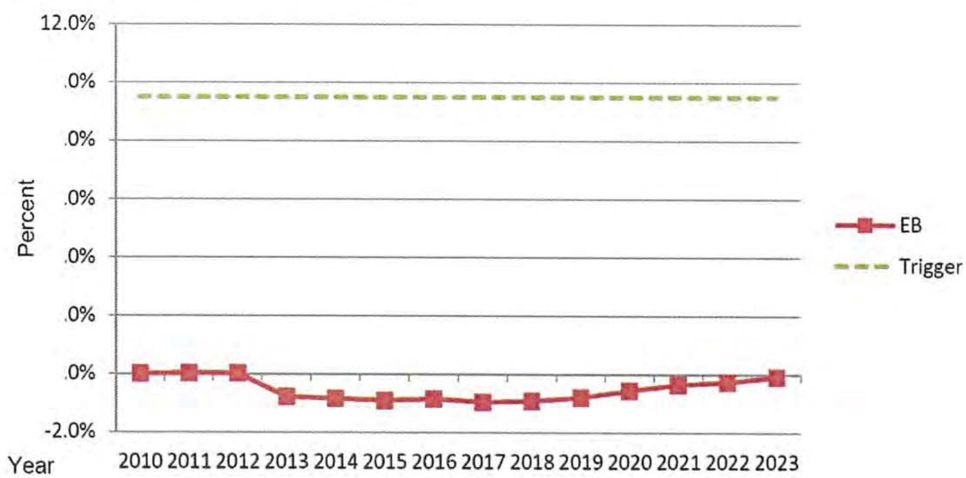


Figure 6.5: Effective Biodiesel Blend Level Forecast



Source: CARB Initial Statement of Reasons. Note that Figure 6.5 is reproduced directly from the ISOR, which is missing some increments on the y-axis.

15. Next, CARB needs to modify the proposed ADF regulation in order to address CARB staff's faulty assumption that biodiesel blends of up to five percent will have no impact on NOx emissions. With respect to five percent blends, CARB staff states on page ES-3 of the Staff ADF B3-97

Report that "biodiesel used in blends at B9 or below, including the B5 (B0 to B5) in predominant use today, does not increase NOx." The Staff Report also attempts to justify the exclusion of five percent blends from the EB calculation by arbitrarily excluding these blends from the ADF regulation. That assertion is undercut by the Staff Report's frank and correct admission on page 51 that "[g]iven the significant price premium for higher biodiesel blends such as B20 or B100, it is highly unlikely that operators of heavy-duty, legacy diesel fleets would opt to use the more expensive, higher biodiesel blends when comparable, lower cost conventional CARB diesel or B5 blends are readily available." ADF B3-97 cont.

16. As noted above, Mr. Crawford's analysis demonstrates that statistically significant increases in NOx emissions will occur from the use of five percent biodiesel blends and, as Table 1 shows, the available emissions data relied upon by CARB staff indicate that at the five percent blend level, biodiesel use is expected to increase NOx emission by between about 0.5 and one percent. There is no doubt that unmitigated NOx emission increases of this magnitude have the potential to create significant adverse environmental impacts in areas of California with severe air quality problems. ADF B3-98

17. It is also important for CARB to understand the import of the staff's prediction that biodiesel blends of five percent or less will be the primary means by which biodiesel will be used in California. As the Staff Report states on page 30:

> Staff has communicated with many of the stations that sell biodiesel as well as the major terminal operators in the state, and has found that the vast majority of the biodiesel currently being sold in California and expected to be sold in the future is sold as blends of B5 or less. ADF B3-99

The fact that most biodiesel used in California will be sold as blends of five percent biodiesel or less, coupled with the fact that – as Mr. Crawford has explained – the available data show statistically significant increases in NOx emissions from such blends, means that biodiesel use in

California under the proposed ADF regulation will result in unmitigated increases in NOx emissions. Again, the critical nature of the CARB staff's invalid assumption about the NOx impacts of blends at or below five percent simply cannot be ignored by CARB. ADF B3-99 cont.

18. Even if it were correct that blends of B5 and less have no impact on NOx emissions, the EB calculation double-counts for the supposedly benign effect of those blends, and therefore makes mitigation even more unlikely. This can be illustrated by noting that CARB staff estimates that 450 million gallons per year of biodiesel will be used in California in 2023. (See Figure 6.2 of the Staff Report.) A recent California Energy Commission forecast[2] for total Diesel use in California in 2023 is about 4 billion gallons. On that basis, and without discounting for low NOx, renewable Diesel, or voluntary mitigation, the actual Effective Blend Level would be 11.25 percent and mitigation would be required for at least some biodiesel blends under the proposed ADF. Under CARB staff's approach, however, if a substantial portion of that biodiesel — for example, 50 percent — is five percent or lower blends, the Effective Blend Level drops to 5.6 percent and no mitigation of any kind is required for any biodiesel blends. That result is clearly incorrect, and the EB calculation must be modified to include, rather than exclude, B5 blends. ADF B3-100

19. Another fundamental problem with the proposed EB calculation is that it is based on annual statewide average fuel use. NOx emissions have local and immediate impacts on air quality, with the questions of when and where they occur in the state being of critical importance with respect to the significance of those impacts. It follows directly that mitigation of NOx increases associated with biodiesel use must occur in the same area at the same time if air quality ADF B3-101

---

[2] See *http://www.energy.ca.gov/2011publications/CEC-600-2011-007/CEC-600-2011-007-SD.pdf*.

impacts are to be avoided. However, the EB completely fails to provide this assurance because CARB staff has either (1) ignored that reductions in NOx emissions from mitigation must take place at the same time and in the same area as NOx increases from biodiesel use, or (2) without support from anything in the rulemaking file, assumed that mitigation will occur in the same area and at the same time as the increases in NOx emissions.

ADF B3-101 cont.

20. To illustrate the problems the EB creates for mitigation, consider, for example, that under the proposed ADF regulation, increases in NOx emissions could occur from trucks operating on biodiesel in Los Angeles during August and exacerbate already high ambient ozone levels in that area. In turn, this increase in NOx emissions could be "mitigated" by reductions in NOx emissions from trucks operating on renewable diesel in the San Francisco area during December, when high ozone levels are not a problem. In this example, the EB concept would allow residents of Los Angeles to suffer adverse environmental impacts while the residents of San Francisco would realize no environmental benefit. Clearly the approach to mitigation designed into the EB concept by CARB staff makes no sense.

ADF B3-102

C. CARB Staff's Assumption that Biodiesel Use Will not Increase Emissions from New Technology Diesel Engines Is Not Adequately Supported

21. In the Staff Report, CARB staff makes frequent statements regarding the impact of biodiesel on NOx emissions from "new technology diesel engines" (or "NTDEs"). For example, on page ES-3 of the ISOR, the staff states categorically that "use of biodiesel in 2010-compliant engines and other so-called 'New Technology Diesel Engines' does not increase NOx, regardless of the biodiesel blend level." Only one reference, Lammert et al.,[3] is provided in the staff report

ADF B3-103

[3] Lammert, M., McCormick, R., Sindler, P. and Williams, A., "Effect of B20 and Low Aromatic Diesel on Transit Bus NOx Emissions Over Driving Cycles with a Range of Kinetic Intensity," *SAE Int. J. Fuels Lubr.* 5(3):2012,

(Continued...)

to support this and other, analogous, statements by CARB staff. As CARB staff acknowledges, this single study involved chassis dynamometer testing of only two urban buses with NTDEs, with both engines being the same model produced by the same manufacturer. The extrapolation of that limited testing to the entire population of heavy-duty Diesel vehicles with NTDEs used in different applications and with different engine designs produced by a number of different manufacturers is simply not credible or reliable.

ADF B3-103 cont.

22. In addition, the CARB staff fails to acknowledge the following statement made by the authors of the Lammert study about the measurement of NOx emissions: "For much of the cycle[,] NOx would be at or near the detection limit of the laboratory equipment which resulted in a 95 percent confidence interval that was high relative to the value of the cycle emissions." That effect, which can be clearly seen in Figures 10 and 11 of the Lammert study, renders the claim that there was no statistically significant increase in NOx emissions observed from the use of biodiesel in NTDEs an artifact attributable to the lack of sensitivity of the NOx measurement instrumentation used in the study.

ADF B3-104

23. In sum, the CARB staff's unequivocal statements regarding the impact of biodiesel on NOx emissions from all vehicles with NTDEs is simply not reasonable based on data from (1) a single study that (2) that tested only two urban buses equipped with the same engine and (3) used instrumentation that was, at best, barely able to measure NOx emissions from the test vehicles in general, and clearly was not sensitive enough to reliably detect changes in NOx emissions due to use of different fuels. Nothing else in the rulemaking file supports the CARB staff's claim that there will not be increased NOx emissions from the use of biodiesel in NTDEs.

ADF B3-105

I declare under penalty of perjury under the laws of California that the foregoing is true and correct to the best of my knowledge and belief.

Executed this __12th__ day of December 2013 at Sacramento, California.

James M. Lyons

12_B_LCFS_GE Responses (Page 211 – 224)

713. Comment: **ADF B3-93 through ADF B3-97 and ADF B3-100 through ADF B3-102**

Agency Response: This comment is responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

714. Comment: **ADF B3-98, ADF B3-99, ADF B3-103 through ADF B3-105**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

ATTACHMENT A

sierra
research

1801 J Street
Sacramento, CA 95811
Tel: (916) 444-6666
Fax: (916) 444-8373
Ann Arbor, MI
Tel: (734) 761-6666
Fax: (734) 761-6755

Résumé

James Michael Lyons

Education

1985, M.S., Chemical Engineering, University of California, Los Angeles

1983, B.S., Cum Laude, Chemistry, University of California, Irvine

Professional Experience

4/91 to present — Senior Engineer/Partner/Senior Partner
Sierra Research

Primary responsibilities include oversight and execution of complex analyses of the emission benefits, costs, and cost-effectiveness of mobile source air pollution control measures. Mr. Lyons has developed particular expertise with respect to the assessment of control measures involving fuel reformulation, fuel additives, and alternative fuels, as well as accelerated vehicle/engine retirement programs, the deployment of advanced emission control systems for on- and non-road gasoline- and Diesel-powered engines, on-vehicle evaporative and refueling emission control systems, and Stage I and Stage II service station vapor recovery systems. Additional duties include assessments of the activities of federal, state, and local regulatory agencies with respect to motor vehicle emissions and reports to clients regarding those activities. Mr. Lyons has extensive litigation experience related to air quality regulations, product liability, and intellectual property issues.

7/89 to 4/91 — Senior Air Pollution Specialist
California Air Resources Board

Supervised a staff of four professionals responsible for identifying and controlling emissions of toxic air contaminants from mobile sources and determining the effects of compositional changes to gasoline and diesel fuel on emissions of regulated and unregulated pollutants. Other responsibilities included development of new test procedures and emission standards for evaporative and running loss emissions of hydrocarbons from vehicles; overseeing the development of the state plan to control toxic emissions from motor vehicles; and reducing emissions of CFCs from motor vehicles.

4/89 to 7/89 Air Pollution Research Specialist
California Air Resources Board

Responsibilities included identification of motor vehicle research needs; writing requests for proposals; preparation of technical papers and reports; as well as monitoring and overseeing research programs.

9/85 to 4/89 Associate Engineer/Engineer
California Air Resources Board

Duties included analysis of vehicle emissions data for trends and determining the effectiveness of various types of emissions control systems for both regulated and toxic emissions; determining the impact of gasoline and diesel powered vehicles on ambient levels of toxic air contaminants; participation in the development of regulations for "gray market" vehicles; and preparation of technical papers and reports.

Professional Affiliations

American Chemical Society
Society of Automotive Engineers

Selected Publications (Author or Co-Author)

"Review of CARB Staff Analysis of 'Illustrative' Low Carbon Fuel Standard (LCFS) Compliance Scenarios," Sierra Research Report No. SR2012-02-01, prepared for the Western States Petroleum Association, February 20, 2012.

"Review of CARB On-Road Heavy-Duty Diesel Emissions Inventory," Sierra Research Report No. SR2010-11-01, prepared for The Ad Hoc Working Group, November 2010.

"Identification and Review of State/Federal Legislative and Regulatory Changes Required for the Introduction of New Transportation Fuels," Sierra Research Report No. SR2010-08-01, prepared for the American Petroleum Institute, August 2010.

"Technical Review of EPA Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis for Non-GHG Pollutants," Sierra Research Report No. SR2010-05-01, prepared for the American Petroleum Institute, May 2010.

"Effects of Gas Composition on Emissions from Heavy-Duty Natural Gas Engines," Sierra Research Report No. SR2010-02-01, prepared for the Southern California Gas Company, February 2010.

"Effects of Gas Composition on Emissions from a Light-Duty Natural Gas Vehicle," Sierra Research Report No. SR2009-11-01, prepared for the Southern California Gas Company, November 2009.

"Technical Review of 2009 EPA Draft Regulatory Impact Analysis for Non-GHG Pollutants Due to Changes to the Renewable Fuel Standard," Sierra Research Report No. SR2009-09-01, prepared for the American Petroleum Institute, September 2009.

"Effects of Vapor Pressure, Oxygen Content, and Temperature on CO Exhaust Emissions," Sierra Research Report No. 2009-05-03, prepared for the Coordinating Research Council, May 2009.

"Technical Review of 2007 EPA Regulatory Impact Analysis Methodology for the Renewable Fuels Standard," Sierra Research Report No. 2008-09-02, prepared for the American Petroleum Institute, September 2008.

"Impacts of MMT Use in Unleaded Gasoline on Engines, Emission Control Systems, and Emissions," Sierra Research Report No. 2008-08-01, prepared for McMillan Binch Mendelsohn LLP, Canadian Vehicle Manufacturers' Association, and Association of International Automobile Manufacturers of Canada, August 2008.

"Attachment to Comments Regarding the NHTSA Proposal for Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015, Docket No. NHTSA-2008-0089," Sierra Research Report No. SR2008-06-01, prepared for the Alliance of Automobile Manufacturers, June 2008.

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act – Part 1: Impacts on New Vehicle Fuel Economy," SAE Paper No. 2008-01-1852, Society of Automotive Engineers, 2008.

"Basic Analysis of the Cost and Long-Term Impact of the Energy Independence and Security Act Fuel Economy Standards," Sierra Research Report No. SR 2008-04-01, April 2008.

"The Benefits of Reducing Fuel Consumption and Greenhouse Gas Emissions from Light-Duty Vehicles," SAE Paper No. 2008-01-0684, Society of Automotive Engineers, 2008.

"Assessment of the Need for Long-Term Reduction in Consumer Product Emissions in South Coast Air Basin," Sierra Research Report No. 2007-09-03, prepared for the Consumer Specialty Products Association, September 2007.

"Summary of Federal and California Subsidies for Alternative Fuels," Sierra Research Report No. SR2007-04-02, prepared for the Western States Petroleum Association, April 2007.

"Analysis of IRTA Report on Water-Based Automotive Products," Sierra Research Report No. SR2006-08-02, prepared for the Consumer Specialty Projects Association and Automotive Specialty Products Alliance, August 2006.

"Evaluation of Pennsylvania's Implementation of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2006-04-01, prepared for Alliance of Automobile Manufacturers, April 12, 2006.

"Evaluation of New Jersey's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-03, prepared for the Alliance of Automobile Manufacturers, September 30, 2005.

"Evaluation of Vermont's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-02, prepared for the Alliance of Automobile Manufacturers, September 19, 2005.

"Assessment of the Cost-Effectiveness of Compliance Strategies for Selected Eight-Hour Ozone NAAQS Nonattainment Areas," Sierra Research Report No. SR2005-08-04, prepared for the American Petroleum Institute, August 30, 2005.

"Evaluation of Connecticut's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-08-03, prepared for the Alliance of Automobile Manufacturers, August 26, 2005.

"Evaluation of New York's Adoption of California's Greenhouse Gas Regulations On Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-07-04, prepared for the Alliance of Automobile Manufacturers, July 14, 2005.

"Review of MOVES2004," Sierra Research Report No. SR2005-07-01, prepared for the Alliance of Automobile Manufacturers, July 11, 2005.

"Review of Mobile Source Air Toxics (MSAT) Emissions from On-Highway Vehicles: Literature Review, Database, Development, and Recommendations for Future Studies," Sierra Research Report No. SR2005-03-01, prepared for the American Petroleum Institute, March 4, 2005.

"The Contribution of Diesel Engines to Emissions of ROG, NOx, and PM2.5 in California: Past, Present, and Future," Sierra Research Report No. SR2005-02-01, prepared for Diesel Technology Forum, February 2005.

"Fuel Effects on Highway Mobile Source Air Toxics (MSAT) Emissions," Sierra Research Report No. SR2004-12-01, prepared for the American Petroleum Institute, December 23, 2004.

"Review of the August 2004 Proposed CARB Regulations to Control Greenhouse Gas Emissions from Motor Vehicles: Cost Effectiveness for the Vehicle Owner or Operator – Appendix C to the Comments of The Alliance of Automobile Manufacturers," Sierra Research Report No. SR2004-09-04, prepared for the Alliance of Automobile Manufacturers, September 2004.

"Emission and Economic Impacts of an Electric Forklift Mandate," Sierra Research Report No. SR2003-12-01, prepared for National Propane Gas Association, December 12, 2003.

"Reducing California's Energy Dependence," Sierra Research Report No. SR2003-11-03, prepared for Alliance of Automobile Manufacturers, November 25, 2003.

"Evaluation of Fuel Effects on Nonroad Mobile Source Air Toxics (MSAT) Emissions: Literature Review, Database Development, and Recommendations for Future Studies," Sierra Research Report No. SR2003-10-01, prepared for American Petroleum Institute, October 3, 2003.

"Review of Current and Future CO Emissions from On-Road Vehicles in Selected Western Areas," Sierra Research Report No. SR03-01-01, prepared for the Western States Petroleum Association, January 2003.

"Review of CO Compliance Status in Selected Western Areas," Sierra Research Report No. SR02-09-04, prepared for the Western States Petroleum Association, September 2002.

"Impacts Associated With the Use of MMT as an Octane Enhancing Additive in Gasoline – A Critical Review", Sierra Research Report No. SR02-07-01, prepared for Canadian Vehicle Manufacturers Association and Association of International Automobile Manufacturers of Canada, July 24, 2002.

"Critical Review of 'Safety Oversight for Mexico-Domiciled Commercial Motor Carriers, Final Programmatic Environmental Assessment', Prepared by John A Volpe Transportation Systems Center, January 2002," Sierra Research Report No. SR02-04-01, April 16, 2002.

"Critical Review of the Method Used by the South Coast Air Quality Management District to Establish the Emissions Equivalency of Heavy-Duty Diesel- and Alternatively Fueled Engines", Sierra Research Report No. SR01-12-03, prepared for Western States Petroleum Association, December 21, 2001.

"Review of U.S. EPA's Diesel Fuel Impact Model", Sierra Research Report No. SR01-10-01, prepared for American Trucking Associations, Inc., October 25, 2001.

"Operation of a Pilot Program for Voluntary Accelerated Retirement of Light-Duty Vehicles in the South Coast Air Basin," Sierra Research Report No. SR01-05-02, prepared for California Air Resources Board, May 2001.

"Comparison of Emission Characteristics of Advanced Heavy-Duty Diesel and CNG Engines," Sierra Report No. SR01-05-01, prepared for Western States Petroleum Association, May 2001.

"Analysis of Southwest Research Institute Test Data on Inboard and Sterndrive Marine Engines," Sierra Report No. SR01-01-01, prepared for National Marine Manufacturers Association, January 2001.

"Institutional Support Programs for Alternative Fuels and Alternative Fuel Vehicles in Arizona: 2000 Update," Sierra Report No. SR00-12-04, prepared for Western States Petroleum Association, December 2000.

"Real-Time Evaporative Emissions Measurement: Mid-Morning Commute and Partial Diurnal Events," SAE Paper No. 2000-01-2959, October 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," SAE Paper No. 2000-01-2958, October 2000.

"A Comparative Analysis of the Feasibility and Cost of Compliance with Potential Future Emission Standards for Heavy-Duty Vehicles Using Diesel or Natural Gas," Sierra Research Report No. SR00-02-02, prepared for Californians For a Sound Fuel Strategy, February 2000.

"Critical Review of the Report Entitled 'Economic Impacts of On Board Diagnostic Regulations (OBD II)' Prepared by Spectrum Economics," Sierra Research Report No. SR00-01-02, prepared for the Alliance of Automobile Manufacturers, January 2000.

"Potential Evaporative Emission Impacts Associated with the Introduction of Ethanol-Gasoline Blends in California," Sierra Research Report No. SR00-01-01, prepared for the American Methanol Institute, January 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," Sierra Research Report No. SR99-10-03, prepared for the Coordinating Research Council, October 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," SAE Paper No. 1999-01-3676, August 1999.

"Future Diesel-Fueled Engine Emission Control Technologies and Their Implications for Diesel Fuel Properties," Sierra Research Report No. SR99-08-01, prepared for the American Petroleum Institute, August 1999.

"Analysis of Compliance Feasibility under Proposed Tier 2 Emission Standards for Passenger Cars and Light Trucks," Sierra Research Report No. SR99-07-02, July 1999.

"Comparison of the Properties of Jet A and Diesel Fuel," Sierra Research Report No. SR99-02-01, prepared for Pillsbury Madison and Sutro, February 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," Sierra Research Report No. SR98-12-02, prepared for the American Petroleum Institute, December 1998.

"Analysis of New Motor Vehicle Issues in the Canadian Government's Foundation Paper on Climate Change – Transportation Sector," Sierra Research Report No. SR98-12-01, prepared for the Canadian Vehicle Manufacturers Association, December 1998.

"Investigation of the Relative Emission Sensitivities of LEV Vehicles to Gasoline Sulfur Content - Emission Control System Design and Cost Differences," Sierra Research Report No. SR98-06-01, prepared for the American Petroleum Institute, June 1998.

"Costs, Benefits, and Cost-Effectiveness of CARB's Proposed Tier 2 Regulations for Handheld Equipment Engines and a PPEMA Alternative Regulatory Proposal," Sierra

Research Report No. SR98-03-03, prepared for the Portable Power Equipment Manufacturers Association, March 1998.

"Analysis of Diesel Fuel Quality Issues in Maricopa County, Arizona," Sierra Research Report No. SR97-12-03, prepared for the Western States Petroleum Association, December 1997.

"Potential Impact of Sulfur in Gasoline on Motor Vehicle Pollution Control and Monitoring Technologies," prepared for Environment Canada, July 1997.

"Analysis of Mid- and Long-Term Ozone Control Measures for Maricopa County," Sierra Research Report No. SR96-09-02, prepared for the Western States Petroleum Association, September 9, 1996.

"Technical and Policy Issues Associated with the Evaluation of Selected Mobile Source Emission Control Measures in Nevada," Sierra Research Report No. SR96-03-01, prepared for the Western States Petroleum Association, March 1996.

"Cost-Effectiveness of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-05, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"Cost of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-04, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"A Comparative Characterization of Gasoline Dispensing Facilities With and Without Vapor Recovery Systems," Sierra Research Report No. SR95-10-01, prepared for the Province of British Columbia Ministry of Environment Lands and Parks, October 1995.

"Potential Air Quality Impacts from Changes in Gasoline Composition in Arizona," Sierra Research Report No. SR95-04-01, prepared for Mobil Corporation, April 1995.

"Vehicle Scrappage: An Alternative to More Stringent New Vehicle Standards in California," Sierra Research Report No. SR95-03-02, prepared for Texaco, Inc., March 1995.

"Evaluation of CARB SIP Mobile Source Measures," Sierra Research Report No. SR94-11-02, prepared for Western States Petroleum Association, November 1994.

"Reformulated Gasoline Study," prepared by Turner, Mason & Company, DRI/McGraw-Hill, Inc., and Sierra Research, Inc., for the New York State Energy Research and Development Authority, Energy Authority Report No. 94-18, October 1994.

"Phase II Feasibility Study: Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley," Sierra Research Report No. SR94-09-02, prepared for the Greater Vancouver Regional District, September 1994.

"Cost-Effectiveness of Mobile Source Emission Controls from Accelerated Scrappage to Zero Emission Vehicles," Paper No. 94-TP53.05, presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, OH, June 1994.

"Investigation of MOBILE5a Emission Factors, Assessment of I/M Program and LEV Program Emission Benefits," Sierra Research Report No. SR94-06-05, prepared for American Petroleum Institute, June 1994.

"Cost-Effectiveness of the California Low Emission Vehicle Standards," SAE Paper No. 940471, 1994.

"Meeting ZEV Emission Limits Without ZEVs," Sierra Research Report No. SR94-05-06, prepared for Western States Petroleum Association, May 1994.

"Evaluating the Benefits of Air Pollution Control - Method Development and Application to Refueling and Evaporative Emissions Control," Sierra Research Report No. SR94-03-01, prepared for the American Automobile Manufacturers Association, March 1994.

"The Cost-Effectiveness of Further Regulating Mobile Source Emissions," Sierra Research Report No. SR94-02-04, prepared for the American Automobile Manufacturers Association, February 1994.

"Searles Valley Air Quality Study (SVAQS) Final Report," Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

"A Comparative Study of the Effectiveness of Stage II Refueling Controls and Onboard Refueling Vapor Recovery," Sierra Research Report No. SR93-10-01, prepared for the American Automobile Manufacturers Association, October 1993.

"Evaluation of the Impact of the Proposed Pole Line Road Overcrossing on Ambient Levels of Selected Pollutants at the Calgene Facilities," Sierra Research Report No. SR93-09-01, prepared for the City of Davis, September 1993.

"Leveling the Playing Field for Hybrid Electric Vehicles: Proposed Modifications to CARB's LEV Regulations," Sierra Research Report No. SR93-06-01, prepared for the Hybrid Vehicle Coalition, June 1993.

"Size Distributions of Trace Metals in the Los Angeles Atmosphere," *Atmospheric Environment*, Vol. 27B, No. 2, pp. 237-249, 1993.

"Preliminary Feasibility Study for a Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley Area," Sierra Research Report No. 92-10-01, prepared for the Greater Vancouver Regional District, October 1992.

"Development of Mechanic Qualification Requirements for a Centralized I/M Program," SAE Paper No. 911670, 1991.

"Cost-Effectiveness Analysis of CARB's Proposed Phase 2 Gasoline Regulations," Sierra Research Report No. SR91-11-01, prepared for the Western States Petroleum Association, November 1991.

"Origins and Control of Particulate Air Toxics: Beyond Gas Cleaning," in Proceedings of the Twelfth Conference on Cooperative Advances in Chemical Science and Technology, Washington, D.C., October 1990.

"The Effect of Gasoline Aromatics on Exhaust Emissions: A Cooperative Test Program," SAE Paper No. 902073, 1990.

"Estimation of the Impact of Motor Vehicles on Ambient Asbestos Levels in the South Coast Air Basin," Paper No. 89-34B.7, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"Benzene/Aromatic Measurements and Exhaust Emissions from Gasoline Vehicles," Paper No. 89-34B.4, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"The Impact of Diesel Vehicles on Air Pollution," presented at the 12th North American Motor Vehicle Emissions Control Conference, Louisville, KY, April 1988.

"Exhaust Benzene Emissions from Three-Way Catalyst-Equipped Light-Duty Vehicles," Paper No. 87-1.3, presented at the 80th Annual Meeting of the Air Pollution Control Association, New York, NY, June 1987.

"Trends in Emissions Control Technologies for 1983-1987 Model-Year California-Certified Light-Duty Vehicles," SAE Paper No. 872164, 1987.

12_B_LCFS_GE Responses (Page 225 – 234)

715. Comment: **James Lyons' Resume**

Agency Response: This is submittal two of six of James Lyon's resume. It does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

growth energy™
America's Ethanol Supporters

777 North Capitol Street, NE, Suite 805, Washington, D.C. 20002
PHONE 202.545.4000 FAX 202.545.4001 GrowthEnergy.org

September 16, 2013

By Electronic Mail

Alexander Mitchell
Floyd Vergara
California Air Resources Board
Stationary Source Division
1001 I Street
Sacramento, California 95812

Re: Comments Regarding CARB's Alternative Diesel Fuels Rulemaking

Dear Sirs:

Growth Energy, an organization of ethanol producers and supporters, has a number of concerns with the Alternative Diesel Fuels (ADF) Regulations currently under development by the staff of the California Air Resources Board (CARB) which were the subject of a September 5th workshop held in Sacramento. These concerns, which are described in detail below, focus on the treatment of biodiesel and biodiesel blends currently being proposed by CARB staff. Overall, the provisions of the proposed ADF regulations would allow for the widespread use of biodiesel and biodiesel blends in California without adequately mitigating the resulting increases in emissions of oxides of nitrogen (NOx). The treatment being proposed by CARB staff for biodiesel and biodiesel blends is unacceptable in that it will result in adverse air quality impacts and violates several of the "underlying principles" in the February 15, 2013, CARB White Paper concerning its conceptual approach to the regulation of alternative diesel fuels, including:[1]

1. Protection of public health;
2. Preservation or improvement of air quality; and
3. Reliance on the best scientific knowledge available.

Given the above, Growth Energy urges CARB staff to revise the proposed ADF regulations to eliminate the potential for biodiesel use in California to result in increased emissions, degraded air quality and adverse impacts on public health.

[1] See page 3 of CARB's White Paper "Discussion of Conceptual Approach to Regulation of Alternative Diesel Fuels", February 15, 2013 which is available at http://www.arb.ca.gov/fuels/diesel/altdiesel/20130212ADFRegConcept.pdf

1. The Proposed ADF Regulation Incorrectly Ignores Increases in NOx Emissions Associated with Use of Biodiesel Blends

As currently drafted, the proposed ADF regulation fails to require any mitigation for increases in NOx emissions associated with the use of biodiesel until total biodiesel usage in the state amounts to at least 10% of all fuel used in diesel engines in California on an annual basis.[2] While the potential for increased NOx emissions due to this arbitrarily established "significance level" for biodiesel use is discussed in Section 2 below, its basic premise appears to be an assumption that there are no NOx emissions associated with the use of biodiesel blends at or below the B10 level. In support of the inaccurate assumption that there is some threshold level below which biodiesel use will not increase emissions, CARB cites its White Paper, which states:[1]

> *Furthermore, for purposes of this rulemaking B5 blends will be considered a legal California diesel fuel with no emissions mitigation required.*

This arbitrary threshold is not supported by any data or analysis, and we are unaware of any published analysis of emissions test data that supports the assumptions that there are no increases in NOx emissions at either the B5 or up to the B10 levels. ADF B3-106

In contrast, a preliminary analysis of data from CARB's most recently funded biodiesel testing program[3] demonstrates that NOx emissions would increase significantly at the B5 and B10 levels in at least some engines and for some biodiesel types. Here, the term "significant" means both that the NOx increase is statistically significant and that it is large enough to be of concern. Although the fact that CARB has not made all of the emissions data from this testing program publically available makes analysis difficult, results of a preliminary analysis are shown in Table 1 below for a 2006 model-year Cummins heavy-duty diesel engine. As shown, the relationship between increasing biodiesel content and increased NOx emissions is statistically significant at the 95% confidence level in all cases for soy-based biodiesel and at the 90% confidence level or better for animal-based biodiesel. ADF B3-107

Further, the R^2 statistics for soy-based fuels show that the emissions effect of biodiesel is almost perfectly linear with increasing biodiesel content. Although not as high because the emissions effect is smaller and measurement errors are relatively larger in comparison to the trend, the R^2 statistics for the animal-based fuels also clearly establish a linear increase in NOx emissions with increasing biodiesel content. Because the slope or the regression equations are statistically significant in all cases and the R^2 statistics are high, there is no evidence in the data for the Cummins engine of the "threshold effect" that CARB staff claims which purports that biodiesel content has to reach the B5 or B10 level before NOx emissions begin to increase.

[2] See slide 18 of the staff presentation for the September 5th workshop which is available at http://www.arb.ca.gov/fuels/diesel/altdiesel/20130905ADFWorkshopPresentation.pdf

[3] Available at http://www.arb.ca.gov/fuels/diesel/altdiesel/20111013_CARB%20Final%20Biodiesel%20Report.pdf

PRELIMINARY ANALYSIS SUBJECT TO REVISON

Table 1. 2006 Cummins Engine (Dynamometer Testing)

Model: NOx = A + B · BioPct

(Note: Dataset does not yet include the data on B5.)

Bright yellow highlight indicates result is statistically significant at 95% confidence level or better.
Light yellow highlight indicates result is statistically significant at the 90% confidence level or better.

Biodiesel Type	Test Cycle	R^2	Intercept A	BioPct Slope B		Predicted NOx Increase for B5	Predicted NOx Increase for B10
			Value	Value	p value	% Change	Pct Change
Soy-based							
	UDDS	0.997	5.896	0.0100	0.001	0.8%	1.7%
	FTP	0.995	2.024	0.0052	0.003	1.3%	2.6%
	40 mph	1.000	2.030	0.0037	<0.0001	0.9%	1.8%
	50 mph	0.969	1.733	0.0028	0.016	0.8%	1.6%
Animal-based							
	UDDS	0.847	5.911	0.0021	0.080	0.2%	0.4%
	FTP	0.981	2.067	0.0031	0.001	0.7%	1.4%
	50 mph	0.887	1.768	0.0011	0.058	0.3%	0.6%

Turning to the importance of the magnitude of the NOx increases, the South Coast Air Quality Management District (SCAQMD) Final 2012 Air Quality Management Plan estimates 2014 NOx emissions from on-road and non-road diesel vehicles to be approximately 190 tons per day.[4] This means that the approximately 1% increase in NOx emissions due to B5 blends translates to an increase of about 2 tons per day in NOx emissions in the South Coast Air Basin alone, while an approximately 2% increase at B10 equals 4 tons per day within that basin. Continuing to B20 the impact would be 8 tons per day. That these are significant increases is clearly evidenced by the fact that both CARB and SCAQMD have adopted numerous emission control measures targeting NOx that have achieved reductions that are similar to or smaller than these values.

ADF B3-108

Instead of acknowledging emissions testing data CARB itself generated that show increases in NOx emissions associated with B5 and B10 blends, CARB staff instead claims that more research is necessary before it can consider mitigation of B5 impacts: [5]

> *Staff is currently contracting with the University of California at Riverside to develop data to determine whether there are significant adverse air-related impacts from the use of B5 blends sufficient to warrant mitigation in the future.*

[4] See Figure 3-9 available at http://www.aqmd.gov/aqmp/2012aqmp/Final-February2013/MainDoc.pdf

[5] See page 4 of CARB's White Paper "Discussion of Conceptual Approach to Regulation of Alternative Diesel Fuels", February 15, 2013 which is available at http://www.arb.ca.gov/fuels/diesel/altdiesel/20130212ADFRegConcept.pdf

This represents an impermissible deferral of analysis and mitigation of significant impacts under CEQA. Moreover, as participants in the process that lead to the adoption of CARB's Low Carbon Fuel Standard (LCFS) regulation in 2009 where CARB adopted indirect land use change (ILUC) values based on preliminary and unsubstantiated modeling results claiming a need to rely on the best available science, Growth Energy finds CARB staff's current position that ignores actual data showing NOx increases from low level biodiesel blends to be unsupported.

ADF B3-108 cont.

2. The Proposed "Significance Threshold" for Biodiesel would Allow Significant Increases in NOx Emissions to Occur in the South Coast and San Joaquin Valley Air Basins Exacerbating Existing Air Quality Problems

In addition to CARB staff's failure to analyze low-level biodiesel blends, the "significance threshold" proposed by CARB staff for biodiesel use in California would allow significant increases in NOx emissions due to biodiesel use to occur in the South Coast and San Joaquin Valley air basins that experience the worst air quality problems in the state.

According to CARB staff's presentation for the September workshop,[6] staff is proposing to evaluate the significance of NOx increases due to biodiesel use on a statewide rather than a regional basis. Given the proposed use of a statewide average biodiesel level and the B10 significance threshold, the potential exists for significant quantities of B20 or even higher levels of biodiesel blends to be used without mitigation in areas of the state with significant air quality problems, such as the South Coast and/or San Joaquin Valley air basins. At this point, even CARB staff acknowledges that use of B20 blends results in significant NOx increases and as noted above based on CARB's own test data B20 use in the South Coast Air Basin could increase NOx emissions by as much as 8 tons per day in 2014.

ADF B3-109

Given the severe air quality problems that exist in the South Coast and San Joaquin Valley air basins, CARB must modify the proposed ADF regulation so that it guarantees that increased NOx emissions related to biodiesel use would not occur in these areas. The reduction of NOx emissions is important, particularly in light of CARB's "Vision for Clean Air,"[7] which demands the elimination of NOx emissions from diesel engines in both air basins as a perquisite for achieving the state's air quality goals.

3. The Proposed Transfer of Credit for Reductions in NOx Emissions Generated by Low NOx Diesel Producers to Offset Increases in NOx Emissions Generated by Biodiesel Producers is Not Equitable

[6] See slide 18 of the staff presentation for the September 5th workshop which is available at http://www.arb.ca.gov/fuels/diesel/altdiesel/20130905ADFWorkshopPresentation.pdf
[7] See http://www.arb.ca.gov/planning/vision/docs/vision_for_clean_air_public_review_draft.pdf

According to CARB staff's presentation at the September workshop,[8] staff is proposing to directly offset increases in NOx emissions resulting from the use of biodiesel with reductions in emissions due to the use of "low NOx" diesel fuels, which are defined by specific properties as shown in the staff presentation for the September 5th workshop.[9] To date, however, we are unaware of any information or explanation from CARB staff as to why producers of low NOx diesel fuels should be forced by CARB regulations to surrender credit for the NOx emission reductions their fuels achieve in order to benefit the producers of biodiesel fuels which increase NOx emissions.

Given that the production of low NOx diesel fuel is not currently mandated by any existing CARB regulation, the resulting emission benefits should be considered "surplus," and could presumably be used to generate Mobile Source Emission Reduction Credits under CARB regulations.[10] Further, the use of such fuels by fleets or distribution of such fuels by fuel providers could potentially be considered to be projects that qualify for incentive funding under the Carl Moyer Program.[11] ADF B3-110

Instead of forcing producers of low NOx diesel fuels to transfer the credit for the NOx reductions attributable to their products without compensation to producers of biodiesel fuels that increase NOx emissions, CARB should establish a market mechanism to incentivize the production of low NOx fuels and to disincentivize the production of NOx-increasing biodiesel fuels. The most logical approach to accomplish this would seem to be providing NOx reduction credits to producers of low NOx fuels under the LCFS regulation while assigning NOx emission debits to producers of biodiesel and then requiring the latter to purchase and surrender credits sufficient to offset the increases in NOx emissions associated with their products.

4. The Proposed Treatment of Biodiesel and Biodiesel Blends Used in "New Technology Diesel Engines" (NTDEs) is Not Equitable With CARB's Treatment of Other Fuels

In addition to defects with the proposed ADF regulations described above, we are unaware of any published analysis or supporting data that the use of biodiesel at any concentration in NTDE's would not result in increased NOx emissions. The rationale for this treatment appears to be an assumption that the advanced emission control systems found on NTDEs eliminate any impact of fuel composition on emissions of NOx and potentially other pollutants.

ADF B3-111

Our primary concern with this proposal is that CARB staff has not provided any supporting data or analysis. In addition, if NTDEs are truly insensitive to fuel composition impacts, CARB should make changes similar to those proposed by biodiesel for other fuels. More specifically, if CARB staff's assumption that NTDE emissions are not sensitive to fuel composition is in fact correct, it follows that there is no longer any need to use CARB diesel fuel in NTDEs instead of less expensive federal diesel fuels which could be substituted without any adverse emission impacts.

---

[8] See slide 19 of the staff presentation for the September 5th workshop which is available at http://www.arb.ca.gov/fuels/diesel/altdiesel/20130905ADFWorkshopPresentation.pdf

[9] See slide 24 of the staff presentation for the September 5th workshop which is available at http://www.arb.ca.gov/fuels/diesel/altdiesel/20130905ADFWorkshopPresentation.pdf

[10] See http://www.arb.ca.gov/msprog/mserc/mserc.htm

[11] See http://www.arb.ca.gov/msprog/moyer/moyer.htm

Clearly, CARB could develop a "significance threshold" for the sale of federal diesel fuel in California similar to that proposed for biodiesel which would achieve this objective while providing the benefit of reduced diesel costs without adverse air quality impacts. Growth Energy therefore encourages CARB staff to revise the ADF to avoid these impacts.

ADF B3-111 cont.

Sincerely,

David Bearden

David Bearden
General Counsel

12_B_LCFS_GE Responses (Page 235 – 242)

716. Comment: **ADF B3-106, ADF B3-107, and ADF B3-109**

Agency Response: This comment is responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

717. Comment: **ADF B3-108, ADF B3-110 through ADF B3-111**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

OTHER EXHIBITS

Public Review Draft
June 27, 2012

Vision for Clean Air: A Framework for Air Quality and Climate Planning

This document has been prepared by the staffs of the California Air Resources Board, the South Coast Air Quality Management District and the San Joaquin Valley Unified Air Pollution Control District. Publication does not signify that the contents reflect the views and policies of the Air Resources Board, the South Coast Air Quality Management District or the San Joaquin Valley Unified Air Pollution Control District. This document will be presented as an informational item at a noticed public meeting scheduled for June 28, 2012.

Table of Contents

Executive Summary

As California plans for the future, transformational technologies, cleaner energy, and greater efficiency are expected to provide the foundation for meeting air quality standards and climate goals. California's success in reducing smog has largely relied on technology and fuel advances, and as health-based air quality standards are tightened, the introduction of cleaner technologies must keep pace. More broadly, a transition to zero- and near-zero emission technologies is necessary to meet 2023 and 2032 air quality standards and 2050 climate goals. Many of the same technologies will address both air quality and climate needs. As such, strategies developed for air quality and climate change planning should be coordinated to make the most efficient use of limited resources and the time needed to develop cleaner technologies.

Vision for Clean Air: A Framework for Air Quality and Climate Planning takes a coordinated look at strategies to meet California's multiple air quality and climate goals well into the future. Its quantitative demonstration of the needed technology and energy transformation provides a foundation for future integrated air quality and climate program development. *Vision for Clean Air* focuses on mobile sources and associated energy production. Similar analyses will be necessary for industrial and other emission sources to develop a complete foundation for integrated planning.

Recognizing that the severity of California's air quality problems varies by region, *Vision for Clean Air* examines what is needed to attain air quality standards by the federal deadlines in the areas with the worst air quality -- the South Coast Air Basin and the San Joaquin Valley Air Basin. However, the technologies and strategies identified will pay clean air dividends for all air districts, helping them achieve or maintain federal air quality standards and reduce local air toxics exposure.

Ozone and Climate Planning Horizons

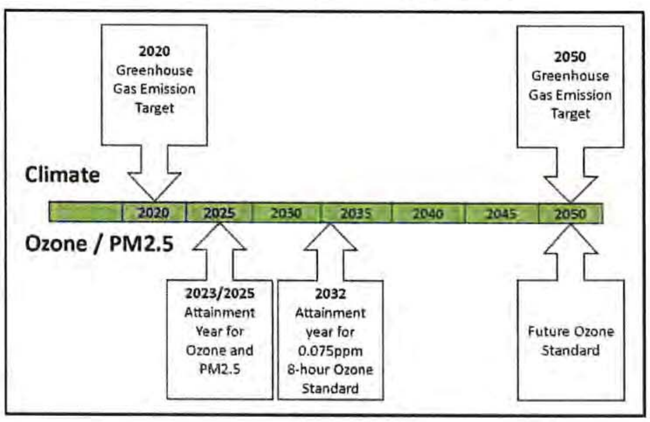


Figure 1

Achieving the 2020 greenhouse gas emission target established by the Global Warming Solutions Act of 2006 (AB 32) is a statewide goal. For the long term, California has set for itself the 2050 goal of greenhouse gas emissions of 80 percent less than 1990 levels overall, and specifically 80 percent less than 1990 levels for the transportation sector.[1] In 2013, the

[1] Governor Brown Executive Order B-16-2012

AB 32 Scoping Plan will be updated to address post-2020 greenhouse gas emissions.

In 2009, the Air Resources Board (ARB), the South Coast Air Quality Management District (SCAQMD) and the San Joaquin Valley Air Pollution Control District (SJVAPCD) developed a partnership with the U.S. Environmental Protection Agency (U.S. EPA) to promote technology advancements needed to meet air quality standards by federal deadlines. In *Vision for Clean Air,* ARB and the South Coast and San Joaquin Valley air districts examine how those technologies can meet both air quality and climate goals over time.

California's deadlines for meeting federal air quality standards extend past 2020, and U.S. EPA recently announced that the deadline for the updated ozone standard will be 2032.[2] Since scientific studies continue to document health impacts of air pollution at progressively lower levels, air quality standards are periodically revised, becoming more stringent over time. Broad deployment of zero- and near-zero emission technologies in the South Coast and San Joaquin Valley air basins will be needed in the 2023 to 2032 timeframe to attain current national health-based air quality standards as required by federal law.

For greenhouse gases, California's 2050 climate goal provides an ambitious long-term target. Many strategies developed to meet the shorter-term air quality standards — notably use of cleaner energy sources — will have benefits toward the longer-term climate goal. Pursuing cleaner energy sources is also the focus of the State's energy policies, providing the opportunity for economic, as well as environmental benefits. Coordinated planning with identified milestones will support the transition to zero-and near-zero emission technologies needed to meet these goals.

To explore the scope of technology advancements needed to meet air quality and climate goals, several key questions are posed:

- What technologies, fuels, and other strategies are needed to meet local air quality and greenhouse gas goals? Are they the same?
- What are the implications of federal air quality deadlines coming 20 to 30 years before the 2050 greenhouse gas goal?
- How can the strategies to meet local air quality targets and greenhouse gas goals best complement each other?
- What are the energy infrastructure demands of coordinated air quality and greenhouse gas strategies?

[2] *Vision for Clean Air* uses 2035 as the target date for the updated ozone standard. After the analytical effort for *Vision for Clean Air* began, U.S. EPA formally set the attainment deadline at 2032.

- How do California's air quality and climate policies need to adapt as emissions move from the vehicle itself to predominantly upstream sources such as electricity and hydrogen or equivalent generation facilities?

Quantitative scenarios were developed for key transportation-related sectors to gain insight into the key questions above. The sectors that are the focus of this report are by far the largest contributors to greenhouse gas emissions and regional air pollution in California. Greenhouse gas emission reduction goals are statewide and the scenarios use a lifecycle emissions analysis approach. The analysis of smog-forming pollutants is regional, reflecting the need to meet air quality standards on that basis. The localized impacts of toxic diesel particulate matter are recognized, and play an important role when evaluating the passenger and freight transport systems. Reducing emissions in these mobile source sectors is key to attaining air quality and climate goals, but does not represent all of the emission reductions needed for individual regions to demonstrate attainment of federal air quality standards. Comprehensive attainment strategies containing both mobile and stationary source measures will be developed as individual regions develop new air quality plans.

The scenarios illustrate the nature of the technology transformation needed to meet the multiple program milestones through 2050. The scenarios highlight the interplay between reducing smog-forming pollutants and greenhouse gases. The scenario results demonstrate the importance of considering the multi-pollutant impacts of policy choices. Planning efforts, public investment, and rulemaking decisions by State, federal, and local agencies will play an important role in the outcome. In making these decisions, agencies will need to consider factors including technical feasibility and cost, downstream and upstream emission reduction potential, energy production capacity and infrastructure, and the necessary pace of transformation needed to meet air quality and climate goals.

In designing the scenarios, it was necessary to make general assumptions about future growth, the pace of introduction of various technologies, and other factors. It is recognized that the scenarios contained herein are not the only pathways to meet air quality and climate goals. Thus, the scenarios are not refined analyses that would be directly used for program development, but will provide input into future planning efforts by air quality agencies. Similarly, economic and environmental analyses are steps that need to be done in future plans.

An update to the AB 32 Scoping Plan is due in 2013. State Implementation Plans (SIPs) to meet the federal particulate matter air quality standards in the South Coast and the San Joaquin Valley are due later this year and major ozone SIPs for the recently updated federal ozone standard will be due in 2015. More detailed analyses will begin to emerge as part of these efforts.

Achieving California's Air Quality and Climate Goals

The federal Clean Air Act requires states to identify the reductions of smog-forming emissions necessary to meet each federal air quality standard. Also under the federal planning process, states must identify the actions needed to bring emissions down to the attainment levels by the required deadlines. These two parts of a state's SIP comprise the attainment demonstration. Federal rules set out detailed procedures, technical requirements, and public processes for the development of attainment demonstrations. As mentioned earlier, the scenarios in *Vision for Clean Air* are not intended to be attainment demonstrations within the meaning of the Clean Air Act, but they do serve to illustrate the scale of technology change needed to meet the federal standards in 2023 and beyond. The federal Clean Air Act specifically recognizes the need for advanced technologies in attainment demonstrations for extreme ozone nonattainment areas. The South Coast and San Joaquin Valley air basins are the only two extreme ozone areas in the nation.

> ***Meeting Federal Ozone Standards***
>
> **For the South Coast Air Basin, it is estimated that oxides of nitrogen, one of the key ingredients in ozone and fine particulate formation, must be reduced by around 80 percent from 2010 levels by 2023, and almost 90 percent by 2032. Similar levels of emissions reductions are likely needed in the San Joaquin Valley by 2032.**

The federally approved SIPs for these two regions rely on a mix of currently available technologies and the development of advanced technologies in order to attain the ozone air quality standard by 2023. Reaching the longer-term 2032 ozone air quality standard and the 2050 climate goal requires even greater transformation. This includes, for example, nearly complete transformation of passenger vehicles to zero-emission technologies, approximately 80 percent of the truck fleet to zero-or near-zero technology, and nearly all locomotives operating in the South Coast air basin to be using some form of zero-emission technology.

> ***Meeting Climate Change Goals***
>
> **To meet the goal of reducing California's greenhouse gas emissions to 1990 levels by 2050, emissions must be reduced by 85 percent from today's levels.**

The Global Warming Solutions Act of 2006 set the 2020 greenhouse gas emissions reduction goal into law. It directed ARB to develop early actions to reduce greenhouse gases while also preparing a Scoping Plan to identify how best to reach the 2020 limit. The State's goal to further reduce greenhouse gases by 2050 was first established when Governor Schwarzenegger signed Executive Order S-3-05 in 2005. In March 2012, Governor Brown issued Executive Order B-16-2012 setting a California target for reductions of greenhouse gas emissions from the transportation sector of 80 percent less than 1990 levels by 2050 and calling for the establishment of benchmarks for the penetration of zero-emission vehicles and infrastructure for 2015, 2020, and 2025.

Coordinated Air Quality and Climate Planning

The *Vision for Clean Air* scenarios illustrate seven key concepts that together provide a foundation for coordinated solutions to California's air quality and climate goals.

- **Technology Transformation:** Transformation to advanced, zero-and near-zero emission technologies, renewable clean fuels, and greater efficiency that can achieve both federal air quality standards and climate goals.
- **Early Action:** Acceleration of the pace of transformation to meet federal air quality standard deadlines, with early actions to develop and deploy zero- and near-zero technologies also needed to meet climate goals.
- **Cleaner Combustion:** Advanced technology NOx emissions standards for on- and off-road heavy-duty engines beyond the cleanest available today to meet federal air quality standards in a timely manner.
- **Multiple Strategies:** A combination of strategies — technology, energy, and efficiency — applied to each sector.
- **Federal Action:** Federal actions, in addition to actions by state and local agencies and governments, to help clean-up sources that travel nationally and internationally such as trucks, ships, locomotives and aircraft.
- **Efficiency Gains:** Greater system and operational efficiencies to mitigate the impacts of growth, especially in high-growth freight transport sectors and vehicle efficiency gains to reduce fuel usage and mitigate the cost of new technologies.
- **Energy Transformation:** Transformation of the upstream energy sector and its greenhouse gas and smog forming emissions concurrent with the transformation to advanced technologies downstream.

Development of coordinated solutions to California's air quality and climate goals will require the efforts of multiple agencies at all levels of government. The solutions span all sectors, rely on the development of multiple technologies, and require the coordinated deployment of technologies and energy infrastructure. ARB has the role of setting technology-forcing standards for mobile sources that have been the distinguishing feature of the State's air quality progress and climate leadership. Action by the federal government, for trucks, locomotives, aircraft, and ships, is also critical. Finally, transformation of the energy sector will require multiple agencies, including the California Energy Commission, the Public Utilities Commission, ARB, and local air districts, to share a common vision.

The SCAQMD, SJVAPCD, and other local air districts play a key role through actions to accelerate the use of new, cleaner mobile technologies at the regional level to improve air quality and meet federal air quality standards. While *Vision for Clean Air* focuses on the mobile sectors and the energy system to power them, attainment of the federal air quality standards will also require similar transformation of traditional stationary sources covered through SIP planning. Air districts will need to continue their actions to reduce emissions from these sources in order to meet federal requirements. Metropolitan planning organizations, port authorities, and local governments will also play important roles in the overall pollution control strategies.

Private sector activities will be key to developing the technology, building the engines, and implementing the necessary transformation. Engine and vehicle manufacturers will need to continue the development and marketing of advanced technologies. Energy industries will need to supply the renewable fuels and energy, including the necessary infrastructure. In the freight transport industries, increased efficiencies that support growth while mitigating environmental impacts will be essential. Both public and private investment will be needed to enable the technology transformation necessary to achieve California's air quality and climate goals.

Vision for Clean Air lays the foundation for an integrated approach to develop and deploy the cleanest emissions control technologies. For many of the sectors discussed, zero- and near-zero emission technologies have been developed or anticipated to be developed over the next few years. *Vision for Clean Air* provides a timeline for coordinated development and accelerated deployment of the types of technologies expected to be needed in each of the sectors.

Vision for Clean Air is being released as a draft document for discussion at a public meeting in June 2012 and at public workshops in August. The document sets the stage for subsequent planning efforts through scenarios designed to illustrate the scope of change needed to meet federal air quality standards and California's climate goals. The scenarios presented are not intended to identify a specific course of action to meet each air quality and climate goal. Nor are the scenarios a prediction of the actual mix of vehicle technologies, fuels, and clean energy sources expected to emerge in the long term. Public and private investment, regulatory decisions, and consumer preferences will all affect the success of specific strategies and options to meet these ambitious goals.

An Approach for Integrating Air Quality and Climate Planning

The federally approved 2007 State Implementation Plans for the South Coast Air Basin and the San Joaquin Valley Air Basin call for broad use of advanced technologies, clean energy, and greater efficiencies to provide the foundation for meeting federal air quality standards. The 2008 Scoping Plan, required by California's Global Warming Solutions Act of 2006, similarly called for a statewide transition to clean energy and advanced technologies and outlined actions toward that end. To understand the interplay among strategies to meet air quality and climate goals, and to develop common and effective solutions to both, basic questions need to be answered. These include:

Crosscutting Issues

Figure 2

- What technologies, fuels, and other strategies are needed to meet local air quality and greenhouse gas goals? Are they the same?
- What are the implications of federal air quality deadlines coming 20 to 30 years before the 2050 greenhouse gas goal?
- Is the pace of needed transformation the same? How can the strategies to meet air quality targets and greenhouse gas goals best complement each other?
- What are the energy infrastructure demands of coordinated air quality and greenhouse gas strategies?
- How do California's air quality and climate policies need to adapt as emissions move from the vehicle itself to predominantly upstream sources such as electricity and hydrogen generation facilities?

To begin to answer these questions and lay a foundation for future coordinated planning for criteria pollutants regulated through air quality standards (i.e., criteria pollutants), toxic pollutants such as diesel particulate matter, and greenhouse gases, *Vision for Clean Air* uses quantitative scenarios. These scenarios examine the nature of the technology and fuel transformation needed to meet the multiple air quality and greenhouse gas milestones between now and 2050.

Vision Scenarios

Under the Clean Air Act, traditional air quality planning typically focuses on the emissions reductions expected in a single future year from regulations adopted in the immediate three to five years. *Vision for Clean Air* takes a broader approach and uses scenarios to illustrate the change needed in multiple milestone years to meet future emissions targets. This effort is not a plan, but rather, it provides valuable insight for future planning efforts that will include a stakeholder input process. This long-term approach is more common in greenhouse gas analyses. The advantage of long-term planning is that it reveals the scope of advanced technologies needed, how quickly the technologies need to come on line, and the key decision points for technology development and deployment along the way.

A scenario is a combination of technology, energy, and efficiency assumptions that change over time. Scenarios represent a projection of what could be possible — a ~~-~~what if" story that provides context for decision-making. Scenarios are intended to inform decision-making but are not predictions of what the future will be. So rather than being a list of State Implementation Plan or SIP-ready control measures, the scenarios provide a view of a mix of technologies that could be successful in helping California meet its multi-pollutant goals. Further, the scenarios do not represent a policy choice that favors certain technologies and fuels over others. This scenario planning effort does not identify winners or losers on a specific path to meet air quality and climate goals. Rather, it demonstrates a combination of technologies and fuels that yield the scale of needed transformation. Any other mix of technologies and fuels achieving equivalent or better regional criteria pollutant and life cycle greenhouse gas reductions can be considered part of the scenario.

A Scenario is a "What If" Set of Assumptions about Technologies, Fuels and Efficiencies

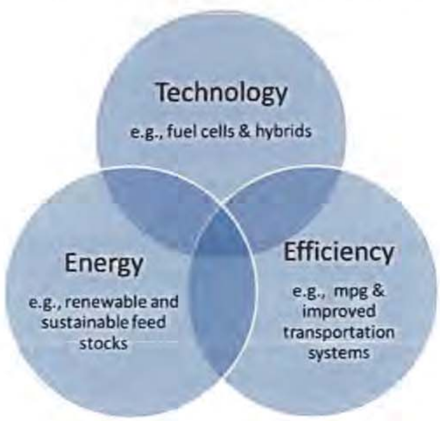


Figure 3

Scenarios were developed through an iterative process of assuming varying levels of technology sales penetration, fuel supply, and efficiency changes. These are ambitious assumptions going beyond the existing programs, and could be expected to require further actions, such as innovation, investment, incentives, and regulations to achieve. However, the scenarios do not include actions such as further incentive funding to accelerate penetration of advanced technologies and clean fuels to meet federal

Scenarios for Mobile Sectors

Scenarios have been developed for passenger cars; freight transport, including trucks, ships, locomotives, cargo handling equipment, and harbor craft; planes, and off-road equipment. The scenarios also include the refineries and power plants needed to produce the fuels and electricity to power the engines in these devices. Together, this covers approximately 45 percent of the State's greenhouse gas emissions and approximately 85 percent of its NOx emissions. The remainder of the greenhouse gas emissions are from non-transportation related sources such as industrial, power generation, commercial, residential and agricultural uses.

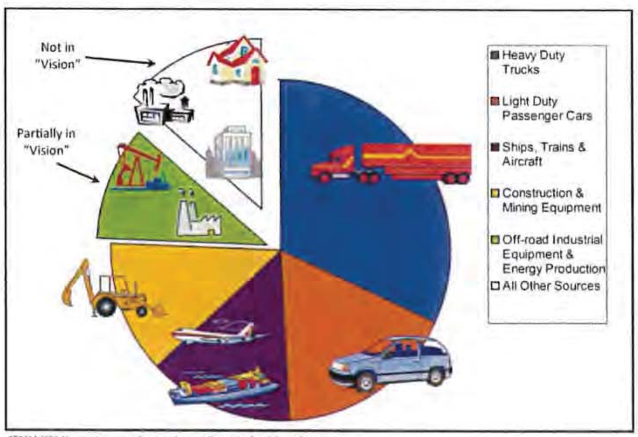
air quality deadlines. For example, expedited turnover of vehicles, as has been achieved with incentives programs implemented by State and local jurisdictions, is not assumed in the scenarios. All of the scenarios include as the starting point all technology and fuel regulations in place today, including passenger vehicle standards, truck and engine standards, the low carbon fuel standard, and the 33 percent renewable electricity requirement.

Most of the technologies and energy sources relied on in the scenarios exist in some form today; some technologies are already on the market, while others are still maturing through demonstration programs and limited test markets.[3] As a result, *Vision for Clean Air* focuses on the development and deployment of emerging technologies not the invention of undefined future technologies. The available technologies that provide fewer smog-forming and greenhouse gas emissions are fuel cells, electric hybrids with a large portion operating in an —all lectric range", and electric vehicles, a combination of which is assumed to be the future norm over time. Similarly, alternative fuels such as hydrogen and clean biofuels such as cellulosic ethanol and biomethane and other renewable energy sources are assumed to play an important role in the energy sectors. Additional operational efficiencies to reduce vehicle miles traveled and overall energy demand are also assumed to occur.

Vision Targets

Targets are characterized as the percent reduction needed from today's emission levels in order to meet the federal air quality standards for ozone and the State's long-term goal to reduce greenhouse gas emissions to 80 percent below 1990 levels by 2050. New federal air quality standards for particulate matter are also expected in the near future. Legally-binding emission targets to attain federal air quality standards are established through the air quality planning process set out in State and federal law. The attainment targets for the 0.080 ppm ozone standard, with a 2023 attainment date, are set in the State's federally approved ozone plans. Planning for the 0.075 ppm federal standard is just beginning, but the attainment target is 2032 for the

Relationship of Vision Inventory to SIP Inventory
2010 NOx SIP Sources as Portion of Total Inventory



CEPAM 2009 Almanac Inventory, Summer Average Emissions, South Coast Emissions

Figure 4

[3] The single exception is the carbon capture sequestration process that will be necessary if fossil fuels are to remain in the energy mix of the future. This process has been demonstrated in limited cases, but long-term data has yet to be developed.

extreme ozone areas of the South Coast Air Basin and San Joaquin Valley. The targets used here are estimates of what the attainment targets could be past 2023 based on current air quality information. *Vision for Clean Air* focuses on oxides of nitrogen (NOx) emissions as NOx is the most critical pollutant for reducing regional ozone and fine particulate matter.

The SIP air quality targets and the 2050 greenhouse gas goal apply to the total emissions from all sources. In developing future SIPs and climate plans, the full spectrum of emissions sources must be considered. *Vision for Clean Air* focuses on mobile sectors and assumes the same percent reduction must be achieved by each. Future planning efforts will need to look at the tradeoffs among strategies for specific source categories that achieve relatively more or fewer reductions in light of technological, economic, and other factors. The following are the air quality goals used in the scenario development process:

- Achieve the 0.08 ppm 8-hour federal ozone standard by 2023 by reducing NOx emissions by 80 percent from 2010 levels.

- Achieve the 0.075 ppm 8-hour federal ozone standard by 2032 by reducing NOx emissions by 90 percent from 2010 levels.

- Reduce greenhouse gas emissions by 80 percent below 1990 levels by 2050. This is equivalent to 85 percent from today's levels.

This document does not evaluate emission reductions needed to attain a potential new ozone standard (i.e., 0.06 - 0.07 ppm 8-hr standard). As scientific studies are documenting health impacts of air pollution at very low levels, it is expected that further NOx reductions will be needed in the long-term. U.S. EPA is expected to consider adopting an ozone standard lower than 0.075 ppm in 2013. Achieving a future ozone standard in the range EPA is expected to consider could require additional NOx emissions reductions, totaling 95 percent from 2010 levels.

Air Quality Challenges in the South Coast and San Joaquin Valley

California is home to two of the nation's most pressing air quality challenges. The South Coast and the San Joaquin Valley are the only two areas in the country designated as extreme nonattainment for the federal ozone standard. These same two areas also experience high levels of fine particulate matter. Because of the severity of the air quality changes in these two areas, they determine the transformational change needed to meet federal air quality standards throughout the State. Still, while they face a similar air quality challenge, they are different in terms of the nature of their emission sources.

South Coast Air Basin

The 2007 SIP for the federal ozone standard contains commitments for emission reductions from mobile sources that rely on advancement of technologies, as authorized under Section 182(e)(5) of the federal Clean Air Act. These measures, which have come to be known as the —Black Box," account for a substantial portion of the NOx emission reductions needed to attain the federal ozone standards — over 200 tons/day. Attaining these standards will require reductions in emissions of nitrogen oxides (NOx) well beyond reductions resulting from current rules, programs, and commercially-available technologies.

Mobile sources emit over 80 percent of regional NOx and therefore must be the largest part of the solution. For the South Coast, the top NOx emission sources projected in 2023 are shown in Figure 5. On-road truck categories are projected to comprise the single largest contributor to regional NOx in 2023. Other equipment involved in goods movement, such as marine vessels, locomotives and aircraft, are also substantial NOx sources.

Largest South Coast NOx Emission Sources
2023 in tons per day

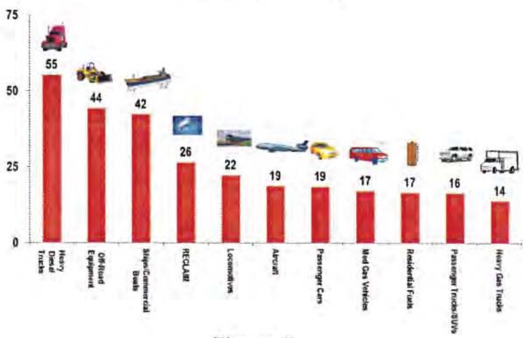


Figure 5

Preliminary projections indicate that the region must reduce regional NOx emissions by about two-thirds by 2023 beyond the benefits of adopted rules and programs, and three quarters by 2032, to attain the national ozone standards as required by federal law.

Since most of the significant sources are already controlled by over 90 percent, attainment of the ozone standards in the South Coast Air Basin will require broad deployment of zero- and near-zero emission technologies in the 2023 to 2032 timeframe. On-land transportation sources such as trucks, locomotives, and cargo handling equipment have technological potential to achieve zero- and near-zero emission levels. Current and potential technologies include hybrid-electric, battery-electric, and hydrogen fuel cell on-road vehicle technologies. Other technologies and fuels may also serve regional

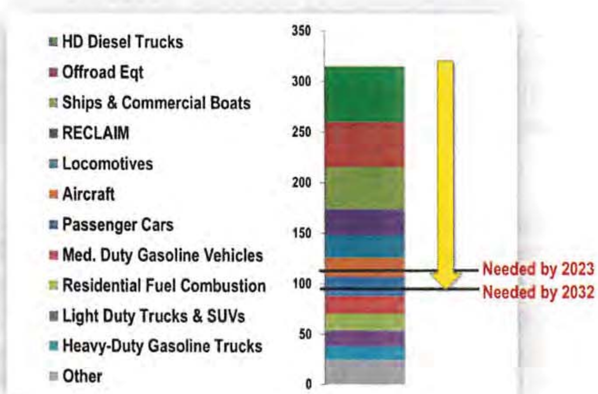


Figure 6

needs, e.g. natural gas-electric hybrids or alternative fuels coupled with advanced aftertreatment technologies. Air quality regulatory agencies have historically set policies and requirements that are performance based and allow any technologies that will achieve needed emission reductions on time.

While there has been much progress in developing and deploying transportation technologies with zero- and near-zero emissions (particularly for light-duty vehicles and passenger transit), additional technology development, demonstration, and commercialization will be required prior to broad deployment in freight and other applications.

San Joaquin Valley Air Basin

Diesel trucks are also the single largest source of NOx emissions in the San Joaquin Valley. However, truck traffic in the Valley is dominated by interstate trucks and other through traffic traveling on the major north-south corridors of Interstate 5 and State Route 99. In contrast, a significant amount of South Coast truck traffic is associated with freight transport from the ports and inland. As a result, the age and activity of the trucks in the two regions differ, suggesting that there may be different options and constraints in terms of technology transformation for trucks that operate in the Valley.

Passenger vehicles are the second largest source of NOx emissions in the San Joaquin Valley. The Valley may present different challenges in terms of infrastructure to support advanced technology passenger vehicles given the nature of urban development in the region.

With the most productive agricultural region in the nation, the San Joaquin Valley is also home to the unique emissions sources of the agricultural industry. While mobile agricultural equipment emissions are significant, a separate scenario was not developed for these sources. Efforts are underway now to clean up mobile agricultural equipment to the cleanest currently available conventional technology. Emission reductions from those efforts are important for reducing ozone levels and measures to achieve these reductions are part of the region's ozone SIP. Given the challenges posed by the operational requirements of this type of equipment and the importance of continuing the current cleanup efforts, consideration of potential future technologies is not included here.

The current NOx targets are set in the approved ozone SIP for the San Joaquin Valley. Like the South Coast, the San Joaquin Valley SIP includes longer-term (—BlackBox") emission reductions due by 2023. Because emissions in the South Coast are so large compared to the Valley, the absolute magnitude of the reductions needed is less than in the South Coast. Nevertheless, the scale of needed transformation is similar. Air quality modeling for the San Joaquin Valley to determine what emission reductions are needed to attain the 0.075 ppm ozone standard in 2032 will be done for the SIP due in 2015. Given the stringent level of the standard, it is expected that on a percentage basis the San Joaquin Valley and South Coast will need a similar magnitude of new reductions.

Vision Tool

A spreadsheet-based tool developed from the Argonne National Laboratory Vision 2011 Model was used to evaluate the scenarios. The Argonne model was intended to be used to evaluate transportation energy policy questions in the context of greenhouse gas emissions. The *Vision for Clean Air* effort started with the Argonne model and was heavily modified and expanded, such that the tool used for *Vision for Clean Air* is fundamentally a different model.

The basic steps outlined in Figure 7 forecast penetration of vehicle technology and fuels into passenger car and truck fleets based on vehicle stock turnover rates, the rates at which new vehicles and technologies enter the fleet and old vehicles leave. The Argonne model is limited in that it only models greenhouse gases and only for passenger vehicles and trucks based on national fleet characteristics. The tool used for *Vision for Clean Air* adds forecasting capability for smog-forming pollutants (NOx and reactive organic gases) and diesel particles. It is also a California-specific model using new vehicle sales, vehicle miles traveled, vehicle survival rates, and emission rates from ARB's mobile source emissions model, EMFAC. Finally, non-road mobile sources, off-road equipment, locomotives, ships, harbor craft, and cargo handling equipment are included based on ARB's existing emissions inventory models for these sources.

Vision for Clean Air Modeling Structure

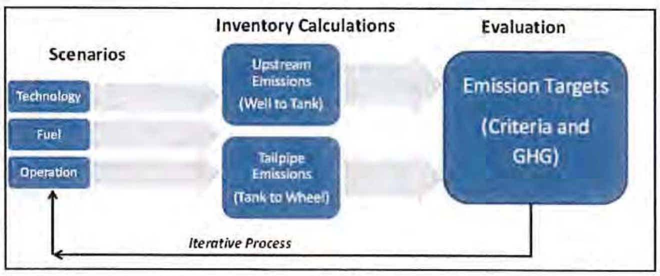


Figure 7

Fuel and electricity demand are estimated by type based on the fleet technology mix, vehicle miles traveled, and engine efficiencies. Emissions from energy production activities are then calculated using assumptions about fuel feedstock, carbon intensity, and NOx emission rates. Carbon emissions are calculated with a global lifecycle from energy production to end use. Smog-forming emissions use a modified life-cycle approach where upstream, fuel pathway emissions are included only if they are within the region studied in the scenario. For simplicity, it was assumed that one half of the NOx emissions from mobile source-related energy production occur within the region in which the energy is used.

This modified lifecycle approach for analyzing smog-forming emissions associated with mobile-source energy production differs from typical air quality planning. In SIPs, mobile and stationary source emissions (including refineries and power plants) are calculated and reported separately. The advantage to linking upstream and

12_B_LCFS_GE Responses (Page 243 – 258)

718. Comment: **Vision for Clean Air: A Framework for Air Quality and Climate Planning June 27, 2012 (Partial Reproduction)**

Agency Response: This document is a collaborative report between ARB, SCAQMD, and SJVAPCD. Only the first 13 pages were submitted. It does not constitute an objection or suggestion on the proposal; however the document was referenced in comment **ADF B3-109**. This comment is responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

This page intentionally left blank.

EPA United States Environmental Protection Agency

http://www.epa.gov/airquality/ozonepollution/designations/2008standards/final/region9f.htm

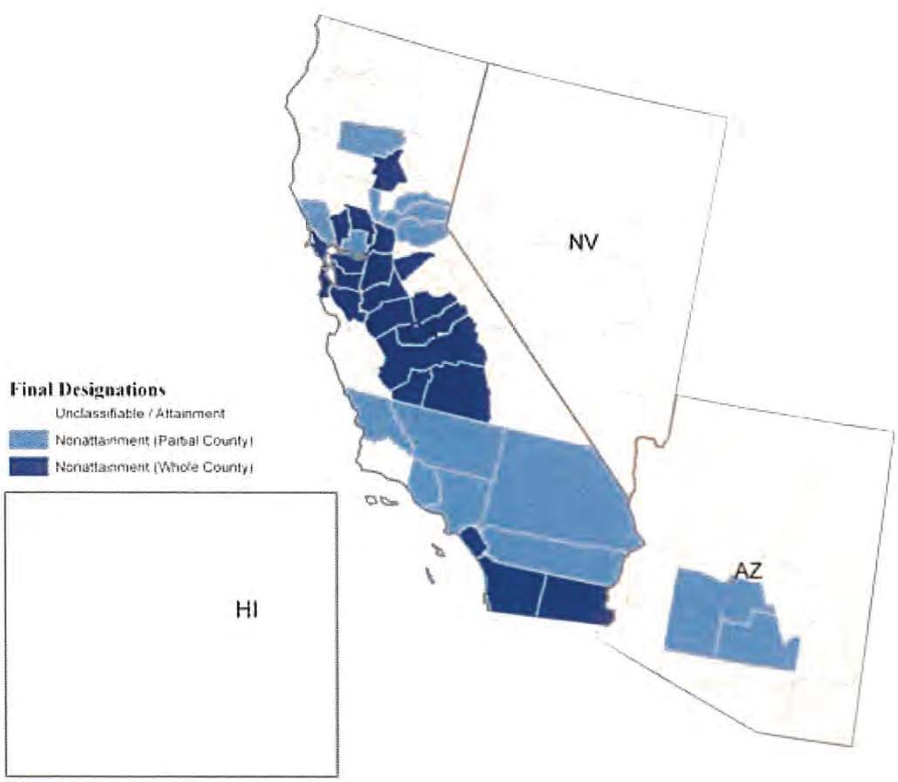
Area Designations for 2008 Ground-level Ozone Standards

2008 Ground-level Ozone Standards — Region 9 Final Designations, April 2012

EPA is implementing the 2008 ozone standards as required by the Clean Air Act. Meeting these standards will provide important public and environmental health benefits. EPA has worked closely with states and tribes to identify areas in the country that meet the standards and those that need to take steps to reduce ozone pollution.

EPAs final designations are based on air quality monitoring data, recommendations submitted by the states and tribes, and other technical information. EPA will work closely with states and tribes to implement the standards using a common sense approach that improves air quality, maximizes flexibilities and minimizes burden on state and local governments.

Map of Final Designations - EPA Region 9



This table identifies area designations for EPAs region 9 states. In some cases EPA designated partial counties. These are identified by a (P). If a county is not listed below, EPA has designated it as unclassifiable/attainment.

EPA Areas for Designations for the 2008 Ozone Standards

State	Area Name	Counties	Area Classification
American Samoa	Entire territory is unclassifiable/attainment		
Arizona	Phoenix-Mesa, AZ	Maricopa (p)	Marginal
		Pinal (p)	
	Rest of state is unclassifiable/attainment		
California	Calaveras County, CA	Calaveras	Marginal
	Chico (Butte County), CA	Butte	Marginal
	Imperial County, CA	Imperial	Marginal
	Kern County (Eastern Kern), CA	Kern (p)	Marginal
	Los Angeles-San Bernardino Counties (West Mojave Desert), CA	Los Angeles (p)	Severe
		San Bernardino (p)	
	Los Angeles-South Coast Air Basin, CA	Los Angeles (p)	Extreme
		Orange	
		Riverside (p)	
		San Bernardino (p)	
	Mariposa County, CA	Mariposa	Marginal
	Nevada County (Western part), CA	Nevada (p)	Marginal
	Riverside County (Coachella Valley), CA	Riverside (p)	Severe
	Sacramento Metro, CA	El Dorado (p)	Severe
		Placer (p)	
		Sacramento	
		Solano (p)	
		Sutter (p)	
		Yolo	
	San Diego County, CA	San Diego	Marginal
	San Francisco Bay Area, CA	Alameda	Marginal
		Contra Costa	
		Marin	
		Napa	
		San Francisco	
		San Mateo	

State	Area Name	Counties	Area Classification
		Santa Clara	
		Solano (p)	
		Sonoma (p)	
	San Joaquin Valley, CA	Fresno	Extreme
		Kern (p)	
		Kings	
		Madera	
		Merced	
		San Joaquin	
		Stanislaus	
		Tulare	
	San Luis Obispo (Eastern San Luis Obispo), CA	San Luis Obispo (p)	Marginal
	Tuscan Buttes, CA	Tehama (p)	Marginal
	Ventura County, CA	Ventura (p)	Serious
	Morongo Areas of Indian Country (Morongo Band of Mission Indians)	Areas of Indian Country	Serious
	Pechanga Areas of Indian Country (Pechanga Band of Luiseno Mission Indians of the Pechanga Reservation)	Areas of Indian Country	Moderate
	Rest of state is unclassifiable/attainment		
Guam	Entire territory is unclassifiable/attainment		
Hawaii	Entire state is unclassifiable/attainment		
Nevada	Entire state is unclassifiable/attainment		
Northern Mariana Islands	Entire territory is unclassifiable/attainment		

< Back to US map

Tribal information is available on the Tribal Designations page.

Recommendations from Region 9 States and EPA Responses

Last updated on Friday, February 01, 2013

12_B_LCFS_GE Responses (Page 259 – 261)

719. Comment: **2008 Ground-level Ozone Standards - Region 9 Final Designations, April 2012**

Agency Response: This document is a print of EPA's website. It does not constitute an objection or suggestion on the proposal; however the document was referenced in comment **ADF B3-109**. This comment is responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

This page intentionally left blank.

South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4182
(909) 396-2000 ≠ www.aqmd.gov

SCAQMD Air Quality Significance Thresholds

Mass Daily Thresholds [a]		
Pollutant	**Construction [b]**	**Operation [c]**
NOx	100 lbs/day	55 lbs/day
VOC	75 lbs/day	55 lbs/day
PM10	150 lbs/day	150 lbs/day
PM2.5	55 lbs/day	55 lbs/day
SOx	150 lbs/day	150 lbs/day
CO	550 lbs/day	550 lbs/day
Lead	3 lbs/day	3 lbs/day

Toxic Air Contaminants (TACs), Odor, and GHG Thresholds	
TACs (including carcinogens and non-carcinogens)	Maximum Incremental Cancer Risk ≥ 10 in 1 million Cancer Burden > 0.5 excess cancer cases (in areas ≥ 1 in 1 million) Chronic & Acute Hazard Index ≥ 1.0 (project increment)
Odor	Project creates an odor nuisance pursuant to SCAQMD Rule 402
GHG	10,000 MT/yr CO2eq for industrial facilities

Ambient Air Quality Standards for Criteria Pollutants [d]	
NO2 1-hour average annual arithmetic mean	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 0.18 ppm (state) 0.03 ppm (state) and 0.0534 ppm (federal)
PM10 24-hour average annual average	10.4 $\pi g/m^3$ (construction)[e] & 2.5 $\pi g/m^3$ (operation) 1.0 $\pi g/m^3$
PM2.5 24-hour average	10.4 $\pi g/m^3$ (construction)[e] & 2.5 $\pi g/m^3$ (operation)
SO2 1-hour average 24-hour average	0.25 ppm (state) & 0.075 ppm (federal – 99th percentile) 0.04 ppm (state)
Sulfate 24-hour average	25 $\pi g/m^3$ (state)
CO 1-hour average 8-hour average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 20 ppm (state) and 35 ppm (federal) 9.0 ppm (state/federal)
Lead 30-day Average Rolling 3-month average Quarterly average	 1.5 $\pi g/m^3$ (state) 0.15 $\pi g/m^3$ (federal) 1.5 $\pi g/m^3$ (federal)

[a] Source: SCAQMD CEQA Handbook (SCAQMD, 1993)
[b] Construction thresholds apply to both the South Coast Air Basin and Coachella Valley (Salton Sea and Mojave Desert Air Basins).
[c] For Coachella Valley, the mass daily thresholds for operation are the same as the construction thresholds.
[d] Ambient air quality thresholds for criteria pollutants based on SCAQMD Rule 1303, Table A-2 unless otherwise stated.
[e] Ambient air quality threshold based on SCAQMD Rule 403.

KEY: lbs/day = pounds per day   ppm = parts per million $\pi g/m^3$ = microgram per cubic meter   ≥ = greater than or equal to
MT/yr CO2eq = metric tons per year of CO2 equivalents   > = greater than

Revision: March 2011

12_B_LCFS_GE Responses (Page 262)

720. Comment: **SCAQMD Air Quality Significance Thresholds**

Agency Response: This document does not constitute an objection or suggestion on the proposal; however the document was referenced in comment **ADF B3-108**. This comment is responded to in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

GUIDE FOR ASSESSING AND MITIGATING AIR QUALITY IMPACTS

Prepared by
the Mobile Source/CEQA Section
of the Planning Division
of the San Joaquin Valley Air Pollution Control District
1990 E. Gettysburg Avenue
Fresno, CA 93726

January 10, 2002 revision
Adopted August 20, 1998

This document is an advisory document, that provides Lead Agencies, consultants, and project applicants with uniform procedures for addressing air quality in environmental documents. Copies and updates are available from the SJVAPCD Planning Division at (559) 230-5800. Questions on content should be addressed to either the Mobile Source/ CEQA Section at (559) 230-5800 or the SJVAPCD CEQA representative at the regional office that covers the county in which the project is located.

David L. Crow – Executive Director/Air Pollution Control Officer
Mark Boese – Deputy Air Pollution Control Officer
Robert Dowell – Director of Planning
Richard Milhorn – Planning Manager

ACKNOWLEDGEMENTS

The principal authors of this document were:

- Dave Mitchell – Supervisor, Mobile Source / CEQA Section
- Joe O'Bannon – (former) Air Quality Planner, Southern Region
- Joan Merchen – Senior Air Quality Planner, Central Region

Significant contributions were also made by:

- Phil Jay – District Counsel
- Tracy Bettencourt – (former) Environmental Planner, Northern Region
- Cheryl Lesinski – (former) Environmental Planner, Central Region
- Dave Stagnaro – (former) Environmental Planner, Northern Region

GUIDE FOR ASSESSING AND MITIGATING AIR QUALITY IMPACTS

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

Demolition Asbestos Impacts. Project construction sometimes requires the demolition of existing buildings at the project site. Buildings often include materials containing asbestos. Airborne asbestos fibers pose a serious health threat if adequate control techniques are not carried out when the material is disturbed. The demolition, renovation, or removal of asbestos-containing materials is subject to the limitations of the National Emissions Standards for Hazardous Air Pollutants (NESHAP) regulations as listed in the Code of Federal Regulations[34] requiring notification and inspection. Most demolitions and many renovations are subject to an asbestos inspection prior to start of activity. The SJVAPCD's Compliance Division in the appropriate region should be consulted prior to commencing any demolition or renovation of any building to determine inspection and compliance requirements. Strict compliance with existing asbestos regulations will normally prevent asbestos from being considered a significant adverse impact.

4.3.2 Thresholds of Significance for Impacts from Project Operations

The term "project operations" refers to the full range of activities that can or may generate pollutant emissions when the development is functioning in its intended use. For projects such as office parks, shopping centers, residential subdivisions, and other indirect sources, motor vehicles traveling to and from the projects represent the primary source of air pollutant emissions. For industrial projects and some commercial projects, equipment operation and manufacturing processes can be of greatest concern from an emissions standpoint. Significance thresholds discussed below address the impacts of these emission sources on local and regional air quality. Thresholds are also provided for other potential impacts related to project operations, such as odors and toxic air contaminants.

(Lead Agencies may refer to Section 5, for guidance on calculating emissions and determining whether significance thresholds for project operations may be exceeded, and thus whether more detailed air quality analysis may be needed.)

Ozone Precursor Emissions Threshold. Ozone precursor emissions from project operations should be compared to the thresholds provided in Table 4-1. Projects that emit ozone precursor air pollutants in excess of the levels in Table 4-1 will be considered to have a significant air quality impact.

Both direct and indirect emissions should be included when determining whether the project exceeds these thresholds. The following total emissions thresholds for air quality have been established by the SJVAPCD for project operations. Projects in the SJVAB with operation-related emissions that exceed these emission thresholds will be considered to have significant air quality impacts.

[34] 40CFR Part 61, Subpart M

Table 4-1
Ozone Precursor Emissions Thresholds
For Project Operations

Pollutant	Tons/yr.
ROG	10
NOx	10

Local Carbon Monoxide Concentrations Threshold. Estimated CO concentrations, as determined by an appropriate model, exceeding the California Ambient Air Quality Standard (CAAQS) of 9 parts per million (ppm) averaged over 8 hours and 20 ppm for 1 hour will be considered a significant impact.

Odor Impacts Threshold. While offensive odors rarely cause any physical harm, they can be very unpleasant, leading to considerable distress among the public and often generating citizen complaints to local governments and the SJVAPCD. Any project with the potential to frequently expose members of the public to objectionable odors will be deemed to have a significant impact. Odor impacts on residential areas and other sensitive receptors, such as hospitals, day-care centers, schools, etc., warrant the closest scrutiny, but consideration should also be given to other land uses where people may congregate, such as recreational facilities, worksites, and commercial areas. Analysis of potential odor impacts should be conducted for the following two situations:

- **Generators** – projects that would potentially generate odorous emissions proposed to locate near existing sensitive receptors or other land uses where people may congregate, *and*

- **Receivers** – residential or other sensitive receptor projects or other projects built for the intent of attracting people locating near existing odor sources.

The SJVAPCD has determined some common types of facilities that have been known to produce odors in the SJV. These are presented in Table 4-2 along with a reasonable distance from the source where the degree of odors could possibly be significant.

A Lead Agency should use Table 4-2 to determine whether the proposed project, either as a generator or a receiver, would result in sensitive receptors being within the distances indicated in Table 4-2. In addition, recognizing that this list of facilities is not meant to be all-inclusive, the Lead Agency should evaluate facilities not included in the table or projects separated by greater distances than indicated in Table 4-2 if warranted by local conditions or special circumstances. If the proposed project would result in sensitive receptors being located closer than the screening level distances indicated in Table 4-2, a more detailed analysis, as described in Section 5, should be conducted.

12_B_LCFS_GE Responses (Page 263 – 270)

721. Comment: **Guide for Assessing and Mitigating Air Quality Impacts**

Agency Response: This document is a partial reproduction a SJVAPCD report. It does not constitute an objection or suggestion on the proposal; however the document was referenced in comment **ADF B3-109**. This comment is responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

This page intentionally left blank.

ATTACHMENT B

sierra
research
1801 J Street
Sacramento, CA 95811
Tel: (916) 444-6666
Fax: (916) 444-8373
Ann Arbor, MI
Tel: (734) 761-6666
Fax: (734) 761-6755

VIA EMAIL

February 18, 2014

Jim Aguila, Manager
Substance Evaluation Section
Stationary Source Division
California Air Resources Board
1001 I Street
Sacramento, CA 95812

Dear Mr. Aguila:

This letter transmits comments regarding the workshop held on February 13, 2014, concerning the Alternative Diesel Fuels (ADF) regulations proposed by the staff on October 15, 2013. The scope of the comments presented here was constrained by the fact that there were only five calendar days and only two business days provided between the date of the workshop and the February 18th deadline for comments announced by CARB staff at the workshop.

ADF B3-112

As explained below, the modified ADF regulations discussed at the workshop would allow for the widespread use of biodiesel and biodiesel blends in California without adequately mitigating the resulting increases in emissions of oxides of nitrogen (NOx). The workshop proceedings also confirm concerns expressed during the 45-day comment period for the ADF regulations last year that CARB is not providing adequate and prompt public access to relevant documents and information that are in the agency's possession.

Sincerely,

Jim Lyons
Senior Partner

Attachments

ADF Regulation Comments
Submitted by James M. Lyons, Sierra Research
February 18, 2014

1. **CARB Has Not Published the Comments from the South Coast Air Quality Management District That Underlie Staff's Proposed Modifications for Extreme Ozone Non-Attainment Areas.**

In the January 31, 2014 workshop notice,[1] CARB states:

> *During the 45-day public review process, staff received comments and proposed alternatives to the noticed regulation that staff would like to more fully consider and evaluate. Staff will be preparing modifications to the original proposal and make the modifications available for public review during a supplemental 15-day public comment period.*

Furthermore, CARB staff notes on slide 8 of the workshop presentation[2] with respect to "45-day rulemaking comments" that:

> *SCAQMD comment requested additional protections for extreme ozone non-attainment areas (South Coast Air Basin, Jan Joaquin Valley).*

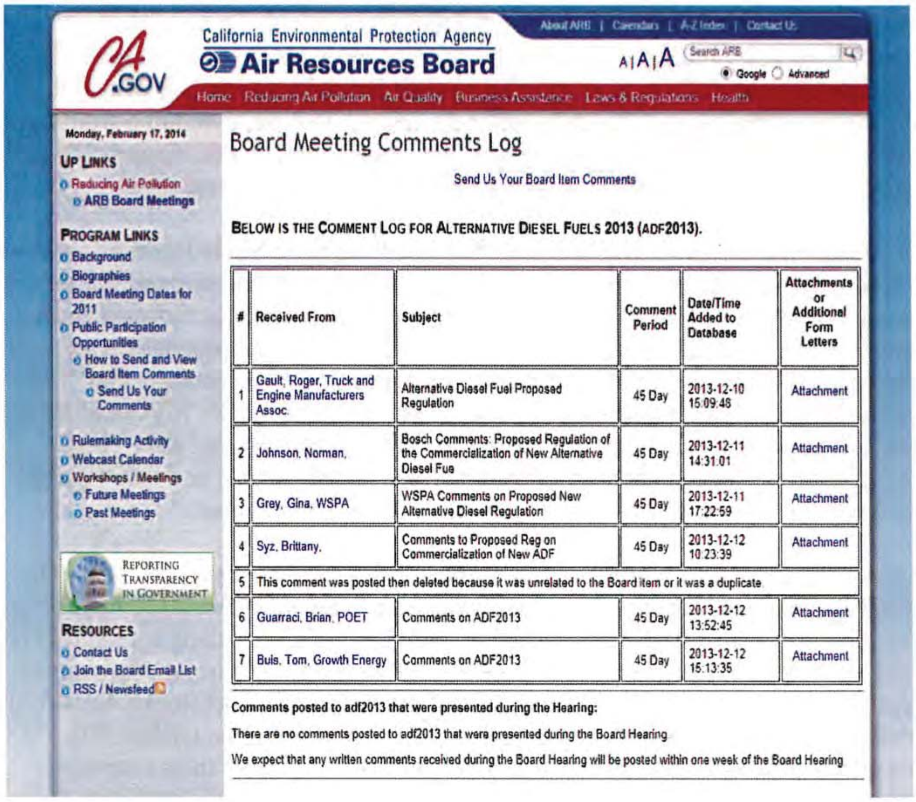
ADF B3-113

However, the relevant comment document from the South Coast Air Quality Management District ("SCAQMD") does not appear as part of the comments submitted during the 45-day comment period posted on the CARB website as shown in the screen shot taken on February 17, 2014, and presented as Figure 1 below. In addition, since there was no public hearing on the proposed regulations held on December 12 or 13, 2013, no comment document could have been provided in that venue.

Because the SCAQMD comments have not been made available to the public, it is impossible for any stakeholder to understand or comment on either the scope of the SCAQMD request or the responsiveness of the modifications proposed by CARB staff at the workshop. CARB staff should make all documents and correspondence related to the SCAQMD comments publicly available and include them in the rulemaking file.

[1] *http://www.arb.ca.gov/fuels/diesel/altdiesel/ADFmtgnotice_021314.pdf*
[2] *http://www.arb.ca.gov/fuels/diesel/altdiesel/021314_PublicMeetingPres.pdf*

Figure 1
Screen Shot From CARB Website on February 17, 2014



About ARB | Calendars | A-Z Index | Contact Us

California Environmental Protection Agency

Air Resources Board

Home | Reducing Air Pollution | Air Quality | Business Assistance | Laws & Regulations | Health

Monday, February 17, 2014

UP LINKS
- Reducing Air Pollution
  - ARB Board Meetings

PROGRAM LINKS
- Background
- Biographies
- Board Meeting Dates for 2011
- Public Participation Opportunities
  - How to Send and View Board Item Comments
    - Send Us Your Comments
- Rulemaking Activity
- Webcast Calendar
- Workshops / Meetings
  - Future Meetings
  - Past Meetings

REPORTING TRANSPARENCY IN GOVERNMENT

RESOURCES
- Contact Us
- Join the Board Email List
- RSS / Newsfeed

Board Meeting Comments Log

Send Us Your Board Item Comments

BELOW IS THE COMMENT LOG FOR ALTERNATIVE DIESEL FUELS 2013 (ADF2013).

#	Received From	Subject	Comment Period	Date/Time Added to Database	Attachments or Additional Form Letters
1	Gault, Roger, Truck and Engine Manufacturers Assoc.	Alternative Diesel Fuel Proposed Regulation	45 Day	2013-12-10 15:09:48	Attachment
2	Johnson, Norman,	Bosch Comments: Proposed Regulation of the Commercialization of New Alternative Diesel Fue	45 Day	2013-12-11 14:31:01	Attachment
3	Grey, Gina, WSPA	WSPA Comments on Proposed New Alternative Diesel Regulation	45 Day	2013-12-11 17:22:59	Attachment
4	Syz, Brittany,	Comments to Proposed Reg on Commercialization of New ADF	45 Day	2013-12-12 10:23:39	Attachment
5	This comment was posted then deleted because it was unrelated to the Board item or it was a duplicate				
6	Guarraci, Brian, POET	Comments on ADF2013	45 Day	2013-12-12 13:52:45	Attachment
7	Buis, Tom, Growth Energy	Comments on ADF2013	45 Day	2013-12-12 15:13:35	Attachment

Comments posted to adf2013 that were presented during the Hearing:

There are no comments posted to adf2013 that were presented during the Board Hearing.

We expect that any written comments received during the Board Hearing will be posted within one week of the Board Hearing

2. CARB Staff Has Failed to Include Results from On-Going CARB-Sponsored Research Regarding the Impacts of Biodiesel on NOx Emissions in the Rulemaking Process.

During last week's workshop, a representative of the SCAQMD commented that increases in NOx emissions due to biodiesel use at levels as low as five percent biodiesel ("B5") remained a concern to his agency based on emission test results from an ongoing CARB-sponsored study being conducted by the University of California, Riverside ("UCR"). The SCAQMD representative stated that the UCR data showed statistically significant increases in NOx emissions for some types of B5 blends compared to conventional diesel fuel. CARB staff's response to this comment was that the study was still "on-going" and that no conclusions can be drawn from the emission testing until the study is completed. In response to questioning, CARB staff indicated that the contract for the project expires in July 2014 and suggested that all work related to the study would be complete by that date. As stakeholders have previously commented, CARB staff must include all available emission data regarding biodiesel impacts on emissions of NOx and other pollutants in the file for this rulemaking. ADF B3-114

It should be noted that, even if some members of the CARB staff consider the UCR work to be incomplete, other members of the CARB staff evidently consider the UCR data to be complete enough to warrant use in public meetings. Direct evidence supporting the assertion made by the SCAQMD representative at the workshop is provided by a presentation made by Georgios Karavalakis of UCR on April 10, 2013, at the 23rd Coordinating Research Council (CRC) Real World Emission Workshop, which lists among the coauthors two CARB staff members and acknowledges funding from CARB contract No. 10-417. A copy of this presentation and documentation demonstrating that it was presented at the April 2013 workshop is attached to these comments. ADF B3-115

In the section of the presentation labelled "CARB HD Engine Study Results," data are presented from preliminary emissions testing of B5 blends of both soy and waste vegetable oil ("WVO") based biodiesels using procedures similar to those set forth in Appendix A of the Initial Statement of Reasons ("ISOR") for the proposed ADF regulations. Based on these data, the authors conclude in the presentation that "NOx emissions showed slight but statistically significant, increase for B5-WVO and B5-soy blends." The authors conclude with respect to "certification testing" that "NOx emissions showed a statistically significant increase for B5-WVO" and that "The B5-WVO failed the statistical certification test, based on NOx emissions." ADF B3-116

This presentation raises a number of issues that CARB staff must address. First, the presentation provides evidence that directly contradicts the assertion made by CARB staff in the ISOR that there is no evidence of increased NOx emissions at biodiesel levels below B10—an assertion that is the foundation for the CARB environmental impact analysis presented in the ISOR. Second, these data directly support Robert Crawford's conclusions[3] that biodiesel use at levels below B10 will result in increased NOx emissions. Mr. Crawford's work was included by Growth Energy in its comments submitted to CARB staff during the 45-day comment period. Third, given that these data were available at least as early as April 2013, CARB staff should explain why they were not included in the staff's analysis of NOx impacts published in the ISOR nor in the rulemaking file for the ADF regulation. ADF B3-117

Again, CARB staff must include in the rulemaking file for this proceeding all emission test data currently available from this B5 testing program and any other biodiesel testing programs that the agency is sponsoring or otherwise participating in. This is particularly important here as the test data being excluded do not support the staff's assumption in the ISOR that there is no increase in NOx emissions until biodiesel blends reach the B10 level. ADF B3-118

3. **The Proposed Modifications to the ADF Regulation Affecting Extreme Ozone Non-Attainment Areas Will Not Prevent Significant Increases in NOx Emissions from Biodiesel Use.**

As presented by CARB staff at last week's workshop, the modifications to the proposed ADF regulation that would impose different requirements for extreme ozone non-attainment areas would be limited to the following: ADF B3-119

[3] Crawford, R., "NOx emission Impact of Soy- and Animal-based Biodiesel fuels: A Re-Analysis", December 10, 2013.

1. Establishment of "effective blend" (EB) requirements for biodiesel producers and importers;

2. Requirements for biodiesel producers and importers to submit compliance plans demonstrating how NOx emission increases will be mitigated once their EB level reaches five percent; and

3. Implementation of NOx mitigation measures once their EB level reaches seven and a half percent.

Presumably CARB staff has proposed these changes because they recognize that the originally proposed ADF regulation could lead to unacceptable increases in NOx emissions in the South Coast and San Joaquin Valley Air Basins. Nevertheless, the changes do nothing to ensure that increased NOx emissions due to biodiesel use will not actually occur.

ADF B3-119 cont.

The basic problem with the staff's proposed modifications is their continued reliance on the flawed effective blend (or EB) concept which, as pointed out in comments provided during the 45-day comment period, virtually ensures that the use of biodiesel in California will result in unmitigated increases in NOx emissions. As stakeholders indicated during the 45-day comment period, the only way to ensure that there are no increases in NOx emissions is for CARB staff to abandon the EB concept and to impose appropriate mitigation requirements based on the **actual** biodiesel content of all biodiesel blends. Furthermore, by appropriately mitigating the increases in the NOx emissions associated with biodiesel use, areas like the South Coast and San Joaquin Valley Air Basins will also realize the benefits of any NOx reductions associated with the use of "Low NOx diesel."

4. **The Proposed ADF Regulation Should Be Modified to Require Determination and Reporting of the Biodiesel Content of All Biodiesel Blends Prior to Their Sale to Ultimate Consumers.**

During last week's workshop, it became clear that the proposed ADF regulation will not ensure that the biodiesel content of blends sold in California will be accurately known or reported to CARB. As indicated by workshop participants, at present CARB has no requirement for determining the biodiesel content of diesel fuels being imported or distributed in the state that contain biodiesel up to the B5 level. Given this, a party interested in blending 5% biodiesel into a "diesel" fuel may be unaware of the fact that the "diesel" fuel could already contain up to 5% biodiesel and that the resulting blend would therefore be B10, not B5. Similarly, a party interested in blending 20% biodiesel into a "diesel" could in fact produce a B25 blend, instead of the intended B20 blend. Obviously, both circumstances have substantial ramifications with respect to potential NOx increases associated with the use of biodiesel in California.

ADF B3-120

Given the above, CARB must modify as necessary its existing diesel fuel regulations as well as the proposed ADF regulations to ensure that the biodiesel content of all blends of biodiesel and diesel sold in California is accurately known and reported to both CARB as well as the Division of Measurement Standards. This could easily be accomplished by requiring that all "diesel" fuels used in biodiesel blends be tested before blending for Fatty Acid Methyl Ester (FAME) content using appropriate test procedures such as the EN14103:2011 procedure already referenced in the proposed ADF Regulations or the ASTM D7371 procedure. Alternatively, CARB could require testing of final blends for FAME content. Again, failure by CARB to require accurate measurement and reporting of the biodiesel content of biodiesel-diesel blends will lead to unmitigated increases in NOx emissions along with other potential issues, including violations of pump labeling and vehicle manufacturer warranty requirements.

ADF B3-120 cont.

5. CARB Staff Must Publish an Analysis of All Alternatives to the Proposed ADF Regulation Raised During the 45-Day Comment Period.

The "Analysis of Alternatives" presented on pages 62 and 63 of the ISOR states:

> *Specifically for biodiesel, we considered two alternatives to the proposal: business as usual (i.e., no proposed regulation), and requiring implementation of the mitigation measures for all biodiesel blends above B10 immediately without the proposed phase in process.*

ADF B3-121

CARB staff must perform an expanded analysis of alternatives that includes not only the modifications to the original proposal discussed at the workshop but also all alternatives recommended during the 45-day comment period. No such analysis was presented at last week's workshop. Clearly CARB staff should perform this analysis and consider the results, including public comment, before formally proposing modifications to the ADF regulation.

12_B_LCFS_GE Responses (Page 271 – 277)

722. Comment: **ADF B3-113 through ADF B3-115, ADF B3-117 through ADF B3-121**

Agency Response: These comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

723. Comment: **ADF B3-112 and ADF B3-116**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

UCR | College of Engineering- Center for Environmental Research & Technology

BIODIESEL AND RENEWABLE DIESEL CHARACTERIZATION AND TESTING IN MODERN LD DIESEL PASSENGER CARS AND TRUCKS AND HD ENGINES

Georgios Karavalakis[1], Maryam Hajbabaei[1], Daniel Short[1], Diep Vu[1], Robert L. Russell[1], Tom Durbin[1], Akua Asa-Awuku[1], Kent C. Johnson[1], Alexander Mitchell[2], and Jim Guthrie[2]

[1]University of California, Riverside
Bourns College of Engineering
Center for Environmental Research and Technology (CE-CERT)
[2]California Air Resources Board, 1001 "I" Street, P.O. Box 2815, Sacramento, CA 95812

www.cert.ucr.edu

Introduction

- **Potential Sources of Biodiesel**
  - Vegetable oils
    - Edible oils: Soybean oil, rapeseed oil, palm oil, etc.
    - Inedible oils: Jatropha, Camelina, Karanja, etc.
  - Animal Fats
  - Waste Cooking Oils
  - 'Alternative' Oils
    - Algae
- **Benefits**
  - Reduce petroleum dependence
  - Reduce overall life cycle CO_2 emissions
  - Potential improvements in "smog" emissions

Alternative Fuels Legislation

Federal

- Energy Policy Act
  - Renewable Fuels Standard
  - Biofuels Research and Development

California

- Low Carbon Fuel Standard (LCFS)
  - Reduce 10% carbon intensity of California's transport fuels by 2020.
- AB 32 – Global Warming Solutions Act
- Bioenergy Action Plan
- AB 1007 – Alternative Fuels Plan
- AB 118 – Alternative and Renewable Fuel and Vehicle Technology Program

UCR | College of Engineering- Center for Environmental Research & Technology

Concerns about using Biodiesel from Emissions Perspective

- Concern about NOx emissions increases with biodiesel
  - Lack of information with vehicles/engines fitted with DPF, SCR, and LNT controls
- A general trend towards higher aldehyde emissions (i.e., formaldehyde, acetaldehyde, acrolein, etc.)
- Biodiesel origin and quality may adversely affect the formation of light molecular-weight PAH emissions
- Characterization of biodiesel exhaust from SCR-fitted vehicles is still incomplete; potential formation of nitrogen-containing compounds (nitro-PAHs)
- Concern about nanoparticle number emission increases with biodiesel

www.cert.ucr.edu

Objectives of the AVFL – 17b Study

- Evaluation of fuel type and quality on exhaust emissions of modern technology light-duty diesel vehicles.
- Assessment of the impact of modern technology aftertreatment control devices on the emissions formation from biodiesel and renewable diesel fueled vehicles.
- Emphasis on gaseous toxic emissions, ammonia, and ultrafine particles.
- Chemical characterization of PM emissions; Concern about EC/OC fractions, PAH, and nitro-PAH compounds some of which are carcinogenic and mutagenic to humans.
- Evaluation of emissions during DPF regeneration events on different fuels; physicochemical characterization of PM.

Test Fuels and Vehicles for the AVFL – 17b Study

- A total of seven fuels will be used in the study
  - A Federal ULSD and a CARB ULSD, which will serve as baseline fuels
  - Three biodiesels obtained from soy, waste cooking oil, and animal fat
  - A renewable diesel (Hydrogenated Vegetable Oil - HVO)
  - All biodiesels and HVO will be blended with Federal diesel at 20% by volume. CARB diesel will be blended with WCO.
- Currently, we tested a total of 3 vehicles with plans to test 5 additional vehicles.

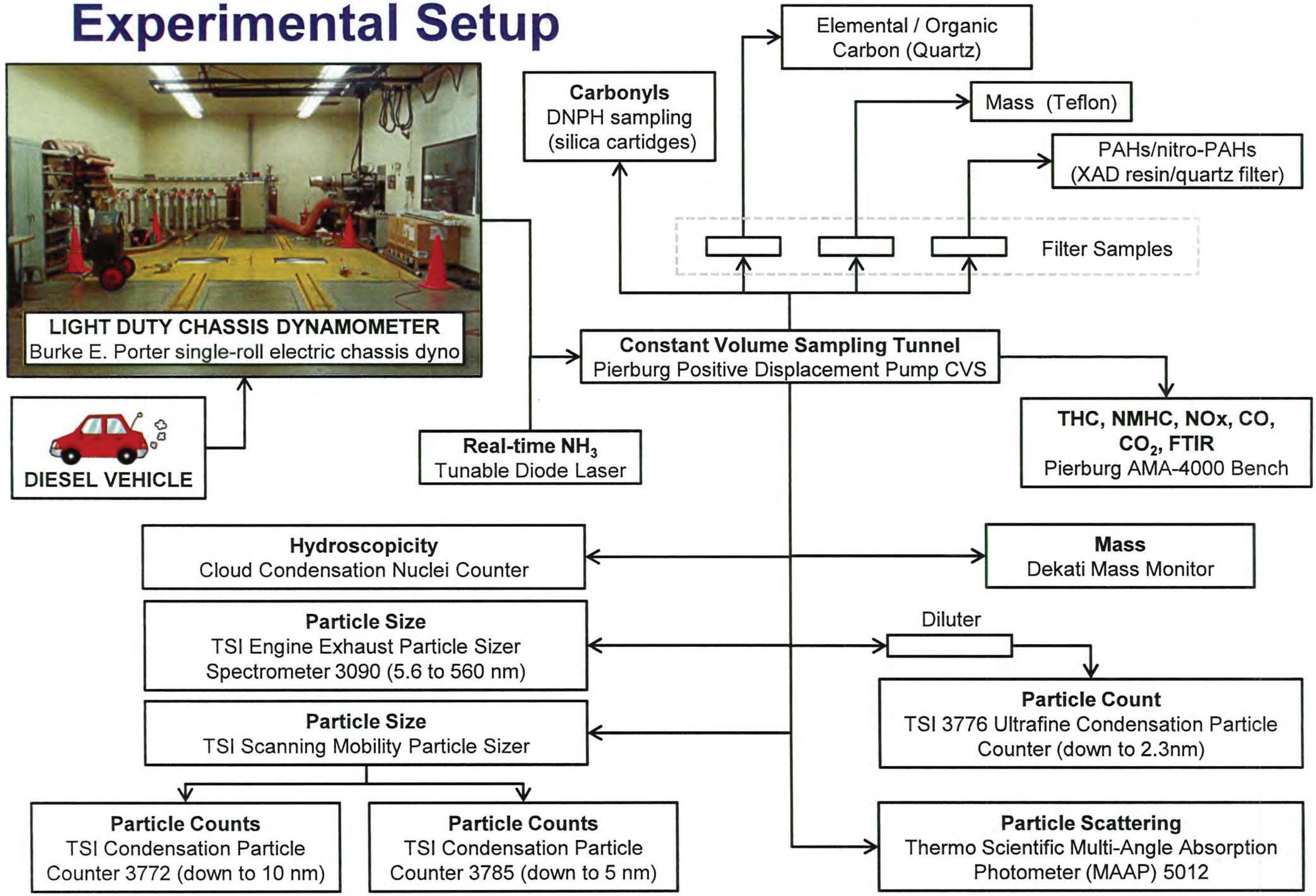
#	Aftertreatment	MY	Displacement	Configuration
Veh #1	DOC+DPF+SCR	2012	3.0L	V6
Veh #2	DOC+DPF+SCR	2012	6.6L	V8
Veh #3	DOC+DPF+SCR	2012	2.0L	4 cylinders
Veh #4	DOC+DPF+LNT	2012 or 2013	6.7L	6 cylinders
Veh #5	DOC+DPF+SCR	2012/13	6.7L	V8
Veh #6	DOC+DPF+SCR	2012/13	3.0L	V6
Veh #7	DOC+DPF+LNT	2012/13	2.0L	4 cylinders
Veh #8	TBD	2012 or 2013	TBD	TBD

Testing Protocol

- Emissions and fuel economy tests will be performed on the Federal Test Procedure (FTP) driving cycle.
  - Each vehicle/fuel combination will be tested at least twice.
  - A third test will be performed if the differences in FTP regulated emissions exceed a predefined limit: THC 33%, NO_x 29%, CO 70%, provided the absolute difference in the measurements is greater than 5 mg/mi.
- For the oil conditioning protocol, the vehicle will be conditioned on the oil for a period approximately equivalent to two US06 cycles, followed by an LA4 and a US06 cycle sequence repeated twice. This protocol provides more robust preconditioning, especially for improving the repeatability of the nucleation mode particles under hot start/running conditions.

UCR | College of Engineering- Center for Environmental Research & Technology

Experimental Setup



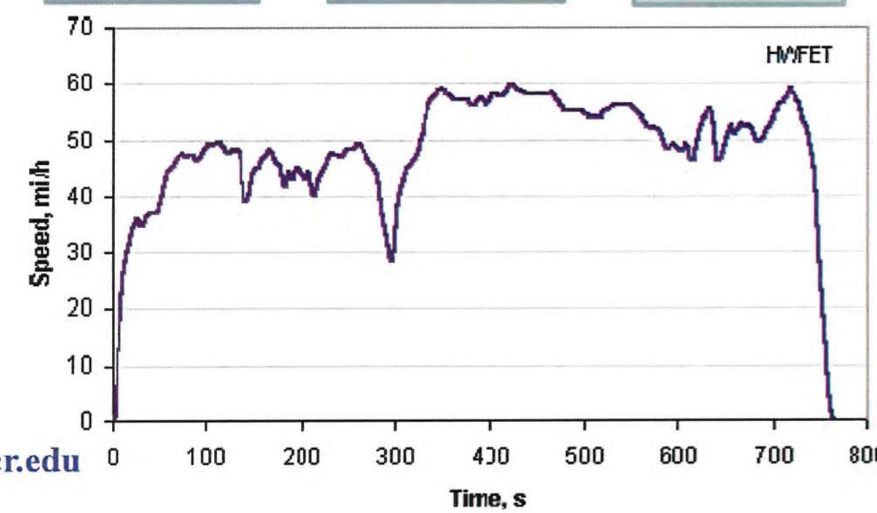
UCR | College of Engineering- Center for Environmental Research & Technology

Regeneration Testing Protocol

- A total of two fuels were tested during regeneration testing: Federal ULSD and Fed/SME-20.
- The regeneration testing protocol included driving the vehicle on-road on a route designed to simulate the LA4 portion of the FTP cycle in terms of typical speeds as well as number of stops, for approximately 170 miles (20 LA4s) to build up soot in the DPF.
- Testing was conducted over a double EPA Highway Fuel Economy Cycle (HWFET).

Baseline HWFET (emissions collection) → Baseline Regen → 20 LA4s (on-road) → Regen #1 → 20 LA4s (on-road) → Regen #2

- Regulated emissions, PM mass, particle number emissions and particle size distributions, carbonyls, PAHs/nitro-PAHs, EC/OC, and NH_3 emissions will be measured during a regeneration event for each vehicle/fuel combination.



www.cert.ucr.edu

Current Status

- Measurements are being made for:
  - Regulated emissions (NOx, PM, THC, CO, CH_4, NMHC, and CO_2) and fuel economy
  - Aldehydes and ketones
  - Real-time ammonia
  - EC/OC fractions
  - Particle number emissions
  - PAHs and nitro-PAHs
- Additional measurements are being made for:
  - Particle size distributions
  - Black carbon
  - Particles solubility
  - Hydroscopicity

Additional Work

- Comprehensive statistical analysis based on a complete data set
- QA/QC

- Future Work:
  - Further study on the emissions from low-environmental impact feedstock biodiesels, such as algae-based fuels
  - A more complete assessment on the emissions performance of high concentration renewable diesel (HVO) blends in modern technology diesel vehicles.
  - More information is needed on the physical, chemical, and biological characterization of particulate emissions during regeneration events from light- and heavy-duty vehicles operated on alternative fuels.

Acknowledgements

- This project is totally funded by the Coordinating Research Council (CRC) under contract No. CRC AVFL – 17b.
- Mr. Kurt Bumiller and Mr. Mark Villela of the University of California, Riverside for their contributions in conducting the emissions testing for this program.
- Thanks for the technical guidance from the CRC AVFL- committee and the AVFL-17b technical panel led by Dr. Mani Natarajan of Marathon Petroleum Company.
- Thanks to Mercedes Benz and Volkswagen for providing the vehicles.
- The Panel Members are: Brent Bailey (CRC), Mani Natarajan (Marathon Petroleum Company), Bill Cannella (Chevron), Dominic DiCicco (Ford), King Eng (Shell), Garry Gunter (Phillips 66), Scott Jorgensen (GM), David Lax (API), Shailesh Lopes (GM), Jenny Sigelko (Volkswagen), Marie Valentine (Toyota), William Woebkenberg (Daimler), Krystal Wrigley (Exxon Mobil)

UCR | College of Engineering- Center for Environmental Research & Technology

CARB HD Engine Study Results

www.cert.ucr.edu

Objectives of the HD Engine Study

- Evaluation and development of NO_x neutral biodiesel formulations
- Certification of one or more biodiesel blends under CARB Alternative Diesel Fuel Formulation Certification Procedure

UCR | College of Engineering- Center for Environmental Research & Technology

Test Fuels

- B5-animal, B5-WVO and B5-soy
- CARB Reference fuel

(title 13, CFR, section 2282(g)(3) fuel specification with nominally 10% aromatic content)

Test Matrix

- Preliminary/scoping testing with B5-animal, B5-WVO and B5-soy
- Full Certification Test with B5-animal and B5-WVO

Testing Details

- 2006 Cummins ISM 370 : In-line, 6 Cylinder, Turbocharged, with EGR
- Federal Testing Procedure (FTP)
- THC, NMHC, CO, NO_x, CO_2, PM, Soluble Organic Fraction (SOF)

Test Sequence

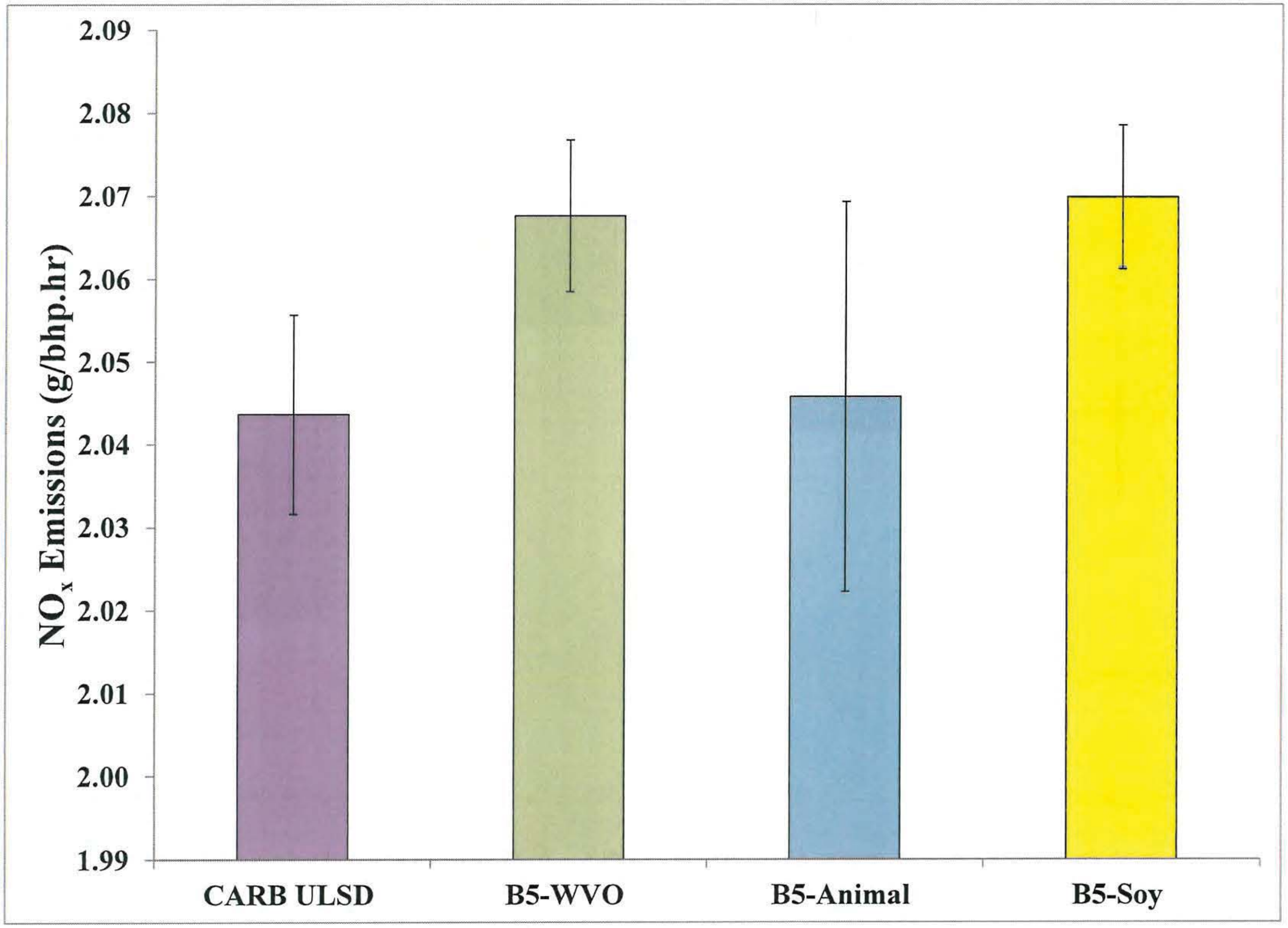
Day	Fuel Test Sequence
1	RC CR RC CR
2	RC CR RC CR
3	RC CR RC CR
4	RC CR RC CR
5	RC CR RC CR

Fuel Properties

Property	Test Method	Units	CARB	B100-Animal	B100-WVO	B100-Soy	B5-Animal	B5-WVO
Heating value	ASTM D240	BTU/lb	19689	17133	17076	17140	19661	19649
API Gravity@60°F	ASTM D4052			30.20	28.40	28.43	38.5	38.2
Specific Gravity @60°F	ASTM D4052		0.839	0.8750	0.8851	0.8848	0.8326	0.8339
Carbon	ASTM D5291	wt%	85.80	76.19	76.67	77.10	85.78	85.85
Hydrogen	ASTM D5291	wt%	13.61	12.28	11.98	11.85	13.8	13.82
Carbon Unit per Energy		Carbon lbs./BTU	4.36×10^{-5}	4.45×10^{-5}	4.49×10^{-5}	4.50×10^{-5}	4.36×10^{-5}	4.37×10^{-5}
Sulfur		ppm	4.7	6.5	11.1	1.1	4.5	5.3
Cetane number			53.1	61.1	54.6	49.2	61	52.2

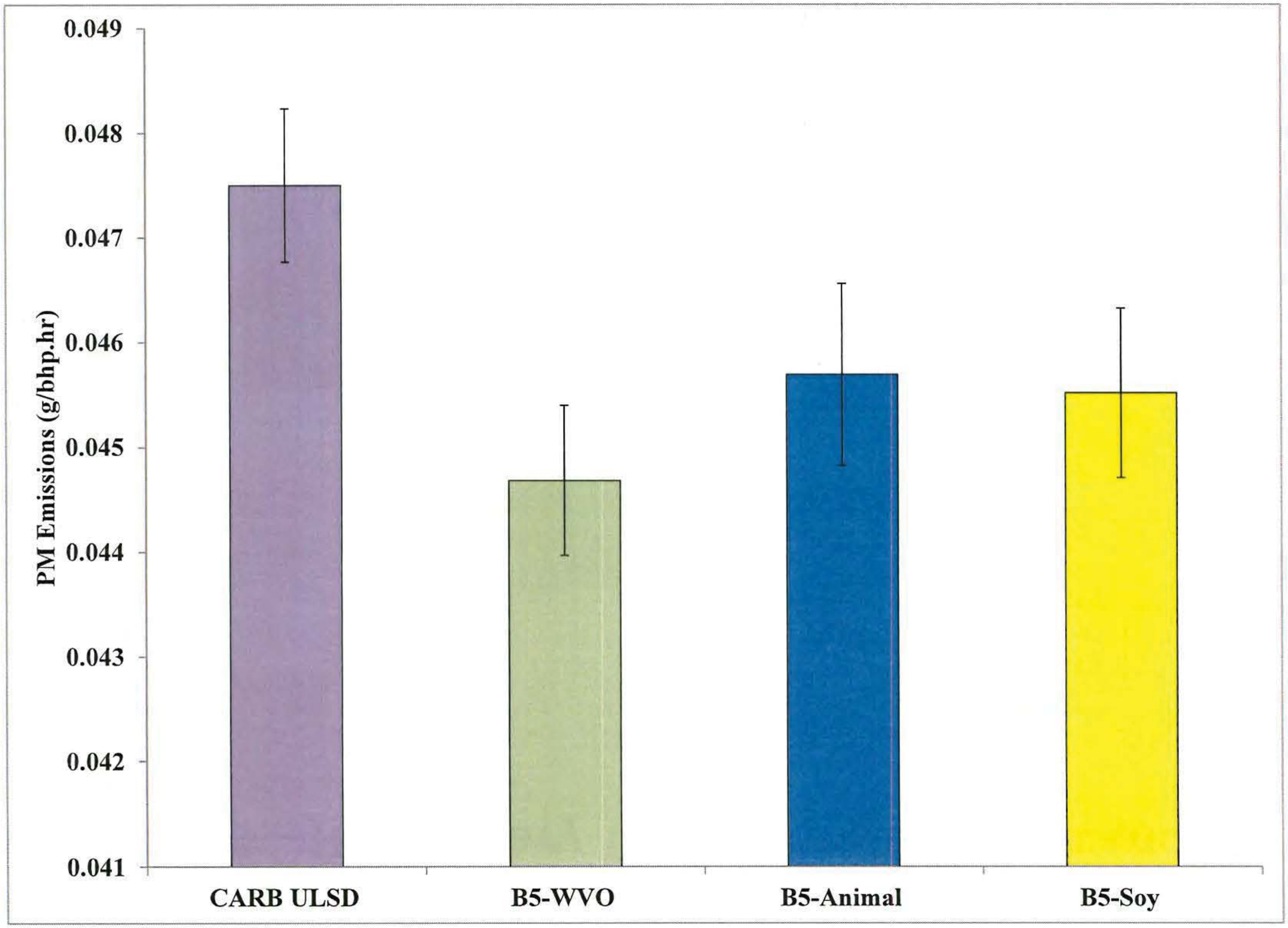
UCR | College of Engineering- Center for Environmental Research & Technology

NO_x Emissions – Preliminary Testing of B5 Certification



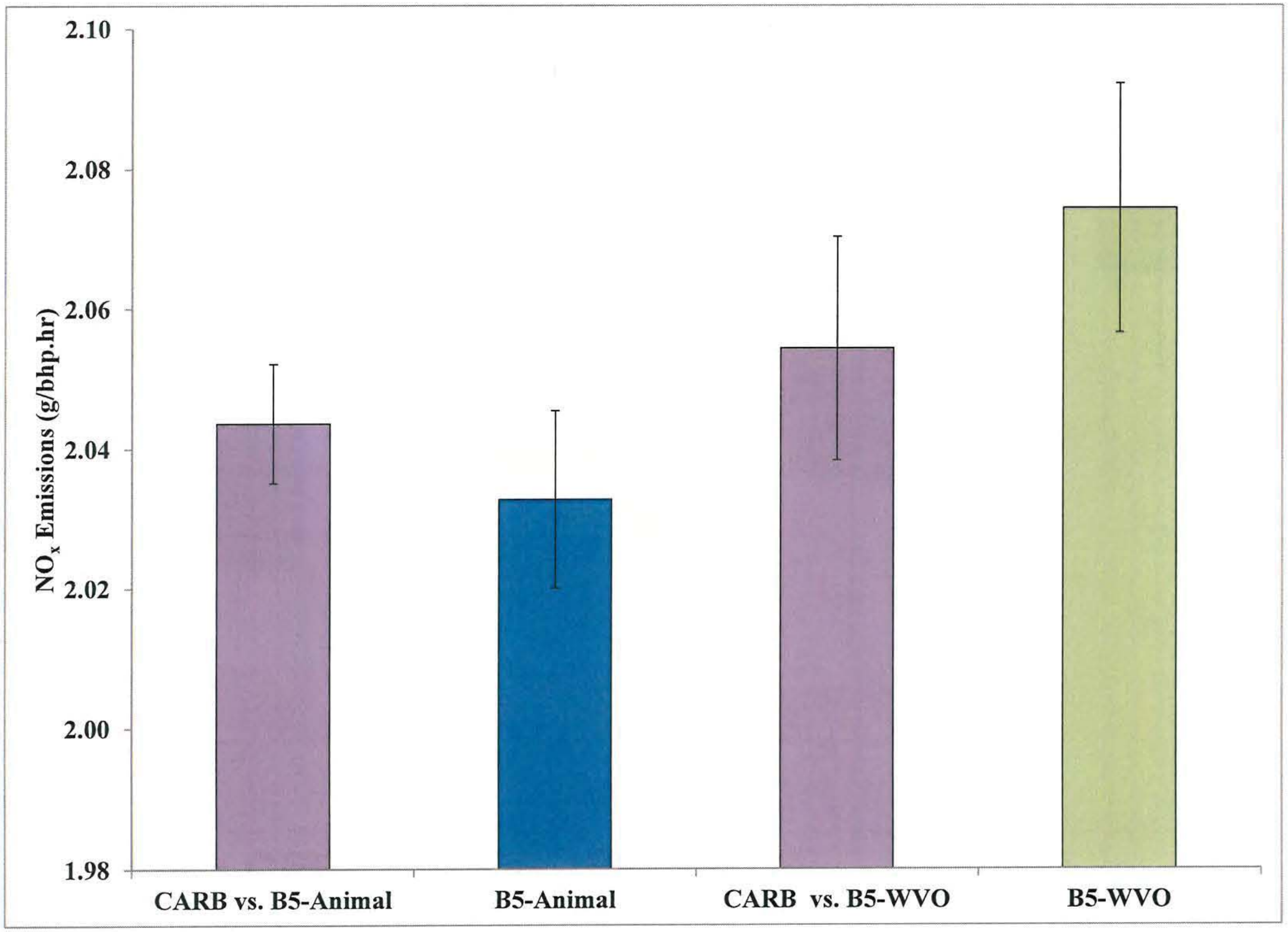
www.cert.ucr.edu

PM Emissions – Preliminary Testing of B5 Certification



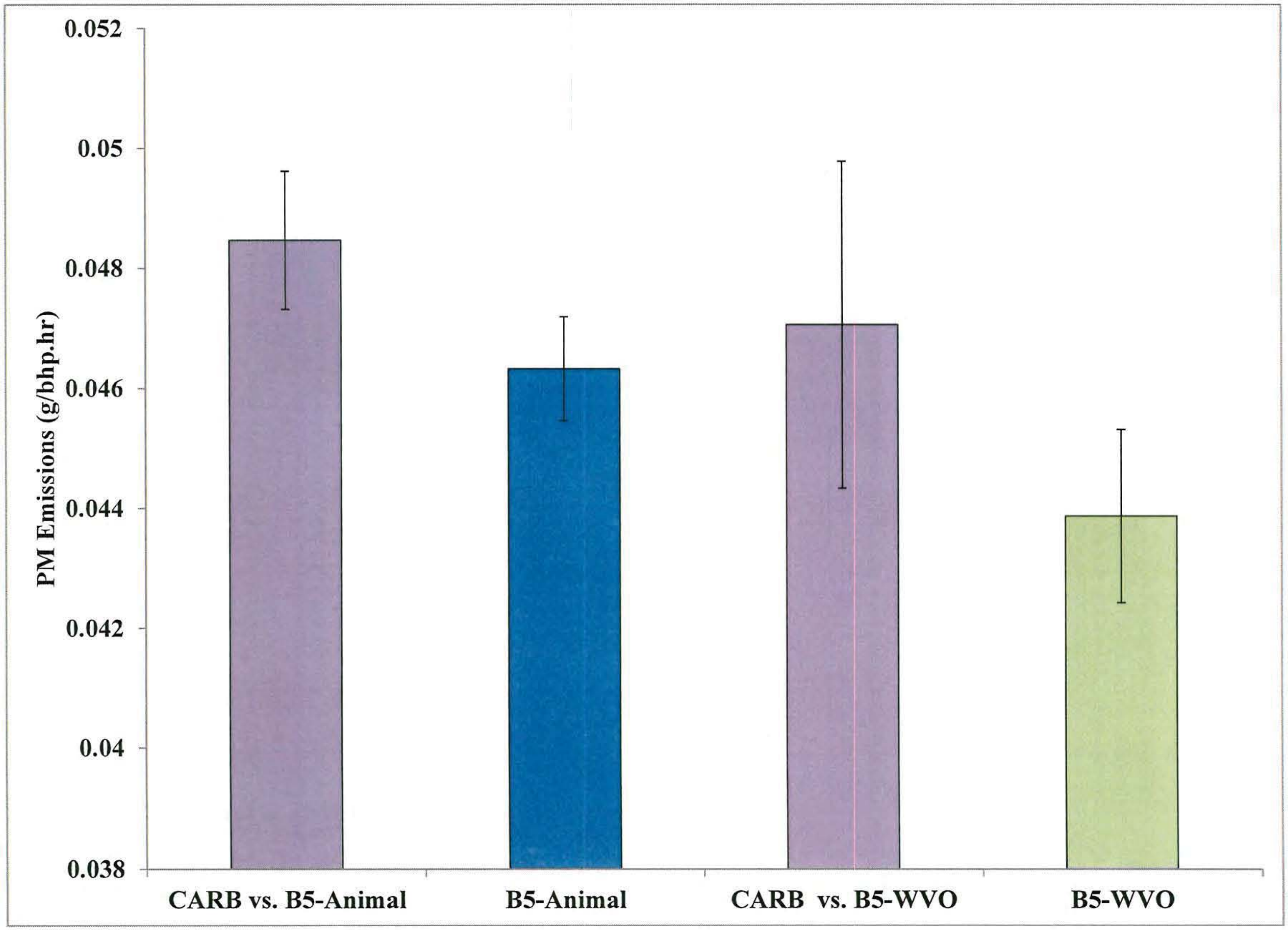
UCR | College of Engineering- Center for Environmental Research & Technology

NO_x Emissions- Certification Testing



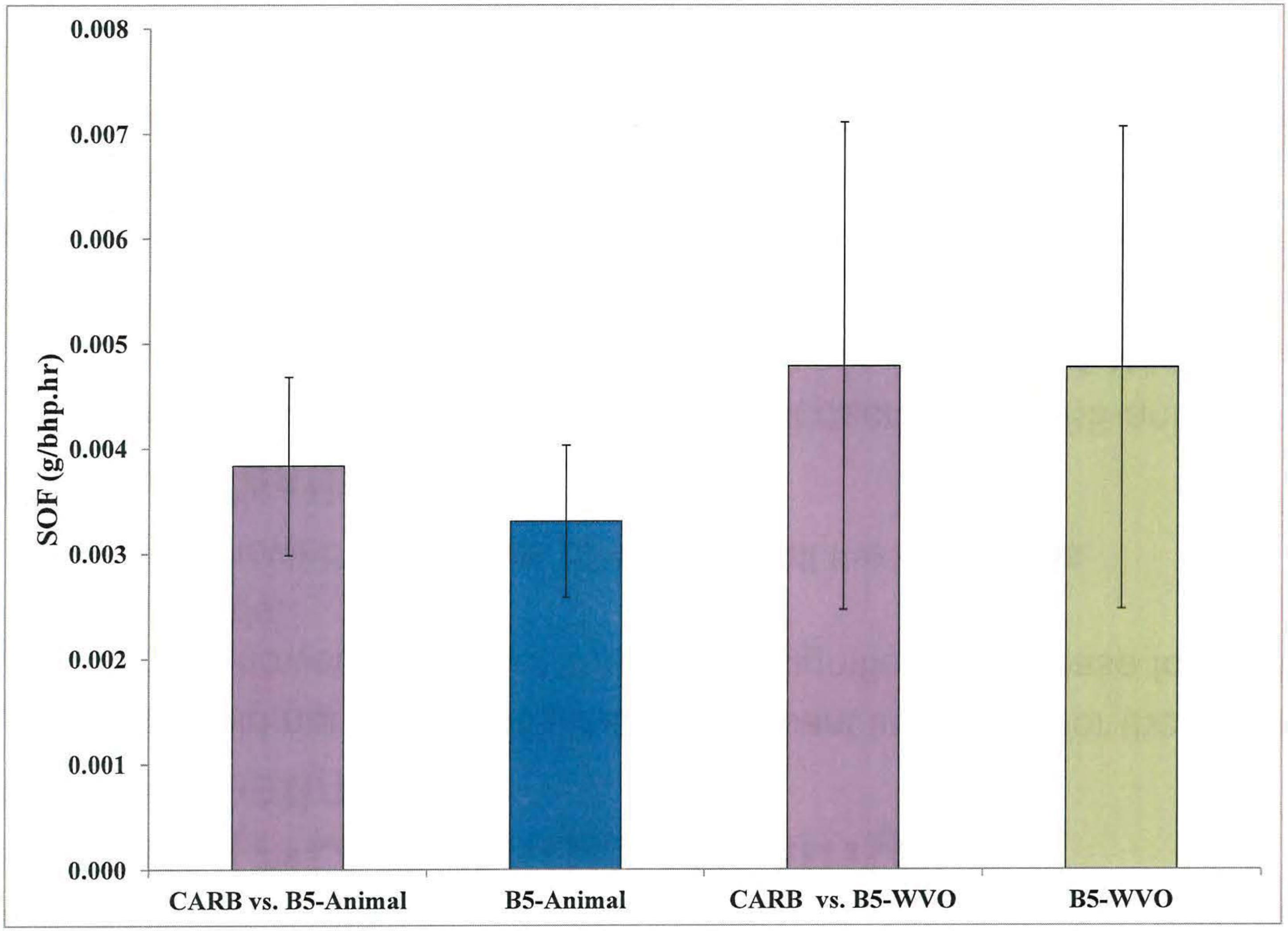
UCR | College of Engineering- Center for Environmental Research & Technology

PM Emissions - Certification Testing



UCR | College of Engineering- Center for Environmental Research & Technology

SOF Analysis- Certification Testing



Summary (HD Engine Testing)

Preliminary Testing

- NO_x emissions did not show statistically significant increases for the B5-animal.
- NO_x emissions showed slight, but statistically significant, increase for B5-WVO and B5-soy blends.
- PM emissions showed reductions of 4-6% for all the B5 blends.

Certification Testing

- NO_x emissions showed a statistically significant decrease for B5-animal.
- NO_x emissions showed a statistically significant increase for B5-WVO.
- PM showed reductions for both tested B5 blends.
- B5-animal showed a reduction in SOF compared to CARB reference fuel.
- The B5-animal successfully passed the certification statistical test.
- The B5-WVO failed the statistical certification test, based on NO_x emissions.

Additional work

- Further testing on B20 blends with additives has been conducted and is being analyzed.
- A more comprehensive study of the impacts of B5 on NO_x emissions in CARB diesel is planned in the near future.

Acknowledgements

- Funding from the California Air Resources Board (CARB) under contract No. 10-417.
- University of California Transportation Center (UCTC) Dissertation Grant
- Mr. Edward O'Neil, Mr. Donald Pacocha, Mr. Joe Valdez, and Mr. William Le Fevre of the University of California, Riverside for their contributions in conducting the emissions testing for this program.

12_B_LCFS_GE Responses (Page 278 – 300)

724. Comment: **UCR Presentation**

Agency Response: This document is a UCR presentation on renewable and biodiesel testing. It does not constitute an objection or suggestion on the proposal; however the document was referenced in comment **ADF B3-114** and **ADF B3-115**. Both comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

This page intentionally left blank.

AGENDA

23rd CRC REAL WORLD EMISSIONS WORKSHOP

Workshop Organizers

Mani Natarajan, Co-Chairman, Marathon Petroleum Company
Dominic DiCicco, Co-Chairman, Ford Motor Company
Alberto Ayala, California Air Resources Board
Brent Bailey, Coordinating Research Council
Megan Beardsley, U.S. Environmental Protection Agency OTAQ
Kevin Black, Federal Highway Administration
Rob R. Graze, Jr., Caterpillar, Inc. Technical Center
Philip Heirigs, Chevron Global Downstream
Jorn Dinh Herner, California Air Resources Board
Henry Hogo, South Coast Air Quality Management District
John Koupal, Eastern Research Group
Tom Long, U.S. Environmental Protection Agency NRMRL
Chris Tennant, Coordinating Research Council
Matthew Thornton, National Renewable Energy Laboratory

Hyatt Regency Mission Bay, San Diego, California
April 7-10, 2013

23rd CRC Real World Emissions Workshop

Schedule of Events

Sunday, April 7, 2013		
4:30 PM	- 6:00 PM	Registration and Poster Setup
6:00 PM	- 7:00 PM	Welcome Reception
Monday, April 8, 2013		
7:30 AM	- 8:30 AM	Registration and Continental Breakfast
8:30 AM	- 8:40 AM	Welcome from the Chairs
8:40 AM	**- 10:15 AM**	**Session 1: Emission Rates and Inventory**
10:15 AM	- 10:55 AM	Poster Session and Demonstrations
10:55 AM	**- 12:00 PM**	**Session 2: Emissions Control Measures and Emerging Technologies**
12:00 PM	- 1:30 PM	Lunch
1:30 PM	**- 2:15 PM**	**Session 2 continued**
2:15 PM	**- 2:50 PM**	**Session 3: I/M and In-Field Measurement Method Development**
2:50 PM	- 3:20 PM	Poster and Demonstration Viewing
3:20 PM	**- 4:35 PM**	**Session 3 continued**
4:35 PM		End of Day
6:00 PM	- 9:30 PM	Evening Cruise of San Diego Harbor
Tuesday, April 9, 2013		
7:30 AM	- 8:00 AM	Registration and Continental Breakfast
8:00 AM	- 8:50 AM	Keynote Speaker
8:50 AM	**- 9:40 AM**	**Session 4: Emission Trends and Modeling**
9:40 AM	- 10:20 AM	Poster and Demonstration Viewing
10:20 AM	**- 11:05 AM**	**Session 4 continued**
11:05 AM	**- 12:10 PM**	**Session 5: Laboratory Measurement Method Development**
12:10 PM	- 1:40 PM	Lunch
1:40 PM	**- 2:55 PM**	**Session 5 continued**
2:55 PM	- 3:25 PM	Poster and Demonstration Viewing
3:25 PM	**- 5:15 PM**	**Session 6: Particulate Matter Characterization**
5:15 PM		End of Day
5:30 PM	- 6:30 PM	Poster Exhibition and Reception
Wednesday, April 10, 2013		
7:30 AM	- 8:00 AM	Registration and Continental Breakfast
8:00 AM	**- 10:05 AM**	**Session 7: Off-Road**
10:05 AM	- 10:35 AM	Poster and Demonstration Viewing
10:35 AM	**- 12:10 PM**	**Session 8: Fuel Effects: Spark Ignition**
12:10 PM	- 1:40 PM	Lunch
1:40 PM	**- 3:05 PM**	**Session 9: Fuel Effects: Compression Ignition**
3:05 PM	- 3:25 PM	Open Discussion
3:25 PM		End of Workshop

Welcome Sunday, April 07, 2013

4:30-6:00 pm	**Registration in Bayview Ballroom Foyer and Poster Setup in Mission Ballroom**
6:00-7:00 pm	**Welcome Reception in the Cabanas**

DAY ONE Monday, April 08, 2013

All sessions take place in Bayview Ballroom unless otherwise noted.

7:30 AM	**Registration in Bayview Ballroom Foyer** Continental Breakfast in Mission Ballroom		
8:30 AM	Welcome from the Chairs: Mani Natarajan, Marathon Petroleum Co., and Dominic DiCicco, Ford Motor Co.		

SESSION 1: Emission Rates and Inventory

8:40 AM	*Introduction by Session Leaders Henry Hogo, South Coast Air Quality Management District, and John Koupal, Eastern Research Group*		
■ 8:45 AM	Black Carbon and Primary Organic Aerosol Emissions From On-Road Gasoline and Diesel Vehicles	Robert Harley	University of California Berkeley
■ 9:00 AM	Trends in Heavy-Duty Truck Emissions in the South Coast Air Basin	Gary Bishop	University of Denver
■ 9:15 AM	Cold Temperature Measurement of Particulate and Gaseous Emissions from Tier 2 MSAT Vehicles	David Hawkins	U.S. Environmental Protection Agency
■ 9:30 AM	Characterization of Drayage Activities at the Port of Houston	Carl Fulper	U.S. Environmental Protection Agency
■ 9:45 AM	Integrated Emissions from 938 Heavy-Duty Vehicles under Realistic Driving Conditions in Vancouver Canada	Don Stedman	University of Denver
10:00 AM	General Discussion of Session 1		

10:15 AM Poster Session and Demonstrations in Mission Ballroom *(see Pages 10-12 for Listings)*

SESSION 2: Emissions Control Measures and Emerging Technologies

10:55 AM	*Introduction by Session Leader Jorn Herner, California Air Resources Board*		
■ 11:00 AM	Phase 2 of the Advanced Collaborative Emissions Study (ACES): Highlights of Project Finding	Imad Khalek	Southwest Research Institute
■ 11:15 AM	Summary of Heavy-Duty Diesel Vehicle Selective Catalytic Reduction (SCR) Performance: Lessons to Date	John Collins	California Air Resources Board
■ 11:30 AM	The Air Quality Impacts of Trains in London Paddington Station	Uven Chong	University of Cambridge
■ 11:45 AM	Investigation on the Effect of Injection System Parameters on Emission Characteristics During Low Temperature Combustion Using Response Surface Methodology	Mario Velardi	West Virginia University

12:00 PM Lunch in Red Marlin Restaurant

■	1:30 PM	Quantification of Perturbation Effects on an Alternative Ignition System	Greg Yoder	West Virginia University
■	1:45 PM	Bivento.org - An Online Platform to Manage Real Traffic Emissions	Francisco Gala	Bivento-Technet
	2:00 PM	General Discussion of Session 2		

SESSION 3: I/M and In-Field Measurement Method Development

	2:15 PM	*Introduction by Session Leader Phil Heirigs, Chevron Global Downstream*		
■	2:20 PM	Assessing the Prevalence and Emissions Impact of High Emitters in California	Sherrie Sala-Moore	California Air Resources Board
■	2:35 PM	Results of Field Study of On-Board Diagnostic (OBD) Evaporative Codes	Carl Fulper	U.S. Environmental Protection Agency
	2:50 PM	**Poster and Demonstration Viewing in Mission Ballroom** *(see Pages 10-12 for Listings)*		
■	3:20 PM	Characterizing Emissions Reduction Performance and Test Methods of In-Use Diesel Retrofit Technologies from the National Clean Diesel Campaign	Britney McCoy	U.S. Environmental Protection Agency
■	3:35 PM	Synchronization of Portable Emissions Measurements Systems Data	Chris Frey	North Carolina State University
■	3:50 PM	Establishment of the PEMS-M Instrumentation Specifications for the In-Service Conformity of HDE in Europe	Athanasios Mamakos	Southwest Research Institute
■	4:05 PM	Evaluation, Quantification, and Performance of Accurate In-Use Fuel Economy Measurements	Kent Johnson	University of California, Riverside (CE-CERT)
	4:20 PM	General Discussion of Session 3		
	4:35 PM	**END OF DAY**		
	6:00 PM	Evening cruise of San Diego Harbor - meet in front of hotel lobby to board coaches. LAST BUS LEAVES AT 6:10 PM		

DAY TWO Tuesday, April 09, 2013

	7:30 AM	**Registration in Bayview Ballroom Foyer**		
		Continental Breakfast in Mission Ballroom		
	8:00 AM	KEYNOTE SPEAKER		

SESSION 4: Emission Trends and Modeling

	8:50 AM	*Introduction by Session Leader Megan Beardsley, U.S. Environmental Protection Agency*		
■	8:55 AM	Improving the Accuracy of Modeling Compressed Natural Gas Transit Buses in MOVES	Andrew Eilbert	U.S. Environmental Protection Agency
■	9:10 AM	Projecting 2025 California Light-Duty Vehicle Fleet Emissions -- MOVES, EMFAC, and Suggested Updates	Robert Sawyer	University of California, Berkeley
■	9:25 AM	Current Analysis and Potential Updates to the EMFAC Model in California	Sam Pournazeri	California Air Resources Board
	9:40 AM	Poster and Demonstration Viewing in Mission Ballroom *(see Pages 10-12 for Listings)*		
■	10:20 AM	Updated Emissions Estimates for Pleasure Craft and Recreational Vehicles in California	David Chou	California Air Resources Board
■	10:35 AM	Development of a Simplified Version of MOVES and Incorporation into a Traffic Simulation Model	Chris Frey	North Carolina State University
■	10:50 AM	General Discussion of Session 4		

SESSION 5: Laboratory Measurement Method Development

	11:05 AM	*Introduction by Session Leaders Kevin Black, Federal Highway Administration, and Matt Thornton, NREL*		
■	11:10 AM	Low PM Mass Assessment and Analysis E-99	Kent Johnson	University of California, Riverside (CE-CERT)
■	11:25 AM	An Analysis of Sub 1 mg/mi PM Mass from Light-Duty Vehicles	Jim Watson	California Air Resources Board
■	11:40 AM	A New Laboratory Method for Very Low Particular Mass Emissions Measurement	Jonathan Bushkuhl	AVL North America
■	11:55 AM	Particle Generator for Engine Exhaust Simulation	Imad Khalek	Southwest Research Institute
	12:10 PM	Lunch in Red Marlin Restaurant		
■	1:40 PM	Optimization of the Pegasor Particle Sensor for Automotive Exhaust Measurements	Leonidas Ntziachristos	Aristotle University
■	1:55 PM	Toward the Inclusion of FT-IR in the Certification of Engine Emissions for Both Standard and Alcohol-Based Fuel Blends	Richard Frazee	AVL North America
■	2:10 PM	Real-time Measurements of Metallic Ash Emissions from Engines	David Kittelson	University of Minnesota
■	2:25 PM	Impact of Modern Diesel Engine and Aftertreatment Technology on Test Repeatability and Emissions Prediction	Nigel Clark	West Virginia University CAFEE
	2:40 PM	General Discussion of Session 5		

2:55 PM Poster and Demonstration Viewing in Mission Ballroom *(see Pages 10-12 for Listings)*

SESSION 6: Particulate Matter Characterization

	3:25 PM	*Introduction by Session Leader Rob Graze, Caterpillar, Inc.*		
■	3:30 PM	Real-time DPF Filtration Efficiencies and Particle Number Emissions from Modern Diesel and Dual-Fueled HD Engines	Marc Besch	West Virginia University
■	3:45 PM	Morphology and Nanostructures of Particulates from an Engine-Simulating Particle Generator	Heeje Seong	Argonne National Laboratory
■	4:00 PM	Study of Variability in Particulate Mass Measurement and Comparison with Particle Number Count Measurement Method	Pragalath Thiruvengadam	West Virginia University
■	4:15 PM	Quantifying Particulate Matter Emissions from Gasoline and Diesel Vehicles: Gas Particle Portioning and Sampling Artifacts	Albert Presto	Carnegie Mellon University
■	4:30 PM	Physiochemical and Toxicological Properties of Size Segregated PM Emissions from a 2010 Compliant Heavy-Duty Diesel Truck - Is Diesel PM Still Diesel PM?	Jorn Herner	California Air Resources Board
■	4:45 PM	Investigation of Particle Size Distributions in a Exhaust Plume Emitted by Heavy-Duty Diesel Trucks at Cruise and Idling Operations	Presented by Mario Velardi for Daniele Littera	West Virginia University
	5:00 PM	General Discussion of Session 6		

5:15 PM **END OF DAY**

5:30 PM Poster Exhibition and Reception in the Mission Ballroom (5:30-6:30 pm)

DAY THREE Wednesday, April 10, 2013

7:30 AM	**Registration in Bayview Ballroom Foyer** Continental Breakfast in Mission Ballroom		

SESSION 7: Off-Road

8:00 AM	*Introduction by Session Leader Alberto Ayala, California Air Resources Board*		
■ 8:05 AM	Load Factors, Emission Factors, Duty Cycles, and Activity of Diesel Nonroad Vehicles	Tim DeFries	Eastern Research Group
■ 8:20 AM	Emission Factors from In-Use Non-Road Construction Equipment Using 1065 Compliant PEMS	Tanfeng (Sam) Cao	University of California, Riverside (CE-CERT)
■ 8:35 AM	Remote Sensing Measurements of In-Use Locomotive NOx Emissions	Matthew Breuer	University of Puget Sound
■ 8:50 AM	Projected Growth for Ocean-Going Vessels	Louis Browning	ICF International
■ 9:05 AM	Evaluation of Hybrid Retrofit System for a Tugboat	Nicholas Gysel	University of California, Riverside (CE-CERT)
■ 9:20 AM	In-Use Measurement of Passenger Diesel Locomotive Emissions for Biodiesel and Petroleum Diesel Fuels	Christopher Frey	North Carolina State University
■ 9:35 AM	Particulate Matter and Other Criteria Pollutants Reduced by Algae Fuels in Marine Vessels	Yusuf Khan	University of California, Riverside (CE-CERT)
9:50 AM	General Discussion of Session 7		

10:05 AM **Poster and Demonstration Viewing in Mission Ballroom** *(see Pages 10-12 for Listings)*

SESSION 8: Fuel Effects: Spark Ignition

10:35 AM	*Introduction by Session Leader Tom Long, U.S. Environmental Protection Agency*		
■ 10:40 AM	Characterization of Particular Matter Emissions from Light-Duty Vehicles Technologies Using Physical, Chemical and Cellular Assays	Satya Sardar	California Air Resources Board
■ 10:55 AM	Effects of Five Gasoline Properties on Exhaust Emissions from Light-Duty Tier 2 Vehicles	Aron Butler	U.S. Environmental Protection Agency
■ 11:10 AM	Effects of Fuel Sulfur Level on Emissions from Tier 2 Vehicles in the In-Use Fleet	Aron Butler	U.S. Environmental Protection Agency
■ 11:25 AM	Criteria Emissions, Toxic Pollutants, and Particle Number Emissions from Gasoline PFI and GDI Vehicles Operated on Ethanol and Isobutanol Blends	Daniel Short	University of California, Riverside (CE-CERT)
■ 11:40 AM	A Comprehensive Evaluation of PM, NOx, Ammonia, and Greenhouse Gas Emissions from Current Model Year Heavy-Duty Vehicles	Arvind Thiruvengadam	West Virginia University
11:55 AM	General Discussion of Session 8		

12:10 PM Lunch in Red Marlin Restaurant

SESSION 9: Fuel Effects: Compression Ignition

1:40 PM	*Introduction by Session Leader Mani Natarajan, Marathon Petroleum Company*		
■ 1:45 PM	Biodiesel and Renewable Diesel Characterization and Testing in Modern LD Diesel Passenger Cars and Trucks and HD Engines	Georgios Karavalakis	University of California, Riverside (CE-CERT)
■ 2:05 PM	Emissions, Fuel Economy and Duty Cycle Testing and Analysis of Hybrid Electric Trucks Operating in the California Fleet	Matthew Thornton	National Renewable Energy Laboratory
■ 2:20 PM	Hybrid and Electric Bus Emissions and Energy Test Program in South America	Sebastian Tolvett	Sistemas Sustentables
2:35 PM	General Discussion of Session 9		
2:50 PM	Open discussion - Mani Natarajan and Dominic DiCicco, Chairmen		

3:25 PM **END OF Workshop**

Poster Exhibits

Emission Rates and Inventory

Measurement of Regulated and Greenhouse Gas Emissions from In-Use Vehicle Activity during a Cross-Continental Trip	Hemanth Kappanna [presented by Pragalath Thirvengadam]	West Virginia University
On-Board Measurement of Reduced-Nitrogen Emissions from Vehicles during Real-World Driving	John Moss	Oak Crest Institute of Science
Technology Significantly Lowers Emissions from Yard Tractors over Past 10 Years	Poornima Dixit	University of California, Riverside (CE-CERT)
Benchmarking Vehicle Fleet Performance: Real World Monitoring as an Everyday Activity	Stephen Hanley	University of Leeds Institute for Transport Studies
Emissions of Air Toxic Species from Light-Duty Vehicles with Gasoline Direct Injection (GDI) and Port Fuel Injection (PFI) Engines	Oliver Chang	California Air Resources Board
Idling Emissions from Recent Model Year Heavy-Duty Diesel Vehicles	Doh-Won Lee (presented by Josias Zietsman)	Texas A&M Transportation Institute
Contribution of Cold Starts to Real-World Total Trip Emissions for Light-Duty Gasoline Vehicles	Chris Frey	North Carolina State University

Emission Control Measures and Emerging Technologies

Exhaust Emissions Reductions Using a Seawater Scrubber on a Container Ship	Andrew Burnette	Infowedge
In-Use NOx Emissions from 2010 or Newer Heavy-Duty Diesel Engines Equipped with OEM Aftertreatment Devices	Chandan Misra [presented by John Collins]	California Air Resources Board
Update on Pase 2 of the Advanced Collaborative Emissions Study (ACES Phase 2)	Chris Tennant	Coordinating Research Council

I/M and In-Field Measurement Methods

Results of the TEDDIE Project and Future Developments Concerning Emissions Testing in Europe EmissionCheck 2020	Hans Juergen Maeurer	DEKRA Automobil GmBH Germany
Operational Challenges Faced During Vehicle Emissions Testing in Hong Kong	Kwok-Lam Ng	Hong Kong Environmental Protection Department
Evidence of Flipper Vehicles in Arizona Random Sample Triplicate IM147 Data	Tom Wenzel	Lawrence Berkeley National Laboratory
Ultrafine Particle Measurements and Evaluation of the Mobile Source Contribution in New York City	Robert Anderson	TSI, Inc.

■	Comparison of a Portable FTIR with SEMTECH-DS under Real-World Urban Driving Conditions	Eddie Lo	Hong Kong Environmental Protection Department
■	Relative Amounts of Gases in Exhaust Plumes by Laser Remote Sensing	Stewart Hager	HEAT, LLC
■	Off-Cycle Light-Duty Diesel Vehicle Emissions Measurement with PEMS: Project Description and Preliminary Data	Marc Besch	West Virginia University

Emission Trends and Modeling

■	Methodology to Predict Real World Aerodynamic Drag Losses Due to On-Road Cross-Wind Effects	Nigel Clark	West Virginia University

Laboratory Measurement Methods Development

■	An Analysis of Light-Duty Vehicle PM Data Generated in CARB HSL Cell 2 and Cell 3	Mang Zhang	California Air Resources Board
■	Time-Resolved FTIR Measurements of Non-Methane Organic Gases (NMOG) in Vehicle Exhaust Gas	Christine Gierczak	Ford Motor Company
■	Pulse Height Monitor to Improve Data Reliability of Condensation Particle Counter for Engine Emission Applications	Tim Johnson	TSI, Inc.
■	Measurement of Dioxin Formation in Heavy-Duty Diesel Engines	Robert Fanick	Southwest Research Institute
■	~~Variability of PM Mass Measurement for Two Sub 1 Mg/Mi Vehicles~~ (withdrawn)	~~Satya Sardar~~	~~California Air Resources Board~~
■	Onsite Checks on Particle Number Equipment	Manfred Linke	AVL List GmbH

Particulate Matter Characterization

■	Determination of Suspended Exhaust PM Mass for Light-Duty Vehicles	Heejung Jung	University of California Riverside (CE-CERT)
■	Insight Into Detailed Properties of Nano-Particles from Various Engine Combustion Sources	Kyeong Lee	Argonne National Laboratory

Off-Road

■	Real-World In-Use Tailpipe Emissions Measurements of Over the Snow Vehicles at Yellowstone National Park	Christopher Frey	North Carolina State University
■	Hybrid Off-Road Equipment Evaluation: Part 1 - Duty Cycle Development	Tangfeng (Sam) Cao	University of California Riverside (CE-CERT)

■ Techniques for the Convenient Off-Road Monitoring an dEnforcement of Heavy-Duty Vehicle Exhaust Emissions	Peter McClintock	Applied Analysis
■ Characterization of Real-World Emissions from Heavy Haulers in Canadian Oil Sands Mining	Xiaoliang Wang	Desert Research Institute

Fuel Effects: Compression Ignition

■ Effect of Biodiesel Feedstock on Regulated Emissions, Gaseous Toxics, and Ultrafine Particles from Two Trucks Fitted With and Without Aftertreatment Controls	Nicholas Gysel	University of California Riverside (CE-CERT)

Fuel Effects: Spark Ignition

■ Impact of Natural Gas Fuel Composition on Criteria and Toxic Emissions from Transit Buses	Maryam Hajbabaei	University of California Riverside (CE-CERT)

Demonstrations

■ TSI Engine Emissions Solutions	Tim Johnson Bob Anderson	TSI, Inc.
■ Photoacoustic Measurement of Black Carbon Emissions	Gavin McMeeking	Droplet Measurement Technologies
■ Particle Mass and Particle Number Measurement for Automotive Engine and Aircraft Turbine Applications	Siegfried Roeck	AVL
■ RDE Real Driving Emissions Measurement with AVL PEMS Equipment*	Siegfried Roeck	AVL
■ Sensors, Inc.	Robert Wilson	Sensors, Inc.
■ Dekati and Pegasor Instruments for PM Sampling, Conditioning, and Analysis	Tyler Beck	Particle Instruments
■ Real-World Emissions Testing Based on FTIR Technology	Ron Tandy	A&D Technology

*This demonstration is located in the parking lot outside the ballroom.

Chairmen

■ Mani Natarajan, Co-Chairman, Marathon Petroleum Company

Mani Natarajan is currently working at Marathon Petroleum Company as a Fuels Technology Advisor. He is leading a CRC project on biodiesel and renewable diesel characterization in modern LD diesel passenger cars and trucks. He is currently the co-chairman of the CRC Real World Emissions and Emissions Modeling Group. He is a member of the CRC Emissions Committee, CRC AVFL Committee, CRC Atmospheric Impacts Committee and API Vehicle Emissions Group. Over the past 23 years, he has been very active in CRC and API projects, conducting fuels/emissions-related research. He has a B.S and M.S. in Chemistry and a M.S. and Ph.D. in Chemical Engineering. He was an Associate Professor at the College of Engineering, The University of Toledo. Previously, as Manager of Research at Surface Combustion, he led projects in advanced combustion, renewable energy and heat treatment. He was a consultant for Pratt & Whitney in the super alloy manufacturing development of the Integrally Bladed Rotors (IBR) for jet engines. He is a member of SAE, AIChE and ACS.

■ Dominic DiCicco, Co-Chairman, Ford Motor Company

Dominic DiCicco was recently appointed to the position of Environmental Policy Manager in the Sustainability and Vehicle Environmental Matters Division at Ford Motor Company. His new role involves supporting the execution of Ford Motor Company's strategic product plans as well as topics of mutual interest on improving fuel quality and regulations, requiring interaction with the US Environmental Protection Agency (US EPA), California Air Resources Board (CARB) and other government entities around the world. Mr. DiCicco is the co-chairman of the CRC Real World Emissions and Emissions Modeling Group and serves as a member on both the CRC Emissions Committee and CRC AVFL Committee. He is a Ford representative on the Fuels Working Group of United States Council for Automotive Research (USCAR), the Alliance of Automobiles and other industry-related efforts. Recent and past major projects have included key roles in working towards the successful reduction in sulfur content in fuels, elimination of manganese across the Canadian marketplace and more recently in the evaluation of mid-level ethanol blends (such as E15 and E20). His career with Ford Motor Company is nearly 20 years young, more than half this time supporting fuels after starting at the Ford Research Laboratory in the Chemical Engineering Department researching exhaust emission catalytic systems. Mr. DiCicco holds a M.S. and B.S. in Chemical Engineering and a B.A. in Chemistry, all from Wayne State University.

Session Leaders

■ Alberto Ayala, California Air Resources Board

Alberto Ayala was appointed as Deputy Executive Officer of the California Air Resources Board at the end of 2012. In this capacity, Alberto is responsible for the Board's ambient monitoring and laboratories and mobile source control and operations programs. Alberto became a member of CARB's research staff in 2000 and has since held various management assignments in programs such as Carl Moyer Incentives, AB 32 early actions, mobile refrigerant rules, diesel retrofits, and car, truck, and bus emissions research. Most recently he served as Chief of the Monitoring and Laboratory Division. Alberto oversees the full range of policy, regulatory, and research efforts of over 400 professionals focused on achieving CARB's goals for clean, zero-emission, and low-carbon transportation; state-of-the-art monitoring for air and climate pollution; and a widely recognized motor vehicle emissions and fuels testing program. He contributed to the first car GHG emissions regulation in 2004 and is now directing one of CARB's most important efforts, the advanced clean cars program.

Prior to CARB, Alberto was a member of the engineering faculty at West Virginia University, where he now holds an adjunct appointment, and was an ordnance system design engineer for Teledyne Ryan Aeronautical. He holds B.S., M.S., and Ph.D. degrees in Mechanical Engineering from the University of California, Davis. His internships were with GE, the California Energy Commission, and the Atmospheric Boundary Layer Wind Tunnel Laboratory at UC Davis. He has published extensively, been a speaker nationally and internationally, and lectured as a Visiting Professor in California and abroad.

■ Megan Beardsley, US Environmental Protection Agency OTAQ

Megan Beardsley is an environmental scientist in the Air Quality & Modeling Center within the Assessment and Standards Division of EPA's Office of Transportation and Air Quality. Her group is responsible for the development of mobile source models, including MOVES and NONROAD, and supporting EPA programs and policies through emissions and activity research, policy analysis, emissions inventory development and air quality modeling support. Megan has worked for EPA since 1992. She has an interdisciplinary B.S. from Stanford University and an M.S. in Resource Policy from the University of Michigan.

■ Kevin Black, Federal Highway Administration

Kevin Black is a Highway Engineer working as an Air Quality Analyst on air quality issues for the Federal Highway Administration's Resource Center in Baltimore. He has a B.A. in Geography from George Mason University, a B.S. in Civil Engineering from Virginia Tech and an M.S. in Civil Engineering from George Mason University. He has worked in several offices within FHWA, including the Office of Research, the Office of Engineering, the Office of Natural and Human Environment, and currently the Resource Center. His present position is responsible for analyzing the environmental impacts of air pollutants in support of FHWA air quality policy.

■ R. Rob Graze, Jr., Caterpillar, Inc. Technical Center

Rob Graze is degreed in Physics with additional study in Mechanical Engineering. His Research Background includes work in the areas of tribology, lube system and bearing design, diesel and large SI engine combustion development, particulate and gaseous emissions measurement, and partial flow dilution system design and refinement.

■ Philip Heirigs, Chevron Global Downstream

Phil Heirigs, a native of California, holds a B.S. in Engineering and a M.S. in Chemical Engineering from the University of California, Los Angeles, and is a licensed Professional Engineer in the state. His professional career began with a short stint in the nuclear power industry, which was followed by nearly seven years with the California Air Resources Board. Mr. Heirigs then spent 15 years at Sierra Research, a Sacramento-based consulting firm. In June 2007, Mr. Heirigs joined Chevron, where his key responsibilities have included the analysis of issues related to the life cycle assessment of transportation fuels, vehicle fuel economy, advanced vehicle technologies and costs, transportation fuel demand, the impact of fuel specification changes on vehicle emissions, and vehicle emissions modeling.

■ Jorn Dinh Herner, California Air Resources Board

Jorn Herner has worked for the last eight years at the California Air Resources Board. In his current position as Chief of the Research Planning and Emission Mitigation Branch in the Research Division, he oversees the division's extramural research program, the implementation of measures to reduce greenhouse gases, and the vehicle emissions research program. His main research interests are the effect of new emission control technologies and fuels and the relative toxicity of emissions from various combustion sources. Jorn has a B.A. and M.S. from the University of California, Berkeley, and earned his Ph.D. in Civil and Environmental Engineering from the University of California, Davis.

■ Henry Hogo, South Coast Air Quality Management District

Henry Hogo is the Assistant Deputy Executive Officer for the Mobile Source Division in the Office of Science and Technology Advancement at the South Coast Air Quality Management District (SCAQMD). Mr. Hogo received a Bachelor of Science degree in chemistry from the University of California, Berkeley, and has been working in the air pollution field for over 35 years. As Assistant Deputy Executive Officer in the Mobile Source Division, Mr. Hogo is responsible for the implementation of the District's Clean Fleet Vehicle Rules, development of mobile source strategies for the SCAQMD's air quality management plans, analysis of mobile source emissions impacts on air quality, and providing input on state and federal mobile source regulations.

■ John Koupal, Eastern Research Group

John Koupal is a Principal Engineer with Eastern Research Group, Inc. (ERG) with over twenty years of experience in mobile source emission research, policy, modeling and inventory development in the U.S. and abroad. Prior to joining ERG, Mr. Koupal served many roles within the U.S. EPA's Office of Transportation and Air Quality, including directing the group responsible for mobile source modeling and emission inventory development, providing technical and analytical support for several EPA rules, and leading the development of the MOVES model. Mr. Koupal worked for Nissan from 1995-1997 on emissions certification and regulatory issues. Mr. Koupal was named to the Advisory Committee on the National Mobile Source Emission Inventory of China in 2010, and the Board of Advisors for UC Riverside?s Center for Environmental Research and Technology (CE-CERT) in 2012. Mr. Koupal graduated from the University of Michigan with a Bachelor's Degree in Industrial and Operations Engineering in 1989.

■ Tom Long, US Environmental Protection Agency NRMRL

Tom Long received his M.S. in Engineering from West Virginia University, where he worked with Nigel Clark on the design of the first heavy-duty mobile dynamometer. Later, he served as the West Coast Coordinator for West Virginia's Center for Alternative Fuels, Engines, and Emissions (CAFEE). After working as a contractor to the U.S. EPA in RTP, North Carolina, Tom was hired by the government to coordinate the dynamometer facility operated by the EPA's Office of Research and Development. His area of research includes the measurement of mobile source emissions using both stationary and chassis dynamometer, PEMS, and near road stationary sites. He is particularly interested in fuel and temperature effects on the quantity and characteristics of mobile source emissions.

■ Matthew Thornton, National Renewable Energy Laboratory

Matt Thornton is a principal research engineer at the National Renewable Energy Laboratory. He received his Ph.D. from Georgia Institute of Technology. He is involved in testing and analysis research programs that assess the fuel economy and performance impacts of advanced fuels and powertrains for light- and heavy-duty vehicles, and is currently the acting director for NREL's Center for Transportation Technologies and Systems.

12_B_LCFS_GE Responses (Page 301 – 316)

725. Comment: **CRC Emissions Workshop Agenda**

Agency Response: This document is an agenda from the April 2013 CRC Emissions Workshop. It does not constitute an objection or suggestion on the proposal; however the document was referenced in comment **ADF B3-115**. The comment is responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

This page intentionally left blank.

ATTACHMENT C

Comments of Growth Energy on the Air Resources Board Staff Presentations at a Public Consultation Meeting on Regulations for Commercialization of Alternative Diesel Fuels

These comments respond to the CARB staff's request for comments on the staff's presentations at the April 17, 2014 public consultation meeting on the proposed adoption of regulations to govern commercialization of alternative diesel fuels, including as part of compliance strategies for the California low-carbon fuel standard ("LCFS") regulation.

1. CARB-Sponsored and Related Emissions Testing and Research

During the April 17th meeting, CARB staff indicated that the agency had an "ongoing" study of the emission impacts of B5 and B10 blends underway and that data from that study would be released to the public and incorporated into the rulemaking process. Incorporation of this data into the rulemaking process is essential in order to comply with the Global Warming Solutions Act of 2006 and other statutes that apply to CARB's implementation of the 2006 Act.[1] CARB must provide not only a full report on that study, but also all data that it has obtained in connection with the study and related materials. Nearly four weeks have passed since the April 17th public meeting and, to Growth Energy's knowledge, the CARB staff has not met its commitments.[2] Growth Energy and other stakeholders will need sufficient time to review the data and related materials in order to participate effectively in the ADF and LCFS rulemakings. Also during the course of the workshop, CARB staff indicated that two other agency-sponsored studies of biodiesel blends had been conducted but not yet released to the public. Again, all

ADF B3-122

1 *See, e.g.*, Cal. Health & Safety Code § 38562(e) ("The state board shall rely upon the best available ... scientific information ... when adopting regulations required by this section."); *see also id.* § 38563(b)(4) (regulations to implement the 2006 Act must not "interfere with[] efforts to achieve and maintain federal and state ambient air quality standards."). The California Environmental Quality Act's requirements likewise cannot be met unless CARB considers all relevant data on the potential of biodiesel usage to increase NOx emissions.

2 Much of the data from this study and related materials may also be responsive to a Public Records Act request that Growth Energy has filed with CARB, but no data and very few related materials have been released to date.

reports as well as underlying data and other relevant materials must be made publicly available. All these materials, from each study, must be placed in a public rulemaking file without further delay, pursuant to subsections 6 and 7 of section 11347.3(a) of the Government Code. ADF B3-122 cont.

2. Methodology to Establish a Significance Threshold and Related Issues

To date, CARB staff has indicated that it has attempted to identify a significance threshold for biodiesel blends by comparing emissions results when engines are tested on nominally specific biodiesel blends, and when the same engines are tested in similar ways on fuel containing no diesel. The defect in such a method is that it does not permit assessment of emissions when engines are operated on biodiesel blends other than those tested, including, for example, biodiesel blends below B5. The appropriate method to determine the significance threshold is contained in an analysis prepared for Growth Energy by Mr. Robert Crawford and placed in the rulemaking file last year.[3] After evaluating the linearity and statistical significance of the relationship between NOx emissions and biodiesel content, Mr. Crawford demonstrates that use of biodiesel even at levels below B5 will result in increased NOx emissions. CARB should adopt Mr. Crawford's approach to establishing the significance threshold for biodiesel, or explain in full any reasons for not doing so. ADF B3-123

Despite the fact that CARB staff has correctly chosen to propose mitigation of biodiesel NOx impacts on a per-gallon basis in extreme ozone non-attainment areas, this issue is important because the use of the current methodology for establishing the significance level will not prevent significant increases in NOx emissions in these areas. ADF B3-124

---

3 Crawford, R., "NOx Emission Impact of Soy- and Animal-based Biodiesel Fuels: A Re-Analysis," December 10, 2013.

3. Protection of the Environment on a Statewide Basis

Based on the presentation at the recent public consultation meeting, CARB staff continues to propose the highly flawed "effective blend" approach for determining the point at which mitigation of biodiesel NOx impacts would be required under the proposed ADF regulation. Instead, CARB staff should also require the per-gallon mitigation concept proposed for extreme ozone nonattainment areas and the appropriate significance threshold to be used in all other areas of the state. ADF B3-125

4. Minimum Requirements to Determine and Report Blend Levels

The CARB staff's presentation at the recent meeting did not clarify how the proposed ADF regulation will ensure that the biodiesel content of blends sold in California will be accurately known to fuel purchasers or reported to CARB. At present, CARB appears to have no requirement for determining the biodiesel content of diesel fuels being imported or distributed in the state that contain biodiesel up to the B5 level. Given this, a party interested in blending 5% biodiesel into a "diesel" fuel may be unaware of the fact that the "diesel" fuel could already contain up to 5% biodiesel and that the resulting blend would therefore be B10, not B5. Similarly, a party interested in blending 20% biodiesel into a "diesel" could in fact produce a B25 blend, instead of the intended B20 blend. Obviously, both circumstances have substantial ramifications with respect to potential NOx increases associated with the use of biodiesel in California. ADF B3-126

Given the above, CARB must modify as necessary its existing diesel fuel regulations as well as the proposed ADF regulations to ensure that the biodiesel content of all blends of biodiesel and diesel sold in California is accurately known and reported to both CARB as well as the Division of Measurement Standards. This could easily be accomplished by requiring that all ADF B3-127 "diesel" fuels used in biodiesel blends be tested before blending for Fatty Acid Methyl Ester ("FAME") content using appropriate test procedures such as the EN14103:2011 procedure already referenced in the proposed ADF regulations or the ASTM D7371 procedure. Alternatively, CARB could require testing of final blends for FAME content. Again, failure by CARB to require accurate measurement and reporting of the biodiesel content of biodiesel-diesel blends will lead to unmitigated increases in NOx emissions along with other potential issues, including violations of pump labeling and vehicle manufacturer warranty requirements.

ADF B3-127 cont.

Respectfully submitted,

GROWTH ENERGY

12_B_LCFS_GE Responses (Page 317 – 321)

726. Comment: **ADF B3-122, ADF B3-126 and ADF B3-127**

Agency Response: These comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

727. Comment: **ADF B3-123 and ADF B3-125**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

NOx Emissions Impact of Soy- and Animal-based Biodiesel Fuels: A Re-Analysis

December 10, 2013

Prepared for:

Sierra Research
1801 J Street
Sacramento, CA 95811

Prepared by:

Robert Crawford
Rincon Ranch Consulting
2853 South Quail Trail
Tucson, AZ 85730-5627
Tel 520-546-1490

NOX EMISSIONS IMPACT OF SOY- AND ANIMAL-BASED BIODIESEL FUELS: A RE-ANALYSIS

prepared for:

Sierra Research, Inc.

December 10, 2013

prepared by:

Robert Crawford
Rincon Ranch Consulting
2853 South Quail Trail
Tucson, AZ 85730-5627
Tel 520-546-1490

NOX IMPACT OF SOY- AND ANIMAL-BASED BIODIESEL FUELS: A RE-ANALYSIS

Table of Contents

List of Tables

List of Figures

1. EXECUTIVE SUMMARY

1.1 Background on the Proposed Rule

The California Air Resources Board (CARB) has proposed regulations on the commercialization of alternative diesel fuel (ADF) that were to be heard at the December 2013 meeting of the Board. The proposed regulations seek to "... create a streamlined legal framework that protects California's residents and environment while allowing innovative ADFs to enter the commercial market as efficiently is possible."[1] In this context ADF refers to biodiesel fuel blends. Biodiesel fuels are generally recognized to have the potential to decrease emissions of several pollutants, including hydrocarbons (HC), carbon monoxide (CO), and particulate matter (PM), but are also recognized to have the potential to increase oxides of nitrogen (NOx) unless mitigated in some way. NOx emissions are an important precursor to smog and have historically been subject to stringent emission standards and mitigation programs to prevent growth in emissions over time. A crucial issue with respect to biodiesel is how to "... safeguard against potential increases in oxides of nitrogen (NOx) emissions."[2]

The proposed regulations are presented in the Staff Report: Initial Statement of Reasons (ISOR) for the Proposed Regulation on the Commercialization of New Alternative Diesel Fuels[3] (referenced as ISOR). Chapter 5 of the document describes the proposed regulations, which exempt diesel blends with less than 10 percent biodiesel (B10) from requirements to mitigate NOx emissions:

> There are two distinct blend levels relative to biodiesel that have been identified as important for this analysis. Based on our analysis to date, we have found that diesel blends with less than 10 percent biodiesel by volume (<B10) have no significant increase in any of the pollutants of concern and therefore will be regulated at Stage 3B (Commercial Sales not Subject to Mitigation). However, we have found that biodiesel blends of 10 percent and above (≥B10) have potentially significant increases in NOx emissions, in the absence of any mitigating factors, and therefore those higher blend levels will be regulated under Stage 3A (Commercial Sales Subject to Mitigation).[4]

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

---

[1] "Notice of Public Hearing to Consider Proposed Regulation on the Commercialization of New Alternative Diesel Fuels." California Air Resources Board, p. 3. http://www.arb.ca.gov/regact/2013/adf2013/adf2013notice.pdf.

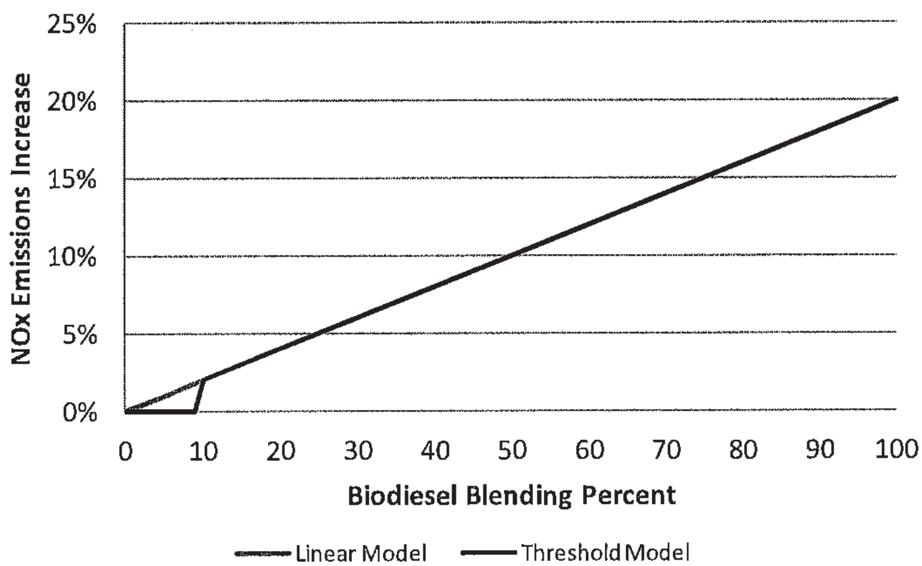
[2] Ibid. p. 3.

[3] "Proposed Regulation on the Commercialization of New Alternative Diesel Fuels. Staff Report: Initial Statement of Reason." California Air Resources Board, Stationary Source Division, Alternative Fuels Branch. October 23, 2013. http://www.arb.ca.gov/regact/2013/adf2013/adf2013isor.pdf.

[4] Ibid, p. 22.

Existing research on the NOx emission effects of biodiesel has consistently been conducted under the hypothesis that the emission effect will be linearly proportional to the blending percent of neat biodiesel (B100) with the base diesel fuel. The Linear Model that has been accepted by researchers is shown as the blue line in Figure 1-1. The Staff position cited above is that biodiesel fuels do not increase NOx emissions until the fuel blend reaches 10% biodiesel. This so-called Staff Threshold Model departs from the Linear Model that underlies past and current biodiesel research by claiming that NOx emissions do not increase until the biodiesel content reaches 10 percent.

Figure 1-1
Linear and Staff Threshold Models for Biodiesel NOx Impacts



The Staff Threshold model is justified by the statement: "Based on our analysis to date, we have found that diesel blends with less than 10 percent biodiesel by volume (<B10) have no significant increase in any of the pollutants of concern." Other portions of the ISOR state that Staff will track "... the effective blend level on an annual statewide average basis until the effective blend level reaches 9.5 percent. At that point, the biodiesel producers, importers, blenders, and other suppliers are put on notice that the effective blend-level trigger of 9.5 percent is approaching and mitigation measures will be required once the trigger is reached."[5] Until such time, NOx emission increases from biodiesel blends below B10 will not require mitigation.

Section 6 of the ISOR presents a Technology Assessment that includes a literature search the Staff conducted to obtain past studies on the NOx impact of biodiesel in heavy-duty

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

[5] Ibid, p. 24.

engines using California diesel (or other high-cetane diesel) as a base fuel. Section 6.d presents the results of the literature search with additional technical information provided in Appendix B. The past studies include the Biodiesel Characterization and NOx Mitigation Study[6] sponsored by CARB (referenced as Durbin 2011).

The results of the Staff literature search are summarized in Table 1-1, which has been reproduced from Table 6.1 of the ISOR. For B5 and B20, the data represent averages for a mix of soy- and animal-based biodiesels, which tend to have different impacts on NOx emissions (animal-based biodiesels increase NOx to a lesser extent). For B10, the data represent an average for soy-based biodiesels only. Staff uses the +0.3% average NOx increase at B5 in comparison to the 1.3% standard deviation to conclude:

> Overall, the testing indicates different NOx impacts at different biodiesel percentages. Staff analysis shows there is a wide statistical variance in NOx emissions at biodiesel levels of B5, providing no demonstrable NOx emissions impact at this level and below. At biodiesel levels of B10 and above, multiple studies demonstrate statistically significant NOx increases, without additional mitigation.[7]

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Table 1-1
Results of Literature Search Analysis

Biodiesel Blend Level	NOx Difference	Standard Deviation
B5	0.3%	1.3%
B10[a]	2.7%	0.2%
B20	3.2%	2.3%

Source: Table 6.1 of Durbin 2011
Notes:
[a] Represents data using biodiesel from soy feedstocks.

The Staff conclusion is erroneous because it relies upon an apples-to-oranges comparison among the blending levels. Each of the B5, B10, and B20 levels include data from a different mix of studies, involving different fuels (soy- and/or animal-based), different test engines, and different test cycles. The B5 values come solely from the CARB Biodiesel Characterization study, while the B10 values come solely from other studies. The B20 values are a mix of data from the CARB and other studies. The results seen in the table above are the product of the uncontrolled aggregation of different studies that produces incomparable estimates of the NOx emission impact at the three blending levels.

[6] "CARB Assessment of the Emissions from the Use of Biodiesel as a Motor Vehicle Fuel in California: Biodiesel Characterization and NOx Mitigation Study." Prepared by Thomas D. Durbin, J. Wayne Miller and others. Prepared for Robert Okamoto and Alexander Mitchell, California Air Resources Board. October 2011.

[7] ISOR, p. 32.

As will be demonstrated in this report, the Staff conclusion drawn from the data in Table 1-1 is not supported by past or current biodiesel research, including the recent testing program sponsored by CARB. In fact, past and current studies indicate that biodiesel blends at any level will increase NOx emissions in proportion to the blending percent unless specifically mitigated by additives or other measures.

1.2 Summary and Conclusions

The following sections of this report examine the studies cited by CARB one-by-one. As evidenced from this review, it is clear that the data do not support the Staff conclusion and, indeed, the data refute the Staff conclusion in some instances. Specifically:

- There is no evidence supporting the Staff conclusion that NOx emissions do not increase until the B10 level is reached. Instead, there is consistent and strong evidence that biodiesel increases NOx emissions in proportion to the biodiesel blending percent.

- There is clear and statistically significant evidence that biodiesel increases NOx emissions at the B5 level in at least some engines for both soy- and animal-based biodiesels.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Considering each of the six past studies obtained from the technical literature and their data on high-cetane biodiesels comparable to California fuels, we find the following:

1. None of the six studies measured the NOx emissions impact from biodiesel at blending levels below B10. Only two studies tested a fuel at the B10 level. All other testing was at the B20 level or higher. Because none tested a B5 (or similar) fuel, none of them can provide direct evidence that NOx emissions are not increased at B5 or other blending levels below B10.

2. These studies provide no data or evidence supporting the validity of the Staff's Threshold Model that biodiesel below B10 does not increase NOx emissions. In fact, all of the studies are consistent with the contention that biodiesel increases NOx emissions in proportion to the blending percent.

3. Two of the studies present evidence and arguments that the NOx impact from biodiesel is a continuous effect that is present even at very low blending levels and will increase at higher levels in proportion to the blending percentage.

Considering the CARB Biodiesel Characterization report, we find that:

4. For the three engines where CARB has published the emission values measured in engine dynamometer testing, all of the data demonstrate that biodiesel fuels significantly increase NOx emissions for both soy- and animal-based fuels by amounts that are proportional to the blending percent. This is true for on-road and off-road engines and for a range of test cycles.

5. Where B5 fuels were tested for these engines, NOx emissions were observed to increase. NOx emission increases are smaller at B5 than at higher blending levels and the observed increases for two engines were not statistically significant by themselves based on the pair-wise t-test employed in Durbin 2011.[8] However, the testing for one of the engines (the 2007 MBE4000) showed statistically significant NOx emission increases at the B5 level for both soy- and animal-based blends.

By itself, the latter result is sufficient to disprove the Staff's contention that biodiesel blends at the B5 level will not increase NOx emissions.

Based on examination of all of the studies cited by CARB as the basis for its proposal to exempt biodiesels below B10 from mitigation, it is clear that the available research points to the expectation that both soy- and animal-based biodiesel blends will increase NOx emissions in proportion to their biodiesel content, including at the B5 level. CARB's own test data demonstrate that B5 will significantly increase NOx emissions in at least some engines.

Based on data in the CARB Biodiesel Characterization report, soy-based biodiesels will increase NOx emissions by about 1% at B5 (and 2% at B10), while animal-based biodiesels will increase NOx emissions by about one-half as much: 0.45% at B5 (and 0.9% at B10). All of the available research says that the NOx increases are real and implementation of mitigation measures will be required to prevent increases in NOx emissions due to biodiesel use at blending levels below B10.

Finally, we note that CARB has not published fully the biodiesel testing data that it relied on in support of the Proposed Rule and thereby has failed to adequately serve the interest of full public disclosure in this matter. The CARB-sponsored testing reported in Durbin 2011 is the sole source of B5 testing cited by CARB as support for the Proposed Rule. Durbin 2011 publishes only portions of the measured emissions data in a form that permits re-analysis; it does not publish any of the B5 data in such a form. It has not been possible to obtain the remaining data through a personal request to Durbin or an official public records request to CARB and, to the best of our knowledge, the data are not otherwise available online or through another source.

CARB should publish all of the testing presented in Durbin 2011 and any future testing that it sponsors in a complete format that allows for re-analysis. Such a format would be (a) the measured emission values for each individual test replication; or (b) averages across all test replications, along with the number of replications and the standard error of the individual tests. The first format (individual test replications) is preferable because that would permit a full examination of the data including effects such as test cell drift over time. Such publication is necessary to assure that full public disclosure is achieved and that future proposed rules are fully and adequately informed by the data.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

[8]As discussed in Section 3.3, the pair-wise t-test is not the preferred method for demonstrating statistical significance.

1.3 Review of 2013 CARB B5 Emission Testing

In December 2013, after the release of the ISOR and in response to an earlier Public Records Act request, CARB released a copy of new CARB-sponsored emission testing conducted by Durbin and others at the University of California CE-CERT[9]. The purpose of the study was "... to evaluate different B5 blends as potential emissions equivalent biodiesel fuel formulations for California."[10] Three B5 blends derived from soy, waste vegetable oil (WVO), and animal biodiesel stocks were tested on one 2006 Cummins ISM 370 engine using the hot-start EPA heavy-duty engine dynamometer cycle. A preliminary round of testing was conducted for all three fuels followed by emissions-equivalent certification testing per 13 CCR 2282(g) for two of the fuels. As noted by Durbin: "[t]he emissions equivalent diesel certification procedure is robust in that it requires at least twenty replicate tests on the reference and candidate fuels, providing the ability to differentiate small differences in emissions."[11]

Soy and WVO B5 Biodiesel

The B5-soy and B5-WVO fuels were blended from biodiesel stocks that were generally similar to the soy-based stock used in the earlier CARB Biodiesel Characterization Study (Durbin 2011) with respect to API gravity and cetane number. In the preliminary testing, the two fuels "...showed 1.2-1.3% statistically significant [NOx emissions] increases with the B5-soy and B5-WVO biodiesel blends compared to the CARB reference fuel."[12] The B5-WVO fuel caused the smaller NOx increase (1.2%) and was selected for the certification phase of the testing. There, it "... showed a statistically significant 1.0% increase in NOx compared to the CARB reference fuel"[13] and failed the emissions-equivalent certification due to NOx emissions.

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

Animal B5 Biodiesel

The B5-animal derived fuel was blended from an animal tallow derived biodiesel that was substantially different from the animal based biodiesel used in the earlier Durbin study, and was higher in both API gravity and cetane number. The blending response for cetane number was also surprising, in that blending 5 percent by volume of a B100 stock (cetane number 61.1) with 95% of CARB ULSD (cetane number 53.1) produced a B5 fuel blend with cetane number 61.

In preliminary testing, the B5-animal fuel showed a small NOx increase which was not statistically significant, causing it to be judged the best candidate for emissions-equivalent certification. In the certification testing, it "...showed a statistically

[9] "CARB B5 Biodiesel Preliminary and Certification Testing." Prepared by Thomas D. Durbin, G. Karavalakis and others. Prepared for Alexander Mitchell, California Air Resources Board. July 2013. This study is not referenced in the ISOR, nor was it included in the rule making file when the hearing notice for the ADF regulation was published in October 2013.
[10] Ibid, p. vi.
[11] Ibid, p. viii.
[12] Ibid, p. 8.
[13] Ibid, p. 9.

significant 0.5% reduction in NOx compared to the CARB reference fuel"[13] and passed the emissions-equivalent certification. The NOx emission reduction for this fuel blend appears to be real for this engine, but given the differences between the blendstock and the animal based biodiesel blendstock used in the earlier Durbin study it is unclear that it is representative for animal-based biodiesels in general..

Summary

The conclusions drawn in the preceding section are not changed by the consideration of these new emission testing results. For plant-based biodiesels (soy- and WVO-based), the new testing provides additional and statistically significant evidence that B5 blends will increase NOx emissions at the B5 level. The result of decreased NOx for the B5 animal-based blend stands out from the general trend of research results reviewed in this report. However:

- The same result – reduced NOx emissions for some fuels and engines – has sometimes been observed in past research, as evidenced by the emissions data considered by CARB staff in ISOR Figure B.3 (reproduced in Figure 2.1 below). As shown, some animal-based B5 and B20 fuels reduced NOx emissions while others increased NOx emissions with the overall conclusion being that NOx emissions increase in direct proportion to biodiesel content of the blends and that there is no emissions threshold.

- Increasing cetane is known to generally reduce NOx emissions and has already been proposed by CARB as a mitigation strategy for increased NOx emissions from biodiesel[14]. The unusual cetane number response in the blending and the high cetane number of the B5-animal fuel may account for the results presented in the recently released study.

Considering the broad range of plant- and animal-based biodiesel stocks that will be used in biodiesel fuels, we conclude that the available research (including the recently released CARB test results) indicates that unrestricted biodiesel use at the B5 level will cause real increases in NOx emissions and that countermeasures may be required to prevent increases in NOx emissions due to biodiesel use at blending levels below B10.

###

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

[14] For example, see Durbin 2011 Section 7.0 for a discussion of NOx mitigation results through blending of cetane improvers and other measures.

2. CARB LITERA TURE REVIEW

The Staff ISOR explains that the Appendix B Technology Assessment is the basis for CARB's conclusion that biodiesels below B10 have no significant impact on NOx emissions. The assessment is based on data from seven studies (identified in Table 2-1) that tested high-cetane diesel fuels. The first study (Durbin 2011) is the Biodiesel Characterization Study that was conducted for CARB, while the others were obtained through a literature search.

Tab le 2-1
List of Studies from High-Cetane Liter ature Sear ch

Primary Author	Title	Published	Year
Durbin	Biodiesel Mitigation Study	Final Report Prepared for Robert Okamoto, M.S. and Alexander Mitchell, CARB	2011
Clark	Transient Emissions Comparisons of Alternative Compression Ignition Fuel	SAE 1999-01-1117	1999
Eckerle	Effects of Methyl Ester Biodiesel Blends on NOx Emissions	SAE 2008-01-0078	2008
McCormick	Fuel Additive and Blending Approaches to Reducing NOx Emissions from Biodiesel	SAE 2002-01-1658	2002
McCormick	Regulated Emissions from Biodiesel Tested in Heavy-Duty Engines Meeting 2004 Emissions	SAE 2005-01-2200	2005
Nuszkowski	Evaluation of the NOx emissions from heavy duty diesel engines with the addition of cetane improvers	Proc. I Mech E Vol. 223 Part D: J. Automobile Engineering, 223, 1049-1060	2009
Thompson	Neat fuel influence on biodiesel blend emissions	Int J Engine Res Vol. 11, 61-77.	2010

Source: Table B.2 of Durbin 2011

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

Figure 2-1 reproduces two exhibits from Appendix B that show increasing trends for NOx emissions with the biodiesel blending level. Based on the slopes of the trend lines,

Figure 2-1
NOx Emission Increases Observed in Biodiesel Research Cited in Staff ISOR

Figure B.2: NOx Impact of Soy Biodiesel Blended in High Cetane Base Fuel

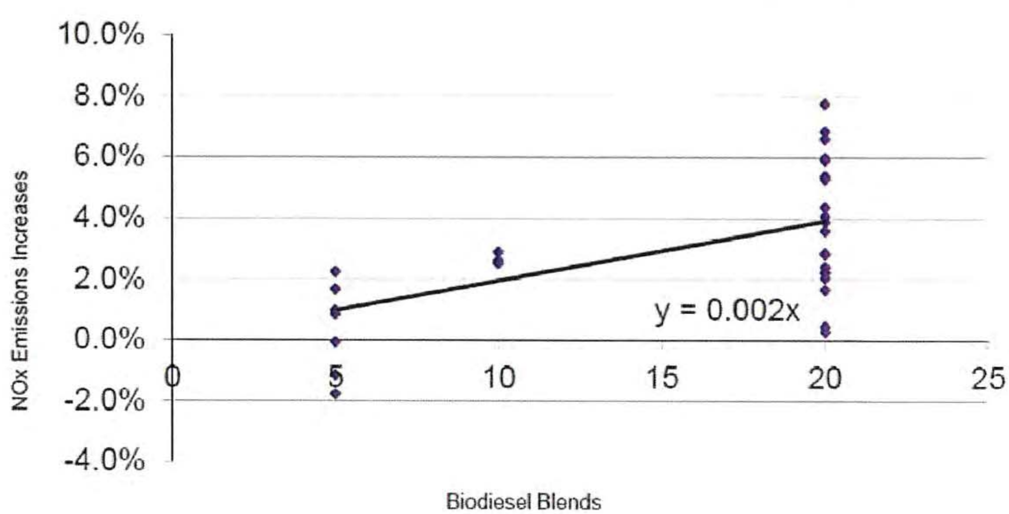
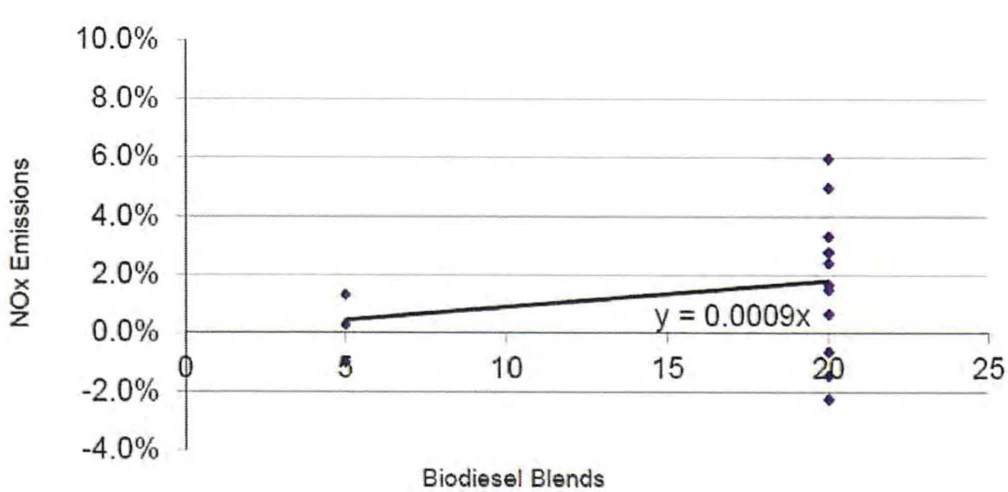


Figure B.3: NOx Impact of Animal Biodiesel Blended in High Cetane Base Fuel



Source: Figures B.2 and B.3 of Appendix B: Technology Assessment

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

soy-based biodiesels are shown to increase NOx emissions by approximately 1% at B5, 2% at B10, and 4% at B20. Animal-based biodiesels are shown to increase NOx emissions by about one-half as much: 0.45% at B5, 0.9% at B10, and 1.8% at B20. Although there is substantial scatter in the results, these data do not appear to support the Staff Threshold Model that biodiesel does not increase NOx emissions at B5 but does so at B10.

We will examine the Durbin 2011 study at some length in Section 3. In this section, we look at each of the other studies cited by the Staff to find out what the studies say about NOx emissions impacts at and below B10.

2.1 Review of Literature Cited in the ISOR

The Staff literature search sought and selected testing that used fuels with cetane levels comparable to California diesel fuels; the Staff does not, however, list those fuels or provide the data that support the tables and figures in Appendix B of the ISOR. Therefore, we have necessarily made our own selection of high-cetane fuels in the course of reviewing the studies. The key testing and findings of each study are summarized below, with a specific focus on what they tell us about NOx emission impacts at B10 and below.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

2.1.1 Clark 1999

This study tested a variety of fuels on a 1994 7.3L Navistar T444E engine. Of the high-cetane base fuels, one base fuel (Diesel A, off-road LSD) was blended and tested at levels of B20, B50, and B100. NOx emissions were significantly increased for all of the blends. The other base fuel (CA Diesel) was tested only as a base fuel. Its NOx emissions were 12% below that of Diesel A, making it is unclear whether Diesel A is representative of fuels in CA. This study conducted no testing of the NOx emissions impact from biodiesels at the B10 level or below.

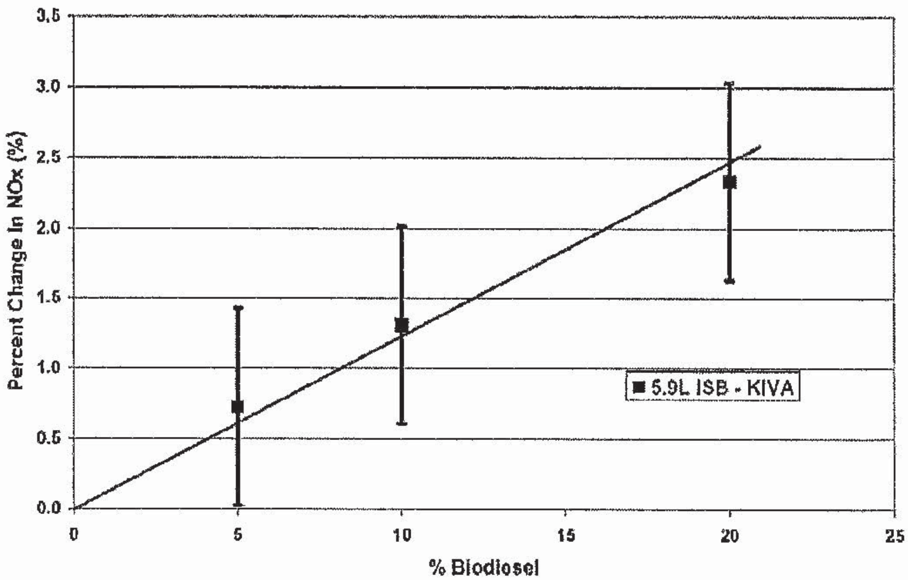
2.1.2 Eckerle 2008

This study tested low and mid/high-cetane base fuels alone and blended with soy-based biodiesel at the B20 level. The Cummins single-cylinder test engine facility was used in a configuration representative of modern diesel technology, including cooled EGR. Testing was conducted under a variety of engine speed and load conditions. FTP cycle emissions were then calculated from the speed/load data points. The test results show that B20 blends increase NOx emissions compared to both low- and high-cetane base fuels. This study conducted no testing of the NOx emissions impact from biodiesels at the B10 level or below.

The study notes that two other studies "show that NOx emissions increase nearly linearly with the increase in the percentage of biodiesel added to diesel fuel." Eckerle's Figure 21 (reproduced below as Figure 2-2) indicates a NOx emissions increase at B5, which is the basis for the statement in the abstract that "Results also show that for biodiesel blends containing less than 20% biodiesel, the NOx impact over the FTP cycle is proportional to

the blend percentage of biodiesel." The authors clearly believe that biodiesel fuels have NOx emission impacts proportional to the blending percent at all levels including B5.

Figure 2-2
Impact of Biodiesel Blends on Percent NOx Change for the 5.9L ISB Engine Operation Over the FTP Cycle



Source: Figure 21 of Eckerle 2008

2.1.3 McCormick 2002

This study tested low- and mid-cetane base fuels alone and blended with soy- and animal-based biodiesel at the B20 level. The testing was conducted on a 1991 DDC Series 60 engine using the hot-start U.S. heavy-duty FTP. NOx emission increases were observed for both fuels at the B20 level. Mitigation of NOx impacts was investigated by blending a Fisher-Tropsch fuel, a 10% aromatics fuel and fuel additives. This study conducted no testing of the NOx emissions impact from commercial biodiesels at the B10 level or below.

This study also tested a Fisher-Tropsch (FT) base fuel blended at the B1, B20, and B80 levels. Although the very high cetane number (≥75) takes it out of the range of commercial diesel fuels, it is interesting to note that the study measured higher NOx emissions at the B1 level than it did on the FT base fuel and substantially higher NOx emissions at the B20 and B80 levels. While the B1 increase was not statistically significant given the uncertainties in the emission measurements (averages of three test runs), it is clear that increased NOx emissions have been observed at very low blending levels.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

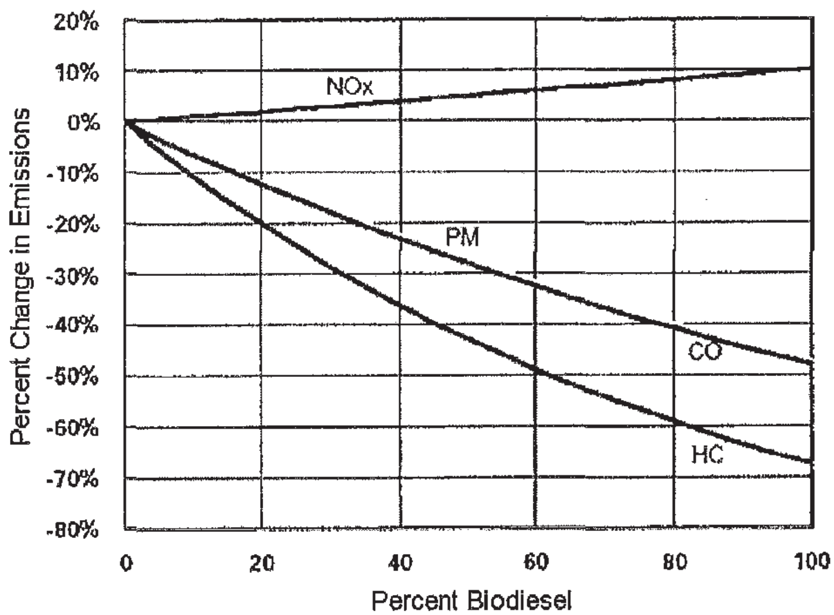
2.1.4 McCormick 2005

This study tested blends of soy- and animal-based biodiesels with a high-cetane ULSD base fuel at B10 levels and higher. Two engines were tested – a 2002 Cummins ISB and a 2003 DDC Series 60, both with cooled EGR. The hot-start U.S. heavy-duty FTP test cycle was used. The majority of testing was at the B20 level with additional testing at the B50 and B100 levels. One soy-based fuel was tested at B10. The study showed NOx emission increases at B10, B20, and higher levels. The study also investigated mitigation of NOx increases. This study conducted no testing of the NOx emissions impact from biodiesels below the B10 level.

The authors present a figure (reproduced as Figure 2-3) in their introduction that shows their summary of biodiesel emission impacts based on an EPA review of heavy-duty engine testing. It shows NOx emissions increasing linearly with the biodiesel blend percentage.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Figure 2-3
Trend in HC, CO, NOx and PM Emissions with Biodiesel Percent



Source: McCormick 2005

2.1.5 Nuszkowski 2009

This study tested five different diesel engines: one 1991 DDC Series 60, two 1992 DDC Series 60, one 1999 Cummins ISM, and one 2004 Cummins ISM. Only the 2004 Cummins ISM was equipped with EGR. All testing was done using the hot-start U.S. heavy-duty FTP test cycle. The testing was designed to test emissions from fuels with and without cetane-improving additives. Although a total of five engines were tested, the base diesel and B20 fuels were tested on only two engines (one Cummins and one DDC Series 60) because there was a limited supply of fuel available. NOx emissions increased on the B20 fuel for both engines. A third engine (Cummins) was tested on B20 and B20 blended with cetane improvers to examine mitigation of NOx emissions. This study conducted no testing of the NOx emissions impact from biodiesels at the B10 level or below.

2.1.6 Thompson 2010

This study examined the emissions impacts of soy-based biodiesel at the B10 and B20 levels relative to low-cetane (42), mid-cetane (49), and high-cetane (63) base fuels using one 1992 DDC Series 60 engine. The emissions results were measured on the hot-start U.S. heavy-duty FTP cycle. The study found that NOx emissions were unchanged (observed differences were not statistically significant) at B10 and B20 levels for the low- and mid-cetane fuels. NOx emissions increased significantly at B10 and B20 levels for the high-cetane fuels. This study conducted no testing of the NOx emissions impact from biodiesels at levels below B10.

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

2.2 Conclusions Based on Studies Obtained in Literature Search

From the foregoing summary of the studies cited by Staff, we reach the conclusions given below.

1. None of the six studies measured the NOx emissions impact from commercial-grade biodiesel at blending levels below B10, and only two studies tested a fuel at the B10 level. All other testing was at the B20 level or higher. Because none tested a B5 (or similar) fuel, none is capable of providing direct evidence regarding NOx emissions at B5 or other blending levels below B10.

2. These studies provide no data or evidence supporting the validity of Staff's Threshold Model that biodiesel below B10 does not increase NOx emissions. In fact, all of the studies are consistent with the contention that biodiesel increases NOx emissions in proportion to the blending percent.

3. Two of the studies present evidence and arguments that the NOx impact from biodiesel is a continuous effect that is present even at very low blending levels and will increase at higher levels in proportion to the blending percentage. One study tested a Fischer-Tropsch biodiesel blend at B1 and observed NOx emissions to increase (but not by a statistically significant amount).

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

###

3. CARB BIODIESEL CHARACTERIZATION STUDY

3.1 Background

CARB sponsored a comprehensive study of biodiesel and other alternative diesel blends in order "... to better characterize the emissions impacts of renewable fuels under a variety of conditions."[15] The study was designed to test eight different heavy- duty engines or vehicles, including both highway and off-road engines using engine or chassis dynamometer testing. Five different test cycles were used: the Urban Dynamometer Driving Schedule (UDDS), the Federal Test Procedure (FTP), and 40 mph and 50 mph CARB heavy-heavy-duty diesel truck (HHDDT) cruise cycles, and the ISO 8178 (8 mode) cycle. Table 3-1 (reproduced from Table ES-1 of Durbin 2011) documents the scope of the test program. Because the Staff relied only on engine dynamometer testing in its Technology Assessment, only the data for the first four engines (shaded) are considered here.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Table 3-1
A Breakdown of the Test Engines for the Different Categories of Testing

2006 Cummins ISM[a]	Heavy-duty on-highway	Engine dynamometer	
2007 MBE4000	Heavy-duty on-highway	Engine dynamometer	
1998, 2.2 liter, Kubota V2203-DIB	Off-road	Engine dynamometer	
2009 John Deere 4.5 L	Off-road	Engine dynamometer	
2000 Caterpillar C-15	Heavy-duty on-highway	Chassis dynamometer	Freightliner chassis
2006 Cummins ISM	Heavy-duty on-highway	Chassis dynamometer	International chassis
2007 BME4000	Heavy-duty on-highway	Chassis dynamometer	Freightliner chassis
2010 Cummins ISX15	Heavy-duty on-highway	Chassis dynamometer	Kenworth chassis

Source: Table ES-1 of Durbin 2011, page xxvi
Notes:
[a] Data for the first four engines (shaded) are considered in this report.

[15] Durbin 2011, p. xxiv.

The original goal of this report was to subject all of the NOx emission testing in Durbin 2011 to a fresh re-analysis. However, it was discovered that Durbin 2011 did not report all of the data that were obtained during the program and are discussed in the report. The chassis dynamometer testing was conducted at the CARB Los Angeles facility. Emission results for the chassis dynamometer testing are presented in tabular and graphical form, but the report does not contain the actual emissions test data. For the engine dynamometer testing, some of the measured emission values are not reported even though the emission results are reported in tabulated or graphical form. Requests for the missing data were directed to Durbin in a personal request and to CARB through an official records request. No information has been provided in response and we have not been able to obtain the missing data from online or other sources.

For this report, we have worked with the data in the forms that are provided in Durbin 2011 as being the best-available record of the results of the CARB study. Because Staff used only data obtained in engine dynamometer testing, the analysis presented in this report has done the same. Nevertheless, the results of the chassis dynamometer testing are generally supportive of the results and conclusions presented here. Durbin 2011 notes:

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

> "... The NOx emissions showed a consistent trend of increasing emissions with increasing biodiesel blend level. These differences were statistically significant or marginally significant for nearly all of the test sequences for the B50 and B100 fuels, and for a subset of the tests on the B20 blends."[16]

Durbin notes that emissions variability was greater in the chassis dynamometer testing, which leads to the sometimes lower levels of statistical significance. There was also a noticeable drift over time in NOx emissions that complicated the results for one engine.

3.2 Data and Methodology

Table 3-2 compiles descriptive information on the engine dynamometer testing performed in Durbin 2011. The experimental matrix involves four engines, two types of biodiesel fuels (soy- and animal-based), and up to four test cycles per engine. However, the matrix is not completely filled with all fuels tested on all engines on all applicable test cycles. The most complete testing is for the ULSD base fuel and B20, B50, and B100 blends. There is less testing for the B5 blend, and B5 is tested using only a subset of cycles. For this reason, we first examine the testing for ULSD, B20, B50, and B100 fuels to determine the overall impact of biodiesels on NOx emissions. We then examine the more limited testing for B5 to determine the extent to which it impacts NOx emissions.

This examination is limited by the form in which emissions test information is reported in Durbin 2011. A complete statistical analysis can be conducted only for the two on-road engines for which Appendices G and H of Durbin 2011 provide measured emissions, and for a portion of the testing of the Kubota off-road engine for which Appendix I provides

[16] Durbin 2011, p. 126.

Table 3-2
Experimental Matrix for Heavy-Duty Engine Dynamometer Testing Reported in Durbin 2011

Engine	Biodiesel Type	Fuels Tested	Test Cycles	Notes
On-Road Engines				
2006 Cummins ISM	Soy	ULSD, B20, B50, B100, B5	UDDS, FTP, 40 mph, 50 mph	B5 tested on 40 mph and 50 mph cruise cycles
	Animal	ULSD, B20, B50, B100, B5	UDDS, FTP, 50 mph	B5 tested only on FTP.
2007 MBE4000	Soy	ULSD, B20, B50, B100, B5	UDDS, FTP, 50 mph	B5 tested only on FTP.
	Animal	ULSD, B20, B50, B100, B5		B5 tested only on FTP.
Off-Road Engines				
1998 Kubota V2203-DIB	Soy	ULSD, B20, B50, B100, B5	ISO 8178 (8 Mode)	none
	Animal	Not tested		
2009 John Deere	Soy	ULSD, B20, B50, B100	ISO 8178 (8 Mode)	B5 not tested
	Animal	ULSD, B20, B5		none

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

measured emissions. The data needed to support a full re-analysis consist of measured emissions on each fuel in gm/hp-hr terms, which are stated in Durbin 2011 as averages across all test replications along with the number of replications and the standard error of the individual tests. With this information, the dependence of NOx emissions on biodiesel blending percent can be determined as accurately as if the individual test values had been reported and the appropriate statistical tests for the significance of results can be performed.

Regression analysis is used as the primary method of analysis. For each engine and test cycle, the emission averages for each fuel are regressed against the biodiesel blending percent to determine a straight line. The regression weights each data point in inverse proportion to the square of its standard error to account for differences in the number and reliability of emission measurements that make up each average. The resulting regression line will pass through the mean value estimated from the data (i.e., the average NOx emission level at the average blending percent), while the emission averages for each fuel may scatter above and below the regression line due to uncertainties in their measurement. The slope of the line estimates the dependence of NOx emissions on the blending percentage.

Where the data points closely follow a straight line and the slope is determined to be statistically significant, one can conclude that blending biodiesel with a base fuel will increase NOx emissions in proportion to the blending percent. The regression line can then be used to estimate the predicted emissions increase for a given blending percent. The predicted emissions increase is the value one would expect on average over many measurements and is comparable to the average emissions increase one would expect in a fleet of vehicles.

The same level of analysis is not possible for the testing on B5 fuel, which is reported as a simple average for the on-road engines and is not reported at all for the off-road engines. For the B5 fuel, Durbin 2011 presents emission test results in a tabulated form where the percentage change in NOx emissions has been computed compared to ULSD base fuel. This form supports the presentation of results graphically, but it does not permit a proper statistical analysis to be performed. Specifically, the computation of percentage emission changes will perturb the error distribution of the data, by mixing the uncertainty in measured emissions on the base fuel with the uncertainties in measured emissions on each biodiesel blend, and it can introduce bias as a result of the mixing. Further statistical analysis of the computed percent values should be avoided because of these problems. Therefore, a more limited trend analysis of the NOx emissions data for B5 and the John Deere engine is conducted.

3.3 2006 Cummins Engine (Engine Dynamometer Testing)

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Table 3-3 shows the NOx emission results for the 2006 model-year Cummins heavy-duty diesel engine based on a re-analysis of the data for this report. As indicated by highlighting in the table, the relationship between increasing biodiesel content and increased NOx emissions for soy-based biodiesel is statistically significant at >95% confidence level[17] in all cases. For the animal-based biodiesel, the relationship is statistically significant at the 92% confidence level for the UDDS cycle, the 94% confidence level for the 50 mph cruise, and the >99% confidence level for the FTP cycle.

For the soy-based fuels, the R^2 statistics show that the emissions effect of biodiesel is almost perfectly linear with increasing biodiesel content over the range B20, B50, and B100. Although not as high for the animal-based fuels (because the emissions effect is smaller and measurement errors are relatively larger in comparison to the trend), the R^2 statistics nevertheless establish a linear increase in NOx emissions with increasing biodiesel content over the same range. The linearity of the response with blending percent is well supported by the many NOx emissions graphs contained in Durbin 2011.

The table also gives the estimated NOx emission increases for B5 and B10 as predicted by the regression lines. For soy-based fuels, the values are 1% for B5 (range 0.8% to 1.3% depending on the cycle) and 2% for B10 (range 1.6% to 2.6% depending on cycle).

[17] A result is said to be statistically significant at the 95% confidence level when the p value is reported as $p \leq 0.05$. At the $p \leq 0.01$ level, a result is said to be statistically significant at the 99% confidence level, and so forth.

Table 3-3 Re-Analysis for 2006 Cummins Engine (Engine Dynamometer Testing) Model: NOx = A + B · BioPct Using ULSD, B20, B50, and B100 fuels							
Biodiesel Type	Test Cycle	R^2	Intercept A Value	BioPct Slope B Value	p value	Predicted NOx Increase for B5 Pct Change	Predicted NOx Increase for B10 Pct Change
Soy-based							
	UDDS	0.997	5.896	0.0100 [a]	0.001	0.8%	1.7%
	FTP	0.995	2.024	0.0052	0.003	1.3%	2.6%
	40 mph	1.000	2.030	0.0037	<0.0001	0.9%	1.8%
	50 mph	0.969	1.733	0.0028	0.016	0.8%	1.6%
Animal-based							
	UDDS	0.847	5.911	0.0021 [b]	0.080	0.2%	0.4%
	FTP	0.981	2.067	0.0031	0.001	0.7%	1.4%
	50 mph	0.887	1.768	0.0011	0.058	0.3%	0.6%

Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better.
[b] Orange highlight indicates result is statistically significant at the 90% confidence level or better.

For animal-based fuels, the values are approximately one-half as large: 0.4% for B5 (range 0.2% to 0.7%) and 0.8% for B10 (range 0.4% to 1.4%). These predicted increases are statistically significant to the same degree as the slope of the regression line from which they are estimated. That is, the NOx increases predicted by the regression line for soy-based fuels are statistically significant at the 95% confidence level (or better) on all cycles and the predicted NOx increases for animal-based fuels are statistically significant at the 90% confidence level (or better) on all cycles and at the >99% confidence level for the FTP.

Because the limited data on B5 were not used to develop the regression lines for each cycle, and no test data on B10 are available, use of the lines to make predictions for B5 and B10 depends on their linearity over the range between ULSD and B20. Based on the R^2 statistics and the graphs in Durbin 2011, the slopes observed between ULSD and B20 are the same as the slopes observed between B20 and B100 for each of the test cycles. We believe that the linearity of the response with blending percent for values over the range ULSD to B100 would be accepted by the large majority of researchers in the field, as would the use of regression analysis to make predictions for B5 and B10.

The Durbin 2011 report takes a different approach for determining the statistical significance of NOx emission increases for each fuel. For each fuel tested, it computes a percentage change in emissions for NOx (and other pollutants) relative to the ULSD base fuel. It then determines the statistical significance of each observed change using a conventional t-test for the difference of two mean values (2-tailed, 2 sample equal

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

variance t-test). The t-test is conducted on the measured emission values before the percentage emission change is computed.

The t-test would be the appropriate approach for determining statistical significance if only two fuels were tested. However, it is a simplistic approach when three or more fuels are tested because it is applied on a pair-wise basis (B5 vs. ULSD, B20 vs. ULSD, etc.) and does not make use of all of the data that is available. It will have less power than the regression approach to detect emission changes that are real. This limitation is in one direction, however, in that the test is too weak when 3 or more data points are available, but a finding of statistical significance is valid when it occurs. As long as the linear hypothesis is valid, the regression approach should be the preferred method for analysis and for the determination of whether biodiesel blending significantly increases NOx emissions.

Because emission changes will be smallest for B5 (because of the low blending volume), the pair-wise t-test is most likely to fail to find statistical significance at the B5 level. In cases where the pair-wise t-test for B5 says that the emission change vs. ULSD is not statistically significant – but slope of the regression line <u>is</u> statistically significant – the proper conclusion is that additional B5 testing (to improve the precision of the emission averages) would likely lead to the detection of a statistically significant B5 emissions change using the t-test. In this case, <u>the failure to find statistical significance using the t-test is not evidence that B5 does not increase NOx emissions</u>.

For this engine, soy-based B5 was tested on the 40 mph and 50 mph cruise cycles and animal-based B5 was tested on the FTP. To examine this matter further, Table 3-4 reproduces NOx emission results reported in Tables ES-2 and ES-3 of Durbin 2011. Soy-based B5 was shown to increase NOx emissions on the 40 mph cruise cycle, but not on the 50 mph cruise cycle. Animal-based B5 was shown to increase NOx emissions on the FTP. Durbin 2011 noted (p. xxxii) that "[t]he 50 mph cruise results were obscured, however, by changes in the engine operation and control strategy that occurred over a segment of this cycle." Therefore, we discount the 50 mph cruise results and do not consider them further. Neither of the remaining B5 NOx emission increases (for the 40 mph Cruise and FTP cycles) were found to be statistically significant using the t-test, although the 40 mph cruise result for soy-based fuels comes close to being marginally significant (it would be statistically significant at an 86.5% level). The NOx emission increases at higher blending levels were found have high statistical significance (>99% confidence level).

This format, used throughout Durbin 2011 to report emission test data and to show the effect of biodiesel on emissions, is subject to an important statistical caveat. The percent changes are computed by dividing the biodiesel emission values by the emissions measured for the ULSD base fuel. Therefore, measurement errors in the ULSD measurement are blended with the measurement errors for each of the biodiesel fuels. The blending of errors in each computed percent change can bias the apparent trend of emissions with increasing biodiesel content. As will be shown in Section 3.3.2, we can see this problem in the animal-based B5 test data for this engine.

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

Table 3-4 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 2006 Cummins Engine (Engine Dynamometer Testing)						
	Soy-based Biodiesel				Animal-based Biodiesel	
	40 mph Cruise		50 mph Cruise		FTP	
	NOx % Diff	p value	NOx % Diff	p value	NOx % Diff	p value
B5	1.7%	0.135	-1.1%	0.588	0.3%	0.298
B20	3.9% [a]	0.000	0.5%	0.800	1.5%	0.000
B50	9.1%	0.000	6.3%	0.001	6.4%	0.000
B100	20.9%	0.000	18.3%	0.000	14.1%	0.000

Source: Table ES-2 and ES-3 of Durbin 2011, p. xxviii
Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on the pair-wise t-test.

3.3.1 NOx Impact of Soy-based Biodiesel at the B5 Level

Figures 3-1a and 3-1b display the trend of NOx emissions with blending percent for the soy-based biodiesel on the 40 mph cruise cycle. Figure 3-1a plots the percentage increases as reported by Durbin 2011 in contrast to two different analytical models for the relationship:

- The Linear Model shown by the blue line; and
- The Staff Threshold model (black line), in which the NOx emission change is zero through B9 and then increases abruptly to join the linear model.

In Figure 3-1a, the linear model is an Excel trendline for the computed percent changes. While the data violate a key assumption for the proper use of regression analysis, this approach is the only way to establish a trendline given the form in which Durbin 2011 tabulates the data and presents the results of its testing.

Figure 3-1b plots the actual measured emission values in g/bhp-hr terms in contrast to the same two analytical models. Here, the linear model line is determined through a proper use of regression analysis, in which each emission average in g/bhp-hr terms is weighted inversely by the square of its standard error, using the data for ULSD, B20, B50 and B100 (i.e., excluding the B5 data point). In the case of this engine and biodiesel fuel, both forms of assessment show generally the same trend for NOx emissions as a function of blending percent. Although the NOx emission increases for B5 may fail the t-test for significance, emissions are increased at B5 and the B5 data point is fully consistent with the Linear Model. The Threshold model is clearly a less-satisfactory representation of the test data.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Figure 3-1a
Durbin 2011 Assessment: 40 mph Cruise Cycle NOx Emissions Increases for Soy-Biodiesel Blends (2006 Cummins Engine)

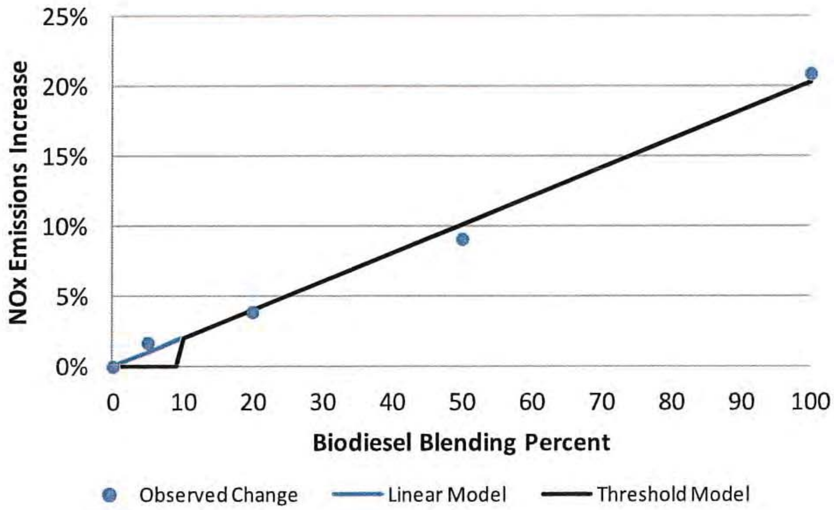
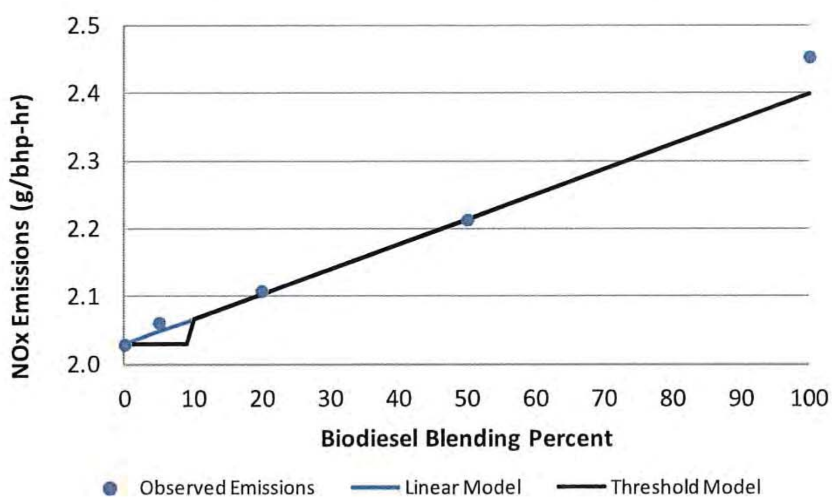


Figure 3-1b
Re-assessment of 40 mph Cruise Cycle NOx Emissions Increases for Soy-Biodiesel Blends (2006 Cummins Engine)



Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Note that the slope of the trendline (Figure 3-1a) is greater than the slope of the regression line (Figure 3-1b). In the latter figure, the B100 data point stands above the regression line, which passes below it. The regression line (but not the trendline) is fit in

a manner that accounts for the uncertainties in each data point, so that the line will pass closer to points that have smaller uncertainties and farther from points that have greater uncertainties. For these data, the B100 data point has the largest uncertainty (±0.026 g/bhp-hr) followed by the B20 data point (±0.025 g/bhp-hr). The other three data points (ULSD, B5, and B50) have uncertainties less than ±0.001 g/bhp-hr. The B20 data point happens to fall on the line, but the B100 data point is found to diverge above. Because the regression analysis can account for the relative uncertainties of the data points, it provides a more accurate and reliable assessment of the impact on NOx emissions.

3.3.2 NOx Impact of Animal-based Biodiesel at the B5 level

Figures 3-2a and 3-2b display the trend of NOx emissions with blending percent for the animal-based biodiesel on the FTP test cycle as reported by Durbin 2011 and as re-assessed in this report using regression analysis, respectively. As Figure 3-2a shows, the NOx percent change values reported by Durbin 2011 appear to follow the Staff Threshold model in that NOx emissions are not materially increased at B5, but are increased significantly at B20 and above. As a result, the blue trendline in the figure (fit from the B20, B50 and B100 data points) has a negative intercept.

Figure 3-2b paints a very different picture from the data. Here, the ULSD and B5 data points stand above the weighted regression line (blue) developed from the data for ULSD, B20, B50 and B100. In the data used to fit the regression line, the ULSD data point has the largest uncertainty (±0.013 g/bhp-hr) while the other three data points (B20, B50, and B100) have uncertainties of ±0.002 g/bhp-hr (one case) and ±0.001 g/bhp-hr (two cases). Considering all of the data, the B5 data point has the second highest uncertainty (±0.007 g/bhp-hr). The regression line closely follows a linear model with a high R^2 (0.981) considering the weighted errors, while the ULSD and B5 points lie above it.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Because the ULSD data point is subject to more uncertainty and appears to be biased high compared to the regression line, the NOx percent changes computed by Durbin 2011 are themselves biased. The trendline result in Figure 3-2a that appeared to be supportive of the Staff Threshold model now appears to be the result of biases in the ULSD and B5 emission averages.

Two important conclusions can be drawn from the foregoing:

1. Accurate and reliable conclusions regarding the impact of B5 on NOx emissions cannot be drawn from the computed percent changes that are reported in Durbin 2011. Nor can accurate and reliable conclusions be drawn from visual inspection of graphs that present such data. Weighted regression analysis of the measured emission values (g/bhp-hr terms) must be performed so that the uncertainties in emissions measurements can be fully accounted for.

2. When a weighted regression analysis is performed using the testing for this engine, there is no evidence that supports the conclusion that B5 blends will not increase NOx emissions. In fact, the data are consistent with the conclusion that biodiesel increases NOx emissions in proportion to the blending percent.

Figure 3-2a
Durbin 2011 Assessment: FTP NOx Emissions Incr eases for Animal-based Biodiesel Blends (2006 Cumm ins En gine)

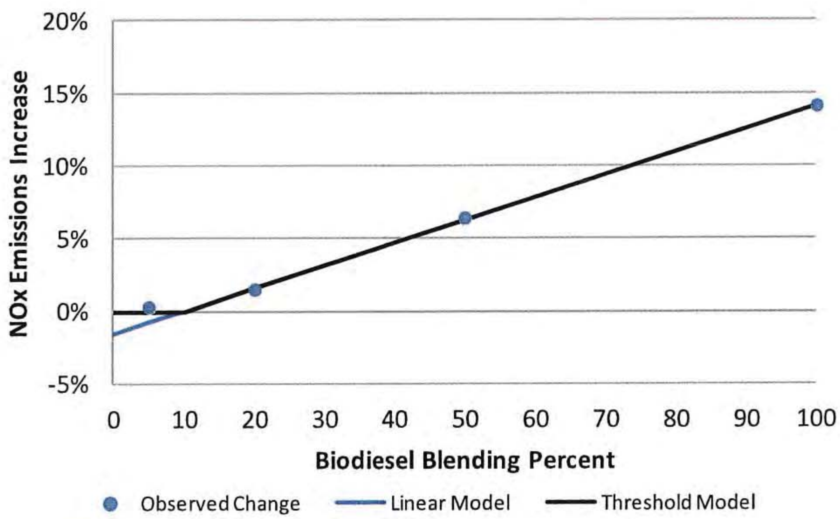
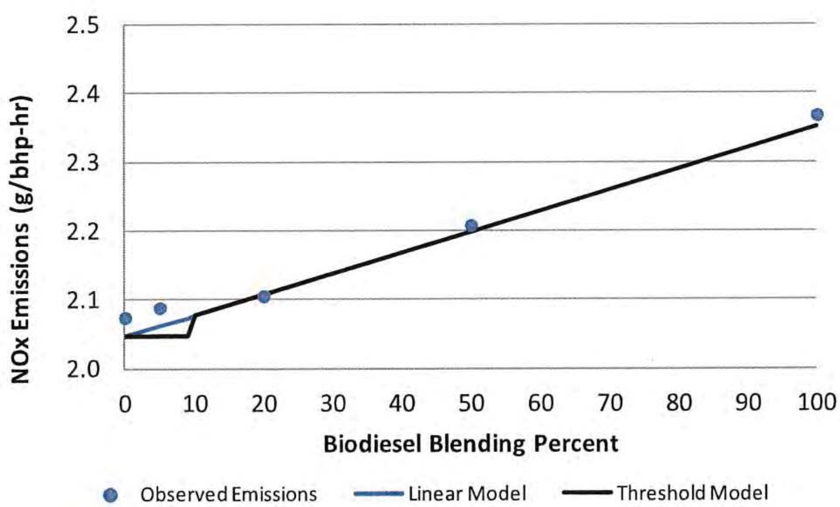


Figure 3-2b
Re-assessment of FTP NOx Em issions Incre ases for Anim al-based Biodiesel Blends (2006 Cumm ins En gine)



Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

3.4 2007 MBE4000 Engine (Engine Dynamometer Testing)

To analyze the data for the 2007 MBE4000 engine, it has proved necessary to remove two data points, one for the soy-based B20 fuel on the 50 mpg cruise cycle and one for the animal-based B50 fuel on the FTP test cycle:

- Appendix H reports the 50 mph cruise emission average for soy-based B20 to be 0.014 ± 0.020 g/bhp-hr. This value is implausible and wholly inconsistent with the NOx emission change of +6.9% reported in Table ES-4 of Durbin 2011, which would imply a NOx emission average of 1.21*1.069 = 1.30 g/bhp-hr.

- Appendix H reports the FTP emission average for the animal-based B50 fuel to be 2.592 ± 0.028 g/bhp-hr, which stands well above the other test data on animal-based biodiesel. This value is also inconsistent with the NOx emission change of +12.1% reported in Table ES-4 of Durbin 2011, which would imply a NOx emission average of 1.29*1.121 = 1.45 g/bhp-hr.

We believe these reported values are affected by typographical errors and have deleted them from the dataset used here.

With these corrections, Table 3-5 shows the results of the NOx emissions analysis for the 2007 model-year MBE4000 heavy-duty diesel engine. As indicated by highlighting in the table, the relationship between increasing biodiesel content and increased NOx emissions is statistically significant at >99% confidence level in two cases for soy-based biodiesel (the UDDS and FTP cycles) and at the 90% confidence level in one case (the 50 mph cycle). For the animal-based biodiesel, the relationship is statistically significant at the 96% confidence level for the UDDS cycle, the 98% confidence level for the FTP cycle, and >99% confidence level for the 50 mph cycle.

Durbin 2011 again notes a problem with the 50 mph cruise test results, saying (p. xxxii) that "[the NOx] trend was obscured, however, by the differences in engine operation that were observed for the 50 mph cruise cycle." Therefore, we will focus the discussion on the UDDS and FTP results.

For the soy-based fuels, the R^2 statistics show that the emissions effect of biodiesel is almost perfectly linear with increasing biodiesel content over the range from ULSD to B20, B50, and B100 for all cycles (including the 50 mph cruise). That is, the NOx emissions increase between ULSD and B20 shares the same slope as the NOx emissions increase between B20 and B100. For the animal-based biodiesel, the R^2 statistics also establish a linear increase in NOx emissions with increasing biodiesel content over the same range. The linearity of the response with blending percent is also well supported by the many NOx emissions graphs contained in Durbin 2011.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Table 3-5 Re-Analysis for 2007 MBE4000 Engine (Engine Dynamometer Testing) Model: NOx = A + B · BioPct Using ULSD, B20, B50, and B100 fuels							
Biodiesel Type	Test Cycle	R^2	Intercept A	BioPct Slope B		Predicted NOx Increase for B5	Predicted NOx Increase for B10
			Value	Value	p value	Pct Change	Pct Change
Soy-based							
	UDDS	0.989	2.319	0.0090 [a]	0.005	4.6%	9.1%
	FTP	0.998	1.268	0.0049	0.006	2.5%	5.0%
	50 mph	0.979	1.198	0.0054 [b]	0.092	2.7%	5.5%
Animal-based							
	UDDS	0.913	2.441	0.0036	0.044	2.0%	4.0%
	FTP	0.999	1.288	0.0038	0.020	2.5%	5.0%
	50 mph	0.994	1.205	0.0049	0.003	2.5%	5.0%

Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better.
[b] Orange highlight indicates result is statistically significant at the 90% confidence level or better.

The table also gives the estimated NOx emission increases for B5 and B10 as predicted by the regression lines. For soy-based fuels, the values are ~3.5% for B5 (range 2.5% to 4.6% depending on the cycle) and ~7.5% for B10 (range 5.0% to 9.1% depending on cycle). For animal-based fuels, the values are approximately two-thirds as large: ~2.3% for B5 (range 2.0% to 2.5%) and ~4.5% for B10 (range 4.0% to 5.0%). The predicted increases are statistically significant to the same degree as the slope of the regression line from which they are estimated. That is, the predicted NOx increases are statistically significant at the >99% confidence level for soy-based fuels on the UDDS and FTP cycles and at the >95% confidence level for animal-based fuels on all cycles. The predicted NOx increase is statistically significant at the 90% confidence level for soy-based fuels on the 50 mph cruise cycle.

For this engine, soy- and animal-based B5 were tested on the FTP. Table 3-6 reproduces the NOx emission results reported in Tables ES-4 and ES-5 of Durbin 2011. While there are caveats on use of the pair-wise t-test, the FTP test data for this engine show NOx emissions at the B5 level for both soy- and animal-based fuels that are statistically significant at the 99% confidence level (or better) in this case. That is, the test data for this engine as reported by Durbin 2011 refute the Staff Threshold Model that biodiesel blends below B10 do not increase NOx emissions.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Tab le 3-6 Percentage Chan ge in NOx Em issions for Biodiesel Blends Relative t o ULSD: 2007 MBE4000 En gine (En gine Dynamome ter Testing)				
	Soy-Based Biodiesel FTP		Animal-Based Biodiesel FTP	
	NOx % Diff	p value	NOx % Diff	p value
B5	0.9% [a]	0.007	1.3%	0.000
B20	5.9%	0.000	5%	0.000
B50	15.3%	0.000	12.1	0.000
B100	38.1%	0.000	29%	0.000

Source: Table ES-4/5 of Durbin 2011, p. xxix
Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on pair-wise t-test.

Figures 3-3a and 3-3b below compare the FTP data for this engine to the regression line representing the linear model (blue) and the Staff Threshold model (black) for both soy- and animal-based biodiesel. In both cases, the regression line was developed using the data for ULSD, B20, B50, and B100 (i.e., excluding the B5 data point). For both soy- and animal-based biodiesels, the data point for B5 falls on the established line, while the Staff Threshold model is inconsistent with the data. For this engine, it is clear that soy- and animal-based biodiesels increase NOx emissions at all blending levels.

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

Figure 3-3a
Re-assessment of FTP Cycle NOx Emissions Incre ases for Soy -based Biodiesel Blends (2007 MBE4000 En gine)

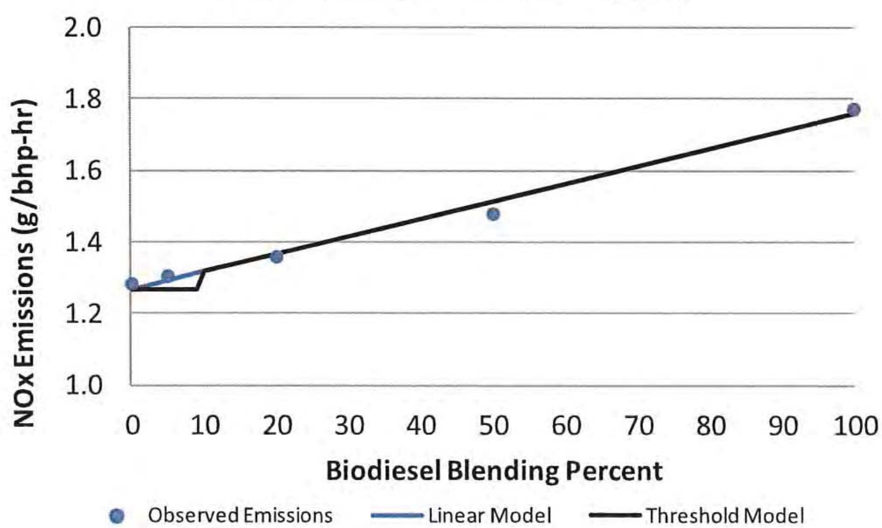
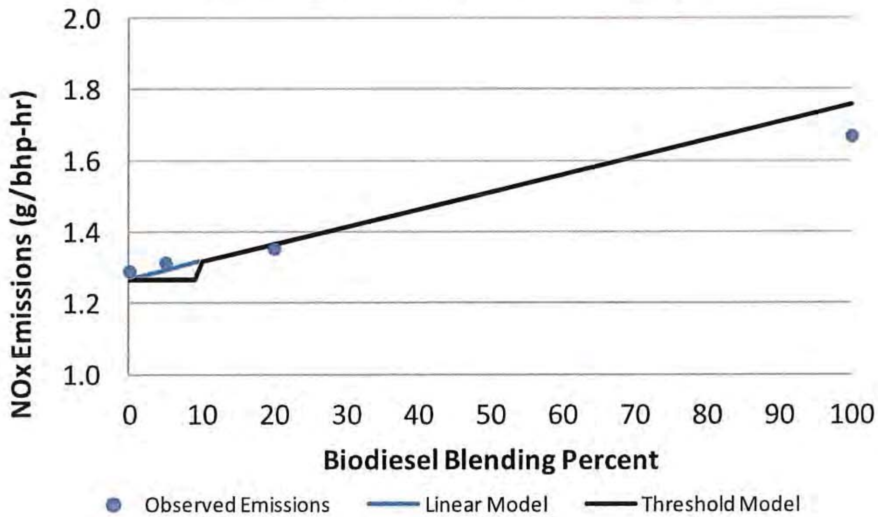


Figure 3-3b
Re-assessment of FTP Cycle NOx Emissions Increases for Animal-based Biodiesel Blends (2007 MBE4000 Engine)



Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

3.5 1998 Kubota TRU Engine (Engine Dynamometer Testing)

The 1998 Kubota V2203-DIB off-road engine was tested on the base fuel (ULSD) and soy-based biodiesel at four blending levels (B5, B20, B50, B100) in two different series using the ISO 8178 (8-mode) test cycle. Appendix I reports the measured emissions data only for the first series (ULSD, B50, B100). Using this subset of data, Table 3-7 summarizes the results of the re-analysis for this engine.

As for the other engines, the results of the analysis demonstrate the following:

- The high R^2 statistic shows that the emissions effect of biodiesel is almost perfectly linear over the range B50 and B100. That is, the slope from ULSD to B50 is the same as the slope from B50 to B100. The slope of the regression line is statistically significant at the 99% confidence level.

- NOx emissions are estimated to increase by 1.0% at the B5 level and by 2.1% at the B10 level. These estimated NOx emission increases are statistically significant to the same high degree as the regression slope on which they are based.

Table 3-7 Re-Analysis for 1998 Kubota V2203-DIB Engine (Engine Dynamometer Testing) Model: NOx = A + B · BioPct Using ULSD, B50, and B100 fuels							
Biodiesel Type	Test Cycle	R^2	Intercept A Value	BioPct Slope B Value	BioPct Slope B p value	Predicted NOx Increase for B5 Pct Change	Predicted NOx Increase for B10 Pct Change
Soy-based	ISO 8178	0.999	12.19	0.0256 [a]	0.01	1.0%	2.1%

Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better.

The second test series involved ULSD, B5, B20, and B100 fuels. Measured emissions data are not given in Appendix I, so we must work with the calculated percent changes in NOx emissions tabulated in Durbin 2011. Table 3-8 reproduces the NOx emission results reported in Table ES-8 of Durbin 2011 for the two test series. For the second test series, biodiesel at the B5 level increased NOx emissions, but the result fails the pair-wise t-test for statistical significance. The NOx emission increase at the B20 level was statistically significant at the 90% confidence level, and the increase at the B100 level was statistically significant at the >99% confidence level. The significance determinations use the pair-wise t-test, which is subject to caveats, but this is the only method available to gauge significance because re-analysis of the computed percentage changes is not possible.

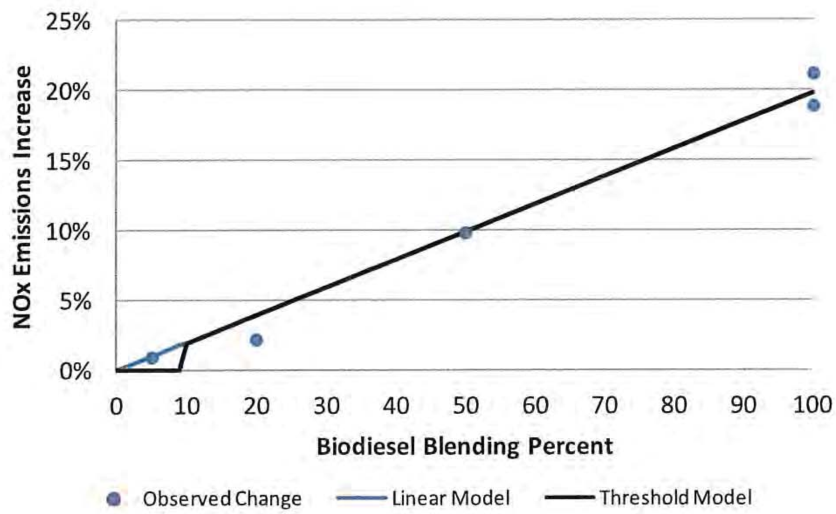
Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Table 3-8 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 1998 Kubota TRU Engine (Engine Dynamometer Testing)				
	Soy-Based Biodiesel Series 1 ISO 8178		Soy-Based Biodiesel Series 2 ISO 8178	
	NOx % Diff	p value	NOx % Diff	p value
B5	Not tested		0.97%	0.412
B20	Not tested		2.25% [a]	0.086
B50	7.63% [b]	0.000	Not tested	
B100	13.76%	0.000	18.89%	0.000

Source: Table ES-8 of Durbin 2011, p. xxxviii
Notes:
[a] Orange highlight indicates result is statistically significant at the 90% confidence level or better based on pair-wise t-test.
[b] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on pair-wise t-test

Figure 3-4 displays the trend of NOx emissions with blending percent for the first and second test series combined. As the figure shows, the available data points scatter around the trendline determined from the emission change percentages (not from regression analysis). The B20 data point falls below the trend line while the two B100 data points bracket the trend line. It is not possible to explain the divergence of the B20 data point

Figure 3-4
Durbin 2011 Assessment: ISO 8178 Cycle NOx Emissions Increases for Soy-based Biodiesel Blends (1998 Kubota Engine, Test Series 1 and 2 Combined)



because the emissions data for the second test series are not published in Durbin 2011. The B5 data point clearly supports the Linear Model and is inconsistent with the Staff Threshold Model.

3.6 2009 John Deere Off-Road Engine (Engine Dynamometer Testing)

The only information on the 2009 John Deere off-road engine comes from the tabulation of calculated percentage emission changes. Table 3-9 reproduces these data from Table ES-7 of Durbin 2011. For the soy-based biodiesel, NOx emissions are significantly increased at the B20 and higher blend levels. The increase for B20 is statistically significant at the 90% confidence level and the increases for B50 and B100 are statistically significant at the >99% confidence level based on the pair-wise t-test. A soy-based B5 fuel was not tested.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Table 3-9 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 2009 John Deere Engine (Engine Dynamometer Testing)				
	Soy-Based Biodiesel ISO 8178		Animal-Based Biodiesel ISO 8178	
	NOx % Diff	p value	NOx % Diff	p value
B5	Not tested		-3.82	0.318
B20	2.82%[a]	0.021	-2.20	0.528
B50	7.63%	0.000	Not tested	
B100	13.76%	0.000	4.57	0.000

Source: Table ES-7 of Durbin 2011, p. xxxviii
Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on pair-wise t-test.

For animal-based biodiesel, the testing shows the unusual result that B5 and B20 appear to decrease NOx emissions, while B100 increases NOx. The B5 and B20 decreases are not statistically significant, while the B100 increase is statistically significant at the >99% confidence level. Durbin 2011 concludes:

> The animal-based biodiesel also did not show as great a tendency to increase NOx emissions compared to the soy-based biodiesel for the John Deere engine, with only the B100 animal-based biodiesel showing statistically significant increases in NOx emissions.[18]

Durbin 2011 does not discuss these results further and does not note any problems in the testing, making further interpretation of the results difficult. Figure 8-1 of Durbin 2011 presents the NOx results for this engine with error bars. First, we note that the figure appears to suggest that NOx emissions were increased on the B20 fuel in contradiction to the table above. Second, it is clear that the error bars are large enough that no difference in NOx emissions can be detected among ULSD, B5, and B20 fuels. Overall, this result could be consistent with the Staff Threshold Model through B5, but the failure to detect a NOx emission increase at B20 is not. Without further information, it is not possible to determine whether the result seen here is a unique response of the John Deere engine to animal-based biodiesel or is the result of a statistical fluctuation or an artifact in the emissions data.

3.7 Conclusions

The Biodiesel Characterization report prepared by Durbin et al. for CARB is an important source of information on the NOx emissions impact of biodiesel fuels in heavy-duty engines. It is the sole source of information on the NOx impact of B5 blends cited in the ISOR. When the engine dynamometer test data are examined for

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

[18] Durbin 2011, p. xx.

the three engines for which emissions test data have been published, we find clear evidence that biodiesel increases NOx emissions in proportion to the blending percent. Where B5 fuels were tested for these engines, NOx emissions are found to increase above ULSD for both soy- and animal-based blends in all three engines and by statistically significant amounts in one engine.

Specifically, a re-analysis of the NOx emissions test data demonstrates the following:

1. For the 2006 Cummins engine, biodiesel fuels are found to significantly increase NOx emissions for both soy- and animal-based blends by amounts that are proportional to the blending percent. This result indicates that biodiesels will increase NOx emissions at blending levels below B10. When B5 fuels were tested, NOx emissions were observed to increase but by amounts that fail to reach statistical significance according to the pair-wise test.[19] Graphical analysis demonstrates that NOx emissions measured for B5 fuels are consistent with the Linear Model, but not the Staff Threshold Model.

2. For the 2007 MBD4000 engine, biodiesel fuels are found to significantly increase NOx emissions for both soy- and animal-based blends by amounts that are proportional to the blending percent. This result indicates that biodiesels will increase NOx emissions at blending levels below B10. When B5 fuels were tested, NOx emissions were observed to increase and by amounts that are found to be statistically significant using the pair-wise t-test.[13] This result alone is sufficient to disprove the Staff Threshold Model. Graphical analysis demonstrates that NOx emissions measured for B5 fuels are consistent with the Linear Model, but not the Staff Threshold Model.

3. For the 1998 Kubota TRU (off-road) engine, soy-based biodiesel fuels are found to significantly increase NOx missions. Animal-based biodiesel was not tested. When a soy-based B5 fuel was tested, NOx emissions were observed to increase but by amounts that fail to reach statistical significance according to the pair-wise test.[13] Graphical analysis demonstrates that NOx emissions measured for B5 fuels are consistent with the Linear Model, but not the Staff Threshold Model.

The measured emissions test data for the other off-road engine (2009 John Deere) are not contained in the Durbin 2011 report and CARB has not made them publicly available. Thus, a re-analysis was not possible. Based on the tables and figures in Durbin 2011, soy-based biodiesel fuels were shown to significantly increase NOx emissions at B20 levels and higher, but B5 was not tested. Testing of animal-based blends shows no change in NOx emissions at B5 and B20 levels, but B100 is shown to significantly increase NOx emissions. Durbin 2011 discusses this result only briefly, and it is unclear what conclusions can be drawn from it.

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

###

[19] As discussed in Section 3.3, the pair-wise t-test is not the preferred method for demonstrating statistical significance.

12_B_LCFS_GE Responses (Page 322 – 358)

728. Comment: **NOx Emissions Impact of Soy- and Animal-based Biodiesel Fuels: A Re- Analysis December 10, 2013**

Agency Response: This is the second time this document was submitted by Growth Energy. It is a reproduction of comments **ADF B3-46** through **ADF B3-92**. The comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

This page intentionally left blank.

APPENDIX A

RESUME OF ROBERT W. CRAWFORD

Education

1978 Doctoral Candidate, ScM. Physics, Brown University, Providence, Rhode Island
1976 B.A. Physics, Pomona College, Claremont, California

Professional Experience

1998-Present Independent Consultant

Individual consulting practice emphasizing the statistical analysis of environment and energy data with an emphasis on how data and statistics are properly used to make scientific inferences. Mr. Crawford provides support on statistical, data analysis, and modeling problems related to ambient air quality data and emissions from mobile and stationary sources.

Ambient Air Quality and Mobile Source Emissions – Mr. Crawford has worked with Sierra Research on elevated ambient CO and PM concentrations in Fairbanks AK and Phoenix AZ, including the effect of meteorological conditions on ambient concentrations, the relationship of concentrations to source inventories, and the use of non-parametric techniques to infer source location from wind speed and direction data. Ongoing work is employing Principal Components Analysis to elucidate the relationship between meteorology and $PM_{2.5}$ concentrations in Fairbanks. In the past year, this work led to creation of the AQ Alert System, a tool used by air quality staff to track $PM_{2.5}$ monitor concentrations during the day and to prepare AQ alerts over the next 3 days based on the meteorological forecast.

In past work for Sierra, he has also conducted studies of fuel effects on motor vehicle emissions for Sierra. For CRC, he determined the relationship between gasoline volatility and oxygen content on tailpipe emissions of late model vehicles at FTP and cold-ambient temperatures. For SEMPRA, he determined the relationship between CNG formulation and tailpipe emissions of criteria pollutants and a range of air toxics. Other work has included the design of vehicle surveillance surveys and determination of sample sizes, development of screening techniques similar to discriminant functions to improve the efficiency of vehicle recruitment, the analysis of vehicle failure rates measured in inspection & maintenance programs, and the statistical evaluation of data collected on freeway speeds using automated sensors.

Stationary Source Emissions – Over the past 5 years, Mr. Crawford has worked with AEMS, LLC on EPA's MACT and CISWI rulemakings for Portland Cement plants, in which significant issues related to data quality, data reliability, and emissions variability are evident. Key issues include the need to properly account for uncertainty and emissions variability in setting emission standards. He also supported AEMS in the

current EPA rulemaking on reporting of greenhouse gas emissions from semiconductor facilities, where the proper characterization of emission control device performance was a key issue. He is currently supporting AEMS in a regulatory process to re-determine emission standards for an industrial facility where the new standard will be enforced by continuous emissions monitoring (CEMS). At issue is how to set the standard in such a way that there will be no more than a small, defined risk that 30-day emission averages will exceed the limitations while emissions remain well-controlled .

Advanced Combustion Research – In recent work for Oak Ridge National Laboratory, Mr. Crawford conducted a series of statistical studies on the fuel consumption and emissions performance of Homogenous Charge Compression Ignition (HCCI) engines. One of these studies was for CRC, in which fuel chemistry impacts were examined in gasoline HCCI. In HCCI, the fuel is atomized and fully-mixed with the intake air charge outside the cylinder, inducted during the intake stroke, and then compressed to the point of spontaneous combustion. The timing of combustion is controlled by heating of the intake air. If R&D work can demonstrate a sufficient understanding of how fuel properties influence engine performance, the HCCI combustion strategy potentially offers the fuel economy benefit of a diesel engine with inherently lower emissions.

1979-1997 Energy and Environmental Analysis, Inc., Arlington, VA. Director & Partner (from 1989).

Primary work areas: Studies of U.S. energy industries for private and institutional clients emphasizing statistical analysis, business planning and computer modeling/forecasting. Responsible for the EEA practice area that provided strategic planning and forecasting services to major energy companies. Primary topical areas included: U.S. energy market analysis and strategic planning; gas utility operations; and natural gas supply planning.

U.S. Energy Market Analysis

During 1995-1997, Mr. Crawford directed EEA's program to provide comprehensive energy supply and demand forecasting for the Gas Research Institute (GRI) in its annual Baseline Projection of U.S. Energy Supply and Demand. Services included: development of U.S. energy supply, demand, and price forecasts; sector-specific analyses covering energy end-use (residential, commercial, industrial, transportation), electricity supply, and natural gas supply and transportation; and the preparation of a range of publications on the forecasts and energy sector trends.

From 1989 through 1997, he directed the use of EEA's Energy Overview Model in strategic planning and long-term market analysis for a client base of major energy producers, pipelines, and distributors in both the United States and Canada. The Energy Overview Model was used under his direction as the primary analytical basis for the 1992 National Petroleum Council study The Potential for Natural Gas in the United States. Mr. Crawford also provided analysis for clients on a wide range of other energy market issues, including negotiations related to an LNG import project intended to serve U.S. East Coast markets. This work assessed the utilization and economic value of seasonal

gas deliverability in order to develop LNG pricing formulas and evaluate the project's viability.

Other topical areas of work during his period of employment with EEA include:

Gas Load Analysis and Utility Operations – Principal investigator in a multi-year research program for the Gas Research Institute (GRI) that examined seasonal gas loads, utility operations, and the implications for transmission and storage system reliability and capacity planning.

Gas Transmission and Storage – Principal investigator for a study of industry plans for expansion of underground gas storage capacity in the post-Order 636 environment, including additions of depleted-reservoir and salt-formation storage, an engineering analysis of capital and operating costs for the projects, and unbundled rates for new storage services.

Natural Gas Supply Planning – Mr. Crawford was EEA's senior manager and lead analyst on gas supply planning issues for both pipeline and distribution companies, which included technical and analytic support in development and justification of gas supply strategies; and identification of optimal seasonal supply portfolios for Integrated Resource Planning proceedings.

Transportation Systems Research

Mr. Crawford also had extensive experience in motor vehicle fuel economy and emissions while at EEA. He participated for five years in a DOE research program on fuel economy, with emphasis on the evaluation of differences between laboratory and on-road fuel economy. His work included analysis of vehicle use databases to understand how driving patterns and ambient (environmental) conditions influence actual on-road fuel economy. He also developed a software system to link vehicle certification data systems to vehicle inspection and testing programs and participated in a range of studies on vehicle technology, fuel economy, and emissions for DOE, EPA, and other governmental agencies.

SELECTED PUBLICATIONS (emissions and motor vehicle-related topics)

Statistical Assessment of $PM_{2.5}$ and Meteorology in Fairbanks, Alaska: 2013 Update. Crawford and Dulla. Prepared for the Alaska Department of Environmental Conservation. (forthcoming).

Statistical Assessment of $PM_{2.5}$ and Meteorology in Fairbanks, Alaska. Crawford and Dulla. Prepared for the Alaska Department of Environmental Conservation. March 2012.

Principal Component Analysis: Inventory Insights and Speciated $PM_{2.5}$ Estimates. Crawford. Presentation at Air Quality Symposium 2011, Fairbanks and North Star Borough, Fairbanks, AK. January 2011.

Influence of Meteorology on $PM_{2.5}$ Concentrations in Fairbanks Alaska: Winter 2008-2009. Crawford. Presentation at Air Quality Symposium 2009, Fairbanks and North Star Borough, Fairbanks, AK. July 2009.

Analysis of the Effect of Fuel Chemistry and Properties on HCCI Engine Operation: A Re-Analysis Using a PCA Representation of Fuels. Bunting and Crawford. 2009. Draft Report (CRC Project AFVL13C)

The Chemistry, Properties, and HCCI Combustion Behavior of Refinery Streams Derived from Canadian Oil Sands Crude. Bunting, Fairbridge, Mitchell, Crawford, et al. 2008. (SAE 08FFL 28)

The Relationships of Diesel Fuel Properties, Chemistry, and HCCI Engine Performance as Determined by Principal Components Analysis. Bunting and Crawford. 2007. (SAE 07FFL 64).

Review and Critique of Data and Methodologies used in EPA Proposed Utility Mercury MACT Rulemaking, prepared by AEMS and RWCrawford Energy Systems for the National Mining Association. April 2004.

PCR+ in Diesel Fuels and Emissions Research. McAdams, Crawford, Hadder. March 2002. ORNL/TM-2002/16.

A Vector Approach to Regression Analysis and its Application to Heavy-duty Diesel Emissions. McAdams, Crawford, Hadder. November 2000. ORNL/TM-2000/5.

A Vector Approach to Regression Analysis and its Application to Heavy-duty Diesel Emissions. McAdams, Crawford, Hadder. June 2000. (SAE 2000-01-1961).

Reconciliation of Differences in the Results of Published Shortfall Analyses of 1981 Model Year Cars. Prepared by Energy and Environmental Analysis, Inc. for the U.S. Department of Energy under Contract DE-AC01-79PE-70045. October 1985

Short Test Results on 1980-1981 Passenger Cars from the Arizona Inspection and Maintenance Program. Darlington, Crawford, Sashihara. August 1984.

Seasonal and Regional MPG as Influenced by Environmental Conditions and Travel Patterns. Prepared by Energy and Environmental Analysis, Inc. for the U.S. Department of Energy under Contract DE-AC01-79PE-70045. March 1983.

Comparison of EPA and On-Road Fuel Economy -- Analysis Approaches, Trends, and Impacts. McNutt, Dulla, Crawford, McAdams, Morse. June 1982. (SAE 820788)

Regionalization of In-Use Fuel Economy Effects. Prepared by Energy and Environmental Analysis, Inc. for the U.S. Department of Energy under Contract DE-AC01-79PE-70032. April 1982.

1985 Light-Duty Truck Fuel Economy. Duleep, Kuhn, Crawford. October 1980. (SAE 801387)

PROFESSIONAL AFFILIATIONS

Member, Society of Automotive Engineers.

HONORS AND AWARDS

2006 Barr y D. McNutt Award for Excellence in Automotive Policy Analysis. Society of Automotive Engineers.

US Patent 7018524 (McAdams, Crawford, Hadder, McNutt). Reformulated diesel fuels for automotive diesel engines which meet the requirements of ASTM 975-02 and provide significantly reduced emissions of nitrogen oxides (NO_x) and particulate matter (PM) relative to commercially available diesel fuels.

US Patent 7096123 (McAdams, Crawford, Hadder, McNutt). A method for mathematically identifying at least one diesel fuel suitable for combustion in an automotive diesel engine with significantly reduced emissions and producible from known petroleum blend stocks using known refining processes, including the use of cetane additives (ignition improvers) and oxygenated compounds.

###

12_B_LCFS_GE Responses (Page 359 – 364)

729. Comment: **Robert Crawford's Resume**

Agency Response: This is submittal two of four of Robert Crawford's resume. It does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

ATTACHMENT D

growth energy™
America's Ethanol Supporters

777 North Capitol Street, NE, Suite 805, Washington, D.C. 20002
PHONE 202.545.4000 FAX 202.545.4001 GrowthEnergy.org

August 15, 2014

Via Electronic Mail

Mr. Alexander Mitchel
Transportation Fuels Branch
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Alternative Diesel Fuel Rulemaking

Dear Mr. Mitchell:

Please find attached the comments of Growth Energy in response to the staff's request for public input on alternatives to the 2013 regulatory proposal for the Alternative Diesel Fuel regulation. Growth Energy hopes to make a further submission regarding regulatory alternatives following the public consultation meeting to discuss biodiesel emissions testing sponsored by the Board.

ADF B3-128

Please place this letter and its attachments in the public docket that I understand the staff is establishing for materials it receives in connection with this rulemaking effort.

Sincerely,

David Bearden

David Bearden
General Counsel and Secretary

cc: Dr. Irena Asmundson (via Electronic Mail)
Mr. Michael S. Waugh (via Electronic Mail)

STATE OF CALIFORNIA

AIR RESOURCES BOARD

RESPONSE TO REQUEST FOR PUBLIC INPUT ON REGULATION OF ALTERNATIVE DIESEL FUEL

GROWTH ENERGY

AUGUST 15, 2014

Growth Energy's Response to Request for Public Input
On Regulation of Alternative Diesel Fuel

Growth Energy respectfully submits this response to the request by the staff of the California Air Resources Board ("CARB") for public input on alternatives to the staff's currently proposed method for regulating the use of alternative diesel fuel ("ADF") as part of compliance with the low-carbon fuel standard ("LCFS") regulation. The CARB staff presented its request for public comment in a notice dated July 29, 2014, and has established today as the deadline for that input. In these brief comments, Growth Energy assumes CARB's familiarity with and incorporates by reference its June 23, 2014 submission in response to a similar staff request concerning the LCFS regulation itself, as well as Growth Energy's submissions in an earlier phase of the ADF rulemaking in 2013.

I. Introduction and Background

The stated purpose of the July 29 notice is to seek input on regulatory alternatives pursuant to the 2011 amendments to the Government Code contained in SB 617. The proposed ADF regulation is intended to provide a legal pathway for new emerging diesel fuel substitutes to enter the commercial market in California, while managing and minimizing environmental and public health impacts, and to preserve the emission benefits derived from the CARB motor vehicle diesel regulations.[1] In light of that goal, the current ADF rulemaking as most recently described by CARB staff would establish: ADF B3-129

- A general process governing the commercialization of new ADF formulations in California, and
- Specific requirements for biodiesel and biodiesel blends that are consistent with the general ADF process and that would mitigate increases in emissions of oxides

[1] *See* "Initial Statement of Reasons, Proposed Regulation on the Commercialization of New Alternative Diesel Fuel," October 23, 2013 available at http://www.arb.ca.gov/regact/2013/adf2013/adf2013isor.pdf.

of nitrogen (NOx) from diesel engines and vehicles that have been identified to occur relative to conventional California diesel fuel from the use of biodiesel and biodiesel blends.[2]

There are no specific compositional requirements proposed for ADFs other than "biodiesel," inasmuch as none have yet sought to be commercialized in California.

CARB has a duty to mitigate any potential significant environmental impacts that could result from commercialization of biodiesel. Mitigation strategies will drive the costs and affect the benefits of the ADF regulation, and so the first step in the SB 617 process for the ADF regulation should be to develop a range of potential mitigation strategies. CARB has sponsored, but has not yet fully digested, a body of tests using biodiesel fuels. The CARB staff, for its part, has recently asserted that those tests have informed several major findings about mitigation strategies; nevertheless, the staff also acknowledges that some of its major findings are preliminary and subject to change because the data upon which they are based has only recently made available to the public. Nor has the CARB staff fully developed and explained its findings. Once the staff does so, it should then seek better-informed public input under SB 617.

ADF B3-129 cont.

Based on its current analysis, the CARB staff has indicated that it expects that the yet unpublished proposed ADF regulation will require NOx mitigation for biodiesel blends containing more than five percent of an animal-based biodiesel or more than one percent of soy-based or other types of biodiesel blends. Staff also indicates that it expects to propose an exemption for all biodiesel blends when used in vehicle fleets containing more than 95% "new technology diesel engines (NTDEs)"[3] from NOx mitigation requirements and a sunset clause

ADF B3-130

---

2 *See* "Preliminary Rulemaking Proposal for Biodiesel Use as an Alternative Diesel Fuel," July 29, 2014 available at http://www.arb.ca.gov/fuels/diesel/altdiesel/20140729ADF_SRIA_Proposal.pdf.

3 In the October 23, 2013 Initial Statement Reasons, CARB staff defined NTDEs as meaning:

eliminating all NOx mitigation requirements "once NTDEs represent 95 percent of the heavy duty diesel engines in California."

The CARB staff's approach appears to rest on two beliefs: (i) no NOx increases occur in blends containing five percent or less of animal-based biodiesel or one percent or less of soy-based or other biodiesel; and (ii) there are no NOx increases from biodiesel use in NTDEs.

Turning first to the need to mitigate NOx emissions for animal-based biodiesel blends below five percent and below one percent for soy-based and other biodiesel blends, the flaws here are due to the fact that the CARB staff continues to cling to the concept of there being a "threshold" biodiesel blend level below which there are no increases in NOx emissions, rather than accepting that there is a linear relationship between NOx emissions and increases in biodiesel content. That the staff's "threshold" model is flawed with respect to both soy- and animal-based biodiesel blends and should be replaced by the linear model was made clear in a technical report prepared by Robert Crawford[4] that was submitted to CARB as part of Growth Energy's formal comments on the abandoned 2013 ADF rulemaking.

ADF B3-130 cont.

With respect to the impact of biodiesel on NOx emissions from NTDEs, CARB staff's major finding in this area — that biodiesel does not increase NOx emissions from NTDEs — continues to rely, as it did in the October 2013 rulemaking, on only one reference, a paper by

ADF B3-131

a diesel engine that meets at least one of the following criteria:

(1) 2010 ARB emission standards for on-road heavy duty diesel engines under 13 CCR 1956.8,
(2) Tier 4 emission standards for non-road compression ignition engines under 13 CCR 2421, 2423, 2424, 2425, 2425.1, 2426, and 2427, or
(3) equipped with or employs a Diesel Emissions Control Strategy (DECS), verified by ARB pursuant to 13 CCR 2700 et seq., which uses selective catalytic reduction to control NOx.

ADF B3-130 cont.

4 Crawford, R., "NOx Emission Impact of Soy- and Animal-based Biodiesel Fuels: A Reanalysis," December 10, 2013.

Lammert *et al.*[5] The flaws in the basis for this major finding were explained in Growth Energy's submission in the 2013 ADF rulemaking.[6] A 2014 peer-reviewed publication authored by researchers from the University of California at Riverside[7] (Gysel, *et al.*) who report results from a study funded by the South Coast Air Quality Management District confirms that CARB staff's major finding in this area is flawed. With respect to biodiesel impacts on NOx emissions from NTDEs, Gysel *et al.* report large percentage increases in NOx emissions with biodiesel use in NTDEs and state:

> Lammert *et al.* showed that the effect of SCR aftertreatment negates the effect of fuels on NOx emissions when they tested a 2011 Cummins ISL engine on B20 and B100. This is in strong contrast to the current study vehicle shows that there is rather strong fuel effect with the B50 blends compared to CARB ULSD from the Cummins ISX-15 engine with SCR.

In addition, Gysel *et al.*, provides a discussion referencing at least four other peer-reviewed technical papers[8] which further confirm this flaw in the staff's finding, showing increases in

ADF B3-131 cont.

---

5 Lammert, M., McCormick, R., Sindler, P. and Williams, A., "Effect of B20 and Low Aromatic Diesel on Transit Bus NOx Emissions Over Driving Cycles with a Range of Kinetic Intensity," *SAE Int. J. Fuels Lubr.* 5(3):2012, doi:10.4271/2012-01-1984.

6 As an expert stated in Growth Energy's submission:

> ... [T]he CARB staff's unequivocal statements regarding the impact of biodiesel on NOx emissions from all vehicles with NTDEs is simply not reasonable based on data from (1) a single study that (2) tested only two urban buses equipped with the same engine and (3) used instrumentation that was, at best, barely able to measure NOx emissions from the test vehicles in general, and clearly was not sensitive enough to reliably detect changes in NOx emissions due to use of different fuels. Nothing else in the rulemaking file supports the CARB staff's claim that there will not be increased NOx emissions from the use of biodiesel in NTDEs.

Declaration of James M. Lyons, ¶ 23 (Dec. 12, 2013).

7 Gysel, N., Karavalakis, G., Durbin, T., Schmitz, D., and Cho, A., "Emission and Redox Activity of Biodiesel Blends Obtained from Different Feedstocks from a Heavy-Duty Vehicle Equipped with DFS/SCR Aftertreatment and a Heavy-Duty Vehicle without Control Aftertreatment," SAE Technical Paper 2014-01-1400, April 1, 2014.

8 Walkowicz, K., Na, K., Robertson, W., Sahay, K., Bogdanoff, M., Weaver C., and Carlson, R., "On-road and In-Laboratory Testing to Demonstrate Effects of ULSD, B20 and B99 on a Retrofit Urea-SCR Aftertreatment System," SAE Technical Paper 2009-01-2733, November 2, 2009; McWilliam, L. and Zimmermann, A., "Emissions and Performance Implications of Biodiesel Use in an SCR-equipped Caterpillar C6.6," SAE Technical Paper 2010-01-2157, October 25, 2010; Mizushima, N., Murata, Y., Suzuki, H., Ishii, H., Goto, Y.,

NOx emissions from biodiesel use with NTDEs. It should also be noted that the observed NOx increases from biodiesel use in NTDEs are consistent with the widely accepted linear model form which Crawford's report demonstrates is technical superior to CARB's flawed threshold model. ADF B3-131 cont.

II. Necessary Changes in the CARB Staff's Approach

In light of the currently available data and the relevant literature, the CARB staff's current approach is insufficient to mitigate the impacts of biodiesel usage. On that basis, Growth Energy asks the staff to consider a regulatory alternative having the following three key elements: ADF B3-132

1. Require that the mitigation strategies for increased NOx emissions be applied to all biodiesel and blends of biodiesel and diesel fuel where biodiesel was intentionally blended.[9] ADF B3-133

2. Eliminate exemptions from NOx mitigation requirements for biodiesel used in vehicle fleets comprised of at least 95% NTDEs. ADF B3-134

3. Eliminate the sunset provision for NOx mitigation requirements. ADF B3-135

It is critical for the staff to evaluate the need for those three changes in light of other measures that CARB has adopted or is considering adopting to reduce NOx emissions, including the Advanced Clean Cars program and CARB's Sustainable Freight Transport Initiative which involve requirements for "zero-emission" heavy-duty vehicles. ADF B3-136

---

and Kawano, D., "Effect of Biodiesel on NOx Reduction Performance of Urea-SCR System," SAE Technical Paper 2010-01-2278, October 25, 2010.

9 The reference to intentional blending has been included to ensure that mitigation is not required for inadvertent blends of biodiesel and diesel that could result from mixing of diesel with biodiesel remaining in storage tanks or in fuel transfer lines.

Growth Energy appreciates the opportunity to provide this input on alternatives to the current approach to developing an ADF regulation, and as noted above, plans to provide additional input once the CARB staff has reviewed the available data in one or more workshops.

Respectfully submitted,

GROWTH ENERGY

12_B_LCFS_GE Responses (Page 365 – 376)

730. Comment: **ADF B3-128 and ADF B3-129**

Agency Response: These comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

731. Comment: **ADF B3-130 and ADF B3-136**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

STATE OF CALIFORNIA

AIR RESOURCES BOARD

RESPONSE TO REQUEST FOR PUBLIC INPUT ON ALTERNATIVES TO THE LOW- CARBON FUEL STANDARD REGULATION

GROWTH ENERGY

JUNE 23, 2014

Executive Summary

The staff of the California Air Resources Board ("CARB") has identified the Low-Carbon Fuel Standard ("LCFS") as a "major regulation" that requires enhanced review for compliance with SB 617 (Calderon and Pavley), a 2011 amendment to the California Administrative Procedure Act (the "APA"). The California Department of Finance ("the Department") has published regulations that implement SB 617. Those regulations require rulemaking agencies like CARB to seek early public input on possible alternatives to the rules being developed by the rulemaking agencies.

Growth Energy, an association of the Nation's leading ethanol producers and other companies that serve America's need for renewable fuels, is submitting to the CARB staff a proposed alternative to the LCFS regulation that would allow the State to eliminate the LCFS program without loss of environmental benefits. Growth Energy's proposal recognizes important changes in the regulatory baseline for the control of greenhouse gas ("GHG") emissions that have occurred since 2009. In particular, the federal renewable fuels standard ("RFS") program, combined with the California cap-and-trade program and a number of California-specific vehicle- and engine-based regulations, now assure that California will receive most if not all of the direct GHG emissions reductions that can be attributed to the LCFS regulation. To the extent that CARB believes that there is still an emissions shortfall from elimination of the LCFS or that it has authority to address lifecycle GHG emissions occurring outside of California under state and federal law (which are issues not addressed in this submittal), Growth Energy proposes that CARB address those remaining issues by modifying the California GHG cap-and-trade regulations, which are now in effect in California and which apply to transportation fuels providers beginning in 2015.

Growth Energy's description of its proposed alternative to the LCFS regulation is as detailed as possible, given currently available information. In this submittal, Growth Energy urges the CARB staff to provide the additional information needed to provide further analysis of alternatives to the LCFS regulation.

Reproduction
of Pages 191 - 218
of Comment
Letter
46_OP_LCFS_GE/
17_OP_ADF_GE
Consisting of Comments
LCFS 46-195
through
LCFS 46-232

Table of Contents

Page

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

Growth Energy's Response to Request for Public Input
On Alternatives to the Low-Carbon Fuel Standard Regulation

Growth Energy respectfully submits this response to the request by the staff of the California Air Resources Board ("CARB") for public input on alternatives to the low-carbon fuel standard ("LCFS") regulation. The CARB staff presented its request for public comment in a notice dated May 23, 2014, and has established today as the deadline for that input.

The CARB staff is seeking public input in connection with its proposal that CARB revise and readopt the LCFS regulation at a public hearing later this year. The purpose of the LCFS regulation, which the Board first adopted in 2009, is to achieve reductions in greenhouse gas ("GHG") emissions from the California transportation sector pursuant to the Global Warming Solutions Act of 2006, commonly called AB 32. Other regulations adopted since 2008 under AB 32 to achieve the same objectives as the LCFS regulation include the "cap and trade" regulation (17 C.C.R. §§ 95801-96022), the GHG emissions standards contained in the Advanced Clean Cars (or "ACC") program (13 C.C.R. §§ 1960.1-1962.2), and a set of regulations to control GHG emissions from heavy-duty vehicles and engines.[1]

Reproduction
of Pages 191 - 218
of Comment
Letter
46_OP_LCFS_GE/
17_OP_ADF_GE
Consisting of Comments
LCFS 46-195
through
LCFS 46-232

Overview

Growth Energy has organized its analysis of alternatives to the LCFS regulation in this submission into four parts.

Part I of this submission briefly outlines the statutory and regulatory framework for the CARB staff's request for input on alternatives to the LCFS regulation. As explained in Part I, regulations adopted by the California Department of Finance pursuant to a recent amendment to the APA require CARB to seek and permit effective early public input on rulemaking concerning

[1] These include California's Heavy-Duty GHG regulations now completing the rulemaking process, a second phase of regulations that are under development, and the so-called "Tractor-Trailer" GHG regulation adopted in 2008. *See* http://www.arb.ca.gov/regact/2013/hdghg2013; http://www.arb.ca.gov/cc/hdghg/hdghg.htm.

"major" regulations, including the LCFS. That amendment was contained in SB 617 (Calderon and Pavley). The LCFS rulemaking, and this stage of the LCFS rulemaking, are particularly important, because this rulemaking is one of the first CARB rulemakings governed by SB 617. *See* pp. 4-7 below.

Part II of Growth Energy's submittal addresses some of the important factors that affect a regulatory alternatives analysis undertaken under SB 617. Since 2009, there have been significant changes in the "baseline" conditions for GHG regulation relevant to the LCFS program. As explained in Part II, most of the GHG emissions reductions sought by CARB when it adopted the LCFS regulation in 2009 will be provided by a combination of the federal renewable fuels standard ("RFS") program, along with California's cap-and-trade regulation, ACC program, and regulations limiting GHG emissions from heavy-duty vehicles and engines. Given that most, if not all, of the GHG emissions reductions sought by CARB in 2009 through the LCFS regulation are now assured by those other programs, the LCFS regulation has been rendered largely superfluous from an environmental perspective, even though it imposes huge financial burdens on the regulated community and requires a large commitment of resources by CARB. As a threshold matter, CARB should therefore carefully and fully consider whether, based on regulatory and program developments related to GHG emission control since 2009, there is any continuing need for the LCFS regulation. *See* pp. 8-14 below.

Part III of this submittal explains that, to the extent that the CARB staff finds any continuing need for the LCFS regulation to control GHG emissions, that need could be met instead through a simple modification of the cap-and-trade regulation. Taking that step -- modifying the cap-and-trade regulation -- would fully eliminate any conceivable remaining need for the LCFS regulation, while doing nothing to alter CARB's overall regulatory strategy to

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

address GHG emissions from the California transportation sector. The GHG emissions reductions benefits of the LCFS program would be fully realized from the suite of other GHG regulations adopted federally and in California since 2009, and by the modification of the cap-and-trade program. The direct regulatory costs of the LCFS program are borne primarily by the California motor vehicle fuels marketing industry, which can to some extent pass those costs to its retail customers. Insofar as the LCFS program imposes costs on California businesses and consumers, the alternative presented here (relying on the cap-and-trade program) would not materially alter the allocation of costs and would at the same time reduce regulatory costs by eliminating an entire regulatory program (the LCFS regulation). Judging from the strong concern about the LCFS regulation expressed by oil industry stakeholders, the regulatory relief and reform proposed here warrants full consideration and further development. *See* pp. 14-20 below.

Part IV of Growth Energy's submittal recommends specific next steps that CARB should consider, including full involvement by the Chief Counsel's Office to ensure compliance with the APA. As will be apparent throughout this submittal, Growth Energy's analysis of regulatory alternatives can be no more detailed than the publicly available information about (i) the new version of the LCFS regulation that the CARB staff is considering for proposal to the Board, and (ii) the information that the CARB staff has provided about the benefits that it is attributing to the LCFS program. Contrary to the position taken in communications to Growth Energy by CARB's Transportation Fuels Section on this subject, very little information on the new version of the LCFS regulation or its estimated benefits -- which are critical to an effective SB 617 process -- has been provided to the public to date. In order to achieve substantial compliance with the APA, the CARB staff needs to provide the public with a full picture of its proposed new

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

LCFS regulation, and in particular describe any new features of the regulation intended to reduce compliance costs. The CARB staff also needs to completely identify for the public all benefits that it is attributing to the LCFS regulation that would bear on an SB 617 alternatives analysis. Then, after the public has had sufficient time to analyze the relevant information from CARB, the public should be permitted to provide updated regulatory alternative analyses, which the CARB staff should fully consider and address in the Standardized Regulatory Impact Assessment required by 1 C.C.R. § 2002. That approach would ensure compliance with the APA, without conflicting or otherwise undermining any other mandates or obligations applicable to the LCFS regulation. *See* pp. 20-24 below.

I. The Statutory Framework for the Regulatory Alternatives Analysis under SB 617

The CARB staff is seeking submittals from the public on regulatory alternatives to the LCFS regulation because it has a legal obligation to do so. For many years, section 11346.3 of the APA has provided in part as follows:

> (a) State agencies proposing to adopt, amend, or repeal any administrative regulation shall assess the potential for adverse economic impact on California business enterprises and individuals, avoiding the imposition of unnecessary or unreasonable regulations or reporting, recordkeeping, or compliance requirements. ...
>
> (2) The state agency, prior to submitting a proposal to adopt, amend, or repeal a regulation to the office, shall consider the proposal's impact on business, with consideration of industries affected including the ability of California businesses to compete with businesses in other states. For purposes of evaluating the impact on the ability of California businesses to compete with businesses in other states, an agency shall consider, but not be limited to, information supplied by interested parties.

Cal. Gov't Code § 11346.3(a)(2). Based on evidence that rulemaking agencies did not adequately consider the burdens that regulations impose on the public, in SB 617 the Legislature added a requirement that rulemaking agencies prepare a detailed assessment of the costs and benefits of any proposed major regulation, for review by the California Department of Finance

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

("the Department") ***before*** initiating the traditional informal rulemaking process. *See id.* § 11346.3(c). Those detailed assessments are called Standardized Regulatory Impact Assessments (or "SRIAs."). *See id.* § 11346.36. The Legislature also made it clear in SB 617 that the obligation to consider and use early public input on regulatory impacts could not be met by merely going through the formalities of seeking public input.[2]

The Department completed work on regulations to implement SB 617 in the fall of 2013. The Department's regulations require, among other steps, the following:

> The [rulemaking] agency shall also seek public input regarding alternatives from those who would be subject to or affected by the regulations ... prior to filing a notice of proposed action with OAL unless the agency is required to implement federal law and regulations which the agency has little or no discretion to vary. An agency shall document and include in the SRIA the methods by which it sought public input.

1 C.C.R. § 2001(d). As the rulemaking file for the Department's regulations implementing SB 617 shows, many state regulatory agencies, CARB not excepted, recognized that SB 617 (as implemented by the Department) would mean the end of "business as usual" in the California rulemaking process.[3]

In responding to objections from rulemaking agencies concerning the obligations created by its SB 617 regulations, the Department explained that "[i]nvolving the Department and affected parties early in the [rulemaking] process could result in the discovery of additional and

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

---

[2] Thus, SB 617 deleted text from section 11346.3(a)(2) of the APA that, up to 2011, had provided that the APA's public-input requirements were not "inten[ded]" to "impose additional criteria on agencies" engaged in rulemaking. *See* Stats. 2011, c.496 (SB 617), subd. (a); Cal. Office of Admin. Law, *California Rulemaking Law under the Administrative Procedure Act* (2012) 57 (legislative history of section 11346.3).

[3] Several rulemaking agencies filed sharp objections to the Department's proposed regulations to implement SB 617 on the ground that the regulations would require major changes in the timing used by the agencies to develop regulations and to obtain public input. *See, e.g.,* Dep't of Finance, *Regulations to Implement SB 617 Re Major Regulations, Responses to 45-day Comment Period (Chart A)* (hereinafter "Chart A"), available at http://www.dof.ca.gov/research/economic_research_unit/SB617_regulation/documents/Response%20to%20Comments%20Chart A.pdf. The Department dealt fully with all those objections and made no material changes in its proposed regulations to implement SB 617.

perhaps more cost-effective alternatives to [a] proposed major regulation, consistent with the intent of SB 617."[4] Similarly, when rulemaking agencies (including CARB) objected to the burdens of preparing the early regulatory analyses of costs and benefits needed for an effective SB 617 process, the Department correctly concluded that the amended APA "clearly contemplates that an agency will have considered [regulatory] alternatives prior to filing a notice of a proposed action" with the Office of Administrative Law and publication of the regulatory notice for further public comment.[5] The Department also made it clear that under the SB 617 process, the "no action" alternative to regulation -- which is an outcome seldom if ever seen in a major California rulemaking -- had to receive full and fair consideration at the beginning of the rulemaking process.[6]

In requiring significant change in the California rulemaking process, the statute and the implementing regulations are salutary. The LCFS regulation in 2009 was typical of major rulemakings affecting the motor vehicle fuels industries in California. Beginning in 2008, CARB had convened a series of public consultation meetings prior to its formal proposal for rulemaking in March 2009. Not until publication of the Initial Statement of Reasons for the LCFS regulation, however, was the public given any opportunity to review the economic analysis of costs and benefits for the proposed regulation; the written comments on economic issues were due a scant 45 days later (in April 2009), and at the Board's April 2009 public hearing, most private-sector speakers were limited to five minutes to make a presentation to

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

[4] *See* Chart A at 24.

[5] *Id.* at 27.

[6] *Id.* at 47-48.

CARB. The public cannot have a significant role in serious economic analysis of a major regulation within such a constrained process.

Unsurprisingly, major economic assumptions and issues were not fully addressed within the time frame for written comments in March to April 2009, nor at the Board hearing. Among the assumptions and factors that could not as a practical matter be "pressure-tested" in the public comment process was the CARB staff's belief that advanced ethanol production methods would eventually drive down gasoline costs at the retail level and make the LCFS program cost-neutral for California consumers or even generate savings of up to $11 billion.[7] That assumption was unsound in 2009, and has since been disproven by experience.[8] Likewise, in the 2009 rulemaking, the CARB staff gave little attention to the ability of the federal RFS program to accomplish the same goals and purposes of the LCFS regulation, and offered largely opaque comparisons between the GHG reductions that the two programs could achieve. Now in its fifth year of implementation, the LCFS regulation has made little or no impact on the supply of lower-GHG fuels in California.[9] SB 617 and the Department's implementing regulations require the Board to improve the quality and depth of the economic analysis for major regulations like the LCFS program.

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

---

7 Air Resources Board, *Proposed Regulation to Implement the Low Carbon Fuel Standard -- Staff Report: Initial Statement of Reasons* (hereinafter "ISOR") at ES-26.

8 As the ISOR itself noted, "Economic factors, such as tight supplies of lower-carbon-intensity fuels ... could result in overall net costs, not savings, for the LCFS." The fact that the cost savings forecast in 2009 proved ephemeral is implicit in the CARB staff's decision, less than two years after the regulation went into effect, to develop "cost reduction" features for the LCFS regulation, which would assist "regulated parties ... unable to meet their compliance obligations ... due to limited supplies of low carbon fuels or LCFS credits in the market." Air Resources Board, *Low Carbon Fuel Standard 2011 Program Review Report* (Dec. 8, 2011) (hereinafter "2011 Program Review") 16.

9 There have been substantial increases in the efficiency of Midwest corn ethanol production facilities since CARB first embarked on the LCFS rulemaking, and those increases have reduced the lifecycle GHG emissions of those facilities under some analyses; but those reductions in GHG emissions have been caused by market forces (the need to reduce energy consumption in order to remain competitive), not by virtue of the LCFS regulation. *See* note 25 below.

II. Factors Affecting the Regulatory Alternatives Analysis

According to the CARB staff, the goal of the LCFS regulation in 2009 was, and still remains, to "reduce the carbon intensity of transportation fuels used in California by at least 10 percent by 2020 from a 2010 baseline," and also to "support the development of a diversity of cleaner fuels with other attendant co-benefits."[10] Growth Energy sought clarification of the staff's description of the goals of the regulation for purposes of its input in the SB 617 process.[11] Lacking greater specificity or clarification, Growth Energy can only turn to the 2009 rulemaking, in which CARB quantified the "10 percent" target as being a reduction of 16 million metric tons of carbon dioxide equivalent ("MMTCO2eq") GHG emissions associated with combustion of transportation fuels in California, along with a 7 MMTCO2eq reduction in "upstream" emissions, yielding a total 23 MMTCO2eq reduction in worldwide annual GHG emissions in 2020.[12] As explained below, achieving the direct GHG emissions reduction attributed to the LCFS regulation in 2009 -- the 16 MMTCO2eq -- no longer requires the existence of the LCFS regulation.

A. Changes in the Regulatory Baseline Since 2009

The most significant development in the regulatory baseline since 2009 has been the adoption and full implementation of the federal renewable fuels standard program under the Energy Independence and Security Act of 2007, pursuant to a Final Rule adopted by the U.S.

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

[10] The staff identified that goal on June 5, 2014, well after the period for preparation of SB 617 public input had begun, in response to a specific request from Growth Energy. *See* Letter from D. Bearden to K. King, May 30, 2014 (included here as Attachment 1) *and* Letter from M. Waugh to D. Bearden, June 5, 2014 (included here as Attachment 2).

[11] *See* Letter from D. Bearden to M. Waugh, June 11, 2014 (included here as Attachment 3). To date, no response to Mr. Bearden's letter of June 11, 2014, has been received.

[12] *See* ISOR at VII-1. According to the 2009 ISOR, "These reductions account for a 10 percent reduction of the GHG emissions from the use of transportation fuel." *Id.* That 10 percent target, which the CARB staff also sometimes cites, originates in Executive Order S-01-07 of January 18, 2007. *See* Executive Order S-01-07, § 1, available at http://www.arb.ca.gov/fuels/lcfs/eos0107.pdf.

Environmental Protection Agency in 2010.[13] The federal RFS program assures an adequate supply of low-cost renewable fuel for California, *i.e.*, ethanol produced from corn starch at biorefineries located mainly in the Midwest.[14] Because ethanol produced by any method from any renewable feedstock has the same physical and chemical properties when used in motor fuel, gasoline blended with 10 percent ethanol will achieve the same reduction in exhaust or "tailpipe" GHG emissions regardless of the production process or renewable feedstock used to create the ethanol. Consequently, the portion of the 16 MMTCO2eq reduction in GHG emissions from the California transportation fleet operated on gasoline can and will be obtained by virtue of the federal RFS program.[15] Oil companies will continue to buy and blend ethanol into gasoline sold in California under the federal program even if there were no LCFS program, in order to comply with the federal RFS program. The portion of the California fleet operated on diesel fuel can also achieve its part of the 16 MMTCO2eq reduction in GHG emissions by virtue of the federal RFS

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

---

13 *See* U.S. EPA, *Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Final Rule*, 75 Fed. Reg. 14,669 (Mar. 26, 2010).

14 The RFS program, which in its early stages was effectively non-binding on ethanol usage, has begun to cause substantial increases in biofuel production. Total production of biofuels has increased steadily over the last year and a half, reaching approximately 16 billion gallons in the 12 months through April 2014. *See* http://www.epa.gov/otaq/fuels/rfsdata/.

15 The term "fleet," as used here, includes off-road vehicles and engines in other equipment.

When the CARB staff considered the matter in 2009, it made a number of assumptions about the efficacy of the federal RFS program that need to be reconsidered. The most significant assumption, which was empirically unsupported, was that the federal program (which at the time was still under development) would provide only 30 to 40 percent of the GHG reductions that the staff predicted for the LCFS program. That assumption appears to have been based on a belief that without the LCFS regulation, only 11.3 percent of the advanced or cellulosic biofuels required nationwide by the RFS program would be consumed in California, while a substantially higher amount of those fuels would be drawn from the nationwide fuel pool to California as the result of the LCFS regulation. The advanced biofuels required by the RFS regulation that would be drawn to California by the LCFS program would have been used elsewhere in the absence of the LCFS program, leading to the same reductions in GHG emissions. To the extent that the cellulosic ethanol industry has experienced limits on achieving full commercial launch, those are national and even global economic and technical factors that the existence of the LCFS regulation has not to date, and will not in the future, be able to change or influence.

program, because the federal program results in blending biodiesel and renewable diesel into diesel fuel produced from petroleum.[16]

As for the portion of the California fleet powered in whole or in part with electricity or hydrogen, there is similarly no continuing need for the LCFS program, owing to other changes in the regulatory baseline since 2009. The Advanced Clean Cars program now assures that electricity and hydrogen will be full participants in the California transportation fuel pool. In 2009, CARB's baseline for the alternatives analysis of the LCFS regulation included the then-current version of the Board's regulations to control GHG emissions from new motor vehicles that had been adopted in 2004, and that set GHG emission standards for 2009 to 2016 model-year new vehicles, sometimes called the "Pavley standards." In addition, the baseline also included the then-current provisions of the agency's Zero Emission Vehicle ("ZEV") standards which require manufacturers offer electric and/or hydrogen fuel cell vehicles for sale in California. CARB has now adopted new-vehicle GHG standards applicable to 2017 to 2025 model-year new vehicles and has made significant revisions to the ZEV standards as part of the ACC rulemaking in 2012.[17]

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

---

[16] One reason why California is assured of receiving an adequate supply of ethanol is that ethanol for use in gasoline commands a higher price -- the so-called "California premium" -- in California than in other parts of the United States, as can be readily seen from data available under contract or license from the Oil Price Information Service ("OPIS"). While there are many reasons why the "California premium" exists, one major reason is that refineries producing finished gasoline products for the California retail market tend to have higher production costs than other refineries.

[17] In its 2009 LCFS alternatives analysis, the CARB staff assumed that manufactures would sell more electric vehicles than required by the ZEV standards, as they existed in 2009. Vehicle manufacturer compliance with the ZEV, new vehicle GHG, and criteria emission standards is determined on a "fleet-average" basis. What this means is that to the extent that manufacturers sell more ZEVs than required, they can in turn sell greater numbers of less fuel efficient or higher emitting vehicles provided that they remain in compliance on average. In addition, manufacturers that over comply can sell "credits" to manufacturers that would not otherwise be in compliance. Therefore, even if the LCFS regulation might lead to greater demand and use of electric vehicles, there would be no net reduction in GHG emissions.

CARB has also taken and is taking a number of actions to reduce GHG emissions associated with the use of diesel fuel in heavy-duty vehicles which also need to be taken into account in the baseline for the 2014 LCFS analysis. The relevant measures include California's Tractor-Trailer regulation adopted in 2008 which requires use of aerodynamic improvement devices and low-rolling resistance tires, as well as the Phase I and the soon-to-be proposed Phase II heavy-duty GHG regulations that impose specific GHG emission requirements on new heavy-duty vehicles beginning with the 2014 model-year.[18]

B. Necessary Information for Development of a Detailed Alternative Program

In addition to properly defining the baseline for the alternatives analysis, it is important to have a clear and complete picture of the revised LCFS program that the CARB staff plans to propose. In addition to full information concerning the estimated benefits of the LCFS program (both in terms of GHG reductions and in any other relevant aspect), the currently unknown elements of that program include the following:

- Updated carbon intensity values for transportation fuels that will be included in the proposed 2014 LCFS regulation.
- The detailed form of any proposed "cost-containment" provisions which could allow parties subject to the LCFS regulation to comply with the program's standards, without actually achieving the CI reductions required under the regulation.
- CARB staff's current analysis of the manner in which regulated parties will most likely attempt to comply with the proposed 2014 LCFS.

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

[18] In addition to ensuring that the GHG emissions reductions associated with those regulations are properly accounted for in the baseline for the 2014 LCFS, CARB staff must also ensure that they properly account for the fact that compliance with the latter regulations is determined on a manufacturer fleet average basis in order to avoid improper assignment of GHG reductions to the 2014 LCFS regulation.

- A full description of any other intended goals of the LCFS regulation, such as stimulating "fundamental" changes in the "transportation fuel pool," along with the metrics to be used to measure progress and success in meeting those other goals.[19]

Contrary to the position taken in the CARB staff's recent correspondence with Growth Energy and in related postings on the CARB website, none of those elements have been disclosed to the public at present. In addition to providing that undisclosed information concerning its analysis, the CARB staff should address the following other pertinent questions, which follow from the foregoing review of changes in the regulatory baseline since 2009:

- Does the CARB staff agree that the federal RFS program would, in the absence of an LCFS regulation, assure some level of reductions in GHG exhaust emissions from the California in-use vehicle population that is operated on gasoline? If not, why not; and if so, what would be that level of GHG emissions reductions, on an annual or some other specific basis, if the LCFS program were to be discontinued at the end of 2015?
    - Does the staff have any disagreement with the position that the federal RFS program and the "California premium" (*see* note 15 above) would cause Midwest corn ethanol producers to continue preferentially to deliver ethanol to California, and cause the California gasoline marketing sector to blend that Midwest corn ethanol into gasoline up to the current 10 percent limit, even in the absence of the LCFS regulation? If so, what are the specific reasons why the staff disagrees?
    - Does the staff believe that the LCFS regulation would result in wider usage of E85 in California than the federal RFS program would cause, and if so, what is the empirical basis for that view?
    - Would a possible need for a diesel component to an LCFS program justify an unnecessary gasoline component for an LCFS program, and if so, why?
- The 2009 regulatory analysis predicted that ultra-low-CI fuels would be available and would bring the costs of the LCFS program down to the point where the program would be cost-neutral at the consumer level, or would result in savings of up to $11 billion.[20]

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

---

[19] *See* Air Resources Board, *California's Low Carbon Fuel Standard -- Final Statement of Reasons* (hereinafter "FSOR") 24.

[20] *See* ISOR at ES-26.

Does that remain the CARB staff's position? If not, what will be the consumer costs of the staff's proposed revised LCFS regulation, predicted annually or in some other manner? What uncertainties and assumptions affect those cost estimates?

- Are the ACC program and other vehicle-based GHG reduction programs adopted to implement AB 32 designed to obtain, and will they obtain, the maximum technologically feasible and cost effective reductions in GHG emissions from the new vehicles that are subject to those standards? (*See, e.g.*, Cal. Health & Safety Code § 38562(a).) If not, why not? With the ACC program and other non-LCFS regulations discussed above in Part II. A. now in place, would the LCFS program actually produce any incremental increase in the displacement of liquid motor vehicle fuels by electricity in ZEVs or hybrid electric vehicles or hydrogen in fuel cell vehicles? If so, what are the relevant increases, and on what assumptions do the predicted increases depend? Why would a vehicle manufacturer that over-achieved the ZEV requirement not use the credit gained from the overachievement by selling a higher-emitting conventional vehicle fleet? To what extent would the staff attribute to the LCFS program any displacement of vehicle miles traveled in conventional vehicles by vehicles powered by fuel cells, and what is the basis for that prediction?

- The CARB staff sometimes refers to Executive Order S-07-01 as a basis for maintaining the LCFS regulation. Should the requirements of Executive Order S-07-01 be reconsidered in the current rulemaking process insofar as the Executive Order called for creation of the LCFS regulation? Does Executive Order S-07-01 limit in any way CARB's discretion in adopting and enforcing measures to implement AB 32? Does AB 32 require adoption and enforcement of the LCFS regulation, if the same GHG reductions that the LCFS regulation can achieve could be achieved by other means?

- To the extent that the LCFS program is still intended to stimulate "fundamental changes in the transportation fuel pool" in California,[21] to what extent had the program succeeded in its first five years? Is achieving that objective consistent with the potential "cost reduction" mechanisms under consideration for a revised LCFS regulation? How should the Department and the public try to weigh that objective against the potential costs for California consumers and businesses in meeting that objective?

Having now presented the above questions to the CARB staff, Growth Energy believes that the staff should address them in the SRIA for the Department, or concurrently in a separate submittal to the Department made available to the public, if the staff does not intend otherwise to respond to those questions. Each question bears on the need for the LCFS regulation, the costs and benefits of the LCFS regulation, or the legal authority that would limit the analysis of regulatory

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

[21] *See* note 19 above.

alternatives. If the CARB staff does not believe that one or more of the above questions are relevant to the evaluation of regulatory alternatives, Growth Energy requests that the CARB staff explain why, with respect to each such question.

III. Regulatory Alternatives

The CARB regulations adopted since 2009 and the federal RFS program adequately provide for full control of the direct GHG emissions from the California vehicle fleet that the LCFS regulation may have been intended to control. In 2009, CARB claimed that the LCFS regulation would provide additional GHG reductions on a lifecycle basis; the "upstream" component of the GHG benefits attributed to the LCFS regulation in 2009 was 7 MMTCO2eq in 2020.[22]

Putting to one side the question whether CARB has legal authority to adopt and enforce a regulation to control GHG emissions occurring outside California, there are several reasons to question whether the LCFS regulation actually achieves any reduction in upstream emissions. As CARB has recognized, the LCFS regulation has to date caused "fuel shuffling" -- ethanol that might have been sold in California prior to the LCFS regulation is still being produced, and is sold somewhere else.[23] Ethanol production processes and pathways that have putatively higher upstream emissions have, at this point, neither terminated nor curtailed operations as a result of the LCFS regulation.[24] In addition, many Midwest corn ethanol biorefineries have qualified for

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

22 *See* ISOR at VII-1.

23 *See* FSOR at 477 ("Without the wider adoption of fuel carbon-intensity standards, fuel producers are free to ship lower-carbon-intensity fuels to areas with such standards, while shipping higher-carbon-intensity fuels elsewhere. The end result of this fuel 'shuffling' process is little or no net change in fuel carbon-intensity on a global scale.") The "wider adoption" of LCFS-type standards to which CARB referred in the 2009 FSOR has not occurred.

24 That is not to say, however, that the LCFS regulation is not injurious to the national market in ethanol, nor neutral in its impact on lifecycle GHG emissions. By causing fuel shuffling, the LCFS regulation disrupts the national market in ethanol, imposes costs, and increases transportation-related GHG emissions. Eventually, by effectively banning Midwest corn ethanol from California (if, for example, the LCFS for 2015 established in

lower-carbon-intensity LCFS "pathways" since 2009, on a scale that the CARB staff has admitted was "not expected in 2009."[25] Moreover, the estimates of upstream emissions attributed to Midwest corn ethanol in 2009 were grossly inflated: no one, including CARB, is still prepared to defend the indirect land-use change emissions factors accepted by CARB in 2009, and the current literature demonstrates that the "science" of indirect land-use change is too unreliable to be used as a basis for regulation.[26]

To the extent there is any remaining basis for attributing upstream GHG emissions reduction benefits to the LCFS regulation, those benefits certainly do not warrant the continuation or re-adoption of the LCFS regulation. The more efficient approach would be to adjust the cap-and-trade regulation in Title 17 of the *California Code of Regulations* to account for whatever increment of GHG emissions reductions would be forgone by eliminating the LCFS regulation.[27] To the extent necessary, modifications to the cap-and-trade regulation would be

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

2009 were to be enforced), the LCFS regulation will leave California with no commercially viable method of complying with the standard; the staff appears to recognize this problem to some extent, with the currently ill-defined "cost reduction" features that it plans to propose. *See* Air Resources Board, *Low Carbon Fuel Standard Re-Adoption Concept Paper* (March 2014) at 6-7. The reduction in nationwide demand for Midwest corn ethanol will then also impose serious economic harm on the Midwest ethanol industry.

25 *See* 2011 Program Review at 169. The Midwest ethanol production facilities that have qualified for lower-carbon-intensity LCFS pathways have not done so through modifications in their production processes intended to obtain those special LCFS pathways: they have a competitive incentive to increase efficiency, and would have done increased their efficiency in the absence of the LCFS regulation. A Growth Energy member has demonstrated this point in the ongoing *Rocky Mountain* litigation involving some aspects of the LCFS regulation. *See* Declaration of Erin Heupel, P.E. (included here as Attachment 6) ¶¶ 5-6. Notably, in the *Rocky Mountain* litigation, CARB offered no competent evidence to the contrary. As Ms. Heupel also demonstrated, the specific features of the LCFS regulation will eventually force even the highest-efficiency Midwest corn production facilities out of the California market. *See id.* ¶¶ 9-11.

26 The CARB staff has begun to revise and to reduce the indirect land-use change emission factors that were included in the 2009 LCFS regulation. *See* letter from G. Cooper to K. Sideco, April 9, 2014, available at http://www.arb.ca.gov/fuels/lcfs/regamend14/rfa_04092014.pdf. It remains Growth Energy's position that the modeling methods used by CARB to generate indirect land-use change values are too unreliable for use in a regulation intended to comply with AB 32. *See* Letter from D. Bearden to J. Goldstene, May 10, 2010 (included here as Attachment 4).

27 In 2009, CARB received substantial comments on the relative inefficiency of the LCFS approach from one of its independent peer reviewers, who urged that CARB consider a cap-and-trade alternative. *See*, e.g., FSOR at 24 (review by Dr. John Reilly); *see also id.* (summarizing Dr. Reilly's review as stating, "The economic analysis

simple and straightforward. Initially, CARB should determine what, if any, upstream GHG reductions should be attributable to the LCFS regulation, using a scientifically reliable process. CARB would also need an appropriate estimate of the total GHG emissions expected from the use of gasoline and diesel fuel in 2020. A CARB emissions forecast prepared in 2010[28] indicates that total GHG emissions from gasoline and diesel fuel use in California are expected to be approximately 175 million metric tons in 2020 under business as usual conditions. Assuming that the generally required 22 percent reduction in emissions in 2020 under the cap-and-trade program[29] applies to gasoline and diesel fuel use, total 2020 emissions without the LCFS program would be about 135 million metric tons.

Continuing the analysis, and by way of example, suppose that the cap-and-trade regulation had to cover the entire annual 16 MMTCO2eq of GHG emissions that the CARB staff identified as the benefit of the LCFS regulation for 2020. That level of GHG control could be achieved by amending the cap-and-trade regulations to require providers of gasoline and diesel fuel to submit 151 (135+16) million metric tons of allowances – or in other words requiring gasoline and diesel fuel suppliers to surrender 1.11 (151/136) allowances for every ton of GHG emissions they report from the fuels they supply.[30]

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

[for the LCFS regulation] was done incorrectly. It does not meet [the] technical standards of economics. The baseline assumptions are mutually inconsistent, and if these assumptions were executed in a proper model it would show that the LCS was unnecessary.") CARB stated in 2009 that it would consider the role of cap-and-trade further in addressing the objectives of the LCFS program once the cap-and-trade regulations were completed. *See* FSOR at 452.

28 *See* Air Resources Board, "California GHG Emissions -- Forecast 2008-2020 (updated Oct. 28, 2010), available at http://www.arb.ca.gov/cc/inventory/data/tables/2020_ghg_emissions_forecast_2010-10-28.pdf

29 This is based on the general percentage reduction requirements established by CARB for total allowances issued. *See* Air Resources Board, "Overview of ARB Emissions Trading Program (October 2011), available at http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf

30 The cap-and-trade regulation already begins to take effect for the gasoline and diesel fuel marketing sector in 2015.

The modifications to the existing text of the cap-and-trade regulation would be minor and limited to section 95852(d) of the regulation.[31] Further, the CARB staff at its discretion could also create a compliance offset program in order to incentivize low- carbon intensity fuels similar to those in place which incentivize other innovative GHG reduction strategies.[32] Insofar as one goal of the APA is to eliminate unnecessary regulation, this approach would well-serve the goals

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

---

[31] Thus, the text of section 95852(d), with the modification shown in italics, and assuming that the full 10 percent GHG emission reduction attributed to the LCFS regulation would be covered by cap-and-trade, would provide as follows:

> Suppliers of RBOB and Distillate Fuel Oils. A supplier of petroleum products covered under sections 95811(d) or 95812(d) has a compliance obligation *equal to 1.x allowances* for every metric ton CO_2e of GHG emissions included in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned that would result from full combustion or oxidation of the quantities of the following fuels that are removed from the rack in California, sold to entities not licensed by the California Board of Equalization as a fuel supplier, or imported into California and not directly delivered to the bulk-transfer/terminal system as defined in section 95102 of MRR, except for products for which a final destination outside California can be demonstrated:

(1) RBOB;
(2) Distillate Fuel Oil No. 1; and
(3) Distillate Fuel Oil No. 2.

> *The value of "x" above will be established by Executive Officer by the prior October 31 for each year beginning with 2015 to ensure that actual GHG emissions from the use of RBOB and Distillate Fuel Oil No. 1 and Distillate Fuel Oil No. 2 are reduced to the level that would have been achieved had the Carbon Intensity of those fuels been reduced according to the following schedule relative to 2010.*

Required Carbon Intensity Reduction Relative to 2010	
Year	Reduction
2015	2.7%
2016	3.7%
2017	5.2%
2018	6.7%
2019	8.2%
2020	10.0%

As illustrated above for 2020, the value of "x" would be 0.11 and the compliance obligation for suppliers of gasoline and diesel fuels would be 1.11 times the number of tons of CO_2e emissions reported.

[32] *See* Air Resources Board, "Climate Change Programs -- Compliance Offset Program" (updated June 11, 2014), available at http://www.arb.ca.gov/cc/capandtrade/offsets/offsets.htm

of the APA. By eliminating the LCFS regulation, CARB would also free the California transportation fuel sector from continuing uncertainty about the availability and cost of ultra-low-carbon-intensity alternative fuels necessary for future compliance with the LCFS. As the Western States Petroleum Association ("WSPA") has stated:

> The LCFS, as envisioned by Governor Schwarzenegger in his Executive Order and as developed by the ARB, is infeasible. ... [S]taying the course now could result in disruptions in the transportation fuels markets. ... A successful fuels policy must protect against fuel supply disruptions, severe job losses in the state's refining industry and unacceptable economic harm to California and its citizens.[33]

While Growth Energy believes that its proposal has sufficient merit without endorsement by other organizations, the concerns expressed by WSPA are important. One benefit of the change that Growth Energy is proposing, and a benefit that is particularly important to Growth Energy and the enterprises it represents, is that elimination of the LCFS regulation would eliminate a major conflict between regulations adopted by California and the federal RFS program, a conflict that will only increase if the LCFS regulation is re-adopted.

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

In considering Growth Energy's proposal, and in addition to the questions presented in Part II of this submittal, the CARB staff should in the SRIA address the following questions:

- The CARB staff's May 23, 2014, notice soliciting public input for the SRIA sought "alternative LCFS approaches." (See Attachment 5.) Does the CARB staff believe the alternatives analysis for the SRIA and public submittals related to the SRIA must be confined to regulatory alternatives that include or would preserve in some form the LCFS regulation? If so, what is the basis for such a limitation?

- Other than emissions created in generating electricity for delivery in California, does AB 32 give CARB the authority to regulate upstream emissions occurring outside California, or to account for upstream emissions occurring outside

[33] The reference is to Executive Order S-01-07, with its "10 percent" by 2020 goal, which according to the CARB staff remains the target for the LCFS regulation. *See* Letter from G. Grey to K. Sideco, June 13, 2014 at 2, available at http://www.arb.ca.gov/fuels/lcfs/regamend14/wspa_06132014.pdf. WSPA has also stated that modification of the LCFS program through "cost reduction" provisions would "simply penalize fuel suppliers for not meeting an infeasible standard." *See* Letter from C. Reheis-Boyd to K. Sideco, April 11, 2014 at 10, available at http://www.arb.ca.gov/fuels/lcfs/regamend14/wspa_04112014.pdf.

California in adopting regulations to meet the statewide greenhouse gas emissions limit? (*See* Cal. Health & Safety Code § 38505(m), (n); 38562(a).) If AB 32 authorizes CARB to regulate or consider out-of-state GHG emissions attributed to ethanol production, does AB 32 also authorize CARB to address those emissions through the cap-and-trade regulation?

- Can the California cap-and-trade regulations be modified to provide the same numerical reductions in GHG emissions as the LCFS regulation? If not, why not?

- If the CARB staff is concerned that the state measures to control GHG emissions and the federal RFS program might not be fully implemented and enforced at some time in the future, would adoption of a revised LCFS regulation as a "backstop" measure, to be implemented only if those other programs are not meeting defined objectives, address that concern? If not, why not?

- If the CARB staff believes some regulated parties might prefer to comply with a revised LCFS regulation rather than a modified cap-and-trade regulation, could that issue be addressed by including a revised LCFS as a part of a regulatory alternative (with appropriate opt-in provisions) that would be an option for parties that did not wish to comply with a modified cap-and-trade regulation?

- What are the current and expected future levels of resources at CARB, in terms of personnel and other resources, that are allocated to the LCFS regulation? What would be the budgetary impact for CARB if the LCFS program were eliminated? What would be the budgetary impact for CARB caused by the change in the cap-and-trade regulation proposed here?

- To the extent the CARB staff would attribute other beneficial impacts, different from GHG emissions reductions, to the LCFS regulation, to whom do those benefits accrue? With regard to those other beneficial impacts, are California consumers benefitted and, if so, how and to what extent? With regard to those other beneficial impacts, are California businesses benefitted and if so, how and to what extent? Do those other beneficial impacts justify or support continuation of the LCFS regulation, and if so, what is the basis for CARB's authority to adopt and enforce the LCFS regulation to obtain those benefits? If those other beneficial impacts include the possibility that sources for alternative fuels will be increased or diversified, are there any peer-reviewed or other studies that support such a proposition? If not, what is the staff's basis for attributing such benefits to the LCFS regulation? Could those benefits be realized through the development of a compliance offset program under the cap-and-trade regulation?

As with the questions presented in Part II, the CARB staff's responses to these questions are important in understanding its evaluation of Growth Energy's proposal. If the CARB staff does not believe that one or more of the above questions are relevant to the evaluation of

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

regulatory alternatives, Growth Energy requests that the CARB staff explain why, with respect to each such question.

IV. Next Steps

As noted at the outset of this submittal, Growth Energy's analysis of alternatives to the LCFS regulation can be no more detailed than the available information about the staff's intended revised LCFS regulation. If CARB does nothing further to facilitate the public input into the SB 617 process for use in the SRIA, it will not have substantially complied with the APA as amended by SB 617 and implemented in the Department's regulations.

In the CARB staff's first notice that it was ready to receive public input on regulatory alternatives, published on May 23, 2014, the staff set a deadline for that input of June 6, 2014 -- nine business days later. The staff indicated in that notice that the public should, among other things, "submit the quantities of low-CI fuels used each year" in the proposed alternative to the LCFS regulation, "as well as the associated cost and benefit information, and their sources." [34] According to the May 23 notice, that information was needed "to enable comparison of economic impacts."[35] The May 23 notice stated that the objective for public input should be to provide "alternative LCFS approaches," meaning "any approach that may yield the same or greater benefits than those associated with the proposed regulation, or that may achieve the goals at lower cost."[36]

The "proposed regulation" to which the May 23 proposal referred (i) had not been provided to the public for review as of May 23, nor (ii) has it been provided at any time since

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

[34] *See* Attachment 5.

[35] *Id.*

[36] *Id.*

May 23.[37] The May 23 notice was not accompanied by any information that provided the CARB staff's own prediction of "the quantities of low-CI fuels [that would be] used each year" under the CARB staff's proposed regulation, nor the benefits that the CARB staff attributed to the LCFS regulation. Growth Energy requested that the CARB staff give the public the information needed to prepare a complete SB 617 submission and requested that the public be given additional time to prepare SB 617 analyses after the necessary information was released.[38]

The CARB staff responded by extending the deadline for public submittals that would be addressed in the SRIA to June 23, 2014 (31 days after the May 23 notice), but did not provide any of the information requested by Growth Energy and needed to provide the type of input sought in the May 23 notice, and necessary under the Department's SB 617 regulations. Instead, the staff referred to the GHG emissions reductions targeted in the 2009 rulemaking, to a March 2014 "Concept Paper" that discussed the staff's approach to revision of the LCFS regulation, and to material provided to the public in connection with regulatory workshops held in ARB's offices.[39] The March 2014 Concept Paper raises more questions about the staff's approach than it answers: it included, for example, a general description of two different "cost reduction" concepts without indicating how either of them would work, how they would reduce costs, or how they would affect the GHG emissions reduction benefits of the LCFS program. If the March 2014 Concept Paper provided a basis for preparing SB 617 submittals, then there is no reason why the CARB staff should have waited until May 23 to solicit public input under the Department's regulations. Had the staff informed the public when it released the Concept Paper

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

---

[37] The CARB staff has released some draft regulatory text for their proposed revised LCFS, but that partial text does not include, for example, the "cost reduction" feature intended for the new regulation, nor the carbon intensity values to be assigned to each alternative fuel.

[38] *See* Attachment 1.

[39] *See* Attachment 2.

and discussed the Concept Paper at one of its March 2014 regulatory workshops that the Concept Paper was intended to provide a basis for SB 617 input, Growth Energy (and perhaps other stakeholders) would have pointed out at that time that the Concept Paper was inadequate for that purpose; in that event, perhaps the CARB staff would have been able to provide the necessary information for public input into the SRIA.

The materials provided in connection with the regulatory workshops -- including the partial regulatory text released on May 28, after the staff had launched the public input process -- likewise do not provide the necessary information for detailed public submittals consistent with SB 617 and the Department's regulations. Growth Energy has studied those materials carefully, and with the greatest respect, would challenge the CARB staff to indicate where in those materials the staff identifies GHG emissions reduction targets for a revised LCFS regulation; where the staff identifies any other putative benefits of the LCFS regulation; and where in those materials the staff provides specific and concrete information about the impact of the "cost reduction" concepts on the quantities of alternative fuels that would be used in order to comply with the revised LCFS regulation, or permits a quantification of costs and benefits of a revised LCFS regulation that includes a cost-reduction feature.

Finally, it is important to address comments by the CARB staff at one recent workshop, which suggested that the timing of the current regulatory effort has been affected by the Board's need to comply with the mandate in litigation under the APA and the California Environmental Quality Act ("CEQA").[40] In that litigation, the Superior Court has allowed CARB all the time

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

[40] The case is *POET LLC et al. v. California Air Resources Board*, Case No. 09 CE CG 04659 (Sup'r Ct., Fresno County). The Writ of Mandate in that proceeding does not require CARB to commence or conclude rulemaking by a particular date, but to proceed in good faith without delay. The Writ of Mandate was issued more than six months ago, by which time CARB presumably knew that it had to comply with the Department's SB 617 regulations.

that the Board has requested in order to comply with the mandate. If CARB needs more time in order to conduct the SB 617 process in a manner that allows sufficient time for effective public input into the preparation of an SRIA, CARB should so inform the Superior Court. (Notably, in its filings with the Superior Court, CARB has not adverted to SB 617 or the Department's implementing regulations.) In addition, the CARB staff would surely agree that even before issuance of the mandate in that litigation, it was aware that it had major program review obligations for the LCFS regulation in 2014.[41] Particularly in light of those program review obligations, the CARB staff's inability to provide more information now to the public, needed to participate fully in the SB 617 process, seems inexcusable.

Against that backdrop, Growth Energy urges the CARB staff to reconsider its present approach to the SB 617 process, and specifically the staff's approach to obtaining public input for the SRIA. As the staff might expect, if one response to Growth Energy's proposed regulatory

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

---

[41] In 2009, when it first adopted the LCFS regulation, the Board directed the CARB staff to conduct and to present by January 1, 2015 a "review of implementation of the LCFS program" that was to "include, at a minimum, consideration of the following areas:

"(1) The LCFS program's progress against LCFS targets;
"(2) Adjustments to the compliance schedule, if needed;
"(3) Advances in full, fuel-lifecycle assessments;
"(4) Advances in fuels and production technologies, including the feasibility and cost-effectiveness of such advances;
"(5) The availability and use of ultralow carbon fuels to achieve the LCFS standards and advisability of establishing additional mechanisms to incentivize higher volumes of these fuels to be used;
"(6) An assessment of supply availabilities and the rates of commercialization of fuels and vehicles;
"(7) The LCFS program's impact on the State's fuel supplies;
"(8) The LCFS program's impact on state revenues, consumers, and economic growth;
. . .
"(12) Significant economic issues; fuel adequacy, reliability, and supply issues; and environmental issues that have arisen; and
"(13) The advisability of harmonizing with international, federal, regional, and state LCFS and lifecycle assessments."

17 C.C.R. § 95489(a).

alternative is that Growth Energy's proposal lacks a detailed comparison with the costs, benefits, and cost-effectiveness of the staff's proposal in the SRIA, Growth Energy will attribute its lack of specificity to the staff's failure to provide the information needed to offer a more specific regulatory analysis. Because this is one of the first major rulemakings at CARB that is required to comply with SB 617 and the Department's SB 617 regulations, it is also important for the Department to take a proactive role in providing guidance to CARB, the stakeholders, and other members of the public interested in the LCFS program.

Reproduction of Pages 191 - 218 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-195 through LCFS 46-232

Respectfully submitted,

GROWTH ENERGY

12_B_LCFS_GE Responses (Page 377 – 404)

732. Comment: **Response to Request for Public Input on Alternatives to the Low Carbon Fuel Standard Regulation June 23, 2014**

Agency Response: This is the second time this document was submitted by Growth Energy. It is a reproduction of comments **LCFS 46-195** through **LCFS 46-232**. See responses to these comments above.

This page intentionally left blank.

NOx Emissions Impact of Soy- and Animal-based Biodiesel Fuels: A Re-Analysis

December 10, 2013

Prepared for:

Sierra Research
1801 J Street
Sacramento, CA 95811

Prepared by:

Robert Crawford
Rincon Ranch Consulting
2853 South Quail Trail
Tucson, AZ 85730-5627
Tel 520-546-1490

NOX EMISSIONS IMPACT OF SOY- AND ANIMAL-BASED BIODIESEL FUELS: A RE-ANALYSIS

prepared for:

Sierra Research, Inc.

December 10, 2013

prepared by:

Robert Crawford
Rincon Ranch Consulting
2853 South Quail Trail
Tucson, AZ 85730-5627
Tel 520-546-1490

NOX IMPACT OF SOY- AND ANIMAL-BASED BIODIESEL FUELS: A RE-ANALYSIS

Table of Contents

List of Tables

List of Figures

1. EXECUTIVE SUMMARY

1.1 Background on the Proposed Rule

The California Air Resources Board (CARB) has proposed regulations on the commercialization of alternative diesel fuel (ADF) that were to be heard at the December 2013 meeting of the Board. The proposed regulations seek to "... create a streamlined legal framework that protects California's residents and environment while allowing innovative ADFs to enter the commercial market as efficiently is possible."[1] In this context ADF refers to biodiesel fuel blends. Biodiesel fuels are generally recognized to have the potential to decrease emissions of several pollutants, including hydrocarbons (HC), carbon monoxide (CO), and particulate matter (PM), but are also recognized to have the potential to increase oxides of nitrogen (NOx) unless mitigated in some way. NOx emissions are an important precursor to smog and have historically been subject to stringent emission standards and mitigation programs to prevent growth in emissions over time. A crucial issue with respect to biodiesel is how to "... safeguard against potential increases in oxides of nitrogen (NOx) emissions."[2]

The proposed regulations are presented in the Staff Report: Initial Statement of Reasons (ISOR) for the Proposed Regulation on the Commercialization of New Alternative Diesel Fuels[3] (referenced as ISOR). Chapter 5 of the document describes the proposed regulations, which exempt diesel blends with less than 10 percent biodiesel (B10) from requirements to mitigate NOx emissions:

> There are two distinct blend levels relative to biodiesel that have been identified as important for this analysis. Based on our analysis to date, we have found that diesel blends with less than 10 percent biodiesel by volume (<B10) have no significant increase in any of the pollutants of concern and therefore will be regulated at Stage 3B (Commercial Sales not Subject to Mitigation). However, we have found that biodiesel blends of 10 percent and above (≥B10) have potentially significant increases in NOx emissions, in the absence of any mitigating factors, and therefore those higher blend levels will be regulated under Stage 3A (Commercial Sales Subject to Mitigation).[4]

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

[1] "Notice of Public Hearing to Consider Proposed Regulation on the Commercialization of New Alternative Diesel Fuels." California Air Resources Board, p. 3. http://www.arb.ca.gov/regact/2013/adf2013/adf2013notice.pdf

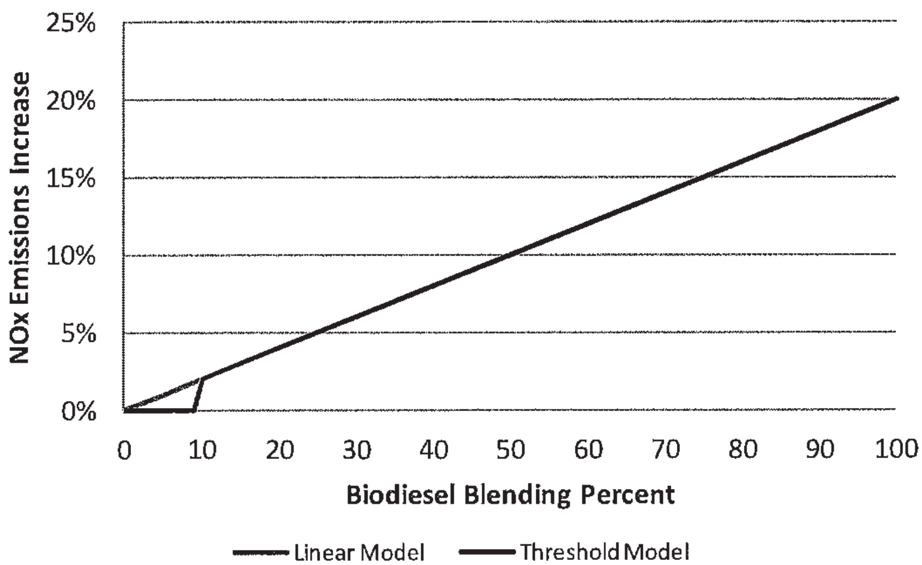
[2] Ibid. p. 3.

[3] "Proposed Regulation on the Commercialization of New Alternative Diesel Fuels. Staff Report: Initial Statement of Reason." California Air Resources Board, Stationary Source Division, Alternative Fuels Branch. October 23, 2013. http://www.arb.ca.gov/regact/2013/adf2013/adf2013isor.pdf

[4] Ibid, p. 22.

Existing research on the NOx emission effects of biodiesel has consistently been conducted under the hypothesis that the emission effect will be linearly proportional to the blending percent of neat biodiesel (B100) with the base diesel fuel. The Linear Model that has been accepted by researchers is shown as the blue line in Figure 1-1. The Staff position cited above is that biodiesel fuels do not increase NOx emissions until the fuel blend reaches 10% biodiesel. This so-called Staff Threshold Model departs from the Linear Model that underlies past and current biodiesel research by claiming that NOx emissions do not increase until the biodiesel content reaches 10 percent.

Figure 1-1
Linear and Staff Threshold Models for Biodiesel NOx Impacts



Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

The Staff Threshold model is justified by the statement: "Based on our analysis to date, we have found that diesel blends with less than 10 percent biodiesel by volume (<B10) have no significant increase in any of the pollutants of concern." Other portions of the ISOR state that Staff will track "... the effective blend level on an annual statewide average basis until the effective blend level reaches 9.5 percent. At that point, the biodiesel producers, importers, blenders, and other suppliers are put on notice that the effective blend-level trigger of 9.5 percent is approaching and mitigation measures will be required once the trigger is reached."[5] Until such time, NOx emission increases from biodiesel blends below B10 will not require mitigation.

Section 6 of the ISOR presents a Technology Assessment that includes a literature search the Staff conducted to obtain past studies on the NOx impact of biodiesel in heavy-duty

[5] Ibid, p. 24.

engines using California diesel (or other high-cetane diesel) as a base fuel. Section 6.d presents the results of the literature search with additional technical information provided in Appendix B. The past studies include the Biodiesel Characterization and NOx Mitigation Study[6] sponsored by CARB (referenced as Durbin 2011).

The results of the Staff literature search are summarized in Table 1-1, which has been reproduced from Table 6.1 of the ISOR. For B5 and B20, the data represent averages for a mix of soy- and animal-based biodiesels, which tend to have different impacts on NOx emissions (animal-based biodiesels increase NOx to a lesser extent). For B10, the data represent an average for soy-based biodiesels only. Staff uses the +0.3% average NOx increase at B5 in comparison to the 1.3% standard deviation to conclude:

> Overall, the testing indicates different NOx impacts at different biodiesel percentages. Staff analysis shows there is a wide statistical variance in NOx emissions at biodiesel levels of B5, providing no demonstrable NOx emissions impact at this level and below. At biodiesel levels of B10 and above, multiple studies demonstrate statistically significant NOx increases, without additional mitigation.[7]

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

Table 1-1
Results of Literature Search Analysis

Biodiesel Blend Level	NOx Difference	Standard Deviation
B5	0.3%	1.3%
B10[a]	2.7%	0.2%
B20	3.2%	2.3%

Source: Table 6.1 of Durbin 2011
Notes:
[a] Represents data using biodiesel from soy feedstocks.

<u>The Staff conclusion is erroneous because it relies upon an apples-to-oranges comparison among the blending levels</u>. Each of the B5, B10, and B20 levels include data from a different mix of studies, involving different fuels (soy- and/or animal-based), different test engines, and different test cycles. The B5 values come solely from the CARB Biodiesel Characterization study, while the B10 values come solely from other studies. The B20 values are a mix of data from the CARB and other studies. The results seen in the table above are the product of the uncontrolled aggregation of different studies that produces incomparable estimates of the NOx emission impact at the three blending levels.

[6] "CARB Assessment of the Emissions from the Use of Biodiesel as a Motor Vehicle Fuel in California: Biodiesel Characterization and NOx Mitigation Study." Prepared by Thomas D. Durbin, J. Wayne Miller and others. Prepared for Robert Okamoto and Alexander Mitchell, California Air Resources Board. October 2011.
[7] ISOR, p. 32.

As will be demonstrated in this report, the Staff conclusion drawn from the data in Table 1-1 is not supported by past or current biodiesel research, including the recent testing program sponsored by CARB. In fact, past and current studies indicate that biodiesel blends at any level will increase NOx emissions in proportion to the blending percent unless specifically mitigated by additives or other measures.

1.2 Summary and Conclusions

The following sections of this report examine the studies cited by CARB one-by-one. As evidenced from this review, it is clear that the data do not support the Staff conclusion and, indeed, the data refute the Staff conclusion in some instances. Specifically:

- There is no evidence supporting the Staff conclusion that NOx emissions do not increase until the B10 level is reached. Instead, there is consistent and strong evidence that biodiesel increases NOx emissions in proportion to the biodiesel blending percent.

- There is clear and statistically significant evidence that biodiesel increases NOx emissions at the B5 level in at least some engines for both soy- and animal-based biodiesels.

Considering each of the six past studies obtained from the technical literature and their data on high-cetane biodiesels comparable to California fuels, we find the following:

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

1. None of the six studies measured the NOx emissions impact from biodiesel at blending levels below B10. Only two studies tested a fuel at the B10 level. All other testing was at the B20 level or higher. Because none tested a B5 (or similar) fuel, none of them can provide direct evidence that NOx emissions are not increased at B5 or other blending levels below B10.

2. These studies provide no data or evidence supporting the validity of the Staff's Threshold Model that biodiesel below B10 does not increase NOx emissions. In fact, all of the studies are consistent with the contention that biodiesel increases NOx emissions in proportion to the blending percent.

3. Two of the studies present evidence and arguments that the NOx impact from biodiesel is a continuous effect that is present even at very low blending levels and will increase at higher levels in proportion to the blending percentage.

Considering the CARB Biodiesel Characterization report, we find that:

4. For the three engines where CARB has published the emission values measured in engine dynamometer testing, all of the data demonstrate that biodiesel fuels significantly increase NOx emissions for both soy- and animal-based fuels by amounts that are proportional to the blending percent. This is true for on-road and off-road engines and for a range of test cycles.

5. Where B5 fuels were tested for these engines, NOx emissions were observed to increase. NOx emission increases are smaller at B5 than at higher blending levels and the observed increases for two engines were not statistically significant by themselves based on the pair-wise t-test employed in Durbin 2011.[8] However, the testing for one of the engines (the 2007 MBE4000) showed statistically significant NOx emission increases at the B5 level for both soy- and animal-based blends.

By itself, the latter result is sufficient to disprove the Staff's contention that biodiesel blends at the B5 level will not increase NOx emissions.

Based on examination of all of the studies cited by CARB as the basis for its proposal to exempt biodiesels below B10 from mitigation, it is clear that the available research points to the expectation that both soy- and animal-based biodiesel blends will increase NOx emissions in proportion to their biodiesel content, including at the B5 level. CARB's own test data demonstrate that B5 will significantly increase NOx emissions in at least some engines.

Based on data in the CARB Biodiesel Characterization report, soy-based biodiesels will increase NOx emissions by about 1% at B5 (and 2% at B10), while animal-based biodiesels will increase NOx emissions by about one-half as much: 0.45% at B5 (and 0.9% at B10). All of the available research says that the NOx increases are real and implementation of mitigation measures will be required to prevent increases in NOx emissions due to biodiesel use at blending levels below B10.

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

Finally, we note that CARB has not published fully the biodiesel testing data that it relied on in support of the Proposed Rule and thereby has failed to adequately serve the interest of full public disclosure in this matter. The CARB-sponsored testing reported in Durbin 2011 is the sole source of B5 testing cited by CARB as support for the Proposed Rule. Durbin 2011 publishes only portions of the measured emissions data in a form that permits re-analysis; it does not publish any of the B5 data in such a form. It has not been possible to obtain the remaining data through a personal request to Durbin or an official public records request to CARB and, to the best of our knowledge, the data are not otherwise available online or through another source.

CARB should publish all of the testing presented in Durbin 2011 and any future testing that it sponsors in a complete format that allows for re-analysis. Such a format would be (a) the measured emission values for each individual test replication; or (b) averages across all test replications, along with the number of replications and the standard error of the individual tests. The first format (individual test replications) is preferable because that would permit a full examination of the data including effects such as test cell drift over time. Such publication is necessary to assure that full public disclosure is achieved and that future proposed rules are fully and adequately informed by the data.

---

[8]As discussed in Section 3.3, the pair-wise t-test is not the preferred method for demonstrating statistical significance.

1.3 Review of 2013 CARB B5 Emission Testing

In December 2013, after the release of the ISOR and in response to an earlier Public Records Act request, CARB released a copy of new CARB-sponsored emission testing conducted by Durbin and others at the University of California CE-CERT[9]. The purpose of the study was "... to evaluate different B5 blends as potential emissions equivalent biodiesel fuel formulations for California."[10] Three B5 blends derived from soy, waste vegetable oil (WVO), and animal biodiesel stocks were tested on one 2006 Cummins ISM 370 engine using the hot-start EPA heavy-duty engine dynamometer cycle. A preliminary round of testing was conducted for all three fuels followed by emissions-equivalent certification testing per 13 CCR 2282(g) for two of the fuels. As noted by Durbin: "[t]he emissions equivalent diesel certification procedure is robust in that it requires at least twenty replicate tests on the reference and candidate fuels, providing the ability to differentiate small differences in emissions."[11]

Soy and WVO B5 Biodiesel

The B5-soy and B5-WVO fuels were blended from biodiesel stocks that were generally similar to the soy-based stock used in the earlier CARB Biodiesel Characterization Study (Durbin 2011) with respect to API gravity and cetane number. In the preliminary testing, the two fuels "...showed 1.2-1.3% statistically significant [NOx emissions] increases with the B5-soy and B5-WVO biodiesel blends compared to the CARB reference fuel."[12] The B5-WVO fuel caused the smaller NOx increase (1.2%) and was selected for the certification phase of the testing. There, it "... showed a statistically significant 1.0% increase in NOx compared to the CARB reference fuel"[13] and failed the emissions-equivalent certification due to NOx emissions.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Animal B5 Biodiesel

The B5-animal derived fuel was blended from an animal tallow derived biodiesel that was substantially different from the animal based biodiesel used in the earlier Durbin study, and was higher in both API gravity and cetane number. The blending response for cetane number was also surprising, in that blending 5 percent by volume of a B100 stock (cetane number 61.1) with 95% of CARB ULSD (cetane number 53.1) produced a B5 fuel blend with cetane number 61.

In preliminary testing, the B5-animal fuel showed a small NOx increase which was not statistically significant, causing it to be judged the best candidate for emissions-equivalent certification. In the certification testing, it "...showed a statistically

---

[9] "CARBB5 Biodiesel Preliminary and Certification Testing." Prepared by Thomas D. Durbin, G. Karavalakis and others. Prepared for Alexander Mitchell, California Air Resources Board. July 2013. This study is not referenced in the ISOR, nor was it included in the rule making file when the hearing notice for the ADF regulation was published in October 2013.

[10] Ibid, p. vi.

[11] Ibid, p. viii.

[12] Ibid, p. 8.

[13] Ibid, p. 9.

significant 0.5% reduction in NOx compared to the CARB reference fuel"[13] and passed the emissions-equivalent certification. The NOx emission reduction for this fuel blend appears to be real for this engine, but given the differences between the blendstock and the animal based biodiesel blendstock used in the earlier Durbin study it is unclear that it is representative for animal-based biodiesels in general..

Summary

The conclusions drawn in the preceding section are not changed by the consideration of these new emission testing results. For plant-based biodiesels (soy- and WVO-based), the new testing provides additional and statistically significant evidence that B5 blends will increase NOx emissions at the B5 level. The result of decreased NOx for the B5 animal-based blend stands out from the general trend of research results reviewed in this report. However:

- The same result – reduced NOx emissions for some fuels and engines – has sometimes been observed in past research, as evidenced by the emissions data considered by CARB staff in ISOR Figure B.3 (reproduced in Figure 2.1 below). As shown, some animal-based B5 and B20 fuels reduced NOx emissions while others increased NOx emissions with the overall conclusion being that NOx emissions increase in direct proportion to biodiesel content of the blends and that there is no emissions threshold.

- Increasing cetane is known to generally reduce NOx emissions and has already been proposed by CARB as a mitigation strategy for increased NOx emissions from biodiesel[14]. The unusual cetane number response in the blending and the high cetane number of the B5-animal fuel may account for the results presented in the recently released study.

Considering the broad range of plant- and animal-based biodiesel stocks that will be used in biodiesel fuels, we conclude that the available research (including the recently released CARB test results) indicates that unrestricted biodiesel use at the B5 level will cause real increases in NOx emissions and that countermeasures may be required to prevent increases in NOx emissions due to biodiesel use at blending levels below B10.

###

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

[14] For example, see Durbin 2011 Section 7.0 for a discussion of NOx mitigation results through blending of cetane improvers and other measures.

2. CARB LITERATURE REVIEW

The Staff ISOR explains that the Appendix B Technology Assessment is the basis for CARB's conclusion that biodiesels below B10 have no significant impact on NOx emissions. The assessment is based on data from seven studies (identified in Table 2-1) that tested high-cetane diesel fuels. The first study (Durbin 2011) is the Biodiesel Characterization Study that was conducted for CARB, while the others were obtained through a literature search.

Table 2-1
List of Studies from High-Cetane Literature Search

Primary Author	Title	Published	Year
Durbin	Biodiesel Mitigation Study	Final Report Prepared for Robert Okamoto, M.S. and Alexander Mitchell, CARB	2011
Clark	Transient Emissions Comparisons of Alternative Compression Ignition Fuel	SAE 1999-01-1117	1999
Eckerle	Effects of Methyl Ester Biodiesel Blends on NOx Emissions	SAE 2008-01-0078	2008
McCormick	Fuel Additive and Blending Approaches to Reducing NOx Emissions from Biodiesel	SAE 2002-01-1658	2002
McCormick	Regulated Emissions from Biodiesel Tested in Heavy-Duty Engines Meeting 2004 Emissions	SAE 2005-01-2200	2005
Nuszkowski	Evaluation of the NOx emissions from heavy duty diesel engines with the addition of cetane improvers	Proc. I Mech E Vol. 223 Part D: J. Automobile Engineering, 223, 1049-1060	2009
Thompson	Neat fuel influence on biodiesel blend emissions	Int J Engine Res Vol. 11, 61-77.	2010

Source: Table B.2 of Durbin 2011

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Figure 2-1 reproduces two exhibits from Appendix B that show increasing trends for NOx emissions with the biodiesel blending level. Based on the slopes of the trend lines,

Figure 2-1
NOx Emission Increases Observed in Biodiesel Research Cited in Staff ISOR

Figure B.2: NOx Impact of Soy Biodiesel Blended in High Cetane Base Fuel

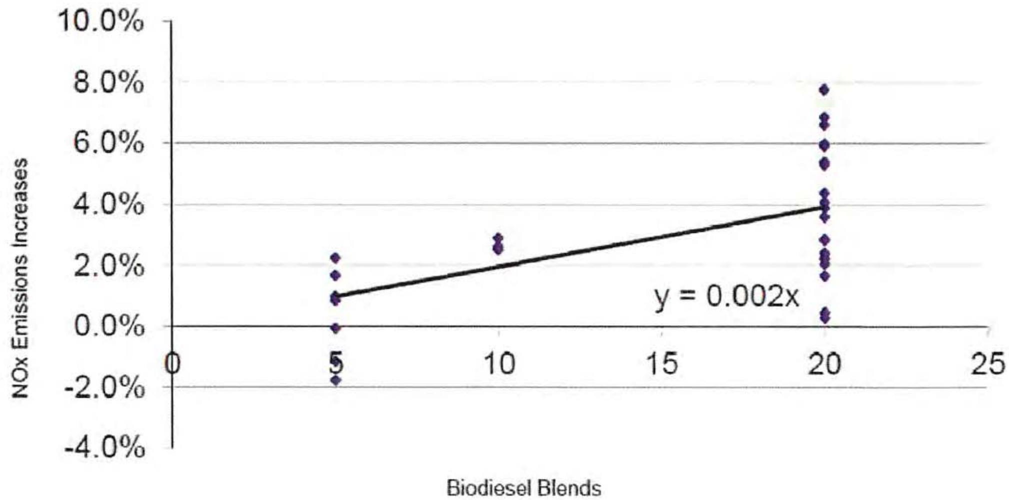
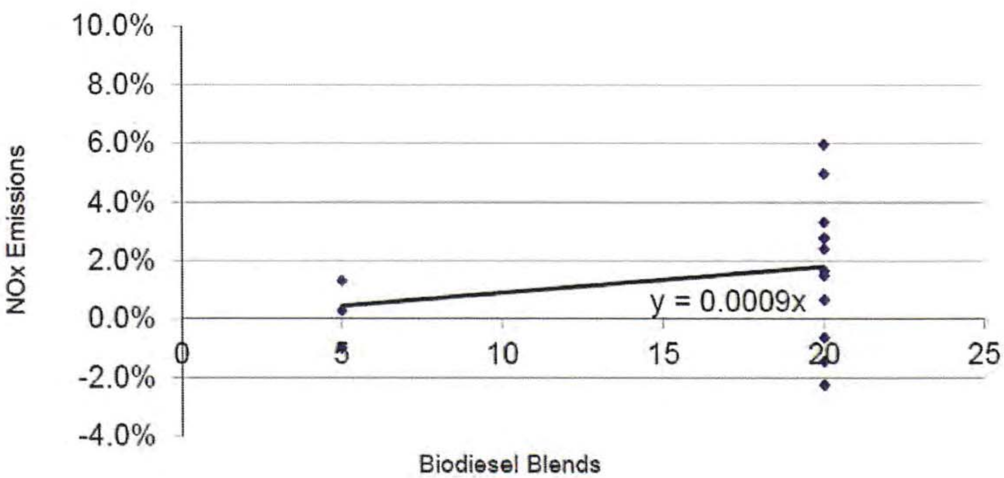


Figure B.3: NOx Impact of Animal Biodiesel Blended in High Cetane Base Fuel



Source: Figures B.2 and B.3 of Appendix B: Technology Assessment

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

soy-based biodiesels are shown to increase NOx emissions by approximately 1% at B5, 2% at B10, and 4% at B20. Animal-based biodiesels are shown to increase NOx emissions by about one-half as much: 0.45% at B5, 0.9% at B10, and 1.8% at B20. Although there is substantial scatter in the results, these data do not appear to support the Staff Threshold Model that biodiesel does not increase NOx emissions at B5 but does so at B10.

We will examine the Durbin 2011 study at some length in Section 3. In this section, we look at each of the other studies cited by the Staff to find out what the studies say about NOx emissions impacts at and below B10.

2.1 Review of Literature Cited in the ISOR

The Staff literature search sought and selected testing that used fuels with cetane levels comparable to California diesel fuels; the Staff does not, however, list those fuels or provide the data that support the tables and figures in Appendix B of the ISOR. Therefore, we have necessarily made our own selection of high-cetane fuels in the course of reviewing the studies. The key testing and findings of each study are summarized below, with a specific focus on what they tell us about NOx emission impacts at B10 and below.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

2.1.1 Clark 1999

This study tested a variety of fuels on a 1994 7.3L Navistar T444E engine. Of the high-cetane base fuels, one base fuel (Diesel A, off-road LSD) was blended and tested at levels of B20, B50, and B100. NOx emissions were significantly increased for all of the blends. The other base fuel (CA Diesel) was tested only as a base fuel. Its NOx emissions were 12% below that of Diesel A, making it is unclear whether Diesel A is representative of fuels in CA. This study conducted no testing of the NOx emissions impact from biodiesels at the B10 level or below.

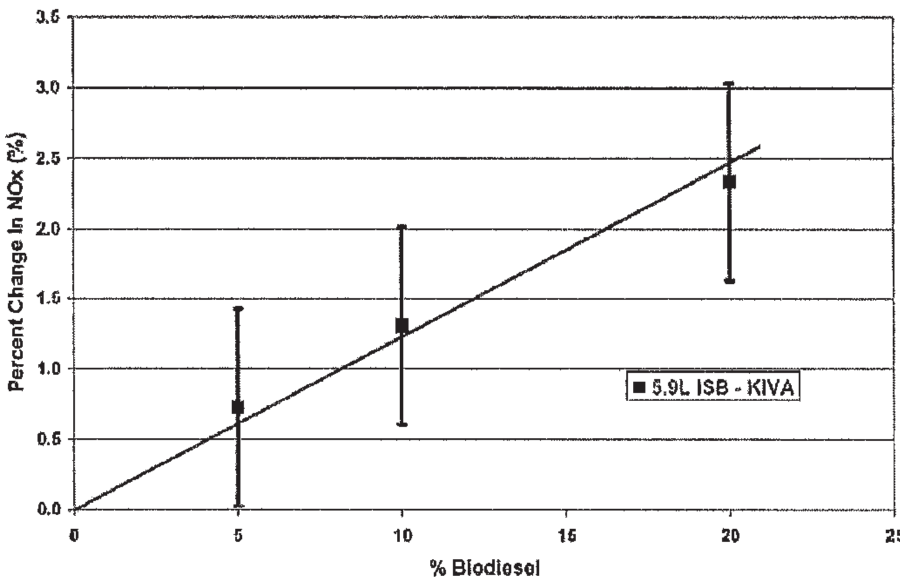
2.1.2 Eckerle 2008

This study tested low and mid/high-cetane base fuels alone and blended with soy-based biodiesel at the B20 level. The Cummins single-cylinder test engine facility was used in a configuration representative of modern diesel technology, including cooled EGR. Testing was conducted under a variety of engine speed and load conditions. FTP cycle emissions were then calculated from the speed/load data points. The test results show that B20 blends increase NOx emissions compared to both low- and high-cetane base fuels. This study conducted no testing of the NOx emissions impact from biodiesels at the B10 level or below.

The study notes that two other studies "show that NOx emissions increase nearly linearly with the increase in the percentage of biodiesel added to diesel fuel." Eckerle's Figure 21 (reproduced below as Figure 2-2) indicates a NOx emissions increase at B5, which is the basis for the statement in the abstract that "Results also show that for biodiesel blends containing less than 20% biodiesel, the NOx impact over the FTP cycle is proportional to

the blend percentage of biodiesel." The authors clearly believe that biodiesel fuels have NOx emission impacts proportional to the blending percent at all levels including B5.

Figure 2-2
Impact of Biodiesel Blends on Percent NOx Change for the 5.9L ISB Engine Operation Over the FTP Cycle



Source: Figure 21 of Eckerle 2008

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

2.1.3 McCormick 2002

This study tested low- and mid-cetane base fuels alone and blended with soy- and animal-based biodiesel at the B20 level. The testing was conducted on a 1991 DDC Series 60 engine using the hot-start U.S. heavy-duty FTP. NOx emission increases were observed for both fuels at the B20 level. Mitigation of NOx impacts was investigated by blending a Fisher-Tropsch fuel, a 10% aromatics fuel and fuel additives. This study conducted no testing of the NOx emissions impact from commercial biodiesels at the B10 level or below.

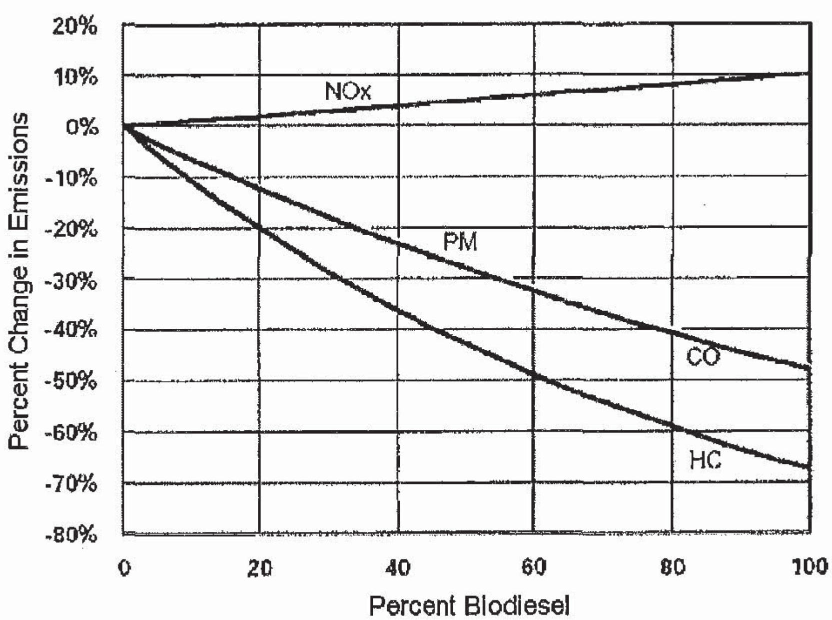
This study also tested a Fisher-Tropsch (FT) base fuel blended at the B1, B20, and B80 levels. Although the very high cetane number (≥75) takes it out of the range of commercial diesel fuels, it is interesting to note that the study measured higher NOx emissions at the B1 level than it did on the FT base fuel and substantially higher NOx emissions at the B20 and B80 levels. While the B1 increase was not statistically significant given the uncertainties in the emission measurements (averages of three test runs), it is clear that increased NOx emissions have been observed at very low blending levels.

2.1.4 McCormick 2005

This study tested blends of soy- and animal-based biodiesels with a high-cetane ULSD base fuel at B10 levels and higher. Two engines were tested – a 2002 Cummins ISB and a 2003 DDC Series 60, both with cooled EGR. The hot-start U.S. heavy-duty FTP test cycle was used. The majority of testing was at the B20 level with additional testing at the B50 and B100 levels. One soy-based fuel was tested at B10. The study showed NOx emission increases at B10, B20, and higher levels. The study also investigated mitigation of NOx increases. This study conducted no testing of the NOx emissions impact from biodiesels below the B10 level.

The authors present a figure (reproduced as Figure 2-3) in their introduction that shows their summary of biodiesel emission impacts based on an EPA review of heavy-duty engine testing. It shows NOx emissions increasing linearly with the biodiesel blend percentage.

Figure 2-3
Trend in HC, CO, NOx and PM Emissions with Biodiesel Percent



Source: McCormick 2005

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

2.1.5 Nuszkowski 2009

This study tested five different diesel engines: one 1991 DDC Series 60, two 1992 DDC Series 60, one 1999 Cummins ISM, and one 2004 Cummins ISM. Only the 2004 Cummins ISM was equipped with EGR. All testing was done using the hot-start U.S. heavy-duty FTP test cycle. The testing was designed to test emissions from fuels with and without cetane-improving additives. Although a total of five engines were tested, the base diesel and B20 fuels were tested on only two engines (one Cummins and one DDC Series 60) because there was a limited supply of fuel available. NOx emissions increased on the B20 fuel for both engines. A third engine (Cummins) was tested on B20 and B20 blended with cetane improvers to examine mitigation of NOx emissions. This study conducted no testing of the NOx emissions impact from biodiesels at the B10 level or below.

2.1.6 Thompson 2010

This study examined the emissions impacts of soy-based biodiesel at the B10 and B20 levels relative to low-cetane (42), mid-cetane (49), and high-cetane (63) base fuels using one 1992 DDC Series 60 engine. The emissions results were measured on the hot-start U.S. heavy-duty FTP cycle. The study found that NOx emissions were unchanged (observed differences were not statistically significant) at B10 and B20 levels for the low- and mid-cetane fuels. NOx emissions increased significantly at B10 and B20 levels for the high-cetane fuels. This study conducted no testing of the NOx emissions impact from biodiesels at levels below B10.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

2.2 Conclusions Based on Studies Obtained in Literature Search

From the foregoing summary of the studies cited by Staff, we reach the conclusions given below.

1. None of the six studies measured the NOx emissions impact from commercial-grade biodiesel at blending levels below B10, and only two studies tested a fuel at the B10 level. All other testing was at the B20 level or higher. Because none tested a B5 (or similar) fuel, none is capable of providing direct evidence regarding NOx emissions at B5 or other blending levels below B10.

2. These studies provide no data or evidence supporting the validity of Staff's Threshold Model that biodiesel below B10 does not increase NOx emissions. In fact, all of the studies are consistent with the contention that biodiesel increases NOx emissions in proportion to the blending percent.

3. Two of the studies present evidence and arguments that the NOx impact from biodiesel is a continuous effect that is present even at very low blending levels and will increase at higher levels in proportion to the blending percentage. One study tested a Fischer-Tropsch biodiesel blend at B1 and observed NOx emissions to increase (but not by a statistically significant amount).

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

###

3. CARB BIODIESEL CHARACTERIZATION STUDY

3.1 Background

CARB sponsored a comprehensive study of biodiesel and other alternative diesel blends in order "… to better characterize the emissions impacts of renewable fuels under a variety of conditions."[15] The study was designed to test eight different heavy- duty engines or vehicles, including both highway and off-road engines using engine or chassis dynamometer testing. Five different test cycles were used: the Urban Dynamometer Driving Schedule (UDDS), the Federal Test Procedure (FTP), and 40 mph and 50 mph CARB heavy-heavy-duty diesel truck (HHDDT) cruise cycles, and the ISO 8178 (8 mode) cycle. Table 3-1 (reproduced from Table ES-1 of Durbin 2011) documents the scope of the test program. Because the Staff relied only on engine dynamometer testing in its Technology Assessment, only the data for the first four engines (shaded) are considered here.

Table 3-1
A Breakdown of the Test Engines for the Different Categories of Testing

2006 Cummins ISM[a]	Heavy-duty on-highway	Engine dynamometer	
2007 MBE4000	Heavy-duty on-highway	Engine dynamometer	
1998, 2.2 liter, Kubota V2203-DIB	Off-road	Engine dynamometer	
2009 John Deere 4.5 L	Off-road	Engine dynamometer	
2000 Caterpillar C-15	Heavy-duty on-highway	Chassis dynamometer	Freightliner chassis
2006 Cummins ISM	Heavy-duty on-highway	Chassis dynamometer	International chassis
2007 BME4000	Heavy-duty on-highway	Chassis dynamometer	Freightliner chassis
2010 Cummins ISX15	Heavy-duty on-highway	Chassis dynamometer	Kenworth chassis

Source: Table ES-1 of Durbin 2011, page xxvi
Notes:
[a] Data for the first four engines (shaded) are considered in this report.

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

[15] Durbin 2011, p. xxiv.

The original goal of this report was to subject all of the NOx emission testing in Durbin 2011 to a fresh re-analysis. However, it was discovered that Durbin 2011 did not report all of the data that were obtained during the program and are discussed in the report. The chassis dynamometer testing was conducted at the CARB Los Angeles facility. Emission results for the chassis dynamometer testing are presented in tabular and graphical form, but the report does not contain the actual emissions test data. For the engine dynamometer testing, some of the measured emission values are not reported even though the emission results are reported in tabulated or graphical form. Requests for the missing data were directed to Durbin in a personal request and to CARB through an official records request. No information has been provided in response and we have not been able to obtain the missing data from online or other sources.

For this report, we have worked with the data in the forms that are provided in Durbin 2011 as being the best-available record of the results of the CARB study. Because Staff used only data obtained in engine dynamometer testing, the analysis presented in this report has done the same. Nevertheless, the results of the chassis dynamometer testing are generally supportive of the results and conclusions presented here. Durbin 2011 notes:

> "... The NOx emissions showed a consistent trend of increasing emissions with increasing biodiesel blend level. These differences were statistically significant or marginally significant for nearly all of the test sequences for the B50 and B100 fuels, and for a subset of the tests on the B20 blends."[16]

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Durbin notes that emissions variability was greater in the chassis dynamometer testing, which leads to the sometimes lower levels of statistical significance. There was also a noticeable drift over time in NOx emissions that complicated the results for one engine.

3.2 Data and Methodology

Table 3-2 compiles descriptive information on the engine dynamometer testing performed in Durbin 2011. The experimental matrix involves four engines, two types of biodiesel fuels (soy- and animal-based), and up to four test cycles per engine. However, the matrix is not completely filled with all fuels tested on all engines on all applicable test cycles. The most complete testing is for the ULSD base fuel and B20, B50, and B100 blends. There is less testing for the B5 blend, and B5 is tested using only a subset of cycles. For this reason, we first examine the testing for ULSD, B20, B50, and B100 fuels to determine the overall impact of biodiesels on NOx emissions. We then examine the more limited testing for B5 to determine the extent to which it impacts NOx emissions.

This examination is limited by the form in which emissions test information is reported in Durbin 2011. A complete statistical analysis can be conducted only for the two on-road engines for which Appendices G and H of Durbin 2011 provide measured emissions, and for a portion of the testing of the Kubota off-road engine for which Appendix I provides

[16] Durbin 2011, p. 126.

<table>
<tr><th colspan="5">Table 3-2
Experimental Matrix for Heavy-Duty Engine Dynamometer
Testing Reported in Durbin 2011</th></tr>
<tr><th>Engine</th><th>Biodiesel Type</th><th>Fuels Tested</th><th>Test Cycles</th><th>Notes</th></tr>
<tr><td colspan="5">On-Road Engines</td></tr>
<tr><td rowspan="2">2006 Cummins ISM</td><td>Soy</td><td>ULSD, B20, B50, B100, B5</td><td>UDDS, FTP, 40 mph, 50 mph</td><td>B5 tested on 40 mph and 50 mph cruise cycles</td></tr>
<tr><td>Animal</td><td>ULSD, B20, B50, B100, B5</td><td>UDDS, FTP, 50 mph</td><td>B5 tested only on FTP.</td></tr>
<tr><td rowspan="2">2007 MBE4000</td><td>Soy</td><td>ULSD, B20, B50, B100, B5</td><td rowspan="2">UDDS, FTP, 50 mph</td><td>B5 tested only on FTP.</td></tr>
<tr><td>Animal</td><td>ULSD, B20, B50, B100, B5</td><td>B5 tested only on FTP.</td></tr>
<tr><td colspan="5">Off-Road Engines</td></tr>
<tr><td rowspan="2">1998 Kubota V2203-DIB</td><td>Soy</td><td>ULSD, B20, B50, B100, B5</td><td rowspan="2">ISO 8178 (8 Mode)</td><td rowspan="2">none</td></tr>
<tr><td>Animal</td><td>Not tested</td></tr>
<tr><td rowspan="2">2009 John Deere</td><td>Soy</td><td>ULSD, B20, B50, B100</td><td rowspan="2">ISO 8178 (8 Mode)</td><td>B5 not tested</td></tr>
<tr><td>Animal</td><td>ULSD, B20, B5</td><td>none</td></tr>
</table>

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

measured emissions. The data needed to support a full re-analysis consist of measured emissions on each fuel in gm/hp-hr terms, which are stated in Durbin 2011 as averages across all test replications along with the number of replications and the standard error of the individual tests. With this information, the dependence of NOx emissions on biodiesel blending percent can be determined as accurately as if the individual test values had been reported and the appropriate statistical tests for the significance of results can be performed.

Regression analysis is used as the primary method of analysis. For each engine and test cycle, the emission averages for each fuel are regressed against the biodiesel blending percent to determine a straight line. The regression weights each data point in inverse proportion to the square of its standard error to account for differences in the number and reliability of emission measurements that make up each average. The resulting regression line will pass through the mean value estimated from the data (i.e., the average NOx emission level at the average blending percent), while the emission averages for each fuel may scatter above and below the regression line due to uncertainties in their measurement. The slope of the line estimates the dependence of NOx emissions on the blending percentage.

Where the data points closely follow a straight line and the slope is determined to be statistically significant, one can conclude that blending biodiesel with a base fuel will increase NOx emissions in proportion to the blending percent. The regression line can then be used to estimate the predicted emissions increase for a given blending percent. The predicted emissions increase is the value one would expect on average over many measurements and is comparable to the average emissions increase one would expect in a fleet of vehicles.

The same level of analysis is not possible for the testing on B5 fuel, which is reported as a simple average for the on-road engines and is not reported at all for the off-road engines. For the B5 fuel, Durbin 2011 presents emission test results in a tabulated form where the percentage change in NOx emissions has been computed compared to ULSD base fuel. This form supports the presentation of results graphically, but it does not permit a proper statistical analysis to be performed. Specifically, the computation of percentage emission changes will perturb the error distribution of the data, by mixing the uncertainty in measured emissions on the base fuel with the uncertainties in measured emissions on each biodiesel blend, and it can introduce bias as a result of the mixing. Further statistical analysis of the computed percent values should be avoided because of these problems. Therefore, a more limited trend analysis of the NOx emissions data for B5 and the John Deere engine is conducted.

3.3 2006 Cummins Engine (Engine Dynamometer Testing)

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Table 3-3 shows the NOx emission results for the 2006 model-year Cummins heavy-duty diesel engine based on a re-analysis of the data for this report. As indicated by highlighting in the table, the relationship between increasing biodiesel content and increased NOx emissions for soy-based biodiesel is statistically significant at >95% confidence level[17] in all cases. For the animal-based biodiesel, the relationship is statistically significant at the 92% confidence level for the UDDS cycle, the 94% confidence level for the 50 mph cruise, and the >99% confidence level for the FTP cycle.

For the soy-based fuels, the R^2 statistics show that the emissions effect of biodiesel is almost perfectly linear with increasing biodiesel content over the range B20, B50, and B100. Although not as high for the animal-based fuels (because the emissions effect is smaller and measurement errors are relatively larger in comparison to the trend), the R^2 statistics nevertheless establish a linear increase in NOx emissions with increasing biodiesel content over the same range. The linearity of the response with blending percent is well supported by the many NOx emissions graphs contained in Durbin 2011.

The table also gives the estimated NOx emission increases for B5 and B10 as predicted by the regression lines. For soy-based fuels, the values are 1% for B5 (range 0.8% to 1.3% depending on the cycle) and 2% for B10 (range 1.6% to 2.6% depending on cycle).

[17] A result is said to be statistically significant at the 95% confidence level when the p value is reported as $p \leq 0.05$. At the $p \leq 0.01$ level, a result is said to be statistically significant at the 99% confidence level, and so forth.

Table 3-3 Re-Analysis for 2006 Cummins Engine (Engine Dynamometer Testing) Model: NOx = A + B · BioPct Using ULSD, B20, B50, and B100 fuels							
Biodiesel Type	Test Cycle	R^2	Intercept A	BioPct Slope B		Predicted NOx Increase for B5	Predicted NOx Increase for B10
			Value	Value	p value	Pct Change	Pct Change
Soy-based							
	UDDS	0.997	5.896	0.0100 [a]	0.001	0.8%	1.7%
	FTP	0.995	2.024	0.0052	0.003	1.3%	2.6%
	40 mph	1.000	2.030	0.0037	<0.0001	0.9%	1.8%
	50 mph	0.969	1.733	0.0028	0.016	0.8%	1.6%
Animal-based							
	UDDS	0.847	5.911	0.0021 [b]	0.080	0.2%	0.4%
	FTP	0.981	2.067	0.0031	0.001	0.7%	1.4%
	50 mph	0.887	1.768	0.0011	0.058	0.3%	0.6%

Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better.
[b] Orange highlight indicates result is statistically significant at the 90% confidence level or better.

For animal-based fuels, the values are approximately one-half as large: 0.4% for B5 (range 0.2% to 0.7%) and 0.8% for B10 (range 0.4% to 1.4%). These predicted increases are statistically significant to the same degree as the slope of the regression line from which they are estimated. That is, the NOx increases predicted by the regression line for soy-based fuels are statistically significant at the 95% confidence level (or better) on all cycles and the predicted NOx increases for animal-based fuels are statistically significant at the 90% confidence level (or better) on all cycles and at the >99% confidence level for the FTP.

Because the limited data on B5 were not used to develop the regression lines for each cycle, and no test data on B10 are available, use of the lines to make predictions for B5 and B10 depends on their linearity over the range between ULSD and B20. Based on the R^2 statistics and the graphs in Durbin 2011, the slopes observed between ULSD and B20 are the same as the slopes observed between B20 and B100 for each of the test cycles. We believe that the linearity of the response with blending percent for values over the range ULSD to B100 would be accepted by the large majority of researchers in the field, as would the use of regression analysis to make predictions for B5 and B10.

The Durbin 2011 report takes a different approach for determining the statistical significance of NOx emission increases for each fuel. For each fuel tested, it computes a percentage change in emissions for NOx (and other pollutants) relative to the ULSD base fuel. It then determines the statistical significance of each observed change using a conventional t-test for the difference of two mean values (2-tailed, 2 sample equal

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

variance t-test). The t-test is conducted on the measured emission values before the percentage emission change is computed.

The t-test would be the appropriate approach for determining statistical significance if only two fuels were tested. However, it is a simplistic approach when three or more fuels are tested because it is applied on a pair-wise basis (B5 vs. ULSD, B20 vs. ULSD, etc.) and does not make use of all of the data that is available. It will have less power than the regression approach to detect emission changes that are real. This limitation is in one direction, however, in that the test is too weak when 3 or more data points are available, but a finding of statistical significance is valid when it occurs. As long as the linear hypothesis is valid, the regression approach should be the preferred method for analysis and for the determination of whether biodiesel blending significantly increases NOx emissions.

Because emission changes will be smallest for B5 (because of the low blending volume), the pair-wise t-test is most likely to fail to find statistical significance at the B5 level. In cases where the pair-wise t-test for B5 says that the emission change vs. ULSD is not statistically significant – but slope of the regression line is statistically significant – the proper conclusion is that additional B5 testing (to improve the precision of the emission averages) would likely lead to the detection of a statistically significant B5 emissions change using the t-test. In this case, the failure to find statistical significance using the t-test is not evidence that B5 does not increase NOx emissions.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

For this engine, soy-based B5 was tested on the 40 mph and 50 mph cruise cycles and animal-based B5 was tested on the FTP. To examine this matter further, Table 3-4 reproduces NOx emission results reported in Tables ES-2 and ES-3 of Durbin 2011. Soy-based B5 was shown to increase NOx emissions on the 40 mph cruise cycle, but not on the 50 mph cruise cycle. Animal-based B5 was shown to increase NOx emissions on the FTP. Durbin 2011 noted (p. xxxii) that "[t]he 50 mph cruise results were obscured, however, by changes in the engine operation and control strategy that occurred over a segment of this cycle." Therefore, we discount the 50 mph cruise results and do not consider them further. Neither of the remaining B5 NOx emission increases (for the 40 mph Cruise and FTP cycles) were found to be statistically significant using the t-test, although the 40 mph cruise result for soy-based fuels comes close to being marginally significant (it would be statistically significant at an 86.5% level). The NOx emission increases at higher blending levels were found have high statistical significance (>99% confidence level).

This format, used throughout Durbin 2011 to report emission test data and to show the effect of biodiesel on emissions, is subject to an important statistical caveat. The percent changes are computed by dividing the biodiesel emission values by the emissions measured for the ULSD base fuel. Therefore, measurement errors in the ULSD measurement are blended with the measurement errors for each of the biodiesel fuels. The blending of errors in each computed percent change can bias the apparent trend of emissions with increasing biodiesel content. As will be shown in Section 3.3.2, we can see this problem in the animal-based B5 test data for this engine.

Table 3-4 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 2006 Cummins Engine (Engine Dynamometer Testing)						
	Soy-based Biodiesel				Animal-based Biodiesel	
	40 mph Cruise		50 mph Cruise		FTP	
	NOx % Diff	p value	NOx % Diff	p value	NOx % Diff	p value
B5	1.7%	0.135	-1.1%	0.588	0.3%	0.298
B20	3.9% [a]	0.000	0.5%	0.800	1.5%	0.000
B50	9.1%	0.000	6.3%	0.001	6.4%	0.000
B100	20.9%	0.000	18.3%	0.000	14.1%	0.000

Source: Table ES-2 and ES-3 of Durbin 2011, p. xxviii
Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on the pair-wise t-test.

3.3.1 NOx Impact of Soy-based Biodiesel at the B5 Level

Figures 3-1a and 3-1b display the trend of NOx emissions with blending percent for the soy-based biodiesel on the 40 mph cruise cycle. Figure 3-1a plots the percentage increases as reported by Durbin 2011 in contrast to two different analytical models for the relationship:

- The Linear Model shown by the blue line; and
- The Staff Threshold model (black line), in which the NOx emission change is zero through B9 and then increases abruptly to join the linear model.

In Figure 3-1a, the linear model is an Excel trendline for the computed percent changes. While the data violate a key assumption for the proper use of regression analysis, this approach is the only way to establish a trendline given the form in which Durbin 2011 tabulates the data and presents the results of its testing.

Figure 3-1b plots the actual measured emission values in g/bhp-hr terms in contrast to the same two analytical models. Here, the linear model line is determined through a proper use of regression analysis, in which each emission average in g/bhp-hr terms is weighted inversely by the square of its standard error, using the data for ULSD, B20, B50 and B100 (i.e., excluding the B5 data point). In the case of this engine and biodiesel fuel, both forms of assessment show generally the same trend for NOx emissions as a function of blending percent. Although the NOx emission increases for B5 may fail the t-test for significance, emissions are increased at B5 and the B5 data point is fully consistent with the Linear Model. The Threshold model is clearly a less-satisfactory representation of the test data.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Figure 3-1a
Durbin 2011 Assessment: 40 mph Cruise Cycle NOx Emissions Increases for Soy-Biodiesel Blends (2006 Cummins Engine)

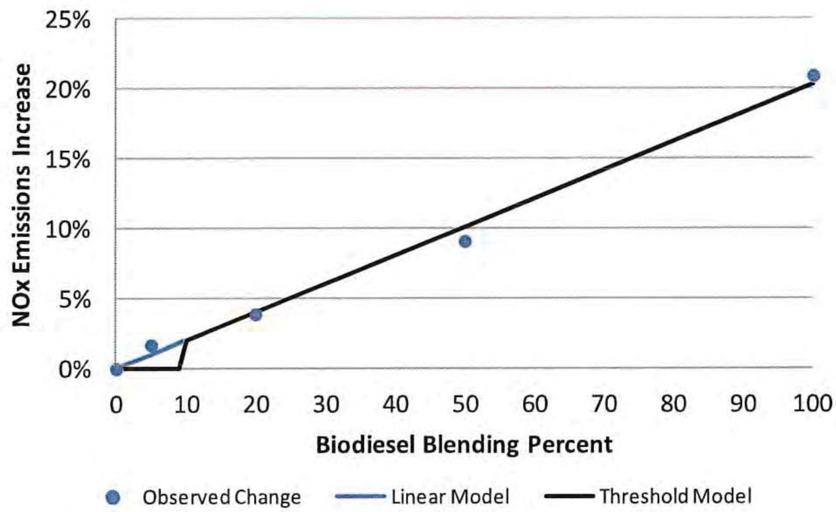
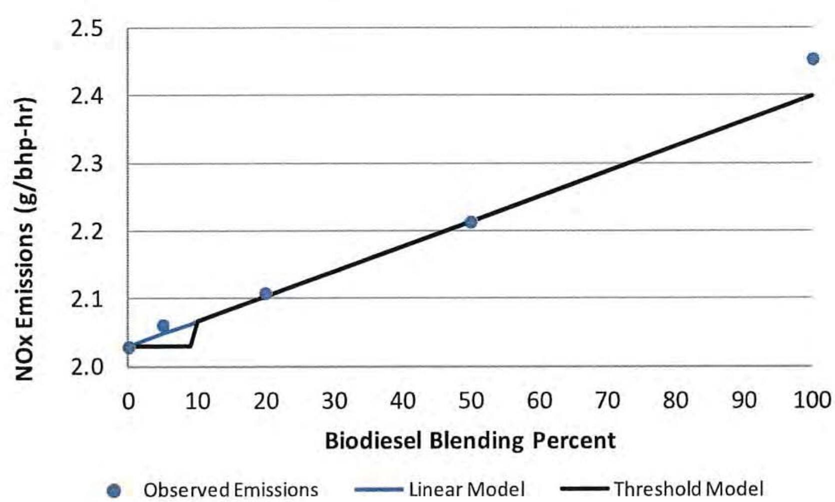


Figure 3-1b
Re-assessment of 40 mph Cruise Cycle NOx Emissions Increases for Soy-Biodiesel Blends (2006 Cummins Engine)



Note that the slope of the trendline (Figure 3-1a) is greater than the slope of the regression line (Figure 3-1b). In the latter figure, the B100 data point stands above the regression line, which passes below it. The regression line (but not the trendline) is fit in

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

a manner that accounts for the uncertainties in each data point, so that the line will pass closer to points that have smaller uncertainties and farther from points that have greater uncertainties. For these data, the B100 data point has the largest uncertainty (±0.026 g/bhp-hr) followed by the B20 data point (±0.025 g/bhp-hr). The other three data points (ULSD, B5, and B50) have uncertainties less than ±0.001 g/bhp-hr. The B20 data point happens to fall on the line, but the B100 data point is found to diverge above. Because the regression analysis can account for the relative uncertainties of the data points, it provides a more accurate and reliable assessment of the impact on NOx emissions.

3.3.2 NOx Impact of Animal-based Biodiesel at the B5 level

Figures 3-2a and 3-2b display the trend of NOx emissions with blending percent for the animal-based biodiesel on the FTP test cycle as reported by Durbin 2011 and as re-assessed in this report using regression analysis, respectively. As Figure 3-2a shows, the NOx percent change values reported by Durbin 2011 appear to follow the Staff Threshold model in that NOx emissions are not materially increased at B5, but are increased significantly at B20 and above. As a result, the blue trendline in the figure (fit from the B20, B50 and B100 data points) has a negative intercept.

Figure 3-2b paints a very different picture from the data. Here, the ULSD and B5 data points stand above the weighted regression line (blue) developed from the data for ULSD, B20, B50 and B100. In the data used to fit the regression line, the ULSD data point has the largest uncertainty (±0.013 g/bhp-hr) while the other three data points (B20, B50, and B100) have uncertainties of ±0.002 g/bhp-hr (one case) and ±0.001 g/bhp-hr (two cases). Considering all of the data, the B5 data point has the second highest uncertainty (±0.007 g/bhp-hr). The regression line closely follows a linear model with a high R^2 (0.981) considering the weighted errors, while the ULSD and B5 points lie above it.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Because the ULSD data point is subject to more uncertainty and appears to be biased high compared to the regression line, the NOx percent changes computed by Durbin 2011 are themselves biased. The trendline result in Figure 3-2a that appeared to be supportive of the Staff Threshold model now appears to be the result of biases in the ULSD and B5 emission averages.

Two important conclusions can be drawn from the foregoing:

1. Accurate and reliable conclusions regarding the impact of B5 on NOx emissions cannot be drawn from the computed percent changes that are reported in Durbin 2011. Nor can accurate and reliable conclusions be drawn from visual inspection of graphs that present such data. Weighted regression analysis of the measured emission values (g/bhp-hr terms) must be performed so that the uncertainties in emissions measurements can be fully accounted for.

2. When a weighted regression analysis is performed using the testing for this engine, there is no evidence that supports the conclusion that B5 blends will not increase NOx emissions. In fact, the data are consistent with the conclusion that biodiesel increases NOx emissions in proportion to the blending percent.

Figure 3-2a
Durbin 2011 Assessment: FTP NOx Emissions Incr eases for Animal-based Biodiesel Blends (2006 Cumm ins En gine)

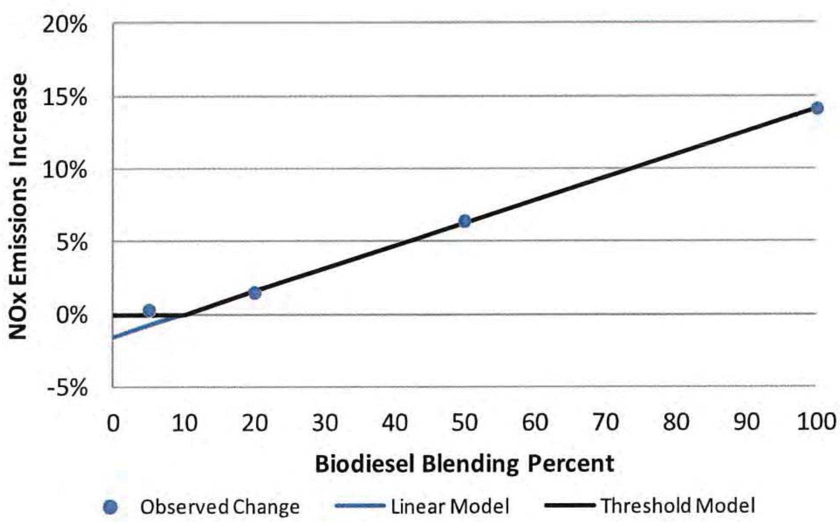
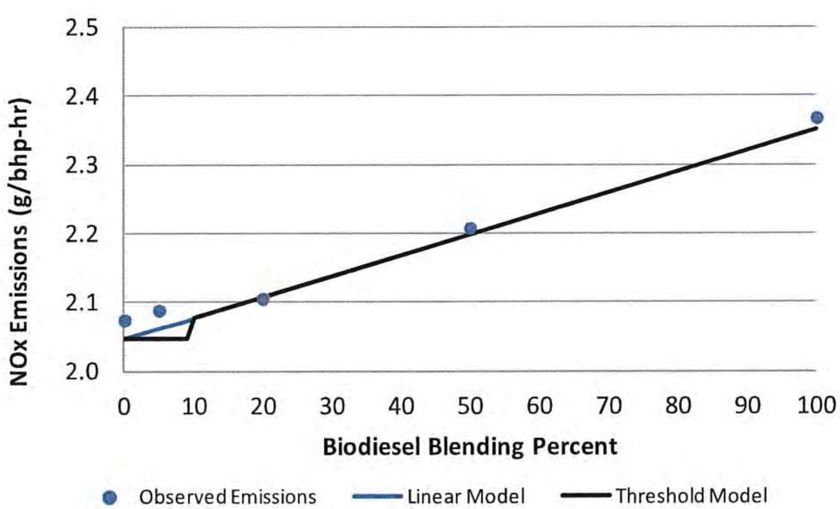


Figure 3-2b
Re-assessment of FTP NOx Em issions Incre ases for Anim al-based Biodiesel Blends (2006 Cumm ins En gine)



Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

3.4 2007 MBE4000 Engine (Engine Dynamometer Testing)

To analyze the data for the 2007 MBE4000 engine, it has proved necessary to remove two data points, one for the soy-based B20 fuel on the 50 mpg cruise cycle and one for the animal-based B50 fuel on the FTP test cycle:

- Appendix H reports the 50 mph cruise emission average for soy-based B20 to be 0.014 ± 0.020 g/bhp-hr. This value is implausible and wholly inconsistent with the NOx emission change of +6.9% reported in Table ES-4 of Durbin 2011, which would imply a NOx emission average of 1.21*1.069 = 1.30 g/bhp-hr.

- Appendix H reports the FTP emission average for the animal-based B50 fuel to be 2.592 ± 0.028 g/bhp-hr, which stands well above the other test data on animal-based biodiesel. This value is also inconsistent with the NOx emission change of +12.1% reported in Table ES-4 of Durbin 2011, which would imply a NOx emission average of 1.29*1.121 = 1.45 g/bhp-hr.

We believe these reported values are affected by typographical errors and have deleted them from the dataset used here.

With these corrections, Table 3-5 shows the results of the NOx emissions analysis for the 2007 model-year MBE4000 heavy-duty diesel engine. As indicated by highlighting in the table, the relationship between increasing biodiesel content and increased NOx emissions is statistically significant at >99% confidence level in two cases for soy-based biodiesel (the UDDS and FTP cycles) and at the 90% confidence level in one case (the 50 mph cycle). For the animal-based biodiesel, the relationship is statistically significant at the 96% confidence level for the UDDS cycle, the 98% confidence level for the FTP cycle, and >99% confidence level for the 50 mph cycle.

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Durbin 2011 again notes a problem with the 50 mph cruise test results, saying (p. xxxii) that "[the NOx] trend was obscured, however, by the differences in engine operation that were observed for the 50 mph cruise cycle." Therefore, we will focus the discussion on the UDDS and FTP results.

For the soy-based fuels, the R^2 statistics show that the emissions effect of biodiesel is almost perfectly linear with increasing biodiesel content over the range from ULSD to B20, B50, and B100 for all cycles (including the 50 mph cruise). That is, the NOx emissions increase between ULSD and B20 shares the same slope as the NOx emissions increase between B20 and B100. For the animal-based biodiesel, the R^2 statistics also establish a linear increase in NOx emissions with increasing biodiesel content over the same range. The linearity of the response with blending percent is also well supported by the many NOx emissions graphs contained in Durbin 2011.

Table 3-5 Re-Analysis for 2007 MBE4000 Engine (Engine Dynamometer Testing) Model: NOx = A + B · BioPct Using ULSD, B20, B50, and B100 fuels							
Biodiesel Type	Test Cycle	R^2	Intercept A Value	BioPct Slope B Value	BioPct Slope B p value	Predicted NOx Increase for B5 Pct Change	Predicted NOx Increase for B10 Pct Change
Soy-based							
	UDDS	0.989	2.319	0.0090 [a]	0.005	4.6%	9.1%
	FTP	0.998	1.268	0.0049	0.006	2.5%	5.0%
	50 mph	0.979	1.198	0.0054 [b]	0.092	2.7%	5.5%
Animal-based							
	UDDS	0.913	2.441	0.0036	0.044	2.0%	4.0%
	FTP	0.999	1.288	0.0038	0.020	2.5%	5.0%
	50 mph	0.994	1.205	0.0049	0.003	2.5%	5.0%

Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better.
[b] Orange highlight indicates result is statistically significant at the 90% confidence level or better.

The table also gives the estimated NOx emission increases for B5 and B10 as predicted by the regression lines. For soy-based fuels, the values are ~3.5% for B5 (range 2.5% to 4.6% depending on the cycle) and ~7.5% for B10 (range 5.0% to 9.1% depending on cycle). For animal-based fuels, the values are approximately two-thirds as large: ~2.3% for B5 (range 2.0% to 2.5%) and ~4.5% for B10 (range 4.0% to 5.0%). The predicted increases are statistically significant to the same degree as the slope of the regression line from which they are estimated. That is, the predicted NOx increases are statistically significant at the >99% confidence level for soy-based fuels on the UDDS and FTP cycles and at the >95% confidence level for animal-based fuels on all cycles. The predicted NOx increase is statistically significant at the 90% confidence level for soy-based fuels on the 50 mph cruise cycle.

For this engine, soy- and animal-based B5 were tested on the FTP. Table 3-6 reproduces the NOx emission results reported in Tables ES-4 and ES-5 of Durbin 2011. While there are caveats on use of the pair-wise t-test, the FTP test data for this engine show NOx emissions at the B5 level for both soy- and animal-based fuels that are statistically significant at the 99% confidence level (or better) in this case. That is, <u>the test data for this engine as reported by Durbin 2011 refute the Staff Threshold Model that biodiesel blends below B10 do not increase NOx emissions</u>.

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

Table 3-6 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 2007 MBE4000 Engine (Engine Dynamometer Testing)				
	Soy-Based Biodiesel FTP		Animal-Based Biodiesel FTP	
	NOx % Diff	p value	NOx % Diff	p value
B5	0.9% [a]	0.007	1.3%	0.000
B20	5.9%	0.000	5%	0.000
B50	15.3%	0.000	12.1	0.000
B100	38.1%	0.000	29%	0.000

Source: Table ES-4/5 of Durbin 2011, p. xxix
Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on pair-wise t-test.

Figures 3-3a and 3-3b below compare the FTP data for this engine to the regression line representing the linear model (blue) and the Staff Threshold model (black) for both soy- and animal-based biodiesel. In both cases, the regression line was developed using the data for ULSD, B20, B50, and B100 (i.e., excluding the B5 data point). For both soy- and animal-based biodiesels, the data point for B5 falls on the established line, while the Staff Threshold model is inconsistent with the data. For this engine, it is clear that soy- and animal-based biodiesels increase NOx emissions at all blending levels.

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

Figure 3-3a
Re-assessment of FTP Cycle NOx Emissions Increases for Soy-based Biodiesel Blends (2007 MBE4000 Engine)

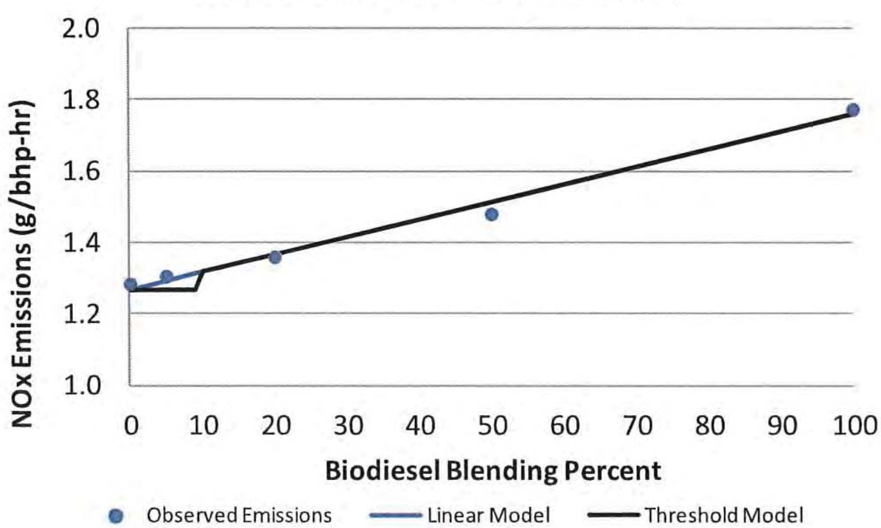
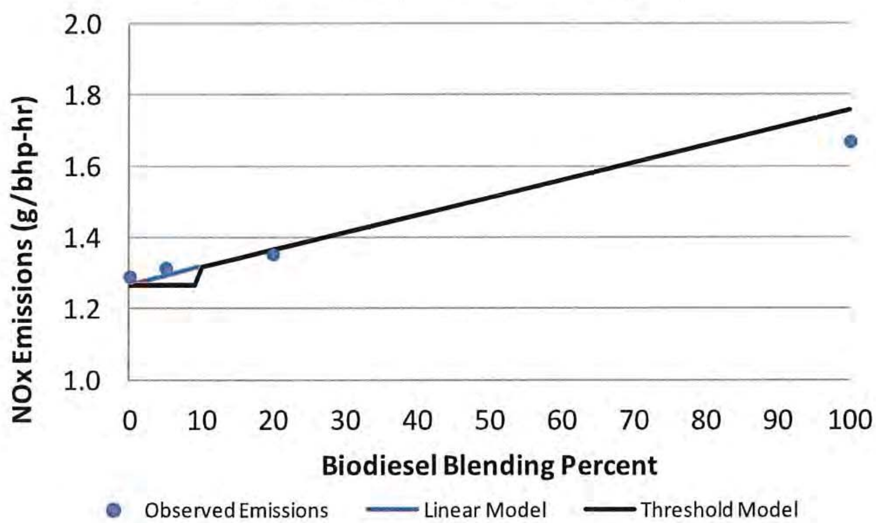


Figure 3-3b
Re-assessment of FTP Cycle NOx Emissions Increases for Animal-based Biodiesel Blends (2007 MBE4000 Engine)



Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

3.5 1998 Kubota TRU Engine (Engine Dynamometer Testing)

The 1998 Kubota V2203-DIB off-road engine was tested on the base fuel (ULSD) and soy-based biodiesel at four blending levels (B5, B20, B50, B100) in two different series using the ISO 8178 (8-mode) test cycle. Appendix I reports the measured emissions data only for the first series (ULSD, B50, B100). Using this subset of data, Table 3-7 summarizes the results of the re-analysis for this engine.

As for the other engines, the results of the analysis demonstrate the following:

- The high R^2 statistic shows that the emissions effect of biodiesel is almost perfectly linear over the range B50 and B100. That is, the slope from ULSD to B50 is the same as the slope from B50 to B100. The slope of the regression line is statistically significant at the 99% confidence level.

- NOx emissions are estimated to increase by 1.0% at the B5 level and by 2.1% at the B10 level. These estimated NOx emission increases are statistically significant to the same high degree as the regression slope on which they are based.

Table 3-7 Re-Analysis for 1998 Kubota V2203-DIB Engine (Engine Dynamometer Testing) Model: NOx = A + B · BioPct Using ULSD, B50, and B100 fuels							
Biodiesel Type	Test Cycle	R^2	Intercept A Value	BioPct Slope B Value	p value	Predicted NOx Increase for B5 Pct Change	Predicted NOx Increase for B10 Pct Change
Soy-based	ISO 8178	0.999	12.19	0.0256 [a]	0.01	1.0%	2.1%

Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better.

The second test series involved ULSD, B5, B20, and B100 fuels. Measured emissions data are not given in Appendix I, so we must work with the calculated percent changes in NOx emissions tabulated in Durbin 2011. Table 3-8 reproduces the NOx emission results reported in Table ES-8 of Durbin 2011 for the two test series. For the second test series, biodiesel at the B5 level increased NOx emissions, but the result fails the pair-wise t-test for statistical significance. The NOx emission increase at the B20 level was statistically significant at the 90% confidence level, and the increase at the B100 level was statistically significant at the >99% confidence level. The significance determinations use the pair-wise t-test, which is subject to caveats, but this is the only method available to gauge significance because re-analysis of the computed percentage changes is not possible.

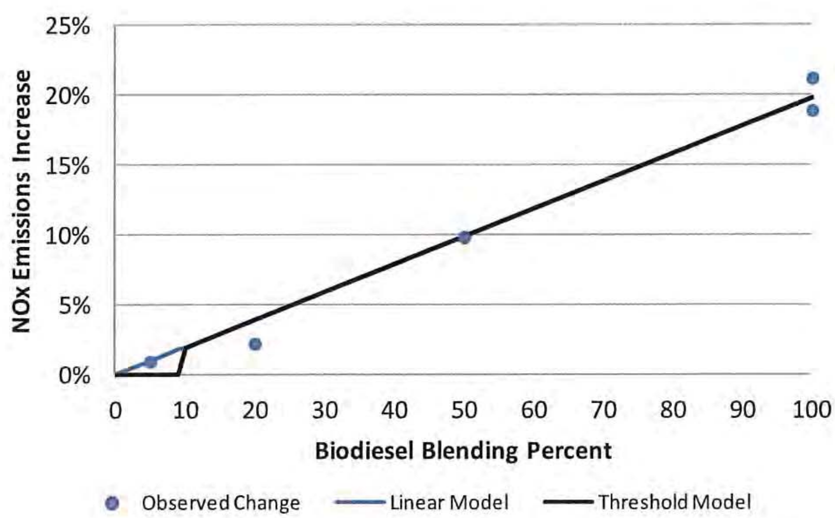
Table 3-8 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 1998 Kubota TRU Engine (Engine Dynamometer Testing)				
	Soy-Based Biodiesel Series 1 ISO 8178		Soy-Based Biodiesel Series 2 ISO 8178	
	NOx % Diff	p value	NOx % Diff	p value
B5	Not tested		0.97%	0.412
B20	Not tested		2.25% [a]	0.086
B50	7.63% [b]	0.000	Not tested	
B100	13.76%	0.000	18.89%	0.000

Source: Table ES-8 of Durbin 2011, p. xxxviii
Notes:
[a] Orange highlight indicates result is statistically significant at the 90% confidence level or better based on pair-wise t-test.
[b] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on pair-wise t-test

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

Figure 3-4 displays the trend of NOx emissions with blending percent for the first and second test series combined. As the figure shows, the available data points scatter around the trendline determined from the emission change percentages (not from regression analysis). The B20 data point falls below the trend line while the two B100 data points bracket the trend line. It is not possible to explain the divergence of the B20 data point

Figure 3-4
Durbin 2011 Assessment: ISO 8178 Cycle NOx Emissions Increases for Soy-based Biodiesel Blends (1998 Kubota Engine, Test Series 1 and 2 Combined)



Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

because the emissions data for the second test series are not published in Durbin 2011. The B5 data point clearly supports the Linear Model and is inconsistent with the Staff Threshold Model.

3.6 2009 John Deere Off-Road Engine (Engine Dynamometer Testing)

The only information on the 2009 John Deere off-road engine comes from the tabulation of calculated percentage emission changes. Table 3-9 reproduces these data from Table ES-7 of Durbin 2011. For the soy-based biodiesel, NOx emissions are significantly increased at the B20 and higher blend levels. The increase for B20 is statistically significant at the 90% confidence level and the increases for B50 and B100 are statistically significant at the >99% confidence level based on the pair-wise t-test. A soy-based B5 fuel was not tested.

Table 3-9 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 2009 John Deere Engine (Engine Dynamometer Testing)				
	Soy-Based Biodiesel ISO 8178		Animal-Based Biodiesel ISO 8178	
	NOx % Diff	p value	NOx % Diff	p value
B5	Not tested		-3.82	0.318
B20	2.82% [a]	0.021	-2.20	0.528
B50	7.63%	0.000	Not tested	
B100	13.76%	0.000	4.57	0.000

Source: Table ES-7 of Durbin 2011, p. xxxviii
Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on pair-wise t-test.

For animal-based biodiesel, the testing shows the unusual result that B5 and B20 appear to decrease NOx emissions, while B100 increases NOx. The B5 and B20 decreases are not statistically significant, while the B100 increase is statistically significant at the >99% confidence level. Durbin 2011 concludes:

> The animal-based biodiesel also did not show as great a tendency to increase NOx emissions compared to the soy-based biodiesel for the John Deere engine, with only the B100 animal-based biodiesel showing statistically significant increases in NOx emissions.[18]

Durbin 2011 does not discuss these results further and does not note any problems in the testing, making further interpretation of the results difficult. Figure 8-1 of Durbin 2011 presents the NOx results for this engine with error bars. First, we note that the figure appears to suggest that NOx emissions were increased on the B20 fuel in contradiction to the table above. Second, it is clear that the error bars are large enough that no difference in NOx emissions can be detected among ULSD, B5, and B20 fuels. Overall, this result could be consistent with the Staff Threshold Model through B5, but the failure to detect a NOx emission increase at B20 is not. Without further information, it is not possible to determine whether the result seen here is a unique response of the John Deere engine to animal-based biodiesel or is the result of a statistical fluctuation or an artifact in the emissions data.

3.7 Conclusions

The Biodiesel Characterization report prepared by Durbin et al. for CARB is an important source of information on the NOx emissions impact of biodiesel fuels in heavy-duty engines. It is the sole source of information on the NOx impact of B5 blends cited in the ISOR. When the engine dynamometer test data are examined for

Reproduction of
Pages 167 - 204
Consisting of
Comments ADF B3-146
through ADF B3-92

[18] Durbin 2011, p. xx.

the three engines for which emissions test data have been published, we find clear evidence that biodiesel increases NOx emissions in proportion to the blending percent. Where B5 fuels were tested for these engines, NOx emissions are found to increase above ULSD for both soy- and animal-based blends in all three engines and by statistically significant amounts in one engine.

Specifically, a re-analysis of the NOx emissions test data demonstrates the following:

1. For the 2006 Cummins engine, biodiesel fuels are found to significantly increase NOx emissions for both soy- and animal-based blends by amounts that are proportional to the blending percent. This result indicates that biodiesels will increase NOx emissions at blending levels below B10. When B5 fuels were tested, NOx emissions were observed to increase but by amounts that fail to reach statistical significance according to the pair-wise test.[19] Graphical analysis demonstrates that NOx emissions measured for B5 fuels are consistent with the Linear Model, but not the Staff Threshold Model.

2. For the 2007 MBD4000 engine, biodiesel fuels are found to significantly increase NOx emissions for both soy- and animal-based blends by amounts that are proportional to the blending percent. This result indicates that biodiesels will increase NOx emissions at blending levels below B10. When B5 fuels were tested, NOx emissions were observed to increase and by amounts that are found to be statistically significant using the pair-wise t-test.[13] This result alone is sufficient to disprove the Staff Threshold Model. Graphical analysis demonstrates that NOx emissions measured for B5 fuels are consistent with the Linear Model, but not the Staff Threshold Model.

3. For the 1998 Kubota TRU (off-road) engine, soy-based biodiesel fuels are found to significantly increase NOx missions. Animal-based biodiesel was not tested. When a soy-based B5 fuel was tested, NOx emissions were observed to increase but by amounts that fail to reach statistical significance according to the pair-wise test.[13] Graphical analysis demonstrates that NOx emissions measured for B5 fuels are consistent with the Linear Model, but not the Staff Threshold Model.

The measured emissions test data for the other off-road engine (2009 John Deere) are not contained in the Durbin 2011 report and CARB has not made them publicly available. Thus, a re-analysis was not possible. Based on the tables and figures in Durbin 2011, soy-based biodiesel fuels were shown to significantly increase NOx emissions at B20 levels and higher, but B5 was not tested. Testing of animal-based blends shows no change in NOx emissions at B5 and B20 levels, but B100 is shown to significantly increase NOx emissions. Durbin 2011 discusses this result only briefly, and it is unclear what conclusions can be drawn from it.

###

Reproduction of Pages 167 - 204 Consisting of Comments ADF B3-146 through ADF B3-92

[19] As discussed in Section 3.3, the pair-wise t-test is not the preferred method for demonstrating statistical significance.

12_B_LCFS_GE Responses (Page 405 – 442)

733. Comment: **NOx Emissions Impact of Soy- and Animal-based Biodiesel Fuels: A Re- Analysis December 10, 2013**

Agency Response: This is the third time this document was submitted by Growth Energy. It is a reproduction of comments **ADF B3-46** through **ADF B3-92**. The comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

This page intentionally left blank.

APPENDIX A

RESUME OF ROBERT W. CRAWFORD

Education

1978 Doctoral Candidate, ScM. Physics, Brown University, Providence, Rhode Island
1976 B.A. Physics, Pomona College, Claremont, California

Professional Experience

1998-Present Independent Consultant

Individual consulting practice emphasizing the statistical analysis of environment and energy data with an emphasis on how data and statistics are properly used to make scientific inferences. Mr. Crawford provides support on statistical, data analysis, and modeling problems related to ambient air quality data and emissions from mobile and stationary sources.

Ambient Air Quality and Mobile Source Emissions – Mr. Crawford has worked with Sierra Research on elevated ambient CO and PM concentrations in Fairbanks AK and Phoenix AZ, including the effect of meteorological conditions on ambient concentrations, the relationship of concentrations to source inventories, and the use of non-parametric techniques to infer source location from wind speed and direction data. Ongoing work is employing Principal Components Analysis to elucidate the relationship between meteorology and $PM_{2.5}$ concentrations in Fairbanks. In the past year, this work led to creation of the AQ Alert System, a tool used by air quality staff to track $PM_{2.5}$ monitor concentrations during the day and to prepare AQ alerts over the next 3 days based on the meteorological forecast.

In past work for Sierra, he has also conducted studies of fuel effects on motor vehicle emissions for Sierra. For CRC, he determined the relationship between gasoline volatility and oxygen content on tailpipe emissions of late model vehicles at FTP and cold-ambient temperatures. For SEMPRA, he determined the relationship between CNG formulation and tailpipe emissions of criteria pollutants and a range of air toxics. Other work has included the design of vehicle surveillance surveys and determination of sample sizes, development of screening techniques similar to discriminant functions to improve the efficiency of vehicle recruitment, the analysis of vehicle failure rates measured in inspection & maintenance programs, and the statistical evaluation of data collected on freeway speeds using automated sensors.

Stationary Source Emissions – Over the past 5 years, Mr. Crawford has worked with AEMS, LLC on EPA's MACT and CISWI rulemakings for Portland Cement plants, in which significant issues related to data quality, data reliability, and emissions variability are evident. Key issues include the need to properly account for uncertainty and emissions variability in setting emission standards. He also supported AEMS in the

current EPA rulemaking on reporting of greenhouse gas emissions from semiconductor facilities, where the proper characterization of emission control device performance was a key issue. He is currently supporting AEMS in a regulatory process to re-determine emission standards for an industrial facility where the new standard will be enforced by continuous emissions monitoring (CEMS). At issue is how to set the standard in such a way that there will be no more than a small, defined risk that 30-day emission averages will exceed the limitations while emissions remain well-controlled .

Advanced Combustion Research – In recent work for Oak Ridge National Laboratory, Mr. Crawford conducted a series of statistical studies on the fuel consumption and emissions performance of Homogenous Charge Compression Ignition (HCCI) engines. One of these studies was for CRC, in which fuel chemistry impacts were examined in gasoline HCCI. In HCCI, the fuel is atomized and fully-mixed with the intake air charge outside the cylinder, inducted during the intake stroke, and then compressed to the point of spontaneous combustion. The timing of combustion is controlled by heating of the intake air. If R&D work can demonstrate a sufficient understanding of how fuel properties influence engine performance, the HCCI combustion strategy potentially offers the fuel economy benefit of a diesel engine with inherently lower emissions.

1979-1997 Energy and Environmental Analysis, Inc., Arlington, VA. Director & Partner (from 1989).

Primary work areas: Studies of U.S. energy industries for private and institutional clients emphasizing statistical analysis, business planning and computer modeling/forecasting. Responsible for the EEA practice area that provided strategic planning and forecasting services to major energy companies. Primary topical areas included: U.S. energy market analysis and strategic planning; gas utility operations; and natural gas supply planning.

U.S. Energy Market Analysis

During 1995-1997, Mr. Crawford directed EEA's program to provide comprehensive energy supply and demand forecasting for the Gas Research Institute (GRI) in its annual Baseline Projection of U.S. Energy Supply and Demand. Services included: development of U.S. energy supply, demand, and price forecasts; sector-specific analyses covering energy end-use (residential, commercial, industrial, transportation), electricity supply, and natural gas supply and transportation; and the preparation of a range of publications on the forecasts and energy sector trends.

From 1989 through 1997, he directed the use of EEA's Energy Overview Model in strategic planning and long-term market analysis for a client base of major energy producers, pipelines, and distributors in both the United States and Canada. The Energy Overview Model was used under his direction as the primary analytical basis for the 1992 National Petroleum Council study The Potential for Natural Gas in the United States. Mr. Crawford also provided analysis for clients on a wide range of other energy market issues, including negotiations related to an LNG import project intended to serve U.S. East Coast markets. This work assessed the utilization and economic value of seasonal

gas deliverability in order to develop LNG pricing formulas and evaluate the project's viability.

Other topical areas of work during his period of employment with EEA include:

Gas Load Analysis and Utility Operations – Principal investigator in a multi-year research program for the Gas Research Institute (GRI) that examined seasonal gas loads, utility operations, and the implications for transmission and storage system reliability and capacity planning.

Gas Transmission and Storage – Principal investigator for a study of industry plans for expansion of underground gas storage capacity in the post-Order 636 environment, including additions of depleted-reservoir and salt-formation storage, an engineering analysis of capital and operating costs for the projects, and unbundled rates for new storage services.

Natural Gas Supply Planning – Mr. Crawford was EEA's senior manager and lead analyst on gas supply planning issues for both pipeline and distribution companies, which included technical and analytic support in development and justification of gas supply strategies; and identification of optimal seasonal supply portfolios for Integrated Resource Planning proceedings.

Transportation Systems Research

Mr. Crawford also had extensive experience in motor vehicle fuel economy and emissions while at EEA. He participated for five years in a DOE research program on fuel economy, with emphasis on the evaluation of differences between laboratory and on-road fuel economy. His work included analysis of vehicle use databases to understand how driving patterns and ambient (environmental) conditions influence actual on-road fuel economy. He also developed a software system to link vehicle certification data systems to vehicle inspection and testing programs and participated in a range of studies on vehicle technology, fuel economy, and emissions for DOE, EPA, and other governmental agencies.

SELECTED PUBLICATIONS (emissions and motor vehicle-related topics)

Statistical Assessment of $PM_{2.5}$ and Meteorology in Fairbanks, Alaska: 2013 Update. Crawford and Dulla. Prepared for the Alaska Department of Environmental Conservation. (forthcoming).

Statistical Assessment of $PM_{2.5}$ and Meteorology in Fairbanks, Alaska. Crawford and Dulla. Prepared for the Alaska Department of Environmental Conservation. March 2012.

Principal Component Analysis: Inventory Insights and Speciated $PM_{2.5}$ Estimates. Crawford. Presentation at Air Quality Symposium 2011, Fairbanks and North Star Borough, Fairbanks, AK. January 2011.

Influence of Meteorology on $PM_{2.5}$ Concentrations in Fairbanks Alaska: Winter 2008-2009. Crawford. Presentation at Air Quality Symposium 2009, Fairbanks and North Star Borough, Fairbanks, AK. July 2009.

Analysis of the Effect of Fuel Chemistry and Properties on HCCI Engine Operation: A Re-Analysis Using a PCA Representation of Fuels. Bunting and Crawford. 2009. Draft Report (CRC Project AFVL13C)

The Chemistry, Properties, and HCCI Combustion Behavior of Refinery Streams Derived from Canadian Oil Sands Crude. Bunting, Fairbridge, Mitchell, Crawford, et al. 2008. (SAE 08FFL 28)

The Relationships of Diesel Fuel Properties, Chemistry, and HCCI Engine Performance as Determined by Principal Components Analysis. Bunting and Crawford. 2007. (SAE 07FFL 64).

Review and Critique of Data and Methodologies used in EPA Proposed Utility Mercury MACT Rulemaking, prepared by AEMS and RWCrawford Energy Systems for the National Mining Association. April 2004.

PCR+ in Diesel Fuels and Emissions Research. McAdams, Crawford, Hadder. March 2002. ORNL/TM-2002/16.

A Vector Approach to Regression Analysis and its Application to Heavy-duty Diesel Emissions. McAdams, Crawford, Hadder. November 2000. ORNL/TM-2000/5.

A Vector Approach to Regression Analysis and its Application to Heavy-duty Diesel Emissions. McAdams, Crawford, Hadder. June 2000. (SAE 2000-01-1961).

Reconciliation of Differences in the Results of Published Shortfall Analyses of 1981 Model Year Cars. Prepared by Energy and Environmental Analysis, Inc. for the U.S. Department of Energy under Contract DE-AC01-79PE-70045. October 1985

Short Test Results on 1980-1981 Passenger Cars from the Arizona Inspection and Maintenance Program. Darlington, Crawford, Sashihara. August 1984.

Seasonal and Regional MPG as Influenced by Environmental Conditions and Travel Patterns. Prepared by Energy and Environmental Analysis, Inc. for the U.S. Department of Energy under Contract DE-AC01-79PE-70045. March 1983.

Comparison of EPA and On-Road Fuel Economy – Analysis Approaches, Trends, and Impacts. McNutt, Dulla, Crawford, McAdams, Morse. June 1982. (SAE 820788)

Regionalization of In-Use Fuel Economy Effects. Prepared by Energy and Environmental Analysis, Inc. for the U.S. Department of Energy under Contract DE-AC01-79PE-70032. April 1982.

1985 Light-Duty Truck Fuel Economy. Duleep, Kuhn, Crawford. October 1980. (SAE 801387)

PROFESSIONAL AFFILIATIONS

Member, Society of Automotive Engineers.

HONORS AND AWARDS

2006 Barry D. McNutt Award for Excellence in Automotive Policy Analysis. Society of Automotive Engineers.

US Patent 7018524 (McAdams, Crawford, Hadder, McNutt). Reformulated diesel fuels for automotive diesel engines which meet the requirements of ASTM 975-02 and provide significantly reduced emissions of nitrogen oxides (NO_x) and particulate matter (PM) relative to commercially available diesel fuels.

US Patent 7096123 (McAdams, Crawford, Hadder, McNutt). A method for mathematically identifying at least one diesel fuel suitable for combustion in an automotive diesel engine with significantly reduced emissions and producible from known petroleum blend stocks using known refining processes, including the use of cetane additives (ignition improvers) and oxygenated compounds.

###

12_B_LCFS_GE Responses (Page 443 – 448)

734. Comment: **Robert Crawford's Resume**

Agency Response: This is submittal three of four of Robert Crawford's resume. It does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

BEFORE THE
CALIFORNIA AIR RESOURCES BOARD

In re:	)
	)
Proposed Regulation on the Commercialization of Alternative Diesel Fuels (Public Hearing Scheduled for March 20, 2014)	)
	)

Declaration of James M. Lyons

I, James M. Lyons, declare and state as follows:

1. I am an engineer with training and expertise in motor vehicle fuels, automotive emissions control, and automotive air pollution. I am a Senior Partner of Sierra Research, Inc. ("Sierra"), an environmental consulting firm located at 1801 J Street, Sacramento, California. Sierra specializes in research and regulatory matters pertaining to air pollution control, and does work for both governmental and private sector clients. I have been employed at Sierra Research since 1991. I received a B.S. degree in Chemistry from the University of California, Irvine, and a M.S. Degree in Chemical Engineering from the University of California, Los Angeles. Before joining Sierra in 1991, I was employed by the State of California in the Mobile Source Division of the California Air Resources Board ("CARB").

Reproduction of Pages 211 - 224 Consisting of Comments ADF B3-93 through ADF B3-105

I. Introduction, Qualifications, and Materials Considered

2. I have prepared this Declaration and the analysis it contains for Growth Energy. I hold the opinions expressed in this Declaration with a reasonable degree of engineering and scientific certainty. I plan to request an opportunity to testify before CARB at the public hearing scheduled for this matter, so that I may answer any questions concerning my opinions and the analysis and sources on which I have based those opinions. I also request that CARB review and

respond to each part of the analysis and opinions presented in this Declaration before deciding what action to take on the CARB staff's proposed alternative diesel fuel ("ADF") regulation.

3. During my career, I have worked on many projects related to the following areas: (1) the assessment of emissions from on- and non-road mobile sources, including ships and locomotives; (2) analyses of the unintended consequences of regulatory actions; and (3) the feasibility of compliance with air quality regulations. I have also studied how the use of biodiesel fuels can influence exhaust emissions of oxides of nitrogen ("NOx") when used in vehicles and engines operated in California, and I have prepared and filed declarations regarding that issue in *POET LLC et al. v. California Air Resources Board*, an action in which I was a co-petitioner.

Reproduction of Pages 211 - 224 Consisting of Comments ADF B3-93 through ADF B3-105

4. I have testified as an expert under state and federal court rules in cases involving CARB regulations for gasoline, Stage II vapor recovery systems and their design, combustion chamber system design, and issues related to emissions from heavy-duty vehicles and engines. While at Sierra I have acted as a consultant on automobile air pollution control matters for CARB and other governmental organizations. I am a member of the American Chemical Society and the Society of Automotive Engineers and have co-authored nine peer-reviewed monographs concerned with automotive emissions, including greenhouse gases and their control. In addition, over the course of my career, I have conducted peer-reviews of numerous papers related to a wide variety of issues associated with pollutant emissions and air quality. My résumé is attached as Attachment A.

5. I have reviewed a report being filed along with this Declaration by Growth Energy that has been prepared by Mr. Robert Crawford of Rincon Ranch Consulting, entitled *NOx Emissions Impact of Soy- and Animal-based Biodiesel Fuels: A Re-Analysis* (December

2013). I have also studied the CARB Initial Statement of Reasons ("ISOR" or "Staff Report") released to support the proposed ADF regulation, and the studies cited in the ISOR that are pertinent to Mr. Crawford's analysis. The additional materials I have considered to prepare this Declaration are identified as references.

6. Mr. Crawford's report examines the empirical basis for the CARB staff's claims that the use of biodiesel in California is unlikely to warrant environmental mitigation, and that the use of biodiesel blends below the ten percent blend level (B10) in California pursuant to the proposed ADF regulation will not result in increases in NOx emissions.

7. Mr. Crawford's report applies generally accepted methods of data analysis and demonstrates expertise in the subject-matter of the report; Mr. Crawford is an expert in the field in which he opines in his report; and his report is the type of analysis on which experts in the field of automotive emissions control rely.

Reproduction of Pages 211 - 224 Consisting of Comments ADF B3-93 through ADF B3-105

II. Analysis and Opinions

A. Increases in NOx Emissions from Biodiesel Blends Below B10

8. As explained in detail in Mr. Crawford's report, a proper statistical analysis of the available emissions data relied upon by CARB staff in developing the proposed ADF regulation demonstrates that statistically significant increases in NOx emissions will result from biodiesel blends that contain less than ten percent biodiesel, including at the five percent level (B5) and below. In addition, Mr. Crawford's report demonstrates that NOx emissions increase in direct proportion of the amount of biodiesel in a blend and there is not, as CARB staff claims, a "threshold" below which biodiesel use in a blend will not increase NOx emissions. Given this, as I explain below in more detail, CARB staff should be proposing a Significance Level of zero, rather than ten percent, for biodiesel. Given the issues identified with the CARB staff analysis of

biodiesel impacts on NOx emissions by Mr. Crawford, CARB has no credible scientific basis upon which to adopt the ADF regulation as proposed with the biodiesel Significance Level set at ten percent.

9. CARB staff presents, in Figures B.2 and B.3 of the ISOR, regressions of all the available emissions data considered by CARB staff in developing the proposed ADF regulation. Based on Mr. Crawford's findings, the slopes of these regression lines can be used to calculate the increases in NOx emissions expected from the use of soy- and animal-based biodiesel as a function of biodiesel content in the blend. The values calculated for soy- and animal-based biodiesel at selected blends levels over the range from one percent to twenty percent are shown in Table 1.

Reproduction of Pages 211 - 224 Consisting of Comments ADF B3-93 through ADF B3-105

Table 1
Expected Increases In NOx Emissions from Biodiesel Use Based on Available Emissions Data Considered by CARB Staff

Biodiesel Blend Level %	Percentage Increase in NOx Emissions	
	Soy-Based	Animal-Based
1	0.2	0.09
2	0.4	0.18
3	0.6	0.27
4	0.8	0.36
5	1	0.45
10	2	0.90
20	4	1.80

10. As shown in Table 1, the magnitude of the NOx increase for animal-based biodiesel is approximately half that observed for soy-based biodiesel. As also shown in Table 1, the emissions data considered by CARB show that increases in NOx emissions between about one and two percent occur at the proposed B10 significance threshold.

B. The "Effective Blend Level" Concept Provides No Assurance Against Increases in NOx Emissions Due to Biodiesel Use

11. The proposed ADF regulation relies on a concept called the "Effective Blend Level" (EB) for biodiesel to determine when mitigation would be required. The formula proposed by CARB staff for calculating the Effective Blend Level for biodiesel is found in proposed Section 2293.6(a) and is reproduced below.

$$EB = 100 \times \left[\frac{NBV - 0.5LN - 0.73RD - VM - 0.55AB}{TCV}\right]$$

As specified in Section 2293.6(a), the above formula is to be used to compute an annual average statewide value for the Effective Blend Level relative to the total volume of fuel used in compression ignition engines excluding alternative fuels such as natural gas and liquefied petroleum gas ("TCV") in the state during that year.

12. The calculation begins with establishing the net volume of biodiesel of all types used in California *excluding biodiesel used in blends of five percent or less* (NBV) — a step that has no scientific basis, as demonstrated by Mr. Crawford's analysis, and that, on its own, completely invalidates the use of the EB metric for the intended purpose. The NBV value is then further reduced by subtracting 50% of the volume of low NOx Diesel (LN) used statewide and 73% of the volume of renewable Diesel used statewide. The remainder is then further reduced by subtracting the volume of biodiesel of all types used in blends where steps have been taken to voluntarily mitigate NOx increases (VM) and then again by subtracting 55% of the volume of animal-based biodiesel (AB) to account for the smaller magnitude of the NOx emission increases observed with that fuel.[1] The final value is then divided by TCV (i.e., the total volume of fuel

Reproduction of Pages 211 - 224 Consisting of Comments ADF B3-93 through ADF B3-105

1 Those voluntary mitigation measures are assumed to have been taken before the so-called "Significance Level" is reached and mitigation would be required under the staff's proposal. *See* ¶ 13.

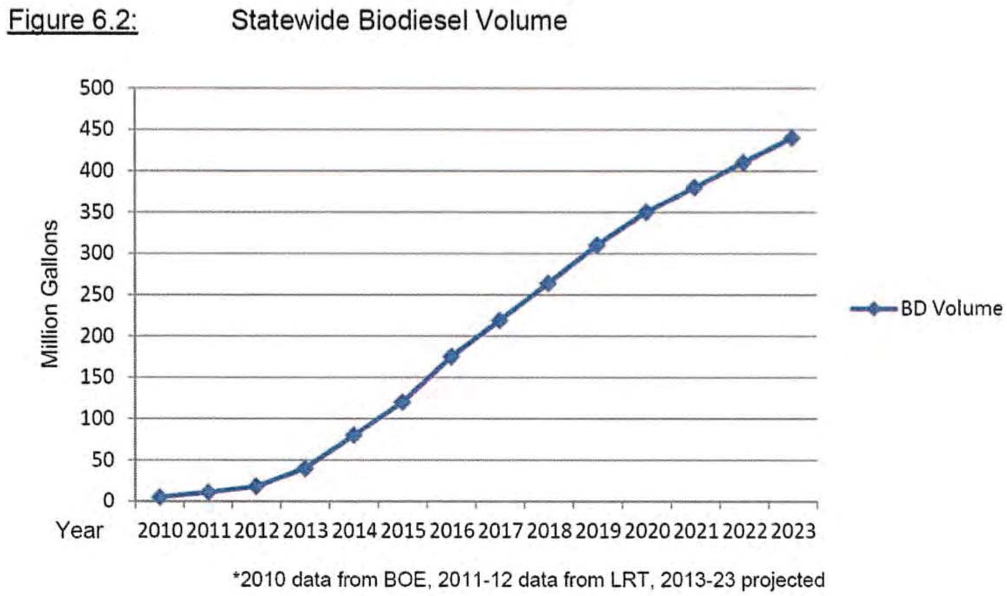
used in compression ignition engines excluding alternative fuels such as natural gas and liquefied petroleum gas in the state during that year) and multiplied by 100 to yield the Effective Blend Level on a percentage basis.

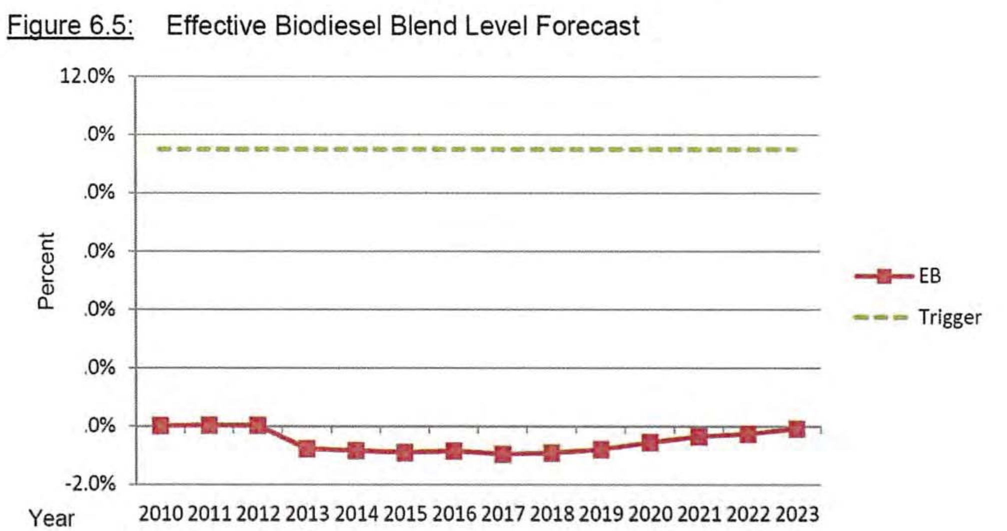
13. As specified in proposed Section 2293.5(c)(4), mitigation of NOx increases associated with biodiesel would be required only when the value of EB reaches 9.5 percent, which is 95% of the 10% Significance Level proposed for biodiesel.

14. There are a number of specific problems with the concept and calculation of the predicted Effective Blend Level that create the potential for significant increases in NOx emissions to result from the use of biodiesel in California; these are explained in detail below and should be addressed by CARB. As an initial matter, however, the overall problem with the EB concept will allow massive increases in the amount of biodiesel used in California without requiring any mitigation of the associated increase in NOx emissions. This can be seen readily by comparing CARB staff's projections of biodiesel use in California (Figure 6.2 of the ISOR) with CARB staff's projections regarding the Effective Blend Level for biodiesel (Figure 6.5 of the ISOR). Those two figures are reproduced below in Figure 1. As can been seen, despite the forecast nine-fold increase in annual biodiesel use in California from 50 million to 450 million gallons from 2013 to 2023 shown in Figure 6.2 of the ISOR, the forecast Effective Blend Level of biodiesel **decreases** to less than zero over virtually all of the period in question — meaning that, under the CARB staff's proposal, no mitigation of the increase in NOx emissions in California from biodiesel use will ever occur. CARB needs to confront and eliminate the EB concept from the staff's proposal, in light of this very simple demonstration of why the EB concept will not protect the environment against increases in NOx emissions.

Reproduction of Pages 211 - 224 Consisting of Comments ADF B3-93 through ADF B3-105

Figure 1. CARB Biodiesel Forecasts





Source: CARB Initial Statement of Reasons. Note that Figure 6.5 is reproduced directly from the ISOR, which is missing some increments on the y-axis.

15. Next, CARB needs to modify the proposed ADF regulation in order to address CARB staff's faulty assumption that biodiesel blends of up to five percent will have no impact on NOx emissions. With respect to five percent blends, CARB staff states on page ES-3 of the Staff

Reproduction of Pages 211 - 224 Consisting of Comments ADF B3-93 through ADF B3-105

Report that "biodiesel used in blends at B9 or below, including the B5 (B0 to B5) in predominant use today, does not increase NOx." The Staff Report also attempts to justify the exclusion of five percent blends from the EB calculation by arbitrarily excluding these blends from the ADF regulation. That assertion is undercut by the Staff Report's frank and correct admission on page 51 that "[g]iven the significant price premium for higher biodiesel blends such as B20 or B100, it is highly unlikely that operators of heavy-duty, legacy diesel fleets would opt to use the more expensive, higher biodiesel blends when comparable, lower cost conventional CARB diesel or B5 blends are readily available."

16. As noted above, Mr. Crawford's analysis demonstrates that statistically significant increases in NOx emissions will occur from the use of five percent biodiesel blends and, as Table 1 shows, the available emissions data relied upon by CARB staff indicate that at the five percent blend level, biodiesel use is expected to increase NOx emission by between about 0.5 and one percent. There is no doubt that unmitigated NOx emission increases of this magnitude have the potential to create significant adverse environmental impacts in areas of California with severe air quality problems.

Reproduction of Pages 211 - 224 Consisting of Comments ADF B3-93 through ADF B3-105

17. It is also important for CARB to understand the import of the staff's prediction that biodiesel blends of five percent or less will be the primary means by which biodiesel will be used in California. As the Staff Report states on page 30:

> Staff has communicated with many of the stations that sell biodiesel as well as the major terminal operators in the state, and has found that the vast majority of the biodiesel currently being sold in California and expected to be sold in the future is sold as blends of B5 or less.

The fact that most biodiesel used in California will be sold as blends of five percent biodiesel or less, coupled with the fact that – as Mr. Crawford has explained – the available data show statistically significant increases in NOx emissions from such blends, means that biodiesel use in

California under the proposed ADF regulation will result in unmitigated increases in NOx emissions. Again, the critical nature of the CARB staff's invalid assumption about the NOx impacts of blends at or below five percent simply cannot be ignored by CARB.

18. Even if it were correct that blends of B5 and less have no impact on NOx emissions, the EB calculation double-counts for the supposedly benign effect of those blends, and therefore makes mitigation even more unlikely. This can be illustrated by noting that CARB staff estimates that 450 million gallons per year of biodiesel will be used in California in 2023. (See Figure 6.2 of the Staff Report.) A recent California Energy Commission forecast[2] for total Diesel use in California in 2023 is about 4 billion gallons. On that basis, and without discounting for low NOx, renewable Diesel, or voluntary mitigation, the actual Effective Blend Level would be 11.25 percent and mitigation would be required for at least some biodiesel blends under the proposed ADF. Under CARB staff's approach, however, if a substantial portion of that biodiesel — for example, 50 percent — is five percent or lower blends, the Effective Blend Level drops to 5.6 percent and no mitigation of any kind is required for any biodiesel blends. That result is clearly incorrect, and the EB calculation must be modified to include, rather than exclude, B5 blends.

19. Another fundamental problem with the proposed EB calculation is that it is based on annual statewide average fuel use. NOx emissions have local and immediate impacts on air quality, with the questions of when and where they occur in the state being of critical importance with respect to the significance of those impacts. It follows directly that mitigation of NOx increases associated with biodiesel use must occur in the same area at the same time if air quality

Reproduction of Pages 211 - 224 Consisting of Comments ADF B3-93 through ADF B3-105

[2] See *http://www.energy.ca.gov/2011publications/CEC-600-2011-007/CEC-600-2011-007-SD.pdf*.

impacts are to be avoided. However, the EB completely fails to provide this assurance because CARB staff has either (1) ignored that reductions in NOx emissions from mitigation must take place at the same time and in the same area as NOx increases from biodiesel use, or (2) without support from anything in the rulemaking file, assumed that mitigation will occur in the same area and at the same time as the increases in NOx emissions.

20. To illustrate the problems the EB creates for mitigation, consider, for example, that under the proposed ADF regulation, increases in NOx emissions could occur from trucks operating on biodiesel in Los Angeles during August and exacerbate already high ambient ozone levels in that area. In turn, this increase in NOx emissions could be "mitigated" by reductions in NOx emissions from trucks operating on renewable diesel in the San Francisco area during December, when high ozone levels are not a problem. In this example, the EB concept would allow residents of Los Angeles to suffer adverse environmental impacts while the residents of San Francisco would realize no environmental benefit. Clearly the approach to mitigation designed into the EB concept by CARB staff makes no sense.

Reproduction of Pages 211 - 224 Consisting of Comments ADF B3-93 through ADF B3-105

C. CARB Staff's Assumption that Biodiesel Use Will not Increase Emissions from New Technology Diesel Engines Is Not Adequately Supported

21. In the Staff Report, CARB staff makes frequent statements regarding the impact of biodiesel on NOx emissions from "new technology diesel engines" (or "NTDEs"). For example, on page ES-3 of the ISOR, the staff states categorically that "use of biodiesel in 2010-compliant engines and other so-called 'New Technology Diesel Engines' does not increase NOx, regardless of the biodiesel blend level." Only one reference, Lammert et al.,[3] is provided in the staff report

[3] Lammert, M., McCormick, R., Sindler, P. and Williams, A., "Effect of B20 and Low Aromatic Diesel on Transit Bus NOx Emissions Over Driving Cycles with a Range of Kinetic Intensity," *SAE Int. J. Fuels Lubr.* 5(3):2012,

(Continued...)

to support this and other, analogous, statements by CARB staff. As CARB staff acknowledges, this single study involved chassis dynamometer testing of only two urban buses with NTDEs, with both engines being the same model produced by the same manufacturer. The extrapolation of that limited testing to the entire population of heavy-duty Diesel vehicles with NTDEs used in different applications and with different engine designs produced by a number of different manufacturers is simply not credible or reliable.

22. In addition, the CARB staff fails to acknowledge the following statement made by the authors of the Lammert study about the measurement of NOx emissions: "For much of the cycle[,] NOx would be at or near the detection limit of the laboratory equipment which resulted in a 95 percent confidence interval that was high relative to the value of the cycle emissions." That effect, which can be clearly seen in Figures 10 and 11 of the Lammert study, renders the claim that there was no statistically significant increase in NOx emissions observed from the use of biodiesel in NTDEs an artifact attributable to the lack of sensitivity of the NOx measurement instrumentation used in the study.

23. In sum, the CARB staff's unequivocal statements regarding the impact of biodiesel on NOx emissions from all vehicles with NTDEs is simply not reasonable based on data from (1) a single study that (2) that tested only two urban buses equipped with the same engine and (3) used instrumentation that was, at best, barely able to measure NOx emissions from the test vehicles in general, and clearly was not sensitive enough to reliably detect changes in NOx emissions due to use of different fuels. Nothing else in the rulemaking file supports the CARB staff's claim that there will not be increased NOx emissions from the use of biodiesel in NTDEs.

Reproduction of
Pages 211 - 224
Consisting of
Comments ADF B3-93
through ADF B3-105

I declare under penalty of perjury under the laws of California that the foregoing is true and correct to the best of my knowledge and belief.

Executed this __12th__ day of December 2013 at Sacramento, California.

James M. Lyons

Reproduction of Pages 211 - 224 Consisting of Comments ADF B3-93 through ADF B3-105

12_B_LCFS_GE Responses (Page 449 – 460)

735. Comment: **Declaration of James M. Lyons**

Agency Response: This is the second time this document was submitted by Growth Energy. It is a reproduction of comments **ADF B3-93** through **ADF B3-105**. The comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

This page intentionally left blank.

ATTACHMENT A

Résumé

James Michael Lyons

sierra
research

1801 J Street
Sacramento, CA 95811
Tel: (916) 444-6666
Fax: (916) 444-8373
Ann Arbor, MI
Tel: (734) 761-6666
Fax: (734) 761-6755

Education

1985, M.S., Chemical Engineering, University of California, Los Angeles

1983, B.S., Cum Laude, Chemistry, University of California, Irvine

Professional Experience

4/91 to present — Senior Engineer/Partner/Senior Partner
Sierra Research

Primary responsibilities include oversight and execution of complex analyses of the emission benefits, costs, and cost-effectiveness of mobile source air pollution control measures. Mr. Lyons has developed particular expertise with respect to the assessment of control measures involving fuel reformulation, fuel additives, and alternative fuels, as well as accelerated vehicle/engine retirement programs, the deployment of advanced emission control systems for on- and non-road gasoline- and Diesel-powered engines, on-vehicle evaporative and refueling emission control systems, and Stage I and Stage II service station vapor recovery systems. Additional duties include assessments of the activities of federal, state, and local regulatory agencies with respect to motor vehicle emissions and reports to clients regarding those activities. Mr. Lyons has extensive litigation experience related to air quality regulations, product liability, and intellectual property issues.

7/89 to 4/91 — Senior Air Pollution Specialist
California Air Resources Board

Supervised a staff of four professionals responsible for identifying and controlling emissions of toxic air contaminants from mobile sources and determining the effects of compositional changes to gasoline and diesel fuel on emissions of regulated and unregulated pollutants. Other responsibilities included development of new test procedures and emission standards for evaporative and running loss emissions of hydrocarbons from vehicles; overseeing the development of the state plan to control toxic emissions from motor vehicles; and reducing emissions of CFCs from motor vehicles.

4/89 to 7/89 Air Pollution Research Specialist
California Air Resources Board

Responsibilities included identification of motor vehicle research needs; writing requests for proposals; preparation of technical papers and reports; as well as monitoring and overseeing research programs.

9/85 to 4/89 Associate Engineer/Engineer
California Air Resources Board

Duties included analysis of vehicle emissions data for trends and determining the effectiveness of various types of emissions control systems for both regulated and toxic emissions; determining the impact of gasoline and diesel powered vehicles on ambient levels of toxic air contaminants; participation in the development of regulations for "gray market" vehicles; and preparation of technical papers and reports.

Professional Affiliations

American Chemical Society
Society of Automotive Engineers

Selected Publications (Author or Co-Author)

"Review of CARB Staff Analysis of 'Illustrative' Low Carbon Fuel Standard (LCFS) Compliance Scenarios," Sierra Research Report No. SR2012-02-01, prepared for the Western States Petroleum Association, February 20, 2012.

"Review of CARB On-Road Heavy-Duty Diesel Emissions Inventory," Sierra Research Report No. SR2010-11-01, prepared for The Ad Hoc Working Group, November 2010.

"Identification and Review of State/Federal Legislative and Regulatory Changes Required for the Introduction of New Transportation Fuels," Sierra Research Report No. SR2010-08-01, prepared for the American Petroleum Institute, August 2010.

"Technical Review of EPA Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis for Non-GHG Pollutants," Sierra Research Report No. SR2010-05-01, prepared for the American Petroleum Institute, May 2010.

"Effects of Gas Composition on Emissions from Heavy-Duty Natural Gas Engines," Sierra Research Report No. SR2010-02-01, prepared for the Southern California Gas Company, February 2010.

"Effects of Gas Composition on Emissions from a Light-Duty Natural Gas Vehicle," Sierra Research Report No. SR2009-11-01, prepared for the Southern California Gas Company, November 2009.

"Technical Review of 2009 EPA Draft Regulatory Impact Analysis for Non-GHG Pollutants Due to Changes to the Renewable Fuel Standard," Sierra Research Report No. SR2009-09-01, prepared for the American Petroleum Institute, September 2009.

"Effects of Vapor Pressure, Oxygen Content, and Temperature on CO Exhaust Emissions," Sierra Research Report No. 2009-05-03, prepared for the Coordinating Research Council, May 2009.

"Technical Review of 2007 EPA Regulatory Impact Analysis Methodology for the Renewable Fuels Standard," Sierra Research Report No. 2008-09-02, prepared for the American Petroleum Institute, September 2008.

"Impacts of MMT Use in Unleaded Gasoline on Engines, Emission Control Systems, and Emissions," Sierra Research Report No. 2008-08-01, prepared for McMillan Binch Mendelsohn LLP, Canadian Vehicle Manufacturers' Association, and Association of International Automobile Manufacturers of Canada, August 2008.

"Attachment to Comments Regarding the NHTSA Proposal for Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015, Docket No. NHTSA-2008-0089," Sierra Research Report No. SR2008-06-01, prepared for the Alliance of Automobile Manufacturers, June 2008.

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act – Part 1: Impacts on New Vehicle Fuel Economy," SAE Paper No. 2008-01-1852, Society of Automotive Engineers, 2008.

"Basic Analysis of the Cost and Long-Term Impact of the Energy Independence and Security Act Fuel Economy Standards," Sierra Research Report No. SR 2008-04-01, April 2008.

"The Benefits of Reducing Fuel Consumption and Greenhouse Gas Emissions from Light-Duty Vehicles," SAE Paper No. 2008-01-0684, Society of Automotive Engineers, 2008.

"Assessment of the Need for Long-Term Reduction in Consumer Product Emissions in South Coast Air Basin," Sierra Research Report No. 2007-09-03, prepared for the Consumer Specialty Products Association, September 2007.

"Summary of Federal and California Subsidies for Alternative Fuels," Sierra Research Report No. SR2007-04-02, prepared for the Western States Petroleum Association, April 2007.

"Analysis of IRTA Report on Water-Based Automotive Products," Sierra Research Report No. SR2006-08-02, prepared for the Consumer Specialty Projects Association and Automotive Specialty Products Alliance, August 2006.

"Evaluation of Pennsylvania's Implementation of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2006-04-01, prepared for Alliance of Automobile Manufacturers, April 12, 2006.

"Evaluation of New Jersey's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-03, prepared for the Alliance of Automobile Manufacturers, September 30, 2005.

"Evaluation of Vermont's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-02, prepared for the Alliance of Automobile Manufacturers, September 19, 2005.

"Assessment of the Cost-Effectiveness of Compliance Strategies for Selected Eight-Hour Ozone NAAQS Nonattainment Areas," Sierra Research Report No. SR2005-08-04, prepared for the American Petroleum Institute, August 30, 2005.

"Evaluation of Connecticut's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-08-03, prepared for the Alliance of Automobile Manufacturers, August 26, 2005.

"Evaluation of New York's Adoption of California's Greenhouse Gas Regulations On Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-07-04, prepared for the Alliance of Automobile Manufacturers, July 14, 2005.

"Review of MOVES2004," Sierra Research Report No. SR2005-07-01, prepared for the Alliance of Automobile Manufacturers, July 11, 2005.

"Review of Mobile Source Air Toxics (MSAT) Emissions from On-Highway Vehicles: Literature Review, Database, Development, and Recommendations for Future Studies," Sierra Research Report No. SR2005-03-01, prepared for the American Petroleum Institute, March 4, 2005.

"The Contribution of Diesel Engines to Emissions of ROG, NOx, and PM2.5 in California: Past, Present, and Future," Sierra Research Report No. SR2005-02-01, prepared for Diesel Technology Forum, February 2005.

"Fuel Effects on Highway Mobile Source Air Toxics (MSAT) Emissions," Sierra Research Report No. SR2004-12-01, prepared for the American Petroleum Institute, December 23, 2004.

"Review of the August 2004 Proposed CARB Regulations to Control Greenhouse Gas Emissions from Motor Vehicles: Cost Effectiveness for the Vehicle Owner or Operator – Appendix C to the Comments of The Alliance of Automobile Manufacturers," Sierra Research Report No. SR2004-09-04, prepared for the Alliance of Automobile Manufacturers, September 2004.

"Emission and Economic Impacts of an Electric Forklift Mandate," Sierra Research Report No. SR2003-12-01, prepared for National Propane Gas Association, December 12, 2003.

"Reducing California's Energy Dependence," Sierra Research Report No. SR2003-11-03, prepared for Alliance of Automobile Manufacturers, November 25, 2003.

"Evaluation of Fuel Effects on Nonroad Mobile Source Air Toxics (MSAT) Emissions: Literature Review, Database Development, and Recommendations for Future Studies," Sierra Research Report No. SR2003-10-01, prepared for American Petroleum Institute, October 3, 2003.

"Review of Current and Future CO Emissions from On-Road Vehicles in Selected Western Areas," Sierra Research Report No. SR03-01-01, prepared for the Western States Petroleum Association, January 2003.

"Review of CO Compliance Status in Selected Western Areas," Sierra Research Report No. SR02-09-04, prepared for the Western States Petroleum Association, September 2002.

"Impacts Associated With the Use of MMT as an Octane Enhancing Additive in Gasoline – A Critical Review", Sierra Research Report No. SR02-07-01, prepared for Canadian Vehicle Manufacturers Association and Association of International Automobile Manufacturers of Canada, July 24, 2002.

"Critical Review of 'Safety Oversight for Mexico-Domiciled Commercial Motor Carriers, Final Programmatic Environmental Assessment', Prepared by John A Volpe Transportation Systems Center, January 2002," Sierra Research Report No. SR02-04-01, April 16, 2002.

"Critical Review of the Method Used by the South Coast Air Quality Management District to Establish the Emissions Equivalency of Heavy-Duty Diesel- and Alternatively Fueled Engines", Sierra Research Report No. SR01-12-03, prepared for Western States Petroleum Association, December 21, 2001.

"Review of U.S. EPA's Diesel Fuel Impact Model", Sierra Research Report No. SR01-10-01, prepared for American Trucking Associations, Inc., October 25, 2001.

"Operation of a Pilot Program for Voluntary Accelerated Retirement of Light-Duty Vehicles in the South Coast Air Basin," Sierra Research Report No. SR01-05-02, prepared for California Air Resources Board, May 2001.

"Comparison of Emission Characteristics of Advanced Heavy-Duty Diesel and CNG Engines," Sierra Report No. SR01-05-01, prepared for Western States Petroleum Association, May 2001.

"Analysis of Southwest Research Institute Test Data on Inboard and Sterndrive Marine Engines," Sierra Report No. SR01-01-01, prepared for National Marine Manufacturers Association, January 2001.

"Institutional Support Programs for Alternative Fuels and Alternative Fuel Vehicles in Arizona: 2000 Update," Sierra Report No. SR00-12-04, prepared for Western States Petroleum Association, December 2000.

"Real-Time Evaporative Emissions Measurement: Mid-Morning Commute and Partial Diurnal Events," SAE Paper No. 2000-01-2959, October 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," SAE Paper No. 2000-01-2958, October 2000.

"A Comparative Analysis of the Feasibility and Cost of Compliance with Potential Future Emission Standards for Heavy-Duty Vehicles Using Diesel or Natural Gas," Sierra Research Report No. SR00-02-02, prepared for Californians For a Sound Fuel Strategy, February 2000.

"Critical Review of the Report Entitled 'Economic Impacts of On Board Diagnostic Regulations (OBD II)' Prepared by Spectrum Economics," Sierra Research Report No. SR00-01-02, prepared for the Alliance of Automobile Manufacturers, January 2000.

"Potential Evaporative Emission Impacts Associated with the Introduction of Ethanol-Gasoline Blends in California," Sierra Research Report No. SR00-01-01, prepared for the American Methanol Institute, January 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," Sierra Research Report No. SR99-10-03, prepared for the Coordinating Research Council, October 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," SAE Paper No. 1999-01-3676, August 1999.

"Future Diesel-Fueled Engine Emission Control Technologies and Their Implications for Diesel Fuel Properties," Sierra Research Report No. SR99-08-01, prepared for the American Petroleum Institute, August 1999.

"Analysis of Compliance Feasibility under Proposed Tier 2 Emission Standards for Passenger Cars and Light Trucks," Sierra Research Report No. SR99-07-02, July 1999.

"Comparison of the Properties of Jet A and Diesel Fuel," Sierra Research Report No. SR99-02-01, prepared for Pillsbury Madison and Sutro, February 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," Sierra Research Report No. SR98-12-02, prepared for the American Petroleum Institute, December 1998.

"Analysis of New Motor Vehicle Issues in the Canadian Government's Foundation Paper on Climate Change – Transportation Sector," Sierra Research Report No. SR98-12-01, prepared for the Canadian Vehicle Manufacturers Association, December 1998.

"Investigation of the Relative Emission Sensitivities of LEV Vehicles to Gasoline Sulfur Content - Emission Control System Design and Cost Differences," Sierra Research Report No. SR98-06-01, prepared for the American Petroleum Institute, June 1998.

"Costs, Benefits, and Cost-Effectiveness of CARB's Proposed Tier 2 Regulations for Handheld Equipment Engines and a PPEMA Alternative Regulatory Proposal," Sierra

Research Report No. SR98-03-03, prepared for the Portable Power Equipment Manufacturers Association, March 1998.

"Analysis of Diesel Fuel Quality Issues in Maricopa County, Arizona," Sierra Research Report No. SR97-12-03, prepared for the Western States Petroleum Association, December 1997.

"Potential Impact of Sulfur in Gasoline on Motor Vehicle Pollution Control and Monitoring Technologies," prepared for Environment Canada, July 1997.

"Analysis of Mid- and Long-Term Ozone Control Measures for Maricopa County," Sierra Research Report No. SR96-09-02, prepared for the Western States Petroleum Association, September 9, 1996.

"Technical and Policy Issues Associated with the Evaluation of Selected Mobile Source Emission Control Measures in Nevada," Sierra Research Report No. SR96-03-01, prepared for the Western States Petroleum Association, March 1996.

"Cost-Effectiveness of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-05, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"Cost of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-04, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"A Comparative Characterization of Gasoline Dispensing Facilities With and Without Vapor Recovery Systems," Sierra Research Report No. SR95-10-01, prepared for the Province of British Columbia Ministry of Environment Lands and Parks, October 1995.

"Potential Air Quality Impacts from Changes in Gasoline Composition in Arizona," Sierra Research Report No. SR95-04-01, prepared for Mobil Corporation, April 1995.

"Vehicle Scrappage: An Alternative to More Stringent New Vehicle Standards in California," Sierra Research Report No. SR95-03-02, prepared for Texaco, Inc., March 1995.

"Evaluation of CARB SIP Mobile Source Measures," Sierra Research Report No. SR94-11-02, prepared for Western States Petroleum Association, November 1994.

"Reformulated Gasoline Study," prepared by Turner, Mason & Company, DRI/McGraw-Hill, Inc., and Sierra Research, Inc., for the New York State Energy Research and Development Authority, Energy Authority Report No. 94-18, October 1994.

"Phase II Feasibility Study: Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley," Sierra Research Report No. SR94-09-02, prepared for the Greater Vancouver Regional District, September 1994.

"Cost-Effectiveness of Mobile Source Emission Controls from Accelerated Scrappage to Zero Emission Vehicles," Paper No. 94-TP53.05, presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, OH, June 1994.

"Investigation of MOBILE5a Emission Factors, Assessment of I/M Program and LEV Program Emission Benefits," Sierra Research Report No. SR94-06-05, prepared for American Petroleum Institute, June 1994.

"Cost-Effectiveness of the California Low Emission Vehicle Standards," SAE Paper No. 940471, 1994.

"Meeting ZEV Emission Limits Without ZEVs," Sierra Research Report No. SR94-05-06, prepared for Western States Petroleum Association, May 1994.

"Evaluating the Benefits of Air Pollution Control - Method Development and Application to Refueling and Evaporative Emissions Control," Sierra Research Report No. SR94-03-01, prepared for the American Automobile Manufacturers Association, March 1994.

"The Cost-Effectiveness of Further Regulating Mobile Source Emissions," Sierra Research Report No. SR94-02-04, prepared for the American Automobile Manufacturers Association, February 1994.

"Searles Valley Air Quality Study (SVAQS) Final Report," Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

"A Comparative Study of the Effectiveness of Stage II Refueling Controls and Onboard Refueling Vapor Recovery," Sierra Research Report No. SR93-10-01, prepared for the American Automobile Manufacturers Association, October 1993.

"Evaluation of the Impact of the Proposed Pole Line Road Overcrossing on Ambient Levels of Selected Pollutants at the Calgene Facilities," Sierra Research Report No. SR93-09-01, prepared for the City of Davis, September 1993.

"Leveling the Playing Field for Hybrid Electric Vehicles: Proposed Modifications to CARB's LEV Regulations," Sierra Research Report No. SR93-06-01, prepared for the Hybrid Vehicle Coalition, June 1993.

"Size Distributions of Trace Metals in the Los Angeles Atmosphere," *Atmospheric Environment*, Vol. 27B, No. 2, pp. 237-249, 1993.

"Preliminary Feasibility Study for a Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley Area," Sierra Research Report No. 92-10-01, prepared for the Greater Vancouver Regional District, October 1992.

"Development of Mechanic Qualification Requirements for a Centralized I/M Program," SAE Paper No. 911670, 1991.

"Cost-Effectiveness Analysis of CARB's Proposed Phase 2 Gasoline Regulations," Sierra Research Report No. SR91-11-01, prepared for the Western States Petroleum Association, November 1991.

"Origins and Control of Particulate Air Toxics: Beyond Gas Cleaning," in Proceedings of the Twelfth Conference on Cooperative Advances in Chemical Science and Technology, Washington, D.C., October 1990.

"The Effect of Gasoline Aromatics on Exhaust Emissions: A Cooperative Test Program," SAE Paper No. 902073, 1990.

"Estimation of the Impact of Motor Vehicles on Ambient Asbestos Levels in the South Coast Air Basin," Paper No. 89-34B.7, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"Benzene/Aromatic Measurements and Exhaust Emissions from Gasoline Vehicles," Paper No. 89-34B.4, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"The Impact of Diesel Vehicles on Air Pollution," presented at the 12th North American Motor Vehicle Emissions Control Conference, Louisville, KY, April 1988.

"Exhaust Benzene Emissions from Three-Way Catalyst-Equipped Light-Duty Vehicles," Paper No. 87-1.3, presented at the 80th Annual Meeting of the Air Pollution Control Association, New York, NY, June 1987.

"Trends in Emissions Control Technologies for 1983-1987 Model-Year California-Certified Light-Duty Vehicles," SAE Paper No. 872164, 1987.

12_B_LCFS_GE Responses (Page 461 – 472)

736. Comment: **James Lyons' Resume**

Agency Response: This is submittal three of six of James Lyon's resume. It does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

ATTACHMENT E

NOx Emission Impacts of Biodiesel Blends:

Technical Summary

Prepared by Robert Crawford
Rincon Ranch Consulting
Tucson, AZ 85730

October 20, 2014

Issues Addressed

- Biodiesel NOx impact
  - How large is it?
  - Does it depend on dataset selection (which blend levels and studies to include)?
- Differences by blendstock type
  - Soy-based blends
  - Animal-based blends
- Emissions differences among animal-based feedstocks
- Are soy- and animal-based blends categorically different in their impact on NOx?
- Some implications for allowing biodiesels into California market

References to Literature

Author	Title	Feedstocks Studied	Blends Studied
Clark 1999	Transient Emissions Comparisons of Alternative Compression Ignition Fuel	Soy	B20
McCormick 2002	Fuel Additive and Blending Approaches to Reducing NOx Emissions from Biodiesel	Soy, UCO	B20
McCormick 2005	Regulated Emissions from Biodiesel Tested in Heavy-Duty Engines Meeting 2004 Emissions	Soy, Canola, Animal	B20
Eckerle 2008	Effects of Methyl Ester Biodiesel Blends on NOx Emissions	Soy	B20
Nuszkowski 2009	Evaluation of the NOx emissions from heavy duty diesel engines with the addition of cetane improvers.	Soy	B20
Nikanjam 2010	Performance and emissions of diesel and alternative diesel fuels	Soy	B5, B20
Thompson 2010	Neat fuel influence on biodiesel blend emissions	Soy	B10, B20
Durbin 2011	Biodiesel Characterization and NOx Mitigation Study	Soy, Animal	B5, B10, B20
Durbin 2013A	CARB B5 Preliminary and Certification Testing	Animal	B5
Durbin 2013B	CARB B20 Biodiesel Preliminary and Certification Testing	Soy, UCO	B20
Karavalakis 2014	CARB Comprehensive B5/B10 Biodiesel Blends Heavy-Duty Engine Dynamometer Testing	Soy, Animal	B5, B10

Datasets Used in Analysis

- ARB Individual Test Run Dataset ("raw data")
  - 4 tables: B5-soy, B10-soy, B5-animal, B10-animal
  - Individual test run measurements for the 3 UCR studies
  - Emission averages for other literature sources
- ARB Literature Dataset
  - Emission averages by engine, test cycle, and blend
  - Through B20 blend level
- We have added the following
  - Number of test replications for emission averages (estimated in some cases)
  - Cetane number for CARB Diesel, biodiesel blends, biodiesel feedstocks
  - Additional testing at B50 and B100 levels (where available).

NOx Impact of Soy-based Biodiesels

- The literature on soy-based blends is large and diverse (see Table 1):
  - 10 different studies (3 UCR studies sponsored by ARB)
  - 13 different vegetable feedstocks (10 soy, 2 UCO, 1 canola)
  - Conducted on a wide variety of engines in different labs
  - 7 different test cycles
- In spite of the diversity, the 3 UCR studies dominate the dataset.
  - The number of test replications (NReps) is used as a weighting factor in this analysis to reflect the better precision of results based on more tests.
  - When this is done, the UCR studies account for 82.5% of the literature dataset. The weight is even larger at the B5 and B10 levels, which come almost solely from the UCR studies.
- It is important to recognize that the effective diversity is less as a result of the weighting. The UCR studies examine only 3 different soy feedstocks.

Table 1: Scope of Emissions Testing for Soy-based Biodiesel

	Clark 1999	McCormick 2002	McCormick 2005	Eckerle 2008	Nuszkowski 2009	Nikanjam 2010	Thompson 2010	Durbin 2011	Durbin 2013A/B	Karavalakis 2014
Biodiesel Feedstocks	Soy	Soy, UCO	Soy, Canola	Soy	Soy	Soy	Soy	Soy	Soy, UCO	Soy
Blend Levels Tested	B20	B20	B20	B20	B20	B5, B20	B10, B20	B5, B20, B50, B100	B5, B20	B5, B10
Engines Tested	One	One	Two	One	Three	One	One	Two On-Road Two Off-Road	One	Two
Test Cycles	FTP	FTP	FTP	FTP	FTP	FTP, ESC	FTP, ESC	FTP, UDDS, 40mph, 50mph, ISO 8178	FTP	FTP, SET, UDDS
Test Replications on Biodiesel	3	9	9	3	9	16	12	172	36	80

NOx Impact of B5 Soy Blends Compared to CARB Diesel

- All B5 blends are soy-based
- The T-Test is the most direct method to assess the difference in mean NOx emissions (B5 vs. CARB Diesel) for individual engines
  - Requires that individual test runs (or standard deviations) be available. Cannot be applied to the Nikanjam data.
- B5 Soy blends clearly increase NOx emissions (see Table 2):
  - In 9 of 12 cases, NOx emissions are observed to increase
  - The NOx emission increases are statistically significant in 6 of the 9 cases (highly significant in 5 cases)
  - All NOx emission increases on the FTP cycle are statistically significant (when the test can be made)
  - None of the 3 observed NOx decreases is statistically significant.
- Conclusion: B5 Soy blends increase NOx emissions across a range of engines and test cycles.

Table 2. T-Test Results for NOx Impact of B5 Soy-based Blends

Source	Feedstock ID	Engine	Cycle	NReps (total)	ΔNOx (gm/bhp-hr)	Prob > |t|	Statistical Significance
Nikanjam 2010	Soy	1991 DDC 60	FTP	8	T-Test not applied. Requires test runs or standard deviations.		
Nikanjam 2010	Soy	1991 DDC 60	ESC	8	T-Test not applied. Requires test runs or standard deviations.		
Durbin 2011	Soy #1	1999 Kubota TRU	ISO 8178-4 C	19	+ 0.084	$p = 0.41$	Not significant
Durbin 2011	Soy #1	2006 Cummins ISM	40mph Cruise	5	+ 0.034	$p = 0.14$	Not significant
Durbin 2011	Soy #1	2006 Cummins ISM	50mph Cruise	12	- 0.020	$p = 0.59$	Not significant
Durbin 2011	Soy #1	2006 Cummins ISM	FTP	39	+ 0.046	$p < 0.001$	Highly significant
Durbin 2011	Soy #1	2007 MBE4000	FTP	12	+ 0.011	$p = 0.001$	Highly significant
Durbin 2013A	Soy #2	2006 Cummins ISM	FTP	12	+ 0.026	$p = 0.002$	Highly significant
Karavalakis 2014	Soy #3	1991 DDC 60	FTP	16	+ 0.045	$p < 0.001$	Highly significant
Karavalakis 2014	Soy #3	1991 DDC 60	SET	8	- 0.030	$p = 0.36$	Not significant
Karavalakis 2014	Soy #3	1991 DDC 60	UDDS	16	+ 0.035	$p = 0.05$	Significant
Karavalakis 2014	Soy #3	2006 Cummins ISM	FTP	16	+ 0.021	$p < 0.001$	Highly significant
Karavalakis 2014	Soy #3	2006 Cummins ISM	SET	8	- 0.011	$p = 0.16$	Not significant
Karavalakis 2014	Soy #3	2006 Cummins ISM	UDDS	17	+ 0.066	$p = 0.23$	Not significant

Note: The t-test analysis uses the ARB dataset of individual test runs ("raw data")

Composite NOx Impact of B5 Soy Blends Compared to CARB Diesel

- To estimate a composite impact across engines, a different statistical approach is needed that will account for the varying NOx emission levels of the engines and test cycles.
- Weighted regression analysis with dummy variables for N-1 engine/test cycle combinations "*i*" has been used to estimate Regression Model 1:

$$\log NOx = a + \sum_{i=2}^{N} \delta_i + b \cdot \delta_{B5}$$

where:

- Coefficients a and δ_i represent the average log *NOx* emission level on CARB Diesel for each engine/test cycle combination. (These values are not reported in the summary of results that follows.)
- $\delta_{B5} = 0$ for CARB Diesel tests; $\delta_{B5} = 1$ for B5 Soy tests
- Coefficient b gives the composite NOx impact of B5 Soy across engines/test cycles.

- The log *NOx* formulation assumes that the emissions impact on a percentage basis is proportional to blend level. The percentage impact on NOx emissions equals $100 \cdot [\exp(b)-1]$

Result for Composite B5 Soy Impact on NOx

- Based on the ARB test run dataset ("raw data")
  - The Nikanjam 2010 B5 testing (with weight of 4 for its NOx averages) can be included with the UCR testing (with weight of 1 for each test run).
- Regression Model 1 Result:
  - $R^2 = 0.9995$ (dominated by the dummy variables that represent the differing NOx emission levels among engines and test cycles)
  - Coefficient b for the δ_{B5} effect has the value: +0.0096 ± 0.0026. The statistical significance is $p = 0.0003$ (highly significant).
- The equivalent percentage NOx increase is **+0.96%** at the B5 level
  - or 0.19% for each 1 percent biodiesel in a blend.

Composite NOx Impact of Soy Blends Through B10

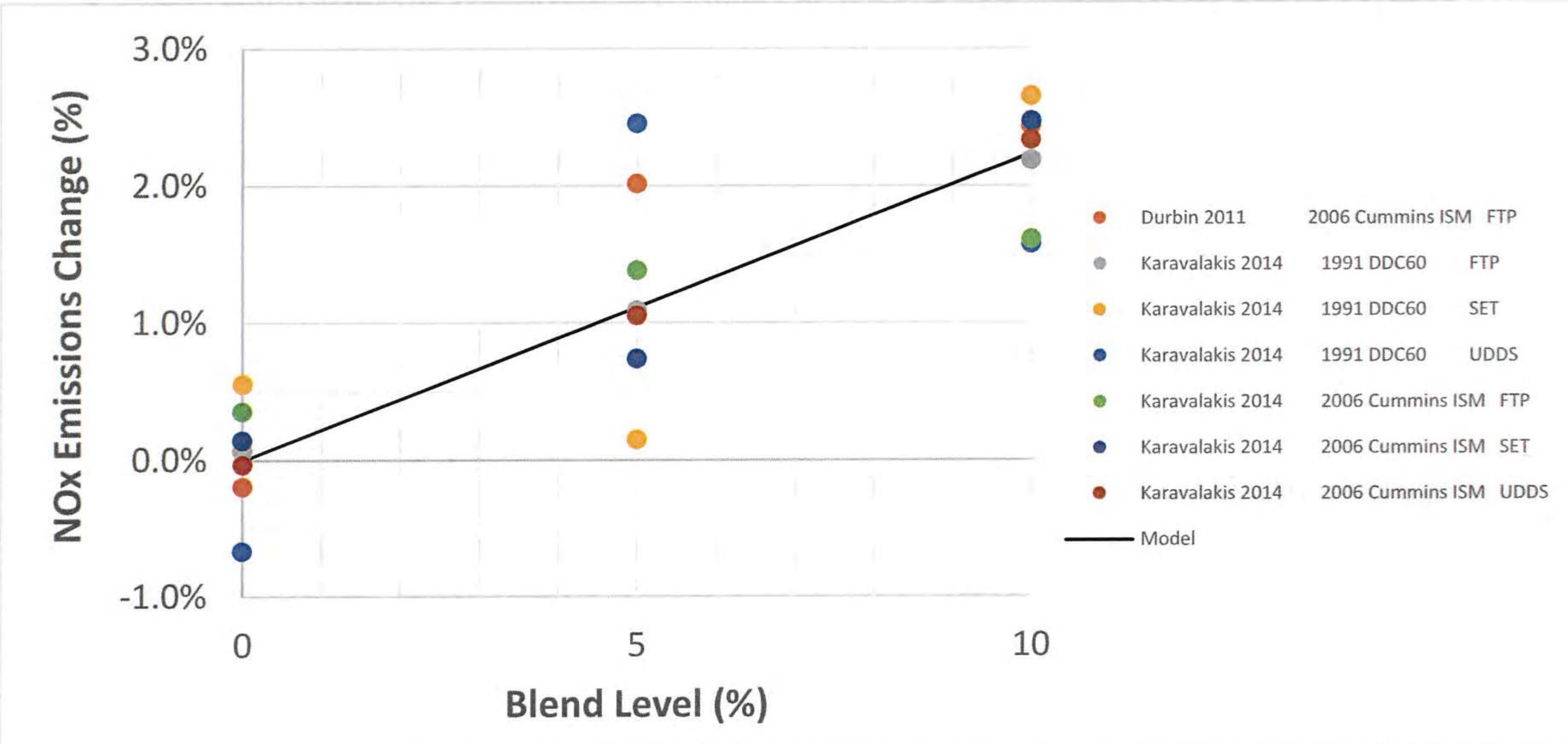
- To assess the composite NOx impact through B10, the regression model is modified to use blend level as the predictive variable. Here, the revised model is fit using the subset of data where individual tests are available ("raw data").
- Unweighted regression analysis with dummy variables for N-1 engine/test cycle combinations "*i*" has been used to estimate Regression Model 2:

$$\log NOx = a + \sum_{i=2}^{N} \delta_i + b \cdot BioPct$$

where:

- Coefficients a and δ_i represent the average log *NOx* emission level on CARB Diesel for each engine/test cycle combination. (These values are not reported in the summary of results that follows.)
- BioPct is the blend level (percentage biodiesel in the blend). CARB Diesel is BioPct = 0; B5 is BioPct = 5.
- Coefficient b gives the composite NOx impact across engines/test cycles for each 1 percent biodiesel in a blend.

Soy biodiesels cause statistically significantly increases in NOx emissions at B10, B5 and Lower blend levels



NOx Impact of Vegetable Biodiesels At Higher Blend Levels

- To include more sources, blends and feedstocks, we shift to analysis of the literature dataset with blend levels above B5. NOx emissions are reported as averages on CARB Diesel and for each BioPct blend level tested.
- Regression Model 2 is fit using emission averages weighted by the number of replications on each blend:

$$\log NOx = a + \sum_{i=2}^{N} \delta_i + b \cdot BioPct$$

where:

- Coefficients a and δ_i represent the average log *NOx* emission level on CARB Diesel for each engine/test cycle combination. (These values are not reported in the summary of results that follows.)
- BioPct is the blend level (percentage biodiesel in the blend). CARB Diesel is BioPct = 0; B5 is BioPct = 5.
- Coefficient b gives the composite NOx impact across engines/test cycles for each 1 percent biodiesel in a blend.

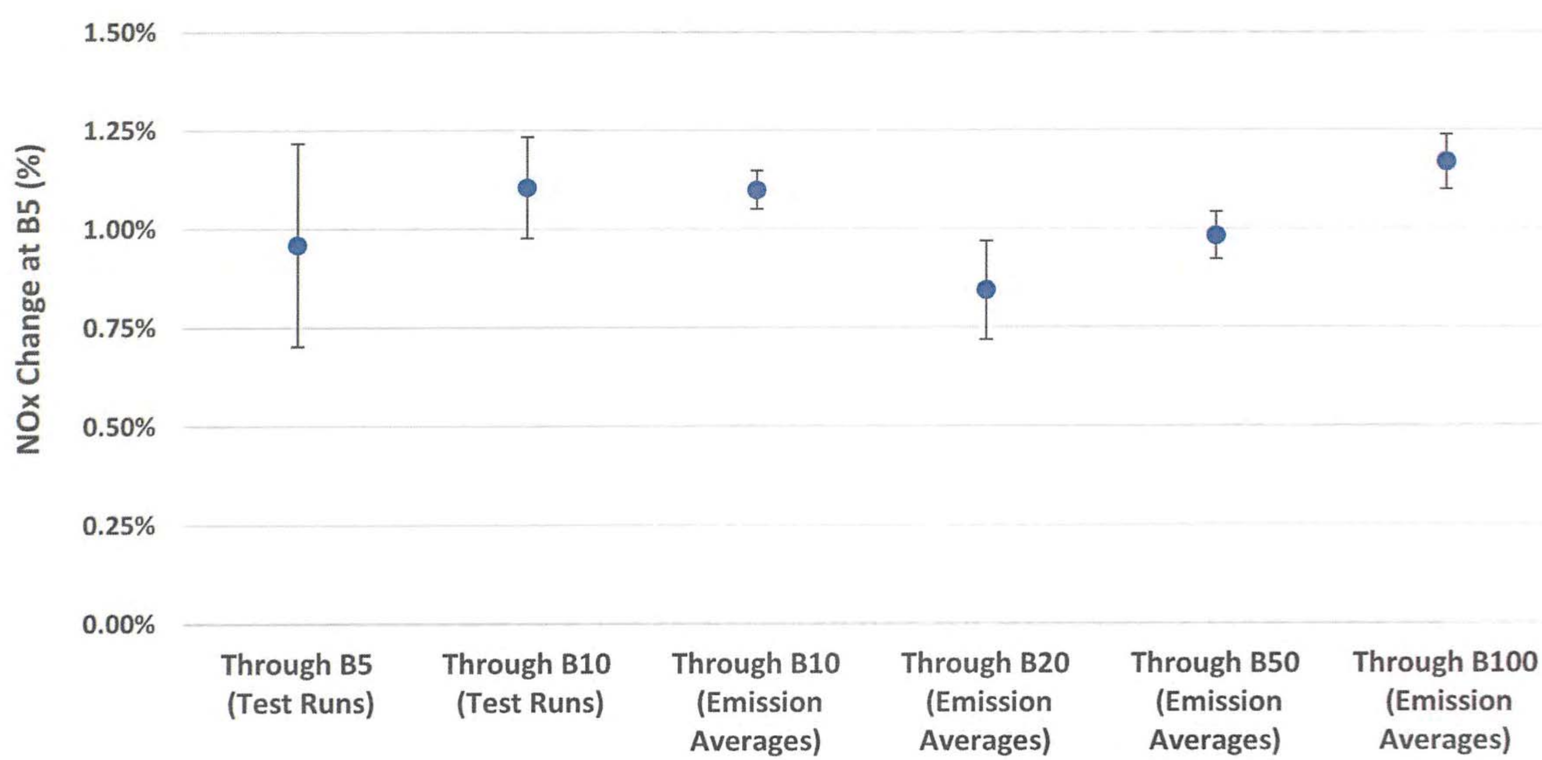
Composite Soy Impact on NOx at Higher Blend Levels

- Including all data through B100 gives the greatest diversity in sources, blends and feedstock.
- Result:
  - $R^2 = 0.9990$ (dominated by the dummy variables that represent the differing NOx emission levels among engines and test cycles)
  - Regression coefficient b for the BioPct effect has value: $+0.00220 \pm 0.00016$. The statistical significance is $p < 0.0001$ (highly significant).
- The equivalent percentage NOx increase is **+1.10%** at the B5 level
  - Or, 0.22% for each 1 percent biodiesel in a blend.
- This result is nearly the same as given by the regression analysis of the individual runs dataset through B5.

Composite Soy Impact on NOx at Higher Blend Levels

- The composite soy impact is also robust with respect to data selection (see Figure 1)
- Different choices for the dataset (test runs versus emissions averages) and the highest blend level to include (through B10, through B20, through B50, and through B100) give different results for the NOx slope with BioPct blending level. However, the results all fall within the errors bars of the estimate based on the B5 test runs alone.
- This indicates that the NOx response is linear with BioPct through high blend levels and that systematic differences among the studies are not large.
- Statistical tests show no difference among soy, UCO, and canola in their NOx impact. However, the UCO and canola samples are small and capable of detecting only large differences.

Figure 1: The NOx Impact of B5 Soy as a Function of Dataset Selection



Conclusions for Soy-based Biodiesels

- Soy biodiesel increases NOx emissions by amounts that can be estimated with good statistical confidence.
- NOx will increase ~1% on average at the B5 level and ~2% at B10.
- The NOx response is linear with the BioPct blend level. <u>There is no threshold level where soy biodiesel does not increase NOx.</u>
- This result is supported by all of the available studies and data (none disagree substantially)
  - Individual blends, engines and test cycles may still vary to some extent.
- NOx increases may be expected for UCO, canola and other vegetable biodiesels, but the data are very limited.

NOx Impact of Animal-based Biodiesel

- The literature on animal-based blends is much smaller than for soy (see Table 3):
  - Only 4 studies (3 UCR studies sponsored by ARB)
  - Only 4 animal feedstocks in total
  - Conducted primarily on engines at UCR CE-CERT (only 6 test replications conducted elsewhere)
  - A variety of test cycles
- The 3 UCR studies dominate the animal-blend dataset to a greater extent than for soy:
  - Counting test replications, the UCR studies account for 97.5% of the dataset. All of the data at the B5 and B10 levels comes from the UCR studies.
- There are notable differences among the four studies on the size of the NOx impact and its relationship to BioPct.
  - *The available studies may not permit a reliable, general understanding of the impacts of animal-based feedstocks.*

Table 3: Scope of Emissions Testing for Animal-based Biodiesels

	McCormick 2005	Durbin 2011	Durbin 2013A	Karavalakis 2014
Biodiesel Feedstock	Animal #1	Animal #2	Animal #3	Animal #4
Blend Levels Tested	B20	B5, B20, B50, B100	B5	B5, B10
Engines Tested	2 on-road	3 on-road, 1 off-road	1 on-road	1 on-road
Test Cycles	FTP	FTP, UDDS, 50 mph, ISO 8178	FTP	FTP, SET, UDDS
Test Replications on Biodiesel	6	126	26	80
NOx Increase Observed?				
At / Below B10	–	Yes	No	No
Above B10	Yes	Yes	–	–

NOx Impact of B5 Animal Compared to CARB Diesel

- The T-Test is the most direct method to assess differences in mean NOx levels between B5 and CARB Diesel for individual engines.
- The McCormick 2005 study tested the Animal #1 feedstock at the B20 level and found a statistically significant increase in NOx, but did not test at the B5 level considered here.
- Table 4 reports this comparison for animal-based biodiesels. Results:
  - Animal #2 *increases* NOx in 2 of 3 engines. The increase is highly significant for 1 engine.
  - Animal #3 *decreases* NOx in one engine. The increase is statistically significant at the $p=0.05$ level. The blend was certified as NOx neutral at B5.
  - Animal #4 *increases* NOx in 3 of 6 cases and *decreases* NOx in the other 3 cases. The results are inconclusive as none of the changes are statistically significant. The blend may or may not change NOx.

T-Test for NOx Impact of B5 Animal Blends

Source	Feedstock ID	Engine	Cycle	NReps (total)	ΔNOx (gm/bhp-hr)	Prob > |t|	Statistical Significance
Durbin 2011	Animal #2	2006 Cummins ISM	FTP	12	+ 0.0067	p = 0.29	Not Significant
Durbin 2011	**Animal #2**	**2007 MBE4000**	**FTP**	**12**	+ 0.0168	p < 0.001	Highly Significant
Durbin 2011	Animal #2	2009 John Deere	ISO 8178	13	- 0.0342	p = 0.21	Not Significant
Durbin 2013A	**Animal #3**	**2006 Cummins ISM**	**FTP**	**52**	- 0.0072	p = 0.054	Significant
Karavalakis 2014	Animal #4	1991 DDC 60	FTP	16	+ 0.0031	p = 0.81	Not Significant
Karavalakis 2014	Animal #4	1991 DDC 60	SET	8	+ 0.0095	p = 0.77	Not Significant
Karavalakis 2014	Animal #4	1991 DDC 60	UDDS	16	- 0.1119	p = 0.31	Not Significant
Karavalakis 2014	Animal #4	2006 Cummins ISM	FTP	16	- 0.0073	p = 0.61	Not Significant
Karavalakis 2014	Animal #4	2006 Cummins ISM	SET	8	+ 0.0025	p = 0.90	Not Significant
Karavalakis 2014	Animal #4	2006 Cummins ISM	UDDS	16	- 0.0993	P = 0.16	Not Significant

Notes: The t-test analysis uses the ARB dataset of individual test runs ("raw data")

NOx Impact of Animal Biodiesels Through B10

- Only Karavalakis 2014 reports testing on B5 <u>and</u> B10 to support an assessment of NOx impacts through B10. This involves a single animal feedstock (Animal #4) and cannot be generalized to a wider range of biodiesels.
- The analysis is based on Regression Model 2 which is linear in BioPct.
- For Animal #4, the NOx trend with BioPct is relatively flat through B10 (see Table 5).
  - The NOx slope is positive (NOx is increased) in 3 of 6 cases and negative (NOx is decreased) in 3 of 6 cases.
  - One slope (1991 DDC 60 on SET cycle) is positive and statistically significant.
- Conclusion: Animal #4 increases NOx through B10 in at least one engine and test cycle.

Table 5. NOx Trend Results Through B10 for An Animal Feedstock

Regression Model 2: $\log NOx = a + \sum_{i=2}^{N} \delta_i + b \cdot BioPct$

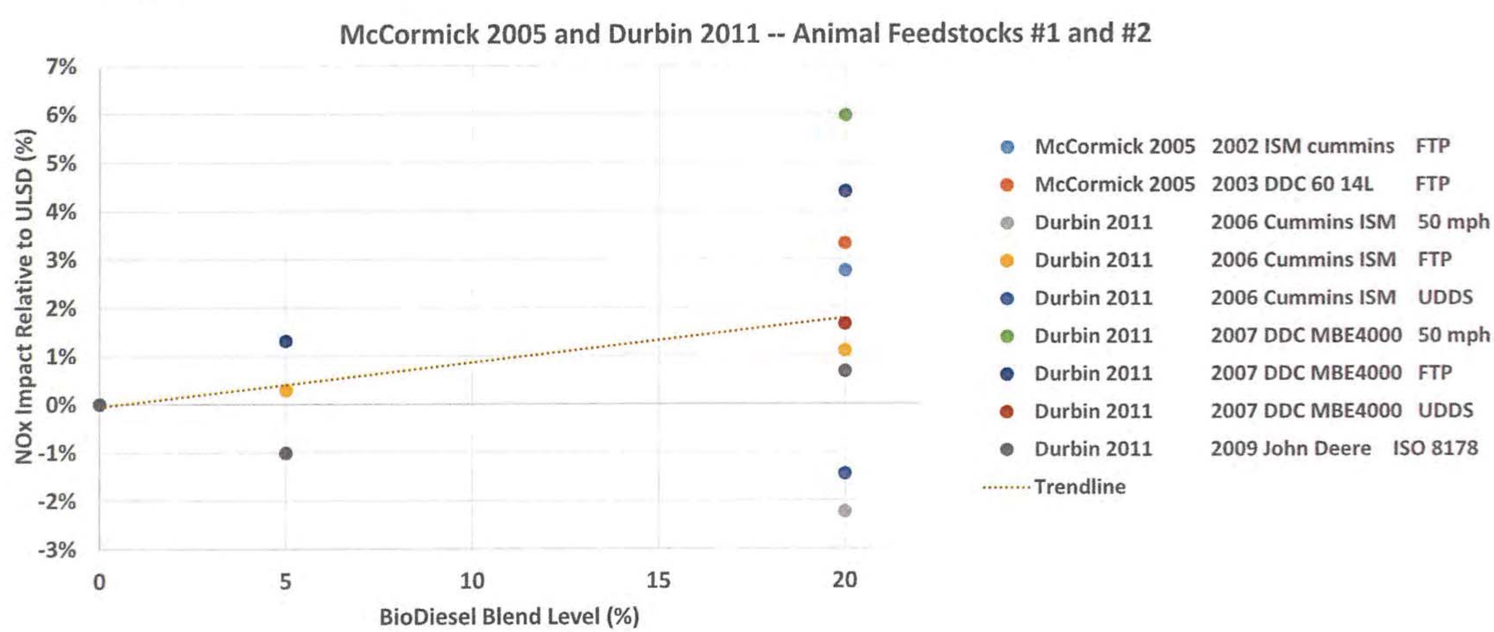
Source	Feedstock ID	Engine	Cycle	BioPct Slope (B) (gm/bhp-hr per % Biodiesel)	Prob > |t|	Statistical Significance
Karavalakis 2014	Animal #4	1991 DDC 60	FTP	+ 0.0012	p = 0.33	Not Significant
Karavalakis 2014	Animal #4	1991 DDC 60	SET	+ 0.0069	p = 0.05	Significant
Karavalakis 2014	Animal #4	1991 DDC 60	UDDS	- 0.0051	p = 0.67	Not Significant
Karavalakis 2014	Animal #4	2006 Cummins ISM	FTP	- 0.0006	p = 0.59	Not Significant
Karavalakis 2014	Animal #4	2006 Cummins ISM	SET	+ 0.0006	p = 0.77	Not Significant
Karavalakis 2014	Animal #4	2006 Cummins ISM	UDDS	- 0.0088	p = 0.19	Not Significant

Note: The regression analysis uses the ARB dataset of individual test runs ("raw data").

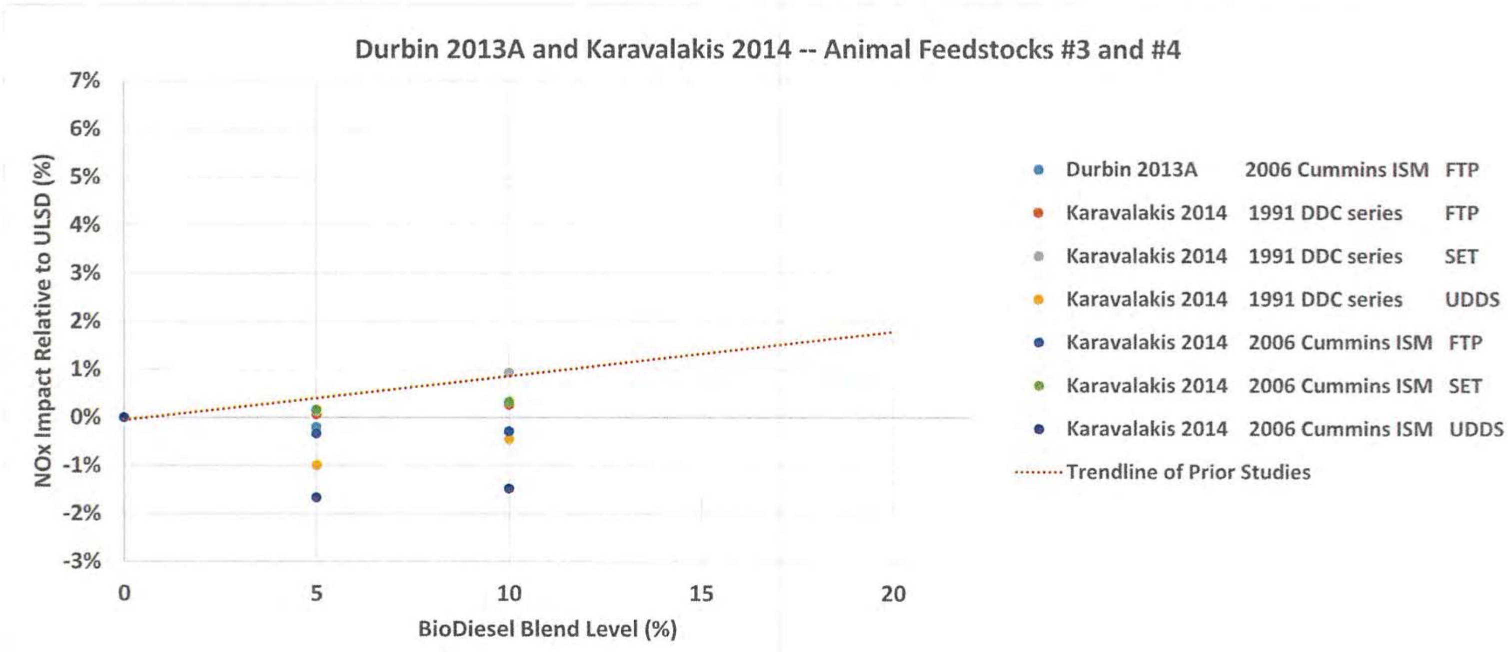
NOx Impact of Animal Biodiesels Through B20

- To include more sources, blends and feedstocks, we shift to analysis of the literature dataset. NOx measurements are reported as averages on CARB Diesel and for each BioPct blend level tested.
- Only graphical analysis is presented through B20 because most sources tested only two blend levels per feedstock (so regression analysis is not useful).
- As the following charts show, the latest ARB studies show substantially lower NOx impacts than the earlier studies and no clear trend with BioPct blend level.
- Each study tested a different animal feedstock. We interpret these results as indicating that the NOx impact can vary in important ways from one animal feedstock to another.

- In the first two studies of animal-based biodiesel:
  - NOx is significantly increased at B20
  - A smaller increase is observed at B5 consistent with a linear model



- In the two most-recent studies of animal-based biodiesel:
  - No appreciable NOx increase is observed through B10
  - NOx impacts are below the trendline of the two prior studies



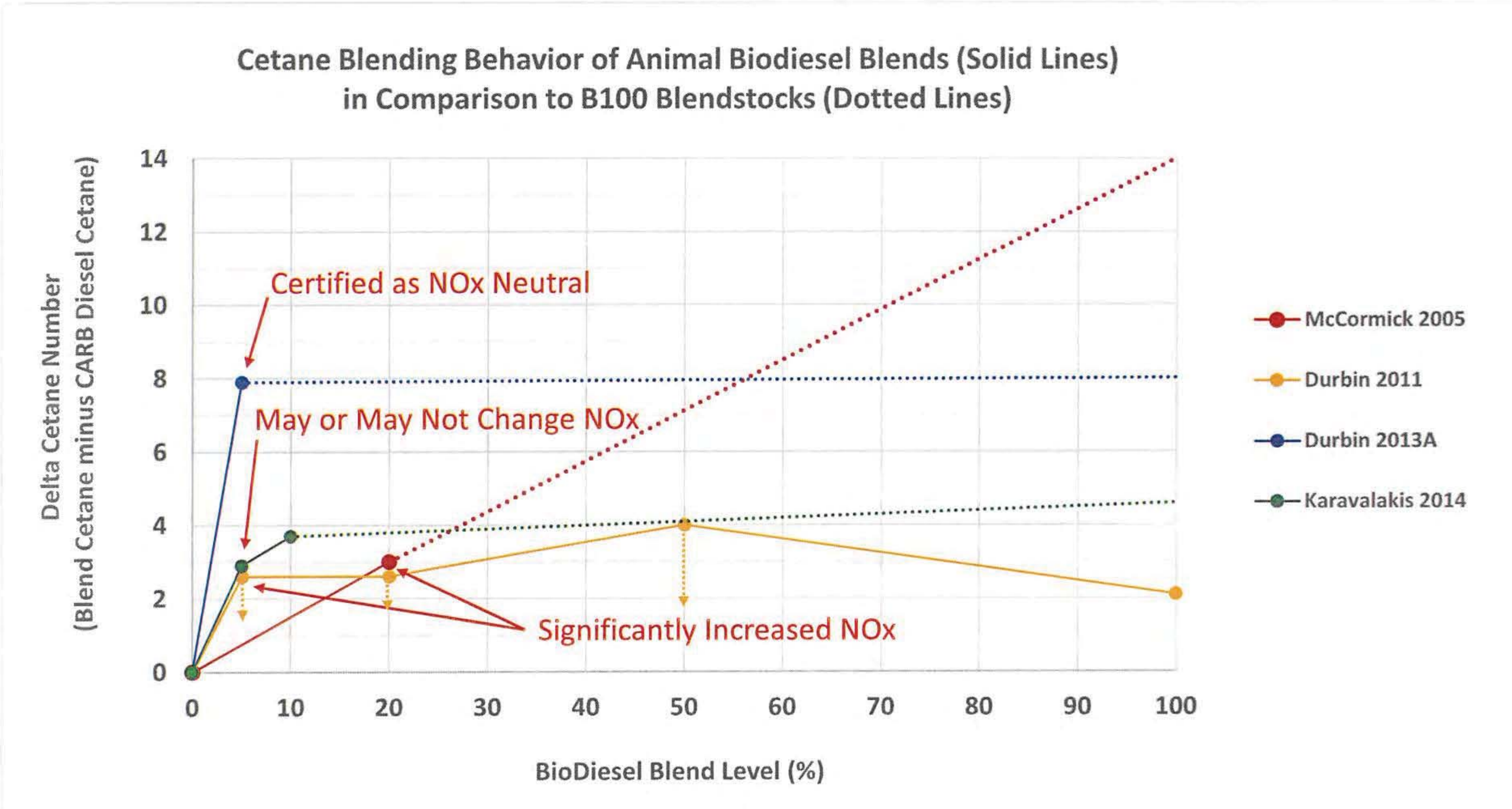
What is the Composite NOx Impact for Animal-based Biodiesel?

- It depends on the blend level range that is considered
- This choice determines the influence given to each study and animal feedstock in the estimate.
- Including higher blending levels (more studies, more feedstocks) gives a better ability to resolve the slope with blend level and may yield a more general result.
- Including only lower blending levels reduces the number of feedstocks and blends considered. Results may not be general.

	Highest Blend Level Considered			
	B10	B20	B50	B100
Weight Given to Studies				
McCormick 2005	0%	2%	2%	2%
Durbin 2011	15%	59%	63%	67%
Durbin 2013A	21%	10%	9%	8%
Karavalakis 2014	65%	30%	27%	24%
Composite BioPct Slope				
ΔNOx (%) per 1% Biodiesel	- 0.03%	+ 0.05%	+ 0.29%	+ 0.16%
Standard Error of Estimate	± 0.03%	± 0.03%	± 0.09%	± 0.06%
Prob > |t|	p = 0.35	p = 0.15	p < 0.01	p = 0.01
Statistically Significant?	No	No	Yes	Yes

A Better Understanding of Cetane Effects is Needed

- The higher cetane number of animal feedstocks is a likely reason that animal-based blends have lower NOx impacts than soy-based blends.
- Cetane is complicated and may or may not blend linearly with volume.
- The following chart shows that <u>all</u> of the UCR animal-based blends have a large cetane benefit, achieving most (or all) of the B100 cetane at low blend levels.
  - Lab differences could be involved. Durbin 2011 measured cetane for the blends at CE-CERT, while cetane for CARB Diesel and B100 was determined by an outside lab.
  - The large cetane boosts at low blend levels help to offset NOx increases.
- The McCormick 2005 animal feedstock behaves differently, with cetane blending linearly with BioPct in the B20 blend. The cetane benefit of this feedstock expected at the B5 level is small compared to the three UCR feedstocks.
- *What is the evidence that the rapid cetane boost observed for the UCR blends is real and representative of the cetane behavior of animal feedstocks available in the California market?*


Cetane Blending Behavior of Animal Biodiesel Blends (Solid Lines)
in Comparison to B100 Blendstocks (Dotted Lines)
Delta Cetane Number
(Blend Cetane minus CARB Diesel Cetane)
14
12
10
8
6
4
2
0
0
10
20
30
40
50
60
70
80
90
100
BioDiesel Blend Level (%)
Certified as NOx Neutral
May or May Not Change NOx
Significantly Increased NOx
McCormick 2005
Durbin 2011
Durbin 2013A
Karavalakis 2014

31

What Do We Know About the Animal-based blends?

- Not enough to fully understand the emissions results. ARB should release all available information on its animal feedstocks and blends, including the distillation curves and the FAME and oxygen content analysis (if performed).
- ARB should clarify how it has determined cetane number in the 3 UCR studies and confirm its animal-blend cetane numbers with outside testing.

	McCormick 2005	Durbin 2011	Durbin 2013A	Karavalakis 2014
Feedstock Description	Beef Tallow	Animal	Animal Tallow	Animal
B100 Cetane Number	65	57.9	61.1	58.0
Flash Point (°C)	159	164	144	165
Cloud Point (°C)	14	13	15	–
Kinematic Viscosity 40C (mm^2/s)	4.71	4.41	4.691	4.714
Specific Gravity	0.8754	–	0.8750	0.875
API Gravity	–	28.5	30.2	30.3
Distillation T90 (°C)	351	348	352	Not Reported
Iodine Number	56	Not Reported	Not Reported	Not Reported

Conclusions on NOx Impact of Animal-based Biodiesel Blends

- Animal-based biodiesels have smaller NOx impacts than soy-based blends. The tendency of animal feedstocks to increase cetane is a likely reason.
- The animal-blends dataset is much more limited than for soy, with only four different feedstocks examined in the entire literature.
- There is disagreement among the studies on the NOx impact of B5 animal blends:
  - One B5 blend has significantly increased NOx on one engine and test cycle.
  - One B5 blend has been certified as NOx neutral on one engine and test cycle.
  - Other B5 blends may or may not increase NOx depending on engine and test cycle
- We need to understand the cetane behavior in the UCR blends and what is representative of animal biodiesels in California before more general conclusions can be drawn for animal-based blends.

The Influence of Cetane on Biodiesel NOx Impacts

Cetane is a Key Driver of the NOx Impact for Biodiesel

- This section presents an analysis that demonstrates that soy- and animal-based blends are <u>not categorically different</u> once their differing effect on blend cetane is accounted for.
  - Soy-based feedstocks have more unsaturated carbon bonds and tend to reduce cetane below that of CARB Diesel, although some soy and other vegetable feedstocks can increase cetane.
  - Animal-based feedstocks are more highly saturated and tend to increase cetane above that of CARB Diesel in most cases.
- When a cetane term is added, soy- and animal-based blends can be represented by the same model.
- The preliminary analysis indicates a method of predicting which biodiesel blends will have the greatest impact on NOx emissions.

Cetane-based Model of the Biodiesel NOx Impact

- The analysis uses the complete literature dataset – all blends at blending levels through B20 – in a modified regression analysis.
- Regression Model 3 is fit using emission averages weighted by the number of replications on each blend:

$$\log NOx = a + \sum_{i=2}^{N} \delta_i + b \cdot BioPct + c \cdot \Delta Cetane$$

where:

- Coefficients a and δ_i represent the average log NOx emission level on CARB Diesel for each engine/test cycle combination. (These values are not reported in the summary of results that follows.)
- BioPct is the blend level (percentage biodiesel in the blend). CARB Diesel is BioPct = 0;

  B5 is BioPct = 5.
- ΔCetane is the change in cetane number of the blend compared CARB Diesel
- Coefficient b gives the composite NOx impact across engines/test cycles for each 1 percent biodiesel in a blend at constant cetane (i.e., ΔCetane = 0).
- Coefficient c gives an adjustment to NOx emissions in proportion to ΔCetane.

Result for Cetane-based Model of Biodiesel NOx Impacts

- Result: $R^2 = 0.9948$ (dominated by the dummy variables that represent the differing NOx emission levels among engines and test cycles)

Coefficient	Estimate	Prob > |t|	Statistical Significance
b	+ 0.00156	$p < 0.0001$	Highly Significant
c	- 0.00303	$p < 0.0001$	Highly Significant

- The NOx increase is 0.16% for each 1 percent biodiesel in a blend, or 0.8% for B5 <u>at constant cetane</u>.
  - – Soy blends have an additional, adverse cetane effect on average that increases the NOx impact to ~1%.
  - – Animal blends tend to increase Cetane, so have reduced NOx impacts in comparison.

Result for Cetane-based Model of Biodiesel NOx Impacts

- The *c* coefficient estimates that +5 Cetane Numbers will decrease NOx emissions by 1.5%.
  - Other work* also finds a 1.5% NOx reduction for +5 Cetane Numbers in base blends with Cetane levels of ~50.
- An increase of $-b/c = 0.5$ Cetane Numbers is needed to offset the NOx increase expected from each 1% biodiesel added. For B5, an increase of 2.5 Cetane numbers is required to offset the NOx increase.
- Statistical tests of the residuals indicate that the model explains all of the observed differences among biodiesel types (animal, soy, UCO, canola) and among studies.

* *The Effect of Cetane Number Increase Due to Additives on NOx Emissions from Heavy-Duty Highway Engines.* EPA420-R-03-002. February 2004. Figure IV.A.-1.

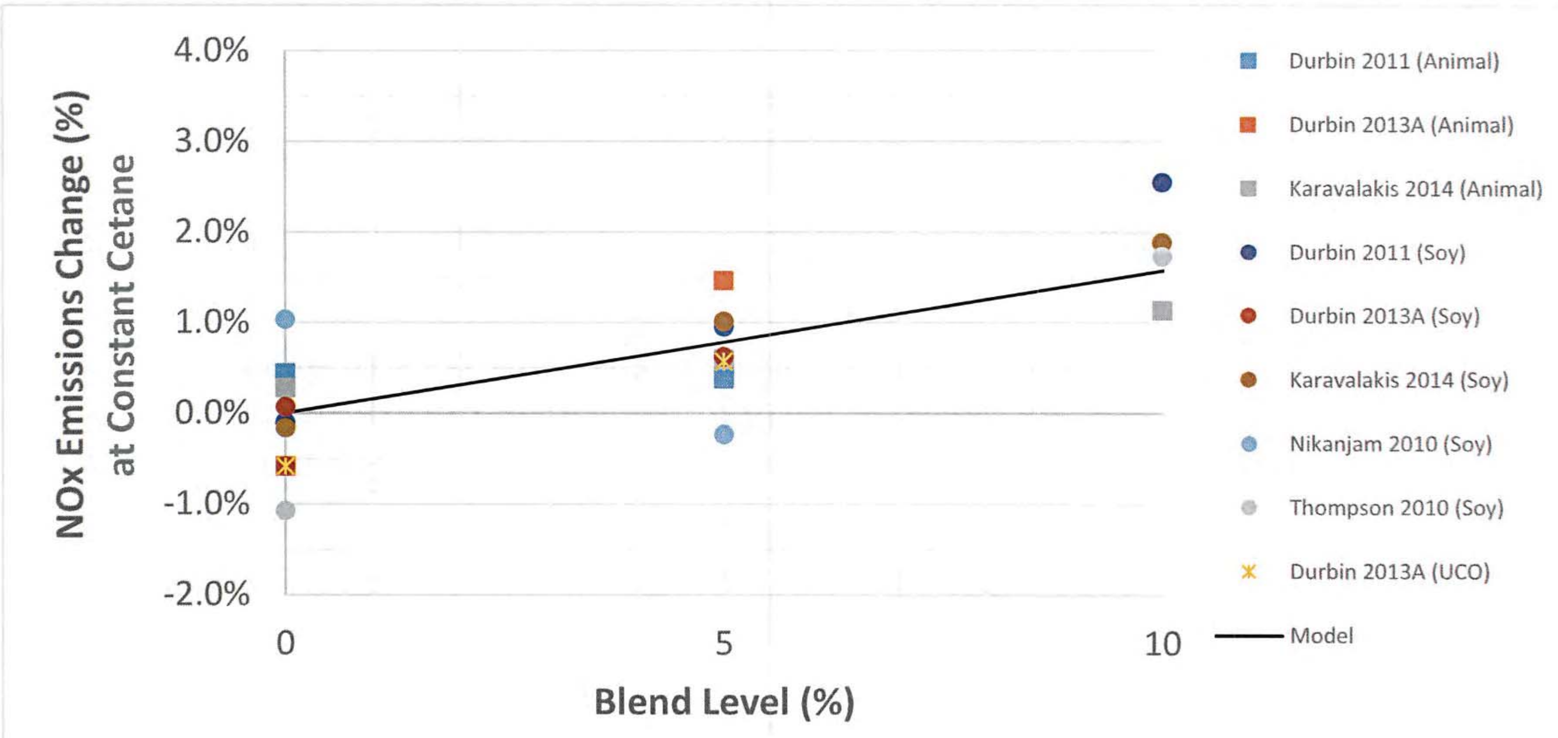
NOx Emission Changes At Constant Cetane

- The *c* coefficient can be used to remove the effect of cetane changes from the measured NOx emission values. The adjustment takes each biodiesel blend back to the cetane number of the CARB diesel used as the base blend in its testing.
- For each combination *i* (study, feedstock, engine, and test cycle), the percent change in NOx emissions at blend level *j* can be estimated as follows:

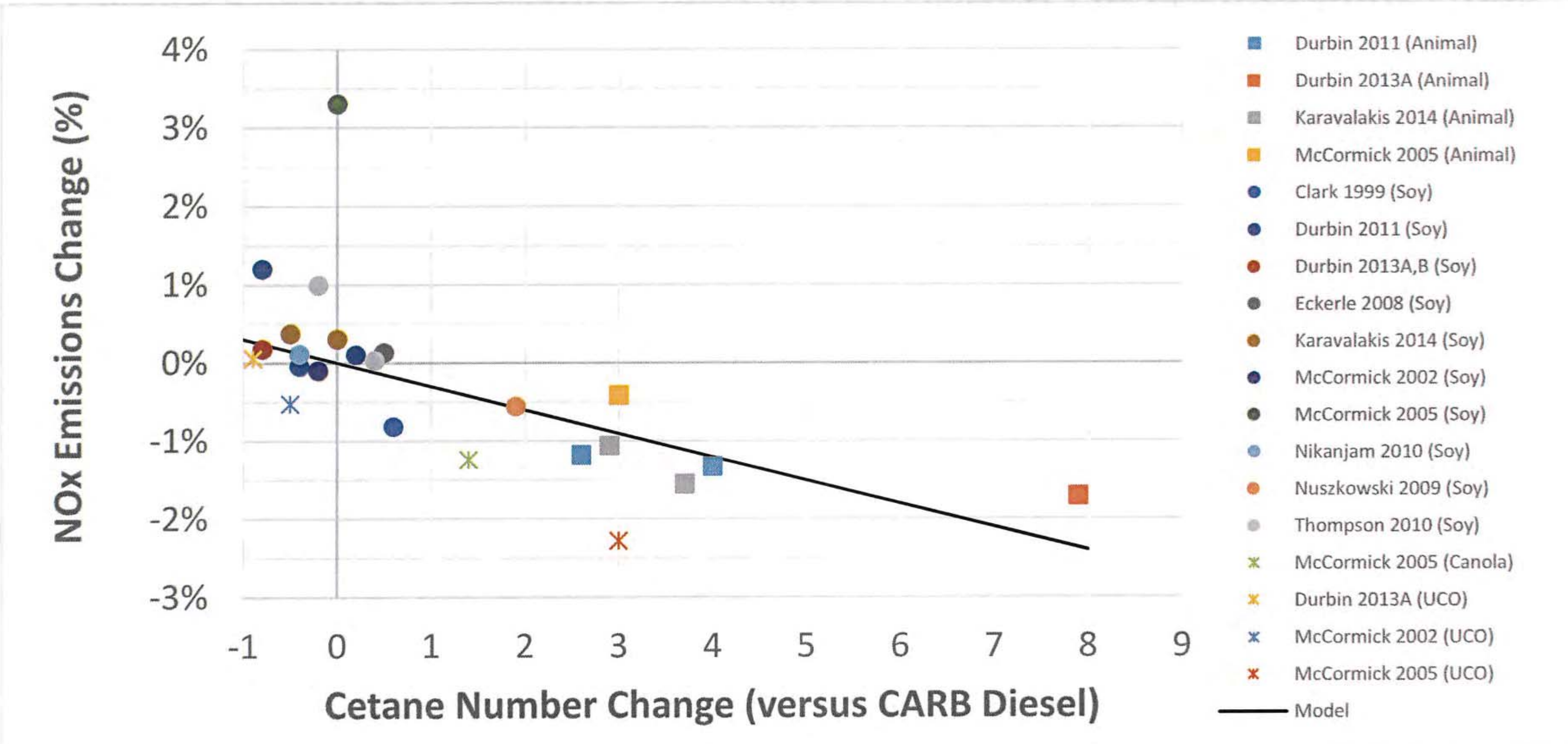
$$\Delta NOx_{i,j} = \exp\left[\ln NOx_{i,j} - (a_i + \textstyle\sum_{i=2}^{N} \delta_i) - c \cdot \Delta Cetane_i\right] - 1$$

- This approach references the percent change in NOx to the emission intercept $a_i + \sum_{i=2}^{N} \delta_i$ estimated on CARB diesel for each engine/test cycle.
- Average percentage changes for each study, feedstock, engine, test cycle, and blend level are then plotted in the following figure.

There is no detectable difference among feedstock types when NOx emission changes are adjusted to constant Cetane Number



The Response of NOx to Cetane Number is the Same for Soy- and Animal-based Biodiesel Blends (When Adjusted for Blend Level)



Cetane-based Model of Biodiesel NOx Impacts

- Our preliminary analysis suggests a method of predicting the NOx emission impacts of biodiesel blends.
- Further work is needed:
  - To demonstrate that blends mitigated using DTBP or by co-blending with renewable diesel obey the same model
  - To assess whether the four animal feedstocks that have been tested are representative of all animal feedstocks available in the California market.
  - Additional emissions testing may be needed if we see that the four animal feedstocks are not fully representative.
- More advanced statistical techniques (Mixed Effects modeling) may also be needed, as used in the Predictive Model for gasoline.

Some Implications for Biodiesel in California

- Soy- and animal-based blends are not categorically different fuels once their differing effect on blend Cetane is accounted for.
- There is no threshold blend level where biodiesel fuels as a group do not increase NOx, whether soy- or animal-based.
- Soy-based blends clearly and significantly increase NOx by ~1% at B5 and by correspondingly larger amounts at higher blend levels. Soy blends <u>require</u> mitigation at all levels to offset increased NOx emissions.
- Animal-based blends are more complicated. The current research is limited and the evidence is mixed:
  - At least one B5 animal blend significantly increases NOx, while another has been certified as NOx neutral.
  - Other B5 animal blends may or may not increase NOx depending on their effect on Cetane Number (and possibly other factors).
- Animal-based blends cannot be assumed to have no impact on NOx emissions without an assessment of the impact of feedstock blending on Cetane number.

12_B_LCFS_GE Responses (Page 473 – 518)

737. Comment: **NOx Emission Impacts of Biodiesel Blends: Technical Summary**

Agency Response: This document is a presentation of a study conducted by Rincon Ranch. It does not constitute an objection or suggestion on the proposal; however the document was referenced in comments **ADF B3-137** through **ADF B3-152**. The comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

This page intentionally left blank.

ATTACHMENT F

NOx Emission Impacts of Biodiesel Blends

1. Introduction

In the Alternative Diesel Fuels rulemaking, the California Air Resources Board (ARB) is attempting to create a regulatory framework that will permit biodiesel and other alternative diesel fuels to increase their penetration of the California market. Biodiesel is known to increase emissions of nitrogen oxides (NOx). NOx emissions are an important precursor to smog and have historically been subject to stringent emission standards and mitigation programs to prevent growth in emissions over time. A crucial issue with respect to biodiesel is how to "... safeguard against potential increases in oxides of nitrogen (NOx) emissions."[1] ADF B3-137

In July 2014, ARB released two datasets that represent the fruit of their efforts to compile biodiesel NOx emissions test data available in the literature on heavy-duty truck (HDT) engines. This document and the companion file *"Biodiesel Emissions Analysis Technical Summary 102014.pdf"* present the results of a statistical analysis of the data sets released by ARB that was performed by Rincon Ranch Consulting at the request of Growth Energy.

This analysis focused on whether soy and animal blends will increase NOx at low blend levels. The following issues were examined:

- The NOx impacts of soy and animal blends at B5 and B10;
- The NOx emission differences observed among animal feedstocks and blends;
- For animal blends, the effect on NOx emissions of the Cetane Number (CN) change relative to base fuel that is caused by blending of the animal feedstock; and
- The development of a cetane-based model of the biodiesel NOx impacts of soy and animal blends.

The key results and conclusions of the study are summarized here. For additional information, the reader is directed to *"Biodiesel Emissions Analysis Technical Summary 102014.pdf"* which has been provided along with this document.

2. Data Used in the Analysis

As noted above, in July 2014, ARB released two datasets of NOx emissions data from testing of biodiesel blends in HDT engines. One file ("B5 & B10 Raw NOx Data") contains the subset of testing for B5 and B10 blends (soy and animal). The test data generated in the four ARB-sponsored UCR studies are present in the form of the individual test run measurements. Because test run information was not reported in their publications, the B5 soy data from Nikanjam 2010 and the B10 soy data from Thompson 2010 are present in the form of emission averages. No animal blends have been tested at the B5 or B10 levels except in the ARB-sponsored emissions testing. A second file ("2014 Biodiesel ADF B3-138

[1] "Proposed Regulation on the Commercialization of New Alternative Diesel Fuels. Staff Report: Initial Statement of Reason." California Air Resources Board, Stationary Source Division, Alternative Fuels Branch. October 23, 2013. http://www.arb.ca.gov/regact/2013/adf2013/adf2013isor.pdf.

Literature Search Database") contains all of the biodiesel testing available in the literature through the B20 level (soy and animal), including ARB-sponsored testing and the literature search. The data are in the form of emission averages by engine, test cycle, feedstock type, and blend level.

For purposes of this analysis, the following information was added to the ARB datasets:

- The number of test replications for emissions averages for each study (estimated when the source did not report the number);
- The CN for CARB diesel, the biodiesel blends, and the biodiesel feedstocks; and
- Additional NOx emissions testing at the B50 and B100 levels (where available).

ADF B3-138 cont.

Appendix Table A presents a list of the studies included in the dataset and the author references used in citations here.

3. NOx Emissions from Soy Biodiesel Blends

Most past research on biodiesel emissions has focused on soy blends. As a result, the literature is relatively large and diverse. The dataset assembled by ARB is derived from 10 different studies, covers 13 different vegetable feedstocks (10 soy, 2 used cooking oil [UCO], 1 canola), and was conducted using 7 different test cycles on a wide variety of engines in different labs. Most of the data, in terms of number of data points, is derived from the three UCR studies (Durbin 2011, Durbin 2013B, and Karavalakis 2014) sponsored by ARB.

We subjected the soy dataset to a number of different analyses using different statistical techniques and selections of the data to ensure that the conclusions we drew were robust across analytical techniques and datasets. The statistical analysis included the T-Test for the difference in mean values (e.g., between B5 and CARB diesel) and linear regression analysis using several different models. The data subsets were selected to use either individual test runs or emission averages and to contain testing through maximum blend levels of B5, B10, B20, B50, and B100.

ADF B3-139

Our analyses show that there is a consensus among the studies on the NOx impact of soy biodiesel without regard to the specific analytical methods or data used. Soy biodiesel increases NOx emissions by amounts that can be estimated with good statistical confidence because of the large size of the available dataset. The key conclusions are as follows:

- Soy biodiesel increases NOx emissions by ~1% at B5 and ~2% at B10;
- NOx emissions increase in a linear fashion with increasing blend level to reach ~4% at B20 and proportionately larger values at higher blend levels; and
- There is no evidence in the data for a threshold level below which soy biodiesel does not increase NOx.

These conclusions are supported by all of the available studies and data. None of the studies disagree substantially, and while the results for individual blends, engines, and test cycles will vary to some extent, the evidence across a wide range of engines and test cycles is clear. NOx increases can be expected for UCO, canola, and other vegetable biodiesels, but the data are very limited and it is not possible to draw definitive conclusions for these blends.

4. NOx Emissions from Animal Biodiesel Blends

The literature on NOx emissions from animal blends is much smaller. It consists of only four studies, three of which (Durbin 2011, Durbin 2013A, and Karavalakis 2014) were sponsored by ARB. Except for the McCormick 2005 study, the emissions testing was conducted at the UCR CE-CERT lab. A variety of test cycles were used, but most of the testing was conducted on the hot-start FTP cycle. Table 1 presents a summary of the emissions studies for animal biodiesel.

Table 1. Scope of Emissions Testing for Animal Biodiesel

	McCormick 2005	Durbin 2011	Durbin 2013A	Karavalakis 2014
Biodiesel Feedstock	Animal #1	Animal #2	Animal #3	Animal #4
Blend Levels Tested	B20	B5, B20, B50, B100	B5	B5, B10
Engines Tested	2 on-road	3 on-road, 1 off-road	1 on-road	1 on-road
Test Cycles	FTP	FTP, UDDS, 50 mph, ISO 8178	FTP	FTP, SET, UDDS
Test Replications on Biodiesel	6	126	26	80
Is NOx Increase Observed?				
At / Below B10	–	Yes	**No**	**No**
Above B10	Yes	Yes	–	–

ADF B3-140

It is important to understand the limitations of this small dataset. Without the ARB-sponsored testing, we would have only the six test replications (individual runs) conducted in the McCormick 2005 study. While the three UCR studies accumulated 232 test replications, the work involved only three different animal feedstocks. Including the McCormick 2005 study, the entire literature on NOx emissions from animal biodiesel is based on only four different animal feedstocks. The small number is an important limitation because animal feedstocks are much less homogenous than soy due the greater variety possible in animal sources and compositions. Further, there are notable differences among the four studies as to whether animal biodiesel increases NOx at the B5 and B10 levels (as indicated by the red circles in the table).

As in the soy analysis, we subjected the animal biodiesel data to a number of different analyses using different statistical techniques and selections of the data to ensure that the conclusions we drew were robust. The T-Test is the most direct method to assess whether NOx emissions are higher at B5 compared to CARB diesel. Using the individual test run data available from the three UCR studies, we find the following for animal biodiesel at the B5 blend level:

- The animal feedstock used in Durbin 2011 increases NOx in 2 of 3 engines. The increase is highly significant[2] statistically for one engine.

[2] The term "significant" is used in this report only to refer to statistical significance. When a result reaches the p=0.05 level, we can be 95 percent confident that it is real. In such case, and at smaller p values, the result is said to be statistically significant. "Significant" has been used by others to indicate that an emissions increase, even if real, is too small to warrant concern. For example, the Predictive Model for RFG will permit alternative gasoline formulations to increase NOx emissions by up to 0.05% and still be classified as emissions compliant. To our

- The animal feedstock used in Durbin 2013A decreases NOx in one engine. The decrease is statistically significant at the p=0.05 level and the blend was certified as NOx neutral at B5.
- The animal feedstock used in Karavalakis 2014 increases NOx in three of six cases and decreases NOx in the other three cases. None of the changes are statistically significant. The blend may or may not change NOx.

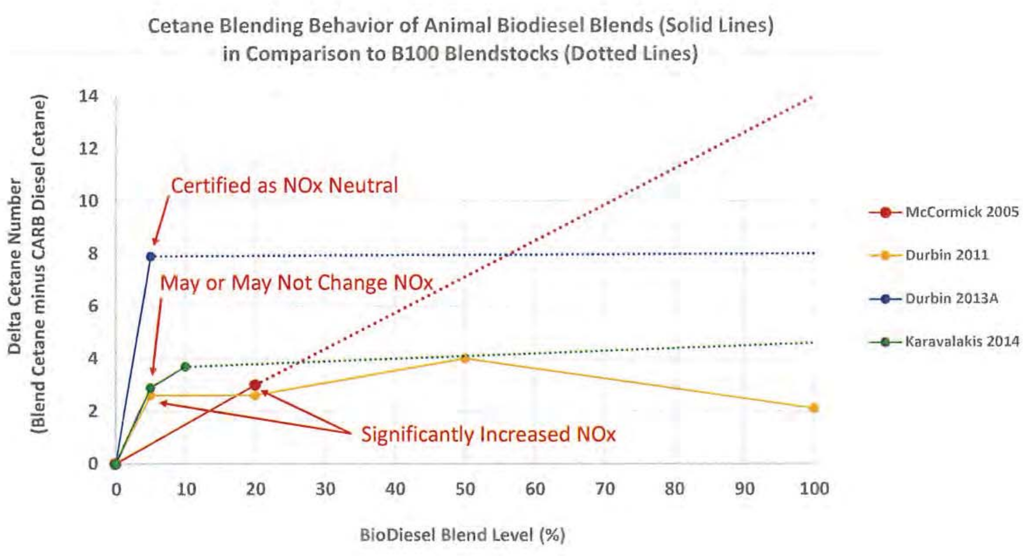
ADF B3-140 cont.

Contrary to Staff's assertion that no NOx increase occurs in B5 animal blends, it is clear that <u>some animal blends will significantly increase NOx emissions, while other animal blends will not</u>. The fundamental issue is then understanding what the NOx impact of a particular animal biodiesel blend will be.

The effect of feedstock blending on the CN of the resulting animal blend is the reason for the apparently discordant results among the studies. Figure 1 plots the four series of animal blends in the literature with the blend level on the horizontal axis and the change in blend CN (relative to CARB diesel) on the vertical axis. CN blended linearly to B20 for the McCormick feedstock, which showed a much smaller CN benefit than the feedstocks used by UCR – only three numbers at B20 (0.6 numbers at B5). In contrast, all three UCR animal blends achieve a large CN boost at low blending levels in which most or all of the CN benefit of the feedstock is achieved at B5.

ADF B3-141

Figure 1. Cetane Blending Behavior of Animal Blends (Solid Lines) Compared to B100 Feedstocks (Dotted Lines)



In Durbin 2011, the CNs for the blends are above that of the B100 feedstock. This result is probably caused by lab-to-lab differences (blend CN was determined at CE-CERT, while CN for CARB diesel and the

knowledge, ARB has not formulated a position on the level of NOx increase from alternative diesel fuel that is too small to warrant concern.

B100 feedstock were determined by an outside lab). The actual CN changes are surely lower than shown here – at or below +2 CNs.

The two animal feedstocks that caused statistically significant NOx increases have the smallest CN benefits: McCormick 2005 (red) at B20 and Durbin 2011 (yellow) at B5. The animal B5 blend that passed certification testing as NOx neutral in Durbin 2013A (blue) has the highest CN benefit, where it achieved the entire B100 CN at just 5 percent blending. The Karavalakis 2014 B5 blend (green) had an intermediate CN benefit and may or may not change NOx.

The blending behavior of the UCR blends is surprising in comparison to the McCormick study, and we find relatively little research on the CN blending behavior of animal feedstocks. All conclusions from this dataset will be influenced by the CN blending behavior of the specific animal feedstocks involved. For such conclusions to be reliable, we must be confident that the large CN boost reported for the UCR blends is both real and representative of all animal feedstocks in California. Also, only limited information is available on the sources and characteristics of the animal feedstocks. ADF B3-141 cont.

To permit all parties to better understand the animal feedstocks that were tested, ARB should release all information that it has on the following:

- CNs (methods of determination and measured values) for the Durbin 2011 and other UCR studies;
- Physical and chemical properties of the animal feedstocks and biodiesel blends tested;
- The distribution of sources, characteristics, and properties in the population of animal feedstocks that are available for use in the California market; and
- How the specific animal feedstocks tested at UCR were selected, including any information that would demonstrate that the feedstock properties and their CN blending behavior are representative of the animal feedstock population available for use in California.

5. Development of a Cetane-based Model of NOx Impacts from Soy and Animal Biodiesel

The results presented above indicate the important role that CN plays in determining the NOx response for animal blends. Animal feedstocks tend to increase the CN of the blend above that of the CARB diesel and the CN change can be large at low blend levels. Soy feedstocks have generally adverse effects and tend to decrease the CN of the blend below that of the CARB diesel; for soy, the CN change at low blend levels can be smaller than the uncertainty in determining CN. The result of our work on a cetane-based model demonstrates that soy and animal blends are not categorically different fuels once their differing effect on CN is accounted for. Their NOx impacts can be represented by the same model as a function of blend level and the change in CN compared to CARB diesel. ADF B3-142

The document that accompanies this report explains the development of the cetane-based model in some detail. In brief, it was developed using conventional linear regression analysis with log(NOx) emissions as the dependent variable. Intercept terms were included to represent the varying emission levels on CARB diesel for each combination of study, feedstock type, engine, and test cycle. A *b* coefficient was included to represent the change in NOx emissions for each 1 percent biodiesel in a blend at constant CN. A *c* coefficient was included to represent the change in NOx emissions for each 1 number change in CN compared to CARB diesel at constant blend level. Both soy and animal blends ADF B3-143 were included in the estimation, along with the small number of canola and UCO data points, at blend levels up to (and including) B20.

The model estimation shows that the *b* and *c* coefficients are highly significant statistically ($p < 0.0001$). The estimation results also show the following:

- The *b* coefficient has a value of +0.00156, which estimates that soy and animal biodiesel will increase NOx emissions by 0.16% for each 1 percent biodiesel at constant CN or by 0.8% at B5.
- The *c* coefficient estimates that +5 CNs will decrease NOx emissions by 1.5 percent at constant blend level. This result is completely consistent with earlier work[3] on the relationship between CN and NOx emissions in HDT engines, which also found that +5 CNs will decrease NOx emissions by 1.5 percent in base fuels with CN ~50.
- An increase of $-b/c = 0.5$ CNs is needed to offset the NOx increase expected from each 1% biodiesel added. For B5, an increase of 2.5 CNs is required to offset the expected NOx increase.

The results explain why soy and animal blends appear to be different fuels. Soy blends have an additional, adverse CN effect that increases their NOx impact to ~1% at B5. Animal blends will generally increase CN and that reduces their NOx impact to about one-half the soy level or less depending on the CN change caused by blending. The results also explain why some animal blends do not increase NOx emissions. If an animal feedstock increases CN by more than ~0.5 numbers for each 1% biodiesel blended, then the resulting fuel may not increase NOx emissions. ADF B3-143 cont.

To demonstrate these conclusions, Figure 2 presents NOx emissions as a function of blend level for all fuels used to estimate the model once NOx emissions are adjusted for the CN change observed for each blend (animal blends are plotted as squares, soy blends as circles, and the non-soy vegetable blends as asterisks). For example, if an animal blend increased CN, then its NOx impact is increased as we return it to the base fuel CN. If a soy blend decreases CN, then its NOx impact is decreased as we return it to the base fuel CN. Once adjusted, percent changes in emissions are calculated. As seen in the figure, there is no discernable difference among feedstock types once CN changes are taken into account. Animal and soy blends scatter on both sides of the regression line, indicating that they obey the same blend level model.

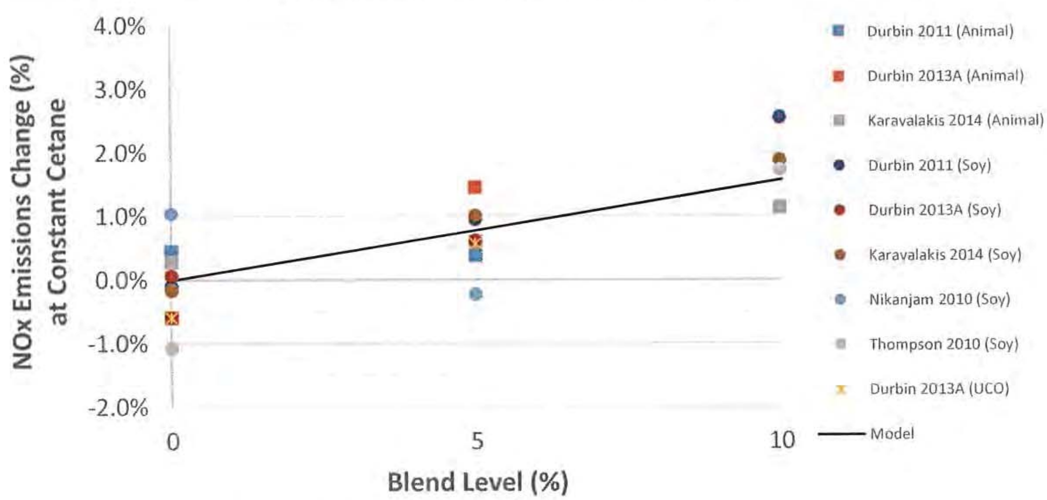
Note the scatter of points around the regression line (which gives the "average" response). Some of the scatter is due simply to emissions measurement error. But other factors may be involved in determining the NOx impact for a given feedstock, including differences in the FAME composition and uncertainty in determining CN for the blends. If ARB were to adopt a predictive model to determine the CN improvement needed to mitigate NOx, it should use the model to evaluate a "worst case" feedstock, meaning a point near the upper end of the range at each blend level.

The most important conclusion of this work is that soy and animal biodiesel blends are not categorically different fuels. Their emissions effects are similar, but they show different NOx impacts because they have different effects on CN. Further, this work provides a potential answer to the problem that some animal blends will significantly increase NOx emissions, while other blends will not, by indicating what individual blends may do.

---

[3] *The Effect of Cetane Number Increase Due to Additives on NOx Emissions from Heavy-Duty Highway Engines.* EPA420-R-03-002. February 2004. Figure IV.A-1.

Figure 2. There Are No Detectable Differences Among Feedstock Types Once NOx Emissions Are Adjusted to Constant CN



Note: Animal blends are plotted as squares, soy blends as circles, and the non-soy vegetable blends as asterisks.

6. Summary and Conclusions

Based on the results summarized above, ARB must consider as part of the current rulemaking a regulatory structure in which the NOx impacts of soy and animal biodiesel are accounted for using a statistical model analogous to the Predictive Model for RFG. We see the cetane-based model presented here as a possible draft for a biodiesel predictive model, but further work is needed to: ADF B3-144

- Demonstrate that blends mitigated using DTBP obey the same model; and
- Assess whether the four animal feedstocks that have been tested are representative of all animal feedstocks available in the California market.

Additional emissions testing may be needed if it is determined that the four animal feedstocks that have been tested are not representative of the population of animal feedstocks available for use in the California market. ADF B3-145

Further, more advanced statistical techniques should be used as was done in developing the Predictive Model for California Reformulated gasoline. The dataset used here is highly unbalanced, meaning that there are varying numbers of data points for each combination of study, feedstock type, engine, and test cycle. In fact, only a fraction of all possible study/feedstock/engine/test cycle cells are represented by one or more data points. A technique known as Mixed Effects Modeling is appropriate in such cases and its use will assure that coefficient estimates are not biased by the unbalanced distribution of the data. ADF B3-146

The key conclusions of this study are summarized below.

- Soy and animal blends are not categorically different fuels once their differing effects on blend CN are taken into account. ADF B3-147
- There is no evidence in the data of a threshold level below which biodiesel fuels as a group do not increase NOx, whether soy or animal. However, individual blends may not increase NOx if the CN gain caused by blending is sufficiently large to offset the underlying tendency of all biodiesel blends to increase NOx emissions. ADF B3-148
- Soy blends clearly and significantly increase NOx by ~1% at B5 and by proportionately larger amounts at higher blend levels. Soy blends <u>require</u> mitigation at all levels to offset increased NOx emissions. ADF B3-149
- Animal blends are more complicated. The current research is limited and the evidence is mixed. At least one B5 animal blend significantly increased NOx, while another has been certified as NOx neutral. Other B5 animal blends may or may not increase NOx depending on their effect on CN (and possibly other factors). ADF B3-150
- Staff's assertion that no NOx increase occurs at B5 in animal blends is incorrect. <u>Some animal blends will significantly increase NOx emissions, while other animal blends will not</u>. ADF B3-151
- Animal blends cannot be assumed to have no impact on NOx emissions without a determination of the impact of feedstock blending on CN. ADF B3-152

###

APPENDIX TABLE A: REFERENCES TO LITERATURE

Author	Title	Feedstocks Studied	Blends Studied
Clark 1999	Transient Emissions Comparisons of Alternative Compression Ignition Fuel	Soy	B20
McCormick 2002	Fuel Additive and Blending Approaches to Reducing NOx Emissions from Biodiesel	Soy, UCO	B20
McCormick 2005	Regulated Emissions from Biodiesel Tested in Heavy-Duty Engines Meeting 2004 Emissions	Soy, Canola, Animal	B20
Eckerle 2008	Effects of Methyl Ester Biodiesel Blends on NOx Emissions	Soy	B20
Nuszkowski 2009	Evaluation of the NOx emissions from heavy duty diesel engines with the addition of cetane improvers.	Soy	B20
Nikanjam 2010	Performance and emissions of diesel and alternative diesel fuels	Soy	B5, B20
Thompson 2010	Neat fuel influence on biodiesel blend emissions	Soy	B10, B20
Durbin 2011	Biodiesel Characterization and NOx Mitigation Study	Soy, Animal	B5, B10, B20
Durbin 2013A	CARB B5 Preliminary and Certification Testing	Animal	B5
Durbin 2013B	CARB B20 Biodiesel Preliminary and Certification Testing	Soy, UCO	B20
Karavalakis 2014	CARB Comprehensive B5/B10 Biodiesel Blends Heavy-Duty Engine Dynamometer Testing	Soy, Animal	B5, B10

12_B_LCFS_GE Responses (Page 519 – 528)

738. Comment: **ADF B3-139 through ADF B3-152**

Agency Response: These comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

739. Comment: **ADF B3-137 and ADF B3-138**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

sierra
research

1801 J Street
Sacramento, CA 95811
Tel: (916) 444-6666
Fax: (916) 444-8373
Ann Arbor, MI
Tel: (734) 761-6666
Fax: (734) 761-6755

DELIVERED BY HAND

February 18, 2015

Tracy Jensen
Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: "Comments on the LCFS and ADF rulemaking proposals."

Dear Clerk of the Board:

I have discovered that one attachment to my Declaration included in electronic filing for Growth Energy that Josh Wilter of my staff made yesterday was not included in the upload. I am enclosing the attachment here and am emailing it to Jim Aquila and Lex Mitchel who are listed as the staff contacts for this item in the Hearing Notice. The contents of this attachment do not differ from the content of my Declaration, and the bulk of the analysis in the attachment was provided to the ARB staff on October 24, 2014 as workshop comments.

Sincerely,

Jim Lyons
Senior Partner

Attachments:

NOx EMISSIONS IMPACTS OF BIODIESEL BLENDS

Prepared by:

Rincon Ranch Consulting
2853 S. Quail Trail
Tucson, AZ 85730

Prepared for:

Sierra Research
1801 J. Street
Sacramento, CA 95811

February 10, 2015

NOx EMISSIONS IMPACTS OF BIODIESEL BLENDS

Table of Contents

List of Figures

List of Tables

NOx EMISSION IMPACTS OF BIODIESEL BLENDS

1. EXECUTIVE SUMMARY

The purpose of the Alternative Diesel Fuels (ADF) rulemaking, according to the Air Resources Board (ARB), is to create a regulatory framework that will permit biodiesel and other low-carbon, alternative diesel fuels to "enter the commercial market in California, while mitigating any potential environmental or public health impacts." [1]

The work presented in this report assesses the impacts of biodiesel use on NOx emissions from conventional and new technology diesel engines. It was performed by Rincon Ranch Consulting under subcontract to Sierra Research at the request of Growth Energy.

At present, most diesel fuel and biodiesel is consumed in conventional diesel engines that do not have exhaust gas after-treatment to reduce NOx emissions. The consensus of the literature is that biodiesel will increase NOx emissions by amounts that depend on the blending percentage (how much biodiesel is present in the diesel fuel) and the type of biodiesel feedstock (soy versus animal sources). NOx increases of 1-2% are expected from soy biodiesel at blend levels of B5 to B10 with smaller increases expected, in general, from animal biodiesel at the B5 to B10 level. ADF B3-153

Over time, new technology diesel engines (NTDEs) equipped with exhaust gas after-treatment controls for NOx will increasingly make up the heavy duty fleet in response to other ARB programs. While baseline emissions from these engines will be reduced compared to conventional engines, the consensus of the literature available today is that use of biodiesel will still increase NOx emissions above the reduced baseline. At the B20 level, the NOx increase appears to be greater on a percentage basis than would be expected in conventional diesel engines. ADF B3-154

The results of this work indicate the following with respect to conventional diesel engines:

- Soy biodiesels will increase NOx emissions at the B5 and B10 levels by approximately 1% and 2%, respectively. This work and Staff's analysis concur in both the conclusion and the estimated levels of NOx increase at B5 and B10. Soy biodiesels in this blend range require NOx mitigation on a per-gallon basis in order to prevent increases in NOx emissions. ADF B3-155

- The consensus of the research community is that the effect of soy biodiesel on NOx emissions is continuous and linear with respect to the blending percentage. NOx ADF B3-156

[1] "Proposed Regulation on the Commercialization of New Alternative Diesel Fuels. Staff Report: Initial Statement of Reason." California Air Resources Board, Stationary Source Division, Alternative Fuels Branch. January 2, 2015. http://www.arb.ca.gov/regact/2015/adf2015/adf15isor.pdf. Page 11.

increases have been observed at levels as low as B1.[2] The statistical analysis performed for ARB by Rocke supports this conclusion and estimates that soy biodiesel will increase NOx emissions by about 0.2% for each 1% biodiesel in the blend (0.99% for each 5% biodiesel). ADF B3-156 cont.

In spite of this consensus, the Staff proposal requires NOx mitigation for soy-based biodiesel only above the B5 level in summer months and above the B10 level in winter months. Soy biodiesel blended at the B5 and lower levels would not require mitigation in any circumstance. The ADF regulatory framework must require mitigation of soy-based biodiesels at all blend levels if it is to ensure that such fuels do not increase NOx emissions. ADF B3-157

- The effect of animal-based biodiesel on NOx emissions is more complicated than for soy-based blends. As the available literature demonstrates, some animal-based biodiesels will increase NOx emissions while other animal biodiesels will not. While Staff's proposal would establish B10 as the control level for animal-based biodiesel (e.g., mitigation would be required year-round for blends above B10), the available data do not support Staff's conclusion that there will not be increases in NOx emissions from B10 and lower blends. Given the Staff proposal, the only way to ensure that animal-based biodiesel does not increase NOx emissions is to require mitigation at all blend levels. ADF B3-158
- Staff presents information indicating that animal biodiesels decrease NOx by 0.2% on average and that the emissions change in comparison to CARB diesel fuel is not statistically significant. The average and the test for statistical significance are both flawed by the failure to consider the varying effects that animal feedstocks have on Cetane Number (CN). The absence of CN as a variable in Staff's analysis leads Staff to wrongly conclude that animal biodiesels will not increase NOx below the B10 level. ADF B3-159
- It is well established that increasing CN will reduce NOx emissions from diesel engines. Whether an animal biodiesel will increase NOx depends primarily on the extent to which the feedstock blending increases the CN of the blended fuel. Soy and animal biodiesel blends are not categorically different fuels once the differing effect of soy- and animal-feedstocks on CN is taken into account. ADF B3-160

With respect to new technology diesel engines (NTDEs):

- Staff is incorrect in concluding that biodiesel use will not increase NOx in NTDEs. This conclusion is based on a highly selective reading of the technical literature (choosing one of four available studies) and relies on the one study in which the laboratory was not well equipped to measure the low levels of tailpipe NOx emissions from NTDEs. ADF B3-161
- A fair reading of the technical literature indicates that B20 biodiesel will increase NOx emissions by about 20% in NTDEs. The four best studies estimate that B20 biodiesel ADF B3-162

---

[2] McCormick 2002 tested a Fisher-Tropsch (FT) base fuel blended at the B1, B20, and B80 levels. Although the very high FT cetane number (≥75) takes it out of the range of commercial diesel fuels, the study nevertheless measured higher NOx emissions at the B1 level than it did on the FT base fuel.

increases NOx by 18-22% in NTDEs and that the increase is statistically significant. This is a greater percentage NOx increase in proportion to blend level than the increase caused by soy biodiesel in conventional diesel engines (1% at B5, 2% at B10 and ~4% at B20). ADF B3-162 cont.

- The technical literature also indicates that one should expect NOx emissions to increase at blend levels below B20, with the size of the NOx increase being proportionate to blend level. At the B5 level, NOx emissions from NTDEs are expected to increase by about 5%. ADF B3-163

- Staff makes no mention of the concern that use of biodiesel fuels in NTDEs may lead to the loss of NOx conversion efficiency in urea-SCR systems by shifting the NO_2/NOx ratio to lower values. Staff's proposal to allow B20 biodiesel to be used in NTDEs without mitigation potentially places at risk the investment in NOx after-treatment systems to meet the stringent NOx certification levels now in effect. ADF B3-164

This analysis demonstrates that the proposed regulations will not "ensure that the use of biodiesel due to LCFS will not result in increases in NOx emissions in California." In fact, the regulations will result in increased NOx emissions in California from the following: ADF B3-165

- B5 and lower soy biodiesels year round;
- B6 to B10 soy biodiesels in winter;
- At least some B10 and lower animal biodiesels year-round; and
- B20 and lower biodiesels of all types in NTDEs.

To our knowledge, ARB has not formulated a position on the level of NOx increase from alternative diesel fuel that is too small to warrant concern. A point of comparison for the NOx increases permitted by the proposed ADF regulations is the ARB program for Reformulated Gasoline (RFG). The RFG program permits alternative gasoline formulations to be sold in the California market provided they are demonstrated to be emissions equivalent to a reference gasoline using the Predictive Model for RFG. The emissions analysis differs somewhat for winter and summer gasoline, but in no instance may the alternative formulation increase emissions of the pollutants considered by more than 0.05%. ADF B3-166

The biodiesel NOx emission increases permitted under the proposed ADF regulations dwarf the 0.05% threshold applied to RFG. Soy biodiesel will increase NOx by more than 0.05% at blend levels above 0.25% biodiesel (B0.25). Some animal biodiesels will increase NOx by 0.05% or more at blend levels twice as high (B0.5). The NOx emissions increase in NTDEs appears to be substantially greater on a percentage basis, so that biodiesels will exceed the 0.05% threshold at much lower blend levels. ADF B3-167

In the ISOR, Staff uses the term "low saturation" to refer to soy and other feedstocks with CN < 56 and "high saturation" to refer to feedstocks, including animal sources, with CN ≥ 56. Classification based on saturation is useful because of its association with CN. By itself, however, it does not alleviate the concerns regarding NOx increases from unmitigated fuels. ADF B3-168

The analysis presented here indicates that CN changes induced by biodiesel blending have a large influence on the size of the NOx increase that is observed. Soy (low saturation) biodiesels adversely affect CN leading to larger NOx increases; animal (high saturation) biodiesels increase CN leading to smaller NOx increases. In fact, soy and animal biodiesels are not categorically different fuels once their differing effect on blend CN is taken into account. ADF B3-169

It is strongly recommended that ARB consider as part of the ADF rulemaking a regulatory structure in which the NOx impacts of soy and animal biodiesel are accounted for using a statistical model analogous to the Predictive Model for RFG. The analysis documented in this report provides a possible form for a biodiesel predictive model. ADF B3-170

2. NOX EMISSIONS FROM CONVENTIONAL DIESEL ENGINES

2.1 ARB Analysis in Support of the Proposed Regulations

In support of the proposed regulations, ARB commissioned an analysis of the available NOx emissions data by David M. Rocke, PhD. The results of the analysis are reported in Appendix G: Supplemental Statistical Analysis[3] to the ISOR. The analysis used NOx emission measurements on ULSD, B5, and B10 fuels in conventional diesel engines from five studies. The dataset is substantially the same as that used by Rincon Ranch Consulting in the analysis presented later in this section.

The Rocke analysis formulated a series of statistical models involving log(NOx) as the dependent variable and used a statistical approach termed Mixed Effects modeling to estimate the coefficient values. The Mixed Effects approach has statistical advantages over more commonly used methods when dealing with unbalanced datasets, as is the case here. A number of different models were specified, estimated, and the results compared in order to ensure that conclusions drawn from the analysis do not depend upon the model specifications. ADF B3-171

For soy-based biodiesel, the Rocke study concludes that soy fuels increase NOx by 1% at B5 and by 2% at B10. The study also demonstrated that the NOx increase is linearly related to the blend level. The slope was estimated to be 0.99% for each 5% biodiesel in a blend and was highly significant statistically ($p \ll 0.001$). These results agree with the Rincon Ranch analysis presented later in this report. <u>There is no controversy with regard to the NOx impact of soy-based biodiesel.</u> Soy biodiesel will increase NOx emissions at all blend levels by about 0.2% for each 1% biodiesel in the blend.

With respect to animal biodiesel, the Rocke study concludes that animal biodiesel does not increase NOx emissions at B5 or B10. The emission changes that are observed are not statistically significant. <u>There is controversy here because the Rocke analysis did not account for the effect of feedstock blending on the CN of the tested fuels</u>. The CN change compared to ULSD is a fixed effect that must be accounted for because the four animal feedstocks that have been used in the technical literature show substantially different cetane behavior in blending. ADF B3-172

---

[3] http://www.arb.ca.gov/regact/2015/adf2015/adf15appg.pdf.

The case for cetane as an explanatory variable for NOx emissions in animal blends is made in Section 2.2.4 of this report. It is well established that increasing CN will reduce NOx emissions from diesel engines. For example, ARB has shown that the additive DTBP can be used to raise CN and mitigate NOx increases caused by biodiesel blending. Whether an animal biodiesel will increase NOx depends primarily on the extent to which the feedstock blending increases CN of the blended fuel. The two animal blends that showed the smallest CN gain over ULSD caused statistically significant NOx increases in the engines tested. The one animal blend that showed the largest CN gain was certified to be NOx neutral, while the animal blend with the next largest CN gain may or may not be NOx neutral. Cetane appears to blend linearly when using soy feedstocks, so that the CN gain over ULSD is highly correlated with blend level. The same is not true for animal feedstocks, where highly non-linear blending behavior has been observed.

The Rocke analysis used a Mixed Effects model to estimate the NOx emissions change at B5 and B10. For animal blends, it concluded that the observed emission changes are not statistically significant. Implicit in the approach is the assumption that the fuels being tested are different, individual realizations from a homogenous population. In this instance, the residual variation not accounted for by the blend level is a random effect representing the scatter in test results due to a variety of factors. The statistical significance of the blend level effect (a fixed effect) is judged in comparison to the residual variation. When the residual variation is large in comparison to the fixed effect, the latter is said to be not statistically significant.

The assumption of a homogenous population is appropriate for soy-based biodiesels. One soybean is much like the next, and the only appreciable differences among soy fuels will result from the methods of preparation. However, the assumption of homogeneity is not appropriate for animal-based biodiesels, which can be drawn from a variety of animal sources and prepared in different ways. The non-homogeneity is seen most readily in the greatly different cetane responses of biodiesel fuels:

ADF B3-172 cont.

- In the McCormick 2005 and Durbin 2011 studies, the animal feedstocks increased the CN of the biodiesel blends by small amounts. These fuels led to statistically significant increases in NOx.
- In the Durbin 2013A study, blending at the B5 level was sufficient to raise the CN of the blend by 8 numbers to reach the cetane level of the feedstock itself. This fuel was certified as NOx neutral at B5.
- The animal feedstock used in the Karavalakis 2014 study was intermediate in its CN effect and also intermediate in its NOx effect.

Because the ARB and Rocke studies have not included cetane as an explanatory variable for animal-based biodiesels, the residual variation term has been enlarged since a portion of it could be accounted for by including a fixed-effects term for cetane. With an enlarged estimate of the residual variance, the studies more easily find that the fixed effect of blend level is not statistically significant.

The absence of cetane as an explanatory variable also affects other methods of analysis used by Rocke. In a t-test comparison of emission differences between biodiesel and ULSD, Rocke finds two cases in which animal B5 changes NOx by statistically significant amounts (one increasing NOx and the other decreasing NOx) and one such case in animal B10 (decreasing NOx), while the other cases show no statistically significant change compared to the base fuel. The study wrongly concludes that these results demonstrate no or little systematic evidence for B5 or B10 animal to increase NOx emissions. In fact, these cases are systematically related to the CN gain of the animal blends in comparison to the base fuel. ADF B3-172 cont.

The Rocke analysis was well planned and executed, and we concur with the conclusions drawn for soy-based blends. Because the analysis for animal-based blends is flawed by omission of a cetane variable, it should be revised to address CN gain. We expect that a revised analysis will shed further light on the circumstances in which animal-based biodiesels will and will not increase NOx emissions.

2.2 Rincon Ranch Analysis of ARB NOx Emissions Data

In July 2014, ARB released two datasets that represent the fruit of its efforts to compile the available biodiesel NOx emissions test data on conventional heavy-duty truck (HDT) engines. This report and the companion file *"Biodiesel Emissions Analysis Technical Summary 102014.pdf,"* which is attached to and incorporated in this report, present the results of a statistical analysis of the data sets released by ARB that was performed by Rincon Ranch Consulting at the request of Growth Energy.

The analysis presented below focused on whether soy and animal blends will increase NOx at low blend levels in conventional diesel engines. The following issues were examined:

- The NOx impacts of soy and animal blends at B5 and B10;
- The NOx emission differences observed among animal feedstocks and blends;
- For animal blends, the effect on NOx emissions of the CN change relative to base fuel that is caused by blending of the animal feedstock; and
- The development of a cetane-based model of the biodiesel NOx impacts of soy and animal blends.

2.2.1 Data Used in the Analysis

As noted above, in July 2014, ARB released two datasets of NOx emissions data from testing of biodiesel blends in HDT engines. One file ("B5 & B10 Raw NOx Data") contains the subset of testing for B5 and B10 blends (soy and animal). The test data generated in the four ARB-sponsored UCR studies are present in the form of the individual test run measurements. Because test run information was not reported in their publications, the B5 soy data from Nikanjam 2010 and the B10 soy data from Thompson 2010 are present in the form of emission averages. No animal blends have been tested at the B5 or B10 levels except in the ARB-sponsored emissions testing. A second file ("2014 Biodiesel Literature Search Database") contains all of the biodiesel ADF B3-173 testing available in the literature through the B20 level (soy and animal), including ARB-sponsored testing and the literature search. The data are in the form of emission averages by engine, test cycle, feedstock type, and blend level.

For purposes of this analysis, the following information was added to the ARB datasets:

- The number of test replications for emissions averages for each study (estimated when the source did not report the number);
- The CN for CARB diesel, the biodiesel blends, and the biodiesel feedstocks; and
- Additional NOx emissions testing at the B50 and B100 levels (where available).

Appendix Table A presents a list of the studies included in the dataset and the author references used in citations here.

ADF B3-173 cont.

2.2.2 NOx Emissions from Soy Biodiesel Blends

Most past research on biodiesel emissions has focused on soy blends. As a result, the literature is relatively large and diverse. The dataset assembled by ARB is derived from 10 different studies, covers 13 different vegetable feedstocks (10 soy, 2 used cooking oil [UCO], 1 canola), and was conducted using 7 different test cycles on a wide variety of engines in different labs. Most of the data, in terms of number of data points, are derived from the three UCR studies (Durbin 2011, Durbin 2013B, and Karavalakis 2014) sponsored by ARB.

We subjected the soy dataset to a number of different analyses using different statistical techniques and selections of the data to ensure that the conclusions we drew were robust. The statistical analyses included the t-test for the difference in mean values (e.g., between B5 and CARB diesel) and linear regression analysis using several different models. The data subsets were selected to use either individual test runs or emission averages and to contain testing through maximum blend levels of B5, B10, B20, B50, and B100.

ADF B3-174

Our analyses show that there is a consensus among the studies on the NOx impact of soy biodiesel without regard to the specific analytical methods or data used. Soy biodiesel increases NOx emissions by amounts that can be estimated with good statistical confidence because of the large size of the available dataset. The key conclusions are as follows:

- Soy biodiesel increases NOx emissions by ~1% at B5 and ~2% at B10;
- NOx emissions increase in a linear fashion with increasing blend level to reach ~4% at B20 and proportionately larger values at higher blend levels; and
- There is no evidence in the data for a threshold level below which soy biodiesel does not increase NOx.

These conclusions are supported by all of the available studies and data. None of the studies disagree substantially, and while the results for individual blends, engines, and test cycles will vary to some extent, the evidence across a wide range of engines and test cycles is clear. NOx increases can be expected for UCO, canola, and other vegetable biodiesels, but the data are very limited and it is not possible to draw definitive conclusions for these blends. ADF B3-174 cont.

2.2.3 NOx Emissions from Animal Biodiesel Blends

The literature on NOx emissions from animal blends is much smaller—it consists of only four studies, three of which (Durbin 2011, Durbin 2013A, and Karavalakis 2014) were sponsored by ARB. Except for the McCormick 2005 study, the emissions testing was conducted at the UCR CE-CERT lab. A variety of test cycles were used, but most of the testing was conducted on the hot-start FTP cycle. Table 1 presents a summary of the emissions studies for animal biodiesel. ADF B3-175

Table 1. Scope of Emissions Testing for Animal Biodiesel

	McCormick 2005	Durbin 2011	Durbin 2013A	Karavalakis 2014
Biodiesel Feedstock	Animal #1	Animal #2	Animal #3	Animal #4
Blend Levels Tested	B20	B5, B20, B50, B100	B5	B5, B10
Engines Tested	2 on-road	3 on-road, 1 off-road	1 on-road	1 on-road
Test Cycles	FTP	FTP, UDDS, 50 mph, ISO 8178	FTP	FTP, SET, UDDS
Test Replications on Biodiesel	6	126	26	80
Is NOx Increase Observed?				
At / Below B10	–	Yes	No	No
Above B10	Yes	Yes	-	-

It is important to understand the limitations of this small dataset. Without the ARB-sponsored testing, we would have only the six test replications (individual runs) conducted in the McCormick 2005 study. While the three UCR studies accumulated 232 test replications, the work involved only three different animal feedstocks. Including the McCormick 2005 study, the entire literature on NOx emissions from animal biodiesel is based on only four different animal feedstocks. The small number is an important limitation because animal feedstocks are much less homogenous than soy due the greater variety possible in animal sources and compositions. Further, there are notable differences among the four studies as to whether animal biodiesel increases NOx at the B5 and B10 levels (as indicated by the red circles in the table).

As in the soy analysis, we subjected the animal biodiesel data to a number of different analyses using different statistical techniques and selections of the data to ensure that the conclusions we drew were robust. The t-test is the most direct method to assess whether NOx emissions are higher at B5 compared to CARB diesel. Using the individual test run data available from the three UCR studies, we find the following for animal biodiesel at the B5 blend level:

- The animal feedstock used in Durbin 2011 increases NOx in 2 of 3 engines. The increase is highly significant[4] statistically for one engine.

- The animal feedstock used in Durbin 2013A decreases NOx in one engine. The decrease is statistically significant at the p=0.05 level, and the blend was certified as NOx neutral at B5.

- The animal feedstock used in Karavalakis 2014 increases NOx in three of six cases and decreases NOx in the other three cases. None of the changes are statistically significant. The blend may or may not change NOx.

ADF B3-175 cont.

Contrary to Staff's assertion that no NOx increase occurs in B5 animal blends, it is clear that some animal blends will significantly increase NOx emissions, while other animal blends will not. The fundamental issue is then understanding what the NOx impact of a particular animal biodiesel blend will be.

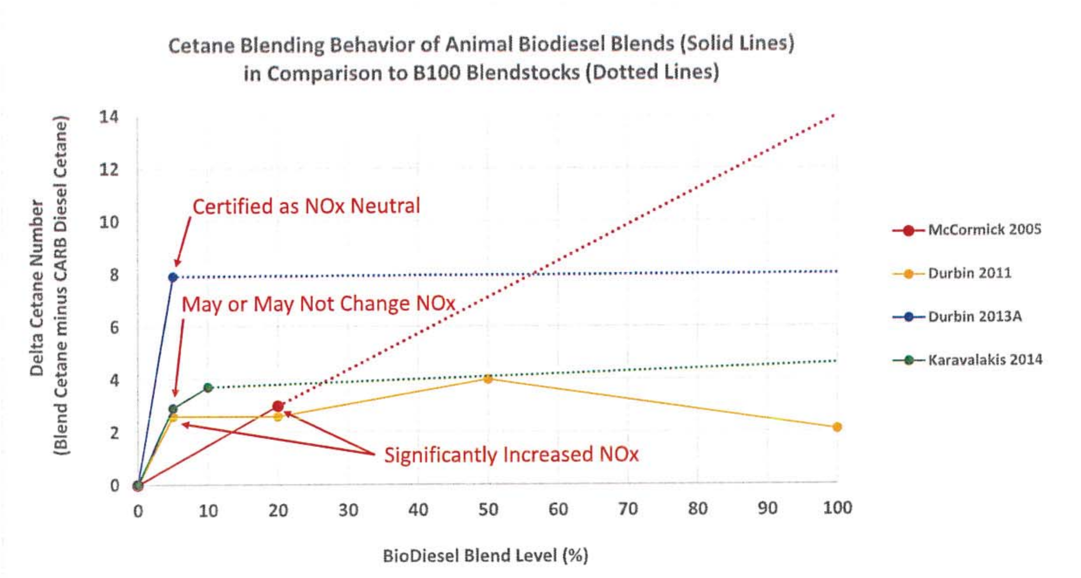
The effect of feedstock blending on the CN of the resulting animal blend is the reason for the apparently discordant results among the studies. Figure 1 plots the four series of animal blends used in the studies, with blend level on the horizontal axis and the change in blend CN (relative to CARB diesel) on the vertical axis. CN blended linearly to B20 for the McCormick feedstock, which showed a much smaller CN benefit than the feedstocks used by UCR—only three numbers at B20 (0.6 numbers at B5). In contrast, all three UCR animal blends achieve a large CN boost at low blending levels in which most or all of the CN benefit of the feedstock is achieved at B5.

In Durbin 2011, the CNs for the blends are above that of the B100 feedstock. This result is probably caused by lab-to-lab differences (blend CN was determined at CE-CERT, while CN for CARB diesel and the B100 feedstock were determined by an outside lab). The actual CN changes are surely lower than shown here—at or below +2 CNs. ADF B3-176

The two animal feedstocks that caused statistically significant NOx increases have the smallest CN benefits: McCormick 2005 (red) at B20 and Durbin 2011 (yellow) at B5. The animal B5 blend that passed certification testing as NOx neutral in Durbin 2013A (blue) has the highest CN benefit, where it achieved the entire B100 CN at just 5% blending. The Karavalakis 2014 B5 blend (green) had an intermediate CN benefit and may or may not change NOx.

[4] The term "significant" is used in this report only to refer to statistical significance. When a result reaches the p=0.05 level, we can be 95 percent confident that it is real. In such case, and at smaller p values, the result is said to be statistically significant.

Figure 1. Cetane Blending Behavior of Animal Blends (Solid Lines) Compared to B100 Feedstocks (Dotted Lines)



The blending behavior of the UCR blends is surprising in comparison to the McCormick study, and we find relatively little research on the CN blending behavior of animal feedstocks. All conclusions from this dataset will be influenced by the CN blending behavior of the specific animal feedstocks involved. For such conclusions to be reliable, we must be confident that the large CN boost reported for the UCR blends is both real and representative of all animal feedstocks in California. Also, only limited information is available on the sources and characteristics of the animal feedstocks. ADF B3-176 cont.

To permit all parties to better understand the animal feedstocks that were tested, ARB should release all information that it has on the following:

- CNs (methods of determination and measured values) for the Durbin 2011 and other UCR studies;
- Physical and chemical properties of the animal feedstocks and biodiesel blends tested;
- The distribution of sources, characteristics, and properties in the population of animal feedstocks that are available for use in the California market; and
- How the specific animal feedstocks tested at UCR were selected, including any information that would demonstrate that the feedstock properties and their CN blending behavior are representative of the animal feedstock population available for use in California.

Staff's use of the terms low saturation (for soy) and high saturation (for animal) to classify biodiesel is useful to differentiate between feedstocks that will tend to decrease CN and those that will tend to increase it. However, it is not a sufficient step in that the CN change at each blend level is the determinative factor for NOx emissions, not the CN of the feedstock itself. Soy feedstocks appear to blend linearly with respect to cetane; however, animal feedstocks often lead to a highly non-linear CN response, as shown in Figure 1. ADF B3-176 cont.

2.2.4 Development of a Cetane-based Model of NOx Impacts from Soy and Animal Biodiesel

The results presented above indicate the important role that CN plays in determining the NOx response for animal blends. Animal feedstocks tend to increase the CN of the blend above that of the CARB diesel and the CN change can be large at low blend levels. Soy feedstocks generally decrease the CN of the blend below that of the CARB diesel; for soy, the CN change at low blend levels can be smaller than the uncertainty in determining CN. The result of our work on a cetane-based model demonstrates that soy and animal blends are not categorically different fuels once their differing effect on CN is taken into accounted. Their NOx impacts can be represented by the same model as a function of blend level and the change in CN compared to CARB diesel.

The document that accompanies this report explains the development of the cetane-based model in some detail. In brief, it was developed using conventional linear regression analysis with log(NOx) emissions as the dependent variable. Intercept terms were included to represent the varying emission levels on CARB diesel for each combination of study, feedstock type, engine, and test cycle. A *b* coefficient was included to represent the change in NOx emissions for each one percent biodiesel in a blend at constant CN. A *c* coefficient was included to represent the change in NOx emissions for each one number change in CN compared to CARB diesel at constant blend level. Both soy and animal blends were included in the estimation, along with the small number of canola and UCO data points, at blend levels up to (and including) B20. ADF B3-177

The model estimation shows that the *b* and *c* coefficients are highly significant statistically ($p < 0.0001$). The estimation results also show the following:

- The *b* coefficient has a value of +0.00156, which estimates that soy and animal biodiesel will increase NOx emissions by 0.16% for each one percent biodiesel at constant CN or by 0.8% at B5.
- The *c* coefficient estimates that +5 CNs will decrease NOx emissions by 1.5% at constant blend level. This result is completely consistent with earlier work[5] on the relationship between CN and NOx emissions in HDT engines, which also found that +5 CNs will decrease NOx emissions by 1.5% in base fuels with CN ~50.

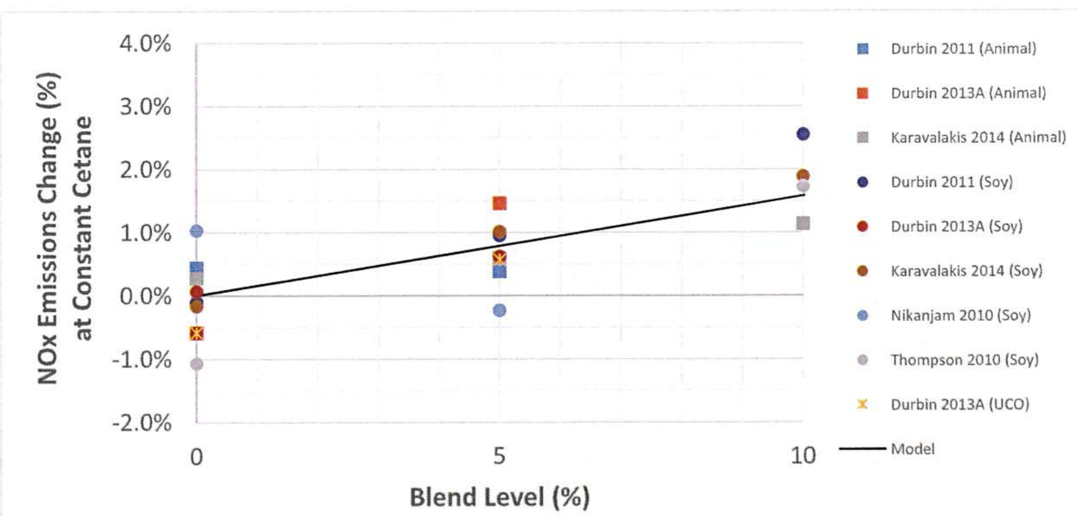
[5] The Effect of Cetane Number Increase Due to Additives on NOx Emissions from Heavy-Duty Highway Engines. EPA420-R-03-002. February 2004. Figure IV.A-1.

- An increase of -b/c = 0.5 CNs is needed to offset the NOx increase expected from each 1% biodiesel added. For B5, an increase of 2.5 CNs is required to offset the expected NOx increase.

The results explain why soy and animal blends appear to be different fuels. Soy blends have an additional, adverse CN effect that increases their NOx impact to ~1% at B5. Animal blends will generally increase CN and that reduces their NOx impact to about one-half the soy level or less, depending on the CN change caused by blending. The results also explain why some animal blends do not increase NOx emissions. If an animal feedstock increases CN by more than ~0.5 numbers for each 1% biodiesel blended, then the resulting fuel may not increase NOx emissions.

To demonstrate these conclusions, Figure 2 presents NOx emissions as a function of blend level for all fuels used to estimate the model once NOx emissions are adjusted for the CN change observed for each blend. For example, if an animal blend increased CN, then its NOx impact is <u>increased</u> as we return it to the base fuel CN. If a soy blend decreases CN, then its NOx impact is <u>decreased</u> as we return it to the base fuel CN. Once adjusted, percent changes in emissions are calculated. As seen in the figure, there is no discernable difference among feedstock types once CN changes are taken into account. Animal and soy blends scatter on both sides of the regression line, indicating that they obey the same blend level model.

Figure 2. There Are No Detectable Differences Among Feedstock Types Once NOx Emissions Are Adjusted to Constant CN



Note: Animal blends are plotted as squares, soy blends as circles, and the non-soy vegetable blends as asterisks.

Note the scatter of points around the regression line (which gives the "average" response). Some of the scatter is due simply to emissions measurement error; however, other factors may be involved in determining the NOx impact for a given feedstock, including differences in the

ADF B3-177 cont.

FAME (fatty acid methyl ester) composition and uncertainty in determining CN for the blends. If ARB were to adopt a predictive model to determine the CN improvement needed to mitigate NOx, it should use the model to evaluate a "worst case" feedstock, meaning a point near the upper end of the range at each blend level.

The most important conclusion of this work is that soy and animal biodiesel blends are not categorically different fuels. Their emissions effects are similar, but they show different NOx impacts because they have different effects on CN. Furthermore, this work provides a potential answer to the problem that some animal blends will significantly increase NOx emissions, while other blends will not, by indicating what individual blends may do.

ADF B3-177 cont.

3. NOX EMISSIONS IN NEW TECHNOLOGY DIESEL ENGINES

Staff's position is that biodiesel will not increase NOx emissions in NTDEs at levels up to and including B20. Its assessment is stated in the ISOR as follows:

> *Engines that meet the latest emission standards through the use of Selective Catalytic Reduction (SCR) have been shown to have no significant difference in NOx emissions based on the fuel used. A study conducted by the NREL looked at two Cummins ISL engines that were equipped with SCR, and found that NOx emissions control eliminates fuel effects on NOx, even for B100 and even in fuels compared against a CARB diesel baseline.*[20] *However, a recent study at UC Riverside tested B50 blends and found a NOx increase with a 2010 Cummins ISX.*[21] *The UC Riverside study did not look at blends below B50. Staff proposes to take a precautionary approach and in the light of data showing there may be a NOx impact at higher biodiesel blends but not at lower biodiesel blends, Staff is limiting the conclusion of no detrimental NOx impacts in NTDEs to blends of B20 and below. Additional studies on NTDEs have been completed, however since they included either retrofit engines or non-commercial engines Staff did not include their results in this analysis.*[22,23,24] (Page 24)

Staff's reliance on Lammert 2012 (Ref. 20) is misplaced because the NREL lab was not equipped to measure the low NOx emission levels of the test vehicles, as the abstract of the Lammert paper clearly notes.[6] In fact, none of the emission changes observed in the study (with one exception) were statistically significant due to the high standard errors that necessarily exist when measurements are made close to the level of detection. In this instance, the failure to observe statistically significant NOx emissions increases from biodiesel at the B20 level is not a demonstration that such increases do not exist.

ADF B3-178 cont.

This specific shortcoming of the Lammert study is why its negative results are in conflict with the finding of the UC Riverside study (Gysel 2014) cited by Staff and the three other studies (Walkowicz 2009, McWilliam 2010, Mizushima 2010) that Staff dismissed. With respect to the

ADF B3-179

[6] "SCR systems proved effective at reducing NOx to near the detection limit on all duty cycles and fuels, including B100." Lammert 2012, Abstract.

three other studies, we see no reason why they should be dismissed. It is not the case that factory-designed NOx after-treatment systems will reduce NOx levels to below the detection limit of well-equipped labs (see Gysel 2014 and engine certification testing). Testing conducted using retrofit NOx after-treatment systems that achieve representative levels of NOx control, as in these studies, is entirely suitable for determining whether biodiesel increases tailpipe NOx emissions on a percentage basis. Having a different absolute level of emissions does not preclude reliable measurement of a percentage change.

ADF B3-179 cont.

When all available studies are included, a consensus of the literature is that biodiesel at the B20 level will increase NOx emissions from NTDEs in most, if not all cases. Lammert 2012 is the one study at odds with the rest of the literature. A range of biodiesel types were used in the studies. NOx increases should be expected at the B20 level for all biodiesel types until such time as additional research indicates differential impacts for biodiesels derived from different sources

3.1 Review of the NTDE Literature

The following sections briefly summarize the NTDE testing conducted in the studies and the conclusions drawn on the NOx emissions impact of biodiesel fuels. Testing of conventional diesel engines without NOx after-treatment is not considered, nor is testing on non-California fuels (low aromatics ULSD was considered equivalent to CARB ULSD). Appendix Table B presents a list of the studies included in the NTDE dataset and the author references used in citations here.

Walkowicz 2009. Chassis dynamometer testing was conducted using a 2005 International 9200i tractor equipped with and without a retrofit diesel oxidation catalyst (DOC) and urea-SCR NOx after-treatment system. On-road emissions measurements also were made using a RAVEM portable emissions measurement system. A ULSD base fuel was tested, as were B20 and B99 biodiesel blends. The type of biodiesel (soy or animal) was not specified, but was mostly likely soy-based as this is the feedstock most common in the market and in engine research.

- Under loaded, on-road conditions, biodiesel increased NOx by 17% at B20 and by about 40% at B99. At B20, the increase was marginally significant ($p=0.10$); at B99, the increase was statistically significant ($p=0.05$).
- Chassis dyno testing was done 24 months later at an ARB lab. The vehicle was determined to have high oil consumption, and lubricating oil was likely present in the exhaust stream. On the UDDS cycle, biodiesel increased NOx by 7% at B20 (marginally significant at $p=0.07$) and by 35% at B99 (highly significant, $p<0.01$).

The authors concluded "The use of biodiesel did result in higher NOx emissions than the use of ULSD (in tests with statistical significance)." The B20 test results did not reach the usual $p=0.05$ level for statistical significance, but were marginally significant ($0.05 < p \leq 0.10$).

McWilliam 2010. A Caterpillar 6.61 engine equipped with DOC and urea-SCR NOx after-treatment was tested using the European non-road transient cycle (NRTC). The fuels used were ULSD plus B20 and B100 biodiesels blended from a rapeseed methyl ester. Figure 9 of the paper shows tailpipe NOx emissions of the vehicle in g/kWh units. Reading from the graph because numerical emission values were not given, tailpipe NOx emissions increase ~15% at B20 and ~150% at B100. Based on the narrow error bars shown in the figure, both of these increases are statistically significant.

This study was conducted by Caterpillar because previous work had highlighted the potential for biodiesel to have an adverse impact on the NOx conversion efficiency of urea-SCR after-treatment systems. Thus, reductions in conversion efficiency have the potential to increase NOx emissions by amounts that exceed that caused by the biodiesel itself. At B20, only a 1% loss of conversion efficiency was noted, but a substantial 6% loss was observed at B100.

The authors of this paper concluded "Additional control strategies will be necessary to correct for NOx increases during biodiesel operation on installations requiring compliance regardless of fuel used."

Mizushima 2010. An inline 4-cylinder diesel engine equipped with DOC, diesel particulate trap (DPT), and urea-SCR NOx after-treatment system was tested using the JE-05 exhaust emissions test cycle used for heavy-duty vehicles in Japan. The fuels used were ULSD plus B20 and B100 blended from waste vegetable oil (WVO). Figure 4 of the paper shows tailpipe NOx emissions of the engine in g/kWh units. NOx emissions are highly linear with biodiesel blending level. Reading from the graph because numerical emission values were not given, tailpipe emissions increase ~20% at B20 and ~100% at B100. The paper does not address the statistical significance of these results.

With respect to NOx conversion efficiency, the study noted a drop from 76% on ULSD to 47% at B100, with a smaller but still measurable drop at B20. The impact on NOx conversion efficiency was linked to the effect of biodiesel in lowering the overall NO_2/NOx ratio at the SCR inlet leading to reduced conversion efficiency.

The authors drew no conclusions regarding the NOx emissions effects of B20 biodiesel as the focus of their research was on the B100 fuel.

Lammert 2012. The NREL study examined NOx emissions from transit buses on both EPA and CARB diesel fuels, B20 soy blends of each, and B100 soy. Chassis dynamometer testing was conducted using the Manhattan Bus (MAN), Orange County Transit Authority (OCTA) and UDDS test cycles. Two of the buses were NTDEs, including a 2010 Cummins ISL and 2011 Gillig/Cummins ISL. Only the 2010 Cummins was tested using the CARB ULSD base fuel and the biodiesel fuels.

NOx emission results for the 2010 Cummins bus are shown in Figure 10 of the paper. For B20, NOx emissions decreased compared to CARB ULSD on all three cycles (MAN, OCTA, and UDDS), and for B100 on the MAN cycle (OCTA and UDDS were not tested). None of the differences were statistically significant except for B20 on the UDDS cycle, and the standard errors plotted in the figure are large in comparison to the emission averages.

The authors explain the non-significance of their results as follows:

> *For much of the cycle NOx would be at or near the detection limit of the laboratory equipment, which resulted in a 95% confidence interval error that was high relative to the value of the cycle emissions.* (Page 6)

One of the authors' conclusions is that SCR NOx after-treatment appears to nearly negate the effect of fuels on NOx emissions. Another conclusion is that SCR NOx after-treatment also negates any duty cycle effect on NOx. (Page 8) For buses without NOx after-treatment, NOx emissions are strongly related to the kinetic intensity (load) of the test cycle. This result is consistent with all past vehicle and engine research studies, which show that NOx emissions are increased when a diesel engine is operated under increased load. However, no such relationship is observed for SCR-equipped buses. Increased load will increase engine-out NOx levels in an SCR-equipped bus. Unless this is accompanied by an increase in NOx conversion efficiency, tailpipe NOx emissions should also increase. <u>Neither conclusion is reliable because of the study's problems in measuring NOx emissions even on ULSD fuel</u>.

<u>Gysel 2014</u>. A 2010 Cummins ISX-15 equipped with DOC, DPF and urea-SCR NOx after-treatment was tested on CARB ULSD and B50 biodiesel blended from soy, waste cooking oil (WCO) and animal fat feedstocks. Chassis dynamometer testing was performed at CE-CERT using the UDDS test cycle.

Figure 7 of the paper shows the NOx emissions measured on ULSD and the three B50 biodiesel blends. The soy and WCO B50 blends increased NOx by 43% and 101%, respectively, with both increases being highly statistically significant ($p<0.01$). The animal B50 blend increased NOx by 47%, which was marginally significant ($p=0.065$). The authors' conclude that "Overall, NOx emissions exhibited increases with biodiesel for both vehicles with the differences in NOx emissions relative to CARB ULSD being statistically significant for the new Cummins ISX-15 engine." (Page 6)

The authors note the negative results reported by Lammert 2012 as being in contrast to those of their study, "which shows that there is a relatively strong fuel effect with the B50 blends compared to CARB ULSD from the Cummins ISX-15 engine with SCR." (Page 6). They also note the following:

> *The NOx increase with biodiesel for SCR-equipped engines is usually attributed by a reduction of exhaust temperature and the change of NO_2/NO ratio in NOx emissions [38]. In general, the lower exhaust temperatures with biodiesel will lower the oxidation rates of NO to NO_2 from the DOC. It has been shown that a NO_2/NOx ratio below 0.5 significantly changes SCR reaction chemistry lowering the SCR removal efficiency of NOx [39]. Walkowicz et al. [40] found increases in NOx emissions of 7% with B20 and 26% with B99 compared to ULSD for a heavy-duty diesel vehicle equipped with a 2004 Caterpillar 400 hp C13 engine. For the same vehicle equipped with a urea-based SCR system, NOx increases were very similar on a percentage basis, with B20 and B99 having 7% and 27%, respectively, higher NOx than ULSD.* (Page 6)

The authors continue to say:

> *The trend of increasing NOx emissions for biodiesel blends is consistent with a wide range of studies found in the literature. Comprehensive investigations conducted by Mueller et al. [41] and Sun et al. [42] confirmed that biodiesel promotes a combustion process that is shorter and more advanced than conventional diesel, which contributes to the formation of thermal NOx. The higher NOx emissions with biodiesel for both vehicles could also be a consequence of the higher oxygen content in biodiesel, which enhances the formation of NOx. The lower volatility of biodiesel compared to diesel fuel could also contribute to decreased fractions of premixed burn, as a result of fewer evaporated droplets during the ignition delay period [43]. Another contributing factor for NOx emissions increase could be the engine control module (ECM), which may dictate a different injection strategy based on the lower volumetric energy content of biodiesel. Eckerle et al. [44] suggested that a higher fuel flow is required with biodiesel compared to diesel fuel for an engine to achieve the same power. The ECM interprets this higher fuel flow as an indicator of higher torque, and therefore makes adjustments to engine operating parameters that, under certain operating conditions, increase NOx emissions.* (Page 6).

The engineering mechanisms described by the authors indicate that <u>biodiesel should be expected to increase NOx emissions in NTDEs at blend levels below the B50 examined in the study</u>. There is no basis in these mechanisms to believe that biodiesel <u>will not</u> increase NOx emissions at B20 but <u>will</u> increase NOx emissions at B50. ADF B3-180

3.2 Consensus on Biodiesel NOx Impacts

Table 2 presents a summary of the available literature on the NOx emissions impact of biodiesel at the B20 blend level. Four of the five studies tested B20 fuels on NTDEs. Staff choose to rely on the one study in which NOx emissions were at or near the detection limit of the laboratory equipment for much of the test cycle on each fuel and to dismiss the other three studies "… since they included either retrofit engines or non-commercial engines …". The study that was retained did not observe a NOx increase because it had trouble measuring NOx emissions from the NTDE tested. The studies that were dismissed showed consistent NOx emission increases in the range of 10-20% at B20.

Staff notes the Gysel study, which found significantly increased NOx emissions at B50 compared to CARB ULSD, as its reason for setting the biodiesel control level at B20 for NTDEs. ADF B3-181
However, Staff did not note the study's discussion indicating that the Lammert results were in contrast to their results and to the results of other studies in the literature. Nor did Staff note the discussion of mechanisms by which biodiesel is believed to increase NOx emissions in NTDEs. These mechanisms include a reduction of the NO_2/NOx ratio that leads to loss of NOx conversion efficiency in urea-SCR systems, promotion of a combustion process that contributes to increased formation of thermal NOx, higher NOx emissions due to the oxygen content of biodiesel, and the lower volatility and lower volumetric energy content of biodiesel. <u>These mechanisms indicate that biodiesel can be expected to increase NOx emissions in NTDEs at blend levels below the B50 examined in the study</u>.

Table 2. Summary of NTDE Literature on NOx Emissions Impact of B20

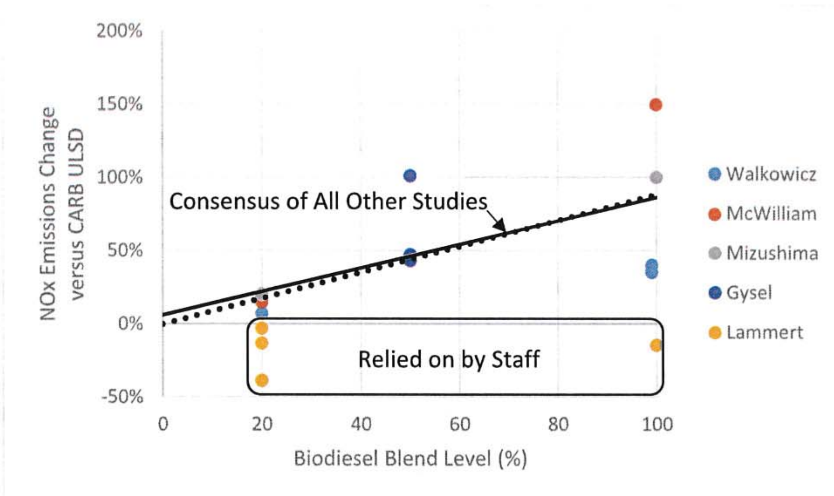
	B20 NOx Emissions Change (%) versus CARB ULSD	Comments
Studies Relied on by Staff		
Lammert 2012	NOx emissions decrease on three cycles	UDDS cycle decrease is statistically significant. NOx emissions on all fuels were at or near the detection limit of the laboratory equipment.
Gysel 2014	B20 not tested	The paper discusses how biodiesel effects NOx emissions. These mechanisms suggest that biodiesel <u>should</u> increase NOx emissions at levels below B50.
Studies Dismissed by Staff		
Walkowicz 2009	+17% on-road + 7% chassis dyno	Both results are marginally significant ($0.10 \leq p < 0.05$)
McWilliam 2010	~15% increase	European transient cycle
Mizushima 2010	~20% increase	Japanese heavy-duty test cycle

ADF B3-182

Figure 3 summarizes the impact of biodiesel on NTDE NOx emissions at all blend levels. The four studies (excluding Lammert 2012) establish a linear relationship between NOx emissions and blend level. The first trend line (solid black) passes very nearly through the origin without being constrained to do so. The second trend line (dotted black) is constrained to pass through the origin. While there is substantial scatter around the trend lines, the consensus of the four studies is that biodiesel increases NOx by 18-22% at B20, by 45-50% at B50, and by 90-100% at B100.

In spite of this consensus, Staff chose to rely only on the Lammert 2012 study, which shows that biodiesel <u>decreases</u> NOx emissions at both the B20 and B100 blend levels. This is the study that had difficulty measuring NOx emissions because NOx was at or near the detection limit of the laboratory equipment for much of the test cycle on all fuels.

Figure 3. The Impact of Biodiesel on NTDE NOx Emissions



To test the statistical significance of the trend lines shown in the figure, conventional regression analysis was conducted using the data reported by four of the studies (Lammert 2012 excluded) as summarized in Table 3. Regression A corresponds to the figure's solid trend line and is not constrained to pass through the origin. Its slope is +0.80% increase per 1% biodiesel in the blend; it is statistically significant at the p=0.035 level. Regression B corresponds to the dotted trend line and is constrained to pass through the origin. Its slope is +0.89% increase per 1% biodiesel, and it is statistically significant at the p<0.001 level. The two regression models predict a 22% and 18% increase, respectively, in NOx emissions at B20 in NTDEs.

ADF B3-183

Table 3. Statistical Significance of Biodiesel NOx Effect in NTDEs

	Intercept	Significance	Slope (% NOx Increase per 1% biodiesel)	Significance	Predicted NOx Increase at B20
Regression A	6.4	p = 0.80	+0.80% (±0.32%)	p = 0.035	22%
Regression B	None	n/a	+0.89% (±0.16%)	p <0.001	18%

A fair reading of the technical literature would lead Staff to expect that biodiesel will increase NOx emissions in NTDEs by about 20% at B20 and by proportionately smaller amounts at blend levels below B20. At the B5 level, the impact is expected to be an increase in NOx emissions of about 5%. At the B20 level, the NOx increase appears to be greater on a percentage basis than would be expected in conventional diesel engines (1% at B5, 2% at B10, and ~4% at B20). The loss of NOx conversion efficiency when biodiesel fuels are used is one likely reason for the greater impact. ADF B3-183 cont.

4. SUMMARY AND CONCLUSIONS

The key conclusions of this study are summarized below with respect to conventional diesel engines and new technology diesel engines.

Conventional Diesel Engines

- Soy and animal blends are not categorically different fuels once their differing effect on blend CN is taken into account. ADF B3-184
- There is no evidence in the data of a threshold level below which biodiesel fuels as a group do not increase NOx, whether soy or animal. As shown here, the magnitude of the NOx impact observed depends on both the blend level and the change in CN that results from blending of the biodiesel feedstock. ADF B3-185
- Soy blends clearly and significantly increase NOx by ~1% at B5 and by ~2% at B10. The effect is continuous and linear with respect to the blend level at all levels above ULSD. Soy blends require mitigation at all levels to offset increased NOx emissions. ADF B3-186
- Staff's proposal requires NOx mitigation in summer months for soy fuels at blend levels greater than B5. Because soy fuels increase NOx at all blend levels, mitigation should be required for B5 and lower blends to prevent increased NOx emissions. ADF B3-187
- Animal blends are more complicated. The current research is limited, and the evidence is mixed. At least one B5 animal blend significantly increased NOx, while another has been certified as NOx neutral. Other B5 animal blends may or may not increase NOx depending on their CN effect (and possibly other factors). ADF B3-188
- Staff's assertion that no NOx increase occurs at B5 in animal blends is incorrect: some animal blends will significantly increase NOx emissions, while other animal blends will not. ADF B3-189
- Animal blends cannot be assumed to have no impact on NOx emissions without a demonstration that feedstock blending raises CN enough to offset potential NOx increases. ADF B3-190

New Technology Diesel Engines

- Staff is incorrect in concluding that biodiesels will not increase NOx in NTDEs. The Staff conclusion is based on a highly selective reading of the technical literature that relies on the one study in which the laboratory was not well equipped to measure the low levels of tailpipe NOx emissions from NTDEs. ADF B3-191

- There is greater reason to exclude the study Staff relied on than the three studies that Staff excluded. If that is done, there are no test data at the B20 level or below in NTDEs and no basis whatsoever to permit biodiesel fuels in NTDEs in California. ADF B3-192

- While the available data are limited, the four best studies (excluding Lammert 2012) support the conclusion that biodiesel increases NOx by 18-22% at B20 and that the increase is statistically significant. Staff has no basis to claim that no NOx impacts are associated with biodiesel at the B20 level and below in NTDEs. ADF B3-193

- A fair reading of the technical literature would lead Staff to expect that biodiesel will increase NOx emissions by about 20% at B20 and by proportionately smaller amounts at lower blend levels. This is a greater percentage NOx increase in proportion to blend level than the increase caused by soy biodiesel in conventional diesel engines (1% at B5, 2% at B10, and ~4% at B20). ADF B3-194

- Staff makes no mention of the concern that the use of biodiesel fuels may lead to the loss of NOx conversion efficiency in urea-SCR after-treatment systems by shifting the NO_2/NOx ratio to lower values. Conversion losses were observed at B20 in two of the studies. ADF B3-195

Based on the results summarized above, it is strongly recommended that ARB consider as part of the ADF rulemaking a regulatory structure in which the NOx impacts of soy and animal biodiesel are accounted for using a statistical model analogous to the Predictive Model for RFG. We see the cetane-based model presented here as a possible draft for a biodiesel predictive model, but substantial additional work is needed to: ADF B3-196

- Demonstrate that blends mitigated using DTBP obey the same model; and

- Further assess the impacts of biodiesel produced from animal feedstocks on both CN gain in blends as well as NOx emissions.

Further, more advanced statistical techniques should be used as was done in developing the Predictive Model for California Reformulated gasoline. The dataset used here is unbalanced, meaning that there are varying numbers of data points for each combination of study, feedstock type, engine, and test cycle. In fact, only a fraction of all possible study/feedstock/engine/test cycle cells are represented by one or more data points. Mixed Effects modeling is appropriate in such cases and its use will assure that coefficient estimates are not biased by the unbalanced distribution of the data. ADF B3-197

###

APPENDIX TABLE A: REFERENCES TO LITERATURE ON CONVENTIONAL DIESEL ENGINES

Author	Title	Feedstocks Studied	Blends Studied
Clark 1999	Transient Emissions Comparisons of Alternative Compression Ignition Fuel	Soy	B20
McCormick 2002	Fuel Additive and Blending Approaches to Reducing NOx Emissions from Biodiesel	Soy, UCO	B20
McCormick 2005	Regulated Emissions from Biodiesel Tested in Heavy-Duty Engines Meeting 2004 Emissions	Soy, Canola, Animal	B20
Eckerle 2008	Effects of Methyl Ester Biodiesel Blends on NOx Emissions	Soy	B20
Nuszkowski 2009	Evaluation of the NOx emissions from heavy duty diesel engines with the addition of cetane improvers.	Soy	B20
Nikanjam 2010	Performance and emissions of diesel and alternative diesel fuels	Soy	B5, B20
Thompson 2010	Neat fuel influence on biodiesel blend emissions	Soy	B10, B20
Durbin 2011	Biodiesel Characterization and NOx Mitigation Study	Soy, Animal	B5, B10, B20
Durbin 2013A	CARB B5 Preliminary and Certification Testing	Animal	B5
Durbin 2013B	CARB B20 Biodiesel Preliminary and Certification Testing	Soy, UCO	B20
Karavalakis 2014	CARB Comprehensive B5/B10 Biodiesel Blends Heavy-Duty Engine Dynamometer Testing	Soy, Animal	B5, B10

APPENDIX TABLE B: REFERENCES TO LITERATURE ON NEW TECHNOLOGY DIESEL ENGINES

Author	Title	Feedstocks Studied	Blends Studied
Walkowicz 2009	On-road and In-Laboratory Testing to Demonstrate Effects of ULSD, B20 and B99 on a Retrofit Urea-SCR Aftertreatment System	Soy?	B20, B99
McWilliam 2010	Emissions and Performance Implications of Biodiesel Use in an SCR-equipped Caterpillar C6.6	Rapeseed	B20, B100
Mizushima 2010	Effect of Biodiesel on NOx Reduction Performance of Urea-SCR System	WVO	B20, B100
Lammert 2012	Effect of B20 and Low Aromatic Diesel on Transit Bus NOx Emissions Over Driving Cycles with a Range of Kinetic Intensity	Soy	B20, B100
Gysel 2014	Emissions and Redox Activity of Biodiesel Blends Obtained from Different Feedstocks from a Heavy-Duty Vehicle Equipped with DPF/SCR Aftertreatment and a Heavy-Duty Vehicle without Control Aftertreatment	Soy, WCO, animal	B50

12_B_LCFS_GE Responses (Page 529 – 558)

740. Comment: **ADF B3-153, ADF B3-154, ADF B3-169, ADF B3-184, and ADF B3-197**

Agency Response: These comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

741. Comment: **ADF B3-155 through ADF B3-168, ADF B3-170 through ADF B3-183, and ADF B3-185 through ADF B3-196**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

Jim Lyons

From: Jim Lyons
Sent: Wednesday, February 18, 2015 11:32 AM
To: 'Mitchell, Alexander (Lex)@ARB'; 'Aguila, Jim@ARB'
Cc: 'cotb@arb.ca.gov'; 'Sideco, Katrina@ARB'
Subject: Comments on the LCFS and ADF rulemaking proposals
Attachments: BioDieselNOxAssessment20150210.pdf; Statistical Analysis; Sharp_20150218_111952_0000d3b16c98.pdf

Jim and Lex:

I have discovered that one attachment to my Declaration included in electronic filing for Growth Energy that Josh Wilter of my staff made yesterday was not included in the upload. I am enclosing the attachment here. The contents of this attachment do not differ from the content of my Declaration, and the bulk of the analysis in the attachment was provided to the ARB staff on October 24, 2014 as workshop comments. That email is also attached.

Jim Lyons

Jim Lyons

From:	Jim Lyons
Sent:	Friday, October 24, 2014 6:38 AM
To:	Scheehle, Elizabeth@ARB; amitchel@arb.ca.gov; Aguila, Jim@ARB
Cc:	rincon-ranch@earthlink.net
Subject:	Statistical Analysis
Attachments:	BioDieselNOxAssessment2014.pdf; Biodiesel Emissions Analysis TechnicalSummary 102014.pdf

Please find attached a slide deck and short narrative describing the statistical analysis performed by Robert Crawford of Rincon Ranch Consulting that I summarized during my presentation at Monday's ADF workshop. Please direct any questions regarding the work to Robert who is copied on this email. As was also discussed on Monday, I request that these materials be posted along with the other materials from Monday's workshop on the CARB website.

Thank you.

Jim Lyons

Jim Lyons

From: Jim Lyons
Sent: Wednesday, February 18, 2015 3:37 PM
To: 'Mitchell, Alexander (Lex)@ARB'; 'Aguila, Jim@ARB'
Cc: 'cotb@arb.ca.gov'; 'Sideco, Katrina@ARB'
Subject: Comments on the LCFS and ADF rulemaking proposals

Jim and Lex:

Just wanted to let you know that we'll be filing the report in hard-copy form tomorrow at the hearings. We tried to file a hard copy version today with the Clerk of the Board, but were instructed instead to bring hard copies tomorrow to the hearing room for filing.

I'd only planned to bring two copies tomorrow (one for each rulemaking file based on my conversation today with Steve Adams) as we don't plan to offer oral testimony on this issue and therefore don't plan to ask that the report be handed around to the Board members. However, please let me know if you'd like me to bring hard copies for you. If you were able review to our October 24 post-workshop comments that were submitted to you then as part of the ADF rule development process, you've already seen the Rincon Ranch analysis of the biodiesel test data and the related literature, which I had summarized at the October 20 workshop. The only new thing in this version of the report is the NTDE discussion, which is also covered in my Declaration that was filed yesterday.

Jim Lyons

12_B_LCFS_GE Responses (Page 559 – 561)

742. Comment: **Emails from Jim Lyons**

Agency Response: The emails pertain to the submittal of public comment. They do not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

C. TESTIMONY PRESENTED AT THE FEBRUARY 19, 2015 HEARING

Fifty-one stakeholders testified during at the February 19 board hearing. The transcript of the testimony is reproduced below with responses following.

This page intentionally left blank.

The following group of comments is testimony given at the First Board Hearing.

This page intentionally left blank.

MEETING

STATE OF CALIFORNIA

AIR RESOURCES BOARD

CAL/EPA HEADQUARTERS

BYRON SHER AUDITORIUM

SECOND FLOOR

1001 I STREET

SACRAMENTO, CALIFORNIA 95814

THURSDAY, FEBRUARY 19, 2015

9:12 A.M.

TIFFANY C. KRAFT, CSR
CERTIFIED SHORTHAND REPORTER
LICENSE NUMBER 12277

APPEARANCES

BOARD MEMBERS

Ms. Mary Nichols, Chairperson

Dr. John Balmes

Ms. Sandra Berg

Mr. Hector De La Torre

Mr. John Eisenhut

Supervisor John Gioia

Ms. Judy Mitchell

Mrs. Barbara Riordan

Supervisor Ron Roberts

Supervisor Phil Serna

Dr. Alexander Sherriffs

Professor Daniel Sperling

STAFF

Mr. Richard Corey, Executive Officer

Dr. Alberto Ayala, Deputy Executive Officer

Ms. Edie Chang, Deputy Executive Officer

Mr. Kurt Karperos, Deputy Executive Officer

Ms. Ellen Peter, Chief Counsel

Ms. LaRhonda Bowen, Ombusdman

Mr. Michael Benjamin, Division Chief, MLD

Mr. Jack Kitowski, Assistant Division Chief, ISD

APPEARANCES CONTINUED

STAFF

Mr. Lex Mitchell, Manager, Emerging Technology Section, ISD

Mr. Scott Monday, Air Resources Engineer, MLD

Ms. Katrina Sideco, Air Resources Engineer, Fuels Section, Industrial Strategies Division

Mr. Manisha Singh, Manager, Fuels Section

Mr. Samuel Wade, Branch Chief, Transportation Fuels Branch

ALSO PRESENT

Mr. Mckinly Addy, Adtra

Mr. Jason Barbose, Union of Concerned Scientists

Mr. Will Barrett, American Lung Association in California

Mr. Todd Campbell, Clean Energy

Mr. Tim Carmichael, CNGVC

Ms. Jennifer Case, New Leaf Biofuel

Mr. Harrison Clay, Clean Energy Renewables

Mr. David Cox, Coalition for Renewable Natural Gas

Mr. Thomas Darlington, POET

Mr. Jesse David, Growth Energy

Mr. Dayne Delahoussaye, Neste Oil

Ms. Celia DuBose, California Biodiesel Alliance

Mr. Nick Economides, Chevron

Mr. Evan Edgar, Clean Fleets

APPEARANCES CONTINUED

ALSO PRESENT

Ms. Susan Frank, California Business Alliance for a Green Economy

Mr. Joe Gershen

Ms. Gina Grey, WSPA

Mr. Gary Grimes, Paramount Petroleum

Mr. Jamie Hall, CALSTART

Mr. Miles Heller, Tesoro

Mr. Scott Hedderich, Renewable Energy Group

Mr. Christopher Hessler, AW, Inc.

Ms. Melinda Hicks, Kern Oil & Refining Company

Ms. Bonnie Holmes-Gen, American Lung Association

Ms. Kirsten James, Ceres

Dr. Joseph Kubsh, MECA

Mr. Tom Koehler

Ms. Julia Levin, Bioenergy Association of California

Mr. Jonathan Lewis, Clean Air Task Force

Ms. Jerilyn Lopez Mendoza, So Cal Gas

Mr. Bill Magavern, Coalition for Clean Air

Mr. John McKnight

Mr. Matt Miyasato, South Coast AQMD

Mr. Ralph Moran, BP America

Ms. Lisa Mortenson, Community Fuels

APPEARANCES CONTINUED

ALSO PRESENT

Mr. Colin Murphy, Next Gen Climate America

Mr. Ross Nakasone, Blue Green Alliance

Mr. Shelby Neal, National Biodiesel Board

Mr. Graham Noyes, Low Carbon Fuels Coalition

Mr. Tim O'Connor, Environmental Defense Fund

Mr. John O'Donnell, Glass Point Solar

Mr. Tim Olson, California Energy Commission

Ms. Michelle Passero, TNC

Ms. Katherine Phillips, Sierra Club California

Ms. Leticia Phillips, Unica-Brazilian Sugarcane Industry Association

Mr. Matthew Plummer, PG&E

Mr. Harry Simpson, Crimson Renewable Energy, LP

Ms. Mary Solecki, E2

Mr. Tim Taylor, Sacramento Metropolitan AQMD

Mr. Russell Teall, Biodico Sustainable Biorefineries

Ms. Eileen Tutt, California Electric Transportation Coalition

Mr. Stefan Unnasch, Life Cycle Associates

Mr. Chuck White, Waste Management

Mr. Curtis Wright, IWP

INDEX

INDEX CONTINUED

INDEX CONTINUED

PROCEEDINGS

CHAIRPERSON NICHOLS: Good morning, everybody. The February 19th, 2015, public meeting of the Air Resources Board will come to order. We will begin with the Pledge of Allegiance. And Mrs. Riordan is going to lead us in that.

(Thereupon the Pledge of Allegiance was Recited in unison.)

CHAIRPERSON NICHOLS: Thank you.

Madam Clerk, would you please call the roll?

BOARD CLERK JENSEN: Dr. Balmes?

BOARD MEMBER BALMES: Yes. Here.

BOARD CLERK JENSEN: Ms. Berg?

BOARD MEMBER BERG: Here.

BOARD CLERK JENSEN: Mr. De La Torre?

BOARD MEMBER DE LA TORRE: Here.

BOARD CLERK JENSEN: Mr. Eisenhut.

BOARD MEMBER EISENHUT: Here.

BOARD CLERK JENSEN: Supervisor Gioia?

BOARD MEMBER GIOIA: Here.

BOARD CLERK JENSEN: Ms. Mitchell?

BOARD MEMBER MITCHELL: Here.

BOARD CLERK JENSEN: Mrs. Riordan?

BOARD MEMBER RIORDAN: Here.

BOARD CLERK JENSEN: Supervisor Roberts?

BOARD MEMBER ROBERTS: Here.
BOARD CLERK JENSEN: Supervisor Serna?
BOARD MEMBER SERNA: Here.
BOARD CLERK JENSEN: Dr. Sherriffs?
BOARD MEMBER SHERRIFFS: Yes.
BOARD CLERK JENSEN: Professer Sperling?
Chairman Nichols?
CHAIRPERSON NICHOLS: Here.
BOARD CLERK JENSEN: Madam Chairman, we have a quorum.
CHAIRPERSON NICHOLS: Thank you. Very nice to have you all here.
I have a few announcements, which I want to relate before we begin. A reminder in case there is anyone who is new to these proceedings that if you want to testify, we appreciate it if you fill out a request to speak card. These are available in the lobby outside or with the clerk. We appreciate it if you turn it into the Board Clerk over here before we actually begin the discussion of that particular item.
Also, we will be imposing a three-minute time limit on all speakers. We appreciate it if you summarize any written testimony that you've already submitted or are going to be submitting because we can read a lot faster than you can talk. So it helps us if we have the written

testimony, but then if you just summarize it in your own words.

Also, I want to point out the exits in this room. There are two at the rear and two on either side of the dais here. If there is a fire alarm, we are required to evacuate the room immediately and go down the stairs and exit the building until we hear the all-clear signal that allows us to come back to the hearing room. And that actually has happened in my time here. So I can appreciate it if everybody will follow that instruction.

And with that, we'll begin this morning with one consent item. I understand no one has signed up to testify on it. This is a minor revision to the South Coast 2012 PM2.5 State Implementation Plan. So unless there is anyone on the Board who wishes to take the item off consent, I would appreciate a motion to approve.

BOARD MEMBER MITCHELL: I move approval.

BOARD MEMBER RIORDAN: Second.

CHAIRPERSON NICHOLS: Very good. All in favor please say aye.

(Unanimouse aye vote)

(Board Member Sperling not present at vote)

CHAIRPERSON NICHOLS: Any opposition or abstentions? Great.

We'll move on to the public hearing to consider the adoption of the evaporative emissions control requirements for spark ignition marine watercraft. I'll ask the staff to begin that presentation.

I want to just comment that this is an area where I know staff has been working with industry for a long time on this issue. We still need more reductions in reactive organic gases to achieve our federal health standards for ozone and spark ignition marine watercraft, which includes inboard, outboard, stern drive, and personal watercraft are a major source of reactive organic gases. So the proposal here today is something that will be an important step on one of our most vexing air quality issues, which is ozone.

So with that, Mr. Corey, would you please introduce the item.

EXECUTIVE OFFICER COREY: Yes, thank you, Chairman.

Mobile sources have historically been the largest source of reactive organic gas emissions in California. With the success of our control programs for on-road vehicles, the emissions contribution from less well controlled off-road categories has become relatively more important.

Reducing reactive organic gas emissions from marine watercraft is key to meeting our air quality goals in ozone non-attainment areas, such as South Coast.

Today, staff will present a regulatory proposal for reducing evaporative emissions from spark ignition marine watercraft configured with engines greater than 30 kilowatts. By setting more stringent evaporative emission than those adopted by U.S. EPA, this regulation is expected to further reduction. This regulatory proposal requires both builders to certify spark ignition marine watercraft to ensure the enforceability of the proposed standards.

Now I'd like to ask Scott Monday to begin the presentation. Scott.

(Thereupon an overhead presentation was presented as follows.)

AIR RESOURCES ENGINEER MONDAY: Thank you, Mr. Corey.

Good morning, Chair Nichols and members of the Board.

Today, I will present the proposed regulation to control evaporative emissions from spark ignition marine watercraft. For purposes of the Board presentation today, we will be using the term "watercraft."

--o0o--

AIR RESOURCES ENGINEER MONDAY: Today's presentation will cover the watercraft regulatory background followed by the details of watercraft emission control. And then I will present the regulatory proposal, and finally staff's recommendation.

Staff evaluated innovative technology solutions and also updated the watercraft emissions inventory to quantify the cost effective emission reductions from this category. The proposed regulation is a result of extensive collaboration between ARB and stakeholders and will yield needed emission benefits.

I will now begin presenting the background for the watercraft regulatory proposal.

--o0o--

AIR RESOURCES ENGINEER MONDAY: The goals of the watercraft regulatory proposal are first to harmonize, where possible, federal watercraft regulation, including elements such as regulatory format, test procedures, and labeling. This will have the benefit of minimizing the regulatory burden on stakeholders.

And second, to obtain additional emission reductions beyond those being achieved with the federal rule in order to meet California's unique air quality needs and State Implementation Plan, or SIP, commitments.

--o0o--

AIR RESOURCES ENGINEER MONDAY: Evaporative emissions from motor vehicles have been controlled for more than 40 years. However, evaporative emissions from watercraft were not controlled until U.S. EPA adopted a rule for new watercraft in 2008. The federal regulations were fully implemented by 2012 and are expected to reduce reactive organic gas emissions by more than eight tons a day in 2037.

Now we are proposing the next step to further reduce evaporative emissions starting in model year 2018. ARB's proposal will provide an additional one ton per day above and beyond the U.S. EPA existing rule. As with the federal rule, the proposal we present today will apply to new watercraft only.

--o0o--

AIR RESOURCES ENGINEER MONDAY: The types of watercraft this proposal would reduce evaporative emission from are gasoline-powered marine watercraft with install fuel tanks. This includes outboard boats, personal watercraft, inboard stern drive and jet drive boats.

As boat sales recover in California, without new controls, evaporative emissions from watercraft will increase.

--o0o--

AIR RESOURCES ENGINEER MONDAY: Dr. Haagen-Smit identified reactive organic gas emissions as ozone precursors. Together with oxides of nitrogen and sunlight, they create ground level ozone.

Reactive organic gas emissions also contain toxic components like benzene, which is known as a public health risk.

Watercraft are a source of reactive organic gas emission statewide. Their control is especially important in non-attainment areas, such as the South Coast. The 2007 SIP calendar commits ARB to developing a regulation to reduce reactive organic gas emissions from watercraft. The proposal we are outlining today meets the commitment described in the 2007 SIP.

--o0o--

AIR RESOURCES ENGINEER MONDAY: In order to determine the best approach for controlling evaporative emissions from watercraft, it is important to understand how the emissions are generated. There are three driving mechanisms of evaporative emissions: Permeation through the fuel tank and fuel lines; venting out of the fuel tank vent; and liquid fuel leakage from the carburetor and connectors.

--o0o--

AIR RESOURCES ENGINEER MONDAY: The three mechanisms, permeation, venting, and liquid leakage, occur in various magnitudes during three distinct usage modes.

Running loss emissions occurring occur during engine operation. Hot soak emission are generated immediately after engine operation when the fuel system heats up. And diurnal emissions are generated when the watercraft is stored.

Current federal regulations that were promulgated in 2008 control these evaporative processes. However, more stringent standards are technically feasible.

--o0o--

AIR RESOURCES ENGINEER MONDAY: I will now discuss the technical basis for controlling watercraft evaporative emissions.

--o0o--

AIR RESOURCES ENGINEER MONDAY: This chart highlights the need for evaporative emissions control and specifically diurnal emissions control. Diurnal, or storage emissions, make up two-thirds of watercraft evaporative emissions. Diurnal emissions are doubly important because of usage patterns. Watercraft are often used in ozone attainment areas. However, they are predominantly stored in urban non-attainment areas where diurnal emissions contribute to ambient ozone formation.

With this as background, we can start to look at how the proposed regulation was developed.

--o0o--

AIR RESOURCES ENGINEER MONDAY: Staff conducted extensive testing and assessment of technology that can be applied to watercraft to determine an appropriate evaporative emission standards. Based on this evaluation, we developed prototype watercraft evaporative emission control systems. The control technology was transferred from on-road vehicles. This technology includes low permeation fuel hoses and fuel tanks, carbon canisters and pressure relief valves, and fuel injection.

--o0o--

AIR RESOURCES ENGINEER MONDAY: On-road vehicles have used similar control technology for over 20 years to greatly reduce evaporative emissions.

--o0o--

AIR RESOURCES ENGINEER MONDAY: To evaluate the optimized evaporative emission control, staff conducted extensive emissions testing of a representative sample watercraft in California using a sealed housing for evaporative determination or, shed, as shown in this slide.

Staff identified representative watercraft populations through the Department of Motor Vehicles, or DMV, database and then procured the watercraft from California boat owners. Over 30 watercraft were tested at ARB's facilities in El Monte.

In-use watercraft were tested to develop base line emission factors, and watercraft were tested with and without emissions control technology. This process provided ARB with a comprehensive understanding of the watercraft evaporative emissions and their sources.

Once the testing was complete, the watercraft were either transferred to other state agencies or sold. The difference between the shed results from watercraft with and without evaporative emission controls demonstrates the overall emission benefits.

--o0o--

AIR RESOURCES ENGINEER MONDAY: A number of factors, such as the decline of watercraft sales during the economic recession, compelled staff to re-evaluate and update the emissions inventory. The improved emissions inventory developed by staff incorporates new evaporative emission factors measured using the shed method described in the previous slide and watercraft usage and storage patterns derived from the California State University Sacramento survey.

The updated forecast reflects the recession and future year marine watercraft population and sales, which are based on the most current boater registration data from the DMV, the housing start data provided by the UCLA Anderson School of Business and human population growth provided by the California Department of Finance. The updated inventory was used to evaluate base line and control emissions.

--o0o--

AIR RESOURCES ENGINEER MONDAY: This slide shows the actual and projected sales data of outboard marine watercraft in California, which accounts for about 55 percent of total sales. Similar projections were developed for other watercraft categories, including inboard stern drive, personal watercraft, and jet drive.

Historical DMV registration data represented in this slide by the black line shows a large decline during the recession. As a discretionary item, the watercraft sales were hit hard by the recession, especially for small boat builders.

However, the past five years indicate a recovery in watercraft sales due to the improved economy. Our analysis found a strong correlation between US housing starts and outboard watercraft sales.

Our near-term forecast shown here by the dashed red line to 2019 assumes this relationship continues during the economic recovery. Our long-term forecast, shown by the solid green line, begins in 2020 and assumes new watercraft sales grow at the same 1.2 percent rate as the human population in California.

--o0o--

AIR RESOURCES ENGINEER MONDAY: The projections made in the inventory are further supported by the June 2014 publication of the UCLA Anderson forecast, which shows a strong rebound in housing starts both nationally and in California. As the proposed regulation is implemented in model year 2018, emission benefits will be generated through sales of new watercraft that comply with the more proposed stringent evaporative standards.

--o0o--

AIR RESOURCES ENGINEER MONDAY: Implementing this proposal would reduce reactive organic gas emissions from watercraft. However, the emission benefits will not be fully realized for almost 20 years due to the long ownership periods.

On average, boat owners keep their watercraft for about 30 years, with some keeping a boat for 50 to 60 years. Since watercraft has a longer lifetime, emission benefits will phase in gradually over time, which is expected to be proportional to new watercraft sales.

Therefore, it is particularly important to start controlling evaporative emission from this category now. This proposal pays off in the long term by reducing reactive organic gas emission by about one ton per day in 2037 time frame and beyond. Reduced benzene exposure is also an important co-benefit of this proposal.

--o0o--

AIR RESOURCES ENGINEER MONDAY: I will now present details of the regulatory proposal, including the implementation schedule, control technology, and cost effectiveness.

--o0o--

AIR RESOURCES ENGINEER MONDAY: Here is an overview of the standards implementation dates and applicable categories. Most watercraft can be divided into smaller watercraft with portable marine tanks and larger watercraft with install tanks, where the dividing line between the two is about 30 kilowatts, which is equivalent.

For most watercraft with engines less than or equal to 20 the Board adopted a regulation and harmonize awarded the U.S. EPA. Staff determined that it was not cost effective to seek further reduction from the smaller engine category because it would require significant engine design and retooling.

For watercraft with engines greater than 30 kilowatts more stringent standard for fuel hose fuel tank venting control and fuel injection begin in model year 2018. Upon commercial availability, a more stringent fuel hose requirement will be implemented in model year 2020.

These standards are more stringent than the current U.S. EPA evaporative standards and provide a cost effective way to reduce reactive organic gas emissions. So to better illustrate --

--o0o--

AIR RESOURCES ENGINEER MONDAY: -- what control technology the ARB standards will require, this slide shows the anticipated components that will be likely used for the proposed regulation. Staff anticipates that to meet the proposed new standards, manufacturers would use low permeation fuel tanks, carbon canister, or pressure relief valve, lower permeation fuel hose, and fuel injection or low evaporative emission carburetors. We estimate the total cost of regulatory control will be about $50 for an average boat price of 30,000, which is less than two-tenths of a percent of the total cost. We believe that manufacturers are migrating to fuel injection with new watercraft to meet consumer preferences and needs. And therefore staff does not see this as a cost associated with the proposed regulation.

--o0o--

AIR RESOURCES ENGINEER MONDAY: Carbon canisters are expected to be the primary vented emissions control technology used to comply with stringent diurnal standards. However, pressure relief valves may be used for diurnal control as well. The proposed test procedures require that the evaporative emission control system be designed to withstand exposures consistent with typical operation in California.

The ultimate goal of this regulation is to control evaporative emissions over the entire life of the watercraft. Durability performance criteria are required for all new watercraft to ensure that the added cost of control technology results in real-world emission reductions.

--o0o--

AIR RESOURCES ENGINEER MONDAY: This regulatory proposal has been carefully developed to be cost effective by maximizing emission reductions while avoiding unnecessary costs. It is not expected to limit the types of watercraft available in California. The cost effectiveness was calculated using industry reported costs and accounts for industry markup. The cost of this regulation is balanced by the benefits of the proposal.

--o0o--

AIR RESOURCES ENGINEER MONDAY: In this final segment, I would like to present the staff recommendation for the regulatory proposal.

--o0o--

AIR RESOURCES ENGINEER MONDAY: The proposed regulation was collaboratively developed with the stakeholders beginning in 2006. Five public workshops and over 40 stakeholders meetings were held. We included manufacturers of watercraft in these discussions as they had extensive experience complying with similar emission standards.

--o0o--

AIR RESOURCES ENGINEER MONDAY: During the regulatory process, staff worked with stakeholders to develop the most cost effective proposal. Industry provided valuable input and suggestions for improving the regulatory proposal.

As a result, staff was able to mitigate concerns without compromising the integrity of the proposal, including harmonizing test procedures to reduce cost to manufacturers, delaying implementation during economic recession, and reducing the scope of the proposal.

--o0o--

AIR RESOURCES ENGINEER MONDAY: We have become aware that the regulation needs a few minor modifications. To accommodate industry's comments and suggestions, we are proposing a 15-day change that will modify the regulation and test procedures to improve clarity for manufacturers. These changes include clarifying the requirements to certify pressure relief valves and clarifying design specifications for fuel fill deck plates.

--o0o--

AIR RESOURCES ENGINEER MONDAY: In summary, controlling evaporative emissions from watercraft will provide emission reductions that are critical for ARB to meets its air quality goal. ARB has tested prototype evaporative systems on watercraft that demonstrate the proposed standards are feasible with available control technology. The proposal was developed with extensive stakeholder participation and is cost effective relative to comparable evaporative emission regulations adopted by the Board.

The proposal will improve public health by reducing ambient ozone concentrations and exposure to benzene.

Staff recommends that the Board adopt the proposed regulation with the 15 day changes.

This completes the watercraft presentation. I'll be happy to answer any questions you may have.

CHAIRPERSON NICHOLS: Thank you. Why don't we go to testimony. We have two witnesses who have signed up on this one. The first is Dr. Joseph Kubsh and the second is John McKnight. So we will listen to you.

Hi. Good morning.

Dr. KUBSH: Good morning, Madam Chair and members of the Board.

My name is Joe Kubsh. I'm the Executive Director of the Manufacturers Emissions Controls Association. Our association includes many of the major manufacturers of both exhaust and evaporative emission controls for mobile sources, and I'm here today to indicate my industry's strong support for the staff proposal.

MECA agrees with the staff assessment that proven cost effective evaporative emission control technology derived from the automotive sector can be implemented on spark ignited marine engines to comply with the staff proposal.

In our written comments, we highlight these available evaporative emission control technologies, and we also provide some suggested modifications to some of the test procedures aimed at making these regulations more easily implementable.

I'd like to thank the staff for their efforts in bringing this proposal forward, and I would ask the Board to adopt the proposal as presented to you this morning. I would be happy to answer any questions. Thank you.

CHAIRPERSON NICHOLS: Thank you. I don't see any questions.

MR. MCKNIGHT: Good morning, Madam Chair and members of the Air Resources Board. I'm John McKnight. I'm with National Marine Manufacturers Association, and we represent the boat builders in the United States and here in California. Want to thank you for the opportunity to testify here today.

NMMA did write a letter supporting the rule. That's pretty much for the record. I do want to say while I have a chance here at the podium to tell you the history of what hapened here. We started working with CARB and EPA in 2001. We put a boat in the shed like Scott showed. We got our own boat, because we wanted to make sure what they were doing was the right thing and we started working on this. We were moving pretty quickly on the rule. Things were looking good.

Around 2007-2008, we had a thing called the recession. And what happened here in California was absolutely devastating. I mean, sales nationwide for boats were down 80 percent. Here in California, we had some engine manufacturers who sold less than 100 engines in that year. I mean, dealers were closing. Fifty percent of the dealers in California had closed. And your two trade associations out here, Southern California Marine Association and the Northern California Marine association went bankrupt, closed their doors. And since that time, NMMA has come in and helped bring those associations back to life.

What does that mean like in the sense of business out here? Well, you have a San Diego Boat Show. That closed. The L.A. Boat Show, that closed. You had the Long Beach Boat Show and the San Francisco Boat Show. All those boat shows closed out here. The association has stepped in and they are back and running. The L.A. Boat Show opened yesterday.

And our association is bullish on California. We figure 38 million people have to start having fun out here.

Anyway, on the flip side, I'm on the business side. Look on the flip side. The ARB, I kind of had to be sympathetic to them because we were the last unregulated category for emissions as far as evap emissions. We would be happy to stay that way, but we know it's not going to happen with these guys.

So anyway, we also know that we are a significant source of emissions. You know, you take a fuel tank on a boat, 40 gallons is small. We had fuel tanks on boats 250 gallons. That's a lot of gasoline ends up in your air. Creates pollution. So we knew we had to be regulated, and we also knew that the technology exists, because like I said, we threw a boat in the shed in 2001, start taking a look at it.

So, you know, there's been a lot going on here. Like I say, we now are running the boat shows out in

California. We're supporting. We're bringing jobs back to California. We are part of the California business community out here.

And staff understood that. That's the first thing I went in to talk to Dr. Ayala and said, "We want to make it happen for you. You have to help us make it happen for us." There was -- staff worked with us on a lot of flexibility on the rule. Much more flexibility than I've ever seen on other rules. I've been doing this for a quarter of a century.

And also, we have a novel approach. I think it's a better approach for us and them.

I want to thank you. Thank all the staff here. And also I would like to ask one thing of the Board, and that is in closing to just kind of direct the staff to work with us between now and 2008 as we implement this rule to help us with training and education. I got about 3,000 boat builders worldwide. I want to make sure they know what they have to do to sell into California.

CHAIRPERSON NICHOLS: Where are you based? Where's your office?

MR. MC KNIGHT: Our main office is in Washington, D.C. We have a California office in Riverside to run the boat shows.

CHAIRPERSON NICHOLS: So you'll come back to

California?

MR. MC KNIGHT: I love coming out here. Invite me back, I'm your man.

CHAIRPERSON NICHOLS: Good. That's excellent. That helps our tourism, helps our economy.

MR. MC KNIGHT: Thank you very much.

CHAIRPERSON NICHOLS: Thank you.

Well, that is it as far as the list of witnesses is concerned. And I do want to close the record at this point, but we can open it up for Board discussion. And I see at the far end, Dr. Sherriffs.

BOARD MEMBER SHERRIFFS: Thank you. Thanks for all that enthusiasm.

You know, this is very important in the San Joaquin Valley, because the boats are not only operated in areas of ozone challenge, they're stored in areas of ozone challenge. So it's a big issue.

Mostly, we're worrying about NOx, but the reactive organics are very important in that, too. So it's a small very important contribution. So it's great that we're finally addressing it, and it's great that the industry is on board and enthusiastic.

One question. You know, it actually took us a long time to get here. And 2018 is a long way away. And I'm wondering is there any way to move this up a little bit. The technology is there. It's not a fancy technology. And it would appear to be pretty easy to apply, as long as people understand. It's not a terribly expensive -- not a big proportion of the overall cost of these things. That's one question.

The other, what are we doing to be sure that when the people are fixing their old boats that, in fact, they're using better equipment? If they have to replace a gas tank or go down and get a new hose for my gas line, I hope we're thinking about, if we haven't already, ensured that we're selling the best stuff out there to help clean the air and improve our health.

CHAIRPERSON NICHOLS: Good questions.

Mr. Monday, do you want to answer?

MLD DIVISION CHIEF BENJAMIN: This is Michael Benjamin, Chief of the Monitoring and Lab Division.

In the first question regarding potentially moving up the implementation date, you're correct that technically it would be possible. But I think the challenge here -- and this is highlighted by the testimony that we heard from NMMA and Mr. McKnight, is that implementation in the phase-in of this is going to be critical so that we don't hurt the boat builders in California.

And so there is still some issues that we need to work through on the labeling side, on the certification side. And those details, even though 2018 may sound like it's not very far away, it's going to take us a couple years to finalize and work through some of those issues with industry and also do the outreach that Mr. McKnight referred to.

So I think what we want to do is to have a regulation that will get the emission reductions that we need as soon as possible, but do it in a meaningful way with stakeholder buy-in and with appropriate outreach. So the time line that we developed really tried to take all of that into account. So that's the response to the first question.

On the second one regarding replacement of parts, you're correct that as parts wear out -- and on boats, typically fuel tanks don't wear out very quickly. They have a lifetime that oftentimes is the life of the boat or maybe even at a minimum 20 or 30 years. Those don't tend to get replaced on existing boats. What tends to get replaced are the hoses. The hoses that are available right now comply with the low permeation standards established by U.S. EPA. And what would be available in the market as this rule gets ruled out would be CARB certified components.

So we fully anticipate that existing boat owners will be using the lower -- the new lower permeation of hoses that are available.

One of the challenges that we had will be though addressing things like Internet sales and boat owners purchasing potentially non-compliant replacement parts that don't meet our standard. So that's going to be a challenge we'll have.

CHAIRPERSON NICHOLS: Given the cooperation that we seem to have established with the industry, hopefully we can get them to help us get the word out through these to the owners about the boats and about the benefits of going with the better ARB certified equipment.

MLD DIVISION CHIEF BENJAMIN: I agree absolutely. I think one of the things we've achieved through this rulemaking process is having a very collaborative relationship with NMMA and other boat builders and associations. And I think that that relationship will enable us to really role this out in a way where we get maximum benefits, both from new boats and potentially additional emission reduction opportunities from existing boats.

CHAIRPERSON NICHOLS: Okay. Any other questions or comments before we go to a Resolution?

If not, I think Mr. Roberts is ready. Supervisor.

BOARD MEMBER ROBERTS: Thank you.

I would guess, although I'm not certain, we have a disproportionately high number of boats in San Diego. So I'm enthusiastic about this. I have to observe I don't -- given the last speaker, I don't think I've ever seen anybody happier as we lead them to the gallows here. We appreciate that kind of cooperation, and I'll move the Resolution.

BOARD MEMBER RIORDAN: I'll second.

BOARD MEMBER BALMES: Second.

CHAIRPERSON NICHOLS: In that case, I'll call for a vote. All in favor please say aye.

(Unanimous aye vote)

(Board Member Sperling not present for vote)

CHAIRPERSON NICHOLS: Any opposed?

Any abstentions? All right. Thank you all very much.

The next item is an informational item on some significant findings from recent climate change assessments, both national and international. And I think it's a good opportunity for the Board to be updated on some of the most important recent findings as we strive to make decisions that are based on the best possible science.

We've invited one of the top experts on climate change science and communication, Dr. Susan Moser, to speak to us today. And I will ask Mr. Corey to introduce the item.

EXECUTIVE OFFICER COREY: Thank you, Chairman.

Today's presentation will be a brief overview of the headline statements from the recent Intergovernmental Panel on Climate Change, or IPCC report. The presentation will also provide an overview of the national climate assessment, with an emphasis on the finding and implications for California and the west coast.

By way of introduction, Dr. Susan Moser formerly served as research scientist at the National Center for Atmospheric Research in Bolder and a Research Fellow at Harvard Kennedy School of Government and Heinz Center in Washington, D.C. She's now a Social Science Research Fellow at the Woods Institute for Environment at Stanford University and a Research Associate at the University of California Santa Cruz Institute for Marine Science.

Dr. Moser's work focuses on adaptation to climate change, resilience, communication, and decision support. She contributed to the IPCC's fourth and fifth assessment reports. She's also the lead author for the Coastal Chapter of the third U.S. national climate assessment and has been involved in California's climate impacts and vulnerability assessments since 1999.

I'll now ask Dr. Moser to please begin the presentation.

(Thereupon an overhead presentation was presented as follows.)

DR. MOSER: Thank you very much, Chairman Nichols and Board members.

Good morning. It's a great pleasure to be here and have this honor to brief you on the IPCC and the national climate assessment. I want to do that by placing --

--o0o--

DR. MOSER: -- this briefing in a long history of California climate policy being deeply informed and motivated by the latest findings on the climate science. So let me just give you a very brief overview of that history --

--o0o--

DR. MOSER: -- and place the IPCC findings in that context.

As you know, the IPCC was formed founded in 1988 and then produced its first assessment in 1990. And about every five, six years, it comes out with another assessment. The most recent one, IPCC AR-5, the assessment report number five, in 2013 and '14. That, of course, has been paralleled. As you are well aware with assessments done here for California, and that actually goes back also as early as the 1990s, the first-ever assessment led back then by the California Energy Commission, a study by the Union of Concerned Scientists and the Ecological Society of America, often known here in the state as the Green Book, that was very influential in shaping early policy and then it goes on from there.

I mentioned just briefly that as part of the first national climate assessment, which of course is a Congressly mandated process, a first report on California was produced in 2002. For the second assessment, there was no such California assessment, but there was one conducted just more recently in 2014 for the southwest, which includes California.

So I want to put that in the context of the big milestones, if you will. And I, of course, was selective in putting these forward. But you are familiar with them. And they have become successively more stringent are have put in place the implementation of these ambitions. And of course, after IPCC, the most recent report came out and the national climate assessment, Governor Brown in his inauguration state of the state was very ambitious and that's been followed now by legislation. So we're -- this is the sort of history that I want to lay out in terms of how much it's been motivated.

--o0o--

DR. MOSER: Let me begin in a brief retrospective by thinking back to the 1990s when the IPCC first talked about climate change. The headlines back in the 1990s -- I don't know if you recall this -- was basically, yep, I think something is going on. We think we're seeing something, but we're not quite sure.

--o0o--

DR. MOSER: That and the second assessment in 1995 was really strengthened and the headlines back then in the news media was really about a discernable human influence. That was not there in the first assessment. At that point, we thought maybe we could see that humans are having something to do with the kinds of changes that were observed.

--o0o--

DR. MOSER: And at that point, the IPCC established sort of a nomenclature for its level of confidence about the scientific findings. I want to put them out here for you to review. To the extent it was possible, you know, just to assign confidence levels which are based on the laws of physics and the extent of the evidence, the theories and the model projections ranging from very low to very high. And where we could, we attached actually probabilistic likelihoods, which it's always important to put numbers with those names because it's actually known that the public when you say likely understand, it can mean anything from one percent chance to 99 percent chance.

So in the IPCC nomenclature, likely means at least a chance of two-thirds or very likely at least a nine out of ten chance of actually being true.

And to the extent we are really certain, we use the terms unequivocal. So you'll find these words here in a minute.

But in the third assessment, those terms were not yet fully applied. When the IPCC came out, the big headlines back then were not just we can now demonstrate show the earth's climate has changed, but we had so many different pieces of evidence that we could say there is a collective picture of a warming world. That was really at that point what we could say. And just think back, you know, this is about the time when the Pavely bill was being written.

So then the second most important finding at that time was that most of the warming observed, just the warming, was attributable to human activity. So that much we could say about 12, 13 years ago.

By the time of the fourth assessment, there was really a sea change in the amount of evidence available, the quality of the models available, so much so that the IPCC concluded warming is unequivocal. That's the top level of certainty that scientists are happy to express. They said that at that point they attached a probabilistic likelihood to the fact that the observed increases in temperature are very likely, that is, more than 90 percent chance due to the increases in human emissions, and a greater than 66 percent chance that there is also a discernable influence on the impacted systems, the physical systems like the water resources, the biological systems, ecosystems, and so forth both on land and in the ocean.

Now it's important here to just point out that there is a lower likelihood because, of course, the temperature changes in rainfall, they all need to translate into the impacts on the physical or natural systems. So that is at least where we could now see an influence.

--o0o--

DR. MOSER: And now we come to the fifth assessment, what is -- is there anything more to say, if you will.

--o0o--

DR. MOSER: Well, it is very significant I think what the IPCC is now willing to say. One is that the human influence on the climate system, the entire climate system, is clear and greenhouse gases are the highest in history. And we see now widespread impact on human and natural systems. That is yet another layer further down in the chain of impacts now of widespread impacts on human and natural systems. The warming is unequivocal. And many of the observed changes are unprecedented over a decades to millennium. That's important, and I'll come back to that in a moment here.

--o0o--

DR. MOSER: This is what it looks like. You see the temperature curve. You've probably seen these many, many times. And of course, you know, it was in the news that even after the IPCC was released that 2014 is the warmest year since temperature referenced with thermometers have begun, 38th consecutive year the warming average is -- the global average is above average. Nine out of the ten warmest years all have occurred since 2000. So you know, it's just -- I think this is becoming no more news, you know. It's like on an exponential curve. Every next year is going to be higher than the last. So I think this is something you must get used to.

--o0o--

DR. MOSER: This is what it looks like when you spread it out over geographically. And what I want to point out here, very important point, is that the land areas warm faster than the oceans. Of course, that means when I give you global temperature projections, that you should add a few degrees for the land areas, which is where we all live.

And you know, the right-hand graphic here shows that it's quite a significant amount warmer on land than it is over the ocean areas.

--o0o--

DR. MOSER: As I said, this set of indicators that we now use, it is that collective picture of the warming world, the glaciers are going down on land over the sea ice as well as the big ice sheets, temperature records in every arena. And of course, then we see it in the natural systems, the spring is coming sooner. Species are migrating cold-ward or upward in altitude.

I always like to point out that they're not republican or democratic. They don't have an agenda. They simply go where they're most comfortable. So I think it is pretty hard to dispute that some major changes are underway.

--o0o--

DR. MOSER: Important also to point out that the drivers behind this warming are unprecedented, at unprecedented levels in at least 800,000 years.

And I like to put that in perspective. The human species actually only has been around for 200,000 years of that period. Or if you maybe want to put this even in starker perspective, 10,000 years ago at the end of the last ice age, there were about five million people, members of that homosapien species on the entire planet. That's about the size of L.A. and San Diego combined, spread out over the entire planet. Now we have how many L.A.s and San Diegos on this planet. And that is why these numbers of CO2 methane and nitrous oxide are going up.

--o0o--

DR. MOSER: Let me show you in these terms here. What you see on the top of this graphic is very clearly since the industrial revolution how the use of fossil fuels -- they also include cement there which emit CO2, has just been growing exponentially. And what you see in the bottom there is that the proportion of emissions from land use changes, such as deforestation, has actually been going down. We are no longer on an upward trend in that. Even though it is in many ways unacceptable for biodiversity reasons and whatnot. But that amount of CO2 increase is relatively smaller compared to those from fossil fuels.

But importantly, at the same time, the natural sinks that we have, the forests, the oceans that take up our CO_2, that capacity is going down. They are basically -- the sewers are filling up, if you will. They shouldn't be considered sewers, but we seem to have done that.

--o0o--

DR. MOSER: That means that you see the amount of CO_2 that is accumulating in the atmosphere is actually growing faster.

So this is a good graphic here. I'll date myself here. I put that little red quote there about half of the cumulative human emissions of CO_2 have occurred just in the last 40 years. I'm 48 years old. That's my lifetime. So most of what we've put in the atmosphere we've done over my lifetime.

You see it in every record that we've been tracking, whether it's land use, whether it's population growth, whether it's any of the emissions that you see depicted here. They see the area that is now mainly driven by the human impact on the planet not likely to stop any time soon, given economic and population drivers behind that.

--o0o--

DR. MOSER: Now, as a result of these kind of changes, we are now observing that many, many extreme weather events are actually increasing over that same time period. That was much harder to say even five years ago because the evidence was simply not in. We hadn't had as many good data. And many of these now also can be linked to human influences. You know, climate change did not invent hurricanes. It did not invent draughts. But we can now say with confidence that many of these events actually have an influence of humans behind it. And you see them listed here, cold extreme are going down, warm extremes increasing, higher sea levels. And the number of days with extreme rain events are increasing, at least in several regions.

--o0o--

DR. MOSER: That brings up the question is what we're currently seeing here in California, is that due to climate change? There was a study that was actually put forward by NOAA more recently than the IPCC. I just want to put it forward. They did try to model basically with natural or anthropogenic forces, whether this particular draught can be attributed to global warming. And they found it cannot.

So interestingly enough, this type of event falls within the envelope of natural variability. We cannot discern this has been given solely by the human causes. Very important finding. Now what makes it worse, however, is that we have much higher temperatures.

--o0o--

DR. MOSER: I'll show you that in a moment what it looks like for California. When you have higher temperatures, of course, the demand for water is much higher. And so we see worsening conditions.

But I think the bigger issue is not just can we attribute any one of these events to human causation. The big issue is the last time we had this kind of a draught in the state, we're about five million people here, in 1927. So at that point, much fewer -- far fewer people wanted that little water we have. Now we have 35 million. So that's the issue that you have the extreme events, plus the growing vulnerability that makes these events much more severe and in terms of impacts for us than otherwise.

Let me very quickly mention a couple of other findings from the latest IPCC before turning into the things that happen here in the state.

For the first time, we actually see the IPCC say something very strong about severe, pervasive, and irreversible impacts. Irreversible impacts is not the word you want to see in an assessment like this. That's the stuff that really should keep you all up at night. Irreversible impacts on people, on ecosystems. Irreversible losses in the species in the systems that support our economy, our livelihoods.

And of course, the other thing that we have from the IPCC is a very clear assessment. Mind you, they're not policy prescriptive. But they're trying to assess for you basically whether or not we can reach emission reductions, substantial ones. And basically what they're saying is the only way to get below a two degree warming above pre-industrial conditions is if there are substantial and sustained reductions in greenhouse gas emissions, very much like California is considering.

Let me just say, so you're already at the forefront of this. Some other states and nations are beginning to take some efforts.

What the IPCC is saying that without additional efforts -- so if you're thinking you're doing much, yes, you do. But without additional efforts, we're going to see warming on the magnitude of the kind of warming we've seen since the ice ages.

I'm basically pulling this together, five degrees of warming since the last ice age to pre-industrial conditions. Well, another three and a half to four or five almost over just 100 years, if that's the median range here. We say that with high confidence. So something that should keep you up at night.

Mitigation scenarios that have a greater than 66 percent chance of staying below that two degree guardrail, if you will, need to end up with no more than 450 parts per million concentrations of CO_2 in the atmosphere. You see the past way they describe here, 40 to 70 percent below greenhouse gas emission reductions by the middle of the century and near zero or below -- in other words taking CO_2 back out of the atmosphere -- by 2100 to get to that. That's just a 66 percent chance. But you know, that would be really great if we would get there.

I don't want to spend a lot of time on this particular question or set of projections that they put forward that these represent the emissions pathways that are associated with these different temperature projections I just put forward.

The point I simply want to make, if we want to get to that two degree chance of achieving two degrees of warming, most of the curves bend very significantly downward by 2020. That's tomorrow. You pointed out 2018 is far out. For emission reductions, it's about yesterday. So I think this points to the fact that there is no time to lose if you want to get there.

--o0o--

DR. MOSER: Of course, we know that these -- many of these environmental changes, for example, sea level rise, will continue for centuries to millennium. We are putting in place changes that will effect generations to come. And the more we push the system, I guess the bottom line here is that these abrupt and irreversible changes are becoming more likely.

--o0o--

DR. MOSER: I want to say one thing here about as a result of this, that the longevity of this, it's not like an air pollutant where you cut it and it is gone out of the air. CO2 and other greenhouse gases stay in the atmosphere for decades to centuries. And of course, that commits us to having to deal with the impacts as well as dealing with the emission reductions.

What this graphic here is trying to show is that we sort of have a space, if you will, between the societal stressors we already experience and between the climate stressors and other biophysical stressors that might impinge on us. In that squeeze space between them, we might have a resilient future. And the more we take care of the emissions and lower the risks of severe climate change, the greater that space from the outside, if you will, of the envelope. The more we reduce through adaptation and other measures societal stressors and non-complimental environmental stressors, the more we have, if you will, the breathing space to actually deal with these impacts. It's the combination between mitigation and adaptation that we both need to have a livable and thriveable situation.

--o0o--

DR. MOSER: Let me turn very quickly to the third assessment that came out last May. And of course, one of the chapters focuses on the southwest. I want to emphasize that underneath that is the third climate assessment that was done here for the state. That was a big technical input into the larger assessment for the region. And of course, you know that --

--o0o--

DR. MOSER: -- California is currently working on or beginning to work on its four assessment.

Here, just the key findings from the southwest chapter. None of them will surprise you. You've heard them many times. I think the pictures probably speak much louder than the particular words.

Last year, when we had a bad snow pack, you saw that kind of picture, satellite picture of the sierra. This year, at the same time, it looks like this. Basically no snow in the sierra. This summer will be a very difficult summer for anyone depending on that.

--o0o--

DR. MOSER: And of course, it is not just our problem. What happens to California, you all know this, happens to the bread basket, the food basket of the nation and beyond. It is the number one producer of many high-value specialty crops. Of course, that means many people's livelihoods depends on it. It is the water deficiency and the increasing temperatures that make the difference for many --

--o0o--

DR. MOSER: -- in California.

I want to point out this graphic here produced or based on data from the California climate tracker. It shows basically the temperature increases over the last century in California. And you see here that this past year was exceptionally the warmest ever year, not just in the world, but in California as well, and making the problems with the draught much worse. And this part here is climate driven, even if the draught, per se, we cannot attribute to the problem. It is the combination of those two factors that creates the problems we see and we need to take care of it.

--o0o--

DR. MOSER: You know, these problems, the less snow pack there is, the higher the temperature, the longer the snow-free season, dry season. We have many more wild fires. We also have a track record that twelve is the largest fires we've ever seen in the state have occurred since 2000. So there is much that forest managers in this state need to deal with.

And of course, this effects also any efforts that we might want to do to manage our public lands and private forest lands for carbon sequestration. Very important to consider that the impacts are already effecting the very systems that we now want to capture more.

--o0o--

DR. MOSER: On the coast, these are the pictures. And I guess I should have maybe taken a picture right now driving up from Santa Cruz and showing the king tides currently going on in the delta. You see the water standing everywhere. And this is, if you will, the sunny day inundation. You don't need a big storm anymore to have severe erosion and flooding impacting people's lives in California.

--o0o--

DR. MOSER: Lastly, the finding here relates to the combination of heat and air pollution. I was very glad to see what you just decided just before my speech here, because ozone basically is a greater risk with higher air temperatures. And you see that this is going to be particularly important for urban areas, but also for people who work outside in our fields. So very important impacts on our public health systems as well as electricity and water supplies that all depend on functioning energy supplies.

--o0o--

DR. MOSER: Just very briefly want to point out we're now working on the fourth assessment, which is this time led by the Natural Resources Agency, but the EPIC program from the California Energy Commission will contribute major new studies on impacts on the energy sector. Very important how this has changed over time. You know, originally, we just sort of did these top-down impact studies on different sectors. Now we're looking at multi-sectoral impacts and what happens in the water sector happens and so on, so forth.

We're looking more at extreme events because they cost the most. They cost the most lives. And we try to create much more adaptation related information for policy makers at all levels, which then becomes available through Cal Adapt as many of you know and is widely used in the state by local policy makers.

--o0o--

DR. MOSER: So I want to close here with that there is -- your efforts and what has just been put forward by the Governor and the Legislature cannot come soon enough. I think it's essential that you succeed as a model for the world. You've seen the sort of ever-growing urgency in the tone of the IPCC and reflected in the national climate assessment.

So I thank you and really appreciate the opportunity to brief you on this. I'm happy to answer any questions. Thank you.

CHAIRPERSON NICHOLS: Thank you, Dr. Moser.

First of all, thank you for being with us and for your work and contributions as well. As you have pointed out, this Board has been working on this issue for quite a long time. And we're very proud I would say of the role that California has played in this area and everybody who is on this Board has had an opportunity to be a participant in acting on the kind of good information that you have brought us.

We don't have any public witnesses who have signed up today, and I doubt that's an indication of the fact there is nobody in California who is a climate skeptic or who has doubts, either about whether it's real or whether there is anything that can be done.

I think if anything, the situation may have become more polarized in recent years with those who are either denying the existence of a problem or don't think anything can be done about it. Simply going back to their respective barricades and not wanting to deal with the situation at all. Clearly, that's not the view of the

Governor or the leadership of the Legislature. So there is going to continue to be activity in this area.

But those of us who have positions of responsibility also have a role in the community. And we talk to people. And people talk to us. And I think it's important that we be armed with the best information that we have and also with the best wisdom that's out there about how to effectively communicate about the nature of the problem and what's being done about it.

So in addition to your presentation today, I think it would be helpful if the staff could be providing all the members of the Board at a minimum with these California climate assessment documents that are out there as kind of a basis for all of our libraries and presumably they can then access more copies if they need that sort of thing to make available to others.

And I would welcome any thoughts or suggestions from my fellow Board members about additional ways to act on this, starting with you, Mr. Gioia.

BOARD MEMBER GIOIA: Thank you, Chair Nichols.

I really do think this was an important presentation to have.

As Chair Nichols has said, it is incumbent on all of us working with others to continue to get information out. I think so often people have become unfortunately more skeptical of even very clear scientific conclusions of evidence. I think that's really unfortunate.

And what's so important often is the messenger becomes as important as the message. So that's why all of us folks here and many of the groups that we work with are important messengers. Because often times, people will believe things more when they hear it from somebody they trust, which is often someone they know, as opposed to someone who should be trusted like a scientist, including a few folks, physicians on our Board here.

So I think the issue is about increasing the universe of messengers who have relationships with others to be able to convey this information. I think that's important. The messenger is as important as the message. I appreciate the comments of the Chair in really encouraging this.

BOARD MEMBER BALMES: May I follow up?

CHAIRPERSON NICHOLS: Yes, Dr. Balmes.

BOARD MEMBER BALMES: Well, again, I'd like to add my thanks to Dr. Moser for that very good overview of mostly threats to the environment related to climate change, the environment that we have to live in. And you touched on some health issues.

But I would be remiss if I didn't stress that there are major public health issues related to climate change. You mentioned I think very importantly that farm workers in the valley will not be able to work on the future scenarios that you outlined so well. But it's not just the farm workers. We won't be able to have construction workers work in the Central Valley without space suits. So there is that occupational health component which often is ignored when talking about climate change.

But in terms of cardiovascular and respiratory disease, there are major impacts from the heat, from the air pollution, from increased allergen exposure. And eventually, the people most vulnerable would get the double whammy of worse air quality and heat stress. So I I just wanted to underline that sort of area of climate change impact.

Now in response to Supervisor Gioia, there are groups that are working to try to get physicians to get out there with the message. The Lung Association of California has doctors for Climate Health Social Network. I just added my state photo and a little blurb about the importance of --

CHAIRPERSON NICHOLS: Dr. Sherriffs has already been featured.

BOARD MEMBER BALMES: I know. I'm just trying to play catch up.

But there is actually a national effort out of George Mason University. It's a Climate Change Communications Center, and there is a physician who just spoke at U.C. Berkeley yesterday who's been doing outreach to various physician groups, including the professional organization that I work with as a pulmonologist, the American Thoracic Society. We just published a survey of pulmonary physicians around the country, which no surprise most pulmonary physicians think that climate change is a problem. They believe it. And that they're actually already starting to see the effect in some of their patients. She's working with other physician groups as well.

So it's only one communications pathway, but I think it's an important one for the reasons that Supervisor Gioia mentioned.

And the final thing I want to say is something I learned for a fellow faculty member at Berkeley Robert Rice, who said, it's one thing you can get elected with ideology, but you have to govern the effects. So --

CHAIRPERSON NICHOLS: Good comment.

BOARD MEMBER GIOIA: Well stated.

CHAIRPERSON NICHOLS: Ms. Berg.

BOARD MEMBER BERG: Yeah, thank you very much for this update. And I just would like to piggy-back on the outreach.

For most of us, the overwhelmingness of climate change is difficult to put into some sort of context or some kind of focus about what to do. And as these reports are critical for policy and government and leadership, as we're delivering the message, I think it's really, really important that we're delivering a message of what needs -- of what we're facing, but also what is being done. But more important, what one or two steps could every citizen take that would truly make a difference, that that way they have something to engage in.

As you were going through and it was really helpful to me as an ARB Board member to hear this, but quite frankly overwhelming and under what context as a citizen do I start other than the work that I'm doing here. And I know there are some things I could do. I know there's some choices as a consumer I could be making.

But when I look at things that suggest that we could be a day late and a dollar short and so what's the point, I've got other things that are facing me right now today I've got to make decisions on.

So I think in this education, if we really truly want to embrace and to engage citizens, that we really need to look at an educational mechanism that allows people to put this in context and really make two, three, five critical behavioral changes that they make a difference today for their grandchildren tomorrow. So I'd really encourage that. And thank you so much for this report.

DR. MOSER: May I respond? I would love to respond, because we have two physicians here, I would like to relate this to work I've been doing as a communication expert on hope. What gives people hope.

Well, medical psychology is actually a treasure trove for that. I want to tell you what the ingredients of true hope, because I think all of you can include that in your outreach, in your speeches, in whatever you do.

It begins with a real diagnosis. No rosy, oh, it's not so bad. No. You tell people really what the issue is.

And the next thing is that you paint a picture of what is achieveable. What is the possible. This is work that's been done with terminally ill patients where basically the outlook is pretty dire. So what do you tell someone like that? Well, you might be healed. You might become well. You might have a longer life. You might die without pain. Whatever the achieveable goal is, be very clear about that.

And then paint a picture of the path. How do we get from this diagnosis to that positive outcome that is realistically achieveable? And then how people understand that echoes very much what you just said, what can you do to help get there. What is my role as a patient to be part of this? And what will you do as the doctor?

So for you to say to people what they can do and what you, as Commissioners, as Board members will do or what the State does already is enormously important. So people see themselves as being part of a bigger solution. Changing a lightbulb will not answer that question if you are confronted with the kind of facts I just put there.

The next ingredient is what you will do in case of a setback. Because, you know, sometimes the chemo doesn't work. What do you do? Well, tell people what your plan is. And tell them they're not alone, that you will work with them to do this. So those are the actually five or six ingredients of any message of hope in a very severe circumstance. And I encourage you to use that recipe for your own communication.

CHAIRPERSON NICHOLS: There are actually some groups that are coming together to help, particularly, I know advocates to craft those kinds of messages. So this is a topic that we should perhaps take up later, either at a workshop or in a Board meeting, because I think there would be a lot of interest in that.

Any -- I'm sorry. Supervisor Roberts and that Ms. Mitchell.

BOARD MEMBER ROBERTS: Well, thank you.

One of the strengths of this Board is we all look at things somewhat differently. I would share with you I've been on the Board for a long, long time. This was without a doubt one of the best, most sobering presentations we've had on this subject. Appreciate that.

While I was sitting here, I was thinking sort of the opposite and Sandy was, how do we get people -- I'm thinking how do we get this message out? You've got a lot of information here. And what I usually see is Twittered about and these social media things where it's just sound bytes with no comprehensive picture here doing just the opposite. I was thinking we need to package a video. You've got great information. And I think in the right form, we can reach a lot of people. And I think everybody is looking for content that lasts more than a few minutes.

It could form the basis of -- I mean, I could see this thing being done, taken around and shared with people in other places that would be very effective. So I don't know what production capability we might have, but I sure think that would be -- maybe there is a way to --

CHAIRPERSON NICHOLS: I was chuckling because we have actually increased our ability to produce pretty good quality material of that sort within the last couple of years. So there is some -- we may not be at the Hollywood studio level yet, but we can do videos.

BOARD MEMBER ROBERTS: I would really think about -- because you've got the information. You're a terrific presenter. I would like to encourage us to give some thought. I'd like to have to have access to something like that that I could share in all different kind of ways. So I would encourage staff to work with you to see what our almost Hollywood level production can do.

CHAIRPERSON NICHOLS: Thank you.

Ms. Mitchell.

BOARD MEMBER MITCHELL: Thank you.

Thank you so much for your presentation this morning. And as several people have noted, it's very sobering information.

And I think for us, we're sitting on this Board and thinking what an overwhelming task that we have before us. But one of the things that comes to mind as I think all of us sit here is here we are in California and we are working as hard as we can on these issues. One of the reasons we work so hard on it is because we also have air quality issues here. And we can see co-benefits on working on reducing greenhouse gases and reducing the pollutants that we are trying to reduce.

But we also sit here and think what is the rest of the nation doing? What is the rest of the world doing? I know there are some strides being made other places. But I also hear from our east coast friends what a bunch of kooks you are out in California doing some of the things you're doing. And I'd like to get your input on how that is going across our nation and what more can we do. I know we can do things in California. But how can we bring the rest of the world along with us and certainly the rest of our nation?

DR. MOSHER: It's a very good question. Just as a summative approach, the National Climate Assessment did have for the first time a chapter on mitigation. Not to tell anybody what to do, but it basically looked at do all these efforts that are going on at the local level, at the state level, do they add up to what they need to do? Basically they found that we're barely scraping sort of the bottom of this problem with what we're doing already.

I mean, this goes right back to the message that the IPCC had without additional efforts you will still see something like three and a half to five degrees of warming globally. We're actually not doing nearly enough. For me, the hope comes out of the history of environmental policy making in this country. And it typically goes like this. The state's, California among them, typically as the leading ones, a few in the northeast, maybe eventually someone in the Midwest, starts to do something different. Then you have the different rules all over in these state laboratories, if you will, that basically make business very, very challenging. Because the rules change every time you cross the state line. And eventually, that really upsets the people in Congress or basically the business community that then go to Congress and say could you please level the playing field.

And then your experiments, the ones that are successful, are the ones that actually then will model what will be implemented nationally. This is how we got the Clean Air Act, the Clean Water Act, and many others.

So what more can you do? I think working with your neighboring states to bring them on board to show them how you're accomplishing what you're doing. Literally being out and showing the how-to of how you got to making these changes both politically, but also technically.

And those, to me, are the two key features. Figuring out the financing is obviously a big challenge. I don't need to tell you that. But I mean, that's what many of them are seeing, of course. It helps us with the natural gas prices where they are, the renewables becoming more affordable. So I think, you know, those are the kinds of things that, in general, move the ball forward.

But I think your showing by example is probably the most important and forming coalitions with your neighbors that you already are tied with in the electricity and transportation, those are the kinds of things that at least from my perspective that have worked and I encourage you to do more of.

CHAIRPERSON NICHOLS: Supervisor Gioia.

BOARD MEMBER GIOIA: One additional thought. I think it is really important for us also to show that the steps that are being taken to address long-term climate change issues are having immediate benefits on residents of the state of California. I think that -- and they are. And the co-benefits that are achieved from many of the steps that have been taken on the energy efficiency side, just one example.

So I think drawing that link between the benefits we're getting today that we're not necessarily waiting for the benefits to occur decades down the road while they will. We're getting immediate benefits today. And I think that is important, because you're right. People look at how is this effecting me today. There will be people who will obviously adjust their actions because they want to make a difference long term. Others who will adjust their actions to get the immediate benefit. So we need to show both. And I know we're doing that in some ways, but I think we can do even better.

CHAIRPERSON NICHOLS: One more, yes. Dr. Sherriffs.

BOARD MEMBER SHERRIFFS: It's such an important topic, I can't not. I also can't let the American Thoracic Society down. To remind people this is physicians everywhere, the California Academy of Family Physicians is on record. I'm looking at the California Medical Association. 40,000 doctors in California two years ago reiterated through its House of Delegates its support for the work of AB 32, our work here, and not incidentally coming up later today, stay tuned, low carbon fuel standard programs. So that's very important.

I really am looking forward to do a YouTube with Supervisor Roberts. And I really do appreciate these comments, because this is so constant with the kinds of things we do as doctors that we have to do. And it's such a great model in terms of a clear diagnosis, engendering hope, looking at not just the immediate benefits but the long-term benefits, and walking the talk, doing what we're doing. And demonstrating clearly to people what they can do and having a Plan B. I think that's also an important thing, because I think many people who are concerned and are terrified think, you know, this mitigation stuff, wait a minute. That takes our eyes off the ball. We have to be doing prevention. We can't be spending a penny on mitigation.

I think the answer is no. There is a very good case we have to be doing both. We have to focus on prevention because in the long term that is the most cost-effective, the most important, leads to the fewest disruptions. But we do need that whole package. Thank you very much for your presentation.

CHAIRPERSON NICHOLS: I'm going to draw this to a close, only because we have a couple of other agenda items to address this morning. But I want to make just a couple of very short comments.

First of all, I'm delighted this presentation has set off a healthy competition on my Board. There is nothing like competition bring out the best in all of us. Thank you for that.

And thank you for a really thought-provoking presentation and for being available to us through your work as part of the California Climate Assessment as well. This is not the last time we will have an opportunity to take advantage of Dr. Moser's work.

In that regard, I want to just say two quick things. First of all, with respect to the fact that we are part of a global problem here and a lot of global effort, I do want to call out the fact that going back to the original signing really of AB 32 by Governor Schwarzenegger and now intensified and given more concrete steps by Governor Brown, we have been engaged internationally in working with other regions of the world, work that California has done has been not only an inspiration and a model for programs in other places, but we have increasingly direct engagement at ARB and some of our sister agencies as well in technology transfer and benchmarking and communications with others, which has just expanded the importance of the work that we've been doing here at ARB.

And the other thing I want to say is that in your presentation -- and you pass over this somewhat lightly -- you noted that there is one area of at least somewhat good news mitigating all of this bad news, which is the apparent slowing or reduction of loss of forests and therefore the potential that there's some more ability to reverse what looked like a really terrible situation not that long ago and to come up with some ways to restore our ability to store carbon in our land and forests.

And this is an area where California is I think really just beginning to comprehensively take a look at other ways in which we can be a model. We have not had a comprehensive policy in this regard. The Governor did mention it in his inaugural speech, and there's now a great deal more activity going on. Edie Chang is representing us with the Forestry Climate Action Team, which is working with the Resources Agency and that whole area of California's tremendous natural resource base that we begin with is really just kind of beginning to emerge as a full element of our climate thinking and planning.

And even though it's not as easy for us, particularly as ARB, to directly be involved in because we don't have the parts per million or the direct emissions to work with, we do actually have a responsibility in our role as the keepers of the AB 32 Scoping Plan for assessing, documenting, and monitoring what's going on in that area.

So just a thought really to plant here with everyone that I think this is going to be something we're going to increasingly be talking about in the years to come.

And with that, I want to thank you. And hope we'll see you again.

DR. MOSER: thank you so much.

CHAIRPERSON NICHOLS: We have the proposed readoption of the low carbon fuel standard.

For those planning their day, we are planning to take a lunch break. There is going to be an executive session at lunch today. So we certainly will not get to the alternative diesel fuels item until after the lunch break.

Okay. New team taking their places here. We now proceed to the proposed readoption of the low carbon fuel standard. We're hearing this proposal today in response to a decision of a State Appeals Court that dealt with the procedural issues regarding our original adoption of the rule.

But in addition to the procedural aspects of this, we're also going to hear some proposed amendments that are designed to strengthen the rule and to make sure that it's sending the strongest signals for ongoing investment in low carbon fuels in California.

As I think everybody knows, the overall goal of this low carbon fuel standard is to reduce the carbon intensity of transportation fuels in California 10 percent by 2020. It's a key piece of the portfolio of AB 32 policies to cut greenhouse gas emissions to 1990 levels by 2020.

As we look beyond 2020, increasing volumes of low carbon fuels will be needed to meet the Governor's recently announced goal of cutting petroleum consumption in the state by 50 percent by 2030.

It's been five years since the Board originally adopted the low carbon fuel standard. But the core principles that were embodied in the regulation remain valid. And the basic framework of the rule, including the use of life cycle analysis, as well as the creation of a credit market and a reporting tool, have been working -- have all been working quite well, despite the efforts over the years to undermine this rule or challenge its existence in a variety of different forums.

One of things we hear most frequently from businesses that we regulate is a need for certainty. And that's a very valid concern and one that we need to pay attention to. Certainty allows businesses to plan over the long term, gives each individual business the ability to comply in the ways that make the most sense for them. And right now, we think the best thing that can be done is to move forward in a way that will create as much certainty as we can, given that we have to always remain open to things that happen in the world of science, the world of technology, but we need to make sure that we are, in fact, sending a signal that includes as much certainty as possible.

We will be monitoring and adjusting elements of the program as necessary as we always do at ARB, but particularly given the sensitivity of gasoline as a commodity if the people in this state are perhaps disproportionately reliant on. We need to be making sure that we continue to be watching what's going on out there.

But at the same time, we also can see there is a framework here that's needed and that we need to make sure that we're communicating and implementing in ways that will allow us to bring volumes of cleaner as well as increasingly affordable low carbon fuels into California.

So before turning this item over to the staff, the Executive Officer will introduce the item as usual. Just want to make sure that people understand the context that we're in today. The Board today will not be voting on the actual proposal. We will be listening and paying attention to the comments that we received already as well as those we'll get today and the written and the oral testimony as well as the written testimony. And we will be acting on a Resolution that will direct the staff to make any additional changes that are needed and to bring this item back for a formal vote a few months from now.

So this is a two-step process that we have to engage in as a result of the procedural requirements, which we are now fully implementing and so we will be listening. We'll be learning. We'll be directing the staff via a Resolution. The actual final adoption of the rule will not happen until there is an opportunity for one more hearing.

So with all of that, Mr. Corey, would you please introduce this item.

EXECUTIVE OFFICER COREY: Yes, thank you, Chairman.

As you stated the low carbon fuel standard is intended to reduce the carbon intensity transportation fuels used in California. Reducing carbon intensity will reduce greenhouse gas emissions and support the development of cleaner fuels with the attended co-benefits. Low carbon fuel standard is one of several California programs to reduce GHG emissions from transportation by improving vehicle technology, reducing fuel consumption and the carbon content, as well as increasing transportation options.

When the Board approved the regulation in 2009 and then its 2011 amendments, the Board directed staff to consider various aspects of the regulation, many of which are addressed in this readoption. Additionally, staff included updates and revisions compared to the original regulation to strengthen the signal for investments in the cleanest fuels, offer additional flexibility, update technical information, and provide for improved efficiency and enforcement for the regulation.

Now before I turn this over to staff, I'd like to note that Mike Waugh, many of you know is the face of the low carbon fuel standard program for many years here retired at the end of 2014. And he helped us get the publication of this report, and we really appreciate the tremendous contribution Mike made and wish him well.

I'd also like to acknowledge Sam Wade, who has capably taken over the fuels group for Mike.

And with that, I'll introduce Katrina Sideco, who will give the staff presentation. Katrina.

(Thereupon an overhead presentation was presented as follows.)

AIR RESOURCES ENGINEER SIDECO: Thank you, Mr. Corey.

Good morning, Chairman Nichols and members of the Board.

We are pleased to have this opportunity to present staff's proposal on the readoption of the low carbon fuel standard, or LCFS.

We want to remind the Board that this is the first of two Board hearings for this rulemaking and the Board is not being asked to consider adoption of the proposed regulation today.

--o0o--

AIR RESOURCES ENGINEER SIDECO: In today's presentation, we will first provide background information on the LCFS as well as its current status. We will discuss the proposed regulation, followed by its environmental and economic impacts.

We will then present areas of potential 15-day changes and conclude with a proposed time line for this rulemaking.

--o0o--

AIR RESOURCES ENGINEER SIDECO: The Board approved the LCFS regulation in 2009 to reduce the carbon intensity, or CI, of transportation fuel used in California by all least ten percent by 2020 from a 2010 base line. The Board then approved amendments to the LCFS in 2011. This program is one of the key AB 32 measures to reduce greenhouse gas emissions in California.

The LCFS also has other significant benefits that are sometimes overlooked. It transforms and diversifies the fuel pool in California to reduce petroleum dependency and achieves the air quality benefits, which are two state priorities that precede the LCFS.

--o0o--

AIR RESOURCES ENGINEER SIDECO: The LCFS is designed to reduce greenhouse gas emissions in the transportation sector, which is a responsable for about 40 percent of the greenhouse gas emissions, 80 percent of ozone-forming gas emissions, and over 95 percent of diesel particulate matter.

It is a key part of a comprehensive set of programs in California to reduce emissions from the transportation sector, including the Cap and Trade Program, Advanced Clean Car Program, and SB 375.

The LCFS is also a key program to achieve the Governor's goal of cutting petroleum use in half by 2030.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Other jurisdictions are following California's footsteps, which is evident in the Pacific Coast Collaborative, a regional agreement between California, Oregon, Washington, and British Columbia to strategically align policies to reduce greenhouse gases and promote clean energy.

One of provisions of this collaborative explicitly addresses low carbon fuel standard programs. Oregon and Washington have committed to adopting LCFS programs, while California and British Columbia have existing LCFS programs.

Staff has been routinely working with these jurisdictions, providing assistance where we can. Over time, these LCFS programs will build an integrated west coast market for low carbon fuels that will create greater market pull, increased confidence for investors of low carbon alternative fuels, and synergistic implementation and enforcement programs.

--o0o--

AIR RESOURCES ENGINEER SIDECO: In addition, recent ICCT research finds that the clean fuel goals of all jurisdictions can be achieved simultaneously.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Now I want to briefly touch on how the LCFS works. The LCFS has a couple of key requirements. It sets annual carbon intensity standards, which reduce over time, for gasoline, diesel, and the fuels that replace them.

Carbon intensity is expressed in grams of carbon dioxide equivalent per megajoule of energy provided by that fuel. CI takes into account the greenhouse gas emissions associated with all the steps of producing, transporting, and consuming a fuel, also known as a complete life cycle of that fuel.

The LCFS is fuel neutral and lets the market determine which mix of fuels will be used to reach the program targets.

--o0o--

AIR RESOURCES ENGINEER SIDECO: The LCFS accounting system is pretty straight forward. Fuels and fuel blend stocks introduced into the California fuel system that have a CI higher than the applicable standard generate deficits. Similarly, fuels and fuel blend stocks with CIs below the standard generate credits. Compliance is achieved when a regulated party uses credits to offset its deficits.

Since the regulation was first adopted, the compliance curves have been back-loaded to allow time for the development of low CI fuels in advanced vehicles. Due to this program's design choice, there has always been the expectation that excess credits generated in the early years of the program would be available for use in more stringent future years, if needed.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Since the regulation went into effect, low carbon fuel use has increased due to the LCFS, the federal renewable fuel standard, and other factors.

Staff have continually monitored the program and found that regulated parties in the aggregate have over-complied with the LCFS standards in every quarter since implementation.

Even with the standards frozen at one percent, tangible results can be seen today. For example, the amount of renewable natural gas used in vehicles in California has increased by over 700 percent since the program started. The amount of biodiesel has quadrupled. Renewable diesel has grown dramatically to become more than three percent of the total diesel market in California in 2013. And the average crude CI used by California refiners has remained below the 2010 base line, meaning that the carbon footprint of the crude slate has not increased.

--o0o--

AIR RESOURCES ENGINEER SIDECO: This figure shows the total credits and deficits reported by regulated parties through 2011 up to the third quarter of 2014. For reference, one credit equals one metric ton of carbon dioxide equivalent. Cumulatively, through the end of the third quarter of 2014 there has been a net total of about 3.9 million excess credits.

--o0o--

AIR RESOURCES ENGINEER SIDECO: This is the slide we've borrowed from our colleagues at the California Energy Commission who work on the Alternative and Renewable Fuel and Vehicle Technology Program, also known as the AB 118, which offers grants for low carbon fuel projects. The dots show the location of some of the major low carbon fuel investments that have been made in California.

As you can see, there is a lot of private and public capital flowing to this industry throughout the state.

--o0o--

AIR RESOURCES ENGINEER SIDECO: This slide focuses on the shift of fuels generating credits in the program between 2011 and 2014. Credits so far have been generated primarily from low CI ethanol. The carbon intensity of ethanol has continued to decline, demonstrating that the LCFS incentives significant innovation, even for established biofuels like ethanol. The contributions from non-ethanol fuels, such as biodiesel, renewable diesel, and renewable natural gas continue to expand.

We've also seen a small but increasing contribution from electricity and hydrogen. We expect LCFS credits from these fuels to continue to increase as electric and fuel cell vehicles come into the California market in greater numbers.

I would also like to highlight the major contribution of renewable diesel at 16 percent of the credits in 2014. These charts demonstrate the ability of the LCFS to pull low carbon fuels to California.

--o0o--

AIR RESOURCES ENGINEER SIDECO: The LCFS has two lawsuits, one federal and one state. These legal challenges have caused uncertainty in low carbon fuel investment.

The Federal Court of Appeals ruled in favor of ARB on some claims and remanded the other claims back to the district court for further proceedings. The State Court of Appeal found procedural issues with the way in which ARB complied with the California Environmental Quality Act, or CEQA, and the Administrative Procedures Act.

Specifically, the state court felt ARB did not fully consider the fact that the low carbon fuel standard may incentivize additional biodiesel use, which could potentially have a negative impact on air quality due to increased emissions of nitrogen oxides from higher blends of biodiesel compared to conventional diesel fuel.

Although the decision found ARB improperly deferred mitigation of biodiesel, the court allowed ARB to enforce the program at 2013 CI levels while addressing the court's concerns.

To address the ruling, ARB staff conducted an environmental analysis of the proposed LCFS regulation and proposes that the Board re-adopt the regulation and adopt the alternative diesel fuel regulation that directly mitigates potential NOx impacts from higher blends of biodiesel.

As we will describe later in this presentation, staff has conducted a joint environmental analysis of the two rules to study this interaction and you will hear more about this during the alternative diesel fuel presentation later today.

--o0o--

AIR RESOURCES ENGINEER SIDECO: In response to the lawsuit, we are proposing to re-adopt the entire LCFS regulation.

In addition to addressing the legal challenge, staff is also proposing revisions to improve the current LCFS. Although implementation of the LCFS has gone smoothly, there are opportunities to improve the rule.

Several factors are driving the staff's proposed revisions. First, based on stakeholder comments received in both the original 2009 rulemaking and the 2011 amendments, the Board directed staff to consider revisions to the regulation in specific areas.

Additionally, staff has received feedback from regulated parties and other stakeholders throughout the implementation of the LCFS, to which staff has been responsive.

Staff also identified proposed revisions for clarity and enhancement to the regulation based on our experience from five years of implementation of the LCFS.

Also, staff is incorporating the latest science and technical knowledge to update the tools used to calculate the carbon intensity of fuels.

Finally, the readoption along with proposed revisions will provide certainty as we move forward.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Staff went through an extensive public process to engage stakeholder participation for this readoption. In addition to conducting 20 public workshops in 2013 and 2014, staff also conducted two advisory panel meetings in 2014. Staff has also initiated an external scientific peer review of staff's methodology in calculating Carbon intensity values. This process will be completed before the second Board hearing.

--o0o--

AIR RESOURCES ENGINEER SIDECO: We will now discuss the proposed regulation.

So summarize the readoption of the LCFS, it is important to note that the LCFS is working and the core concepts remain unchanged. However, staff identified key areas of improvement, including updating the tools used to calculate carbon intensity to reflect the latest science, adjusting the 2016-2020 carbon intensity targets, and capping the credit price at $200 dollars per credit. We'll be talking more in detail about each of these improvements in the upcoming slides.

--o0o--

AIR RESOURCES ENGINEER SIDECO: One of the key areas of improvement is our proposal to adjust the compliance curve. As mentioned, there has been an uncertain investment market due to the standards being frozen by the court to 2013 levels.

Thus, staff is proposing to adjust the target stringency from 2016 through 2019 to allow the market time to get back on track. However, the requirement to reduce the average carbon intensity by ten percent by 2020 will be retained.

--o0o--

AIR RESOURCES ENGINEER SIDECO: So how do we see low carbon fuel deployment changing to meet our proposed compliance curve? This slide shows the current sources of LCFS credits in 2014 on the left and the projected sources of credits in 2020 in staff's illustrative scenario on the right.

In this scenario, we expect to see strong contributions from a balanced portfolio of low carbon fuels. Since this program is market-based, this is unlikely to be the actual fuel mix by which we achieve compliance in 2020, but it serves to illustrate staff's current best guess as to which low carbon fuels will be the strongest contributors.

--o0o--

AIR RESOURCES ENGINEER SIDECO: The major 2020 sources of credits in this scenario include renewable diesel, biodiesel, renewable natural gas, and a different ethanol slate. Since we are benefitting from the zero emission vehicle program, electricity is also more significant in contributing them today.

This scenario includes a significant use of bank credits in 2020. This is due to the scenario's relatively conservative assumptions about low carbon fuel volumes. Staff felt it was appropriate to use more conservative volume estimates, due to the legal challenges to LCFS mentioned previously, and regulatory uncertainty in the federal renewable fuel standards.

If low carbon fuel investments accelerates faster than shown in this scenario, to 10 percent reduction could be achieved without banked credits used in 2020.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Another key area of improvement is updating the tools used to calculate the carbon intensity for each fuel.

In general, the CI includes a direct effects of producing and using the fuel, as well as indirect effects that are primarily associated with crop-based biofuels.

Two models are used to calculate the direct effects which are the GREET model and the OPGEE model. To calculate the indirect effects, the GTAP model was updated and the AEZ-EF model was created to supplement GTAP's estimates of greenhouse gas emissions from various types of land conversions.

Staff conducted a robust stakeholder process to update these tools to reflect the latest science and is in the process of subjecting these updated tools to a final peer review.

--o0o--

AIR RESOURCES ENGINEER SIDECO: The next two slides show the carbon intensity for both gasoline substitutes and diesel substitutes used in staff's illustrative scenario. This slide shows the changes between 2014 and 2016 for a few gasoline substitutes, with the existing values shown on the left and an updated value shown on the right for each fuel or blend stock.

Note that the emissions associated with indirect land use change, shown in orange, have gone down for all crop-based biofuels.

--o0o--

AIR RESOURCES ENGINEER SIDECO: This slide shows the changes in staff's scenario for diesel substitutes.

Given the continuously evolving research in this area and recent written comments received from the Natural

Gas Vehicle Coalition, we do believe some continued technical work between the first and second Board hearing is warranted, especially for natural gas fuels. So we expect these values to change during the 15-day process.

Finally, we should note again that most of these CIs are merely representative values. Individual low carbon fuel producers have the ability to improve the specific carbon intensity value assigned to their fuel by demonstrating improvements through the pathway application process, which I'll discuss on the next slide.

--o0o--

AIR RESOURCES ENGINEER SIDECO: To date, the fuel pathway application process has successfully determined individual CIs for over 230 unique fuels. Through this process, fuel producers have been able to receive credit for both incremental improvements to existing methods and innovative new production processes. However, the process has proven to be more resource intensive for all participants and staff than originally anticipated.

It is important to simplify this process for stakeholders in California's program and so other jurisdictions can adopt our approach. But an inherent trade-off exists between the simplicity and recognition of all actions that reduce carbon intensity.

Staff is proposing to streamline this process using a two-tiered system to focus greater attention on next generation fuels, such as cellulosic alcohols, biomethane from sources other than landfill gas, hydrogen, electricity, and drop-in fuels. These advanced fuels will be eligible for a process very similar to the one currently in place.

Conventionly produced first generation fuels, such as corn ethanol, will still be able to receive credit for incremental improvements, but this recognition will be given using a simplified calculator, which will shorten staff review of these applications.

Helping all market participants adapt to this new approach and familiarize themselves with the updated tools will be challenging in the short-term, but is expected to create significant improvement in the long term.

--o0o--

AIR RESOURCES ENGINEER SIDECO: The staff proposal includes new cost containment features. But before we cover the new addition, we'd like to first review the cost containment provisions we currently have in place and explain how useful they've been to the program so far.

One example is the trading of credits. The program has seen 530 credit transactions from 2012 through November of last year and about 2.7 million metric tons of credits were traded in that time frame. Presumably, the purchasers of these credits saw these purchases as a lower cost compliance option than directly reducing the CI of the fuels they control.

Another example is that credits are fungible between the gasoline and diesel pools. In staff's illustrative scenario, over-compliance from diesel fuel substitutes is expected to help with compliance on the gasoline side.

The voluntary opt-in provision allows credits to be generated from sources not required to participate in the regulation. The carry-back provision also provides additional flexibility.

Finally, credits have no expiration date, so unlimited banking of credits is also permissible, which we will cover in detail on the next slide.

--o0o--

AIR RESOURCES ENGINEER SIDECO: This slide shows more detail on how the credit banking provides flexibility in staff's illustrative scenario.

Here, you see the initial compliance curve prior to the litigation depicted by the gray dotted line. Here is what actually happened to the compliance curve so far, which is illustrated by the black line. You can see that the standards are frozen at one percent until 2015 due to the lawsuit.

This green line shows the percentage of carbon intensity reductions so far. Due to the frozen standards, we can see a significant bank of credits being built up.

The percentage of carbon intensity reduction from staff's illustrative scenario is depicted by the green dashed line. We believe this scenario is a reasonably conservative estimate of how carbon intensity would change in the future, given the proper programmatic signals. Note that we show the rate of CI reduction increasing slightly in 2016 due to program readoption and again post-2020.

The black dotted line shows the compliance curve as adjusted by the readoption proposal. As you can see, there is a period where the projected CI may be higher than the standard. During this period, the credit bank allows time for low carbon fuel investments to accelerate.

Also, this figure makes it clear that future adjustments are likely needed post-2020 to address the Governor's 2030 petroleum reduction goals.

--o0o--

AIR RESOURCES ENGINEER SIDECO: We are proposing to add a new cost containment provision called the credit clearance market to prevent price spikes in the unlikely event the market experiences credit shortages.

This provision provides consumer protection by establishing a maximum credit price, and thus a maximum impact on fossil fuel prices from the program. This also prevents short-term price issues that reduces the potential for market manipulation.

In the unlikely case there are not enough low carbon fuels in the market to comply, this provision will give regulated parties and ARB up to five years to make adjustments.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Staff is proposing to add a provision to give credit for greenhouse gas emission reductions made at refineries that supply fuel to California. This provision adds flexibility to the regulation and can also be thought of as additional cost containment as it introduces new potential sources of lower cost abatement into the program.

Example project types that would be eligible include solar steam generation or biogas to hydrogen for the refining process. Clear eligibility threshholds are established, and projects cannot increase criteria or toxic emissions.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Similar to the new refinery crediting provision, staff is also proposing refinements to the existing crediting program to support innovative technologies for crude oil production.

The proposal refines the provision to better promote the development and implementation of innovative crude oil production methods. Major changes include an adjustment to the eligibility threshhold and the addition of new project types.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Per Board direction, staff is proposing to add a low complexity-low energy use refinery provision to this regulation to provide a benefit to smaller refineries.

A refinery would have to qualify as a low complexity-low energy use refinery by being below the threshold for both complexity and energy usage. If a refinery qualifies for this provision, it will be able to receive a credit for the refining step carbon intensity and will have a one-time opportunity to have a crude oil incremental deficit calculated on a refinery-specific basis.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Staff is proposing minor refinements related to electricity as a transportation fuel.

First, the proposal adds fixed guideway transit systems and electric forklifts as eligible to generate credits. Fixed guideway transit includes electric light rail, trams, and buses.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Secondly, the proposal adds specific vehicle efficiency values for electric fixed guideway, buses, forklifts, and trucks.

Finally, due to the fact that consumer preferences of electric vehicle owners have not resulted in widespread installation of separate metering in residences, the proposal removes the transition to direct-metering in 2015 required by the existing rule and instead continues the current practice of applying estimation methods to calculate electric vehicle crediting.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Finally, staff is proposing to enhance the enforcement provisions of the program. Among these enhancements is clarifying the jurisdiction to include opt-in parties, registered brokers, and entities applying for fuel pathway certification.

Staff also clarified that the Executive Officer has authority to suspend, revoke, or restrict an account when violations have occurred or when an account is being investigated. Staff also defined a per-deficit violation with a maximum penalty of $1,000.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Now we will go into the environmental and economic impacts associated with this regulation.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Staff prepared one draft environmental analysis, or EA, that covered both the proposed LCFS and ADF regulations because the two rules are inter-connected.

The draft EA was prepared according to the requirements of ARB's certified regulatory program under the California Environmental Quality Act, or CEQA. The analysis focused on changes in the fuel production, supply, and use.

The existing regulatory and environmental setting in 2014 is used as the base line for determining the significance of the proposed regulations impacts on the environment.

--o0o--

AIR RESOURCES ENGINEER SIDECO: The LCFS and ADF will result in beneficial environmental impacts to greenhouse gases, air quality, and energy. In combination with other state and federal GHG reduction programs, implementation of the proposed LCFS and ADF regulations is anticipated to result in environmental benefits that included an estimated reduction in greenhouse gas emissions of more than 60 million metric tons of carbon dioxide equivalent from transportation fuels used in California from 2016 through 2020.

Lower carbon diesel fuel substitutes would result in beneficial air quality impacts for particulate matter, carbon monoxide, toxic air contaminants, and other air pollutants. Specifically, the estimated total reduction of PM2.5 emissions would be more than 1200 tons from transportation fuels in California from 2016 through 2020.

--o0o--

AIR RESOURCES ENGINEER SIDECO: The draft EA identified less than significant impacts to certain resources, such as minerals and recreation. However, potential significant impacts were identified in a number of resource categories, such as agricultural, biological, hydrology and water quality. Significant cumulative impacts were also identified for many resources.

While some of these identified impacts are related to long-term operational changes, others are potential short-term effects related to construction of new fuel production facilities.

This is a programmatic analysis. To the extent new fuel production facilities are built, the location of the facilities and consequently their specific environmental impacts will not be known until development plans are announced and local permits are sought. The site-specific environmental impacts would be analyzed at that time by the permitting authorities, which will typically include local air districts and land use agencies.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Because the ADF and LCFS proposals were so interlinked, the macro-economic impacts of the proposals could not be disaggregated. Therefore, the evaluation was completed using the simultaneous effects of both proposals on the fuel volumes and prices.

Staff employed a conserve extensive automotive framework. It assumed all costs to the regulated parties are passed on to customers. It does not assign a monetary value to climate protection benefits associated with fewer greenhouse gases, health benefits associated with reduced criteria pollutants, and toxic air contaminants or benefits due to reduced oil dependence. Also, unlike the environmental analysis, it does not account for interactions with other policies.

Finally, it does not assume any reduced cost due to innovation and low carbon fuels.

All of these assumption directionally reduce the estimated economic benefits of the proposed rule but capture the potential costs of the rule.

--o0o--

AIR RESOURCES ENGINEER SIDECO: The macro-economic portion of the economic analysis was conducted using the regional economic models incorporated, or REMI, tool.

Together, the LCFS and ADF were found to have very small impact on California's gross state product and have very small impacts on employment. Even under the conservative assumptions employed by staff, impacts of the proposed rule are very small, considering the size and diversity of California's economy.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Taking a simplified firm-level view of the economics of the proposed rule, we can see how the value of the LCFS credits creates a shift in fuel producer costs. The LCFS credit value benefits the producers of low carbon fuels significantly on a cents per gallon basis. For example, if credit prices were to rise to $100 per ton, the average biodiesel producer would benefit by emission inventory than a dollar per gallon in 2020, as shown in the orange bars.

Even if credit prices were to remain near current levels around $25 per ton through 2020, the benefit to low carbon fuel producers is noticeable, as shown in the blue bars.

However, covering LCFS deficits increase the cost of traditional fossil fuels only slightly on a cents per gallon basis because the costs are spread over such a larger volume of fossil fuels.

Also remember that these values are presented for the full 10 percent reduction in carbon intensity in 2020. For a fixed credit price, benefits to low carbon fuel producers at a given CI are larger in the earlier years of the program because they generate more credits relative to the more lenient early years of the standard. Costs associated with high carbon fuel producers are lower in earlier years because they generate fewer deficits relative to the standard in the early years.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Moving forward, the second Board hearing is tentatively scheduled in the summer of this year. Between now and the second Board hearing, staff is planning additional stakeholder coordination to further refine the proposal we presented today. We are also proposing 15-day changes which we will cover in the next slide. Should the Board re-adopt the

LCFS with proposed revisions, the implementation of the improved LCFS would begin on January 1, 2016.

--o0o--

AIR RESOURCES ENGINEER SIDECO: As I mentioned, staff has identified a few areas of potential 15-day changes. Staff will continue to update the GREET model with a special attention to natural gas vehicle issues. Staff will also work to clarify the refinery investment provisions further.

We've listed a few minor areas of possible adjustments, including the inclusion of indirect land use change CI values in the regulation, revising the reporting parameters for electricity, and moving the program review forward to 2017.

--o0o--

AIR RESOURCES ENGINEER SIDECO: Finally, these are our next steps before the next Board hearing. The environmental review of the proposed LCFS and ADF regulations will be completed.

Staff will prepare written responses to environmental comments and undertake any needed updates to the draft environmental analysis released in December. We will also complete the external per review and work with stakeholders to draft any 15-day changes needed.

This concludes my presentation. And we thank you again for the opportunity to present staff's proposal on the readoption of the low carbon fuel standard.

CHAIRPERSON NICHOLS: Thank you.

I have a list in front of me of 41 witnesses, and I understand there is another page coming. So we have some work to do here.

I would note with our Board packet we received a list of the written comment log, which is also very extensive. I actually had an opportunity to look at a number of these. But there is about 65 of them at last count. And so for those who have already commented in writing, just know that this material is also in front of the Board.

BOARD MEMBER SHERRIFFS: Can I ask a short question?

CHAIRPERSON NICHOLS: Yes, sir.

BOARD MEMBER SHERRIFFS: Thank you for that. Actually clarified a lot.

On your slide about the impact on gross state product and deployment, that is all cost. There is no consideration of potential benefits in terms of decreased health costs; correct?

TRANSPORTATION FUELS BRANCH CHIEF WADE: That's correct.

CHAIRPERSON NICHOLS: Okay. Thank you. So let's begin. And our first witness -- the list is broadcast up there on the wall, so you can keep track of where you are on the left. Begin with Tim Taylor and then Matt Miyasato.

DIVISION CHIEF FLOYD: Madam Chair, we asked our colleagues from the Energy Commission to speak.

CHAIRPERSON NICHOLS: Of course. Yes. Mr. Olson, sorry. I had a note and I forgot about it. Welcome.

MR. TAYLOR: Thank you, Chair Nichols and members of the Board. Tim Taylor. I'm the Division Manager at the Sacramento --

CHAIRPERSON NICHOLS: I apologize. We're going to call on our colleague from the Energy Commission first. Another Tim.

MR. TAYLOR: Which Tim was it?

CHAIRPERSON NICHOLS: The better looking one.

(Laughter)

01_T_LCFS _TOlson

MR. OLSON: Thank you very much for allowing us to make a comment here.

LCFS T1-1

The California Energy Commission supports the proposed action over the next few months to re-adopt the low carbon fuel standard. And we'd like to note the success of the Energy Commission's incentive funding, you had a brief look at it here in the presentation, the

Alternative Renewable Fuel Vehicle Technology Program is dependent on and compliments the LCFS.

Just to give you -- you had some information on some of the projects. Over the last five years, the Energy Commission has awarded over $547 million in awards and matched with an equal amount of private investment for projects in California. Of that amount, over close to $160 million awarded for 43 biofuel, biomethane projects, with average carbon intensities of 28 grams of CO_2 per megajoule. There's some negative and some a little higher than that. But that's the average.

And they all qualify for LCFS credits. All those projects are in various stages. Some of them are advanced in commercial. Some of them are pre-commercial. Most of them are expected to produce pretty significant quantities in the next -- by 2020. So we're going to be adding more performance there.

That's significant for another reason. Right now, California imports 80 percent of its biofuels that we use today, and we think that in-state development is an important aspect. LCFS is a big contributor to that to make that work.

Also would like to -- we also appreciate the ongoing interaction with ARB staff mutual exchange of information and analysis, which has been used in our

LCFS T1-1 cont.

policy documents, notably the integrated energy policy report, our annual report to the Governor and Legislature. We use your analysis a lot in that process, particularly the LCFS and the ZEV mandate and other programs. And it helps us in justifying the expected forecast of transportation energy supply. And what we're seeing is a shift from petroleum to alternative fuels. And we look forward to that continued interaction.

LCFS T1-1 cont.

And at this point, we just wanted to Support your activity. Thank you very much.

CHAIRPERSON NICHOLS: Thank you very much.

By way of a partial explanation from my factitiousness there, it is a fact that the relationship between the Energy Commission and the Air Resources Board around this program is a very close and interdependant one. But the Legislature in its wisdom chose to give ARB the regulatory authority and the Energy Commission the money. So there we go. That's why we call them good looking.

02_T_LCFS _TTaylor

MR. TAYLOR: Thank you so much for clarifying that. Now I can say the nice things about the Energy Commission that I was planning to say.

I'm Tim Taylr, Division Manager at the Sacramento Metropolitan Air Quality Management District here today to speak in strong support of the low carbon fuel standard.

LCFS T2-1

As you heard in your staff report, transportation is a very significant part of the greenhouse gas emission inventory. Reducing the greenhouse gases from this sector of the economy is critically important if we're going to meet the standards that have been set. Your Board in cooperation with handsome folks from the California Energy Commission has accomplished a great deal toward lowering these emissions through programs encouraging more efficient vehicles, electric and alternative fueled vehicles, and regional transportation planning to reduce VMT. But as your own staff's analyses have shown, without lowering the carbon content of the fuels themselves, it will not be possible to achieve the standards that have been set.

LCFS T2-1 cont.

The low carbon fuel standard creates regulatory certainty and will spur economic and technology development. In our region alone, we have hundreds of natural gas vehicles currently ruining on renewable natural gas from food waste and landfill gas. We have electric vehicles running on electricity that's made from renewable electricity, solar, wind, and from renewable methane. We're working to develop a pilot renewable diesel project here in Sacramento. E85 is readily available in our region.

In summary, the technologies exist and they're increasing. The need is obvious. The Sacramento Air District strongly supports the low carbon fuel standard, and we encourage you to adopt it when it comes back to you for adoption. Thank you very much.

LCFS T2-1 cont.

03_T_LCFS _MMiyasato

CHAIRPERSON NICHOLS: Thank you, Mr. Taylor.

Mr. Miyasato.

MR. MIYASATO: Thank you, Madam Chair, members of the Board. Also want to acknowledge Council Member Mitchell who also sits on our Board.

So by way of for the record, I'm Matt Miyasato, the Deputy Executive Officer for Science and Technology Advancement at the South Coast Air Quality Management District.

I'm here on behalf of my boss, my Executive Officer Dr. Barry Wallerstein. That's to voice our support for the low carbon fuel standard and your staff's recommendation to re-adopt the standard. We believe this regulatory mechanism is important not only for reducing greenhouse gas emissions, but more importantly for our region for getting co-benefits and reducing criteria pollutant emission benefits that your staff highlighted in the environmental impact assessment.

LCFS T3-1

In particular, we believe the widespread use of fuels that you've identified in particular, natural gas and hydrogen, those that give us zero tailpipe emissions, reduce toxics, reduce PM, but especially for our region, reducing NOx emissions will help us meet our attainment goals to achieve federal standards.

We support the LCFS adoption, and we urge your approval when it ultimately comes back for your vote. Thank you.

CHAIRPERSON NICHOLS: Thank you.

MS. Passero.

MS. PASSERO: Good morning. Michelle Passero with the Nature Conservancy. Thank you for the opportunity to comment.

I'm here on behalf of the conservancy to voice our strong support for the readoption of the low carbon fuel standard. It's critical to the programs, both the short-term and long-term goals of reducing emissions in California and in setting a precedent for other regions.

And as you already mentioned, there is a need for certainty for investments in new technologies and transitions to an expansion of low carbon fuels.

So being optimistic about the readoption of the LCFS, we also want to continue working with ARB staff and the Board to encourage implementation of best practices for these new technologies and new fuels to help minimize any trade-offs and also to encourage multiple benefits.

And also, we hope to consider third party

LCFS T3-1 cont.

04_T_LCFS_MPassero

LCFS T4-1

certification programs that can help with implementation of best practices. We did submit a letter along with other NGOs, so there's details in that, and we're certainly happy to follow up and help. So thank you very much.

LCFS T4-1 cont.

05_T_LCFS _GGrey

CHAIRPERSON NICHOLS: Thank you.

Mary Solecki. Is she here?

Gina Grey, WSPA.

MS. GREY: Good morning, Madam Chair, Board members, and staff.

My name is Gina Grey. I'm with the Western States Petroleum Association. We have submitted about 93 pages of written comments for the record, so I'll just try to touch on a few points today.

First, I'd just like to say in case there is any doubt on the member -- the Board member's part about what our position is in our industry, we do still oppose the low carbon fuel standard, as you can imagine. Not so much for the actual goal, which is to reduce obviously transportation sector emissions, but it's more about the policy structure.

LCFS T5-1

Originally, ARB had a lot of optimism in 2009 when the program was cast as a transformative regulation that was going to save the State approximately $11 billion in the ten-year period, as well as produce obviously a lot of in-state jobs and low carbon fuel facilities.

From what we see in this proposed program today seems to be a bit of emission creep whereby the original central goal was to foster innovation and transportation fuels. It seems to have morphed into a program that attempts to satisfy ever-more objectives.

LCFS T5-1 cont.

The staff now proposes to include several credit-generating measures in the reauthorization package, along with a cost containment mechanism to fill what we credit to be the fuel CI gap.

LCFS T5-2

And we still believe the compliance schedule is infeasible, which I'm sure you've heard a lot of. Very low CI fuels, such as cellulosic ethanol, have not materialized in the forecasted volume, but there is an over reliance as well on the significant volumes of credits that have been generated early in the program.

We contracted again with the Boston Consulting Group to update a number of studies that we have been doing with them since 2010. And they have concluded that approximately 5.1 percent is the sustainable reduction that can be achieved by 2020 through the use of both fuel and the credits.

LCFS T5-3

To touch on cost, I would just say that some folks are now saying that credit costs must rise to around $200 per metric ton in order for the program to be

LCFS T5-4

effective and transformative. In addition, there seems to be a duplicative accounting taking place by other states that are embracing the LCFS. The increased competition for the limited fuel volumes and the credits may lead to some interesting market dynamics.

LCFS T5-4 cont.

There have been several recent ARB presentations characterizing the LCFS program as a success. Although there has been movement in lower CIs in terms of corn-based ethanol, an increase in renewable diesel and biodiesel use, for example, we basically don't feel that this defines success while we're under a one percent compliance target at the moment in that kind of a world.

LCFS T5-5

And as well, we don't believe that having credit costs rise to approximately $85 a ton during the initial part of the program before the credit freeze and having them draw it back down defines success.

LCFS T5-6

To summarize, we have two things to ask of the Board today. One is we obviously request ongoing staff reviews. And rather than what was in the program in terms of the dates in there, we would like to have those be on an annual basis that would allow stakeholder input and also help the Board help track of the health of the program.

LCFS T5-7

The second is that we request no further effort on ARB's part to create any post-020 LCFS targets. That's

LCFS T5-8

it.

CHAIRPERSON NICHOLS: Okay. Thank you.

Mr. Clay.

MR. CLAY: Good morning. Thank you for the opportunity to testify today.

I'm Harrison Clay, the President of Clean Energy Renewable Fuels. We are the largest producer, marketer, and distributer of biomethane vehicle fuel in the state of California. We produce and sell biomethane under the trademark Redeem.

In 2013, we sold 14 million gasoline gallon equivalents of Redeem in California. In 2014, we sold 20 million gasoline gallon equivalents. This year, we project we will exceed 40 million gasoline gallon equivalents of biomethane vehicles sold through clean energy stations.

This growth is a sign the LCFS program is working. It's creating incentives for companies like ours to get ultra low carbon fuel out to California's fleets. All of the CNG, LNG, the clean energy sales today from our retail CNG and LNG fuel stations is biomethane. That's a tremendous accomplishment and one we're very proud of and one that wouldn't have been possible without the LCFS program. As such, we are obviously strong supporters of the program and encourage the Board to re-adopt the rule.

06_T_LCFS _HClay

LCFS T6-1

We do have concerns about the administration of the rule. Really, there are two fundamental principles which I think are vital to the continued success of the the LCFS from the perspective of fuel producers like us. One of them is the regulation continues to be technology neutral. It is crucial that the staff and the Board administer the regulation in a way that allows for the lowest cost best performing low carbon fuels to come to market without interfering with the process or, for example, setting carbon intensity numbers based on political preference or an idea of what would be ideal under the right circumstances.

Regulatory stability and certainty is crucial. When CI numbers are published for fuel pathways, the business community, the fuel producers, we depend on those numbers. We count on those numbers. We have investment expectations that are set based on those numbers. And those numbers need to stay the way they are unless or until there is overwhelming unambiguous third-party scientific evidence they need to be changed. That is really crucial. If we end up in a situation where carbon intensity numbers become a matter of advocacy or subjective opinions of what kind of fuel is the best fuel for California, the regulation will really be threatened and the ability to raise money and put money into

LCFS T6-1 cont.

production of low carbon fuels will be compromised.

LCFS T6-1 cont.

With that, I would like to again thank you for the opportunity to testify and that concludes my remarks.

CHAIRPERSON NICHOLS: Great.

Before we get to the next witness, Ms. Solecki who was number four, returned. Please come forward and we'll hear from you now.

07_T_LCFS _MSolecki

MS. SOLECKI: Sorry about that. I was just trying to make an entrance earlier.

My name is Mary Solecki, and I'm the Western States Advocate for E2. And I'm here on behalf of E2's 600 California members that believe that the LCFS is a vital way for us to reduce our greenhouse gas emissions and to diversify our transportation fuels in the state.

And we have been really enjoying working with staff over the past -- well, not just this year, many years to refine and enhance the LCFS.

LCFS T7-1

We are looking forward to continuing to work with staff to refine and enhance the LCFS. And we would just urge you to re-adopt the LCFS when it is time for your vote. And we look forward to continuing to work on this really important program and support it. Thank you very much.

CHAIRPERSON NICHOLS: Thank you.

Mr. Heller.

08_T_LCFS _MHeller

MR. HELLER: Good morning, Madam Chair, Board members and staff. Miles Heller with Tesoro. We are a supplier of fuels in California and obligated party in the LCFS.

CARB staff has worked extremely hard to craft this regulation to meet the Board's goals. However, in our opinion, this is an impossible, given the availability and blending constraints of alternative fuels and the complexities of this proposed regulation.

LCFS T8-1

Given the brief comment time today, I ask the Board carefully consider the written comments submitted by WSPA and other obligated parties as the compliance buck stops with us. Tesoro's door is always open should you have questions about our comments.

Putting aside our view of fuel constraints, I would like to discuss CARB's illustrative compliance scenario which can be found in Appendix B, Table B 22. Taking their numbers at face value and focus on the reliance of banked credits. CARB's own numbers indicate some infeasibility. That by 2019, the credits that are generated from available fuels will not be adequate to offset the deficits generated in that year.

By 2020, there is a considerable gap. Only 70 percent of what is needed will be generated and the availability of credits for gasoline is only 36 percent of

LCFS T8-2

what's needed. That is the light green pie slice you saw in our presentation.

The only way the obligation is met in these years and beyond is by utilizing banked credits. These will run out. This is not sustainable. And we do not think that designing a program to rely on banked credits is wise. This is like telling a student at the beginning of a semester they will fail the final exam, but they can still pass the class if they do extra credit projects throughout the semester.

This does not bring certainty. And moreover, we believe overreliance on banked credits is flawed. First staff projections of credit accumulation in this scenario have already proven to be overly optimistic. Based on the most recent quarter, the projection is already off.

LCFS T8-2 cont.

Secondly, CARB presumes all credits will flow to match the need in both quantity and timing. It is not prudent to assume that obligated parties holding credits will sell to competitors at any price, particularly when they believe the credits will run out. Tesoro recommends CARB set the compliance schedule based on reasonable assumptions of fuel availability and blending capabilities and allow extra credits to be used for compliance margin in the hedge of future shortages.

LCFS T8-3

On a positive note, Tesoro appreciates CARB staff

LCFS T8-4

including language enabling refinery GHG reduction projects. We think this is a level playing field for all the other components and the life cycle analysis. While we support the concept, we find that some of the provisions CARB has proposed creates barriers that will significantly limit the credits from these projects. I cannot go through these limitations now, but we discussed solutions in our written comments. We discussed our concerns with staff and have expressed the willingness to work on these in the 15-day process. We ask the Board direct staff to help us in this regard.

LCFS T8-4 cont.

Thank you for your time.

CHAIRPERSON NICHOLS: Thank you.

Mr. Miller, could I -- since you're the first individual company to come up, I want to just clarify one thing.

As I read the staff report, they're not suggesting that you should comply using credits. They're just showing that as sort of the default if you will that indicates that the 2020 goal is not out of sight or out of reach.

But I hope you don't take this as meaning that we don't think you should be accelerating your efforts to develop and bring in other lower carbon alternatives that would help you comply. I mean, that's not the goal to

LCFS T8-1 cont.

have credits be the major way in which companies comply.

MR. HELLER: No. I certainly understand that. We've been bringing in the fuels to meet our compliance obligation and exceed it in some cases.

But the question becomes in the future when there is not even enough fuels available to do that, then you're left with using whatever credits have been banked in the system. And that's what I was trying to highlight.

LCFS T8-1 cont.

CHAIRPERSON NICHOLS: Okay. Thank you very much. Appreciate that.

09_T_LCFS _NEconomides

MR. ECONOMIDES.

MR. ECONOMIDES: Good morning, Madam Chair, members of the Board, staff.

My name is Nick Economides. I'm the Manager of state fuels regulation at Chevron. We, too are a regulated party under LCFS and a member of WSPA. And we have submitted extensive written comments for the record that we are sure you are going to take a look at. I will try to summarize some of my key points from that submission.

Chevron has worked closely with ARB over the period going back to last March on the proposed LCFS readoption, and we have outlined our concerns on the proposed revisions of the program. We appreciate staff's openness throughout that process, and we recognize that

LCFS T9-1

substantial refinements have been made in some areas. For example, the target CI reduction goals for 2016 through 2019. We remain hopeful that we will be able to continue working closely with staff in the coming months as the final package is prepared for your consideration.

Having said that, the LCFS program in our view will likely fall short of its original intended targets and should be adjusted to more accurately reflect the real world rate of development in market penetration of advanced low carbon intensity fuels.

Simply put, advanced cellulosic fuel development has not proceeded at the rate originally envisioned by ARB, and Chevron has first-hand knowledge of this. We have invested heavily in aggressive programming technology and regretfully we have not been successful. Staff's recognizes a challenges that lie ahead of us. Unfortunately, they're insufficient, as the previous speaker said, to establish the sustainability of the program. The Board should look beyond targets that are met largely through accumulated credits and weigh heavily where the program can stand on its own two feet. I.e. in any one single year, will there be enough CI reductions generated to match what is needed for that year?

LCFS T9-1 cont.

Chevron's view is that the proposed 2020 target of 10 percent is essentially aspirational. It depends on

LCFS T9-2

unrealistic credit build up leading up to 2016, bigger than justified contributions from renewable biogas and renewable diesel and unsubstantiated credits from refinery efficiency projects.

LCFS T9-2 cont.

I will conclude by coming back to something that was said earlier regarding strategy and certainty. We advocate that this program should bring certainty to the regulated community. We know you share that objective. But this strategy of setting higher-than-achieveable goals denies the regulated community the strategy needed to go forward. And it continues the climate of uncertainty that has shrouded this program since its inception.

We would like to be able to turn our attention to compliance, to implementation, to know that we have something that we can achieve and to go off and get it done. And until this happens, I'm afraid we will be here again meeting you shortly to discuss further adjustment to the program's goal. Thank you for your time.

LCFS T9-3

CHAIRPERSON NICHOLS: Thank you.

Melinda Hicks and then Dayne Delahoussaye.

10_T_LCFS _MHicks

MS. HICKS: Chairman Nichols, members of the Board, thank you for the opportunity to come before you today and provide testimony.

My name is Melinda Hicks. I'm the Environmental Health and Safety Manager for Kern Oil and Refining

LCFS T10-1

Company, a small independently-owned refinery located in Bakersfield.

Kern refines approximately 26,000 barrels per day of crude oil for the production of CARB gasoline and diesel. And Kern is proud to say that we have continuously operated without fail since the 1930s, surviving a difficult industry through economic downturns and increased regulatory burden. Where many others cannot say the same.

Further, Kern is proud to say we have embraced the LCFS, being the first refiner in the state to produce renewable diesel and one of the first to blend biomass-based diesel with CARB diesel.

Overall, Kern is supportive of the proposal. We would like to highlight our support in three separate specific provisions today:

First, Kern strongly supports the low complexity, low energy use refinery provision. This provision addresses an inequality inherent to the program's reliance on the average refinery to fit the extremely broad range of refineries that operate in California.

Kern is grateful that the Board previously directed staff to consider such amendments. Certainly, years of extensive staff analysis using refinery data and stakeholder input have resulted in the low complexity, low

LCFS T10-1 cont.

energy use refiner provision. And the ISOR clearly lays the strong scientific and technical basis for both the magnitude of the credit and the criteria for eligibility. The provision will correct what has been a disproportionate negative impact on refineries like Kern that do not fit the average.

LCFS T10-1 cont.

Second, Kern supports the refineries specific incremental deficit option. Kern is encouraged that staff acknowledges that refiners like ourselves can be adversely impacted by the California average crude CI, but themselves cannot effect the sector-wide average. This provision gives us the option to be individually evaluated based on our own base line.

LCFS T10-2

Third, Kern supports the refinery investment credit and appreciate ARB's incentive to perform projects that will reduce a facility's carbon intensity through real GHG reductions.

LCFS T10-3

Of course, I would be remiss this morning were I not to say many thanks to staff for all of their dedication and endurance in working with Kern over the past few years. Thank you.

CHAIRPERSON NICHOLS: Great. Thanks.

Mr. Delahoussaye.

11_T_LCFS _DDelahoussaye

MR. DELAHOUSSAYE: Good morning. My name is Dayne Delahoussaye, and I'm here on behalf of Neste Oil.

LCFS T11-1

Neste Oil is supportive of the readoption program, and I just want to take the time to testify to give additional context for your consideration.

We, along with many other low carbon fuel producers, made significant capital investments in response to the LCFS implementing the demand for renewable and low carbon fuel. Specifically, we invested well over two billion dollars as part of our global capacity. Changing the course or significantly alter the goals of the program at this late stage will have a severe chilling effect on any future potential investments as participants, investors in capital markets will lose confidence in California's commitment to follow through with its policy goals.

According to readoption of a stable LCFS is necessary as a next step to fulfill the commitment California has made to those producers to support those investments and realize true change in the air quality resulting in California's transportation fuels.

Implementation of a stable low carbon fuel standard in California will send a proper signal to fuel producers like Neste Oil and will provide a significant driver to draw low carbon fuels to the state and adequate volumes to comply with the target of 10 percent carbon reduction.

LCFS T11-1 cont.

In addition, the stabilization, the ARB should use this readoption conversation as a spring board to begin to formulate and implement longer-term targets. Producers cannot recoup large capital investments in short economic cycles. We support the investments and continue growth and production of low carbon fuels. The market will require signals effective and robust beyond the 2020 time frame currently at issue here. LCFS T11-2

Additionally, proper implementation of the program is paramount to the success of the LCFS, not just design. The LCFS receives staff's continued ability to timely process and approve complete pathway applications as an obstacle to additional volumes of carbon fuels to be available to California.

Fuels with lower carbon intensity by definition have a higher economic return on the system. However, absent the confirmed CI determination, a producer might reduce fuel production or send the fuel to a more economical market outside of California. Removal of those barriers to otherwise credit generating fuels through the California transportation fuel could generate shortage not because of a failure of the market or program design, but again as a failure of just timely implementation. LCFS T11-3

And we encourage the Board to work with staff to put an approval process in place to make new fuels that LCFS T11-4 are compliant yet timely and prompt CI scores so they can participate in the fuel to generate credits.

LCFS T11-4 cont.

The final thing I want to talk about is I heard some potential comments about the blend levels of renewable diesel and that can be an obstacle. I would encourage the Board to not give that significant value, that that are high values and renewable diesels being available as compliant within California.

LCFS T11-5

Additionally, we see the path forward for getting different labeling solutions being feasible and something that can be likely achieved in the short term and not going to be a long-term detriment to the 2020 goals and the use of this particular combined fuel.

LCFS T11-6

I'm available for any questions, should you have any.

CHAIRPERSON NICHOLS: Yes.

BOARD MEMBER SPERLING: One quick question.

What do you think of the $200 price cap for credits?

MR. DELAHOUSSAYE: The $200 price cap I don't have a basis for and it the current economic it makes sense. But that assumes that there is a valid rent in place with the federal program and that. Absent the federal program that seems to be an arbitrary number that does not support California on its own. So 200 dollars I

LCFS T11-7

would say is only valid in this up to 2020 period anything beyond that I think need to be re evaluated and needs to be viewed in cooperation with the federal mandate that already exists for these fuels.

LCFS T11-7 cont.

CHAIRPERSON NICHOLS: Thank you.

Mr. Grimes.

MR. GRIMES: Good morning, Chairman Nichols and Board members. I'm Gary Grimes, Director of Technology at Paramount Petroleum, an Alon USA company. Alon owns and operates two small refineries in Southern California. We strongly support the Board's decision over two years ago to recognize the differences between the state's smaller lower complexity refineries in its larger higher complexity brethren.

We wish to thank your staff for quantifying this difference and developing a workable regulatory mechanism that is included in today's proposal.

12_T_LCFS _GGrimes

The LCLE provision, as it's known, appropriately accounts for the reality of California's two distinct refinery populations. Lower complexity refineries produce gasoline and diesel fuel using less than half the energy in carbon intensity per gasoline of the larger complex refineries. This is the sound technical reason behind the policy recognized in the LCLE category. Alon supports the inclusion of the LCL provisions.

LCFS T12-1

Although our Bakersfield refinery has not been in full operation since the bankruptcy proceeding a few years ago, the facility still maintains small operation and contractually delivers fuel from its racks.

Also, there is considerable engineering and permit work being done at the local level to allow restoring much of its previous operations. At such time when it comes back, its carbon intensity profile will fit within the small refinery grouping. Therefore, it's important to get the eligibility criteria right during this rulemaking.

LCFS T12-2

On that front, Alon has been working with staff to ensure that the LCLE provisions incorporate all facilities that should be considered LCLE. These discussions are ongoing, and we look forward to positive resolution before the next Board meeting.

Besides the enormous local benefit to Bakersfield of operating this existing energy asset, there will be an ongoing benefit as well to the state. Annually, the refinery emissions associated with the fuel production from the Bakersfield refinery are expected to be 350,000 metric tons of CO_2 lower than the fuel that was produced by an average California refinery. This is clearly a significant and material reduction for this program.

LCFS T12-3

In conclusion, Alon's respectfully supports the

LCLE provision and looks forward to a continue dialogue on this issue. Thank you.

CHAIRPERSON NICHOLS: Great. Thanks.

Celia.

MS. DU BOSE: Good morning, Chair Nichols, Board members, and staff.

My name is Celia DuBose. I'm the Executive Director of the California Biodiesel Alliance. We are the industry trade association for biodiesel. We represent over 50 stakeholders, including feedstock suppliers, distributors, marketers, retailers, and all of the state's producers.

So I'm happy to be here today in support of comments from the National Biodiesel Board, which will be coming up, and to stand with the low carbon fuel sector in urging your support of the readoption of the low carbon fuel standard.

First, I want to thank staff for the extraordinary effort that they put out in gathering comments, incorporating these comments, drawing on your own experience from running the program to build a better LCFS. And we value very much in all of this there is a high priority placed on creating a stable regulatory environment as key to the investor community.

13_T_LCFS
_CDuBose

So our industry has gone on record in support of LCFS T13-1 the compliance curve, the price cap. And we've let you know just how much biodiesel is available to reach program targets. In addition to our 59 million capacity in state, there is over 1.5 billion gallons of biodiesel. And to put a very fine point on this, this is an advanced bio fuel. It's renewable. It's non-toxic. It's biodegradable. It's American made.

LCFS T13-1 cont.

So bio diesel has generated an increasing number of LCFS credits since the program began. Our cumulative number is up to 13, as of the third quarter in 2014. And we are growing. Our industry in the state has grown as a result of LCFS as an incentive. We expect that to continue. We are really happy about our ability to bring the low carbon profile of biodiesel, this emissions profile, to the goals of LCFS. And we look forward to being able to provide more biodiesel benefits to other programs, which we'll talk about later. So thank you very much.

CHAIRPERSON NICHOLS: Thank you.

Ms. Case.

14_T_LCFS _JCase

MS. CASE: My name is Jennifer Case. I'm one of the founders of New Leaf Biofuel, a biodiesel refinery in San Diego.

Thank you for the opportunity to speak today. And thank you to staff and leadership who has spent

LCFS T14-1

countless hours coming up with solutions that help lower greenhouse gases here in California.

I was working as one of California's many lawyers when AB 32 was signed. And don't hold that against me. But due to the groundbreaking legislation and a grant from this agency, the alternative fuels incentive program, my friends and I were able to come together and build our biodiesel refinery in San Diego in the disadvantaged community of Barrio Logan.

Our business plan has always focused on recycling a low value feedstock into an ultra low carbon fuel that we sell back to the community in blends up to and including B20. Our community scale model allows local fleets to reduce their carbon footprint and support a local business at a cost that is comparable to the petroleum diesel alternative.

LCFS T14-1 cont.

I fully support the readoption of the low carbon fuel standard, and I look forward to continuing to work with this agency on the alternative diesel fuel regulation, specifically with regard to finding solutions that allow my business to continue its mission to work with my local community to improve air quality and public health. Thank you.

CHAIRPERSON NICHOLS: Thank you.

Mr. Neal.

MR. NEAL: Thank you, Madam Chair and members of the Board. My name is Shelby Neal. I serve as Director of State Governmental Affairs for the National Biodiesel Board.

For those of you that may not know, the NBB is the national trade association for both the biodiesel and renewable hydrocarbon biodiesel industries. We added renewable diesel to our membership about a year and a half ago.

In order to be brief, I'll just confine my comments to one particular issue. Sometimes I find in a matter of when we have long protracted discussions and debates, the simple facts of the matter are lost or at least obscured. I think sometimes that's happened a little bit here with regard to fuel availability, which is really what I want to focus on. LCFS T15-1

So just a few verifiable facts about fuel availability on the diesel side. So you can go on U.S. EPA's website and check these out.

So when we look at what's happened in biodiesel and renewable diesel space in the U.S. the last couple of years, in the U.S. domestically, we produce 1.4 billion gallons of product. In 2013, we produce 1.5 billion gallons of product. That's a lot of product, considering especially ten years ago you were buying biodiesel by the jar. Now we're at 1.5 billion gallons. If you look at the U.S. market, it's been 1.8 billion gallons the past two years. There was already a lot of biodiesel and renewable diesel in this country. California would only require a fraction of that.

But the real story is not production. The real story is capacity. Capacity -- this is registered, verifiable on U.S. EPA's website -- is over 3 billion gallons. That's 3 billion gallons of product in potentially California we require one-eighth of that.

So we're here today and we're affordable. If you look at pricing across the country, for the past three years, we have this data biodiesel has been 22 cents cheaper than petroleum at the wholesale level. So I think the story with fuel availability -- and I'll confine my comments to the diesel fuel side because that's our particular expertise, is a real positive one.

In the biodiesel industry, our motto from the beginning has always been local feedstock, local production, local markets. So the question is what's happening in California. Again, very positive story. I pulled our production data from last year so pre-LCFS, California really, with all due respect to our members, was not on the national radar screen on production. Now California ranks 13th out of 46 states in biodiesel

LCFS T15-1 cont.

production. We're nearly in the top quartile. And we moved from the bottom quartile in a very short period of time.

Now, by 2018 and 2020 with these regulations based on our experience and other states, we would expect California to possibly enter into the top five of production.

So one final thing. Again, there has been a lot of -- I think there there is some areas of this regulation that are extremely complex. And it's necessary to engage in informed speculation. But this isn't one of them.

And I'll continue.

So if you look at the state of Illinois, Illinois has a very strong biodiesel use policy. Three quarters of the --

BOARD MEMBER BERG: If you could give us a concluding statement, that would be helpful.

MR. NEAL: Illinois has a biodiesel policy that's providing between a nine and ten percent GHG benefit. So there is already a state that on the diesel side is meeting the 2020 requirement here. There should be no need for speculation.

LCFS T15-1 cont.

BOARD MEMBER BERG: Great. Thank you very much.

16_T_LCFS _RTeall

Russell Teall.

MR. TEALL: I was going to say good morning. I

LCFS T16-1

guess it's not anymore.

My name is Russell Teall. I'm the President of Biodico. We're a sustainable biodiesel facility using anaerobic digestion, gasification, and solar. So 100 percent renewable.

I'm also the president of the California Biodiesel Alliance and have been on both advisory panels for the low carbon fuel standard. So I've watched this program evolve over time and with the trials and tribulations of the lawsuit.

Richard Corey and his staff should be commended for hazardous duty being in the line of fire, having to negotiate between the biofuels groups, the NGOs, the oil companies, et cetera. I think they've actually done an excellent job. And it goes all the way down through the staff level. The staff people that we've dealt with have been open, receptive, trying to operate on a factual basis. And, you know, nothing is perfect. But I think it's a good compromise.

Our particular facilities are being expanded as a result of the low carbon fuel standard. So we began in California in 2003 with the US Navy as part of a cooperative research development agreement. And the secretary of the Navy six years ago set a goal by the year 2020 of a 50 percent reduction in fossil fuel use. So

LCFS T16-1 cont.

it's a very strong leadership position. That facility also happens to be or was until redistricting in 600 Pavely district.

So our other facility is in Henry Perea's district in the Central Valley in western Fresno County. That's a new facility. Construction is going on right now. That's slated to be a ten million gallon a year facility.

So I've been talking about biodiesel. But I think that it's going to take, as President Obama said, an all of the above approach. All the biofuels, electricity, hydrogen, fuel cells, renewable diesel, all the alcohols, ethanol, and advanced alcohols, those are all part of the fuel mix and part of the diversity. So I think that the low carbon fuel standard readoption process is setting the right message and the right tone at the right time to stimulate further market capabilities.

LCFS T16-1 cont.

Thank you.

BOARD MEMBER BERG: Thank you. So everybody can check their time, we are at about a few minutes after noon. We're going to take our lunch break at 12:30. And that will go until 1:30. We'll probably get through the next eight speakers, if we kind of look at where you are on the list and we can kind of get lined up. And so that's what we can kind of expect for the next half hour

17_T_LCFS _JLevin

or so. Thank you.

Julia.

MS. LEVIN: Members of the Board, I'm Julia Levin with the Bioenergy Association of California. We represent more than 50 public agencies, local governments, and private companies that are converting organic waste to energy. And we strongly support the readoption of the low carbon fuel standard. We believe it is very much achieveable.

Organic waste alone in California, the organic part of the waste, livestock waste, agricultural waste, wastewater treatment facilities, together those facilities produce enough organic waste to generate two and a half billion gasoline gallons equivalents of very low carbon and sometimes carbon negative transportation fuels. Two and a half billion gasoline gallons equivalents, that's enough to replace three-quarters of all the diesel used by motor vehicles in California.

So in addition to meeting the low carbon fuel standard, we would provide enormous benefits to public health by reducing NOx and particulate matter and toxic air contaminants.

In order to achieve those benefits, California needs to continue to invest not just in a low carbon fuel standard, but specifically in natural gas vehicles and

LCFS T17-1

natural gas infrastructure. Natural gas and biogas are inextricably linked. We use the same vehicles. We depend on much of the same infrastructure.

So we urge the Board not only to re-adopt the low carbon fuel standard, but to continue to invest in natural gas vehicles and the natural gas infrastructure that makes it possible to use biogas, the very lowest carbon transportation. Thank you.

LCFS T17-1 cont.

MS. MENDOZA: Good afternoon, Jerilyn Lopez Mendoza representing the Southern California Gas Company.

I first of want to apologize for my expression today. I'm very stuffed up and my ears, I can't hear anything because of the flight. So I can't even hear my voice. So if I'm speaking really loud, I apologize.

So first of all, I want to begin my comments by saying Southern California Gas Company is very much in favor of this Resolution moving forward and the Board approving the readoption of the low carbon fuel standard. We believe it's the right way, one of the right ways to get us to the low carbon fuels in the state where we continue to be very supportive.

18_T_LCFS _JMendoza

However -- you know there was going to be a however. We have two concerns moving forward. In terms of the implementation of the program between now and July, the final vote will be as well as beyond July and

LCFS T18-1

implementing the program into the future.

First of all, we want to make sure and we want to emphasize to the Board and to staff that we would like the GREET model to be based on the best available data that we have available to all of us. Meaning, objective scientific analysis, data that's recent, that's from third parties, and from academics and folks who have a lot of expertise in the field with respect to methane leaks and with respect to natural gas and its efficacy within this framework.

LCFS T18-1 cont.

Secondarily, we're also concerned about stakeholder engagement as we move forward. During the presentation in PowerPoint slides number 20 and 37, there were verbal references to engaging stakeholders in the process moving forward between now and July and then beyond July.

But in the next steps articulated by staff in slide number 39, there is no bullet point that specifically relates to stakeholder engagement, stakeholder dialogue. So it's not clear to those of us who are very invested in the process and invested in this program moving forward how can we most appropriately and formally engage with staff and get our concerns on the table before you and have it be part of the ongoing process to ensure that that scientific analysis is as

LCFS T18-2

rigorous as possible. So we just want to make sure there is no confusion as it relates to public review and engagement.

LCFS T18-2 cont.

And finally, we look forward to working with staff towards the continued success of this program. I believe over the past year that I've been working at the gas company we've built up some great relationship. There have been educational dialogues back and forth. And we're learning from each other in terms of staff, from ARB and staff from Southern California Gas. We like to continue to move that forward.

LCFS T18-3

And just my final point I just wanted to appreciate all the time taken by Board members and staff in the last few weeks, particularly in terms of engaging in a meaningful discussion with us about the program. Thank you very much.

CHAIRPERSON NICHOLS: Thank you. Matthew Plummer.

19_T_LCFS_MPlummer

MR. PLUMMER: Matthew Plummer, Pacific Gas and Electric Company.

First, PG&E would like to express its support for the low carbon fuel standard and encourage the Board to move forward with readoption.

Like my colleague at So Cal Gas, we have a number of technical issues we'll need to continue to work with

LCFS T19-1

staff on between now and the Board vote. We also like to thank staff and thank the Board for their continued willingness to meet with stakeholders. We look forward to many more constructive conversations in the months to come. Thank you.

LCFS T19-1 cont.

20_T_LCFS _CWright

BOARD MEMBER BERG: Thank you.

MR. WRIGHT: Good afternoon. I'm Curtis Wright. I manage the biodiesel operations Imperial Western Products. We're a biodiesel plant located in Coachella, California. We've been in operation since 2001. Over this time, we made over 55 million gallons of biodiesel, all from used cooking oil we collect in the area. What's interesting is that since the introduction of the low carbon fuel standard and the last four years we made more than half of that 55 million gallons. It's given our business a lot more certainty and more of a market out there. So we strongly support readoption of the low carbon fuel standard. That will help us to continue to grow, add jobs, and provide clean, low carbon biodiesel to Californians. Thank you.

LCFS T20-1

BOARD MEMBER BERG: Thank you very much, Mr. Wright.

John O'Donnell.

21_T_LCFS _JO'Donnell

MR. O'DONNELL: Good afternoon. My name is John O'Donnell with the Glass Point Solar. We are a leading

LCFS T21-1

provider of solar steam generators for the oil industry.

And I'm here to speak in support of the modifications and the specifically innovative crude provisions of the low carbon fuel standard.

The use of solar energy represents the largest lowest cost and lowest risk approach to reducing the carbon intensity of petroleum fuels produced here in California.

And as part of our written comments, we submitted an economic impact study that was carried out for us recently by ICF, which found that if the identified market opportunity here in California, if those solar projects were built, we would be delivering over their construction and operations some 45,000 cumulative job years and some five billion dollars of increased economic activity, increased gross state product here in California. We believe that the modifications in streamlining and simplification to the innovative crude provisions that are included in the current package set the stage so that our contribution can be brought to reality. And we look forward.

LCFS T21-1 cont.

BOARD MEMBER BERG: Thank you very much.

Ross Nakasone.

MR. NAKASONE: Happy new year to every one. My name is Ross Nakasone with the Blue Green Alliance. We're

22_T_LCFS _RNakasone

a national coalition of labor and environmental groups including the United Steal Workers and Natural Resource Defense Council.

Our mission is to really try to encourage folks to address their environmental challenges in ways that create and maintain sustainable jobs. To that end, Blue Green Alliance supports the readoption of the low carbon fuel standard.

I'd like to thank Richard Corey and the rest of CARB staff for their hard work. Over the past three years, steal workers, NRDC, and Blue Green Alliance have worked together to provide recommendations to CARB staff particularly on program flexibility that encourages investments in refinery projects that reduce GHG emissions.

LCFS T22-1

Credits for refinery improvements represent, we believe, a significant opportunity to spur additional investments that can improve environmental performance of refineries and create secure refinery jobs while reducing the carbon intensity transportation fuels, and of course, fostering additional benefits such as reductions in criteria pollution.

We appreciate staff willingness to hear our ideas and to incorporate them. Steal workers, NRDG, BGA, believe the improvements to the low carbon fuel standard further our shared vision of better jobs and a better environment. With that, BG urges you to approve this Resolution.

MR. UNNASCH: I'm Stefan Unnasch with Life Cycle Associates. Thank you for the opportunity to speak.

I've been involved in fuel LCA issues for the ARB since 1994, including presenting on the environmental impact of ZEVs in 2000 and developing the California GREET model in 2009.

Since that time, the ARB staff has come a long way. They've learned, you know, virtually every aspect of fuel LCA. And I would like to commend their efforts and the whole process of understanding biofuels and petroleum fuels has really moved along. And the LCFS is doing a good job.

23_T_LCFS
_SUnnasch

There are some areas of improvement. I submitted some comments. One of them has to do with the effect of the nitrogen cycle on biofuels. And the other has to do with marginal electricity. Basically, the idea with electricity is we're getting the cleanest electricity into the electric vehicles and into the hydrogen electrolysis in California. There is no nuclear. There is no whole power that's going into those. If you run an electric car, you're not making a coal power plant go on. You're not making a nuclear power plant go on either. What's on

LCFS T23-1

the margin is, you know, fairly well understood. And it's important for several fuel pathways. So those comments should be considered.

LCFS T23-1 cont.

So on balance, you know, we've gone through a lot in the past seven years. And I think we understand a lot more about indirect land use, a lot about all of the fuel pathways, and encourage the ARB Board to readopt the LCFS this summer.

CHAIRPERSON NICHOLS: Thank you very much.

Chuck White.

MR. WHITE: Thank you very much, Chairman and members of the Board.

Chuck White representing Waste Management. Waste Management is a strong supporter of the readoption of the low carbon fuel standard. Waste Management provides comprehensive recycling and solid waste services throughout California and the U.S. And you're probably familiar with my big green heavy duty refuse and recycling trucks you see throughout California. One half that fleet in California is natural gas. In fact, the vast majority of that natural gas fleet is being fueled by renewable natural gas. And a large part of that is being produced -- as far as we know, the only very low carbon fuel production facility here in California that produces LNG or CNG. That's our Altamont landfill, producing

24_T_LCFS
_CWhite

13,000 gallons a day.

Waste Management can build a lot more of these facilities, both in California and fuel is brought to California if we had certainty and security of the price we need to repay the capital cost and operational costs of these ventures.

Unfortunately, the political and legal challenge that the low carbon fuel standard has faced over the last years has created the level of uncertainty that really has deferred us from making further developments until we can see a pathway to get a return on our investments for these. We're anxious to do so and strengthen and readopt a low carbon fuel standard will certainly do that.

We have been unable to get long-term contracts for the production of credits, both green credits and LCFS credits to be able to cover our cost. Without that degree of certainty, we've been unable to do that.

We first saw the LCFS credit for $10 and then $80 a ton and now back down to about $25. We do produce a lot of fuel for California, well less than $200 per LCFS credit, I can assure you of that.

LCFS T24-1

The uncertainty is, like I said, also due to the political and legal uncertainty. But also has to do with the uncertainty over the CI values. I'm glad staff is looking at that during the 15-day re-notice period, the CI

LCFS T24-2

adjustments. That's created a lot of nervousness on the natural gas sector. We're not opposed to the right number being used for the carbon intensity renewable natural gas. It's just making sure it is the right number and making sure it's based upon best science available to ensure that is being supported.

LCFS T24-2 cont.

In summary, it's most important today that you readopt the low carbon fuel standard. I originally thought I would be arguing for a floor. I'd like to have a floor on the price to complement the ceiling on the price at 200, but get the thing readopted. Get it functioning, back on track again. That is by far and away the most important part.

LCFS T24-3

And again, making sure that if you change the CI number, particularly if you increase the CI number on a fuel, you make sure it's the right CI number that's well based on fact and size. Thank you very much.

LCFS T24-4

CHAIRPERSON NICHOLS: Thank you.

Mr. Darlington.

MR. DARLINGTON: Thank you. Good afternoon. My name is Tom Darlington. I'm President of Air Improvement Resource, consulting firm providing engineering and consulting services in the area of alternative fuels.

25_T_LCFS _TDarlington

I'm here to address the modeling indirect land use changes. As indicated, I'm here on behalf of the

LCFS T25-1

POET, which operates 26 corn ethanol bio-refineries in the United States and is a pioneer in the effort to bring cellulosic biofuel to the market.

POET has participated in the rulemaking process on the proposal being considered today and concurs with Growth Energy's comments that were submitted. Our company has participated in all of the ARB workshops on land use emissions and the GREET life cycle model and has provided detailed written comments.

As indicated in those comments, we do not agree with the land use change emissions factor that the staff is proposing for corn starch ethanol.

LCFS T25-1 cont.

The main point I'd like to make today is that the staff has deferred, we feel, too many significant issues raised in the technical literature and by stakeholders since 2009 for future research. Many of these issues were identified several years ago.

LCFS T25-2

The table on the screen shows the status of some of the items that we have recommended. And as you can see, some of these items have been deferred for future research. The most serious of these is the emission of the multi-cropping effect, but others are important as well. We and others, including the expert working group, recommended that ARB include the effects of double and multi-cropping, which refers to the common practices in

LCFS T25-3

certain regions of harvesting more than one crop on the same land per year.

Multi-cropping uses existing crop land more intensively, thereby reducing the need for land conversions from both forest and pasture to crops. The economic model used by ARB does not include double or multi-cropping. This is a serious shortcoming that leads to higher land use emissions from all feed stocks.

LCFS T25-3 cont.

The omission of idle and fowl land is also a serious concern in this model. The importance of including multi-cropping was clearly illustrated by a study recently released by Professor Bill Babcock of Iowa State University. I'll quote a little section, but, "The contribution of this study is to confirm that the primary land use change response of the world's farm is from 2004 to '12 has been to use available land resources more efficiently than to expand the amount of land brought into production. This finding has not been recognized by regulators who calculate indirect land use."

LCFS T25-4

So in sum, if the land use emissions of corn ethanol are over-estimated, then the carbon intensity of corn ethanol is too high, leading to a reduction in corn ethanol in California without a accompanying greenhouse gas reduction. This is not only a problem for POET. It is a problem for California because it leads to

LCFS T25-5

unnecessary fuel shuffling and a loss of greenhouse gas emission benefits. Thank you, again.

LCFS T25-5 cont.

CHAIRPERSON NICHOLS: Thank you for wrapping up.

Jessie David. And then Perry Simpson and Todd Campbell. And then we're going to take our lunch break.

26_T_LCFS _JDavid

MR. DAVID: Thank you.

Again, my name is Jessie David. I'm an economist and partner at Edgeworth Economics Consulting Firm with offices here in California. I received my Ph.D. from Stanford, and I specialize in environmental economics and public finance. I've been doing regulatory evaluation for about 18 years.

I was retained by Growth Energy, an association representing producers and supporters of alternative fuels to analyze the impact of the LCFS on ethanol producers. I'd like to summarize my analysis, which is included as an appendix to Energy's extensive written comments.

I was asked to consider what the analysis in the Initial Statement of Reasons, the ISOR, says regarding the impact of the new program to Midwestern corn-based ethanol in California's motor fuel mix. The ISOR presents an illustrative compliance scenario we heard about today, which is CARB staff's projection of one potential pattern of compliance that we meet the proposed standard.

Staff projects a reduction in corn ethanol

LCFS T26-1

consumed in California by almost half by 2020, with most of that being replaced by cane ethanol from Brazil.

Staff also assumes that the credit price would be $100 in 2016 through 2020. This value presumably would provide the impetus for switching from a less expensive to what's currently more expensive type of ethanol that is currently the primary choice of fuel marketers in California.

So to determine whether credit price of $100 would, in fact, cause marketers to switch in this manner, I analyze the total delivered cost of both types of fuels and their various assumptions. I use data on current projected fuel prices, REN values, and freight rates from public sources. And I supplement it with information about freight patterns and costs. I use CARB's projections of the future average CI level for those fuels.

LCFS T26-1 cont.

I calculated based on currently available forecasts which shows a narrowing of the price spread between corn and cane ethanol in 2016, a credit price of about $36 would lead to a switch from corn ethanol with CI ratings in the low 90s to cane ethanol with a CI rating of 72. A credit price of around $77 would cause a switch from corn with CI ratings in the low 80s to cane ethanol.

Moreover, if cane ethanol can attain the average

LCFS T26-2

ratings predicted by CARB, then the switch to cane from corn would occur at even lower credit prices. For example, CARB projects Brazilian cane ethanol with an average CI rating of 40 by 2016. At this level, a credit price of only $23 would result in a switch from corn to cane, which CARB projects would have a CI rating of 70. That is corn as of 2016.

LCFS T26-2 cont.

CARB's illustrative compliance scenario indicating a substantial decline in the use of corn ethanol with replace it. Cane ethanol is therefore not only plausible, but likely, if assuming the availability of sufficient Brazilian ethanol is rejected by CARB. This is true, even assuming credit prices well below $100.

In sum, based on the current ratings predicted by the ISOR, the future midwest corn ethanol is at risk in California. Even ratings as low as 70 would be at risk under these conditions. And if the industry can't achieve those ratings, the impact could be more severe. Thank you.

LCFS T26-3

CHAIRPERSON NICHOLS: Mr. Simpson.

MR. SIMPSON: Hi. I'm Harry Simpson from Renewable Energy. I am the President. And we, last year, had the distinction of being the largest biodiesel producer in California.

So, first, I want to thank the ARB staff and leadership for their consistent engagement over the last many years and really reaching out to all stakeholders to get that input to craft the proposed regs that we have before us today.

And I also want to thank them on behalf of our employees here in California and the local community that we serve in the valley for their commitment to a more sustainable and broadly beneficial future for transportation fuels in California.

Secondly, I'd like to say that LCFS is working. It has been working as intended as originally envisioned. The credit generation thus far has been consistent with ARB staff projections. Credit generation through Q3 of 2014 was nearly four million metric tons of excess credits, which was consistent with the original projections once the compliance requirements froze one percent.

27_T_LCFS _HSimpson

We strongly urge the Board to accept the staff recommendations to stay with the original time line of a ten percent reduction in 2020. We believe that this is fully achieveable and echo the comments that you've heard from various industry groups and individual companies concerning different types of alternative fuels, be it biodiesels, renewable diesel, biogas, electric vehicles, and I'm sure some others that I haven't come up with yet.

LCFS T27-1

We believe this is critical to send a strong market signal. Indeed, the only reason why we chose o build this plant this California back in 2008 and '09 was because of LCFS. If it wasn't for LCFS, we wouldn't be here and I wouldn't be speaking today.

Having the certainty of this time line will inspire additional investment on a broadly macro level if you will, but also on an individual company level. In the case of a company like ours, it may inspire additional investment in the form of expansion or taking on new projects to reduce our CI, to take advantage of lower CI feed stocks, or to engage in the development of renewable energy sources to a few more plants, such as biogas from a co-gen turbine system.

I urge the Board to consider ongoing carbon reductions beyond 2020 to keep the momentum moving forward and send those market signals as well. Thank you.

LCFS T27-2

CHAIRPERSON NICHOLS: Thank you.

Mr. Campbell.

MR. CAMPBELL: Good afternoon, Madam Chair and members of the Board.

28_T_LCFS _TCampbell

Todd Campbell, Vice President of Public Policy and Regulatory Affairs for Clean Energy. Clean Energy has been an original supporter of AB 32 and the low carbon fuel standard. And we are proud to remain in strong

LCFS T28-1

support of the rule's re-adoption. The fuel neutrality of the standard is perhaps the most attractive to Clean Energy because it encourages innovation of fuels and processes.

LCFS T28-1 cont.

And Clean Energy, as you know, has been a leader in developing not just natural gas in the conventional sense, but also renewable natural gas on a broad scale. So much so that when you pull up to our station, any station within California and fill your natural gas vehicle up, it is being fueled with renewable natural gas and ultra low carbon fuel. None of this, of course, would be possible without your collective leadership, staff's and Board's. And so I want to congratulate you on that.

In an effort to support the Air Resources Board further, clean energy has been actively engaged in supporting other low carbon fuel markets in Oregon and Washington, and we believe those markets will succeed as well.

However, it is critical that we get the carbon intensity values of natural gas and renewable natural gas correct. We have been working extensively with staff over the last few months. We believe that we've achieved some success with the staff. We do believe that we need to continue to work with staff.

LCFS T28-2

I want to acknowledge the several mentionings of staff during the presentation that they recognize that there is a continuing effort to or a need to continue to work on these CI values. We at Clean Energy significantly appreciate that ability or that willingness to continue to work with us before the rule is finally adopted.

I also like to say that just so the Board understands why we care so much about this, we have ICF International and GNA working with us closely on trying to help ARB staff get to the right number. And for every gram per megajoule that is added from the original GREET model showing our carbon intensity, using a medium value or base case scenario of a credit value of $50, it could mean a 15 to $58 million potential economic benefit or loss for our industry. And if we're going to help achieve 2020 values -- and I suspect this agency is going to look for 2030, 2040, 2050 -- we need to be able to have certainty, and we need to be able to continue investing in ultra low carbon fuels that will get us to where we need to be to prevent climate change. Thank you.

LCFS T28-2 cont.

BOARD MEMBER SPERLING: One tiny question.

What percentage of your gas that you're supplying to vehicles is biomethane renewable gas?

MR. CAMPBELL: In California and all our public stations it's 100 percent.

BOARD MEMBER SPERLING: What about going forward?

MR. CAMPBELL: In other words, if you looked at other fuels that use blends, we can also in future years as you go further up in carbon intensity reductions, you know, the blend probably will go down. But we will do our best to maintain 100 percent, of course.

But as Julia mentioned earlier, this is not just a 20 or 40 million gallon market where just for clean energy delivery alone. It's several billion gallons potentially, if not more. And I think staff -- I think we're helping staff become believers in renewable natural gas as a transportation fuel, because in the past, if you looked at the proposed scenarios, you wouldn't see very much renewable natural gas in there. But you're starting to see a significant slice of the pie in those forecasted scenarios.

BOARD MEMBER SPERLING: I like it. Thank you.

CHAIRPERSON NICHOLS: On that note, we're going to take a lunch break. We're going to try to keep it to an hour. The Board will be in executive session during that period. And we'll see you all back here at 1:30. Thanks.

(Whereupon a lunch recess was taken at 12:32 p.m.)

CHAIRPERSON NICHOLS: Welcome back, everybody. Before I forget, if you didn't sign up on the list and you've suddenly been inspired with a desire to speak to us on this issue, would you please sign up with the Clerk over here, because we would like to close off the list just so we can know that we actually could close off the hearing on this item. We do have a couple of Board members who have to leave and who really want to be able to speak to this issue and to participate in the Resolution.

CHIEF COUNSEL PETER: Madam Chair, you need to report on the closed session.

CHAIRPERSON NICHOLS: I will. We had a closed session. Thank you. And it was Board members only. No staff were included. The topic was a personnel review. It was a report by two Board members on the review they had been asked to do. They reported successfully. No action was taken. Thank you.

Okay. Let's continue with Jonathan Lewis.

29_T_LCFS _JLewis

MR. LEWIS: Thank you and good afternoon. My name is Jonathan Lewis. I'm Senior Counsel at Clean Air Task Force. CATF is a nonprofit organization that works to help safeguard against the impacts of climate change by catalyzing the rapid global development and deployment of low carbon energy and technologies. CATF has submitted written comments and made several points. First and foremost, that ARB should adopt the LCFS through 2020.

LCFS T29-1

Achieving compliance with the 2020 target would be difficult. The LCFS remains the most promising policy available nationwide for reducing climate impacts in the transportation sector.

LCFS T29-1 cont.

The issue that I'd like to draw the Board's attention to today has to do with the model relationship between corn ethanol production, food consumption, and net CO_2 emissions.

The key point I hope to make is that by developing the relevant data and determining which data sets to use and which to exclude in the life cycle model are subjective exercises, as are processes of choosing a programming relational assumptions that drives the model. Viewed in this context, the proposal to reduce corn ethanol to indirect land use change or ILUC score can be more appropriately understood as the product of subjective process, one that reflects the current availability of certain data analyses that would contribute to a lower ILUC score, but fails to account for a host of counter-vailing factors that ARB knows are significant but has not yet modeled.

An important way in which ILA's estimates are the product of subjective decisions and not just objective calculations relates to the treatment of reductions in food consumption associated with the policy and reduced

LCFS T29-2

demand for biofuels. As explained in a recently published paper that looked at ILUC analysis and used by ARB, ILUC emissions estimates depend on various modeling choices such as whether reduction of food consumption resulting from biofuels expansion is treated as climate benefit. ARB currently chooses to count GHG reductions that result from reduced food consumption when analyzing the life cycle emissions of biofuels. But that again is a subjective decision.

Several studies indicate that if ARB instead chose to assume society woul limt the extent to which food consumption would decline, ARB estimates corn ethanol ILUC emissions would increase substantially as detailed in our written comments.

The highly subjective treatment of reduced food consumptions reinforces the point that ARB is not obligated to reduce the ILUC score for corn ethanol on the basis of the most recent highly and complete modeling results.

LCFS T29-2 cont.

CATF urges the Board to recognize these limitations as well as the necessary role that it and ARB staff play in interpreting and acting upon the modeling results. The Board should exercises its best judgement in light of the overarching policy objectives of the LCFS and CATF, which CATF understands to be a meaningful reduction

LCFS T29-3

in GHG emissions from the transportation sector. Because corn ethanol's life cycle GHG emission reductions, which are very modest to begin with, depend on an assumption of reduced food consumption in developing countries and because increased reliance in corn ethanol would frustrate the development of more innovative and effective compliance options, the proposal to reduce ILUC score for corn ethanol undermines the objectives of the LCFS.

LCFS T29-3 cont.

Accordingly, the CATF urges the Board to table any proposal to reduce the carbon intensity value ARB uses for corn ethanol.

LCFS T29-4

Thank you for the opportunity to comment on this critically important policy.

CHAIRPERSON NICHOLS: Thank you.

MS. PHILLIPS: Good afternoon, Madam Chairman, fellow members of the Board, ladies and gentlemen. It's a pleasure to be here today speaking in support of the low carbon fuel standard.

I represent the Brazilian Sugarcane Industry Association, Unica, and my members are the largest ethanol producers in Brazil. And we represent about 50 percent of all the ethanol production in the country.

Today, sugarcane ethanol is a modest but important role in supplying the U.S. in general and California in particular with low carbon clean fuel. From

2012 to 2014, Brazilian sugarcane ethanol supplied 13 percent of the total U.S. supply in spite of use.

As the low carbon fuel standard readoption process takes place over 2015, we believe sugarcane ethanol is uniquely positioned to help reduce transportation fuel emissions. And that's because CARB studies considered sugarcane ethanol the best performing low CARB liquid fuel commercially available today to contribute to the program. This distinction is important as CARB considers more stringent life cycle carbon intensity rules for transportation fuel, which are projected by CARB to increase sugarcane ethanol use to 400 million gallons per year by 2020.

California can rely on Brazilian sugarcane ethanol. That's because for the past ten years we've been making the necessary investments to increase supply in the country. We know by the profile of our companies and the companies invested in the sector that Brazil can quickly ramp up production to meet higher market demand. This is very important as Brazil's expected to move into higher blend as early as next month. We know that there is capacity in Brazil to supply California with the volumes that CARB has projected. And we know we can do this in a very sustainable way.

I have submitted comments -- written comments on

30_T_LCFS _Phillips

two technical items that I think needs a little bit of reveal from the staff before you can readopt this. And I just wanted to conclude with these points. We know that electricity cogeneration by sugarcane mills in Brazil are replacing fossil fuel sources of power in the country. We urge CARB staff to factor in this marginal displacement rather than using an average electricity mix for Brazil. At the very least, we ask CARB to update the EIA electricity production numbers for Brazil that right now are for 2011. And we have more updated numbers that we have shared with staff that reflects the sharp decrease in hydroelectricity power in Brazil. Another point is --

LCFS T30-1

CHAIRPERSON NICHOLS: Please finish up.

MS. PHILLIPS: Sure. We are very glad to see that ILUC reduction for cane ethanol, but would love to ask the staff to capture the double cropping in Brazil. It's been a pleasure for us to contribute to CARB and with the staff for these past years. We think the low carbon fuel standard is a model to be emulated by the rest of the country. And we ask you to readopt it. Thank you.

LCFS T30-2

MR. KOEHLER: Thank you. My name is Tom Koehler with Pacific Ethanol. I'm representing today the California low carbon ethanol producers, all of whom are producing in the Central Valley over $500 million worth of investment for plants, 200 million gallons. We have been

31_T_LCFS _TKoehler

from day one and continue to be big supporters of the LCFS, and we urge the readoption today. We also are supporting a further signal beyond 2020 and would urge the Board to do that as well.

LCFS T31-1

We have been part of a larger coalition of alternative fuel providers and a lot of the providers other than ethanol you're hearing from today. And we're proud to be with them all because we realize it's going to take all of the fuels to succeed to their fullest to meet the goals, not only the low carbon standard, but the Governor's goals as well.

I would like to flag the ILUC issue, the gentleman just spoke about it. There is -- since the staff proposal came out, there is new data which is actually real world data, so not dependent upon one person's assumptions, of actual land use change that has occurred worldwide over the last ten years. And Wally Tiner from Purdue and GTAP, Son Ye from U.C. Davis are embarking on a study to calibrate the GTAP model, back cast it. And I would urge the Board to ask for the results of that to come back. It's too late for the 15-day notice. But when that study is done, I would urge the Board to ask to review the ILUC.

LCFS T31-2

CHAIRPERSON NICHOLS: Thank you.

MS. HOLMES-GEN: Good afternoon. I'm Bonnie

Holmes-Gen, Senior Director, Air Quality and Climate Change for the American Lung Association in California.

And on behalf of the American Lung Association in California and health and medical groups throughout the state, I urge your readoption of the low carbon fuel standard as soon as you can vote on it. Since its original adoption in 2009, public health and medical groups and our organization have supported the LCFS as a critical component of California's visionary clean air and climate strategy. And we see the LCFS as a critical tool to help Californians kick their addiction to petroleum fuels and transition to a cleaner future. The LCFS is bringing real and measurable health benefits a long way.

Our research has evaluated benefits from the tons of pollution reduced through the low carbon fuel standard and fuels under the cap and found over eight billion in avoided health costs by 2025, including over 800 avoided death and thousands of avoided asthma attacks and many other avoided health emergencies, as you can see here. And this is just a down payment on the tremendous benefits to come.

This version of the LCFS before you has substantial improvements from the earlier regulation, including expanded electric transportation credits and their refinery investment provisions that will help to accelerate clean fuels progress to while protecting community health. And we are pleased to have over 30 health and medical organizations that are signed onto the letter that you've received, including the American Cancer Society, Cancer Action Network, Blue Shield of California, California Thoracic Society, Dignity Health, American Academy of Pediatrics, and many others. Our groups stand behind the LCFS as a vital and proven strategy that's transforming our transportation here and being pursued now in other western states.

32_T_LCFS_BHolmes-Gen

And as we go forward, we know there will be additional improvements. One area we have flagged is the need to update the biorefineries guidance document to incorporate updated tools that evaluate community impacts. And we look forward also to setting the post-2020 targets.

LCFS T32-1

I would like to close with a brief quote from Dr. Perdiga who's a physician and participant in our Doctor's for Climate Health Campaign picture here and would like to note we greatly appreciate the engagement of Dr. Sherriffs and Dr. Balmes also in this campaign. And here's Dr. Perdiga's quote. "We have no control over the air we breathe. But we do have a say in what pollutes it. My patients in the San Joaquin Valley suffer the side effects of pollution every day, whether they live in cities or rural areas. They have the most to lose in we don't continue pushing for cleaner air. Their health is at stake and we must do more. That is in I support California taking the lead in reducing carbon pollution from transportation fuels."

Thank you again. And as always, we look forward to working with you.

CHAIRPERSON NICHOLS: Great. Thank you.

Tim Carmichael.

MR. CARMICHAEL: Good afternoon. At the risk of another zinger from the Chair, I want to stand in solidarity with all the Tims that are going to testify today.

33_T_LCFS
_TCarmichael

More seriously, Tim Carmichael with the California Natural Gas Vehicle Coalition. We are here to support the program. And I want to encourage all of you to feel empowered to support this. And one of the measures that leads me to that comment is the breadth of the portfolio of alternative fuels that you are not speaking here today, but engaged in the market already.

And you know, this is a good program. ARB has programs that tend to go up and down based on one technology's success or not. That is not the case here. You have a lot going in the right direction with this program. And that gives you all the confidence to continue to support it.

LCFS T33-1

For the natural gas industry specifically, I just want to mention a couple of things. We've made good progress over the last several months working with the staff on some technical issues related to the model and carbon intensities. Those have been referred to. I want to thank Richard Corey for his personal engagement on these issues and the whole LCFS team's hard work. It's not easy stuff. We are talking about technical calculations and a lot of moving pieces. But as I said, we've made a lot of progress.

We have a handful of issues we haven't resolved yet. The staff have referred to those. They mentioned they're committed to working with us to resolve those.

In your resolution package, there is a reference to this as an attachment, a suggestion that you add a bullet that relates to these on going conversations and supports the staff continuing to have those conversations.

We respectfully ask that you include that in your Resolution today as part of your direction of staff. I think that request is consistent with what the staff shared earlier. We just think it's so important to get it right for the reasons that have been mentioned, the financial impacts within the state, as well as the impacts that our success in California is going to have on other states.

LCFS T33-2

One quick detail on that. You have literally dozens of people that are working on this issue in California. Many other states have one or two people assigned to this program. So California getting it right is going to -- just that much more important. So those other states can rely on our technical work.

LCFS T33-2 cont.

Thank you very much. Appreciate your time.

CHAIRPERSON NICHOLS: Thank you. Tim is actually one of my favorite names.

David Cox.

MR. COX: Thank you, Chairman Nichols, Board members, staff.

My name is David Cox. I'm the Director of Operations for the Coalition for Renewable Natural Gas.

I'd like to begin by complimenting Mr. Corey on his leadership. And at the risk of leaving someone out specifically, I just want to publicly thank and knowledge Mr. Vergara, Mr. Kitowski, and Mr. Imgrahm, and your very capable team in the front row. You guys have really done a great job.

The Renewable Natural Gas Coalition advocates for advanced applications of renewable natural gas derived from cellulosic waste sources. We do this so present and future generations have access to domestic, renewable clean fuel and energy supply.

We represent the leading renewable natural gas companies and organizations who collectively they produce and distribute more than 90 percent of the transportation fuel from renewable natural gas delivered in North America.

Ms. Sideco mentioned earlier that R&G volumes have grown about 70 percent since LCFS was first adopted. This is tremendous growth for our economy and for our environment. We also like this particulate stat because it also correlates with the founding coalition and our respective growth.

34_T_LCFS _DCox

I'd like to focus my comments today on the GREET cost containment provisions on a going-forward basis. I think we have a come a long way. I'll just echo everything that Mr. Carmichael just mentioned.

But specifically, the importance of having a sound process to deal with these, because I think they are the two issues that will most impact renewable natural gas on a going-forward basis.

LCFS T34-1

And as to the GREET model, I'm certain by now you're familiar with how highly we consider the stakes of the GREET model. We appreciate your commitment to fuel neutrality and also to ensuring the GREET is driven by sound data and ask for your continued commitment on those points.

LCFS T34-2

As to cost containment, staff has proposed a $200 cap on credit prices. We think that should absolutely be paired with a provision and cost containment on the low end in the event that credit prices go down.

LCFS T34-3

And so we thank you. We have submitted comments and talked with staff throughout the workshop process on specifics on how to do that. And we just encourage you to continue to address cost containment on a going-forward basis. That will conclude my comments.

CHAIRPERSON NICHOLS: Thank you.

35_T_LCFS _JBarbose

MR. BARBOSE: Good afternoon. My name is Jason Barbose. I'm with the Union of Concerned Scientists. And on behalf of our 73,000 supporters in California, speaking in support of moving forward with the readoption process for low carbon fuel standard.

About a year ago, more than 150 California climate scientists and economists sent a letter to Governor Brown and the Legislature urging the state continue to be a leader in addressing climate change and to adopt 2030 carbon emissions targets that put the state on a path to meeting our 2050 goal of 80 percent reductions.

LCFS T35-1

And in that letter, the researchers also highlighted the need for additional policies that promote low carbon fuels and cleaner transportation. And with

LCFS T35-2

that back drop in mind, we view the LCFS as a critical element of the State's approach to reducing greenhouse gas emissions while continuing to thrive economically.

We also view it as an important part of Governor Brown's new goal to cut petroleum use in half by 2030, which echoes my organization's half the oil plant of the United States.

LCFS T35-2 cont.

I'd like to note three important technical changes that are being proposed that UCS supports.

One is the update to the life cycle analysis that's been based on the best available science.

LCFS T35-3

The second is the innovative crude and refinery provisions that will encourage the oil industry to reduce emissions from its own supply chain.

LCFS T35-4

And the third is the cost containment mechanism that will maintain a stable investment plan for low carbon fuel production while ensuring that any unforeseen delays would not destabilize the policy of California consumers.

LCFS T35-5

UCS has been performing analysis and providing technical feedback on the LCFS since its inception. We are confident the diverse sources of the low carbon fuel are available to achieve the ten percent carbon intensity target by 2020.

Earlier the month, we released a study on LCFS compliance from the consulting form Provoto that we co-commissioned with NRDS and EDF, and that study finds first and foremost that compliance, is indeed, feasible through 2020 and beyond. The study also demonstrates that in order to ensure investment in the cleanest fuels, it is important as well that the State establish regulatory stability out beyond 2020.

LCFS T35-6

By maintaining a stable science-based policy framework that recognizes that cleaner rules are indeed more valuable than dirtier fuels in conjunction with similar policies being adopted or pursued in our neighboring states, the LCFS will create a large stable and steadily growing market for clean fuesl, providing investment and innovation and bring down the cost of cleaner alternatives.

And for those reasons, we support moving forward with the readoption process. Thank you.

CHAIRPERSON NICHOLS: Thank you.

MS. MORTENSON: Hello, Chairman Nichols and members of the Board. I'm Lisa Mortenson with Community Fuels. And I'm so excited to be here today and commenting on the low carbon fuel standard.

If you're not familiar with Community Fuels, we produce advanced biofuels at our refinery at the Port of Stockton. Our fuel is primarily sold to major oil companies and refineries for blending with petroleum.

This is exciting because each gallon of our fuel that's blended with petroleum is displacing diesel fuel and is increasing the volumes of clean fuel being used in California. And I hope it's of no surprise to you when I say that petroleum companies do not voluntarily purchase our fuel since our fuel is displacing a portion of the product that they produce.

36_T_LCFS
_LMortenson

And it really underscores the importance of the low carbon fuel standard and programs similar to this. I think some people who don't participate in the market each and every day like Community Fuels does forget that, first on a positive note, we leverage the existing diesel infrastructure by selling our fuel to the petroleum industry. But second, the petroleum industry only purchases our fuel because it enables them to meet multiple compliance obligations. So it is so important -- and I say this strongly and passionately -- it is so important that we have regulations like the low carbon fuel standard to force the existing infrastructure to incorporate higher volumes of clean fuel.

LCFS T36-1

As a California-based business, we need strong and supportive and consistent regulations. When we built our biorefinery, our company was started in 2004 and the refinery was built in 2007 when that construction was complete. We needed a long-term trajectory for planning

LCFS T36-2

and to be able to finance the project. We can't work with one, two, three, or even five-year time frames for planning.

LCFS T36-2 cont.

So not only do we support the readoption of the low carbon fuel standard, we encourage you to look far beyond 2020 and let's be ambitious. Let's seize the opportunity to get really aggressive targets that change the way we fuel vehicles in California. Our U.S. biodiesel industry is three billion gallons strong. We have three billion gallons of existing infrastructure. Our industry is ready to deliver. We are ready to deliver high volumes of low carbon fuel to California. So again, we strongly support the readoption, and I hope that we go further.

LCFS T36-3

CHAIRPERSON NICHOLS: Great. Thank you.

I'm making an announcement we're about to close off the list of witnesses. We've got 50 people, and we're now at number 36. And I think we probably covered pretty much or will have covered pretty much every topic by then. Just so you know, we're coming to the end of the list. Okay.

37_T_LCFS _JGershen

MR. GERSHEN: My name is Joe Gershen. I'm a 15-year biodiesel veteran. Also Vice Chair of the California Biodiesel Alliance.

I'd like to thank ARB Board and staff for all

LCFS T36-1

your hard work on these issues, which are vitally important to Californians. I'm very supportive of the readoption of the LCFS. And I commend you on inspiring other low carbon initiatives on the west coast and around North America.

As I've mentioned, I spent nearly 15 years in the California biodiesel industry. And I've been committed to education, fleet transition, and biodiesel acceptance and implementation. I've watched this industry grow from a fledgling idea of a few pioneering environmentalists scientists, engineers into a robust and growing industry providing hundreds of high paying green California jobs in some of the most disadvantaged communities in the state.

Today, the California biodiesel industry is capable of reducing over 600,000 metric tons of carbon emissions, which is also equivalent to taking about 140,000 cars off California roads. These metrics take on important and measureable meaning in the context of the low carbon fuel standard. So thank you.

This ground-breaking and critical policy demonstrates California's commitment to environmental and energy sustainability and simultaneously sends a strong and stable signal to business, which encourages investment and innovation, which will help achieve further carbon reduction goals. Thank you again.

I'm confident that working together with ARB, the California biodiesel industry can build on our successes. Last year, about 16 percent of all LCFS credits were generated by biodiesel industry, which also contributed about $350 million to California economy.

We look forward to contributing over even more to reducing carbon emissions, displacing petroleum usage, lowering emissions, and creating good high-paying green jobs somewhat characteristics of the California's most disadvantaged communities. Thank very much.

38_T_LCFS _CMurphy

CHAIRPERSON NICHOLS: Thank you.

MR. MURPHY: My name is Colin Murphy. I'm a Policy Advocate for Next Gen Climate America. Thank you to the Board for the opportunity to speak.

In recognition of the long list, I'm going to make most of my comments in one sentence summaries. We support readoption of the low carbon fuel standard. We support the cost containment mechanism. We think there probably should be a price floor to go with the price ceiling.

LCFS T38-1

LCFS T38-2

LCFS T38-3

On one other subject, I need a little more depth. We think on the subject of carbon intensities, there needs to be a regular and systematic mechanism for review of the carbon intensity numbers. This recognizes the developing nature of some of the science behind things, particularly

LCFS T38-4

biofuels in areas like indirect land use change and oil sequestration. In the written comments we submitted, we gave you some research regarding oil carbon. We recognize the science is still open on this and there needs to be a balance between giving a target to producers but also recognizing that understanding may change over time. And we think that's such a balance can be achieved through a periodic review. Thank you for your time.

LCFS T38-4 cont.

CHAIRPERSON NICHOLS: Thank you.

Susan Frank.

MS. FRANK: Thank you, Madam Chair and Board members.

I'm Susan Frank, Director of the California Business Alliance for a Clean Economy. I'm here actually just to reference a letter that was submitted on the record this week with a few numbers attached. There were 98 signatories to this letter. If you take a look, you'll see the diversity of signors from all sectors of the state from business and faith and labor and environmental groups, et cetera. At least half of the speakers speaking today have signed the letter. So I will not read the letter. There are at least four people named Tim on the letter. So that should count, too.

39_T_LCFS _SFrank

Really, I just wanted to express the strong support that you have across the state of California and

LCFS T39-1

really across the region for what the action you're going to be taking today and over the next several months. And really proud to be able to be a signor to the letter. So thank you very much.

LCFS T39-1 cont.

CHAIRPERSON NICHOLS: Thank you.

MR. MUI: Good afternoon, members of the Board, Chairman Nichols.

I want to thank you for the opportunity to speak on behalf of Natural Resources Defense Counsel. First off, I do want to wish you a happy Chinese New Years today, a Lunar New Years, the year of the goat, which is an auspicious year, one that is meant to be filled with prosperity and promise. So I do think it is quite fitting that today we are hearing about the proposal to readopt the low carbon fuel standard.

While I don't have red envelopes or dim sum for you, what is impressive to me as a clean fuels and vehicles scientist is that the LCFS standard is already working today, despite the speed bumps and the barriers that have been laid down before it to slow it down. We've now seen ten million tons of reductions by the program, the equivalent of taking two million cars and trucks off the road for a year. And industry has exceeded the standard already by nearly 70 percent, despite the regulatory uncertainty.

40_T_LCFS_Mui

And you know, Tim -- one of the Tims -- mentioned the portfolio approach of the standard. We've already seen and heard today from biodiesel and renewable diesel producers reaching record levels in California. Biomethane an being produce today supply a huge chunk of the natural gas fuel mix. Ethanol producers diversifying to lower carbon feed stocks. And even technology companies finding ways and stepping in to find ways to reduce the carbon intensity from petroleum operations. We've only just begun to see the promise of the LCFS. It's time to clear the path forward. It's time to allow the LCFS and companies to accelerate.

LCFS T40-1

We do strongly support the staff's proposal to maintain the strong standards and to go forward beyond 2020. There are now three separate independent reports and analyses demonstrating ARB's proposed targets are, indeed, achieveable. One of those, a recent consulting report that we commissioned together with Union of Concerned Scientists and EDF, shows that we cannot only meet the standards, but we can exceed and reach higher targets by 2025.

LCFS T40-2

The missing ingredient, however, is regulatory certainty. Let's add that key ingredient today or when you vote in moving forward with the readoption.

LCFS T40-3

We also commend and thank the staff for their very hard work on this program and enhancing the program. These enhancements will make the LCFS more robust, fully capture technology options, provide greater flexibility to the program, and help deliver criteria co-benefits as well.

And it will also work to promote and avoid what if scenarios on extreme credit prices or fuel shortfalls. The proposal staff has laid out very carefully is reasonable, is technically supportable, and should be adopted.

LCFS T40-4

We've now demonstrated that we can protect the environment, public health, and grow the economy. You've now heard from a long list of supporters who are standing together to support the Board and staff to move forward. It's time to clear the path and get moving. In the words of Mike Waugh, it's time to giddy-up. Happy new years and thank you.

CHAIRPERSON NICHOLS: Thank you for that quote.

MS. TUTT: Good afternoon, Madam Chair and members of the Board. My name is Eileet Tutt. I'm with the California Electric Transportation Coalition. Our members include five of the largest utilities in California, as well as many of the smaller utilities, a number of auto makers that are committed to clean technologies and alternative fuel vehicles. We work very closely with the California Municipal Utilities Association on this issue.

We come to you today, not surprisingly, in support of the low carbon fuel standard and its readoption.

I do want to say that I want to really thank staff. Staff has been amazing. And thank you, Mr. Corey, for particularly recognizing Mike Waugh. He was incredible.

We are a small part of the credit values today. We hope to be a lot bigger in the future. The staff never treated us as if we were small. Spent a lot of time working through our issues. You'll read our very brief comments, so I'm not going to reiterate them. But part of the reason they're brief is the account of time that staff spent with us.

41_T_LCFS _ETutt

There is a couple of things I want to just say just to reiterate Simon Mui. We also conducted a study with ICF and a number of the alternative fuels folks indicating very clearly that we can meet this standard by 2020. And to Dr. Sherriffs, your question earlier about the economic assessment, our economic assessment did include the health impacts. And we showed that in certain cases you can certainly improve the economy by sticking to the LCFS course. So again, thank you for your time and

LCFS T41-1

consideration today.

CHAIRPERSON NICHOLS: Thank you.

Mr. Moran.

MR. MORAN: Good afternoon. Ralph Moran with BP America.

We did submit very detailed written comments, so I hope you get a chance to take a look at those. But today wanted to focus on two items. That's the cost of the program and the greenhouse gas emission reductions that are attributable to the program.

42_T_LCFS _RMoran

A lot has changed since 2009 when the LCFS was first adopted. And along with that are the conclusions from the original economic analysis supported the adoption. Back then, it was suggested that the program was going to save fuel consumers billions of dollars because these new fuels are going to be cheaper than the conventional fuels. That analysis also concluded that there was going to be a negative carbon price associated with the low carbon fuel standard, somewhere between negative 120 and negative $140 per ton.

LCFS T42-1

So now the regulation puts in place a cost cap of $200 per ton. And in reading some of the written comments submitted by others, I notice that some of the proponents of low carbon fuel standard are expressing their concern that $200 is not high enough because it's not enough to bring these new fuels to market.

Now I know that there is uncertainty in models and in economic analyses, but we should at least be able to rely on them to get the sign read. There is a big difference between saving billions of dollars and costing billions of dollars. And I hope that difference would cause the Board to pause and at least reflect on where is this going cost-wise.

LCFS T42-1 cont.

Secondly, there's sort of a concept is not very well understood about greenhouse gas reductions and the low carbon fuel standard. Simply put, there are no incremental greenhouse gas reductions that come from the low carbon fuel standard. And the reason for that is the sources of emissions covered under the LCFS are already covered under the cap and trade. So the low carbon fuel standard only displaces emissions reductions that would otherwise occur in the cap and trade program. And those reductions that come from the cap and trade program would also produce co-benefits, so it's even difficult to say there is any co-benefits, incremental co-benefits that come from the low carbon fuel standard.

LCFS T42-2

So what the low carbon fuel standard really does is shift reductions from occurring in a very cost-effective, efficient cap and trade program and forces them to occur in a complex, high cost program. How high

LCFS T42-3

is that cost? Right now, the emission reductions cost about twice as much in the low carbon fuel standard. And people are expecting that that range -- that gap will increase. That's why we have a $200 per ton cost cap in the low carbon fuel standard when we only have about a $40 per ton minimum cost in the low carbon fuel standard.

LCFS T42-3 cont.

So going forward and to conclude, we have a lot of work to do in meeting the state's long-term greenhouse gas policies. We would rather the state focus on the most efficient and cost effective ways to do that, like a well-designed cap and trade program. Thank you.

LCFS T42-4

CHAIRPERSON NICHOLS: Thank you.

Mr. Magavern.

MR. MAGAVERN: Madam Chair and Board members, Bill Magavern with the Coalition for Clean Air.

I was part of the group that stood with then Governor Schwarzenegger when he first announced the low carbon fuel standard to the world. I think it was eight years ago. And I continue to think that this is a valuable policy and the Coalition for Clean Air supports the readoption of the low carbon fuel standard. It now, in fact, looks even more important, given as many speakers have pointed out the governor's goal of reducing oil use in cars and trucks 50 percent by 2030, which is a very important goal and one that we certainly want to help all of you and the other agencies in trying to realize.

One of the main benefits of the low carbon fuel standard has been that it for the most part keeps the dirtiest highest carbon fuels out of California, like the tar sands oils that our friends in Canada so very much want to export to us but would have major consequences to our air and climate.

In addition, as air advocates, we are particularly attracted to the value of the low carbon fuel standard in bringing in cleaner fuels to reduce criteria air pollution. As the South Coast Air Quality Management District pointed out, this standard helps us get closer to attainment of our air quality standards.

43_T_LCFS _BMagavern

California's LCFS has also made a major contribution by being I think the very first jurisdiction to consider indirect land use conversion. And we continue to support that element of this standard.

You've made a couple good additions I think on this round. The recognition of the value of electricity used in transit and in forklifts will help us to continue to clean up those sectors. And we also appreciate the incentives for the refineries to clean up their operations, which as you know, tend to be in communities that have suffered from some of the worst environmental injustices. So this should help some with those

LCFS T43-1

fence-line communities.

So we support and thank the Board and staff for your work.

CHAIRPERSON NICHOLS: Great. Thank you.

MR. NOYES: Good afternoon, Madam Chairm, members of the Board and staff.

Thank you for the opportunity to introduce and speak to this hearing. I'm standing in today is attorney for the law firm of Keys, Fox, and Wheatman and also Executive Director for the Low Carbon Fuels Coalition and like to speak in strong support of the readoption.

It's been said before, but I think recognizing Mike Waugh's work and all the staff and high level leadership that went into the program can't be emphasized enough. Mr. Waugh really set the standard out there in terms of being truly receptive to input, constructively engaged with stakeholders, and Ms. Sideco and others managed the really massive organizational task of keeping these multiple -- what I viewed as multiple rulemaking reallys integrated sufficiently but addressing the very particular details of stakeholders out there and met what I call the gold standard of rulemaking as a regulatory attorney. So really appreciate that.

44_T_LCFS
_GNoyes

The program is working well, as has been emphasized by many. There was no way at the beginning to

LCFS T44-1

predict exactly what the fuel mix was going to be. Of course, we need to try to do that. We need to do our best models. We've heard that cellulosic biofuels have been slow to commercialize. That's certainly the case. However, renewable natural gas and renewable diesel have been fast to commercialize.

So with the kind of portfolio approach that we have here, there is that kind of flexibility. And it's clear from all the objective analysis that's gone in out there that these fuels are available. They're driving the clean economy. They're also driving the political discussion, particularly in the western states right now. We see some real paralysis around the renewable fuel standard on the federal side. So California's market signal is very important out there to the continued growth of the clean economy and all of the different low carbon fuels are out there.

We have seen -- this program is really one of the key workhorses of AB 32. We have seen ten million metric tons in reductions already. That is simply astounding. And ARB holds a unique responsibility and leadership role under the greenhouse gas revenue fund and essentially investment portfolio. And I would recommend that as the Board takes really the benefits of this program and looks at what to do with what's probably going ton in excess of

LCFS T44-1 cont.

two billion dollars in year into the greenhouse gas revenue fund, really think about that as a wise investor, look at this wide portfolio of solutions in the transportation sector of the toughest sector out there and figure out how to get the most cost effective reductions possible. Thank you for your time.

LCFS T44-1 cont.

CHAIRPERSON NICHOLS: Thank you.

Jamie Hall.

MR. HALL: Good afternoon, Madam Chair and members of the Board.

45_T_LCFS _JHall

My name is Jamie Hall, Policy Director for CALSTART. We are a non-profit organization that works with almost 150 companies bringing cleaner transportation solutions to market, here, today, as you can imagine in strong support of the low carbon fuel standard. Want to thank Board and staff for leadership on this. It's been a lot of hard work and it's good to be here today.

The LCFS provides a really important market signal for this industry that's driving investment. It's driving innovation and driving market penetration of cleaner fuels. Readopting the LCFS will make this signal even stronger and will accelerate the progress we're already making.

We held a summit on clean low carbon fuels earlier this month. Many of you were there. We had 50

LCFS T45-1

companies that were engaged in biofuels, natural gas, and electricity and other fuels. The clear signal from this very diverse group was that the LCFS is working.

Of course, there are a lot of other things people would like to see. They would like to see more investments, as Graham just mentioned, like the very successful CEC investments that handsome Tim Olson mentioned this morning. They'd like to see stronger longer-term targets and signals. But the number one message across the board was that the LCFS needs to move ahead. We need to get back on track. So happy to be here in support, and we look forward to working with you on the next steps.

LCFS T45-1 cont.

LCFS T45-2

CHAIRPERSON NICHOLS: Thank you.

Mr. Hedderich.

46_T_LCFS _SHedderich

MR. HEDDERICH: Chair Nichols, members of the Board, thank you. In particular, you pronounced my name right.

I'm Scott Hedderich with Renewable Energy Group. We are North America's largest biodiesel producer, over 350 million gallons of fuel. We also produce renewable hydrocarbon diesel. Also pleased to say we have a significant R&D operation in California in south San Francisco that looks at renewable chemicals and other advanced products.

47_T_LCFS
_KPhillips

When you're 45th on the list, you're expected to be brief. So is this perfect? No. Is it really good? Absolutely. Absolutely. Have staff been responsive? They've been the epitome of professional in dealing with all stakeholders.

So with that, please move forward with the adoption. Thank you.

CHAIRPERSON NICHOLS: Thank you.

Katherine Phillips.

MS. PHILLIPS: Feel like I'm on the Price is Right.

Katherine Phillips with Sierra Club, California. I'm going to keep this very sweet. Thank you for all the work you put into this. Thank you for persisting, despite the court challenges. And there is an expression. It's time to fish or cut bait. I say let's fish.

Thank you. My members support this.

CHAIRPERSON NICHOLS: Okay. Mr. O'Connor.

MR. O'CONNOR: Chair Nichols, distinguished Board members, Tim O'Connor, Environmental Defense Fund.

Environmental Defense Fund has participated in studies showing the feasibility of this standard. We've documented the tremendous health and economic savings that are associated with the full implementation of this alongside cap and trade.

We've shown the dramatic growth of businesses throughout California that are engaged in the value chain of delivering these fuels up and down the state. And we've profiled the amazing innovation that California businesses and business leaders have brought forth to bring these fuels.

48_T_LCFS _TO'Connor

And for that reason, we, of course, see that this standard is working and support its continued readoption. But as an attorney that's been following the court cases of this regulation, I must say that there, of course, have been some comments filed today that assert that what we're doing is still not going to comply with what the court had wanted or what CEQA requires.

And I must say in this readoption process, which is now over a year in the making and which piles onto a tremendous process that went into the first standard adoption, that I have not seen a record of decision and a level of analysis such as which has been brought by the staff and by the Board. And I'm continually impressed with all the work that continues to go in. And I'm confident that as the Board comes to a decision on this, it will be based on reason and sound analysis that's presented to it and should hold up with all the legal standards which the court will require. Thank you.

LCFS T48-1

CHAIRPERSON NICHOLS: Thank you.

Kirsten James.

MS. JAMES: Good afternoon, Kirsten James representing Ceres and Bicep.

So for those of you who with us, we are a nonprofit organization working to mobilize the investor and business communities with policy members to pass meaningful energy and climate legislation and help a thriving sustainable global economy.

Bicep stands for the Business for Innovative Climate and Energy Policy. And this is a project of Ceres. It's a coalition of 34 mainstream businesses which are committed to the efforts on passing meaningful climate and energy policies.

So together, these 34 businesses represent over $350 billion in annual revenues and coalition members range from Nike to Patagonia to Gap to Ebay, to just name a few.

So Ceres combined with Biceps and our investor network have long recognized the significant economic risks and opportunities associated with climate change. Thus, we strongly support the readoption and extension of the LCFS program as it's a proven market-based technology neutral tool. The LCFS will reduce climate risk and foster economic opportunities.

49_T_LCFS _KJames

LCFS T49-1

So you've already heard today about the

feasibility of the program, and I'm going to focus really quickly on the economic benefits. So from the business and consumer side, we see that this is an important route for it in order to insulate businesses and consumers from the oil price volatility and we need that diversity in our fuel supply.

LCFS T49-1 cont.

Secondly, from the societal benefit standpoint, we believe the LCFS will result in an estimated 1.4 to $4.8 billion in societal benefits by 2020 from the reduced air pollution, for example, an increased energy security.

LCFS T49-2

Next on the job side, in addition to the growth of the clean fuels industry, we'll move California forward economically. Currently, 40,000 California businesses serving advanced energy markets, employing roughly 430,000 employees. So the LCFS alone could contribute at least 9100 jobs in our estimation.

LCFS T49-3

And then finally on the investor side, Ceres has a strong and extensive investor network, and we truly believe that in order to spur innovation and allow the clean fuels industry to continue to grow, the investors need these long term policy signals. And to provide these signals, it is critical not only to readopt the LCFS, but to extend the program as well.

LCFS T49-4

So in conclusion, we strongly support the readoption of the LCFS as it's an effective and necessary tool for reducing carbon emissions in addition to bringing significant economic benefits. Thank you.

CHAIRPERSON NICHOLS: Great. Thank you.

Mckinly Addy, and our last witness is Christopher Hessler.

MR. ADDY: Good afternoon, Madam Chair and Board members. It's McKinly Addy.

CHAIRPERSON NICHOLS: I'm sorry.

MR. ADDY: That's okay. A lot of people tend to turn the name around.

But I'm the Vice President of the company called Adtra. We are virtual integraters of low carbon high efficiency technologies at scale. That's what differentiates us from a lot of other companies in the clean energy space.

But our company supports the objectives of the low carbon fuel standard and its readoption. I want to commend the staff for their very hard work. Many of them I worked with when I was at the California Energy Commission.

50_T_LCFS _MAddy

I also particularly want to highlight John Corey, Neal as well as Katrina Sideco, but particular John and Neal because of their very hard work on dealing with the treatment of indirect land use change emissions. We started sort of working on that

LCFS T50-1

LCFS T50-1 cont.

when I was at the Commission as well.

But we believe that transportation natural gas is a strong candidate for helping compliance with the low carbon fuel standard. Combined with next generation natural gas engines, which are near zero emission for NOx and PM, but also when combined with renewable natural gas, you have a real option for true zero emission transportation propulsion solutions. Near zero greenhouse gas emissions, near zero NOx, near zero PM.

LCFS T50-2

I want to highlight a cautionary note here, and it's the enthusiasm for the readoption. In other meetings that I've attended, many of the participants talk a lot about the need for government incentives to get a lot of these low carbon transportation fuel solutions into the marketplace. What you don't hear about are the private capital requirements for the successful penetration of these technologies at scale that would move forth the policy objectives that the low carbon fuel standard and the State alternative fuels plan have laid out.

LCFS T50-3

So I'm wondering whether it made sense for the staff to consider as a contingency what might happen if some of the key players in low carbon transportation fuel space don't have access to capital and therefore might not be viable. What might that do with the possibilities for compliance with the low carbon fuel standard. That's the

LCFS T50-3 cont.

recommendation. And with that, thank you for the chance to give input here.

CHAIRPERSON NICHOLS: Thank you, Mr. Addy.

Last witness, Mr. Hessler.

MR. HESSLER: Good afternoon. I'm Christopher Hessler with AJW. Our firm's expertise is around advising clients regarding how public policies will influence market demand for innovative energy and environmental technologies.

51_T_LCFS _CHessler

A couple quick points. Number one, the program as many have said is working. And it is influencing market demand.

LCFS T51-1

And secondly, I want to talk about scarcity and the issue of this $200 pricing, what we would expect in the market as a result.

On the first, about five years ago, one of my friends in the petroleum industry when I said, you talk about feasibility and this program is feasible, define feasible to me. And he said, one and a half percent reduction, that's as far as we can see it going. Today, the oil industry testified that five percent was as far as they could see it going. So by my math, we keep going on that progression by 2020, we'll be at 15 percent. So everything is fine.

Little more seriously, this program draws its DNA in many ways from the acid rain program, the first program that really allowed for credit trading as a compliance tool. And that's important because there was at the time of the adoption of the acid rain program one compliance strategy. And that was basically putting bag houses on the back of coal-fired incinerators. That program was the single most successful environmental program in the United States. If we measure success by early compliance, by over compliance, and by the relative cost of compliance, relative to initial estimates. Here in this technology neutral platform the low carbon fuel standard, we have -- and you've heard today -- dizzying array of fuels that five years ago people weren't talking about as real potential fuels. We've got renewable diesel. We've got the real potential that renewable natural gas can overtake fossil natural gas. We have renewable hydrogen being explored for decarbonizing our base fossil fuel gasoline and diesel. That's happening very rapidly.

LCFS T51-1 cont.

On this question of $200, what the staff has proposed is effectively a cap on the marginal cost of this program. The concern in the petroleum industry legitimately is at some moment in the program we don't have -- there is a scarcity. There is not enough fuel or credits for us to comply. Well, in the scarce market, prices go up. And what the staff is proposing is to limit

LCFS T51-2

how high those prices can go. It does two things. It is tremendous consumer protection. It prevents this program will ever having a very adverse consumer effect in the worst case scenario.

The other thing it does is provides the level of confidence and stability of the program that investors and all market actors need to proceed with the program.

So it's an excellent draft. Your staff is indefatigable in terms of their work trying to investigate the best options here. It's a great product. And it will lead the world in the right direction. Thank you very much.

LCFS T51-2 cont.

CHAIRPERSON NICHOLS: Thank you very much.

That concludes the witnesses. I'm going to close the record on this agenda item at this point. But the record will be reopened when the 15-day notice of public availability is issued. Written and oral comments received after this date but before the 15-day notice is issued will not be accepted as part of the official record on this agenda item. But when the record is reopened for the 15-day comment period, the public will then be able to submit written comments on the proposed changes.

This will be considered and responded to in the Final Statement of Reasons for the regulation. And if you followed that, you're definitely a pro and probably has spent more time than you should have at ARB.

But we really do appreciate the importance of this regulation. I can assure you that the amount of time that's gone into it is perhaps more than most regulations I've ever dealt with. But it is proportional to how innovative it is, as well as intellectually challenging. We've had a history of really terrific people working on it.

I would actually like to return to the Board for questions and comments now, but I'm going to call on -- I didn't warn him of this, but I know he's always prepared, fellow Board Member Dan Sperling, because Dan is one of the people who from his post in far distant academia was responsible for helping to design this program, at least conceptually along with colleagues. But I'd like to give him an opportunity to reflect at this stage.

BOARD MEMBER SPERLING: You did surprise me. But I did have actually so many pages of notes that I can consolidate.

You know, looking back historically, it is remarkable how the original concept of this has been robust and has actually been implemented. Mike Scheible was there at the beginning also when we were thinking about this. And really the basic structure has held up, which is really impressive for such a unique, innovative, hugely important program.

Because what we're talking about here is we're debating details. And even the oil industry as they said, you know says, okay, we don't like some of the details and we think the target is too high, but is pretty much acknowledging that this is a good program for going -- good structure for going forward. And if I go back to those original discussions that we had actually with the oil companies in particular -- and at that time, this is 2007, and they were saying, okay, we see climate is important. Actually, they thought it was more important than now. And they said this is -- this does look like -- if we're going to focus on climate, this is probably about the best way to do it. We can't come up with any better ideas. And through all these years, I've given many, many talks. And people always criticize it. I say, well, do you have a better idea? And I have to report after, what, eight years now. I haven't heard anyone come up with a better idea, except maybe carbon tax or oil industry now likes cap and trade I noticed.

So you know, I'll summarize. But I think I like all the changes that the staff has proposed here. I think the three most important are the cost containment provision, the price cap, the streamlining of the certification process. And that one in particular is because what we have here is not only something important for California, but to the U.S. and the world. It has to work elsewhere. It has to be easily replicated or compatible in some way.

So this effort to streamline the administrative part of it I think is really important. And in fact, if I said anything, you know, if I suggest anything big, it is that going forward we keep thinking about how can we streamline it even more. How can we make it so it really is compatible with other stats and can be scaled up nationally and internationally.

And the third part that I did want to strongly support is the idea of incentives at the refinery level and upstream. And in terms of encouraging carbon capture and sequestration and other kinds of improvements. I think all of those are really important as we go forward.

So I guess one other comment and that is there was a lot of discussion that really dealt with the idea of making it science based, but at the same time others talk about certainty. And there is a tension there. And we're I think the staff has been working hard at trying to figure that out. Just the ILUC is a good example of it is going -- to get precision on that means -- to bring science to that, we are going to be updating it over time as we learn more. But it would change it then we're reducing certainty and regulatory certainty. So how do we manage that process going forward.

And I think we stick to the numbers as much as possible. We stick to the process and the methods as much as possible. And we deviate only when the scientific evidence is really strong for making it different. And so in the case of ILUC, there is a proposal to reduce the ILUC, as many have suggested and the science as I see it supports that. And so there will be that.

So the only other thought I would have is that it has been -- there is a question is it really successful or has staff overstated it by saying it's been a very successful program so far. And depends how you define success, of course.

But as we heard here, there's so many companies and so many processes and so many fuels that are being developed that we did not anticipate at the beginning. And we have been disappointed the cellulosic technologies have not gone forward as much and as fast as we hoped for at that time as expected. On the other hand, a lot of these biodiesel renewable, diesel have gone forward much more so.

We always thought in the beginning the diesel part of this was going to be a really hard part and the gasoline part was going to be the easy part. Turned out to be just the opposite. And that just lends more support for the whole structure of this is that we have created something that is technology neutral, that does provide incentive, that is market based to a large extent. And you know, in that sense, it's working now. Yes, we're only at one percent reductions, so I don't think we should be claiming too much credit yet, because we have a long ways to go.

But it is headed in the right direction, and I don't -- I personally don't see any major speed bumps along the way. And so I look forward to this as it evolves over time and will be thinking in a couple years from now what next.

CHAIRPERSON NICHOLS: Great. Thank you.

Mrs. Riordan.

BOARD MEMBER RIORDAN: Yes. I have a question to the staff.

Attachment A is I think important to us. And I wondered after listening to the testimony if your bullet points coverevery thing that you feel needs to be covered there or if there is something you would wish that the Board might add to give you some latitude to deal with something you might not necessarily have thought of at the time of the printing, but after the hearing, you feel might be helpful to you.

BRANCH CHIEF WADE: We feel like the list you have in front of you is relatively inconclusive. We'd like to highlight a few things on that list.

First, we believe a targeted public process on the GREET changes, especially with respect to natural gas vehicles, is essential. And we plan to conduct that prior to releasing a 15-day package.

Secondly, we feel the refinery investment provisions do deserve a little bit more attention as well in that time period. So we'll be going through the 65 or so written comments we received. Go out and have that dialogue with stakeholders on those issues. Release a 15-day package and return to the Board tentatively in July or so.

BOARD MEMBER RIORDAN: Thank you.

CHAIRPERSON NICHOLS: So just to an addendum to that. It's probably included in this, but this vexing issue which Dr. Sperling also mentioned of how you update based on new information, but not do it so often that you create uncertainty, have you thought about or are you prepared to think about including a specific provision on how frequently this matter will come back with amendments?

BRANCH CHIEF WADE: Certainly. We do believe having additional certainty for a period of essentially around three years or so would be useful. The work that's done on these complex models takes a huge amount of staff resources and does take away from the implementation of the program or the day-to-day running of the program. So --

CHAIRPERSON NICHOLS: From the time of adoption, whenever that is, hopefully this summer, you would then put in that regular three-year process for updating the science?

BRANCH CHIEF WADE: I think we have a time line for general program review. But we feel like the revisiting of the models is separate from --

CHAIRPERSON NICHOLS: Are two different things. Right. Right.

BOARD MEMBER SPERLING: To follow up on that, there has been a question that a lot of the -- some of the stakeholders have talked about, the natural gas the most, about the process part of that.

And I do -- so the question is should there be a more formal process or the stakeholder engagement in dealing with these GREET numbers and perhaps others. And I'm up of the mind that it should not be a formal process. But I think that's probably something that should be considered at some point. It really -- I think that the stakeholders pretty much feel comfortable that the staff has done a very good job of incorporating it. But in this modern day and age of transparency and so on, I think it is something that should be considered.

CHAIRPERSON NICHOLS: I think we should at least address the type of review and the process for review in a more robust way than we have until now.

Other comments at this point?

Yes, Ms. Berg.

BOARD MEMBER BERG: I'd just like to follow up on the timing of the actual review. If we look at we are in 2015 now, and I know in the staff report we have 2017, it feels to me that the first getting back on track is 2016 and we'll be circling back.

I think it would be helpful maybe to distinguish the type of informational how we're going to come back to the Board. For example, I would be interested -- very interested around the '17 time to understand how the investments are doing, to look at how the program is now ramping up or any challenges that we're having. But as far as doing a program review, much before we have a couple of years under our belt, I think would be more uncertain than creating the certainty. So I'd like to look at --

CHAIRPERSON NICHOLS: A progress report.

BOARD MEMBER BERG: Exactly. Rather than a review. So in looking at the 15-day changes, I would encourage instead of as outlined in the staff report that we're looking at an update in 2017 that you come back to us with a mix maybe of Board briefings on particular topics that are of interest to the Board and then actual program review and model review. So when we're voting on it, that it's a little bit more clear both for us and expectations that we're setting for the stakeholders and the market really what we're looking at. Thank you very much.

CHAIRPERSON NICHOLS: I see a head nodding there. I think that's acceptable.

BRANCH CHIEF WADE: That makes a lot of sense to us. We're happy to pursue the details of that with you moving forward.

CHAIRPERSON NICHOLS: Great. Other comments or questions before we call the question?

Yes. Supervisor.

BOARD MEMBER ROBERTS: I'll go quickly. It's obvious from the review we're talking about if there are things that are not going as we think, we want to highlight those for sure.

On one of the slides, there was a comment about add electric transit systems and electric forklifts. I don't want to leave that out. I'm sure that's important to somebody who is eligible to generate credits. Can somebody elaborate more on what are the rules? I presume we're talking about public transit systems.

BRANCH CHIEF WADE: That's right. So we're talking about light rail or electric buses with fixed guideways. And essentially, this is a new crediting provision for those types of transit systems. Do you want me to go into details of how?

BOARD MEMBER ROBERTS: Would it be on existing systems?

BRANCH CHIEF WADE: Yes, on --

BOARD MEMBER ROBERTS: And new systems?

BRANCH CHIEF WADE: -- are eligible, yes.

BOARD MEMBER ROBERTS: I'm curious about that. We're just getting ready to --

CHAIRPERSON NICHOLS: San Diego is looking for some new investments here.

BOARD MEMBER ROBERTS: That may be the nicest thing that happened. But I know I can provide a slide, but we're also exploring a new overhead electric system, a gondola, an urban gondola. I presume since that's all electric, that would apply.

BRANCH CHIEF WADE: We would happy to evaluate that project when it comes forward.

BOARD MEMBER ROBERTS: I seems we're beyond the exploring state. I presume that would fit into the category also.

CHAIRPERSON NICHOLS: Yes, the general category.

BRANCH CHIEF WADE: The general category, yes. We have to look at the actually --

BOARD MEMBER ROBERTS: We're not just saying light rail.

CHAIRPERSON NICHOLS: If it doesn't have wheels that go along the ground.

BRANCH CHIEF WADE: There is none of that in the definition. It believe that's the first case of this that we've seen it.

BOARD MEMBER ROBERTS: You'll see more of them I think. But that's far more efficient and cleaner than any other kind of transportation that we're aware of.

BOARD MEMBER SPERLING: Just to encourage you more, if you look at how much these credits could be worth -- so bring this back to San Diego -- is that these are worth in the tens of thousands of dollars. It depends on how much they're used and what the credit value is. We're talking about tens of thousands of dollars over a 10 or 15-year period for each, like a bus equivalent. So it's not trivial, but it's substantial. So what we'd like to see is cities making these investments, this will stimulate more investment

BOARD MEMBER ROBERTS: No, you know, I can share with you. Any of these things, they don't cover their operational expenses. So anything that can go to further that will be an incentive to increase those systems. It's at 26, $27 dollars right now as I understand it with the $200 cap. I'm not trying to push to get it out. But we'll see how the market works. I promised everybody that's involved in light rail that we --

CHAIRPERSON NICHOLS: You're down at the other end looking at starting up a bus company. So --

BOARD MEMBER MITCHELL: I'm thinking the gondolas at the ski resorts.

CHAIRPERSON NICHOLS: Supervisor Gioia.

BOARD MEMBER GIOIA: It was really good to hear from the range of speakers and really the excitement about this whole new field of alternative fuel development. I mean, it truly shows this when it was an active fuel neutral and something happened that sounds like this Board when it passed expected and some of the things happened that it didn't expect. That's sort of the true measure of the fuel neutrality.

But I think this is a very important rule regulation. And it's part of a whole suite of measures this Board has adopted to really encourage the development and demand for alternative fuels and alternative vehicles. I think it's accomplishing that. They all don't -- each of them don't achieve success on their own. It's all how they work in tandem in conjunction with each other, the cap and trade program, the clean cars program, low carbon fuel standard. And we understand that, that they're all intertwined. They're all important. And we need them all in order to achieve success. It was great to hear the excitement and the positive successes that have happened as a result of this original regulation.

CHAIRPERSON NICHOLS: Other comments.

Mr. Balmes.

BOARD MEMBER BALMES: I actually have a question. And it may be more appropriately addressed in the future. I don't want to hold us up.

But on slides 19 and 20 of the staff presentation, you show fairly impressive decreases in the carbon intensity for sugar cane ethanol, corn ethanol on the gas substitutes. And likewise for soy bean biodiesel.

And I realize this comes from a re-evaluation of the -- probably comes from a re-evaluation of indirect land use, but could you -- I don't need sort of a super detailed answer with regard to the model. But in terms of the major changes in the model, could you summarize what those are? Since there's been a lot of controversy over how we calculate the carbon intensity values. So this is a big picture answer, not down in the details of the model.

BRANCH CHIEF WADE: Let me open it up by saying the ILUC changes are some of the major drivers we've seen. If you'd like a bullet list of what some of those are --

BOARD MEMBER BALMES: A bullet list would be good.

MANAGER SINGH: Let me just say briefly -- and I can go more on this. Between 2009 -- I'm very passionate about what I do. I could go on forever.

Between 2009 when we first presented in '09 ILUC was something, you know, nobody had heard of and there was a lot of controversy. And over the course of the last five years, people have embraced indirect land use change.

In terms of the model, land use science has improved tremendously between 2007 through 2014. We have incorporated several of the changes in new data sets that have come out and new science that has come out with land use change.

To sort of summarize the critical changes that have impacted the indirect land use change results that we are presenting today is we made structural changes to the model to reflect how land conversion happens in the world. Originally, one of the contentions was we're changing a lot of forests in a lot of the countries of the world. We made structural modifications to account for more of the changes going to pasture land and land that is comparable to pasture land, which is used for crop growing. That was one of the biggest drivers that lowered land use change numbers.

The other one was the productivity of existing and new crop land. When you have new land that is converted, in the 2009 analysis, we had just an average number. But we had a lot of science and work that went into. Of course, we have to give consider to Purdue University and we implemented some of those changes.

Overall, our methodology and understanding of indirect land use change has tremendously changed between 2009 and today. And we've implemented sort of what we call harmonization of treatment across all biofuels that we've analyzed. That's sort of a quick summary.

BOARD MEMBER BALMES: That was just what I asked for and only a passionate person could have given it to me.

CHAIRPERSON NICHOLS: Great. Yes, Dr. Sherriffs.

BOARD MEMBER SHERRIFFS: Actually going back to a comment I made earlier. In terms of the reviews -- not the word we want to use -- but in 2017 report, I would like to be sure that staff looks at, in fact, trying to measure some of the health benefits that have come out of this and reporting back on that because I do think that's an important aspect of what we do with this.

BRANCH CHIEF WADE: Let me just ask you, so quantifying health benefits and assigning them economic value or quantifying them?

BOARD MEMBER SHERRIFFS: Boy, if you can do both, go ahead.

The other thing I would want to say, Mr. Corey, there was lots of thanks for all your work here. I think you can acknowledge that thanks by taking a weekend off.

CHAIRPERSON NICHOLS: The whole weekend? Wow. Okay. I think we're nearing time for a vote on the Resolution here.

I do have just one additional comment that I want to make. And I hope it's taken in the right spirit. But obviously, we did not hear a lot of support from major oil companies here at today's hearing. We heard a lot of support from others, but continued if not more serious I would say opposition to the very concept of a low carbon fuel standard, which is disappointing. And I'm not going to try to debate that politics or the economics of it really at all. But just to talk a little bit about the fact that there was a comment -- and I can't remember -- I think it was Chevron commented about the fact that we weren't really creating certainty because in the mind of the witness they didn't know how they were going to comply and, therefore, the technology is uncertain. And, therefore, there was not such a thing as certainty.

It just made me want to reflect and comment that this Board has for decades now been in the business of setting technology-forcing standards that were ahead of exactly where the people who were regulated knew how they were going to comply, but were based on a substantial knowledge and analysis of the potential for technology, as well as increasingly more sophisticated economic analysis, which doesn't mean that we're perfect or that we're ahead of where companies are in terms of analyzing their own businesses, but just that we think we are well rounded in terms of what the potential is for compliance here.

And I think it's important that perhaps this is not an area that the petroleum industry is accustomed to being pushed in. And I just want to say that I think we have a good track record of working with the regulated community and adjusting regulations, when it turns out that our predictions were wrong. But that overall by pushing towards goals that we believe are achieveable and occasionally adjusting time lines, if we had to, that we've achieved just tremendous progress and we look forward to doing the same thing here.

BOARD MEMBER SPERLING: So let me just elaborate just a bit on this.

This being serious, this really is hard. The challenge we've laid out really is a huge, challenge and we shouldn't understate that. And we should also appreciate -- and for the oil industry, I mean, we're basically telling them, you know, we want you to change your business model and your main product. And that's pretty tough stuff.

But at the same time, this is the larger social goal of the goal we're aiming for. So you know, I can sympathize with the oil industry. We're attacking their basic business model. But we are as, Chairman Nichols was saying, we are providing a lot of flexibility. We're providing -- the staff is creating incentives for doing things like CCS. So I think we are going out of our way to try to make this transition and this transformation as smooth and as efficient as possible while still achieving the goals that we're aiming for.

CHAIRPERSON NICHOLS: Thank you. Without further ado, do I have a motion?

BOARD MEMBER GIOIA: I'll make a motion.

BOARD MEMBER SERNA: Second.

BOARD MEMBER GIOIA: And a comment.

And I think it's important to acknowledge you were on a panel with an executive from Shell on alternative energy. Frankly, it is entirely possible for the oil companies to do more of what Shell's doing, which is looking at alternative opportunities, alternative fuel opportunities. So while it may be a challenge to their existing business model, it will help develop a new business model. So or help move toward a new business model.

CHAIRPERSON NICHOLS: Okay. We have a motion and a second.

All in favor please say aye.

(Unanimous aye vote)

CHAIRERSON NICHOLS: Any abstentions? All right. Thank you very much. Everybody.

And we'll be back. We have one item related to this one. The last item today is the proposed regulation on commercialization of alternative diesel fuels. And this is the issue that was directly connected with the challenge to the low carbon fuel standard. Because of the successful implementation of renewable fuel policies like the low carbon fuel standard, a variety of innovative alternative diesel fuels are currently in the marketplace or in development.

People, please if you're going to chat, do it outside because we are taking up the next item.

There is a variety of new types of diesel fuels that are currently in the marketplace or in development in laboratories and demonstration settings. To ensure that these fuels are available to help us transition to a low carbon future, staff is proposing new regulations that streamline the requirements for emerging alternative diesel fuels. It also will provide for robust environmental review of these fuels before they enter the market to ensure that current environmental protections are maintained.

Mr. Corey, please introduce this item.

EXECUTIVE OFFICER COREY: Yes, thank you, Chairman Nichols.

Since the initial implementation of low carbon fuel standard, significant changes have started to occur in California's fuel market which we talked about that for a while. The carbon intensity of our state's fuel pool is declining. As fuels like renewable diesel, biodiesel, natural gas, ethanol, electricity, and hydrogen are more prevalent, today's proposed regulation represents a vital step in supporting this important transition.

Staff's proposal today provides a clear pathway of commercialization of alternative diesel fuels, incorporates the best available science, and maintains our current environmental protections. In particular, the proposal will address NOx emissions related to the use of biodiesel.

The proposal works in conjunction with proposed low carbon fuel standard re-adoption you just heard about to ensure that we deploy fuels that contribute to our climate and as well as our air quality goals.

In addition, staff's proposal is part of ARB's response to the State Appeals Court decision we talked about earlier.

Now I'd like to invite Lex Mitchell of the Industrial Strategies Division to begin the staff presentation.

(Thereupon an overhead presentation was presented as follows.)

MANAGER MITCHELL: Good afternoon, Chair Nichols and members of the Board.

Today, I will presenting the proposal to establish a regulation on the commercialization of alternative diesel fuels, also called ADFs. As with the earlier item on the LCFS, we will not be asking the Board to take any approval action today.

--o0o--

MANAGER MITCHELL: As an overview, there will be five portions of this presentation which are listed here. We will first discuss the need for the proposal, then provide background, and outline our regulatory development process. We will then discuss the proposed process for approving alternative diesel fuels, the specific requirements for biodiesel as an ADF, and the impacts and benefits of the proposed regulation.

Finally, we will present potential 15-day changes.

--o0o--

MANAGER MITCHELL: We will start the presentation with the need for the ADF proposal

--o0o--

MANAGER MITCHELL: In order to minimize confusion, we will first cover what is and isn't considered an alternative diesel fuel under the current proposal. Examples of ADFs include biodiesel, which is already being used and is the first ADF proposed to be regulated under this process, and dimethyl ether, an ADF in the beginning stages of the environmental review process.

Both of these fuels are chemically different than conventional diesel and neither has an existing ARB specification. Examples of compression ignition fuels that are not ADFs include renewable diesel, which is a liquefied hydrocarbon chemically indistinguishable from conventional diesel and natural gas, which already has an ARB specification.

From here on, blends of ADFs, primarily biodiesel blends, will be discussed and some familiarity with how blends are referred to as needed. Biodiesel blends are referred to as BXX, where X represents the percentage blend level. For example, B10 is a blend of the 10 percent biodiesel and 90 percent conventional diesel.

--o0o--

MANAGER MITCHELL: Before we go any further, I'd like to spend some time clarifying the difference between biodiesel and renewable diesel, two terms that frequently get intermixed. Biodiesel is a fatty acid methyl ester and is chemically different from conventional diesel.

The biodiesel molecule contains two oxygen groups, unlike conventional diesel, which contains none.

Renewable diesel, on the other hand, is a hydrocarbon chemically indistinguishable from conventional diesel, but with lower aromatic content that is typically found in petroleum diesel.

Despite their differences, biodiesel and renewable diesel are complimentary fuels. Biodiesel's good lubricity and renewable diesel's good cold temperature performance can complement each other.

--o0o--

MANAGER MITCHELL: Now that we've covered what ADFs are, why do we think an ADF regulation is necessary?

First of all, ADFs can deliver significant environmental benefits. And we expect to see their volumes grow as both state and federal policies drive their supply and demand.

In order to encourage this expected increase in ADF volumes, it is essential that market certainty and regulatory clarity be provided to emerging ADFs. As these volumes increase, it is essential that ARB ensure their commercialization is done in a manner that protects environmental and public health.

The ADF proposal is designed to address all of these objectives. In addition the proposed regulation addresses one of the problems a court found with ARB's adoption of the original LCFS regulation in 2009 by addressing potential NOx impacts from biodiesel use.

--o0o--

MANAGER MITCHELL: Staff has extensively studied biodiesel and renewable diesel emissions and has found that both lower GHG, PM, and toxic emission. For example, a blend of 20 percent biodiesel has been found to decrease PM by about 20 percent.

Additionally, renewable Diesel decreases NOX relative to petroleum diesel primarily due to its lower aromatic content.

Staff has found that biodiesel can increase NOx in some situations in older heavy-duty vehicles. The ADF proposal applies the lessons learned from the evaluation process for biodiesel in order to develop a process to evaluate future ADFs. In addition, the proposal allows biodiesel use while addressing the NOx concerns recognized during biodiesel testing, maximizing environmental benefits.

--o0o--

MANAGER MITCHELL: This table shows the LCFS credits generated by biodiesel and renewable diesel in 2014 and 2020. Biodiesel and renewable diesel make up a large and increasing portion of the total LCFS credits as time goes by and significantly contribute to the success of the program.

--o0o--

MANAGER MITCHELL: In addition to biodiesel, which is already contributing to the LCFS, other ADFs are expected to emerge as incentives continue. Current evaluation of these fuels involves various regulations and statute. The ADF proposal would take these requirements, clarify them, and compile them into one regulatory framework, which will provide additional certainty for proponents of upcoming ADFs, such as dimethyl ether, which is currently undergoing evaluation.

--o0o--

MANAGER MITCHELL: Let's move now to the

regulatory development process.

--o0o--

MANAGER MITCHELL: ARB has spent the last eight years developing and conducting studies on biodiesel emissions and analyzing the results of these studies, including spending about three million for testing to understand biodiesel's impact.

In addition to the original research conducted by ARB, staff conducted a literature review and sponsored an independent statistical analysis of the data. Staff has had extensive interaction with stakeholders on our biodiesel program, including 13 public meetings to discuss testing and seven reg development workshops.

The combination of comprehensive biodiesel testing and continual stakeholder involvement and feedback led to the ADF proposal presented today.

--o0o--

MANAGER MITCHELL: During the multimedia evaluation and additional review of biodiesel emissions, nitorgen oxides, or NOx, was found to be a pollutant of concern whose emissions varied by feedstock.

For example, on this graph, you can see that biodiesel derived from soy feedstocks leads to greater NOx increases than biodiesel derived from animal feedstocks. Whereas, renewable diesel decreases NOx. All of these impacts were measured for pre-2010 heavy-duty engines. Light-duty, medium-duty, and new technology heavy-duty diesel engines have been found to have no biodiesel NOx impacts.

We'll come back to this slide later in the presentation.

--o0o--

MANAGER MITCHELL: Moving on to the objectives of the proposed regulation. In development of the ADF proposal, ARB has adhered to the following objectives:

Establishment of a clear pathway for commercialization of ADFs in order to provide regulatory certainty and encourage the use of ADFs. Ensuring public health and air quality protections from ADFs used as a replacement for conventional diesel in order to ensure the integrity of our existing air pollution reduction programs. And establishment of criteria for biodiesel use and NOx emissions control, to ensure that the benefits of biodiesel use can be realized without associated degradation in ozone-related air quality.

--o0o--

MANAGER MITCHELL: We will now go through an overview of the ADF proposal. The ADF proposal includes two main provisions, the general evaluation process for environmental analysis of emerging ADFs and the fuel specifications and in-use requirements for biodiesel.

The environmental evaluation process for emerging ADFs consists of three stages, following ADFs from lab to demonstration to commercial scale.

The proposal will limit fuel volumes and consider test location. Through this review and evaluation process, the conclusion may lead to staff to develop additional in-use controls and specifications for that fuel, or if there are no detrimental effects found, only reporting may be required.

The fuel specifications being proposed for biodiesel and, in fact, the three-stage evaluation requirements are based on staff's multimedia evaluation of biodiesel, as well as renewable diesel, both of which are nearing completion and will be completed by the follow up Board hearing.

--o0o--

MANAGER MITCHELL: Let's move on to the evaluation process for emerging ADFs.

--o0o--

MANAGER MITCHELL: The three stage evaluation process for commercialization of ADFs was developed to evaluate environmental impacts and control potential detrimental impacts prior to the widespread use of an emerging fuel.

During this process, staff would complete a multimedia evaluation of the fuel to determine adverse emission impacts for any pollutants of concern considering offsetting factors to determine the need for in-use requirements or fuel specifications for the ADF. The mechanism for dealing with pollutant increases would be to set a pollutant control level above which pollutant reduction strategies would be required.

--o0o--

MANAGER MITCHELL: This graphic shows the three stages and hypothetical volumes of fuel distributed as the fuel progresses through the stages. Initially, an ADF proponent would apply for a pilot program under Stage 1, which would include disclosure of ADF composition, preliminary emissions testing, evaluation of potential environmental and health effects, and volumetric limit of no more than one million gallons per year.

In Stage 2, the focus is on fuel specification development and would include a full multimedia evaluation, consensus standards development, consideration of engine concerns, determination of potential adverse emission impacts, and volumetric limit of 30 million gallons per year.

After completing Stage 2, a fuel may advance to either Stage 3A or 3B, depending on its environmental impacts. If adverse emission impacts are found, the fuel would be regulated under Stage 3A, which includes development of in-use requirements and fuel specifications. If a fuel is found to have no detrimental impacts, it would be eligible for Stage 3B, where only reporting is required.

As noted earlier, this three stage process is reflective of current regulatory requirements and policies already in place.

--o0o--

MANAGER MITCHELL: Let's move now to the biodiesel specific requirements of the proposal.

--o0o--

MANAGER MITCHELL: In order to control the NOx increases from biodiesel, staff developed specific in-use requirements and fuel specifications. The proposal included reporting provisions which begin in 2016, but in-use requirements do not begin until 2018. This time lime allows for implementation of mitigation options for compliance pathways.

A pathway for certification of additional in-use options has been included to allow testing of novel methods the offset NOx emission, including novel Additives, blend stocks, or production methods.

The biodiesel in-use requirements will sunset when vehicle miles traveled in the on-road heavy-duty fleet is greater than 90 percent new technology diesel engines. This is currently anticipated to occur by 2023. Additionally, the biodiesel provisions will undergo a program review to be completed by 2020.

--o0o--

MANAGER MITCHELL: Beginning in 2018, biodiesel would be limited to B5 or B10, depending on feedstock and season. Feedstocks under this proposal would be distinguished by cetane number rather than prescription of feedstock source and cetane cutoff for determining feedstock is 66.

Higher cetane biofuels such as animal-based biodiesel tends to produce less NOx than lower cetane biodiesel, such as soy-based biodiesel, and therefore be used in higher blends.

Additionally, blends up to B20 could be sold if they use an additive or other certified control. Biodiesel used in light-duty and medium-duty vehicles has been shown not to increase NOx. Newer heavy-duty vehicles have been shown not to experience the NOx increase from biodiesel as well that is seen in older heavy-duty vehicles due to the use of selective catalytic reduction emission controls. The ADF proposal includes an exemption process for these vehicles.

--o0o--

MANAGER MITCHELL: You'll recall this slide from earlier. The important point here is that our extensive testing showed that biodiesel are not created equally and the different feedstocks result in different NOX effects. Just as importantly, our testing also showed the offsetting effect on NOx from the use of renewable diesel. These two findings informed the proposed regulation.

--o0o--

MANAGER MITCHELL: As part of staff's analysis of the effects of biodiesel use, offsetting factors were considered to determine the real world effect of its use, rather than simply the lab results of engine testing.

Most importantly, it was found that new heavy-duty new technology diesel engines or or NTDEs do not experience a NOx increase with biodiesel up to B20 due to SCR emission controls and the heavy-duty market is substantial and increasingly complied of NTDEs.

Additionally, the NOx decrease from renewable diesel means that some of the emissions from biodiesel are offsetting, leading to less need for in-use requirements on biodiesel, especially considering the recent and expected continual increase in volumes of renewable diesel. These offsetting factors combine to eliminate the NOx increase from biodiesel over time, hence the sunset provisions, by in the mean time controls on NOx are needed.

--o0o--

MANAGER MITCHELL: This graph shows the increase in vehicle miles traveled by new technology diesel engines as well as the NOx increase from biodiesel.

As newer vehicles become an increasingly large contributor, the vehicle miles traveled in the on-road heavy-duty diesel fleet as shown by the shaded bars. The corresponding NOx increase from biodiesel becomes increasingly reduced.

As you can see, in 2023, when newer vehicles are expected to contribute more than 90 percent VMTs, the NOx increase from biodiesel becomes negligible. At that point, we are proposing to sunset the biodiesel in-use requirements.

--o0o--

MANAGER MITCHELL: Practically speaking, we expect regulated entities to comply with the regulation primarily by selling biodiesel blends at or below a B5 blend level.

However, the proposed includes other options that will increase flexibility for compliance which are listed here. For example, for businesses geared toward B10 sales, either a high cetane feedstock may be used or any feedstock may be used in the winter.

For businesses geared toward B20 sales, either targeted sales to exempt vehicles or additive use will accommodate these sales. The table on this slide shows the NOx control level by both feedstock and time of year, which lead to these compliance options.

--o0o--

MANAGER MITCHELL: As was mentioned earlier, the NOx emissions from biodiesel are expected to decrease over time leading to a sunset of the in-use requirements when new heavy-duty on-road trucks are more than 90 percent of vehicle miles traveled. This is expected to occur by 2023.

Additionally, as the fuel market is still in flux in its transition to diesel substitutes, a review of the program will be completed by 2020. This review will consider a variety of factors, such as SCR adoption and fuel volumes, and whether we are on the right trajectory toward the projected sunset of biodiesel blend limits.

--o0o--

MANAGER MITCHELL: Let's move now to the impacts and benefits of the alternative diesel fuels proposal.

--o0o--

MANAGER MITCHELL: Staff prepared one draft environmental analysis, or EA, that covered both the proposed LCFS and ADF regulations because two rules are interconnected. The draft EA was prepared according to the requirements of ARB's certified regulatory program under the California Environmental Quality Act, or CEQA. The analysis focused on changes in fuel production supply and use. The existing regulatory and environmental setting or the actual physical environmental conditions in 2014 is used as a base line for determining the significance of the proposed regulations impacts on the environment.

--o0o--

MANAGER MITCHELL: As discussed in the previous presentation for LCFS, the draft environmental analysis identified both beneficial impacts and adverse environmental impacts from the proposed regulation.

Beneficial impacts were identified in the areas of reduced GHG emissions, reduced criteria pollutants, including reduced PM2.5 emissions and energy. The draft EA identified less than significant impacts to certain resources such as minerals and recreation.

Potential significant impacts were identified in a number of resource categories such as agriculture, biological, and hydrology and water quality. Significant cumulative impacts were also identified for resources.

While some of these identified impacts are related to long-term operational changes, others are potential short-term effects related to construction of new fuel production facilities.

--o0o--

MANAGER MITCHELL: The economic impacts of the ADF proposal were evaluate in two ways, as part of a state-wide macro economic evaluation of the effects of the ADF and LCFS proposals and as the direct costs of the ADF proposal provisions.

Because the ADF and LCFS proposals were so interlinked, the macro and economic impact of the proposals could not be desegregated and therefore the evaluation was completed using the simultaneous effects of both proposals on fuel volumes and prices.

As was discussed in the LCFS presentation, the macro economic evaluation employed a conservative framework and found that the combination of proposals would have a very small impact on the overall state economy.

Compliance with the ADF provisions are expected to result in costs of about one-tenth of a cent per gallons on B5 diesel in 2018. And as the fleet transitions to newer engines is expected to shrink and eventually be eliminated by 2023. For biodiesel producers whose business is reliant on sales of higher biodiesel blend levels and who are not located near a terminal with biodiesel blending facilities, there are will be additional challenges to the regulation.

Staff continues to work with stakeholders to identify additional flexibility to address this challenge while maintaining the NOx protections of the proposal.

--o0o--

MANAGER MITCHELL: The primary reason why alternative diesel fuels and other diesel substitutes are important and should be encouraged is due to their variety of beneficial impacts. For example, biodiesel, renewable diesel, and dimethyl ether can all reduce PM and toxics compared to conventional diesel, leading to lower localized toxic exposure, and renewable diesel can reduce NOx emissions.

All of these fuels can be produced from feedstocks that lower greenhouse gas emissions and are capable of contributing to our 2020 and 2030 air quality goals. Additionally, all of these fuels can be produced from domestic sources produced in the USA, leading to increased energy security.

--o0o--

MANAGER MITCHELL: We will now move on to 15-day changes and next steps.

--o0o--

MANAGER MITCHELL: Staff has included some potential 15-day changes for consideration in Attachment A of the Resolution. Examples of potential changes include further flexibility for captive fleets that would not adversely effect air quality, clarification of certification procedures, definitional changes, and minor clarifications, and corrections.

--o0o--

MANAGER MITCHELL: This is the first of two Board hearings so the Board will not adopt the ADF today. We recommend that the Board direct staff to continue working with stakeholders to refine the proposal and coordinate development with the LCFS team.

--o0o--

MANAGER MITCHELL: Going forward, staff will complete and respond to comments on the environmental analysis document. The peer review of our biodiesel multimedia evaluation is in progress and the multi-media process will be completed by the second Board hearing.

Staff will also propose 15-day changes for comment prior to the second Board hearing.

Thank you for your attention. This concludes staff's presentation. I would be happy to answer any questions you may have.

CHAIRPERSON NICHOLS: We do have 14 witnesses who have signed up. But yes.

BOARD MEMBER SERNA: Thank you, Madam Chair.

Quick question for staff on the chart that you showed twice that showed the NOx effect of biodiesel in older heavy-duty vehicles, are you encouraging us not to get too hung up on the soy feedstock biodiesel because that's only applicable to the older engines. And with the introduction of newer engines that that NOx concern will go away?

MANAGER MITCHELL: I wouldn't characterize it as the difference in the feedstocks. We think that the NOx effect goes away over time, like you said, due to the newer vehicles. More or less what the proposal does is it assumes that unless you take an action and use a cleaner feedstock that you're using one of the soy feedstocks, which we consider the lower cetane fuels.

ASSISTANT DIVISION CHIEF KITOWSKI: Maybe I can recharacterize that a little bit.

The use of soy and animal as part of the testing programs, but they weren't very good metrics for regulation. So in moving from the test program to the regulation, we shifted from soy and animal feedstocks to high saturation or high cetane and low saturation low cetane. They're area pretty much analogous.

BOARD MEMBER GIOIA: Thank you.

CHAIRPERSON NICHOLS: Before we go, you have a question?

BOARD MEMBER ROBERTS: You'll have to indulge me. I know I'm the only one that doesn't know the answer to this.

The difference between biodiesel and renewable biodiesel? And why do they call it renewable because it doesn't seem like it's renewable?

MANAGER MITCHELL: Biodiesel and renewable diesel are both produced from the same feedstocks. Those are any fat or oil that you can find.

The difference is in the processing. So the biodiesel process is it takes this kind of lighter chemical treating to create this fatty acid methyl ester, which is a distinct type of chemical.

Renewable diesel takes those same feedstocks and it uses a more similar to a refinery process a hydro treating process to create a fully non-oxygenated saturated fuel.

The reasoning why they're called something different I think is that biodiesel was kind of the first adoptor of this technology so that biodiesel was there first. And then to distinguish, they just wanted to make sure that what people are calling fatty acid methyl esters is biodiesel and it's different from renewable diesel, which came along later. So it's not that one is renewable, one's not.

CHAIRPERSON NICHOLS: Renewable sounds good and --

BOARD MEMBER ROBERTS: It sounds like it's going to be there after you use it. So --

CHAIRPERSON NICHOLS: It's just terminology.

BOARD MEMBER ROBERTS: It's in the process you're starting with similar products. And that's where the --

MANAGER MITCHELL: Transetherification is the chemical process for producing biodiesel and hydro treating is the chemical process for producing renewable diesel.

BOARD MEMBER ROBERTS: You made it so crystal clear.

CHAIRPERSON NICHOLS: The whole concept of fatty acids is not really worth talking about.

BOARD MEMBER GIOIA: There is a good band name in there somewhere.

CHAIRPERSON NICHOLS: With that, I think we should proceed to hearing from the witnesses. So we'll start with Matt.

MR. MIYASATO: Thank you, Madam Chair.

For the record, Matt Miyasato, the Deputy Executive Officer for Science and Technology Advancement at the South Coast Air Quality Management District.

I'm here to voice our support for the staff recommendation and your ultimate approval of the ADF regulation.

I also want to point out that you've heard a lot of accolades about your staff. They continue to work, go out of their way to work with us. We brought up the concerns we had over NOx increases or potential for NOx increases. And they do what we do, they rely on data to make the recommendations before your Board which is in your package today. So we appreciate staff continueing to work with us.

So again, we urge your ultimate approval when this comes before you for a vote. Thank you.

CHAIRPERSON NICHOLS: Thank you. Ms. Case.

MS. CASE: I'm going to sound like a broken record when I thank everybody again.

CHAIRPERSON NICHOLS: Could you raise the mike?

MS. CASE: Richard Corey and Lex Mitchell and everybody on the staff for all the work that they've put into this, because it really has been a lot of work. And I do appreciate it.

As I said in my earlier testimony, my biodiesel plant is in San Diego, which is one of the smaller diesel markets that is not at this point terminal blending. We make our biodiesel from 100 percent used cooking oil captured from restaurants. So we convert french fry oil into biodiesel.

The biodiesel that we make on the our plant is one of the lowest carbon biodiesels out there, because we are making it from the used cooking oil. And it's soon to be lower as we are in the middle the project to install cogeneration at our plant, which we are really proud of.

This regulation I know was pain-stakenly arrived at over a long period of time, and I believe it represents a great compromise for all sides. I particularly support that there is the in-use time line, which will allow our business to adapt. We do sell a lot of our fuel into the B20 market. So we do need to make some changes to our business plan. And we look forward to continuing to work with staff on finding ways that we can target fleets that will not cause increased NOx and in addition work with our trade industry group on developing additives.

So thank you for everything that you've done to get to this point. And in this spirit of the Chairman's comment earlier, I'm very confident that we will innovate and adapt to these changes as we have in the past and everyone should to protect our environment. Thank you.

CHAIRPERSON NICHOLS: Okay. Thank you.

Curtis Wright? Curtis Wright here?

Celia DeBose.

MS. DE BOSE: So this is Celia DeBose again with the California Biodiesel Alliance, the industry trade association representing over 50 stakeholders.

And again, we're supporting the comments of the National Biodiesel Board and urging the adoption of this regulation. So if staff needs more kudos, kudos.

And the interesting thing about this is that it's not just you guys, but it's generations before because we really have been working on this for about ten years. What we've been engaged in is a process of bringing in new fuel to market in California. So we've marked with State agencies, helped them check off what they need to check off. And what's important now is that the Air Resources Board moved forward with this important step so that we can move forward with a structure and a process that allows us to deal with this one criteria pollutant.

So we really appreciate the exemption, the exemption for the 90 percent new technology diesel engines for heavy-duty fleets, the exemption for the light and medium duty fleets, the opportunity to create our own additive. And I was very happy to see further blend level flexibility for captive fleets as something that we can talk about. So thank you again. We really look forward to continued engagement as we finalize and implement this.

Just on another note, it's great to have our fuel recognized for its beneficial qualities. And we know that we do well under the low carbon fuel standard because we reduce greenhouse gases. But it's nice to hear you guys also recognize all the other benefits. We really look forward to bringing the health benefits to California as much as possible and especially the PM reductions that have been really noted -- Richard Corey mentioned this at our conference on February 4th saying that biodiesel is important for reductions in toxic diesel particular matter. So we do this already. We want to do it more. We want to help provide solutions in the communities that are most impacted that suffer the most from the diseases caused by diesel pollution. And a lot of our plants are located in these areas. So we're going to accomplish this by creating more good family supporting jobs. So thank you guys so much.

CHAIRPERSON NICHOLS: Thank you.

MR. NEAL: Thank you, Madam Chair and members of the Board.

Shelby Neal with the National Biodiesel Board representing the biodiesel and renewable diesel industries. We are not quite as excited to be headed to the gallows as the gentleman was this morning. But we are never the less excited.

We would like to thank the ARB Board and especially staff and particularly Richard Corey for really in my 17 years in and around government unprecedented level of focus and work on an extraordinarily dull topic. So thank you really all of you for doing that.

I'm no expert in business, but Warren Buffet it often says this, he says capital goes to where it can get the highest return with predictable risks. So it's the last clause in that sentence where we've had trouble. Predictable risk. But this regulation along with LCFS readoption fixes that.

So this should move our industry from survival mode, which is surviving is better than the alternative, but it's no way to live long term. So this should move us into a more comfortable area. And in 2023, or when we can develop an additive so-called solution which we are working on already, we can thrive and we can flourish in the state. I think we will.

I want to thank ARB staff for just doing an incredible job. We stated in our public comments that we didn't think this regulation was necessary in a perfect world. But that's not intended to be a criticism. ARB has a very different mission than our industry does or other scientists who look at this. And every step they took the most conservative path, the most protective of public health. We support that view. That's why we willingly accept these limitations. Thank you very much for your time.

CHAIRPERSON NICHOLS: Mr. Teall.

MR. TEALL: Russ Teall, Biodico and currently President of the California Biodiesel Alliance.

I will try not to repeat the things that have been already said. I agree with them entirely.

But the history of this goes back to 1993. That was our first meeting with the Air Resources Board to talk about biodiesel. It was brand-new at the time. And so it's been a 22-year journey up to this point. And is it perfect? It's as close to perfect as you can get. There's been a lot of give and take, back and forth. And the complexity of the regulation reflects a desire I think to get it right. You know, it's a complex topic. And in order to balance the needs of industry with the needs of the environment, I think it's a well crafted decision.

One point that needs to be made is that biodiesel substantially reduces air toxics, other than the criteria pollutants, all the polyaeromatic hydrocarbons, et cetera, we're the only fuel that's been through Tier 1 and Tier 2 health effect testing the U.S. EPA successfully. So that's a point that was recognized by staff.

Thirteen public meetings, seven ADF workshops, countless private meetings, phone calls, e-mails, I'm going to look forward to getting back to Santa Barbara at the end of this journey.

Other than thanking Richard, Floyd, and Jack have done a tremendous job, you know, transitioning Floyd in the beginning directing this entire process, setting a mood that was correct in terms of listening to industry, reacting. And I think as a two-way learning, we learn things along the way that about ARB and what the objectives are. And I think they learned as well.

So I guess in conclusion, we whole heartedly support the ADF program in part because of staff. You know, we know that staff is there. They're listening. And we look forward to continuing the dialogue during this 15-day notice period. Thank you.

CHAIRPERSON NICHOLS: Thank you.

Mr. Von Wedel.

MR. GERSHEN: I think Randall left.

Thank you again. At the risk of sounding a little repetitive, the development of this ADF regulation has been a challenging process. We appreciate ARB has been mindful of all the stakeholder interests.

As I'm sure you know by now, California biodiesel industry is made up of independent producers marketers, feedstock suppliers, a variety of stakeholder feedstock, all sizes and shapes. A big challenge has been to be inconclusive, and ARB staff has been very attentive to our needs and demonstrating the willingness to work with our industry to help develop a variety of compliance options. And we really do appreciate that. Thank you.

As mentioned in my prior comments, I'm confident that working together with ARB, California biodiesel can build on our successes. We look forward to continue working with you even more to reducing carbon emissions, lowering emissions, and creating high paying green jobs in disadvantaged community across the state. Thanks.

CHAIRPERSON NICHOLS: Lisa Morenton again.

MS. MORTENSON: Hello, Chairman Nichols and members of the Board.

I sincerely appreciate the opportunity to talk about the ADF. This is a very personal issue for me. I cannot count the number of sleepless nights that I have had during the twists and turns of the development of the ADF rulemaking. So this is very important to our industry.

As you know, biodiesel use in California has made a positive impact. It reduces harmful emissions and it also stimulates the economy. It's important to remember that biodiesel is an advanced biofuel that is proven. It's reliable. And it is available in commercially significant volumes. And it is our commercial success is why we are in the Stage 3 as a commercial fuel under the ADF rulemaking. So part of this is very positive. The commercial success of biodiesel have moved us into this new level of regulation.

Biodiesel does have strong public and bipartisan support, and that's because it has so many terrific benefits. It has wonderful performance benefits. It has very strong lubricity properties, which reduces wear and tear on engines, and it also has strong detergent properties.

It has terrific environmental benefits reducing harmful emissions which improve human health. And we heard from Lex Mitchell earlier that biodiesel lowers localized toxic exposure. That is so important to protect our most impacted communities. And it's also important to remember that the diesel engine is 20 to 30 percent more efficient than electric engine.

And we, of course, can't forget the economic benefits. Biodiesel creates jobs, revenues, and taxes. When you have in-state production such as what we do at Community Fuels, you're creating advanced manufacturing jobs, which have the highest multiplier effect of any industry. So biodiesel is really exciting and really good for California.

I ask you to put on your imagination cap and imagine if biodiesel were the typical diesel fuel used in California and petroleum diesel were trying to gain approval. Imagine how different that conversation would be.

We spoke about how biodiesel is ready to deliver significant volumes to California. The ADF proposal will impose limitations and constrain how biodiesel is used within the state. While I understand why the alternative diesel fuel rulemaking is necessary, I do request that CARB pay very close attention to this ADF rulemaking and to work hard to sunset this regulation at the earliest possible opportunity.

We want to grow biodiesel in California. We want to realize all the benefits that biodiesel has for this state. And to do that, we need more flexibility and higher volumes of biodiesel. And just quickly, I want to thank Mr. Corey for his personal involvement in this very important issue. He made a big impacts in the direction of this regulation. Thank you.

CHAIRPERSON NICHOLS: Okay. Thank you. Extra time always allowed for thanks.

MR. SIMPSON: Madam Chair and members of the Board. Harry Simpson with Crimson Renewable Energy, biodiesel producer here in California.

Obviously, we paid very close attention over this marathon process that we've gone through in getting to where we are today with the ADF regs. I think in our company was formed in '07, and I think some of the stuff started even before that.

So we would certainly like to thank Mr. Corey and Lex and Floyd and the many others who have been on this road to get us to the proposed regs today.

I know that sounds like a broken record, but you guys really do deserve a hand for that. You guys have consistently engaged with all the different stakeholders and that was certainly no easy feat. And your willingness to do it on a very regular basis and hear what everyone had to say went to I think what many of us would call a grand compromise in terms of the regs that we have before us today.

That compromise was the product of a lot of strong data, a lot of technical analysis, a lot of fighting back and forth as to how that shook out. In the end, I think you were able to acknowledge the significant health and carbon reduction benefits that biodiesel offers and reconcile that with any issues and the need to safeguard air quality in terms of NOx.

So while it's not ideal, we fully support it. And I think it provided much needed regulatory certainty.

Like Lisa said, I, too, have had many sleepness nights wondering if the close to $30 million we have invested in our plant is going to go up in smoke. And we get essentially regulated out of business.

So I'm happy to say that's not the case, and I think the community in which we in the state of California I think last year we contributed about $40 million directly into the economy. When we're done with our expansion, it will be $80 million in 2016. It's good to see that investment will continue to make a contribution and bring much needed carbon reduction benefits to the LCFS. Thank you. We support the regs.

CHAIRPERSON NICHOLS: Great. Mr. Barrett.

MR. BARRETT: Good afternoon. I'm Will Barrett with the American Lung Association of California.

And as noted in the letter that we submitted along with our colleagues that CERT, the Coalition for Clean Air, NRDC, we support the proposed diesel regulation. You'll hear from some of the other signors of that letter in a few minutes.

We believe the proposal successfully addresses the need for cleaner alternatives to harmful fossil fuels, with the need to ensure that no additional harm is caused by these alternatives as they come into the market or the market expands because of the potential for biodiesel to increase smog-forming NOx emissions under certain formulations or engine models or operating conditions put forward by CARB set to avoid backsliding on NOx is appropriate.

We also do appreciate that the proposal and Lex's presentation included compliance strategies to maximize the greenhouse gas and particulate benefits of buy diesel. We encourage ARB to explore additional opportunities to capture NOx neutral and NOX reducing particulate and carbon pollution benefits of this alternative.

The air pollution public health and health equity impacts of petroleum fuels are well documented and must continue to be addressed through strong regulations that get all fuels impacts on lung health in our climate. We believe the ADF proposal is an important step in this process of curbing many harmful pollutants at once and protecting the health of future generations of Californians. So I just wanted to add to the chorus and thank for the staff's work on this. And thank you all.

CHAIRPERSON NICHOLS: Great. Mr. Magavern.

MR. MAGAVERN: Bill Magavern, Coalition for Clean Air in support. I did not go through all the ins and outs of this long regulatory process. I have a lot of respect for those who did. I'm very impressed with the final result.

For years, we've had this tension. I think as we heard earlier today just, about everybody other than the oil companies wants to bring lower carbon fuels to market. And we need to reduce our reliance on petroleum so there are a lot of good arguments for alternative fuels.

At the same time, as air advocates, we want to make sure we're not unintentionally increasing any air pollutants. And of course, it's your mission to prevent that from happening. So I think that this balance has been struck and this regulation really achieves that. Petroleum diesel is a plague on our health, so let's bring on the biodiesel with the appropriate protections. Thank you very much.

CHAIRPERSON NICHOLS: Okay.

MR. DELAHOUSSAYE: Good afternoon. Dayne Delahoussaye representing Neste Oil. Neste Oil support supports the ADF regulation and and we're advocating the Board continue forward with it.

We're glad and proud that the findings of the NOx reductions agrees with our research and our experience as well. So we are supportive of California moving forward with that step.

The one technical comment I would point out and I made this in more detail in my written submissions for both the LCFS and the ADF because they tie together is the definitional language specifically when you're discussioning this fuel.

I believe one of them calls them non-renewable diesel. The other calls it renewable. At a minimum, encourage the same terminology for both of these funds referring to the same fuel.

Additionally, the ADF goes into great pains to describe -- the fuel they described was the hydrocarbon fuel. And so we would encourage as we're trying to develop a right technology for this and consistency that renewable hydrocarbon diesel be the term we're describing so we can avoid any confusion between different usage and different markets of other uses and that kinds of stuff. For example, some Canadian jurisdictions define renewable diesel as both hydro treated and biodiesel stuff. I think having a more clear definition of what it is renewable as opposed to what it's not non-ester renewable diesel being a more appropriate and simple definition for that kind.

And as well as then align the two definitions. They both have different public parts and things like that and there is a lot of overlap, but they're not unanimous. I would encourage being at least under the same division to have a definition that is in line and in agreement with each other. And you don't have two jurisdictions within the Air Resources Board playing that game. Other questions, I'm happy. Otherwise, thank you for your time.

CHAIRPERSON NICHOLS: Good point. Probably requires the equivalent of a spell check to be used. And make sure we use the same terms each time. Okay.

Mr. Hedderich.

MR. HEDDERICH: So 13 is much better than 45 or 46. Moving up in.

And I understand why, Chair Nichols, you pronounced my name correctly. It's misspelled. It ends in an H.

I'm not going to repeat the comments you heard from other folks. We're very supportive as the nation and north America's largest biodiesel producer and also a significant producer of renewable hydrocarbon biodiesel. Very supportive of all the comments that you heard. Agree there is some definitional issues we need to work out to make sure we're using the same language.

I was going to offer to Supervisor Roberts if he wants to see what the different plants look like, happy to show him. This has been a torturous process, I'll say. It needs to come to conclusion so our industry can move forward, so we can move forward with the LCFS, so we can have some certainty. Very much appreciate all the effort that staff did to bring this issue to closure. And with that, let's move forward and get closure. Thank you.

CHAIRPERSON NICHOLS: Okay. Thank you.

Mr. Mui.

MR. MUI: Good afternoon. Simon Mui with NRDC.

We also support the adoption of the ADF regulation. And like Bill Magavern, I've been on the periphery and following and reading.

But I do have to commend staff and management for really balancing the need to achieve the GHG reduction goals while mitigating any NOx issues. And we do think that ARB -- this is one great example where ARB has really ensured as we transition to new energy sources, we are managing the trade-offs.

So I really commend staff. And I know that often times industry may have sleepless nights. I can guess that ARB and staff has had sleepless nights. Maybe as a Resolution Richard can actually take a weekend off.

But I do want to say that this is reasonable. Our understanding is looking at the science that this is based on the best available technical studies and work. And we are very enthusiastically supporting this as maximizing both the LCFS and ADF together are really maximizing the public health benefits of these programs. Thank you.

CHAIRPERSON NICHOLS: Thank you.

And last, Mr. Fulks, from the Diesel Technology

Forum.

MR. FULKS: Madam Chair, Board members, always awesome to be batting cleanup, standing between you and going home. So I will be as brief as I possibly can.

The Diesel Technology Forum is not taking a position on ADF, but we did want to come in and acknowledge the professionalism, the courtesy, and the just plain decency of your staff in the development of not just the ADF, but also the LCFS. It's been a pleasure to work with your staff. I'm just piling on, I know.

I did want to take a yellow highlighter to the precedent-setting policy that you were engaging here with the ADF in that it is an acknowledgement that emission control systems for diesel engines will be used as a NOx mitigant for this fuel moving forward after 2018.

We did note that under the LEV III development process the notion of using fuel as a NOx mitigant for vehicle hardware was never even allowed to be considered. So this is a precedent-setting policy change that we will be taking note of as we move into the future trying to reach the Governor's 50/50/50 by 30 goals. We're going to be relying on diesel for a while to get some of these fuel economy gains.

And as there may be a clash between those goals and the ultra low NOx rule that is a voluntary rule now but may be coming back to you as a mandatory measure. So therefore, I just wanted to plant the seed that now that the precedent has been established that you can use hardware to mitigate NOx from fuel, it may come back to you some day that maybe perhaps we can consider using fuel as a NOx mitigant for hardware down the line.

So thank you for your attention. And again tip of the hat to your staff.

CHAIRPERSON NICHOLS: Well, it's an interesting comment, but I'm not really buying it.

MR. FULKS: I'll put it in the record anyway.

CHAIRPERSON NICHOLS: I'll tell you why, because I think that there is a lot of precedent for recognizing that emissions occur when fuel is used in an engine. And when you're projecting emissions, you have to look at what the engine is doing as well as what the fuel is doing.

So I don't think that position that the staff has taken here -- and I could be corrected on this -- is that the new vehicle standards are a mitigation for the fuel any more than the fuel is a mitigation for the engines when we're certifying engines. We certify engines based on a type of fuel that we assume is going to be in the marketplace. And this is the same thing in reverse.

MR. FULKS: Understood. We wanted to open the dialog as we move forward with ultra low NOx.

CHAIRPERSON NICHOLS: Always good to see you. Mr. Corey needed another round of thanks. That's great. Thank you.

Okay. That's it for the witness list. And are there any additional comments by the Board? Question, Mr. Dr. Sperling.

BOARD MEMBER SPERLING: I'm not speaking as a Board member yet. As a scientist, I look at Table 12 and I see these are really very small differences when you take into account we're talking about 50, 90, 95 percent reductions otherwise. So are there -- there's uncertainty. There has to be a lot of uncertainty here. So I'm wondering if I was looking as a scientist, I would say, okay, what are the confidence intervals here. What's probablistically, what are we talking about here. But one percentage? Two percentage? I know there is judges involved and that stuff. So that's why you I'm asking this as a scientist first.

MANAGER MITCHELL: I can parrot some of what we put in the staff report. We did do an ARB staff level statistical analysis and we commissioned a statistical analysis from an independent researcher, and they both found basically that we've got these results are statistically significant.

BOARD MEMBER SPERLING: At what level? At 90 percent?

MANAGER MITCHELL: Generally, we look if you want to, P values of .05 or less.

BOARD MEMBER SPERLING: Yeah. Okay. I had to ask that.

CHAIRPERSON NICHOLS: What does that lead you to think?

BOARD MEMBER SPERLING: That it's unfortunate we got to put it. We created this complex set of rules and, you know, burdens on companies. And it's a small effect. And I know, you know, we don't want to be -- our goal is to reduce NOx, not to increase it. But it really is a tiny amount, and it's not even relevant to anything except old engines. We've created this complex rule. So I'm kind of holding my -- I'm trying to accept it because I know we need to do it or that's my understanding because of lawsuits. But as public policy, it's kind of questionable.

CHAIRPERSON NICHOLS: Well, it's what happens when you get mixed up with CEQA.

BOARD MEMBER SPERLING: I know. That's why I don't want to be part of the next lawsuit either.

CHAIRPERSON NICHOLS: But it is -- isn't just lawsuits. But it is the law actually that requires that we be able to say with more certainty than you might like that it will not be an increase in NOx as a result of what we're doing. That's a hard thing to prove, I know.

BOARD MEMBER SPERLING: I'll say one last thing. You could look at electric vehicles and say some -- I'm not going to go there.

CHAIRPERSON NICHOLS: You're not going there. You can think whatever you like.

Ms. Mitchell.

BOARD MEMBER MITCHELL: Thank you.

I also wanted to thank staff for working on this. And Jack Kitowski, I know he put a lot of time in it. And as you all know for South Coast, it's really important that we prevent further NOx -- increases in the NOx emissions. We have a fairly daunting task ahead of us for 2016 AQMP and our reductions that are needed by 2023 and 2032. I talked about it many times sitting on this Board. So this was a hard thing to do.

It does result in some complexity, but I think staff did a really good job working it out. And I know they worked very closely with staff at South Coast to iron out all the little wrinkles in this to get to a point where it's acceptable and will help South Coast reach the targets that we have to reach. So thank you for all the work that you've put in on it.

CHAIRPERSON NICHOLS: Thank you.

BOARD MEMBER BERG: I'd like to just make one observation as I was listening to the testimony and the regulated community, it really came to mind as I look at this and saw all of the support and the accolades for staff, but actually the accolades for the industry, because I did hear how challenging -- it was a marathon. It was torture. It's not ideal. It caused sleepless nights. And then from the environmental of our NGO friends that, you know, the tension of finding balance, the managing of trade-offs. And all of this very rarely produces a public testimony sheet of all support. And it made me think, you know, a roomful of an entrepreneurs and a roomful of people that really want to get the job done, this is what it looks like. So congratulations.

CHAIRPERSON NICHOLS: Okay. With that, did you properly close the record or did I never do that? Well, I should have.

The record is closed for this agenda item, but again, it's going to be reopened when the 15-day notice of public availability is issued.

So once again, we will not be receiving comments after today on this item. But after the 15-day notice there will be an opportunity for comment on the 15-day notice items. And they will be responded to in the Final Statement of Reasons for the regulation, which will also come back to the Board. And we're planning on doing these again in tandem so this rule accompanies the low carbon fuel standard rule and that will keep everything neat. So

we have a before us resolution Number 15-5. And do I have a motion?

BOARD MEMBER BERG: So moved.

BOARD MEMBER SHERRIFFS: So moved.

BOARD MEMBER RIORDAN: A second.

CHAIRPERSON NICHOLS: A second, Mrs. Riordan.

All in favor, please say aye.

(Unanimous aye vote)

(Dr. Balmes not present at vote)

CHAIRPERSON NICHOLS: Any opposed? Any abstentions? Okay. Great. Good work.

This really is a culmination of a lot of work, but it isn't over. There's more still to be done. But we're well on our way. So thanks to all. Before we can adjourn, we do have to make time for any public comment. There's no general public comment today. All right. Then we are adjourned.

BOARD MEMBER GIOIA: Chair Nichols, I certainly would be remiss given the team of today's hearing thanking Mr. Corey on several accounts. I want to add to that at the previous meeting last month staff gave a very detailed presentation on our 2015 priorities which I think we all appreciated.

I made the comment after the presentation and I think it was some public testimony that it would be nice to see some accounting of what we are doing to advance environmental justice kind of cross-pollinated across all the programs and rulemakings and the policies that deal with the Air resources Board. I just wanted to thank them because I'm in receipt of a slide he took it very seriously and sent me a slide doing exactly what I had suggested.

So I wanted to thank you, Richard, for doing that and I think it demonstrates how serious not just Richard but all of our staff take that particular aspect of what we do here.

BOARD MEMBER GIOIA: Can you send that slide to all of us, Richard?

EXECUTIVE OFFICER COREY: Will do. It will be posted as well.

CHAIRPERSON NICHOLS: Oh, good. Everybody will be able to take advantage of it. Thank you all. Safe travel.

(Whereupon the Air Resources Board adjourned at 4:06 p.m.)

CERTIFICATE OF REPORTER

I, TIFFANY C. KRAFT, a Certified Shorthand Reporter of the State of California, and Registered Professional Reporter, do hereby certify:

That I am a disinterested person herein; that the foregoing hearing was reported in shorthand by me, Tiffany C. Kraft, a Certified Shorthand Reporter of the State of California, and thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said hearing nor in any way interested in the outcome of said hearing.

IN WITNESS WHEREOF, I have hereunto set my hand this 4th day of March, 2015.

____

TIFFANY C. KRAFT, CSR, RPR
Certified Shorthand Reporter
License No. 1227

1_T_LCFS_TOlson

743. Comment: **LCFS T1-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

2_T_LCFS_TTaylor

744. Comment: **LCFS T2-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

3_T_LCFS_MMiyasato

745. Comment: **LCFS T3-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

4_T_LCFS_MPaserro

746. Comment: **LCFS T4-1**

The comment supports the re-adoption of the LCFS regulation and looks forward to contributing to future development of certification requirements.

Agency Response: ARB thanks the commenter for the support, and looks forward to working on future regulatory improvements.

5_T_LCFS_GGrey

747. Comment: **LCFS T5-1**

The comment contends that the LCFS regulation is an attempt to satisfy too many objectives, and misses the original goal.

Agency Response: ARB disagrees. The goal of the LCFS regulation continues to be the same, namely to reduce the carbon intensity of transportation fuels used in California by at least ten percent by 2020 from a 2010 baseline, thereby reducing greenhouse gas emissions, among other benefits. The basic framework of the LCFS is working and will continue. The primary objective of the proposed revisions to the current LCFS are to clarify, streamline, and enhance certain provisions of the regulations. The goal of the LCFS regulation to reduce the carbon intensity of transportation fuels is still the driving force informing this rulemaking.

748. Comment: **LCFS T5-2**

The comment alleges that the credit generating measures and the cost containment mechanism are not necessary to meet the program's original objectives.

Agency Response: Please see responses to **LCFS T5-1** regarding additional credit-generating mechanisms, and **LCFS 32-9**, **LCFS 37-11**, **LCFS 38-3**, **LCFS 40-14**, **LCFS 40-16**, and **LCFS 40-18** regarding the cost containment mechanism.

749. Comment: **LCFS T5-3**

The commenter states that the compliance schedule is infeasible.

Agency Response: The schedule is feasible. Please see responses to **LCFS 38-1**.

750. Comment: **LCFS T5-4**

The comment argues that there is a risk that credit costs must rise in order for the program to be effective, and that duplicate accounting may be taking place in other states that embrace the LCFS regulation.

Agency Response: The price cap provides an upper bound on the potential cost of credits, and should not be construed as a projection of future credit prices or as a projection of future cost of compliance. ARB does not project future credit prices.

Even with a series of conservative assumptions informing the economic analysis, the results indicate that with an illustrative credit price of $100 LCFS encourages the production and consumption of innovative, low-CI transportation fuels. Historically, the volumes of low-CI fuels consumed in California indicate a strong market response to the regulation stimulating demand for low-CI fuels. The LCFS has been continuously implemented in California since 2010, and regulated parties have generated more credits than needed every year at prices much lower than $200. Since 2010, the production of low-CI fuels has increased in response to the financial incentives provided by the existing LCFS regulation. Many innovative, low-CI fuel technologies have moved past the demonstration stage, and have overcome techno-economic challenges that have in recent years limited the supplies of innovative, very-low CI fuels such as cellulosic ethanol, renewable diesel, and renewable natural gas. Staff analysis indicates that the supplies of low-CI fuels in future years will continue to exhibit the existing trend of increasing production.

751. Comment: **LCFS T5-5**

The comment questions whether or not the LCFS regulation has been successful.

Agency Response: The LCFS is working as designed and intended. To date, more than 155 active entities have registered for reporting in the LCFS Reporting Tool, and since the regulation went into effect, regulated parties have successfully operated under the LCFS program. Furthermore, fuel producers are innovating and achieving material reductions in their fuel pathways' carbon intensity, an effect the LCFS regulation is expressly designed to encourage. Credits have been generated from ethanol (60 percent), renewable diesel (15 percent), biodiesel (13 percent), natural gas (ten percent), and electricity (two percent). Despite the standards being frozen at one percent, the regulated parties are still over-complying, which is reflected in the amount of excess credits (4.33 million by the end of the fourth quarter of 2014) that have been generated.

752. Comment: **LCFS T5-6**

The comment states that the fluctuation of the LCFS credit costs should not be considered a success.

Agency Response: The value of the LCFS credit does not define the success of the program. Instead, achieving the goals as outlined in Executive Order S-01-07 (2007) is the aim of the regulation. However, the fact that credits have exceeded deficits in every compliance period of the program and that there is activity in the credit market are indicator of a successful working policy.

753. Comment: **LCFS T5-7**

The commenter requests that the Board require ongoing staff reviews of the LCFS regulation on an annual basis that would allow stakeholder input.

Agency Response: See response to **LCFS 38-2**.

754. Comment: **LCFS T5-8**

The comment asks that no further effort be made to create post-2020 LCFS targets.

Agency Response: See response to **LCFS 5-2**.

6_T_LCFS_HClay

755. Comment: **LCFS T6-1**

The comment supports the re-adoption of the LCFS regulation and expresses concerns with how the LCFS regulation is administered, with regards to technology neutrality and maintaining regulatory stability.

Agency Response: The proposed LCFS is a fuel-neutral, performance-based regulation that allows regulated parties to find the most cost-effective approaches to compliance. The proposed regulation provides the incentive structure to foster the low-CI fuels market; individual business decisions and the economics of producing the low-CI fuels will determine where the resultant increases in supplies come from.

As set forth in the ISOR, and its appendices and references, ARB has relied on the best available economic and scientific analyses it could find (or perform, in instances where no prior researcher had addressed a particular topic).

The direct CI values are provided by the GREET-2.0 model and were updated for this rulemaking to account for the additional information obtained since the 2009 rulemaking.[55] These direct CI values will only change if and when the GREET model is updated which has only occurred once since the beginning of the LCFS program. To the extent that the GREET model needs to be updated, ARB will undertake another regulation to update the

[55] See page ES-5 of Staff Report for additional information.

model. ARB agrees that stability is desirable, and has no plans to change CI scores lightly or frequently.

7_T_LCFS_MSolecki

756. Comment: **LCFS T7-1**

The commenter supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

8_T_LCFS_MHeller

757. Comment: **LCFS T8-1**

The commenter states that it is impossible to meet the goals for the LCFS regulation given the availability and blending constraints of alternative fuels and the complexity of the LCFS regulation.

Agency Response: The schedule is feasible. Please see responses to **LCFS 38-1**. The compliance schedule included in the regulation was explicitly designed to enable over compliance in the 2016 to 2018 period so that sufficient credits can be accumulated and banked for later year use. ARB staff agrees that some companies may desire to carry substantial amounts of banked credits to ensure future compliance or lower the credit costs they might otherwise encounter. Unlike the commenter, who sees banking as a sign that LCFS is not sustainable, ARB sees credit purchases and banking as a market force to spur innovation and production of low CI fuels.

758. Comment: **LCFS T8-2**

The commenter states that the overreliance on banked credits to meet future obligations is flawed.

Agency Response: See response to **LCFS 38-1**.   ARB also recognizes that the estimate of credit generation in the second half of 2014 was lower than projected in the ISOR, but disagrees with the commenter's pessimistic interpretation. Staff has reassessed the feasibility of the compliance curve in light of 2014 results and found that the prospects for compliance with the 10 percent standard in 2020 are not impacted in any significant manner.

759. Comment: **LCFS T8-3**

The commenter recommends that ARB staff set the compliance schedule based on alternative assumptions of fuel availability and blending capabilities, allowing extra credits to be used for compliance margin in the hedge of future shortages.

Agency Response: See response to **LCFS 38-1**.

760. Comment: **LCFS T8-4**

The commenter states that there are limitations to the Refinery Investment Credit provision that they have provided in written comments.

Agency Response: See response to **LCFS 38-7**, **LCFS 38-9**, **LCFS 38-10**, **LCFS 38-11**, **LCFS 38-12**, and **LCFS 38-13**.

9_T_LCFS_NEconomides

761. Comment: **LCFS T9-1**

The commenter states that the development of lower CI fuels has not proceeded as originally envisioned and that the compliance schedule should be modified.

Agency Response: ARB staff provided extensive information in the ISOR on the potential volumes of low CI fuels that are expected to be available over the next ten years and does not concur with the claim that the 2020 compliance targets are higher-than- achievable. See response to **LCFS 38-1**.

762. Comment: **LCFS T9-2**

The commenter states that the 2020 target of 10 percent reduction is aspirational.

Agency Response: See response to **LCFS 38-1**.

763. Comment: **LCFS T9-3**

The commenter states that the LCFS regulation's goals deny the regulated community the strategy and certainty that is needed to move forward.

Agency Response: See response to **LCFS 38-1**.

10_T_LCFS_MHicks

764. Comment: **LCFS T10-1**

The commenter supports the LC/LE refinery provision.

Agency Response: ARB staff appreciates the support for the LC/LE provision.

765. Comment: **LCFS T10-2**

The commenter supports the refinery-specific incremental deficit option.

Agency Response: We acknowledge the commenter's support for the refinery-specific incremental deficit option.

766. Comment: **LCFS T10-3**

The commenter supports the Refinery Investment Provision

Agency Response: ARB staff appreciates the support for the Refinery Investment provision.

11_T_LCFS_DDelahoussaye

767. Comment: **LCFS T11-1**

The commenter supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

768. Comment: **LCFS T11-2**

The commenter requests that ARB staff use re-adoption as a springboard to discuss and formulate longer-term targets.

Agency Response: See response to **LCFS 5-2**.

769. Comment: **LCFS T11-3**

The commenter states that timely processing and approval of a complete pathway application is important to the success of the LCFS regulation.

Agency Response: See response to **LCFS 61-2**.

770. Comment: **LCFS T11-4**

The commenter encourages the Board to work with ARB staff to include an approval process to provide new fuels with a prompt CI score.

Agency Response: See response to **LCFS 61-2**.

771. Comment: **LCFS T11-5**

The comment recognizes that some parties may feel that there are issues with availability of RD, and encourages the board to disregard that opinion.

Agency Response: Staff's opinions about the availability Renewable Diesel (RD) are expressed in Appendix B of the Initial Statement of Reasons. Further, see response to comment **LCFS 38-6.**

772. Comment: **LCFS T11-6**

The commenter states that labeling solutions for renewable diesel can be achieved without causing detriment to the 2020 goals.

Agency Response: Staff agrees with the commenter. In the Alternative Diesel Fuel Initial Statement of Reasons, we identified several ways that renewable diesel use in the State could increase within the confines of the labeling requirements, including some pathways that would be low to no cost and would not require any regulatory changes.

773. Comment: **LCFS T11-7**

The commenter states that the price cap seems arbitrary in absence of a federal program. However it will work until 2020, needing re-evaluation after that point.

Agency Response: Please see the response to comment **LCFS 6-4.**

12_T_LCFS_GGrimes

774. Comment: **LCFS T12-1**

The comment supports the Low Complexity/Low Energy use provision in the LCFS regulation.

Agency Response: ARB staff appreciates the support for the proposed Low Complexity/Low Energy Use provision.

775. Comment: **LCFS T12-2**

The commenter states that it is important to get the eligibility criteria right for the LC/LE provision.

Agency Response: See response to **LCFS B5-1**, **LCFS FF9-6**, and **LCFS FF9-8**.

776. Comment: **LCFS T12-3**

The commenter asserts that the Alon refinery will emit less GHGs than the average refinery in California.

Agency Response: See response to **LCFS B5-1**.

13_T_LCFS_CDuBose

777. Comment: **LCFS T13-1**

The comment supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

14_T_LCFS_JCase

778. Comment: **LCFS T14-1**

The comment supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

15_T_LCFS_SNeal

779. Comment: **LCFS T15-1**

The comment supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

16_T_LCFS_RTeall

780. Comment: **LCFS T16-1**

The comment supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

17_T_LCFS_JLevin

781. Comment: **LCFS T17-1**

The comment urges the Board to re-adopt the LCFS regulation and to continue to invest in natural gas vehicles and infrastructure.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS.

18_T_LCFS_JMendoza

782. Comment: **LCFS T18-1**

The comment directs ARB staff to ensure that the CA-GREET model is based on the best available data.

Agency Response: ARB staff shares with the commenter a desire to continue basing the CA-GREET model on the best available scientific data. Maintaining a technically sound scientific basis for the LCFS continues to be one of our highest priorities.

783. Comment: **LCFS T18-2**

The commenter requests an avenue for stakeholder engagement during the ongoing process, presumably referring to the period between the first and second board hearing.

Agency Response: ARB is and has been committed to engaging in a robust public process to develop the most effective regulation. Between the February and September 2015 Board Hearings, staff conducted a public workshop to discuss changes to the CA-GREET 2.0 model and continued its collaboration with stakeholders.

784. Comment: **LCFS T18-3**

The commenter hopes that ARB staff and stakeholders continue to engage in future discussions regarding the LCFS regulation.

Agency Response: Staff acknowledges the comment and is committed to an extensive public process to develop and implement the LCFS regulation.

19_T_LCFS_MPlummer

785. Comment: **LCFS T19-1**

The commenter supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

20_T_LCFS_CWright

786. Comment: **LCFS T20-1**

The commenter supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

21_T_LCFS_JO'Donnell

787. Comment: **LCFS T21-1**

The commenter supports the innovative crude provision and the re-adoption of the LCFS regulation and discusses some of the economic benefits.

Agency Response: ARB staff appreciates the support for the proposed innovative crude provision.

22_T_LCFS_RNakasone

788. Comment: **LCFS T22-1**

The commenter supports re-adoption of the LCFS regulation particularly refinery investment provisions.

Agency Response: ARB staff appreciates the support for the proposed refinery investment provision.

23_T_LCFS_SUnnasch

789. Comment: **LCFS T23-1**

The commenter supports the LCFS program and discusses marginal electricity uses.

Agency Response: Staff appreciates Life Cycle Associates' support of proposed LCFS regulation. Please also see responses to **LCFS 62-1** and **LCFS 65-1**.

24_T_LCFS_CWhite

790. Comment: **LCFS T24-1**

The commenter supports re-adoption of the LCFS regulation and requests more certainty for investors. He also states that they can produce a significant amount of fuel for less than $200 per ton.

Agency Response: Staff is analyzing the potential benefits of a price floor to send a stronger price signal to increase investments in low-CI fuels and to further reduce market uncertainty and credit price volatility. Staff appreciates the ongoing dialogue with, and feedback from, stakeholders regarding whether this topic should be proposed as a future LCFS amendment.

791. Comment: **LCFS T24-2**

The comment supports the ARB continuing to evaluate the natural gas CI values.

Agency Response: ARB staff has made adjustments to the natural gas CI values as part of a 15-day change.

792. Comment: **LCFS T24-3**

The commenter supports re-adoption of the LCFS regulation, but encourages ARB staff to consider a price floor provision.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS. With regards to the price floor, see response to **LCFS 6-5**.

793. Comment: **LCFS T24-4**

The commenter reminds ARB staff to use best available data to support any CI value updates.

Agency Response: ARB staff makes every effort to both base our CIs on the best available science and to consistently conduct our lifecycle analyses in an objective, uniform, and fuel-neutral manner.

25_T_LCFS_TDarlington

794. Comment: **LCFS T25-1**

The commenter disagrees with the land use change emissions factor by ARB staff for corn starch ethanol.

Agency Response: See response to **LCFS 8-1**.

795. Comment: **LCFS T25-2**

The commenter claims that ARB staff has not considered significant issues raised in technical literature and by stakeholders.

Agency Response: The current approach used by ARB is appropriate since it uses the most current data and the latest modeling structure. Any specific issues that were not considered for the current analysis were either due to lack of detailed data or because modeling structure did not allow for the inclusion of a particular effect.

796. Comment: **LCFS T25-3**

The comment states that the current economic model used by ARB staff does not include double or multi-cropping.

Agency Response: See responses to **LCFS 46-102**, **LCFS 46-112, LCFS 46-114**, **LCFS 8-5** and **LCFS 8-10**.

797. Comment: **LCFS T25-4**

The commenter states that the current GTAP model should account for idle and fallow land as well as multi-cropping.

Agency Response: The claim that idle/fallow land should be accessed by GTAP land pool is questionable. See responses to **LCFS 8-5**, **LCFS 46-83**, and **LCFS 46-113**.

798. Comment: **LCFS T25-5**

The comment alleges that the inflated iLUC emissions will lead to high CI values for corn ethanol fuels and a reduction in corn ethanol us with no emission benefits.

Agency Response: ARB does not agree with commenter that the analysis conducted inflated iLUC emissions. See response to **LCFS 8-1**, **LCFS 29-2**, and **LCFS 46-216**.

With respect to concerns about fuel shuffling, see response to **LCFS 46-40**.

26_T_LCFS_JDavid

799. Comment: **LCFS T26-1**

The commenter discusses their economic analysis of expected behavior of the Midwestern corn ethanol market as it relates to CI values and Brazilian sugar cane imports.

Agency Response: The LCFS program is designed to encourage reductions in the overall CI of transportation fuels. Corn ethanol plants in particular have been successful in changing their practices to reduce the CI at their facilities. While this comment presents two static alternatives, the world post-regulation is dynamic and will likely yield very different results. For instance, the CI values presented in this comment are much higher than the values that will be realized post-regulation as the land use CI for corn ethanol is much lower in the current proposal.

Over time we are seeing that the value of credits appears to be leading to lowering of CI values for many alternative fuels. The regulation will further incentivize reductions, especially as the required CI reduction increases over time. The more strict the standard, the higher the value on the low-CI fuels, and the larger the incentive for investment in reducing the CI values for all fuels. Additionally, the Midwestern corn ethanol plants could lower their CI by using innovative strategies, for example Poet[56] who put in an application for a facility-specific CI based upon their diversion of methane from a city landfill to power their ethanol plant. This large infrastructure cost is estimated to give them a CI of 63.88 for corn ethanol (and with the new land use values, this could potentially be

[56] http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/poet-cha-sum-022014.pdf

less than 53). Corn ethanol plants that invest in cleaner energy will be able to compete more easily in California.

800. Comment: **LCFS T26-2**

The commenter states that the switch to cane ethanol from corn ethanol may occur at lower than expected credit prices.

Agency Response: This is the result of the commenter's analysis that does not constitute an objection or recommendation on the proposal.

801. Comment: **LCFS T26-3**

The commenter agrees that ARB's illustrative scenario is plausible with regard to corn ethanol and sugar cane ethanol and expresses concern that the Midwest corn ethanol industry may be at great risk of losing the ability to participate in the California market.

Agency Response: See response to **LCFS 46-27** and **LCFS 46-28**.

27_T_LCFS_HSimpson

802. Comment: **LCFS T27-1**

The commenter expressed support for the proposed timeline.

Agency Response: ARB staff appreciates the support for the compliance curve.

803. Comment: **LCFS T27-2**

The commenter states that keeping the current compliance schedule is critical and that the Board should consider ongoing reductions beyond 2020.

Agency Response: ARB staff appreciates the support for the proposed timeline. With regard to post-2020 reductions, see response to **LCFS 5-2**.

28_T_LCFS_TCampbell

804. Comment: **LCFS T28-1**

The commenter supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

805. Comment: **LCFS T28-2**

The commenter states that it is critical for ARB staff to correctly determine CI numbers for renewable natural gas. They also add their willingness to work with staff toward that goal.

Agency Response: ARB staff also looks forward to continued participation and would like to maintain an open collaborative public process. ARB staff makes every effort to base our CIs on the best available science.

29_T_LCFS_JLewis

806. Comment: **LCFS T29-1**

The commenter states that while achieving compliance with the 2020 target would be challenging the LCFS regulation remains the most promising policy available for reducing climate impacts in the transportation sector.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

807. Comment: **LCFS T29-2**

The comment alleges that choosing which data sets to use or exclude in a life cycle model is a subjective exercise.

Agency Response: ARB does not agree with commenter that the use of data sets and inputs are subjective exercises. In the current analysis, ARB evaluated all available data and used data as appropriate within the current modeling limitations. The ARB proposed carbon intensity (CI) targets and standards for biofuels are designed to be fuel neutral. In other words, all biofuels including corn ethanol, sugarcane ethanol, sorghum ethanol, soy oil biodiesel, canola biodiesel, and palm oil biodiesel have the opportunity to contribute to LCFS and their CI is estimated using the same methodology. The adjustments to the carbon intensity (CI) of corn ethanol as well as the adjustments for other biofuels are based on the latest and improved modeling analysis.

ARB recognizes that some effects such as from fertilizers, reforestation related to forest products using the current structure for forest land cover, food security, etc. have the potential to increase iLUC values for biofuels. Limitations related to the structural aspects of the GTAP model and lack of comprehensive data did not allow ARB to consider modeling some of these effects related to the items detailed above. When detailed data becomes available and relevant structural modifications to the GTAP model can be accomplished, the impacts of such effects on iLUC values will be considered.

The non-inclusion of food effects is not a subjective decision. The model as currently structured has limitations and it does not allow a detailed evaluation of the impacts of biofuels on global food security. To evaluate such effects we must collect and include in the analysis, data for calorific content of food and feed production, and the modeling structure needs to be modified accordingly. When these data become available and are collected, future revisions of the model would allow the evaluation of global food security effects and the effect will be incorporated into the iLUC analysis. See also responses to **LCFS 8-1**, **LCFS 29-3**, **LCFS T29-3**, and **LCFS T29-4**.

808. Comment: **LCFS T29-3**

The commenter claims that reducing the iLUC score for corn ethanol undermines the objectives of the LCFS regulation.

Agency Response: ARB does not agree with commenter that the current analysis is likely to undermine the LCFS by over reliance on corn ethanol to comply with the regulation. ARB's approach is based on performance standards and is fuel-neutral. Corn ethanol or other fuels are evaluated on the basis of GHG emissions potential and their participation in the program is based on carbon intensity values. To specifically address the comments, ARB has detailed below:

1. *The reason for deferring the consideration of food security*.

   The adjustments to the carbon intensity (CI) of corn ethanol as well as the adjustments for other biofuels are based on the latest and improved modeling analysis. Please see response to **LCFS 35-4** on the reason to defer the food issue.

2. *Non-reliance on corn ethanol for compliance, particularly as the standard gets stricter starting 2016-2017*.

   The use of corn ethanol as part of the compliance strategy does not undermine the LCFS targets. The ARB proposed carbon intensity (CI) targets and standards are designed to be fuel neutral. See also responses to **LCFS 8-1**, **LCFS 29-2**, **LCFS 29-3** and **LCFS T29-2**.

809. Comment: **LCFS T29-4**

The commenter requests that the Board resist any proposal to reduce the CI value for corn ethanol.

Agency Response: ARB does not agree with commenter that the iLUC value changes in the current proposal should be postponed. ARB's analysis represents the culmination of several years of refinements to the iLUC analysis originally proposed in 2009. The current analysis uses the latest data and updates to land use science and represents the best estimate for iLUC value for corn ethanol and 5 other biofuels considered for this rulemaking. See also response to **LCFS 8-1** and **LCFS 29-2**.

30_T_LCFS_Phillips

810. Comment: **LCFS T30-1**

The commenter requests ARB staff to factor in the marginal displacement of electricity cogeneration by sugarcane mills in Brazil.

Agency Response: See response to **LCFS B1-2**.

811. Comment: **LCFS T30-2**

The commenter requests that ARB staff account for double cropping in Brazil in the iLUC score for cane ethanol. The commenter also supports re-adoption of the LCFS regulation.

Agency Response: ARB recognizes support offered by the commenter to readopt the LCFS regulation. Regarding double cropping, see responses to **LCFS 8-1, LCFS 8-9, LCFS 8-10** and **LCFS B1-3**.

31_T_LCFS_TKoehler

812. Comment: **LCFS T31-1**

The commenter supports both the re-adoption of the LCFS regulation and the development of further requirements beyond 2020.

Agency Response: See response to **LCFS 5-2**.

813. Comment: **LCFS T31-2**

The commenter requests that ARB staff incorporate recently released data regarding actual land use change over the last ten years into the GTAP model.

Agency Response: The iLUC analysis as currently proposed by ARB is based on the latest and best available scientific and economic information. ARB is aware of the proposed study to calibrate the GTAP model using new data. When this study is completed, ARB will conduct a comprehensive review and consider refinements if warranted. See also response to **LCFS 8-5**.

32_T_LCFS_BHolmes-Gen

814. Comment: **LCFS T32-1**

The commenter directs ARB staff to update the biorefinery guidance document.

Agency Response: See response to **LCFS 42-17**.

33_T_LCFS_TCarmichael

815. Comment: **LCFS T33-1**

The comment supports the re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

816. Comment: **LCFS T33-2**

The commenter requests that ARB staff add a statement to the Resolution, requiring ongoing communication between staff and stakeholders.

Agency Response: In response to Board direction in Resolution 15-6, as well as this comment and other similar requests for further dialogue from the natural gas vehicle coalition, staff held a workshop on March 3, 2015 to discuss natural gas carbon intensity and other CA-GREET model adjustments.

34_T_LCFS_DCox

817. Comment: **LCFS T34-1**

The commenter stresses the importance of having a process to deal with cost containment for the LCFS regulation.

Agency Response: Please see response to **LCFS T33-2**.

818. Comment: **LCFS T34-2**

The commenter requests a continued commitment by ARB staff to fuel neutrality and ensuring the CA-GREET model is driven by sound data.

Agency Response: ARB staff's commitment to high quality technical data and to fuel neutrality will continue to be unwavering.

819. Comment: **LCFS T34-3**

The commenter supports the $200 credit price cap and suggests that ARB staff also incorporate a price floor.

Agency Response: See response to **LCFS 6-5**.

35_T_LCFS_JBarbose

820. Comment: **LCFS T35-1**

The comment states support for continued efforts to decrease carbon emissions to meet the 2050 goal of 80 percent reductions.

Agency Response: See response to **LCFS 5-2**.

821. Comment: **LCFS T35-2**

The commenter states that the LCFS is a critical element of California's approach to reducing GHG emissions while continuing to thrive economically.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation**.**

822. Comment: **LCFS T35-3**

The commenter supports the proposal of ARB staff, to update the life cycle analysis.

Agency Response: ARB staff appreciates the support for the proposed update to the life cycle analysis.

823. Comment: **LCFS T35-4**

The comment supports the addition of the innovative crude and refinery provision.

Agency Response: ARB staff appreciates the support for the proposed innovative crude and refinery investment provisions.

824. Comment: **LCFS T35-5**

The comment supports the addition of the cost containment mechanism.

Agency Response: ARB staff appreciates the support for the proposed cost containment provision.

825. Comment: **LCFS T35-6**

The comment states that in order to ensure investment in the cleanest fuels it is important to establish regulatory stability out beyond 2020.

Agency Response: See response to **LCFS 5-2.**

36_T_LCFS_LMortenson

826. Comment: **LCFS T36-1**

The comment states that the LCFS regulation is essential to force the existing infrastructure to incorporate higher volumes of clean fuel.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

827. Comment: **LCFS T36-2**

The comment states that industry needs regulatory certainty to perform long-term trajectory planning and investment.

Agency Response: Staff acknowledges the comment and anticipates that re-adoption of the LCFS will provide regulatory certainty. In addition to proposing to re-adopt the entire regulation, staff has proposed a suite of updates and revisions compared to the current regulation to provide a stronger signal for investments in, and production of, the cleanest fuels, offer additional flexibility, and update critical technical information, among other things.

828. Comment: **LCFS T36-3**

The comment supports re-adoption of the LCFS regulation and encourages evaluation of possible requirements beyond 2020.

Agency Response: See response to **LCFS 5-2.**

37_T_LCFS_JGershen

829. Comment: **LCFS T37-1**

The comment supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

38_T_LCFS_CMurphy

830. Comment: **LCFS T38-1**

The comment supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

831. Comment: **LCFS T38-2**

The comment supports the proposed cost containment provision.

Agency Response: ARB staff appreciates the support for the proposed cost containment provision.

832. Comment: **LCFS T38-3**

The comment states there should be a price floor to go along with the price ceiling.

Agency Response: See response to **LCFS 6-5**.

833. Comment: **LCFS T38-4**

The comment suggests that CI updates should follow a regular and systematic mechanism of review.

Agency Response: ARB staff concurs with commenter on the need to account for new scientific and technological advances for CI calculations. To do so, ARB staff is proposing to update the CA-GREET-2.0 model at predictable intervals – no more frequently than every three years. We will continue to thoroughly analyze and incorporate the best scientific data.

39_T_LCFS_SFrank

834. Comment: **LCFS T39-1**

The comment supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

40_T_LCFS_SMui

835. Comment: **LCFS T40-1**

The comment supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

836. Comment: **LCFS T40-2**

The comment states that the 2020 targets are feasible and that ARB staff should maintain strong standards and expectations going forward.

Agency Response: See response to **LCFS 5-2**.

837. Comment: **LCFS T40-3**

The commenter states that regulatory certainty will be provided by the re-adoption of the LCFS regulation.

Agency Response: Staff agrees with the comment and anticipates that re-adopting the LCFS will provide regulatory certainty. See response to **LCFS T36-2**.

838. Comment: **LCFS T40-4**

The comment states that the LCFS regulation is reasonable, technically supported, and should be adopted.

Agency Response: Staff acknowledges the comment and appreciates the support for the re-adoption of the LCFS.

41_T_LCFS_ETutt

839. Comment: **LCFS T41-1**

The comment supports the re-adoption of the LCFS regulation and adds that its requirements to 2020 are economically feasible.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

42_T_LCFS_RMoran

840. Comment: **LCFS T42-1**

The commenter asserts that the 2009 LCFS regulation was written under the assumption of saving billions of dollars while the current LCFS regulation will cost billions of dollars.

Agency Response: The baseline in the 2009 economic analysis was different than the current analysis found in the ISOR and includes many of the complimentary programs that have come into existence post the 2009 rulemaking; therefore the two analyses cannot be meaningfully compared. In addition to the billions of dollars in benefits outlined in the 2009 rulemaking, the commenter did not mention that the 2009 ISOR also describes the infrastructure and other costs of the regulation, as estimated based upon the baseline for that analysis. In the current rulemaking, the cost analysis, as presented in the economic chapter in the 2014 ISOR is a worst-case scenario that will likely over-estimate the costs, without monetizing many of the benefits. With respect to the question about the price cap please see response to comment **LCFS 32-9**.

841. Comment: **LCFS T42-2**

The comment states that there will be no incremental GHG reductions coming from the LCFS regulation because sources of emissions covered under the LCFS are already covered under the Cap-and-Trade program.

Agency Response: ARB staff strongly disagrees that there will be no incremental GHG reductions from the LCF regulation See response to **LCFS 32-6** and **LCFS 46-41**.

842. Comment: **LCFS T42-3**

The commenter argues that the LCFS regulation merely shifts reductions that would occur under the Cap-and-Trade program.

Agency Response: See response to **LCFS 32-6** and **LCFS 32-7**.

843. Comment: **LCFS T42-4**

The commenter asserts that the Cap-and-Trade program would be more effective than re-adopting the LCFS regulation, in meeting California's long-term GHG policies.

Agency Response: See response to **LCFS T42-3**.

43_T_LCFS_BMagavern

844. Comment: **LCFS T43-1**

The commenter supports the electricity and refinery investment provisions.

Agency Response: ARB staff appreciates the support for the proposed electricity and refinery investment provisions.

44_T_LCFS_GNoyes

845. Comment: **LCFS T44-1**

The commenter states that the LCFS regulation is an important signal to the market to provide certainty and supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS.

45_T_LCFS_JHall

846. Comment: **LCFS T45-1**

The comment supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

847. Comment: **LCFS T45-2**

The comment supports re-adoption of the LCFS regulation and would like to see more investments and stronger long-term targets.

Agency Response: See response to **LCFS 5-2**.

46_T_LCFS_SHedderich

848. Comment: **LCFS T46-1**

The comment supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

47_T_LCFS_KPhillips

849. Comment: **LCFS T47-1**

The comment supports re-adoption of the LCFS regulation.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

48_T_LCFS_TO'Connor

850. Comment: **LCFS T48-1**

The comment supports re-adoption of the LCFS regulation and adds that they believe that the new regulation will meet the CEQA requirements.

Agency Response: ARB believes the process followed to develop the LCFS and ADF proposals and the proposed regulations themselves are in compliance with California law, including CEQA, and with applicable federal law. More specifically, ARB believes the proposed rulemaking process and the proposed regulations are consistent with the rulings issued by date by both state and federal courts that have heard challenges to California's original LCFS regulation. To the extent the commenter is expressing support for the proposed LCFS regulation and the process used to bring it to the Board, the comment is noted.

49_T_LCFS_KJames

851. Comment: **LCFS T49-1**

The commenter supports re-adoption of the LCFS regulation and considers it an important route to insulate businesses and consumers from oil price volatility.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

852. Comment: **LCFS T49-2**

The commenter believes that the LCFS regulation will result in an enormous societal benefit by 2020.

Agency Response: Staff appreciates the support of proposed LCFS regulation. Staff acknowledges the societal benefits of LCFS through reducing air pollution and increasing energy security.

853. Comment: **LCFS T49-3**

The commenter states that the LCFS regulation could contribute thousands of jobs to the California market.

Agency Response: ARB staff appreciates the support for the re-adoption of the LCFS regulation.

854. Comment: **LCFS T49-4**

The commenter states that, in order to spur innovation in clean fuels, investors need long term policy signals like re-adoption of the LCFS regulation.

Agency Response: See response to **LCFS 5-2**.

50_T_LCFS_MAddy

855. Comment: **LCFS T50-1**

The comment thanks ARB staff members for their hard work on the indirect land use change emissions.

Agency Response: ARB appreciates commenter's acknowledgements of staff's efforts in addressing the challenges in developing the best estimates for iLUC emissions.

856. Comment: **LCFS T50-2**

The comment notes that getting low carbon transportation fuel solutions into the marketplace will require private capital.

Agency Response: ARB staff agrees that motivating private capital to invest in low carbon fuels is a goal of the LCFS.

857. Comment: **LCFS T50-3**

The comment suggests that industry may have difficulty complying with the LCFS regulation if insufficient capital is available.

Agency Response: Higher credit prices, particularly if they are sustained, will increase the incentive to innovate and invest because revenues generated by LCFS credit can be used to increase profit margins or to offset up-front capital costs; these additional revenues will attract investments in low-CI fuels. Many new fuels will require large capital investments; some of these fuels are eligible for government incentive programs, are part of long-term planning by California (such as AB 8 that provides infrastructure to expand distribution of hydrogen), and will be eligible for revenue increases due to LCFS credit revenues.

The supply of low-CI fuels and potential shortfall scenarios are discussed on page VII-4 of the staff report. Staff has analyzed the projected availability of low-CI fuel technologies, which is summarized in Chapter II and presented in more detail in Appendix B of the staff report.

51_T_LCFS_CHessler

858. Comment: **LCFS T51-1**

The comment states that the compliance schedule of the LCFS regulation is feasible.

Agency Response: ARB staff appreciates the support for the compliance schedule.

859. Comment: **LCFS T51-2**

The comment expresses support for the price cap provision.

Agency Response: ARB staff appreciates the support for the cost containment provision.

This page intentionally left blank.

D. COMMENTS RECEIVED DURING THE FIRST 15-DAY COMMENT PERIOD

Fifty-nine comment letters were received during the first 15-day comment period. Each comment letter is reproduced below with responses following.

This page intentionally left blank.

Comment letter code: 1-FF-LCFS-Proterra

Commenter: Leacock, Kent

Affiliation: Proterra

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

1_FF_LCFS _Proterra

PROTERRA

1001 Bayhill Drive, San Bruno, CA 94066
Phone (925) 698-1431
www.proterra.com

June 5, 2015

Michael S. Waugh, Chief
Transportation Fuels Branch
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Subject: Low Carbon Fuel Standard Energy Economy Ratio Update

Dear Michael Waugh and LCFS Staff,

Thank you for the opportunity to provide comments on the Low Carbon Fuel Standard (LCFS) program. We strongly support the goals of the LCFS program and applaud programs within the California Air Resources Board (ARB) that provide needed incentives to reduce the carbon intensity of fuels to help achieve California's health based air quality standards and aggressive greenhouse gas emission goals.

Proterra is the leading U.S. manufacturer of zero-emission commercial transit solutions and makes the world's first all-electric, fast-charge public transit bus. These buses are currently in service in California at Foothill Transit and Stockton RTD, as well as many locations throughout the country. Proterra's buses charge along their routes in less than 7 minutes with an automated roof top charger and then continue on their routes all day long, offering functionally unlimited range. In addition, Proterra now offers range-extension on the fast-charge public transit bus to address the needs of transit operators for longer routes. Proterra's CATALYST™ bus achieves 21+ miles per gallon equivalent performance, 500%+ better than diesel and CNG buses. Proterra's advanced technology reduces carbon emissions by 70% or more compared to CNG or diesel buses. Zero-emission transit buses provide the opportunity for all Californian's to ride an electric vehicle and realize the health and other associated benefits.

We appreciate ARB updating the Energy Economy Ratio (EER) for heavy-duty battery electric vehicles and respectfully request ARB increase the EER to adequately reflect the updated miles per diesel equivalent of fast-charge battery electric compared to diesel transit buses. Proterra recently received the Altoona results of the updated CATALYST™ bus that demonstrates an increase in the average MPG diesel equivalent, thus increasing the Energy Economy Ratio (EER) for heavy-duty battery electric buses. Please see the updated Altoona Report attached.

LCFS FF1-1

In addition, the proposed EER of 4.2 for heavy-duty battery electric buses does not accurately represent the real ratio between new fast-charge battery electric buses and new diesel transit bus fleets. The proposed EER for heavy-duty battery electric buses averages the EER among battery electric buses – Proterra and BYD. To help ensure an equal comparison, we recommend averaging the fuel economy across all similar Altoona-tested diesel buses, including Gillig and Nova—in addition to New Flyer. Based on the Altoona testing for the most recent 40ft, low-floor, diesel buses over the three test cycles identified by ARB (Central Business District, Arterial, and Commuter), the Gillig bus averages 4.74 MPG, Nova 2.97 MPG, and New Flyer 4.82 MPG, generating an overall overage of 4.18 MPG. Using the updated average 20.53 MPG diesel equivalent for battery electric transit buses and the average 4.18 MPG for diesel transit buses, we respectfully request updating the EER to at least 4.91 for heavy-duty, battery electric vehicles in order to provide an equal comparison of battery electric and diesel transit buses and accurately recognize the significant fuel efficiency and air quality benefits of zero-emission transit buses. LCFS FF1-1 cont.

But even an EER of 4.91 does not accurately capture the unique fuel efficiency gains associated with Proterra's fast-charge technology. Therefore, we further request the consideration of a separate LCFS category for fast-charge, battery-electric buses, similar to ARB's additional incentive for fast-charge in the Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP), in order to recognize the technology's functionally unlimited range, efficiency, and greater miles per gallon diesel equivalent. Charging along the route in less than 7 minutes allows the fast-charge, battery-electric buses to operate continuously – similar to a fuel cell or other long-range advanced technology. In addition, the buses have greater efficiency and MPG equivalent due to their light weight and advanced technology, as the fast-charge, battery-electric transit buses have fewer batteries and less weight on-board the vehicle. Therefore, we strongly encourage recognizing a separate LCFS category for fast-charge, battery electric buses with an EER of 5.3—using the 22.16 MPG diesel equivalent achieved at Altoona under three identified test cycles and the average diesel transit bus at the same test cycles of 4.18 MPG. LCFS FF1-2

We thank you for the opportunity to provide comments on the Low Carbon Fuel Standard, and appreciate the efforts of the California Air Resources Board to reduce the carbon intensity of fuels to support California's climate goals, help clean the air, and promote clean, low-carbon fuels to improve California's energy security and energy independence.

Sincerely,

F. Kent Leacock

F. Kent Leacock
Director Governmental Relations
kleacock@comcast.net

1_FF_LCFS_Proterra

860. Comment: **LCFS FF1-1**

The comment suggests that ARB staff include two more diesel buses with lower efficiencies in the calculations for the Energy Economy Ratio (EER) for electric buses, which increases the electric bus EER to 4.91

Agency Response: See response to **LCFS 16-2**.

861. Comment: **LCFS FF1-2**

The comment suggests that ARB staff include a new EER category for fast-charging battery electric buses in the proposed regulation.

Agency Response: See response to **LCFS 16-3**.

This page intentionally left blank.

Comment letter code: 3-FF-LCFS-BNSF

Commenter: Elgie, Rocky

Affiliation: BNSF Railway Company

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

Comments to the California Air Resources Board Regarding Modified Regulation Order, Low Carbon Fuel Standard

2_FF_LCFS_BE

By Beyond Energy
June 8, 2015

Elon D. Rubin, Esq.
Email: elon@evcredits.com

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, California 95811

Dear Madams and Sirs:

We appreciate this opportunity to comment on the Air Resources Board's ("ARB") proposed readoption of and modified regulation order to the Low Carbon Fuel Standard ("LCFS").

Beyond Energy focuses on prospective investment in EV and Electric Forklift ("EF") infrastructure and services. Among prospective partners of Beyond Energy are EV and EF electric charging infrastructure providers, distribution centers and end users. In addition, Beyond Energy evaluates investment opportunities in the renewable energy space.

We would like to express our strong concern over the proposed requirements in §95483(e)(7) of the LCFS that would restrict the regulated party definition for electric forklifts to only Electric Distribution Utilities ("EDU"), and exclude fleet operators of EF fleets from qualifying for LCFS Credits.[1]

ARB's rationale articulated in the Initial Statement of Reasoning for excluding EF from qualifying for LCFS credits and the latest regulatory modifications are most likely incorrect. As ARB may or may not know, many EFs are charged by dedicated high frequency chargers with easily obtainable data. In light of this information, we propose to amend §95483(e)(7) to allow EF fleets to opt-in, while keeping EDUs as the default regulated party ("modified §95483(e)(7) rule"). Compared to the current §95483(e)(7) rule, our proposed modification of §95483(e)(7) provides better consistency in the LCFS regulation, promotes innovation, fosters investment and affords flexibility, while still allowing for the maximum amount of EF LCFS credits to be claimed. Of equal importance, modifying §95483(e)(7) will not cause undue delay to the adoption of the LCFS for the reasons set forth below.

LCFS FF2-1

Section I provides context and background of the EF regulated party rule. Section II proposes verbiage for modifying §95483(e)(7) to enable EF fleets to opt-into LCFS. Section III expands upon high efficiency chargers and available data, articulates why the benefits of modifying §95483(e)(7) significantly outweigh the burdens previously articled by ARB, and explains why modifying §95483(e)(7) will not cause undue delay to the readoption of the LCFS. Section IV concludes with our closing thoughts. Thank you very much again for your time and attention to this comment.

[1] The latest modification of §95483(e)(7) reads "[f]or transportation fuel supplied to electric forklifts, the Electrical Distribution Utility is eligible to generate credits for the electricity, and must meet the requirements set forth in section 95483(e)(1)(B) through (D)."

I. Context of the Rulemaking

1. Public Meetings

The Board directed staff in Resolutions 09-31 and 11-39 to evaluate the feasibility of issuing credits for non-road electricity-based transportation sources to LCFS.[2] In particular, ARB considered allowing electric forklifts ("EF") to qualify for LCFS credits.[3] Staff held several meetings in 2012 and 2013 to work with stakeholders to develop EF fleet rules. On February 13th, 2013, ARB proposed "fleet operators could become the regulated parties if interested."[4] On March 5th, 2013, ARB again mentioned "regulated parties, with fleet operators able to participate if interested."[5] On April 3, 2013, ARB held another electricity workgroup meeting, not mentioning the definition of a regulated party in the workshop presentation.[6] On May 23, 2013, ARB proposed a regulated party definition for EF fleets excluding EF fleet operators.[7] ARB recommended against this approach, in part, because all credits will likely all not be realized. ARB, therefore, proposed utilities to be the regulated parties for EF.[8]

2. Low Carbon Fuel Standard Re-Adoption Paper

In the LCFS Re-Adoption Concept Paper, ARB discussed the significant impact EF fleets have in potential GHG reduction, stating that increased EF use coupled with decreased internal combustion engine ("ICE") forklift use will decrease GHG emissions and contribute to the goals of the LCFS Program.[9] ARB staff proposed Electric Distribution Utilities ("EDUs") qualify for LCFS credit generation, and excluded EF fleet operators to qualify for LCFS.[10] ARB reasoned: (1) many forklifts don't have dedicated meters, and battery chargers charge multiple equipment types; and (2) tracking down data would likely be cost prohibitive.[11]

3. Subsequent Public Meetings

ARB conducted a public EF meeting on May 30, 2014 on the LCFS Re-Adoption Paper, after the release by ARB of the LCFS re-adoption Paper. ARB presented Regulated Party definitions again on a July 10, 2014 meeting, containing the concept paper re-adoption.

4. LCFS Initial Statement Of Reasons

On January 2nd, 2015, ARB released its Initial Statement of Reasons For Rulemaking. ARB's reasoning for EDUs as regulated parties for EFs is largely identical to the re-adoption paper.[12] ARB did not discuss the previously proposed alternative definition of § 95483(e)(7), allowing EF fleets to opt in as regulated parties. In addition, there appears to be no additional supporting evidence for the rationale of the construction of §95483(e)(7).

---

[2] *Staff Report, Initial Statement of Reasons For Proposed Rulemaking* ES-14 (California Air Resources Board 2014), *available at* http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15isor.pdf ("ISOR" hereafter).
[3] *Id.*
[4] *See LCFS Electricity Workgroup Meeting Presentation*, Slide 12, ARB, February 13, 2013, *available at* http://www.arb.ca.gov/fuels/lcfs/workgroups/elect/021513eletricity-workshop-presentation.pdf.
[5] *Low Carbon Fuel Standards Proposed Amendments*, Slide 22, ARB, March 5, 2013, *available at* http://www.arb.ca.gov/fuels/lcfs/regamend13/030513presentation.pdf.
[6] *Low Carbon Fuel Standards Proposed Amendments*, April 3, 2013, ARB, *available at* http://www.arb.ca.gov/fuels/lcfs/regamend13/040313presentation.pdf.
[7] *Low Carbon Fuel Standard Proposed Amendments*, May 24, 2013, ARB, *available at* http://www.arb.ca.gov/fuels/lcfs/regamend13/052413presentation_revised.pdf.
[8] From our inquiry into the meeting records posted at the LCFS web portal, we could not find meeting transcripts for the previously mentioned workshops. Available materials consisted of a combination or both of meeting agendas and presentations. http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm,
[9] Low Carbon Fuel Standard Re-Adoption Paper C-3 (ARB 2014)
[10] *Id.*
[11] *Id.* at C-3.
[12] ISOR, *supra* note 2.

5. Modified Regulation Order

On June 4th, 2015, ARB modified the LCFS regulation, and provided a copy of the updated regulatory text and additional documents.[13]

6. Stakeholder Participation

Part of the purpose of the regulatory process is to involve parties who could be subject to the regulations in public discussions. It appears, however, that utilities have provided most of the input on electric forklifts in this rulemaking. Also, from our examination of the public documents released on the ARB website, it appears that there is no additional information, records or reports on the docket that shed light on the degree to which members of the electric forklift industry and related forklift stakeholders participated in the process. To the extent that electric forklift stakeholders have not participated in the rulemaking process, we are humbled at the opportunity to contribute to this process.

II. Suggested Modification To §95483(e)(7)

We believe the most equitable way to construct §95483(e)(7) would be to keep EDUs as the default party, and allow EF fleet operator to opt-in, as first proposed in the February 13th, 2013 meeting by ARB. The propose language is below:

§ 95483(e)(7)[14]

For transportation fuel supplied to electric forklifts, the Electrical Distribution Utility is eligible to generate credits for the electricity, and must meet the requirements set forth in section 95483(e)(1)(B) through (D). <u>Upon submittal to and approval by the Executive Officer of an electric forklift fleet operator's written request to opt in and generate credits associated with a specified fleet, the electric forklift fleet operator is eligible to generate the credits for the electricity. To receive credit for transportation fuel supplied to an EF fleet, an accounting of the number of EFs in the fleet must be included as supplemental information in annual compliance reporting.</u>

LCFS
FF2-2

III. Discussion

1. ARB Current Rationale For Excluding EF Fleet Operators From Generating LCFS Credits Is Incorrect

<u>i. Nearly Quarter of EF Chargers In California are High Frequency Chargers</u>

ARB may or may not know that many EFs in California are charged by high frequency chargers ("HFC"). HFCs, compared to legacy chargers[15], have "improved energy efficiency, charge control and power factor can provide energy savings, a smaller and lighter charger and better charge control and flexibility."[16] Users of HFC, compared to the poorest chargers, save approximately 10,740 kWh/yr if they were to upgrade to a HFC.[17] In fact, PG&E, in a study conducted in 2009, recommended purchasing HFC because of substantial energy savings potential.[18]

HFCs are dedicated to EFs. That is, HFCs only charge EFs.[19] HFCs produce easily retrievable data that could be submitted to ARB for compliance. HFCs produce energy reports, easily retrievable, which contain the following:

---

[13] *Modified Regulation Order* (ARB 2015).
[14] Our proposed additions are underlined.
[15] Legacy chargers are SCR, Ferroresonant and Hybrid Chargers. Ryan Matley, *Measuring Energy Efficiency Improvements in Industrial Battery Chargers* 1, PACIFIC GAS AND ELECTRIC COMPANY, May 12, 2009, *available at* http://repository.tamu.edu/bitstream/handle/1969.1/91085/ESL-IE-09-05-32.pdf?sequence=1.
[16] *Id.* at 2.
[17] *Id.* at 2.
[18] *Id.*
[19] *Id.*

(a) Amp hours used. This can be easily converted into kWh
(b) Data for each individual charge
(c) Daily usage
(d) Percent of time charging and in use
(e) Station ID number
(f) Location address
(g) Fleet operator name
(h) Number of electric forklifts used by the fleet operator

There are roughly 110,000 forklifts in California.[20] One HFC charges three forklifts. Conventional chargers charge two forklifts. **We estimate 9,000 HFCs in California in 2015, meaning 27,000, or 24.5% of EF in CA are charged by HFCs.** We find it surprising that utility stakeholders would not bring the existence of HFC to ARBs attention.

ii. We Believe ARBs Rationale For § 95483(e)(7), Therefore, Is Likely Incorrect

We would like to take this opportunity to address ARB's rationale for § 95483(e)(7) point by point in light of the existence of HFCs.

ARB Rationale #1: Many forklifts don't have dedicated meters, and battery chargers charge multiple equipment types

We found nothing on the record substantiating the above statement, aside from ARB's statement that they consulted with stakeholders. As stated above, **we estimate 24.5% of chargers in California are HFC, and 27,000 EF are charged by HFCs**.

ARB Rationale #2: Tracking down metered data for thousands of forklifts would likely be cost prohibitive

We are assuming that rationale #2 does not take into account HFCs. **As stated above, tracking down data from HFCs is not cost prohibitive.** Moreover, one could make the same statement about public electric vehicle service equipment. Yet, ARB did not state this as a reason for excluding eligibility for EVSE, and EVSE is eligible to generate credits.

2. Allowing EF Fleet Operators To Opt In To Generate LCFS Credits Better Promotes Goals of LCFS

Reason #1 - Allowing EF Fleet Operators To Opt In To Generate LCFS Credits Better Promotes Consistency and Harmonization

As ARB is probably aware, when an agency submits a regulation to the Office of Administrative Law ("OAL"), OAL reviews the submitted regulation according to several factors, including consistency.[21] In addition, in the ISOR, ARB stated that one of the goals with the Re-Adopted LCFS is to promote flexibility in rules.[22] §95483(e)(7), as currently proposed, promotes inconsistency in treatment of regulated parties in the LCFS.

EF fleet operators are treated differently than other qualifying electricity regulated parties. The statutory scheme proposed for EV fleet operators[23] and public EVSP[24] and private charging stations[25] provide that the EDU is the default regulated party, and allows fleet operators, EVSP providers for public charging stations and private business that own charging stations to opt-in to become regulated parties. Furthermore, the hydrogen forklift regulated party are the fleet owners qualify for generation of LCFS credits.[26]

---

[20] *See California Electric Transportation Coalition Electric Pathway Presentation* Slide 10 .
[21] CAL GOV'T CODE § 11349(a).
[22] ISOR, *supra note 2*, at ES-1.
[23] *Attachment A, Proposed 15-Day Regulation Order,* §95483(e)(3), ARB, *available at* http://www.arb.ca.gov/regact/2015/lcfs2015/regorderfinal.pdf ("Regulation Order").
[24] *Id.* §95483(e)(4).
[25] *Id.* §95483(e)(5).
[26] *Id.* §95483(f).

Allowing EF fleet operators to opt in to generate LCFS credits mirrors the construction of other provisions in §§ 95483(e) & (f), better promoting consistency, and harmonizing LCFS with OAL review requirements. In addition, our proposed update both ensures that the maximum number of credits is claimed by EF fleet operators while furthering the goal of flexibility stated in the ISOR.

Reason #2 - Allowing EF Fleet Operators To Opt In To Generate LCFS Credits Better Encourages Innovation and Fosters Investment

As part of the regulatory process, an agency is required to prepare a regulatory impact analysis that addresses how a proposed regulation: (i) affects increase or decrease of investment in the state; and (ii) incentivizes for innovation in products, materials or processes.[27] In addition, in the ISOR, ARB mentioned a purpose of the re-adoption of LCFS is "to foster investments in the production of the low-CI fuels."[28]

Myriad scholarship has established that it is more effective to provide money directly to fleet operators in the form of credits or grants than rate reductions by utilities. For example, in a report conducted by Berkeley Transportation Sustainability Research Center for the LCFS adoption in 2007, the authors noted that consumers tend to focus on the upfront cost of purchasing a vehicle and overlook fuel efficiency as a significant vehicle attribute.[29] A report analyzing the effects of the Alternative Fuel Credit Program created by the Energy Policy Act of 1992 also concluded that incentives/grants given to fleet operators better encourages the development of electric infrastructure.[30] In addition, ARB itself has said that the best way to encourage innovation in fleets is to give credits to fleet owners.

Incentivizing electric forklifts directly through LCFS credits means more electric forklifts will be purchased. Manufacturers will have higher incentive to increase the production of electric forklifts. More entrants into the market will increase competition, thereby lowering prices. As electric forklifts become less and less expensive, manufacturers will look to provide additional value proposition, including more features, better efficiency and better financing. Accordingly, enabling EFs to be eligible to generate LCFS credits as obligated parties, will better incentivize innovation and foster investment.

3. Modifying §95483(e)(7) Will Not Cause Undue Delay In Implementation of LCFS

ARB staff mentioned to us that a potential reason, at this point in the LCFS readoption process, is that modification of rules may cause timing issues. We would like to clarify with ARB the regulatory approval process. First, a nonsubstantial modification of a regulation does not require a subsequent 15 day comment period. Even if our proposed modification of §95483(e)(7) is considered a substantial and sufficiently related modification, a second 15-day comment period would not cause undue delay to adoption of the LCFS. Regulations must be submitted and approved by OAL prior to becoming effective. In order to have a regulation become effective by January 1st, an agency must submit the adopted regulation by November 30th. OAL must review the application within 30 days. Even if, for some reason, ARB does not manage to submit the adopted LCFS regulation to OAL by November 30th, 2015, an earlier effective date may be prescribed by OAL if an agency requests an earlier effective date with good cause. Given the importance of EF to furthering the purpose of LCFS, and the impact EF fleets have on GHG emissions in California, requesting an earlier effective date, we believe, constitutes good cause.

i. ARB Must Consider Comments From 15 Day Comment Period And May Still Modify LCFS

"An agency must consider comments received during the 15-day comment period and may modify the proposed regulations."[31] "A rulemaking agency must summarize and respond on the record to timely comments that are directed at

---

[27] CAL GOV'T CODE §§ 11346.3 (c)(1)(D)-(E).
[28] ISOR, *supra note 2*, at ES-1.
[29] Alexander E. Farrell et al., *A Low-Carbon Fuel Standard For California Part 2: Policy Analysis 21* (UC BERKELEY TRANSPORTATION SUSTAINABILITY RESEARCH CENTER 2007).
[30] Alexander E. Farrell et al., *The AFP Credit Market And Its Role In Future AFV Market Development* 5 (UNIVERSITY OF PENNSYLVANIA 1997), *available at* http://opim.wharton.upenn.edu/risk/downloads/archive/arch226.pdf.
[31] *The Regular Rulemaking Process*, OAL, *available at* http://www.oal.ca.gov/Regular_Rulemaking_Process.htm (referencing CAL GOV'T CODE §11346.8(c)).

the proposal or at the procedures followed by the agency during the regulatory action. With each comment, the agency must either (1) explain how it has amended the proposal to accommodate the comment, or (2) explain the reasons for making no change to the proposal."[32]

ii. Allowing EF Fleet Operators to Opt-In To Generate LCFS Credits Is Nonsubstantial, Not Requiring 15 Days Notice To Public

After receiving a comment, if an agency decides to modify a regulation pursuant to that comment, the agency must first decide if the change to the regulation is 1) nonsubstantial; (2) substantial and sufficiently related; or (3) substantial and not sufficiently related.[33] A rulemaking agency must make each substantial, sufficiently related change to its initial proposal available for public comment for at least 15 days before adopting such a change.[34]

We believe that our proposed modification is nonsubstantial because it was previously discussed by ARB and stakeholders, and therefore they have been put on notice of a potential change to §95483(e)(7) and have been given opportunity to comment on §95483(e)(7).

iii. Even if ARB Determines Our Proposal TO Modify §95483(e)(7) Is Substantial and Sufficiently Related, It Will Not Cause Undue Delay To Adoption of LCFS

The current comment period ends on June 19, 2015. An agency may conduct more than one 15-day opportunity to comment on modifications.[35] Assume, for the sake of discussion, ARB adopts our proposed modification and issues a second 15-day comment period on June 20th, the end of the 15-day period would be July 5, 2015. Assume it takes one week for ARB to evaluate the second 15-day comment period comments. This would mean that comments close on July 12, 2015.

ARB must submit a finalized report to OAL by November 30th for a January 1, 2016 effective date.[36] OAL has 30 working days to conduct a review.[37] A July 12 comment close date for a second 15-day comment, therefore, gives ARB 141 days to submit a finalized regulation and corresponding requirements to OAL. We respectfully cannot envision a situation whereby it takes more than 141 days - after all comments are received – to meet OAL requirements.

Even if, for some reason, ARB fails to submit the LCFS regulation by November 30th, adopted regulations may have an earlier effective date if an agency requests an earlier effective date and shows good cause.[38] Given the importance of EF to furthering the purpose of LCFS, and the impact EF fleets have on GHG emissions in California, requesting an earlier effective date, we believe, constitutes good cause.

Accordingly, we believe this section clarifies any ARB worry about timing, and means that amending §95483(e)(7) will not cause undue delay in implementation of the LCFS.

IV. Conclusion

The regulatory process exists as it does so that agencies, stakeholders and the public work together to refine and improve regulations prior to them going into effect. Now is our opportunity to make a common sense change that will spur innovation for electric forklifts, fleet operators and electric forklift charging stations. Now is our opportunity to ensure that §95483(e)(7) is crafted with the right rationale. Now is our opportunity to significantly impact climate change, not just for California, but also other states and the United States.

---

[32] *Id.*
[33] *Id.*
[34] *Id.*
[35] *Id.*
[36] CAL GOV'T CODE § 11343.4
[37] *Rulemaking Process*, *supra* note 34.
[38] CAL GOV'T CODE § 11343.4(B). *See Also* OAL REVIEW PROCESS, *available at* http://www.oal.ca.gov/res/docs/pdf/OAL%20Review%20Process_FINAL_June%202014.pdf.

Based on the foregoing, it appears that the rationale for §95483(e)(7) excluding electric forklift fleet operators is incorrect. We estimate 24.5% of electric forklifts – or 27,000 forklifts – are charged by high frequency chargers. These chargers produce easily retrievable data, meaning data collection will not be costly. Our proposed revision of §95483(e)(7) – allowing electric forklift fleets to opt-in, with EDUs being the default credit generator - better promotes consistency and harmonization of the LCFS, spurs innovation and investment in electric forklifts, and better incentivizes the right actors – electric forklift fleet operators and battery charging station manufacturers – to buy more electric forklifts and improve electric forklift technology. Moreover, our proposed revision of §95483(e)(7) provides more flexibility to the LCFS rules, and ensures the maximum number of EF fleet LCFS credits are generated. Finally, amending of §95483(e)(7) will not cause undue delay in the adoption of LCFS because there is still ample time prior to November 30th, and a regulation can go into effect prior to an effective date if an agency requests and has good cause.

We believe, therefore, it would be unreasonable for ARB to adopt §95483(e)(7)[39], and ARB should not make a finding that, in light of our suggested modification to§95483(e)(7), §95483(e)(7) (excluding EF fleets as eligible to generate LCFS credits) either (a) would be more effective in carrying out the purpose of the LCFS; (b) would be as effective and less burdensome to affected private persons than the proposed action; or (c) would be more cost effective to affected private persons and equally effective in implementing LCFS.[40] §95483(e)(7), in either form, only affects which regulated parties can be eligible for LCFS credit generation for electric forklifts. Affected private persons, therefore, are electric forklift fleets and electric forklift charging station providers and manufacturers. In instance b, §95483(e)(7) is more burdensome for electric forklift fleets because they cannot generate LCFS credits. In instance c, §95483(e)(7) would not be more cost effective than our proposed modification because EF Fleets cannot generate LCFS credits.

We strongly urge ARB to modify §95483(e)(7) to allow electric forklift fleet operators to be eligible to opt-in to the LCFS to generate LCFS credits with either our suggested verbiage contained herein or similar verbiage.

We conclude our comment by again applauding ARB and California for taking a lead on climate change. Every staff member we have spoke to thus far has been incredibly kind, and well intentioned. It is a testament to ARB and the CA regulatory process to have such inspired, intelligent and dedicated staff working on one of the most important regulations of our epoch. We very much welcome ARB's comments, are available to answer any questions ARB may have on these comments, and respectfully request setting up a meeting with staff as soon as practicable.

Respectfully submitted,

Elon D. Rubin

[39] CAL GOV'T CODE §11346.5(A) requires that an agency proposing to adopt a regulation to assess the potential for "avoiding the imposition of unnecessary or unreasonable regulations."

[40] CAL GOV'T CODE §11346.5 requires, in a Final Statement of Reasoning, "[a] statement that the adopting agency must determine that no reasonable alternative considered by the agency or that has otherwise been identified and brought to the attention of the agency would be more effective in carrying out the purpose for which the action is proposed, would be as effective and less burdensome to affected private persons than the proposed action, or would be more cost effective to affected private persons and equally effective in implementing the statutory policy or other provision of law."

2_FF_LCFS_BE

862. Comment: **LCFS FF2-1**

The comment suggests that ARB staff allow electric forklift fleet operators to be eligible to generate LCFS credits.

Agency Response: ARB staff considered the comments and made the corresponding changes in the second 15-day change package, which was publicly released on June 23, 2015.

863. Comment: **LCFS FF2-2**

The comment provides suggested regulation language that would allow electric forklift fleet operators to be eligible to generate LCFS credits.

Agency Response: See response to **LCFS FF2-1**.

This page intentionally left blank.

3_FF_LCFS _BNSF

BNSF RAILWAY

Rocky Elgie
General Director Fuel Mgmt.

BNSF Railway Company
P.O. Box 961034
2600 Lou Menk Drive
Fort Worth, TX 76161-0034

817-352-1235
Rocky.elgie@bnsf.com

June 16, 2015

Clerk of the Board, Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Proposed Re-Adoption of the Low Carbon Fuel Standard

To Whom It May Concern:

BNSF Railway ("BNSF") has been in communication with California Air Resources Board ("CARB") staff since approximately October 2014 regarding its concerns with the Low Carbon Fuel Standard Regulation ("Regulation") and, more specifically, its inability to take advantage of the exemption in the Regulation for fuel consumed by interstate locomotives. Despite multiple conversations and the submittal of multiple proposals, BNSF remains without a clear path to compliance that allows it to: 1) take advantage of the exemption for fuel consumed by interstate locomotives; and 2) avoid overpayment under the Regulation.

As a means to resolving this issue, BNSF is providing brief comments on the proposed additional changes to section 95483(a)(2) contained in the June 4, 2015 re-adoption package. More specifically, BNSF requests that certain language currently contained on Regulation page 17 be revised. Per the existing language, a transaction must occur above the rack in order for ownership of the LCFS obligation to be transferred. BNSF is unclear about why this language cannot apply to both above and below the rack transactions, at the buyer's discretion.

LCFS FF3-1

Such a change would give BNSF the ability to take on the LCFS obligation for all of its purchases. In doing so, BNSF would be able to avoid the scenario where suppliers pass along the cost of the obligation on all fuel, and instead, could provide an accurate accounting of what fuel purchased in California is used for intrastate and interstate consumption, respectively. Based on that accounting, it could then meet the obligation on only that portion of fuel purchased for intrastate consumption. BNSF has explored a variety of mechanisms for availing itself to the express exemption contained in the regulation and currently believes that from a practical perspective, this language change, would provide the simplest means to doing so.

Thank you for your consideration.

Sincerely,

R-h. Elgie

Rocky Elgie
General Director Fuel Management
BNSF Railway

3_FF_LCFS_BNSF

864. Comment: **LCFS FF3-1**

The comment is asking that staff modify the proposed regulation to allow the compliance obligation to be transferred below the rack so that the commenter can more easily take advantage of the exemption for fuels used in interstate locomotives.

Agency Response: ARB does not support the commenter's proposed method for tracking intrastate locomotive fuel consumption and export volumes. This method would allow railroads to remove fuel purchased without obligation from their compliance obligation. This is not possible under the LCFS because the deficits incurred on fuel purchased without obligation are the responsibility of the fuel seller to offset. No further credit/debit account balancing based on this fuel is available to the purchaser.

The current LCFS regulation allows ultra-low sulfur diesel (ULSD) purchased below the rack to be purchased with or without obligation. This provision has proved problematic for smaller entities, such as retail outlet operators, who have limited or no ability to comply with the LCFS.

The proposed regulation does not allow ULSD to be purchased below the rack (defined as a diesel fuel transaction of less than 10,000 gallons) with obligation. It also brings the diesel and gasoline provisions into conceptual alignment. In both cases, end users and retail outlets will be protected from receiving the compliance obligation. Once the proposed regulation goes into effect, therefore, with-obligation purchases may only occur above the rack.

We recognize that the commenter wishes to find an administratively simple way of claiming the interstate rail exemption. Staff is committed to continuing to work with the commenter on this issue in the future.

This page intentionally left blank.

Comment letter code: 4-FF-LCFS-GP

Commenter: O'Donnell, John

Affiliation: GlassPoint Solar

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

4_FF_LCFS _GP

GlassPoint

TEL:
+1 (415) 778-2800

FAX:
+1 (415) 762-1966

ADDRESS:
GlassPoint Solar, Inc.
46421 Landing Parkway
Fremont, CA 94538

WEB:
www.glasspoint.com

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

June 16, 2015

Via electronic submittal to: http://www.arb.ca.gov/lispub/comm/bclist.php

Re: 15-Day Amendment Package for Low Carbon Fuel Standard (LCFS)

GlassPoint Solar Inc. (GlassPoint) appreciates and supports ARB's efforts to readopt the Low Carbon Fuel Standard (LCFS) to create a workable regulatory framework. We are pleased to provide these comments on the June 4, 2015 LCFS 15-Day Regulatory amendment package. The proposed final language is the result of a cooperative rulemaking process that GlassPoint believes has made the regulation better, and specifically the Innovative Crude Provisions. We look forward to the expeditious conclusion of the rulemaking as GlassPoint is ready to build new low-carbon projects once regulatory standards are finalized in California.

GlassPoint is a California company that manufactures solar steam generators for thermal enhanced oil recovery (EOR). Our renewable energy technology has proven reliable, safe and economical in field operations in California and the Middle East. We were pleased to be selected by the U.S. State Department as one of nine finalists for the Secretary of State's prestigious 2014 Award for Corporate Excellence (ACE) for our technology and corporate behavior.

Thermal EOR, or steam injection, extends the value and the life of California's oilfields. Today, thermal EOR accounts for more than 40% of California's oil production and consumes more than 200 MM MMBTU per year of fuel for steam generation. Solar energy can replace a substantial fraction of that existing fuel use, reducing emissions resulting from upstream production. Of the potential innovative methods, the use of solar energy is the lowest-cost, lowest-risk, and largest-scale opportunity to reduce the CI of petroleum fuels produced and used in California. Solar powered oil production technologies—solar steam generation and solar electric power generation—have the potential to contribute to California's economy significantly while reducing costs and risks associated with meeting the LCFS.[1]

GlassPoint appreciated ARB's understanding of the potential impact of solar EOR. The technical amendments to the Innovative Crude portions of the regulation are technically sound and appropriate. GlassPoint also appreciates the additional category of steam quality that is now eligible for credits (55%). LCFS FF4-1

[1] January 2015, ICF Report: The Impact of Solar Powered Oil Production on California's Economy, An economic analysis of Innovative Crude Production Methods under the LCFS. Previously submitted.

GlassPoint strongly supports the Innovative Crude mechanisms and procedures as provided in the proposed regulation and amendments. LCFS FF4-1 cont.

One final reminder on regulatory timing must be noted. This regulatory adoption schedule has been delayed several times and now creates challenges for customers and project developers to harvest the benefits of the Federal solar tax incentives, which expires at the end of 2016. An effective 20% price increase will occur for projects which come online after that date. GlassPoint wishes to continue the discussion on how we can send a signal to the investment community as soon as possible about the longevity of, and the benefits of, this program. That is the easiest way to start in-state investments in lower CI fuel production. We look forward to working with ARB so that projects can capture the Federal benefits and minimize total costs. LCFS FF4-2

Thank you for the opportunity to comment and we look forward to the conclusion of this lengthy rulemaking, and to working on building a lower carbon infrastructure for California.

Sincerely,

John O'Donnell
Vice President, Business Development

314692641.1

4_FF_LCFS_GP

865. Comment: **LCFS FF4-1**

Agency Response: ARB staff appreciates the support for the innovative crude oil provision and the inclusion of a new category for solar steam.

866. Comment: **LCFS FF4-2**

Agency Response: ARB staff appreciates the commenter's observation regarding regulatory timing and federal solar tax incentives that will expire at the end of 2016. The LCFS regulation will be considered for adoption by the Board in 2015 and, if the Board approves the regulation, the regulation will be effective at the beginning of 2016.

This page intentionally left blank.

Comment letter code: 5-FF-LCFS-Koehler

Commenter: Koehler, Tom

Affiliation: Pacific Ethanol

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

5_FF_LCFS
_Koehler

California Environmental Protection Agency
Air Resources Board

Comment Log Display

BELOW IS THE COMMENT YOU SELECTED TO DISPLAY.
COMMENT 5 FOR LOW CARBON FUEL STANDARD 2015 (LCFS2015) - 15-1.

First Name: Tom
Last Name: Koehler
Email Address: tomk@pacificethanol.net
Phone Number:
Affiliation:

Subject: CI of denaturaunt
Comment:
The denaturaunt used by domestic ethanol producers is Natrual Gasoline. This product has a lower CI than CARBOB. Brazilian Ethanol marketers use CARBOB for their denaturant. There should be a new default pathway for domestic ethanol denaturuant reflecting the use of Natural Gasoline.

LCFS FF5-1

Attachment:

Original File Name:

Date and Time Comment Was Submitted: 2015-06-17 10:17:26

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

5_FF_LCFS_Koehler

867. Comment: **LCFS FF5-1**

The comment states that there should be a new default pathway for domestic ethanol denaturant reflecting the use of Natural Gasoline.

Agency Response: ARB staff is aware that there are multiple additives which qualify as denaturant under the ASTM standard. Staff will continue to monitor industry blending practices and will consider refining CIs for commonly used materials such as natural gasoline in the future. For the time being, due to a lack of reporting data on pathway-specific blending materials, all denaturant is assessed as CARBOB representing a uniform conservative assumption for all denatured ethanol consumed in California.

This page intentionally left blank.

Comment letter code: 6-FF-LCFS-Vidak

Commenter: Senator Andy Vidak
Senator Jean Fuller

Affiliation: California State Senators,
districts 14 and 16

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

6_FF_LCFS _Vidak

California State Senate

STATE CAPITOL
SACRAMENTO, CA 95814
(916) 651-4014

SENATOR
ANDY VIDAK
FOURTEENTH SENATE DISTRICT

June 17, 2015

The Honorable Mary Nichols, Chairwoman
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Comments on Low Carbon Fuel Standard's (LCFS) provisions for Low Complexity – Low Energy (LCLE) Refiners

Thank you for allowing us to provide our comments on the Low Carbon Fuel Standard's (LCFS) provisions for Low Complexity – Low Energy (LCLE) Refiners. These provisions recognize that not all refineries are the same. We believe that there are policy and technical justifications for a distinction in the LCFS. The Air Resources Board, as well as, the U.S. Environmental Protection Agency has traditionally recognized the unique value small refiners occupy in the oil and finished fuel markets, as well as, their unique configurations and operating constraints.

Given the value of LCLE Refiners, we were concerned that the proposed final regulatory proposal for the re-adoption of California's LCFS fails to recognize Alon's Bakersfield Refinery as a LCLE producer. The facility is configured and engineered to produce low carbon intensive base fuels. Board staff had an opportunity to make the LCFS's LCLE provisions work for all low carbon intensity refineries in California, but decided against various compromise proposals presented, including proposals to limit the benefit any single LCLE refiner could receive. LCFS FF6-1

As the final LCFS regulation is before you, we ask that the Board please look again at the value of all LCLE refineries and the benefits that they provide to the state. Thank you again for allowing us to provide our comments on the re-adoption of the LCFS.

Sincerely,

ANDY VIDAK
Senator, 14th District

JEAN FULLER,
Senator, 16th District

6_FF_LCFS_Vidak

868. Comment: **LCFS FF6-1**

The commenter believes that ARB has excluded the Alon Bakersfield refinery from the Low Complexity-Low Energy Use Refiner provisions of the rule despite the facility being configured and engineered to produce low carbon intensive base fuels.

Agency Response: See comment responses to **LCFS B5-1**, **LCFS FF9-6**, and **LCFS FF9-8**.

This page intentionally left blank.

Comment letter code: 7-FF-LCFS-IBEW

Commenter: Elrod, Jim

Affiliation: Int'l Brotherhood of Electrical Workers

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

Local Union No. 428

INTERNATIONAL BROTHERHOOD of ELECTRICAL WORKERS

7_FF_LCFS _IBEW

June 19, 2015

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Alon's Bakersfield Refinery

On behalf of the entire membership of IBEW Local 428, I would like to extend our strong support of the Low Carbon Fuel Standard's provisions for Low Complexity—Low Energy Use Refiners. Clearly, not all refiners are the same, and these provisions recognize that. Both the Air Resources Board and U.S. Environmental Protection Agency have long recognized in their regulatory programs the unique space small refiners occupy in the oil and gas industry. This distinction is a very necessary and positive step. LCFS FF7-1

Unfortunately, it seems the proposed final regulatory provisions for the re-adoption of California's Low Carbon Fuel Standard (15-day changes) fails to recognize Alon's Bakersfield Refinery as a low carbon fuel producer, even though it is configured and engineered to produce low CI base fuels. This is a huge mistake, especially in light of the fact that staff had every opportunity to make the LCFS's LCLE provisions work for ALL low carbon intensity refineries in California, instead deciding against the several compromise proposals presented. LCFS FF7-2

It is for these reasons that IBEW Local 428 strongly urges the Board to direct staff to revisit this issue at the earliest opportunity.

Sincerely,

James S. Elrod

James S. Elrod
Business Manager/ Financial Secretary

3921 N. SILLECT AVE., BAKERSFIELD, CALIFORNIA 93308 PHONE (661) 323-2979 FAX (661) 323-1834

7_FF_LCFS_IBEW

869. Comment: **LCFS FF7-1**

The commenter supports the provisions for Low Complexity-Low Energy Use Refiners.

Agency Response: ARB staff appreciates the support for the LC/LE provision.

870. Comment: **LCFS FF7-2**

The commenter believes that ARB has excluded the Alon Bakersfield refinery from the LC/LE provision even though it is configured to produce low CI base fuels.

Agency Response: See comment responses to **LCFS B5-1**, **LCFS FF9-6**, and **LCFS FF9-8**.

This page intentionally left blank.

Comment letter code: 8-FF-LCFS-PPRF

Commenter: Gomez, Steven

Affiliation: Plumbers, Pipe and Refrigeration
Fitters Union

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

UNITED ASSOCIATION
of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada

Founded 1889

8_FF_LCFS _PPRF

Mark McManus
General Secretary-Treasurer

Stephen F. Kelly
Assistant General President

UA Local Union:

Plumbers, Pipe and Refrigeration Fitter Local Union 460
6718 Meany Avenue Bakersfield, California 93308
Phone: (661) 589-4600 Fax: (661) 589-3196
Email address: lu460@sbcglobal.net

Letters should be confined to one subject

Subject:

June 18, 2015

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Comments on the 15 Day Regulatory package for the LCFS Regulation

The UA Plumbers, Pipefitters & Steamfitters Local Union 460 strongly supports the Low Carbon Fuel Standard's (LCFS or regulation) provisions for Low Complexity – Low Energy Use Refiners (LCLE Refiners). These provisions recognize that not all refineries are the same. We believe that there are solid policy and technical justifications for this distinction to be codified in the LCFS. The Air Resources board (CARB or Board), as well as, the U.S. Environmental Protection Agency have traditionally recognized in their regulatory programs the unique value small refiners (LCLE) occupy in both the oil and finished fuel markets, as well as, their unique configurations and operating constraints. Recognizing that difference is a very positive step.

However, we are disappointed that the proposed final regulatory provisions for the re-adoption of California's Low Carbon Fuel Standard (15-day changes) fails to recognize Alon's Bakersfield Refinery as a low carbon fuel producer (LCLE). The facility is configured and engineered to produce low CI base fuels. It is for this reason that we are saddened that staff was unable to agree on a solution that would include all of California's truly LCLE refineries. The staff had an opportunity to make the LCFS'S LCLE provisions work for all low carbon intensity refineries in California, but decided against various compromise proposals presented, including proposals to limit the benefit any single LCLE refiner could receive in an attempt to deal with staff's concerns for "regulatory creep" and "breaking the Bank". LCFS FF8-1

UA Plumbers, Pipefitters & Steamfitters Local Union 460 strongly urges the Board to direct staff to revisit this issue at the earliest opportunity.

Respectfully submitted,

Steven Gomez
Local Union 460
Business Manager

8_FF_LCFS_PPRF

871. Comment: **LCFS FF8-1**

The commenter believes that ARB has excluded the Alon Bakersfield refinery from the LCLE provision even though it is configured to produce low CI base fuels.

Agency Response: See comment responses to **LCFS B5-1** and **LCFS FF9-6**.

This page intentionally left blank.

Comment letter code: 9-FF-LCFS-ALON

Commenter: Grimes, Gary

Affiliation: Paramount Petroleum

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

9_FF_LCFS _ALON

ALON USA

June 19, 2015

Via electronic submittal to: http://www.arb.ca.gov/lispub/comm/bclist.php

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Comments on the 15 Day Regulatory package for the LCFS Regulation

Alon USA Energy (Alon) strongly supports the Low Carbon Fuel Standard's (LCFS or regulation) provisions for Low Complexity – Low Energy Use Refiners (LCLE Refiners). These provisions recognize that not all refineries are the same. We believe that there are solid policy and technical justifications for this distinction to be codified in the LCFS. The Air Resources Board (CARB or Board), as well as, the U.S. Environmental Protection Agency have traditionally recognized in their regulatory programs the unique value small refiners (LCLE) occupy in both the oil and finished fuel markets, as well as, their unique configurations and operating constraints. Additionally, smaller, less complex refiners also have the added distinguishing characteristic that they produce finished fuel with a lower Carbon Intensity (CI), the heartbeat of the LCFS. Recognizing that difference is a very positive step. LCFS FF9-1

That being said Alon, is very disappointed that the proposed final regulatory provisions for the re-adoption of California's Low Carbon Fuel Standard (15-day changes) fails to recognize Alon's Bakersfield Refinery as a low carbon fuel producer (LCLE). The facility is configured and engineered to produce lower CI fuels. Alon, CARB staff and the Board have been actively discussing the concept of a LCLE refiner provision since 2011, including adopting previous resolution language on the subject matter. Over the past four years, the policy construct behind recognizing the inherently lower carbon intensity of smaller, less complex refineries has been fully agreed upon. It is for this reason that Alon is saddened that staff was unable to agree on a solution that would include all of California's truly LCLE refineries. Unfortunately, the final limited LCLE definition has several negative implications, including: creating an uneven competitiveness within the smaller refinery subsector, increasing statewide GHG emissions from California's transportation fuel sector, not recognizing the true economic impact on Bakersfield, and setting a precedent regarding use of data. Finally, it locks into place a significant regulatory and economic obstacle to restarting the Alon Bakersfield refinery. **Alon strongly urges the Board to direct staff to revisit this issue at the earliest opportunity.** LCFS FF9-2

The LCLE provision was intended to be an all-encompassing policy acknowledgment by the Board that there are refineries in California that produce transportation fuels while consuming substantially less energy per finished gallon. Nobody would ever say the Alon Bakersfield facility looks or operates like California's biggest refineries.

As we know, the LCFS regulation impacts refineries that are both operating AND may resume operations shortly by providing the "rules of the game" for many years to come. This regulation will not only impact Alon's Bakersfield refinery but could have consequences for Alon's Paramount refinery where we are in the process of modifying some of the process units to produce renewable diesel from animal and vegetable fats. [1] LCFS FF9-2 cont.

California's smaller, less complex refineries are few in number and have been historically acknowledged by CARB to operate at a market disadvantage. This historical recognition started in the earliest of CARB rulemakings on California's transportation fuel (clean diesel and reformulated gasoline). Recent regulatory actions by the agency to implement AB 32 have not been consistent in recognizing these differences. In fact, rationale provided to Alon by CARB staff for not recognizing small refiners under the Cap and Trade program was that this issue would be better suited for the LCFS regulation. Now both regulations have been updated, and both regulations leave Alon's Bakersfield refinery abandoned. LCFS FF9-3

The staff recommendation itself was disappointing, but Alon is equally disappointed that neither the Bakersfield refinery, or its data were considered when analyzing the LCLE provisions initially, even though we had been in active discussion with staff for years. At the direction of CARB Alon waited almost a year for new Mandatory Reporting (MRR) to be collected and analyzed for the statewide refinery fleet. Unfortunately, the updated MRR did not include the requirement for over-the-fence purchased hydrogen data which would further demonstrate the large difference in carbon intensity between the LCLE refineries and the other refineries in the state. Soon after learning that the data needed to help draw the distinctions wasn't coming, the draft LCFS regulation was written to exclude the Bakersfield refinery from the LCLE category without the benefit of its data. Since that point, staff has not wanted to adjust the eligibility criteria. The inertia of the initial draft was significant. Alon feels the Bakersfield refinery was a victim of the regulatory adoption system. LCFS FF9-4

Though Alon's Bakersfield refinery is currently operating in a very limited mode, Alon is actively working to bring production back to 2008 levels and has spent millions of dollars in the environmental review process. The Kern County Board of supervisors has approved an Environmental Impact Report to allow Alon to reconfigure the Refinery and the necessary engineering work has commenced. The impacts of the LCFS and the potential mitigating effects of the LCLE refiner provisions are significant economic considerations for the facility. By leaving the Bakersfield Refinery outside the LCLE universe CARB staff has substantially increased the economic impact that the facility will need to overcome and decreased the likelihood that California will receive the low carbon fuel supplies that it could provide. LCFS FF9-5

Alon believes that the inclusion of the Bakersfield refinery in the LCLE would have been a win for the environment and a win for the central valley economy -- Because the CI of the Bakersfield facility is materially lower than the average California refinery, the fuels produced by the facility would save as much as 400,000 metric tons of GHG emissions annually over what would otherwise LCFS FF9-6

---

[1] The Paramount Refinery meets the LCLE criteria and an economic evaluation will be needed to determine if it is economic to produce low carbon intensity conventional fuel at the facility.

be emitted by an average in-state refinery and its inclusion would have helped assure good middle class construction and refinery jobs in the economically hard it central valley. LCFS FF9-6 cont.

The potential loss of these GHG reductions is a significant environmental impact. In fact, it is almost equal to the GHG emission reduction benefits of an entirely new Major Regulation currently proposed—The Crude Oil and Natural Gas Operations regulation. That entire regulation, estimated to cost more than $50 million dollars to California business is anticipated to only achieve 556,000 tons of reductions The failure to analyze the environmental impacts associated with the Bakersfield refinery being in the LCLE universe is a serious CEQA issue. Alon worked diligently over the past year trying to understand CARB's concerns. The 15- Day package was an opportunity to make the LCFS's LCLE provisions work for all low carbon intensity refineries in California, and Alon offered various compromise proposals, including proposals to limit the benefit any single LCLE refiner could receive in an attempt to deal with staff's concerns regarding "regulatory creep" and "breaking the bank". Unless the Board directs staff to revisit this issue at the earliest of re-openings, Alon must wait years for the next scheduled LCFS revision in 2018. LCFS FF9-7

In summary, while Alon strongly supports the concept of LCLE provisions, the proposed LCLE provisions missed the mark because the LCLE eligibility criteria of "5/5" isn't reflective of the complete category of refineries that fit its important policy goal. **Alon respectfully asks the Board to direct staff to revisit this decision as soon as practicable.** LCFS FF9-8

If you have any questions on these comments please contact Gary Grimes at 562-531-2060 (ggrimes@ppcla.com).

Respectfully submitted,

Glenn Clausen

Glenn Clausen
Vice President, Refining
Paramount Petroleum

314711021.1

9_FF_LCFS_ALON

872. Comment: **LCFS FF9-6 and LCFS FF9-7**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

873. Comment: **LCFS FF9-1**

Agency Response: ARB staff appreciates the support for the Low Complexity/Low Energy Use provision.

874. Comment: **LCFS FF9-2**

The comment states that the LC/LE provision as written effectively excludes the Alon-Bakersfield refinery from the benefits of the provision.

Agency Response: See response to **LCFS FF9-6**.

875. Comment: **LCFS FF9-3**

The comment states that both Cap and Trade and LCFS leave Alon's Bakersfield refinery abandoned by failing to recognize it as a smaller, less complex, and disadvantage refinery.

Agency Response: See response to **LCFS FF9-6**.

876. Comment: **LCFS FF9-4**

The commenter expresses disappointment that neither the Bakersfield refinery, nor its data were considered when analyzing the LCLE provisions initially, even though they had been in active discussion with staff for years.

Agency Response: See response to **LCFS FF9-6**.

877. Comment: **LCFS FF9-5**

The commenter states that the LC/LE provision as written effectively excludes the Alon-Bakersfield refinery from the benefits of the provision and has substantially increased the economic impact that the facility will need to overcome.

Agency Response: See response to **LCFS FF9-6**.

878. <u>Comment</u>: **LCFS FF9-8**

In summary, while Alon strongly supports the concept of LC/LE provisions, the proposed LC/LE provisions missed the mark because the LC/LE eligibility criterion of "5/5" isn't reflective of the complete category of refineries that fit its important policy goal. The commenter respectfully asks the Board to direct staff to revisit this decision as soon as practicable."

<u>Agency Response:</u> Data provided by Alon to ARB staff regarding Alon Bakersfield's future refinery operations and capacity indicate that Alon Bakersfield's carbon intensity, albeit lower than that of the statewide average, was still significantly higher than the carbon intensity of the current LC/LE qualifying refineries and equivalent to, or in some cases higher than, that of simpler complex refineries. See response to **LCFS B5-1** and **LCFS FF9-6**.

Comment letter code: 10-FF-LCFS-NBB

Commenter: Neal, Shelby

Affiliation: National Biodiesel Board

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

10_FF_LCFS _NBB

BIODIESEL® America's Advanced Biofuel

June 18, 2015

Mary D. Nichols
Chair
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95814
Submitted via electronic mail.

Re: Written comments from the National Biodiesel Board on the Proposed Re-Adoption of the Low Carbon Fuel Standard.

Dear Chair Nichols:

Thank you for the opportunity to comment on this regulation. We sincerely value the job you and all ARB board members and staff undertake in protecting the state's environment and public health.

By way of background, the National Biodiesel Board (NBB) serves as the trade association for the U.S. biodiesel and renewable diesel industries. The NBB represents more than 90 percent of domestic biodiesel and renewable diesel production. In addition to governmental affairs activities, the association coordinates the industry's research and development efforts.

Our comments on this matter are brief, reflecting broad agreement with the work staff have done in crafting the regulation. Listed below are a few relatively minor matters we hope can be clarified or addressed before the regulation receives final approval.

Tier 1 and Tier 2 Classifications

Biodiesel is unique. While it is an established technology, having been in commercial production for more than a decade, the industry is, at the same time, continuing to evolve and advance in exciting ways—both in terms of feedstock development and processing technology. In addition, numerous feedstocks and processes exist for creating ASTM grade biodiesel. For these reasons, we believe that ARB should include Tier 1 pathways for integrated oil and biodiesel producers, or integrated biodiesel producers should be able to utilize the Tier 2 GREET model, should circumstances merit it. Two specific examples are provided below.

LCFS FF10-1

Used Cooking Oil (Cooking Not Required)
It appears that the pathway for "uncooked" used cooking oil (UCO) has been removed and is therefore not available under Tier 1. This pathway is particularly relevant for California biodiesel producers, some of whom collect grease directly from restaurants and do not "cook" or otherwise refine the product before inputting the UCO into their biodiesel production processes. Therefore, using the proposed Tier 1 (cooked) UCO pathway would result in a double counting penalty for these producers equating to several carbon intensity points. LCFS FF10-2

We also believe integrated operations should be accounted for in the Tier 1 pathways. For example, a biodiesel production facility that is attached to a canola processing facility should be able to input its specific feedstock processing values rather than being forced to rely on default inputs. This would provide the most accurate carbon intensity value for the fuel.

Hydrochloric Acid (HCL)
It appears that staff may develop numerous methods for HCL recording. Typically, we support this type of flexibility for a diverse industry such as ours. In this particular case, however, we think the matter sufficiently simple as to not warrant such an approach. Instead, we recommend providing guidance in the regulation that HCL should be recorded as if it were 100% HCL rather than the actual volume of diluted HCL. LCFS FF10-3

Thank you, in advance, for your consideration of our views. We very much appreciate the continued excellent work of ARB staff. If I may be of any assistance, please feel free to contact me at any time at (573) 635-3893.

Sincerely,

Shelby Neal
Director of State Governmental Affairs

10_FF_LCFS_NBB

879. Comment: **LCFS FF10-1**

The commenter believes that ARB should include Tier 1 pathways for integrated oil and biodiesel producers, or integrated biodiesel producers should be able to utilize the Tier 2 GREET model, should circumstances merit it.

Agency Response: ARB staff will be conducting workshops post Board Hearing regarding the Tier 1 and Tier 2 categories and will provide subsequent guidance regarding pathway processing between Tier 1 and Tier 2. Staff currently believes that integrated oil and biodiesel facilities, or a biodiesel facility linked with an oil production facility would likely be a Tier 2 pathway.

880. Comment: **LCFS FF10-2**

The commenter states that it appears that the pathway for "uncooked" used cooking oil (UCO) has been removed and is therefore not available under Tier 1.

Agency Response: ARB staff currently assumes that if applicants do not need to process the used cooking oil by cooking prior to biodiesel production then those applicants should apply under Tier 2 to substantiate the lack of need to cook the oil and provide the sources of the UCO. See response to **LCFS FF10-1**.

881. Comment: **LCFS FF10-3**

The commenter recommends providing guidance in the regulation that HCL should be recorded as if it were 100% HCL rather than the actual volume of diluted HCL.

Agency Response: At this time ARB does not want to amend CA-GREET so as to create confusion based on unnecessary differences between CA-GREET and ANL's widely-used current GREET model. ARB plans to work with ANL in the future to address issues related to HCL.

This page intentionally left blank.

Comment letter code: 11-FF-LCFS-AJW

Commenter: Hessler, Christopher

Affiliation: AJW, Inc.

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

11_FF_LCFS
_AJW

June 19, 2015

Mr. Richard Corey
Executive Officer
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Mr. Corey:

The development of revisions to Low Carbon Fuel Standard (LCFS) has taken years, during which time you and your staff have exhibited the highest degree of professionalism and dedication. Sustained attention to detail has been evident by Air Resources Board Staff, even regarding occasionally esoteric market issues. The highest level of public service has been a constant for staff that, like you, have been engaged on this issue for years, as well as for staff only recently added to the LCFS team.

Not surprisingly, the result is an excellent set of proposed revisions to the LCFS which should strengthen the program and quicken the private sector's efforts to supply the California market with innovative, affordable, low carbon fuels.

Today I write to you seeking clarification on one provision in the proposed 15-Day Regulation Order. One requirement of the proposed Renewable Hydrogen Refinery Credit Pilot Program is that the renewable hydrogen used "must annually replace a minimum of one percent of all fossil hydrogen in the production of CARBOB or diesel fuel."

It seems reasonable to interpret the displacement of one percent of fossil hydrogen to be measured against the hydrogen used as refining feedstock for that refinery. This seems logical given that any credits generated under this provision would accrue to the refinery as a measure of the amount of fossil hydrogen displaced in that refining process by the renewable hydrogen. That said, the language quoted above does not specify this, leaving open the possibility that the language could be interpreted more broadly. LCFS FF11-1

Could you please clarify that the one percent displacement pertains to the refining feedstock of the individual refinery, and not to the fossil hydrogen used elsewhere in the refinery for process energy, or outside the refinery gate by the same regulated party or other parties? Thank you very much.

Regards,

Christopher J. Hessler

2200 Wilson Boulevard • Suite 310 • Arlington VA 22201 • Phone: 202.296.8086 • Fax: 202.289.3588

11_FF_LCFS_AJW

882. Comment: **LCFS FF11-1**

The commenter asks for clarification on the requirement of the proposed Renewable Hydrogen Refinery Credit Pilot Program that the renewable hydrogen used “must annually replace a minimum of one percent of all fossil hydrogen in the production of CARBOB or diesel fuel.”

Agency Response: Under the Renewable Hydrogen Refinery Credit Pilot Program, one percent displacement pertains to the refining feedstock of the individual refinery. The one percent displacement does not pertain to the fossil hydrogen used elsewhere in the refinery for process energy, and also does not pertain to fossil hydrogen used outside the refinery gate by the same regulated party or other parties.

This page intentionally left blank.

Comment letter code: 12-FF-LCFS-WPE

Commenter: Guilfoil, Elena

Affiliation: Washington State Dept. of Ecology

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

12_FF_LCFS
_WSDE

From: Guilfoil, Elena (ECY) [egui461@ECY.WA.GOV]
Sent: Monday, June 15, 2015 1:00 PM
To: Wade, Samuel@ARB
Subject: suggestion

Sam

While looking at the first line (Jan 31 for Electrical Distribution Utility) in Table 12, I had a lot of trouble finding the associated rule language. I assumed it would be in the annual reporting section. I suggest inserting a reference to 95491(a)(3)(D) for this line (as footnote maybe?) or include a pointer reference in the annual compliance report section directing the reader to the quarterly report section.

LCFS FF12-1

Elena Guilfoil

Elena Guilfoil / Air Quality Program / Department of Ecology / egui461@ecy.wa.gov / (360) 407-6855

12_FF_LCFS_WSDE

883. Comment: **LCFS FF12-1**

The comment suggests staff insert a reference such as footnote of the first line of Table 12 to Section 95491(a)(3)(D).

Agency Response: ARB made the suggested change and posted the revised proposal on June 4, 2015.

This page intentionally left blank.

Comment letter code: 13-FF-LCFS-CalETC

Commenter: Tutt, Eileen

Affiliation: California Electric Transport Coalition

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

13_FF_LCFS _CalETC

From: Eileen Tutt <Eileen@caletc.com>
Date: June 17, 2015 at 3:36:26 PM PDT
To: "Samuel.Wade@arb.ca.gov" <Samuel.Wade@arb.ca.gov>
Subject: LCFS regulation

Hi Sam

There are a couple typos you may want to consider fixing in the reg:

Page 102 – in paragraph c both references should probably be to section 95491(a)(1)(A)

Page 103 – on the 3rd line reference should probably be 95491(a)(1)(A) as well

LCFS FF13-1

Best

Eileen

Eileen Wenger Tutt
Executive Director
California Electric Transportation Coalition
1015 K Street, Suite 200
Sacramento, California 95814
(916) 551-1943 (o)
(916) 952-7026 (c)
eileen@caletc.com

13_FF_LCFS_CalETC

884. Comment: **LCFS FF13-1**

The commenter identified possible typographical errors in the proposed regulation.

Agency Response: ARB staff acknowledges the recommendation and has updated the regulatory text to fix these errors in the second 15-day package.

This page intentionally left blank.

Comment letter code: 14-FF-LCFS-MPP

Commenter: Constantino, Jon

Affiliation: Manatt, Phelps & Phelps

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

14_FF_LCFS
_MPP

From: Costantino, Jon [mailto:JCostantino@manatt.com]
Sent: Monday, June 08, 2015 8:38 AM
To: Vergara, Floyd@ARB; Kitowski, Jack@ARB
Cc: Wade, Samuel@ARB
Subject: 95849 typo

Floyd and Jack,

FYI--I think I found a couple of typos in the 15 day package. Page 33 and 101 refer to section 95849 rather than 95489.

LCFS FF14-1

Jon

Jon Costantino
Senior Advisor

Manatt, Phelps & Phillips, LLP
1215 K Street, Suite 1900
Sacramento, CA 95814
D (916) 552-2365 **C** (916) 716-3455

JCostantino@manatt.com
manatt.com

CONFIDENTIALITY NOTICE: This e-mail transmission, and any documents, files or previous e-mail messages attached to it, may contain confidential information that is legally privileged. If you are not the intended recipient, or a person responsible for delivering it to the intended recipient, you are hereby notified that any disclosure, copying, distribution or use of any of the information contained in or attached to this message is STRICTLY PROHIBITED. If you have received this transmission in error, please immediately notify us by reply email and destroy the original transmission and its attachments without reading them or saving them to disk. Thank you.

14_FF_LCFS_MPP

885. Comment: **LCFS FF14-1**

The commenter identified two typographical errors in the 15 day package. Page 33 and 101 refer to section 95849 rather than 95489

Agency Response: The errors were addressed in the second 15-day package.

This page intentionally left blank.

Comment letter code: 15-FF-LCFS-POET

Commenter: Darlington, Tom

Affiliation: Poet

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

15_FF_LCFS _POET

From: Chowdhury, Hafizur@ARB
Sent: Friday, June 19, 2015 9:22 AM
To: 'Heather Gullic'; Tom Darlington
Cc: Bob Whiteman; Wade, Samuel@ARB; Brieger, William@ARB
Subject: RE: Conference call on records needed

Hi Heather:

Yes, as the proposal is written, the company would need all of the records available and the auditor would verify that they existed and had the content reported to ARB.

LCFS FF15-1

Regards,
-Hafizur

From: Heather Gullic [mailto:HeatherGullic@poetep.com]
Sent: Thursday, June 18, 2015 10:57 AM
To: Chowdhury, Hafizur@ARB; Tom Darlington
Cc: Bob Whiteman; Wade, Samuel@ARB; Brieger, William@ARB
Subject: RE: Conference call on records needed

Hi Hafizur,

I am wondering about the 3rd party option – does the auditor need to see all 2 years' worth of invoices? The only difference between the two options is one is viewed on site and the other is scanned and submitted to CARB?

We would like to understand the 3rd party option now so we have time to submit a formal comment if needed. Thanks again for answering some of our questions.

LCFS FF15-1 cont.

Heather Gullic
Tax Supervisor

Poet Ethanol Products
Poet Grain, LLC
3939 N. Webb Rd.
Wichita, KS 67226
P/316.303.1386
F/316.267.1071
poetep.com

From: Chowdhury, Hafizur@ARB [mailto:hchowdhu@arb.ca.gov]
Sent: Thursday, June 18, 2015 12:43 PM
To: Tom Darlington
Cc: Bob Whiteman; Heather Gullic; Wade, Samuel@ARB; Brieger, William@ARB
Subject: RE: Conference call on records needed

Tom:

Our apologies for the delayed response. Due to the LCFS re-adoption workload and preparing Board materials for July Board Hearing, we prefer to respond to your question via email rather than hold a conference call. The proposed regulation would require all the invoices and receipts you describe. If this is problematic we encourage you to submit a formal written comment on this issue.

In addition, I'd call your attention to the fact that the proposed regulation also provides an option for the applicant to submit an independent third-party audit report which documents all the feedstock purchases, fuel sales and co-product sales to cover a two-year period. We think this option will allow facilities to avoid extensive submission of information to ARB. We'll be working to flesh out this option in greater detail next year.

Regards,
-Hafizur

Hafizur Chowdhury, P.E.
Air Resources Engineer
California Air Resources Board
(916) 322-2275

California is in a drought emergency. Visit www.SaveOurH2O.org for water conservation tips.

From: tdarlington21@gmail.com [mailto:tdarlington21@gmail.com] **On Behalf Of** Tom Darlington
Sent: Thursday, June 18, 2015 9:10 AM
To: Chowdhury, Hafizur@ARB
Cc: Whiteman, Bob; Gullic, Heather
Subject: Re: Conference call on records needed

Hafizur - are we going to have a call today? I am tied up after 2pm PT.

On Mon, Jun 15, 2015 at 3:47 PM, Chowdhury, Hafizur@ARB <hchowdhu@arb.ca.gov> wrote:

Tom:

Thanks for the email. Let me get back to you on those dates to find out who is available for the conference call.

Regards,
-Hafizur

From: tdarlington21@gmail.com [mailto:tdarlington21@gmail.com] **On Behalf Of** Tom Darlington
Sent: Monday, June 15, 2015 8:56 AM
To: Chowdhury, Hafizur@ARB
Cc: Whiteman, Bob; Gullic, Heather
Subject: Conference call on records needed

Hafizur - We would like to schedule a conference call with you on the 17th or 18th to discuss the records request for recertifying under the new LCFS. I am suggesting these dates because at least one of us is not available on other dates in the next 2 weeks.

I will participate, along with Heather Gullick and Bob Whiteman of POET. I will prepare an agenda.

Overall, we view the records request (as we understand it) as extreme. We need to try to find a way to make it less extreme and more workable for everyone. LCFS FF15-2

Thanks,

Tom Darlington

Confidentiality Notice: The information contained in this e-mail message, including any attachments, is for use by the intended recipient(s) only and contains information that may be legally privileged, confidential, trade secret, proprietary in nature or copyrighted under applicable law. If you are not the intended recipient(s), you are hereby formally notified that any use, disclosure, copying, distribution or the taking of any action in reliance on the contents of this e-mail transmission, in whole or in part, is strictly prohibited. This e-mail transmission does not constitute a consent to the use of sender's contact information for direct marketing purposes or for transfers of data to third parties. If you are not the intended recipient(s), please promptly notify the sender by reply e-mail and destroy all copies of the original message.

15_FF_LCFS_POET

886. Comment: **LCFS FF15-1**

The commenter asks if the auditor is required to review two years of data and invoices with the third party option.

Agency Response: Under section 95488(c)(3)(A)(3), applicants may choose to utilize a 3rd party verification in lieu of receipts or invoices for energy consumption, fuel sales, feedstock purchases, or co-product sales. The auditor is still required to review the plant's two years data and invoices.

887. Comment: **LCFS FF15-2**

The commenter believes Tier 1 application submittal documentations (such as invoices and receipts for all forms of energy consumptions, fuel production process, all fuel sales, all feedstocks purchases, and all co-products sold) to be excessive.

Agency Response: Staff has made a few adjustments in the regulation under second 15-day changes package for Tier 1 fuel pathways. Under the section 95488(a)(2) for *recertification of legacy pathways* fuel providers may apply for recertification as set forth below to replace pathway certifications subject to being deactivated.

> *(A) Applicants seeking to recertify a legacy pathway shall begin the application process by completing the online account registration process and submitting an electronic New Pathway Request Form prior to February 1, 2016, indicating that they are seeking recertification of a legacy pathway.*
>
> *(B) Recertifications will be processed by the Executive Officer using information previously supplied to the Executive Officer under the provisions of the former LCFS regulation order, provided such information was complete pursuant to the former LCFS regulation's requirements. The requirements of subsections 95488(c)(3)-(5) and subsection 95488(e) are not applicable to recertifications, unless the Executive Officer specifically requests such information from an applicant.*
>
> *(C) The Executive Officer will determine the classification of each recertification under the tier structure described in subsection 95488(b).*

(D) The result of the Executive Officer's decisions on recertifications shall be final and not subject to further appeal. Denied applicants may submit New Pathway Request Forms pursuant to section 95488.

However, if applicants submit a New Pathway Request form and have been notified by the Executive Officer that the pathway described in the New Pathway Request Form falls under the Tier 1 provisions found at section 95488(b)(1) the applicants are required to submit necessary documentations stated under 95488(c)(3). Staff currently receives process energy receipts and fuel sales information. Without other information, such as feedstock purchase/consumption documentation it is not possible to confirm the yield of the fuel. Yield is typically in terms of volume of fuel produced per mass of feedstock (corn ethanol gal/Btu). Furthermore, the co-product credits can be substantial and the only way to verify that a co-product credit is warranted is to establish that it was used for something, which can most easily be proven through documentation or receipts. Staff have been maintaining confidential business information (CBI) since the inception of the LCFS regulation and plan to keep the same strategy and treat this new category of CBI likewise.

Comment letter code: 16-FF-LCFS-POET

Commenter: Darlington, Tom

Affiliation: Poet

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

16_FF_LCFS _POET

From: Tom Darlington [mailto:tdarlington@airimprovement.com]
Sent: Monday, June 08, 2015 6:35 PM
To: Chowdhury, Hafizur@ARB
Subject: Re: guidance

I will try. They are pretty anxious about this records request. They want to find a workable solution ASAP.

On 6/8/15 1:29 PM, Chowdhury, Hafizur@ARB wrote:

Tom:

Would you please hold this discussion as I mentioned you on our earlier phone conversation. Let me find out more information for you. Okay.

Hafizur

From: Tom Darlington [mailto:tdarlington@airimprovement.com]
Sent: Monday, June 08, 2015 10:21 AM
To: Chowdhury, Hafizur@ARB
Subject: Fwd: RE: guidance

They are still having problems with this record request. See below. I will call you.

Tom

-------- Forwarded Message --------
Subject: RE: guidance
Date: Mon, 8 Jun 2015 16:34:19 +0000
From: Bob Whiteman <bobwhiteman@poetep.com>
To: Heather Gullic <HeatherGullic@poetep.com>, Tom Darlington <tdarlington@airimprovement.com>, Sahay, Shailesh <Shailesh.Sahay@POET.COM>
CC: Shon Van Hulzen <Shon.VanHulzen@POET.COM>

Yes Tom, this is much, much more than a utility invoice where you would have around 24 over a 2 year period. For our larger facilities, we could be talking about well over 10,000 records for grain receipts, and DDG/ethanol sales. Even in an enforcement scenario, I would say it would be very unusual to ask for scanned copies of all records if those records weren't suspected of being fraudulent through the earlier sample.

LCFS FF16-1

It would be a more manageable request if they were going to be happy with a download of data, but a request for scanned copies of all records will result in the plants needing to actually employ an addition person(s) to assemble that volume of information. We would be happy to participate in the call with CARB if that would help.
Thanks,
Bob

Bob Whiteman
CFO
Poet Ethanol Products
3939 N Webb Rd
Wichita, KS 67226
(316) 303-1382
(316) 267-1071 fax

From: Heather Gullic
Sent: Monday, June 08, 2015 11:11 AM
To: Tom Darlington; Sahay, Shailesh; Bob Whiteman
Cc: Shon Van Hulzen
Subject: RE: guidance

Hi Tom,

Thanks for checking into this. I don't agree with their audit argument. In most audits, samples are picked and details like invoices etc are provided just for the sample transactions. I have never seen anyone ask for 2 years of invoices for every transaction. LCFS FF16-1 cont.

Could you follow up and find out what needs to be seen on the items – meaning what are we allowed to redact/black out? Providing this info would show - for example - farmers name and address, price, volume and origin. We would also be sharing all of this detail for DDG and ethanol (along with where the product is shipped). I am concerned about push back from the plants. They prefer for their business details to remain private. LCFS FF16-2

Thanks,
Heather

From: Tom Darlington [mailto:tdarlington@airimprovement.com]
Sent: Monday, June 08, 2015 10:57 AM
To: Sahay, Shailesh; Heather Gullic; Bob Whiteman
Cc: Shon Van Hulzen
Subject: Re: guidance

I talked with ARB about the fact that it is a big job to scan all this information in and create these spreadsheets. But ARB does not see a way around scanning in all these invoices and creating the spreadsheets. They realize it is a lot of work, but they also note that every plant that sells into California will have to do this anyway in the future, in case ARB comes out and audits the plant. If there are are other questions about this, I would be glad to continue to contact ARB. LCFS FF16-1 cont.

Tom

On 6/4/15 11:25 AM, Sahay, Shailesh wrote:

> Thanks, Heather. I absolutely agree with your reaction, and asked Tom about this myself. I've copied the language from the proposed regs regarding what invoices need to be produced for a Tier 1 application below. It appears that, with the approval of CARB, we could produce a report by a third-party auditor documenting the sales in lieu of producing all the invoices. Of course, the third-party auditor might demand to see the invoices anyway. LCFS FF16-3
>
> Tom is calling CARB to see if he can get clarification on the invoice requirement. I've cc'd him here in case he has any other input at this point. I also am not yet comfortable with handing over this quantity of sales information to the agency. LCFS FF16-2 cont.
>
>> 2. Invoices and receipts for all forms of energy consumed in the fuel production process, all fuel sales, all feedstock

purchases, and all co-products sold. Invoices shall be submitted in electronic form. Each set of invoices shall be accompanied by a spreadsheet summarizing the invoices. Every invoice submitted shall appear as a record in the summary. Each record shall, at a minimum, specify in a separate column the period covered by the purchase, the quantity of energy purchased during that period, the invoice amount, and any special information that applies to that record (the special information column need not be populated for every record). For each form of energy consumed, the two-year total and average consumption shall be reported in the spreadsheet. These two-year totals and averages shall be used to calculate the per-million-Btu and per-megajoule energy consumption inputs used to calculate the life cycle CI of the fuel pathway.

a. *Period Covered.* The period covered shall be the most recent two-year period of relatively typical operation.

b. *Production Processes Covered.* The invoices submitted under this provision shall cover the energy consumed in all unit operations devoted to feedstock handling and pre-processing; fuel production; co-product handling and processing; waste handling, processing, and treatment; the handling, processing and use of chemicals, enzymes, and organisms; the generation of process energy, including the generation, handling and processing of combustion fuels; and all plant monitoring and control systems. If the fuel produced or any by-products or co-products receive additional processing after they leave site, such as additional distiller's grains drying or fuel distillation, invoices covering the energy consumed for those processes must also be submitted. If the fuel production facility is co-located with one or more unrelated facilities, and energy consumption invoices are not separately available for the fuel production process, the applicant shall obtain a third-party energy audit sufficient to establish the long-term, typical energy consumption patterns of the fuel production facility.

3. In lieu of receipts or invoices for fuel sales, feedstock purchases, or co-product sales, the applicant may seek Executive Officer approval to submit audit reports prepared by independent, third-party auditors that document fuel sales, feedstock purchases, or co-product sales.

900 7th Street NW, Suite 820
Washington, DC 20001
P/ +1 (202) 756-5604
F/ +1 (202) 735-5430
C/ +1 (202) 740-8554
poet.com

-----Original Message-----
From: Heather Gullic [mailto:HeatherGullic@poetep.com]
Sent: Wednesday, June 03, 2015 2:56 PM
To: Sahay, Shailesh; Whiteman, Bob
Cc: Van Hulzen, Shon
Subject: RE: guidance

Hi Shai,

I have a question. Reading pages 3 & 4, Tom says that for the renewal of pathways ALL invoices for feedstock purchases, ethanol sales, and DGS sales for a 2 year period must be submitted to CARB. Can we confirm this? The volume of this is crazy and redacting information on the invoices would be a huge undertaking. The rest makes sense, it will be a big job and we should start preparing items now if we want to be ready to submit July or shortly after.

LCFS FF16-1 cont.

Thanks,
Heather

-----Original Message-----
From: Sahay, Shailesh [mailto:Shailesh.Sahay@POET.COM]
Sent: Wednesday, June 03, 2015 1:10 PM
To: Heather Gullic; Bob Whiteman
Cc: Shon Van Hulzen
Subject: FW: guidance

Bob and Heather,

Our consultant Tom Darlington prepared the attached guidance for us on applying for pathway approval under the new California LCFS regs, assuming that the regs are finalized as proposed.

Please let me know if you have any questions.

-Shai

Shailesh Sahay
Regulatory Counsel

POET
900 7th Street NW, Suite 820
Washington, DC 20001
F/ +1 (202) 735-5430

C/ +1 (202) 740-8554
poet.com

-----Original Message-----
From: Tom Darlington [mailto:tdarlington@airimprovement.com]
Sent: Wednesday, June 03, 2015 9:51 AM
To: Sahay, Shailesh
Subject: guidance

Use this one instead. I turned the editing function off.

Tom

--
Tom Darlington
Office: 616-335-8922
Cell: 248-921-5096

Confidentiality Notice: The information contained in this e-mail message, including any attachments, is for use by the intended recipient(s) only and contains information that may be legally privileged, confidential, trade secret, proprietary in nature or copyrighted under applicable law. If you are not the intended recipient(s), you are hereby formally notified that any use, disclosure, copying, distribution or the taking of any action in reliance on the contents of this e-mail transmission, in whole or in part, is strictly prohibited. This e-mail transmission does not constitute a consent to the use of sender's contact information for direct marketing purposes or for transfers of data to third parties. If you are not the intended recipient(s), please promptly notify the sender by reply e-mail and destroy all copies of the original message.

--
Tom Darlington
Office: 616-335-8922
Cell: 248-921-5096

Confidentiality Notice: The information contained in this e-mail message, including any attachments, is for use by the intended recipient(s) only and contains information that may be legally privileged, confidential, trade secret, proprietary in nature or copyrighted under applicable law. If you are not the intended recipient(s), you are hereby formally notified that any use, disclosure, copying, distribution or the taking of any action in reliance on the contents of this e-mail transmission, in whole or in part, is strictly prohibited. This e-mail transmission does not constitute a consent to the use of sender's contact information for direct marketing purposes or for transfers of data to third parties. If you are not the intended recipient(s), please promptly notify the sender by reply e-mail and destroy all copies of the original message.

--
Tom Darlington
Office: 616-335-8922
Cell: 248-921-5096

16_FF_LCFS_POET

888. Comment: **LCFS FF16-1**

The commenter believes Tier 1 application submittal documentations (such as invoices and receipts for all forms of energy consumptions, fuel production process, all fuel sales, all feedstocks purchases, and all co-products sold) to be excessive.

Agency Response: See response to **LCFS FF15-2**.

889. Comment: **LCFS FF16-2**

The commenter is asking for guidance in redacting confidential information for Tier 1 applications.

Agency Response: See response to **LCFS FF15-2**.

890. Comment: **LCFS FF16-3**

The commenter asks if the auditor is required to review two years of data and invoices with the third party option.

Agency Response: See response to **LCFS FF15-1**.

This page intentionally left blank.

Comment letter code: 17-FF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

17_FF_LCFS _HBC

From: Logan Caldwell, Houston BioFuels Consultants, LLC June 19, 2015

Documentation of Tier 1 Application Input Data: Chemical, Enzyme and Yeast Use

While purchase invoices show the amount of chemicals, enzymes and yeast purchased or sold by the ethanol producer during a given period, they do not indicate how much was used. To get an accurate estimate of the amount used, the starting and ending inventory of these items would be needed such that the amount used could be calculated. **What documentation would be acceptable for the starting and ending inventory?** LCFS FF17-1

Also, some of these are purchased frequently, a frequently as daily in some cases from what I understand, but others are purchased infrequently. Those with frequent purchases will have voluminous documentation. LCFS FF17-2

The regulations do not provide for the independent, third-party auditor to attest in lieu of documentation. It is proposed that attestation from the producer or attestation by an independent, third party auditor be considered as an alternative to detailed documentation? LCFS FF17-3

From: Logan Caldwell, Houston BioFuels Consultants, LLC June 19, 2015

Documentation of Tier 1 Application Input Data: Chemical, Enzyme and Yeast Use

For the DGS yield/gallon of ethanol production, what documentation will be required? LCFS FF17-4

The calculation of DGS yield requires an accurate measure of the moisture in the DGS to calculate the bone dry yield, what documentation requirements will there be, if any, for the moisture? LCFS FF17-5

DGS is often shipped by the ethanol producer by the truckload. Should documentation of each shipment be required, there will an enormous amount of documentation and there will still be an issue of documenting the starting and ending inventory in a given period. LCFS FF17-6

It is suggested that an attestation of the yield, in lieu of detailed documentation, be permitted as a means of documenting the DGS yield. Attestation could either be by the producer or an independent, third party. LCFS FF17-7

From: Logan Caldwell, Houston BioFuels Consultants, LLC June 19, 2015

Documentation of Tier 1 Application Input Data: Third Party Auditor

Third Party Auditor

95488(c)(3)(A)(3) of the proposed regulations states: "In lieu of receipts or invoices for fuel sales, feedstock purchases, or co-product sales, the applicant may seek Executive Officer approval to submit audit reports prepared by independent, third-party auditors that document fuel sales, feedstock purchases, or co-product sales."

Comments:

Presently, for 2A and 2B applications, a top company official prepares an attestation letter in lieu of submitting documentation of fuel sales, feedstock purchases, and co-product sales. **What will be the criteria to determine whether a person is a qualified independent, third-party auditor?** LCFS FF17-8

From: Logan Caldwell, Houston BioFuels Consultants, LLC June 19, 2015

Documentation of Tier 1 Application Input Data: Transportation Distances and Mode

Feedstock

Regarding transportation of corn to the ethanol plant, the Midwest ethanol producer receives corn from a storage facility on the farm where the corn is produced or from an elevator. In neither case is the truck delivering the corn going to have included on its bill of lading the distance from the field to the collection center (storage facility or elevator). Developing this information from each ethanol producer is likely to be time-consuming and the amount of documentation is going to be voluminous for a two year period. LCFS FF17-9

Regarding transportation of corn from the collection center to the ethanol plant, there are an extraordinary number of truckloads of corn, and so the documentation will be voluminous.

For both of these, how will the ethanol plant get this data going back two years if it does not yet have a system in place to document?

As an alternative to documentation of the actual distances, it is suggested that the Midwest ethanol producers (and others in similar situation) have an option of using the 1.8b default values for transportation distances, and attesting that the default values are reasonable estimates of actual distances. LCFS FF17-10

Otherwise an extraordinary amount of work would be needed to prepare the documentation, as well as to audit the documentation, whether it is the third-party auditor or the CARB compliance auditor. LCFS FF17-9 cont.

For other facility locations outside the Midwest, the plants ship feedstock and products by rail, so that is somewhat easier to document, but again the documentation is voluminous, and using the current method of having the producer attest to the accuracy would be a more practical. LCFS FF17-11

Ethanol Product

Midwest plants typically load the ethanol onto railcars at the production facility. There is normally no trucking of ethanol from the ethanol facility to the rail loading location. **What documentation will be needed to demonstrate to CARB that it is zero?** LCFS FF17-12

Midwest plants typically ship to multiple locations in California. Each will have a different distance. The physical pathway demonstration requires only one supply route. **Can the ethanol producer use the same distance as in the physical pathway demonstration, and can that documentation be sufficient for documenting this distance?** LCFS FF17-13

Midwest plants typically do not know details of transport of their ethanol once it reaches the first terminal in California. **How then are they to document the distance by truck to the blending terminal? For the transport of EtOH from the blending terminal to the retail outlet, the CA-GREET 2.0 uses a default value. How about allowing a default value for this too?** LCFS FF17-14

From: Logan Caldwell, Houston BioFuels Consultants, LLC June 19, 2015

Retroactive Credit Generation Comments

In section 95486(a)(2) dealing with "No Retroactive Credit Generation" there is the following section:

"Notwithstanding this section, the Executive Officer may convert provisional credits to fully transferrable credits at any time, pursuant to section 95488 (d) and (e). Where an application or demonstration pursuant to sections 95488 or 95489 has been completed but not yet approved, the applicant may report, and the LRT-CBTS will reflect, information supporting provisional credits/deficits. Such provisional credits may not be used for any purpose until fully recognized. When the Executive Officer approves the section 95488 or 95489 application or demonstration, the Executive Officer will recognize any such provisional credits generated during the quarter in which the approval takes place, and one previous quarter, provided that the application was complete during that previous quarter."

Two comments:

1. Please provide details on how "completed" will be determined for the purposes of this section. Often during the course of review of an LCFS Method 2A or 2B application, ARB staff will request additional information or supporting documentation. Should such a request be made, would this deem the application incomplete? It may be helpful to all concerned if CARB issued a detailed checklist of the items required to be included with the application package for it to be deemed complete. The challenge will be that new pathway features, not appearing in previous pathways, may have unique information and documentation requirements, and be difficult to know beforehand what constitutes completeness. LCFS FF17-15
2. Considering the number of applications to be considered by ARB staff when processing the "batches" of applications, it may be that more than two quarters elapses. This could mean that a significant number of carbon credits are ineligible. Please consider providing retroactive credit generation for more than two quarters in the context of processing the batches of applications. LCFS FF17-16

17_FF_LCFS_HBC

891. Comment: **LCFS FF17-1**

The comment requests clarification on what chemicals, enzymes and yeast documentation would be acceptable for the starting and ending inventory.

Agency Response: ARB staff proposes that the applicant provide the year-end facility inventory report from the company's accounting department where feedstock, fuels, and warehouse inventory should be documented. Individual receipts are not needed as long as the accounting department certifies the records provided. This proposal will be presented to stakeholders in a future workshop and draft guidance document.

892. Comment: **LCFS FF17-2**

The comment states that some of items are purchased frequently, as frequently as daily, and those will have voluminous documentation.

Agency Response: ARB staff proposes that certified accounting department data could be submitted in place of individual receipts. The company's accounting department should have a ledger book showing all transactions. If the ledger book data is certified by the accounting department, it could be used in place of receipts. This will be explored further in a future workshop and draft guidance document.

893. Comment: **LCFS FF17-3**

The comment states that the regulations do not provide for the independent, third-party auditor to attest in lieu of documentation and asks if that is something that could be reconsidered.

Agency Response: The regulation specifies that a third party verifier could be used to audit the data. As mentioned in the response to **LCFS FF17-2**, the company's accounting department could provide the values needed.

894. Comment: **LCFS FF17-4**

The comment asks what documentation will be required for the DGS yield per gallon of ethanol production.

Agency Response: Similar to the response to **LCFS FF17-2**, the accounting department should have a record of ethanol production and sales, DGS production and sales, as well as purchased bushels of corn (or feedstock) because it has to collect payment from buyers and pay the vendors. The amounts of feedstock and fuel volumes should be recorded in the ledger book for year-end tax purposes.

895. Comment: **LCFS FF17-5**

The comment asks what documentation will be required in order to determine the DGS yield per gallon.

Agency Response: Tier 2 applicants need to have the moisture content for each type of DGS (wet, modified, and dry) from the on-site facility's lab or recorder. Besides DGS, corn oil production associated with ethanol production also needs to be factored into the calculation and report. See response to **LCFS FF17-4**.

896. Comment: **LCFS FF17-6**

The comment states that DGS is often shipped by the ethanol producer by the truckload. Should documentation of each shipment be required, there will an enormous amount of documentation and there will still be an issue of documenting the starting and ending inventory in a given period.

Agency Response: See response to **LCFS FF15-1** and **LCFS FF17-2**.

897. Comment: **LCFS FF17-7**

The comment suggests that an attestation of the yield, in lieu of detailed documentation, be permitted as a means of documenting the DGS yield. Attestation could either be by the producer or an independent, third party.

Agency Response: Please see response to **LCFS FF15-1**.

898. Comment: **LCFS FF17-8**

The comment states that for 2A and 2B applications under the current LCFS, a top company official prepares an attestation letter in lieu of submitting documentation of fuel sales, feedstock purchases, and co-product sales. The commenter then asks what criteria will be used to determine whether a person is a qualified independent, third-party auditor.

Agency Response: The commenter's first statement is not accurate. The attestation letter from the company headperson certifies the accuracy of data provided to ARB but does not substitute for the need to provide documentation of fuel sales, feedstock purchases, and co-product sales in the form of accounting department records. Staff will explore the detailed criteria for determining qualified auditors in a future workshop. See response to **LCFS 7-3** and **LCFS 32-20**.

899. Comment: **LCFS FF17-9**

The comment states that documenting the transportation of corn from the field to collection center and collection center to the ethanol plant will be voluminous.

Agency Response: CA-GREET2.0 includes two corn transportation segments for ethanol produced at Midwestern facilities: from corn field to collection center over a distance of 10 miles by Medium Diesel Truck (MDT) and 40 miles to the ethanol plant by Heavy Duty Diesel Truck (HDDT). For corn transport to California, in addition to distances stated above, there is an average1,400-mile distance by rail to the California ethanol facilities from Midwest. These transportation values can be used as default parameters when accompanied by an attestation that the default values are reasonable estimates of actual distances. When the default values are not a reasonable estimate, applicants should provide an estimate of mileage which will be verified by staff based on the plant location. Please also see response to **LCFS FF15-1**.

900. Comment: **LCFS FF17-10**

The commenter requests that as an alternative to the documentation of actual distances, Midwest ethanol producers (and others in similar situation) have the option of using the 1.8b default values for transportation distances, and attesting that the default values are reasonable estimates of actual distances.

Agency Response: See response to **LCFS FF17-9**. For fuel transport to California, applicants must specify exact mileage distances from the fuel production facilities to locations in Northern or Southern California. These distances can be obtained from generic websites, for instances, truck transport from Google Maps, ship or rail transport from ship and rail companies.

901. Comment: **LCFS FF17-11**

The comment states that documenting transportation distances for facilities located outside the Midwest would be onerous and suggests that the producer use the current method and have the producer attest to the accuracy.

Agency Response: See response to **LCFS FF17-9**.

902. Comment: **LCFS FF17-12**

The comment states that Midwest plants typically load the ethanol onto railcars at the production facility. There is normally no trucking of ethanol from the ethanol facility to the rail loading location and inquires as to what documentation will be needed to demonstrate to CARB that the trucking distance is zero.

Agency Response: There are several ways to demonstrate that no trucking of ethanol from the ethanol facility to the rail loading occurs, including photos of rail loading at the ethanol plant, satellite images, the head of the facility's attestation letter, or a third party verifier.

903. Comment: **LCFS FF17-13**

The comment states that Midwest plants typically ship to multiple locations in California. Each will have a different distance. Can the ethanol producer use the same distance as in the physical pathway demonstration, and can that documentation be sufficient for documenting this distance?

Agency Response: For ethanol shipped to California, the applicant can submit the exact distance by rail from the origin to the Stockton rail yard (for Northern California unloading) and to Commerce or Los Angeles (for Southern California unloading).

904. Comment: **LCFS FF17-14**

The comment states that Midwest plants typically do not know details of transport of their ethanol once it reaches the first terminal in California. How then are they to document the distance by truck to the blending terminal? How about allowing a default value?

Agency Response: If the distance by truck to the blending terminal is unknown, the applicant can use 50 miles for 80 percent shares (20 percent is assumed to have negligible transportation).

905. Comment: **LCFS FF17-15**

The commenter requests clarification on when an application is deemed complete.

Agency Response: ARB staff currently process applications and deems them complete once all information to determine a CI has been received and the applicant has addressed all pertinent comments and questions from staff. Staff will be conducting workshops post Board Hearing regarding the Tier 1 and Tier 2 categories and will provide a staff proposal and subsequent guidance regarding pathway processing between Tier 1 and Tier 2. Issues and detailed concerns regarding a pathway application being deemed complete will be discussed with stakeholders and subsequent guidance will be provided.

906. Comment: **LCFS FF17-16**

The commenter requests that ARB consider providing retroactive credit generation for more than two quarters in the context of processing the batches of applications.

Agency Response: Staff appreciates the commenters concern regarding processing of applications and for suggesting a potential mitigating solution by allowing for retroactive credits. Staff will be conducting workshops after Board Hearing regarding pathway application processing and will discuss issues related to this timing. The LCFS does not provide for retroactive crediting due to fairness problems that would result when retroactive credits entered the LCFS credit market after market participants had made credit buying and selling decision based on data that had been timely reported in the LRT-CBTS. Under § 95486(a)(2), "Unless expressly provided elsewhere in this subarticle, no credits may be generated or claimed based on section 95489 provisions, supplying electricity for transportation, or any transaction or activity regarding a transportation fuel for any act occurring in a quarter for which the quarterly reporting deadline has passed." Staff will process applications as rapidly as possible. Tier 1 and Tier 2 fuels will likely move through the process more quickly than the commenter assumes based upon the second 15-day changes to the regulation. Under § 95488(a)(2)(B) the regulation allows recertification to be conducted using existing information for the pathways. Using the existing information supplied to staff for Method 2 or Method 1 defaults should save time when processing recertification pathways. The time saved from processing recertification pathways should also save time overall and should reduce the need for stakeholders to request retroactive credits.

Comment letter code: 18-FF-LCFS-CE

Commenter: Campbell, Todd

Affiliation: Clean Energy Fuels

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

18_FF_LCFS_CE

From: Todd R. Campbell [mailto:Todd.Campbell@cleanenergyfuels.com]
Sent: Friday, June 12, 2015 4:10 PM
To: Wade, Samuel@ARB; Vergara, Floyd@ARB; Prabhu, Anil@ARB; Singh, Manisha@ARB; Corey, Richard@ARB
Cc: Harrison Clay; Brandon Price; Ryan Kenny; Tim Carmichael; Philip Sheehy; Jeff Rosenfeld (jeffrey.rosenfeld@icfi.com); Patrick Couch (patrick.couch@gladstein.org)
Subject: Memo addressing CE's concerns and need for clarification on the 15 Day Proposed Regulation Order of the LCFS

Attachments: LCFS Re-Adoption Memo 2015 06 10 FINAL.pdf

Dear Sam and ARB LCFS Team,

First, on behalf of Clean Energy's LCFS Team, we would like to collectively thank you for your willingness to meet and discuss with us our concerns over the LCFS' 15 Day Proposed Regulation Order on Tuesday, June 9. Your immediate attention to our industry's concerns is very much valued.

Second, based on your recommendation during our meeting earlier this week, we are submitting the attached memo that outlines our primary concerns and need for further confirmation or clarification of the proposed regulation order's intent.

Finally, we would like to express our gratitude in advance for your thoughtful and timely response to the attached memo as it will provide our industry with a clear understanding of the ARB staff's regulatory intent on pathways and credit generation under the proposed rule. Thank you!

Sincerely,

Todd R. Campbell

Vice President of Public Policy & Regulatory Affairs

Clean Energy

office 949.437.1400 | **fax** 562-395-1666
email tcampbell@cleanenergyfuels.com

To: **Sam Wade & Staff, Air Resources Board**

From: **Todd Campbell & Harrison Clay, Clean Energy Fuels Corp.**

Re: **LCFS Re-Adoption Language; 15 Day Comment**

Date: **June 12, 2015**

We would like to thank you all for taking the time to meet with us on June 9th to address our concerns with the latest iteration of the LCFS Re-Adoption rule currently up for comment. The purpose of this memo is to memorialize the concerns and clarifications that were discussed in the meeting and to help facilitate a smooth transition to the LCFS Re-Adoption starting in 2016. Clean Energy is committed to working with the ARB to develop and implement suitable solutions to ensure the ongoing success of the LCFS program.

Topics of Discussion:

1. **§ 95488(a): Current and Pending LCFS Pathways Grandfathered into the Re-Adoption.** Our understanding is that the Re-Adoption allows for all fuel pathways that were in effect on 12/31/2015 to remain valid until ARB re-certifies the carbon intensities for CNG and LNG fuels with CA-GREET2.0. This re-certification could occur as late as Q4 2016. Upon re-certification, (no later than 12/31/2016), all "grandfathered" pathways will be deactivated and replaced by the re-certified carbon intensity pathway. We were concerned that the language for the deactivation schedule suggests that "grandfathering" may be limited to pathways certified by 12/31/2015 *and* applied for before 12/1/2014. We have a number of pathways applied for after 12/1/2014 that we were concerned would lose their ability to generate and sell credits after 1/1/2016. Therefore we were greatly relieved that the ARB confirmed in our meeting that every pathway in effect as of 12/31/2015 will be valid and remain in effect through the start of the Re-Adoption until re-certification (no later than 12/31/2016). LCFS FF18-1

   CE currently has three pathways (CERF Shelby, Westside, and EIF Kansas City) that are up for public comment and should be certified in the next month. CE also has two outstanding applications submitted after 12/1/2014 (MDU and BFI/Complexe Enviro). Both MDU and BFI/Complexe Enviro were submitted after 12/1/2014 and need to be certified in order to be grandfathered into the Re-Adoption. The ARB assured us during the meeting that all current pending applications will be approved and certified by 12/31/2015. It is our understanding that the ARB is going to spend the remainder of 2015 certifying all pending pathways under the old LCFS rule and then re-certify all those same pathways during 2016. This means that both MDU and BFI will be certified by 12/31/2015 and will be able to generate and monetize LCFS credits through 2016 while their recertification applications are pending.

LCFS FF18-1 cont.

BFI/Complex Enviro first started production around September 2014 - which means that the facility will not have the full two years of operational data to support a fully certified pathway until September 2016. However, it is our understanding that since BFI will be grandfathered under the old LCFS program, CE will be able to generate *and* monetize credits pursuant to the old LCFS regulation during 2016. Once two years of operating data is received in 2016, CE will notify the ARB to re-certify the BFI/Complexe Enviro pathway which will occur before the end of 2016.

With respect to Clean Energy's CNG and LNG sales from fossil fuel natural gas, it is our understanding that the following process will apply:

- Clean Energy's approximately 150 CNG stations will be grouped and file a Tier 1 application.
- Pending approval of the CNG stations pathway, Clean Energy will continue to be able to generate and sell credits *under the existing LCFS CNG default pathway through 2016.*
- Clean Energy LNG pathways will be filed individually by facility in a Tier 1 application.
- Clean Energy will be able to generate and sell LNG credits *under the existing LNG pathways for those facilities during 2016* while the Tier 1 applications are pending.

LCFS FF18-2

2. § 95488(d)(1-2): Monetizing Credits Generated under Temporary or Provisional Fuel Pathway Codes.

Under the current LCFS rule, facilities with pending application approvals are able to generate and monetize LCFS credits under the various ARB approved "default" pathways (CE specifically utilizes CNG006 and LNG021). Furthermore, several of these facilities are classified as provisional since they have been in operation for less than the ARB mandate of two (2) years. Nonetheless, the current regulation allows such provisional facilities to monetize credits under a default or provisional pathway regardless of the length of time in operation.

LCFS FF18-3

As discussed, the proposed LCFS Re-Adoption appears to eliminate the ability to monetize credits generated under any temporary or provisional pathways until a facility receives a certified CI and pathway. These prohibitions on monetization of provisional and temporary pathway credits carry unintentional but potentially fatal consequences to the biomethane production market. Biomethane producers rely on the revenue generated from the monetization of both LCFS credits and RINs to offset the higher costs of producing renewable natural gas. Disallowing credit sales for any period, let alone a full two years, is enough to discourage the development of these biomethane production facilities which is detrimental to the ARB's goal of increasing the flow of renewable transportation fuel in California.

It is understood that any regulatory changes at this point would require a new 15-day comment period which could also be detrimental to the LCFS program as a whole. For this reason, CARB has agreed to explore the best method to eliminate the restriction on sale of credits generated under temporary or default pathways - including potentially the issuance of an advisory opinion to clarify the language in the Re-Adoption and allow for the monetization of credits under both the temporary and provisional pathways.

LCFS FF18-3 cont.

3. § 95488(a)(3): Re-Certification of Pathways approved under old LCFS Rule

Under the Re-Adoption, all existing grandfathered pathways as well as any new pathways will have to be re-certified in 2016 under either a Tier 1 or Tier 2 pathway using the GREET 2.0 model. Tier 1 pathways apply to all conventionally-produced alternative fuels which includes biomethane sourced from landfills. In order to re-certify a pathway that was approved under the previous LCFS rule, CE will have to make a request to the ARB via the new online LRT registration system. The ARB will then automatically re-certify each requested pathway under a new Tier 1 pathway and assign a new CI. Applications for re-certification will be processed in batches following a predetermined priority order:

1. Ethanol
2. Biodiesel
3. Renewable Diesel
4. CNG
5. LNG

LCFS FF18-4

Once a pathway has been re-certified and given a new CI, the previous pathway and CI will be deactivated. The ARB will re-certify each grandfathered pathway before 12/31/2016 which will prevent any lapse in credit generation.

With respect to Clean Energy's biomethane pathways, MDU is in a unique position. Because the MDU facility is located at an unregulated landfill, CE must apply for a Tier 2 pathway in order to quantify and realize the complete value of the voluntary methane capture and destruction that occurs at the site. Based on our meeting, it is our understanding that MDU's filed Method 2 application will be approved by the ARB before the end of 2015, and MDU will be able to generate *and sell* credits under this pathway while the Tier 2 pathway is pending. CE will apply for a new pathway under Tier 2 for MDU as soon as possible which will also be certified before the end of 2016.

4. § 95486(a)(2): No Retroactive or Incremental Credit Generation

The Re-Adoption appears not to allow for any retroactive credit generation for any quarter in which the reporting deadline has already passed. The only exception to this rule applies to the initial generation of provisional credits from facilities that have been operating for less than two years. Once the provisional pathway is approved, the ARB will allow a facility to generate provisional credits for the quarter in which the approval takes place and one previous quarter (assuming the application was complete during that previous quarter). It is noted that the provisional CI is subject to change as the ARB receives more operational data. However, once the pathway is fully certified the credit generator will not be able to automatically generate "incremental" additional credits if the final CI is lower than the provisional CI – although they may be able to file a petition to do so. If the final CI is higher than the provisional CI, the ARB will automatically retire the excess credits generated.

The temporary pathways are meant to allow obligated parties that have facilities with more than two years of operating history to generate credits while the ARB processes their applications and provides full certification. However, notably for biomethane pathways, the temporary pathway CIs are representative of a "worst case" operating scenario resulting in exceedingly high CI values that are not an accurate representation of CE's actual pathways. In fact, the temporary fuel pathway CIs for biomethane CNG and LNG increased approximately 10%-15% in the newest version of the Re-Adoption. As we understand it, there is no allowance or mechanism in the rule for retroactive incremental credit generation based on the delta between the certified CI and the temporary pathway. We believe that producers should be able to retroactively claim these credits. Due to the large difference between CE's certified pathway CIs and the temporary pathway CIs, the ARB should allow for at least two quarters of retroactive incremental credit generation – automatically - in order to accurately compensate obligated parties for their true reduction in carbon.

LCFS FF18-5

CE also has serious concerns regarding retroactivity as applied the regulation prior to re-adoption and effectiveness of the new regulation. The idea of retroactive incremental credit generation has been openly discussed by CE and the ARB under the old LCFS rule. During the November 2014 LCFS workshop, the issue of retroactive credit generation was openly discussed in the context of the delayed approval of LCFS pathways due to the re-adoption process. The slide specifically stated:

No retroactive credits except for specific provisions:

- Fuel Pathway Application
- Physical Transport Mode

It was also discussed during this workshop and with ARB staff that up to two quarters of retroactivity was possible and that LCFS pathway applicants would apply for retroactivity at the time of final application approval. The application needed to justify that the delays in the pathway being approved were due to ARB and staff and not the applicant.

As such, CE has requested the ability to generate incremental credits for all newly posted pathways based on the delta between the actual CI in the posted pathway and the default number that CE used to generate credits while its pathway applications were pending with the ARB. To our surprise, our request to generate these incremental credits has been denied. CE urges the ARB to re-examine this request and approve retroactive incremental credit generation. The retroactivity should be limited to the two quarters prior to the quarter in which the pathway was certified. Since the credit generator can already use the new CI to generate credits for the quarter in which the pathway was certified (credits are generated in the two months following the quarter end) the ARB needs to define the two quarters of retroactivity as the two quarters prior to approval.

LCFS FF18-5 cont.

CE would be able to generate an additional 65,229 LCFS credits if it was allowed to generate incremental credits as described above - across six different facilities. At current credit pricing ($32/Credit) this equates to approximately $2.1MM in additional credit revenue that the producers are anticipating. There is no sound policy reason to deny the generation of these credits given that the fuel was delivered at the certified CI and achieved the reductions reflected.

5. § 95488(e): Evidence of Fuel Transport Mode (Physical Pathway Description)

Each pathway application must include a description of the physical pathway used to transport the fuel for end use to CA. Transactions for fuels in which a physical pathway demonstration application has yet to be approved must be reported using the transport code PHY10 in the LRT. According to the Re-Adoption:

"A regulated party may not generate credits pursuant to section 95486 unless it has demonstrated to the Executive Officer that a fuel transport mode exists for each of the transportation fuels for which it is responsible under the LCFS regulation, and that each fuel transport mode has been approved by the Executive Officer pursuant to this section."

LCFS FF18-6

CE has approximately 14 fuel pathways either certified or pending with the ARB. Each of these pathways needs a filed and approved physical pathway demonstration. CE was previously told by the ARB to keep the physical pathway application separate from the Method 2B application and to submit only one physical pathway application at a time. CE submitted the physical pathway for the Pinnacle LNG pathway (LNG020) over seven months ago and the ARB has yet to issue an approval. CE has demonstrated the physical connectivity between the point of production to final consumption along with providing all contracts, production reports, transaction confirmations, and bills of lading. This has created a concern about the timing of approvals and the ability to generate credits following the Re-Adoption. This first physical pathway approval needs to serve as a template for all subsequent physical pathways to ensure much quicker approval timeframes. CE will submit all remaining physical pathway applications by Q3 2015, and it is our understanding all will be approved by the ARB before year end.

Although the Re-Adoption states that LCFS credits cannot be generated without approved physical pathway applications, the ARB reassured CE that the delay in approvals will not prevent credit generation under the Re-Adoption. Furthermore, the ARB committed to reviewing the application process as a whole in an effort to streamline approvals.

LCFS FF18-6 cont.

We appreciate your review of these topics and please inform us if there has been any misunderstanding conveyed in this memo.

18_FF_LCFS_CE

907. Comment: **LCFS FF18-1**

This commenter restates its understanding of new section § 95488(a) and how it will apply to certain facilities.

Agency Response: The comment does not contain a recommendation or objection regarding the proposal, and needs no response. We note that staff will be providing guidance and conducting workshops after Board Hearing to explain the details of how provisional pathways under the current regulation will be processed under the new regulation.

908. Comment: **LCFS FF18-2**

This comment is related to pathway processing, and generation and sale of LCFS credits.

Agency Response: See response to **LCFS FF18-1**.

909. Comment: **LCFS FF18-3**

The commenter states its understanding of the current and initially-proposed-for-re-adoption LCFS. The comment further points out that an inability to sell credits for the first two years of operation would impose a significant financial burden on the commenter.

Agency Response: See response to **LCFS FF18-1**. Regarding the ability to promptly sell credits generated under temporary or provisional pathways, 15-day changes to section 95488(d) addressed the commenter's concerns, allowing the generation and sale of temporary and provisional credits under specified conditions.

910. Comment: **LCFS FF18-4**

This comment restates the commenter's understanding of the proposed LCFS and how it might apply to a particular facility.

Agency Response: See response **LCFS FF18-1**. We note that commenter's understanding is not correct in every particular.

911. Comment: **LCFS FF18-5**

This comment restates the commenter's understanding of the proposed LCFS. The commenter believes that not allowing retroactive credit for the difference between conservative temporary pathway CIs and subsequently-approved CIs should automatically be awarded. The commenter also recommends that retroactivity be expanded to cover not just the quarter in which an application is approved plus one prior quarter, but to encompass the quarter in which an application is approves plus *two* previous quarters. Failure to make that change will reduce the commenter's revenue.

Agency Response: See response **LCFS FF18-1**. ARB does not agree that the incremental CI improvements (as compared to temporary pathway values) and the associated credits should be approved retroactively after a party has reported using the temporary pathway values. The temporary pathways are already generous in the sense that they can be used promptly even in the absence of certain information. To the extent the temporary CI values are higher than the commenter would wish, that delta is intended in part to encourage parties to promptly submit and complete their applications under Tier 1 or Tier 2.

912. Comment: **LCFS FF18-6**

The commenter has expressed concern about how long certain of commenter's pathway applications and physical transport demonstrations have taken to obtain approval.

Agency Response: See response **LCFS FF18-1**.

Comment letter code: 19-FF-LCFS-WSDE

Commenter: Guifoil, Elena

Affiliation: Washington State Dept. of Ecology

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

19_FF_LCFS
_WSDE

From: Guilfoil, Elena (ECY) [egui461@ECY.WA.GOV]
Sent: Friday, June 12, 2015 4:35 PM
To: Wade, Samuel@ARB
Subject: typo

Typo

Refer to New table 11 - Summary of reporting requirements
"Aggregated indicator" is the term while the definition is "aggregation indicator". LCFS FF19-1

Elena Guilfoil / Air Quality Program / Department of Ecology / egui461@ecy.wa.gov / (360) 407-6855

19_FF_LCFS_WSDE

913. Comment: **LCFS FF19-1**

The commenter identified possible typographical errors in new Table 11 - Summary of reporting requirements: “Aggregated indicator” is the term while the definition is “aggregation indicator”.

Agency Response: ARB staff acknowledges the recommendation and has updated the regulatory text to address this comment. The term now reads “Aggregated Transaction Indicator” in Table 11 and in the Definitions.

This page intentionally left blank.

Comment letter code: 20-FF-LCFS-FHR

Commenter: Guillemette, Phillip

Affiliation: Flint Hills Resources

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

20_FF_LCFS
_FHR

From: Guillemette, Philip E. [Philip.Guillemette@fhr.com]
Sent: Monday, June 15, 2015 4:01 PM
To: Chowdhury, Hafizur@ARB
Cc: Hardy, Rita; Smading, Dan
Subject: ARB Proposed Regulation 95488(d)(2) Provisional Pathways - Question

Hello Hafizur,

Per my telephone message, I would like to gain a better understanding of how the proposed LCFS regulations would apply to a newly constructed biodiesel plant.

Duonix Beatrice is constructing a biodiesel facility that will start-up later this year. Duonix Beatrice plans to sell its biodiesel to Flint Hills Resources, who may import the biodiesel into California for sale or blend with purchased CARB diesel for sale in California. On behalf of Duonix Beatrice, we have submitted a pathway application under the existing LCFS regulations and expect to have at least three months of operation prior to the end of 2016. Our consultant, EcoEngineers, has be working with Todd Dooley on the application.

If I understand correctly, the soon to be approved proposed regulations will require us to submit another pathway application before 1/1/2016, and since Duonix Beatrice will not have achieved full commercial production for 2 years, it appears that the provisional pathway regulations would apply.

My key question is related to the restrictions related to provisional credits. The proposed rules state that provisional credits may not be sold, transferred, or retired for compliance, nor may fuel with a provisional CI be transferred with obligation, until the Executive Officer has adjusted the CI or informed the producer that the provisional CI has been successfully corroborated by operational records covering a full two years of commercial operation.

LCFS FF20-1

If my understanding is correct, it appears that Flint Hills Resources will be unable to sell biodiesel with obligation, or sell, transfer or retire credits from CARB diesel blending, until after two years of operation. This restriction seems inconsistent with the current process, whereby ARB has the discretion to allow facilities to obtain fuel pathway approvals prior to start-up, sell biofuels with obligation after start-up, as well as sell, transfer or retire credits from fuel blending, so long as quarterly data is provided to ARB continuing to support the approved fuel pathway carbon intensity.

Please give me a telephone call, when you get a chance. I am hoping that I am missing something or am not understanding the proposed regulations correctly.

Thank you for your help,
Philip

Philip Guillemette
Flint Hills Resources, LP
Telephone: 316-828-8440
Fax: 316-828-4905

20_FF_LCFS_FHR

914. Comment: **LCFS FF20-1**

The commenter is concerned that provisional credits may not be sold, transferred, or retired for compliance, nor may a fuel with a provisional CI be transferred with obligation.

Agency Response: ARB made changes to the proposal to facilitate credit generation in a facility's early years. These changes are in section 95488.

This page intentionally left blank.

Comment letter code: 21-FF-LCFS-HG

Commenter: Del Core, Rob

Affiliation: HydroGenics

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

21_FF_LCFS_HG

HYDROGENICS
SHIFT POWER | ENERGIZE YOUR WORLD

Hydrogenics USA
12707 High Bluff Drive, Suite 200
San Diego, California 92130
Phone: 858.386.8930
Fax: 905.361-3626
www.hydrogenics.com

June 19, 2015

California Air Resources Board
Richard W. Corey
Executive Director
Re: Low Carbon Fuel Standard regulation
1001 I St
Sacramento, CA 95812-2815

Dear Mr. Corey and CARB staff:

Hydrogenics is pleased to provide comments on the LCFS regulatory language as posted online for 15-day comments. As a leading hydrogen technology and hydrogen fuel provider, we welcome and thank you for the opportunity to provide our input to help fostering California into a leading edge State in renewable energy technology.

Please kindly consider our following comments:

- We support the inclusion of hydrogen as a renewable fuel and energy storage medium qualifying for credits; and
- It is also important to include medium duty and heavy duty fuel cell powered vehicles using hydrogen fuel as qualifying vehicles for low carbon credits to encourage mass adoption of fuel cell powered commercial vehicles

LCFS FF21-1

Thank you for the opportunity to comment and consider our input. Your leadership and effort help shape a sustainable landscape for fuel cell electric vehicles and hydrogen as a fuel in a long term.

Please do not hesitate to contact me at (858) 386-8930 if you have any questions or require clarification.

Thank you very much again for the opportunity.

Sincerely,

Rob Del Core
Director, Business Development
Hydrogenics USA

21_FF_LCFS_HG

915. Comment: **LCFS FF21-1**

The comment suggests staff allow medium and heavy duty hydrogen fuel cell vehicles qualify for LCFS credits.

Agency Response: All hydrogen fuel cell vehicles (light/medium/heavy duties) are eligible to generate LCFS credits under current LCFS regulation.

Staff conducted Energy Economy Ratio (EER) analyses for fuel cell forklifts (medium duty), and fuel cell buses (heavy duty). Based on the results, staff created a new EER category for fuel cell forklifts. The calculated value for fuel cell buses is identical to the existing fuel cell vehicle EER, so is covered by that value. Staff acknowledges that the fuel cell vehicle technologies will continue to improve, and as a result, the EERs for medium and heavy duty fuel cell vehicles will continue to increase. Staff commits to reevaluate fuel cell vehicle EERs as newer technologies and data become available.

This page intentionally left blank.

Comment letter code: 22-FF-LCFS-EEEA

Commenter: Edgar, Evan

Affiliation: Efgar & Associates

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

22_FF_LCFS
_EEEA

California Environmental Protection Agency
Air Resources Board

Comment Log Display

BELOW IS THE COMMENT YOU SELECTED TO DISPLAY.
COMMENT 22 FOR LOW CARBON FUEL STANDARD 2015 (LCFS2015) - 15-1.

First Name: Evan
Last Name: Edgar
Email Address: evan@edgarinc.org
Phone Number: 916-739-1200
Affiliation: Efgar & Associates

Subject: CIs and EERs - Support with one page chart
Comment:
CARB:

We have participated in and supported the CI pathways for HSAD.

Edgar & Associates, Inc. has produced the attached table taking the new CIs and EERs and placed them in one place to compare life-cycle and economic efficiencies of transportation fuels.

CARB staff should produce a similar graph for all stakeholders to use. LCFS FF22-1

Thanks

Evan

Attachment: www.arb.ca.gov/lists/com-attach/107-lcfs2015-UTQGYQBeAjIFYgJw.pdf

Original File Name: EA Carbon Intensity Graph Handout 1.pdf

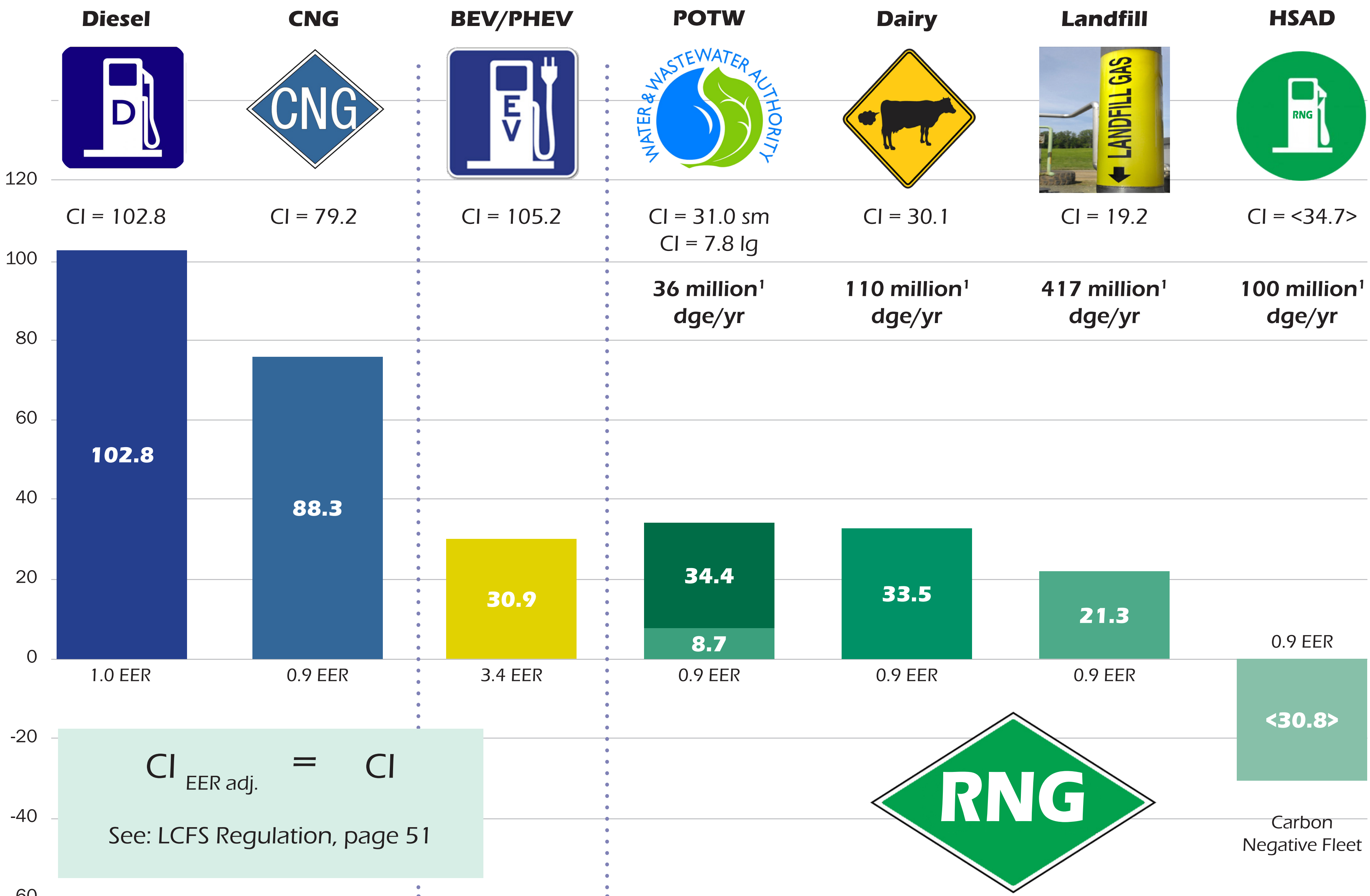
Date and Time Comment Was Submitted: 2015-06-19 13:04:56

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Carbon Intesity for Diesel & Substitues, grams CO2 emitted per unit of energy adjusted for energy (g CO2 e/MJ)

(June 25, 2015, California Air Resources Board Staff Report)



[1] UC Davis

Prepared by Edgar & Associates, Inc. 6/9/15

Waste Sector (Organics, Recycling, MSW)

Class 7 - 12,000 in CA still on diesel

Class 8 - 3,000 in CA - all on diesel

Incremental CNG truck cost compared to Diesel truck

$40,000 per truck average - 15,000 Class 7 and 8 trucks from Diesel to CNG

$600 million for 15,000 trucks (2015/16-2020/21) - $100 million year

CNG Fleet with RNG Off-Take Agreement

Demand 15,000 trucks - 50 dge/day/truck - 200 million dge per year

- RNG Supply - 100 million dge from Organics/HSAD (minus 21 carbon intensity)
- RNG Supply - 417 million dge from Landfills (13 carbon intensity)
- RNG Supply - 36 million dge from Wastewater Plants (9 to 34 carbon intensity)

22_FF_LCFS_EEEA

916. Comment: **LCFS FF22-1**

The commenter is suggesting that ARB publish a graphic that illustrates life-cycle CI of all fuels in a side-by-side comparison.

Agency Response: The suggestion appears to be that ARB use a particular approach to communicate with the public and those in the fuel industry, not a specific recommendation or objection concerning the proposal. Accordingly, no response is required, but the suggestion has been noted and will be considered in future public presentations regarding the LCFS.

This page intentionally left blank.

Comment letter code: 23-FF-LCFS-SF

Commenter: Duff, John

Affiliation: National Sorghum Producers

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

23_FF_LCFS
_SG

June 19, 2015

Mary Nichols, Chairman
California Air Resources Board
1001 I Street
Sacramento, CA 95812

RE: LCFS Re-adoption

Chairman Nichols,

National Sorghum Producers (NSP) is a trade association representing the interests of over 50,000 sorghum producers on issues related to legislative and regulatory policy in Washington as well as various state capitals. NSP led efforts to secure an advanced biofuel pathway for sorghum under the RFS2 and has performed extensive analysis on several models and datasets over the last four years, including several datasets similar to those used by the Argonne National Laboratory as well as the ARB in modeling the CI of sorghum ethanol.

NSP applauds the ARB for undertaking an extensive update of the LCFS and is very appreciative of the time committed by ARB staff to ensure not only the integrity of the data used but their representativeness of real-world conditions as well. NSP also thanks the ARB for its special attention to sorghum fertilizer requirements and N_2O emissions from sorghum stover. In addition to these areas, NSP strongly recommends that the ARB focus attention on information related to sorghum root:shoot ratios, and as it becomes available, incorporate this information into future versions of CA-GREET. LCFS FF23-1

NSP also recommends that the ARB revisit sorghum iLUC as soon as possible. As we have stated previously, we do not feel the EPA's FAPRI-based analysis of sorghum iLUC was accurate, and we believe that the ARB has the opportunity to shed a correct light on the issue in future iterations of AEZ-EF. We look forward to working with ARB staff and sorghum stakeholders on this in the future. LCFS FF23-2

Thank you for the opportunity to provide feedback. We feel strongly that sorghum ethanol can play a large role in helping California meet the greenhouse gas reduction goals set by the LCFS while at the same time promoting the use of water-sipping crops like sorghum.

Please do not hesitate to let me know if you have any questions.

Regards,

J.B. Stewart

J.B. Stewart
Chairman
National Sorghum Producers
4201 N. Interstate 27
Lubbock, TX 79403
Phone: (806) 749-3478

23_FF_LCFS_SG

917. Comment: **LCFS FF23-1**

The commenter strongly recommends that the ARB focus attention on information related to sorghum root:shoot ratios, and as it becomes available, incorporate this information into future versions of CA-GREET.

Agency Response: ARB staff appreciates the National Sorghum Producers providing data to ARB and Argonne to update and improve agricultural phase parameters in CA-GREET. See response to comment **LCFS 9-2.**

918. Comment: **LCFS FF23-2**

The commenter recommends that the ARB revisit sorghum iLUC as soon as possible.

Agency Response: ARB staff is committed to updating iLUC values in the future and appreciates working with the National Sorghum Producers. However, updating iLUC values frequently would create regulatory risk for stakeholders required to modify their pathway CIs every time an iLUC value is updated to reflect the findings of a single report. Staff plans to review literature and reports related to advancements in land use change science and modeling methodology and update iLUC values no more frequently than once every three years. The next update will occur as part of the program review that will conclude prior to January 1, 2019. ARB is committed to working with stakeholders during the update process.

This page intentionally left blank.

Comment letter code: 24-FF-LCFS-LCA

Commenter: Pont, Jennifer

Affiliation: Life Cycle Associates

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

24_FF_LCFS_LCA

From: jennifernpont@gmail.com on behalf of jennifer pont <pont@lifecycleassociates.com>
Sent: Thursday, June 18, 2015 3:41 PM
To: d'Esterhazy, Stephen@ARB
Cc: Susan Boland; Stefan Unnasch
Subject: Question about proposed provisional pathway language

Hi Stephen -

Thanks for talking today. The proposed regulation order in 95488 (d)(2)Provisional Pathways states that credits generated by fuel producers with provisional pathway CI values may not be traded, sold, used for compliance for a period of 2 years or until 2 years of operational data are provided to validate the CI number. At this point the CI value is either adjusted up or left where it is and it seems the provisional credits become actual credits.

Our question is whether this provision applies to all fuel producers with provisional CI values or just newly provisional (going forward). Do these credit limitations apply to fuel producers that already have provisional pathway CI values?

LCFS FF24-1

Thanks!
Jenny

--
Jennifer Pont | Senior Engineer | **Life Cycle Associates, LLC**
884 Portola Road Suite A11
Portola Valley, CA 94028
O:+1.650.740.0410 | **F:** +1.484.313. 9504 | **E:** pont@lifecycleassociates.com
www.LifeCycleAssociates.com | Follow us on LinkedIn

24_FF_LCFS_LCA

919. Comment: **LCFS FF24-1**

The commenter is concerned that provisional credits may not be sold, transferred, or retired for compliance, nor may a fuel with a provisional CI be transferred with obligation.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

This page intentionally left blank.

Comment letter code: 25-FF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

25_FF_LCFS _HBC

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Thursday, June 11, 2015 5:06 PM
To: Chowdhury, Hafizur@ARB
Subject: RE: Documenting DGS Yield per gallon of ethanol production

Thanks. I look forward to working with you on these issues to find a solution that meets CARB's needs and is not overly burdensome for the applicants (and consultants and ARB staff that has to review).

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

---

From: Chowdhury, Hafizur@ARB [mailto:hchowdhu@arb.ca.gov]
Sent: Thursday, June 11, 2015 7:00 PM
To: Logan Caldwell
Subject: RE: Documenting DGS Yield per gallon of ethanol production

I got all of them. Thanks Logan.

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Thursday, June 11, 2015 4:56 PM
To: Chowdhury, Hafizur@ARB
Subject: Documenting DGS Yield per gallon of ethanol production

Hafizur:

For the DGS yield/gallon of ethanol production, what documentation will be required? LCFS FF25-1

In particular, since the calculation requires an accurate measure of the moisture in the DGS to calculate the bone dry yield, what documentation requirements will there be, if any, for the moisture? LCFS FF25-2

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

25_FF_LCFS_HBC

920. Comment: **LCFS FF25-1**

The comment asks what documentation will be required for the DGS yield/gallon of ethanol production.

Agency Response: See response to **LCFS FF17-4**.

921. Comment: **LCFS FF25-2**

The comment asks what documentation will be required in order to determine the DGS yield per gallon.

Agency Response: See response to **LCFS FF17-5**.

This page intentionally left blank.

Comment letter code: 26-FF-LCFS-AltEn

Commenter: Meeker, Bryce

Affiliation: AltEn

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

June 19th, 2015

California Air Resources Board
Transportation Fuels Branch, SSD
Fuels Evaluation Section
1001 I Street
Sacramento, CA 95814

Re: Comments on Calculating GHG Reduction Credits for the Displacement of an Open Anaerobic Lagoon with an Anaerobic Digester

Dear CARB Staff,

We are submitting comments regarding the credits assigned to methane emissions from an open anaerobic waste treatment lagoons. The conversion of these operations into anaerobic digestion facilities represents a significant reduction in methane emissions from these operations as methane that was emitted to the atmosphere is captured (with the exception of fugitive emissions). Correctly accounting the credits these operations receive will have an impact on whether or not open anaerobic lagoons will be converted and will divert methane from the atmosphere.

Methane is a potent greenhouse gas that has 25 times higher global warming potential than carbon dioxide, and has been generated from anaerobic waste lagoons and emitted directly to the atmosphere at many cattle operations across the country. Diverting the manure created at these facilities to an anaerobic digester avoids releasing methane emissions to the atmosphere, and reduces the negative impact of these facilities. Therefore, we believe the avoided methane emissions should be counted as a credit towards the biogas produced from anaerobic digesters used to replace these open lagoons.

LCFS FF26-1

The current methodology adopted by CARB[1] and Argonne National Laboratory[2] for the analysis of anaerobic digestion-based renewable natural gas (RNG) production assumes that CH_4 generated is flared, and that the resulting CO_2 emissions and fugitive methane are the only credits received by the biogas produced by the digester. This assumed baseline is reasonable because the original destination of these wastes would be a landfill where the collection and flaring of biogas is feasible and has already been implemented.

However, in most current open anaerobic lagoon systems, <u>no</u> biogas is being collected. Furthermore, once the biogas is collected from a covered lagoon and/or a bio-digester, the biogas will likely be sold or used for on-site energy generation. It is <u>highly</u> unlikely that biogas collected would be flared after the capital and operational costs have been put into the facility to capture and use the gas.

LCFS FF26-2

[1] CARB, 2009. Detailed California-Modified GREET Pathway for Compressed Natural Gas (CNG) from Dairy Digester Biogas. Version 1.0

[2] Han J.,Mintz M., and Wang M., 2011. Waste-to-Wheel Analysis of Anaerobic-Digestion-Based Renewable Natural Gas Pathways with the GREET Model. ANL/ESD/11-6

In a report published by US EPA in 2010, of the 157 digester projects operating on commercial scale livestock facilities, only 15 (or 9.6%) were flaring the biogas full time[3]. Based on this information, it is at least questionable that the flaring of biogas should be used as a reference case since it does not reflect actual operations at a high percentage of digester projects.

We believe the reference case for calculating the avoided methane emissions should be that all the biogas generated from the open anaerobic lagoon is fugitive to the atmosphere. Consequently, the CH_4 emissions captured by the anaerobic digester should be accounted for as credits in the GREET model. **LCFS FF26-3**

We would like to encourage you to take this into consideration when finalizing the GREET 2.0 model to allow for reductions based on the methane emissions that are captured and utilized. This will allow for better accounting and encourage reducing ghg emissions from these operations, and from other emerging technologies. **LCFS FF26-4**

Thank you for the opportunity to submit these comments and to participate in the re-adoption of the LCFS. Please let us know if you need any additional information or have any questions on the above points!

Sincerely,

Dennis M. Langley
President
AltEn, LLC
1344 County Road 10
Mead, NE, 68041

[3] US EPA, 2010. U.S. Anaerobic Digester Status Report. US EPA AgStar Program.

26_FF_LCFS_AltEn

922. Comment: **LCFS FF26-1**

The commenter is requesting recognition of avoided fugitive methane emissions from open manure-bearing lagoons as a fuel pathway credit.

Agency Response: ARB staff notes that this comment is not related to "15-day changes" being proposed in the Modified Regulation Order posted for public comment on June 4, 2015. As a courtesy however, staff is providing a response to the comments below.

Producers of renewable natural gas from anaerobic digesters using manure as feedstock should apply under the Tier 2 application process and modify CA-GREET2.0 themselves to reflect producer-specific digester design, productivity and energy consumption parameters, as well as to estimate the emissions avoided by diverting the animal waste. In order to assess the avoided emissions from manure diversion, staff suggests using the U.S. EPA emission factors for each management system and manure type which are built into GREET, along with the applicant's state-specific Greenhouse Gas Inventory[57] (or other verifiable reference source) to determine the share of manure treated by each management practice, at the state level.

923. Comment: **LCFS FF26-2**

The commenter believes it is highly unlikely that biogas collected would be flared after the capital and operational costs have been put into the facility to capture and use the gas.

Agency Response: See response to **LCFS FF26-1**.

924. Comment: **LCFS FF26-3**

The commenter asserts that the reference case for calculating the avoided methane emissions should be that all the biogas generated from the open anaerobic lagoon is fugitive to the atmosphere. And, consequently, the CH_4 emissions captured by the anaerobic digester should be accounted for as credits in the GREET model.

Agency Response: See response to **LCFS FF26-1**.

[57] See index of calculations for California animal waste operations: http://www.arb.ca.gov/cc/inventory/doc/doc_index.php.

925. Comment: **LCFS FF26-4**

The commenter urges ARB to incorporate their suggestions before finalizing GREET 2.0.

Agency Response: See response to **LCFS FF26-1**.

Comment letter code: 27-FF-LCFS-DuPont

Commenter: Koninckx, Jan

Affiliation: DuPont

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

27_FF_LCFS _DuPont

June 19, 2015

Samuel Wade
California Air Resources Board
Branch Chief, Transportation Fuels Branch
1001 I Street
Sacramento, CA 95814

Re: Proposed 15-day Regulation Order containing Modified Text and Availability of Additional Documents and Information for the Proposed Re-Adoption of the Low Carbon Fuel Standard

Dear Samuel Wade:

On behalf of DuPont, thank you for the opportunity to comment on the proposed modified text for the LCFS. DuPont has significant investments in advanced biofuels that meet the specified greenhouse gas reduction threshold. These fuels will make transformative contributions to our nation's energy security, reduce greenhouse gas emissions and strengthen rural economies. These fuels represent a tremendous shift in how we energize our planet and are being commercialized due in large part to visionary state fuels programs like the CA Low Carbon Fuel Standard. We look forward to doing business in California; however, the proposed modification to Provisional Pathways in sections 95488(c)(3) and (c)(4)(I)2 will prevent any new fuel from being sold in California beyond what is being produced today and is so overly restrictive in granting approvals for CI credits that many fuel producers will likely be driven out of business. These hurdles will also discourage additional investment in cellulosic ethanol and other advanced biofuels.

LCFS FF27-1

Introduction

DuPont is an industry leader in providing products for agricultural energy crops, feedstock processing, animal nutrition, and biofuels. Our three-part approach to biofuels includes: (1) improving existing ethanol production through differentiated agriculture seed products, crop protection chemicals, as well as enzymes and other processing aids; (2) developing and supplying new technologies to allow conversion of cellulose to ethanol; and (3) developing and supplying next generation biofuels with cellulosic ethanol and biobutanol.

We bring the perspective of a company deeply involved in the agricultural and biofuels industries. Our seed business DuPont Pioneer sells corn seed to farmers growing for a variety of end-use markets, including grain ethanol production. Our intimate relationship with our farmer customers and our extensive research provides us significant insight into the agronomics of the harvest and management of corn stover as a cellulosic feedstock. We provide a variety of products for the grain ethanol business as well, including saccharification enzymes and fermentation processing aids, and so have an intimate knowledge of the operation of these relevant sugar fermentation operations.

DuPont began its research into cellulosic technology a decade ago. What started as a lab scouting project grew into a full scale commercialization effort. In 2009, DuPont opened a demonstration facility in eastern Tennessee producing cellulosic ethanol from both corn stover and switchgrass. For the past four years, we have brought together growers, academia, public institutions like the USDA and custom equipment makers to conduct harvest trials on corn stover. All this work culminated in the groundbreaking of a 30 million gallon per year facility in December of 2012 in Nevada, Iowa, located approximately 40 miles north of Des Moines. I am happy to report that we are in the very final stages of construction, commissioning has been initiated and we will be open for business later this year. We anticipate that a number of other companies in addition to DuPont will bring cellulosic volumes to the market. Multiple companies are constructing, starting up or operating facilities producing renewable fuels from a wide variety of cellulosic feedstocks including corn stover, switchgrass, wheat straw, municipal solid waste and wood fiber. Many of these are large, well-capitalized, sophisticated companies with long track records in designing, constructing and operating manufacturing facilities. This diversity of operations provides a high level of confidence for multiple technologies succeeding at commercial scale.

In addition to cellulosic ethanol, DuPont is pursuing another advanced renewable fuel with our partner BP in a 50/50 joint venture called Butamax™. The joint venture has developed and extensively tested bio-butanol, a higher alcohol fuel produced by fermenting biomass. Biobutanol has excellent fuel properties, with higher energy density than ethanol and the ability to be distributed via the existing gasoline infrastructure, including pipelines. It also reduces volatility, allowing butanol gasoline blends to be used in the summer in regions that currently require waivers from air quality regulation for the use of ethanol-gasoline blends. Because butanol has less affinity for water and is a weaker solvent than ethanol, it will be more compatible with existing equipment, including small engines.

The proposed modification to Provisional Pathways

In the Proposed 15-day Regulation Order containing Modified Text and Availability of Additional Documents and Information for the Proposed Re-Adoption of the Low Carbon Fuel Standard, the Air Resources Board proposes the following:

> (2) Provisional Pathways. As set forth in sections 95488(c)(3) and (c)(4)(I)2., LCFS fuel pathways are generally developed for fuels that have been in full commercial production for at least two years. In order to encourage the development of innovative fuel technologies, however, applicants may submit New Pathway Request Forms, as set forth in section 95488(c)(1), covering Tier 1 and Tier 2 facilities that have been in full commercial operation for less than two years, provided they have been in full commercial production for at least one full calendar quarter. If that form is subsequently approved by the Executive Officer, as set forth in section 95488(c)(2), the applicant shall submit operating records covering all prior periods of full commercial operation, provided those records cover at least one full calendar quarter. The following subsections govern the development, evaluation, and post-certification monitoring of such provisional pathways.

Following the provisional certification of a fuel pathway application, the applicants shall submit copies of receipts for all energy purchases each calendar quarter until the Executive Officer is in possession of receipts covering two full calendar years of commercial production. At any time during those two years, the Executive Officer may revise as appropriate the plant's actual operational CI based on those receipts. Based on timely reports, the applicant may generate provisional credits. Such credits may not be sold, transferred, or retired for compliance, nor may fuel with a provisional CI be transferred with obligation. The applicant may not sell credits generated under a provisionally-approved fuel pathway, or transfer the provisional fuel with obligation, until the Executive Officer has adjusted the CI or informed the producer that the provisional CI has been successfully corroborated by operational records covering a full two years of commercial operation.

(A) If the plant's operational CI is higher than the provisionally-certified CI, the Executive Officer will replace the certified CI with the operational CI in the LRT-CBTS system and adjust the producer's credit balance accordingly.

(B) If the plant's operational CI appears to be lower than the certified CI, the Executive Officer will take no action. The applicant may, however, petition the Executive Officer for a provisional CI reduction to reflect operational data. In support of such a petition, the applicant must submit a revised application packet that fully documents the requested reduction.

Analysis and Recommendations

The proposed text is overly restrictive and burdensome for both California and biofuels interests that are set to bring new technologies and fuels to market in California. DuPont fully appreciates the need for accurate CI values for fuel that is sold pursuant to the LCFS while also encouraging production and growth for the advanced biofuels sector. For this reason, we are highlighting the following major concerns with the proposed modified text from above: LCFS FF27-2

1. Requiring biofuels manufacturers to produce commercial fuel for a full calendar quarter prior to submitting New Pathway Request Forms is overly burdensome, unnecessary and does not meet the stated goal of encouraging the development of innovative fuel technologies. Fuel and plant specific data if it is required to be submitted to the Air Resources Board prior to commercial production will provide the requisite information LCFS FF27-3

needed for a Fuel Pathway. In addition, actual biofuel production for the first quarter or any period thereafter does not warrant a de facto CI value equal to gasoline. LCFS FF27-3 cont.

2. A provisional certification that prevents a biofuels producer from generating certified CI credits (not provisional credits) for any period of time will prevent fuel from being sold in California. DuPont's cellulosic ethanol is being manufactured in Iowa. Without the benefit of the CI credit, it would be unreasonable for us to make special arrangements to ship our fuel to California. In addition, obligated parties in California would have no reason to purchase fuel without CI credits. Given their obligations under the LCFS, they would need to purchase fuel with CI credits. LCFS FF27-4

3. The provisional certification covering two full calendar years of commercial production will drive many biofuel producers out of business. New technologies and plants are especially sensitive to economics. New facilities need to be able to sell fuel for full market value from initial production in order to survive. In addition, encouraging growth in the cellulosic and advance biofuels sector can only be achieved with supportive federal and state biofuels policies. A provisional certification will discourage rather than encourage growth. LCFS FF27-5

Given the concerns above, we recommend that the Air Resources Board significantly revise the details for Provisional Pathways and Fuel Pathways. While there may be some situations when provisional pathways and/or provisional certifications should apply, a blanket provisional pathway or certification is fundamentally unfair to all new biofuels facilities that are not yet producing fuel. In addition, the provisional certification would put new facilities at a disadvantage to facilities that received pathway approval prior to start-up under the current regulation. For all biofuel producers who intend to sell in California, there should be an immediate pathway to qualifying for CI credits. Any waiting period, even six months is burdensome and will discourage fuels being sold in California. DuPont absolutely supports the energy data collection via copies of receipts on a quarterly basis so that the Air Resources Board can adjust the CI value as needed. We would also support additional auditing measures if it meant that certified CI credits would be available to fuel producers upon commercial fuel production. LCFS FF27-6

Thank you for the opportunity to comment on the Proposed 15-day Regulation Order for the Proposed Re-Adoption of the Low Carbon Fuel Standard as this is an important issue for DuPont's biofuels business. Please contact me at Jan.Koninckx@dupont.com if you have any questions about the comments provided.

Sincerely,

Jan Koninckx

Jan Koninckx, Global Business Director for Biorefineries
DuPont Industrial Biosciences

27_FF_LCFS_DuPont

926. Comment: **LCFS FF27-1**

The commenter states that the proposed modification to Provisional Pathways in sections 95488(c)(3) and (c)(4)(I)2 will prevent any new fuel from being sold in California beyond what is being produced today and is so overly restrictive in granting approvals for CI credits that many fuel producers will likely be driven out of business."

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF31-1** and **LCFS FF27-3**.

927. Comment: **LCFS FF27-2**

This paragraph summarizes comments **LCFS FF27-3** through **LCFS FF27-6**. The commenter generally believes that the proposed text is overly restrictive and burdensome for both California and biofuels interests that are set to bring new technologies and fuels to market in California.

Agency Response: Please see responses to **LCFS FF27-3** through **LCFS FF27-6**. Staff appreciates the time the commenter has taken to inform staff about the burdens of the regulation from their perspective. Staff will address the applicable comments that this blocked comment introduces**.**

928. Comment: **LCFS FF27-3**

The commenter asserts that requiring biofuels manufacturers to produce commercial fuel for a full calendar quarter prior to submitting New Pathway Request Forms is overly burdensome, unnecessary and does not meet the stated goal of encouraging the development of innovative fuel technologies.

Agency Response: Staff appreciates the commenters concerns regarding being able to generate and sell LCFS credits as soon as commercial production begins. Under § 95488(d)(2) the requirement of being in commercial production for one calendar quarter in order to submit a fuel pathway remains as part of the regulation. ARB considers that period of time necessary to generate reasonably meaningful data about a production process. While an application may not be submitted until commercial production has occurred for one calendar quarter, § 95486(a)(2) states,

> "…the Executive Officer will recognize any **such provisional** credits generated during the quarter in which the approval takes place, and one previous quarter, provided that the application was complete during that previous quarter."

§ 95486(a)(2) allows the provisional applicant the ability to have their credits recognized and generated during the quarter that approval of the pathway occurs (presumably the second quarter of commercial production) and the previous quarter (presumably the first quarter of commercial production).

929. Comment: **LCFS FF27-4**

The commenter asserts that a provisional certification that prevents a biofuels producer from generating certified CI credits (not provisional credits) for any period of time will prevent fuel from being sold in California.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

930. Comment: **LCFS FF27-5**

This comment is related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

931. Comment: **LCFS FF27-6**

This comment is related to provisional pathways not being able to generate or sell LCFS credits for any amount of time and to the data requirements in the regulation for pathway applications, and is the closing paragraph for the commenter's more specific comments. The commenter also states support for the energy data collection via copies of receipts on a quarterly basis so that the Air Resources Board can adjust the CI value as needed.

Agency Response: See response to **LCFS FF31-1** and **LCFS FF56-2.** ARB staff appreciates the commenter's time to share the challenges they see with the regulation. Staff will be conducting workshops and will provide guidance surrounding the process of applying for fuel pathways. All such workshops are open to the public. Through workshops and guidance developed by staff and stakeholders, staff believes that the concerns that the commenter has with the burdens of the pathway application data and the requirement to have one quarter of commercial operation prior to applying for a provisional pathway may be less burdensome. Staff notes that the two-year prohibition on credit transfers for provisional pathways has been removed and can be reviewed in the revised regulation order released June 23, 2015**.**

This page intentionally left blank.

Comment letter code: 28-FF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

28_FF_LCFS _HBC

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Thursday, June 11, 2015 4:54 PM
To: Chowdhury, Hafizur@ARB
Subject: Documenting ethanol transportation from the Production Facility to the California Blending Terminal

Hafizur:

Midwest plants typically load the ethanol onto railcars at the production facility. Trucking is zero, but what documentation will be needed to prove it is zero? LCFS FF28-1

Midwest plants typically ship to multiple locations in California. Each will have a different distance. The physical pathway demonstration requires only one supply route. Can the ethanol producer use the same distance as in the physical pathway demonstration, and can that documentation be sufficient for documenting this distance? LCFS FF28-2

Midwest plants typically do not know details of transport of their ethanol once it reaches the first terminal in California. How then are they to document the distance by truck to the blending terminal? For the transport of EtOH from the blending terminal to the retail outlet, the CA-GREET 2.0 uses a default value. How about allowing a default value for this too? LCFS FF28-3

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

28_FF_LCFS_HBC

932. Comment: **LCFS FF28-1**

The comment states that Midwest plants typically load the ethanol onto railcars at the production facility. There is normally no trucking of ethanol from the ethanol facility to the rail loading location. What documentation will be needed to demonstrate to CARB that it is zero?

Agency Response: See response to **LCFS FF17-12**.

933. Comment: **LCFS FF28-2**

The comment states that Midwest plants typically ship to multiple locations in California. Each will have a different distance. Can the ethanol producer use the same distance as in the physical pathway demonstration, and can that documentation be sufficient for documenting this distance?

Agency Response: See response to **LCFS FF17-13**.

934. Comment: **LCFS FF28-3**

The comment states that Midwest plants typically do not know details of transport of their ethanol once it reaches the first terminal in California. How then are they to document the distance by truck to the blending terminal? How about allowing a default value?

Agency Response: See response to **LCFS FF17-14**.

This page intentionally left blank.

Comment letter code: 29-FF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

29_FF_LCFS _HBC

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Thursday, June 11, 2015 4:52 PM
To: Chowdhury, Hafizur@ARB
Subject: Documenting Tier 1 Ethanol Pathway chemical, enzyme and yeast use

Hafizur:

While purchase invoices show the amount of chemicals, enzymes and yeast purchased or sold by the ethanol producer during a given period, they do not indicate how much was used. To get an accurate estimate of the amount used, the starting and ending inventory of these items would be needed such that the amount used could be calculated. What documentation would be acceptable for the starting and ending inventory? LCFS FF29-1

Also, some of these are purchased frequently, a frequently as daily in some cases from what I understand, but others are purchased infrequently. Those with frequent purchases will have voluminous documentation. LCFS FF29-2

The regulations do not provide for the independent, third-party auditor to attest in lieu of documentation. Is that something that could be reconsidered? LCFS FF29-3

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

29_FF_LCFS_HBC

935. Comment: **LCFS FF29-1**

The comment requests clarification on what chemicals, enzymes and yeast documentation would be acceptable for the starting and ending inventory.

Agency Response: See response to **LCFS FF17-1**.

936. Comment: **LCFS FF29-2**

The comment states that some of items are purchased frequently, as frequently as daily, and those will have voluminous documentation.

Agency Response: See response to **LCFS FF17-2**.

937. Comment: **LCFS FF29-3**

The comment states that the regulations do not provide for the independent, third-party auditor to attest in lieu of documentation. Is that something that could be reconsidered?

Agency Response: See response to **LCFS FF17-3**.

This page intentionally left blank.

Comment letter code: 30-FF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

30_FF_LCFS _HBC

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Thursday, June 11, 2015 4:21 PM
To: Chowdhury, Hafizur@ARB
Subject: Documenting transportation distances and mode for Tier 1 applications

Regarding transportation of corn to the ethanol plant, the Midwest ethanol producer receives corn from a storage facility on the farm where the corn is produced or from an elevator. In neither case is the truck delivering the corn going to have included on its bill of lading the distance from the field to the collection center (storage facility or elevator). Developing this information from each ethanol producer is likely to be time-consuming and the amount of documentation is going to be voluminous.

Regarding transportation of corn from the collection center to the ethanol plant, there are an extraordinary number of truckloads of corn, and so the documentation will be voluminous.

LCFS FF30-1

For both of these, how will the ethanol plant get this data going back two years if it does not yet have a system in place to document?

I would suggest that the Midwest ethanol producers have an option of using the 1.8b default values for transportation distances, and attesting that the default values are reasonable estimates of actual distances.

LCFS FF30-2

Otherwise an extraordinary amount of work would be needed to prepare the documentation, as well as to audit the documentation, whether it is the third-party auditor or the CARB compliance auditor.

For other facility locations outside the Midwest, the plants ship feedstock and products by rail, so that is somewhat easier to document, but again the documentation is voluminous.

LCFS FF30-1 cont.

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly

prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

30_FF_LCFS_HBC

938. Comment: **LCFS FF30-1**

The comment states that documenting the transportation of corn from the collection center to the ethanol plant will be voluminous.

Agency Response: See response to **LCFS FF17-9**.

939. Comment: **LCFS FF30-2**

The commenter requests that as an alternative to the documentation of actual distances, Midwest ethanol producers (and others in similar situation) have the option of using the 1.8b default values for transportation distances, and attesting that the default values are reasonable estimates of actual distances.

Agency Response: See response to **LCFS FF17-9**.

This page intentionally left blank.

Comment letter code: 31-FF-LCFS-Murex

Commenter: Draney, Lisa

Affiliation: Murex

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

MUREX

31_FF_LCFS
_Murex

Lisa Draney
7160 N Dallas Pkwy Suite 300
Plano, TX 75024
June 19th, 2015

Mary Nichols, Chairman
California Air Resources Board
1001 I Street, PO box 2815
Sacramento, CA 95812

Dear Chairman Nichols:

I would like to thank you for the opportunity to comment on the proposed changes to the California Air Resources Board's Low Carbon Fuel Standard. Murex LLC is a marketing partner for ethanol producers, and in particular several low carbon producers and potential low carbon producers in the California market. We consider programs such as California's Low Carbon Fuel Standard an important element in our partners' success in bringing innovative low carbon products into the fuel market.

In regards to the proposed changes to the program for presentation to the board in July, there was one amendment that raised concern:

> (2) Provisional Pathways. As set forth in sections 95488(c)(3) and (c)(4)(I)2.,
>
> LCFS fuel pathways are generally developed for fuels that have been in full commercial production for at least two years. In order to encourage the development of innovative fuel technologies, however, applicants may submit New Pathway Request Forms, as set forth in section 95488(c)(1), covering Tier 1 and Tier 2 facilities that have been in full commercial operation for less than two years, provided they have been in full commercial production for at least one full calendar quarter. If that form is subsequently approved by the Executive Officer, as set forth in section 95488(c)(2), the applicant shall submit operating records covering all prior periods of full commercial operation, provided those records cover at least one full calendar quarter. The following subsections govern the development, evaluation, and post-certification monitoring of such provisional pathways.
>
> Following the provisional certification of a fuel pathway application, the applicants shall submit copies of receipts for all energy purchases each calendar quarter until the Executive Officer is in possession of receipts covering two full calendar years of commercial production. At any time during those two years, the Executive Officer may revise as appropriate the plant's actual operational CI based on those receipts. Based on timely reports, the applicant may generate provisional credits. Such credits may not be sold, transferred, or retired for compliance, nor may fuel with a provisional CI be transferred with obligation. The applicant may not sell credits generated under a provisionally-approved fuel pathway, or transfer the provisional fuel with obligation, until the Executive Officer has adjusted the CI or informed the producer that the provisional CI has been successfully corroborated by operational records covering a full two years of commercial operation.

(A) If the plant's operational CI is higher than the provisionally-certified CI, the Executive Officer will replace the certified CI with the operational CI in the LRT-CBTS system and adjust the producer's credit balance accordingly.

(B) If the plant's operational CI appears to be lower than the certified CI, the Executive Officer will take no action. The applicant may, however, petition the Executive Officer for a provisional CI reduction to reflect operational data. In support of such a petition, the applicant must submit a revised application packet that fully documents the requested reduction.

Murex has several concerns with the above proposal:

- It will put new fuel producers at a disadvantage in the marketplace to all competitors capable of generating carbon credits. The regulated parties that are ultimately responsible for meeting the lowered carbon standards will want to purchase fuels that produce credits that can be transferred with obligation. LCFS FF31-1

- Because of the above disadvantage, new low carbon fuel producers will not be competitive in the California market and will have to ship to other markets, slowing the introduction of low carbon fuels into California, and making the new lower carbon targets harder to meet. LCFS FF31-2

- Innovative fuel producers in and near California will be especially disadvantaged as, unable to meet the carbon requirements of California buyers, they may have to ship the product and bear transportation costs as opposed to serving the local markets. LCFS FF31-3

Given the above concerns, Murex would like to formally request that the California Air Resources Board consider allowing new producers with new technologies to produce and transfer credits at the start of production, with quarterly reviews to ensure that operations coincide with the carbon intensity allowed, and adjust the carbon intensity on a forward basis. LCFS FF31-4

Furthermore, Murex would like to propose that the California Air Resource Board consider certifying third parties to conduct these audits on new producers, within established guidelines. This will allow close monitoring of new fuels to ensure the credits generated are in line with production, without being overly burdened with the increased oversight. LCFS FF31-5

Programs like California's LCFS are essential to bringing new low carbon technologies to the fuels market worldwide. This support is most important in the first stages of the new technology. Please consider revising the above proposal to allow new fuels to produce carbon credits in California. LCFS FF31-6

If you have any further questions, I can be reached at ldraney@murexltd.com, or by phone at 972.735.3316.

Thank you,

Lisa Draney

Lisa Draney, Carbon Compliance Manager

Murex LLC • 7160 N Dallas Pkwy Suite 300 • Plano, TX 75024 • www.murexltd.com

31_FF_LCFS_Murex

940. Comment: **LCFS FF31-1**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

941. Comment: **LCFS FF31-2**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

942. Comment: **LCFS FF31-3**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

943. Comment: **LCFS FF31-4**

The comment is related to provisional pathways being able to generate credits as soon as commercial production begins, the quarter the provisional pathway is approved, and the prior quarter.

Agency Response: Please see response to comment **LCFS FF27-3.**

944. Comment: **LCFS FF31-5**

This comment is related to ARB certifying third parties to conduct audits on new producers.

Agency Response: ARB staff appreciates the suggestion for allowing third parties to audit new fuel producers. However, staff notes that this comment is not related to 15-day changes being proposed in the Modified Regulation Order proposed on June 4,

2015. Staff would like to direct the commenter to one example of third party auditors being allowed to conduct such audits. Section 95488(c)(3)(A)3 states:

> "In lieu of receipts or invoices for energy consumption, fuel sales, feedstock purchases, or co-product sales, the applicant may seek Executive Officer approval to submit audit reports prepared by independent, third-party auditors that document energy consumption, fuel sales, feedstock purchases, or co-product sales."

945. Comment: **LCFS FF31-6**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes. In addition, the commenter states how essential the LCFS is for new technology.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

Comment letter code: 32-FF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

32_FF_LCFS
_HBC

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Thursday, June 11, 2015 4:14 PM
To: Chowdhury, Hafizur@ARB
Subject: Definition and Qualifications of an Independent, Third Party Auditor?

Hafizur:
95488(c)(3)(A)(3) of the proposed regulations states: "In lieu of receipts or invoices for fuel sales, feedstock purchases, or co-product sales, the applicant may seek Executive Officer approval to submit audit reports prepared by independent, third-party auditors that document fuel sales, feedstock purchases, or co-product sales."

As you know presently for 1.8b applications a top company official prepares an attestation letter in lieu of submitting documentation of fuel sales, feedstock purchases, and co-product sales.

What will be the criteria to determine whether a person is a qualified independent, third-party auditor? Will someone with a CPA suffice? Is this definition somewhere else in the CARB regulations? If so, can you point me in the direction so I can review. LCFS FF32-1

Thanks!

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

32_FF_LCFS_HBC

946. Comment: **LCFS FF32-1**

The commenter asks for clarification on the definition and criteria to determine whether a person is qualified independent third-party auditor.

Agency Response: See response to **LCFS FF17-8.**

This page intentionally left blank.

Comment letter code: 33-FF-LCFS-Nuvera

Commenter: Block, Gus

Affiliation: Nuvera

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

Comment Log Display

33_FF_LCFS _Nuvera

Below is the comment you selected to display.
Comment 33 for Low Carbon Fuel Standard 2015 (lcfs2015) - 15-1.

First Name: Gus
Last Name: Block
Email Address: gblock@nuvera.com
Phone Number: 617-245-7553
Affiliation: Nuvera Fuel Cells

Subject: LCFS Credit Proposal
Comment:
Nuvera Fuel Cells is a provider of fuel cell systems for mobility applications and of hydrogen generation and refueling equipment. The company is owned by NACCO Materials Handling Group, a global manufacturer of industrial vehicles, including Hyster(R) and Yale(R) brand forklift trucks.

Nuvera endorses the proposed inclusion of hydrogen fuel for fuel cell-powered forklifts as a means for generating LCFS credits. We also propose extending the application beyond forklifts to other industrial vehicles, such as ground support equipment, transport refrigeration, and container handling equipment. These measures will help drive the adoption of low carbon fuel alternatives within California's large industrial vehicle sector, which includes distribution centers, warehouses, manufacturing facilities, ports, and other venues that are concentrated emissions sources.

LCFS FF33-1

Nuvera advises against the adoption of the proposed Provisional Credit clause that would allow companies to earn provisional LCFS credits but would not allow them to be traded for two years. This provision would be a significant disincentive for prospective producers.

LCFS FF33-2

Attachment:

Original File Name:

Date and Time Comment Was Submitted: 2015-06-19 13:57:04

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

33_FF_LCFS_Nuvera

947. Comment: **LCFS FF33-1**

The comment endorses the proposed inclusion of hydrogen used in fuel cell powered forklifts as eligible to generate LCFS credits and proposes expanding this provision to other vehicles use of hydrogen.

Agency Response: ARB staff acknowledges that the fuel cell vehicle technologies will continue to improve and is open to meeting with stakeholders to discuss possibilities for including more industrial fuel cell vehicles, if the LCFS reporting and record keeping requirements for hydrogen use can be met. Staff commits to revisit the hydrogen provisions as newer technologies and data become available.

948. Comment: **LCFS FF33-2**

The comment is related to provisional pathways being able to generate credits as soon as commercial production begins, the quarter the provisional pathway is approved, and the prior quarter.

Agency Response: See response to **LCFS FF27-3**.

This page intentionally left blank.

Comment letter code: 34-FF-LCFS-FHR

Commenter: Guillemette, Phillip

Affiliation: Flint Hills Resources

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

34_FF_LCFS_FHR

FLINT HILLS
resources

June 19, 2015

Electronically Submitted at http://www.arb.gov/lispub/comm/bclist.php

Clerk of the Board
Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Sir or Madam:

Flint Hills Resources (FHR) is pleased to submit the following comments in response to the following Notice of Public Availability of Modified Text and Availability of Additional Documents and Information:

Proposed Re-Adoption of the Low Carbon Fuel Standard (Public Availability Date: June 4, 2015)

FHR through its subsidiaries is an industry leader in refining, chemicals, and biofuels and ingredients, with operations primarily in Texas and the Midwest. Its manufacturing capability is built upon six decades of refining experience, and the company has expanded its operations through capital projects and acquisitions worth more than $11 billion since 2002. FHR's subsidiaries produce and market gasoline, diesel, jet fuel, asphalt, ethanol, biodiesel, liquefied natural gas, olefins, polymers, intermediate chemicals, as well as base oils, inedible corn oil and distillers grains. Based in Wichita, Kansas, the company has about 5,000 employees and is a wholly owned subsidiary of Koch Industries, Inc.

FHR operates fuel ethanol plants in Iowa, Nebraska and Georgia, and manufactures significant volumes of denatured fuel ethanol. FHR is currently constructing a biodiesel plant in Beatrice, Nebraska and intends to market and distribute this fuel in California and, therefore, has a vital interest in the above referenced proposal.

<u>Provisional Pathway Provision Should be Modified to Avoid Unintended Consequences</u>

The modified Provisional Pathway provision of proposed Section 95488(d)(2) (see Summary of Proposed Modifications Item #25), which has been expanded to include Tier 1 facilities, may not fully meet its intended purpose of encouraging the development of innovative fuel technologies. Specifically, FHR believes that a restriction from selling, transferring, or retiring credits for compliance, or transferring fuel with obligation for facilities in commercial operation for less than two years will likely stymie the development and supply of Tier 1 alternative fuels. LCFS FF34-1

- 4111 East 37th Street North - Wichita, Kansas 67220 - P.O. Box 2917 - Wichita, Kansas 67201 -

FHR believes that Section 95488(d)(2) may be misinterpreted to limit the Executive Director's authority to approve fuel pathway codes and carbon intensities (CIs) for fuels produced for less than two years. Section 95488(d)(2) states, "The applicant may not sell credits generated under a provisionally-approved fuel pathway, or transfer the provisional fuel with obligation, until the Executive Officer has adjusted the CI or informed the producer <u>that the provisional CI has been successfully corroborated by operational records covering a full two years of commercial operation</u> (emphasis added)". FHR is concerned that the ending phrase, underlined above, could be interpreted to mean that an adjusted, certified CI must be supported with a minimum of two years of operational records. LCFS FF34-1 cont.

FHR believes that the Executive Officer should have the discretion to waive the two year operational records requirement and certify CIs. This discretion would mirror the current practice, whereby the Executive Officer certifies a prospective CI, after receiving a pathway application substantiated by plant engineering design mass and energy balance information, and by requiring the applicant to subsequently submit operational records on a quarterly basis, as a means to validate the CI. In the case of a prospective CI, as well as any certified fuel CI, the applicant would be subject to ARB's authority under Section 95495 to suspend, revoke, or modify an approved CI that is determined to be invalid, as well as the LCFS Fuel Producer Attestation requirement within Section 95488(c)(2)(C). LCFS FF34-2

If a determination is made that the Executive Officer must require two years of operational records, FHR believes that investments in production facilities for Tier 1 alternative fuels will be deterred and the supply of alternative fuels will be constrained, based on the following economic consequences:

1. Alternative fuel producers restricted from selling credits will have delayed income for up to two years.
2. Alternative fuel producers restricted from retiring credits for compliance may need to purchase credits from the ongoing LCFS credit market to meet an annual compliance obligation, thereby increasing expenses for up to two years.
3. Alternative fuel producers restricted from transferring fuel with obligation will need to purchase credits from the ongoing LCFS credit market and transfer the credits to fuel-buying regulated parties, thereby increasing expenses for up to two years.

LCFS FF34-3

<u>FHR Recommends Minor Text Changes</u>

FHR believes that a misinterpretation can be avoided by ARB incorporating the following minor changes in "**bold**" to Section 95488(d)(2):

> The applicant may not sell credits generated under a provisionally-approved fuel pathway, or transfer the provisional fuel with obligation, until the Executive Officer has **either: 1)** ~~adjusted~~ **certified** the CI, or **2)** informed the producer that the provisional CI has been successfully corroborated by operational records covering a full two years of commercial operation.

LCFS FF34-4

Should you have any questions, please contact FHR's VP, Quality and Compliance, Rita Hardy (rita.hardy@fhr.com, 316/828-7840), or myself, for further information or to schedule a meeting to discuss.

Sincerely,

Philip Guillemette

Philip Guillemette
Compliance Manager, Operations
Flint Hills Resources
philip.guillemette@fhr.com, 316/828-8440

34_FF_LCFS_FHR

949. Comment: **LCFS FF34-1**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

950. Comment: **LCFS FF34-2**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

951. Comment: **LCFS FF34-3**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

952. Comment: **LCFS FF34-4**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

This page intentionally left blank.

Comment letter code: 35-FF-LCFS-NVGC

Commenter: Carmichael, Tim

Affiliation: Natural Gas Vehicle Coalition

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

35_FF_LCFS _NVGC

June 19, 2015

Richard Corey
Executive Officer
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Re: Comments on Proposed 15-Day Regulation Order for the Low-Carbon Fuel Standard

Dear Executive Officer Corey:

The California Natural Gas Vehicle Coalition (CNGVC), NGVAmerica (NGVA), and the Coalition for Renewable Natural Gas (RNGC)[1] are pleased to provide these joint comments regarding ARB's proposed re-adoption of the Low Carbon Fuel Standard (LCFS) regulation. Specifically, this letter provides our detailed joint comments on ARB's "Attachment A: Proposed 15-Day Regulation Order," which was released for public comment on June 4, 2015.

Below, we present our joint, detailed comments and recommendations. We want to be clear that our three organizations continue to support ARB's proposed re-adoption of the LCFS regulation. We greatly appreciate the time and effort put forth by ARB staff over the last several months to meet with our representatives and address our specific concerns. We are pleased that ARB has made changes that corrected erroneous information and updated obsolete inputs in early drafts of the proposed CA-GREET model revision (version 2.0). We are committed to continue working closely with ARB staff, right up until the LCFS program re-adoption is anticipated at the Board's July 23, 2015 meeting.

A. Comments on Proposed LCFS Regulatory Changes

Our detailed comments regarding ARB's proposed LCFS regulatory changes are presented below, in six specific areas.

1. Provisional Pathway Process

Staff is proposing a "provisional pathway" process for facilities with less than two years of operational data. Under this new process, facilities with less than two years of operational data would generate provisional credits. Such credits could not be traded or sold unless certain conditions are met. One interpretation of the regulatory text might be that all credits generated under a provisional pathway may not be sold until the facility has completed the application process and received a fully certified "operational CI." This process could take up to two years, depending on the amount of operational data available for the facility at the time of application.

[1] For more information about our three organizations and respective memberships, please refer to the many previous formal comment letters that we uploaded over the last nine months to the ARB LCFS comments website.

In effect, this process would prevent new facilities from monetizing LCFS credits for up to two years. This would be disastrous for the development of new low carbon fuel sources for the California market. The development of facilities to produce low carbon transportation fuels typically requires significant upfront capital investment and risk. Further, the lowest carbon intensity fuels, such as renewable natural gas, are currently more expensive to produce than fossil based fuels. Revenue from credits generated under the LCFS and other programs help mitigate some of the project risk and are critical to creating feasible financial plans for the development of these facilities. Delaying revenue generation from credit sales significantly undermines the financial feasibility of such projects, thereby limiting the growth in supply of low carbon fuels. This is at odds with the intent of the LCFS program and the stated intent of the provisional pathways process to "encourage the development of innovative fuel technologies…" LCFS FF35-1

We believe that a strict reading of Section 95488(d)(2) <u>does allow</u> applicants to sell provisional credits during the period the facility is operating under a provisional pathway. As described in the regulatory text, "The applicant may not sell credits generated under a provisionally-approved fuel pathway, or transfer the provisional fuel with obligation, **<u>until the Executive Officer has adjusted the CI</u>** or informed the producer that the provisional CI has been successfully corroborated by operational records covering a full two years of commercial operation" (emphasis added). Further, "At any time during those two years, the Executive Officer may revise as appropriate the plant's actual operational CI based on those receipts."

Based on these elements of Section 95488(d)(2), we believe that the regulation distinguishes between an "adjusted CI" and a CI that has been corroborated by two years of operational data and, that once the Executive Officer adjusts the CI of a provisional pathway (including, but not limited to, the issuance of any CI that differs from the Temporary FPC values in Table 7), all credits generated under that pathway become available for trade, sale, or transfer. Hence, once an applicant has submitted at least one quarter (three months) of receipts and reported credits generated in the LRT, the Executive Officer should issue an adjusted operational CI, enabling the full use of the provisional credits by the applicant and any future credits generated under the provisional pathway. LCFS FF35-2

It should also be noted that the regulation does not define the terms, "Provisional CI", "Operational CI", or "Provisional Credits." For clarity, we believe that the following are reasonable interpretations of each term.

Provisional CI – A CI issued to a provisionally approved pathway. This includes CIs based on "default" values in Table 7 and Operational CIs.

Operational CI – A CI that has been issued or adjusted by the Executive Officer based on operational data submitted by the applicant. An Operational CI can apply to a Provisional Pathway or a fully approved pathway. Operational CIs for provisional pathways may be adjusted multiple times as the Executive Officer receives additional quarters of operational data. LCFS FF35-3

Provisional Credits – Credits generated under a Provisional Pathway. Provisional Credits generated under an Operational CI can be traded, sold, or transferred.

Because these elements of the provisional pathway process are potentially confusing, we respectfully request that Staff clarify the intent of Section 95488(d)(2) and confirm that the Executive officer will timely adjust the LCFS FF35-4

CI of the provisional pathway based on the receipt of at least one quarter of operational data. Further, we request that Staff clarify that such an adjustment would allow the applicant to trade, sell, or retire these provisional credits, or transfer the underlying fuel with obligation. Such a clarification is crucial to avoid harming the development of new low carbon fuel supplies and is consistent with the stated intent of the LCFS and the provisional pathway process. LCFS FF35-4 cont.

If Staff do not believe our interpretation of the regulatory text is accurate, we strongly urge ARB to modify the rule to allow the monetization of Provisional Credits immediately upon issuance of a Provisional CI, and allow generation of credits from the date the application is submitted to ARB. LCFS FF35-5

2. Temporary FPC Values

Table 7 of the regulation proposes temporary carbon intensities for fuels where a specific fuel pathway cannot be identified. These may also potentially be used as "default" values for facilities awaiting application approval or in the beginning stages of the Provisional Pathway process. Hence, the values in Table 7 have a material impact on the credits and deficits generated under the LCFS. Despite the importance of these values, ARB staff have not provided information regarding the underlying assumptions used to determine most of the values in Table 7 (excluding the CIs for diesel and CARBOB, which are clearly documented elsewhere). We believe that the values in Table 7 are not consistent with typical values expected for natural gas pathways providing fuel to California. In fact, values for LNG from North American natural gas, and CNG or LNG derived from landfill gas are significantly higher than the illustrative values provided by ARB staff at the April 3rd workshop at which updates to CA-GREET 2.0 were extensively discussed. LCFS FF35-6

In sum, the currently proposed revisions to Table 7 further increase the CIs for natural gas pathways above values previously proposed by staff, and these increases do not appear to be explainable by documented revisions to the CA-GREET model. We believe that it is inappropriate to further increase the values in Table 7 without providing details on the assumptions underlying these changes. Consequently, we request that ARB staff not modify the values in Table 7 from the values proposed in February. At the very least, we believe that any modifications to the values in Table 7 should be clearly linked to documented changes and updates to the CA-GREET model.

3. Application Review Timeline

Section 95488(c)(5)(B) proposes to eliminate the 60-day deadline for ARB staff to review an application and notify the applicant about its completeness. However, Staff is not proposing to modify the 180-day deadline for an applicant to provide a complete application. Staff notes that this change is being proposed to eliminate "unrealistic deadlines" during times when Staff will be working to recertify hundreds of existing pathways.

This removal of the 60-day deadline may be acceptable for applications covered by an existing pathway and able to generate credits as late as December 31, 2016. However, the proposed change <u>is not acceptable for new applications</u>. It is crucial that ARB continue to provide timely feedback to applicants regarding the completeness of their applications and any deficiencies that must be addressed. Delays in the review process can translate directly into lost credit generation, the associated revenue, and verified carbon reductions. LCFS FF35-7

Further, we note that the removal of the 60-day requirement is not limited to the 2016 timeframe. It is inappropriate to establish a regulation in which Staff have no obligation to complete a timely review of an application but where the applicant is simultaneously constrained to a fixed deadline and dependent on Staff's review of the application. LCFS FF35-7 cont.

Similarly, Staff propose to remove the 15-day deadline for review and notification of completeness of a fuel transport mode as defined in Section 95488(e)(5). We have similar concerns and objections to the removal of this requirement for timely review of the fuel transport mode application as we do for the pathway application review process in Section 95488(c)(5). LCFS FF35-8

We urge Staff to retain the 60-day and 15-day deadlines in Sections 95488(c)(5)(B) and 95488(e)(5), respectively, and to provide the LCFS program the necessary resources to conduct timely review of applications during the 2016 timeframe. It is critically important that industry has a process for application review that includes firm deadlines for ARB's actions. LCFS FF35-9

4. Treatment of Business Confidential Information

Staff are proposing to eliminate language providing protection of credit transaction data as Business Confidential information. Section 95487(c)(1)(B) currently requires ARB to treat all data reported in Credit Transfer Forms as business confidential, with limited exceptions for reporting of aggregated data described in Section 95487(d).

Credit Transfer Forms contain a number of sensitive pieces of information including, but not limited to:

- Names and contact information of individuals at companies involved in the transaction;
- Parties to specific transactions;
- Price and number of credits involved with a specific transaction.

LCFS FF35-10

There is no basis for broad public disclosure of the names and contact information of private persons, particularly when they are acting simply in an administrative role for a private organization. Further, the disclosure of the parties, pricing, types of credits, and number of credits associated with a particular transaction can be damaging to the business interests of regulated parties. The disclosure of such sensitive information is not consistent with other regulatory programs including the US EPA's Renewable Fuel Standard.

It should also be noted that, while the regulation allows brokers to facilitate "blind transactions," the disclosure of data in the Credit Transfer Forms would undermine blind transactions for any transactions where the broker does not first aggregate the credits from multiple buyers or sellers.

We urge Staff to retain the Business Confidential protection language in Section 95487(c)(1)(B). Confidentiality provisions are the industry standard for commodity transactions. However, we can support providing information for the sole purpose of calculating a published index.

5. Definition of L-CNG and Bio-L-CNG

The proposed regulatory text currently defines L-CNG as "LNG that has been liquefied and transported to a dispensing station where it was then re-gasified and compressed to a pressure greater than ambient pressure."

Similarly, Bio-L-CNG is defined as "biogas-derived biomethane which has been compressed, liquefied, re-gasified, and re-compressed into L-CNG, and has performance characteristics at least equivalent to fossil L-CNG."

In both definitions, it is assumed that L-CNG is created by gasifying LNG and then compressing the resulting gas to pressures suitable for CNG, typically 3,600 psi. This is not an accurate description for most L-CNG and Bio-L-CNG facilities. The pumping of liquids to high pressures is much less energy intensive than the compression of gas. Most L-CNG facilities take advantage of this fact by first pumping LNG to high pressures and then re-gasifying the LNG at pressure, ultimately producing CNG without the need for a gas compression process. Such a distinction is important because it has a meaningful impact on the carbon intensity for L-CNG fuels. We note that this issue was raised in our comments submitted to ARB on December 15, 2014. Following that submission, Staff updated the CA-GREET model to reflect the typical operation of L-CNG stations.

LCFS FF35-11

We recommend that Staff modify the definition of L-CNG and Bio-L-CNG to be consistent with the processes modeled in CA-GREET 2.0. Specifically, by eliminating the text asserting that L-CNG and Bio-L-CNG necessarily involve "compression" or "re-compression" of natural gas at the station.

6. Retroactivity

Section 95486(a)(2) limits the generation of retroactive credits to a maximum of two quarters; the quarter in which the complete application was submitted and the quarter in which the Executive Officer approves the application. Exceptions are made for provisional credits generated during the period that the applicant is accruing two years of operational data.

While the two-quarter limit on retroactive credit generation appears reasonable, it is predicated on the assumption that the Executive Officer will approve a complete application by the end of the quarter following submission of the application. Considering that Staff acknowledge the likelihood of significant delays in application processing during 2016, and in light of the proposed elimination of the 60-day and 15-day review deadlines discussed in item 3 above, we believe that retroactivity should not be constrained by a two-quarter limit. Specifically, we propose that retroactive credit generation should apply from the quarter the applicant submits a completed application or demonstration to the quarter in which the Executive Officer approves the application or demonstration. Hence, if the approval of the application or demonstration by the Executive Officer requires more than one quarter, the applicant does not lose credits due to delays outside the applicant's control.

LCFS FF35-12

This proposed change is both reasonable and important. However, we do not believe it is worth delaying the adoption of the LCFS, provided that Staff ensures the timely review of applications as noted in our comments under Item 3, above. Instead, we strongly urge Staff to consider making this change in a future update to the

LCFS, retain the 60-day and 15-day deadlines for review in the current rulemaking (or alternative reasonable timeline with a firm deadline), and ensure that the LCFS program has sufficient resources to provide timely review of applications. LCFS FF35-12 cont.

B. Comments on CA-GREET Model Update

We would like to thank Staff for their efforts to address our concerns related to the draft CA-GREET 2.0 model over the last nine months. These interactions have resulted in important improvements to the model.

In the latest draft of CA-GREET, Staff incorporated estimates of Tank to Wheels (TTW) methane and nitrous oxide emissions from natural gas vehicles, based on a recent whitepaper from Argonne National Laboratory (ANL).[2] The whitepaper provides estimated emissions for various vehicle types and applications, including combination long haul trucks, combination short haul trucks, refuse trucks, buses, heavy duty trucks and vans, and medium duty vehicles. Staff rely on the emissions rates in the ANL report, combined with estimates of the composition of the natural gas vehicle fleet, to calculate fleet-averaged TTW emissions rates for CNG and LNG.

The emissions rates calculated by ARB staff are not insignificant. As shown in Table 1, ARB assumes that the fleet-averaged emissions of methane and nitrous oxide for CNG and LNG vehicles are 4.90-4.91 gCO2e/MJ. This represents a 6% increase in pathway emissions for CNG and LNG from fossil sources, and potentially more than 25% of emissions from renewable natural gas pathways. However, as shown, emissions from some vehicle types are much lower than the calculated fleet average.

LCFS FF35-13

Table 1. Non-CO2 GHG emissions assumptions for natural gas vehicles

Vehicle Type	Non-CO2 vehicle emissions
ARB CNG Fleet Average	4.90 gCO2e/MJ
Light-Duty/Medium Duty	0.99 gCO2e/MJ
Heavy-Duty Class 8b	2.42 gCO2e/MJ
ARB LNG Fleet Average	4.91 gCO2e/MJ

Both heavy-duty class 8b vehicles and light/medium duty vehicles are estimated to have much lower TTW emissions than the fleet-average. Because of such wide variation in the emissions from vehicle types, the fleet-averaged emissions are very sensitive to the assumed fleet composition. Overestimating the fraction of the fleet in higher emitting applications raises the fleet average and potentially penalizes lower emitting applications.

We raise two specific concerns here, as described below.

1. Basis for the Current Fleet Mix

Staff calculates the current mix of applications consuming CNG and LNG based on data from the US Energy Information Administration's (EIA) Alternative Fuel User Database. The latest year for available data is 2011. LCFS FF35-14

[2] Cai, H. et al, The GREET Model Expansion for Well-to-Wheels Analysis of Heavy-Duty Vehicles, 2015

We note that the data are both out of date, and inconsistent with other industry specific data sources. As an example, we note that ARB staff estimate that transit buses consume 60% of the 55 million gallons of LNG sold in 2014. This equates to nearly 22 million GGE, or 150% more LNG for transit buses than reported by EIA. The National Transportation Database (NTDB) reports that California transit fleets consumed only 7 million gallons of LNG, or approximately 4.6 million GGE in 2011; roughly half of the fuel consumption reported by EIA. Finally, it is unclear to what extent reported LNG consumption actually reflects LNG delivered to an LCNG station.

LCFS FF35-14 cont.

The dominant purchasers of LNG in California for transit applications are Orange County Transportation Authority (OCTA) and Santa Monica's Big Blue Bus (BBB). These two agencies represent almost 95% of LNG purchased in 2011, according to the NTDB. Examination of a recent LNG purchase contract from OCTA reveals that the agency consumes roughly 22,000 gallons of LNG per weekday, or approximately 5.5 million LNG gallons per year.[3] A city council report on the BBB LNG fuel procurement for 2010-2011 reported that BBB purchases roughly 200,000 LNG gallons per month to serve a mix of BBB vehicles as well as city vehicles and the Santa Monica Unified School District.[4] BBB operates a mix of CNG and LNG buses, supplying the CNG buses through their LCNG station. Consequently, only a fraction of the BBB LNG purchases are actually used in transit applications. In total, the two largest purchasers of LNG for transit applications only represented less than 7.7 million LNG gallons in 2011. Again, this value is much lower than that reported by EIA.

Such disparities between EIA and other data sources make it clear that EIA is not a reliable basis upon which to develop a fleet-average emissions rates.

2. Evolving Fleet Mix

EIA's last available estimate of the population of NGVs in the US is 121,650 vehicles in 2011. Based on industry sales data, NGVA estimates that the current population of NGVs is in excess of 155,000 and growing. New deployments show growth in sales of Class 8 trucks in addition to sales in more traditional transit and refuse applications. It is clear that the mix of NGVs is changing and that it is not possible to accurate predict the future fleet mix. Further, because of the relatively small number of NGVs in the state (relative to traditional petroleum fueled vehicles), modest growth in any application could significantly alter the fleet mix.

LCFS FF35-15

Recommendations Regarding CA-GREET Update

Based on the two concerns described above – and the fact that the TTW emissions rates employed by ARB have non-trivial variations based on the vehicle type/application – we request that ARB allow fuel producers the option to adjust their pathway carbon intensities based on the vehicle type receiving the fuel. For example, a CNG or LNG station owner that documents the volume of fuel dispensed to Class 8b trucks would adjust their pathway CI based on non-CO2 TTW emissions of 2.42 gCO2e/MJ, rather than the fleet average of 4.90 or 4.91 gCO2e/MJ.

LCFS FF35-16

[3] Orange County Transportation Authority, Award of Liquefied Natural Gas Contract – Staff Report, 2013 http://atb.octa.net/AgendaPDFSite/10775_Staff%20Report.pdf

[4] City of Santa Monica, LNG Fuel for the Big Blue Bus, Agenda Item 3-E, February 8, 2011. http://www.smgov.net/departments/council/agendas/2011/20110208/s2011020803-E.htm

This option would help incentivize the deployment of NGVs in the lowest emitting categories by recognizing their specific emissions profiles and would require minimal changes to the data tracked in the LRT. Currently light and medium-duty natural gas consumption is tracked separately from heavy-duty natural gas fuel consumption in the LRT. Implementing the proposed recommendation would only require the separation of Class 8b fuel consumption from the remaining heavy-duty vehicle applications. Where the vehicle type cannot be determined or is not documented, the credit generator would continue to use the fleet-averaged TTW emissions rates. LCFS FF35-16 cont.

Closing Comment

Our three organizations support re-adoption of the LCFS regulation. We genuinely appreciate the cooperation that ARB staff have shown in working with our industry representatives to improve the program, especially the critically important CA-GREET model. Leading up to the July 23 Board meeting, we urge you to expeditiously address the issues identified in this letter.

Thank you for the opportunity to comment. If we can provide additional information, please contact any of us.

Sincerely yours,

Tim Carmichael, President
California Natural Gas Vehicle Coalition
916-448-0015

Matthew Godlewski, President
NGVAmerica
202-824-7360

David Cox, Director of Operations & General Counsel
Coalition for Renewable Natural Gas
916-678-1592

35_FF_LCFS_NVGC

953. Comment: **LCFS FF35-1**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

954. Comment: **LCFS FF35-2**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

955. Comment: **LCFS FF35-3**

The commenter suggests definitions for provisional and operational CIs and for provisional credits. In order to remedy the apparent error related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

956. Comment: **LCFS FF35-4**

The comment is related to provisional pathways being able to generate credits as soon as commercial production begins, the quarter the provisional pathway is approved, and the prior quarter.

Agency Response: See response to **LCFS FF27-3**.

957. Comment: **LCFS FF35-5**

The comment suggests ARB amend the proposal for monetizing provisional credits.

Agency Response: See response to **LCFS FF27-3**.

958. Comment: **LCFS FF35-6**

The comment states that the currently proposed revisions to Table 7 further increase the CIs for natural gas pathways above values previously proposed by staff, and these increases do not appear to be explainable by documented revisions to the CA-GREET model.

Agency Response: Table 7 CI values are intended for use only when no information has been provided to ARB to evaluate the fuel, as stated in the Initial Statement of Reasons (ISOR) (Summary of Section 95488(d), p VIII-11):

> A fuel provider is seeking to sell a volume of fuel which has no CI associated with it. Section (d) provides a table of temporary default CIs that can be used to report transactions involving such fuel.

These CIs must represent a conservative scenario – rather than average or typical – in order to maintain the integrity of the program and the scientific defensibility of GHG emission reductions, as well as to encourage producers who regularly wish to provide fuel for use in California to apply for a certified carbon intensity value. To model these conservative CIs, the following guidelines were utilized:

> When a range of data was available, either from the pool of existing applications, government reports or published literature, ARB staff selected the highest reasonable value for Tier 1 calculator inputs. Examples include quantities of energy consumption, material inputs, and transportation distances.
>
> If a sufficient pool of data to define a range of probable inputs was not available, average values were used and a 5 percent "safety factor" was applied to estimate the high-intensity scenario.

Changes to temporary CIs since the first Regulation Order are consistent with model changes, meaning no additional input assumptions were altered, with the exception of RNG: the pipeline transmission distance was increased to reflect the furthest likely producer. No distinction was possible between sources of RNG due to the small number of anaerobic digester pathway applications that have been evaluated by ARB.

959. Comment: **LCFS FF35-7**

The commenter asserts that it is inappropriate to establish a regulation in which staff has no obligation to complete a timely review of an application but where the applicant is simultaneously constrained to a fixed deadline and dependent on staff's review of the application.

Agency Response: The 180-day timeline for submitting a complete application remains in place to ensure timely responses for other applicants. The opportunity to reapply or submit a complete application is always available to applicants; functionally, the 180-day limit means that the application loses its priority in the queue: it will be evaluated after any other complete applications submitted in the time period following the applicant's original (incomplete) application and the final (complete) application.

ARB staff has removed the 60-day deadline for the initial ARB staff review to account for the 2016 recertification process, and to acknowledge that some pathways are simpler than others for staff to process. This change is primarily intended to allow for flexibility during the transition time period, as the commenter notes, during which time producers may continue using CIs generated using CA-GREET 1.8b which were approved under the existing regulation.

Further, staff will be setting self-imposed public deadlines for the recertification process. Staff will outline the deadlines that staff will adhere to in guidance that will be developed through stakeholder feedback and workshops after the Board Hearing. Beyond the recertification time period, staff expects timely reviews for new applications, as demonstrated in the past.

Similarly, the removal of the 15-day timeline for staff to approve demonstration of fuel transport modes is to allow for flexibility during the transition. As producers may generate credits backdated to the time of first shipment, this change will not result in a loss of credit generating potential. Historically, approval of fuel transport mode demonstration has been well within the 15-day time period which was allotted, however, many regulated parties have been delinquent in providing this demonstration to ARB. Hence, a 90-day timeline is now in place to ensure that regulated parties meet requirement within a quarter such that they will not be adversely impacted by the two quarters retroactivity limit.

960. Comment: **LCFS FF35-8**

The commenter states that staff propose to remove the 15-day deadline for review and notification of completeness of a fuel transport mode as defined in Section 95488(e)(5). They have concerns and objections to the removal of this requirement for timely review of the fuel transport mode application as we do for the pathway application review process in Section 95488(c)(5).

Agency Response: See response to **LCFS FF35-7**.

961. Comment: **LCFS FF35-9**

The commenter urges staff to retain the 60-day and 15-day deadlines in Sections 95488(c)(5)(B) and 95488(e)(5), respectively, and to provide the LCFS program the necessary resources to conduct timely review of applications during the 2016 timeframe.

Agency Response: Additional ARB staff will be allocated for pathway recertification in 2016. See response to **LCFS FF35-7**.

962. Comment: **LCFS FF35-10**

The commenter objects to the removal of language guaranteeing that credit transfer information submitted online would be treated as confidential business information (CBI). The commenter appears to assume that there will automatically be "broad public disclosure" of data reported in connection with credit transfers.

Agency Response: ARB staff disagrees. Blind transactions facilitated by brokers are still expressly allowed by the regulation. Staff disagrees that removal of language, which is duplicative of other laws, will result in public disclosure of CBI. ARB staff does not believe that the original language was necessary. State law protects trade secrets, and existing ARB regulations provide a means by which a CBI claim may be asserted. (Cal. Code Regs., tit. 17, §91011.) Moreover, it is not appropriate to predetermine that all information regarding transactions in a government-created market with a public, environmental purpose is CBI.

963. Comment: **LCFS FF35-11**

The commenter recommends that staff modify the definition of L-CNG and Bio-L-CNG to be consistent with the processes modeled in CA-GREET 2.0.

Agency Response: The structure of CA-GREET2.0 model's Tier 1 calculator allows the user to accurately calculate the impacts of energy use in the conversion of LNG to CNG using either technical approach described by the commenter: regasification to natural gas at ambient pressure followed by compression of gas to CNG, or compression as a liquid and regasification under pressure. While the L-CNG definition provided does not precisely reflect the variety of methods utilized by all L-CNG producers, ARB staff finds the distinction noted by the commenter to be immaterial, as the emissions at this stage are based on energy use which can be verified by receipts regardless of the number of steps taken or order in which they are performed. Furthermore, contrary to the statement in the comment, the CA-GREET model was not updated (individual input fields are provided for energy use in regasification and in compression; if no energy is used for one of these steps the user may enter 0.001), as it was demonstrated that this structure was sufficient to accurately reflect multiple approaches to conversion of LNG to CNG.

964. Comment: **LCFS FF35-12**

The commenter proposes that retroactive credit generation should apply from the quarter the applicant submits a completed application or demonstration to the quarter in which the Executive Officer approves the application or demonstration. However, the commenter does not believe it is worth delaying the adoption of the LCFS. The commenter also repeats the suggestion to retain deadlines for ARB review.

Agency Response: ARB staff appreciates the commenter's prioritization of proposed changes. Beyond the recertification time period, staff expects timely reviews for new applications, as demonstrated in the past. See response to **LCFS FF35-7**.

965. Comment: **LCFS FF35-13 and LCFS FF35-14**

The comment states that overestimating the fraction of the NGV fleet in higher emitting applications raises the fleet average and potentially penalizes lower emitting applications. The commenter believes that EIA data are not a reliable basis upon which to develop fleet-average emissions rates.

Agency Response: ARB staff presented the intention to use EIA fuel consumption shares representing data year 2011 in a public workshop and documented it in Appendix C of the ISOR posted in December 2014. The EIA Alternative Fuel User Database represents the most detailed and most recent data available on fuel consumption by California NGVs. Staff will continue to monitor and consider updating vehicle emissions as more recent fleet data becomes available, and invites stakeholder participation in maintaining awareness of available data sources.

Staff agrees that the “fleet average” emission factor is sensitive to the fleet mix (which is represented by the fuel consumption of each vehicle type, rather than the number of vehicles), due to the wide variation in emissions from each vehicle type and application, however, staff maintains the proposed approach for the following reasons:

> The use of a single fleet-wide average emission factor to represent the vehicle operation phase of each fuel CI is established practice for petroleum and other fuels under the LCFS. The variation among NGV types does not constitute sufficient reason to model emissions from NG vehicles differently than other fuels. Staff finds it appropriate to apply a single fleet-wide average emission factor to each fuel CI because the LCFS regulates fuels, and not vehicles. Tracking fuel distribution to each vehicle type and duty application would require an impractical level of documentation and staff believes such onerous measures would be strongly opposed, with little benefit to the accuracy and scientific integrity of the program. .

966. Comment: **LCFS FF35-15**

The comment states that the mix of NGVs is changing and that it is not possible to accurate predict the future fleet mix. The comment further asserts that modest growth in any application could significantly alter the fleet mix.

Agency Response: See response to **LCFS FF35-13**.

967. Comment: **LCFS FF35-16**

The commenter requests that ARB allow fuel producers the option to adjust their pathway carbon intensities based on the vehicle type receiving the fuel.

Agency Response: See response to **LCFS FF35-13**.

Comment letter code: 36-FF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

36_FF_LCFS _HBC

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Tuesday, June 09, 2015 12:12 PM
To: Chowdhury, Hafizur@ARB
Subject: Use of Revised CI values prior to recertification?

Hafizur:

Since it may not be until well into 2016 before the existing pathways are recertified, I am thinking about whether the revised CI values can be used before the CI's are certified and posted. The answer could have a significant impact on the carbon credit balances for 2016 and also 2017. From the regulations, it appears that perhaps two quarters of volume may be eligible for using the new CI value on a provisional basis before it is certified, if I am reading the proposed regulations correctly. In section 95486(a)(2) dealing with "No Retroactive Credit Generation" there is the following section:

"Notwithstanding this section, the Executive Officer may convert provisional credits to fully transferrable credits at any time, pursuant to section 95488 (d) and (e). Where an application or demonstration pursuant to sections 95488 or 95489 has been completed but not yet approved, the applicant may report, and the LRT-CBTS will reflect, information supporting provisional credits/deficits. Such provisional credits may not be used for any purpose until fully recognized. When the Executive Officer approves the section 95488 or 95489 application or demonstration, the Executive Officer will recognize any such provisional credits generated during the quarter in which the approval takes place, and one previous quarter, provided that the application was complete during that previous quarter."

LCFS FF36-1

Am I interpreting this correctly?

If existing and new pathways in the batches are eligible for this, what will constitute "completeness", which looks like will be one of the requirements?

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

36_FF_LCFS_HBC

968. Comment: **LCFS FF36-1**

The commenter is inquiring if revised CI values can be used before the CIs are certified and posted.

Agency Response: All the new and revised CIs under the proposed regulation will be available on or after the effective date of the regulation in order. During the recertification process applicants can continue to use their existing CIs to report to the LRT-CBTS to generate credits. If the applicants do not have any CIs to use, they are allowed to use the temporary CIs (Table 7) until their application is evaluated, certified, and posted.

This page intentionally left blank.

Comment letter code: 37-FF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

37_FF_LCFS _HBC

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Friday, June 05, 2015 1:58 PM
To: Chowdhury, Hafizur@ARB
Subject: Exclusion from Resubmitting Lifecycle Analysis for Existing Tier 1 Pathways?

Hafizur:
On the phone yesterday, you mentioned that producers with existing Method 2A pathways would not need to resubmit a revised lifecycle analysis to get their pathways recertified. I am looking in the regulations for that exception and cannot locate it. Could you clarify or point me in the direction of that provision in the regulations?

LCFS FF37-1

I see the provision that the demonstration of physical pathway has been "grandfathered" for existing pathways in 95488(e), which was added as part of the changes accompanying the 15 day package, but I don't see a similar provision for the LCA.

Sorry to trouble you if it is there and I can't find it.

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

37_FF_LCFS_HBC

969. Comment: **LCFS FF37-1**

The commenter is asking if the Life Cycle Analysis (LCA) report is required to process the existing Method 2A fuel pathways.

Agency Response: Applicants are not required to submit the LCA report to recertify their pathways under the legacy pathway process. The legacy pathway recertification process uses information previously submitted by the applicants, unless staff request additional or updated information. However, if applicants submit new pathway, or a revised existing pathway with new data under Tier 1, then they are required to submit the associated documentations stated under the section 95488(a)(2).

This page intentionally left blank.

Comment letter code: 38-FF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

38_FF_LCFS _HBC

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Friday, June 05, 2015 1:12 PM
To: Chowdhury, Hafizur@ARB
Subject: Batch processing applications

Hafizur:
I would appreciate discussing this topic briefly with you. I am referring to the new section in the modified regs stating:

"Batch" processing in 2016. Applications to recertify fuel pathway certifications, registrations that were approved under the previous LCFS (and still in effect on the date this regulation goes into effect) and new applications for fuel pathways in 2016 will, to the extent feasible, be processed in groups based on fuel type in the following order of priority: ethanol, biodiesel, renewable diesel, compressed natural gas, liquefied natural gas, and all others.

LCFS FF38-1

I need to explain to clients what this means, or might mean, so any guidance would be most helpful. Does it mean there is no hurry in getting revised applications submitted because the last one to submit will get their updated application at the same time as the first? Will there be posted deadlines to be included in a batch, and if not how will it be managed?

What are the possibilities?

If you want to call me, call my cell phone. I'm available anytime today.

Thanks for the heads-up yesterday that this was coming soon!

Thanks!

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

38_FF_LCFS_HBC

970. Comment: **LCFS FF38-1**

The commenter is inquiring about fuel pathways recertification and "batch" processing by fuel type.

Agency Response: Under section 95488(a)(2) applicants are required to inform ARB through LRT-CBTS by completing the online account registration process and submitting an electronic New Pathway Request Form prior to February 1, 2016, indicating that they are seeking recertification of a legacy pathway.

In 2016 Staff will process fuel pathways by "batch" according to its fuel type (e.g., ethanol, biodiesel, renewable diesel, compressed natural gas, liquefied natural gas, and all others).

Each batch will be processed and released on the same date. For example, once all the ethanol pathways are processed, regardless of the order of submission within the proposed deadline, they will be certified and released at the same time. Simultaneously, all of the legacy ethanol pathways will be deactivated from the system. Staff selected this approach to avoid any competitiveness impacts.

Similarly, in order to avoid competitiveness impacts, staff's current thinking is that any new application that wishes to be completed prior to the conclusion of each batch must be submitted to ARB prior to February 1, 2016. New applications will, to the extent possible, be processed as part of each batch.

If the Board readopts the LCFS, ARB staff plans to hold a workshop after the board hearing to solicit additional feedback on this process (including feedback on the appropriate completion date for each batch) and provide draft guidance on the new pathway process.

This page intentionally left blank.

Comment letter code: 39-FF-LCFS-UNICA

Commenter: Phillips, Leticia

Affiliation: UNICA

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

39_FF_LCFS _UNICA

From: Leticia Phillips <leticia@unica.com.br>
Date: June 19, 2015 at 1:08:53 PM PDT
To: "cpham@arb.ca.gov" <cpham@arb.ca.gov>
Cc: "swade@arb.ca.gov" <swade@arb.ca.gov>, "Ahuja, Kamal@ARB" <Kamal.Ahuja@arb.ca.gov>
Subject: CA GREET 2.0 Comments - UNICA

Dear Mr. Pham,

My name is Leticia Phillips and I serve as the North American Representative for the Brazilian Sugarcane Industry Association (UNICA).

I wanted to write you with a few comments regarding the CA GREET 2.0 documents that were posted on CARB's webpage on June 4, 2015.

While we appreciate staff's effort to update the electricity resource mix for Brazil, based on the most up to date data, we are still disappointed that CARB is proposing using energy mix all together. We believe Brazilian sugarcane ethanol pathway is only accurately represented if using the marginal electricity resource mix. LCFS FF39-1

On page 2 of the *CA GREET 2.0 Supplemental Documents and Table Changes*, CARB states that "Staff determined that the simplest, most equitable and defensible method is to apply the regional average across all pathways." We believe that the simplest method is to use the marginal values accepted by IPCC – which I believe was already provided to CARB by AgroIcone in Brazil. LCFS FF39-2 We also believe that the adoption of energy mix for Brazil unfairly penalizes the country because it benefits pathways dependant on energy in detriment of pathways that generate energy, like in our case. LCFS FF39-3 And finally, since the original GREET already has a marginal value calculated, it is hard to defend using a new number that worsens the model. LCFS FF39-4

Another point that I do not understand and would like clarification is how each mill will present its electricity credit; kWh per gallon of ethanol. The default value do not exist anymore? LCFS FF39-5

We have always admired and supported the work of CARB staff on the LCFS, we believe it is an incredible program that can curb GHG emissions and deliver better air quality for the citizens of California. We disagree from CARB's move to use electricity resource mix in the CA GREET 2.0 for Brazil. We know you are working on a tight deadline but we urge you to review this decision. LCFS FF39-6

I look forward to continue to collaborate with CARB and to hearing from you.

Best regards,

Leticia Phillips

UNICA

39_FF_LCFS_UNICA

971. Comment: **LCFS FF39-1**

The comment states that the Brazilian sugarcane ethanol pathway is only accurately represented if using the marginal electricity resource mix.

Agency Response: The comment provided is not related to any "15-day changes" being proposed in the Modified Regulation Order posted for public comment on June 4, 2015.[58] ARB staff notes that a response to the concerns re-expressed by the commenter here was provided in the staff response to **LCFS B1-2**. There is no change in staff assessment to warrant an additional response.

972. Comment: **LCFS FF39-2**

The commenter believes that the simplest method for GREET 2.0 is to use the marginal values accepted by IPCC.

Agency Response: See response to **LCFS FF39-1**.

973. Comment: **LCFS FF39-3**

The commenter believes that the adoption of energy mix for Brazil unfairly penalizes the country because it benefits pathways dependent on energy in detriment of pathways that generate energy.

Agency Response: See response to **LCFS FF39-1**.

974. Comment: **LCFS FF39-4**

The comment states that since the original GREET had a marginal value calculated they find it hard to understand using a new number that worsens the model.

Agency Response: See response to **LCFS FF39-1**.

[58] http://www.arb.ca.gov/regact/2015/lcfs2015/regorderfinal.pdf

975. Comment: **LCFS FF39-5**

The comment discusses the methodology to determine the co-product credit for Brazilian sugarcane-based ethanol pathway applicants to the LCFS program who cogenerate and export surplus electricity.

Agency Response: This comment is not related to any "15-day changes" being proposed in the Modified Regulation Order posted for public comment on June 4, 2015. As a courtesy, ARB staff is providing a response.

The co-product will now be based upon the actual surplus export rate of cogenerated electricity as opposed to a default value previously determined for ARB's internal pathway developed for Brazilian sugarcane-based ethanol.[59] Staff believes the actual co-product credit will benefit those applicants who previously could not qualify to meet the minimum, benchmarked rate of surplus cogeneration (0.96 kWh per gallon of ethanol produced), as well as those applicants who cogenerate and export larger amounts of electricity than the default value.

976. Comment: **LCFS FF39-6**

The commenter disagrees with ARB staff's decision to use electricity resource mix in the CA GREET 2.0 for Brazil.

Agency Response: See response to **LCFS FF39-1**.

[59] ARB, 2009. "Detailed California-Modified GREET Pathways for Brazilian Sugarcane Ethanol: Average Brazilian Ethanol, With Mechanized Harvesting and Electricity Co-product Credit, With Electricity Co-product Credit," Stationary Source Division, Version 2.3, September 23, 2009. http://www.arb.ca.gov/fuels/lcfs/092309lcfs_cane_etoh.pdf

Comment letter code: 40-FF-LCFS-Tesoro

Commenter: Heller, Miles

Affiliation: Tesoro

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

40_FF_LCFS
_Tesoro

TESORO

June 19, 2015

Clerk of the Board
Air Resources Board
1001 I Street
Sacramento, CA 95814

Electronic Submittal

RE: CARB Low Carbon Fuel Standard Re-Adoption, 15-day package release 6-4-2015

Dear Chairwoman Nichols and Honorable Board Members:

Tesoro appreciates the opportunity to comment on the proposed re-adoption of the Low Carbon fuel Standard (LCFS) and specifically on the 15-day regulatory amendments released on June 4, 2015.

We understand that the Western States Petroleum Association has provided comments on this 15-day package as well. Tesoro generally supports those comments, but wishes to focus comments on some specific implementation issues in Section 95489 (f) – Refinery Investment Credit.

Tesoro appreciates the inclusion of Section 95489 (f) – Refinery Investment Credit which may help companies justify projects to reduce the carbon intensity of transportation fuel production and greenhouse gas (GHG) emissions from the refineries. We raised concerns in our comments on the 45-day amendment package and at the hearing on the restrictive nature of the language originally proposed.

After the 45 day amendment was introduced, we met with staff to discuss specific implementation issues and have found staff to be responsive to some of our concerns and suggestions in the 15-day package. However, we are requesting clarifications on some remaining issues as outlined below.

Eligibility Criteria

95489 (f)(1)(E) precludes projects whose "primary objectives" are refinery equipment shutdowns, reductions in refinery or equipment throughput and refinery maintenance from eligibility. Under the simplest scenario, we understand that shutting down the refinery, reducing crude throughput, or a temporary shutdown of equipment for turnaround maintenance does not qualify as a refinery investment credit project. However, a refinery is a large complex operation comprised of a multitude of complex process units that facilitate complex chemical reactions to convert crude oil to transportation fuels. Consequently, a refinery may find a more efficient means to produce a similar overall volume of transportation fuels in a manner that enables shut LCFS FF40-1 down or reduced throughput at a process unit in favor of operating other units more efficiently. The term "primary objective" in this section appears subjective, to ensure correct interpretation during the implementation phase, we seek additional clarification regarding this requirement as discussed below. LCFS FF40-1 cont.

- Replacement Project: A refinery may replace an old piece of equipment with newer equipment that performs the same function but more efficiently. This may not be identical replacement, but functionally equivalent. Examples include replacing old inefficient boilers used for steam generation with new turbines that generate steam and electricity, and replacing unit heaters or furnaces with newer, more energy efficient units or improved heat integration with exchangers. It is our understanding that although the old equipment is shutdown, the credits created based on the difference between the old and the new unit emissions are qualified for refinery investment credits under CARB's proposal. Please clarify the regulatory intent with respect to this type of project. LCFS FF40-2

- Many projects must be executed when equipment is shutdown during turnarounds. The fact that the project is executed during a maintenance turnaround should not exclude it from eligibility. Please confirm. LCFS FF40-3

- Process Efficiency Improvement Project: There may be instances for which a process unit is shut down due to process efficiency optimization. For example, a refinery found a more efficient means to produce CARBOB or diesel utilizing five instead of six process units integral to the production. Although one of the process units may be shutdown, it is our understanding that this type of project would still be eligible to generate refinery investment credits based on the difference in emissions between the production process with six process units and five process units. Please clarify the regulatory intent with respect to this type of project. LCFS FF40-4

- Similar to the scenario describe above, a refinery may choose to optimize the volume of each transportation fuels produced (CARBOB and diesel.) In doing so, process unit feed volume or output volume may decrease in one process unit (perhaps the less carbon efficient unit) and increase in the other (the more carbon efficient) process unit. Although this project involves reducing throughput in one or more process units, it should qualify for the refinery investment credits. Please confirm that this type of project is still eligible for credit. LCFS FF40-5

<u>Clarification on the Refinery Investment Credit Calculation</u>

1. Additional clarification is needed regarding the definitions of $Volume_i^{XD}$, $Volume_i^{Total}$ and V^{XD} as follows:

a. Does $Volume_i^{XD}$ as expressed in subsections 95489 (f)(2)(B) and (C) represents the annual volume of CARBOB or diesel produced at the refinery including the volume exported, but excluding imported volume? LCFS FF40-6

b. $\text{Volume}_i^{\text{Total}}$ is defined in subsection 95489 (f)(2)(B) as "the total volume of CARBOB and diesel for data year i in bbl." Although the definition did not specifically refer to refinery product output, is it correct to assume that it is the total annual volume of CARBOB and diesel produced at the refinery (including volume exported, but excluding imported volume)?

c. V^{XD} is defined in subsection 95489 (f)(2)(F) as "the volume of either CARBOB or diesel in gallons." Since this is the volume used to determine the amount of refinery investment credits received, is it the intent of the regulation that V^{XD} only include fuel volumes sold, supplied, exchanged, transfer or offered for sale in California? Tesoro would appreciate clarification regarding the treatment of import and export CARBOB and diesel in the determination of V^{XD}.

LCFS FF40-6 cont.

2. As we understand, the value of Volume_i^{XD}, $\text{Volume}_i^{\text{Total}}$ and V^{XD} are to be derived from LCFS Reporting Tool (LRT). However, it is unclear from the proposed regulation which data elements or activities in the LRT are to be extracted from the LRT for determining Volume_i^{XD}, $\text{Volume}_i^{\text{Total}}$ and V^{XD}. We would appreciate a more detail explanation regarding application of data in the LRT.

LCFS FF40-7

Tesoro appreciates the opportunity to submit comments on the LCFS regulation 15-day amendments. Please contact me at (916) 462-5062 if you have any questions.

Sincerely,

Miles Heller
Director, CA Fuels and Regulatory Affairs

40_FF_LCFS_Tesoro

977. Comment: **LCFS FF40-1**

The commenter states that the refinery credit 95489 (f)(1)(E) precludes projects whose "primary objectives" are refinery equipment shutdowns, reductions in refinery or equipment throughput and refinery maintenance from eligibility. The term "primary objective" in this section appears subjective and the commenter seeks additional clarification as specifically cited in **LCFS FF40-2** through **LCFS FF40-5**.

Agency Response: See response to comment **LCFS FF43-47**.

978. Comment: **LCFS FF40-2**

The commenter requests clarification as to the regulatory intent with respect to replacement projects and if replacements would qualify for credit under this provision.

Agency Response: The examples cited would appear to qualify for the refinery credit. However, staff would need to see the full details of the project to make a definitive statement. See response to comment **LCFS FF43-47**.

979. Comment: **LCFS FF40-3**

The commenter requests confirmation that when a project is executed during a maintenance turnaround, this does not exclude it from eligibility.

Agency Response: The fact that a project is executed during a maintenance turnaround is not likely to exclude it from the refinery credit. However, the reduced emissions during the shutdown would also not be eligible for credits. ARB staff would need to see the full details of the project to make a definitive statement. See response to comment **LCFS FF43-47**.

980. Comment: **LCFS FF40-4**

The commenter requests clarity on specific types of refinery projects.

Agency Response: One of the purposes of the refinery investment credit is to incent innovative projects that change the way petroleum is currently refined. It is hard to say if the project mentioned in the comment would qualify for a refinery investment credit without more details. On the surface it would appear this project would qualify as a permanent equipment shutdown and would not be eligible for a refinery investment credit. However, if the applicant could show that through some revolutionary optimization technique or equipment modification, that the refinery only needed five pieces of equipment instead of six, while still processing the same inputs to produce CARBOB or diesel, then the project may qualify for a credit. However, staff would need to see the full details of the project to make a definitive statement.

981. Comment: **LCFS FF40-5**

The commenter asks that if a process unit feed volume or output volume decreases in one process unit (perhaps the less carbon efficient unit) and increases in the other (the more carbon efficient) process unit does it qualify for the refinery investment credits?

Agency Response: As mentioned above, the objective of the credit is to incentivize innovative projects and one output to another would not qualify. However, staff would need to see the full details of the project to make a definitive statement. See response to **LCFS FF40-4**.

982. Comment: **LCFS FF40-6**

The commenter requests clarification of the following terms: $Volume_i^{XD}$, $Volume_i^{Total}$_, and V^{XD}.

Agency Response: $Volume_i^{XD}$ represents the annual volume of CAROB or diesel produced at the refinery, excluding imported volumes of finished CARBOB or diesel.

$Volume_i^{Total}$ is meant to represent the total annual volume of CARBOB and diesel produced at the refinery (including volume exported, but excluding imported finished CARBOB or diesel).

V^{XD} in 95489 (f)(2)(F) is meant to represent the total annual volume of CARBOB or diesel produced at the refinery that is sold, supplied, exchanged, transfer or offered for sale in California. Import and export volumes of finished CARBOB and diesel are not meant to be a part of V^{XD}.

983. Comment: **LCFS FF40-7**

The comment states that it is unclear from the proposed regulation which data elements or activities in the LRT are to be extracted from the LRT for determining $Volume_i^{XD}$, $Volume_i^{Total}$ and V^{XD}.

Agency Response: ARB staff is currently working to update the LRT to incorporate amendments to the LCFS regulation. That process is ongoing and staff will provide additional detail in the near future.

This page intentionally left blank.

Comment letter code: 41-FF-LCFS-CP

Commenter: Smart, Anne

Affiliation: ChargePoint

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

chargepoint.com

chargepoint

ChargePoint, Inc.
1692 Dell Avenue | Campbell, CA 95008 USA
+1.408.841.4500 or US toll-free +1.877.370.3802

June 19, 2015

Mr. Michael S. Waugh, Chief
Transportation Fuels Branch
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Proposed 15-Day Regulation Order, Low Carbon Fuel Standard

Dear Mr. Waugh and LCFS Staff:

We appreciate this opportunity to provide the comments of ChargePoint, Inc. (ChargePoint) on proposed changes to the regulations governing California's Low Carbon Fuel Standard (LCFS) issued on June 4, 2015 pursuant to the Notice of Public Availability of Modified Text and Availability of Additional Documents and Information (Notice) relating to the Proposed Re-Adoption of the LCFS. We strongly support the goals of the LCFS program, and recognize the California Air Resources Board (ARB) as a national leader in implementing this important program as part of the state's larger effort to reduce the carbon intensity of transportation fuels and decrease greenhouse gas (GHG) emissions for the benefit of all Californians. For the reasons discussed below, ChargePoint urges you to modify the proposed changes in the regulations addressing requirements for Regulated Parties for Electricity.

Introduction

Headquartered in Campbell, California, ChargePoint is the world's largest and most open EV charging network with more than 22,000 level 2 and DC fast charging spots. Every 6 seconds, a driver connects to a ChargePoint station and by initiating over 9.65 million charging sessions, ChargePoint drivers have driven over 210 million gas free miles.

Since 2009 ChargePoint has been actively participating in the development of the LCFS regulations before the ARB, and in proceedings at the California Public Utilities Commission to establish procedures for use of the revenues from sale of LCFS credits by the jurisdictional investor-owned utilities.

ChargePoint has not yet registered as a regulated party, but is preparing to do so. In fact, ChargePoint has been involved for some time in evaluating approaches to participation in the market for LCFS credits, and considering how it may effectively monetize the value of LCFS credits for the benefit of EV drivers and site hosts under the regulations applicable to public access, workplace and multi-unit dwelling locations. This process has taken time for two reasons: (1) As a business participating in an expanding and competitive market, ChargePoint has had to weigh the initial and ongoing costs of participation in the LCFS program as a regulated party against the benefits to the company and its customers, EV drivers and site hosts. (2) It was unclear in the very early period of LCFS credit market development how the market would function and what opportunities would be available to third parties. As market growth accelerates, third parties like ChargePoint are now in a position to begin participating in the LCFS program, using the network functions and embedded metering in networked charging stations to facilitate participation and deliver value to EV drivers and the site hosts that have invested in EV charging infrastructure and services.

The key to facilitating participation by third parties will be clear rules and a simple, straightforward process. If the procedures for opting in as a regulated party for electricity are burdensome or administratively complex, third parties cannot be expected to participate in the program, and the value of their participation will be lost. For this reason, ChargePoint opposes the proposal to alter the current default designations in Section 95483(e) of the LCFS Regulations.[1]

LCFS FF41-1

The default provisions for Regulated Parties for Electricity should not be changed.

On June 4, 2015 ARB issued a Notice of Public Availability of Modified Text proposing modifications to the current LCFS regulations. These reflect modifications discussed in the February 19, 2015 public hearing process, and additional changes subsequently proposed by ARB staff.

Among the new proposed changes are modifications to Section 95483(e) of the LCFS Regulations that will impose additional obligations on non-utility providers of EV charging services at public charging, EV fleet and non-public workplace locations. Specifically, Sections 95483(e)(2), (3)(A) and (4) of the LCFS Regulations have each been revised to designate the Electrical Distribution Utility as the default regulated party rather than the Electric Vehicle Service Provider (EVSP) (in the case of public access EV charging), the fleet operator (in the case of fleet charging), and the site host (in the case of private access EV charging equipment at a business or workplace. These proposed revisions are not supported by factual explanation or statement of reasons, and could disadvantage third party providers of charging services. There is no need for "clarification" since the existing regulations clearly establish the utility's ability to generate LCFS credits at sites where the EVSP, fleet operator, or workplace site host chooses not to participate in the program.

LCFS FF41-2

Public Access EV Charging

Under the existing regulations, an EVSP "that has installed the equipment, or had an agent install the equipment, and who has a contract with the property owner or lessee where the equipment is located to maintain or otherwise service the charging equipment" is eligible to generate LCFS credits if it complies with applicable registration and reporting requirements.[2] If the EVSP is not reporting or has not complied with the requirements to opt in as a regulated party, the Electric Distribution Utility is entitled to generate credits at the location, provided it requests and receives Executive Officer approval.

The proposed regulations reverse the current default provision, obliging the EVSP to request and obtain approval by the Executive Officer in order to opt in and generate credits at a public access EV charging location.[3] It is unclear whether an EVSP must go through this process on a location by location basis, or whether a single submittal may cover multiple locations. The ARB staff has previously observed that the non-utility EVSPs were designated as the default regulated parties for public access charging because "[t]he credit revenue that they will be eligible for will reward them for establishing the public charging network that is required to support a successful EV market."[4] This reasoning remains sound.

LCFS FF41-3

In order to effectuate the purpose of rewarding third party EVSPs for their investments and provide an incentive for further private sector investment in public EV charging, the regulations should remain unchanged. EVSPs already must comply with all applicable registration and reporting requirements in order to receive LCFS credits from public access EV charging stations. Imposing the additional step of requesting

[1] 17 CCR §95483.
[2] LCSF Regulations § 95483(e)(2).
[3] Proposed LCFS Regulations p. 20.
[4] State of California, Air Resources Board, Staff Report: Initial Statement of Reasons for Proposed Rulemaking (October 26, 2011) p.45.

–chargepoint.

Executive Officer approval on the EVSP is unnecessary and could serve as a disincentive to participation. This proposed change has already raised questions among industry participants currently considering participation in the program. The utilities have ample resources to meet this requirement in the event that the EVSP serving a public access location chooses not to participate in the program, and so there is no reasonable justification for change. The regulations should retain the EVSP as the default party. LCFS FF41-3 cont.

If the proposed change is adopted and EVSPs are obliged to submit a written request for Executive Officer approval in order to opt in and generate LCFS credits, the process should be simple and streamlined. For example, an EVSP should be permitted to seek and be granted approval for multiple locations in a single request.

EV Fleet Charging

In a manner similar to the proposed change applicable to public access charging, the proposed regulations would shift the obligation to seek Executive Officer approval to generate credits associated with fuel supplied to a fleet of EVs onto the fleet operator rather than the Electric Distribution Utility.[5] For the reasons discussed above, this proposal should not be adopted.

LCFS FF41-4

If the proposed change is adopted and fleet operators (or their agents) are obliged to submit a written request for Executive Officer approval in order to opt in and generate LCFS credits, the process should be simple and streamlined. For example, a fleet operator with EVs at multiple locations, or an agent representing fleet operators at multiple locations should be permitted to seek and be granted approval for multiple locations in a single request.

Private Access EV Charging

The proposed regulations also shift the obligation to seek Executive Officer approval from the utility to site hosts at a business or workplace offering EV charging services.[6] For the reasons discussed above, this change has not been justified. Again, in order to appropriately reward site hosts for their willingness to provide a location for on-site charging to employees and visitors, and to encourage such private investment, the process through which the site host can receive and monetize LCFS credits should be as simple and straightforward as possible.

LCFS FF41-5

If the proposed change is adopted and site hosts are obliged to submit a written request for Executive Officer approval in order to opt in and generate LCFS credits, the process should be streamlined and user-friendly. Businesses or workplace owners (or their agents) should be permitted to seek and be granted approval for multiple locations in a single request. It is not clear why the term "business owner" has been replaced with "site host." It will be important for ARB to recognize that site hosts' arrangements with providers of EV charging equipment and services vary, and the term "site host" should be interpreted inclusively.

Let the Market Grow

As noted above, the Notice does not explain why the staff is proposing changes to section 95483(e) when the market for EVSE, EV charging services, and LCFS credits are just beginning to grow and flourish. This would seem the right time to take exactly the opposite approach, and avoid unnecessary regulatory changes that may send mixed signals to new market participants. LCFS FF41-6

[5] Proposed LCFS Regulations p. 21.
[6] Id. p.22.

If the proposed changes in default provisions in Section 95483(e) are due to a misperception that only utilities are interested in participating as regulated parties, or that third parties are unable or unwilling to consider participating in the LCFS program, ChargePoint encourages further discussion and fact finding. As discussed above, we are actively engaged in preparation to register as a regulated party, and are aware that other third party providers of EV charging services are as well. We urge ARB not to make assumptions based on an early and undeveloped market, but rather to make every effort to facilitate broader participation by providers of public and private access charging, fleet operators, and site hosts.

LCFS FF41-6 cont.

Conclusion

ChargePoint appreciates this opportunity to provide comments on the current proposed revisions of the LCFS Regulations.

Sincerely,

Colleen Quinn

Colleen Quinn
Vice President, Government Relations and Public Policy
ChargePoint

41_FF_LCFS_CP

984. Comment: **LCFS FF41-1**

The commenter opposes the proposed 15-day change they believe sets Electrical Distribution Utilities (EDUs) as the default credit generators for many of LCFS electricity provisions, since it will increase burdens and administrative complexities of EVSP.

Agency Response: ARB staff agrees that the process for opting in as a regulated party for electricity should not be burdensome or administratively complex. Staff disagrees that the changes to Section 95483(e) have increased the administrative burden on EVSPs. See the response to **LCFS FF41-2** below for more details.

985. Comment: **LCFS FF41-2**

The comment states that the proposed 15-day will impose additional obligations on non-utility providers of EV charging services at public charging, EV fleet, and non-public workplace locations and that the regulations have been revised to designate the Electrical Distribution Utility as the default regulated party rather than the Electric Vehicle Service Provider (EVSP) (in the case of public access EV charging), the fleet operator (in the case of fleet charging), and the site host (in the case of private access EV charging equipment at a business or workplace.

Agency Response: We believe the commenter may have misinterpreted the intent of the rule language. The final proposal does not set Electrical Distribution Utilities (EDUs) as the default credit generators for public charging, EV fleet and non-public workplace charging. It merely clarifies the eligibility framework and streamlines the reporting requirements for all parties.

EDUs are eligible to generate credits from these EV charging activities if no other party is interested in generating the credits. The prior language was unclear as to how this lack of interest from other parties would be communicated so that a utility knew to request credits for public, workplace and fleet charging (e.g., the utility had no way of knowing if an non-utility Electric Vehicle Service Provider (EVSP) was opting not to participate in the program).

The changes in the final proposal clarify that the utility is eligible to claim the credits for charging that it has accurate data for on its system, until another party steps forward and opts in to supersede the utility's claim. Under such a circumstance, the EDUs are no longer eligible for the credits, and ARB staff will make administrative changes to the LRT accounts of the EDUs and EVSP to inform both parties and avoid double counting of the credits.

Staff also notes that under the current LCFS regulation, the EVSP has to opt in to the LCFS to be eligible to generate credits. In the proposed rule, more detail is provided about this opt-in process. Specifically, the EVSP is eligible to generate credits, "upon submittal to and approval by the Executive Officer of its written acknowledgement that it will opt in and generate credits." Therefore the proposed 15-day change neither increase burden nor imposes additional obligations for EVSPs. The adjustments merely provide additional clarity about the process for opting in.

Currently, public, workplace and fleet charging activities have not been an active source of credit generation in the program. Staff believes these clarifications will encourage utility participation in these areas and help avoid "stranded credits" associated with public, workplace and fleet EV charging that is currently occurring.

It is ARB's intention to keep the approval process for EVSP requests as simple and streamlined as possible. We encourage the EVSPs to include multiple locations in a single application.

986. Comment: **LCFS FF41-3**

The comment states that, for public EV charging, the proposed 15-day will impose additional step for the EVSPs to request and obtain approval of the Executive Officer in order to opt in and generate credits. The comment further states that there is no need to make such change since under current LCFS regulation as the utilities can generate the credits if EVSPs choose not to. The comment states that if the proposed regulation is adopted, the process for EVSP to request ARB approval should be simple and streamlined.

Agency Response: See response to **LCFS FF41-2**.

987. Comment: **LCFS FF41-4**

The comment repeats similar concerns to comment **LCFS FF41-3** for EV fleet charging. The comment states that if the proposed regulation is adopted, the process for EV fleet owner to request ARB approval should be simple and streamlined.

Agency Response: See response to **LCFS FF41-2**.

988. Comment: **LCFS FF41-5**

The comment repeats similar concerns for **LCFS FF41-3** and **LCFS FF41-4** for EV fleet charging.

Agency Response: See response to **LCFS FF41-2**.

989. Comment: **LCFS FF41-6**

The comment urges ARB not to make assumptions based on an early and undeveloped market, but rather to make every effort to facilitate broader participation of providers of public and private access charging, fleet operators, and site hosts.

Agency Response: ARB staff agrees and commits to make every effort to facilitate broader participation of providers of public and private access charging, fleet operators, and site hosts.

This page intentionally left blank.

Comment letter code: 42-FF-LCFS-NS

Commenter: Van De North, John

Affiliation: NexSteppe, Inc.

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

42_FF_LCFS_NS

NexSteppe

Comments to the California Air Resources Board

Modified Text and Availability of Additional Documents and Information for the Proposed Re-Adoption of the Low Carbon Fuel Standard

NexSteppe Inc. (NexSteppe) appreciates the opportunity to submit comments on the Low Carbon Fuel Standard Proposed 15-Day Regulation Order (LCFS). NexSteppe, headquartered in South San Francisco, California, is a developer and producer of high performance sweet sorghum and biomass sorghum hybrids. Our sweet sorghum hybrids are grown as feedstocks for advanced ethanol (as a supplement to sugar cane) and our biomass hybrids as a feedstock for cellulosic ethanol on a worldwide basis.

We commend the collaborative nature of CARB's rulemaking process. We have reviewed the LCFS and offer the following comments:.

1. We note that in Table 7 of the LCFS there is no default pathway for new cellulosic feedstock crops being converted to ethanol nor for sugar crops being converted to ethanol (similarly to sugar cane). The only feedstock listed is corn stover, a feedstock that is not optimized for ethanol production and is not available in many parts of the United States. We do not believe that the cellulosic ethanol industry will be able to supply sufficient fuel at competitive prices using only corn stover as a feedstock- and the omission of all other cellulosic feedstock crops from this table disadvantages many of the feedstocks that will be used in the production of cellulosic ethanol. Examples of those feedstocks would be biomass sorghum, arundo donax, switchgrass, miscanthus, woody biomass among others. LCFS FF42-1

2. In Table 5 there is an iLUC number quoted for "sorghum ethanol." We assume that this refers to ethanol derived from the grain of the sorghum plant—not ethanol produced from the cellulosic sugars present in biomass sorghum or the free sugars LCFS FF42-2

LCFS FF42-2 cont.

present in sweet sorghum. We request that this iLUC value be accordingly limited to grain sorghum.

3. Under Section 95488(d)(2) the LCFS proposes to issue "provisional certification of a fuel pathway application" but only in the event that the facility has been "in full commercial production for one full calendar quarter." We interpret this as requiring any cellulosic ethanol facility (regardless of how long it has been in operation) to report data for a full calendar quarter of operation with any new feedstock before a provisional certification is issued. To put this in perspective; we would estimate that to operate a 30 million gallon per year commercial cellulosic ethanol facility for 90 days would require nearly 100,000 dry tons of feedstock—or in the case of biomass sorghum— approximately 4,000 to 5,000 hectares of production. The story would be similar for other feedstocks—switchgrass, miscanthus, arundo donax etc. We do not see how, under this requirement, any producer could reasonably be expected to add new feedstocks to its supply chain given the significant cost of such a trial. The proposed regulation entrenches feedstocks and appears to create a significant barrier to the adoption of new feedstocks.

LCFS FF42-3

4. We also note that the LCFS appears to require two years of "full commercial production." For reasons driven by cost, land required for storage of biomass and risk many cellulosic ethanol producers will use a mix of feedstocks delivered on a "just-in-time" basis. The same will occur in cane-to ethanol plants that adopt sweet sorghum as a supplementary feedstock. In these scenarios one feedstock will be used for only part of a year—if "two years of commercial production" were in fact to be required (aggregating that part of any year in which a feedstock is used) we anticipate that provisional status would persist for some feedstocks anticipated by the LCFS. Indeed, if a plant were to use a mix of biomass sorghum, corn stover, switchgrass and wood chips (a supply chain design that is not uncommon) it would take nearly 8 years for any feedstock to move off provisional status. If cellulosic ethanol plants want to use new feedstocks as they become available during the course of their operational life it's possible that they could be on permanent provisional status.

LCFS FF42-4

5. In order to solve this problem we request that CARB consider issuing "feedstock-only" pathways that would allow existing conversion plants to implement new feedstocks without the one calendar quarter or two-year requirement. Feedstock only pathways would allow the rapid and broad adoption of new, innovative feedstocks with pre-determined cabon intensity scores without years of uncertainty connected to provisional LCFS credits. LCFS FF42-5

We hope that you find these comments useful and look forward to working with CARB on the implementation of the LCFS. Please do not hesitate to contact us if we can be of any assistance in this matter.

Respectfully submitted,

NexSteppe Inc.
400 East Jamie Court
South San Francisco, CA 94080
ATTN: John Van de North
(650) 887-5712
jvandenorth@nexsteppe.com

42_FF_LCFS_NS

990. Comment: **LCFS FF42-1**

This comment is related to temporary fuel pathway codes in Table 7 as they relate to cellulosic feedstocks.

Agency Response: ARB staff notes that this comment is not related to 15-day changes being proposed in the Modified Regulation Order proposed on June 4, 2015. As a courtesy however, staff is providing a response to the commenter's comment.

Staff apologizes for the oversight. A cellulosic ethanol producer may use the corn stover temporary FPC in Table 7, if necessary, and can obtain a specific feedstock/fuel pathway under Tier 2 through the normal pathway application process. Similarly, regarding other sugar based feedstocks/fuels, an applicant can use the, "any starch or sugar feedstock" as a temporary fuel pathway code until the applicant obtains a specific pathway and CI for their feedstock/fuel.

991. Comment: **LCFS FF42-2**

The commenter notes that in Table 5 there is an iLUC number quoted for "sorghum ethanol." They assume that this refers to ethanol derived from the grain of the sorghum plant—not ethanol produced from the cellulosic sugars present in biomass sorghum or the free sugars present in sweet sorghum. The commenter requests that this iLUC value be accordingly limited to grain sorghum.

Agency Response: The iLUC values published for sorghum ethanol represents grain sorghum derived ethanol.

992. Comment: **LCFS FF42-3**

This comment is related to the requirement that fuel production facilities be operating for one calendar quarter prior to applying for an LCFS fuel pathway.

Agency Response: ARB staff notes that this comment is not related to 15-day changes being proposed in the Modified Regulation Order proposed on June 4, 2015. As a courtesy however, staff is providing a response to the commenter's comment. The commenter is not correct with respect to the length of time a facility is in commercial production. A facility must be in commercial production for one full calendar quarter prior to being able to apply for an LCFS fuel pathway. If a pathway applicant changes their process significantly in order to process a different feedstock that they did not apply under an existing pathway then staff will work with the applicant to determine what must be done. In general, staff will be conducting workshops after Board Hearing and providing guidance for many circumstances that stakeholders have questions and comments about. Please refer to the response under comment **LCFS FF27-3** for further explanation.

993. Comment: **LCFS FF42-4**

This comment is related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes. In addition, the commenter questions how new feedstocks could be brought into production if two years of data is required.

Agency Response: See response to **LCFS FF20-1**.

Regarding using supplementary feedstocks in current pathways that reduce the CI, staff is intrigued but needs to evaluate a proposal in more detail before we can develop a framework for such an approach. We would be happy to engage with the commenter further about how to appropriately balance the commercial needs of this business model with the need to have accurate (or at least conservative) CI values in the program.

994. Comment: **LCFS FF42-5**

The commenter suggests that staff provide for feedstock only pathway as a way to solve problems related to the provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: See response to **LCFS FF20-1** and **LCFS FF42-4**.

Comment letter code: 43-FF-LCFS-WSPA

Commenter: Reheis-Boyd, Catherine

Affiliation: Western States Petroleum Assoc.

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

43_FF_LCFS
_WSPA

Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

Catherine H. Reheis-Boyd
President

June 19, 2015

Clerk of the Board, Air Resources Board
1001 I St., Sacramento, CA 95814
Via electronic mail to *http://www.arb.ca.gov/lispub/comm/bclist.php*

Dear Clerk of the Board,

Re. Proposed Re-Adoption of the Low Carbon Fuel Standard
Notice of Public Availability of Modified Text and Availability of Additional Documents and Information

The Western States Petroleum Association (WSPA) is a non-profit trade association representing twenty-five companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California and 5 western states.

Attached is a set of comments – both general and specific – that continue to concern WSPA. We support the inclusion of an additional Periodic Review of the LCFS in 2017. We are prepared to engage again next year, in advance of the 2017 review, in updating the data relative to the projected feasibility and health of the program. LCFS FF43-1

If there are any questions or a need for additional clarification of our comments, please contact Gina Grey of my staff (ggrey@wspa.org) to arrange for further dialogue with WSPA.

Sincerely,

c.c. S. Wade – ARB

<u>Western States Petroleum Association's Comments on ARB's 15-day Notice of Public Availability of Modified Text and Availability of Additional Documents for the Amendments to the Low Carbon Fuel Standard Regulation.</u>

General

WSPA believes that regulations should be based on sound science and free market principles, including a level playing field for all parties. Regulations should also include cost/benefit considerations and provide a clear and reasonable regulatory framework. Several elements of the amendments in the ARB's LCFS 15 day package do not satisfy these criteria; thus we respectfully request ARB revise this package to include these considerations.

Some of our core comments are presented below, with more detailed comments included in the following pages:

- WSPA continues to strongly object to the extremely limited accountability placed on electricity providers in generating LCFS credits. This is in dramatic contrast to the extremely rigorous application process and detailed record-keeping and reporting required on the part of liquid fuel suppliers and does not support the notion of a "fuel neutral" program as the LCFS is purported to be. LCFS FF43-2

- ARB proposes several new and modified methods of credit generation, but with arbitrary and disparate effective dates. This seems to serve no purpose other than to favor one credit generation methodology over another. Staff should move immediately to align the effective dates of all applicable segments of the regulation (e.g., electricity, refinery investments, and innovative crude pathways) to ensure fairness in the treatment of compliance options. LCFS FF43-3

- Credit accounting continues to be exceedingly complex, and the amendments in this 15-day package exacerbate these issues. With over 250 pathways approved by ARB, the lack of ARB oversight as to the validity of those credits and pathways, and a changing regulatory environment in which all fuel pathways must be recalculated using new model criteria, ARB cannot reasonably expect fuel suppliers to verify those credits with such an overly complex accounting system. LCFS FF43-4

- Credit generation from light and heavy duty rail use is inconsistent with both the intent and the ISOR for the LCFS, and should be removed from the program. LCFS FF43-5
    - The use of light and heavy duty rail existed prior to the implementation of the LCFS; as such, its use is not further reducing GHGs from the transport sector.
    - If ARB chooses not to remove these provisions, then ARB must account for such credits distinctly in ARB's quarterly summaries from other electricity credits so stakeholders can understand the contribution from these pre-existing sources.

- The Credit Clearance Market, in which deficit holders must participate, exacerbates an infeasible target, is not market-based, and does not provide the opportunity for fuel suppliers to evaluate the validity of credits. In addition, the publication of a list of Credit Clearance Market LCFS FF43-6 participants and each party's outstanding deficit obligation violates confidential business information practices. The inappropriate disclosure of this information has the distinct possibility of harming a given participant's competitive position in the market. LCFS FF43-6 cont.

- It is critical that staff clarify the language in §95488 apparently prohibiting the sale of credits or fuel with obligation associated with new fuel pathway applications for up to two years. Staff has acknowledged that the currently proposed draft language does not represent what was intended and a very clear message must be issued to allow fuel producers some certainty. LCFS FF43-7

- WSPA does not believe credits generated from the refinery investment credit provisions (as written) will contribute substantially to meeting fuel suppliers' compliance obligation. Despite some positive changes in the 15 day package, the characterization of these provisions as "pilot programs" and the significant barriers that still exist in the draft language substantively impede valid credit generation in apparent conflict with what ARB hopes to incentivize with the measure. LCFS FF43-8

- ARB should not delete the multimedia evaluation provisions from the proposed regulations; to the contrary, ARB should be undertaking a multimedia evaluation for the LCFS as required by California Health & Safety Code. Multimedia evaluations are necessary in order to obtain a full and independent assessment of the range of potential environmental impacts of any newly proposed fuel regulations across all media. ARB's ADF multimedia evaluation and failure to undertake the required multimedia evaluation for the LCFS have not addressed the significant water demands associated with the production and use of biofuels under the LCFS, which may potentially exacerbate the severe drought California currently faces. LCFS FF43-9

Specific

Revised Compliance Schedule

WSPA received confirmation from ARB staff that new compliance information will be provided to the ARB Board at the July 23rd hearing, and we'd like ARB to once again confirm that this information will be provided prior to the July hearing. Additionally, the revised compliance schedule is missing from the staff package. WSPA requests it be re-included. LCFS FF43-10

Arbitrary Dates for Credit Generation

The LCFS reauthorization regulations contain multiple internal inconsistencies with respect to measuring CI reductions and the generation of credits. For example, even though the base year for measuring CI reductions under the regulations is 2010, the regulation as proposed uses refinery energy consumption data from 2011 through 2013 as the basis for estimating the petroleum refining process CI, rather than 2010 data. LCFS FF43-3 cont.

Further, credit generation for fixed guideway systems and electric forklifts is permitted without regard to when these projects began operation. Yet, energy efficiency improvements implemented in petroleum refineries between 2010 and 2016 cannot generate credits, despite the fact that they have reduced the CI of the products.

Innovative crude production credits are available for solar steam and carbon capture and sequestration (CCS) projects that became operational as early as 2010, but are not available until January 1, 2015 for all other innovative crude production projects. There appears to be no consistency in the regulation's various segments as to a common date threshold of eligibility for credit generation.

The following chart illustrates this observation:

Element	***Proposed Code Section***	***Effective Date After Which Credits Can Be Generated***
Fixed guideway systems	95483(e)(6)	No threshold for eligibility—credits can be generated regardless of when operation began
Electric forklifts	95483(e)(7)	No threshold for eligibility—credits can be generated regardless of when operation began
Solar steam and CCS projects	95489(d)(1)(B)	2010
All non-solar steam and carbon capture and sequestration innovative crude projects	95489(d)(1)(B)	2015
Low-energy intense refineries	95489(e)(4)(B)	2015
Refinery investment credits	95489(f)	2017 (Permits received by 1-1-2016 –projects take at least 1 year to construct)

LCFS FF43-3 cont.

It is well-settled under California law that "logic and reason demand that [an] agency explain the basis for its decision." *McBail & Co. v. Solano County Local Agency Formation Com'n* (1998) 62 Cal.App.4th 1223. During the rulemaking process, an agency must provide a rationale for the elements of the proposed regulations; to be valid, regulations must be consistent. *Harris Transportation Co. v. Air Resources Board* (1995) 32 Cal.App.4th 1472, 1479; *see also Voss v. Superior Court* (1996) 46 Cal.App.4th 900, 916.

Federal courts agree that "an internally inconsistent analysis is arbitrary and capricious." *National Parks Conservation Association v. EPA*, Case No. 12-73757 (9th Cir. June 9, 2015), *see also Gen. Chem. Corp. v. United States*, 817 F.2d 844, 857 (D.C. Cir. 1987). An agency cannot simply mandate key elements or formulas within a regulation without an explanation of the basis for that decision. *National Parks Conservation Association, at *15-16*. Instead, an agency must explain the basis for exercising its discretion to craft a regulation in a particular manner; failure to do so will render the regulation invalid as arbitrary and capricious. *Id. at *17*.

But here, ARB proposes an internally inconsistent regulation with no explanation regarding the selection of incongruous dates to serve as the bases for credit generation for certain elements of the regulation. WSPA objects to this level of inconsistency between elements and proposes that ARB adopt consistent dates for credit generation across the board. At the very least, ARB must offer its basis for the existing inconsistency between dates. LCFS FF43-3 cont.

California Reformulated Gasoline and Ethanol Denaturant Calculator Spreadsheet

WSPA understands staff has made changes to the California Reformulated Gasoline and Ethanol Denaturant Calculator Spreadsheet since it was last posted. Since this spreadsheet is used not only to calculate the new baseline CaRFG values but also the new ethanol CI values, WSPA requests that the final version of this spreadsheet be posted for public review. LCFS FF43-11

§ 95481.(a) Definitions

(9) "Biodiesel Blend" - The term "biodiesel blend" is not used anywhere in the LCFS regulation outside this section. The definition should be deleted.

(63) "Petroleum Product" - It is inappropriate to include co-processed biomass in the definition for "petroleum product." Staff should consider a broader term like "refinery product" to avoid confusion.

(67) "Product Transfer Document" - We continue to object to the redefining of "product transfer document" as a single document consolidating information from existing documents. This term should follow the traditional definition to allow flexibility for regulated parties. LCFS FF43-12

(71) "Renewable Hydrocarbon Diesel" – we would prefer the definition include a reference to "elemental composition primarily of hydrogen and carbon". We also have concerns with the definition indicating that a fuel additive may be defined as "Renewable Hydrocarbon Diesel" as currently written.

Suggested language:

(71) "Renewable hydrocarbon diesel" means a diesel fuel that is produced from nonpetroleum renewable resources but is not a mono-alkyl ester, with an elemental composition primarily of hydrogen and carbon, and which is registered as a motor vehicle fuel under 40 Code of Federal Regulations Part 79.

§95483 (a)(2)(A-D). Regulated Parties

We are opposed to the deletion of this section and the associated edits in this section.

Striking a significant block of language related to the identification of regulated parties under the LCFS as part of a 15-day package, with no prior discussion of the change in the many workshops on the LCFS re-adoption, is arbitrary and capricious. Furthermore, this change does not add value to the program and does not address any issues with current compliance. What it does do is introduce an element of risk into compliance by removing the automatic transfer of obligation between regulated parties as product moves through the distribution system upstream of the terminal rack. Summarily removing this language increases the risk of discrepancies between the reports of regulated parties and unnecessarily complicates the nature of transactions between regulated parties. While staff characterizes this as "an unnecessary and complicated provision" in their explanation of the proposed change, the time to address such an issue would have been at the establishment of the program, not several years after the regulated community has developed business processes based upon the provision. LCFS FF43-13

§95483. (e)(2), (e)(3)(A), (e)(3)(B), (e)(4), (e)(5)

As WSPA has stated numerous times in the past, we strongly oppose ARB's electricity provisions, and continue to propose that electricity NOT be part of the LCFS program. ARB should account for the GHGs from electricity separately and reduce the compliance obligation within the LCFS proportionally based on ARB's anticipated success of the roll-out of electric vehicles (EVs). LCFS FF43-14

In addition, we have new concerns specifically related to changes in the 15-day proposed rulemaking package. In general, WSPA feels these changes:

- Are substantive and should not be included in a 15-day regulatory package, LCFS FF43-15
- Are not explained or justified in the Notice of Public Availability, LCFS FF43-16
- Exasperate the un-level playing field for electricity providers, by further reducing their public accountability, recordkeeping, and metering requirements. LCFS FF43-17
- Increase concern regarding validity of credits generated from the electricity sector, and the decreasing amounts of due-diligence and reporting required by providers of electricity as a "transportation fuel". LCFS FF43-18
- Are not clear in regards to whether anyone will make sure there is a true accounting of credits generated from electric vehicle charging. LCFS FF43-19
    - If electricity providers are generating credits from residential charging from registration records and average electricity demand, will ARB subtract credits generated from private / workplace charging?
    - From fleet charging?
    - From public charging?

WSPA strongly opposes the following 15-day changes related to §95483(e) provisions:

1. ***Removal*** of the requirement that Electrical Distribution Utilities to "Use all credits proceeds to benefit current or future EV customers" (§95483(e)(1)(A)) from credits generated from public access charging, EV Fleets, or private EV charging (§95483(e)(2 - 4)). We urge ARB to correct the following reference in all parts of §95483(e) from: LCFS FF43-20

   "must meet the requirements set forth in section 95483(e)(1)(B) through (D)."

   To:

   "must meet the requirements set forth in section 95483(e)(1)(A) through (D)."

2. Under §95483(e), ARB's modifications make the electric distribution utility the default credit generator in essentially all EV charging cases. This approach could have the consequence of the utilities using their power to restrict innovation and experimentation within the electric vehicle charging industry. Instead, ARB should allow the market and customer choice to guide development by allowing companies installing electric vehicle charging stations to generate credits by default. LCFS FF43-21

3. Removal of the list of efforts that may be used to educate the public in 95483(e)(1)(B). LCFS FF43-22

4. Removal of the requirement that ARB post supplemental information for public review each year. LCFS FF43-23

5. The modification to allow investor owned utilities to use Public Utility Commission reporting in lieu of LCFS specific supplemental information. LCFS FF43-24

Furthermore, technology exists to directly measure residential EV electricity use and therefore should be required, consistent with recordkeeping required for other LCFS pathways. We incorporate by reference our February 2015 comments on the electricity provisions in our response to comments for the 45-day rulemaking package. LCFS FF43-25

Combined, these proposed modifications further reduce the standards that electricity providers are held to, as compared to liquid fuel providers. As WSPA has stated in the past, there is also a fairness issue. Liquid fuel providers are expected to submit extremely detailed records for reporting and comply with extensive application processes for obtaining a CI pathway (and the record-keeping requirements for some pathways). The proposed reduction in accountability and reporting requirements for electricity providers, combined with the "estimates" of electricity used for residential charging, does not support the notion of a "fuel neutral" program, and provides inconsistent treatment at best. LCFS FF43-26

In addition, it is not clear from the proposal whether a proper accounting of total credits from electric vehicle charging will be performed by ARB. LCFS FF43-27

§95485. Demonstrating Compliance (Cost Containment Mechanism)

WSPA's concerns regarding the Cost Containment Mechanism (CCM) contained in the LCFS re-adoption package remain, as the proposed 15-day package revisions do not implement any substantial modifications to address the previously-raised concerns regarding this tool's ability to accommodate systemic and prolonged LCFS credit shortages. WSPA remains opposed to the inclusion of the CCM in the LCFS because we do not believe that it will accomplish its stated objective (contain prices) and will instead have a number of undesirable (and unintended) consequences. More specifically, the Credit Clearance Market (CCM): LCFS FF43-28

Offers no certain path to retire carryover deficits

The CCM provisions in the LCFS re-adoption package (post the proposed 15-day package revisions) continue to obligate parties to participate in the year-end credit clearance market at prices as high as the pre-determined "cap" price and parties have no recourse but to carry over any remaining deficit into the following year with interest. The CCM provisions stipulate a five-year maximum deficit carryover period but no specific pathway to retire deficits if shortages persist year to year. Instead, obligated parties face the prospect of an ever-increasing accrued financial liability that is essentially outside their control. In a market that is consistently short credits year after year, the ability to defer unsatisfied obligations (with interest) offers little comfort to the regulated community who remained concerned with the possibility of ever-increasing deficits with no method to retire part of the obligation generated by an infeasible standard. LCFS FF43-29

May drive credit costs up

The CCM provisions in the LCFS re-adoption package (after the proposed 15-day package revisions) may not keep credit prices in check during periods of rising prices (i.e., credit shortages in the open market). The CCM to clear the market at the end of the year is meaningless during a credit-short environment as there will not be any remaining credits to be brought to the table by sellers. The LCFS FF43-30 compounding of interest on the carryover/deferred balances will make it likely that credit buyers will soak up the available pool of real LCFS credits in the market during the year and not wait for the CCM. The pool of real LCFS credits available is fixed – it is only their price that remains in question. Staff's setting of the price cap at $200/ton will likely serve as the benchmark for credit prices in that environment.

LCFS FF43-30 cont.

Conversely, during periods of stable or declining prices (i.e., credit surplus in the open market), the CCM cap price creates an artificial "floor" value below which sellers may be hesitant to offer real LCFS credits for sale to the regulated community at substantially lower prices. This may artificially increase compliance costs – as credit prices could be artificially raised to (or near) the ARB cap with the likely result of fewer transactions taking place before the end-of-year sale. Credit trading could be seriously impaired as the open market may not be allowed to function as it should.

<u>Provides no liability protection against invalid credits</u>

The LCFS re-adoption package (after the proposed 15-day package revisions) continues to lack an acceptable liability defense provision or protocol to protect obligated parties from potentially fraudulent credit sellers. The only protection buyers of credits have is to perform due diligence and carefully screen the parties they choose to engage as partners in LCFS credit-buying transactions. It appears that buyers will not be afforded this luxury in the credits they are obligated to purchase (pro-rata share) through the CCM. Moreover, the timetable being put in place by ARB to organize and complete the CCM does not give parties comfort that the agency will be doing any such screening of the credits that are pledged by sellers for the CCM. WSPA objects to the fact that parties may potentially wind up in a position of non-compliance through no fault of their own simply because there is a credit shortage and buyers need to participate in the CCM where they have no control over what credits they buy and from whom.

LCFS FF43-31

<u>Offers no connection to LCFS program sustainability</u>

LCFS credit market liquidity (measurable potentially through a number of different indicators) is not only essential to the program's success but, also, the absence of such liquidity (as evidenced through the CCM) should be viewed as a clear signal that the program's CI reduction targets are overly aggressive and that the regulated community is finding it difficult to meet its obligations and remain in compliance. There is no connection in the CCM provisions of the
LCFS re-adoption package (after the proposed 15-day package revisions) to bring about a comprehensive program review should the potential trend of systematic credit shortages materialize and persist.

LCFS FF43-32

<u>Does not clarify the mechanics of deficit carryover</u>

The CCM provisions of the LCFS re-adoption package (after the proposed 15-day package revisions), while improved over the initial ISOR version, remain lacking in the execution/implementation details that would allow parties to understand exactly how the CCM would work. We recognize that staff has added some clarification to indicate that parties cannot retire accrued previous years' obligations until they have satisfied (met) their obligation for the immediately previous year. Staff has also included clarification of when the interest on accumulated carryover obligations will occur (i.e., in May each year prior to the start of the CCM in June).

LCFS FF43-33

While this seems to be pointing to a Last-In-First-Out (LIFO) accounting method, it does not explicitly indicate how older obligations are to be addressed. For example: Can parties retire (through blending or purchases) obligation carryover from four years ago before they retire corresponding deficits carried over from two years ago? Moreover, the application of a LIFO method (if indeed that is staff's intent) appears punitive in that it would maximize the accrued interest on obligation deficits carried over from previous years. We emphasize that such obligation carryovers could occur through no fault of the parties (i.e., even after they have made every best faith effort to cover their annual obligation) and find it objectionable that, not only will there be an interest penalty levied for carryovers through the CCM, but that this penalty will be maximized by not allowing the oldest obligations to be retired first. LCFS FF43-34

Furthermore, while we understand at what point during the year the interest will be levied (i.e., in May), we are uncertain as to whether the immediately preceding year's unmet obligation will also be included in the calculated interest. We do not believe that should be the case as parties should be given the opportunity to cover an additional part of any such remaining obligation from the immediately preceding year through the CCM. We believe this to be staff's intent but request clarification that interest will be applied the May following the Credit Clearance Market or one year after the initial annual report is submitted. We propose the following language for section 95485.(c)(5)(A): LCFS FF43-35

(A) Compound Interest on Accumulated Deficits. Regulated Parties with an Accumulated Deficit will be charged interest to be applied annually to all deficits in a regulated party's Accumulated Deficit account. Interest will be applied in terms of additional deficits that must be retired pursuant to section 95485(c)(1)(B), above, at a rate of 5 percent annually, applied May 1, 20XX, where 20XX = compliance year +2.

Based on the proposed 15-day package revisions, the criteria and conditions for retiring deficit carryovers in paragraph 95485(c)(5)(C) appear confusing in that they could be interpreted to limit a regulated party's ability to retire older deficits through the CCM. While we disagree with staff's apparent selection of the LIFO credit accounting method as indicated above, we would like staff to explicitly indicate their intent that regulated parties can buy more credits from the CCM than their immediate prior year's obligation shortfall as long as: a) they have used up all their accumulated credits and still have a carryover balance from years other than the immediately preceding year, and b) they first retire their immediate prior year's obligation through the credits obtained through the CCM. LCFS FF43-36

Additional comments on specific provisions under the CCM are as follows:

<u>§95485. (c)(4)(B)</u>

WSPA continues to strongly object to ARB publishing a list of Credit Clearance Market participants and each participating party's pro-rata share of pledged credits, and WSPA feels ARB's decision to list this information without any explanation or basis is arbitrary and capricious. LCFS credit and/or deficit balances and the individual entity names should be treated as highly confidential business information because the release of this information could adversely impact business operations. This proposal to make public the long and short credit positions of regulated parties violates the principles underlying protection of confidential business information. A regulated party's competitive position could be seriously compromised by the publication of this information. In addition, this information would give competitors both an understanding of a regulated party's compliance strategy and a view LCFS FF43-37 into the regulated party's fuel and credit acquisition activity for the year. Using this information and average market pricing, one could estimate the financial impact of LCFS compliance on a regulated party. It is well-established that this information is protected from disclosure under California law, and ARB should treat it as the highly confidential information it is. *See, e.g*, Cal. Gov. Code § 6254; Cal. Evid. Code §1060. **LCFS FF43-37 cont.**

<u>§95485. (c)(5)(D)</u>
WSPA understands ARB is proposing to prohibit entities that have a roll-over deficit under the credit clearance approach from transferring/selling credits to another party until the deficit is "paid back." WSPA understands this prohibition is only intended to apply to "separated" credit transactions and not to the transfer of obligation with physical fuel. We are requesting that ARB confirm this in writing. WSPA still requests clarification that the prohibition on credit transfers and sales does not include credits attached to biofuels that move by default in the transactions. This could be handled in a response to comment or guidance. **LCFS FF43-38**

<u>§95486. (a)(4)(B)(4)(b) Generating and Calculating Credits and Deficits</u>
WSPA supports ARB allowing regulated parties to use Carryback Credits to minimize any compliance shortfalls.

Section 95486(c) - Credit Generation Frequency. Beginning 2011 and every year afterwards, a regulated party may generate credits quarterly after data are reconciled with its business partner.

WSPA believes the new proposed language is unworkable in its current form. WSPA supports the goals of staff of accurate reporting, and we support the new reporting provisions requiring an initial report followed by a 45 day reconciliation period. Section 95491 Reporting and Recordkeeping (a)(1)(A) calls for reporting parties to "work in good faith with their counter parties to resolve any fuel transaction discrepancies between the parties". WSPA supports this but notes this does not ensure there will not be any discrepancies between reporting parties. To be consistent with section 95491, WSPA believes the language of 95486(c) should be modified to state (proposed change in red): **LCFS FF43-39**

> (c) Credit Generation Frequency. Beginning 2011 and every year afterwards, a regulated party may generate credits quarterly after ~~data are reconciled with its business partner.~~ <u>the quarterly report has been submitted in the LRT. Regulated parties shall</u> **<u>make a good faith effort to</u>** <u>reconcile their data with their business partners before submission.</u>

<u>§95487. (c)(1)(B) Credit Transactions - Confidentiality</u>
ARB proposes to remove the following language from the regulation:

> "Except as provided in section 95487(d) below, the Executive Officer will treat information submitted in the online Credit Transfer Forms as Confidential Business Information."

WSPA objects to ARB's removal of the language and requests that it be reinstated. Protection for such information is well-established under California law. Pursuant to the Government Code, such confidential business information is excluded from responses to Public Records Act requests. *See, e.g,* Cal. Gov. Code § 6254; Cal. Evid. Code §1060. This information has always been designated as Confidential Business Information under the LCFS, and ARB has provided no explanation as to why it **LCFS FF43-40** should be classified differently as part of this rulemaking. Removal of this language without explanation is arbitrary and capricious, and ARB must continue to fulfill its statutory obligation to protect such information from disclosure. Accordingly, WSPA requests that the stricken language be added back into section 95487(c)(1)(B). LCFS FF43-40 cont.

§95488. (a)(3) Obtaining and Using Fuel Pathways.

During the original revisions to the LCFS re-adoption, released in December, 2014, there were apparently significant revisions to Section 95488 relating to Provisional Pathways. The 15-day package released in June of 2015 further revised this section by including Tier 1 pathways. While the regulation does say that "Based on timely reports, the applicant may generate provisional credits", it also says, "such credits may not be sold, transferred, or retired for compliance, nor may fuel with a provisional CI be transferred with obligation." The revised regulation also goes on to say that "The applicant may not sell credits generated under a provisionally-approved pathway, or transfer the provisional fuel with obligation, until the Executive Officer has adjusted the CI or informed the producer that the provisional CI has been successfully corroborated by operational records covering a full two years of commercial operation".

Upon becoming aware of this revision (with respect to the addition of Tier 1 pathways in the 15-day package as well as the original language apparently revised in December 2014), understandable concern was raised by fuel investors and compliance entities alike as this section could be interpreted to mean that start-up facilities and pathways cannot sell credits or sell fuels (with an obligation) until they have operated for 2 full years. Obviously if this interpretation were to hold, this section of the regulation would significantly undermine the innovation that the LCFS itself seeks to encourage. Few, if any, plants or new pathways would be economic if they were not able to sell credits – or sell fuel with obligation– within the first 2 years of operation – a critical time period in the lifetime of a new operation. An Argus article dated June 11 discussed the potential impact of these revisions on the market as follows: LCFS FF43-41

> *The point of the program is to help commercialize new low-carbon fuels, but the provisional credit provision creates two years of uncertainty for affected producers unless they are comfortable with waiting up to two years before they can sell the credits and bank their cash value.*

> *The regulations could lock up significant amounts of credits or actual fuel supplies from new conventional low-carbon fuel producers, said Philip Sheehy, a technical specialist at consultant ICF. Credit prices could rise up to near the program's price cap of $200/t in 2018 or 2019, according to recent ICF forecasts that account for the provision credits system.*

In subsequent conversations, staff acknowledged that this section of the regulation was poorly drafted and that it is not the intent of the regulation to prohibit generation of credits or sale of fuels from start-up operations. It is crucial that staff <u>immediately</u> clarify the language of this section of the regulation by an appropriate mechanism. It is critical that both investors and regulated parties clearly understand the intent of this section of the regulation.

§95489. Provisions for Petroleum-Based Fuels (Refinery Investment Credit and Hydrogen Co-processing)

WSPA's primary concern throughout the process of developing the specific provisions and eligibility criteria related to the refinery investment credit and hydrogen co-processing provisions has been that the stringency of the provisions and criteria not be so restrictive that no projects will be eligible to generate credits. Most of the changes WSPA recommended leading up to the February Board meeting and in subsequent discussions with staff on the 15-day package were aimed at preserving the ability to generate credits from eligible projects.

Staff has made some improvements in addressing our comments consistent with the idea that more projects will be eligible. Unfortunately, some provisions remain problematic despite the changes CARB has proposed; and CARB has added new provisions that go in the wrong direction with respect to enhancing opportunities for project eligibility.

Improvements in the Proposal

- We appreciate staff's revision to allow potential criteria pollutant and/or toxics increases associated with candidate projects to be offset as provided in the applicable project permitting requirements. This was one of the key changes WSPA had identified as necessary to make the proposal viable and equitable. LCFS FF43-42

- WSPA is also in agreement with staff's decision to remove the proposed 50% discount for any credits generated by "less efficient refiners," as the methodology employed was rather arbitrary and had the potential to discriminate against complex refineries or penalize refineries that may have made prior investments in GHG reduction projects. LCFS FF43-43

- WSPA also appreciates staff's decision to reduce the 10% bio-feedstock minimum in the Hydrogen Co-processing provision which should make it more likely for such projects to move forward. LCFS FF43-44

Provisions that were not Sufficiently Addressed

- Staff did not act to avoid other arbitrary restrictions and thresholds to encourage innovative GHG reductions, most notably the 0.1 gCO2e/MJ minimum CI improvement for RIC project eligibility. This remains an inequitable provision as the standard will be much more difficult to meet for larger, fully integrated refineries. WSPA continues to maintain that supplementing this standard with an alternative flat 5,000 metric ton of CO_2e per year project impact threshold would allow more credit generation without unduly burdening staff with an overwhelming number of applications involving small projects. LCFS FF43-45

- While we are well aware of staff's unwillingness to provide retroactive credit for projects that have already started up (even if the start date was after the start of the LCFS program), we are completely puzzled by staff's refusal to implement a simple, practical and equitable criterion for project eligibility pivoting off the project's start date, i.e., the date GHG reduction benefits LCFS FF43-46 begin to accrue. We also highlight the potential unintended adverse impact that the current criterion (permit to construct issued after January 1, 2016) might have on projects currently underway in that it could provide an incentive to delay such projects and potentially withdraw/refile permit applications to ensure that the permit to construct is not issued before January 1, 2016 (rendering the project ineligible for RIC credits). We believe that this was not staff's intent. WSPA continues to maintain that staff's proposed RIC eligibility criteria penalizes early actors. LCFS FF43-46 cont.

As stated above, WSPA feels the base year should be consistent across all elements of the LCFS. However, at a minimum we recommend that, if staff wants to utilize the permit to construct data issuance (instead of project startup date) as the eligibility threshold, at a minimum staff should utilize January 1, 2015 as the associated date and not January 1, 2016.

- Lastly, WSPA notes staff's reiteration in the LCFS 15-day package of the earlier attempt to differentiate RIC candidate projects based on whether they are capital projects or part of routine refinery turnarounds and/or maintenance. We remain uncomfortable with the lack of specificity of the proposed language that calls for identification of the primary purpose or intent of a candidate project. We continue to believe that non-capital projects that offer sustained GHG improvements should be included since many energy efficiency upgrades are considered non-capital and may be part of a multi-pronged refinery strategy to simultaneously upgrade equipment for improved reliability, reduced maintenance and enhanced energy efficiency. Such projects could include shutdowns (i.e., replacement of a fired heater with heat exchangers) and should not be excluded from generating a credit. Staff should clarify that projects whose primary intent is increased energy efficiency but involve equipment shutdowns are not excluded. LCFS FF43-47

<u>New Provisions or Changes that are Problematic</u>

- Staff has removed entirely the ability to generate RIC credits from co-processing liquid bio-feed stocks at facilities, leaving Hydrogen co-processing as the only viable option available to some. While the opportunity to seek dedicated pathway approvals for such applications is still provided, staff's action eliminates substantial flexibility for parties' smaller scale projects/applications that may not warrant the dedication of time and resources to the rigors of the specified pathway approval processes. LCFS FF43-48

- WSPA is disappointed with staff's apparent "change of heart" regarding the RIC as evidenced by staff's recasting of this provision (as well as the Hydrogen Co-processing provision) as "pilot programs" designed to allow staff "time to evaluate the credit potential from these provisions and prevent any unanticipated impacts, if the volumes outstrip current expectations." LCFS FF43-49

  In WSPA's view, this is a fundamental change in staff's approach to what had been a significant part of the LCFS 45-day proposal– one that was discussed extensively during the nearly year-long workshop process leading to the February Board hearing and one that our industry had invested extensive time and resources to ensure it is a workable and practical provision. The implication of a pilot program designation is one of potentially temporary provisions that may be terminated in future program revisions. This leaves our industry with uncertainty as far as proceeding with the necessary investments to implement GHG reduction projects at facilities where projects may be consistent with what was perceived as the original intent of including the RIC provision in the LCFS. LCFS FF43-49 cont.

- Further evidence of staff's concern in this regard can be found in the implementation of largely unsubstantiated "caps" on the potential contribution from the RIC (at 20% of a regulated party's annual credit obligation) and the Hydrogen Co-processing provision (at 10%) whose sole purpose appears to be to provide further "insurance" that our industry could not actually rely on these provisions for anything more than a small percentage of the overall compliance obligation. Such an approach is inconsistent with the concept of 'neutrality" that staff (and the Board) have reiterated upon numerous occasions involving the variety of LCFS compliance options available to regulated parties. . LCFS FF43-50
- The RIC and Hydrogen Co-processing provision included in the LCFS 15-day package go even further in curtailing the practical utility of these provisions in limiting the ability of a party that generates such credits to do anything other than use them for their own compliance purposes, (i.e., prohibiting the sale of such credits in the marketplace). LCFS FF43-51

  We understand that this may not be staff's intent and that this flexibility-limiting provision may be simply the result of limitations in staff's ability to bring about the necessary LRT revisions in a timetable consistent with the LCFS re-adoption schedule. Nevertheless, WSPA once again needs to point out the rather arbitrary application of "neutrality" in that other eligible credit generating mechanisms in the regulations (e.g., electricity) are not limited in the volume of credits that can be generated, or in their ability to participate in the credit markets. LCFS FF43-52

Despite some improvements made by staff in the 15-day package, WSPA still believes that the current proposal substantively impedes valid credit generation in conflict with what ARB hopes to incentivize with the measure. These impediments not only manifest themselves as direct limitations to the quantity of credits that can be generated, but also by creating uncertainty that erodes credit generation prospects. As a result, few, if any, credits are likely to be generated from the provision as written – particularly while the provision remains a "pilot" program. LCFS FF43-53

§95490. Multimedia Evaluation

WSPA strongly disagrees with ARB's decision to completely eliminate the multimedia evaluation provisions in section 95490, as well as the proposed elimination of the definition of "multimedia evaluation" from section 95481(a)(59) and the proposed deletion of the application requirements related to multimedia evaluations in section 95488(c)(4)(G)6.d. LCFS FF43-54

WSPA also strongly disagrees with ARB's statement, in its Notice of Public Availability of Modified Text, that the LCFS "does not establish any fuel specifications." *Notice of Public Availability at 9.* As discussed in our February 17, 2015 comments on the proposed regulations, carbon intensity as established by the LCFS is a criterion or "specification" to which motor vehicle fuels must comply. The Health & Safety Code itself recognizes a fuel specification for light-duty vehicle exhaust emission standards—standards that, like the LCFS, are based on overall emissions from fuels as opposed to quantification of their particular components. Cal. Health & Safety Code § 43018(d)(1). Even the Ninth Circuit has already considered the LCFS to be a fuel control measure. *See Rocky Mountain* LCFS FF43-55

LCFS FF43-55 cont.

Farmers Union v. Corey, 730 F.3d 1070 (9th Cir. 2013) (recognizing that the LCFS is "a control respecting a fuel or fuel additive and was enacted for the purpose of emissions control").

ARB should not delete the multimedia evaluation provisions from the proposed regulations; to the contrary, ARB should be undertaking a multimedia evaluation for the LCFS as required by California Health & Safety Code. Multimedia evaluations are necessary in order to obtain a full and independent assessment of the range of potential environmental impacts of any newly proposed fuel regulations across all media. ARB has enough information regarding the types and blends of fuels that will likely be used to meet the LCFS to conduct a multimedia evaluation for the regulation. LCFS FF43-56

Given the severe drought conditions California currently faces, the multimedia evaluation must take into account the significant water demands associated with the use of biofuels, which are outlined in more detail in the peer-reviewed study by Julian Fulton of the Energy and Resources Group at U.C. Berkeley and Heather Cooley of the Pacific Institute. The multimedia evaluation for the ADF regulations fails to evaluate these potential impacts. LCFS FF43-57

The LCFS' carbon intensity fuel specifications stand to promote the use of multiple types of fuels that have not been fully evaluated for potential water impacts. As Fulton and Cooley note:

> "California's Low Carbon Fuel Standard…has reinforced demand for bioethanol as a means to reduce the greenhouse gas intensity of transportation fuels. Although early LCFS policy assessments raised the issue of water demands and impacts from increased biofuel production, any subsequent efforts to track or address those impacts through policy have been lacking." Fulton and Cooley, The Water Footprint of California's Energy System, 1990-2012 (February 26, 2015) at 10.

LCFS FF43-58

The potential for significant impacts makes a multimedia evaluation for the LCFS all the more critical. The evaluation should be completed as soon as feasible to comply with the Health & Safety Code. LCFS FF43-59

<u>§95491. Reporting and Recordkeeping - Table 12</u>

- WSPA recommends that the requirements for ARB in determining the annual average crude carbon intensity be included in Table 12. LCFS FF43-60

<u>§95491(a)(7) Reporting and Recordkeeping</u>

We object to the removal of annual reports from the section related to Correcting a Previously Submitted Report. There may be instances in which an annual report may also need to be re-opened for corrective edits and resubmittal. The removal of annual reports from this section essentially dis-allows regulated parties to correct previously submitted annual reports. LCFS FF43-61

<u>§95494. Penalties</u>

As discussed in WSPA's comments of February 17, 2015, WSPA opposes a per-day penalty, but does not oppose a maximum penalty of $1000 per tonne of deficit. While AB 32's enforcement provisions provide for per day penalties when a violation results in the emission of an air contaminant, where, as here, no actual emission of air contaminant is occurring on a per day basis, the imposition of such a penalty would be unjustifiably punitive, excessive and onerous. *See* Cal. Health & Safety Code §§ LCFS FF43-62

42400.1, 42400.3. A per deficit penalty approach is authorized by the Health & Safety Code. *See* Cal. Health & Safety Code § 38580(b)(3).

The proposed changes to section 95494(c) appear to embrace a per-deficit penalty, but the vague language needs to be clarified. The proposed language currently reads:

> "Each deficit that is not eliminated at the end of a compliance period or carried over as permitted by section 95485 constitutes a separate day of violation, subject to a penalty not to exceed $1000 per deficit."

LCFS FF43-62 cont.

The addition of the words "day of" essentially turns the per deficit penalty into a per-day penalty for each deficit, which WSPA strongly opposes as unduly onerous and unjustifiably excessive —all the more so because ARB has removed regulated parties' ability to request that their annual reports be re-opened for correction. WSPA suggests the following language be adopted:

> "Each deficit that is not eliminated at the end of a compliance period or carried over as permitted by section 95485 constitutes a separate ~~day of~~ violation, subject to a penalty not to exceed $1000 per deficit."

§95495. Defining "Material Information"

Including in the definition of "material Information" "information that would affect by any amount the Executive Officer's determination of a carbon intensity score…" potentially broadens ARB's authority to suspend, modify, or revoke credits. As discussed in WSPA's February 17, 2015 comments, the regulations penalize credit holders if they hold invalid credits, even if that occurs despite a regulated party's best efforts to hold valid credits. ARB may not require entities to participate in the credit scheme without providing some level of certainty that credits validly represent the reductions they purport to represent. *See* Cal. Health & Safety Code § 38562(d)(1) ["Any regulation adopted by the state board pursuant to this part or Part 5 [market-based compliance mechanisms] shall ensure all of the following: (1) The greenhouse gas emission reductions achieved are real, permanent, quantifiable, ***verifiable***, and enforceable by the state board …"] [emphasis added].

LCFS FF43-63

An appropriate definition of "material information" as used in the subsection would help to minimize the risk of arbitrary invalidation by limiting the bases for invalidation under proposed section 95495(b)(1). WSPA therefore requests that section 95495(b)(1)(G)1 be stricken from the regulation.

§95496. Regulation Review

Assuming continuation of the LCFS program, we support the addition of a 2017 Progress Report on the LCFS to the ARB Board and the inclusion of public review of the Progress Report findings. LCFS FF43-64

43_FF_LCFS_WSPA

995. Comment: **LCFS FF43-9, LCFS FF43-54 through LCFS FF43-59**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

996. Comment: **LCFS FF43-1**

The commenter supports the addition of the program "progress report" in mid-2017.

Agency Response: ARB staff appreciates the support. We look forward to the commenter's engagement in the program going forward.

997. Comment: **LCFS FF43-2**

The commenter strongly objects to the limited accountability placed on electricity providers in generating LCFS credits.

Agency Response: ARB staff disagrees with the comment that there is limited accountability. In the proposed 15-day changes, the credits generated through estimated EV charging will be calculated by ARB staff and well documented within the Electrical Distribution Utility's LRT-CBTS account. This would enhance the credit generation process for electricity providers, and reduce the probability of credit invalidation. If fraud is discovered; the Health and Safety Code and a host of other state and federal statutes may apply, and provide for civil and criminal consequences.

998. Comment: **LCFS FF43-3**

This comment states that ARB staff proposes arbitrary and disparate effective dates for various methods of credit generation under the regulation.

Agency Response: ARB staff disagrees that the dates in question are arbitrary. The effective dates of various types of crediting in the regulation are the result of: (1) various crediting options being proposed for addition to the program at different dates, and (2) different sources of credits requiring different constraints to incent action beyond common practice.

As an example of the first issue, crediting for solar steam projects existed under the prior rule, but crediting for renewable power projects in oil fields was a concept added in this rulemaking. As a result, the effective date for credits generated from solar steam projects is 2010, so as to not exclude any solar steam projects that were under development and anticipating receiving credits under the prior rule. The cut-off for renewable electricity projects is 2015 to incent new renewable capacity beyond what is already built and operating.

As an example of the second issue, a 2015 “project operation” effective date was chosen for innovative crude projects because they all involve technologies that are not common practice in oil extraction currently. In contrast, some refinery investment credits may involve achieving GHG reductions from technologies that are common practice. In order to have greater confidence that the credits value will drive a change in behavior related to these projects, a later eligibility date (2016) and a “permit approval” method of assessing the cut-off was selected.

999. <u>Comment</u>: **LCFS FF43-4**

The commenter believes that the credit accounting is overly complex and the 15-day package made it worse.

<u>Agency Response:</u> In many cases, the final proposal represents a simplification relative to prior mechanisms for credit accounting, therefore, we disagree that the credit accounting is overly complex under the new proposal.

We encourage fuel suppliers to continue to perform their due diligence with respect to verifying the validity of the credits they purchase. We also look forward to the commenter continuing to propose simplifications to the program framework that maintain the environmental integrity of the program.

1000. <u>Comment</u>: **LCFS FF43-5**

The commenter states that the credit generation from electricity use in light and heavy duty rail is inconsistent with both the intent and the ISOR for the LCFS, and should be removed from the program.

<u>Agency Response:</u> The Board directed ARB staff (in Resolutions 09-31 and 11-39) to evaluate the feasibility of issuing credits for non-road, electricity-based transportation sources, including mass transit. These vehicles, such as light and heavy duty rails, displace

gasoline and diesel fuel transportation energy, and use significant and quantifiable electricity for transportation. Therefore they should be allowed to generate LCFS credits.

The credit generations for the light and heavy duty fixed guideways are well documented within the transit agencies' LRT-CBTS accounts. Stakeholders should always be able to identify the sources of the credits. For more information please see response to **LCFS 38-21.**

1001. Comment: **LCFS FF43-6**

The commenter believes the credit clearance market exacerbates an indefensible target and does not provide the opportunities to evaluate the validity of the credits. Finally, the commenter objects to publishing a list of participants in the Credit Clearance Market.

Agency Response: This comment is not directed to any change in the 15-day changes proposal, and as such needs no response. We note that similar comments and responses can be found at **LCFS 40-14** and **LCFS 40-69**.

1002. Comment: **LCFS FF43-7**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

1003. Comment: **LCFS FF43-8**

The commenter does not believe credits generated from the refinery investment credit provisions (as written) will contribute substantially to meeting fuel suppliers' compliance obligation. Despite some positive changes in the 15 day package, characterization of these provisions as "pilot programs" and the significant barriers that still exist substantively impede valid credit generation.

Agency Response: ARB believes that the term "pilot program" is an appropriate term for the new refinery investment credit. It is not meant to imply that this provision can't contribute substantially to meeting fuel suppliers' compliance obligation, especially in the long-run, only that the provision may need updating in the future as experience is gained through evaluating actual projects, dialoging with stakeholders about these projects, and making future rule changes if needed. The refinery investment credit is consistent with ARB's goals by incentivizing measures to lower the CI of transportation fuels while still being quantifiable and verifiable.

1004. Comment: **LCFS FF43-10**

The commenter requests that the revised compliance schedule be posted prior to the board hearing.

Agency Response: This comment is not directed to any change in the 15-day changes proposal, and as such needs no response. Staff will continue to release compliance information publicly after it has been subject to an internal quality control process. Staff will continue to ensure the Board is aware of compliance trends in the program.

1005. Comment: **LCFS FF43-11**

The commenter requests that the final version of the California Reformulated Gasoline and Ethanol Denaturant Calculator Spreadsheet be posted for public review.

Agency Response: The final version of the denaturant calculator was posted June 4, 2015. See http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm. We reiterate for the commenter that identical calculations are embedded within the CA-GREET2.0 model (which is incorporated by reference into the rule), and that the denaturant calculator itself is not used to calculate the CaRFG baseline but merely to make the calculation more transparent.

1006. Comment: **LCFS FF43-12**

The commenter suggests modification to definitions for four diesel related fuels.

Agency Response: ARB staff disagrees with the commenters suggested changes to the four definitions.

The "Biodiesel Blend" was included to align with ADF. Although this definition is not included elsewhere in the regulation staff elects not to remove it. This definition provides general clarity for stakeholders who may go through the GREET lifecycle pathway assessment.

The "Petroleum Product" definition aligns with U.S. EPA's definition.

The Product Transfer Document requested change is a repeated comment from the commenter's submittal during the 45-day comment period. See response to **LCFS 38-39**.

The "Renewable Hydrocarbon Diesel" definition is worded as is in order to align with the Alternative Diesel Fuel Regulation (ADF). Staff elects not to change the definition to maintain harmony with that regulation. The ADF regulation includes a definition for Hydrocarbon, and as the RHD definition in the LCFS aligns with the RHD definition in the ADF regulation, the additional clarity requested in the comment is unnecessary.

1007. Comment: **LCFS FF43-13**

The commenter believes that striking portions of the proposal governing the transfer of regulated party status between upstream parties was arbitrary and capricious, implying that it was inappropriate to make the change as part of a "15-day package."

Agency Response: ARB staff disagrees. The commenter's position appears to be that ARB could not alter the transfer provisions after proposing them, but the law clearly allows ARB to do so. ARB's changes to the proposal were based on experience implementing the current LCFS and feedback from several WSPA members who separately suggested to ARB staff that the 'default obligation transfer' provision was not needed because contractual arrangements addressed the transfer issue. ARB believes that parties transacting in fuels should have the freedom to transfer regulated status, or not, by contract. ARB staff expects that by removing the default that applies only some of the time, reporting parties will be more aware of their transactions in a way that facilitates accurate reporting. The comment goes on to state that such a change should have been made, if at all, years ago. ARB staff disagrees with the notion that once a provision is placed in a regulation, it should not be amended or stricken, regardless whether it has worked poorly in practice.

1008. Comment: **LCFS FF43-14**

The commenter strongly opposes ARB's electricity provisions, and continues to propose that electricity not be part of the LCFS program.

Agency Response: ARB staff disagrees with this comment. One of the objectives of the proposed Low Carbon Fuel Standard is to foster investments in the production of the low carbon intensity (CI) fuels. Electricity has the lowest carbon intensities among commonly available fuels and therefore should be included in the LCFS provisions to move California toward a low-carbon transportation future.

1009. Comment: **LCFS FF43-15**

The commenter states that changes to the provisions setting out regulated party status for various contexts in which electricity is provided as transportation fuel "are substantive" and thus inappropriate as 15-day changes.

Agency Response: While the changes are substantive, ARB staff disagrees with the implication that 15-day changes should be non-substantive. In fact, under the Administrative Procedures Act, non-substantive changes need not even be circulated for 15 days, whereas substantive changes related to the initial proposal must be circulated for a 15-day comment period. (Gov. Code 11346.8, subd. (c).)

1010. Comment: **LCFS FF43-16**

The comment states that the changes to Sections 95483(e)(2) to (e)(5) are not explained or justified in the Notice of Public Availability.

Agency Response: The rationales for the proposed 15-day changes are for clarifications, such as clarifying the Electricity Distribution Utility's role in the regulation to reduce ambiguity and facilitate implementation. Sections 95483(e)(2) to (5) of the LCFS cover the public EV charging, EV fleet charging, and private access EV charging at a business or workplace. Currently, no such EV charging service providers have opted into the LCFS program for credit generation. The main reason of the proposed 15-day change is to facilitate credit generation and avoid credit losses for private access EV charging, EV fleet charging, and private access EV charging at a business or workplace. See **LCFS FF41-2** for further explanations.

1011. Comment: **LCFS FF43-17**

The comment states that the changes for Section 95483(e)(2) to (e)(5) exacerbate the un-level playing field for electricity providers, by further reducing their public accountability, recordkeeping, and metering requirements.

Agency Response: ARB staff disagrees with this comment. ARB does not favor one alternative transportation fuel providers over others. The requirements for application, reporting, and recordkeeping are consistent across all alternative fuel providers. The parameters for credit estimation, however, may differ from one alternative fuel to another, due to the fuel-specific manufacturing, blending, distributing, and marketing processes. Additionally, please see the responses to comments **LCFS 32-11** and **LCFS 40-52**.

1012. Comment: **LCFS FF43-18**

The comment states that the changes to Section 95483(e)(2) to (e)(5) increase concern regarding validity of credits generated from the electricity sector, and the decreasing amounts of due-diligence and reporting required by providers of electricity as a "transportation fuel".

Agency Response: Staff disagrees with the comment. In the proposed 15-day changes, the credits generated through estimated EV charging will be calculated by ARB staff and well documented within the Electrical Distribution Utility's LRT-CBTS account. This would enhance the credit generation process for electricity providers, and reduce the probability of credit invalidation. If fraud is discovered; the Health and Safety Code and a host of other state and federal statutes may apply, and provide for civil and criminal consequences. See response to **LCFS FF43-17**.

1013. Comment: **LCFS FF43-19**

The comment states that the changes to Section 95483(e)(2) to (e)(5) are not clear in regards to whether anyone will make sure there is a true accounting of credits generated from electric vehicle charging.

Agency Response: In the proposed 15-day changes, the credits generated through estimated EV charging will be calculated by ARB staff and documented within the Electrical Distribution Utility's LRT-CBTS account. This enhances the credit generation process for electricity providers, and reduces the probability of double counting or credit invalidation. In the implementation of the LCFS, staff commits to ensure a proper accounting of total credits from electric vehicle charging, and appropriate credits generated from public EV charging, EV fleet charging, and private access EV charging at a business or workplace be subtracted from the credits generated by the residential charging estimation. See response to **LCFS 32-11**.

1014. Comment: **LCFS FF43-20**

The commenter strongly opposes the removal of the requirement that Electrical Distribution Utilities to “Use all credits proceeds to benefit current or future EV customers”.

Agency Response: One of the objectives of the proposed Low Carbon Fuel Standard is to foster investments in the production and delivery of low carbon intensity (CI) fuels. Such investments are not always from current or future EV customers. For example, a site host or business owner of a private access EV charging place that has invested in charging infrastructure should benefit from the LCFS credits proceeds. They may not be an EV customer. Therefore staff only keeps such requirement for residential EV charging, where the investments for low carbon transportation fuel use are purely from EV customers.

1015. Comment: **LCFS FF43-21**

The commenter opposes the proposed 15-day change to make Electrical Distribution Utilities (EDUs) the default credit generators in most settings.

Agency Response: See response to **LCFS FF41-2**.

1016. Comment: **LCFS FF43-22**

The commenter opposes the proposed 15-day change to remove the list of activities constituting public education under 95483(e)(1)(B).

Agency Response: In the current LCFS regulation, Section 95483(e)(1)(B) includes specific efforts that “may include, but are not limited to …”. Such language has little or no effect. The requirements to educate the public remain the same in Sections 95483(e).

1017. Comment: **LCFS FF43-23**

The commenter opposes the proposed 15-day change to remove the requirement that ARB post supplemental information for public review each year.

Agency Response: ARB staff made the change because some of the supplementary information, such as the monetary value returned to each driver, is confidential. ARB must sign a Confidentiality

Agreement with the EDUs before obtaining the reports. See response to **LCFS FF43-24**.

1018. Comment: **LCFS FF43-24**

The commenter opposes the proposed 15-day change to allow investor owned utilities to use Public Utility Commission reporting in lieu of LCFS specific supplemental information.

Agency Response: In the current LCFS Section 95483(e)(1)(D), the supplementary information included in the annual compliance report of electrical distribution utility (EDU) is described as: “an itemized summary of efforts to meet requirements subsections (A) through (C) above and costs associated with meeting the requirements.”

The annual implementation report required under Order 4 of Public Utilities Commission of California (PUC) Decision 14-12-083 for investor owned utilities (IOUs) must include:

- A description of the program, including how electric vehicle drivers were identified;
- the volume of LCFS credits generated and sold; the means by which the credits were sold;
- the amount of revenue generated; the number of drivers to whom LCFS credit revenue was returned;
- the monetary value returned to each driver;
- how the program was marketed to drivers;
- administrative and marketing expenses;
- any other costs, including outreach to auto dealers.

It is clear that such a report includes much broader and more detailed information than the supplementary information requirements under current regulation. Some information in this report, such as the monetary value returned to each driver, is even confidential. ARB must sign Confidentiality Agreement with the EDUs before obtaining the reports. Therefore the proposed 15-day changes will enhance the reporting requirements of the EDUs.

1019. Comment: **LCFS FF43-25**

The commenter states that technology exists to directly measure residential EV electricity use and therefore should be required.

Agency Response: Currently, many EV drivers have elected not to install dedicated EV meters at their residences. The percentage of directly metered EV charging residences varies from 5% to 10% in big utility service territories. Therefore it is necessary to allow estimation to be continued. Installing a separately dedicated meter for residential EV charging can be costly for EV customers. Adding a cost barrier to EV adoption runs counter to the LCFS' goals. The estimation method is sufficiently accurate in calculating the actual electricity use of non-metered residential EV charging**.**

1020. Comment: **LCFS FF43-26**

The commenter states that the proposed 15-day changes reduce the standards that electricity providers are held to, as compared to liquid fuel providers.

Agency Response: ARB staff disagrees. See responses to **LCFS 32-11**, **LCFS 40-52,** and **LCFS FF43-17**.

1021. Comment: **LCFS FF43-27**

The commenter states that it is not clear from the proposal whether a proper accounting of total credits from electric vehicle charging will be performed by ARB.

Agency Response: In the implementation of the LCFS, staff commits to ensuring a proper accounting of total credits from electric vehicle charging and providing adequate public transparency as this calculation is conducted.

1022. Comment: **LCFS FF43-28**

The commenter expresses concern that the 15-day package did not contain any modifications to the cost containment provision.

Agency Response: This comment is not directed to any change in the 15-day changes proposal, and as such needs no response. We note that similar comments and responses can be found at **LCFS 32-9** and **LCFS 40-14**.

A cost containment mechanism is an essential component of the market rules governing the LCFS fuel market. The Cost

Containment Mechanism (CCM) is designed to provide a limit on credit prices in the event that the near-term demand for tradable credit exceeds the supply. If that were to occur regulated parties are allowed to roll over any remaining deficits to be repaid in future years, preventing a situation in which a shortage of credits might result in regulated parties bidding up the price of credits above the ceiling price. Investment decisions in new fuel supplies will depend on having clarity regarding how the program will manage price volatility or shortfalls in low CI fuel. Implementing a clear, predictable provision to handle any credit shortage or price spike reduces the risk of supply shortages or price spikes driven by fears about the long-term viability of the policy. This means that cost containment actually increases the likelihood of meeting the standard by providing regulatory certainty for investors that the LCFS will continue to provide a predictable price premium for low-CI fuels in the future, under all possible outcomes.

1023. Comment: **LCFS FF43-29**

The commenter expresses concern over the possibility that the CCM means there will be chronic shortages of credits.

Agency Response: This comment is not directed to any change in the 15-day changes proposal, and as such needs no response. We note that similar comments and responses can be found at **LCFS 32-9** and **LCFS 40-14**.

The CCM provides a strong price signal that values LCFS credits at up to $200 per metric ton in the case that near-term demand for credits needed for compliance exceeds the supply of credits offered for sale. If this situation occurs and one or more parties must defer repayment of deficits the CCM allows up to five years for full repayment of any one year's deferred deficits. Thus the CCM provides a bridge to full compliance by providing a substantial, but acceptable credit price to motivate the needed production of low CI fuels.

In the case of a chronic, rather than a temporary credit shortfall, ARB staff anticipates that a wide variety of low CI fuels in sufficient quantities to meet the proposed will be feasible and cost-effective to produce at well below the $200 credit price within the five year "payback" period provided by the regulation. As a further backstop the ARB will conduct periodic evaluations that would allow for stringency adjusts within the five year repayment period if the price incentive provided by the CCM proves to be insufficient to incent the needed production and use of low CI fuels.

1024. Comment: **LCFS FF43-30**

The commenter expresses concern that the credit clearance market will not keep prices in check during periods of rising prices.

Agency Response: This comment is not directed to any change in the 15-day changes proposal, and as such needs no response. We note that a similar comment and response can be found at **LCFS 32-9** and **LCFS 40-16**.

1025. Comment: **LCFS FF43-31**

The commenter repeats its concern with possible liability for fraudulent credits it acquires, especially in connection with the Credit Clearance Market, when the time and opportunity for due diligence is compressed.

Agency Response: See response to **LCFS 40-17**. ARB staff disagrees, because WSPA members are in an excellent position to comply with the regulation by making low-CI fuels or long-term contracts, exercising due diligence, with producers of such fuels.

1026. Comment: **LCFS FF43-32**

The commenter believes that there is no connection in the Credit Clearance Market (CCM) provisions of the LCFS re-adoption package to bring about a comprehensive program review should the potential trend of systematic credit shortages materialize and persist.

Agency Response: This comment is not directed to any change in the 15-day changes proposal, and as such needs no response. We note that a similar comment and response can be found at **LCFS 40-18**.

1027. Comment: **LCFS FF43-33**

The commenter asks that more clarity be added to the regulatory language of the credit clearance market.

Agency Response: ARB staff disagrees that the regulation, as originally proposed, was inadequate to define how the CCM will operate, and has proposed only minor clarifications via the 15-day change proposal. Additionally this comment is not directed to any change in the 15-day changes proposal, and as such needs no response.

1028. Comment: **LCFS FF43-34**

The commenter believes that the credit clearance market is a Last-In-First-Out (LIFO) accounting method.

Agency Response: The commenter appears to be misinterpreting the impact of the proposed change. The proposed change does not require a "Last-In-First-Out" accounting method.

1029. Comment: **LCFS FF43-35**

The commenter expresses uncertainty as to whether the immediately preceding year's unmet obligation will be included in the calculated interest.

Agency Response: ARB staff disagrees that the proposed changes are unclear. The interest is applied only to accumulated deficits, those that were outstanding at the end of the previous year's CCM. The interest charge does not apply to deficits that are part of the immediate previous year's compliance obligation.

1030. Comment: **LCFS FF43-36**

The commenter expresses uncertainty about the criteria and conditions for retiring deficit carryovers in paragraph 95485(c)(5)(C).

Agency Response: The CCM is designed to mitigate, to the greatest degree possible, deficit shortfalls that the regulated parties experienced in the most recent compliance year. Credits that have been procured through the CCM can only be used for that limited purpose. Regulated parties must acquire low carbon intensity fuels to self-generate or purchase credits from the regular LCFS credit market to procure credits needed to retire accumulated deficits.

1031. Comment: **LCFS FF43-37**

The commenter objects to ARB publishing a list of Credit Clearance Market participants and each participating party's pro-rata share of pledged credits, and feels ARB's decision to list this information without any explanation or basis is arbitrary and capricious.

Agency Response: This comment is not directed to any change in the 15-day changes proposal, and as such needs no response. We note that a similar comment and response can be found at **LCFS 40-69**.

1032. Comment: **LCFS FF43-38**

The commenter requests clarity on the prohibition of selling credits when the entity has a roll-over deficit.

Agency Response: This comment is not directed to any change in the 15-day changes proposal, and as such needs no response.

1033. Comment: **LCFS FF43-39**

The commenter requests that ARB modify the regulation to allow credit generation before the entities have reconciled with their business partners provided they make a "good faith effort."

Agency Response: As is the case under virtually every environmental regulatory scheme, regulated parties are strictly liable for any failure to comply with the law; good faith efforts are not sufficient, although such efforts can be considered as a mitigating factor in an enforcement context. With the extended period provided for report submission and a specific period for reconciliation, it should provide an ample amount of time to reconcile reports between business partners. It is a requirement that all regulated parties work with their business partners during the reconciliation process to resolve discrepancies.

1034. Comment: **LCFS FF43-40**

The commenter objects to the removal of language guaranteeing that credit transfer information submitted online would be treated as confidential business information (CBI).

Agency Response: ARB staff disagrees that the language was necessary. See response to comment **FF35-10**.

1035. Comment: **LCFS FF43-41**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

1036. Comment: **LCFS FF43-42**

The commenter expressed appreciation for staff's revision to allow potential criteria pollutant and toxics increases associated with candidate projects to be offset as provided in the applicable project permitting requirements.

Agency Response: ARB staff appreciates the support for the proposed changes.

1037. Comment: **LCFS FF43-43**

The commenter expressed agreement with staff's decision to remove the proposed 50% discount for any credits generated by "less efficient refiners".

Agency Response: ARB staff appreciates the support for the proposed changes.

1038. Comment: **LCFS FF43-44**

The commenter also expressed appreciation for staff's decision to reduce the 10% bio-feedstock minimum in the Hydrogen Co-processing provision which should make it more likely for such projects to move forward.

Agency Response: ARB staff appreciates the support for the proposed changes.

1039. Comment: **LCFS FF43-45**

The commenter requests that ARB lower the minimum threshold requirement of 0.1 gCO_2e/MJ minimum CI improvement for RIC project eligibility to a flat 5,000 metric ton of CO2e per year project impact threshold.

Agency Response: This comment is not directed to any change in the 15-day changes proposal, and as such needs no response. We note that a similar comment and response can be found at **LCFS 38-10**.

1040. Comment: **LCFS FF43-46**

The commenter requests staff should utilize January 1, 2015 as the associated date for eligibility and not January 1, 2016.

Agency Response: The purpose of the Refinery Investment Credit Provision is to incent marginal projects that might not have otherwise been economical without the provision. Projects that have undergone permitting have already been deemed economical and are not the target of this provision.

1041. Comment: **LCFS FF43-47**

The commenter states that there still is a lack of specificity of the proposed language that calls for identification of the primary purpose or intent of a candidate project. Staff should clarify that projects whose primary intent is increased energy efficiency but involve equipment shutdowns are not excluded.

Agency Response: The refinery investment provision allows for non-capital projects that offer sustained GHG improvements to qualify under the provision. The provision no longer requires capital projects only. Staff understands the commenter's concerns and considered modifying the regulation language to clarify which projects would qualify for the Refinery Investment Credit Provision. However, ARB staff found there were too many different types of projects to give guidance for in the regulation. Staff considered providing a list of qualifying projects. However, this approach might not include all potential projects. Staff instead decided to provide the maximum amount of flexibility. The intent of the shutdown language is to prevent refineries from generating credits for shutting down major units without upgrading or replacing them and from generating credits for equipment downtime during turnarounds. Equipment taken out of service to be upgraded or replaced is not the target of the shutdown language in the provision.

1042. Comment: **LCFS FF43-48**

The commenter states that staff has removed the ability to generate refinery investment credits from co-processing liquid bio-feed stocks at facilities, leaving Hydrogen co-processing as the only viable option available to some. While the opportunity to seek dedicated pathway approvals for such applications is still provided, staff's action eliminates substantial flexibility for parties' smaller scale projects/applications that may not warrant the dedication of time and resources to the rigors of the specified pathway approval processes.

Agency Response: The existing dedicated pathway approach is a vetted and proven process and is ideal for approving the co-processing of liquid bio-feedstocks at facilities. Including competing pathway approval processes in the regulation would be redundant.

1043. Comment: **LCFS FF43-49**

The commenter believes that adding the term “pilot program” to the title of the Refinery Investment Provision signals staff’s intention to make it a temporary provision.

Agency Response: Please see response to comment **LCFS FF43-8**.

1044. Comment: **LCFS FF43-50**

The commenter is opposed to putting a cap on the amount of refinery investment credits a facility can generate.

Agency Response: Staff imposed these caps to facilitate the learning period for these types of credits as described in **LCFS FF43-8**. The LCFS program could suffer if a large number of new, unestablished credits flooded the marketplace. Staff wishes to avoid this outcome in the LCFS, both by evaluating each credit application rigorously and by imposing the fixed usage limits through the 2020 timeframe. These limits could potentially be relaxed in future rulemakings if the experience with the pilot programs is positive.

1045. Comment: **LCFS FF43-51**

The commenter opposes the limitation on selling refinery investment credits.

Agency Response: See response to **LCFS FF43-52**.

1046. Comment: **LCFS FF43-52**

The commenter believes that this limitation on selling RICs may be simply be the result of limitations in staff’s ability to bring about the necessary LRT revisions in a timetable consistent with the LCFS re-adoption schedule.

Agency Response: The commenter is partially correct. The prohibition on the sale of credits generated from the refinery investment credit and the renewable hydrogen provisions is based, in part, on concerns about the timetable to bring about the necessary LRT revisions to handle limits imposed on the credits generated from the refinery investment credit and the renewable hydrogen provisions.

Additional reasons to limit, for the time being, the sale of these credits include the fact that these are new pilot credit options within the LCFS system. Staff would prefer to gauge the response of the refiners and better understand the types of projects that will be submitted prior to making these credits fully fungible with all other credits.

All eligible regulated parties generating these credits also generate large deficits. They may use the credits from these pilot programs to meet their compliance obligations, which would reduce their need to buy additional credits or free up credits from other sources for sale.

1047. Comment: **LCFS FF43-53**

Despite some improvements made by staff in the 15-day package, WSPA still believes that the current proposal substantively impedes valid credit generation in conflict with what ARB hopes to incentivize with the measure.

Agency Response: See response to comments **LCFS FF43-47**, **LCFS FF43-48**, **LCFS FF43-49**, **LCFS FF43-50**, and **LCFS FF43-52**.

1048. Comment: **LCFS FF43-60**

The commenter recommends that requirements for ARB in determining the Annual Crude Average CI be included in Table 12 of the regulation.

Agency Response: The regulation requirement for posting the Annual Crude Average carbon intensity calculation reads “Within 15 days of receiving the Annual Compliance reports, the Executive Officer shall post the Annual Crude Average carbon intensity calculation at the LCFS web site (http://www.arb.ca.gov/fuels/lcfs/lcfs.htm) for public comment.” Because the posting of the calculation is dependent on when the final Annual Compliance report is received, there is no set date by which the calculation must be posted. Therefore, ARB staff did not include the requirement for posting the calculation in Table 12.

1049. Comment: **LCFS FF43-61**

The commenter objects to the removal of annual reports from the section related to Correcting a Previously Submitted Report. There may be instances in which an annual report may also need to be reopened for corrective edits and resubmittal. The removal of annual reports from this section essentially dis-allows regulated parties to correct previously submitted annual reports.

Agency Response: Staff is striving to limit the amount of corrections requested to previously submitted reports and is ramping up efforts to consider appropriate enforcement action against parties that file incorrect information.

However, if corrections are still needed, the corresponding annual report(s) are automatically opened in the LRT-CBTS whenever a quarterly report is re-opened. The annual report is resubmitted by the regulated party once the quarterly corrections are approved. Therefore, a regulated party does not need to submit a separate request for opening an annual report for quarterly reports.

The other functional reasons to open an annual report in the LRT, other than for quarterly report corrections, are to modify the number of credits “Exported to” another program, which is not permitted. The second case is where a document was not uploaded with the annual report, as required.

Given the additional attention being placed on ensuring accurate reporting, this situation is expected to occur infrequently, not requiring a special process and will be handled by the LRT-CBTS administrator.

1050. Comment: **LCFS FF43-62**

The commenter approves of a change to clarify that penalties for unmatched deficits would be assessed on a per-deficit basis, rather than a per-day basis, but recommends a wording change to clarify that the penalty would not be per deficit, and then multiplied by some number of days.

Agency Response: ARB believes that the regulation as written is consistent with a “per-deficit” approach, not deficits multiplied by days. The wording in question – “each deficit . . . constitutes a separate day of violation” – simply accepts the Legislature’s invitation to “develop a method to convert a violation of any rule . . . into a number of days, where appropriate, for the purposes of the penalty provisions” in the Health & Safety Code – all of which state that each day is a separate violation. (*See* Health & Saf. Code §38580, subd. (b)(3).) ARB chose to equate one deficit with one day, rather than with five days or some other number of violations.

1051. Comment: **LCFS FF43-63**

ARB defined the "material information" which, if incorrect, can serve as a basis for revoking credits. The commenter believes that by defining material information ARB expanded the bases for revocation; the commenter suggests striking the definition.

Agency Response: ARB staff disagrees – a broad power to revoke has always been part of the proposal; the definition simply clarifies and defines that power without expanding it. Eliminating the definition could leave regulated parties to wonder exactly what "material [mis]information" could lead to revocation. The commenter objects to the potential for revocation, faulting ARB for not somehow insuring the validity of credits, citing to the "verifiable" emission reduction requirement in Health & Safety Code section 38562(d)(1). ARB staff disagrees that the credits are not verifiable; indeed the regulation includes a revocation provision on the very assumption that some credits will be verifiably fraudulent or otherwise unsupported. ARB expects that it will be in private parties' best interest (including the commenter's members) to take steps to verify the validity of credits before surrendering them for compliance. See also response to comment **LCFS 40-39**.

1052. Comment: **LCFS FF43-64**

This comment indicates support for the 2017 Progress Report concept.

Agency Response: ARB staff appreciates the support for the 2017 Progress Report concept.

Comment letter code: 44-FF-LCFS-RPMG

Commenter: Hoffmann, Jessica

Affiliation: RPMG, Inc.

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

RPMG™

1157 Valley Park Drive - Suite 100
Shakopee, MN 55379

Main 952.465.3220 Fax 952.465.3221 www.rpmgllc.com

June 19, 2015

Clerk of the Board
Air Resources Board
1001 I Street
Sacramento, CA 95814

Electronic Submittal via http://www.arb.ca.gov/lispub/comm/bclist.php

RE: RPMG Comments on Proposed Re-adoption of the Low Carbon Fuel Standard

Dear Clerk of the Board,

Renewable Products Marketing Group (RPMG) is a biofuel marketing company currently representing 21 ethanol facilities located throughout the Midwest. Of those 21 facilities, RPMG actively markets ethanol and distiller's oil produced from various feedstock types from 10 facilities directly into the California fuels market. RPMG is a supporter of the Low Carbon Fuel Standard (LCFS), which diversifies transportation fuel supply, incentivizes innovative technology and advanced renewable fuel selection, creates jobs, stimulates the California economy, and, most importantly, improves the environment. The track record of the U.S. renewable fuel industry and the LCFS is a shining example of these activities being achieved through hard work and ingenuity. We are writing today to provide comment on the recent proposed re-adoption of the LCFS. Implementation of the re-adopted LCFS is going to take a lot of communication and joint effort between industry and CARB.

Below are our detailed comments and indications of areas needing additional clarification with regard to the proposed 15-day amendments published on June 4, 2015. We have broken down our comments into six subsection groupings for reference. We invite CARB staff to contact us with any questions or requests for additional information on any of the points raised. We sincerely appreciate the opportunity to provide these comments to you today, and we thank you for your thorough consideration of each.

Section 95488, Title 17, California Code of Regulations, "Obtaining and Using Fuel Pathways"

Section 95488(a)(3)

While RPMG acknowledges and supports the general intention to avoid creating artificial market barriers and competition for CARB resources with the proposed changes to 95488(a)(3), it remains largely unclear how this proposal would be carried out in practice. It is imperative that CARB provide guidance such that industry can adequately plan and implement the pursuit of pathway approvals. These are some areas of ambiguity and concern we have identified:

- Is each fuel type placed into a single batch for review with a predeclared deadline for application submission, or will there be multiple scheduled batches per fuel type such that applications received in the defined window will be batched and released by a defined date? LCFS FF44-1
- What is the trigger or signal that a batch is "closed" and ready to move on to the staff review stage (quantity of applications received, defined window of opportunity, etc.)? LCFS FF44-2
- Is staff proposing to wait to review any other fuel type application until ALL ethanol pathways are received and reviewed? LCFS FF44-3

- Has staff reviewed the potential credit losses to the whole program by delaying other fuel type pathways? LCFS FF44-4

- What are the anticipated deadlines and release dates of pathways? LCFS FF44-5

- When will CARB begin accepting pathway applications? LCFS FF44-6

- Has CARB consulted the limited number of pathway consultants and advisors available to industry for their input? What are the expressed and anticipated constraints on those resources available to industry? LCFS FF44-7

- What will be deemed the completeness date in the certification approval documents? LCFS FF44-8

- How are the parameters of completeness defined and/or determined? LCFS FF44-9

Through discussions with staff and knowledgeable industry parties, it has come to our awareness that a guidance document is being compiled by CARB staff. We support the development of this guidance document. It is imperative for industry to prepare for and timely obtain new fuel pathways. This will require the coordination and mobilization of both internal and external resources. Clear and definitive information will allow industry to adequately prepare. In turn this should assist CARB in its own preparation to receive and process those applications. However, we are concerned this document may be published without the opportunity for industry involvement or public input. We suggest that CARB provide a public forum for reviewing concepts of the guidance document and allow the opportunity to make recommendations. LCFS FF44-10

Section 95488(c)(5)(B) and (e)(5)(B)

RPMG sympathizes with the expressed concern of CARB staff in 95488(c)(5)(B) and (e)(5)(B) of "eliminating potentially unrealistic deadlines in various parts of the existing proposal." However, it has been the experience of RPMG and our associated producers throughout the four-year history of implementation of the LCFS that delays, extended review periods and uncertainty (specifically in pathway applications) have become the "status quo." It is essential for the program to provide industry with a means of assessing timely responses that will provide the basis for market certainty. This is not achieved through the imposed deadlines on industry participants while simultaneously proposing to remove a similar expectation of deadlines for CARB staff. RPMG would encourage CARB in the future to maintain clear expectations of deadlines on the part of both the regulated industry and CARB staff. By maintaining equitable treatment in this manner, CARB will ensure that it is sending a strong signal of reliability and accountability to the market. LCFS FF44-11

Section 95488(b)(3)

We appreciate staff's proposal to reduce confusion and clarify that the iLUC values referenced in the ISOR are a part of the proposal with the addition of Table 5 in section 95488(b)(3). We also appreciate the simplicity in having a table to reference in the regulations, which is a place where a regulated party can and should expect to find pertinent details of the program without having to consult multiple reference materials or guidance documents. Our concern is the addition of this table limits iLUC to just these values. Our understanding is once an item is codified in regulation it requires a formal rulemaking process to modify any part. If this is not the case, CARB should clarify further. As such, we caution against the formalization of such a table if it would impact or delay the addition or modification of new values, or the inclusion of new feedstock types. Without the means of modifying iLUC values administratively this table is a hindrance to the environmental and market incentive objectives of the program. Any such hindrance would not justify its codification in the regulations. If that is the case, we highly recommend CARB staff devise an administrative LCFS FF44-12 alternative to approving and incorporating iLUC values for the program.

Section 95488(c)(3) and (c)(4)(I)(2)

Adding the Tier Pathways to this section is problematic for a variety of reasons, including structure and implementation.

Throughout the regulations, we note evidence of establishing Tier 1 and Tier 2 pathways. With these revisions, we are noting a distinct shift to attempting to classify Tier 1 and Tier 2 facilities. By definition, Tier 1 and Tier 2 labels are applicable to pathways, not facilities. This is very simply demonstrated when you consider that a single facility may have the ability to co-process different tier fuels simultaneously, such as conventional corn ethanol and cellulosic ethanol from non-starch cellulosic material. Further, one should consider single facilities installing and utilizing innovative production methods. It is logical to assume that during the periods when relevant innovative technologies and equipment are utilized, the facility would be producing under a Tier 2 pathway, and conversely, when not utilizing that equipment, the fuel would qualify for a Tier 1 pathway. We wish to point out that "commercial operation" of a facility is materially different from "commercial operation" of a pathway or new fuel product stream.

LCFS FF44-13

Adding Tier 1 pathways to the provisional pathways section is concerning because new or expanding facilities are now disincentivized from entering the California fuel market for the requisite two-year "provisional" period. This disincentive will not only impact investments and liquidity of those operations, but it is also a major obstacle for innovative technologies to befit the LCFS program in any meaningful way. This provision creates a barrier to deploying innovative technologies and to supplying the California market with meaningful volumes of low carbon fuel from new sources and those new technologies. With this proposal, CARB is stifling innovation at the greater expense of the explicit goal of the LCFS: to reduce carbon emissions and improve the environment.

LCFS FF44-14

Deficit-generating industry parties have repeatedly indicated they are not interested in procuring "commercial" volumes of fuel without obligation. They do not desire to take on the risk of potentially not benefiting from the fuel or blendstock they procure in terms of credit generation for a two-year period. Further, by the time the two-year "provisional" period sunsets, the credit potential for that fuel has incrementally decreased at the predefined rate of the compliance schedule. Both of these factors are barriers to market entry. This is in direct conflict with the objectives of the LCFS.

LCFS FF44-15

Real-world implementation challenges and interpretation of this section from the perspective of a producer can be expressed in three case scenarios: newly operational commercial fuel producers in California, newly operational commercial fuel producers outside of California, and preexisting operational commercial fuel producers deploying capital investment projects in new and innovative technologies. We interpret fuel producers falling within these three categories would not be allowed to participate in the LCFS for provisional pathway fuels, until they reach one full calendar quarter of commercial operations. We understand this will restrict them from applying for a pathway until they achieve this milestone. If this is inaccurate, CARB should clarify. The potential market for those fuels becomes so small it is almost nonexistent, as regulated parties generating a deficit will be strongly inclined to procure fuel and credits elsewhere (citing regulatory risk, commercial risk, limitations in access to resources, uncertainty in viability of counterparty, etc.). This will place extreme limitations on producer liquidity. Out-of-state producers will not have sufficient incentive to opt in to the program, and all credit potential for those periods will be lost. Consider that the program incentivizes early credit generation and makes it harder to achieve meaningful credit generation over time. Not being allowed to transfer obligation with physical fuel will disincentivize refiners, blenders and other deficit-generating regulated parties from choosing to utilize these fuels, effectively blocking their access to the market and thereby limiting California's environmental benefit.

LCFS FF44-16

This section introduces many unintended consequences by CARB, and we strongly advise staff rework this section of the proposal, even if it means reopening this section after re-adoption of the rule as a whole. LCFS FF44-16 cont.

Section 95488(e)

RPMG supports the clarification by CARB in 95488(e) that existing physical pathway demonstrations that were approved under the previous regulation order will be accepted without any resubmittal requirements. This will ensure that CARB is meeting its objective in streamlining the pathway approval process. LCFS FF44-17

Section 95491, Title 17, California Code of Regulations, "Reporting and Recordkeeping"

Section 95491(a)(7)

RPMG notes that the addition of "for the current compliance period" in section 95491(a)(7) adds ambiguity while addressing end-of-year reporting responsibilities in the new year. Upon review, we are unclear how to interpret "current compliance period" during the old-year to new-year transitioning period affecting Q4 progress reporting and annual compliance reports. We request clarification on this part to ensure clear and understandable boundaries from the perspective of the reporting schedule. LCFS FF44-18

In closing, RPMG acknowledges this program is complex. Re-adoption is helpful and a worthwhile pursuit, but it does leave implementation questions. We encourage additional clarity and guidance. Further, we welcome the opportunity for a continued open dialogue with CARB staff to ensure the program moves forward with the proper foundation and clear expectations for industry to adhere to the program regulations.

Sincerely,

JWHoffmann

Jessica W. Hoffmann
Regulatory and Compliance Manager
RPMG, Inc.

CC: Samuel Wade
Edie Chang
Floyd Vergara
Jack Kitowski
Wes Ingram
Manisha Sighn
Hafizur Chowdley

44_FF_LCFS_RPMG

1053. Comment: **LCFS FF44-1**

The comment is related to batch processing to recertify pathways.

Agency Response: If the Board approves the proposed regulation, Staff will be conducting workshops post Board Hearing and will provide guidance surrounding the administrative process of recertifying pathways.

The deadline to request pathway recertification will be February 1, 2016 (see § 95488(a)(2)(A)).

1054. Comment: **LCFS FF44-2**

The comment is related to batch processing to recertify pathways.

Agency Response: See response to **LCFS FF18-1** and **LCFS FF44-1**.

1055. Comment: **LCFS FF44-3**

The comment is related to batch processing to recertify pathways.

Agency Response: See response to **LCFS FF18-1** and **LCFS FF44-1**.

1056. Comment: **LCFS FF44-4**

This comment is related to batch processing to recertify pathways and a question related to equitable treatment of the batches.

Agency Response: Pathways that are being recertified will be active until recertification. Therefore, it is not likely that credits will be lost due to pathways not being recertified earlier in the process compared to later. Staff will be conducting workshops post Board Hearing and will provide guidance surrounding the process of recertifying pathways.

1057. Comment: **LCFS FF44-5**

The comment is related to batch processing to recertify pathways.

Agency Response: See response to **LCFS FF18-1** and **LCFS FF44-1**.

1058. Comment: **LCFS FF44-6**

This comment is a question related to when staff will accepting pathway applications.

Agency Response: The comment does not make a recommendation or objection regarding the proposal, and needs no response.

1059. Comment: **LCFS FF44-7**

This comment is a question whether staff has knowledge of the constraints on resources to aid industry with pathway applications.

Agency Response: ARB staff views the recertification process as primarily an administrative action undertaken by ARB staff. Staff will attempt to process recertifications with existing data, but will request additional information from the applicant for recertification if needed.

Staff will be conducting workshops post Board Hearing and will provide guidance to assist industry with the process. ARB staff has also been actively receiving feedback prior to the release of the draft regulation from industry consultants. Staff will work with industry, consultants, and all stakeholders alike to enable fuel pathway applicants to receive the necessary information and guidance to help them apply for pathways. It is staff's belief that with the new Tier 1 process, the overall need for consultants and advisors will be reduced significantly.

1060. Comment: **LCFS FF44-8**

The comment is related to LCFS pathway applications being deemed complete.

Agency Response: Staff will be conducting workshops post Board Hearing and will provide guidance surrounding the process of applying for fuel pathways. Generally, an application that is deemed complete contains all relevant information that is required for staff to process the application. The date that all such information is received is the deemed complete date.

1061. Comment: **LCFS FF44-9**

The commenter requests clarification on how the parameters of the completeness of the application are determined.

Agency Response: The comment does not make a recommendation or objection regarding the 15-day modification, and needs no response. See response to **LCFS FF44-8**.

1062. Comment: **LCFS FF44-10**

This comment is related to the commenter being informed that staff will provide guidance to assist stakeholders with pathway application processing.

Agency Response: ARB staff notes that this comment is not directed to any change in the 15-day proposal. As a courtesy however, staff is providing a response to the comment.

Staff will be conducting workshops post Board approval and will provide guidance surrounding the process of applying for fuel pathways. All such workshops are open to the public and staff greatly appreciates stakeholder.

1063. Comment: **LCFS FF44-11**

This comment is related to deadlines being removed under § 95488(c)(5)(B) and § 95488(e)(5)(B).

Agency Response: Please see response to comment **LCFS FF35-7.**

1064. Comment: **LCFS FF44-12**

The commenter requests that ARB not include iLUC values in the regulation if it hinders updating the values frequently.

Agency Response: Updating indirect land use change (iLUC) values will require a formal rulemaking process. This is due to the complexity of updating the science and methodology to estimate iLUC values. The current iLUC values were developed by accounting for updates in land use change science and methodologies in economic modeling of such effects. It required significant effort (and resources) by staff, researchers and stakeholders to consider, evaluate, and include relevant updates for the current round of rulemaking. Updating iLUC frequently would also place an enormous burden on stakeholders required to modify their pathway CIs every time an iLUC value is updated to reflect the findings of a single report. At this time, staff is contemplating an update iLUC values once every three years as part of a rulemaking package.

1065. Comment: **LCFS FF44-13**

This comment is related to the language used when characterizing a fuel pathway as a Tier 1 or Tier 2 facility.

Agency Response: ARB staff appreciates the commenter's keen observation regarding the use of the term facility compared to pathway in the regulation, but does not believe an amendment is needed. Tier 1 and Tier 2 are only related to pathways, but may also apply to a facility that is only Tier 1 or Tier 2. Similarly, a facility may have multiple pathways for which some may be Tier 1 and others may be Tier 2. Furthermore, Tier 1 and Tier 2 do not refer to specific fuels, but to fuel pathways. It would not be possible to implement the regulation if the term facility (Tier 1 or Tier 2) was taken literally.

1066. Comment: **LCFS FF44-14**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

1067. Comment: **LCFS FF44-15**

The commenter believes that the 2-year barrier on sales of provisional credits is a market barrier.

Agency Response: In the second 15-day package, ARB changed the proposal to allow for the sale of credits generated through provisional pathways subject to certain conditions. The Executive Officer still maintains the authority to adjust the number of credits or reverse any provisional credit in the producer's account without a hearing.

1068. Comment: **LCFS FF44-16**

This comment is related to provisional pathways being able to generate credits as soon as commercial production begins. The commenter also suggests that staff can revisit this requirement and make modifications during implementation of the LCFS.

Agency Response: See response to **LCFS FF27-3**. ARB staff looks forward to helping to provide implementable solutions to concerns that the commenter presented.

1069. Comment: **LCFS FF44-17**

The commenter indicates support for the clarification that existing physical pathway demonstrations will not be required to be resubmitted.

Agency Response: ARB staff appreciates the support.

1070. Comment: **LCFS FF44-18**

The commenter is unclear how to interpret "current compliance period" during the old-year to new-year transitioning period affecting Q4 progress reporting and annual compliance reports.

Agency Response: An “Unlock Request” can be made online in the LRT-CBTs to request corrections to previously submitted quarterly reports "for the current compliance period." This applies to where the annual compliance reporting deadline has not yet passed. Regulated parties need to ensure that all corrections to their quarterly and annual reports are completed prior to the deadline for annual reporting.

This page intentionally left blank.

Comment letter code: 45-FF-LCFS-GE

Commenter: Willter, Joshua

Affiliation: Growth Energy

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

45_FF_LCFS_GE

Growth Energy's Comments on June 4, 2015, 15-Day Notice for the Proposed Revisions to the LCFS Regulation

On December 30, 2014, CARB circulated for public review an Initial Statement of Reasons (the "ISOR") and an Environmental Analysis ("EA") for CARB's proposed revisions to the Low Carbon Fuel Standard (the "LCFS regulation"). Following a February 19, 2015, public hearing on the LCFS regulation, the Board directed staff to consider modifications to the LCFS regulation, and respond to environmental comments.

CARB released proposed modifications to the LCFS regulation through its June 4, 2015, Notice of Public Availability of Modified Text and Availability of Additional Documents (the "15-Day Notice"). Due to various concerns regarding the LCFS regulation, including issues raised in the 15-Day Notice, Growth Energy submits the following comments on the proposed modifications to the LCFS regulation under the California Environmental Quality Act, the California Administrative Procedures Act, and the Health & Safety Code.

A. CARB's LUC Value for Corn Ethanol of 19.8 gCO_2e/MJ Is Not Supported By Substantial Evidence, and Would Result in Adverse Climate Change Impacts

CARB's proposed revisions to the LCFS regulation contemplate a land use change ("LUC") value for corn ethanol of 19.8 gCO_2e/MJ. This value, however, is not supported by substantial evidence. Specifically, to calculate the corn ethanol LUC, CARB staff used the average of five price-yield values [0.05, 0.10, 0.175, 0.25, and 0.35], which is 0.19. LCFS FF45-1

As explained in the accompanying declaration of Tom Darlington, a price-yield of 0.19 is contrary to the evidence, as the value recommended by Purdue is 0.25. (Decl. Darlington ¶ 5.) Lower price yields such as 0.05 and 0.10 are also inconsistent with CARB's own modeling. The research that could be read as supporting such low price-yields is based on short-term shock, while CARB's GTAP model uses medium- and long-term shock. (*Id.*)

Moreover, the only study relied upon by CARB to support a low price-yield value was prepared by David Rocke of UC Davis. The Rocke analysis is based on only one set of data – a 2012 dissertation by Juan Francisco Rosas Perez, who concluded that price-yield response was approximately 0.29. Despite the use of this data set, the Rocke study concluded – based on his own "statistical analysis" – that the price yield should be lower. (*Id.* ¶ 6.)

The rulemaking file does not contain an explanation as to how the Rocke study reached this conclusion or performed his statistical analysis. While commenting parties have requested this data, CARB staff has never supplied the data to the public. As a result, there is no evidentiary support for the lower price-yield values, and CARB should eliminate the lowest two values – 0.05 and 0.10 – due to a complete lack of evidentiary support for those values. (*Id.* ¶¶ 5-7.)

This failure is not merely academic. If the lowest two price yield values are eliminated, CARB's average price yield for corn ethanol would be 0.26. This would result in a

LUC value for corn ethanol of 15.53 gCO_2e/MJ, compared to 19.84 gCO_2e/MJ, (*id.* ¶ 7, Table 1), which would in turn lower the Carbon Intensity ("CI") Value for corn ethanol. LCFS FF45-1 cont.

In addition to the practical consequences on the use of corn ethanol in the marketplace, CARB's reliance on unsupported price-yields also has real environmental consequences. The LUC values are a component of the CI Value placed on a fuel by CARB. If CARB inaccurately calculates the LUC (and thus the CI value) of a fuel as being too high, it will incentivize the use of fuels that have a higher carbon intensity, creating an adverse climate change impact. In the rulemaking for the first LCFS regulation, CARB's consultants explained the importance of accurately calculating the CI Values in the Lookup Table: LCFS FF45-2

> [I]f we make a mistake in one direction in estimating these numbers, we'll use too much of a biofuel that's actually higher carbon [than] we thought and will therefore increase global warming. And if we use numbers that are too low, then we'll use too little of a biofuel that's lower carbon than we thought and will therefore increase global warming.

(Attachment "C" at 73-74 [excerpts from April 23, 2015, CARB Meeting].)

To avoid these potential adverse consequences, and to develop LUC Values (and thereby CI Values) that are based on scientific data, CARB should eliminate the lowest two values – 0.05 and 0.10 – for its average price-yield for corn ethanol.

B. CARB's LUC Value for Brazilian Cane Ethanol Is Not Supported By <u>Substantial Evidence, Due to Errors in the GREET Model</u>

LCFS FF45-3

The most recent version of the GREET model made available in June 2015 contains an error in its estimation of emissions resulting from ethanol produced from sugar cane in Brazil. Specifically, as explained in the accompanying declaration of Tom Darlington, an error in the GREET model results in cane ethanol plants with no mechanized harvesting having the same emissions as plants with 100% mechanized harvesting. (Decl. Darlington ¶ 10.) The correction of this error would obviously result in an increase in the CI Value for cane ethanol.

C. CARB Should Not Eliminate the Multimedia Evaluation Provisions <u>From the LCFS</u>

The 15-day Notice for the revised LCFS regulation suggests that CARB is proposing to eliminate the multimedia evaluation ("MME") provisions for new fuels contained in Sections 95490, 95481(a)(59), and 95488(c)(4)(G). As explained in the Declaration of Jim Lyons, the removal of the MME for new fuels has the potential to result in additional emissions and other adverse impacts. (Decl. Lyons ¶¶ 7-10.) Further, this change is not sufficiently related to the original text of the regulation such that a member of the directly affected public could have been put on notice that the changes had the potential to occur. Thus, CARB should reinstate the MME provisions and/or recirculate the proposed LCFS regulation for a full 45-day public review. LCFS FF45-4

1. The Elimination of the MME for New Fuels Could Result in <u>Additional Emissions</u>

The elimination of the MME requirement for new fuels will result in potentially significant environmental effects. First, the MME process provides important safeguards to help ensure new fuels will not result in increases in emissions. (See, e.g., Health & Saf., § 43830.8.) Without such safeguards, fuels can be allowed in California that result in additional emissions of criteria pollutants. LCFS FF45-5

For example, CARB permitted the introduction of biodiesels into the California market without requiring a MME under Section 43830.8. (Decl. Lyons ¶ 8.) "Based on CARB staff estimates, in 2014, biodiesel use for compliance with the LCFS regulation allowed by CARB without an approved [MME] . . . resulted in increased NOx emissions of 1.2 tons per day statewide." (*Id.*) Had CARB adopted fuel specifications, and required biodiesels to complete the MME process in 2009, these increased emissions could have been eliminated. (*Id.* ¶¶ 8-9.) CARB should learn from its past mistakes – not repeat them – and require new fuels to undergo the MME evaluation process.

2. The Elimination of the MME Requirement for New Fuels Is Not Sufficiently Related to the Original Text, and Requires Recirculation of the LCFS Regulation for a 45-Day Comment <u>Period</u>

California law provides that "[n]o state agency may adopt, amend or repeal a regulation which has been changed from that which was originally made available to the public . . . unless the change is . . . ***sufficiently related*** to the original text that the public was adequately placed on notice that the change could result from the originally proposed regulatory action." (Govt. Code, § 11346.8(c) [emphasis added].) To be "sufficiently related," changes must be such that "a reasonable member of the directly affected public could have determined from the [original text of the] notice that these changes to the regulation could have resulted." (1 Cal. Code Regs, § 42.)

LCFS FF45-6

California generally requires all new fuels to undergo the MME process under Section 43830.8 of the Health & Safety Code. Neither the original LCFS regulation nor the revised LCFS regulation circulated for a 45-day public review suggested that new fuels would be exempt from the MME process. Despite this, the 15-day notice now suggests many new fuels will be exempt from the MME requirement. Because Section 43830.8 is a preexisting requirement for new fuels that is unrelated to the LCFS regulation, the public could not have anticipated that the MME requirements would be eliminated by CARB. Thus, the elimination of the MME requirement for new fuels is not "sufficiently related" to the original text and, unless the MME requirement is reinstated, CARB must recirculate the revised LCFS regulation for a new 45-day public review period. (Govt. Code, § 11346.8(c); 1 Cal. Code Regs., § 42.)

D. CARB Failed to Include All Required Documents in the Rulemaking <u>File</u>

CARB recently added a series of email documents to the LCFS rulemaking file (see LCFS 15-Day Notice at 13), all of which date from 2013 or 2014. According to CARB, it is adding those materials to the rulemaking file, and inviting public comment on them, because the documents "might be characterized as containing non-privileged factual information submitted to ARB from ARB consultants." (*Id.* at 13.)

Those emails, likely along with many other documents from 2013 and 2014 submitted to CARB in connection with the proposed regulatory amendments, should have been included in the rulemaking file that CARB opened at the time of the notice of proposed rulemaking, which was dated December 16, 2014. CARB cannot cure this self-evident violation of section 11347.3 of the Government Code by adding those materials to the rulemaking file and inviting 15-day comments; CARB must cure this deficiency, along with numerous other violations of the governing statutes and regulations, by noticing the LCFS regulation for another public hearing after allowing 45-days for public comment.

The requirements of the Government Code are clear. Section 11347.3 of the Government Code requires CARB to maintain a "file of [the] rulemaking proceeding" for any proposed regulatory action subject to the APA, including the LCFS regulation." The rulemaking file must include, among other items, the following:

> (6) All *data and other factual information***,** any studies or reports, and written comments submitted to the agency in connection with the adoption, amendment, or repeal of the regulation. LCFS FF45-7
>
> (7) All data and other factual information, *technical*, *theoretical*, and *empirical studies or reports*, if any, on which the *agency is relying* in the adoption, amendment, or repeal of a regulation, including any cost impact estimates as required by Section 11346.3.

(Govt. Code, § 11347.3, subds. (b)(5), (b)(6) [emphasis added].) The entire rulemaking file, including the foregoing material, must be "available to the public for inspection" from the time when the first notice of the proposed rulemaking is published in the California Regulatory Notice Register, (*id.* at § 11347.3, subd. (a)), which in the case of the low-carbon fuel standards occurred on March 6, 2009. (See Cal. Reg. Notice Reg., Vo. 10-Z at 371.)

As the above-quoted text makes clear, rulemakings at ARB must include the creation of a rulemaking file that includes "*[a]ll* data and other factual information, any studies or reports, and written comments submitted to the agency" in connection with the proposal. (Govt. Code § 11347.3, subds. (a), (b)(6) [emphasis added].) To assure immediate public access to the supporting materials as soon as the 45-day materials are released, the APA requires that the 45-day notice include a statement that the agency on the date of the notice "has available *all* information upon which [the] proposal is based." (*Id.* § 11346.5, subd. (a)(16) [emphasis added].) A separate provision confirms that the agency must in fact make those records, and any other "public records, including reports, documentation, and other materials, related to the proposed action," available. (*Id.* § 11346.5, subd. (b).)

The "written comments" that must be placed in the record are not simply those submitted to the agency in a particular manner or at a particular time, such as during the period between publication of the notice of a public hearing and public hearing – an agency must put "all" it receives "in connection with" a regulatory proposal in the rulemaking file. The Legislature's choice of words to describe what comments must be placed in the file – "in connection with" – sweep with intentional breadth, and require inclusion of any comments that bear on the subject of the regulatory effort. In addition, the period of public availability must "[c]ommenc[e] *no later than* the date that the notice of the proposed action is published." (*Id.* § 11347.3, subd. (a) [emphasis added].) The use of the term "no later than" makes it clear that the Legislature expected written comments submitted in connection with a proposed regulatory action and received before publication of the required notice to be included in the rulemaking file.

LCFS FF45-7 cont.

In addition to failing to include these new, late-added documents in the rulemaking file, CARB has not properly construed or applied the relevant provisions of the Government Code. In particular, the rulemaking file is not to be limited to "factual information" that comes from "consultants" to CARB: Section 11347.3(b)(5) does not use the word "consultant," and it covers "any . . . written comments submitted to the agency in connection with" the adoption or amendment of a regulation. If "factual information" from sources that CARB defines as "consultants" received before CARB opened the rulemaking file for the current LCFS rulemaking warrant inclusion into the rulemaking file, so do any other written comment submitted to CARB in connection with the adoption or amendment of the LCFS regulation, or the adoption of the proposed alternative diesel fuels regulation. In addition, materials received from external sources, such as consultants, are presumptively not "privileged" and must be included in the rulemaking file.

LCFS FF45-8

Growth Energy therefore requests the following:

- An explanation of the reasons, if any, why CARB does not interpret section 11347.3 to require that all written comments received from any source in connection with the adoption or amendment of the LCFS regulation, or the adoption of the proposed alternative diesel fuels regulation, be included in the rulemaking file;

LCFS FF45-9

- An explanation of the reasons why the 2013-2014 documents that have now been added to the rulemaking file were not included in the rulemaking file at the time the file was first opened for public access; and

LCFS FF45-10

- An identification of each record from a consultant (or any person or entity retained by CARB) that would otherwise have been placed in the rulemaking file has not been placed in the file under color of privilege, so that compliance with section 11347.3 can be assessed by the public.

LCFS FF45-11

E. CARB Failed to Perform an Adequate External Scientific Peer Review for the Revised LCFS Regulation

This portion of Growth Energy's comments addresses the requirements of section 57004 of the Health and Safety Code, and CARB's failure substantially to comply with those requirements in the LCFS rulemaking.[1] LCFS FF45-12

1. Factual and Legal Background

Section 57004 of the Health and Safety Code creates several mandatory duties that must be fulfilled before CARB can take "any action" to adopt the proposed regulation to replace the current LCFS program. (Health & Saf. Code, § 57004, subd. (d).) Those duties include the following:

- CARB must submit "the scientific portion of the proposed rule" — in this instance, the regulation that the staff has proposed for final approval by the Board as a replacement for the current LCFS regulation — for review by an appropriate "external scientific peer review entity," along with "a statement of the scientific findings, conclusions, and assumptions on which the scientific portions of the proposed rule are based and the supporting scientific data, studies, and other appropriate materials." (*Id.*, § 57004, subd. (d) (1). LCFS FF45-13

- The "external scientific peer review entity" must then "prepare a written report." That report must "contain[] an evaluation of the scientific basis for the proposed rule." (*Id.*, § 57004, subd. (d)(2).) LCFS FF45-14

Memoranda sent by the CARB staff to the Manager of the Cal/EPA Scientific Peer Program dated November 19, 2014, and January 21, 2015, indicate an intent to comply to with section 57004. A letter from the Manager of the Cal/EPA Scientific Peer Program dated May 5, 2014, appears intended to convey the results of the external scientific peer review entity created for the proposed new LCFS rule. Neither the memoranda to the Manager of the Program nor the Manager's letter indicate that compliance with section 57004 in the current rulemaking was not mandatory, or that complete compliance with section 57004 was not required. Nor does the record indicate that there was insufficient time to permit CARB to ensure compliance with the requirements of section 57004. Those who were responsible for compliance with section 57004 had twice the time to complete their work than the public was provided to comment on the proposed regulation, the scientific portions of which were to receive review by the external scientific peer review entity.[2] LCFS FF45-15

---

[1] CARB posted some of the external scientific peer review materials for the new LCFS regulation on May 21, 2015, and additional materials on May 27, 2015 (*see* Attachment A), even though the peer review materials appear to have been completed weeks prior to May 21.

[2] There were 104 calendar days from January 21, 2105, to May 5, 2015. The rulemaking notice for the proposed regulation was dated December 16, 2014, but was not announced on the CARB website and made available to the public along with some supporting material until

Comment on the May 5, 2014 letter and its attachments is appropriate now, because the letter and its attachments comprise Reference 26 on the list of Additional References and Supplemental Documents in the staff's June 4, 2015, 15-Day Notice. Related materials also appear as References 27-29 on the same list.

Section 57004 of the Health and Safety Code defines the "scientific portions" of a proposed rule to include "those foundations of a rule that are premised upon, or derived from, ***empirical data*** or ***other scientific findings, conclusions, or assumptions*** establishing a regulatory level, standard, or other requirement for the protection of public health or the environment." (Health & Saf. Code, § 57004, subd. (a)(2) [emphasis added].) As indicated in the May 5 letter, the Manager of the Cal/EPA Scientific Peer Program intended that the "reviewers" selected for participation in the work would be "ultimately responsible for assessing the relevance and accuracy of ***all information*** upon which the staff report is based." (May 5 Letter at 2 [emphasis added].) While the May 5 letter is not clear about the identity of the "staff report" to which it refers, the reference may refer to the four summary documents that the CARB staff apparently prepared for consideration by the external scientific peer review entity; regardless, because those four documents are derived from the December 2014 Initial Statement of Reasons ("ISOR") for the proposed regulation, the external peer review entity was responsible for assessing the relevance and accuracy of all the information on which the ISOR was based. If CARB disagrees with that interpretation of the scope of the external scientific peer review entity's responsibilities in the current rulemaking, Growth Energy requests that CARB fully explain its reasons for disagreement in the response to these 15-day comments required by the California Administrative Procedures Act (the "APA"). LCFS FF45-16

Finally, it is important to be clear on one other point. The CARB staff memoranda to the Manager of the Cal/EPA Scientific Peer Program specified the number of reviewers whom the CARB staff considered necessary for various elements of the proposed LCFS regulation, and the required expertise for the reviewers who were to comprise the external scientific peer review entity. Nevertheless, Cal/EPA requires the "UC Project Director," following "careful consideration of the information" submitted by an agency, to determine the number of reviewers and the expertise required of the reviewers, presumably before the review gets under way.[3] Any such determination by a UC Project Director appears to be missing from the rulemaking file, and for all that appears, is mandatory in order for CARB substantially to comply with the provisions of the Health and Safety Code. LCFS FF45-17

Growth Energy requests an explanation for that omission in response to this comment as required by the APA.

December 30, 2014. There were 50 calendar days from December 30, 2014 to February 17, 2015, the deadline established by the Executive Officer for comment on the LCFS proposal, and 52 days from December 30, 2014 to the public hearing on February 19, 2015.

[3] G.W. Bowes, "Exhibit F -- Cal/EPA External Scientific Peer Review Guidelines" (Nov. 2008) at 8, *available at* http://www.arb.ca.gov/fuels/lcfs/peerreview/exhib_f.pdf.

2. CARB Has Failed to Comply With Section 57004 Because it Did Not Obtain an Evaluation of the "Scientific Portions" of the LCFS Regulation By an "Entity," as the Statute Requires, and Instead Has Provided Disaggregated Comments by Individual Reviewers

The text of Section 57004 makes plain that the evaluation of the scientific portions of a rule must be conducted by an "external scientific peer review entity," which must prepare "a written report," and that the entity must make certain findings. Individuals who participate in the work of that entity are not, acting themselves, the same as the "entity." (Health & Saf. Code, § 57004, subd. (d)(2).) When the statute refers to individual reviewers, who are called "person[s]," (*id.*, § 57004, subd. (c)), it does so explicitly, in establishing the minimum credentials for participation in the work of the external scientific review entity. (*Id.*, § 57004, subds. (b),(c).) The report and the findings of the "entity" are to come from the entity, as a singular being, and not separately from each individual reviewer: thus, if the "entity finds," (*id.*, § 57004, subd. (d)(2)), one or another conclusion to be true — and not what multiple reviewers might "find" — various consequences follow. The stature requires "a report," (*id.*, § 57004, subd. (d)(2)), not multiple reports.

A single, unitary "entity" must do what the statute requires, for any number of reasons (though no specific reasons need be identified, given the clarity of the statute). A report that reflects the evaluation of more than one external reviewer might, for example, have been expected to have greater balance and to reflect a collective and therefore more thoughtful insight and analysis that what could be expected from a single reviewer. If the Legislature had intended for individual reviewers to make the necessary report and findings, it would have used the term "reviewer" in subsection 57004(d)(2), as it was able to do in other portions of the statute, such as subsection 57004(c). If the words used by the Legislature are to have any real meaning, "reviewer[s]" are not the same as the "external scientific review entity" in section 57004. LCFS FF45-18

Against that statutory backdrop, CARB has not complied, substantially or otherwise, with the clear requirements of the statute. The collection of the separate reviews of the four individuals as attachments to the May 5 letter, which itself does not and cannot make any competent findings of the type required by the statute, do not constitute an "entity" of any type, much less the external scientific peer review entity that the statute requires, nor is the May 5 letter itself a "report" as the statute requires. The fact that CARB may not have complied with the statute in the past does not change the requirements of the statute: repeated noncompliance with section 57004 does not change that section's requirement. CARB cannot take "any action" to finally approve the proposed LCFS regulation until it has obtained the necessary report and findings from an external scientific peer review entity as the statute requires. Once that report and those findings have been obtained, CARB must permit at least the same opportunity for public review and comment that it has provided with respect to the materials for which comment was invited on June 4. There is time for CARB to undertake and complete this process consistent with its goal of completing consideration of amendments to the LCFS regulation this year.

3. The Individual Evaluations of the Four Separate Peer Reviews Do Not Each Demonstrate Full or Adequate Command of the "Scientific Portions" of the LCFS Proposal and Do Not, Alone or on a Consolidated Basis, Adequately Evaluate the Proposed Regulation's Lifecycle Emissions Analysis

Four individuals have provided written documents that appear intended to address various aspects of the scientific portions of the proposed LCFS regulation. Even if one could ignore the statutory text that requires a written report and certain findings from an entity, rather than from four separate reviewers, the four memoranda attached to the May 5 letter do not constitute competent and fully informed and considered reports that meet the purposes of the statute, which include providing a fully informed and well-considered external review of the CARB staff's scientific analysis.

Dr. Clarens' Memorandum. Starting with Dr. Clarens' memorandum, which is only two pages in length, it is apparent that Dr. Clarens did not have a basic understanding of some of the main features of the lifecycle analysis on which the proposed rule is based. Perhaps for reasons beyond his control, Dr. Clarens did not even know the indirect land-use change value being assigned in the proposed rule to corn ethanol. Thus, he states: "The report does not provide the actual value of the iLUC contribution that CARB is using but I found it online (30 g/MJ) . . . ." (Clarens memorandum page 2.) The proposed ILUC value for corn ethanol of 19.8 g/MJ appears on page ES-6 of the ISOR. Dr. Clarens was obliged to conduct an "online" search to ascertain the ILUC values for alternative fuels like corn ethanol, and thought it important enough to include what he found "online" in his report (which is only two pages). Nevertheless, his online research gave him an obsolete and incorrect value for the indirect land-use emission factor assigned to corn ethanol. It is unclear what, if any, indirect land-use change values, for other alternative fuels, Dr. Clarens assumed or applied in his analysis, whether he considered those emissions factors for any alternative fuels other than corn ethanol, or indeed if he understood that different alternative fuels have been assigned different ILUC values that he needed to evaluate. While Dr. Clarens may be "confident" that the "methods" reflected scientific portions of the proposed rule that he reviewed "are based on sound science and represents [*sic*] the state of the art in CI estimation," no one reading his report can have any confidence in Dr. Clarens' analysis.

LCFS FF45-19

In addition to his clear error concerning ILUC values, Dr. Clarens shows confusion about the treatment of coproducts in GREET in this portion of his brief memorandum:

> As written, the report states that the source must be directly consumed in the production process. But this is ambiguous in certain contexts such as those fuels that produce co-products. For example, if a corn feedstock were used to make ethanol and the stover were also used to make fuel (but was not consumed in the same production process) would that not trigger a switch from Tier 1 to Tier 2? It seems like it should but as written it might not. Clarifying this language is key for groups seeking to obtain co-product credit through the CA-LCFS.

In this statement, Dr. Clarens is referring to coproducts, corn feedstock, and stover. In his question, it is not clear whether he believes stover is a coproduct of the corn feedstock, or is a separate feedstock. If he believes stover is a coproduct of corn ethanol, clearly it is not. If he understands that both corn and stover are by themselves feedstocks, then it is not clear why he is mentioning the impact of coproducts the Tier 1/Tier 2 categories. In any event, Dr Clarens imagines a relevant confusion among "groups seeking to obtain co-product credit" that evades Growth Energy.

LCFS FF45-19 cont.

Insofar as Dr. Clarens is one of the reviewers expected to evaluate the OPGEE portions of the proposed rule, all he says is that the OPGEE model "goes into great detail" and that "the results are fascinating." Yet there is no indication that Dr. Clarens actually reviewed any models in order to prepare his evaluation: his memorandum refers only to "reviewing … three staff reports." The May 5 letter claims that it was the responsibility of individual reviewers to assess the "relevance and accuracy" of 'all information" on which the staff's reports are based. (See *supra*.) Dr. Clarens' memorandum raises serious questions about the staff's efforts to facilitate review of their proposal, or the process of selecting external reviewers and the standards applied in accepting materials from the reviewers for publication, or perhaps both. For the foregoing reasons, Dr. Clarens' memorandum cannot properly be used in order to comply with CARB's duties under section 57004.

Dr. Matthews' Memorandum. Turning next to Dr. Matthews' memorandum, there are also clear signs that Dr. Matthews lacked an adequate understanding of the scientific portions of the proposed rule, although his errors may seem not so blatant as those of Dr. Clarens'. Dr. Matthews's comment — which he calls his "first impression" — that "the net effect on a CO2e basis would be neutral between increasing VOC and decreasing CO emissions factors," to the extent his comment is intelligible, does not appear to be directed at what the CARB staff and Cal/EPA would call the "Big Picture." Conversely, Dr. Matthews (the reviewer with a background most heavily concentrated in economics) does not take account in his discussion of "the actual reduction in greenhouse gas emissions" of the fact that fuels to which higher CI values are assigned can and are produced and sold outside California regardless of the LCFS program. That effect, so-called "fuel shuffling," has been conceded by the CARB staff, and it should have been part of the scientific basis for the proposed regulation to be evaluated, insofar as what Dr, Matthews calls the "actual" impacts on greenhouse gas emissions are relevant, in his opinion, to the proposed rule.

LCFS FF45-20

Dr. Matthews then makes the following observations about the CA-GREET results in one of the documents supplied by the CARB staff:

> The CA-GREET results shown on pages 14-15 (Tables 1 and 2) are presented as 'CI lookup tables'. As presented, it was not clear what these were. However from reading the ISOR my understanding is that these are default values determined ex ante by staff for a generic production of a Tier 2 fuel used for Method 1 (as a default value that would apply for a particular supplier unless they wanted to show a lower value from other use of the methods like 2A or 2B). My lack of understanding has no effect on the scientific merit of the work.

In the above passage, and putting his point more directly, Dr. Matthews is stating that he did not really understand the values presented in the materials supplied to him in order for him to evaluate CA-GREET, but that those values must be acceptable because the CARB staff must have had some basis for using them, and that in any event his own "lack of understanding has no effect on the scientific merit of the work," so that he did not need to do anything further to address his lack of a complete understanding of the CA-GREET results.

With all due respect to Dr. Matthews, the approach to his assignment revealed in the quoted passage reflects substantial abdication of his responsibility as an external peer reviewer. Whether or not his ignorance about CA-GREET or the results of CA-GREET have any impact on the "scientific merit" of the CARB staff's work, if those results were significant enough to warrant the mention that he gives them in his memorandum, he had a duty to assess their scientific merit. Stated another way, the issue is not whether Dr. Matthews' ignorance affects the quality of the scientific portions of the proposed rule, but whether Dr. Matthews was equipped to review the model and the results of the model that he agreed to review, and that he was presumably paid to review. Dr. Matthews may or may not have understood his assignment, but there is no question that his evaluation of the CA-GREET model, such as it is, is incomplete if not useless, and cannot be relied upon in order to demonstrate compliance with section 57004. As with Dr. Clarens' work, Dr. Matthews' work either exhibits a level of ignorance concerning the scientific basis for the portions of the proposed rule for which he was a primary reviewer that requires CARB not to rely on his memorandum, or fails to demonstrate sufficient technical or scientific competence for his assignment to permit such reliance. By either standard, Dr. Matthews' work cannot properly be used to try to demonstrate compliance with section 57004 of the Health and Safety Code.

LCFS FF45-20 cont.

Further questions about whether Dr. Matthews possessed an orientation to his assignment making his work useful in an external review process comes at the end of his memorandum, where he adverts to GTAP:

> **Component 3 -- GTAP/Indirect Land Use Model**
>
> While my area of expertise is connected with the first two models, I did my best to read through the third modeling area. While I was unable to comprehend the model, data, or inputs at the same level of critical insight, I found nothing associated with that work that caused me to doubt its credibility. I thus agree with the staff's conclusion, have no big picture issues, and have no doubt that the work done was based on sound science.

LCFS FF45-21

Again putting Dr. Matthews' statement more simply: he has "no doubt" that the "work done" to assess indirect land-use change was based on sound science, even though, as he states, "I was unable to comprehend the model, data, or inputs" at the "same level of critical insight" as he displayed in his evaluation of CA-GREET. This begs the question: what is Dr. Matthews' reason for having "no doubt" about the scientific basis for the staff's indirect land-use analysis?[4] While the existence of bias is not necessary to demonstrate that Dr. Matthews'

[4] Dr. Matthews states at the outset of his memorandum that it was an "honor" to "look at" the CARB staff's work, and he calls the "work done by this evolving team over time "to have

analysis should not form a part of CARB's external peer review, Growth Energy has never read an external peer review for any CARB rulemaking that reflects bias in the same manner and to the same extent as Dr. Matthews' analysis. LCFS FF45-21 cont.

Dr. McCarl's Memorandum. Compared to the work by Dr. Clarens and Dr. Matthews, a more skeptical and informed analysis might have been expected from the memorandum provided by Dr. McCarl, who holds a Chair at Texas A&M University, and who has experience in econometric analysis of agricultural markets. At the outset, it should be noted that it is possible that the version of Dr. McCarl's memorandum published by CARB was not his final memorandum: on page 7 of the memorandum (which lacks page numbers), the memorandum refers to "G tab," obviously a phonetic version of GTAP, and a sure sign that the published document was dictated but not reviewed by Dr. McCarl (or by the Cal/EPA official in charge of collecting peer review materials, or by the CARB staff). Later, the draft memorandum attributed to Dr. McCarl states:

> In GTAP I believe that there also are increases in emissions from intensification (more irrigation or fertilization) so that the characterization of it only in terms of indirect land use change is not accurate. … In improving the indirect land use analysis when you're looking at corn ethanol byproducts there are also newer developments in terms of extracting corn oil from the DDGs.

LCFS FF45-22

There are no increases in emissions in GTAP attributed to intensification, and so the first quoted statement is untrue, as anyone who has rudimentary knowledge of GTAP would understand. The second statement reflects no understanding of, or consideration of, the fact that the amount of corn oil converted to biodiesel is unknown. As with Dr. Clarens' memorandum, though perhaps for different reasons (such as CARB's apparent failure to obtain from Dr. McCarl a final version of his evaluation), Dr. McCarl's memorandum raises questions about the process used by CARB and the reviewers to provide or obtain adequate understanding of the scientific portion of the proposed rule, the competence of the reviewer to perform the evaluation, or both. Putting those questions aside, the memorandum attributed to Dr. McCarl that has been placed in the public docket reveals that a lack of understanding of GTAP should prevent CARB from attempting to rely on that memorandum in order to demonstrate adequate external review of the scientific portion of the proposed rule.

---

been "one of the most impressive scholarly efforts I have seen in my career." Dr. Matthews, who from the preamble of his memorandum makes it clear that he is a strong supporter of the LCFS program, imagines on page 4 of his memorandum a distinction between "scientific credibility of the method" used in the regulatory proposal, on the one hand, and what he calls the "magnitude of the overall potential benefits of the program." How Dr. Matthews believes that he can separate the "scientific credibility of the method" from the assessment of the potential impacts of the proposed regulation is unclear, unless he considers a "method" that does not permit an assessment of the potential benefits of a proposed regulation to possess scientific credibility, despite that deficiency. The question presented for Dr. Matthews is therefore this: what is the purpose of scientific credibility in a rulemaking intended to establish or create environmental benefits?

One indication that the deficiencies originate at least in part with the CARB staff appears on page 11 of Attachment 1 to CARB's January 21, 2015, memo. There, the CARB staff claims that 2004 is the "most recent year for which a complete global land use database exists." That statement is not correct, and should have been known to the CARB staff not to be correct at the time when written. A report by Iowa State University ("ISU") researchers, which the CARB staff reviewed in the fall of 2014, and which was the subject of testimony at the February 2015 public hearing, used a more recent complete global land-use database, inter alia to impeach or challenge the credibility of CARB's use of the 2004-based GTAP system. It is unknown how and why the CARB staff could advise their reviewers that a data set more than a decade old is the "most recent" that exits. If the CARB staff's use of the word "complete" in the phrase, "complete global land use database" is studied, then the lack of candor and transparency of the CARB staff in presenting relevant information to their reviewers makes a mockery of the peer-review process required by the Health and Safety Code, and makes that process as applied to this rulemaking substantially noncompliant with the statute. To obtain an external review of the scientific basis for the proposed rule with respect to GTAP, CARB must provide the external reviewers with, at a minimum, the ISU study that was a subject of interest to the CARB staff last year, and that was included in the comments filed with the Board prior to the February public hearing.

LCFS FF45-22 cont.

Overall Issues Concerning the Selection of Peer Reviewers. Growth Energy also believes the process used to select the external reviewers for the proposed LCFS regulation did not provide for sufficient depth of review because none of the reviewers expressed, or could have been identified from prior work to have possessed, any skepticism about the scientific portions of the current LCFS regulation or the approach being taken in the new proposed rule. Publications and other work available to the CARB staff since the commencement of the first LCFS rulemaking reveal experts who are both skeptical of the LCFS regulation and not aligned with stakeholders. They include Dr. Valerie Thomas, of the Georgia Institute of Technology, who was an external reviewer for the 2009 rulemaking process. Dr. Thomas noted in her 2009 review that "the values used to quantify the carbon intensity due to land use change for ethanol from corn and sugarcane are not yet sufficiently developed to be scientifically confirmed" and that "refinement and validation of those quantities [are] needed." (*See* Attachment B.) As Dr. Thomas also stated in 2009, "ARB could develop a more data driven and less model-dependent approach by observing and tracking changes in land use patterns that have been observed to date and that will be observed over the next few years . . . ."

Dr. Thomas's earlier external review is significant and raises two questions. The first is why Dr. Thomas did not participate in the current peer review. The second is why, in light of the success in identifying someone with Dr. Thomas' level of skepticism and independence in 2009, Cal/EPA or another appropriate body did not include anyone in the current external review process who expressed a similar, or any, level of skepticism about the scientific portions of the proposed new rule.

LCFS FF45-23

Growth Energy also notes that none of CARB's four current external reviewers appear to have attempted any systematic review of the CA-GREET model for sugarcane ethanol from Brazil, or biodiesel and renewable diesel. Given the importance assigned to those alternative fuels in the compliance scenarios developed for the new proposed rule by the CARB staff, those omissions are significant and make the current external scientific review substantially

LCFS FF45-24

noncompliant with section 57004 of the Health and Safety Code, because CARB has failed to obtain meaningful external review of all the relevant and important CA-GREET models. LCFS FF45-24 cont.

4. Selected List of Specific Questions CARB Staff Must Address

Although the following list of questions does not cover all the comments presented above concerning CARB's LCFS external review, and should not be taken to limit the scope of issues that CARB must address in its response to the 15-day comments, this list includes some of the questions concerning the LCFS peer review that the CARB staff should address. If CARB does not consider itself obliged to respond in full to any of the following questions, Growth Energy requests that for each such question, CARB explain separately why it is taking such a position.

- Did the materials provided or made available to the external peer reviewers include all the "best available economic … information" available to the CARB staff in developing the scientific portions of the proposed rule? (Cal. Health & Safety Code § 38561(e).) Did those materials include all the "best available … scientific information" available to the CARB staff in developing the scientific portions of the proposed rule? (*Id.*) If not, why not? LCFS FF45-25
    - Why were the external peer reviewers not advised of, or given materials concerning, fuel shuffling? LCFS FF45-26
    - Why were the external reviewers not provided with the ISU report co-authored by Dr. Babcock that casts doubt on the use of GTAP in regulatory settings, which was supplied to CARB in the 45-day comment process? LCFS FF45-27
    - What is CARB's definition of a "complete global land use database," as that term is used in the materials provided to the external peer reviewers? Does (or do) the database or databases referenced in the ISU report noted above meet the standard or criteria for a "complete global land use database?" If not, how is the 2004 GTAP database more "complete" than the database or databases referenced in the ISU report? LCFS FF45-28
- Does CARB consider Dr. Clarens to be adequately informed concerning the scientific portion of the proposed rule, notwithstanding the errors in his memorandum noted above? If so, why? Has CARB considered or will CARB consider asking Dr. Clarens to revise his evaluation and address the issues presented here, and if not, why not? LCFS FF45-29
    - What is CARB's understanding of Dr. Clarens' knowledge of the ILUC value assigned to corn ethanol in the proposed rule? Upon receipt of Dr. Clarens' report, did CARB staff attempt to provide Dr. Clarens with additional information? If not, why not? LCFS FF45-30

- What is CARB's understanding of the portion of Dr. Clarens' report excerpted on page 4 of the comments above? If CARB does not agree with Growth Energy's interpretation of that portion of Dr. Clarens' report, or with the identified errors in that portion of Dr. Clarens' report, why not? LCFS FF45-31

- Does CARB have confidence that Dr. Clarens had an adequate understanding of the scientific portions of the proposed rule that he claimed to evaluate, and if so why? LCFS FF45-32

- Does CARB consider Dr. Matthews' comments on the indirect land-use change portions of the scientific basis for the proposed rule to be relevant or useful in the external review of the proposed rule? If so, why? LCFS FF45-33

- Does CARB consider the CA-GREET results to which Dr. Matthews refers in the excerpt from his memorandum on page 5 of the above comments to be part of the scientific portion of the proposed regulation? If not, why did CARB include it in the report provided to the external reviewers? Which external reviews understood completely and reviewed those results? LCFS FF45-34

- Does CA-GREET use the MOVES model? If so, in what respects? If not, did the CARB staff take any action to advise Dr. Matthews of the error postulated on page 5 of the above comments with respect to MOVES? LCFS FF45-35

- Does CARB believe that the "scientific credibility" of the "method" that it used in the proposed rule is not affected by or related to estimates of the "overall potential benefits" of the LCFS regulation, as those terms are used in Dr. Matthews' memorandum? LCFS FF45-36

- Does CARB consider Mr. McCarl to be qualified to evaluate GTAP, notwithstanding the apparent errors in his understanding of GTAP noted on page 7 of the above comments? If so, why? LCFS FF45-37

  - Does GTAP attribute emissions to intensification, as the latter term is used in Dr. McCarl's draft memorandum?

  - Did CARB consider whether to invite Dr. McCarl to review and revise his memorandum? If not, why not?

- How did the CARB staff determine the number of peer reviewers required for each portion of the scientific basis of the proposed regulation? If the evaluations by Dr. Clarens, Dr. Matthews or Dr. McCarl are excluded to any extent from the external review, based on the issues presented here, will CARB seek additional external review? If so, under what specific circumstances, and if not, why not? LCFS FF45-38

Attachment A

Drake, Stuart

From: Adams, Stephen@ARB <Stephen.Adams@arb.ca.gov>
Sent: Wednesday, May 27, 2015 3:19 PM
To: Drake, Stuart
Cc: Elaine Meckenstock (Elaine.Meckenstock@doj.ca.gov); Brieger, William@ARB; tom darlington; Jim Lyons
Subject: RE: LCFS -- External Review Materials
Attachments: 01. CA-GREET_StaffReport.pdf; 02. OPGEE_StaffReport.pdf; 03. iLUC_StaffReport.pdf; CoverPage.pdf

Stuart,

I'm attaching three documents and a cover page that were provided to the LCFS peer reviewers but that were not posted to the peer review page when it was set up. I'm told these files contain all of the content you are asking about. Staff will be adding these documents to the web page as well.

Thank you,
Steve

From: Drake, Stuart [mailto:sdrake@kirkland.com]
Sent: Wednesday, May 27, 2015 11:15 AM
To: Adams, Stephen@ARB
Cc: Elaine Meckenstock (Elaine.Meckenstock@doj.ca.gov); Brieger, William@ARB; tom darlington; Jim Lyons
Subject: RE: LCFS -- External Review Materials

Thanks Steve.

Stuart Drake | Kirkland & Ellis LLP
655 15th Street, NW | Suite 1200
Washington, DC 20005
202-879-5094 Office | 202-450-0051 Mobile
202-654-9527 Direct Fax
stuart.drake@kirkland.com

From: Adams, Stephen@ARB [mailto:Stephen.Adams@arb.ca.gov]
Sent: Wednesday, May 27, 2015 2:12 PM
To: Drake, Stuart
Cc: Elaine Meckenstock (Elaine.Meckenstock@doj.ca.gov); Brieger, William@ARB; tom darlington; Jim Lyons
Subject: RE: LCFS -- External Review Materials

Stuart,

I wanted to make sure you're aware that separate peer reviews were conducted on biodiesel and renewable diesel as part of the multimedia evaluation on those two fuels. Those reviews are listed in the 15-day notice for the ADF regulation that went out Friday, and the peer review documents for those are at
http://www.arb.ca.gov/fuels/diesel/altdiesel/biodocs.htm

Steve

From: Drake, Stuart [mailto:sdrake@kirkland.com]
Sent: Wednesday, May 27, 2015 10:59 AM
To: Adams, Stephen@ARB
Cc: Elaine Meckenstock (Elaine.Meckenstock@doj.ca.gov); Brieger, William@ARB; tom darlington; Jim Lyons
Subject: RE: LCFS -- External Review Materials

Thanks Steve, I appreciate it.

Stuart Drake | Kirkland & Ellis LLP
655 15th Street, NW | Suite 1200
Washington, DC 20005
202-879-5094 Office | 202-450-0051 Mobile
202-654-9527 Direct Fax
stuart.drake@kirkland.com

From: Adams, Stephen@ARB [mailto:Stephen.Adams@arb.ca.gov]
Sent: Wednesday, May 27, 2015 1:57 PM
To: Drake, Stuart
Cc: Elaine Meckenstock (Elaine.Meckenstock@doj.ca.gov); Brieger, William@ARB; tom darlington; Jim Lyons
Subject: RE: LCFS -- External Review Materials

Stuart,

I'm going to ask staff to take a look at your questions and the documents posted as part of the peer review reports. You can expect to hear back from me, or as you suggest I might have staff communicate directly with one of your colleagues if that seems the simpler way to proceed.

Steve

From: Drake, Stuart [mailto:sdrake@kirkland.com]
Sent: Wednesday, May 27, 2015 9:26 AM
To: Adams, Stephen@ARB
Cc: Elaine Meckenstock (Elaine.Meckenstock@doj.ca.gov); Brieger, William@ARB; tom darlington; Jim Lyons
Subject: LCFS -- External Review Materials

Steve --

Tom Darlington, Jim Lyons and I are having some trouble in readily locating some of the documents to which Dr. McCarl and Dr. Kumar, two of the LCFS external reviewers, refer in their April 29 and May 5 reports for the staff.   On behalf of Growth Energy, I wondered if your Office could help us locate those documents, or if they are not currently on the external-review page on CARB's website, if your Office could let us know if there are any plans to post them. If it is more efficient for someone on the technical side to get in touch directly with Tom Darlington and/or Jim Lyons, that's fine too -- maybe we have just overlooked something. It is not possible to understand the external reviews without the ability to look at the same documents that the reviewers did.

Here is an excerpt from the first page Dr. McCarl's report:

"As I understand it the peer review is intended to develop external review opinions on whether the CI methodology used by the ARB staff and supporting parties in calculating carbon intensity values and use of greenhouse gas emission models yields a valid scientific basis for the conclusions in the air resources Board staff reports.

"I also believe that while I was sent three reports and a plain English version that I am only supposed to review those within my field of expertise which limits me to comment on

"Calculating Lifecycle Carbon Intensity Values of Transportation Fuels in California, March 2015 (Staff Report 1)

"Calculating Carbon Intensity Values from Indirect Land Change of Crop-Based Biofuels (Staff Report 3)

"Additionally I will comment on the attachment entitled *Plain English summary of staff's methodology in calculating fuel carbon intensities*."

Page 1 of Dr. Kumar's report refers to "Staff Report 2." That report appears to address carbon intensity values for crude oil.

The "Plain English" summary appears to be a 15-page document attached to Mr. Aguila's Jan. 21, 2015, memo to Dr. Bowes at the Water Board, which is posted on the external review page of the CARB website as part of Mr. Aguila's memo. Mr. Aguila's memo refers to the three Staff Reports but they do not seem to be attached to his memo, and in any event I don't understand how a memo dated January 2015 could have included a report that according to Dr. McCarl is dated March 2015. Are the three referenced Staff Reports also on the CARB website, and if so where? Are there multiple versions of the Staff Reports?

I also wanted to ask if there is a later version of Dr. McCarl's report. On the seventh page, there is a reference to "G tab," which we assume is supposed to be "GTAP."

Here is the url for the external review page:

http://www.arb.ca.gov/fuels/lcfs/peerreview/peerreview.htm

Anil Prabhu is listed as the technical contact person on the website.

Thanks in advance for your help, and my apologies if this is something easy to find that we have just missed. Give me a call if you would like to discuss.

-- Stuart

Stuart Drake | Kirkland & Ellis LLP
655 15th Street, NW | Suite 1200
Washington, DC 20005
202-879-5094 Office | 202-450-0051 Mobile
202-654-9527 Direct Fax
stuart.drake@kirkland.com

****
The information contained in this communication is confidential, may be attorney-client privileged, may constitute inside information, and is intended only for the use of the addressee. It is the property of Kirkland & Ellis LLP or Kirkland & Ellis International LLP. Unauthorized use, disclosure or copying of this communication or any part thereof is strictly prohibited and may be unlawful. If you have received this communication in error, please notify us immediately by return e-mail or by e-mail to postmaster@kirkland.com, and destroy this communication and all copies thereof, including all attachments.
****

****
The information contained in this communication is confidential, may be attorney-client privileged, may constitute inside information, and is intended only for the use of the addressee. It is the property of Kirkland & Ellis LLP or Kirkland & Ellis International LLP. Unauthorized use, disclosure or copying of this communication or any part thereof is strictly prohibited and may be unlawful. If you have received this communication in error, please notify us immediately by return e-mail or by e-mail to postmaster@kirkland.com, and destroy this communication and all copies thereof, including all attachments.
****

****
The information contained in this communication is confidential, may be attorney-client privileged, may constitute inside information, and is intended only for the use of the addressee. It is the property of Kirkland & Ellis LLP or Kirkland & Ellis International LLP. Unauthorized use, disclosure or copying of this communication or any part thereof is strictly prohibited

and may be unlawful. If you have received this communication in error, please notify us immediately by return e-mail or by e-mail to postmaster@kirkland.com, and destroy this communication and all copies thereof, including all attachments.

Attachment B

Valerie Thomas, Ph.D.
Anderson Interface Associate Professor
School of Industrial and Systems Engineering
Georgia Institute of Technology
Atlanta, Georgia

Review of
Proposed Regulation to Implement the Low Carbon Fuel Standard
California Environmental Protection Agency
Air Resources Board

The Air Resources Board has made a great deal of progress in modeling and quantifying the greenhouse gas and other environmental impacts of fuels. This work provides a strong foundation for understanding the impacts of these fuels, and for further development of understanding as experience with alternative fuels increases.

The five issues identified by the ARB to be addressed by the peer reviewers are addressed below.

1. Greenhouse Gas Modeling

a. The description in the text of the greenhouse gas impacts of corn-derived and sugarcane-derive ethanol is solid, and could be emphasized more prominently: "Direct GHG emissions from the production and use of corn and sugarcane ethanol are less than the comparable emissions from gasoline. When land use change emissions are considered, however, the emissions-reduction benefit from corn and sugarcane ethanol is diminished." (p. IV-42)

b. The lookup table values for carbon intensity for the three gasoline fuels appear to be well justified.

c. The evaluation of carbon intensity for eleven different corn-derived ethanol is sound practice and provides a basis for encouraging low-carbon production of corn-derived ethanol. LCFS FF45-39

d. The numerical values assigned to the GHG emissions from production of corn-derived and sugarcane-derived ethanol have some uncertainties that could be reduced through revised analysis and further reduced when more data become available.

i. The calculation of the direct GHG emissions from production of corn-derived and sugarcane-derive ethanol is by-and-large solid and consistent with a well-developed body of scientific research. The calculation of the coproduct credits does, in my view, somewhat overvalue these credits, resulting in an understimate of the direct GHG impacts of corn-derived ethanol of perhaps 10%.

Attachment "B"

2. Land Use Modeling

The calculation of the indirect, land-use-change GHG emissions from production of corn-derived and cane-derived ethanol has significant uncertainties.

a. That observed data have not be used to validate the GTAP model findings is a significant weakness. The changes in corn production resulting from the federal renewable fuel standard, and the changes in Brazilian sugar production resulting from increased ethanol production should be measurable, and should be measured to validate the model assumptions. The ARB model should be adjusted to reflect data.

b. The lack of a time dimension in GTAP results in an awkward match with the question at hand. Corn yields have been increasing largely linearly for some time now in the United States, yet the model appears to use 2008 corn yields to determine land impacts of corn-derived ethanol. The projected steady increase in use of corn for ethanol in the US over the next few years suggests that land use change will be somewhat less than projected here.

c. The greenhouse gas impact of land use change occurs mainly at the time of land clearing. This suggests that the effect of increased use of corn for ethanol will depend on whether and when total global corn production increases. An increase in use of corn for ethanol in a year in which corn demand decreases or stays constant will have a different greenhouse gas effect than in a year in which total corn demand increases. The increased use of corn for ethanol in one year can result in land clearing in a future year, depending on overall global total corn production and production of other crops. The ARB staff has put a great deal of effort in to thinking about the time dimension of this problem. Nevertheless, time-related issues are still addressed in piecemeal way that makes some unjustified assumptions. A more comprehensive approach to the changes in corn production over time would be simpler and could be more accurate. ARB could develop a more data driven and less model-dependent approach by observing and tracking changes in land use patterns that have been observed to date and that will be observed over the next few years as corn-derived and cane-derived ethanol production increases.

d. The development of the land use change analysis for Brazilian sugarcane-derived ethanol appears to be less developed than the analysis of US corn-derived ethanol. The Brazilian analysis should be revised using up-to-date yield values, if they were not used in this analysis, and should reflect data on land use changes in Brazil.

3. Economic Impacts

LCFS FF45-39 cont.

The LCFS staff report predicts that the LCFS will result in an overall savings in the State of California. The economic impacts of the LCFS will depend on future prices of petroleum and the future production costs of alternative fuels and vehicle technologies, which cannot be definitively predicted in advance. Nevertheless, the economic assessment appears reasonable, and the projection that the net economic impact will not be large and may even be slightly positive appears sound.

4. Environmental and Multimedia Impacts

The LCFS staff report covers many of the environmental impacts well. An important set of environmental impacts that are not mentioned are the increased impacts of nitrogen, phosphorus, and other agricultural inputs from increased corn production. As mentioned in the report, the increase in corn production is not likely to take place in California. Nevertheless, the impacts may be significant at the national and international scale. Hypoxia in the Gulf of Mexico is linked to increased corn production.[1] The use of nitrogen fertilizers and other agricultural inputs have a range of other environmental impacts that should be included in the environmental assessment.

5. Credit Trading

The credit trading framework and details appear reasonable. Note that the credit trading provisions may help to reduce the actual land-use-change impacts of corn-derived and sugarcane-derived ethanol: When corn or sugar prices are high, regulated parties may choose to use less corn-derived or sugar-derived ethanol, which would help to moderate corn and sugar demand and reduce pressure to increase plantings of corn and sugarcane.

LCFS FF45-39 cont.

The Big Picture

a. Are there any additional scientific issues to be addressed?

No.

b. Taken as a whole, is the scientific portion of the proposed rule based upon sound scientific knowledge, methods, and practices?

Taken as a whole, the scientific portion of the proposed rule is based upon sound scientific knowledge, methods and practices. Use of a non-zero positive value for the carbon intensity due to land use change for ethanol from corn and sugarcane is sound. The direct emission values for ethanol from corn and sugarcane, and the differences in direct carbon intensity values for different ethanol production processes are sound. However, the values used to quantify the carbon intensity due to land use change for ethanol from corn and sugarcane are not yet sufficiently developed to be scientifically confirmed; refinement and validation of those quantities is needed.

Detailed comments:

[1] US EPA SAB. Hypoxia in the Northern Gulf of Mexico. December 2007. EPA-SAB-08-003 http://epa.gov/msbasin/pdf/sab_report_2007.pdf

Table IV-1, page IV-3. This table appropriately separates the direct emissions from the land use effects, and appropriately shows fewer significant figures for land use effects than for direct emissions. The direct emissions, however, should not be shown to four significant figures because the estimates are not that accurate; these results should be expressed to at most two significant figures.

p. IV-12. Coproduct allocation. Coproduct credits for corn ethanol are allocated in GREET by assuming that the use of coproducts as animal feed results in decreased production of the displaced feed in exactly the amount that is displaced. This effectively assumes completely inelastic demand for the displaced product. This is not consistent with the land use change calculations, which do assume demand elasticities. In other words, the coproduct calculation appears to be overestimated, resulting in a somewhat lower calculation of the direct GHG impact than is probably likely, and indicating uncertainty in the direct emissions results for corn ethanol of at least several percent.

p. IV-17. Among the choices to meet demand for biofuel feedstock, one option not mentioned is to convert existing agricultural lands from non-food crops – such as cotton or tobacco, for example.

p. IV-20. The GTAP model is not time dependent, whereas the land use change from biofuels is time-dependent. In particular, yields of corn and other feedstocks can be expected to increase in time. Although there is extensive discussion of this issue, particularly in Appendix C6, the expected increase in yield of corn beyond 2008 does not appear to be incorporated into the model.

LCFS FF45-39 cont.

p. IV-24. Of the three time accounting methods described, the first one is by far the most sensible. The Net Present Value calculation is not appropriate here. Net present value calculations are used for money because of the potential to invest money and receive a return over time. That is not true for greenhouse gas emissions. The Fuel Warming Potential also is not appropriate; the greenhouse gases will remain in the atmosphere beyond the project time horizon, and presumably the policy interest is to reduce climate change impacts over a longer time horizon than this project time horizon. Presenting the net present value approach and the fuel warming approach gives the impression that these are valid approaches that could be used. I suggest that discussion of these approaches be dropped from the main body of this report, although retained in the Appendices. Development of these ideas in the peer-reviewed literature would provide a basis for inclusion in future ARB analyses.

p. IV-26. ARB staff appropriately uses the annualized method.

p. IV-29. The results of the GTAP model are for a situation in which 13.25 billion gallons of increased ethanol production is produced in the year 2008. Yield will increase in subsequent years, requiring less land for a given amount of ethanol. If the increases in corn production occur after 2008, the land use impact will be less.

p. IV-31. It should be possible to validate with data the projections of land use change shown in Table IV-10, and especially the projections of US land use change.

p. IV-33, Table. IV-12. It should be possible to validate with data he projections of land use change resulting from cane-derived ethanol production in Brazil. The projections seem to be entirely model-derived, with no reference to studies of actual land use change in Brazil. The results should be validated with data. Also, cane yield in Brazil has increased significantly over time. The cane yield used in the GTAP model is not mentioned, but if the 2001 baseline is used, then the modeled land use change would be larger than if the 2006-08 sugarcane yield were used. And, as discussed elsewhere for corn, sugarcane yields can be expected to continue to increase, suggesting that land use change impacts will decrease over time.

p. IV-34. "As an initial estimate, we assumed a 75 percent coproduct credit for soy meal." ARB staff appropriately flags the uncertainty of this estimate.

p. IV-39. Comparison of GTAP results with Observed Market Behavior. The effects of corn ethanol on land use either are, or are not, large enough to be observable. As this section states, there are many factors that influence corn production and corn exports. If the effects of ethanol production are large enough to be measurable and identifiable, then this effect should certainly be taken into account in the assessment of corn-derived ethanol. Observation of the effect and validation of the model results is critical to validation of the greenhouse gas calculation for corn-dervied and cane-derived ethanol. This section indicates that the GTAP model results cannot be validated, or have not yet been validated. Surely there is some aspect of the calculation that could be validated. For example, the changes in US forest and pasture land due to the federal RFS should be measurable.

LCFS FF45-39 cont.

p. IV-41-IV-42. This entire section expresses more certainty than warranted. Some judicious editing would prevent it from being misinterpreted. For example, in the bulleted list on p. IV-42, the word "about" should also be used in the last two bullets – these numbers are very uncertain.

p. IV-42. This statement is solid: "Direct GHG emissions from the production and use of corn and sugarcane ethanol are less than the comparable emissions from gasoline. When land use change emissions are considered, however, the emissions-reduction benefit from corn and sugarcane ethanol is diminished."

pp. IV-46. Increases in crop yield with time. The adjustments made to convert GTAP results from 2001 yields to 2006-08 yields, as described in Appendix C, do appear to be reasonable. However, the time profile of the land use change implied by the LCFS may warrant additional scaling of the GTAP results. In particular, if the increase in corn-derived ethanol is assumed to scale with the federal RFS, then the amount of corn used for ethanol will increase over time; if corn yields also increase over time then the land use impact of the corn-derived ethanol will decrease over time, although it will still be postive. However, if the amount of corn-derived ethanol used to fulfill the LCFS is constant, as suggested by the scenarios presented in appendix E, then the land use change would all be concentrated in the very near future (or even recent past). The time scenario for corn-derived ethanol production (how much in which year, and the total change in demand in each year) will affect the actual land use change and the actual greenhouse gas impacts. The land use change impact will occur in the year that land use changes, which will not necessarily be the same as the year of the increased use of corn-derived ethanol.

p. IV-47. Uncertainties associated with time-accounting. As mentioned before, it would be feasible, and add clarity to the model, to do more explicit time-depedent modeling.

p. IV-48. The paragraph at the bottom of page IV-48 is solid. ARB should continue to refine its analysis and adjust the GHG emission values as the analysis develops, and data become available.

Appendices:
p. iii. The word "not" seems to be missing from lines 2.

p. C-5. Energy Economy Ratios. In Brazil, development of flex-fuel vehicle technologies with higher compression ratios has provided an opportunity to increase the efficiency of vehicles using ethanol fuels somewhat. ERB may not want to incorporate this potential into its LCFS EERs, but this potential may warrant at least a one-sentence mention.

LCFS FF45-39 cont.

p. C-27. A corn yield of 151.3 bushels per acre is mentioned here, but a corn yield of 160 bushels per acre is used in the derivation of the "110,000 acres of U. S. farmland" mentioned on p. IV-42 and derived on page C-41. The 160 bushels per acre may be taking into account future yield increases, as I have advocated above. The yield value assumptions, and the year to which each yield value is associated, should be clarified.

p. C-54. Co-product credit for DDGS. The decision of ARB to not adopt Wang's findings on this issue is solid. However, there is an additional co-product credit issue. In GREET, when a coproduct is used instead of the substitute product, the reduced use of the substitute is assumed to result in exactly that amount of decreased production of that product. This is surely an overestimate, resulting in a small underestimate of the direct GHG impacts of corn-derived ethanol.

p. C-54. "Staff will revisit this issue and make updates to the co-product credit, as appropriate." ARB's commitment to revising the analysis is important and will improve the assessment; increased production of biofuels will provide more data with which to refine the analysis.

Attachment C

MEETING

STATE OF CALIFORNIA

AIR RESOURCES BOARD

JOE SERNA, JR. BUILDING

CALIFORNIA ENVIRONMENTAL PROTECTION AGENCY

BYRON SHER AUDITORIUM, SECOND FLOOR

1001 I STREET

SACRAMENTO, CALIFORNIA

THURSDAY, APRIL 23, 2009

9:04 A.M.

ORIGINAL COPY

JAMES F. PETERS, CSR, RPR
CERTIFIED SHORTHAND REPORTER
LICENSE NUMBER 10063

We've been working in such close collaboration that we scientists merge.

CHAIRPERSON NICHOLS: -- forgotten his last name.

STATIONARY SOURCE DIVISION CHIEF FLETCHER: But Mike has been working with us very closely since the inception of this project, and he has a few comments that he would like to make.

CHAIRPERSON NICHOLS: Thank you.

MR. O'HARE: Oh, I guess we got that to work.

(Thereupon an overhead presentation was Presented as follows.)

MR. O'HARE: So I'd like to make a few remarks on I guess you could call a bigger picture look at the land use change issue especially.

And the general burden of these remarks is to regard the land use change estimates that the staff has given you as being -- I don't want to use the word "conservative," but I would say biofuel favorable in the competition between fuels to satisfy the LCFS requirements. LCFS FF45-40

I do want to say at the beginning that it's not clear what "conservative" means in this context because it is a low carbon fuel standard. And if we make a mistake in one direction in estimating these numbers, we'll use too much of a biofuel that's actually higher carbon than we thought and will therefore increase global warming. And if we use numbers that are too low, then we'll use too little of a biofuel that's lower carbon than we thought and will therefore increase global warming.

So the cost to the world of being wrong in both directions is fairly symmetrical. And there's no obvious conservative direction as there is, for example, in life and safety regulation.

Next slide please.

--o0o--

MR. O'HARE: I want to thank a large and growing group of collaborators, including one of your distinguished Board members, at this point, and also remember Alex who set us out on this path a couple of years ago. This has become quite a large group enterprise. And I think it's good for that reason.

Next slide please.

--o0o--

MR. O'HARE: So let me just quickly recall the history we'd been through and emphasize the policy is forcing the science quite rapidly.

The policy intentions of California and the nation and also other countries is pushing the science forward probably a lot faster than it would otherwise go. On the whole I think this is a good thing.

LCFS FF45-40 cont.

CALIFORNIA ENVIRONMENTAL PROTECTION AGENCY

CALIFORNIA AIR RESOURCES BOARD

DECLARATION OF THOMAS L. DARLINGTON

I, Thomas L. Darlington, declare as follows:

1. I am an engineer with training and expertise in lifecycle emissions analysis, the use of models to estimate lifecycle emissions and to attribute emissions to the production, distribution and use of various fuels, and use of regulations to control mobile-source emissions. My areas of expertise also include land-use change ("LUC") modeling and the application of econometric models to attributional and consequential lifecycle emissions analysis. Following my graduation from the University of Michigan in 1979, I served for eight years as a Project Manager at the United States Environmental Protection Agency's Motor Vehicle Emissions and Fuels Laboratory in Ann Arbor, Michigan. Thereafter I worked at Detroit Diesel Corporation and General Motors Corporation, and as the Director of Mobile Source Programs at Systems Application International. I am the President of Air Improvement Resource ("AIR"), a company formed in 1994 to provide mobile source emission modeling to government and industry. A copy of my CV is attached to this Declaration as Attachment A.

2. I have participated on behalf of renewable fuels producers in the public consultation and rulemaking processes at the California Air Resources Board ("ARB" or "the Board") to consider, adopt and revise the low-carbon fuel standard ("LCFS") regulation since 2008. I testified at the Board's February 2015 hearing concerning proposed amendments to the LCFS regulation. I am fully familiar with the models released by CARB to establish and implement the LCFS regulation, including the versions of the Global Trade Analysis Project ("GTAP") modeling systems used by CARB or proposed for use by the CARB staff as part of the current and proposed LCFS regulation.

3. I make this Declaration based upon my personal knowledge, my training and expertise, and my familiarity with the subjects that I address here. This Declaration is divided into four parts: (1) Access to the Database Used by ARB Consultant David Rocke, (2) Proposed Modification 18 in the 15-Day Notice, (3) Differences between the December and June versions of CA-GREET and (4) Memoranda from ARB's External Scientific Reviewers.

A. Access to the Database Used by ARB Consultant David Rocke

4. ARB's LUC emission factor for corn starch ethanol in the revised LCFS regulation is 19.8 grams of carbon dioxide equivalent emissions per megajoule of energy ("g/MJ"). That is 12.2 g/MJ lower than the 30 g/MJ used in the current LCFS rule. The CARB staff has declined to consider and to propose a different and lower LUC emission factor for corn starch ethanol, in reliance on an analysis of crop price-yield values by David Rocke, an ARB consultant. ARB used Dr. Rocke's work for ARB in selecting price-yield values in its analysis of LUC values for all ethanol feedstocks; that analysis was in turn used in the proposed new LCFS regulation that is now under consideration by the Board. As soon as it learned of the project assigned to Dr. Rocke by

LCFS FF45-41

ARB, in the fall of 2014, AIR requested the data used by Dr. Rocke. As explained below, although ARB staff agreed to provide to the public the data used by Dr. Rocke, but the data were never provided by ARB to me or other members of the public; the lack of timely access to that data has prevented effective public participation in the current LCFS rulemaking. LCFS FF45-41 cont.

5. The ARB analysis applied in the proposed regulation in reliance on the data used by Dr. Rocke and on Dr. Rocke's analysis employs five price-yield values: 0.05, 0.10, 0.175, 0.25, and 0.35. The average of these 5 values is 0.19. Those values are used in ARB's version of the GTAP model, originally developed at Purdue University. The Purdue recommended value is 0.25. CARB's Expert Working Group for the LCFS regulation also recommended 0.25. ARB sponsored research indicated that there was little or no price-yield response (i.e., 0.0). AIR recommended that ARB should drop the lower price yield values (0.05 and 0.10) because the research supporting these lower values was developed over the very short term (1-3 years of price and yield data), and the GTAP model is a longer-term model (5-10 years). [1] ARB utilizes an 11.59 billion gallon per year shock of corn ethanol in its corn ethanol modeling, clearly illustrating that ARB is exercising the model with a medium-term shock, and not a short-term shock. Thus, ARB's use of short term price yield responses with the medium or longer term GTAP model is clearly inconsistent. LCFS FF45-42

6. In the Initial Statement of Reasons ("ISOR") for the new LCFS regulation, ARB references a recent analysis by Dr. Rocke in support of using lower price-yield responses. [2] The Rocke analysis utilized one set of data from a 2012 dissertation by Juan Francisco Rosas Perez. [3] That dissertation indicated that the price-yield response was in the region of 0.29, very close to the Purdue default value. Dr. Rocke obtained the data from the dissertation, conducted his own statistical analysis, and concluded that the data did not support the 0.29 price yield value. LCFS FF45-43

7. Because of the differences between these two analyses (Perez and Rocke), which stakeholders clearly must understand fully, AIR requested from ARB staff the data that Dr. Rocke used for his analysis. While staff said they were trying to get the data for AIR, the data was never supplied by staff. Therefore, AIR was unable to replicate Dr. Rocke's analysis of the Perez data. There is insufficient information in Dr. Rocke's available written work to reject the Perez analysis. (Dr. Rocke's rebuttal is only three pages in length.). In addition, this is only one of two sources (according to Rocke) that were used to support the 0.25 price-yield value, Rocke did not attempt to critique the other source. Thus, because ARB never supplied Rocke's database, AIR was not able to replicate Rocke's sketchy analysis, and Rocke only critiqued one source. To my knowledge no other person or organization has been able further to understand or replicate this portion of the analysis used in the current regulatory proposal. Based on the standards for transparency and public participation that I have observed in other regulatory proceedings, ARB should not rely on the Rocke analysis for its use of low price-yield values, and should therefore eliminate the lowest two values (0.05 and 0.10). The impacts of eliminating the lowest two price-yield values on corn LCFS FF45-44

---

[1] "Discussion of the Yield Price Elasticity of GTAP", Taheripour and Tyner, Purdue University, April 2014. (See Attachment B.)

[2] "Statistical issues Related to the Low-Carbon Fuel Standard", October 31, 2014. (See Attachment C.)

[3] "Essays on the Environmental Effects of Agricultural Production", Dissertation, Perez, Juan Francisco Rosas, Iowa State University. (Copyright material, not included in public filing.)

ethanol LUC emissions are shown in Table 1 below. Without both 0.05 and 0.10, the LUC value is 15.53 gCO2e/MJ instead of 19.84. CARB's choice of the higher emissions factor creates an inefficient bias against the use of corn starch ethanol, by overstating the LUC emissions attributed to the use of corn starch ethanol. LCFS FF45-44 cont.

Table 1. Impact of the Low Price-Yield Values		
Average of ARB Scenarios	Average price-yield	LUC (gCO2e/MJ)
All (ARB value)	0.19	19.84
w/o 0.05, 0.1 price-yield	0.26	15.53

B. Proposed Modification 18 in the 15-Day Notice

8. Proposed Modification 18 in the June 4, 2015, 15-day notice discusses recertification of the approximately 270 existing fuel pathways. Staff is proposing a system for prioritizing that work and eliminating potentially unrealistic deadlines in various parts of the existing proposal. Staff proposes to review and approve fuel pathway applications in batches based on fuel type, so that providers of the same fuel compete on equal terms, obtaining the new carbon intensity score at the same time. The proposed prioritization of fuel types would be: ethanol, followed by biodiesel, renewable diesel, compressed natural gas, liquefied natural gas, and finally all others. This prioritization makes sense, but the record submitting requirements of the recertification process are unnecessary burdensome for ethanol plants. LCFS FF45-45

9. The relevant sections of the recordkeeping requirements for recertification in the proposed regulation order are shown below. Plants are to submit

> *Invoices and receipts for all forms of energy consumed in the fuel production process, all fuel sales, all feedstock purchases, and all co-products sold. Invoices shall be submitted in electronic form. Each set of invoices shall be accompanied by a spreadsheet summarizing the invoices. Every invoice submitted shall appear as a record in the summary. Each record shall, at a minimum, specify in a separate column the period covered by the purchase, the quantity of energy purchased during that period, the invoice amount, and any special information that applies to that record (the special information column need not be populated for every record). For each form of energy consumed, the two-year total and average consumption shall be reported in the spreadsheet. These two-year totals and averages shall be used to calculate the per-million-Btu and per-megajoule energy consumption inputs used to calculate the life cycle CI of the fuel pathway.* LCFS FF45-46
>
> *a. Period Covered. The period covered shall be the most recent two-year period of relatively typical operation.*
>
> *b. Production Processes Covered. The invoices submitted under this provision shall cover the energy consumed in all unit operations devoted to feedstock handling and pre-processing; fuel production; co-product handling and processing; waste handling, processing, and treatment; the handling, processing and use of chemicals, enzymes, and organisms; the generation of process energy, including the generation, handling and*

processing of combustion fuels; and all plant monitoring and control systems. If the fuel produced or any by-products or co-products receive additional processing after they leave site, such as additional distiller's grains drying or fuel distillation, invoices covering the energy consumed for those processes must also be submitted. If the fuel production facility is co-located with one or more unrelated facilities, and energy consumption invoices are not separately available for the fuel production process, the applicant shall obtain a third-party energy audit sufficient to establish the long-term, typical energy consumption patterns of the fuel production facility.

3. In lieu of receipts or invoices for fuel sales, feedstock purchases, or co-product sales, the applicant may seek Executive Officer approval to submit audit reports prepared by independent, third-party auditors that document fuel sales, feedstock purchases, or co-product sales.

LCFS FF45-46 cont.

Ethanol production plants can have dozens of invoices for feedstock every week from many different suppliers. It would not be unusual for plants to have 3000-5000 invoices, DDG sales receipts, ethanol sales receipts, and other information requested by CARB. All of this information would require not only scanning but also significant redacting of key information to protect business relationships. I believe this is unnecessarily burdensome, nor do I believe CARB staff will be able to adequately review all of this information for 270 biofuel plants in the time required. Therefore, I request staff to revise these requirements. I recommend that the requirements be revised to require only summary information of key plant inputs and outputs (feedstock used, natural gas and electricity used, ethanol produced, DDG produced, etc.) on a monthly basis. This would be far more manageable by plants, and would not need as much redacting. The information could be verified by staff through on-site auditing if necessary.

I note that ARB allows applicants to seek Executive Officer approval to submit audit reports prepared by independent, third-party auditors that document fuel sales, feedstock purchases, or co-product sales. I recommend that ARB allow 3rd party audits to be performed using generally accepted auditing standards which would allow for a sampling approach, and would not need to involve every transaction unless there was a significant deficiency in the sampled data.

C. Differences between the December and June versions of CA-GREET

10. The June version of the CA-GREET model differs from the version of the CA-GREET model provide with the ISOR. CA-GREET includes a feature for selecting the presence of, and percentage of, mechanized harvesting of sugarcane. Users may select whether mechanized harvesting is used, and if so, in what percentage of feedstock used by a cane ethanol plant. In both the December (ISOR) and June versions of CA-GREET, when mechanized harvesting is selected, the model reduces emissions from cane straw burning. If 100% mechanized harvesting is selected, the model eliminates emissions from straw burning. Of course, a producer claiming that credit, referred to in the model as the "mechanized harvesting credit," must attest to and demonstrate the use of mechanized harvesting

LCFS FF45-47

11. Unlike the December version of CA-GREET, the new, June versions of CA-GREET awards a producer a mechanized harvesting credit even if a user does not specify, and is not thereby

LCFS FF45-48

requited to attest to, mechanized harvesting. Thus, even if a producer's percent of mechanized harvesting is 0%, the newly proposed regulation still awards a mechanized harvesting credit of 100%. Whether by design or error, a Brazilian sugarcane ethanol plant that had no mechanized harvesting would be assumed to have the same emissions as a plant with 100% mechanized harvesting. LCFS FF45-48 cont.

D. Memoranda from ARB's external scientific reviewers.

12. In one of the memoranda attached to a May 2015 letter concerning the work of various external scientific reviewers retained by CARB, Dr. Clarens states as follows:

> *As written, the report states that the source must be directly consumed in the production process. But this is ambiguous in certain contexts such as those fuels that produce co-products. For example, if a corn feedstock were used to make ethanol and the stover were also used to make fuel (but was not consumed in the same production process) would that not trigger a switch from Tier 1 to Tier 2? It seems like it should but as written it might not. Clarifying this language is key for groups seeking to obtain co-product credit through the CA-LCFS.*

Despite my familiarity with the models to which Dr. Clarens is apparently referring, I am unable to determine whether Dr. Clarens believes stover is a coproduct of the corn feedstock or is a separate feedstock. Stover is not a coproduct of corn ethanol, clearly it is not. To the extent that Dr. Clarens recognizes that stover is a feedstock, I am unable to understand why or how he relates that fact to the impact of coproducts in relation to "trigger[ing] a switch from Tier 1 to Tier 2." In addition, I am unable to understand the point of confusion that Dr. Clarens perceives that would important to clarify for producers whose pathways include coproduct credits, even though I prepare pathway applications for some of those producers and am familiar with the newly proposed changes for registration and certification of ethanol pathways. I also note that Dr. Clarens appears not to know the LUC emissions factor that has been proposed for corn starch ethanol: he believes it to be 30 g/MJ, based on his memorandum. In my opinion, Dr. Clarens's memorandum demonstrates insufficient knowledge of the scientific portions of the proposed regulation to be given credibility in the scientific community as a reviewer of the LUC and CA-GREET portions of the proposed rule. LCFS FF45-49

13. In the memorandum from Dr. Matthews that is attached to the May 5 letter, Dr. Matthews comments on the potential interaction between GHG emissions and emissions of volatile organic compounds and carbon monoxide. Those who work in the fields of GHG regulation and of criteria or related pollutant regulation consider such potential interactions to be minor, compared with the limitations on the effectiveness of GHG emissions regulations that do not address net emissions impact, or "leakage." The phenomenon of "fuel shuffling" -- in whch fuels that are not sold for use in California are still produced for sale elsewhere, regardless of the LCFS regulation -- is well recognized, but is not discussed in Dr. Matthews' memorandum. LCFS FF45-50

14. In the draft memorandum from Dr. McCarl attached to the May 5 letter, Dr. McCarl states as follows: LCFS FF45-51

In GTAP I believe that there also are increases in emissions from intensification (more irrigation or fertilization) so that the characterization of it only in terms of indirect land use change is not accurate.

Dr. McCarl's belief about the contents of GTAP is not correct. There are no increases in emissions in GTAP attributed to intensification. Fertilization rates, for example are addressed in CA-GREET and not in GTAP, for purposes of ARB's lifecycle emissions analysis and standard-setting. I believe this error in Dr. McCarl's memorandum would be identified by anyone familiar with the relevant portions of the scientific basis of the proposed regulation. Although I believe Dr. McCarl to possess expertise in LUC modeling, the draft memorandum attributed to him does not demonstrate a level of familiarity with the scientific portions of the LCFS regulation on which he appears to be opining that can be considered to give the draft memorandum's opinion on those portions of the regulation credibility in the scientific community.

LCFS FF45-51 cont.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 18th day of June, 2015 in Holland, Michigan.

Thomas L. Darlington

Thomas L. Darlington

Attachment A

Thomas L. Darlington
President, Air Improvement Resource Inc.

Profile

Thomas L. Darlington is President of Air Improvement Resource, a company formed in 1994 specializing in mobile source emission modeling. He is an internationally recognized expert in mobile source emissions modeling, lifecycle analysis, and land use modeling.

Professional Experience

1994-Present	President, Air Improvement Resource
1993-1994	Director, Mobile Source Programs, Systems Application International
1989-1994	Senior Engineer, General Motors Corporation, Environmental Activities
1988-1989	Senior Project Engineer, Detroit Diesel Corporation
1979-1988	Project Manager, U.S. EPA, Ann Arbor, Michigan

Recent Major Projects

- Developed Life Cycle reports and complete applications for 8 plants for the California Low Carbon Fuel Standard; six are currently registered, two plants are pending. Five plants were corn ethanol plants, one is sorghum and two are cellulose.
- Participated in and provided written comments on ARB's three 2014 iLUC workshops
- With Purdue and Don O'Connor, conducted study of iLUC emissions of rapeseed and other oilseeds in 2013 utilizing an updated version of GTAP
- Reviewed EPA's palm oil iLUC emissions in 2013
- Submitted comments on ARB's new GREET2.0 model
- Reviewed CARB's land use emissions for soybean biodiesel
- Reviewed the land use impacts of the RFS2 from EPA, including the notice of Proposed Rule, Regulatory Impact Analysis, and approximately one hundred documents in the rulemaking docket.
- Completed a land use study for Renewable Fuels Association and reviewed California Air Resource Board's Initial Statement of Reasons for the Low Carbon Fuel Standard
- Represented three stakeholders in the recent development of the ARB Predictive Model for reformulated gasoline in California (Alliance of Automobile Manufacturers, Renewable Fuels Association and Western States Petroleum Association)
- Represented two stakeholders in EPA's development of the MOVES on-highway emissions model (Alliance of Automobile Manufacturers and Engine Manufacturers Association)

Attachment "A"

- Developed the effects of ethanol permeation on on-highway and off-highway mobile sources in California and other states for the American Petroleum Institute
- Studied gasoline and diesel fuel options for Southeast Michigan (for SEMCOG, API and Alliance of Automobile Manufacturers)

Recent Publications

"Study of Transportation Fuel Life Cycle Analysis: Review of Economic Models Use to Assess Land Use Effects", CRC-E-88-3, July 2014.

"Land Use Change Greenhouse Gas Emissions of European Biofuel Policies Utilizing the Global Trade Analysis Project Model", Darlington, Kahlbaum, O'Connor, and Mueller, August 30, 2013.

"A Comparison of Corn Ethanol Lifecycle Analyses: California Low Carbon Fuels Standard (LCFS) Versus Renewable Fuels Standard (RFS2)", June 14, 2010. Renewable Fuels Association and Nebraska Corn Board. This study compared and contrasted the corn ethanol lifecycle analyses performed by both CARB (as a part of the LCFS) and the EPA (as a part of RFS2).

"Review of EPA's RFS2 Lifecycle Emissions Analysis for Corn Ethanol", September 25, 2009. Conducted for Renewable Fuels Association. This study reviewed EPA's land use GHG emissions assessment for corn ethanol, including the FASOM and FAPRI models and Winrock land-use types converted and emission factors by ecosystem type. The study made many recommendations for improving the land-use and emissions modeling.

"Review of CARB's Low Carbon Fuel Standard Proposal", April 15, 2009. Conducted for Renewable Fuels Association. This study reviewed CARB's analysis of land use emissions using GTAP6 and CARB's overall lifecycle emissions for corn ethanol. This study made many recommendations for improving the land use and lifecycle emissions of corn ethanol.

"Emission Benefits of a National Clean Gasoline", August 2008. Conducted for the Alliance of Automobile Manufacturers. This study evaluated the nationwide criteria pollutant emission reductions of a national clean gasoline standard.

"Land Use Effects of Corn-Based Ethanol", February 25, 2009. Conducted for Renewable Fuels Association. This study evaluates possible land use changes and GHG emissions associated with these land use changes as a result of the renewable fuel standard mandated 15 billion gallons of corn ethanol required by calendar year 2015. The study utilized projections of land use in the US and rest of world performed by Informa Economics, LLC, as well as newer estimates of the land use credits of co-products produced by ethanol plants to evaluate possible land use changes.

"On-Road NOx Emission Rates From 1994-2003 Heavy-Duty Trucks", SAE2008-01-1299, conducted for the Engine Manufacturers Association. This study examined

manufacturers consent decree emissions data to determine on-road NOx emission rates, and deterioration in emissions from heavy-duty vehicles. (Peer reviewed publication)

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act - Part 2: CO2 and GHG Impacts", SAE2008-01-1853, conducted for the Alliance of Automobile Manufacturers. This paper evaluated the comparison of greenhouse gases from cars and light trucks in the US under both the Federal and California GHG policies. (Peer reviewed publication)

"Effectiveness of the California Light Duty Vehicle Regulations as Compared to Federal Regulations", June 15, 2007. Conducted with NERA Economic Consulting and Sierra Research for The Alliance of Automobile Manufacturers. This study compares the emission benefits of the California and Federal light duty vehicle regulations for HC, CO, NOx, PM, SOx, and Toxics taking into account the difference in emission standards, new vehicle costs and its effect on fleet turnover, new vehicle fuel economy and its effect on vehicle miles traveled, and other factors. Both the EPA MOBILE6 and ARB EMFAC on-road emissions models were used to estimate changes in emissions inventories.

"The Case for a Dual Tech 4 Model Within the California Predictive Model", May 20, 2007. Conducted with ICF International and Transportation Fuels Consulting for the Renewable Fuels Association (RFA). This study developed separate emissions vs fuel property models for lower and higher Tech 4 (1986-1995) vehicles, and showed that utilizing this alternative Predictive Model would result in a higher compliance margin for fuels containing higher volumes of ethanol. It was thought that this could lead to higher ethanol concentrations in the state, but even if the dual model is not used, it is a better representation of the 2015 inventory than the ARB single model.

"Updated Final Report, Effects of Gasoline Ethanol Blends on Permeation Emissions Contribution to VOC Inventory From On-Road and Off-Road Sources, Inclusion of E-65 Phase 3 Data and Other Updates", June 20, 2007. Conducted for the American Petroleum Institute. This report updates the earlier March 3, 2005 report for API utilizing data collected by CRC and others since of the time of the earlier report.

Final Report, Development of Technical Information for a Regional Fuels Strategy, February 28, 2006. Conducted for the Lake Air Directors Consortium (LADCO). This report provided guidance to the LADCO states (Midwestern states) concerning how to model different types of fuel control programs (in particular) using EPA mobile source models, and how to set up the baseline input files so that results are consistent between the different states.

"Emission Reductions from Changes to Gasoline and Diesel Specifications and Diesel Engine Retrofits in the Southeast Michigan Area", February 23, 2005. Conducted for the Southeast Michigan Council of Governments (SEMCOG), the Alliance of Automobile Manufacturers, and the American Petroleum Institute. This study examined the on-road and off-road emission benefits of many different possible gasoline and diesel fuel

specifications that the state could adopt to help meet the 8-hour ozone standards. This study formed the basis for the state's move to lower RVP summer gasoline.

"Examination of Temperature and RVP Effects on CO Emissions in EPA's Certification Database, Final Report", CRC Project No. E-74a, April 11, 2005. Conducted for the Coordinating Research Council. This study compared CO vs temperature results from the MOBILE6 model to the certification data, and recommended further testing, which is being conducted by the CRC at this time.

"Effects of Gasoline Ethanol Blends on Permeation Emissions Contribution to VOC Inventory From On-Road and Off-Road Sources" March 3, 2005. Conducted for the American Petroleum Institute (API). Using data from the CRC-E-65 program, and data collected by the California EPA and Federal EPA, this study estimated the impacts of ethanol use on increasing permeation VOC emissions from on-road vehicles, off-road equipment and vehicles, and from portable containers. Emission inventory estimates were made for a number of geographical areas including the state of California, and results showed that the permeation effect increases anthropogenic VOC inventories by 2-4%.

Review of EPA Report "A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions", February 11, 2003. Conducted for the American Petroleum Institute. This study critically examined the methods that EPA used to develop the impacts of biodiesel fuels on HC, CO, NOx, and PM emissions.

"Well-To Wheels Analysis of Advanced Fuel/Vehicle Systems – A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions", May 2005. Conducted for General Motors Corporation, with Argonne National Labs. This study examined many different well to wheels pathways for various fuels, and their impacts on GHG and criteria pollutant emissions.

"Potential Delaware Air Emission Impacts of Switching From MTBE to Ethanol in the Reformulated Gasoline Program", May 26, 2005. Conducted for Lyondell Chemical Company. This study examined the HC, CO, and NOx impacts of switching from MTBE to ethanol.

"Potential Massachusetts Air Emission Impacts of Switching From MTBE to Ethanol in the Reformulated Gasoline Program" June 17, 2005. Conducted for Lyondell Chemical Company. This study is similar to the Delaware study above.

"Potential Maryland Air Emission Impacts of a Ban on MTBE in the Reformulated Gasoline Program", October 18, 2005. Conducted for Lyondell Chemical Company. This study is similar to the Delaware study above.

"MOBILE6.2C with Ethanol Permeation and Ethanol NOx Effects", February 8, 2005. Conducted for Health Canada. This study modified the MOBILE6.2C model for ethanol permeation VOC and ethanol NOx effects.

Education

B. Sc., (Materials and Metallurgical Engineering), University of Michigan, Ann Arbor, 1979
Post Graduate Courses (Business Administration), University of Michigan, Ann Arbor, 1982

Attachment B

Discussion of the Yield Price Elasticity in GTAP

Farzad Taheripour and Wallace E. Tyner
Purdue University

At the March 11, 2014 CARB meeting, there was considerable interest in the yield to price elasticity parameter in GTAP. There also seemed to be a good bit of confusion on what it does and does not do. The purpose of this note is to provide an explanation of the role of this parameter in GTAP, explain why it is there, and to explain other reasons why yields can change in GTAP.

First, the basic idea behind the parameter is that over the medium to long term (the time horizon of GTAP), one would expect the agricultural sector to respond to increases in net returns to crops with appropriate investments in improving yields of crops with growing returns. This investment is certainly not limited to on-farm investment. In fact, a major portion of it may occur off-farm. It could include investments by seed companies to produce higher yielding seeds, investments in chemical companies to produce better herbicides/pesticides, investments by farm equipment companies to produce more efficient machinery for cultivation and harvest, investments by farmers to improve drainage and other soil properties, and other productivity enhancing investments. In other words, this parameter attempts to capture responses throughout the agricultural sector to higher returns in given crops.

The yield to price elasticity does not measure changes over one crop year. In fact, any estimate done over one year would be totally inappropriate for GTAP and should be excluded from consideration in determining appropriate values for the parameter.

What is the precise definition of the yield to price elasticity (YDEL)? YDEL is the percentage change in intensive yield over the percentage changes in relative price of a crop over input prices. In other words it is the intensive yield change with respect to change in variable returns to a crop. If the YDEL value is 0.25, and the change in variable returns of a crop is 10%, then the change in intensive yield would be 2.5%. It is very important to emphasize that the parameter YDEL only governs changes in intensive yield due the changes in net return. Other factors can affect crop yields as well.

How else can yields change in GTAP? Yields are affected by changes on the intensive and extensive margins. As noted in Hertel et al. (2010), there are two important sources which affect the extensive margin of yields. The first source is due to shifting among crops. For example, shifting from corn-soybean rotation to corn-corn rotation could affect yield. The second source of change in extensive yield is due to land conversion from forest or pasture to cropland. In the first case, if there is a corn ethanol shock applied to the model, more corn will be demanded, and there likely will be both crop switching and land cover changes to accommodate the higher demand for corn. With crop switching, there will be more acres of corn and fewer acres of other lower yielding crops. Thus, when one calculates the weighted average yields after the shock, the average likely would be higher. For example, consider typical corn, soybean, and wheat yields of 4.5, 1.2, and 1.7 tons/ac respectively. If the post shock crop mix has more corn acreage, the post shock

Attachment "B"

weighted average yields can be higher even if YDEL were zero. That is simply because corn has a higher mass yield per acre.

Yields can also change when more or less productive acres come into corn from other uses. Crop switching can result in higher or lower productivity. However, land cover changes from pasture or forest typically tends to reduce yields because new land could be lower productivity. The productivity of converted land is affected by the ETA parameter.

Since GTAP is a CGE model, yields can also be influenced by a myriad of other changes such as changes in relative price of variable inputs. The bottom line is that while yields can be and are affected by many factors working in GTAP, the YDEL parameter is only designed to capture the incentive to invest over the medium term in crops with increasing returns.

It is not correct to divide the weighted average of percentage changes in crop yields by the weighted average of percent changes in crop prices as was done in the CARB presentation. This calculation incorporates area changes as well as yield changes. One must take into account percentage changes in variable costs of production as well. The calculated value from the CARB presentation of 0.39 for yield to price elasticity for US for the corn ethanol expansion is meaningless because it includes many factors. If we follow the CARB approach and calculate the same measure for Brazil due to the US corn ethanol shock, we get a yield to price elasticity of -0.16 for Brazil, which obviously does not make sense. Furthermore, CARB has ignored the fact that the yield to price ratio only cover the percentage change in intensive yield not total yield. In their calculations, percentage changes in total yield instead of intensive yield were used. LCFS FF45-52

Attachment C

Statistical Issues Related to the Low-Carbon Fuel Standard
Submitted by
David M. Rocke, PhD
October 31, 2014
Under contract 13-405 (2014)

Analysis of Simulations for ILUC

Two separate simulation methodologies were employed by CARB to help determine factors to which Indirect Land Use Change (iLUC) is sensitive. The iLUC impact of biofuels relates to the unintended increase of carbon emissions due to land-use changes around the world induced by the expansion of croplands for production of biofuels such as ethanol in response to the increased global demand for these fuels. If more biofuels are needed, in general the price of the feedstock would rise compared to other uses of the land. This in turn may result in forests or other uncropped land being converted to agricultural use. Because natural lands, such as rainforests and grasslands, store carbon in their soil and in biomass as plants grow each year, clearance of wilderness for new farms translates to a net increase in greenhouse gas emissions. Due to this change in the carbon stock of the soil and the biomass, indirect land use change has consequences in the greenhouse-gas emissions balance of a biofuel.

Both sets of simulations are based on the Global Trade Analysis Project (GTAP) database and the Agro-ecological Zone Emission Factor (AEZ-EF) Model. One method was to use varying specific values of some parameters as sensitivity analysis. For example, this could consist of YDEL, the price elasticity of yield, ETL1, the elasticity of transformation between forest, cropland, and pasture, ETL2, the elasticity of transformation among crops, PAEL_US, the yield elasticity for cropland/pasture in the US, and PAEL_Brazil, yield elasticity for cropland/pasture in Brazil. The other simulation method used the Monte Carlo methodology in which values for a large number of parameters were chosen at random repeatedly.

In order to determine the most influential factors, we conducted a statistical analysis of the iLUC factor for corn ethanol in terms of the input variables in a simulation with 600 variables and 3,000 trials. This was done using stepwise regression, but since all the parameters were chosen independently in the Monte Carlo (except CDGC and CDGS, which were highly correlated), the coefficient estimates were almost orthogonal, so the results of a single analysis of the 600 variable model would have been very similar, except for CDGC and CDGS. Table 1 gives the results of this analysis. The most influential factors in terms of contribution to the sum of squares were YDEL, the price elasticity of yield, the ESBV parameters, the elasticity of substitution between primary input factors in production, ETA, the elasticity of effective hectares with respect to harvested area, and ETL1, the elasticity of transformation among crops.

Table 1. Statistical Analysis of Corn Ethanol ILUC Factor in a Monte Carlo Simulation

Response: ilucFactor

	Df	Sum Sq	Mean Sq	F value	Pr(>F)	
ESBV.11.0.	1	68324	68324	4989.7281	< 2.2e-16	***
YDEL	1	65612	65612	4791.7008	< 2.2e-16	***
ETA	1	37960	37960	2772.2342	< 2.2e-16	***
ESBV.13.0.	1	17097	17097	1248.6237	< 2.2e-16	***
ETL1	1	13970	13970	1020.2320	< 2.2e-16	***
CDGC	1	13886	13886	1014.0667	< 2.2e-16	***
croplandPastureEmissionRatio	1	7214	7214	526.8437	< 2.2e-16	***
ESBV.12.0.	1	4978	4978	363.5544	< 2.2e-16	***
N2O_N_EF	1	2975	2975	217.2690	< 2.2e-16	***
PAEL.3.0.	1	2268	2268	165.6035	< 2.2e-16	***
pastureSoil_C.0.1.	1	2089	2089	152.5737	< 2.2e-16	***
croplandSoil_C	1	2034	2034	148.5450	< 2.2e-16	***
youngStandAglb	1	1471	1471	107.4001	< 2.2e-16	***
SUBP.0.18.	1	1356	1356	98.9945	< 2.2e-16	***
EFED	1	946	946	69.0674	< 2.2e-16	***
SUBP.0.1.	1	874	874	63.8461	1.934e-15	***
totalTree_C.0.4.	1	890	890	64.9935	1.094e-15	***
croplandLandUseFactor.5.0.	1	752	752	54.9003	1.661e-13	***
PAEL.1.0.	1	694	694	50.7027	1.354e-12	***
SUBP.0.2.	1	644	644	47.0584	8.416e-12	***
totalTree_C.0.1.	1	627	627	45.8145	1.572e-11	***
carbonNitrogenRatio	1	639	639	46.6822	1.016e-11	***
SUBP.0.3.	1	562	562	41.0261	1.751e-10	***
deadwoodByLatitude_C.3.1.	1	525	525	38.3264	6.844e-10	***
croplandLandUseFactor.10.0.	1	488	488	35.6556	2.646e-09	***
deadwoodByRegion_C.4.1.	1	515	515	37.5940	9.912e-10	***
deadwoodByRegion_C.1.1.	1	473	473	34.5168	4.715e-09	***
totalTree_C.0.2.	1	385	385	28.1390	1.215e-07	***
forestSoil_C.0.18.	1	383	383	27.9501	1.339e-07	***
forestSoil_C.0.4.	1	367	367	26.8051	2.407e-07	***
oldStandAglb	1	313	313	22.8335	1.856e-06	***
pastureSubsoilLossFraction	1	323	323	23.5576	1.277e-06	***
totalTree_C.0.18.	1	253	253	18.4775	1.777e-05	***
croplandLandUseFactor.6.0.	1	246	246	17.9905	2.291e-05	***
forestLitter_C.10.1.	1	218	218	15.9474	6.677e-05	***
pastureAgb.6.0.	1	211	211	15.4370	8.732e-05	***
understory_C	1	202	202	14.7871	0.0001230	***
GWP_N2O	1	177	177	12.9423	0.0003267	***
pastureSoil_C.0.19.	1	175	175	12.8020	0.0003520	***
ETL2	1	171	171	12.4815	0.0004175	***
EPSR	1	170	170	12.3870	0.0004391	***
foregoneGrowthRate	1	152	152	11.1033	0.0008727	***
croplandLandUseFactor.4.0.	1	149	149	10.8470	0.0010016	**
ESBM.4.0.	1	143	143	10.4288	0.0012547	**
ESBM.2.0.	1	124	124	9.0317	0.0026764	**
ESBV.25.0.	1	119	119	8.7089	0.0031924	**
pastureSoil_C.0.12.	1	115	115	8.4070	0.0037663	**
pastureSoil_C.0.3.	1	117	117	8.5596	0.0034642	**
ESBV.30.0.	1	105	105	7.6970	0.0055672	**
forestLitter_C.15.1.	1	108	108	7.8711	0.0050571	**
ELEN.9.0.	1	102	102	7.4502	0.0063818	**

ELEN.26.0.	1	103	103	7.5010	0.0062047	**
cropCarbonAnnualizationFactor	1	87	87	6.3746	0.0116303	*
ELEG.19.0.	1	88	88	6.4184	0.0113473	*
pastureSubsoil_C.0.1.	1	86	86	6.2890	0.0122040	*
forestLitter_C.13.1.	1	86	86	6.2485	0.0124856	*
ELNC.16.0.	1	83	83	6.0512	0.0139554	*
ESBM.46.0.	1	76	76	5.5190	0.0188785	*
forestLitter_C.9.1.	1	72	72	5.2607	0.0218848	*
SUBP.0.13.	1	76	76	5.5662	0.0183778	*
pastureSoil_C.0.8.	1	72	72	5.2931	0.0214824	*
ELEN.2.0.	1	71	71	5.1593	0.0231958	*
totalTree_C.0.6.	1	65	65	4.7814	0.0288496	*
ESBV.2.0.	1	68	68	4.9825	0.0256817	*
ELEG.3.0.	1	65	65	4.7447	0.0294704	*
ELKE.10.0.	1	68	68	4.9421	0.0262881	*
deforestedFraction.11.0.	1	64	64	4.6579	0.0309946	*
ELNE.7.0.	1	63	63	4.6191	0.0317009	*
croplandLandUseFactor.15.0.	1	64	64	4.6402	0.0313146	*
forestRootShootRatio	1	63	63	4.5786	0.0324578	*
deadwoodByRegion_C.18.1.	1	59	59	4.2837	0.0385692	*
deforestedFraction.8.0.	1	59	59	4.2987	0.0382306	*
ELKE.37.0.	1	57	57	4.1496	0.0417355	*
pastureSubsoil_C.0.3.	1	57	57	4.1742	0.0411345	*
ELEN.29.0.	1	57	57	4.1843	0.0408909	*
pastureSoil_C.0.18.	1	58	58	4.2081	0.0403236	*
deforestedFraction.13.0.	1	55	55	4.0201	0.0450553	*
hwpFraction.9.0.	1	52	52	3.7859	0.0517839	.
forestLandUseFactor.11.0.	1	52	52	3.7882	0.0517122	.
forestSoil_C.0.13.	1	52	52	3.7649	0.0524376	.
ELNE.22.0.	1	48	48	3.4933	0.0617215	.
totalTree_C.0.12.	1	51	51	3.7565	0.0527010	.
ESBM.41.0.	1	49	49	3.5807	0.0585568	.
ELHL	1	48	48	3.5264	0.0605018	.
croplandLandUseFactor.3.0.	1	47	47	3.4426	0.0636396	.
forestLitter_C.17.1.	1	46	46	3.3286	0.0681885	.
ELNC.13.0.	1	45	45	3.2580	0.0711825	.
ELNE.4.0.	1	43	43	3.1227	0.0773172	.
ESBV.1.0.	1	44	44	3.1827	0.0745296	.
ELNC.19.0.	1	43	43	3.1486	0.0760975	.
forestSoil_C.0.11.	1	42	42	3.0762	0.0795527	.
SUBP.0.4.	1	44	44	3.1855	0.0743993	.
ELEG.2.0.	1	42	42	3.0802	0.0793588	.
PAEL.11.0.	1	41	41	3.0253	0.0820827	.
ELNC.5.0.	1	41	41	2.9984	0.0834557	.
forestBurningEF	1	41	41	2.9782	0.0844994	.
ELKE.15.0.	1	42	42	3.0370	0.0814919	.
pastureSubsoil_C.0.8.	1	39	39	2.8725	0.0902161	.
ESBM.16.0.	1	39	39	2.8535	0.0912852	.
croplandLandUseFactor.1.0.	1	42	42	3.0817	0.0792853	.
ELKE.1.0.	1	39	39	2.8257	0.0928772	.
deforestedFraction.7.0.	1	37	37	2.7211	0.0991387	.
ELVL	1	37	37	2.7172	0.0993831	.
forestSubsoil_C.0.8.	1	39	39	2.8846	0.0895377	.
forestSubsoil_C.0.18.	1	37	37	2.7202	0.0991942	.
ELNE.24.0.	1	39	39	2.8418	0.0919521	.
ELEN.4.0.	1	40	40	2.9344	0.0868207	.
ELNE.6.0.	1	37	37	2.7386	0.0980619	.

```
forestSoilLossFraction           1    35     35   2.5360 0.1113837
forestLandUseFactor.3.0.         1    36     36   2.6196 0.1056590
ELEG.7.0.                        1    33     33   2.3757 0.1233479
ELKE.36.0.                       1    32     32   2.3144 0.1282875
ESBM.33.0.                       1    36     36   2.6437 0.1040686
ELNC.26.0.                       1    35     35   2.5444 0.1107993
ELEN.6.0.                        1    36     36   2.5966 0.1072009
ELNE.34.0.                       1    32     32   2.3068 0.1289195
PAEL.6.0.                        1    32     32   2.3672 0.1240167
ESBV.28.0.                       1    32     32   2.3410 0.1261183
pastureAgb.10.0.                 1    37     37   2.6804 0.1017002
ELNE.16.0.                       1    33     33   2.3810 0.1229333
forestSubsoil_C.0.14.            1    31     31   2.2673 0.1322385
pastureSoil_C.0.16.              1    33     33   2.3782 0.1231485
ELHB                             1    33     33   2.3743 0.1234546
ELNC.1.0.                        1    33     33   2.3922 0.1220537
ELKE.18.0.                       1    35     35   2.5512 0.1103183
ELNC.17.0.                       1    30     30   2.1732 0.1405476
ESBV.19.0.                       1    31     31   2.2578 0.1330512
ELEN.31.0.                       1    33     33   2.4252 0.1195113
pastureAgb.12.0.                 1    30     30   2.1670 0.1411076
ELKE.34.0.                       1    33     33   2.4155 0.1202515
ELNE.33.0.                       1    32     32   2.3370 0.1264439
ELNE.32.0.                       1    32     32   2.3271 0.1272524
ESBM.22.0.                       1    32     32   2.3090 0.1287354
ELKE.41.0.                       1    30     30   2.2042 0.1377488
SUBP.0.5.                        1    34     34   2.4534 0.1173836
ELNC.2.0.                        1    31     31   2.2766 0.1314507
ELNE.14.0.                       1    28     28   2.0659 0.1507380
ELEN.7.0.                        1    28     28   2.0718 0.1501589
forestSubsoil_C.0.11.            1    31     31   2.2497 0.1337495
ELNE.18.0.                       1    31     31   2.2353 0.1350028
ELNE.17.0.                       1    27     27   1.9797 0.1595262
ELNC.14.0.                       1    29     29   2.1052 0.1469068
deforestedFraction.1.0.          1    29     29   2.0978 0.1476215
ELEG.11.0.                       1    28     28   2.0785 0.1494954
ESBM.21.0.                       1    28     28   2.0808 0.1492744
Residuals                     2854 39080     14
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1
```

Price Elasticity of Yield (YDEL)

In view of the importance of YDEL in the analysis, and in view of the conflicting results in the literature on its likely size, the next part of the project undertaken was to analyze one of the data sets upon which these estimates have been based. The data were used in a 2012 dissertation of Juan Francisco Rosas Pérez (also given as Juan Francisco Rosas in a 2014 paper by Rosas, Hayes, and Lence, apparently taken from the dissertation). In these works, the price elasticity of yield was estimated from data on corn (maize) in Iowa for 1960–2004, and was said to be in the range of 0.29. The data set was publicly available so it was used for a re-analysis. The analysis used by Rosas Pérez, was complex, and can be criticized for insufficiently handling autocorrelation in the series. Therefore, a simpler analysis was conducted that should have similar results to the more complex analysis if the latter is not flawed.

The data set used was the one supplied with the Rosas Pérez dissertation, though there is no good data dictionary and the meaning of some of the statistics was less than clear. The most clearly relevant variables were a corn price index series (here called corn.price) and a corn supply index series (corn.supply) and their natural logarithms (lcorn.price and lcorn.supply). There do not seem to be good data on land devoted to corn, or perhaps land at all, since the variable Z4 = Q Land is equal to 1 for all years, so this analysis was aimed at the price elasticity of supply not the price elasticity of yield; this would tend to overestimate the effect of price on supply given that land substitution is often an easier response to greater potential profit from a crop than is attempting to increase yield.

The quantity of interest then would be the ratio of the percentage change in supply to the percentage change in price. Roughly, the percentage change is equal to the actual change on the natural log scale. For example (110 – 100)/100 = 0.10 while log(110) – log(100) = 0.0953, so we will proceed to relate the change on the log scale of supply to the change on the log scale of price.

Without participating in debates about the proper functional form of multi-equation models of the agricultural economy, we can go back to statistical basics using the following principles:

1. All other things being equal, the price elasticity of supply can be estimated by regressing log(supply) on log(price).
2. In regressions with autocorrelated time series, it is important to account for the self-effects of the series being predicted before asking if another series has an effect. This is sometimes called Granger causality analysis.

In fact, both series are autocorrelated in a plausibly autoregressive way, with the ACF function declining slowly and the PACF function dropping of more quickly (see Figures 1 and 2 for the supply series later in the document). As can be seen from the output in Table 2, there is no significant relationship of supply to current or past prices after accounting for last year's supply. In fact, the estimated coefficients are not even positive.

While there may exist alternative explanations of these results with respect to omitted factors, it is hard to find such modeling aspects that provide effects in the direction of reducing the apparent response of supply to price and that themselves could explain a large elasticity that is so hidden. The best interpretation of these results is that

1. The price elasticity of yield implied by the Iowa corn data is likely close to 0 and very unlikely to be as large as 0.10 or 0.20.
2. The results obtained by Rosas Pérez showing an apparently higher elasticity is likely caused by mishandling the autocorrelation in the time series.

As documented in Berry (2011), Berry and Schlenker (2011), and Roberts and Schlenker (2013), much of the literature providing purported estimates of the price elasticity of yield is deeply methodologically flawed. In addition to the problems of endogeneity and autocorrelation that are badly handled, there are other important issues. In Goodwin, Michele Marra, Piggott, and Mueller (2012), for example, 15 years of data are multiplied into 405 data points by considering 27 different districts. But there are still only 15 price values and it is hard to believe that the strong relationships of weather, price, and technology within a given year can be handled by econometric tricks. The analyses, such as those in Roberts and Schlenker (2013), that are methodologically sound all show small to zero price elasticities of yield.

Table 2. Regression Analysis for Price Elasticity of Supply for Iowa Corn

```
> anova(lm(lcorn.supply~lcorn.supply1+lcorn.price+lcorn.price1))

Analysis of Variance Table

Response: lcorn.supply
              Df  Sum Sq Mean Sq F value    Pr(>F)
lcorn.supply1  1 1.58085 1.58085 30.5328 2.191e-06 ***
lcorn.price    1 0.00558 0.00558  0.1078    0.7444
lcorn.price1   1 0.01618 0.01618  0.3125    0.5793
Residuals     40 2.07103 0.05178
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

> anova(lm(lcorn.supply~lcorn.supply1+lcorn.price+lcorn.price1
           +lcorn.price2))

Analysis of Variance Table

Response: lcorn.supply
              Df  Sum Sq Mean Sq F value    Pr(>F)
lcorn.supply1  1 1.39173 1.39173 26.6904 7.889e-06 ***
lcorn.price    1 0.00466 0.00466  0.0894    0.7666
```

```
lcorn.price1   1 0.01436 0.01436  0.2755    0.6027
lcorn.price2   1 0.07523 0.07523  1.4428    0.2371
Residuals     38 1.98145 0.05214
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

> summary(lm(lcorn.supply~lcorn.supply1+lcorn.price+lcorn.price1))

Call:
lm(formula = lcorn.supply ~ lcorn.supply1 + lcorn.price +
lcorn.price1)

Residuals:
     Min       1Q   Median       3Q      Max
-0.64342 -0.11119  0.01966  0.14210  0.52123

Coefficients:
              Estimate Std. Error t value Pr(>|t|)
(Intercept)    0.71117    0.24967   2.848  0.00691 **
lcorn.supply1  0.62929    0.13427   4.687 3.19e-05 ***
lcorn.price   -0.02265    0.23289  -0.097  0.92301
lcorn.price1  -0.12364    0.22116  -0.559  0.57925
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Residual standard error: 0.2275 on 40 degrees of freedom
  (1 observation deleted due to missingness)
Multiple R-squared:  0.4362,    Adjusted R-squared:  0.394
F-statistic: 10.32 on 3 and 40 DF,  p-value: 3.676e-05
```

Figure 1. Autocorrelation of Corn Supply in Iowa

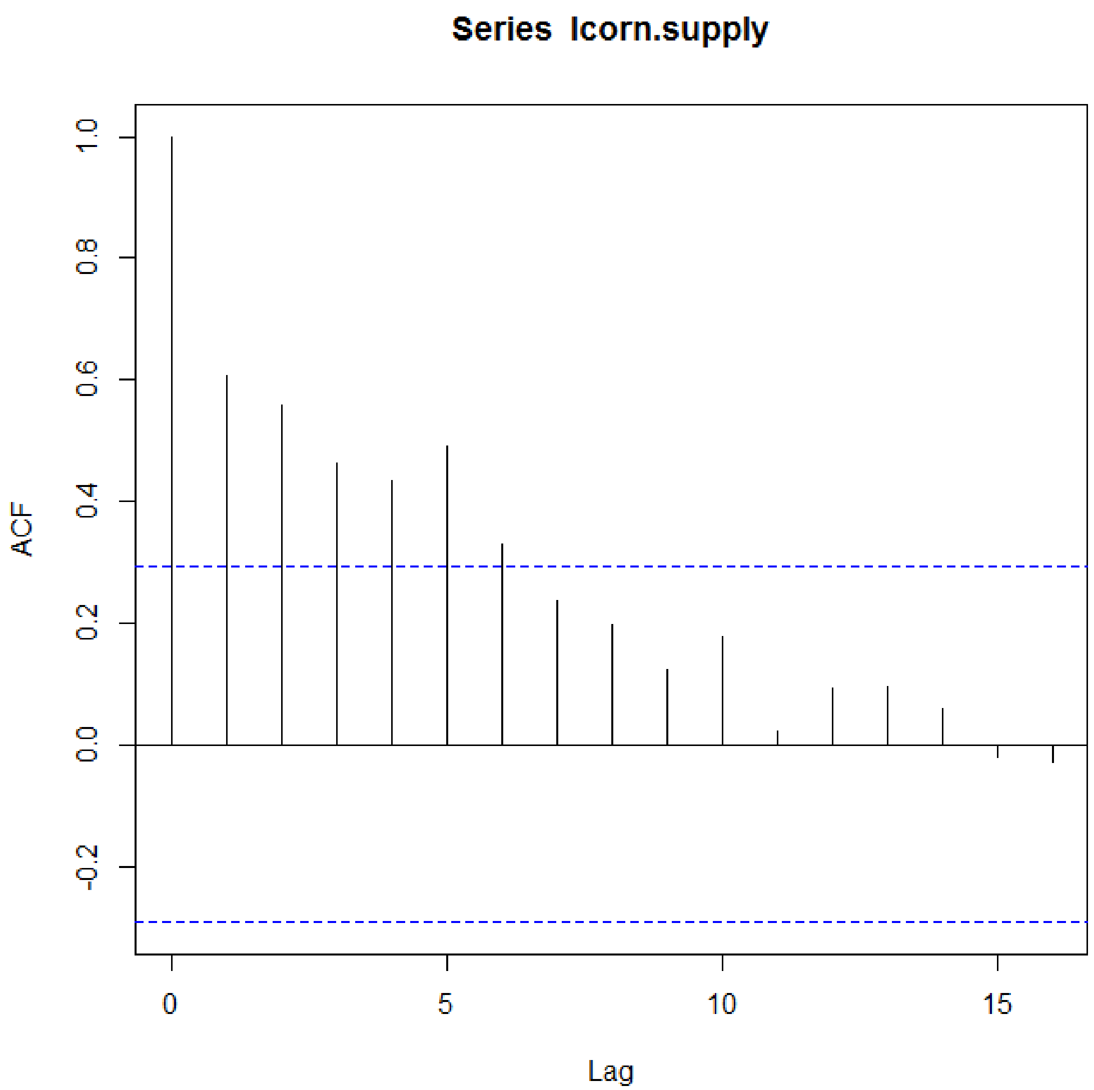
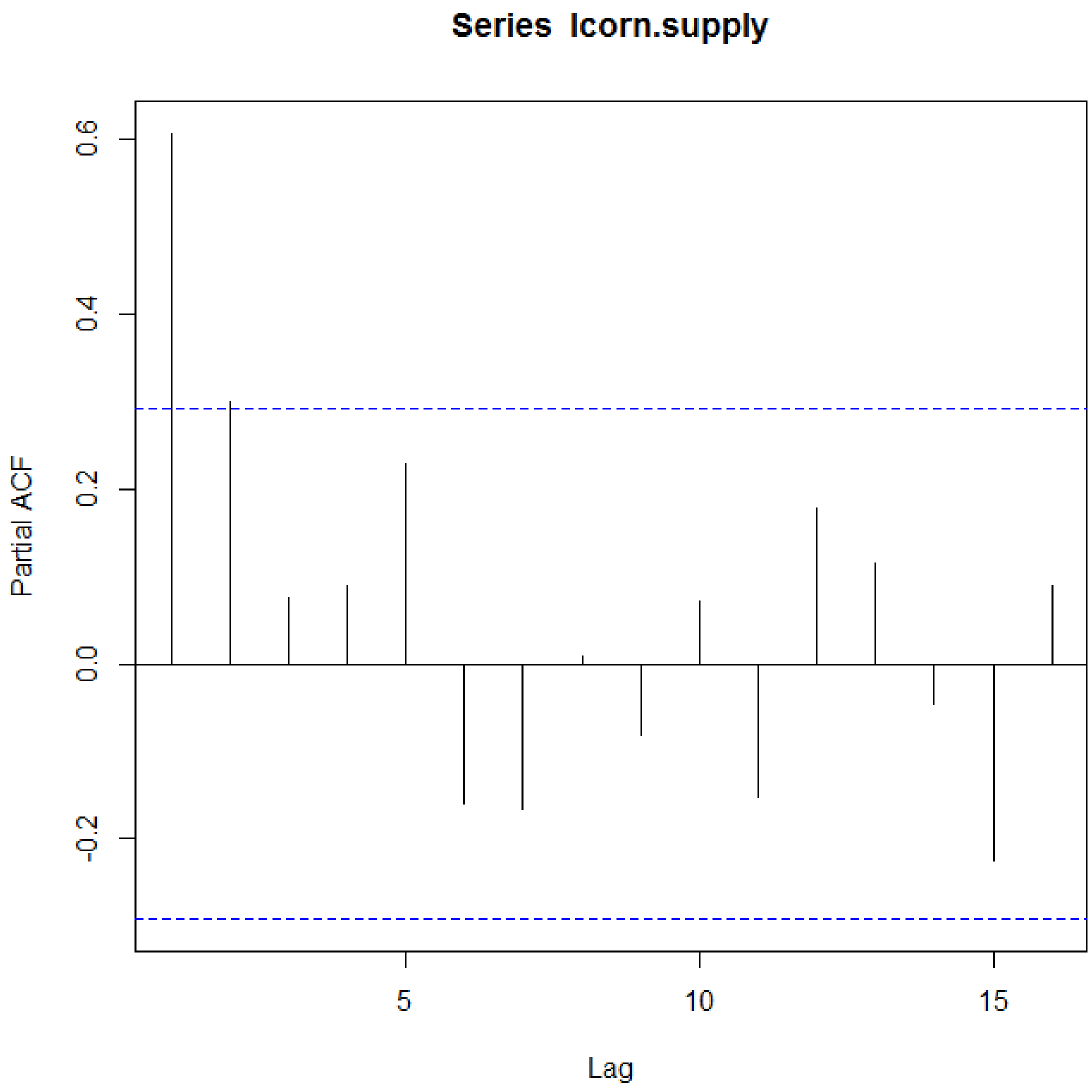


Figure 2. Partial Autocorrelation of Corn Supply in Iowa



Bibliography

Berry, Steven T. (2011) “Biofuels Policy and the Empirical Inputs to GTAP Models,” manuscript.

Berry, Steven and Wolfram Schlenker (2011) “Technical Report for the ICCT: Empirical Evidence on Crop Yield Elasticities,” manuscript.

Goodwin, Barry K., Michele Marra, Nicholas Piggott and Steen Mueller (2012) “Is Yield Endogenous to Price? An Empirical Evaluation of Inter- and Intra-Seasonal Corn Yield Response,” manuscript.

Pérez, Juan Francisco Rosas, (2012) *Essays on the Environmental Effects of Agricultural Production*, Diss. Iowa State University.

Roberts, Michael J. and Wolfram Schlenker (2013) “Identifying Supply and Demand Elasticities of Agricultural Commodities: Implications for the US Ethanol Mandate,” *American Economic Review*, 103, 2265–2295.

Rosas, Juan Francisco, Dermot J. Hayes, and Sergio H. Lence (2014) “Response of Crop Yields to Output Prices: A Bayesian Approach to Complement the Duality Theory Econometrics,” manuscript.

STATE OF CALIFORNIA

BEFORE THE AIR RESOURCES BOARD

Declaration of James M. Lyons

I, James Michael Lyons, declare as follows:

1. I make this Declaration based upon my own personal knowledge and my familiarity with the matters recited herein. It is based on my experience of nearly 30 years as a regulator, consultant, and professional in the field of emissions and air pollution control. A copy of my résumé can be found in Attachment A.

2. I am a Senior Partner of Sierra Research, Inc., an environmental consulting firm located at 1801 J Street, Sacramento, California owned by Trinity Consultants, Inc. Sierra specializes in research and regulatory matters pertaining to air pollution control, and does work for both governmental and private industry clients. I have been employed at Sierra Research since 1991. I received a B.S. degree in Chemistry from the University of California, Irvine, and a M.S. Degree in Chemical Engineering from the University of California, Los Angeles. Before joining Sierra in 1991, I was employed by the State of California at the Mobile Source Division of the California Air Resources Board (CARB).

3. During my career, I have worked on many projects related to the following areas: 1) the assessment of emissions from on- and non-road mobile sources, 2) assessment of the impacts of changes in fuel composition and alternative fuels on engine emissions including emissions of green-house gases, 3) analyses of the unintended consequences of regulatory actions, and 4) the feasibility of compliance with air quality regulations.

4. I have testified as an expert under state and federal court rules in cases involving CARB regulations for gasoline, Stage II vapor recovery systems and their design, factors affecting emissions from diesel vehicles, evaporative emission control system design and function, as well as combustion chamber system design. While at Sierra I have acted as a consultant on automobile air pollution control matters for CARB and for the United States Environmental Protection Agency. I am a member of the American Chemical Society and the Society of Automotive Engineers and have co-authored nine peer-reviewed monographs concerned with automotive emissions, including greenhouse gases and their control. In addition, over the course of my career, I have conducted peer-reviews of numerous papers related to a wide variety of issues associated with pollutant emissions and air quality.

5. This Declaration summarizes the results of my review of the CARB Notice of Public Availability of Modified Text and Availability of Additional Documents for the Proposed Re-Adoption of the Low Carbon Fuel Standard Regulation on the Commercialization of Alternative Diesel Fuels (the LCFS Regulation) dated June 4,

2015. I have performed this review as an independent expert for Growth Energy. If called upon to do so, I would testify in accord with the facts and opinions presented here.

6. Based on my review of the changes proposed to the LCFS regulation by CARB, the elimination of the multimedia evaluation provisions from the LCFS through the deletion of Section 95490 and related deletions in Sections 95481(a)(59) and 95488(c)(4)(G)6.d. creates the potential for significant adverse environmental impacts to occur as the result of the introduction of new lower carbon intensity fuels. I have participated in every aspect of the development of the LCFS regulation in which a member of the public was allowed by CARB to participate. This change to the proposed regulation could not reasonably have been anticipated, based on the notice of proposed rulemaking and the supporting materials made available in December 2014. LCFS FF45-53

7. The discussion of the need for the multimedia evaluation provisions that CARB staff is now proposing to delete is summarized in both the current Initial Statement of Reasons (ISOR) for re-adoption of the LCFS regulation as well as the ISOR prepared in 2009 for the original LCFS regulation. The language relevant to the multimedia evaluation provisions in both the current and 2009 ISOR is virtually identical. With respect to why the multimedia evaluation provisions were needed in the LCFS, both the ISOR for the re-adoption of the LCFS regulation[1] and the 2009 ISOR[2] state that:

> *The LCFS regulation incorporates this principle as a pre-sale prohibition applied to fuels that are subject to an ARB specification that is modified or adopted after adoption of the LCFS regulation. In such cases, regulated parties would be prohibited from selling the affected fuels in California to comply with the LCFS requirements until a multimedia evaluation is approved for those fuels pursuant to H&S §43830.8.*

LCFS FF45-54

Elimination of the multimedia evaluation provisions from the LCFS regulation as now proposed by CARB staff would permit fuel suppliers to sell new fuels in California in order to try to comply with the LCFS without ensuring that adverse environmental impacts associated with their use have been identified and properly mitigated. Such new fuels could include gasoline-butanol blends, alternative diesel fuels other than biodiesel and renewable diesel, and renewable natural gas fuels that fail to comply with CARB's existing natural gas fuel specifications. In addition, these potential impacts of the LCFS regulation were not considered in the Environmental Analysis prepared for the LCFS and ADF regulations.

8. There are several ways in which new fuels which could lead to adverse environmental impacts could be sold in California before the approval of a multimedia LCFS FF45-55

1. [1] Page III-64

[2] Page V-32

evaluation pursuant to H&S §43830.8. The first of these is if the California Division of Measurement Standards (CDMS) rather than CARB adopts fuel specifications allowing the use of the new fuel. In the past, new fuels have been allowed in California through specifications enacted by CDMS that have not been required to undergo multimedia evaluation pursuant to H&S §43830.8. Biodiesel is one such fuel that has created adverse environmental impacts. Based on CARB staff estimates, in 2014, biodiesel use for compliance with the LCFS regulation allowed by CARB[3] without an approved multimedia evaluation pursuant to H&S §43830.8 resulted in increased NOx emissions of 1.2 tons per day statewide.[4] Increased NOx emissions due to the use of biodiesel for purposes of LCFS compliance have occurred since the inception of the LCFS program as a result of CARB's failure to adopt fuel specifications and complete the multimedia evaluation required pursuant to H&S §43830.8 despite having committing to do so as early as 2009.[5] Elimination of the requirements for approval of a multimedia evaluation before allowing new fuels to be sold for purposes of LCFS approval would allow other new fuels to be sold in California that, like biodiesel, create adverse environmental impacts before those impacts have been identified through the multimedia evaluation process. These potential environmental impacts created by the LCFS as a result the elimination of the LCFS multimedia evaluation requirements were not considered in the Environmental Assessment.

LCFS FF45-55 cont.

9. That the increases in NOx emissions resulting from biodiesel use in California without an approved multimedia evaluation were significant can be seen through a comparison of the criteria used to assess air quality impacts in areas of California outside the South Coast and San Joaquin Air Basins and the increases in NOx emissions estimated to result from biodiesel use. Using the Sacramento Metropolitan Air Quality Management District as an example,[6] the significance threshold for NOx emissions projects subject to CEQA is 65 pounds per day or 0.0325 tons per day. The 0.0325 tons per day threshold can be compared to both the 1.2 ton per day increase in NOx emissions due to biodiesel use estimated by CARB staff for 2014 statewide. Clearly, elimination of the requirements for multimedia evaluation for new fuels sold for LCFS compliance could lead to similar, and therefore significant, unmitigated, increases in NOx emissions or significant and unmitigated increases in emissions of other pollutants.

LCFS FF45-56

10. Another way in which new fuels could create potential adverse environmental impacts if the multimedia evaluation requirements are deleted is through the

LCFS FF45-57

[3] See *http://www.arb.ca.gov/fuels/diesel/altdiesel/20111003biodiesel%20guidance.pdf*

[4] See Table 1 of *http://www.arb.ca.gov/regact/2015/adf2015/signedadfnotice.pdf*

[5] See page V-33 of *http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf*

[6] See *http://airquality.org/ceqa/ceqaguideupdate.shtml*

Developmental Engine Fuel Variance Program operated by CDMS.[7] Again, the multimedia evaluation requirements of H&S §43830.8 that apply to fuels for which CARB adopts specifications would not apply in this case and adverse environmental impacts can occur. Allowing new fuels that are part of this program to be sold for purposes of LCFS compliance without having an approved multimedia evaluation would increase the likelihood that fuel producers would seek to use this program and the likelihood that new fuel that leads to unmitigated adverse environmental impacts would be used in California. These potential environmental impacts that the LCFS regulation could create as a result of the proposed elimination of the multimedia evaluation requirements were not considered in the Environmental Assessment. LCFS FF45-57 cont.

11. In addition, the Alternative Diesel Fuel regulation proposed by CARB staff creates another way by which new fuels with potential adverse environmental impacts could be sold in California for purposes of LCFS compliance should the multimedia evaluation requirements be eliminated. Currently, fuels involved in Stage 1 or Stage 2 of the LCFS regulation are not required to have completed a multimedia evaluation and therefore could not be sold for purposes of LCFS compliance until they reach Stage 3, at which point completion of a multimedia evaluation and adoption of fuel specifications by CARB are required. Elimination of the current multimedia evaluation requirements from the LCFS regulation as now proposed by CARB staff, would allow fuels in Stage 1 and Stage 2 to be sold for purposes of LCFS compliance before the potential adverse environmental consequences have been assessed or mitigated. Again, these potential environmental impacts due to the LCFS were not considered in the Environmental Assessment. LCFS FF45-58

12. In summary, retention of the current LCFS requirements that new fuels have received an approved multimedia evaluation pursuant to H&S §43830.8 before being allowed to be sold for purposes of LCFS compliance is the only way to ensure that the LCFS is not responsible for use of these new fuels creating potential adverse environmental impacts. LCFS FF45-59

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 19th day of June, 2015 at Sacramento, California.

____

JAMES M. LYONS

[7] See *http://www.cdfa.ca.gov/dms/programs/petroleum/DevelopmentalFuels/RelevantLawsInstructionsChecklist.pdf*

45_FF_LCFS_GE

1071. Comment: **LCFS FF45-2, LCFS FF45-4 through LCFS FF45-6, LCFS FF45-53 through LCFS FF45-59**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

1072. Comment: **LCFS FF45-1**

The commenter states that 1) ARB's LUC Value for corn ethanol of 19.8 gCO2e/MJ is not supported by substantial evidence and is equivalent to an average value of 0.19 for price-yield, 2) that staff used an inconsistent approach by including the lowest values (i.e., 0.05 and 0.10) of yield-price in the iLUC analysis, and 3) that they do not agree with David Rocke's conclusion related to the analysis of the work completed by Rosas Perez and request that the data used by David Rocke for his report be released to the public.

Agency Response: (1) See response to **LCFS 8-9**. ARB staff does not agree with commenter that the two lowest values of yield price elasticity be eliminated. The data used by David Rocke has been published as part of a 3rd 15-day package released on July 31, 2015. Staff does not consider modifying the current analysis to use of a lower iLUC value (e.g., 15.53 g/MJ) for corn ethanol as suggested by the commenter to be warranted.

In addition, ARB does not agree with commenter that an iLUC value estimated using 0.19 (average of five values as referenced by the commenter) is equivalent to an average iLUC value calculated using all YPE values independently. Each value of YPE results in a simultaneous solution of complex equations that govern the behavior of the GTAP model. Given the complexity of this model, it is unlikely that the output of the model using a single value of YPE (e.g. 0.19) would be equivalent to a calculated average of outputs from five independent runs. In addition, runs completed by staff did not consider only varying YPE but varied other parameters simultaneously (detailed in Appendix I of the ISOR.)

2) *Staff used an inconsistent approach by including the lowest values (i.e., 0.05 and 0.10) of yield-price in the iLUC analysis*.

It is true that in estimating YPE, some studies make a distinction between short-term and long-term yield responses to price but some do not. The studies used by ARB to develop the range of YPE values of 0.05 and 0.35 are all inclusive and presented in ISOR Appendix I, Attachment 1 Table I-2. It should be noted that among these studies only Goodwin, et al. make an explicit distinction between short and long-term price responses. It can be argued that Smith & Sumner also measure short term responses in an implicit way. None of the YPE estimates in the Keeney and Hertel (2009) or ARB's literature review can be characterized as a yield response to price after an exact number of years.

3) *The commenter does not agree with David Rocke's conclusion related to the analysis of the work completed by Rosas Perez and request that the data used by David Rocke for his report be released to the public.*

ARB released the data used by Rocke (3rd 15-day package to be released in August 2015) and does not agree with commenter that the two lowest values should be eliminated. As ARB informed the commenter, permission to release the data had not been provided by Dr. Perez. ARB's legal team was able to determine that this data could be published and accordingly made available the data as part of the 3rd 15-day package released on July 31, 2015. With reference to Rocke's analysis supporting low yield price elasticities, ARB's use of the entire range of values for YPE was not based on David Rocke's analysis. That analysis confirmed other studies in the academic literature which have found that the YPE value should be small. As detailed above, a comprehensive literature review of YPE revealed that there is a wide range of likely values based on econometric/statistical treatment applied to estimate yield price. This review was the basis for ARB to include the entire range of likely values for YPE in the analysis.

See also responses to **LCFS B12-6**, **LCFS 46-79**, **LCFS 46-103**, **LCFS 46-102**, **LCFS 46-107**, and **LCFS 8-9**.

1073. Comment: **LCFS FF45-3**

The comment points out a bug in the CA-GREETv2.0-Tier 1 Calculator that leads to an erroneous credit in the life cycle analysis of Brazilian sugarcane-based ethanol pathways.

Agency Response: ARB staff agrees with the commenter that sugar cane harvested mechanically should be treated differently than sugar cane harvested manually, after burning the cane field. ARB has consistently distinguished between mechanized and manually-harvested sugar cane feedstock since early development of the LCFS program in 2009, again in the Method 1 pathways that were part of the original LCFS, and in the ISOR and CA-GREETv2 model that were part of the proposed re-adoption. While adjusting a different part of CA-GREETv2 as part of the June 4, 2015 15-day modifications a pre-existing link between cells in the model was accidentally not preserved. The missing cross-reference between cells has been replaced. Staff thanks the commenter for notifying ARB of the error.

1074. Comment: **LCFS FF45-7**

The commenter takes exception to the addition of nine emails to the rulemaking record as part of a 15-day Notice, arguing that those nine emails and unidentified others should already have been included in the rulemaking file earlier.

Agency Response: ARB staff disagrees with the commenter's implicit characterization of the emails as either "factual information … submitted to the agency in connection with the adoption, amendment, or repeal of the regulation" or "factual information … on which the agency is relying in the adoption, amendment or repeal of a regulation." The emails are not "factual information;" ARB is not relying on them; and they were not "submitted to" ARB "in connection with the adoption amendment, or repeal of the regulation." Notably, the commenter does not assert otherwise and, indeed, omitted any substantive discussion of the content of the emails from its comment.

ARB also disagrees with the commenter's contention that the rulemaking file is incomplete. ARB complied with the legal requirements for the rulemaking file, and these emails do not suggest otherwise as noted above. The remainder of this comment reflects the commenter's abstract legal opinions and requires no response.

1075. Comment: **LCFS FF45-8**

The commenter believes that ARB has not properly construed or applied the relevant provisions of the Government Code.

Agency Response: See response to **LCFS FF45-7.**

1076. Comment: **LCFS FF45-9**

The commenter believes that ARB did not comply with section 11347.3 of the government code.

Agency Response: See response to **LCFS FF45-7.**

1077. Comment: **LCFS FF45-10**

The commenter wants to know why additional documents from 2013 and 2014 were added to the rulemaking file.

Agency Response: See response to **LCFS FF45-7.**

1078. Comment: **LCFS FF45-11**

The commenter requests a list of all the documents ARB did not include in the rulemaking file.

Agency Response: See response to **LCFS FF45-7.**

1079. Comment: **LCFS FF45-12**

The commenter believes that ARB failed to substantially comply with Health & Safety Code section 57004. The comment begins with quotations from that statute and a recitation setting out various dates together with the commenter's interpretation of correspondence in the record, none of which require a response. More legal quotations follow, then the commenter's application of the commenter's version of the law to the commenter's version of the facts. An interrogatory follows: "If CARB disagrees [with the previous confusing, self-contradicting prose] . . . [commenter] requests that CARB fully explain its reasons . . ."

Agency Response: ARB fully complied with section 57004 by submitting the LCFS and its scientific bases for peer review. Included in the materials submitted for peer review were three staff reports (provided as hard copies in one binder) and several electronic files (provided on CD), including software and program packages, bibliographical references, and supporting documents. The comment's confused, long sentences (e.g., 88 words) are difficult to interpret, but do not appear to include an objection or recommendation regarding the proposal See also response to **LCFS FF45-7**.

1080. Comment: **LCFS FF45-13**

The commenter states that ARB must comply with Health & Safety Code section 57004 subsection (D)(1).

Agency Response: See response to **LCFS FF45-12**.

1081. Comment: **LCFS FF45-14**

The commenter states that ARB must comply with Health & Safety Code section 57004 subsection (D)(2).

Agency Response: See response to **LCFS FF45-12**.

1082. Comment: **LCFS FF45-15**

The commenter states that the peer reviewers had twice the amount of time to review the proposal than the public did.

Agency Response: See response to **LCFS FF45-12**.

1083. Comment: **LCFS FF45-16**

The commenter states that the peer reviewers should have reviewed all documents that the proposal was based on.

Agency Response: See response to **LCFS FF45-12**.

1084. Comment: **LCFS FF45-17**

The commenter claims that a UC Project Director's determination regarding the number and expertise of peer reviewers is "missing from the rulemaking file."

Agency Response: ARB staff disagrees that administrative steps taken by independent outside bodies such as the University of California must be documented beyond what is in the rulemaking file. It is not clear that the desired document even exists. Clearly the determination was made because the review was indeed conducted, and the number of peer reviewers – four—is apparent from the reviews themselves.

1085. Comment: **LCFS FF45-18**

The commenter asserts that "[a] single, unitary 'entity' must do what [§57004] requires," hence the work by four academic experts to conduct and write the peer review failed to comply with the statute.

Agency Response: ARB disagrees. While it is true that section 57004(d)(1) requires evaluation by "the external scientific peer review entity," in section 57004(b) the Legislature provided that the external reviewer may be any of the following:

(1) "the National Academy of Sciences," which does not actually employ or control its approximately 2,250 members and nearly 440 foreign associates, who are dispersed at a wide variety of research, academic, and business settings;

(2) "the University of California," including 10 campuses, 30,835 full time academic staff, and 29,393 part time academic staff as of April 2015;

(3) "the California State University," including 23 campuses and 47,000 faculty and staff;

(4) "any similar scientific institution of higher learning";

(5) "any combination of those entities";

(6) "a scientist or group of scientists of comparable stature and qualifications that is recommended by the President of the University of California."

By definition, the entities listed by the Legislature work only through the individual thoughts and efforts of the human beings associated with the organization. In light of that simple fact, the commenter's complaint that the "four individuals" separately evaluated the proposal rather than an "entity" is merely literalism taken to an absurd extreme. Here, as expressly provided in the statute, the President of the University of California recommended four "scientists of comparable stature and qualifications."

Unsatisfied with the favorable evaluation that the LCFS proposal received, the commenter switches, in comments **LCFS FF45-19** through **LCFS FF45-22**, to *ad hominem* attacks on the reviewers

ARB does not agree with those attacks, or with the repeated implication that ARB staff, who had no contact with the reviewers, actively misled the reviewers and "lack[ed] candor."

1086. Comment: **LCFS FF45-19**

The commenter critiques Dr. Claren's review.

Agency Response: See response to **LCFS FF45-18**.

1087. Comment: **LCFS FF45-20**

The commenter critiques Dr. Matthews' review.

Agency Response: See response to **LCFS FF45-18**.

1088. Comment: **LCFS FF45-21**

The commenter critiques Dr. Matthews' review.

Agency Response: See response to **LCFS FF45-18**.

1089. Comment: **LCFS FF45-22**

The commenter critiques Dr. McCarl's review.

Agency Response: See response to **LCFS FF45-18**.

1090. Comment: **LCFS FF45-23**

The commenter objects that the reviewer selection process must have been improper because none of the peer reviewers had published skeptical reviews prior to being selected. The commenter attaches a review of the 2009 proposal, apparently to illustrate that individuals who are skeptical of the LCFS concept exist.

Agency Response: ARB staff disagrees that any particular reviewer or type of reviewer needed to be appointed, other than someone whom the University of California deemed to have the requisite knowledge and expertise. ARB does not choose the reviewers; the suggestion that the University of California should select reviewers who had pre-judged the merits of a proposal should be directed to the University.

1091. Comment: **LCFS FF45-24**

The commenter expresses dissatisfaction with what they believe is the apparent lack of "systematic" review of certain details residing in the CA-GREET model.

Agency Response: ARB does not agree that it is fair to assume that none of the four reviewers properly reviewed a model that was (1) assigned for review by the University of California and (2) evaluated in a written report by the reviewer.

None of the above comments reasonably suggest that ARB did not comply with section 57004.

1092. Comment: **LCFS FF45-25**

The commenter asks ARB if they provided the peer reviewers the best economic information.

Agency Response: The comment does not make a recommendation about the proposal or an objection, and needs no response. See response to **LCFS FF45-12**.

1093. Comment: **LCFS FF45-26**

The commenter asks if the peer reviewers were given material relating to fuel shuffling.

Agency Response: The comment does not make a recommendation about the proposal or an objection, and needs no response. See response to **LCFS FF45-12**.

1094. Comment: **LCFS FF45-27**

The commenter asks if the peer reviewers were given the ISU report.

Agency Response: The comment does not make a recommendation about the proposal or an objection, and needs no response. See response to **LCFS FF45-12**.

1095. Comment: **LCFS FF45-28**

The commenter asks for the definition of a "complete global land use database."

Agency Response: The comment does not make a recommendation about the proposal or an objection, and needs no response. See response to **LCFS FF45-12**.

1096. Comment: **LCFS FF45-29**

The commenter asks for ARB's opinion on Dr. Clarens.

Agency Response: The comment does not make a recommendation about the proposal or an objection, and needs no response.

1097. Comment: **LCFS FF45-30**

The commenter asks if ARB staff is aware of Dr. Clarens' knowledge of iLUC.

Agency Response: The comment does not make a recommendation about the proposal or an objection, and needs no response. See response to **LCFS FF45-12**.

1098. Comment: **LCFS FF45-31**

The commenter asks if ARB agrees with the commenter's critique of Dr. Clarens' peer review.

Agency Response: The comment does not make a recommendation about the proposal or an objection, and needs no response. See response to **LCFS FF45-12**.

1099. Comment: **LCFS FF45-32**

The commenter asks for ARB's opinion on Dr. Clarens' qualifications.

Agency Response: The comment does not make a recommendation about the proposal or an objection, and needs no response. See response to **LCFS FF45-18** and **LCFS 45-23**.

1100. Comment: **LCFS FF45-33**

The commenter asks if ARB finds Dr. Matthew's peer review useful.

Agency Response: The comment does not make a recommendation about the proposal or an objection, and needs no response. See response to **LCFS FF45-12**.

1101. Comment: **LCFS FF45-34**

The commenter asks ARB if they think any reviewer understood and reviewed CA-GREET.

Agency Response: The comment does not make a recommendation about the proposal or an objection, and needs no response. See response to **LCFS FF45-18** and **LCFS 45-23**.

1102. Comment: **LCFS FF45-35**

The commenter asks if ARB notified Dr. Matthew about his mistake on the MOVES model.

Agency Response: The comment does not make a recommendation about the proposal or an objection, and needs no response. See response to **LCFS FF45-12**.

1103. Comment: **LCFS FF45-36**

The commenter asks ARB if they agree with Dr. Matthew's memorandum.

Agency Response: The comment does not make a recommendation about the proposal or an objection, and needs no response. See response to **LCFS FF45-12**.

1104. Comment: **LCFS FF45-37**

The commenter asks if ARB believes that Dr. McCarl is qualified to review GTAP.

Agency Response: See response to **LCFS FF45-17, LCFS 45-17, LCFS 45-18,** and **LCFS 45-23**.

1105. Comment: **LCFS FF45-38**

The commenter asks how ARB determined the number of peer reviewers.

Agency Response: See response to **LCFS FF45-17** and **LCFS 45-18**.

1106. Comment: **LCFS FF45-39**

The commenter attaches Professor Valerie Thomas' review of the LCFS as it was proposed in 2009.

Agency Response: The review was prepared years ago, and does not contain objections or recommendations regarding the regulation considered by the Board in 2015. Prof. Thomas' review was attached to document the point raised in comment **LCFS FF45-23**, in essence that Prof. Thomas exists, had questions in 2009, and was not selected by the University of California to review the December 30, 2014 proposal. Please see response to **LCFS FF45-17, 45-18** and **LCFS 45-23** above.

1107. Comment: **LCFS FF45-40**

The comment is a copy of part of the transcript from the 2009 Board Hearing.

Agency Response: While this comment is outside the scope of the 15-day changes, ARB staff acknowledges this comment. Since then, the indirect land use change has been updated based on the latest science.

1108. Comment: **LCFS FF45-41**

The commenter states that ARB's LUC Value for corn ethanol of 19.8 gCO2e/MJ is not supported by substantial evidence and is equivalent to an average value of 0.19 for price-yield.

Agency Response: See response to **LCFS FF45-1**.

1109. Comment: **LCFS FF45-42**

The commenter states that staff used an inconsistent approach by including the lowest values.

Agency Response: See response to **LCFS FF45-1**.

1110. Comment: **LCFS FF45-43**

The commenter states that they do not agree with David Rocke's conclusion related to the analysis of the work completed by Rosas Perez and request that the data used by David Rocke for his report be released to the public.

Agency Response: See response to **LCFS FF45-1**.

1111. Comment: **LCFS FF45-44**

Agency Response: See response to **LCFS FF45-1.**

1112. Comment: **LCFS FF45-45**

These comments are related to recertification of fuel pathways and the records required for recertifying pathways.

Agency Response: ARB staff appreciates the commenter's concerns regarding record submittal requirements for fuel pathways during recertification. The commenter is first concerned that the records requirement for recertified pathways is burdensome. Staff has attempted to minimize this burden with the release of the revised regulation order on June 23, 2015. Specifically, § 95488(a)(2)(B) states,

> "Recertifications will be processed by the Executive Officer using information previously supplied to the Executive Officer under the provisions of the former LCFS regulation order,

provided such information was complete pursuant to the former LCFS regulation's requirements. The requirements of subsections 95488(c)(3)-(5) and subsection 95488(e) are not applicable to recertifications, unless the Executive Officer specifically requests such information from an applicant."

Staff believes that using existing data and some defaults will allow the process of recertification to go smoothly and rapidly. Staff will request additional information from pathway recertification applicants if needed. See response to **LCFS FF17-1** and **LCFS FF17-2**.

1113. Comment: **LCFS FF45-46**

These comments are related to recertification of fuel pathways and the records required for recertifying pathways.

Agency Response: See response to **LCFS FF17-2** and **LCFS FF45-45**.

1114. Comment: **LCFS FF45-47**

The comment points out a bug in the CA-GREETv2.0-Tier 1 Calculator that leads to an erroneous credit in the life cycle analysis of Brazilian sugarcane-based ethanol pathways

Agency Response: See response to **LCFS FF45-3**.

1115. Comment: **LCFS FF45-48**

The comment points out a bug in the CA-GREETv2.0-Tier 1 Calculator that leads to an erroneous credit in the life cycle analysis of Brazilian sugarcane-based ethanol pathways

Agency Response: See response to **LCFS FF45-3**.

1116. Comment: **LCFS FF45-49**

The commenter points out that (1) peer reviewer Dr. Clarens' report contained a question, (2) the commenter does not understand exactly what Dr. Clarens meant, and (3) the commenter does not have sufficient familiarity with the models reviewed.

Agency Response: ARB staff disagrees that the peer review process was not conducted as required by health & Safety Code section 57004. See responses to **LCFS FF45-1** through **LCFS FF45-51**.

1117. Comment: **LCFS FF45-50**

The commenter notes that peer reviewer Prof. Matthews did not discuss the phenomenon of “fuel shuffling.”

Agency Response: ARB staff disagrees with the implication that the peer review process was not conducted as required by health & Safety Code section 57004. See responses to **LCFS FF45-1** through **LCFS FF45-51**.

1118. Comment: **LCFS FF45-51**

The commenter believes that peer reviewer Dr. McCarl did not understand that GTAP does not attribute emissions to [crop] intensification. The commenter further believes that McCarl’s report might lack credibility in the ‘scientific community’ that is neither identified, quoted, nor cited by the commenter.

Agency Response: ARB staff disagrees with any implication that the peer review process was not conducted as required by health & Safety Code section 57004. See responses to **LCFS FF45-1** through **LCFS FF45-50**.

1119. Comment: **LCFS FF45-52**

The commenter states that ARB did not calculate the yield to price elasticity correctly.

Agency Response: ARB staff disagrees with the commenter about the interpretation of the results presented at the March 11, 2015 meeting. Also, the comment highlighting the incorrect approach used by ARB to develop a 0.39 value is irrelevant since no structural changes or other modifications were made to negate such effects after staff discovered this particular aspect of the GTAP model. It was the intent of staff to estimate 'net yield' when a specific input value was used for yield-price elasticity (YPE). In the analysis conducted by ARB, staff estimated that when a value of 0.25 was used for YPE, the 'net yield' was 0.39, reflecting a higher effective yield (e.g., in relation to the input value of 0.25). Staff recognizes that the GTAP model includes impacts from both intensive and extensive effects and also a myriad of other changes in determining an equilibrium solution to a given set of input conditions. The higher 'net yield' confirmed the effects of extensive and other factors in addition to intensive effects. Additionally, staff conducted simulations with a value of zero for YPE (~0.01) and observed 'net yields' that were non-zero. These tests served to provide ARB with improved understanding of the interactions of intensive, extensive, and other effects within the GTAP model. None of the GTAP modeling structure or other aspects was changed after staff observed this behavior. The comments are therefore not relevant to the analysis presented by staff as part of the re-adoption of the LCFS rulemaking process. As for the reported value of -0.16 for Brazil, ARB does not have details to replicate this value referenced by the commenter.

Comment letter code: 46-FF-LCFS-Salas

Commenter: Assemblyman Rudy Salas

Affiliation: California State Assembly district 32

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

STATE CAPITOL
P.O. BOX 942849
SACRAMENTO, CA 94249-0032
(916) 319-2032
FAX (916) 319-2132

Assembly
California Legislature

RUDY SALAS, JR.
ASSEMBLYMEMBER, THIRTY-SECOND DISTRICT

46_FF_LCFS
_Salas

COMMITTEES
CHAIR: ACCOUNTABI
ADMINISTRATIVE R
AGRICULTURE
GOVERNMENTAL ORGANIZATION
VETERANS AFFAIRS

SELECT COMMITTEES
CHAIR: REGIONAL APPROACHES TO ADDRESSING THE STATE'S WATER CRISIS
CHAIR: WORKFORCE AND VOCATIONAL DEVELOPMENT IN CALIFORNIA
CYBERSECURITY
DIGITAL DIVIDE IN RURAL CALIFORNIA
EXPANDING ACCESS TO CALIFORNIA'S NATURAL RESOURCES
LOCAL EMERGENCY PREPAREDNESS
RAIL
WASTE REDUCTION AND RECYCLING IN THE 21ST CENTURY CALIFORNIA

June 19, 2015

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Comments on the 15 Day Regulatory package for the LCFS Regulation

I strongly support the Low Carbon Fuel Standard's (LCFS or regulation) provisions for Low Complexity – Low Energy Use Refiners (LCLE Refiners). These provisions recognize that not all refineries are the same. I believe that there is solid policy and technical justifications for this distinction to be codified in the LCFS. The Air Resources Board (CARB or Board), as well as, the U.S. Environmental Protection Agency have traditionally recognized in their regulatory programs the unique value small refiners (LCLE) occupy in both the oil and finished fuel markets, as well as, their unique configurations and operating constraints. Recognizing that difference is a very positive step.

However, I am disappointed that the proposed final regulatory provisions for the re-adoption of California's Low Carbon Fuel Standard (15-day changes) fails to recognize Alon's Bakersfield Refinery as a low carbon fuel producer (LCLE). The facility is configured and engineered to produce low CI base fuels. It is for this reason that I am disappointed that staff was unable to agree on a solution that would include all of California's truly LCLE refineries. The staff had an opportunity to make the LCFS's LCLE provisions work for all low carbon intensity refineries in California, but decided against various compromise proposals presented, including proposals to limit the benefit any single LCLE refiner could receive in an attempt to deal with staff's concerns for "regulatory creep" and "breaking the Bank"

In closing, I strongly urge the Board to direct staff to revisit this issue at the earliest opportunity. Should you have any questions or concerns, please contact me or my Chief of Staff, Yolanda Sandoval, at (916) 319-2032.

LCFS FF46-1

Sincerely,

Rudy Salas

RUDY SALAS
Member of the Assembly
32nd District

RS:ys

This page intentionally left blank.

46_FF_LCFS_Salas

1120. Comment: **LCFS FF46-1**

The commenter believes that ARB staff has excluded the Alon Bakersfield refinery from the LC/LE provision.

Agency Response: See responses to **LCFS FF9-6** and **LCFS B5-1**.

This page intentionally left blank.

Comment letter code: 47-FF-LCFS-CE

Commenter: Waen, Jeremy

Affiliation: Marin Clean Energy

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

47_FF_LCFS
_CE

June 19, 2015

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, California 95811
via email cotb@arb.ca.gov

**Re: Low Carbon Fuel Standard 2015 – Comment Period 15-1.
Marin Clean Energy's Comments on Proposed 15-Day Regulation Order for the Re-Adoption of the Low Carbon Fuel Standard**

I. Introduction

Marin Clean Energy ("MCE"), a joint powers agency which administers California's first operating Community Choice Aggregator ("CCA") program began serving retail generation customers on May 7, 2010. Since that time, MCE has significantly expanded with current membership including: City of Belvedere, City of Benicia, Town of Corte Madera, City of El Cerrito, Town of Fairfax, City of Larkspur, City of Mill Valley, County of Marin, County of Napa, City of Novato, City of Richmond, Town of Ross, Town of San Anselmo, City of San Pablo, City of San Rafael, City of Sausalito, Town of Tiburon. MCE now serves approximately 170,000 customer accounts. MCE's mission "is to address climate change by reducing energy related greenhouse gas emissions and securing energy supply, price stability, energy efficiency and local economic and workforce benefits."[1]

Electricity customers within these member communities are presently able to choose between four retail generation service options, including: 1) MCE Light Green service, which includes a minimum 50 percent renewable energy supply; 2) MCE Deep Green service, a voluntary service election which provides participating customers with 100 percent renewable energy supply; 3) MCE Local Sol, another voluntary service election which will provide participating customers with 100 percent locally produced photovoltaic solar electricity, beginning in late 2015; and 4) generation service provided by Pacific Gas & Electric Company ("PG&E"), the incumbent Investor-Owned Utility ("IOU"). The availability of these choices is fundamental to MCE's business model, as well as the CCA service model generally, providing residential and business customers within MCE's member communities with a variety of electric service options that are responsive to a broad range of customer preferences and priorities. Furthermore,

[1] *See* MCE's website: http://www.mcecleanenergy.org/about-us/.

customers may readily choose to move from MCE to PG&E service, "opting-out" of the CCA program, subject to applicable terms and conditions.

II. Background

MCE approximates it serves somewhere between 2,000 and 6,050 Electric Vehicles ("EVs") within its service territory based upon publically available county-level Clean Vehicle Rebate Program ("CVRP") data.[2] MCE is also actively collaborating with the local municipal governments and transportation planning authorities within its service territory to site and install publically accessible Electric Vehicle Service Equipment ("EVSE"). For these reasons MCE is very interested in engaging in the LCFS to leverage LCFS credit revenues to accelerate the adoption and usage of electricity-fueled vehicles. LCFS FF47-1

Additionally, two of MCE's communities, the Cities of Richmond and Benicia, have operational refineries located within them. MCE is actively pursuing opportunities to work with these refineries to reduce their greenhouse gas emissions through facilitating consumption of renewable electricity. For example MCE is leasing a brownfield site located at Chevron's Richmond facility and is in the process of building a 10.5 MW ground mounted solar photovoltaic array on this land.[3] This installation will leverage local labor, provide hands-on experience for new green job trainees from RichmondBUILD, and provide the community with local renewable energy for the next decade, at least. For these reasons, MCE supports the Air Resource Board's attempts to broaden the means through which oil refineries can reduce their greenhouse gas emissions through both *innovative fuel production methods* and *refinery investment credits.* LCFS FF47-2

III. CCAs Should Be Permitted to Serve as Regulated Parties for Electricity Within the LCFS

MCE believes the Air Resources Board ("CARB") should expand the eligibility requirements within the LCFS to allow CCAs to elect to serve as Regulated Parties for LCFS credit generation tied to electricity usage due to transportation within CCA service territories. Respectfully, it is MCE's opinion that the present LCFS regulation errs by associating the LCFS electricity credit generation process with the delivery functionality of utilities, rather than the generation and retail service functionalities of Load Serving Entities, including CCAs and IOUs. After all, the LCFS credit generation due to electricity consumption as a transportation fuel, is inherently linked to how that electricity is generated, *not* how that electricity is delivered to the customers. Put another way, it is a Load Serving Entity's retail electricity services – not the Electric Distribution Utility's distribution services – that have influence over the Carbon Intensity of the electricity. CCAs enable communities to source cleaner electricity to serve their usage needs, and the LCFS should recognize and reward these communities not only for using electricity to fuel transportation, but also for seeking out the cleanest electricity possible to serve as transportation fuel. The most direct way to allow this would be to enable CCAs to elect to participate as Regulated Parties under the LCFS regulation. LCFS FF47-3

Furthermore, because CCAs are local government entities governed by the same elected officials that serve on the boards for local government land use planning agencies, local and regional transit planning agencies, transportation planning agencies, and air quality management agencies, CCAs are inherently far more connected with the sphere of local government entities that are instrumental to effectively and efficiently promoting electric vehicle adoption and usage, as well as vendor agnostic charging infrastructure deployment, within their communites. Additionally, CCAs are already trusted and authorized by the legislature to administer ratepayer collected funds through Energy Efficiency programs. LCFS FF47-4

[2] *See* http://energycenter.org/clean-vehicle-rebate-project/rebate-statistics.
[3] *See* MCE Solar One at Richmond Brownfield: 10.5 MW: http://www.mcecleanenergy.org/local-projects/.

CCAs are the trusted local authority on electricity matters within their communities and are therefore better suited to effectively and efficiently administer the revenue from LCFS credit sales to directly return this value to the electric vehicle using populous. It is the intent of MCE to reinvest any LCFS revenue back into incentives for the deployment of electric vehicle charging infrastructure and electric vehicle adoption. Specific revisions to the draft regulation language that would enable CCAs to participate as Regulated Parties within the LCFS are provided in Attachment A. LCFS FF47-4 cont.

IV. MCE Supports the Creation of Additional Incentives Within the LCFS to Encourage Oil Refineries and Producers to Reduce Their Fuel and Facility Greenhouse Gas Emissions

As described above, CCAs are able to provide both refiners and the communities in which refineries are located with access to clean, renewable electricity generation. Furthermore, through collaborations like MCE's Solar One facility that is being built on degraded refinery land, CCAs are able to create new local green job and economic opportunities within historically disadvantaged communities through encouraging and facilitating the development of local renewable generation. As part of the Re-Adoption of the LCFS, the CARB has provided two new mechanisms through which oil refineries and producers can leverage on-site renewable generation to either reduce or meet their compliance obligations under the LCFS regulation: 1) § 95489(d) *Credits for Producing Crudes using Innovative Methods*; and 2) § 95489(f) *Refinery Investment Credit Pilot Program*. MCE is supportive of these new incentive mechanisms because MCE believes these incentives will result in further opportunities for collaborative efforts between CCAs and refineries within communities served by CCAs to significantly reduce greenhouse gas emissions and improve local economies. LCFS FF47-5

With that said, MCE believes there is still need to provide additional clarity regarding how these incentive mechanisms would interact with other state policies that address renewable development and climate change. In particular MCE wishes to better understand how Renewable Energy Credits ("RECs") would factor into on-site renewable generation used to by a refinery to participate in either of these two credit mechanisms under the LCFS. Based on its cursory review, it appears that the *Credits for Producing Crudes using Innovative Methods* would be sensitive to the renewable attributes associated with the on-site generation through the f_{renew} factor.[4] <u>CARB should clarify whether RECs associated with on-site generation under the *Credits for Producing Crudes using Innovative Methods*, would retain the California RPS PCC1 designation and count toward RPS compliance.</u> LCFS FF47-6

Alternatively, the *Refinery Investment Credit Pilot Program* appears to only be sensitive as to whether the electricity consumed by the refinery is imported or exported from the grid, as expressed in the *electricity* factor.[5] On-site generation could reduce a refinery's need to import electricity, while also presenting increased opportunities to export more electricity back onto the grid. Whether this on-site generation is coming from a greenhouse gas-emitting or greenhouse gas-free generation resource appears to not be considered within the calculations of this methodology. <u>CARB should also clarify whether RECs associated with on-site generation under the *Refinery Investment Credit Pilot Program*, would retain the California RPS PCC1 designation and count toward RPS compliance.</u> LCFS FF47-7

.

[4] *See* LCFS Regulation at 95489(d)(1)(F) beginning with "For crude oil produced using solar or wind based electricity:".

[5] *See* LCFS Regulation at 95489(f)(2)(A).

V. Conclusions and Recommendations of MCE.

MCE appreciates the opportunity to provide its comments on the Proposed 15-Day Regulation Order for the Re-Adoption of the Low Carbon Fuel Standard and urges the Air Resources Board to recognize and empower CCAs to facilitate greenhouse gas reductions under the LCFS program. LCFS FF47-8

Respectfully submitted,

/s/ Jeremy Waen

JEREMY WAEN
Senior Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6027
Facsimile: (415) 459-8095
E-Mail: jwaen@mceCleanEnergy.org

June 19, 2015

Appendix A:
Revisions to LCFS Regulation

All edits marked in red text.
Additions noted by underlined text. Omissions noted by ~~crossed-through~~ text.

§ 95481. Definitions and Acronyms.

(29) "Retail Electricity Provider ~~Electrical Distribution Utility~~ (REP)" means an entity that provides retail electricity services to ratepayers ~~that owns or operates an electrical distribution system~~, including:

(A) a public utility as defined in the Public Utilities Code section 216 (referred to as an Investor Owned Utility, or IOU); or

(B) a local publicly-owned electric utility (POU) as defined in Public Utilities Code section 224.3; or

(C) an Electrical Cooperative (COOP) as defined in Public Utilities Code section 2776~~.~~; or

(D) a Community Choice Aggregator (CCA) as defined in Public Utilities Code section 366.2.

* * * * *

§ 95483. Regulated Parties.

(e) *Regulated Parties for Electricity.* For electricity used as transportation fuel, the party who is eligible to generate credits is determined as specified below:

(1) For all instances where electricity is utilized as a transportation fuel with the shared service territory of both a Community Choice Aggregator and an Investor Owned Utility, the CCA has priority over the IOU to opt in and serve as the Regulated Party for the electricity used as transportation fuel within its service territory.

(A) Upon submittal to and approval by the Executive Officer of the CCA's written acknowledgment that it will not opt in and generate credits as the Regulated Party for electricity used as transportation fuel within its service territory, the IOU may elect to serve as the Regulated Party for this load;

(B) If a CCA opts in to serve as the Regulated Party for electricity used as transportation fuel within its service territory, and the IOU has previously opted in to serve as the Regulated Party for this same electricity load, then at the start of the next annual reporting cycle the responsibility of reporting on this electricity load will shift to the CCA and the IOU will no longer serve as the Regulated Party on behalf of this load; and

(C) If a CCA that initially opted in to serve as the Regulated Party for electricity used as transportation fuel within its service territory, for whatever reasons, subsequently opts out of serving as the Regulated Party for this load by submitting to and being approved by the Executive Officer of the CCA's written acknowledgment that it will not no longer opt in and generate credits as the Regulated Party for electricity used as transportation fuel within its service territory, then the IOU may elect to serve as the Regulated Party for this load.

(2)~~(1)~~ For on-road transportation fuel supplied through electric vehicle (EV) charging in a single- or multi-family residence, the Retail Electricity Provider ~~Electrical Distribution Utility~~ is eligible to generate credits in its service territory. To receive such credits, the Retail Electricity Provider ~~Electrical Distribution Utility~~ must:

(A) Use all credit proceeds to benefit current or future EV customers;

(B) Educate the public on the benefits of EV transportation (including environmental benefits and costs of EV charging, or total cost of ownership, as compared to gasoline

(C) Provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid; and

(D) Include in annual compliance reporting the following supplemental information: an itemized summary of efforts to meet requirements (A) through (C) above and costs associated with meeting the requirements. For investor owned utilities, this requirement may be satisfied by supplying a copy of the annual implementation report required under Order 4 of Public Utilities Commission of California (PUC) Decision 14-12-083, or any successor PUC Decisions.

(3)~~(2)~~ For on-road transportation fuel supplied through public access EV charging, the Retail Electricity Provider ~~Electrical Distribution Utility~~ is eligible to generate credits in its service territory. Upon submittal to and approval by the Executive Officer of its written request to opt in and generate the credits under this provision, the third-party non-utility Electric Vehicle Service Provider (EVSP) that has installed the equipment, or had an agent install the equipment, and who has a contract with the property owner or lessee where the equipment is located to maintain or otherwise service the charging equipment, is eligible to generate the credits for the electricity. To receive credit for transportation fuel supplied through public access EV charging equipment, the EVSP or Retail Electricity Provider ~~Electrical Distribution Utility~~ must meet the requirements set forth in section 95483(e)(1)(B) through (D).

(4)~~(3)~~ EV Fleets

(A) For on-road transportation fuel supplied to a fleet of EVs, the Retail Electricity Provider ~~Electrical Distribution Utility~~ is eligible to generate credits in its service territory, and must meet the requirements set forth in section 95483(e)(1)(B) through (D). Upon submittal to and approval by the Executive Officer of the fleet operator's written request to opt in and generate credits associated with a specified fleet, the fleet operator is eligible to generate the credits for the electricity. To receive credit for transportation fuel supplied to an EV fleet, an accounting of the number of

EVs in the fleet must be included as supplemental information in annual compliance reporting.

(B) For on-road transportation fuel supplied through the use of a battery switch station, the Retail Electricity Provider ~~Electrical Distribution Utility~~ is eligible to generate credits in its service territory, and must meet the requirements set forth in section 95483(e)(1)(B) through (D). Upon submittal to and approval by the Executive Officer of the station owner's written request to opt in and generate credits associated with a specific location or locations, the station owner is eligible to generate the credits for the electricity.

(5)~~(4)~~ For on-road transportation fuel supplied through private access EV charging equipment at a business or workplace, the Retail Electricity Provider ~~Electrical Distribution Utility~~ is eligible to generate credits in its service territory, and must meet the requirements set forth in section 95483(e)(1)(B) through (D). Upon submittal to and approval by the Executive Officer of the site host's written request to opt in and generate credits associated with a specific location or locations, the site host is eligible to generate the credits for the electricity. To receive credit for transportation fuel supplied through private access EV charging equipment at a business or workplace, the following requirements apply to a site host that opts in:

(A) Educate employees on the benefits of EV transportation (including environmental benefits and costs of EV charging, or total cost of ownership, as compared to gasoline) through outreach efforts directed to all employees, such as meetings, flyers, and preferred parking; and

(B) Include in annual compliance reporting the following supplemental information: a summary of efforts to meet the requirement in 95483(e)(4)(A), above, and an accounting of the number of EVs known to be charging at the business.

(6)~~(5)~~ In the event that there is measured on-road electricity as a transportation fuel that is not covered in subsections 95483(e)(2)~~(1)~~ through (5)~~(4)~~ above, the Retail Electricity Provider ~~Electrical Distribution Utility~~ is eligible to generate credits for the electricity with Executive Officer approval, and must meet the requirements set forth in section 95483(e)(2)~~(1)~~(B) through (D).

(7)~~(6)~~ For transportation fuel supplied to a fixed guideway system, the transit agency operating the system is eligible to generate credits for electricity used to propel the system. Upon submittal to and approval by the Executive Officer of the transit agency's written acknowledgment that it will not opt in and generate credits under this provision, the Retail Electricity Provider ~~Electrical Distribution Utility~~ is eligible to generate the credits for the electricity, and must meet the requirements set forth in section 95483(e)(2)~~(1)~~(B) through (D).

(8)~~(7)~~ For transportation fuel supplied to electric forklifts, the Retail Electricity Provider ~~Electrical Distribution Utility~~ is eligible to generate credits for the electricity, and must meet the requirements set forth in section 95483(e)(2)~~(1)~~(B) through (D).

* * * * *

Additional Universal Edits to LCFS Regulations

All additional references to “Electrical Distribution Utility” or “EDU” throughout the LCFS regulations should be replaced with reference to “Retail Electricity Provider” or “REP” as demonstrated above in sections 95483(e)(2) through (7).

47_FF_LCFS_CE

1121. Comment: **LCFS FF47-1**

The commenter states that it is very interested in engaging in the LCFS to leverage LCFS credit revenues to accelerate the adoption and usage of electricity-fueled vehicles.

Agency Response: Staff acknowledges Marin Clean Energy (MCE)'s interests in participating in the LCFS program.

1122. Comment: **LCFS FF47-2**

MCE supports the Air Resource Board's attempts to broaden the means through which oil refineries can reduce their greenhouse gas emissions through both innovative fuel production methods and refinery investment credits.

Agency Response: ARB staff appreciates the support for the refinery investment and the innovative crude oil provisions.

1123. Comment: **LCFS FF47-3**

The commenter states that ARB should allow Community Choice Aggregator (CCA) to serve as a regulated party for electricity under LCFS.

Agency Response: This comment is beyond the scope of the 15-day changes and, therefore, requires no further response. No CCA has previously suggested inclusion or requested the ability to participate as a regulated party under the LCFS. The level of interest is unknown (apart, perhaps, from the commenter's). To date ARB has not had occasion to explore the interplay between CCAs, public utilities, investor-owned utilities, and the regulatory contexts in which they operate in connection with possible LCFS participation. Absent thorough consideration and public debate, ARB will not amend the LCFS at this time to include CCAs. ARB is open to learning more and evaluating possible roles for CCAs in the future. ARB appreciates the commenter's interest in the LCFS.

1124. Comment: **LCFS FF47-4**

The commenter states that ARB should allow Community Choice Aggregator (CCA) to serve as a regulated party for electricity under LCFS.

Agency Response: See response to **LCFS FF47-3**.

1125. Comment: **LCFS FF47-5**

MCE is supportive because these incentives will result in further opportunities for collaborative efforts between CCAs and refineries within communities served by CCAs to significantly reduce greenhouse gas emissions and improve local economies.

Agency Response: ARB staff appreciates the support for the refinery investment provision. See also response to **LCFS FF47-3**.

1126. Comment: **LCFS FF47-6**

The commenter asks ARB to clarify whether RECs associated with on-site generation under the *Credits for Producing Crudes using Innovative Methods*, would retain the California RPS PCC1 designation and count toward RPS compliance.

Agency Response: These details of the RPS program are not covered under ARB's purview. As a result, ARB staff cannot comment on how on-site generation under the Innovative Crude Provision would affect California RPS PCC1 designation or RPS compliance.

1127. Comment: **LCFS FF47-7**

The commenter suggests ARB should clarify whether RECs associated with on-site generation under the Refinery Investment Credit Pilot Program, would retain the California RPS PCC1 designation and count toward RPS compliance.

Agency Response: See the response to **LCFS FF47-6**.

Comment letter code: 48-FF-LCFS-WE

Commenter: Tjiong, Carol

Affiliation: White Energy

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

WHITE ENERGY
CLEAN ENERGY FOR A CLEAN FUTURE.

48_FF_LCFS _WE

June 19, 2015

California Air Resources Board
1001 I Street
Sacramento, CA 95812

RE: LCFS Re-adoption

Dear Mary Nichols & Staff:

My question concerns the proposed regulation in 95488(d)(2) regarding provisional pathways and the restriction to sell or transfer credits generated under provisional pathways. It appears that the provisional pathway would now include Tier I pathways with innovative fuel technologies. We are evaluating options that would potentially allow us to produce ethanol at our existing facilities with an innovative fuel technology. If a facility has been in full commercial production for over two years but recently deploys an innovative technology to lower the carbon intensity of the fuel, will this facility receive a provisional pathway and also be subject to the restrictions for two years? If so, my concern is the marketability of fuel into California without being able to transfer the associated CI as well as the timing gap to realize any return on investment that is necessary to support investment in innovative technologies.

LCFS FF48-1

LCFS FF48-2

Please feel free to contact me to clarify the provisions or to discuss further. We want to work with ARB to ensure we are helping ARB to continue to improve and strengthen the LCFS program to not only help the state meet its increasing GHG targets, but also to provide a lower carbon intensity product for our customers.

Thank you for the opportunity to comment and provide feedback.

Sincerely,

Carol Tjiong

Carol Tjiong
VP of Corporate Compliance & Administration

2745 N. Dallas Parkway, Suite 670, Plano, TX 75093
Telephone 972.715.6490, Fax 214.751.2595
www.white-energy.com

This page intentionally left blank.

48_FF_LCFS_WE

1128. Comment: **LCFS FF48-1**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

1129. Comment: **LCFS FF48-2**

The commenter is questioning whether an existing facility/pathway could make a change that would result in the facility or pathway entering a new phase of commercial operation and being required to be in operation for two years.

Agency Response: An existing facility in commercial operation adopting an innovative technology will be eligible to apply for a new pathway for their facility and receive a new provisional CI after a quarter of operating the new technology. They must then provide the two years of data on a quarterly basis to substantiate their new fuel pathway. In the first quarter of operating the new technology they may continue to use their existing CI or, at their option, one of the temporary fuel pathway codes from Table 7 of the regulation.

This page intentionally left blank.

Comment letter code: 49-FF-LCFS-Kern

Commenter: Hicks, Melinda

Affiliation: Kern Oil & Refining Co.

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

49_FF_LCFS_
Kern

KERN

Kern Oil & Refining Co.
7724 E. PANAMA LANE
BAKERSFIELD, CALIFORNIA 93307-9210
(661) 845-0761 FAX (661) 845-0330

June 19, 2015

VIA ELECTRONIC POSTING
Comment List: lcfs2015

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento CA, 95814

Dear Chairman Nichols and Board Members:

Kern Oil & Refining Co. (Kern) is providing comments on the California Air Resources Board's (ARB) Proposed 15-Day Regulation Order (15-day Package) of the Low Carbon Fuel Standard (LCFS). Specifically, Kern is providing comments on the following: (1) Low-Complexity/Low-Energy Use (LC/LU) Refinery Adjustment Calculations; (2) Assignment of Default Crude Carbon Intensity within the Refinery-specific Incremental Deficit Option; (3) Inclusion of a De Minimum Threshold for Assessing Incremental Deficits; (4) Limits on the Use of Refinery Investment Credits; and (5) Changes to the Pathway Approval Process.

Kern is an independently owned, small refinery located in the Southern San Joaquin Valley, just outside Bakersfield, California. At a crude oil capacity of 26,000 barrels per day, Kern is literally the smallest refinery currently producing transportation fuels in California. In its comment letter dated February 17, 2015, Kern previously called attention to the potential detrimental impacts to certain refineries that result from methodologies adopted to effectuate program goals in a manageable manner for CARB. Kern gave recognition to the Board and Staff for not only acknowledging these circumstances and functional differences, but for taking action and incorporating provisions that recognize and mitigate the inequalities inherent in the broader LCFS "average refinery" implementation methodologies. Kern echoes that appreciation here, as ARB's continued support for these issues is evidenced within the 15-day Package.

Simplification of Low-Complexity/Low-Energy Use (LC/LU) Refinery Adjustment Calculation

LCFS FF49-1

Kern reiterates its strong support of ARB's inclusion of a provision issuing a carbon intensity adjustment for Low-Complexity/Low-Energy Use (LC/LU) refineries in recognition of the inherent lower carbon intensities (CI) of transportation fuels produced at these facilities. The credit helps address the unfair subsidization of higher than average energy-use refiners that results from the current regulation's reliance upon the "average refinery" in determining CI values for finished transportation fuels. Kern greatly appreciates the extensive work performed by CARB staff in calculating the demonstrable lower CI of the transportation fuels produced by LC/LU refineries, which serves as the strong scientific and technical basis for the credit consideration being given to those refineries.

Staff is proposing to credit the LC/LU refineries 5 gCO2e/MJ for CARBOB and diesel. The 15-day Package contains revisions to the calculations for quantifying the number of LC/LU refinery credits generated in a compliance year. Kern appreciates the added clarity and agrees with Staff's presentation that these revisions simplify the equations. Kern strongly supports the credit proposal and is grateful to staff for the years of work, analysis and stakeholder collaboration that have ultimately culminated in the current proposal.

Assignment of Default Crude CI within the Refinery-specific Incremental Deficit Option

Kern continues to be encouraged by ARB's acknowledgement that low volume refineries are disadvantaged by the current California Average Approach, in that they can be affected by the incremental deficit but cannot affect the sector-wide annual crude average CI. ARB is proposing a one-time opportunity for Low-Complexity/Low-Energy Use (LC/LU) refineries to opt out of the California Average Approach, and instead have their incremental deficits determined through a comparison of the facility's annual average crude CI and its 2010 baseline crude CI. Kern previously commented on the application of a default CI for crude oils that do not have a specific CI assigned in the regulation, noting that the use of the California average CI would have unnecessarily limited, or even prevented, LC/LU refineries from running new crude oils without incurring incremental deficits.

LCFS FF49-2

Kern appreciates Staff's consideration of comments made in Kern's February 17, 2015 letter. The 15-day Package includes revisions to use the individual LC/LU refinery baseline crude average CI as a default CI value for new crude oils until such time the specific CI value is added to the LCFS. This replaces the use of the California average crude CI as a default value which would have disadvantaged LC/LU refineries utilizing the option for individual compliance. Likewise, the 15-day Package incorporates the use of a three-year rolling average approach within the Refinery-specific Incremental Deficit Option, similar to the three-year rolling phase-in approach proposed in the California Average Approach for transitioning from the 2010 Crude CI Lookup Table to the 2012 Crude CI Lookup Table. Kern supports both of these proposed revisions.

Inclusion of a De Minimus Threshold for Assessing Incremental Deficits

LCFS FF49-3

Staff is proposing to include a de minimus value of 0.1 gCO2e/MJ as a minimum threshold prior to assessing incremental deficits resulting from increases to the crude oil CI three-year rolling average. The de minimus threshold would apply to all refineries, regardless of their decision to comply through the California Average Approach or the Refinery-specific Incremental Deficit option. Kern and other refiners have voiced concern for this issue throughout the rulemaking process. Kern is pleased to see this addition to the proposed regulation and supports the revision.

Limits on the Use of Refinery Investment Credits

Kern's previous comment letter expressed cautious optimism for ARB's proposal to reward refiners for projects resulting in demonstrable emission reductions at a stationary source facility by means of incorporating a Refinery Investment Credit provision within the LCFS. Specifically, Kern noted its understanding that Staff's intention is to allow for a project to be implemented in multiple phases over an approved period of time in order to achieve the threshold 0.1 gCO2e/MJ. Kern echoes its previous recommendation that additional language be added to the proposed regulatory text to clarify Staff's intent. As a small refinery, Kern has limited resources and must utilize its efforts, resources and investments with a high degree of efficiency. Allowing flexibility on the timing of a project is critical because it is not always financially feasible to carry out a substantial project all at once.

LCFS FF49-4

Staff has presented revisions within the 15-day Package that refers to the Refinery Investment Credit as a "Pilot Provision" and further has introduced language that will limit the use of credits generated from the provision to satisfaction of no more than 20% of a refinery's annual compliance obligation. Kern recognizes Staff's intent to avoid any unanticipated impacts to the credit market; however, Kern does not support the limited use of the credits, as proposed. Neither the regulatory text nor discussion within the 15-day Package address what is meant by "Pilot Program," what duration such a pilot testing is intended to span, or at what point the limitation expires and the credits then be available for unrestricted use. Similarly, the 15-day Package expresses Staff's concern that the volumes of these credits could outstrip the current expectations; however, there is no discussion of what these current expectations are and at what volumes this concern would actually be realized. Kern believes Staff should provide stakeholders with additional justification for this limitation.

Changes to the Pathway Approval Process

LCFS FF49-5

Staff is proposing revisions within the pathway application process, specifically the certification step of section 95488(c)(5), that would eliminate a 60-day limit within which the Executive Officer would be required to advise an applicant of whether their fuel pathway application is complete or incomplete. Rather, the current proposal leaves this duration open-ended, under the premise that numerous pathways will require recertification within a one-year period and that Staff could be faced with unrealistic deadlines. Coupled with the elimination of the 60-day limit, Staff is proposing to process fuel pathway applications in batches, where like fuels are grouped together for the purpose of review and approval.

Kern certainly appreciates the magnitude of work that will be faced in recertifying the hundreds of pathways and the need to prioritize that work appropriately. The proposal to review and approve pathway applications in batches of like-kind fuels should indeed add a necessary degree of efficiency to the process. However, Kern disagrees that leaving undefined the length of time ARB is granted in notifying an applicant of whether the application package is complete would add any further efficiency to the process. From the applicant's perspective, the effect of this revision is to the contrary; for applicants, this revision would add inefficiency by imposing unnecessary delay in compiling what information and/or data would complete the process. It seems reasonable that ARB would want to have a batch of applications for review and approval, already knowing that each application within the batch is complete. Kern urges Staff to revisit this proposed revision and incorporate a reasonable amount of time for deeming an application complete – one that is serving of both the agency and the applicant's needs.

In conclusion, Kern appreciates ARB's consideration of Kern's comments. As always, Kern is committed to working with Staff throughout this regulatory process.

Sincerely,

Melinda L. Hicks
Manager, Environmental Health and Safety
Kern Oil & Refining Co.

cc. Floyd Vergara, ARB
Elizabeth Scheele, ARB
Sam Wade, ARB
Stephanie Detwiler, ARB
Jim Nyarady, ARB
John Courtis, ARB
Jim Duffy, PhD, ARB

49_FF_LCFS_Kern

1130. Comment: **LCFS FF49-1**

The 15-day Package contains revisions to the calculations for quantifying the number of LC/LE refinery credits generated in a compliance year. Kern appreciates the added clarity and agrees with Staff s presentation that these revisions simplify the equations. Kern strongly supports the credit proposal and is grateful to staff for the years of work, analysis and stakeholder collaboration that have ultimately culminated in the current proposal.

Agency Response: ARB staff appreciates the support for the LC/LE provision.

1131. Comment: **LCFS FF49-2**

The commenter expresses support for the revised default crude oil Cis for the refinery-specific incremental deficit option.

Agency Response: ARB staff appreciates the support for the change made to the default CI under the LC/LEU refinery-specific incremental deficit option.

Staff would like to note, however, that the proposed 15-day changes for the refinery-specific option do not include a “three-year rolling phase in…for transitioning from the 2010 Crude CI Lookup Table to the 2012 Crude CI Lookup Table” as mentioned by the commenter.

1132. Comment: **LCFS FF49-3**

The commenter expresses support for the inclusion of a de minimus threshold for assessing incremental deficits.

Agency Response: ARB staff appreciates the support for the inclusion of a de minimus threshold for assessing incremental deficits.

1133. Comment: **LCFS FF49-4**

The commenter notes its understanding that staff’s intention is to allow for a project to be implemented in multiple phases over an approved period of time in order to achieve the threshold 0.1 $gC0_2e/MJ$. The commenter echoes their previous recommendation that additional language be added to the proposed regulatory text to clarify staff’s intent.

The commenter does not support the limited use of the credits, as proposed. Neither the regulatory text nor discussion within the 15-day Package address what is meant by "Pilot Program," what duration such a pilot testing is intended to span, or at what point the limitation expires and the credits then be available for unrestricted use. Kern believes staff should provide stakeholders with additional justification for this limitation.

Agency Response: ARB staff does not agree that additional language is necessary to address the concerns expressed by Kern. A refinery applying for a Refinery Investment Credit may define the length and scope of the project as appropriate in its application for the Refinery Investment Credit. However, the project cannot generate credits until it meets the 0.1 gCO_2e/MJ threshold from the comparison baseline.

See response to comment **LCFS FF43-8** and **LCFS FF43-50** in regards to the “Pilot Program” portion of the comment.

1134. Comment: **LCFS FF49-5**

This comment is related to the removal of the 60 calendar day period, under § 95488(c)(5) for the Executive Officer to notify the applicant if their fuel pathway application is complete.

Agency Response: Please see response to comment **LCFS FF35-7**.

Comment letter code: 50-FF-LCFS-BIO

Commenter: Batchelor, Stephanie

Affiliation: Biotechnology Industry Organization

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

50_FF_LCFS _BIO

Biotechnology Industry Organization
Comments to the California Air Resources Board

On the Notice of Public Availability of Modified Text and Availability of Additional Documents and Information for the Proposed Re-adoption of the Low Carbon Fuel Standard
June 19, 2015

The Biotechnology Industry Organization (BIO) appreciates the opportunity to submit comments on the modified text and additional documents and information for the proposed re-adoption of the Low Carbon Fuel Standard (LCFS).

BIO is the world's largest trade association representing biotechnology companies, academic institutions, state biotechnology centers and related organizations across the United States and in more than 30 other nations. BIO members are involved in the research and development of innovative healthcare, agricultural, industrial and environmental biotechnology products. BIO represents nearly 90 companies leading the development of new technologies for producing conventional and advanced biofuels that could be used in the California market. Through the application of industrial biotechnology, BIO members are improving conventional biofuel processes, enabling advanced and cellulosic biofuel production technologies and speeding development of new purpose grown energy crops.

BIO and its members support California's efforts to reduce the carbon intensity of transportation fuels through the LCFS regulation. Unfortunately, the proposed modifications to provisional pathways in sections 95488 (c) (3) and (c) (4) (1) (2) would create a serious barrier to entry for any new advanced biofuel coming to market. Indeed, these modifications would be an undue burden on the very fuels that California seeks to incentivize.

LCFS FF50-1

As CARB states on p. 53 in the provisional pathways section 95488, "*applicants are required to have been in full commercial production for at least one full calendar quarter before applying for a new pathway*".

BIO believes that requiring months of commercial production status just to apply for a new pathway seriously disadvantages new fuels and disincentivizes refiners from incorporating new feedstocks into their blending mix for a multitude of reasons, for example, the undue administrative burden placed on the refiner to test and qualify a new feedstock. Further, biofuel refiners use an array of feedstocks – from soy oil, cooking oil, tallow, etc. They also blend feedstock to produce biodiesel and renewable diesel. The way that feedstocks are processed at a facility in the span of three months would make it almost impossible to provide consistent data for a new feedstock in that timeframe. Moreover, the pre-qualification would significantly delay the timeframe to monetize credits --- it can take an operation one year before its pathway is secured from ARB --- and with the provisional credit proposal, there would be an even longer delay.

LCFS FF50-2

As CARB states on p. 54 in the provisional pathways section 95488, "*the applicant is provided only "provisional" credits and may not sell credits for 2 years"*.

BIO strongly urges CARB to allow credit trading for provisional pathway approvals as soon as provisional status is granted. CARB's current proposal would be extremely harmful to new entrants in the market since it would deny monetization of credits for two years. Without the ability to monetize, the economic incentive to sell new advanced biofuels in California is basically gone. In addition to the devastating economic impacts, new feedstock providers who partner with numerous refiners have to start the two year clock anew with each refining partner, which would create a proliferation of pathways for ARB to review.

LCFS FF50-3

To conclude, we strongly urge the Air Resources Board to reformulate the pathways section in a way that encourages new feedstocks and fuels to commercialize and contribute to a low carbon economy. If additional verification of carbon intensity data is needed, is it possible to set a requirement to submit operational data after two years and make the carbon intensity adjustment

LCFS FF50-4

at that point? Please do not hesitate to contact BIO for any additional data or information that may help to further the success of the LCFS. Thank you.

This page intentionally left blank.

50_FF_LCFS_BIO

1135. Comment: **LCFS FF50-1**

The commenter states that the proposed modifications to provisional pathways in sections 95488 (c) (3) and (c) (4) (1) (2) would create a serious barrier to entry for any new advanced biofuel coming to market. Indeed, these modifications would be an undue burden on the very fuels that California seeks to incentivize.

Agency Response: See responses to **LCFS FF31-1** and **LCFS FF56-2**.

1136. Comment: **LCFS FF50-2**

The comment is related to provisional pathways being able to generate credits as soon as commercial production begins, the quarter the provisional pathway is approved, and the prior quarter.

Agency Response: See responses to **LCFS FF31-1** and **LCFS FF56-2**.

1137. Comment: **LCFS FF50-3**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

1138. Comment: **LCFS FF50-4**

This commenter proposes that the requirement for pathways entering commercial production not be required to submit quarterly data.

Agency Response: Staff must review quarterly data during a provisional pathway period that is by definition from a facility that has not been in long-term commercial production. Many innovative fuel pathways that enter commercial production have data based upon demonstration facilities, pilot facilities or on modeling that perform differently at full production scale. In order to ensure that the new fuel pathway producing fuel in a new facility achieves the carbon intensity claimed the quarterly reporting is required. Staff will work with stakeholders at workshops after Board Hearing to consider these topics and ways to make these requirements less burdensome, but will likely be on a case-by-case basis. Staff will also work with stakeholders to develop guidance documents to help ease applicants through this process.

Comment letter code: 51-FF-LCFS-NRDC

Commenter: Barrett, Will

Affiliation: American Lung Assoc. in California

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

51_FF_LCFS
_NRDC

June 19, 2015

Mr. Sam Wade
Transportation Fuels Branch
California Air Resources Board
1001 I Street
Sacramento, CA
95814

Subject: LCFS 15 Day Changes

Dear Mr. Wade

On behalf of the undersigned organizations, we are writing to express our strong support for the re-adoption of the Low Carbon Fuel Standard in July, 2015 by the California Air Resources Board. We view the LCFS as critical to attaining California's health-protective climate and clean air goals, as well as supporting innovative California businesses and workers helping to bring more clean, low-carbon transportation solutions to market.

According to the American Lung Association's *State of the Air* 2015 report, California is home to the five most polluted American cities by unhealthy ozone and particle pollution days, and the seven cities most polluted by annual levels of particle pollution. Over 80 percent of smog-forming NOx emissions are associated with the manufacture, transportation and combustion of petroleum fuels. Petroleum is also responsible for nearly half of California's greenhouse gas pollution. The health burdens posed by unhealthy fuels can affect all residents, but especially those communities living near refineries and other major pollution sources. The LCFS provides an opportunity to reduce the overall impact of air pollution in California by encouraging cleaner investments by the fuels industry, including switching from high carbon, harmful fuels and inputs to healthier, lower carbon alternatives like electricity, hydrogen and advanced renewable, as well as incentivizing clean-up of existing petroleum refineries.

Our comments below focus on the 15 Day Change Package released on June 4, 2015:

Extending the use of Hydrogen in addition to the lift truck proposal: We support the inclusion of the hydrogen lift truck provision and encourage ARB to continue to explore opportunities to expand the market and opportunities to deploy electric-drive technologies, including those powered by low-carbon, renewable hydrogen fuel, within the context of the LCFS. The proposal to clarify the pathway for hydrogen forklifts is an appropriate provision for inclusion in the program to reduce reliance on higher-carbon fuels. In addition, we encourage ARB to ensure the program allows for reporting of hydrogen fuel use in other possible off-road applications (e.g., airport tugs, etc.) and for on-road applications in fuel cell transit buses or other light- medium- and heavy- duty fuel cell vehicle platforms. Like the proposed EER values for Heavy-Duty electricity-fueled vehicle platforms, the program should allow similar applications for fuel cell transit buses and other fuel cell vehicle platforms in the medium- and heavy- duty applications category. In extending provisions for the use of hydrogen as a transportation fuel we would ask CARB to further encourage the use of renewable hydrogen. LCFS FF51-1

Refinery Investment Credit Pilot Program: Our organizations support the intent of this provision, which is to encourage adoption of cleaner, lower carbon-intensity technologies at refineries that can reduce emissions of greenhouse gases, criteria air pollutants and toxic air contaminants that disproportionately impact residents living near refineries. We also agree with other stakeholders that the program can also encourage refinery investments that promote jobs. LCFS FF51-2

We believe that the structure of the application and public review process is appropriate in that refiners would be required to document any changes in criteria air pollutants or air toxics and that the applications for credits would be open to public review and comment. As the provision is implemented over the coming years, we encourage ARB to:

- Prioritize the evaluation of project applications that provide the greatest reductions in greenhouse gas, criteria air pollutants and toxic air contaminants on-site at refineries.
- Ensure adequate notice and public data is given to allow communities neighboring refineries and stakeholders to evaluate and comment on proposed pathways in an open and transparent process.
- Ensure adequate staffing and resources is provided to effectively implement the provisions in a manner that enables adequate monitoring and evaluation of the applications and pathways, identifies good projects that accomplish the above goals, and prevents gaming by regulated parties such as merely “shuffling” emissions associated with processing dirtier, higher carbon feedstocks and products into the “export” category, for example. LCFS FF51-3
- Only credit actual, net reductions across the refinery facilities while avoiding crediting projects in piecemeal fashion, whereby emissions in only one processing unit of the facility decrease while other units increase emissions. In implementing the provisions, ARB should require and ask that applicants provide a broad enough system boundary and data set to capture net emission changes across the refinery operation(s).
- Increase knowledge and information about technologies and trends that can improve environmental performance of the current petroleum supply chain, as well as shed light on technologies and trends that can worsen them. For example, clean investments in improved energy efficiency at refineries may be offset over time if refineries increase overall processing energy for dirtier, heavier crudes.

Our organizations look forward to working with the Board and staff to carefully implement these, and all provisions of the LCFS, to ensure that the program achieves its goals of providing healthier, cleaner fuel choices for all Californians.

Sincerely,

Will Barrett
Senior Policy Analyst
American Lung Association in California

Simon Mui
Senior Scientist and Director, California Vehicles and Fuels
Natural Resources Defense Council

John Shears
Research Coordinator
The Center for Energy Efficiency and Renewable Technologies

51_FF_LCFS_NRDC

1139. Comment: **LCFS FF51-1**

The commenter encourages ARB to ensure the program allows for reporting of hydrogen fuel use in other possible off-road applications, in addition to fuel cell forklifts.

Agency Response: See response to **LCFS FF33-1**.

1140. Comment: **LCFS FF51-2**

The commenter expresses support for the refinery investment provision.

Agency Response: ARB staff appreciates the support for the Refinery Investment provision.

1141. Comment: **LCFS FF51-3**

The commenter supports the refinery investment provision as written. The commenter suggests that ARB prioritize project reviews, ensure public access to application, ensure adequate staffing, credit only actual reductions, and continue to increase knowledge of technologies.

Agency Response: ARB staff appreciates the support for the Refinery Investment provision. Staff will continue to work with stakeholders to evaluate

This page intentionally left blank.

Comment letter code: 52-FF-LCFS-RPMG

Commenter: Hoffmann, Jessica

Affiliation: RPMG

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

52_FF_LCFS _RPMG

From: Jessica W Hoffmann [mailto:jwhoffmann@rpmgllc.com]
Sent: Friday, June 19, 2015 3:39 PM
To: Wade, Samuel@ARB
Cc: Chang, Edie@ARB; Vergara, Floyd@ARB; Kitowski, Jack@ARB; Ingram, Wes@ARB; Singh, Manisha@ARB; Chowdhury, Hafizur@ARB
Subject: RPMG Comments on Proposed Re-adoption of the Low Carbon Fuel Standard

Sam,

RPMG has submitted the following comments on the 15-day LCFS re-adoption package. Please find a copy attached to this email. We did not comment on all sections of the proposed changes. We have instead focused our attention on our identified priority topics. We are happy to make ourselves available to discuss in greater detail.

Sincerely,

Jessica W. Hoffmann|Regulatory and Compliance Manager
Office: (952) 465-3247|Cell: (952) 594-5462
Fax: (952) 465-3221| jwhoffmann@rpmgllc.com

Renewable Products Marketing Group, LLC
1157 Valley Park Drive #100|Shakopee, MN 55379
www.rpmgllc.com

RIN Correspondence: rins@rpmgllc.com
LCFS Correspondence: lcfs@rpmgllc.com

RPMG

Please consider the Environment before printing this email.
CONFIDENTIALITY NOTICE: This electronic transmission (including any files attached hereto) contains confidential information that is legally privileged, confidential, proprietary, and/or exempt from disclosure. The information is intended only for the use of the individual or entity named above. If the reader of this message is not the intended recipient or an employee or agent responsible for delivering the message to the intended recipient, you are hereby notified that any disclosure, dissemination, copying, distribution, or the taking of any action in reliance on the contents of this confidential information is strictly prohibited. If you have received this communication in error, please destroy it and notify me immediately.

This page intentionally left blank.

52_FF_LCFS_RPMG

1142. Comment: **LCFS FF52-1**

Agency Response: The commenter mentions an attachment, but no attachment was uploaded. Staff notes that the commenter also submitted comments **LCFS FF44-1** through **LCFS FF44-18**.

This page intentionally left blank.

Comment letter code: 53-FF-LCFS-NRG

Commenter: Lee, Kevin

Affiliation: NRG EVgo

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

53_FF_LCFS
_NRG

Kevin Lee
Senior Counsel

NRG EV Services LLC
11390 West Olympic Blvd., Suite 250
Los Angeles, CA 90064
(310) 954-2905
Email: kevin.lee@nrg.com

June 19, 2015

Clerk of the Board
Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Low Carbon Fuel Standard Program Amendments for Regulated Parties for Suppliers of Electricity Used as a Fuel Substitute.

Dear Madam or Sir:

NRG EVgo ("EVgo") appreciates the opportunity to review and comment on the referenced amendments to the Low Carbon Fuel Standard Program as they affect suppliers of electricity used as a fuel supplement.

EVgo is a leading Electric Vehicle Services Provider ("EVSP") in the state of California seeking to grow the market for the future of California's EV drivers and the environment. EVgo has a multi-faceted business model engaged in expanding both private and public access EV charging infrastructure throughout California. As a company heavily engaged in the development of EV charging infrastructure, we believe the LCFS credit program can be beneficial to the continued expansion of our business operations and the growth of the EV market in California. The proposed amendments restrict the ability of EVSPs to generate credits to public access charging alone, which unnecessarily constrains incentives for EVSPs in expanding charging opportunities at multifamily dwellings and workplaces. The success of the EVSP industry hinges on the viability of a complete ecosystem of EV charging products covering: home, public access, workplace, and multifamily. EVgo would like to see the California Air Resources Board maximize credit generating opportunities for EVSPs across all public and private access chargers.

LCFS FF53-1

EVgo aims to enroll in the LCFS program shortly and looks forward to working closely with the California Air Resources Board to maximize EV adoption.

Generally, EVgo objects to the elimination of the general category "electricity services supplier" as a regulated party eligible for the full suite of credit generation opportunities.

LCFS FF53-2

The policy objectives supporting the use of electricity in the LCFS should incentivize all market participants to increase electrification and reduce carbon intensity. Restricting certain categories of LCFS eligibility to Electrical Distribution Utilities creates a skewed playing field that unfairly favors utilities over private market participants such as EVSPs. LCFS FF53-2 cont.

EVgo respectfully objects to the proposed language of § 95483(e)(1) for failing to include EVSPs as an eligible regulated party at single- or multi-family residences.

Expanding EV charging into multi-family residences is a critical component of EV adoption in California. EVgo's business model includes contracting with apartment communities to provide turnkey charging services to its residents. The ability to generate credits through these relationships would provide a significant incentive to increasing deployment. Owners of multi-family residences have generally been hesitant to invest in EV infrastructure and manage the authentication, networking, maintenance and billing activities needed to serve residents. Permitting EVSPs to generate credits through the provision of private access residential charging services would encourage further development and lead to more opportunities for EV drivers to charge their vehicles during off-peak hours. LCFS FF53-3

EVgo requests that § 95483(e)(1) be amended to include verbiage similar to § 95483(e)(2) or § 95483(e)(4) (assuming "site host" would include EVSPs) such that EVSPs who have contractual relationships with property owners or managers to provide charging services are permitted to generate credits at single- and multi-family residences.

EVgo respectfully supports the proposed language of § 95483(e)(2) including EVSPs as an eligible regulated party at public access EV charging stations.

EVgo is investing heavily in public access EV charging stations across the state of California. Generating credits through the LCFS will enable us to expand our offerings and increase the pace of deployment. Additionally, the public education requirements align closely with many of EVgo's current programs and its ultimate business objectives. LCFS FF53-4

EVgo respectfully requests clarification of the term "Site Host" in § 95483(e)(4) to include EVSPs in connection with business and workplace charging.

Workplace charging is an essential component of EV adoption in California. EVgo welcomes the opportunity to generate credits as the EVSP of private access charging stations at a business or workplace. The term "site host" should be clarified to include EVSPs who have contractual relationships with a business or property owner to provide charging services. LCFS FF53-5

53_FF_LCFS_NRG

1143. Comment: **LCFS FF53-1**

The commenter encourages ARB to maximize credit generating opportunities for EVSPs across all public and private access chargers.

Agency Response: ARB staff is open to meet with stakeholders such as NRG EVgo to discuss credit generating opportunities for EVSPs for public and private access charging.

1144. Comment: **LCFS FF53-2**

The commenter objects to the elimination of the general category "electricity services supplier" as a regulated party eligible for the full suite of credit generation opportunities.

Agency Response: The term "electricity service supplier" is broad and ambiguous and therefore was not included in the final proposal. The final proposal includes specific provisions for Electric Distribution Utilities, Electric Vehicle Service Provider, and Electric Vehicle Fleet Owner, etc. This does not create a skewed playing field that disadvantages EVSPs. Please see response to **LCFS FF41-2.**

1145. Comment: **LCFS FF53-3**

The commenter objects to the proposed language of § 95483(e)(1) for failing to include EVSPs as an eligible regulated party at single- or multi-family residences.

Agency Response: The proposed 15-day changes did not change the regulated parties for single- or multi-family residences. This comment is beyond the scope of the 15-day changes and, therefore, requires no further response.

1146. Comment: **LCFS FF53-4**

The commenter supports the proposed language of § 95483(e)(2) including EVSPs as an eligible regulated party at public access EV charging stations.

Agency Response: ARB staff appreciates the support from NRG EVgo.

1147. Comment: **LCFS FF53-5**

The commenter requests clarification of the term “Site Host” in § 95483(e)(4).

Agency Response: For private access EV charging equipment, Staff’s goal continues to be to provide the LCFS credit value to the entity that made the initial investment in (or for legacy facilities the entity that currently owns) the charging infrastructure. The term “site host” was chosen to replace the term “business owner” in an attempt to improve clarity. The prior term was ambiguous (i.e., could be read to include either the property owner or the lessee for business properties) and might not always supply the credit value to the entity that made the EV infrastructure investment.

In the case where two or more parties own EV charging infrastructure components at a given location, they should contractually agree as to which party is the site host before applying to ARB for LCFS credits.

Comment letter code: 54-FF-LCFS-FCP

Commenter: Elrick, Bill

Affiliation: California Fuel Cell Partnership

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

54_FF_LCFS _FCP

California FUEL CELL PARTNERSHIP
DRIVING FOR THE FUTURE
California Fuel Cell Partnership
3300 Industrial Blvd., Suite 1000
West Sacramento, CA 95691
(916) 371-2870
www.fuelcellpartnership.org
info@cafcp.org

Daimler
GM
Honda
Hyundai
Nissan
Toyota
Volkswagen
Automotive Fuel Cell Cooperation

Cal/EPA Air Resources Board
California Energy Commission
Office of Governor Edmund G. Brown Jr.
South Coast AQMD
U.S. Department of Energy
U.S. Environmental Protection Agency

Hydrogenics
ITM Power
Linde North America, Inc.
NREL
Sandia National Laboratories
Southern California Gas Company
SunLine Transit Agency
University of California, Berkeley
UC Davis-ITS
UC Irvine-NFCRC
US Hybrid

AC Transit
Air Liquide
BAE Systems
Ballard Power Systems
Bay Area Air Quality Management District
CALSTART
CalState LA
CA Dept of Food and Agriculture
CTE
CEERT
Energy Independence Now
FirstElement Fuel, Inc.

June 19, 2015

California Air Resources Board
Richard W. Corey
Executive Officer
Re: Suggested modifications Low Carbon Fuel Standard regulatory language
1001 I St
Sacramento, CA 95812-2815

Dear Mr. Corey and CARB LCFS staff:

The California Fuel Cell Partnership is pleased to provide input on the suggested modifications to the LCFS regulatory language[i] for 15-day comments. We appreciate the inclusion of hydrogen as a low carbon transportation fuel for credits, including those under the Renewable Hydrogen Refinery Credit Pilot Program. The monetary value of these credits will support the sustainability of hydrogen as a renewable fuel and energy storage medium. With the proposed LCFS language revision and CPUC requiring energy storage for renewable electricity, California is sending a vital signal and builds confidence among all early market participants.

Please consider the following comments for consistency across zero emission vehicle technology platforms and enabling transportation fuels:

a. Throughout the document, include stronger encouragement and support of renewable content based hydrogen as a fuel or energy storage medium. LCFS FF54-1

b. "Electric Vehicle (EV)" (30) (p7) definition should also include Fuel Cell Electric Vehicles. LCFS FF54-2

c. Include definitions for "Fuel Cell Electric Vehicle" and "Battery Electric Vehicle" as "Plug In Hybrid Electric Vehicle" is also defined, and "FCV" and "BEV" are included as Acronyms under (b) (p14). LCFS FF54-3

d. Consider including a definition for "Renewable Hydrogen", as this is used extensively on p93ff. LCFS FF54-4

e. *Add "Hydrogen fueling" as one of the "Transaction Types", this will cover all hydrogen fuel cell vehicle applications, including hydrogen fuel cell forklift fueling (p12-13).* LCFS FF54-5

f. An EER Value for electricity in forklifts and hydrogen in fuel cell forklifts is included, as well as light duty fuel cell vehicles, but no specific EER Values for fuel cell transit buses and a variety of different fuel cell vehicle platforms in the medium- and heavy duty applications category, like the variety of EER Values in the Heavy-Duty Electricity fueled vehicle platforms (Table 4, p32). LCFS FF54-6

The California Fuel Cell Partnership is a collaboration in which several companies and government entities are independent participants. It is not a joint venture, legal partnership or unincorporated association.

g. "Hydrogen for fuel cell electric forklifts" is mentioned as an option to report for to receive transportation fuel credits (p103), but not hydrogen for fuel cell transit buses, other light- medium- and heavy duty fuel cell vehicle platforms, and off-road applications. **LCFS FF54-7**

Thank you for your leadership in helping develop a sustainable market for fuel cell electric vehicles and hydrogen as a fuel, and for the opportunity to provide comments. Please do not hesitate to contact me at (916) 371-2396 or belrick@cafcp.org if you have any questions or require clarification.

Sincerely,

Bill Elrick
Executive Director

cc: Justin Ward, CaFCP Chair

---

[i] As posted at: http://www.arb.ca.gov/regact/2015/lcfs2015/regorderfinal.pdf

54_FF_LCFS_FCP

1148. Comment: **LCFS FF54-1**

The commenter encourages and supports renewable content based hydrogen as a fuel or energy storage medium.

Agency Response: ARB staff acknowledges the importance of hydrogen from renewable sources and has included one fuel pathway - compressed hydrogen from on-site reforming with renewable feedstocks into the regulation. Staff commits to continue working with stakeholders to develop more fuel pathways for hydrogen from renewable sources.

1149. Comment: **LCFS FF54-2**

The commenter states that the EV definition should also include “Fuel Cell Electric Vehicles”

Agency Response: Staff acknowledges that improvements could potentially be made to enhance clarity of definitions related to advanced vehicles and fuels. Staff commits to work with stakeholders to develop improved definitions in the next rule making. Because the vehicle population in this category is still small, the change is not urgent.

1150. Comment: **LCFS FF54-3**

The commenter states that the definitions should also include additional categories of advanced vehicles.

Agency Response: See response to **LCFS FF54-2**.

1151. Comment: **LCFS FF54-4**

The comment requests that ARB consider including a definition for “Renewable Hydrogen”.

Agency Response: See response to **LCFS FF54-2**.

1152. Comment: **LCFS FF54-5**

The commenter suggests adding “Hydrogen fueling” as one of the “Transaction Types”.

Agency Response: See response to **LCFS FF54-2**.

1153. Comment: **LCFS FF54-6**

The commenter states that no specific EER Values for fuel cell transit buses and a variety of different fuel cell vehicles has been provided as was done for electric vehicles.

Agency Response: See response to **LCFS FF21-1**.

1154. Comment: **LCFS FF54-7**

The commenter states that only fuel cell forklifts are mentioned in credits generation, not hydrogen for fuel cell transit buses, and other light/medium/heavy duty fuel cell vehicles.

Agency Response: See response to **LCFS FF21-1**.

Comment letter code: 55-FF-LCFS-CRR

Commenter: Pauley, Clarke

Affiliation: CR&R

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

CR&R INCORPORATED
environmental services

June 19, 2015

Members of the Board
c/o Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Comments to Re-Adoption of the Low Carbon Fuel Standard – Proposed 15 Day Regulation Order

Members of the Board:

CR&R Environmental Services (CR&R) is pleased to provide the following comments and recommendations regarding the above referenced proposed regulation order. We appreciate the opportunity to provide our input to the modification of this extremely important set of regulations for the State of California.

As you may be aware, CR&R is a privately held integrated waste management company based in Southern California serving some 45 cities and jurisdictions, with 3 million residential and 5,000 commercial customers. CR&R has launched a renewable energy division where we have heavily invested in an anaerobic digestion (AD) project in the City of Perris (Riverside County). CR&R has chosen AD as our technology of choice to help our cities and customers meet the State's new organics recycling goals that are phasing in between now and the year 2020. From a feedstock of our collected green and food waste we will be generating approximately one million diesel gallon equivalents (dge) of renewable natural gas (RNG) per year per phase. We have four phases permitted in Perris that will collectively generate 4 million dge per year of RNG at full build out. The RNG we generate will initially fuel our own fleet of CNG trucks with subsequent phases planned to be further processed to be injected into the SoCal Gas pipeline per Rule 30 specifications.

We are grateful for the considerable financial investment the State has made in our Perris AD project. Namely, the California Energy Commission ($4.52 Million), South Coast AQMD ($500,000), and CalRecycle ($3 million) have made Phase 1 and 2 of our project possible. As you are well aware, leading edge technology is expensive and our approximately $60 million dollar investment in Phase 1 and 2 was made possible only with this type of public assistance. We anticipate completion of Phase 1 in November of this year.

On the operations side, when developing our operating budget for the Perris AD project, we relied on the availability of two key carbon incentives, RFS2 and LCFS, to enable us to generate an economic return. **We are concerned that the proposed LCFS amendments delay our ability to monetize LCFS credits which will significantly impact our project's economic viability.**

LCFS FF55-1

We have the following specific concerns with the proposed modifications:

1) **The requirement for 2 years of energy consumption data required under the registration process for Tier 2-LookUp Table Pathway CNG 005 listed in Table 6.**

LCFS FF55-2

11292 Western Ave.
P. O. Box 125
Stanton, CA 90680-2912

t: 800.826.9677
t: 714.826.9049
f: 714.890.6347

crrwasteservices.com

the face of a greener generation

LCFS FF55-2 cont.

The proposed amendments require that CR&R register the project under Tier2-LookUp Table Pathway CNG005 which, among other requirements, calls for the submission of energy invoices for a period no less than **2 years** per 95488(4)(D)(1). Once the registration is approved for that specific CI, the LCFS credits will be generated retroactively based on the fuel production since startup of operations. Furthermore, 95488(4)(E), states that to obtain final approval, the CI chosen has to be approved by the Executive Officer. However, there is no deadline set for the Executive Officer to make this determination. **Our interpretation is that applicants will not be able to sell the LCFS credits generated until at least 2 years after the registration of the project, causing a significant impact on the cash flow of the project.**

In order to resolve this we suggest two solutions:

1. *That CARB reduces the amount of required energy invoices that have to be submitted to one quarter.*
2. *That there is a limit of 30 days for the Executive Officer to make his determination once the energy invoices, and all the other required documentation, is submitted.*

2) The possibility that will have to halt LCFS credit generation when transitioning from the current regulation to the new regulation.

LCFS FF55-3

Our financial pro-forma was based on existing rules where producers start generating LCFS credits upon starting operations. As our plant is expected to come online in November 2015, we expect to register our project under Method 2 CNG005 and start generating credits soon after start-up under the existing regulations. The proposed regulations require that we re-register the facility under the Tier2-LookUp Table Pathway prior to the sunset date of December 2016. **Our interpretation is that at the time of re-registration, applicants will have to halt the generation of LCFS credits until the re-registration is approved. This will cause a hiatus in the planned income from LCFS credits as it was included in our pro-forma.**

In order to resolve this issue, we recommend:

When a project's registration is approved and is generating LCFS credits, the project's registration requirements are grandfathered in under the new regulations with the new respective CI index and therefore there would not be a hiatus in LCFS credit generation.

3) The CI Index for the Temporary FPCs for Indeterminate CI are very high. The production of CNG from an anaerobic digester is included in the Biomethane CNG pathway listed in Table 7.

If we were to be required to use a temporary pathway due to the LCFS cash flow implications of item 1 above, we would have to default to a CI that unrealistically high as compared to the published CARB pathways for anaerobic digester. While we understand that these values need to be conservative, there is no explanation of how these CI were created.

LCFS FF55-4

In order to resolve this issue, we suggest:

Isolate the CNG production from anaerobic digesters from this category. Furthermore, explain the determination of these values.

We very much appreciate the opportunity to comment. Please do not hesitate to contact us if you have any questions regarding these comments.

Sincerely,

P.P.

Paul Relis
Senior Vice President
CR&R Environmental Services

cc:
Mary Nichols - California Air Resources Board
Howard Levenson - CalRecycle
Patrick Serfass- American Biogas Council
Tim Olson - California Energy Commission
Julia Levin - Bioenergy Association of California
Kathy Lynch- Lynch & Associates
Cliff Gladstein, Gladstein and Associates

11292 Western Ave.
P. O. Box 125
Stanton, CA 90680-2912

t: 800.826.9677
t: 714.826.9049
f: 714.890.6347

crrwasteservices.com

the face of a greener generation

This page intentionally left blank.

55_FF_LCFS_CRR

1155. Comment: **LCFS FF55-1**

The commenter expresses concerns that the proposed LCFS amendments delay their ability to monetize LCFS credits which will significantly impact their project's economic viability.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1.**

1156. Comment: **LCFS FF55-2**

The commenter expresses concerns about the requirement for two years of energy consumption data under the registration process for Tier 2 Lookup table pathway code CNG005 listed in Table 6.

Agency Response: Please see responses **LCFS FF15-1** and **LCFS FF31-1**. In order to encourage the development of innovative fuel technologies, applicants may submit New Pathway Request Forms covering Tier 1 and Tier 2 facilities that have been in full commercial operation for less than two years, provided they have been in full commercial production for at least one full calendar quarter. If that form is subsequently approved by the Executive Officer, the applicant shall submit operating records covering all period of full commercial operation, provided those records cover at least one full calendar quarter**.**

1157. Comment: **LCFS FF55-3**

The commenter expresses concern about the possibility that they will have to halt LCFS credit generation when transitioning from the current regulation to the new regulation.

Agency Response: ARB staff does not intend nor believe the recertification process will create any gap in credit generation. In order to ensure that all fuels sold under all certified pathways compete fairly in the California marketplace, all pathway CIs must be calculated using the same model. For this reason, the proposed regulation requires all pathways certified under the current regulation to be recertified with CIs calculated using CA-GREET 2.0. Recertification must occur within one year of the effective date of the proposed regulation. Since the proposed regulation is expected to take effect on January 1, 2016, holders of pathways with CA-GREET 1.8b-based CIs will have until January 1, 2017, to recertify those pathways as long as the data has not changed. As proposed in the proposed regulation, applications to recertify fuel pathway certifications, registrations that were approved under the current LCFS (and still in effect on the date this proposed regulation goes into effect) and new applications for fuel pathways in 2016 will, to the extent feasible, be processed in groups based on fuel type in the following order of priority: ethanol, biodiesel, renewable diesel, compressed natural gas, liquefied natural gas, and all others. For legacy pathways, the CIs will still be in effect until the pathways are recertified or until January 1, 2017. As soon as the recertification is approved, the new CI will be in effect while the previous CI will be deactivated. Therefore, the transition should cause no halt in the credit generation.

1158. Comment: **LCFS FF55-4**

The comment states that the temporary FPCs for fuels with indeterminate CIs are very high.

Agency Response: See response to **LCFS FF35-6**.

Comment letter code: 56-FF-LCFS-Solazyme

Commenter: Ellis, Graham

Affiliation: Solazyme

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

56_FF_LCFS_
Solazyme

solazyme

June 19, 2015

VIA ELECTRONIC FILING
Clerk of the Board
Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: The Proposed Re-Adoption of the Low Carbon Fuel Standard

COMMENTS OF SOLAZYME, INC. ("Solazyme")

Solazyme appreciates the opportunity to comment on the California Air Resources Board's (ARB's) proposal for the 2015 Re-Adoption of the Low Carbon Fuel Standard (LCFS), and we are supportive of the LCFS. Solazyme was founded in California over 12 years ago and is based in South San Francisco. We are in commercial production and already selling biofuel to private fleets in the US, and we are eager to supply advanced biofuels for the California market.

Solazyme understands that the ARB is trying to address concerns over Carbon Intensity (CI) data reporting compliance for new pathways Section 95488 (d)(2). Solazyme agrees that there needs to be a solution to this matter, although we feel that this proposal creates a serious barrier for any new advanced biofuel coming to market through onerous upfront requirements. In fact, the undue burdens created in this proposal are truly a show-stopper for advanced biofuels coming to market in California. Instead, the new requirements as written favor incumbents, such as first generation biofuels, who have legacy operations. Below we outline some areas of concern and look forward to ARB's consideration of these issues. LCFS FF56-1

Introduction to Solazyme

Solazyme has pioneered an industrial biotechnology platform that harnesses the prolific oil-producing ability of microalgae. Our platform is feedstock flexible and can utilize a wide variety of plant-based sugars such as sugarcane-based sucrose, corn-based dextrose, and sugar from other biomass sources including cellulosics. By growing our proprietary microalgae in the absence of light using fermentation tanks to convert photosynthetic plant sugars into oil, we are in effect utilizing "indirect photosynthesis." Solazyme develops and manufactures products for the food, skin-care, industrial chemical and lubricants, and industrial/military fuels sectors.

Solazyme is Currently Producing Advanced Biofuels

At Solazyme, we are creating clean, low carbon, renewable algae-derived advanced biofuels. The company's tailored oils are refined into cost-effective, high-quality, on-spec "drop-in" replacements for diesel and jet fuels. Solazyme's algae-derived fuels are compatible with existing infrastructure, meet industry specifications, and can be used with factory-standard engines, without modifications. The company has worked with Chevron, UOP Honeywell, and other industry leading refining partners, to produce Soladiesel$_{RD}$® renewable diesel, Soladiesel® renewable diesel for ships, and Solajet® renewable jet fuel for both military and commercial application testing.

- Soladiesel$_{BD}$® and Soladiesel$_{RD}$® are the first algae-derived fuels to be successfully road-tested in blended and unblended (B100) forms for thousands of miles in unmodified vehicles. Both fuels are compatible with existing infrastructures, meet current US and European fuel specifications, and may be used in factory-standard diesel engines without modification.
- Soladiesel$_{RD}$® (Renewable #2 Diesel) is ASTM D975 compliant and has demonstrated a cetane rating of over 74, which is more than 60 percent better than standard US diesel fuel. Also, Solazyme produces Soladiesel® that meets the HRD-76 military specifications for ships. It was used as the base fuel for testing and certification of renewable F-76.
- Solajet® is the world's first 100 percent algae-derived jet fuel, for both military and commercial applications. The fuel has been used in a US Navy testing and certification program. Solajet® meets all military specifications for HRJ-5 jet fuel and all non-petroleum commercial specifications for ASTM D 7566.

General Comments

Provisional Pathways

LCFS FF56-2

The language in Section 95488, and specifically 95488(d)(2), is greatly concerning to Solazyme because of the upfront requirements for a new pathway. For instance, the proposal requires applicants to have been in full commercial production for at least one full calendar quarter before applying for a new pathway. This timeline is not feasible for two reasons. First, biofuel refiners use or blend a broad array of feedstocks when making biodiesel or renewable diesel (e.g., cooking oil, tallow, soy oil, etc.). The dynamic nature of feedstocks processed at a facility over the course of one quarter would make it near impossible to generate consistent data for one new feedstock.

LCFS FF56-3

In addition, this timeline does not match the natural course of the commercialization process for a new biofuel. It is standard practice for biofuel refiners to take time to scale up a new feedstock while it is introduced. That means that the refiners will not generate a quarter's worth of consistent data on the new feedstock during its early adoption. This requirement will therefore significantly delay the opportunity for a new pathway and delay advanced biofuels from being introduced into California. It creates an undue administrative burden on the refiners to test and qualify new feedstocks and will greatly reduce their enthusiasm to incorporate new feedstocks. Instead, this requirement rewards incumbents.

LCFS FF56-4

Monetizing the LCFS credits are also delayed as the rule states that the applicant is provided only "provisional" credits and may not sell credits for two years. This is a stonewall barrier for innovative advanced biofuels producers and refiners alike. Without the ability to monetize credits for two years, the economic incentive to sell new advanced biofuels in California is basically gone. Once again, this requirement heavily favors incumbents.

LCFS FF56-5

Any new technology coming to market, and expanding, requires capital to build facilities. In the event that ARB requires a 2 year monetization hold, with the potential to withhold credits, this will also

LCFS FF56-5 cont.

impact the ability of new entrants to finance. Financiers will typically need to discount any credit until it is confirmed. Start-up, and the first years of operation, are also the most critical for a new plant in terms of cash flow. The current proposal makes that initial period worse, and thus increases the cost of commissioning significantly.

Furthermore, as new feedstock producers enter the California market, this will create a proliferation of pathways for ARB staff to handle. Most feedstock providers will partner with numerous refiners to produce the end product: biodiesel or renewable diesel. This means there will be a two year process for each refiner, as well as a new pathway application for each refiner, for the ARB to review.

LCFS FF56-6

California and the ARB have typically lead adoption for new technologies, and we hope this legacy continues, particularly at a time when so many technologies are poised to enter the market.

Table 7 Temporary FOCs for Fuels with Indeterminate CIs

LCFS FF56-7

Microalgae naturally make triglyceride oils, just like the oils made by any animal or plant-based sources. In fact, several types of microorganisms are used by many other companies as the basis for a new generation of advanced biofuels. Table 7. *Temporary FOCs for Fuels with Indeterminate CIs,* however, does not include a default pathway for fuels derived from these sources. Solazyme believes that the ARB should add a category for "Any feedstock *derived from microorganisms*" for Biodiesel and Renewable Diesel fuels. With this new generation of advanced biofuels coming into commercialization, this will allow for California to benefit from new and broad innovation.

LCFS FF56-8

Solazyme understands that lack of compliance for CI verification after two years is an important concern. However, it would seem that this can be addressed by withholding the right to sell credits until compliance is met rather than putting in place requirements for full operational data upfront for new advanced biofuel providers looking to enter the market. We believe this will significantly delay (or halt) the entry of advanced biofuels to the California market.

We appreciate this opportunity to provide comments. Please contact me if you have any questions or require additional information.

Sincerely,

p.p.

Graham Ellis
Senior Vice-President of Business Development and Fuels
Solazyme, Inc.
225 Gateway Boulevard
South San Francisco, CA 94080
650-780-4777 x5155
gellis@solazyme.com

This page intentionally left blank.

56_FF_LCFS_Solazyme

1159. Comment: **LCFS FF56-1**

The commenter is concerned that the requirements and restrictions in the proposed Modified Regulation Order create barriers for developers of newly constructed fuel production facilities or operations that apply for provisional pathways.

Agency Response: This comment introduces those that follow; ARB responds to those detailed comment in responses to **LCFS FF56-2** through **LCFS FF56-8**.

1160. Comment: **LCFS FF56-2**

The comment states that the regulation's requirement for one calendar quarter of operational data makes it difficult to generate data when multiple new feedstocks are processed.

Agency Response: One calendar quarter of operational data is sufficient to commence evaluation of a provisional pathway and verify fuel carbon intensity, providing a minimum amount of data on which to make a CI determination. One quarter of operational data also demonstrates that facility construction is complete and commercial production has commenced, thus precluding applicants with fuel production facility design plans that have not commenced construction from making frivolous applications that may never materialize into tangible fuel pathways. Such applications could lead to abuse of certified CIs, as well as occupy limited staff resources to process pathway applications.

1161. Comment: **LCFS FF56-3**

The comment states that the requirement for one calendar quarter of operational data poses an undue administrative burden on fuel developers and hinders the commercialization and scale-up of processes.

Agency Response: See response to **LCFS FF56-2.**

1162. Comment: **LCFS FF56-4**

The commenter also expresses concern that LCFS credits generated by new fuel producers who have been granted provisional pathways are not liquid for two years; thereby constricting their cash flows and operating capital demanded by advanced biofuel producers and refiners alike.

Agency Response: See response **LCFS FF31-1**. ARB modified that aspect of the proposal to allow generation and sale of provisional credits.

1163. Comment: **LCFS FF56-5**

The comment states that the 2-year hold on monetization will impact a fuel producer's ability to secure financing.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

1164. Comment: **LCFS FF56-6**

The comment states that each feedstock producer will partner with multiple refiners and that will mean multiple pathway applications for each refiner and feedstock combination for ARB staff to review.

Agency Response: See response to **LCFS FF56-2** and **FF56-4**.

1165. Comment: **LCFS FF56-7**

The commenter suggests that there is no specific Temporary Fuel Pathway Code (FPC) for Fuels with Intermediate CIs that caters to Renewable Diesel or Biodiesel derived from micro-organisms.

Agency Response: Temporary FPCs with CIs were created in broad categories so that regulated parties may be able to report purchased-fuel volumes. While an exact match of the Temporary FPC and the applicant's modeled estimate of the fuel CI may not exist, staff believes that the Temporary FPC categories are broad enough to place the applicant's CI in close proximity to the one of many Temporary FPCs. There are temporary FPCs that are reasonably close to CI expectations for renewable diesel and biodiesel derived from micro-organisms, (see Table 7 FPCs BIOD201, and RNWD301T, for example).

1166. Comment: **LCFS FF56-8**

The commenter also expresses concern that LCFS credits generated by new fuel producers who have been granted provisional pathways are not liquid for two years; thereby constricting their cash flows and operating capital demanded by advanced biofuel producers and refiners alike.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

Comment letter code: 57-FF-LCFS-CBA

Commenter: DuBose, Celia

Affiliation: California Biodiesel Alliance

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

57_FF_LCFS
_CBA

June 19, 2015

Mary D. Nichols
Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95812

RE: SUPPORT FOR LCFS READOPTION: 15-Day Proposed Modifications to LCFS

Dear Chair Nichols:

I am very pleased to submit these comments in support of the 15-Day Proposed Modifications on behalf of the California Biodiesel Alliance (CBA) and to reiterate the strongest support for the re-adoption of California's Low Carbon Fuel Standard (LCFS). As California's not-for-profit biodiesel industry trade association, CBA works very closely with and fully supports all of the comments of the national trade association, the National Biodiesel Board (NBB).

We begin by highlighting a key issue, detailed by the NBB, and also requesting that ARB include Tier 1 pathways for integrated oil and biodiesel producers or that the Tier 2 GREET model be available to those integrated biodiesel producers who qualify. To that point, we strongly urge a reinstatement of the "uncooked" used cooking oil (UCO) pathway under Tier 1. We believe it's very important for our California-based biodiesel producers who make biodiesel from used restaurant grease and don't use a cooking process, to benefit from a CI score that has been as much as 4 or more points lower than the pathway in which "cooking" is involved. This is coupled with the request that, toward the goal of accuracy in determining CI values, Tier 1 pathways account for integrated operations by allowing for the input of specific feedstock processing values, not just default values. LCFS FF57-1

Also, while we understand the need for a period of review to determine accurate energy use for commercial-scale operations for provisional pathways, we are concerned about language suggesting a potential 2-year delay in the ability to monetize credits. LCFS FF57-2

In closing, let me reiterate our appreciation for ARB's work, especially the skill and dedication that ARB staff has brought to the difficult tasks involved in LCFS readoption. We can attest to the willingness of staff at all levels to engage and satisfactorily address issues raised by our industry experts. We are very excited about the future of the California biodiesel industry and the growing contributions we can make to the state's carbon and petroleum reduction and related goals.

Thank you for considering these comments. Please call me with questions at 760-398-0815.

Sincerely,

Curtis Wright
Chairman

530 Divisadero St., #119, San Francisco, CA 94117
www.californiabiodieselalliance.org

This page intentionally left blank.

57_FF_LCFS_CBA Responses

1167. Comment: **LCFS FF57-1**

This comment is related to innovative processes and lower energy and emissions for biodiesel.

Agency Response: See response to **LCFS FF10-1** and **LCFS FF10-2**.

1168. Comment: **LCFS FF57-2**

These comments are related to provisional pathways not being able to generate or sell LCFS credits during the two-year provisional period required under the first 15-day changes.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF20-1**.

This page intentionally left blank.

Comment letter code: 58-FF-LCFS-BTC

Commenter: Spaulding, John

Affiliation: Building Trades Council

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

58_FF_LCFS
_BTC

Building Trades Council

Kern, Inyo, & Mono Counties of California AFL-CIO

June 18, 2015

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Comments of the 15 Day Regulatory Package for the LCFS Regulation

The Kern, Inyo and Mono Counties Building and Construction Trades Council strongly supports the Low Carbon Fuel Standard's (LCFS or regulation) provisions for Low Complexity – Low Energy Use Refiners (LCLE Refiners). These provisions recognize that not all refineries are the same. We believe that there are solid policy and technical justifications for this distinction to be codified in the LCFS. The Air Resources Board (CARB or Board), as well as, the U.S. Environmental Protection Agency have traditionally recognized in their regulatory programs the unique value small refiners (LCLE) occupy in both the oil and finished fuel markets, as well as, their unique configurations and operating constraints. Recognizing that difference is a very positive step.

However, we are disappointed that the proposed final regulatory provisions for the re-adoption of California's Low Carbon Fuel Standard (15-day changes) fails to recognize Alon's Bakersfield Refinery as a low carbon fuel producer (LCLE). The facility is configured and engineered to produce low CI base fuels. It is for this reason that we are saddened that staff was unable to agree on a solution that would include all of California's truly LCLE refineries. The staff had an opportunity to make the LCF"s LCLE provisions work for all low carbon intensity refineries in California, but decided against various compromise proposals presented, including proposals to limit the benefit and single LCLE refiner could receive in an attempt to deal with staff's concerns for "regulatory creep" and "breaking the bank". LCFS FF58-1

We strongly urge the Board to direct staff to revisit this issue at the earliest opportunity.

Respectfully submitted,

John Spaulding
Executive Secretary

John Spaulding
Executive Secretary

661-323-7957 Office
661-327-8379 Fax

200 West Jeffrey Street
Bakersfield, California 93305-2434

This page intentionally left blank.

58_FF_LCFS_BTC Responses

1169. Comment: **LCFS FF58-1**

The commenter is disappointed that ARB has not made changes to include the Alon Bakersfield refinery from the LCLE provision.

Agency Response: See comment responses to **LCFS FF9-6** and **LCFS FF9-8**.

This page intentionally left blank.

Comment letter code: 59-FF-LCFS-CalETC

Commenter: Tutt, Eileen

Affiliation: California Electric Transportation Coalition

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

59_FF_LCFS _CalETC

CalETC

California Electric Transportation Coalition

June 19, 2015

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: SUPPORT for Re-Adoption of the Low-Carbon Fuels Standard as modified by the proposed 15-day Regulation Order

Dear Chairman Nichols and Honorable Board Members:

The California Electric Transportation Coalition (CalETC) appreciates the opportunity to comment in support of re-adoption of the Low Carbon Fuels Standard (LCFS) as modified by the proposed 15-day Regulation Order . CalETC is a non-profit association with a board of directors that includes: Los Angeles Department of Water and Power, Pacific Gas & Electric, Sacramento Municipal Utility District, San Diego Gas & Electric and Southern California Edison. Our membership also includes major auto makers and we work closely with our colleagues in the alternative fuels community.

First, we laud the California Air Resources Board (CARB) in the design and implementation of the LCFS. The regulation sets a standard for the regulated industry and allows the industry to determine how best to meet that standard, providing flexibility in an industry long constrained by the transportation sector's near-total dependence on only one fuel. The LCFS program has resulted in unanticipated innovation in both fuels and vehicles and expanded consumer choice. In the first years of implementation of the LCFS, industry is over-complying, credits are being generated from unanticipated and innovative sources, and consumers are responding to expanding choices in fuels and vehicles.

CalETC particularly appreciates CARB's recognition that electricity is a fundamentally different fuel option for consumers. The CARB approach to electricity supports consumer choice in fuels and fueling options and does not tie electricity to a liquid fuel paradigm that could restrict consumer options. The unanticipated innovations the LCFS has helped bring to market, including the proliferation of many vehicle and fueling options for electricity, present unique challenges for CARB. CARB staff has demonstrated an exceptional ability to develop and implement a regulation that allows consumer-driven free-market approaches to reducing the carbon content of our transportation fuels sector.

We respectfully submit the following comments on the proposed 15-day Regulation Order:

- CalETC appreciates the opportunities for utilities to earn LCFS credits for workplace, fleet and public-access locations, in those instances where the site host does not want to take on that role. LCFS FF59-1

- CalETC supports the increased transparency and specificity included for the residential charging LCFS credit estimation formula. CalETC will continue to support CARB and provide as much information as we have to ensure transparency and robustness. LCFS FF59-2
- We also support the other clarification modifications that were included in the electricity section. LCFS FF59-3
- CalETC supports the CARB staff recommended carbon intensity for electricity. LCFS FF59-4

In closing, CalETC supports re-adoption of this groundbreaking and essential regulation. Thank you for your consideration and ongoing leadership.

Regards

Eileen Wenger Tutt, Executive Director
California Electric Transportation Coalition

EWT/kmg

59_FF_LCFS_CalETC Responses

1170. Comment: **LCFS FF59-1**

Agency Response: ARB staff appreciates the support for the electricity provisions.

1171. Comment: **LCFS FF59-2**

Agency Response: ARB staff appreciates the support for the residential charging LCFS credit estimation formula.

1172. Comment: **LCFS FF59-3**

Agency Response: ARB staff appreciates the support for the modifications that were included in the electricity section.

1173. Comment: **LCFS FF59-4**

Agency Response: ARB staff appreciates the support for the proposed carbon intensity value for electricity.

This page intentionally left blank.

Comment letter code: 60-FF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the First 15-day comment period.

This page intentionally left blank.

60_FF_LCFS _HBC

Detwiler, Stephanie@ARB

Subject: FW: Error in CA-GREET 2.0 Tier 1 Calculation of Ethanol CI

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Tuesday, June 09, 2015 11:50 AM
To: Chowdhury, Hafizur@ARB
Cc: Pham, Chan@ARB
Subject: Error in CA-GREET 2.0 Tier 1 Calculation of Ethanol CI

In the recently released Tier 1 calculator there is an error in the calculation of denaturant CI. On the EtOH sheet, cell L436, a fixed amount is used for the feedstock CI. However, since this varies with the pathway, it should be linked to the feedstock CI that is manually entered in sheet “T1 Calculator”, cell c62, after the first step of the upstream/feedstock CI calculation.

LCFS FF17-1

As a result of this error, the denaturant calculation is in error because it does not reflect the CI of the upstream portion of the ethanol pathway.

Please confirm whether sending this to you all is sufficient for this issue to be considered, or whether it needs to be a formal comment.

Thanks!

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

This page intentionally left blank.

60_FF_LCFS_HBC

1174. Comment: **LCFS FF60-1**

The commenter pointed out a broken link in the Tier 1 calculator. The cell in question, L436, is meant to link to a cell containing the applicant's ethanol feedstock CI, but due to a clerical error, in the June 4, 2015 version of CA-GREET2.0 cell L436 instead linked to the wrong place.

Agency Response: That error has been corrected as a nonsubstantial change in the model version provided to OAL "June 4, 2015 CA-GREET2.0 corrected.

This page intentionally left blank.

E. COMMENTS RECEIVED DURING THE SECOND 15-DAY COMMENT PERIOD, JUNE 22 - JULY 8, 2015

Thirteen comment letters were received during the second 15-day comment period. Each comment letter is reproduced below with responses following. Comment letter **8_SF_LCFS_GE** is 421 pages long and will be reproduced in discrete sections with the responses following each section for readability.

This page intentionally left blank.

Comment letter code: 1-SF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the Second 15-day comment period.

This page intentionally left blank.

1_SF_LCFS _HBC

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Friday, June 26, 2015 10:31 AM
To: Chowdhury, Hafizur@ARB
Subject: Which "CI" is the reference for the 20% reduction Tier 2 requirement?

Hafizur:

In section 95488(b) (2)(F)(4) it is written:
"Production process innovations that improve production efficiency such that resulting CI is at least 20 percent lower due to the process innovation."

I have looked at the definition of "carbon intensity", and the acronym "CI" and it is not clear whether this section is referring to the total indirect and direct CI, the direct CI or the CI of the energy consumption in the process facility. LCFS SF1-1

In the definitions section of the proposed regulations, "day" is defined as meaning a calendar day unless specified otherwise. Perhaps "carbon intensity" should also be further specified in the definition to mean the total direct and indirect CI over the full lifecycle unless specified otherwise, or whatever specific definition want to have for the term "carbon intensity". The definition mentions lifecycle, but does not state full lifecycle. LCFS SF1-2

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

This page intentionally left blank.

1_SF_LCFS_HBC Responses

1175. Comment: **LCFS SF1-1**

The commenter states that it is not clear whether section 95488(b)(2)(F)(4) is referring to the total indirect and direct CI, the direct CI or the CI of the energy consumption in the process facility.

Agency Response: Staff notes that this comment is not relevant to the changes made through the second 15-day notice. However, ARB staff appreciates the commenter raising this issue for clarification. The "source-to-tank" CI should be used to determine whether an innovative process sufficiently improves production efficiency to qualify a pathway for Tier 2. As defined in conjunction with the Method 2A substantiality requirement under Section § 95488(c)(4)(G)2:

> "Source-to-tank" means all the steps involved in feedstock production and transport, and finished fuel production, transport, and dispensing. A source-to-tank CI does not include the carbon intensity associated with the use of the fuel in a vehicle; "source-to-tank" is also referred to as "well-to-tank."

Staff suggests that the source-to-tank CI should not include the indirect land use change modifier. To demonstrate 20% reduction, the reference CI should be calculated using all the same inputs as would be appropriate for the proposed Tier 2 pathway, without the innovative process.

1176. Comment: **LCFS SF1-2**

The commenter states that in the definitions section of the proposed regulations, "day" is defined as meaning a calendar day unless specified otherwise. Perhaps "carbon intensity" should also be further specified in the definition to mean the total direct and indirect CI over the full lifecycle unless specified otherwise.

Agency Response: This comment is beyond the scope of the second 15-day changes and, therefore, requires no further response.

.

This page intentionally left blank.

Comment letter code: 2-SF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the Second 15-day comment period.

This page intentionally left blank.

2_SF_LCFS _HBC

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Thursday, June 25, 2015 7:08 PM
To: Chowdhury, Hafizur@ARB
Subject: Assertion in 2nd Notice Summary that no data needed for many legacy pathways

In the summary of the changes in the 2nd 15-day Notice, regarding recertification of "legacy pathways" staff has written: "For many of these pathways ARB staff already has all of the information needed to conduct recertification without any submission of additional data by the applicant." (for convenient reference, I have copied below all of item #3 of the summary that contains this statement)

LCFS SF2-1

Does this mean that no data will be needed for chemical, enzyme and yeast use at fuel ethanol plants and that no transportation distances for feedstocks and ethanol will be needed? How will CARB calculate the CI using the Tier 1 calculator without this information? Has CARB decided to allow legacy pathways to use default values for these items?

Thank you for considering and commenting.

Copy of Item #3:

3. In section 95488, staff is proposing a streamlined recertification process by which "legacy pathways" certified under prior versions of the LCFS regulation could be recertified, pursuant to the proposed regulation, by ARB staff using the CA GREET 2.0 model. The goal of these changes is to minimize disruption of credit generation in the program due to the move from CA-GREET 1.8b to CA-GREET 2.0.

The program currently has over 270 Method 2 legacy pathways, including pathways posted as recently as May of 2015 . During the first 15-day comment

period stakeholders requested additional clarity on the fate of these existing pathways.

For many of these pathways ARB staff already has all of the information needed to conduct recertification without any submission of additional data by the applicant, and an abbreviated pathway re-certification process is appropriate.
Under the proposed changes, ARB staff could request additional information if required.

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

This page intentionally left blank.

2_SF_LCFS_HBC

1177. Comment: **LCFS SF2-1**

The commenter asks if ARB will allow legacy pathways to use default values for chemical, enzyme and yeast use at fuel ethanol plants.

Agency Response: Staff's current thinking is that CA-GREET2.0 default values for chemical and material input quantities will be used to recertify legacy pathways; however, staff may request additional information and documentation if necessary. Presuming the Board adopts the proposed rule, staff plans to include this item in the workshop and draft guidance document that will be discussed after the board hearing.

This page intentionally left blank.

Comment letter code: 3-SF-LCFS-HBC

Commenter: Caldwell, Logan

Affiliation: Houston BioFuels Consultants

The following letter was submitted to the LCFS Docket during the Second 15-day comment period.

This page intentionally left blank.

3_SF_LCFS _HBC

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Thursday, June 25, 2015 6:57 PM
To: Chowdhury, Hafizur@ARB
Subject: What is the Executive Officer likely to request for Recertifications?

Hafizur:

The 2nd 15-day notice modifications provide that portions of the normal certification requirements may not be required for recertification of existing pathways. The problem is knowing which of the requirements are likely to be needed; otherwise, there will be inefficiencies involved in the process from either providing too much or too little with applications for certification. I have summarized for the Tier 1 pathways the items that may or may not be required. It seems to me that certain items will definitely be required, for example the CA-GREET 2.0 Tier 1 model with the Tier 1 sheet completed. Another example is the fuel producer attestation letter. If these are definitely going to be needed, I would suggest rewording the language in the regulations to say so. Then, the only unknown is has to do with the invoices.

LCFS SF3-1

The requirements of subsections 95488(c)(3)… are not applicable to recertifications, *unless the Executive Officer specifically requests such information from an applicant*.
95488(c)(3):

95488 (c) (3)(A) …submit the following information to the Executive Officer for processing and verification:

1. Calculation of CI with CA-GREET 2.0 T1 with T1 interface completed.

2. Invoices and receipts for all forms of energy consumed in the fuel production process, all fuel sales, all feedstock purchases, and all co-products sold. Each set of invoices shall be accompanied by a spreadsheet summarizing the invoices.

- In lieu of receipts or invoices for energy consumption, fuel sales, feedstock purchases, or co-product sales, the applicant may seek Executive Officer approval to submit audit reports prepared by independent, third-party auditors that document energy consumption, fuel sales, feedstock purchases, or co-product sales.

3. LCFS Fuel Producer Attestation Letter

Clarifying this point should make the process smoother for all concerned.

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

This page intentionally left blank.

3_SF_LCFS_HBC

1178. Comment: **LCFS SF3-1**

Regulation should be amended to clarify requirements for legacy pathway re-certification especially with respect to what additional information is needed.

Agency Response: ARB staff appreciates the commenter's suggestion for clarification of the regulation order. At this time we do not anticipate further changes to the regulation. Staff views recertification as largely an administrative process undertaken by ARB staff. Presuming the Board adopts the proposed rule, staff plans include this item in the workshop and draft guidance document that will be discussed after the board hearing. See response to **LCFS FF18-1**.

This page intentionally left blank.

4_SF_LCFS_HBC

From: Logan Caldwell [mailto:lc@hbioc.net]
Sent: Thursday, June 25, 2015 6:42 PM
To: Chowdhury, Hafizur@ARB
Subject: Question regarding: Requirements to be Classified as a Tier 1 Pathway: Three Years seems excessive

The 2nd (and 1st) 15-day notice proposed language states the following at 95488(b)(1):

Tier 1. Conventionally-produced alternative fuels of a type that has been in full commercial production, excluding start-up or ramp-up phase, for at least three years, **and for which certified LCFS pathways have existed for at least three years** shall be classified into Tier 1.

The full commercial production for three years could be an issue for some plants that were out of service due to market conditions for a period of time.

LCFS SF4-1

The bigger question and issue is the requirement "and for which certified LCFS pathways have existed for at least three years." If I assume the reference date for determining three years is January 1, 2016, this means that only pathways that were certified and posted on the ARB web site by January 1, 2013 or earlier will qualify for Tier 1 status. This would eliminate from consideration as Tier 1 pathways approximately 86 of the 125 facility pathways (some facilities have more than one pathway) shown currently on the CARB website: http://www.arb.ca.gov/fuels/lcfs/2a2b/2a-2b-apps.htm . In addition there are a number of Internal ARB-Developed Fuel Pathways that were issued after January 1, 2013, that would be a problem too for any facilities that used them for Method 1 certification.

I think it would be helpful to reconsider or clarify these requirements. Otherwise CARB staff is going to be overwhelmed with Tier 2 applications and the whole LCFS program will obviously suffer.

LCFS SF4-2

Regards,
Logan

Logan Caldwell, President
Houston BioFuels Consultants LLC
Tel: 281-360-8515
Mobile: 281-250-0396
lc@hbioc.net
www.houstonbiofuelsconsultants.com
Yahoo IM: loganethanol

Notice: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately (281-360-8515) and permanently delete this message and any attachments

This page intentionally left blank.

4_SF_LCFS_HBC

1179. Comment: **LCFS SF4-1**

The commenter states that full commercial production for three years could be an issue for some plants that were out of service due to market conditions for a period of time.

Agency Response: This comment is beyond the scope of the second 15-day changes and, therefore, requires no further response. However, for the sake of clarity, ARB staff believes the commenter has misinterpreted the regulation language under section 95488(b)(1), which is meant to clarify "conventionally-produced." This provision does not apply to individual plants or individual LCFS-certified pathways, but rather "to fuels **of a type** that has been in commercial production...**and** for which certified LCFS pathways have existed for at least three years." Thus, a new producer who has been in operation for less than three years, but the same feedstock-fuel pathway has been LCFS certified for at least three years (for example, corn-ethanol), that applicant should apply for a Tier 1 pathway. Conversely, if a producer has been in operation for five years, but uses a feedstock-fuel combination which has not been a LCFS certified pathway for three years (for example, algae-biodiesel), that producer may apply for a Tier 2 pathway.

1180. Comment: **LCFS SF4-2**

The commenter requests clarification on the 3-year requirement for Tier 1 pathways.

Agency Response: See response to **LCFS SF4-1**.

This page intentionally left blank.

Comment letter code: 5-SF-LCFS-GHI

Commenter: Greene, John

Affiliation: GHI Energy

The following letter was submitted to the LCFS Docket during the Second 15-day comment period.

This page intentionally left blank.

GHI ENERGY™
BIOFUELS & RENEWABLES

John M. Greene
President

GHI Energy, LLC
800 Bering Dr, Suite 301
Houston, TX 77057

281 761 7835 Office
713 303 6527 Mobile
832 415 9724 Fax

jmgreene@ghienergy.com

5_SF_LCFS _GHI

Chairman Mary Nichols and Board Members
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Submitted electronically to http://www.arb.ca.gov

RE: Low Carbon Fuel Standard
Proposed Fuel Pathway Registration Process

July 6, 2015

Dear Chairman Nichols and Board Members,

Thank you for the opportunity to provide comments regarding the readoption of the California Low Carbon Fuel Standard and, in particular, the proposed modifications to the fuel pathway registration process as proposed in the draft regulation released on June 4.

LCFS SF5-1

We comment today specifically about §95488(d)(2) subtitled "Provisional Pathways" wherein new biofuel facilities are granted only provisional status while waiting on two full years of operating data before being fully approved by ARB for unrestricted LCFS participation. While previous drafts of the new regulation applied this restriction only to new facilities producing novel and less proven Tier 2 biofuels, the June 4 draft captured new facilities producing established and well understood Tier 1 biofuels as well. Although the June 23 draft eased these restrictions to Tier 1 producers a small bit, they still allow for ARB to make unannounced changes to a new pathway and still retain a great deal of uncertainty to biofuel producers and investors. We believe that this is a serious miscalculation on the part of Staff that undermines the entire rationale for redesigning and streamlining the pathway application process.

LCFS SF5-2

GHI Energy urges ARB to modify this provision and to exclude new Tier 1 facilities from this provisional requirement completely, or, at the very least, **reduce the statutory provisional time period for new Tier 1 facilities to a much shorter duration (for example, three to six months)**. Given than the entire purpose of the new Tier 1 / Tier 2 designation is to "streamline" the application process based on Staff's familiarity with certain common types of biofuels, it would stand to reason that less operational data would be needed to ensure that a new Tier 1 facility is constructed and operating properly as compared to the more new and less proven types of facilities designated as Tier 2 that would logically require more operating data.

If ARB still believes that a two year provisional period is appropriate even for new Tier 1 facilities, then GHI would urge ARB to allow at least a portion of a new Tier 1 facility's' LCFS credits to be marketable and unrestricted, perhaps equal to a maximum "baseline" CI level (much like the Method 1 "Table" lookup in place today), and **make only the incremental portion of the pathway (i.e. CI reductions under the baseline) provisional instead.** LCFS SF5-3

Given that Staff's compliance scenarios are heavily reliant on the introduction of new types of biofuels and the increasing consumption of existing fuels such as biomethane and biodiesel, it would stand to reason that the credit transfer restrictions that come from such a long provisional status could in effect "lock out" the development of new biofuels facilities and prevent the LCFS from achieving its ultimate 2020 carbon reduction goal. Combined with the proposed cost containment mechanism in the new regulation, this provisional designation could further reduce the perceived payback to investors in new biofuel facilities – thus causing them to decline to fund new facilities – and further risk the success of the LCFS in the future. LCFS SF5-4

Sincerely,

John M Greene
President

5_SF_LCFS_GHI

1181. Comment: **LCFS SF5-1**

The commenter believes that the Provisional Pathway section of the regulation retains uncertainty for biofuel producers and investors.

Agency Response: Staff believes the proposed changes provide the appropriate balance of flexibility for low CI producers and the need for LCFS accuracy and reliability. See response to **LCFS FF20-1**.

1182. Comment: **LCFS SF5-2**

The commenter urges ARB to modify the provisional pathway provision to exclude new Tier 1 facilities or reduce the provisional time period for new Tier 1 facilities to a much shorter duration (for example, three to six months).

Agency Response: See response to **LCFS SF5-1** and **LCFS FF20-1**.

1183. Comment: **LCFS SF5-3**

The commenter urges ARB to allow at least a portion of a new Tier 1 facility's' LCFS credits to be marketable and unrestricted, perhaps equal to a maximum "baseline" CI level (much like the Method 1 "Table" lookup in place today), and make only the incremental portion of the pathway (i.e. CI reductions under the baseline) provisional instead.

Agency Response: See response to **LCFS FF20-1**.

1184. Comment: **LCFS SF5-4**

The commenter expresses concern that the 2-year provisional designation for new facilities could reduce the perceived payback to investors in new biofuel facilities.

Agency Response: See response to **LCFS FF20-1**.

This page intentionally left blank.

Comment letter code: 6-SF-LCFS-Ensyn

Commenter: Connors, Karen

Affiliation: Ensyn Corporation

The following letter was submitted to the LCFS Docket during the Second 15-day comment period.

This page intentionally left blank.

6_SF_LCFS
_Ensyn

ENSYN
CORPORATION

ELECTRONIC SUBMITTAL (http://www.arb.ca.gov/lispub/comm/bclist.php)

July 8, 2015

Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Comments regarding proposed modified regulatory language with respect to the re-adoption of the Low Carbon Fuel Standard ("LCFS")

Dear Sir or Madam:

Ensyn Corporation ("Ensyn"), a privately owned U.S. company, is an experienced producer of cellulosic renewable fuels and renewable chemical products made from wood residues and other non-food cellulosic biomass. Ensyn appreciates the efforts of the Air Resources Board (the "Board" or "ARB") to reduce the carbon intensity ("CI") of transportation fuels used in California and the opportunity to provide comment on the above referenced regulations.

ENSYN'S TECHNOLOGY

Ensyn and its affiliated companies have been producing renewable fuels and chemicals commercially since 1989. Over this period, Ensyn's technology has produced over 37 million gallons of liquid product, a volume unmatched by any other cellulosic biofuels company. To date, Ensyn's cellulosic renewable fuel has been combusted in boilers to replace heating oil, and now Ensyn is focusing on expanding into the refinery market.

Ensyn's renewable fuel can be used as a secondary feedstock at a refinery in an application called "Refinery Coprocessing." In this application, a refiner purchases Ensyn's renewable fuel and coprocesses it with crude oil at a refinery to make ASTM-certified gasoline and diesel. In contrast, other biofuel companies produce a biofuel that must be blended downstream with finished gasoline or diesel. Refinery Coprocessing creates an untapped midstream biofuels market that is not subject to "blendwall" concerns and therefore can significantly expand the total quantity of low carbon intensity fuels in California and enable timely achievement of the LCFS CI reduction target.

Ensyn is currently developing production facilities in several regions across North America and globally, with world-class strategic partners, including UOP, a Honeywell Company; Chevron Technology Ventures; and Fibria Cellulose S.A, a Brazilian fiber company that is the world's largest market pulp producer. These projects include production facilities in the Pacific Northwest and California that would ultimately produce renewable fuel for use in California refineries.

Several key attributes contribute to our robust project development pipeline, including the following:

- Feedstock Partners – Ensyn is partnering with large timber management and forest products companies to provide abundant biomass residuals and waste for its projects.
- Offtake Partners – Ensyn is partnering with large global oil refiners, as well as smaller independent refiners, that would be offtake customers for our projects.
- Proven Technology – Ensyn's rapid thermal process (RTP™) technology has been proven in commercial operations for over 25 years. Our joint venture with UOP Honeywell provides commercial performance guarantees further supporting the technology.
- Powerful Economics - Cash production costs of approximately $50 per barrel provide significant downside protection and result in attractive economics for our projects.

Over the past year, Ensyn has spent considerable time and effort developing a life cycle analysis and is nearing completion of its LCFS pathway application. Ensyn considers the LCFS program to be an important policy driver for the expansion of low carbon fuel production. Based on extensive modeling and discussions with ARB staff, Ensyn anticipates that it will receive an extremely low CI score for its fuel pathway, well within the range of an ultra low carbon fuel.

PROVISIONS OF CONCERN

As an innovative producer of ultra low carbon fuel, Ensyn has commentary on the following provisions in the proposed regulations:

Provisional Pathways- Under Section 9588(d)(2) of the proposed regulations, applicants may not submit New Pathway Request Forms covering facilities that have not been in full commercial production for less than one full calendar quarter. At any time during the first two calendar years of the facility's commercial production, the Executive Officer of the Board or his or her designee (the "Executive Officer") may revise as appropriate the facility's actual operational CI based on the receipts for energy purchases submitted by the applicant of the fuel pathway application for the facility. During such two-year period, the applicant may only generate provisional credits and the Executive Officer may adjust the number of credits or reverse any provisional credit in the producer's account without a hearing.

Credit Invalidation- Under Section 95495(b)(1) of the proposed regulations, the Executive Officer may modify or delete an approved CI and invalidate credits or recalculate deficits. Under Section 95495(b)(4), in the event that the Executive Officer makes a final determination that invalidates credits and results in the creation of a deficit in a past compliance period, the deficit holder has 60 days from the date of final determination to purchase sufficient credits to eliminate the entire deficit.

RECOMMENDED CHANGES

We believe that the foregoing provisions would greatly hinder the value of LCFS credits in obtaining financing for any project utilizing an innovative fuel technology. Based on our experience, financial participants are extremely conservative in forecasting revenue streams for advanced biofuel projects. The current proposed language pertaining to provisional pathways and credit invalidation is likely to undermine financing for projects and thereby frustrate attainment of the Board's aggressive CI and petroleum reduction goals. However, relatively modest changes to the proposed language will preserve the Board's goal of ensuring verifiable greenhouse gas emission reductions while also supporting the development and expansion of low CI fuel production facilities.

LCFS SF6-1

Monetization of LCFS Credits- The first aspect of enabling financing of a biofuels facility is to facilitate the monetization of LCFS credits as early in the facility's commissioning as is feasible and consistent with the goals of the LCFS program. In our experience, there is a great deal of plant optimization that occurs as innovative production facilities are brought on line and ramped up to nameplate production capacity. Given the necessity of "proving" CI reductions to the Executive Officer through the submission of actual energy usage data at the specific production facility, the LCFS program is already structured to incentivize a new facility to delay its LCFS commissioning date until energy efficient performance has been achieved. Requiring a full calendar quarter of data is overly burdensome on plants which are being financed and constructed. For newly operational facilities, rather than relying on data from actual operations, third party validation of an applicant's provisional pathway should provide sufficient assurance of performance metrics to the Board. The validation process that has been successfully employed in the British Columbia Carbon Offset Protocol may be used as a template for this approach.

In any case, if the Board believes that operational data is required, a sixty (60) day period would be sufficient to validate the data and would enable much quicker monetizing of credits for project investors.

From a drafting perspective, this change could be achieved simply by changing the following sentence in Section 95488(d)(2) as indicated:

> *"In order to encourage the development of innovative fuel technologies, however, applicants may submit New Pathway Request Forms, as set forth in section 95488(c)(1),*
> *covering Tier 1 and Tier 2 facilities that have been in full commercial operation for less than two years, provided they have been in full commercial production for at least ~~one full calendar quarter~~ sixty (60) days."*

While the third party validation or sixty-day approach enables quicker LCFS credit monetization, the same subsection provides that based on operational data, "the Executive Officer may adjust the number of credits or reverse any provisional credit in the producer's account without a hearing…" This broad oversight power of the Executive

Officer ensures that the Board retains ample authority to ensure that actual CI reductions are being achieved. In addition, the Executive Officer's enhanced enforcement powers under Section 95495 further minimize any risk to LCFS program goals.

Minimizing the Period of Uncertainty- The second aspect of enabling financing is minimizing the period during which the production facility will be regarded by financiers as having an indefinite CI score. During the period in which the credits are provisional and may be adjusted without a hearing, the value of the credits will be considered an uncertainty. This uncertainty factor will adversely affect the facility's pro forma by discounting or nullifying the value of LCFS credits for the entire two-year period. Consequently, we would request that the Board reduce the provisional period to a maximum of six months. Once a facility has been commissioned and has commercially produced fuel for six months, its energy demands are stable so there is no significant risk to programmatic goals resulting from the adoption of a shorter provisional period. By contrast, a two-year provisional period undermines programmatic greenhouse gas and petroleum reduction goals by rendering it more difficult to obtain financing needed to establish innovative ultra low carbon production facilities.

Clarifying Provisional Credits- Regarding provisional credits, we would like to bring your attention to two sentences of Section 95486(a)(2) that could be interpreted inconsistently with the intent of the latest version of the proposed regulations. The clause states: LCFS SF6-2

> *"Where an application or demonstration pursuant to sections 95488 or 95489 has been completed but not yet approved, the applicant may report transactions in the LRT-CBTS. Such provisional credits may not be used for any purpose until fully recognized."*

The phrase "provisional credits" as used here appears to reference non-approved facilities that cannot yet generate credits. However, since the phrase "provisional credits" is used in Section 95488(d)(2) to specifically reference credits from facilities that have Executive Officer approval, we are concerned that this sentence could be interpreted as a lingering restriction on the use of provisional credits. Therefore, we would recommend striking the phrase "provisional credits" from Section 95486(a)(2) and replacing it with "reported transactions".

Remedying a Deficit- We believe that a period of sixty (60) days for a producer to remedy a deficit in a past compliance period caused by an invalidation of credits is an insufficient period and would cause undue economic burden on the producer. We suggest that the appropriate period to remedy the deficit should be one year. LCFS SF6-3

From a drafting perspective, this change could be achieved simply by changing the following sentence in Section 95495(b)(4) as indicated:

> *"Where such action creates a deficit in a past compliance period, the deficit holder has ~~60 days~~ one year from the date of the final determination to purchase sufficient credits to eliminate the entire deficit."*

CONCLUSION

We appreciate the opportunity to provide these comments and are available to work with the Board to assist it in achieving its environmental goals.

Respectfully submitted,

Robert A. Pirraglia
President

This page intentionally left blank.

6_SF_LCFS_Ensyn

1185. Comment: **LCFS SF6-1**

The comment is related to the monetization of the LCFS Credits, stabilization and optimization of processes after a newly-built facility has commenced commercial operations, operating contingency for new LCFS pathway applicants, third-party certification, and a proposed alternate approach to the LCFS regulation requirements.

Agency Response: We agree with the commenter that there is a great deal of plant optimization that occurs as innovative production facilities are brought on line and ramped up to nameplate production capacity, therefore we cannot issue a final certified CI until such issues are worked through. See response **LCFS SF12-5** and **LCFS SF8-22**.

Lastly, the Commenter's suggestion that ARB use third-party certification of pathways for newly-built facilities in operation has been entertained before. Staff will continue to evaluate the merits of such a proposal and find ways to assimilate such a process into the existing LCFS program, framework, and pathway certification process.

1186. Comment: **LCFS SF6-2**

The comment is related to the monetization of the LCFS Credits over the two-year provisional period over which the number of provisional credits generated could be lowered based on actual operating data submitted by the applicant. The commenter has asked the Board to reduce the provisional period from two years to six months citing that once a facility has been commissioned and has been commercially producing fuel for six months, its energy demands have stabilized, and there is no significant risk to programmatic goals resulting from a shorter provisional period.

Agency Response: ARB staff responds that fuel pathway CI certifications have always been based on the applicant's submittal of two years of actual operations data backed by energy invoices, production reports, and other forms of evidence. These requirements enhance accuracy and deter fraud and should remain in place. The commenter has cited the difficulty in procuring financing for construction of newer fuel production facilities with novel ultra-low carbon pathways as the reason for a requiring a shorter provisional period. Staff reiterates that the two-year operating data requirement is the standard we have based for producing fuel pathway CI certifications with lower uncertainty, thereby bringing more credibility to our LCFS program.

The commenter has suggested that “provisional credits” be stricken from Section 95486(a)(2) of the modified LCFS regulation order, and be replaced by “reported transactions.” That section was further modified in the third 15-day change striking the language that the commenter wanted to replace.

1187. Comment: **LCFS SF6-3**

The comment states that a period of sixty (60) days for a producer to remedy a deficit in a past compliance period caused by an invalidation of credits is an insufficient period and would cause undue economic burden on the producer. We suggest that the appropriate period to remedy the deficit should be one year.

Agency Response: Producers of low carbon intensity fuels who are careful to follow the actual operating condition limits in the CI certification would not be facing invalidation of any credits generated for fuel transactions reported. Similarly, importers and entities purchasing “with-obligation” fuels should ensure that the fuels being purchased are consistent with the relevant pathway. Finally, parties who knowingly generate bad credits will be subject to prompt enforcement and remediation.

Section 95495 includes a process and timeline for invalidation of a credit, deficit calculation, or approved CI pathway. These steps are systematic from discovery of the issue to notifying all parties and final determination in resolving the issue. We note that regulated or opt-in parties are free to withhold a small percentage of their credits to ensure that there are always LCFS credits on hand if needed.

Credits and deficits are generated by regulated and opt-in parties after each quarterly reporting period ends and fuel transaction data are submitted in the LCFS reporting tool. These credits are available for use on a quarterly basis. The amount of time in the schedule in this section from discovery to final determination, plus an additional 60-days, gives entities 110 days. Staff believes that this provides producers and regulated parties ample time to clear up any credit invalidation actions taken against them. Additionally, this approach ensures that the Program objectives are met within reasonable timeframes and that regulated and opt-in parties take responsibility and exercise due diligence when purchasing, importing or producing LCFS compliant fuels.

Comment letter code: 7-SF-LCFS-Enerkym

Commenter: Labrie, Marie-Helene

Affiliation: Enerkym

The following letter was submitted to the LCFS Docket during the Second 15-day comment period.

This page intentionally left blank.

7_SF_LCFS
_Enerkem

Enerkem

July 8, 2015

Clerk of the Board,
Air Resources Board
1001 I Street,
Sacramento, California 95814

Dear Sir/Madam,

Enerkem appreciates the opportunity to submit comments on the modified text for the proposed re-adoption of the Low Carbon Fuel Standard (LCFS).

Enerkem is a leading waste-to-biofuels and chemicals company. We produce clean fuels and green chemicals from non-recyclable municipal solid waste, thus helping diversify energy sources while offering a sustainable alternative to landfilling and incineration. Our facility in Edmonton, Alberta (Canada) is the world's first commercial biorefinery to use municipal solid waste to produce biomethanol and ethanol. We are currently developing biorefineries in North America and globally, based on our modular and standardized manufacturing approach and using our proprietary biofuels technology, developed in-house since 2000.

The LCFS makes California a very attractive market for the low carbon ethanol to be produced at our Edmonton biorefinery (currently beginning operations), and also an attractive investment environment for developing future Enerkem facilities in the state.

We would first like to thank the Air Resources Board for taking low carbon fuel producers' concerns into account following the first 15-Day Modified Regulation Order by removing the limitations on the sale and transfer of credits generated under provisional pathways. Dropping this limitation removes a significant barrier to financing of projects to develop new capacity for low carbon fuel production in California and for the California market. LCFS SF7-1

This change, while very important, does not resolve all issues relating to new low carbon fuel production facilities. The proposed rule still requires that facilities be in "full commercial production" for at least one full calendar quarter before even applying for a new pathway. The rule places new facilities in an extremely difficult commercial position, by effectively requiring facilities to be in commercial production but without possibility to sell the fuel produced. Considering the time from submission of a new pathway application to publishing of the CI, new facilities would, in effect, have to be in "full commercial production" for approximately one year before being able to sell fuel into the California market.

This places a significant damper on any plans to develop new low carbon fuel production facilities in California, as it is unclear how such facilities could sell fuel produced during the first year of commercial operations. The uncertainty concerning revenue streams following plant construction, and the barrier to selling fuel in the first year of operations, will undermine financing for projects utilizing innovative fuel technologies and thereby hinder attainment of the Air Resources Board's aggressive CI and petroleum reduction goals.

1130 Sherbrooke Street West
Suite 1500
Montréal QC H3A 2M8 CANADA
www.enerkem.com

The provision also creates a barrier for out-of-state new production facilities that could potentially supply low carbon fuel to the California market, as without a CI it is nearly impossible to secure off-take agreements for low carbon fuel.

Enerkem urges the Air Resources Board to remove the requirement to have been in full commercial production for one quarter prior to applying for a new pathway, in order to encourage the production and commercialization of new low carbon fuels such as municipal waste to ethanol. LCFS SF7-2

Enerkem believes that the power of the Executive Officer to adjust the number of credits or reverse any provisional credit in the producer's account, until the provisional CI has been successfully corroborated by operational records covering a full two years of commercial operation, is sufficient to enable verification of carbon intensity data from new production facilities. However, if the Air Resources Board considers it necessary to have operational data to verify the proposed carbon intensity of the new pathway at the time of application, greater flexibility could be afforded to companies by allowing some of this data to come from the company's existing pilot or demonstration facilities or from commissioning activities at the facility for which the pathway is being requested. LCFS SF7-3

If the Air Resources Board wishes to limit pathway applications to commercial facilities that are being built, rather than leave the door open to the creation of pathways for which commercial projects have not yet been developed, Air Resources Board could consider requiring an independent engineering review and a site visit to be included with the application for a new pathway. LCFS SF7-4

We thank the Air Resources Board for the opportunity to submit comments on the modified text for the proposed re-adoption of the Low Carbon Fuel Standard (LCFS), and hope that the Board will make the small changes necessary to enable low carbon fuel producers to secure the financing required to develop new production facilities, which will be needed to achieve the Board's greenhouse gas emissions reductions goals.

Sincerely,

MHLabrie

Marie-Helene Labrie
Senior Vice-President, Government Affairs and Communications

7_SF_LCFS_Enerkem

1188. Comment: **LCFS SF7-1**

The comment is expressing support for ARB staff's proposed changes for provisional pathways.

Agency Response: See response **LCFS FF56-2**, **LCFS SF12-5**, **LCFS SF8-22**, and **LCFS SF6-1**.

1189. Comment: **LCFS SF7-2**

The commenter has urged the Air Resources Board to remove the proposed requirement for new LCFS applicants to be in full commercial production for one quarter prior to applying for pathway certification.

Agency Response: See response to **LCFS FF56-2**.

1190. Comment: **LCFS SF7-3**

This comment is related to the adjustments of LCFS credits and deficits accrued by the fuel producer over the two-year provisional pathway period by the Executive Officer. The Commenter concurs with the proposed method to adjust the CI and further suggests use of pilot plant data.

Agency Response: The Commenter concurs with the proposed method used by the Executive Officer to adjust the CI or inform the producer that the provisional CI has been successfully corroborated by operational records covering a full two years of commercial operation, and further adjust the number of credits or reverse any provisional credit in the producer's account. The Commenter's suggestion to use pilot or demonstration plant data in lieu of actual operating data from the fuel production facility with provisional certification will not suffice (due to concerns of process scalability, and reliability) for staff to assess life cycle analysis of GHG impacts of the fuel pathway based on actual operational data. See also **LCFS FF56-2**.

1191. Comment: **LCFS SF7-4**

This Comment is related to third-party engineering evaluation and facility visit to corroborate plant design and operating conditions.

Agency Response: ARB staff agrees and has made 15-day changes to address the concern. See response to **LCFS FF15-1**.

This page intentionally left blank.

Comment letter code: 8-SF-LCFS-GE

Commenter: Willter, Joshua

Affiliation: Growth Energy

The following letter was submitted to the LCFS Docket during the Second 15-day comment period.

This page intentionally left blank.

Growth Energy's Comments on June 23, 2015, 15-Day Notice for the Proposed Revisions to the LCFS Regulation

Growth Energy submits the following comments on the California Air Resources Board's ("CARB") June 23, 2015 Notice of Public Availability of Modified Text and Availability of Additional Documents (the "Second 15-Day Notice") for CARB's proposed revisions to the Low Carbon Fuel Standard (the "LCFS regulation").

The Second 15-Day Notice represents the second time CARB staff has performed substantive modifications to the proposed LCFS regulation since it initially circulated an Initial Statement of Reasons (the "ISOR") and an Environmental Analysis ("EA") for public review on December 30, 2014. The first 15-day notice was circulated for public review on June 4, 2015 (the "First 15-Day Notice").

Due to various concerns regarding the LCFS regulation, Growth Energy submitted comments on the ISOR and the EA during the first comment period, as well as the comment period for the First 15-Day Notice, under the California Environmental Quality Act, the California Administrative Procedures Act, and the Health & Safety Code. In addition to the issues raised previously, Growth Energy submits the following comments on the Second 15-Day Notice. Submitted with these comments are the declarations of James C. Lyons and Thomas L. Darlington, which are enclosed as Attachments "A" and "B," respectively.

A. CARB's LUC Value for Cane Ethanol of 11.8 gCO_2e/MJ Is Not Supported By Substantial Evidence, and Could Increase Greenhouse Gas Emissions

CARB's proposed revisions to the LCFS regulation contemplate a land use change ("LUC") value for cane ethanol of 11.8 gCO_2e/MJ, which is a significant departure from the 46 gCO_2e/MJ value stated in the original LCFS regulation. As explained in the Declaration of Thomas L. Darlington, which is provided as Attachment B, the substantial drop in LUC emissions for cane ethanol relates to CARB's estimate of the "perennial reversion GHG emissions" associated with cane. (Darlington ¶ 4.) "These emissions describe the carbon stored in a field when cane is planted after forest is removed for cane." (*Id.*)

Although CARB has produced a report describing the emissions released when various types of land are converted from one use to another, the report contains "no documentation or description for the perennial reversion emissions for various perennials, including cane" ethanol. (Decl. Darlington ¶ 5 [citing *Agro-Ecological Zone Emission Factor Model (v52)*, Plevin, Gibbs, Duffy, *et al.*, December 11, 2014.].) Appendix I of the ISOR likewise does not contain this information. (*Id.*) Because this information has not been provided, and is nowhere available in the public record, experts in the field are unable to "review how the cane LUC emissions were developed." (*Id.*) LCFS SF8-1

Growth Energy's expert, Thomas L. Darlington, has made several attempts to receive this information from CARB, to no avail. Among other things, Mr. Darlington has emailed CARB on several occasions to determine how ARB estimated these emissions. Yet, no substantive information regarding how CARB developed its estimate of the "perennial reversion GHG emissions" was provided. Thus, CARB has either failed to include documents in the rulemaking filed under Section 11347.3(b) of the Government Code, or CARB's LUC for cane ethanol is not based on any evidence, data, or study, and is thus arbitrary and capricious.

CARB's failure to support the 11.8 gCO_2e/MJ LUC value for cane ethanol also raises significant questions about the adequacy of CARB's environmental findings. Growth Energy considers the use of indirect LUC factors in the LCFS regulation to be generally unsound. Nevertheless, CARB has decided to include LUC factors as a component of the Carbon Intensity ("CI") Value placed on a fuel by CARB. If CARB inaccurately calculates the LUC (and thus the CI Value) of a fuel—such as sugarcane ethanol—as being too low, it will make more difficult the task of achieving reductions in greenhouse gas emissions, which is the purpose of the LCFS regulation. By reducing the CI value assigned to sugarcane ethanol below a level that is scientifically supportable relative to other renewable fuels, CARB is incentivizing the use of fuels that do not provide the maximum GHG reductions in a cost-effective manner. The LCFS regulation will create incorrect "market signals" contrary to the intended effect of the overall LCFS program.[1] LCFS SF8-1 cont.

To avoid these potential adverse consequences, and to develop LUC Values (and thereby CI Values) that are based on scientific data, CARB should produce the evidence, data, or study upon which its estimate of the "perennial reversion GHG emissions" for cane was based, (assuming such information exists), and recirculate the revised LCFS regulation for public comment.

B. CARB Staff Failed to Disclose Material Information Regarding the Proposed LCFS Regulation to the California Environmental Policy Council

Prior to the June 23, 2015, public hearing by the California Environmental Policy Council ("CEPC") on the LCFS regulation, Growth Energy and Western States Petroleum Association ("WSPA") submitted written comments on the multimedia evaluation ("MME") prepared for the LCFS regulation. Those written comments are included as Exhibits "F" and "G" to the Lyons Declaration, which is enclosed with these comments as Attachment B.[2] The comments specifically reference flaws in both CARB's proposed MME and the peer review process: (1) the failure ***of the MME*** to assess the environmental impacts of di-tertiary butyl peroxide (DTBP) at higher concentrations than the presently; (2) incorporation ***in the MME*** of an obsolete and incomplete analysis of air quality impacts associated with biodiesel that has been superseded by an analysis CARB staff performed for the ADF rulemaking; and (3) CARB staff's failure to provide ***the MME's peer reviewers*** with all of the relevant scientific information and data available to CARB staff related to air quality impacts associated with biodiesel. The LCFS SF8-2

1 See CARB, "Staff Report: Initial Statement of Reasons, Proposed Regulation to Implement the Low Carbon Fuel Standard," Vol. I at VI-20 (March 5, 2006), available at http://www.arb.ca.gov/fuels/lcfs/030409lcfs_isor_vol1.pdf.

2 The comments stated in Exhibits "F" and "G" to the Lyons Declaration are incorporated into this letter as if set forth fully herein.

comment letter submitted by Growth Energy also referenced a proposed alternative to CARB staff's proposed ADF regulation that would ensure no NOx increases would occur.

Although the comments submitted by Growth Energy and WSPA relate directly to the MME, CARB staff did not summarize those comments to the CEPC. Rather, CARB staff at the June 23, 2015 hearing represented to the CEPC that Growth Energy's and WSPA's comments were "not particularly relevant." After CARB's Assistant Chief Counsel subsequently corrected CARB staff's statements, and conceded that the comments "did pertain to the Multi-Media Evaluation," CARB staff then asserted the comments "did nothing to alter the CARB findings being presented to the CEPC." (Decl. Lyons ¶ 6.) Although CARB staff was asked at several points by CEPC Chair Matthew Rodriquez about the comments, CARB staff preempted a serious discussion of the concerned raised by Growth Energy and WSPA by the CEPC.

LCFS SF8-2 cont.

As a result of these flaws, CARB did not fully discharge its duty under Section 43830.8 of the Health and Safety Code. Among other things, Section 43830.8 requires a "multimedia evaluation" to be based on (i) "the best available scientific data," (ii) "written comments submitted by any interested person," and (iii) "information collected by the state board in preparation for rulemaking." As explained in the comments of Growth Energy and WSPA, CARB complied with none of these requirements, and instead chose to ignore the best available scientific data, concealed arguments submitted in written comments, and declined to disclose more recent information collected by the state board itself. Because CARB failed to comply with its procedural mandate under Section 43830.8, CARB cannot adopt the LCFS regulation at this time.

ATTACHMENT A

Declaration of James M. Lyons

STATE OF CALIFORNIA

BEFORE THE AIR RESOURCES BOARD

Declaration of James M. Lyons

I, James Michael Lyons, declare as follows:

1. I make this Declaration based upon my own personal knowledge and my familiarity with the matters recited herein. It is based on my experience of nearly 30 years as a regulator, consultant, and professional in the field of emissions and air pollution control. A copy of my résumé can be found in Exhibit "A."

2. I am a Senior Partner of Sierra Research, Inc., an environmental consulting firm located at 1801 J Street, Sacramento, California owned by Trinity Consultants, Inc. Sierra specializes in research and regulatory matters pertaining to air pollution control, and does work for both governmental and private industry clients. I have been employed at Sierra Research since 1991. I received a B.S. degree in Chemistry from the University of California, Irvine, and a M.S. Degree in Chemical Engineering from the University of California, Los Angeles. Before joining Sierra in 1991, I was employed by the State of California at the Mobile Source Division of the California Air Resources Board (CARB).

3. During my career, I have worked on many projects related to the following areas: (1) the assessment of emissions from on- and non-road mobile sources, (2) the assessment of the impacts of changes in fuel composition and alternative fuels on engine emissions including emissions of green-house gases, (3) analyses of the unintended consequences of regulatory actions, and (4) the feasibility of compliance with air quality regulations.

4. I have testified as an expert under state and federal court rules in cases involving CARB regulations for gasoline, Stage II vapor recovery systems and their design, factors affecting emissions from diesel vehicles, evaporative emission control system design and function, as well as combustion chamber system design. While at Sierra I have acted as a consultant on automobile air pollution control matters for CARB and for the United States Environmental Protection Agency. I am a member of the American Chemical Society and the Society of Automotive Engineers and have co-authored nine peer-reviewed monographs concerned with automotive emissions, including greenhouse gases and their control. In addition, over the course of my career, I have conducted peer-reviews of numerous papers related to a wide variety of issues associated with pollutant emissions and air quality.

5. This Declaration identifies significant omissions by CARB staff in providing relevant information to the California Environmental Policy Council (CEPC) during the Council's Public Meeting of June 23, 2015. These omissions include (1) the failure of LCFS SF8-3

CARB staff to accurately summarize written comments related to the Multi-Media Evaluation (MME) of biodiesel[1] submitted to the CEPC, and (2) the failure of CARB staff to make the CEPC aware during the meeting of alternatives that would be more environmentally protective than the proposed Alternative Diesel Fuel regulation and therefore the Low Carbon Fuel Standard (LCFS) regulation. A complete electronic video recording of the June 23, 2015 CEPC meeting, which I received from CEPC, has been submitted along with this Declaration and is referred to here as Exhibit "B." In addition, the briefing presentation,[2] staff presentation,[3] and draft resolution[4] that was ultimately approved by the CEPC on June 23, can be found in Exhibits "C," "D," and "E," respectively, to this Declaration. LCFS SF8-3 cont.

6. Both Growth Energy[5] and the Western States Petroleum Association (WSPA)[6] submitted written comments to the CEPC (see Exhibits "F" and "G," respectively, to this Declaration). The sole summary of the written comments submitted by Growth Energy can be found on page 90 of the staff presentation contained in Exhibit "D." As can be seen, there is no substantive summary of either the Growth Energy or WSPA comments. During a discussion of these comments[7] involving CEPC Chair, Matthew Rodriquez, and CARB staff member Jim Aguila, both sets of comments were deemed to be "not particularly relevant." However, later in the proceeding,[8] Stephen Adams, Assistant Chief Counsel of CARB, acknowledged that at least portions of the Growth Energy and WSPA comments "did pertain to the Multi-Media Evaluation" and provided two limited examples from the comments to illustrate that point. Mr. Rodriquez then returned to the issue of the relevance of the Growth Energy and WSPA comments[9] and, in response to his question, was told by CARB that they did nothing to alter the CARB findings being presented to the CEPC. LCFS SF8-4

---

[1] See http://www.arb.ca.gov/fuels/diesel/altdiesel/20150521BD_StaffReport.pdf

[2] See http://www.calepa.ca.gov/cepc/2015/CouncilBrief.pdf

[3] See http://www.calepa.ca.gov/cepc/2015/Presentation.pdf

[4] See http://www.calepa.ca.gov/cepc/2015/Resolution.pdf

[5] See http://www.calepa.ca.gov/cepc/2015/KinseyHelsey.pdf

[6] See http://www.calepa.ca.gov/cepc/2015/BoydWSPA.pdf

[7] This discussion takes place between about 1:44 and 1:46 of the runtime of the recording submitted as Exhibit "B."

[8] This discussion takes place between about 1:53 to 1:55 of the runtime of the recording submitted as Exhibit "B."

[9] This discussion takes place between about 1:57 and 1:58 of the runtime of the recording submitted as Exhibit "B."

7. As documented through the video recording of the June 23, 2015 CEPC public meeting, the CEPC was relying on CARB staff to summarize both the substance and import of the written comments received from Growth Energy and WSPA. As indicated by Mr. Adams, these comments did pertain to the biodiesel MME and, based on my expertise, should be considered by any entity claiming to have reached a conclusion "based on the best available scientific information and public comments received," as is stated in the CEPC resolution. More specifically, issues raised in the Growth Energy and WSPA comments and directly germane to the environmental impacts of biodiesel, but not presented to the CEPC by CARB, include the following:

- Failure of the MME to comprehensively assess the environmental impacts of the use of di-tertiary butyl peroxide (DTBP) at much higher concentrations than it is currently used; LCFS SF8-5
- Incorporation in the MME of an obsolete and incomplete analysis of the air quality impacts associated with the use of biodiesel, which was superseded by the analysis CARB staff actually performed for the ADF rulemaking; LCFS SF8-6
- Failure of CARB staff to provide the peer reviewers of the biodiesel MME with all of the relevant scientific information and data that were available to CARB staff and related to the air quality impacts associated with biodiesel; and that LCFS SF8-7
- Growth Energy has proposed an alternative to the staff's proposed ADF regulation that would ensure that increases in NOx emissions would not occur in California due to the use of biodiesel. LCFS SF8-8

12. In summary, in my opinion, the flaws in the biodiesel MME identified in the written comments supplied by Growth Energy and WSPA to the CEPC render it unsuitable to support a finding that there will be no significant adverse environmental impact from the use of biodiesel in California. Given that the CEPC has relied on the biodiesel MME, its findings regarding the environmental impact of biodiesel use in California are similarly flawed. LCFS SF8-9

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 8th day of July, 2015 at Sacramento, California.

JAMES M. LYONS

This page intentionally left blank.

8_SF_LCFS_GE (Page 1 – 7)

1192. Comment: **LCFS SF8-1, LCFS SF8-2, LCFS SF8-5 through LCFS SF8-9**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

1193. Comment: **LCFS SF8-3**

Furthering its comment **SF8-2** [that ARB did not comply with section 43830.8 of the Health and Safety Code], the commenter attaches the Lyons declaration arguing that ARB failed to provide the CEPC with an accurate summary of written comments regarding the MME, and failed to inform the CEPC regarding alternatives the commenter claims would be more environmentally protective than the proposed ADF.

Agency Response: ARB staff disagrees; the ample record before the CEPC allowed the CEPC to fulfill its role under section 43830.8 of the Health and Safety Code. That record is too voluminous to include in this response, but it is publicly available, and the Board found that the MME process was regularly conducted and approved as required by section 43830.8 of the Health and Safety Code.

1194. Comment: **LCFS SF8-4**

The commenter asserts that the written comments to the CEPC were not adequately summarized in the staff's presentation to that body, and further assumes that the CEPC did not consider comments submitted to it.

Agency Response: This comment seems directed primarily at the actions of the CEPC, which is a separate body from ARB, and thus does not require response. However, as the comment itself shows, the written comments to the CEPC were discussed at the CEPC meeting. Further, the CEPC considered those comments and expressly indicated it had done so: "WHEREAS, the Council received and considered written comments submitted on June 22, 2015 by Growth Energy and by the Western States Petroleum Association, and also received and considered comments from interested parties at the June 23, 2015 meeting of the Council." The CEPC also "RESOLVED, that after review of the biodiesel multimedia evaluation and the proposed ADF regulation, and based on the best available scientific information and public comments received, the Council determines that the use of biodiesel in California consistent with the proposed ADF regulation will not pose a significant adverse impact on public health or the environment compared to CARB diesel fuel."

The CEPC meeting notice specifically requested that written comments be submitted in advance of the hearing precisely so the CEPC members had time to consider them prior to taking action. The written comments were in fact received before the day of the hearing and were provided to CEPC members for their consideration. Council members also listened to oral comments made at the hearing itself prior to taking action. There is no legal requirement that staff separately summarize written or oral comments submitted to the CEPC, and those submitting written comments could have appeared at the hearing to summarize their written comments if they chose to do so, but elected not to.

The commenter appears to ask ARB to disbelieve CEPC's assertion that it considered the written comments presented to it. Setting aside whether ARB could do so, the comment provides no basis to conclude that CEPC's clear findings are erroneous.

Exhibit A to Declaration of James M. Lyons

sierra
research
A Trinity Consultants Company
1801 J Street
Sacramento, CA 95811
Tel: (916) 444-6666
Fax: (916) 444-8373
Ann Arbor, MI
Tel: (734) 761-6666
Fax: (734) 761-6755

Résumé

James Michael Lyons

Education

1985, M.S., Chemical Engineering, University of California, Los Angeles

1983, B.S., Cum Laude, Chemistry, University of California, Irvine

Professional Experience

4/91 to present — Senior Engineer/Partner/Senior Partner
Sierra Research

Primary responsibilities include oversight and execution of complex analyses of the emission benefits, costs, and cost-effectiveness of mobile source air pollution control measures. Mr. Lyons has developed particular expertise with respect to the assessment of control measures involving fuel reformulation, fuel additives, and alternative fuels, as well as accelerated vehicle/engine retirement programs, the deployment of advanced emission control systems for on- and non-road gasoline- and Diesel-powered engines, on-vehicle evaporative and refueling emission control systems, and Stage I and Stage II service station vapor recovery systems. Additional duties include assessments of the activities of federal, state, and local regulatory agencies with respect to motor vehicle emissions and reports to clients regarding those activities. Mr. Lyons has extensive litigation experience related to air quality regulations, product liability, and intellectual property issues.

7/89 to 4/91 — Senior Air Pollution Specialist
California Air Resources Board

Supervised a staff of four professionals responsible for identifying and controlling emissions of toxic air contaminants from mobile sources and determining the effects of compositional changes to gasoline and diesel fuel on emissions of regulated and unregulated pollutants. Other responsibilities included development of new test procedures and emission standards for evaporative and running loss emissions of hydrocarbons from vehicles; overseeing the development of the state plan to control toxic emissions from motor vehicles; and reducing emissions of CFCs from motor vehicles.

4/89 to 7/89 — Air Pollution Research Specialist
California Air Resources Board

Responsibilities included identification of motor vehicle research needs; writing requests for proposals; preparation of technical papers and reports; as well as monitoring and overseeing research programs.

9/85 to 4/89 — Associate Engineer/Engineer
California Air Resources Board

Duties included analysis of vehicle emissions data for trends and determining the effectiveness of various types of emissions control systems for both regulated and toxic emissions; determining the impact of gasoline and diesel powered vehicles on ambient levels of toxic air contaminants; participation in the development of regulations for "gray market" vehicles; and preparation of technical papers and reports.

Professional Affiliations

American Chemical Society
Society of Automotive Engineers

Selected Publications (Author or Co-Author)

"Development of Vehicle Attribute Forecasts for 2013 IEPR," Sierra Research Report No. SR2014-01-01, prepared for the California Energy Commission, January 2014.

"Assessment of the Emission Benefits of U.S. EPA's Proposed Tier 3 Motor Vehicle Emission and Fuel Standards," Sierra Research Report No. SR2013-06-01, prepared for the American Petroleum Institute, June 2013.

"Development of Inventory and Speciation Inputs for Ethanol Blends," Sierra Research Report No. SR2012-05-01, prepared for the Coordinating Research Council, Inc. (CRC), May 2012.

"Review of CARB Staff Analysis of 'Illustrative' Low Carbon Fuel Standard (LCFS) Compliance Scenarios," Sierra Research Report No. SR2012-02-01, prepared for the Western States Petroleum Association, February 20, 2012.

"Review of CARB On-Road Heavy-Duty Diesel Emissions Inventory," Sierra Research Report No. SR2010-11-01, prepared for The Ad Hoc Working Group, November 2010.

"Identification and Review of State/Federal Legislative and Regulatory Changes Required for the Introduction of New Transportation Fuels," Sierra Research Report No. SR2010-08-01, prepared for the American Petroleum Institute, August 2010.

“Technical Review of EPA Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis for Non-GHG Pollutants,” Sierra Research Report No. SR2010-05-01, prepared for the American Petroleum Institute, May 2010.

“Effects of Gas Composition on Emissions from Heavy-Duty Natural Gas Engines,” Sierra Research Report No. SR2010-02-01, prepared for the Southern California Gas Company, February 2010.

“Effects of Gas Composition on Emissions from a Light-Duty Natural Gas Vehicle,” Sierra Research Report No. SR2009-11-01, prepared for the Southern California Gas Company, November 2009.

“Technical Review of 2009 EPA Draft Regulatory Impact Analysis for Non-GHG Pollutants Due to Changes to the Renewable Fuel Standard,” Sierra Research Report No. SR2009-09-01, prepared for the American Petroleum Institute, September 2009.

“Effects of Vapor Pressure, Oxygen Content, and Temperature on CO Exhaust Emissions,” Sierra Research Report No. 2009-05-03, prepared for the Coordinating Research Council, May 2009.

“Technical Review of 2007 EPA Regulatory Impact Analysis Methodology for the Renewable Fuels Standard,” Sierra Research Report No. 2008-09-02, prepared for the American Petroleum Institute, September 2008.

“Impacts of MMT Use in Unleaded Gasoline on Engines, Emission Control Systems, and Emissions,” Sierra Research Report No. 2008-08-01, prepared for McMillan Binch Mendelsohn LLP, Canadian Vehicle Manufacturers’ Association, and Association of International Automobile Manufacturers of Canada, August 2008.

“Attachment to Comments Regarding the NHTSA Proposal for Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015, Docket No. NHTSA-2008-0089,” Sierra Research Report No. SR2008-06-01, prepared for the Alliance of Automobile Manufacturers, June 2008.

“Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act – Part 1: Impacts on New Vehicle Fuel Economy,” SAE Paper No. 2008-01-1852, Society of Automotive Engineers, 2008.

“Basic Analysis of the Cost and Long-Term Impact of the Energy Independence and Security Act Fuel Economy Standards,” Sierra Research Report No. SR 2008-04-01, April 2008.

“The Benefits of Reducing Fuel Consumption and Greenhouse Gas Emissions from Light-Duty Vehicles,” SAE Paper No. 2008-01-0684, Society of Automotive Engineers, 2008.

“Assessment of the Need for Long-Term Reduction in Consumer Product Emissions in South Coast Air Basin,” Sierra Research Report No. 2007-09-03, prepared for the Consumer Specialty Products Association, September 2007.

"Summary of Federal and California Subsidies for Alternative Fuels," Sierra Research Report No. SR2007-04-02, prepared for the Western States Petroleum Association, April 2007.

"Analysis of IRTA Report on Water-Based Automotive Products," Sierra Research Report No. SR2006-08-02, prepared for the Consumer Specialty Projects Association and Automotive Specialty Products Alliance, August 2006.

"Evaluation of Pennsylvania's Implementation of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2006-04-01, prepared for Alliance of Automobile Manufacturers, April 12, 2006.

"Evaluation of New Jersey's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-03, prepared for the Alliance of Automobile Manufacturers, September 30, 2005.

"Evaluation of Vermont's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-02, prepared for the Alliance of Automobile Manufacturers, September 19, 2005.

"Assessment of the Cost-Effectiveness of Compliance Strategies for Selected Eight-Hour Ozone NAAQS Nonattainment Areas," Sierra Research Report No. SR2005-08-04, prepared for the American Petroleum Institute, August 30, 2005.

"Evaluation of Connecticut's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-08-03, prepared for the Alliance of Automobile Manufacturers, August 26, 2005.

"Evaluation of New York's Adoption of California's Greenhouse Gas Regulations On Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-07-04, prepared for the Alliance of Automobile Manufacturers, July 14, 2005.

"Review of MOVES2004," Sierra Research Report No. SR2005-07-01, prepared for the Alliance of Automobile Manufacturers, July 11, 2005.

"Review of Mobile Source Air Toxics (MSAT) Emissions from On-Highway Vehicles: Literature Review, Database, Development, and Recommendations for Future Studies," Sierra Research Report No. SR2005-03-01, prepared for the American Petroleum Institute, March 4, 2005.

"The Contribution of Diesel Engines to Emissions of ROG, NOx, and PM2.5 in California: Past, Present, and Future," Sierra Research Report No. SR2005-02-01, prepared for Diesel Technology Forum, February 2005.

"Fuel Effects on Highway Mobile Source Air Toxics (MSAT) Emissions," Sierra Research Report No. SR2004-12-01, prepared for the American Petroleum Institute, December 23, 2004.

"Review of the August 2004 Proposed CARB Regulations to Control Greenhouse Gas Emissions from Motor Vehicles: Cost Effectiveness for the Vehicle Owner or Operator – Appendix C to the Comments of The Alliance of Automobile Manufacturers," Sierra Research Report No. SR2004-09-04, prepared for the Alliance of Automobile Manufacturers, September 2004.

"Emission and Economic Impacts of an Electric Forklift Mandate," Sierra Research Report No. SR2003-12-01, prepared for National Propane Gas Association, December 12, 2003.

"Reducing California's Energy Dependence," Sierra Research Report No. SR2003-11-03, prepared for Alliance of Automobile Manufacturers, November 25, 2003.

"Evaluation of Fuel Effects on Nonroad Mobile Source Air Toxics (MSAT) Emissions: Literature Review, Database Development, and Recommendations for Future Studies," Sierra Research Report No. SR2003-10-01, prepared for American Petroleum Institute, October 3, 2003.

"Review of Current and Future CO Emissions from On-Road Vehicles in Selected Western Areas," Sierra Research Report No. SR03-01-01, prepared for the Western States Petroleum Association, January 2003.

"Review of CO Compliance Status in Selected Western Areas," Sierra Research Report No. SR02-09-04, prepared for the Western States Petroleum Association, September 2002.

"Impacts Associated With the Use of MMT as an Octane Enhancing Additive in Gasoline – A Critical Review", Sierra Research Report No. SR02-07-01, prepared for Canadian Vehicle Manufacturers Association and Association of International Automobile Manufacturers of Canada, July 24, 2002.

"Critical Review of 'Safety Oversight for Mexico-Domiciled Commercial Motor Carriers, Final Programmatic Environmental Assessment', Prepared by John A Volpe Transportation Systems Center, January 2002," Sierra Research Report No. SR02-04-01, April 16, 2002.

"Critical Review of the Method Used by the South Coast Air Quality Management District to Establish the Emissions Equivalency of Heavy-Duty Diesel- and Alternatively Fueled Engines", Sierra Research Report No. SR01-12-03, prepared for Western States Petroleum Association, December 21, 2001.

"Review of U.S. EPA's Diesel Fuel Impact Model", Sierra Research Report No. SR01-10-01, prepared for American Trucking Associations, Inc., October 25, 2001.

"Operation of a Pilot Program for Voluntary Accelerated Retirement of Light-Duty Vehicles in the South Coast Air Basin," Sierra Research Report No. SR01-05-02, prepared for California Air Resources Board, May 2001.

"Comparison of Emission Characteristics of Advanced Heavy-Duty Diesel and CNG Engines," Sierra Report No. SR01-05-01, prepared for Western States Petroleum Association, May 2001.

"Analysis of Southwest Research Institute Test Data on Inboard and Sterndrive Marine Engines," Sierra Report No. SR01-01-01, prepared for National Marine Manufacturers Association, January 2001.

"Institutional Support Programs for Alternative Fuels and Alternative Fuel Vehicles in Arizona: 2000 Update," Sierra Report No. SR00-12-04, prepared for Western States Petroleum Association, December 2000.

"Real-Time Evaporative Emissions Measurement: Mid-Morning Commute and Partial Diurnal Events," SAE Paper No. 2000-01-2959, October 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," SAE Paper No. 2000-01-2958, October 2000.

"A Comparative Analysis of the Feasibility and Cost of Compliance with Potential Future Emission Standards for Heavy-Duty Vehicles Using Diesel or Natural Gas," Sierra Research Report No. SR00-02-02, prepared for Californians For a Sound Fuel Strategy, February 2000.

"Critical Review of the Report Entitled 'Economic Impacts of On Board Diagnostic Regulations (OBD II)' Prepared by Spectrum Economics," Sierra Research Report No. SR00-01-02, prepared for the Alliance of Automobile Manufacturers, January 2000.

"Potential Evaporative Emission Impacts Associated with the Introduction of Ethanol-Gasoline Blends in California," Sierra Research Report No. SR00-01-01, prepared for the American Methanol Institute, January 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," Sierra Research Report No. SR99-10-03, prepared for the Coordinating Research Council, October 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," SAE Paper No. 1999-01-3676, August 1999.

"Future Diesel-Fueled Engine Emission Control Technologies and Their Implications for Diesel Fuel Properties," Sierra Research Report No. SR99-08-01, prepared for the American Petroleum Institute, August 1999.

"Analysis of Compliance Feasibility under Proposed Tier 2 Emission Standards for Passenger Cars and Light Trucks," Sierra Research Report No. SR99-07-02, July 1999.

"Comparison of the Properties of Jet A and Diesel Fuel," Sierra Research Report No. SR99-02-01, prepared for Pillsbury Madison and Sutro, February 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," Sierra Research Report No. SR98-12-02, prepared for the American Petroleum Institute, December 1998.

"Analysis of New Motor Vehicle Issues in the Canadian Government's Foundation Paper on Climate Change – Transportation Sector," Sierra Research Report No. SR98-12-01, prepared for the Canadian Vehicle Manufacturers Association, December 1998.

"Investigation of the Relative Emission Sensitivities of LEV Vehicles to Gasoline Sulfur Content - Emission Control System Design and Cost Differences," Sierra Research Report No. SR98-06-01, prepared for the American Petroleum Institute, June 1998.

"Costs, Benefits, and Cost-Effectiveness of CARB's Proposed Tier 2 Regulations for Handheld Equipment Engines and a PPEMA Alternative Regulatory Proposal," Sierra Research Report No. SR98-03-03, prepared for the Portable Power Equipment Manufacturers Association, March 1998.

"Analysis of Diesel Fuel Quality Issues in Maricopa County, Arizona," Sierra Research Report No. SR97-12-03, prepared for the Western States Petroleum Association, December 1997.

"Potential Impact of Sulfur in Gasoline on Motor Vehicle Pollution Control and Monitoring Technologies," prepared for Environment Canada, July 1997.

"Analysis of Mid- and Long-Term Ozone Control Measures for Maricopa County," Sierra Research Report No. SR96-09-02, prepared for the Western States Petroleum Association, September 9, 1996.

"Technical and Policy Issues Associated with the Evaluation of Selected Mobile Source Emission Control Measures in Nevada," Sierra Research Report No. SR96-03-01, prepared for the Western States Petroleum Association, March 1996.

"Cost-Effectiveness of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-05, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"Cost of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-04, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"A Comparative Characterization of Gasoline Dispensing Facilities With and Without Vapor Recovery Systems," Sierra Research Report No. SR95-10-01, prepared for the Province of British Columbia Ministry of Environment Lands and Parks, October 1995.

"Potential Air Quality Impacts from Changes in Gasoline Composition in Arizona," Sierra Research Report No. SR95-04-01, prepared for Mobil Corporation, April 1995.

"Vehicle Scrappage: An Alternative to More Stringent New Vehicle Standards in California," Sierra Research Report No. SR95-03-02, prepared for Texaco, Inc., March 1995.

"Evaluation of CARB SIP Mobile Source Measures," Sierra Research Report No. SR94-11-02, prepared for Western States Petroleum Association, November 1994.

"Reformulated Gasoline Study," prepared by Turner, Mason & Company, DRI/McGraw-Hill, Inc., and Sierra Research, Inc., for the New York State Energy Research and Development Authority, Energy Authority Report No. 94-18, October 1994.

"Phase II Feasibility Study: Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley," Sierra Research Report No. SR94-09-02, prepared for the Greater Vancouver Regional District, September 1994.

"Cost-Effectiveness of Mobile Source Emission Controls from Accelerated Scrappage to Zero Emission Vehicles," Paper No. 94-TP53.05, presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, OH, June 1994.

"Investigation of MOBILE5a Emission Factors, Assessment of I/M Program and LEV Program Emission Benefits," Sierra Research Report No. SR94-06-05, prepared for American Petroleum Institute, June 1994.

"Cost-Effectiveness of the California Low Emission Vehicle Standards," SAE Paper No. 940471, 1994.

"Meeting ZEV Emission Limits Without ZEVs," Sierra Research Report No. SR94-05-06, prepared for Western States Petroleum Association, May 1994.

"Evaluating the Benefits of Air Pollution Control - Method Development and Application to Refueling and Evaporative Emissions Control," Sierra Research Report No. SR94-03-01, prepared for the American Automobile Manufacturers Association, March 1994.

"The Cost-Effectiveness of Further Regulating Mobile Source Emissions," Sierra Research Report No. SR94-02-04, prepared for the American Automobile Manufacturers Association, February 1994.

"Searles Valley Air Quality Study (SVAQS) Final Report," Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

"A Comparative Study of the Effectiveness of Stage II Refueling Controls and Onboard Refueling Vapor Recovery," Sierra Research Report No. SR93-10-01, prepared for the American Automobile Manufacturers Association, October 1993.

"Evaluation of the Impact of the Proposed Pole Line Road Overcrossing on Ambient Levels of Selected Pollutants at the Calgene Facilities," Sierra Research Report No. SR93-09-01, prepared for the City of Davis, September 1993.

“Leveling the Playing Field for Hybrid Electric Vehicles: Proposed Modifications to CARB’s LEV Regulations,” Sierra Research Report No. SR93-06-01, prepared for the Hybrid Vehicle Coalition, June 1993.

“Size Distributions of Trace Metals in the Los Angeles Atmosphere,” *Atmospheric Environment*, Vol. 27B, No. 2, pp. 237-249, 1993.

“Preliminary Feasibility Study for a Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley Area,” Sierra Research Report No. 92-10-01, prepared for the Greater Vancouver Regional District, October 1992.

“Development of Mechanic Qualification Requirements for a Centralized I/M Program,” SAE Paper No. 911670, 1991.

“Cost-Effectiveness Analysis of CARB’s Proposed Phase 2 Gasoline Regulations,” Sierra Research Report No. SR91-11-01, prepared for the Western States Petroleum Association, November 1991.

“Origins and Control of Particulate Air Toxics: Beyond Gas Cleaning,” in Proceedings of the Twelfth Conference on Cooperative Advances in Chemical Science and Technology, Washington, D.C., October 1990.

“The Effect of Gasoline Aromatics on Exhaust Emissions: A Cooperative Test Program,” SAE Paper No. 902073, 1990.

“Estimation of the Impact of Motor Vehicles on Ambient Asbestos Levels in the South Coast Air Basin,” Paper No. 89-34B.7, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

“Benzene/Aromatic Measurements and Exhaust Emissions from Gasoline Vehicles,” Paper No. 89-34B.4, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

“The Impact of Diesel Vehicles on Air Pollution,” presented at the 12th North American Motor Vehicle Emissions Control Conference, Louisville, KY, April 1988.

“Exhaust Benzene Emissions from Three-Way Catalyst-Equipped Light-Duty Vehicles,” Paper No. 87-1.3, presented at the 80th Annual Meeting of the Air Pollution Control Association, New York, NY, June 1987.

“Trends in Emissions Control Technologies for 1983-1987 Model-Year California-Certified Light-Duty Vehicles,” SAE Paper No. 872164, 1987.

8_SF_LCFS_GE (Page 8 – 17)

1195. Comment: **James Lyons' Resume**

Agency Response: This is submittal four of six of James Lyon's resume. It does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

Exhibit B to Declaration of James M. Lyons

(video file: Lyons Exhibit B Environmental Policy Council 2015-06-23.mp4)

This page intentionally left blank.

8_SF_LCFS_GE (Page 18)

1196. Comment: **Video of the CEPC hearing**

Agency Response: This video does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

Exhibit C to Declaration of James M. Lyons

California Environmental Protection Agency

Multimedia Workgroup

Briefing for Council Members

Multimedia Evaluations of Biodiesel and Renewable Diesel

June 2015

Why is ARB Interested in Biodiesel and Renewable Diesel?

- Both are low carbon and renewable fuels
- Air quality benefits in toxics, PM, HC, CO_2
- Key strategies for Low Carbon Fuel Std.
- 2030 goal of 40% GHG reduction
- 2030 goal of 50% reduction in petroleum use
- Federal Renewable Fuel Standard 2

Multimedia Evaluation (MME)

- Definition – *Identification and evaluation of **any significant adverse impact** on public health or the environment, including air, water, or soil, that may result from the production, use, or disposal of the motor vehicle fuel that may be used to meet the state board's motor vehicle fuel specifications.* (HSC 43830.8)

- Requirements
  - ✓ MME required before motor vehicle fuel specifications are established
  - ✓ Must address:
    - – *Emissions of air pollutants*
    - – *Contamination of surface water, groundwater, and soil*
    - – *Disposal or use of byproducts and waste materials*
  - ✓ Summary of MME – Multimedia Working Group (MMWG) Staff Report
  - ✓ External Scientific Peer Review
  - ✓ CA Environmental Policy Council (CEPC) Review
  - ✓ CEPC determination of significant impact, less adverse alternatives

CEPC and MMWG

- CEPC
  - Established pursuant to Public Resources Code 71017
  - Council Members
    - *Matthew Rodriquez*, Agency Secretary
    - *Mary D. Nichols*, Chairman, ARB
    - *Lauren Ziese*, Acting Director, OEHHA
    - *Felicia Marcus*, Chairman, Waterboard
    - *Barbara A. Lee*, Director, DTSC
    - *Brian R. Leahy*, Director, DPR
    - *Caroll Mortensen*, Director, CalRecycle

- MMWG
  - Oversees MME process
  - Reviews reports; prepares MME Staff Report
  - Makes recommendations to CEPC
  - Members: ARB, DTSC, OEHHA, Waterboard, OSFM

California Environmental Policy Council Shall:

Determine whether proposed regulation will cause significant adverse impact on public health or environment, whether less-adverse alternatives exist

- No significant adverse impact and no less-adverse alternatives – No further action dictated
- Significant adverse impact or less harmful alternatives exist – Council recommends alternative measures to reduce impacts

ARB MMEs Considered by CEPC

- 2011 – Viscon-Treated Diesel Fuel as verified Diesel Emission Control strategy (vDECS)
- 2004 – PuriNOx-Treated Diesel Fuel as vDECS
- 2004 – Amendments to the California Diesel Fuel Regulations
- 1999 – Ethanol Used in California Reformulated Gasoline

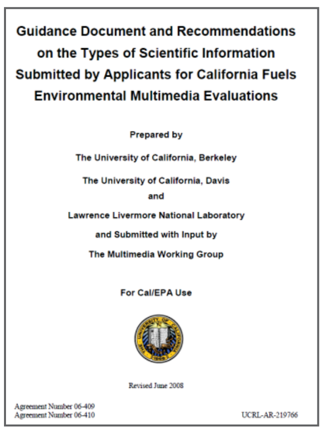
Procedural Requirements/Elements

- Bagley-Keene Act applies to EPC:
  - Agenda and notice must be published by June 12
  - Limits on discussions between EPC members
- CEQA does not apply:
  - Ultimate approval authority lies with ARB, not EPC
  - Impact analysis of MME varies from CEQA analysis
- Conduct of hearing:
  - Legal adviser to EPC (TBD)
  - Each BDO on MMWG will have a presentation
  - Staff will respond to questions from EPC members, but not directly to public comment unless EPC members asked for staff response

Multimedia Evaluation Process

Tier I
Work Plan

Work Plan
- Define framework and scope
- Identify key knowledge gaps
- Feedback provided


Guidance Document and Recommendations on the Types of Scientific Information Submitted by Applicants for California Fuels Environmental Multimedia Evaluations

Prepared by
The University of California, Berkeley
The University of California, Davis
and
Lawrence Livermore National Laboratory
and Submitted with Input by
The Multimedia Working Group

For Cal/EPA Use

Revised June 2008

Agreement Number 06-409
Agreement Number 06-410

UCRL-AR-219766

Tier II
Risk Assessment Protocol

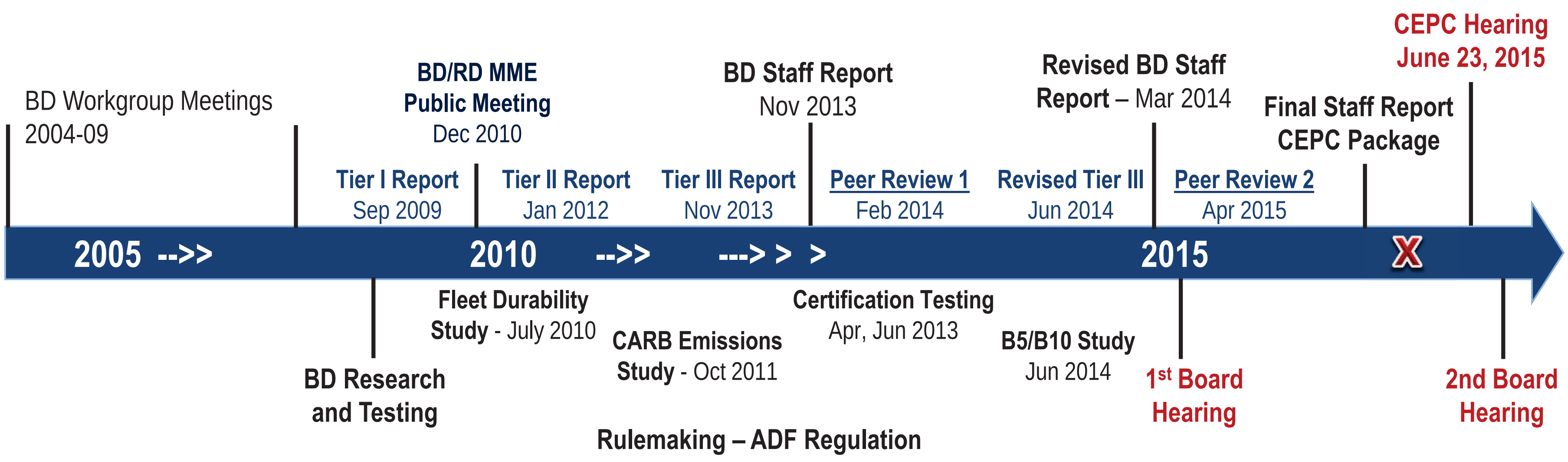
Risk Assessment Protocol
- Experimental design developed and submitted
- Protocol reviewed, feedback provided

Final Report Risk Assessment
- Execution of MME Risk Assessment
- Final report used as basis for MMWG recommendations

Tier III
Multimedia Risk Assessment Final Report

Multimedia Evaluation Guidance Document , June 2008

Biodiesel Overview



13 Contracts and Grants – Biodiesel Research Studies, Testing, and Multimedia Evaluation

- Contractors/Recipients – UCD, UCB, UCR
- Total Funding ~ $3 million

Biodiesel Peer Review Process

- Initial Peer Review: Nov 2013 - Feb 2014
  - 7 reviewers; 4 areas of expertise (air, water, soil, public health)
  - Support MMWG conclusions, which are based on sound scientific knowledge, methods, and practices
  - 2 reviewers provided emerging public health information on oxidative stress and inflammation
  - New B5/B10 Biodiesel Study published June 2014, ARB updated ADF Regulation
- Supplemental Peer Review: Dec 2014 - Apr 2015
  - 4 original reviewers; 2 areas of expertise (air, public health)
  - Limited to OEHHA public health evaluation (oxidative stress and inflammation) and new B5/B10 Biodiesel Study
  - Confirm support of MMWG conclusions

Biodiesel Conclusions

Air:

ARB concludes that with in-use requirements, BD, as specified in the MME and proposed regulation, does not pose a significant adverse impact on public health or the environment from potential air quality impacts.

Water:

Water Board concludes that given the information provided by the UC researchers, biodiesel presents minimal additional risks to beneficial uses of CA waters than that posed by CARB diesel. Water Board supports the MME of BD, which meets the ASTM specifications, and the finding of no significant adverse impact on public health or the environment.

Biodiesel Conclusions (*Continued*)

Public Health:

OEHHA concludes that the information currently available indicates a reduction in cancer risk from the use of biodiesel and a reduction in GHG emissions, which are associated with a myriad of environmental and public health impacts. It is difficult to state with certainty that the use of BD will decrease cardiovascular or respiratory health risks because of the uncertainty introduced by recent studies that provide some evidence for increased oxidative stress and inflammatory response to BD emissions relative to petroleum diesel particles on a mass basis. The reduction in PM and other emissions may offset this potential increased inflammatory response. CEPC may want to emphasize in its determination the continued importance of emissions controls for BD fueled engines, as has been the emphasis for petroleum diesel fuel engines.

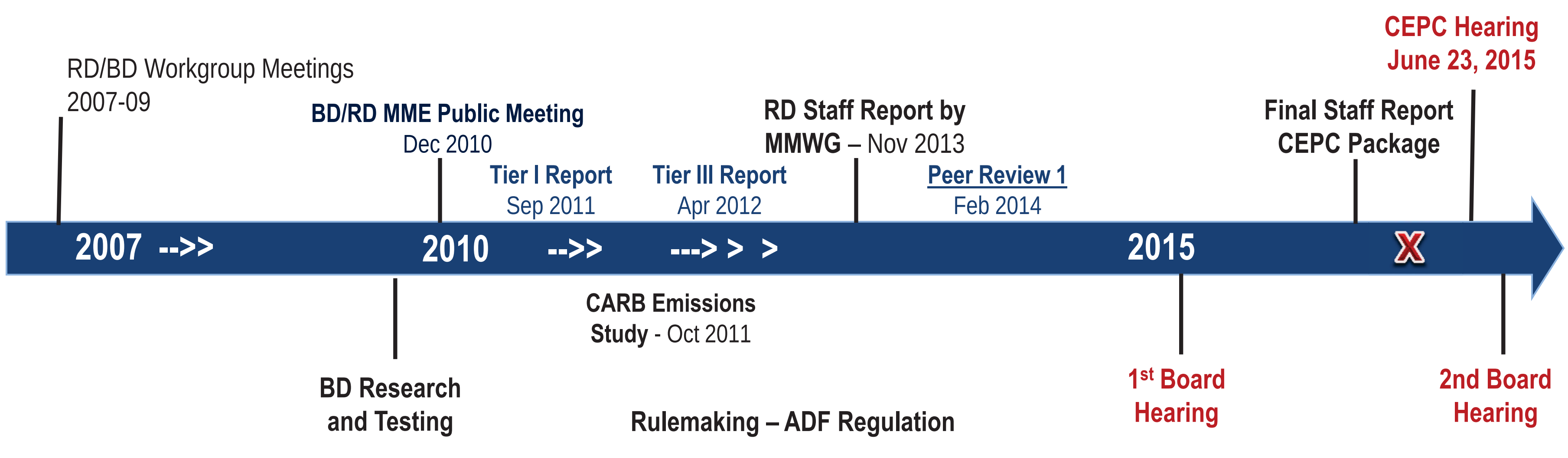
Soil and Hazardous Waste:

DTSC concludes that BD aerobically biodegrades more readily than CARB diesel. Also, some additized biodiesel preliminarily has a higher aquatic toxicity for a small subset of tested species, but further testing is needed to determine a causal relationship. In general, BD has no significant difference in vadose zone infiltration rate. BD's infiltration rate from animal fat appeared to be similar to CARB diesel. However, biodiesel left a noticeable increase in the residual's vertical dimension and spread less extensive horizontally.

Biodiesel Recommendations

- Use of biodiesel does not pose a significant adverse impact compared to CARB diesel fuel
- Conditions
  - Must meet ADF requirements
  - Review:
    - Any new BD formulations/additives
    - New oxidative stress and inflammation literature
    - BD use in light of emerging information

Renewable Diesel Overview



4 Contracts and Grants – RD Elements of BD Research Studies and Testing, and RD Multimedia Evaluation

- Contractors/Recipients – UCD, UCB, UCR
- Total Funding ~ $1 million

Renewable Diesel Peer Review

Peer Review: <u>Nov 2013 - Feb 2014</u>

- 7 reviewers; 4 areas of expertise (air, water, soil, public health)
- Support MMWG conclusions, which are based on sound scientific knowledge, methods, and practices
- No issues raised

Renewable Diesel Conclusions

Air:

Based on a relative comparison between CARB diesel and hydrotreated vegetable oil renewable diesel (HVORD), ARB staff concludes that the use of renewable diesel and the resulting air emissions do not pose a significant adverse impact on public health or the environment.

Water:

Waterboard staff concludes that given the information provided by the UC researchers, and the similarities of renewable diesel and CARB diesel, renewable diesel presents minimal additional risks to beneficial uses of California waters than that posed by CARB diesel alone. Waterboard staff supports the multimedia evaluation of renewable diesel that meets ASTM D975 and the finding of no significant adverse impacts on public health or the environment.

Renewable Diesel Conclusions

Public Health:

OEHHA scientists conclude that use of renewable diesel fuel produced by hydrotreating fatty acids from vegetable oil may reduce the amount of PM and aromatic organic chemicals that is released into the atmosphere in diesel engine exhaust.

Soil and Hazardous Waste:

In comparing renewable diesel with CARB diesel, DTSC's review concludes that the chemical compositions of renewable diesel are almost identical to that of CARB diesel. Therefore, the impacts on human health and the environment in the case of a spill to soil, groundwater, and surface waters would be expected to be similar to those of CARB diesel. Based on the current production, use, transportation, and storage of renewable diesel in California, renewable diesel will not increase the potential negative impacts to human health and the environment.

Renewable Diesel Recommendations

- Use of renewable diesel does not pose a significant adverse impact
- Conditions
  - Must meet CARB diesel specifications
  - Review:
    - New RD formulations/additives
    - RD use in light of emerging information

Proposed Alternative Diesel Fuel (ADF) Regulation

- Creates pathway for commercialization of emerging ADF
- Establishes Biodiesel specifications as ADF
- In-use requirements to preclude NOx increase from legacy fleet
- RD can be used to mitigate NOx from BD
- Exemption for advanced new technology diesel engines with selective catalytic reduction
- Sunset for in-use requirements in 2022 timeframe

Proposed Schedule

TASK	DATE
CEPC Briefings	Late May - Early June
Hearing Notice Released to Public	June 12
Final CEPC Hearing Documents Due to Cal/EPA	June 16
CEPC Hearing	**June 23, 2015**
ARB Hearing on Proposed ADF Regulation	**July 23, 2015**

This page intentionally left blank.

8_SF_LCFS_GE (Page 19 - 39)

1197. Comment: **Briefing Presentation for CEPC Board Members**

Agency Response: This presentation does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

Exhibit D to Declaration of James M. Lyons

Public Meeting of the California Environmental Policy Council

MULTIMEDIA EVALUATION OF BIODIESEL AND RENEWABLE DIESEL

June 23, 2015

Agenda

- Fuels Multimedia Evaluation
- Biodiesel Fuel
  - Individual Agency Presentations: ARB, State Water Board, OEHHA, DTSC
  - Summary of External Peer Review
  - Recommendations
- Renewable Diesel Fuel
  - Individual Agency Presentations: ARB, State Water Board, OEHHA, DTSC
  - Summary of External Peer Review
  - Recommendations
- Proposed Alternative Diesel Fuel Regulation
- Public Comments
- Council Consideration

Multimedia Evaluation

Health & Safety Code 43830.8

- Definition – *Identification and evaluation of* ***any significant adverse impact*** *on public health or the environment, including air, water, or soil, that may result from the production, use, or disposal of the motor vehicle fuel that may be used to meet the state board's motor vehicle fuel specifications. (Health & Safety Code §43830.8(b))*

- Requirements
  - ✓ Required before ARB establishes motor vehicle fuel specifications
  - ✓ Must address:
    - *Emissions of air pollutants*
    - *Contamination of surface water, groundwater, and soil*
    - *Disposal or use of byproducts and waste materials*
  - ✓ Summary of Evaluation – Multimedia Working Group (MMWG) Staff Report
  - ✓ External Scientific Peer Review
  - ✓ CA Environmental Policy Council (CEPC) Review
  - ✓ CEPC determination of significant impact, less adverse alternatives

California Environmental Policy Council Shall:

Determine whether proposed regulation will cause significant adverse impact on public health or environment

- No significant adverse impact and no less-adverse alternatives – No further action dictated

- Significant adverse impact or less harmful alternatives exist – Council recommends alternative measures to reduce impacts

Multimedia Working Group (MMWG)

- Oversees multimedia evaluation process
- Makes recommendations to CEPC
- Members:
  - ARB
  - DTSC
  - OEHHA
  - State Water Board
  - Other agencies consulted as needed

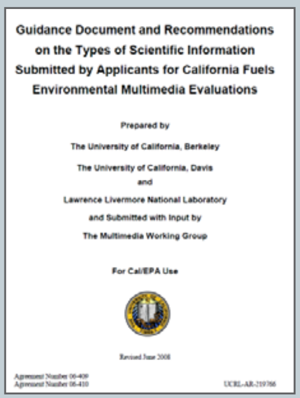
MMWG Responsibilities

- **ARB** – Lead agency, Evaluate air quality impacts
- **State Water Board** – Assess surface water and ground water impacts
- **OEHHA** – Evaluate potential public health impacts
- **DTSC** – Evaluate potential soil and hazardous waste concerns

Evaluation Uses Rigorous Scientific Process

Tier I
Work Plan

Work Plan
- Define framework and scope
- Identify key knowledge gaps
- Feedback provided


Guidance Document and Recommendations on the Types of Scientific Information Submitted by Applicants for California Fuels Environmental Multimedia Evaluations

Prepared by
The University of California, Berkeley
The University of California, Davis
and
Lawrence Livermore National Laboratory
and Submitted with Input by
The Multimedia Working Group

For Cal/EPA Use

Tier II
Risk Assessment Protocol

Risk Assessment Protocol
- Experimental design developed and submitted
- Protocol reviewed, feedback provided

Tier III
Multimedia Risk Assessment Final Report

Final Report Risk Assessment
- Execution of Risk Assessment
- Final report used as basis for MMWG recommendations

Multimedia Evaluation Guidance Document , June 2008

CEPC Action Needed

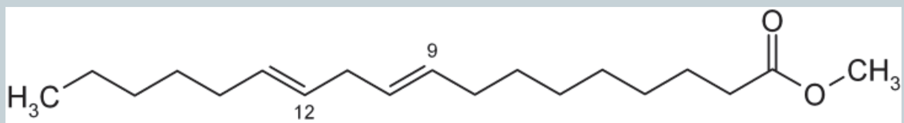
- MMWG prepares summary report
- Summary report and proposed ARB regulation subject to peer review
- CEPC reviews proposed regulation and summary report
- CEPC makes determination

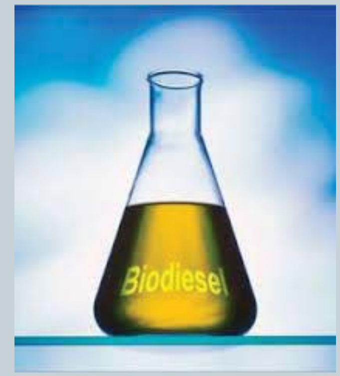
Agenda

- Fuels Multimedia Evaluation
- Biodiesel Fuel
  - Individual Agency Presentations: ARB, State Water Board, OEHHA, DTSC
  - Summary of External Peer Review
  - Recommendations
- Renewable Diesel Fuel
  - Individual Agency Presentations: ARB, State Water Board, OEHHA, DTSC
  - Summary of External Peer Review
  - Recommendations
- Proposed Alternative Diesel Fuel Regulation
- Public Comments
- Council Consideration

Biodiesel Fuel

- *What is Biodiesel?*
  - Fatty acid methyl ester

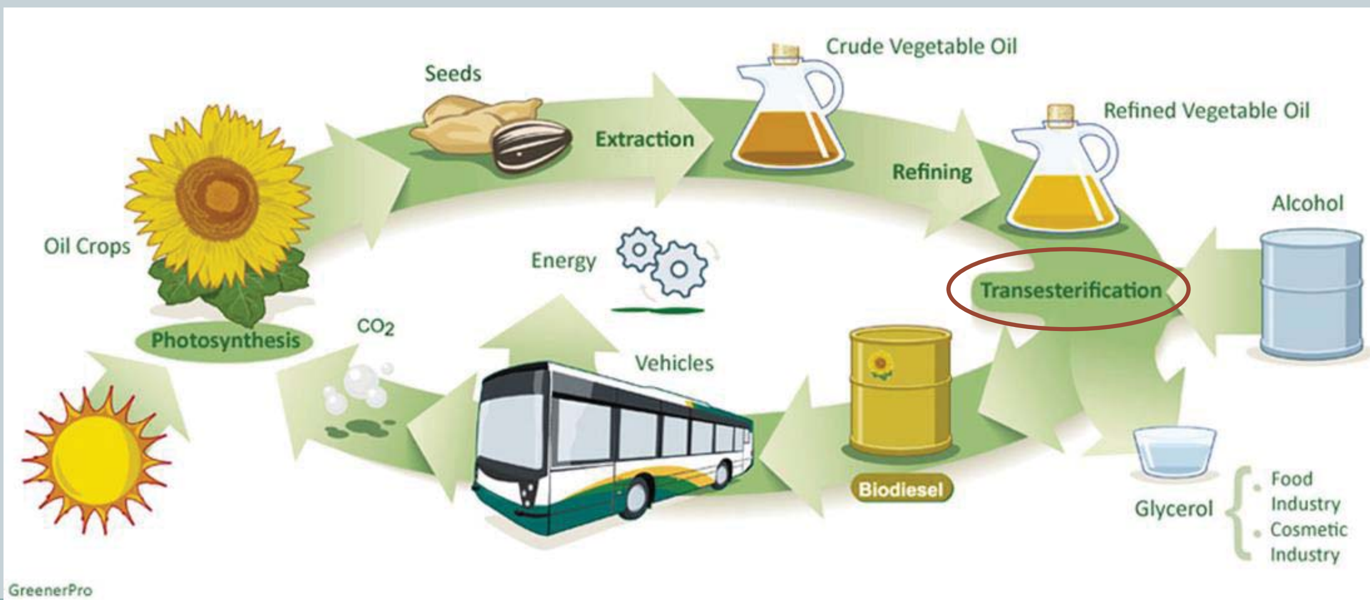




  - Derived from renewable feedstocks
    - Vegetable Oil – Soy, Palm, Corn, Canola, Safflower
    - Animal Fat – Tallow
  - Meets ASTM International Standards
    - D975 – B5
    - D7467 – B6 to B20
    - D6751 – B100

Biodiesel Fuel (*Continued*)

- *How is it Produced?*
  - Transesterifcation – Feedstock is reacted with alcohol in presence of a catalyst to produce glycerin and methyl esters (biodiesel)
  - Produced on relatively small scale



Biodiesel Fuel (*Continued*)

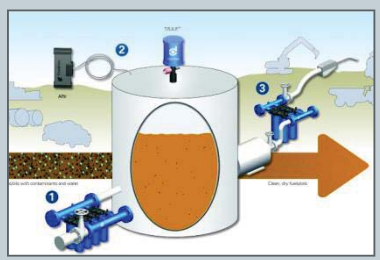
- *How is Biodiesel Transported and Distributed?*

Production Plant

Bulk Terminal

Refueling Station

- *How is Biodiesel Stored?*



Beneficial Aspects of Biodiesel

- Low carbon, renewable, alternative diesel fuel
- Reduces GHG – Supports 2030 and 2050 goals
- Reduces PM, CO, and air toxic emissions
- Key fuel supporting LCFS and Federal RFS2
- Reduces petroleum use – Supports 2030 goal
- Energy security – Feedstocks primarily sourced in U.S.

Air Quality Evaluation

Jim Aguila - ARB

Air Quality Evaluation

- Comparative analysis – Biodiesel compared to CARB diesel
- Criteria pollutants – PM, THC, CO, NO, NOx
- Air toxic emissions – Diesel PM, other Toxics
- Greenhouse gas emissions – CO_2, CH4, others

Air Quality Conclusions

- Reduces PM, THC, CO and some air toxics
- Non-statistically significant increase in 1,2-nanthroquinone, acrolein
- Reduces health risk from PM in diesel exhaust
- Biodiesel is considered low carbon fuel and supports GHG emissions reductions

Air Quality Conclusions (*Continued*)

- Studies found environmental benefits associated with biodiesel compared to CARB diesel
- Slight increased NOx emissions at certain blend levels in older vehicles & equipment
- With in-use requirements biodiesel, as specified in multimedia evaluation and proposed ADF regulation, does not pose a significant adverse impact

Water Evaluation

Laura Fisher- State Water Board

Background and Limitations

- Consistent with University of California, Davis and University of California, Berkeley, Tier I, Tier II, and Tier III Reports the State Water Board staff evaluation is specific to differential environmental impacts between biodiesel and CARB diesel

Background and Limitations (*Continued*)

- State Water Board staff conclusions and recommendations for biodiesel have limited application as they are based on:
  - Fuel additives used during testing (approved additives currently used in CARB diesel)
  - Fuels which meet ASTM fuel specifications

Biodiesel

- Aquatic toxicity screening with biodiesel blends during the Biodiesel Tier II study by UC Davis exhibited somewhat increased toxicity to subsets of screened species compared to CARB diesel
- Both B100 and B20 mixtures caused variable effects on algae cell growth, water flea survival and reproduction and abalone shell development
- However, the chemical analyses did not unambiguously reveal any causative compound for the toxicity

Biodiesel (*Continued*)

- Multimedia Evaluation identifies that unadditized biodiesel and biodiesel blends consistently show increased biodegradation as compared to CARB diesel, and additized biodiesel and biodiesel blends can result in some decreased biodegradation
- These biodegradability scenarios are influenced by additives used and biodiesel blend concentration

Biodiesel (*Continued*)

- Information provided by University of California, Davis and University of California, Berkeley and material compatibility testing has demonstrated that biodiesel and biodiesel blends are incompatible with various products commonly used in California's existing underground storage tank infrastructure

Biodiesel (*Continued*)

- Incompatibility can increases the risk of unauthorized releases, therefore material selection in underground storage tank (UST) equipment and leak detection technology is important
- Material selection resulting in proper compatibility is a statutory and regulatory requirement
- Material compatibility is reviewed and approved by local permitting agencies and implemented by UST owners/operators

Biodiesel (*Continued*)

- State Water Board recently revised UST regulations allow:
  - Biodiesel blends up to B5 may be stored in both single or double-walled USTs
  - Biodiesel blends above B5 may be stored in double-walled USTs

State Water Board Staff Conclusions and Recommendations

Given:

- Information provided by University of California, Davis and University of California, Berkeley
- Stringent design, construction and operational criteria for USTs
- Office of State Fire Marshal finding that aboveground storage tanks in compliance with APSA and SPCC that store biodiesel pose no additional risk to the environment
- UST spills/releases from USTs in California are 4 times lower than the national average, and number of new releases reported each year continues to decrease
- When spills/releases do happen they typically occur on the surface, in the subsurface soil, and/or groundwater and are detected fairly quickly

State Water Board staff concludes that there are minimal additional risks to beneficial uses of California waters posed by biodiesel than that posed by CARB diesel alone

State Water Board Staff Conclusions and Recommendations (*Continued*)

- State Water Board staff supports the Multimedia Evaluation of biodiesel which meets ASTM fuel specifications, and the finding of no significant adverse impacts on public health or environment with the recommendations provided in the Biodiesel Multimedia Evaluation Staff Report

State Water Board Staff Conclusions and Recommendations (*Continued*)

- As identified in the California Biodiesel Multimedia Evaluation Report, Tier III, the potential scope of any unanticipated impacts is difficult to determine due to the limited funding and time of the Multimedia Evaluation, therefore:
  - It is State Water Board staffs recommendation that any unanticipated risks that may have a significant impact on public health, safety or environment, as full scale production and use of biodiesel becomes common, be addressed as they occur by reconvening the Multimedia Working Group

Public Health Evaluation

Dr. Page Painter - OEHHA

Dr. John Budroe - OEHHA

OEHHA Evaluation of Potential Biodiesel Public Health Impacts

OEHHA staff evaluated the potential public health impacts from the use of biodiesel based on:

- A review of toxicity data from the UC Tier reports
- Additional relevant studies comparing toxicity of emissions from petroleum diesel and biodiesel

The evaluation focuses on the relative toxicity differences between biodiesel and petroleum diesel.

Biodiesel/CARB Diesel Exhaust Comparisons

- Substitution of biodiesel for CARB diesel appears to reduce:
  - The rate of addition of carbon dioxide to the atmosphere
  - The amount of carcinogenic PM, benzene, ethyl benzene, and PAHs released into the atmosphere
- Biodiesel use may increase NOx emissions for certain blends.

Biodiesel/CARB Diesel Exhaust Comparisons

- Biodiesel combustion may produce higher levels of some toxic constituents (e.g. 1,2-napthoquinone and acrolein)
- Biodiesel exhaust may contain a larger proportion of total particles as ultrafine particles relative to petroleum diesel exhaust

Biodiesel Exhaust and Oxidative Stress/Inflammation

- Some recent data suggest that exposure to biodiesel combustion emissions may induce enhanced inflammatory and oxidative stress responses relative to petroleum diesel when measured on a PM mass basis

Biodiesel Exhaust and Oxidative Stress/Inflammation (*Continued*)

Experimental data interpretation uncertainties :

- Unclear whether biodiesel combustion emissions would be more potent at inducing oxidative stress/inflammation than petroleum diesel combustion emissions if compared on the basis of PM emissions per mile or per horsepower hour

Biodiesel Exhaust and Oxidative Stress/Inflammation (*Continued)*

Experimental data interpretation uncertainties:

- Different studies used different test conditions. Factors that affect toxicity of diesel emissions:
  - Type of engine
  - Test cycle
  - Biodiesel source
  - Type of petroleum diesel (e.g., CARB diesel, low sulfur Euro diesel, high sulfur diesel, etc.)
- Difficult to compare different studies

Biodiesel Exhaust and Oxidative Stress/Inflammation (*Continued*)

Experimental data interpretation uncertainties:

- Several studies showed increased emissions of carbonyls (oxidative stress-inducers) with certain biodiesel fuels while a few showed decreases
- Differences in study design make comparisons of study results difficult

Biodiesel Exhaust and Oxidative Stress/Inflammation (*Continued*)

- Comparisons of oxidative stress, or other toxicity, needs to be placed in the context of decreased overall emissions

- Oxidative stress is probably just one of the mechanisms involved in the toxicity of diesel exhaust emissions, which include respiratory and cardiovascular health effects, immunotoxicity, and carcinogenicity

Biodiesel Exhaust and Oxidative Stress/Inflammation (*Continued*)

- Further research is warranted to determine if exposure to biodiesel exhaust emissions results in an increase in oxidative stress and/or inflammation compared to CARB diesel exhaust emissions
- Such research would be most useful if performed using test conditions optimized for California (e.g. engine types, test cycles, fuels)

Biodiesel Exhaust Public Health Impacts: Conclusion

OEHHA cannot determine with certainty whether replacing petroleum diesel by biodiesel or biodiesel-petroleum diesel blends for on-road motor vehicle use will reduce adverse human health impacts attributable to oxidative stress and inflammation from toxic chemicals in diesel-engine emissions.

Biodiesel Exhaust Public Health Impacts: Conclusion

However, the information currently available to OEHHA indicates:

- A reduction in cancer risk from use of biodiesel
- A reduction in PM and greenhouse gas emissions, which are associated with myriad environmental and public health impacts

Hazardous Waste and Soil Evaluation

Donn Diebert - DTSC

DTSC Role in Multimedia Fuel Evaluation

- Hazardous Waste Evaluation:
  - Production and Handling
  - Product Properties
- Soil Evaluation:
  - Environmental Fate and Transport in Soil if Spill Occurs
  - Effects on Soil Cleanup of Hazardous Waste Release

Biodiesel Hazardous Waste Evaluation (Production and Handling)

- Potential releases during the production of Biodiesel include:
  - Hexane or CO2 released to the air during seed extraction from feed stocks
  - Potential for odors associated with waste biomass

Biodiesel Hazardous Waste Evaluation (Production and Handling)

- Accidental releases during the production and handling of Biodiesel include spills or leaks of:
  - Bulk feedstock oil (non-hazardous)
  - Chemicals used during production such as methanol, hexane, acid, base
  - Approved additive packages for CARB Diesel such as antioxidants, biocides, cold flow enhancers, urea, etc.

Biodiesel Hazardous Waste Evaluation (Production and Handling)

- CARB Diesel vs. Biodiesel
  - Pure biodiesel aerobically biodegrades more readily than CARB diesel
  - Some additized biodiesel preliminarily has a higher aquatic toxicity for a small subset of tested species

Biodiesel Soil Evaluation (Fate/Transport and Soil Clean Up)

- CARB Diesel vs. Biodiesel
  - Based on the testing, no significant differences in infiltration rate into the soil
    - Some preliminary tests indicated that Biodiesel tended to move faster in the vertical than horizontal direction
  - Break down of CARB Diesel and Biodiesel have similar aerobic break down properties
  - Environment cleanup actions and remediation for soil would be similar

DTSC's Conclusions

- Hazardous waste evaluation:
  - Product Properties of CARB Diesel vs. Biodiesel **- No Significant Difference**
- Soil evaluation:
  - Environmental fate and transport in soil if spill occurs of CARB Diesel vs. Biodiesel **- No Significant Difference**
  - Effects on hazardous waste soil cleanup of CARB Diesel vs. Biodiesel **- No Significant Difference**

External Scientific Peer Review

- Initial Peer Review: <u>Nov 2013 - Feb 2014</u>
  - 7 reviewers; 4 areas of expertise (air, water, soil, public health)
  - Support MMWG conclusions – Based on sound scientific knowledge, methods, and practices
  - 2 reviewers provided emerging public health information on oxidative stress and inflammation
  - New B5/B10 Biodiesel Study published June 2014, Updated ADF Regulation

External Scientific Peer Review (*Continued*)

- Supplemental Peer Review: Dec 2014 - Apr 2015
  - 4 original reviewers; 2 areas of expertise (air, public health)
  - Limited to updated OEHHA public health evaluation (oxidative stress and inflammation) and ARB air quality evaluation (new B5/B10 Biodiesel Study and updated regulation)
  - Confirm support of MMWG conclusions

Recommendations

MMWG recommends that the CEPC:

- Find that the use of biodiesel fuel in California, as specified in this multimedia evaluation and the proposed regulation, does not pose a significant adverse impact on public health or the environment compared to CARB diesel fuel
- Condition the finding on the following
  - Biodiesel must meet the in-use requirements in the ADF regulation to preclude excess NOx emissions as applicable, or may qualify for an exemption

Recommendations (*Continued*)

- Any hazardous substances and hazardous waste used in production, storage, and transportation of biodiesel will be handled in compliance with applicable California laws and regulations
- Fuel formulations and additives not included within the scope of this multimedia evaluation must be reviewed by MMWG for consideration of appropriate action

Recommendations (*Continued*)

- Information regarding oxidative stress and inflammation will continue to be monitored by the MMWG. In event that information indicates potential significant risks to public due to exposure to biodiesel exhaust resulting from biodiesel use, the specific use of biodiesel will be reviewed by the MMWG for appropriate action

- In the event that any relevant available information indicate potential for significant risks to public health or the environment, the specific use of biodiesel will be reviewed by the MMWG for appropriate action

Agenda

- Fuels Multimedia Evaluation
- Biodiesel Fuel
  - Individual Agency Presentations: ARB, State Water Board, OEHHA, DTSC
  - Summary of External Peer Review
  - Recommendations
- <u>Renewable Diesel Fuel</u>
  - Individual Agency Presentations: ARB, State Water Board, OEHHA, DTSC
  - Summary of External Peer Review
  - Recommendations
- Proposed Alternative Diesel Fuel Regulation
- Public Comments
- Council Consideration

Renewable Diesel Fuel

- *What is Renewable Diesel?*
  - Aliphatic hydrocarbons, subset of CARB diesel (C11-C22 vs. CARB diesel C9-C45)
  - Derived from renewable feedstocks (same as biodiesel)
    - Vegetable Oil – Soy, Palm, Corn, Canola, Safflower
    - Animal Fat – Tallow
  - Meets ARB diesel fuel specifications and ASTM D975

- *How is it Produced?*
  - Hydrotreatment of feedstocks – Common refinery process
  - Produced on a relatively large scale

Renewable Diesel Fuel (*Continued*)

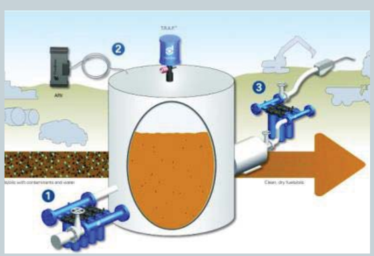
- *How is Renewable Diesel Transported and Distributed?*

Production Plant

Bulk Terminal

Refueling Station

- *How is Renewable Diesel Stored?*



Beneficial Aspects of Renewable Diesel

- Reduces PM, CO, and air toxic emissions
- Reduces NOx emissions
- Important fuel in LCFS and Federal RFS2
- Reduces petroleum use – Help achieve 2030 goal
- Energy security – Feedstocks sourced in U.S.
- Low carbon, renewable, alternative diesel fuel
- Reduces GHG – Help achieve 2030 and 2050 goals

Air Quality Evaluation

Jim Aguila - ARB

Air Quality Evaluation

- Comparative analysis - Hydrotreated vegetable oil renewable diesel compared to CARB diesel
- Criteria pollutants – PM, THC, CO, NO, NOx
- Air toxic emissions – Diesel PM, other Toxics
- Greenhouse gas emissions – CO_2

Air Quality Conclusions (*Continued*)

- Emits less PM, THC, CO, and NOx than CARB diesel
- Toxics results show reductions in most PAHs and VOCs
- Use and resulting air emissions do not pose a significant adverse impact of public health or environment

Water Evaluation

Laura Fisher - State Water Board

Background and Limitations

- Consistent with University of California, Davis and University of California, Berkeley, Tier I, Tier II, and Tier III Reports the State Water Board staff evaluation is specific to differential environmental impacts between renewable and CARB diesel

Background and Limitations (*Continued*)

- State Water Board staff conclusions and recommendations for renewable diesel have limited application as they are based on:
  - Fuel additives used during testing (approved additives currently used in CARB diesel)
  - Fuels that which meet ASTM fuel specifications

Renewable Diesel

- No significant changes in aquatic toxicity were identified by the University of California, Davis and University of California, Berkeley
- Based on data provided, impacts of fate and transport are not expected to be significantly different given similar chemical composition of renewable diesel and CARB diesel

Renewable Diesel (*Continued*)

- No significant impacts to UST material compatibility and leak detection functionality were raised within the Multimedia Evaluation

State Water Board Staff Conclusions and Recommendations

- State Water Board staff concludes that given the information provided by University of California, Davis and University of California, Berkeley there are minimal additional risks to beneficial uses of California waters posed by renewable diesel than that posed by CARB diesel alone

State Water Board Staff Conclusions and Recommendations (Continued)

- State Water Board staff supports the Multimedia Evaluation of renewable diesel which meets the ASTM fuel specifications, and the finding of no significant adverse impacts on public health or environment with recommendations provided in the Renewable Diesel Multimedia Evaluation Staff Report

State Water Board Staff Conclusions and Recommendations (Continued)

- As identified in the California Renewable Diesel Multimedia Evaluation Report, Tier III, the potential scope of any unanticipated impacts is difficult to determine due to the limited funding and time of the Multimedia Evaluation, therefore:
  - It is State Water Board staffs recommendation that any unanticipated risks that may have a significant impact on public health, safety or the environment, as full scale production and use of renewable diesel becomes common, be addressed as they occur by reconvening the Multimedia Working Group

Public Health Evaluation

Dr. Page Painter - OEHHA

Major Activities of OEHHA

- Identification of hazards from exposure to chemicals
- Dose-response assessment for toxic chemicals
- Calculation of health-based acceptable exposure levels for toxic chemicals

Major Activities of OEHHA Staff in the Multimedia Working Group

- Impact assessments of additives in reformulated fuels
- Comparative impact assessment of new fuels

Comparative assessment of a new or alternative diesel fuel requires:

- Comparing chemical concentrations in Combustion Emissions (CE) from a new diesel fuel to those from CARB diesel
- Comparing toxic impacts of CE from a new fuel to those from CARB diesel

Sources of Information Used for Comparative Fuel Impact Assessments

- Scientific studies published in peer-reviewed journals
- Reports submitted to government agencies

Renewable Diesel

- Produced by hydrotreating fatty acids from vegetable oil and is termed hydrotreated vegetable oil renewable diesel (HVORD)
- Composed of aliphatic hydrocarbons, chemicals of low toxicity

Data Sources for HVORD Assessment

- Report by Durbin et al. (2011)
- Four studies comparing CE from HVORD to CE from EN590 diesel

Comparative Evaluation of Particulate Matter (PM) and Toxic Chemicals in CE

- PM decreased in CE from HVORD
- NO_x decreased in CE from HVORD
- Benzene, ethyl benzene, toluene and xylene reduced in CE from HVORD
- Formaldehyde and acetaldehyde reduced in CE from HVORD
- Polycyclic aromatic hydrocarbon (PAH) content is reduced in CE from HVORD in most (but not all) tests

Conclusions

- Use of renewable diesel fuel produced by hydrotreating fatty acids from vegetable oil may reduce the amount of PM and aromatic organic chemicals released.
- OEHHA scientists do not find any evidence that these potential beneficial impacts are offset by adverse impacts on human health that might result from replacing some CARB ULSD use by HVORD use.

Hazardous Waste Evaluation

Donn Diebert - DTSC

Renewable Diesel Hazardous Waste Evaluation (Production and Handling)

- Potential releases during the production of Hydrotreated Renewable Diesel include:
  - n-hexane during the oil extraction process
  - Potential for odors associated with waste biomass

Renewable Diesel Hazardous Waste Evaluation (Production and Handling)

- Accidental releases during the production and handling:
  - Bulk feedstock oil (non-hazardous)
  - Chemicals used during production such as n-hexane
  - Approved additive packages for CARB Diesel such as antioxidants, biocides, cold flow enhancers, urea, etc.

Renewable Diesel Hazardous Waste Evaluation (Product Properties)

- CARB Diesel vs Renewable Diesel
  - The chemical composition and properties of Renewable Diesel are similar to CARB Diesel

Renewable Diesel Soil Evaluation (Fate/Transport and Soil Clean Up)

- CARB Diesel vs. Renewable Diesel
  - Migration of Renewable Diesel through soil is expected to be similar to CARB Diesel
  - Fate and transport of Renewable Diesel is expected to be similar to CARB Diesel
  - Break down of CARB Diesel and Renewable Diesel in the environment is expected to be similar, ultimate soil cleanup actions and remediation would be similar

DTSC's Conclusions

- Hazardous waste evaluation:
  - Product Properties of CARB Diesel vs. Renewable Diesel **- No Significant Difference**
- Soil evaluation:
  - Environmental fate and transport in soil if spill occurs of CARB Diesel vs. Renewable Diesel **- No Significant Difference**
  - Effects on hazardous waste soil cleanup of CARB Diesel vs. Renewable Diesel **- No Significant Difference**

External Scientific Peer Review

Renewable Diesel Peer Review: <u>Nov 2013 - Feb 2014</u>

- 7 reviewers; 4 areas of expertise (air, water, soil, public health)
- Support MMWG conclusions, based on sound scientific knowledge, methods, and practices
- No issues raised

Recommendations

MMWG recommends that the CEPC:

- Find that use of renewable diesel in California, as specified in this multimedia evaluation and proposed regulation, does not pose a significant adverse impact on public health or the environment compared to CARB diesel fuel
- Condition the finding on the following
  - Must meet definition in ADF regulation and California diesel fuel regulations under Title 13, California Code of Regulations, Section 2281-2285

Recommendations (*Continued*)

- Any hazardous substances and hazardous waste used in production, storage, and transportation of biodiesel will be handled in compliance with applicable California laws and regulations
- Fuel formulations and additives not included within scope of this multimedia evaluation must be reviewed by MMWG for consideration of appropriate action
- In the event any relevant available information indicates potential for significant risks to public health or environment, the specific use of biodiesel will be reviewed by the MMWG for appropriate action

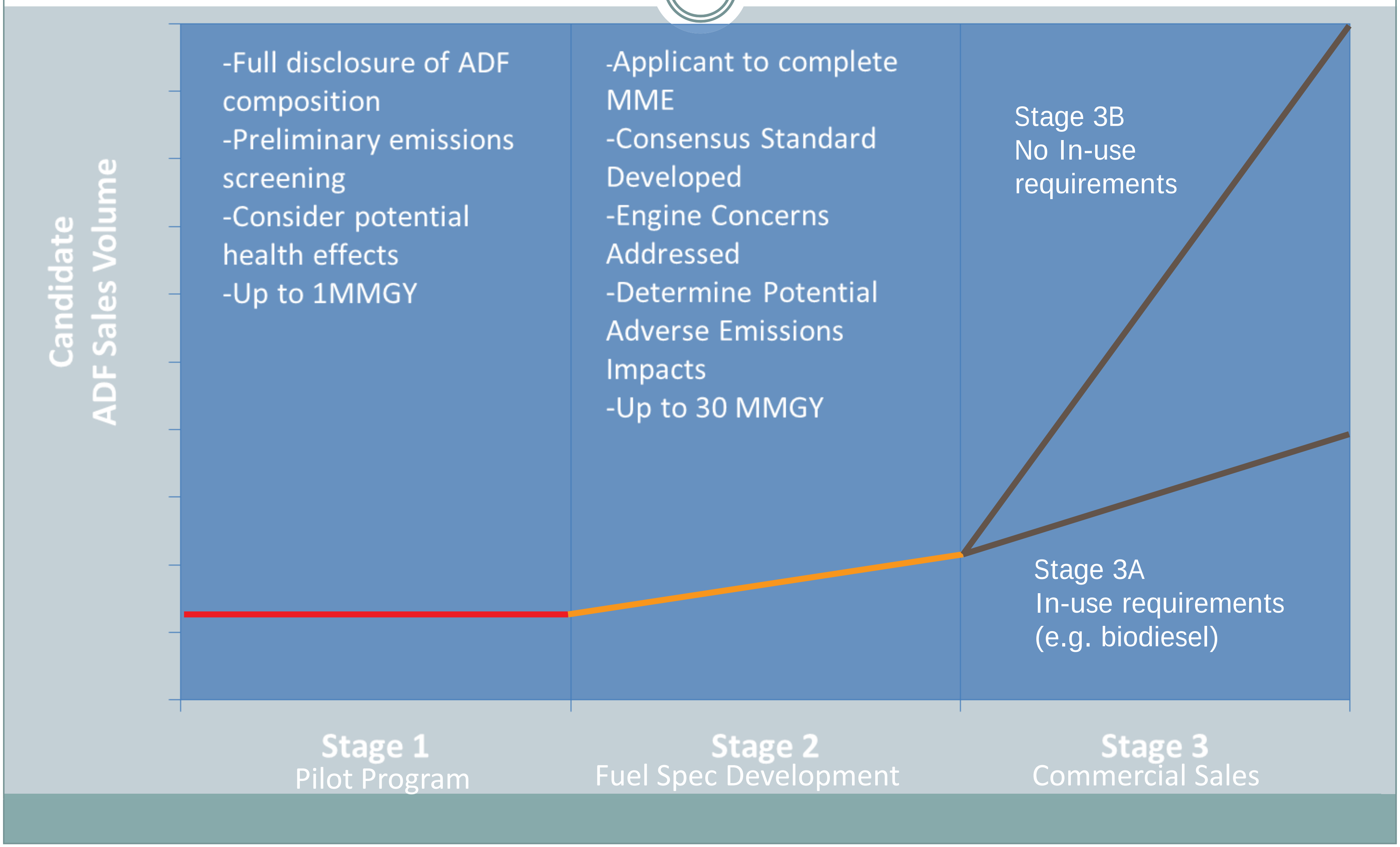
Agenda

- Fuels Multimedia Evaluation
- Biodiesel Fuel
  - Individual Agency Presentations: ARB, State Water Board, OEHHA, DTSC
  - Summary of External Peer Review
  - Recommendations
- Renewable Diesel Fuel
  - Individual Agency Presentations: ARB, State Water Board, OEHHA, DTSC
  - Summary of External Peer Review
  - Recommendations
- <u>Proposed Alternative Diesel Fuel Regulation</u>
- Public Comments
- Council Consideration

Alternative Diesel Fuel Regulation

- Subject to lengthy public process
- Support from both fuels industry and engine manufacturers
- Supports rapid deployment of low carbon diesel replacements
- Two major focuses
  - Three stage introduction of emerging ADFs into commerce
  - Establishes biodiesel as first ADF

Three-Stage Process for Emerging ADFs



Requirements for Biodiesel as First ADF

- Sets neat biodiesel fuel quality specifications
- Covers blends of biodiesel and conventional diesel (B5 to B20)
- Biodiesel blend limit: B10 or B5 depending on season and feedstock
- In-use requirements to preclude NOx increases from legacy fleet
- Exemptions for new technology diesel engines with selective catalytic reduction
- Program review by 2020

Public Comments

- Growth Energy
  - Received yesterday at noon
  - Re-submittal of comments submitted to ADF rulemaking
  - Generally pertain to environmental analysis in support of ADF rulemaking
- Western States Petroleum Association
  - Some comments outside of scope of multimedia evaluation
  - Some comments pertain to environmental analysis in support of ADF rulemaking

Agenda

- Fuels Multimedia Evaluation
- Biodiesel Fuel
  - Individual Agency Presentations: ARB, State Water Board, OEHHA, DTSC
  - Summary of External Peer Review
  - Recommendations
- Renewable Diesel Fuel
  - Individual Agency Presentations: ARB, State Water Board, OEHHA, DTSC
  - Summary of External Peer Review
  - Recommendations
- Proposed Alternative Diesel Fuel Regulation
- <u>Public Comments</u>
- Council Consideration

Agenda

- Fuels Multimedia Evaluation
- Biodiesel Fuel
  - Individual Agency Presentations: ARB, State Water Board, OEHHA, DTSC
  - Summary of External Peer Review
  - Recommendations
- Renewable Diesel Fuel
  - Individual Agency Presentations: ARB, State Water Board, OEHHA, DTSC
  - Summary of External Peer Review
  - Recommendations
- Proposed Alternative Diesel Fuel Regulation
- Public Comments
- Council Consideration

Thank You

8_SF_LCFS_GE (Page 40 - 133)

1198. Comment: **Presentation for CEPC Public Hearing**

Agency Response: This presentation does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

Exhibit E to Declaration of James M. Lyons

California Environmental Protection Agency

State of California
ENVIRONMENTAL POLICY COUNCIL
Resolution
June 23, 2015

WHEREAS, California Health and Safety Code section 43830.8 provides that the Air Resources Board (ARB) may not adopt any regulation that establishes a specification for motor vehicle fuel unless that regulation, and a multimedia evaluation conducted by affected agencies and coordinated by ARB, are reviewed by the California Environmental Policy Council (Council);

WHEREAS, Public Resources Code section 71017 established the California Environmental Policy Council, consisting of the Secretary of Environmental Protection; the Chairpersons of ARB and State Water Resources Control Board (SWRCB); and the Directors of Office Environmental Health Hazard Assessment (OEHHA), Department of Toxic Substances Control (DTSC), Department of Pesticide Regulation (DPR), and Department of Resources Recycling and Recovery (CalRecycle) (formerly the California Integrated Waste Management Board, *see* Public Resources Code section 40400);

WHEREAS, Health and Safety Code section 43830.8(b) specifies that a multimedia evaluation shall include the identification and evaluation of any significant adverse impact on public health or the environment, including air, water, or soil, that may result from the production, use, or disposal of the motor vehicle fuel that may be used to meet ARB's motor vehicle fuel specification;

WHEREAS, Health and Safety Code section 43830.8(c) specifies that the multimedia evaluation shall be based on the best available scientific data, written comments submitted by any interested person, and information collected by ARB in preparation for the rulemaking, and address, at a minimum, an evaluation of the following:

- Emissions of air pollutants, including ozone forming compounds, particulate matter, toxic air contaminants, and greenhouse gases;
- Contamination of surface water, groundwater, and soil; and
- Disposal or use of the byproducts and waste materials from the production of the fuel;

WHEREAS, Health and Safety Code section 43830.8(g) specifies that ARB shall consult with other boards and departments within the California Environmental Protection Agency, the State Department of Public Health (formerly the State Department of Health Services, *see* Health and Safety Code section 20), the State Energy Resources

DRAFT

Conservation and Development Commission (Energy Commission), the Department of Forestry and Fire Protection (CAL FIRE), the Department of Food and Agriculture (CDFA), and other state agencies with responsibility for, or expertise regarding, impacts that could result from the production, use, or disposal of the motor vehicle fuel that may be used to meet the specification;

WHEREAS, Health and Safety Code section 43830.8(d) requires ARB to prepare a written summary of the multimedia evaluation, and submit it for external scientific peer review in accordance with Health and Safety Code section 57004, and to submit its written summary and results of the peer review to the Council;

WHEREAS, Health and Safety Code section 43830.8(e) specifies that if the Council determines that the proposed regulation will cause a significant adverse impact on public health or the environment, or that alternatives exist that would be less adverse, then the Council shall recommend alternative measures that the ARB or other State agencies may take to reduce the adverse impact on public health or the environment;

WHEREAS, Health and Safety Code section 43830.8(f) requires ARB, within 60 days of receiving notification from the Council of a determination of adverse impact, to make revisions to the proposed regulation to avoid or reduce the adverse impact, or the affected agencies are required to take appropriate action that will, to the extent feasible, mitigate the adverse impact so that, on balance, there is no adverse impact on public health or the environment;

WHEREAS, to address the ambient air toxic risk associated with exposure to diesel particulate matter (PM), ARB has adopted the Air Toxics Program, which establishes the process for the identification and control of toxic air contaminants, and includes provisions to make the public aware of significant toxic exposures and provisions for reducing such risks;

WHEREAS, ARB identified diesel PM as a toxic air contaminant with no safe threshold in 1998, and determined that diesel PM accounts for about 70 percent of the toxic risk from all identified toxic air contaminants;

WHEREAS, ARB plans to consider adopting an Alternative Diesel Fuel regulation (ADF regulation, or regulation) that contains a fuel specification and other requirements for biodiesel when used as a transportation fuel, and Council review of the biodiesel multimedia evaluation and the ADF regulation is required before ARB adopts the ADF regulation;

WHEREAS, ARB staff coordinated multimedia evaluations by the affected agencies of both biodiesel and renewable diesel;

WHEREAS, as part of the interagency collaboration through the Multimedia Working Group (MMWG), the ARB, SWRCB, OEHHA, and DTSC staff conducted the multimedia evaluations of both biodiesel and renewable diesel and submitted them for peer review in accordance with Health and Safety Code section 43830.8(d) and Health and Safety Code section 57004: (1) for biodiesel, the review was conducted in two parts, the first part of which was completed in February 2014, with a supplemental review completing the process in April 2015, and (2) for renewable diesel, the review was completed in February 2015;

WHEREAS, the May 2015 reports entitled "*Staff Report: Multimedia Evaluation of Biodiesel*" (Biodiesel Staff Report) and "*Staff Report: Multimedia Evaluation of Renewable Diesel*" (Renewable Diesel Staff Report) contain the results of the peer reviews required by Health and Safety Code sections 43830.8 and 57004;

WHEREAS, as part of the multimedia evaluations, the MMWG also consulted with the DPR, CalRecycle, the State Department of Public Health, the Energy Commission, CDFA, and CAL FIRE;

WHEREAS, the Council met in a duly noticed public meeting on June 23, 2015, and considered the Biodiesel Staff Report and the Renewable Diesel Staff Report, and the Alternative Diesel Fuel regulation proposed by ARB;

WHEREAS, the Council has also received and considered presentations from members of the MMWG, including ARB, SWRCB, OEHHA, and DTSC, summarizing the benefits and potential impacts of using biodiesel and renewable diesel in California;

WHEREAS, the Council received and considered written comments submitted on June 22, 2015 by Growth Energy and by the Western States Petroleum Association, and also received and considered comments from interested parties at the June 23, 2015 meeting of the Council;

WHEREAS, the Biodiesel Staff Report and Renewable Diesel Staff Report, along with other materials from the multimedia evaluations, have been made available for public comment;

WHEREAS, the multimedia evaluation for biodiesel concluded that:

- Biodiesel use must meet the in-use requirements in the proposed ADF regulation, and those requirements will preclude excess NOx emissions or other higher emissions relative to diesel motor fuel that meets current ARB specifications (CARB diesel) that could result in a significant adverse impact on public health or the environment from potential air quality impacts;

- Given the information provided by the UC researchers, there are minimal additional risks to beneficial uses of California waters posed by biodiesel than those posed by CARB diesel, and SWRCB staff supports the multimedia evaluation of biodiesel that meets the ASTM fuel specifications and the finding of no significant adverse impacts on public health or the environment;

- The substitution of biodiesel for CARB diesel appears to reduce the rate of addition of carbon dioxide to the atmosphere and the amount of PM, benzene, ethyl benzene, and polycyclic aromatic hydrocarbons (PAH) released into the atmosphere;

- A reduction in cancer risk is associated with use of biodiesel, as is a reduction in greenhouse gas emissions, which are themselves associated with myriad environmental and public health impacts; and

- Biodiesel aerobically biodegrades more readily than CARB diesel and preliminary testing of some additized biodiesel demonstrated higher aquatic toxicity for a small subset of tested species, but the results are not conclusive due to uncertainty; in general, biodiesel has no significant difference in vadose zone infiltration rate, and biodiesel's infiltration rate from animal fat appears to be similar to CARB diesel;

WHEREAS, testing results evaluated in the Renewable Diesel Staff Report show that the use of renewable diesel can reduce PM emissions by about 30 percent compared to CARB diesel;

WHEREAS, the multimedia evaluation for renewable diesel concluded that:

- In a relative comparison between CARB diesel and hydrotreated vegetable oil renewable diesel (HVORD), ARB staff concluded that the use of renewable diesel and the resulting air emissions do not pose a significant adverse impact on public health or the environment;

- Given the information provided by the UC researchers, and the similarities of renewable diesel and CARB diesel, there are minimal additional risks to beneficial uses of California waters posed by renewable diesel than that posed by CARB diesel alone; SWRCB staff supports the multimedia evaluation of renewable diesel that meets ASTM D975 and the finding of no significant adverse impacts on public health or the environment;

- PM, benzene, ethyl benzene and toluene in combustion emissions from diesel engines using HVORD are significantly lower than they are in combustion emissions from engines using CARB diesel; CO and NOx emissions are significantly lower in some tests using HVORD fuel; and variability between studies preclude drawing a conclusion as to differences in PAH exhaust output levels and PAH/PM exhaust ratios from engines equipped with a diesel oxidation catalyst (DOC)/particle oxidation catalyst (POC) between the two fuel types;

- Use of renewable diesel fuel produced by hydrotreating fatty acids from vegetable oil may reduce the amount of PM and aromatic organic chemicals that are released into the atmosphere in diesel engine exhaust, and OEHHA scientists do not find any evidence that these potential beneficial impacts are offset by adverse impacts on human health that might result from replacing CARB diesel with HVORD;

- In comparing renewable diesel with CARB diesel, diesel is free of the ester compounds found in fatty acid methyl ester biodiesel, has a lower aromatic hydrocarbon content, and the chemical compositions of renewable diesel are almost identical to that of CARB diesel;

- The relative environmental impact in case of a spill or leak of renewable diesel compared to a spill or leak from CARB diesel depends on the types, concentrations and use specifications of diesel additives used with renewable diesel, as well as the different production processes; and

- Based on the current production, use, transportation, and storage of renewable diesel in California, renewable diesel will not increase the potential negative impacts to human health and the environment;

WHEREAS, the Office of the State Fire Marshal (Office) concluded that:

- Since renewable diesel and biodiesel blends are subject to regulation under the Aboveground Petroleum Storage Act and the federal Spill Prevention, Control, and Countermeasure rule, sufficient controls are currently in place to prevent spills and releases to the environment and that aboveground storage of these fuels therefore poses no additional risk to the environment;

- There are no significant fire and panic safety impacts from renewable diesel, based on information in the renewable diesel multimedia evaluation; and

- There are minimal additional risks to public safety posed by biodiesel than posed by CARB diesel alone, and the Office supports the multimedia evaluation of biodiesel, and also supports the finding of no significant adverse impacts on fire and panic safety for biodiesel, related to the authorities of the Office;

WHEREAS, CalRecycle has stated that based on the multimedia evaluations provided by the MMWG, the agency is currently unaware of any significant adverse public health or environmental impacts from the use of biodiesel and renewable diesel;

WHEREAS, the Department of Pesticide Regulation (DPR) has reviewed the Staff Reports on Biodiesel and Renewable Diesel and found that the fuels are not registered as pesticidal active ingredients in California and are unlikely to be a major inert ingredient in pesticide products and, therefore, DPR is unaware of any adverse public health or environmental impacts that may occur.

WHEREAS, any hazardous substances and hazardous waste used in the production, storage, and transportation of biodiesel or renewable diesel is required to be handled in compliance with applicable California laws and regulations;

WHEREAS, renewable diesel must meet the requirements of CARB diesel fuel regulations under California Code of Regulations, title 13, sections 2281-2285;

WHEREAS, all other applicable local and State laws and regulations, including fuel storage requirements, will remain in effect;

WHEREAS, new fuel formulations and new additives that may be introduced into commerce in the future to comply with the ADF regulation, and were not included within the scope of these multimedia evaluations, will be reviewed by the MMWG to determine whether further multimedia evaluation is warranted, and if so, to make recommendations regarding any further action by the Council;

WHEREAS, information regarding oxidative stress and inflammation will continue to be monitored by the MMWG and in the event that new information indicates the potential for a significant adverse impact to public health from exposure to biodiesel exhaust resulting from biodiesel use, the use of biodiesel will be reviewed by the MMWG to determine whether further multimedia evaluation is warranted, and if so, to make recommendations regarding any further action by the Council; and

WHEREAS, in the event that any other new information indicates the potential for a significant adverse impact on public health or the environment from biodiesel use, the use of biodiesel will be reviewed by the MMWG to determine whether further multimedia evaluation is warranted, and if so, to make recommendations regarding any further action by the Council;

NOW, THEREFORE BE IT RESOLVED, that after review of the biodiesel multimedia evaluation and the proposed ADF regulation, and based on the best available scientific information and public comments received, the Council determines that the use of biodiesel in California consistent with the proposed ADF regulation will not pose a significant adverse impact on public health or the environment compared to CARB diesel fuel;

BE IT FURTHER RESOLVED, that after review of the renewable diesel multimedia evaluation and the proposed ADF regulation, and based on the best available scientific information and public comments received, the Council determines that the use of renewable diesel in California consistent with the proposed ADF regulation will not pose a significant adverse impact on public health or the environment compared to CARB diesel fuel;

BE IT FURTHER RESOLVED, that based on its determinations of no significant adverse impact from biodiesel and renewable diesel use, the Council does not identify any alternatives that would be less adverse than the use of biodiesel and renewable diesel as contemplated by the proposed ADF regulation; and

BE IT FURTHER RESOLVED, that the MMWG is instructed to continue to monitor issues relating to the use of renewable diesel or biodiesel, including but not limited to the use of new fuel formulations and additives and potential oxidative stress and inflammation impacts of biodiesel, and in the event that any new information indicates the potential for a significant adverse impact to public health or the environment from the use of renewable diesel or biodiesel, the MMWG is directed to determine whether further multimedia evaluation is warranted, and if so, to make recommendations regarding any further action by the Council to protect the public health or the environment.

DATED:______________________.

________________________________.
Matthew Rodriquez
Secretary for Environmental Protection

8_SF_LCFS_GE (Page 134 - 141)

1199. Comment: **Draft Resolution for CEPC Public Hearing**

Agency Response: This resolution does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

Exhibit F to Declaration of James M. Lyons

WANGER JONES HELSLEY PC
ATTORNEYS

OLIVER W. WANGER
TIMOTHY JONES*
MICHAEL S. HELSLEY
PATRICK D. TOOLE
SCOTT D. LAIRD
JOHN P. KINSEY
KURT F. VOTE
TROY T. EWELL
PETER M. JONES**
JAY A. CHRISTOFFERSON**
MARISA L. BALCH
JENA M. HARLOS***
JOSIAH M. PRENDERGAST
MICAELA L. NEAL
CAMERON M. PEYTON
DYLAN J. CROSBY

* Also admitted in Washington
** Of Counsel
*** Also admitted in Wisconsin

265 E. RIVER PARK CIRCLE, SUITE 310
FRESNO, CALIFORNIA 93720

MAILING ADDRESS
POST OFFICE BOX 28340
FRESNO, CALIFORNIA 93729

TELEPHONE
(559) 233-4800

FAX
(559) 233-9330

WJH

OFFICE ADMINISTRATOR
LYNN M. HOFFMAN

Writer's E-Mail Address:
jkinsey@wjhattorneys.com

Website:
www.wjhattorneys.com

June 22, 2015

VIA EMAIL & UNITED STATES MAIL

Secretary Matthew Rodriquez, Chair
Environmental Policy Council
1011 I Street
P.O. Box 2815
Sacramento, California 95812

Re: Comments of Growth Energy on Multimedia Evaluations of Biodiesel and Renewable Diesel

Dear Mr. Rodriquez:

I am writing on behalf of Growth Energy to provide comments on the Multimedia Evaluation of Biodiesel (the "MME"), which Growth Energy understands will be discussed at the California Environmental Policy Council's June 23, 2015, public hearing.

First, as explained in the declarations submitted by James M. Lyons on February 17, 2015, June 8, 2015, and June 19, 2015, concerning the Alternative Diesel Fuel regulation (the "ADF regulation"), and Low Carbon Fuel Standard (the "LCFS regulation"), the air quality analysis prepared by CARB staff is fatally flawed. (See, e.g., February 17, 2015, Decl. Lyons ¶¶ 12-15; *id.*, Attachment F; June 8, 2015, Decl. Lyons ¶¶ 6-12.) LCFS SF8-10

Mr. Lyons' declarations also explain that the air quality analysis prepared by CARB staff in its Environmental Assessment for the ADF regulation and the LCFS regulation is different from that contained in the MME in several material respects. (See June 8, 2015, Decl. Lyons ¶¶ 13-15.) LCFS SF8-11

Further, CARB did not provide several important documents, including analyses raising questions regarding the air quality analysis underlying the ADF regulation, to either the persons working on the MME, or the MME peer reviewers. Without these documents, the preparers of the MME, and the MME peer reviewers, are provided only a one-sided view of the regulations, LCFS SF8-12 and insufficient information to fully analyze the potential air quality impacts of the regulations. The documents CARB failed to disclose include, but are not limited to, (1) *NOx Emission Impacts of Biodiesel Blends*, Robert Crawford, Rincon Ranch Consulting (February 10, 2015); and (2) February 17, 2015, Declaration of James M. Lyons, with attachments, both of which are enclosed.

LCFS SF8-12 cont.

Due to the above issues, the Environmental Policy Council should not approve the MME at this time, and should instead require CARB to revise its air quality analysis to correct the existing flaws. The Environmental Policy Council should also require CARB to make all relevant analyses – not just those supporting CARB's position – available to both the preparers of the MME and the MME peer reviewers, prior to the Environmental Policy Council's consideration of the MME.

LCFS SF8-13

Respectfully submitted,

John P. Kinsey

Enclosures:

1. Declaration of James M. Lyons (June 19, 2015)

2. Declaration of James M. Lyons (June 8, 2015)

3. Declaration of James M. Lyons (February 17, 2015)

4. *NOx Emission Impacts of Biodiesel Blends*, Robert Crawford, Rincon Ranch Consulting (February 10, 2015)

5. *NOx Emissions Impact of Soy- and Animal-based Biodiesel Fuels: A Re-Analysis*, Robert Crawford, Rincon Ranch Consulting (December 10, 2013)

6. California Air Resources Board, Initial Statement of Reasons, ADF Regulation , Main Text (January 2, 2015)

7. California Air Resources Board, Initial Statement of Reasons, ADF Regulation, Appendix B [Technical Supporting Information] (January 2, 2015)

This page intentionally left blank.

8_SF_LCFS_GE (Page 142 - 144)

1200. Comment: **LCFS SF8-10 through LCFS SF8-12**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

1201. Comment: **LCFS SF8-13**

The commenter attaches a letter addressed to the CEPC in which the commenter's attorneys ask that the regulatory process be delayed, and suggests that the CEPC should require ARB to make additional "relevant analyses" available to the people who prepared and reviewed the MME.

Agency Response: The comment does not identify specific "relevant analyses" that were not provided; it is not clear from the comments whether additional analyses even exist. ARB staff cannot respond to such a vague suggestion, although we note that the MME process was conducted according to law, and duly approved by the CEPC on June 23, 2015.

This page intentionally left blank.

Attachment 1

STATE OF CALIFORNIA

BEFORE THE AIR RESOURCES BOARD

Declaration of James M. Lyons

I, James Michael Lyons, declare as follows:

1. I make this Declaration based upon my own personal knowledge and my familiarity with the matters recited herein. It is based on my experience of nearly 30 years as a regulator, consultant, and professional in the field of emissions and air pollution control. A copy of my résumé can be found in Attachment A.

2. I am a Senior Partner of Sierra Research, Inc., an environmental consulting firm located at 1801 J Street, Sacramento, California owned by Trinity Consultants, Inc. Sierra specializes in research and regulatory matters pertaining to air pollution control, and does work for both governmental and private industry clients. I have been employed at Sierra Research since 1991. I received a B.S. degree in Chemistry from the University of California, Irvine, and a M.S. Degree in Chemical Engineering from the University of California, Los Angeles. Before joining Sierra in 1991, I was employed by the State of California at the Mobile Source Division of the California Air Resources Board (CARB).

3. During my career, I have worked on many projects related to the following areas: 1) the assessment of emissions from on- and non-road mobile sources, 2) assessment of the impacts of changes in fuel composition and alternative fuels on engine emissions including emissions of green-house gases, 3) analyses of the unintended consequences of regulatory actions, and 4) the feasibility of compliance with air quality regulations.

4. I have testified as an expert under state and federal court rules in cases involving CARB regulations for gasoline, Stage II vapor recovery systems and their design, factors affecting emissions from diesel vehicles, evaporative emission control system design and function, as well as combustion chamber system design. While at Sierra I have acted as a consultant on automobile air pollution control matters for CARB and for the United States Environmental Protection Agency. I am a member of the American Chemical Society and the Society of Automotive Engineers and have co-authored nine peer-reviewed monographs concerned with automotive emissions, including greenhouse gases and their control. In addition, over the course of my career, I have conducted peer-reviews of numerous papers related to a wide variety of issues associated with pollutant emissions and air quality.

5. This Declaration summarizes the results of my review of the CARB Notice of Public Availability of Modified Text and Availability of Additional Documents for the Proposed Re-Adoption of the Low Carbon Fuel Standard Regulation on the Commercialization of Alternative Diesel Fuels (the LCFS Regulation) dated June 4,

Reproduction of Pages 58 - 61 of Comment Letter 45_FF_LCFS_GE Consisting of Comments LCFS FF45-53 through LCFS FF45-59

2015. I have performed this review as an independent expert for Growth Energy. If called upon to do so, I would testify in accord with the facts and opinions presented here.

6. Based on my review of the changes proposed to the LCFS regulation by CARB, the elimination of the multimedia evaluation provisions from the LCFS through the deletion of Section 95490 and related deletions in Sections 95481(a)(59) and 95488(c)(4)(G)6.d. creates the potential for significant adverse environmental impacts to occur as the result of the introduction of new lower carbon intensity fuels. I have participated in every aspect of the development of the LCFS regulation in which a member of the public was allowed by CARB to participate. This change to the proposed regulation could not reasonably have been anticipated, based on the notice of proposed rulemaking and the supporting materials made available in December 2014.

7. The discussion of the need for the multimedia evaluation provisions that CARB staff is now proposing to delete is summarized in both the current Initial Statement of Reasons (ISOR) for re-adoption of the LCFS regulation as well as the ISOR prepared in 2009 for the original LCFS regulation. The language relevant to the multimedia evaluation provisions in both the current and 2009 ISOR is virtually identical. With respect to why the multimedia evaluation provisions were needed in the LCFS, both the ISOR for the re-adoption of the LCFS regulation[1] and the 2009 ISOR[2] state that:

> *The LCFS regulation incorporates this principle as a pre-sale prohibition applied to fuels that are subject to an ARB specification that is modified or adopted after adoption of the LCFS regulation. In such cases, regulated parties would be prohibited from selling the affected fuels in California to comply with the LCFS requirements until a multimedia evaluation is approved for those fuels pursuant to H&S §43830.8.*

Elimination of the multimedia evaluation provisions from the LCFS regulation as now proposed by CARB staff would permit fuel suppliers to sell new fuels in California in order to try to comply with the LCFS without ensuring that adverse environmental impacts associated with their use have been identified and properly mitigated. Such new fuels could include gasoline-butanol blends, alternative diesel fuels other than biodiesel and renewable diesel, and renewable natural gas fuels that fail to comply with CARB's existing natural gas fuel specifications. In addition, these potential impacts of the LCFS regulation were not considered in the Environmental Analysis prepared for the LCFS and ADF regulations.

8. There are several ways in which new fuels which could lead to adverse environmental impacts could be sold in California before the approval of a multimedia

Reproduction of Pages 58 - 61 of Comment Letter 45_FF_LCFS_GE Consisting of Comments LCFS FF45-53 through LCFS FF45-59

1. [1] Page III-64

[2] Page V-32

evaluation pursuant to H&S §43830.8. The first of these is if the California Division of Measurement Standards (CDMS) rather than CARB adopts fuel specifications allowing the use of the new fuel. In the past, new fuels have been allowed in California through specifications enacted by CDMS that have not been required to undergo multimedia evaluation pursuant to H&S §43830.8. Biodiesel is one such fuel that has created adverse environmental impacts. Based on CARB staff estimates, in 2014, biodiesel use for compliance with the LCFS regulation allowed by CARB[3] without an approved multimedia evaluation pursuant to H&S §43830.8 resulted in increased NOx emissions of 1.2 tons per day statewide.[4] Increased NOx emissions due to the use of biodiesel for purposes of LCFS compliance have occurred since the inception of the LCFS program as a result of CARB's failure to adopt fuel specifications and complete the multimedia evaluation required pursuant to H&S §43830.8 despite having committing to do so as early as 2009.[5] Elimination of the requirements for approval of a multimedia evaluation before allowing new fuels to be sold for purposes of LCFS approval would allow other new fuels to be sold in California that, like biodiesel, create adverse environmental impacts before those impacts have been identified through the multimedia evaluation process. These potential environmental impacts created by the LCFS as a result the elimination of the LCFS multimedia evaluation requirements were not considered in the Environmental Assessment.

9. That the increases in NOx emissions resulting from biodiesel use in California without an approved multimedia evaluation were significant can be seen through a comparison of the criteria used to assess air quality impacts in areas of California outside the South Coast and San Joaquin Air Basins and the increases in NOx emissions estimated to result from biodiesel use. Using the Sacramento Metropolitan Air Quality Management District as an example,[6] the significance threshold for NOx emissions projects subject to CEQA is 65 pounds per day or 0.0325 tons per day. The 0.0325 tons per day threshold can be compared to both the 1.2 ton per day increase in NOx emissions due to biodiesel use estimated by CARB staff for 2014 statewide. Clearly, elimination of the requirements for multimedia evaluation for new fuels sold for LCFS compliance could lead to similar, and therefore significant, unmitigated, increases in NOx emissions or significant and unmitigated increases in emissions of other pollutants.

10. Another way in which new fuels could create potential adverse environmental impacts if the multimedia evaluation requirements are deleted is through the

Reproduction of Pages 58 - 61 of Comment Letter 45_FF_LCFS_GE Consisting of Comments LCFS FF45-53 through LCFS FF45-59

[3] See *http://www.arb.ca.gov/fuels/diesel/altdiesel/20111003biodiesel%20guidance.pdf*

[4] See Table 1 of *http://www.arb.ca.gov/regact/2015/adf2015/signedadfnotice.pdf*

[5] See page V-33 of *http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf*

[6] See *http://airquality.org/ceqa/ceqaguideupdate.shtml*

Developmental Engine Fuel Variance Program operated by CDMS.[7] Again, the multimedia evaluation requirements of H&S §43830.8 that apply to fuels for which CARB adopts specifications would not apply in this case and adverse environmental impacts can occur. Allowing new fuels that are part of this program to be sold for purposes of LCFS compliance without having an approved multimedia evaluation would increase the likelihood that fuel producers would seek to use this program and the likelihood that new fuel that leads to unmitigated adverse environmental impacts would be used in California. These potential environmental impacts that the LCFS regulation could create as a result of the proposed elimination of the multimedia evaluation requirements were not considered in the Environmental Assessment.

11. In addition, the Alternative Diesel Fuel regulation proposed by CARB staff creates another way by which new fuels with potential adverse environmental impacts could be sold in California for purposes of LCFS compliance should the multimedia evaluation requirements be eliminated. Currently, fuels involved in Stage 1 or Stage 2 of the LCFS regulation are not required to have completed a multimedia evaluation and therefore could not be sold for purposes of LCFS compliance until they reach Stage 3, at which point completion of a multimedia evaluation and adoption of fuel specifications by CARB are required. Elimination of the current multimedia evaluation requirements from the LCFS regulation as now proposed by CARB staff, would allow fuels in Stage 1 and Stage 2 to be sold for purposes of LCFS compliance before the potential adverse environmental consequences have been assessed or mitigated. Again, these potential environmental impacts due to the LCFS were not considered in the Environmental Assessment.

12. In summary, retention of the current LCFS requirements that new fuels have received an approved multimedia evaluation pursuant to H&S §43830.8 before being allowed to be sold for purposes of LCFS compliance is the only way to ensure that the LCFS is not responsible for use of these new fuels creating potential adverse environmental impacts.

Reproduction of Pages 58 - 61 of Comment Letter 45_FF_LCFS_GE Consisting of Comments LCFS FF45-53 through LCFS FF45-59

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 19th day of June, 2015 at Sacramento, California.

JAMES M. LYONS

[7] See *http://www.cdfa.ca.gov/dms/programs/petroleum/DevelopmentalFuels/RelevantLawsInstructionsChecklist.pdf*

This page intentionally left blank.

8_SF_LCFS_GE (Page 145 - 149)

1202. Comment: **Declaration of James M. Lyons**

Agency Response: This is the second time this document was submitted by Growth Energy. It is a reproduction of comments **LCFS FF45-53** through **LCFS FF45-59**.

This page intentionally left blank.

Attachment 2

STATE OF CALIFORNIA

BEFORE THE AIR RESOURCES BOARD

Declaration of James M. Lyons

I, James Michael Lyons, declare as follows:

1. I make this Declaration based upon my own personal knowledge and my familiarity with the matters recited herein. It is based on my experience of nearly 30 years as a regulator, consultant, and professional in the field of emissions and air pollution control. A copy of my résumé can be found in Attachment A.

2. I am a Senior Partner of Sierra Research, Inc., an environmental consulting firm located at 1801 J Street, Sacramento, California owned by Trinity Consultants, Inc. Sierra specializes in research and regulatory matters pertaining to air pollution control, and does work for both governmental and private industry clients. I have been employed at Sierra Research since 1991. I received a B.S. degree in Chemistry from the University of California, Irvine, and a M.S. Degree in Chemical Engineering from the University of California, Los Angeles. Before joining Sierra in 1991, I was employed by the State of California at the Mobile Source Division of the California Air Resources Board (CARB).

Reproduction of Pages 11 - 16 of Comment Letter 5_F_ADF_POET Consisting of Comments ADF F5-15 through ADF F5-22

3. During my career, I have worked on many projects related to the following areas: 1) the assessment of emissions from on- and non-road mobile sources, 2) assessment of the impacts of changes in fuel composition and alternative fuels on engine emissions including emissions of green-house gases, 3) analyses of the unintended consequences of regulatory actions, and 4) the feasibility of compliance with air quality regulations.

4. I have testified as an expert under state and federal court rules in cases involving CARB regulations for gasoline, Stage II vapor recovery systems and their design, factors affecting emissions from diesel vehicles, evaporative emission control system design and function, as well as combustion chamber system design. While at Sierra I have acted as a consultant on automobile air pollution control matters for CARB and for the United States Environmental Protection Agency. I am a member of the American Chemical Society and the Society of Automotive Engineers and have co-authored nine peer-reviewed monographs concerned with automotive emissions, including greenhouse gases and their control. In addition, over the course of my career, I have conducted peer-reviews of numerous papers related to a wide variety of issues associated with pollutant emissions and air quality.

5. This Declaration summarizes the results of my review of the CARB Notice of Public Availability of Modified Text and Availability of Additional Documents for the Proposed Regulation on the Commercialization of Alternative Diesel Fuels (the ADF Regulation) dated May 22, 2015, and the California Environmental Protection Agency's Staff Report, Multi-Media Evaluation of Biodiesel, Prepared by the Multimedia Working

Group and dated May 2015, which has been added by CARB to the ADF rulemaking file. I have performed this critical review as an independent expert for Growth Energy. If called upon to do so, I would testify in accord with the facts and opinions presented here.

6. Based on my review of the changes proposed to the ADF regulation by CARB, the new exemption from mitigation requirements for B6 to B20 fuels provided through Section 2293(a)(5)(C) creates the potential for significant increases in NOx emissions from vehicles operating in areas outside the South Coast or San Joaquin Valley Air Basins. I have participated in every aspect of the development of the ADF regulation in which a member of the public was allowed by CARB to participate. The new exemption could not reasonably have been anticipated, based on the notice of proposed rulemaking and the supporting materials made available in December 2014.

7. CARB staff agrees on page 11 of the notice that the new exemption could result in increased NOx emissions. However, CARB staff claims on pages 11 to 13 of the notice that the agency has conducted "additional analysis" of NOx emissions related to a number of new issues, including the new exemption that will be added to the ADF Regulation record, and concluded that the overall impact of the ADF regulation on NOx emissions will be smaller than it originally estimated. Unfortunately, CARB has failed to provide the detailed information required for public review and comment. As a result, it was not possible for me to review the data and assumptions used by CARB staff, nor to reach a conclusion about the accuracy of the analysis that was purported to have been performed or the conclusions drawn from the analysis by CARB.

Reproduction of Pages 11 - 16 of Comment Letter 5_F_ADF_POET Consisting of Comments ADF F5-15 through ADF F5-22

8. The notice claims, based on undisclosed "additional analysis," that increased emissions due to the new exemption will be mitigated on a statewide basis averaged over an entire year. Even assuming the "additional analysis" is correct, higher NOx emissions could occur due to the new exemption in areas outside the South Coast or San Joaquin Valley Air Basins which are not in attainment with federal and state ambient air quality standards for ozone. Although the South Coast and San Joaquin Valley Air Basins experience the highest ozone levels in the state, there are many other areas in non-attainment of the federal[1] and state[2] standards where increased NOx emissions could create adverse impacts on air quality.

9. CARB should be required to provide the necessary data to perform a careful assessment. Increased NOx emissions resulting from the new exemption could potentially be significant. This can be seen through a comparison of the criteria used to assess air quality impacts in areas of California outside the South Coast and San Joaquin Air Basins and the increases in NOx emissions estimated to result from biodiesel use. Using the Sacramento Metropolitan Air Quality Management District as an example,[3] the significance threshold for NOx emissions projects subject to CEQA is 65 pounds per day

[1] See http://www.arb.ca.gov/desig/adm/2013/fed_o3.pdf

[2] See http://www.arb.ca.gov/desig/adm/2013/state_o3.pdf

[3] See http://airquality.org/ceqa/ceqaguideupdate.shtml

or 0.0325 tons per day. Using the data in the row labeled "Emission Inventory (Diesel TPD)" in Table 1 of the CARB Notice, 0.0325 tons per day can be compared to both the 0.95 ton per day estimate for 2016 statewide increases in NOx due to the ADF regulation in Table 1 of the notice, and also the difference between that value and the 1.27 ton per day value that was CARB's original estimate. Clearly, if the new exemption results in the use of even a small amount of biodiesel in the Sacramento area without mitigation, the increase in NOx emissions could be significant. Further, similar situations where significant increases in NOx emissions occur in other ozone non-attainment areas outside of the South Coast and San Joaquin Air Basins can be expected.

10. The only way to ensure that increased NOx emissions due to the new exemption would not potentially lead to adverse air quality impacts in areas where it is allowed, and thus mitigate impacts to NOx caused by the exemption, would be to require that appropriate amounts of renewable diesel biodiesel are used in the same location and at the same time as the biodiesel provided for under the new exemption. The only way to ensure this would happen would be to require blending of renewable diesel into the biodiesel blends allowed under the new exemption. There is no such requirement in the ADF regulation.

Reproduction of Pages 11 - 16 of Comment Letter 5_F_ADF_POET Consisting of Comments ADF F5-15 through ADF F5-22

11. Another major problem with CARB's "Updated ADF NOx Analysis" presented in Table 1 of the Notice is that CARB has failed to address a key flaw in its analysis of the adverse environmental impacts of biodiesel. This flaw relates to using a baseline for determining the significance of increased NOx emissions from biodiesel use where 65 million gallons of biodiesel are already in-use to conclude, as stated on page 47 of the Initial Statement of Reasons for the ADF regulation, that:

> *The net impacts of the proposal reduce NOx impacts from biodiesel, even assuming increased biodiesel volumes over the subsequent years. Estimated impacts under the proposal are less than the baseline (current year) and will continue to decrease as NTDE use increases in California.*

The correct baseline that is used everywhere else in the ISOR, as well as in the Multi-Media Evaluation and by the Peer Reviewers of that evaluation, is CARB diesel fuel containing **no** biodiesel. Given that the purpose of the ADF regulation is to establish specifications for fuels like biodiesel while identifying and ensuring mitigation of adverse environmental impacts, the no biodiesel baseline is clearly the correct baseline. Based on CARB's own "Updated ADF NOx Analysis," use of this baseline shows unmitigated NOx increases of about one ton per day statewide in California in 2015, 2016, and 2017, and at lower levels through 2020, despite its flaws. Further, as shown in my previous declaration, submitted to CARB prior to the ADF and LCFS public hearings in February 2015, the likely increases in NOx emissions are much larger and can be expected to continue indefinitely into the future.

When viewed in the context of the proper baseline, the data presented in Table 1 of the notice show that the proposed ADF regulation, even after CARB's update of its analysis, fails to mitigate increased NOx emissions due to biodiesel use. That CARB has erred in establishing the baseline for analysis of biodiesel NOx impacts is support by the ADF regulation itself, as sections 2293.5(a)(3)(C), 2293.5(b)(3)(C), 2293.5(b)(5)(B), 2293.5(b)(5)(D), and 2293.5(b)(6)(B), make it clear that increased emissions from an ADF will not be included in baseline. Rather, the baseline required to be used has to reflect conditions in place before the use of the ADF.

12. Notwithstanding the above, CARB's "additional analysis" is also fatally flawed for all of the other reasons set forth in my previous declaration and its attachments dated February 17th 2015, which was filed as part of Growth Energy's comments during the original 45 day comment period on the ADF regulation.

13. Turning to the Staff Report on the Multimedia Evaluation of Biodiesel that has only recently become available for public comment and is now being included in the ADF regulation record, I have reviewed the air quality assessment that is reported to have been prepared by CARB staff, and have found it to be both inconsistent with the analysis presented in the ADF ISOR as well as fatally flawed in that it fails to consider all of the available information regarding the impact of biodiesel on NOx emissions from what CARB refers to as New Technology Diesel Engines (NTDEs). As a direct result, the Supplemental External Scientific Peer Review of the air quality impacts of biodiesel is also flawed.

Reproduction of Pages 11 - 16 of Comment Letter 5_F_ADF_POET Consisting of Comments ADF F5-15 through ADF F5-22

14. The primary conclusion of the Multimedia Evaluation of Biodiesel with respect to air quality is:

> *Based on a relative comparison between biodiesel and CARB diesel (containing no biodiesel), ARB staff concludes that with in-use requirements biodiesel, as specified in the multimedia evaluation and proposed regulation, does not pose a significant adverse impact on public health or the environment from potential air quality impacts.*

This statement clearly highlights the fundamental inconsistency between the baseline used in the ISOR analysis of air quality impacts, where the baseline included biodiesel use, and the baseline identified in the Multimedia Evaluation Staff Report which included no biodiesel. As noted above, the appropriate baseline is the one identified in the Multimedia Evaluation Staff Report.

15. Another major inconsistency between the Multimedia Evaluation and the ISOR is the fact that CARB failed to include much of the information found in Chapters 6 and 7, and in Appendices B and G of the ISOR, all of which addresses the impact of biodiesel on emissions and air quality in the Multimedia Evaluation. Key information omitted includes:

- The finding that NOx emission increases due to soy biodiesel are statistically significant based on all data considered on page 40 of the ISOR;

- The ton per day increases in NOx emissions due to the ADF shown in Tables 7.1 and B-1 of the ISOR;

- The Supplemental Statistical Analysis presented in Appendix G of the ISOR; and

- The following peer reviewed technical papers listed as references 21 through 24 for Chapter 6 of the ISOR, which contradict CARB's claims regarding the impact of biodiesel on NOx emissions from NTDEs:

    - Gysel, Nicholas et al., *Emissions and Redox Activity of Biodiesel Blends Obtained from Different Feedstocks from a Heavy-Duty Vehicle Equipped with DPF/SCR Aftertreatment and a Heavy-Duty Vehicle without Control Aftertreatment*, SAE 2014-01-1400, Published 04/01/2014.

    - McWilliam, Lyn and Zimmermann, Anton, *Emission and Performance Implications of Biodiesel Use in an SCR-equipped Caterpillar C6.6*, SAE 2010-012157 Published, 10/25/2010.

    - Mizushima, Norifumi and Nurata, Yutaka, *Effect of Biodiesel on NOx Reduction Performance of Urea-SCR system*, SAE 2010-01-2278, Published 10/25/2010.

    - Walkowicz, Kevin et al., *On-Road and In-Laboratory Testing to Demonstrate Effects of ULSD, B20, and B99 on a Retrofit Urea-SCR Aftertreatment System*, SAE 2009-01-2733.

Reproduction of Pages 11 - 16 of Comment Letter 5_F_ADF_POET Consisting of Comments ADF F5-15 through ADF F5-22

CARB's failure to include and fully to address the foregoing information and analysis made it impossible for any external reviewers, who were relying upon CARB for full disclosure of all relevant data and information, to perform a credible scientific review of the emissions and air quality evaluation and the conclusions reached by CARB.

16. Similarly, CARB failed to include data and information directly relevant to the issues of biodiesel impacts on emissions and air quality provided during the public comment period on the ADF regulation in the materials considered in the Multimedia Evaluation Staff Report, and therefore by the external reviewers. Data and information provided during the public comment period that contradict CARB's findings regarding biodiesel NOx impacts on NTDEs that was not made part of the Multimedia Evaluation includes:

- "NOx Emission Impacts of Biodiesel Blends," Robert Crawford, Rincon Ranch Consulting, February 17, 2015; and

- Declaration of James M. Lyons, February 17, 2015, with attachments.

Again, CARB's failure to include this information also made it impossible for the Peer Reviewers, who were relying upon CARB for full disclosure of all relevant data and information, to perform a credible scientific review of the emissions and air quality evaluation and the conclusions reached by CARB.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 8th day of June, 2015 at Sacramento, California.

Reproduction of Pages 11 - 16 of Comment Letter 5_F_ADF_POET Consisting of Comments ADF F5-15 through ADF F5-22

JAMES M. LYONS

This page intentionally left blank.

8_SF_LCFS_GE (Page 150 - 156)

1203. Comment: **Declaration of James M. Lyons**

Agency Response: This is the second time this document was submitted. It is a reproduction of comments **ADF F5-15** through **ADF F5-22**. The comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **5_F_ADF_POET**.

This page intentionally left blank.

ATTACHMENT A

RÉSUMÉ

sierra research
A Trinity Consultants Company
1801 J Street
Sacramento, CA 95811
Tel: (916) 444-6666
Fax: (916) 444-8373
Ann Arbor, MI
Tel: (734) 761-6666
Fax: (734) 761-6755

Résumé

James Michael Lyons

Education

1985, M.S., Chemical Engineering, University of California, Los Angeles

1983, B.S., Cum Laude, Chemistry, University of California, Irvine

Professional Experience

4/91 to present	Senior Engineer/Partner/Senior Partner Sierra Research

Primary responsibilities include oversight and execution of complex analyses of the emission benefits, costs, and cost-effectiveness of mobile source air pollution control measures. Mr. Lyons has developed particular expertise with respect to the assessment of control measures involving fuel reformulation, fuel additives, and alternative fuels, as well as accelerated vehicle/engine retirement programs, the deployment of advanced emission control systems for on- and non-road gasoline- and Diesel-powered engines, on-vehicle evaporative and refueling emission control systems, and Stage I and Stage II service station vapor recovery systems. Additional duties include assessments of the activities of federal, state, and local regulatory agencies with respect to motor vehicle emissions and reports to clients regarding those activities. Mr. Lyons has extensive litigation experience related to air quality regulations, product liability, and intellectual property issues.

7/89 to 4/91	Senior Air Pollution Specialist California Air Resources Board

Supervised a staff of four professionals responsible for identifying and controlling emissions of toxic air contaminants from mobile sources and determining the effects of compositional changes to gasoline and diesel fuel on emissions of regulated and unregulated pollutants. Other responsibilities included development of new test procedures and emission standards for evaporative and running loss emissions of hydrocarbons from vehicles; overseeing the development of the state plan to control toxic emissions from motor vehicles; and reducing emissions of CFCs from motor vehicles.

4/89 to 7/89 — Air Pollution Research Specialist
California Air Resources Board

Responsibilities included identification of motor vehicle research needs; writing requests for proposals; preparation of technical papers and reports; as well as monitoring and overseeing research programs.

9/85 to 4/89 — Associate Engineer/Engineer
California Air Resources Board

Duties included analysis of vehicle emissions data for trends and determining the effectiveness of various types of emissions control systems for both regulated and toxic emissions; determining the impact of gasoline and diesel powered vehicles on ambient levels of toxic air contaminants; participation in the development of regulations for "gray market" vehicles; and preparation of technical papers and reports.

Professional Affiliations

American Chemical Society
Society of Automotive Engineers

Selected Publications (Author or Co-Author)

"Development of Vehicle Attribute Forecasts for 2013 IEPR," Sierra Research Report No. SR2014-01-01, prepared for the California Energy Commission, January 2014.

"Assessment of the Emission Benefits of U.S. EPA's Proposed Tier 3 Motor Vehicle Emission and Fuel Standards," Sierra Research Report No. SR2013-06-01, prepared for the American Petroleum Institute, June 2013.

"Development of Inventory and Speciation Inputs for Ethanol Blends," Sierra Research Report No. SR2012-05-01, prepared for the Coordinating Research Council, Inc. (CRC), May 2012.

"Review of CARB Staff Analysis of 'Illustrative' Low Carbon Fuel Standard (LCFS) Compliance Scenarios," Sierra Research Report No. SR2012-02-01, prepared for the Western States Petroleum Association, February 20, 2012.

"Review of CARB On-Road Heavy-Duty Diesel Emissions Inventory," Sierra Research Report No. SR2010-11-01, prepared for The Ad Hoc Working Group, November 2010.

"Identification and Review of State/Federal Legislative and Regulatory Changes Required for the Introduction of New Transportation Fuels," Sierra Research Report No. SR2010-08-01, prepared for the American Petroleum Institute, August 2010.

"Technical Review of EPA Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis for Non-GHG Pollutants," Sierra Research Report No. SR2010-05-01, prepared for the American Petroleum Institute, May 2010.

"Effects of Gas Composition on Emissions from Heavy-Duty Natural Gas Engines," Sierra Research Report No. SR2010-02-01, prepared for the Southern California Gas Company, February 2010.

"Effects of Gas Composition on Emissions from a Light-Duty Natural Gas Vehicle," Sierra Research Report No. SR2009-11-01, prepared for the Southern California Gas Company, November 2009.

"Technical Review of 2009 EPA Draft Regulatory Impact Analysis for Non-GHG Pollutants Due to Changes to the Renewable Fuel Standard," Sierra Research Report No. SR2009-09-01, prepared for the American Petroleum Institute, September 2009.

"Effects of Vapor Pressure, Oxygen Content, and Temperature on CO Exhaust Emissions," Sierra Research Report No. 2009-05-03, prepared for the Coordinating Research Council, May 2009.

"Technical Review of 2007 EPA Regulatory Impact Analysis Methodology for the Renewable Fuels Standard," Sierra Research Report No. 2008-09-02, prepared for the American Petroleum Institute, September 2008.

"Impacts of MMT Use in Unleaded Gasoline on Engines, Emission Control Systems, and Emissions," Sierra Research Report No. 2008-08-01, prepared for McMillan Binch Mendelsohn LLP, Canadian Vehicle Manufacturers' Association, and Association of International Automobile Manufacturers of Canada, August 2008.

"Attachment to Comments Regarding the NHTSA Proposal for Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015, Docket No. NHTSA-2008-0089," Sierra Research Report No. SR2008-06-01, prepared for the Alliance of Automobile Manufacturers, June 2008.

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act – Part 1: Impacts on New Vehicle Fuel Economy," SAE Paper No. 2008-01-1852, Society of Automotive Engineers, 2008.

"Basic Analysis of the Cost and Long-Term Impact of the Energy Independence and Security Act Fuel Economy Standards," Sierra Research Report No. SR 2008-04-01, April 2008.

"The Benefits of Reducing Fuel Consumption and Greenhouse Gas Emissions from Light-Duty Vehicles," SAE Paper No. 2008-01-0684, Society of Automotive Engineers, 2008.

"Assessment of the Need for Long-Term Reduction in Consumer Product Emissions in South Coast Air Basin," Sierra Research Report No. 2007-09-03, prepared for the Consumer Specialty Products Association, September 2007.

“Summary of Federal and California Subsidies for Alternative Fuels,” Sierra Research Report No. SR2007-04-02, prepared for the Western States Petroleum Association, April 2007.

“Analysis of IRTA Report on Water-Based Automotive Products,” Sierra Research Report No. SR2006-08-02, prepared for the Consumer Specialty Projects Association and Automotive Specialty Products Alliance, August 2006.

“Evaluation of Pennsylvania’s Implementation of California’s Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions,” Sierra Research Report No. SR2006-04-01, prepared for Alliance of Automobile Manufacturers, April 12, 2006.

“Evaluation of New Jersey’s Adoption of California’s Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions,” Sierra Research Report No. SR2005-09-03, prepared for the Alliance of Automobile Manufacturers, September 30, 2005.

“Evaluation of Vermont’s Adoption of California’s Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions,” Sierra Research Report No. SR2005-09-02, prepared for the Alliance of Automobile Manufacturers, September 19, 2005.

“Assessment of the Cost-Effectiveness of Compliance Strategies for Selected Eight-Hour Ozone NAAQS Nonattainment Areas,” Sierra Research Report No. SR2005-08-04, prepared for the American Petroleum Institute, August 30, 2005.

“Evaluation of Connecticut’s Adoption of California’s Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions,” Sierra Research Report No. SR2005-08-03, prepared for the Alliance of Automobile Manufacturers, August 26, 2005.

“Evaluation of New York’s Adoption of California’s Greenhouse Gas Regulations On Criteria Pollutants and Precursor Emissions,” Sierra Research Report No. SR2005-07-04, prepared for the Alliance of Automobile Manufacturers, July 14, 2005.

“Review of MOVES2004,” Sierra Research Report No. SR2005-07-01, prepared for the Alliance of Automobile Manufacturers, July 11, 2005.

“Review of Mobile Source Air Toxics (MSAT) Emissions from On-Highway Vehicles: Literature Review, Database, Development, and Recommendations for Future Studies,” Sierra Research Report No. SR2005-03-01, prepared for the American Petroleum Institute, March 4, 2005.

“The Contribution of Diesel Engines to Emissions of ROG, NOx, and PM2.5 in California: Past, Present, and Future,” Sierra Research Report No. SR2005-02-01, prepared for Diesel Technology Forum, February 2005.

“Fuel Effects on Highway Mobile Source Air Toxics (MSAT) Emissions,” Sierra Research Report No. SR2004-12-01, prepared for the American Petroleum Institute, December 23, 2004.

"Review of the August 2004 Proposed CARB Regulations to Control Greenhouse Gas Emissions from Motor Vehicles: Cost Effectiveness for the Vehicle Owner or Operator – Appendix C to the Comments of The Alliance of Automobile Manufacturers," Sierra Research Report No. SR2004-09-04, prepared for the Alliance of Automobile Manufacturers, September 2004.

"Emission and Economic Impacts of an Electric Forklift Mandate," Sierra Research Report No. SR2003-12-01, prepared for National Propane Gas Association, December 12, 2003.

"Reducing California's Energy Dependence," Sierra Research Report No. SR2003-11-03, prepared for Alliance of Automobile Manufacturers, November 25, 2003.

"Evaluation of Fuel Effects on Nonroad Mobile Source Air Toxics (MSAT) Emissions: Literature Review, Database Development, and Recommendations for Future Studies," Sierra Research Report No. SR2003-10-01, prepared for American Petroleum Institute, October 3, 2003.

"Review of Current and Future CO Emissions from On-Road Vehicles in Selected Western Areas," Sierra Research Report No. SR03-01-01, prepared for the Western States Petroleum Association, January 2003.

"Review of CO Compliance Status in Selected Western Areas," Sierra Research Report No. SR02-09-04, prepared for the Western States Petroleum Association, September 2002.

"Impacts Associated With the Use of MMT as an Octane Enhancing Additive in Gasoline – A Critical Review", Sierra Research Report No. SR02-07-01, prepared for Canadian Vehicle Manufacturers Association and Association of International Automobile Manufacturers of Canada, July 24, 2002.

"Critical Review of 'Safety Oversight for Mexico-Domiciled Commercial Motor Carriers, Final Programmatic Environmental Assessment', Prepared by John A Volpe Transportation Systems Center, January 2002," Sierra Research Report No. SR02-04-01, April 16, 2002.

"Critical Review of the Method Used by the South Coast Air Quality Management District to Establish the Emissions Equivalency of Heavy-Duty Diesel- and Alternatively Fueled Engines", Sierra Research Report No. SR01-12-03, prepared for Western States Petroleum Association, December 21, 2001.

"Review of U.S. EPA's Diesel Fuel Impact Model", Sierra Research Report No. SR01-10-01, prepared for American Trucking Associations, Inc., October 25, 2001.

"Operation of a Pilot Program for Voluntary Accelerated Retirement of Light-Duty Vehicles in the South Coast Air Basin," Sierra Research Report No. SR01-05-02, prepared for California Air Resources Board, May 2001.

"Comparison of Emission Characteristics of Advanced Heavy-Duty Diesel and CNG Engines," Sierra Report No. SR01-05-01, prepared for Western States Petroleum Association, May 2001.

"Analysis of Southwest Research Institute Test Data on Inboard and Sterndrive Marine Engines," Sierra Report No. SR01-01-01, prepared for National Marine Manufacturers Association, January 2001.

"Institutional Support Programs for Alternative Fuels and Alternative Fuel Vehicles in Arizona: 2000 Update," Sierra Report No. SR00-12-04, prepared for Western States Petroleum Association, December 2000.

"Real-Time Evaporative Emissions Measurement: Mid-Morning Commute and Partial Diurnal Events," SAE Paper No. 2000-01-2959, October 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," SAE Paper No. 2000-01-2958, October 2000.

"A Comparative Analysis of the Feasibility and Cost of Compliance with Potential Future Emission Standards for Heavy-Duty Vehicles Using Diesel or Natural Gas," Sierra Research Report No. SR00-02-02, prepared for Californians For a Sound Fuel Strategy, February 2000.

"Critical Review of the Report Entitled 'Economic Impacts of On Board Diagnostic Regulations (OBD II)' Prepared by Spectrum Economics," Sierra Research Report No. SR00-01-02, prepared for the Alliance of Automobile Manufacturers, January 2000.

"Potential Evaporative Emission Impacts Associated with the Introduction of Ethanol-Gasoline Blends in California," Sierra Research Report No. SR00-01-01, prepared for the American Methanol Institute, January 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," Sierra Research Report No. SR99-10-03, prepared for the Coordinating Research Council, October 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," SAE Paper No. 1999-01-3676, August 1999.

"Future Diesel-Fueled Engine Emission Control Technologies and Their Implications for Diesel Fuel Properties," Sierra Research Report No. SR99-08-01, prepared for the American Petroleum Institute, August 1999.

"Analysis of Compliance Feasibility under Proposed Tier 2 Emission Standards for Passenger Cars and Light Trucks," Sierra Research Report No. SR99-07-02, July 1999.

"Comparison of the Properties of Jet A and Diesel Fuel," Sierra Research Report No. SR99-02-01, prepared for Pillsbury Madison and Sutro, February 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," Sierra Research Report No. SR98-12-02, prepared for the American Petroleum Institute, December 1998.

"Analysis of New Motor Vehicle Issues in the Canadian Government's Foundation Paper on Climate Change – Transportation Sector," Sierra Research Report No. SR98-12-01, prepared for the Canadian Vehicle Manufacturers Association, December 1998.

"Investigation of the Relative Emission Sensitivities of LEV Vehicles to Gasoline Sulfur Content - Emission Control System Design and Cost Differences," Sierra Research Report No. SR98-06-01, prepared for the American Petroleum Institute, June 1998.

"Costs, Benefits, and Cost-Effectiveness of CARB's Proposed Tier 2 Regulations for Handheld Equipment Engines and a PPEMA Alternative Regulatory Proposal," Sierra Research Report No. SR98-03-03, prepared for the Portable Power Equipment Manufacturers Association, March 1998.

"Analysis of Diesel Fuel Quality Issues in Maricopa County, Arizona," Sierra Research Report No. SR97-12-03, prepared for the Western States Petroleum Association, December 1997.

"Potential Impact of Sulfur in Gasoline on Motor Vehicle Pollution Control and Monitoring Technologies," prepared for Environment Canada, July 1997.

"Analysis of Mid- and Long-Term Ozone Control Measures for Maricopa County," Sierra Research Report No. SR96-09-02, prepared for the Western States Petroleum Association, September 9, 1996.

"Technical and Policy Issues Associated with the Evaluation of Selected Mobile Source Emission Control Measures in Nevada," Sierra Research Report No. SR96-03-01, prepared for the Western States Petroleum Association, March 1996.

"Cost-Effectiveness of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-05, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"Cost of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-04, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"A Comparative Characterization of Gasoline Dispensing Facilities With and Without Vapor Recovery Systems," Sierra Research Report No. SR95-10-01, prepared for the Province of British Columbia Ministry of Environment Lands and Parks, October 1995.

"Potential Air Quality Impacts from Changes in Gasoline Composition in Arizona," Sierra Research Report No. SR95-04-01, prepared for Mobil Corporation, April 1995.

"Vehicle Scrappage: An Alternative to More Stringent New Vehicle Standards in California," Sierra Research Report No. SR95-03-02, prepared for Texaco, Inc., March 1995.

"Evaluation of CARB SIP Mobile Source Measures," Sierra Research Report No. SR94-11-02, prepared for Western States Petroleum Association, November 1994.

"Reformulated Gasoline Study," prepared by Turner, Mason & Company, DRI/McGraw-Hill, Inc., and Sierra Research, Inc., for the New York State Energy Research and Development Authority, Energy Authority Report No. 94-18, October 1994.

"Phase II Feasibility Study: Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley," Sierra Research Report No. SR94-09-02, prepared for the Greater Vancouver Regional District, September 1994.

"Cost-Effectiveness of Mobile Source Emission Controls from Accelerated Scrappage to Zero Emission Vehicles," Paper No. 94-TP53.05, presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, OH, June 1994.

"Investigation of MOBILE5a Emission Factors, Assessment of I/M Program and LEV Program Emission Benefits," Sierra Research Report No. SR94-06-05, prepared for American Petroleum Institute, June 1994.

"Cost-Effectiveness of the California Low Emission Vehicle Standards," SAE Paper No. 940471, 1994.

"Meeting ZEV Emission Limits Without ZEVs," Sierra Research Report No. SR94-05-06, prepared for Western States Petroleum Association, May 1994.

"Evaluating the Benefits of Air Pollution Control - Method Development and Application to Refueling and Evaporative Emissions Control," Sierra Research Report No. SR94-03-01, prepared for the American Automobile Manufacturers Association, March 1994.

"The Cost-Effectiveness of Further Regulating Mobile Source Emissions," Sierra Research Report No. SR94-02-04, prepared for the American Automobile Manufacturers Association, February 1994.

"Searles Valley Air Quality Study (SVAQS) Final Report," Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

"A Comparative Study of the Effectiveness of Stage II Refueling Controls and Onboard Refueling Vapor Recovery," Sierra Research Report No. SR93-10-01, prepared for the American Automobile Manufacturers Association, October 1993.

"Evaluation of the Impact of the Proposed Pole Line Road Overcrossing on Ambient Levels of Selected Pollutants at the Calgene Facilities," Sierra Research Report No. SR93-09-01, prepared for the City of Davis, September 1993.

"Leveling the Playing Field for Hybrid Electric Vehicles: Proposed Modifications to CARB's LEV Regulations," Sierra Research Report No. SR93-06-01, prepared for the Hybrid Vehicle Coalition, June 1993.

"Size Distributions of Trace Metals in the Los Angeles Atmosphere," *Atmospheric Environment*, Vol. 27B, No. 2, pp. 237-249, 1993.

"Preliminary Feasibility Study for a Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley Area," Sierra Research Report No. 92-10-01, prepared for the Greater Vancouver Regional District, October 1992.

"Development of Mechanic Qualification Requirements for a Centralized I/M Program," SAE Paper No. 911670, 1991.

"Cost-Effectiveness Analysis of CARB's Proposed Phase 2 Gasoline Regulations," Sierra Research Report No. SR91-11-01, prepared for the Western States Petroleum Association, November 1991.

"Origins and Control of Particulate Air Toxics: Beyond Gas Cleaning," in Proceedings of the Twelfth Conference on Cooperative Advances in Chemical Science and Technology, Washington, D.C., October 1990.

"The Effect of Gasoline Aromatics on Exhaust Emissions: A Cooperative Test Program," SAE Paper No. 902073, 1990.

"Estimation of the Impact of Motor Vehicles on Ambient Asbestos Levels in the South Coast Air Basin," Paper No. 89-34B.7, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"Benzene/Aromatic Measurements and Exhaust Emissions from Gasoline Vehicles," Paper No. 89-34B.4, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"The Impact of Diesel Vehicles on Air Pollution," presented at the 12th North American Motor Vehicle Emissions Control Conference, Louisville, KY, April 1988.

"Exhaust Benzene Emissions from Three-Way Catalyst-Equipped Light-Duty Vehicles," Paper No. 87-1.3, presented at the 80th Annual Meeting of the Air Pollution Control Association, New York, NY, June 1987.

"Trends in Emissions Control Technologies for 1983-1987 Model-Year California-Certified Light-Duty Vehicles," SAE Paper No. 872164, 1987.

8_SF_LCFS_GE (Page 157 - 166)

1204. Comment: **James Lyons' Resume**

Agency Response: This is submittal five of six of James Lyon's resume. It does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

Attachment 3

STATE OF CALIFORNIA
BEFORE THE AIR RESOURCES BOARD
Declaration of James M. Lyons

I, James Michael Lyons, declare as follows:

1. I make this Declaration based upon my own personal knowledge and my familiarity with the matters recited herein. It is based on my experience of nearly 30 years as a regulator, consultant, and professional in the field of emissions and air pollution control. A copy of my résumé can be found in Attachment A.

2. I am a Senior Partner of Sierra Research, Inc., an environmental consulting firm located at 1801 J Street, Sacramento, California owned by Trinity Consultants, Inc. Sierra specializes in research and regulatory matters pertaining to air pollution control, and does work for both governmental and private industry clients. I have been employed at Sierra Research since 1991. I received a B.S. degree in Chemistry from the University of California, Irvine, and a M.S. Degree in Chemical Engineering from the University of California, Los Angeles. Before joining Sierra in 1991, I was employed by the State of California at the Mobile Source Division of the California Air Resources Board (CARB).

3. During my career, I have worked on many projects related to the following areas: 1) the assessment of emissions from on- and non-road mobile sources, 2) assessment of the impacts of changes in fuel composition and alternative fuels on engine emissions including emissions of green-house gases, 3) analyses of the unintended consequences of regulatory actions, and 4) the feasibility of compliance with air quality regulations.

4. I have testified as an expert under state and federal court rules in cases involving CARB regulations for gasoline, Stage II vapor recovery systems and their design, factors affecting emissions from diesel vehicles, evaporative emission control system design and function, as well as combustion chamber system design. While at Sierra I have acted as a consultant on automobile air pollution control matters for CARB and for the United States Environmental Protection Agency. I am a member of the American Chemical Society and the Society of Automotive Engineers and have co-authored nine peer-reviewed monographs concerned with automotive emissions including greenhouse gases and their control. In addition, over the course of my career, I have conducted peer-reviews of numerous papers related to a wide variety of issues associated with pollutant emissions and air quality.

5. This Declaration summarizes the results of analyses I have performed regarding CARB staff's analysis of different aspects of the re-adoption of the Low Carbon Fuel Standard (LCFS) Regulation and Regulation on the Commercialization of Alternative Diesel Fuels (ADFs) as an independent expert for Growth Energy. If called upon to do so, I would testify in accord with the facts and opinions presented here.

Reproduction of Pages 230 - 242 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-235 through LCFS 46-238 and ADF 17-18 through ADF 17-23

6. Based on a review of the Initial Statement of Reasons (ISOR) for the LCFS regulation and the associated appendices, including the draft Environmental Analysis, it is clear that CARB staff failed to quantify the GHG emission reductions associated with the LCFS regulation itself. Rather, staff notes that the GHG reduction estimates provide are inflated as the result of the "double counting" of GHG reductions due to other regulatory programs.

7. Further, this review shows that CARB staff failed to perform a complete analysis of the potential air quality impacts associated with the LCFS regulation. More specifically, CARB staff's air quality analysis fails to quantitatively assess the impact of the LCFS and ADF on all emission sources that could be affected nor does it consider all of the pollutants for which emission changes might occur. A summary of the review is Attachment B to this declaration.

8. CARB staff rejected a proposed alternative to the LCFS regulation submitted by Growth Energy claiming that it will likely result in the same environmental benefits, but not ensure a transition to lower carbon intensity fuels that CARB staff claims is the main goal of the LCFS regulation. As discussed in detail in Attachment C to this declaration, CARB staff failed to perform any analysis of the Growth Energy Alternative and has provided no support for this finding. Because the Growth Energy Alternative provides greater environmental benefits and is expected to cost less than the LCFS regulation, it must be adopted by CARB instead of the LCFS regulation.

9. As part of the development of the ADF regulation, CARB staff examined the impacts of the proposed regulation on emissions of pollutants including oxides of nitrogen (NOx) emitted from heavy-duty diesel engines operating on blends of diesel fuel and biodiesel.

10. NOx emissions directly affect atmospheric levels of nitrogen dioxide, a compound for which a National Ambient Air Quality Standards (NAAQS) has been established. NOx emissions are also precursors to the formation of ozone and particulate matter, which are also pollutants for which NAAQS have been established. Areas of the South Coast and San Joaquin Valley air basins are in extreme and moderate non-attainment of the most recent ozone and fine particulate standards, respectively.

11. In the Initial Statement of Reasons (ISOR) for the ADF regulation and its' appendices, CARB staff summarized its analysis of increases in NOx emissions from heavy-duty diesel vehicles over the period from 2014 through 2023. The results of the staff's analysis are most clearly summarized in Table B-1 of Appendix B of the ISOR. This table shows that staff estimate that biodiesel use allowed under the ADF regulation will increase NOx emissions by 1.35 tons per day in 2014 and that the magnitude of this emission increase will drop to 0.01 ton per day by 2023.

12. I have performed a review of the staff's assessment of the NOx emission impacts of biodiesel use allowed under the ADF regulation presented in ISOR and its' appendices and find it to be fundamentally flawed such that it is not reliable. First, the bases for total diesel NOx emissions inventory is not described in the ISOR or in other

Reproduction of Pages 230 - 242 of Comment Letter 46_OP_LCFS_GE/17_OP_ADF_GE Consisting of Comments LCFS 46-235 through LCFS 46-238 and ADF 17-18 through ADF 17-23 documents in the record. Second, CARB staff incorrectly assumes that the use of biodiesel in "New Technology Diesel Engines (NTDEs)" equipped with exhaust aftertreatment devices to lower NOx emissions will not lead to increased NOx emissions. Third, CARB staff incorrectly apply ratios of on-road vehicle travel by NTDEs from the now obsolete EMFAC2011 model to account for the amount of biodiesel used in all NTDEs including those found in non-road equipment. Fourth, to assess the overall impact of the ADF regulation on NOx emissions, CARB incorrectly subtracts NOx reductions resulting from the use of "renewable diesel fuel" from increases in NOx emissions resulting from the use of biodiesel.

13. In addition, I have performed a very conservative assessment of the NOx emission impacts of biodiesel use under the ADF that uses the latest CARB emissions models and corrects the flaws in the staff analysis, a summary of which is attached. The results of this assessment indicate that NOx increases from biodiesel will be much larger than those estimated by CARB staff and that the magnitude of the impacts will not decline over time as forecast by CARB staff. In addition, the analysis shows that the ADF regulation will lead to significant increases in NOx emissions in the South Coast and San Joaquin Valley air basins which are already in extreme non-attainment of the federal ozone NAAQS and moderate non-attainment of the federal fine particulate NAAQS. The details of both the review and revised emissions estimates are presented in Attachment D to this declaration.

Reproduction of Pages 230 - 242 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-235 through LCFS 46-238 and ADF 17-18 through ADF 17-23

14. In addition to identifying a fundamentally flawed analysis of the increases in NOx emissions from biodiesel use under the ADF, my review indicates that other elements of the staff's air quality and environmental analyses are also fundamentally flawed. These include incorrectly selecting 2014 as the baseline year for the environmental analysis, lacking documentation and using unsupported assumptions in determination of the NOx control level for biodiesel, and unnecessarily delaying the effective date for the implementation of mitigation requirements under the ADF regulation. All of these issues, which are discussed in detail in Attachment E, cause the adverse environmental impacts of the ADF regulation to be greater than purported by CARB staff.

15. Another important issue that I have identified with the ADF regulation is that it and the related LCFS and California Diesel regulations contain inconsistent and conflicting definitions and lack provisions requiring the determination, through testing, of the biodiesel content of commercial blendstocks. As a result, there is a clear potential for biodiesel blends to actually contain as much as 5% more biodiesel by volume than will be reported to CARB under the ADF regulation. A detailed discussion of the flaws in the ADF regulation that could allow this to occur is provided in Attachment F. Actual biodiesel levels above those reported under the ADF will lead to larger unmitigated increases in NOx emissions than have been estimated by either CARB staff or me.

16. CARB staff has rejected a proposed alternative to the ADF regulation submitted by Growth Energy, claiming that it will result in the same environmental benefits but be more costly than the staff proposal. As discussed in detail in Attachment G to this declaration, this finding is based on the same fundamentally flawed emissions

analysis performed by CARB staff that is discussed above. Given that the Growth Energy alternative is designed to mitigate all potential increases in NOx emissions (when assessed in light of a proper emissions analysis) due to biodiesel use under the ADF as soon as the regulation becomes effective, it yields greater and more timely environmental benefits than the staff proposal. In addition, the Growth Energy alternative would require the same mitigation techniques as the ADF regulation, but simply expands the circumstances under which they must be applied, and has an estimated cost-effectiveness equal to that of ADF regulation. Because the Growth Energy Alternative provides greater environmental benefits as cost-effectively as the ADF regulation, it must be adopted by CARB instead of the ADF regulation.

Reproduction of Pages 230 - 242 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-235 through LCFS 46-238 and ADF 17-18 through ADF 17-23

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 17th day of February, 2015 at Sacramento, California.

JAMES M. LYONS

This page intentionally left blank.

8_SF_LCFS_GE (Page 167 - 171)

1205. Comment: **Declaration of James M. Lyons**

Agency Response: This is the second time this document was submitted. It is a reproduction of comments **LCFS 46-235** through **LCFS 46-238**.

It is also reproduction of comments **ADF 17-18** through **ADF 17-23**. The comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **17_OP_ADF_GE**.

This page intentionally left blank.

sierra
research

1801 J Street
Sacramento, CA 95811
Tel: (916) 444-6666
Fax: (916) 444-8373

Ann Arbor, MI
Tel: (734) 761-6666
Fax: (734) 761-6755

Attachment A

Résumé

James Michael Lyons

Education

1985, M.S., Chemical Engineering, University of California, Los Angeles

1983, B.S., Cum Laude, Chemistry, University of California, Irvine

Professional Experience

4/91 to present	Senior Engineer/Partner/Senior Partner Sierra Research

Primary responsibilities include oversight and execution of complex analyses of the emission benefits, costs, and cost-effectiveness of mobile source air pollution control measures. Mr. Lyons has developed particular expertise with respect to the assessment of control measures involving fuel reformulation, fuel additives, and alternative fuels, as well as accelerated vehicle/engine retirement programs, the deployment of advanced emission control systems for on- and non-road gasoline- and Diesel-powered engines, on-vehicle evaporative and refueling emission control systems, and Stage I and Stage II service station vapor recovery systems. Additional duties include assessments of the activities of federal, state, and local regulatory agencies with respect to motor vehicle emissions and reports to clients regarding those activities. Mr. Lyons has extensive litigation experience related to air quality regulations, product liability, and intellectual property issues.

7/89 to 4/91	Senior Air Pollution Specialist California Air Resources Board

Supervised a staff of four professionals responsible for identifying and controlling emissions of toxic air contaminants from mobile sources and determining the effects of compositional changes to gasoline and diesel fuel on emissions of regulated and unregulated pollutants. Other responsibilities included development of new test procedures and emission standards for evaporative and running loss emissions of hydrocarbons from vehicles; overseeing the development of the state plan to control toxic emissions from motor vehicles; and reducing emissions of CFCs from motor vehicles.

4/89 to 7/89 — Air Pollution Research Specialist
California Air Resources Board

Responsibilities included identification of motor vehicle research needs; writing requests for proposals; preparation of technical papers and reports; as well as monitoring and overseeing research programs.

9/85 to 4/89 — Associate Engineer/Engineer
California Air Resources Board

Duties included analysis of vehicle emissions data for trends and determining the effectiveness of various types of emissions control systems for both regulated and toxic emissions; determining the impact of gasoline and diesel powered vehicles on ambient levels of toxic air contaminants; participation in the development of regulations for "gray market" vehicles; and preparation of technical papers and reports.

Professional Affiliations

American Chemical Society
Society of Automotive Engineers

Selected Publications (Author or Co-Author)

"Development of Vehicle Attribute Forecasts for 2013 IEPR," Sierra Research Report No. SR2014-01-01, prepared for the California Energy Commission, January 2014.

"Assessment of the Emission Benefits of U.S. EPA's Proposed Tier 3 Motor Vehicle Emission and Fuel Standards," Sierra Research Report No. SR2013-06-01, prepared for the American Petroleum Institute, June 2013.

"Development of Inventory and Speciation Inputs for Ethanol Blends," Sierra Research Report No. SR2012-05-01, prepared for the Coordinating Research Council, Inc. (CRC), May 2012.

"Review of CARB Staff Analysis of 'Illustrative' Low Carbon Fuel Standard (LCFS) Compliance Scenarios," Sierra Research Report No. SR2012-02-01, prepared for the Western States Petroleum Association, February 20, 2012.

"Review of CARB On-Road Heavy-Duty Diesel Emissions Inventory," Sierra Research Report No. SR2010-11-01, prepared for The Ad Hoc Working Group, November 2010.

"Identification and Review of State/Federal Legislative and Regulatory Changes Required for the Introduction of New Transportation Fuels," Sierra Research Report No. SR2010-08-01, prepared for the American Petroleum Institute, August 2010.

"Technical Review of EPA Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis for Non-GHG Pollutants," Sierra Research Report No. SR2010-05-01, prepared for the American Petroleum Institute, May 2010.

"Effects of Gas Composition on Emissions from Heavy-Duty Natural Gas Engines," Sierra Research Report No. SR2010-02-01, prepared for the Southern California Gas Company, February 2010.

"Effects of Gas Composition on Emissions from a Light-Duty Natural Gas Vehicle," Sierra Research Report No. SR2009-11-01, prepared for the Southern California Gas Company, November 2009.

"Technical Review of 2009 EPA Draft Regulatory Impact Analysis for Non-GHG Pollutants Due to Changes to the Renewable Fuel Standard," Sierra Research Report No. SR2009-09-01, prepared for the American Petroleum Institute, September 2009.

"Effects of Vapor Pressure, Oxygen Content, and Temperature on CO Exhaust Emissions," Sierra Research Report No. 2009-05-03, prepared for the Coordinating Research Council, May 2009.

"Technical Review of 2007 EPA Regulatory Impact Analysis Methodology for the Renewable Fuels Standard," Sierra Research Report No. 2008-09-02, prepared for the American Petroleum Institute, September 2008.

"Impacts of MMT Use in Unleaded Gasoline on Engines, Emission Control Systems, and Emissions," Sierra Research Report No. 2008-08-01, prepared for McMillan Binch Mendelsohn LLP, Canadian Vehicle Manufacturers' Association, and Association of International Automobile Manufacturers of Canada, August 2008.

"Attachment to Comments Regarding the NHTSA Proposal for Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015, Docket No. NHTSA-2008-0089," Sierra Research Report No. SR2008-06-01, prepared for the Alliance of Automobile Manufacturers, June 2008.

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act – Part 1: Impacts on New Vehicle Fuel Economy," SAE Paper No. 2008-01-1852, Society of Automotive Engineers, 2008.

"Basic Analysis of the Cost and Long-Term Impact of the Energy Independence and Security Act Fuel Economy Standards," Sierra Research Report No. SR 2008-04-01, April 2008.

"The Benefits of Reducing Fuel Consumption and Greenhouse Gas Emissions from Light-Duty Vehicles," SAE Paper No. 2008-01-0684, Society of Automotive Engineers, 2008.

"Assessment of the Need for Long-Term Reduction in Consumer Product Emissions in South Coast Air Basin," Sierra Research Report No. 2007-09-03, prepared for the Consumer Specialty Products Association, September 2007.

"Summary of Federal and California Subsidies for Alternative Fuels," Sierra Research Report No. SR2007-04-02, prepared for the Western States Petroleum Association, April 2007.

"Analysis of IRTA Report on Water-Based Automotive Products," Sierra Research Report No. SR2006-08-02, prepared for the Consumer Specialty Projects Association and Automotive Specialty Products Alliance, August 2006.

"Evaluation of Pennsylvania's Implementation of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2006-04-01, prepared for Alliance of Automobile Manufacturers, April 12, 2006.

"Evaluation of New Jersey's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-03, prepared for the Alliance of Automobile Manufacturers, September 30, 2005.

"Evaluation of Vermont's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-02, prepared for the Alliance of Automobile Manufacturers, September 19, 2005.

"Assessment of the Cost-Effectiveness of Compliance Strategies for Selected Eight-Hour Ozone NAAQS Nonattainment Areas," Sierra Research Report No. SR2005-08-04, prepared for the American Petroleum Institute, August 30, 2005.

"Evaluation of Connecticut's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-08-03, prepared for the Alliance of Automobile Manufacturers, August 26, 2005.

"Evaluation of New York's Adoption of California's Greenhouse Gas Regulations On Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-07-04, prepared for the Alliance of Automobile Manufacturers, July 14, 2005.

"Review of MOVES2004," Sierra Research Report No. SR2005-07-01, prepared for the Alliance of Automobile Manufacturers, July 11, 2005.

"Review of Mobile Source Air Toxics (MSAT) Emissions from On-Highway Vehicles: Literature Review, Database, Development, and Recommendations for Future Studies," Sierra Research Report No. SR2005-03-01, prepared for the American Petroleum Institute, March 4, 2005.

"The Contribution of Diesel Engines to Emissions of ROG, NOx, and PM2.5 in California: Past, Present, and Future," Sierra Research Report No. SR2005-02-01, prepared for Diesel Technology Forum, February 2005.

"Fuel Effects on Highway Mobile Source Air Toxics (MSAT) Emissions," Sierra Research Report No. SR2004-12-01, prepared for the American Petroleum Institute, December 23, 2004.

“Review of the August 2004 Proposed CARB Regulations to Control Greenhouse Gas Emissions from Motor Vehicles: Cost Effectiveness for the Vehicle Owner or Operator – Appendix C to the Comments of The Alliance of Automobile Manufacturers,” Sierra Research Report No. SR2004-09-04, prepared for the Alliance of Automobile Manufacturers, September 2004.

“Emission and Economic Impacts of an Electric Forklift Mandate,” Sierra Research Report No. SR2003-12-01, prepared for National Propane Gas Association, December 12, 2003.

“Reducing California’s Energy Dependence,” Sierra Research Report No. SR2003-11-03, prepared for Alliance of Automobile Manufacturers, November 25, 2003.

“Evaluation of Fuel Effects on Nonroad Mobile Source Air Toxics (MSAT) Emissions: Literature Review, Database Development, and Recommendations for Future Studies,” Sierra Research Report No. SR2003-10-01, prepared for American Petroleum Institute, October 3, 2003.

“Review of Current and Future CO Emissions from On-Road Vehicles in Selected Western Areas,” Sierra Research Report No. SR03-01-01, prepared for the Western States Petroleum Association, January 2003.

“Review of CO Compliance Status in Selected Western Areas,” Sierra Research Report No. SR02-09-04, prepared for the Western States Petroleum Association, September 2002.

“Impacts Associated With the Use of MMT as an Octane Enhancing Additive in Gasoline – A Critical Review”, Sierra Research Report No. SR02-07-01, prepared for Canadian Vehicle Manufacturers Association and Association of International Automobile Manufacturers of Canada, July 24, 2002.

“Critical Review of ‘Safety Oversight for Mexico-Domiciled Commercial Motor Carriers, Final Programmatic Environmental Assessment’, Prepared by John A Volpe Transportation Systems Center, January 2002,” Sierra Research Report No. SR02-04-01, April 16, 2002.

“Critical Review of the Method Used by the South Coast Air Quality Management District to Establish the Emissions Equivalency of Heavy-Duty Diesel- and Alternatively Fueled Engines”, Sierra Research Report No. SR01-12-03, prepared for Western States Petroleum Association, December 21, 2001.

“Review of U.S. EPA’s Diesel Fuel Impact Model”, Sierra Research Report No. SR01-10-01, prepared for American Trucking Associations, Inc., October 25, 2001.

“Operation of a Pilot Program for Voluntary Accelerated Retirement of Light-Duty Vehicles in the South Coast Air Basin,” Sierra Research Report No. SR01-05-02, prepared for California Air Resources Board, May 2001.

"Comparison of Emission Characteristics of Advanced Heavy-Duty Diesel and CNG Engines," Sierra Report No. SR01-05-01, prepared for Western States Petroleum Association, May 2001.

"Analysis of Southwest Research Institute Test Data on Inboard and Sterndrive Marine Engines," Sierra Report No. SR01-01-01, prepared for National Marine Manufacturers Association, January 2001.

"Institutional Support Programs for Alternative Fuels and Alternative Fuel Vehicles in Arizona: 2000 Update," Sierra Report No. SR00-12-04, prepared for Western States Petroleum Association, December 2000.

"Real-Time Evaporative Emissions Measurement: Mid-Morning Commute and Partial Diurnal Events," SAE Paper No. 2000-01-2959, October 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," SAE Paper No. 2000-01-2958, October 2000.

"A Comparative Analysis of the Feasibility and Cost of Compliance with Potential Future Emission Standards for Heavy-Duty Vehicles Using Diesel or Natural Gas," Sierra Research Report No. SR00-02-02, prepared for Californians For a Sound Fuel Strategy, February 2000.

"Critical Review of the Report Entitled 'Economic Impacts of On Board Diagnostic Regulations (OBD II)' Prepared by Spectrum Economics," Sierra Research Report No. SR00-01-02, prepared for the Alliance of Automobile Manufacturers, January 2000.

"Potential Evaporative Emission Impacts Associated with the Introduction of Ethanol-Gasoline Blends in California," Sierra Research Report No. SR00-01-01, prepared for the American Methanol Institute, January 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," Sierra Research Report No. SR99-10-03, prepared for the Coordinating Research Council, October 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," SAE Paper No. 1999-01-3676, August 1999.

"Future Diesel-Fueled Engine Emission Control Technologies and Their Implications for Diesel Fuel Properties," Sierra Research Report No. SR99-08-01, prepared for the American Petroleum Institute, August 1999.

"Analysis of Compliance Feasibility under Proposed Tier 2 Emission Standards for Passenger Cars and Light Trucks," Sierra Research Report No. SR99-07-02, July 1999.

"Comparison of the Properties of Jet A and Diesel Fuel," Sierra Research Report No. SR99-02-01, prepared for Pillsbury Madison and Sutro, February 1999.

“Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles,” Sierra Research Report No. SR98-12-02, prepared for the American Petroleum Institute, December 1998.

“Analysis of New Motor Vehicle Issues in the Canadian Government’s Foundation Paper on Climate Change – Transportation Sector,” Sierra Research Report No. SR98-12-01, prepared for the Canadian Vehicle Manufacturers Association, December 1998.

“Investigation of the Relative Emission Sensitivities of LEV Vehicles to Gasoline Sulfur Content - Emission Control System Design and Cost Differences,” Sierra Research Report No. SR98-06-01, prepared for the American Petroleum Institute, June 1998.

“Costs, Benefits, and Cost-Effectiveness of CARB’s Proposed Tier 2 Regulations for Handheld Equipment Engines and a PPEMA Alternative Regulatory Proposal,” Sierra Research Report No. SR98-03-03, prepared for the Portable Power Equipment Manufacturers Association, March 1998.

“Analysis of Diesel Fuel Quality Issues in Maricopa County, Arizona,” Sierra Research Report No. SR97-12-03, prepared for the Western States Petroleum Association, December 1997.

“Potential Impact of Sulfur in Gasoline on Motor Vehicle Pollution Control and Monitoring Technologies,” prepared for Environment Canada, July 1997.

“Analysis of Mid- and Long-Term Ozone Control Measures for Maricopa County,” Sierra Research Report No. SR96-09-02, prepared for the Western States Petroleum Association, September 9, 1996.

“Technical and Policy Issues Associated with the Evaluation of Selected Mobile Source Emission Control Measures in Nevada,” Sierra Research Report No. SR96-03-01, prepared for the Western States Petroleum Association, March 1996.

“Cost-Effectiveness of Stage II Vapor Recovery Systems in the Lower Fraser Valley,” Sierra Research Report No. SR95-10-05, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

“Cost of Stage II Vapor Recovery Systems in the Lower Fraser Valley,” Sierra Research Report No. SR95-10-04, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

“A Comparative Characterization of Gasoline Dispensing Facilities With and Without Vapor Recovery Systems,” Sierra Research Report No. SR95-10-01, prepared for the Province of British Columbia Ministry of Environment Lands and Parks, October 1995.

“Potential Air Quality Impacts from Changes in Gasoline Composition in Arizona,” Sierra Research Report No. SR95-04-01, prepared for Mobil Corporation, April 1995.

"Vehicle Scrappage: An Alternative to More Stringent New Vehicle Standards in California," Sierra Research Report No. SR95-03-02, prepared for Texaco, Inc., March 1995.

"Evaluation of CARB SIP Mobile Source Measures," Sierra Research Report No. SR94-11-02, prepared for Western States Petroleum Association, November 1994.

"Reformulated Gasoline Study," prepared by Turner, Mason & Company, DRI/McGraw-Hill, Inc., and Sierra Research, Inc., for the New York State Energy Research and Development Authority, Energy Authority Report No. 94-18, October 1994.

"Phase II Feasibility Study: Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley," Sierra Research Report No. SR94-09-02, prepared for the Greater Vancouver Regional District, September 1994.

"Cost-Effectiveness of Mobile Source Emission Controls from Accelerated Scrappage to Zero Emission Vehicles," Paper No. 94-TP53.05, presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, OH, June 1994.

"Investigation of MOBILE5a Emission Factors, Assessment of I/M Program and LEV Program Emission Benefits," Sierra Research Report No. SR94-06-05, prepared for American Petroleum Institute, June 1994.

"Cost-Effectiveness of the California Low Emission Vehicle Standards," SAE Paper No. 940471, 1994.

"Meeting ZEV Emission Limits Without ZEVs," Sierra Research Report No. SR94-05-06, prepared for Western States Petroleum Association, May 1994.

"Evaluating the Benefits of Air Pollution Control - Method Development and Application to Refueling and Evaporative Emissions Control," Sierra Research Report No. SR94-03-01, prepared for the American Automobile Manufacturers Association, March 1994.

"The Cost-Effectiveness of Further Regulating Mobile Source Emissions," Sierra Research Report No. SR94-02-04, prepared for the American Automobile Manufacturers Association, February 1994.

"Searles Valley Air Quality Study (SVAQS) Final Report," Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

"A Comparative Study of the Effectiveness of Stage II Refueling Controls and Onboard Refueling Vapor Recovery," Sierra Research Report No. SR93-10-01, prepared for the American Automobile Manufacturers Association, October 1993.

"Evaluation of the Impact of the Proposed Pole Line Road Overcrossing on Ambient Levels of Selected Pollutants at the Calgene Facilities," Sierra Research Report No. SR93-09-01, prepared for the City of Davis, September 1993.

"Leveling the Playing Field for Hybrid Electric Vehicles: Proposed Modifications to CARB's LEV Regulations," Sierra Research Report No. SR93-06-01, prepared for the Hybrid Vehicle Coalition, June 1993.

"Size Distributions of Trace Metals in the Los Angeles Atmosphere," *Atmospheric Environment*, Vol. 27B, No. 2, pp. 237-249, 1993.

"Preliminary Feasibility Study for a Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley Area," Sierra Research Report No. 92-10-01, prepared for the Greater Vancouver Regional District, October 1992.

"Development of Mechanic Qualification Requirements for a Centralized I/M Program," SAE Paper No. 911670, 1991.

"Cost-Effectiveness Analysis of CARB's Proposed Phase 2 Gasoline Regulations," Sierra Research Report No. SR91-11-01, prepared for the Western States Petroleum Association, November 1991.

"Origins and Control of Particulate Air Toxics: Beyond Gas Cleaning," in Proceedings of the Twelfth Conference on Cooperative Advances in Chemical Science and Technology, Washington, D.C., October 1990.

"The Effect of Gasoline Aromatics on Exhaust Emissions: A Cooperative Test Program," SAE Paper No. 902073, 1990.

"Estimation of the Impact of Motor Vehicles on Ambient Asbestos Levels in the South Coast Air Basin," Paper No. 89-34B.7, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"Benzene/Aromatic Measurements and Exhaust Emissions from Gasoline Vehicles," Paper No. 89-34B.4, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"The Impact of Diesel Vehicles on Air Pollution," presented at the 12th North American Motor Vehicle Emissions Control Conference, Louisville, KY, April 1988.

"Exhaust Benzene Emissions from Three-Way Catalyst-Equipped Light-Duty Vehicles," Paper No. 87-1.3, presented at the 80th Annual Meeting of the Air Pollution Control Association, New York, NY, June 1987.

"Trends in Emissions Control Technologies for 1983-1987 Model-Year California-Certified Light-Duty Vehicles," SAE Paper No. 872164, 1987.

This page intentionally left blank.

8_SF_LCFS_GE (Page 172 - 180)

1206. Comment: **James Lyons' Resume**

Agency Response: This is submittal six of six of James Lyon's resume. It does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

Attachment B

Review of CARB Staff's Analysis of the GHG and Air Quality Impacts of the LCFS Regulation

In developing the proposed Low Carbon Fuel Standard (LCFS) regulation for re-adoption, CARB staff purports to have performed an analysis of the impacts that the regulation will have on emissions of both greenhouse gases and air pollutants. However, as is documented below, a review the CARB analysis demonstrates that the staff's analysis is incomplete and unsuitable for use in determining whether or not all adverse impacts have been identified and properly quantified, and all mitigation measures have been appropriately considered.

Reproduction of Pages 243 - 247 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-239 through LCFS 46-255

Summary of the CARB Staff Air Quality Analysis

On December 30, 2014, CARB staff released the proposed LCFS regulation language and the accompanying Initial Statement of Reasons (ISOR), Draft Environmental Analysis, and other supporting documents. Staff's analysis of the impact of the LCFS proposed for re-adoption is contained in Chapter IV of the ISOR as well as in Chapter 4.3. of the Draft Environmental Analysis.

In Table IV-2 of Chapter IV of the ISOR, CARB staff provides unsupported estimates of the reduction in GHG emissions associated with the LCFS regulation proposed for re-adoption. However, by CARB staff's own admission, the estimates presented in Table IV-2:

> *…do not include a reduction to eliminate the double counting of the Zero Emission Vehicle mandate, the federal Renewable Fuels Standard program, the Pavley standards, or the federal Corporate Average Fuel Economy program.*

Given that CARB staff has failed to estimate and report the GHG reduction benefits of the LCFS regulation proposed for re-adoption separately from other regulations that also seek to reduce GHG emissions from mobile sources, the Board and the public do not know the actual benefits expected to result from the regulation nor can alternatives to the LCFS regulation be properly evaluated by CARB staff.

Turning to the air quality analysis in Chapter IV of the ISOR, CARB staff provides a general discussion of emissions associated with transportation fuel production at California refineries, as well as ethanol, biodiesel, renewable diesel, and potential cellulosic ethanol facilities. Emission factors in, terms of pollutant emissions per year per million gallons of fuel produced, are provided for some facilities. CARB staff also provides an undocumented analysis of NOx and $PM_{2.5}$ emissions associated with "*...the movement of fuel and feedstock in heavy-duty diesel trucks and railcars*" with and without the LCFS and ADF regulations in place. No other assessment of the air quality impacts associated with the LCFS is provided in the LCFS ISOR.

As noted above, the draft Environmental Analysis (EA) for the LCFS and ADF, which is Appendix D to both the LCFS and ADF ISORs, also addresses air quality in Chapter 4.3. Here, short term air quality impacts related to the construction of projects of various types related to the production and distribution of lower carbon intensity fuels under the LCFS are presented. There is, however, no analysis that indicates where these projects will be located within California, nor any quantitative assessment of the emission and environmental impacts beyond the following:

> *Based on typical emission rates and other parameters for abovementioned equipment and activities, construction activities could result in hundreds of pounds of daily NO_x and PM emissions, which may exceed general mass emissions limits of a local or regional air quality management district depending on the location of generation. Thus, implementation of new regulations and/or incentives could generate levels that conflict with applicable air quality plans, exceed or contribute substantially to an existing or projected exceedance of State or national ambient air quality standards, or expose sensitive receptors to substantial pollutant concentrations.*

There is also a general discussion of potential approaches to mitigation, which CARB staff concludes are outside of the agency's authority to adopt. Ultimately, the draft EA concludes that the "short-term construction-related air quality impacts…associated with the proposed LCFS and ADF regulations would be potentially significant and unavoidable."

The draft EA also purports to assess the long-term impacts of the LCFS and ADF regulations, but addresses and attempts to quantify only potential increases in NOx emissions due to the use of biodiesel fuels, and concludes with CARB staff ultimately claiming that the long term impacts of the LCFS and ADF on air quality will be "beneficial."

Review of the CARB Staff Air Quality Analysis

As summarized above, the air quality related analyses performed by CARB staff regarding the proposed LCFS regulation are both limited and cursory. In order to demonstrate that this is in fact the case, one has to look no further than the air quality analysis CARB staff performed in 2009 to support the original LCFS rulemaking.[1]

Reproduction
of Pages 243 - 247
of Comment
Letter
46_OP_LCFS_GE/
17_OP_ADF_GE
Consisting of
Comments
LCFS 46-239
through
LCFS 46-255

[1] California Air Resources Board, Proposed Regulation to Implement the Low Carbon Fuel Standard, Volume I: Staff Report: Initial Statement of Reasons, March 5, 2009 and Volume II: Appendices, March 5, 2009. See in particular, Chapter VII of the ISOR and Appendix F.

The first point of note is that in the 2009 ISOR, CARB staff presents quantification of the GHG reductions expected from the LCFS occurring both in California and worldwide in Tables VII-1 and VII-2. While, those estimates have no relevance to the current rulemaking given the differences in the two regulations, fundamental changes in CARB's expectations with respect to how fuel producers will comply with a LCFS regulations, as well as the evolution of methodologies for estimating GHG emissions, provide clear evidence that the GHG emission benefits of the proposed LCFS can and should be explicitly quantified without any "double counting" of the benefits due to other regulatory programs. It should also be noted that in the 2009 ISOR, CARB staff also breaks down the GHG emission benefits expected from specific substitutes for gasoline and diesel fuel.

Turning to the air quality analysis itself, the lack of documentation provided precludes any detailed review of the accuracy of the assumptions and methodologies underlying the analysis or any effort to attempt to reproduce the staff's results. Given this lack of documentation, additional information was requested from CARB. As part of this request, Sierra Research pointed out that pursuant to the requirements of AB 1085, the agency had provided far more detailed information for other recent major rulemakings, including the Advanced Clean Cars program, than it released regarding the LCFS and ADF proposals. Unfortunately, CARB staff choose not to provide any additional information related to the analyses underlying the proposed LCFS and ADF regulations.

Another striking contrast which highlights the superficiality of the air quality analysis performed for the re-adoption of the LCFS can be seen in the treatment of potential emission impacts associated with the development of biofuel production facilities in California. These impacts are particularly important because the form of the LCFS regulation provides incentives to build biofuel production facilities in areas of California that violate federal National Ambient Air Quality standards, rather than in other states that are in compliance with those standards. The incentive for locating biofuel plants in California is to avoid GHG emissions from fuel and/or feed stock transportation which result in higher carbon intensity values.

As noted above, the air quality analysis for the re-adoption of the LCFS presented in section IV of the ISOR provides only estimates for existing California biofuel production facilities and the potential emissions of NO_x, PM_{10}, and volatile organic compounds (VOCs) associated with a hypothetical "northern California" cellulosic ethanol plant. In contrast, in the 2009 ISOR, staff provides a quantitative estimate of the overall number and types of new biofuel production facilities expected to be built in California (Table VII-6 of the 2009 ISOR) as well as a distribution of the number and type of plants expected to be built in eight of the state's air basins and a map showing expected locations. The increases in emissions of not only NO_x, PM_{10}, and VOC, but also carbon monoxide (CO) and $PM_{2.5}$ associated with these biodiesel production facilities were quantified by CARB staff (Table V11-10 of the 2009 ISOR). Again, although the data presented in the 2009 LCFS ISOR are irrelevant with respect to the current re-adoption of the LCFS regulation, the same level of detail and scope of the analysis performed by CARB staff in 2009 should have at a minimum been applied to the current LCFS air quality analysis.

Another issue noted with the air quality analysis performed for the re-adoption of the LCFS is related to emission impacts associated with "fuel and feedstock transportation and distribution."

Reproduction of Pages 243 - 247 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-239 through LCFS 46-255

The total impact of the LCFS and ADF on NOx and $PM_{2.5}$ emissions from these activities, which constitute a long term operational impact on air quality, are quantified in Table IV-16 of the ISOR. However, the documentation provided describing how the staff's analysis was performed is insufficient to allow one to either review or reproduce it. Further, these emissions are not addressed in the appropriate section of the draft EA. Given that staff estimates that the LCFS/ADF will increase these emissions, they should be identified and assessed as part of the draft EA, particularly given that staff has concluded that the LCFS/ADF impacts on long term air quality are beneficial without considering fuel and feedstock transportation and distribution emissions. The current analysis of these emissions also falls far short of the level of detail shown in the analysis of the same issue performed by CARB staff in the 2009 ISOR, as can be seen in Table VII-11 where impacts on VOC, CO, PM_{10}, and oxides of sulfur (SO_x) were reported by low CI fuel type.

Reproduction of Pages 243 - 247 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-239 through LCFS 46-255

Again, as noted above, the only issue addressed with respect to long term LCFS/ADF air quality impacts in the draft EA are potential NOx emission increases due to the use of biodiesel blends. As discussed in detail elsewhere,[2] the analysis upon which the draft EA and its conclusions are based is fundamentally flawed. However, the air quality analysis in the draft EA is also incomplete in that it fails to address long term changes in motor vehicle emissions beyond those associated with biodiesel and renewable diesel. That such impacts should have been addressed for the current rulemaking can be seen from the CARB staff air quality analysis included in the 2009 ISOR and presentation, which included detailed estimates of motor vehicle impacts on VOC, CO, NOx, SOx, PM_{10}, and $PM_{2.5}$ (rather than just NOx and $PM_{2.5}$) as a function of vehicle and fuel type in Table VII-12.

In addition to the above, two other important issues are: 1) CARB staff's failure to even attempt to quantify construction emissions associated with biofuel production facilities in California after finding them to be potentially significant and unavoidable; and 2) to identify and quantify potential emission increases associated with an increase in the number of tanker visits to California ports as the result of the ADF and LCFS regulations. With respect to the former, a California specific tool, CalEEmod,[3] is readily available that could have been used by CARB staff in estimating construction impacts form biofuel plants located in California.

With respect to the latter, it should be noted that although CARB staff concluded in the 2009 LCFS air quality analysis that there would be "little to no change to emissions at ports," that analysis predates the current proposal[4] regarding the assignment of CI to crude oil which are likely to encourage crude oil shuffling; as well as CARB staff assumptions regarding increases in assumed volumes of renewable diesel fuel potentially coming to California from production facilities in Asia, and the potential for direct importation of cane ethanol into California from Brazil. These factors will undoubtedly result in increased tanker operations in California waters the emission impacts of which can be estimated using the Emissions Estimation Methodology for Ocean-Going Vessels available on CARB's emission inventory website. According to this source, 1,919 visits by crude oil and petroleum product tankers are forecast for 2015 with roughly 50% percent of those trips involving southern California ports that are part of the South

[2] Declaration of James M. Lyons filed as comments to the ADF regulation.
[3] California Emissions Estimator Model, Users Guide, Version 2013.2, July 2013.
[4] See proposed section 95489, Title 17 CCR in LCFS ISOR Appendix A.

Coast air basin. The emissions estimated by CARB to be associated with one tanker visit to California are presented in Table 1. As shown, the tanker emissions associated with a single new visit far exceed the NOx, $PM_{2.5}$ and SOx significance thresholds. Given that multiple new tanker visits are likely to result from the LCFS and ADF regulations, these values demonstrate that CARB staff has failed to identify a potentially significant source that will created adverse air quality impacts in its draft EA.

Reproduction of Pages 243 - 247 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-239 through LCFS 46-255

Table 1
Comparison of Tanker Emissions During A Single Visit to California with South Coast Air Quality Management District Air Quality Significance Thresholds

Pollutant	Significance Threshold (lbs/day)	Tanker Emissions (lbs)
NOx	55	7,700
VOC	55	283
PM_{10}	150	290
$PM_{2.5}$	55	283
SOx	150	1,780
CO	550	629

This page intentionally left blank.

8_SF_LCFS_GE (Page 181 - 185)

1207. Comment: **Review of CARB Staff's Analysis of the GHG and Air Quality Impacts of the LCFS Regulation**

Agency Response: This is the second time this document was submitted. It is a reproduction of comments **LCFS 46-239** through **LCFS 46-255**.

This page intentionally left blank.

Attachment C

The Growth Energy Alternative to the Proposed LCFS Regulation is the Least-Burdensome Approach that Best Achieves the Project Objectives at the Least Cost That Must be Adopted

As part of the rulemaking process leading to CARB staff's proposed re-adoption of the LCFS regulation, staff was required to solicit and consider alternatives to the proposed regulation. Growth Energy submitted such an alternative. While CARB staff acknowledged that the Growth Energy alternative could provide equivalent reductions in GHG emissions, the agency rejected it from further consideration or analysis by stating only that it was insufficient to transition California to alternative, lower carbon intensity fuels. As discussed below, CARB staff's premise for rejecting the Growth Energy alternative is incorrect. Further, given that the Growth Energy Alternative achieves the same environmental benefits through reductions in GHG emissions as the LCFS regulation, likely at the same or lower cost, it should have been analyzed by CARB staff, in which case it would have to be adopted as the least-burdensome approach the best achieves the project objectives at the least cost.

Reproduction of Pages 248 - 252 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-256 through LCFS 46-260

<u>Background</u>

On May 23, 2014, CARB published a "Solicitation of Alternatives for Analysis in the LCFS Standardized Regulatory Impact Assessment" which is attached. On June 5, CARB published a response to a request from Growth Energy extending the deadline for the submission of alternatives from June 5, 2014 to June 23, 2014. On June 23, 2014, Growth Energy submitted an alternative regulatory proposal for the LCFS regulation (which is attached) to CARB in response to the agency's solicitation. On December 30, 2014, CARB staff published both the ISOR for the LCFS regulation as well as a document entitled "Summary of DOF Comments to the Combined LCFS/ADF SRIA and ARB Responses," which is Appendix E to the LCFS ISOR. Appendix E discusses the Growth Energy LCFS alternative and CARB's reason for its rejection.

The staff's assessment of the Growth Energy (GE) Alternative published in Appendix E of the LCFS ISOR is as follows (emphasis added):

> *The proposed alternative assumes that the exclusive goal of the LCFS proposal is to achieve GHG emissions reductions without regard to source. If that were the case, this would be a viable alternative to the LCFS and would be assessed in this analysis. It is likely true that the estimated GHG emissions reductions appearing in the 2009 LCFS Initial Statement of Reasons (California Air Resources Board, 2009) could be achieved by the AB 32 Cap-and-Trade Program, along with the other programs cited by Sierra Research and Growth Energy. The LCFS proposal, however, was designed to address the carbon intensity of transportation*

fuels. Transportation in California was powered almost completely by petroleum fuels in 2010. Those fuels were extracted, refined, and distributed through an extensive and mature infrastructure. Transitioning California to alternative, lower-carbon fuels requires a very focused and sustained regulatory program tailored to that goal. The other regulatory schemes the alternative would rely on are comparatively "blunt instruments" less likely to yield the innovations fostered by the LCFS proposal. In the absence of such a program, post-2020 emissions reductions would have to come from a transportation sector that would, in all likelihood, have emerged from the 2010-2020 decade relatively unchanged.

In the absence of an LCFS designed to begin the process of transitioning the California transportation sector to lower-carbon fuels starting in 2010, post-2020 reductions would be difficult and costly to achieve. This is why the primary goals of the LCFS are to reduce the carbon intensity of California fuels, and to diversify the fuel pool. A transportation sector that achieves these goals by 2020 will be much better positioned to achieve significant GHG emissions reductions post 2020.

ARB is required to analyze only those alternatives that are reasonable and that meet the goals of the program as required by statute. An initial assessment of the program indicates the goals of the LCFS proposal can be achieved by keeping the program "…separate of the AB 32 Cap-and-Trade system initially (at least first 10 years) in order to stimulate innovation and investment in low-GWI [global warming intensity] fuel (or transportation) technologies."[16] Due to the strong justifications that the Cap-and-Trade program alone generates neither the CI reductions nor fuel in the transportation sector, this alternative will not be assessed in this document.

Reproduction of Pages 248 - 252 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-256 through LCFS 46-260

Reference 16 in the above citation is given as:

A Low-Carbon Fuel Standard for California, Part 2: Policy Analysis – FINAL REPORT, University of California Project Managers: Alexander E. Farrell, UC Berkeley; Daniel Sperling, UC Davis. Accessed: 7-15-2015 [*http://www.energy.ca.gov/low_carbon_fuel_standard/*](http://www.energy.ca.gov/low_carbon_fuel_standard/)

Discussion

Given that there is no analysis or other support provided by CARB staff for the assertions it makes in rejecting the Growth Energy alternative other than the one reference, which dates to 2007—before either the original LCFS or Cap-and-Trade regulation were adopted was reviewed. The discussion of interactions between a LCFS program with AB32 regulations from the reference is provided below. As can be determined by the reader, the discussion was written before the AB32 regulations were adopted, and the basic concern expressed is that the lower cost of achieving the same GHG reductions from a broader program will be lower than the cost of doing the same from the LCFS program. Further, the concern expressed regarding lifecycle emission under the LCFS was explicitly addressed in the Growth Energy alternative.

5.2 Interactions with AB32 regulations

RECOMMENDATION 16: The design of both the LCFS and AB32 polices must be coordinated and it is not possible to specify one without the other. However, it is clear that if the AB32 program includes a hard cap, the intensity-based LCFS must be separate or the cap will be meaningless. Including the transport sector in both the AB32 regulatory program and LCFS will provide complementary incentives and is feasible. CARB will soon be developing regulations under AB32 to control GHG emissions broadly across the economy, most likely through a cap-and-trade system plus a set of regulatory policies. Thus, emissions from electricity generation, oil production, refining, and biofuel production are likely to be regulated directly under AB32. These energy production emissions are "upstream" in a fuel's life cycle (while emissions from a vehicle are "downstream"). The recent Market Advisory Committee report recommends including all CO2 emissions from transportation, including tailpipe emissions.

The LCFS regulates consumption emissions—the full life cycle emissions associated with products consumed in California, while it is expected that sector-specific emission caps will be imposed by AB 32 on production emissions—the emissions that are directly emitted within the borders of the state. The different types of boundaries used by these regulations causes certain upstream emissions to be double regulated under the LCFS and AB32. However, the potential for double regulation only applies to fuel production processes in the state of California or other jurisdictions where legislation similar to AB 32 also applies. We agree with the Market Advisory Committee that the LCFS and AB32 regulations will provide complementary incentives and that transportation emissions of GHGs should be included in the AB32 program.

There is no inherent conflict between the LCFS and AB32 caps; both are aimed at reducing GHG emissions and stimulating innovation in low-carbon technologies and processes. However, there are some differences. Most importantly, the LCFS is designed to stimulate technological innovation in the transportation sector specifically, while the broader AB32 program will stimulate technological innovation more broadly. The concerns associated with market failures and other barriers to technological change in the transportation sector (discussed in Section 1.3 of Part 1 and Section 2.3 of Part 2) are the motivation for adopting the sector-specific LCFS. These concerns suggest separating the LCFS from the AB32 emission caps.

The second key difference is that as a product standard using a lifecycle approach, the LCFS includes emissions that occur outside of the state such as

Reproduction of Pages 248 - 252 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-256 through LCFS 46-260

those associated with biofuel feedstock production and the production of imported crude oil. These emissions will not be included in the AB32 regulations.

The third difference is in expected costs. In the absence of transaction costs and other market imperfections, economic theory suggests that a broader cap-and-trade program will be less costly than a narrower one. By allowing more sectors and more firms to participate in a market for emission reductions, one reduces the cost to achieve a given level of emission reductions -- suggesting that the LCFS be linked to the broader AB 32 regulatory system. In addition, commercially available low-carbon options exist in the electricity and other sectors, but not in transportation fuels (see Part 1 of this study, Section 1.3).

The specific regulations and market mechanisms used to implement AB32 are not yet determined, so it is not possible at this time to specify how the LCFS should interact with them. The ARB should carefully consider the differences in incentives and constraints that the combination of rules will create.

Reproduction of Pages 248 - 252 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments LCFS 46-256 through LCFS 46-260

Returning to the issue of diversification of the transportation fuel sector, CARB concerns are directly refuted by Growth Energy's submission. As noted on pages 9 and 10, ethanol will be added to California gasoline, and renewable diesel and biodiesel will be blended into California diesel fuel as the result of the federal RFS program. The range of fuels and feedstocks from which they are produced under the RFS will be diverse. For example, the following fuel/feedstock pathways, among others, are currently recognized by U.S. EPA under the RFS:[1,2,3,4,5]

- Ethanol from
  - Corn
  - Sugar cane
  - Grain sorghum
  - Celluosic materials

- Biodiesel from
  - Camelina oil
  - Soy bean oil
  - Waste oils, fats and greases
  - Corn oil
  - Canola/rapseed oil

- Renewable diesel from
  - Waste oils, fats and greases

[1] EPA-420-F-13-014
[2] EPA-420-F-14-045
[3] EPA-420-F-12-078
[4] EPA-420-F-11-043
[5] EPA-420-F-10-007

- Renewable gasoline from
  - Crop residue and municipal solid waste

- Renewable natural gas from
  - Landfills
  - Digesters

As can be seen from Appendix B to the LCFS ISOR, these are many of the fuels that CARB staff also expects to be used in California under the LCFS. Similarly, electricity and hydrogen will be used as transportation fuels in California given the states regulatory mandates for the production of vehicles that operate on these fuels under the Advanced Clean Cars program. Further, in later years these fuels are expected to be required in heavy-duty vehicles as CARB adopts regulations under its proposed Sustainable Freight Transport Initiative, the purpose of which is stated by CARB staff as follows:

> *The purpose of the Strategy is to identify and prioritize actions to move California towards a sustainable freight transport system that is characterized by improved efficiency, zero or near-zero emissions, and increased competitiveness of the logistics system.*

It should also be noted that fuel providers in California will still be incentivized to provide these fuels in California under the Growth Energy alternative in order to reduce the number of GHG credits they will be required to retire under cap-and-trade program.

Finally, on pages 15 and 16, Growth Energy's proposal for addressing the loss of upstream emission benefits from the LCFS regulation is explicitly discussed.

Given that the Growth Energy alternative:

1. Provides, as determined by CARB staff, the same GHG reductions as the LCFS regulation; and

2. Is expected to result in lower costs of compliance than the LCFS.

CARB must adopt the Growth Energy alternative as it better achieves the stated project objectives in an equally cost-effective manner.

Reproduction of Pages 248 - 252 of Comment Letter 46_OP_LCFS_GE/17_OP_ADF_GE Consisting of Comments LCFS 46-256 through LCFS 46-260

This page intentionally left blank.

8_SF_LCFS_GE (Page 186 - 190)

1208. Comment: **The Growth Energy Alternative to the Proposed LCFS Regulation is the Least-Burdensome Approach that Best Achieves the Project Objectives at the Least Cost That Must be Adopted**

Agency Response: This is the second time this document was submitted. It is a reproduction of comments **LCFS 46-256** through **LCFS 46-260**.

This page intentionally left blank.

Attachment D

Review of CARB Staff Estimates of NOx Emission Increases Associated with the Use of Biodiesel in California Under the Proposed ADF Regulation

In developing the proposed Alternative Diesel Fuel (ADF) regulation, CARB staff has performed a statewide analysis of the increase in NOx emissions that is currently occurring in California due to the use of biodiesel, as well as the increases in NOx emissions that can be expected in the future due to the continued use of biodiesel in California under the proposed ADF regulation. As documented below, a review of the CARB staff analysis performed by Sierra Research demonstrates that the staff's analysis is fatally flawed and cannot be relied upon. Given this, Sierra Research has performed an analysis, also documented below, that demonstrates there will be substantial increases in NOx emissions if the ADF regulation is implemented as proposed. The significance in the NOx emissions increase associated with the use of biodiesel under the proposed ADF is clear given the dramatic reductions which CARB, the South Coast Air Quality Management District, and the San Joaquin Air Pollution Control District are seeking given their "extreme" non-compliance status with respect to the federal National Ambient Air Quality Standard for ozone.[1] This significance is also reinforced by a comparison of the estimated increase in NOx emissions from biodiesel under the proposed ADF regulation with the benefits of proposed and adopted NOx control measures intended for implementation on a statewide basis as well as in the South Coast and San Joaquin Valley air basins, respectively.

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Review of the CARB Staff Analysis

On December 30, 2014, CARB staff released the proposed ADF regulation language and the accompanying Initial Statement of Reasons (ISOR), technical and economic support information, and draft environmental analysis. Staff's analysis of the impact of the proposed ADF regulation on NOx emissions and supporting information and assumptions are contained in Chapters 6 and 7 of the ISOR, as well as Appendix B entitled "Technical Supporting Information."

The first issue that was identified with the staff's emissions analysis is that the information and data supplied by CARB staff are insufficient to determine exactly how the analysis was performed. Specifically, CARB staff provides no source for the values in Table B-1 labeled "Emission Inventory (Diesel TPD)," which are key to the analysis. As illustrated below, a clear understanding of what diesel sources (e.g., on-road heavy-duty, non-road, marine, locomotives, etc.) are included in the "inventory" is critical to assessing the accuracy of the staff's analysis.

[1] It should be noted that the CARB statewide analysis fails to provide any estimate of the impacts of increased NOx emissions from the ADF regulation in these air basins, where the agency has stated that massive reductions in NOx emissions are required to achieve compliance with federal air quality standards.

Given the lack of documentation regarding the source of the diesel emission inventory values, additional information regarding this analysis as well as other analyses associated with the ADF and Low Carbon Fuel Standard (LCFS) rulemakings was requested. As part of this request, Sierra Research pointed out that pursuant to the requirements of AB 1085, the agency had provided far more detailed information for other recent major rulemakings, including the Advanced Clean Cars program, than it released regarding the LCFS and ADF proposals. Unfortunately, CARB staff choose not to provide any additional information related to the analyses underlying the proposed LCFS and ADF regulations.[2]

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Despite the lack of all the information necessary to fully review the CARB staff analysis, it was possible to discern some key assumptions and the general methodology that was applied. The following key assumptions were identified:

1. Actual biodiesel use and the total demand for diesel fuel and substitutes in California will exactly match that forecast by CARB staff in the "illustrative compliance scenarios" developed as part the LCFS rulemaking;[3]

2. Actual renewable diesel use in California will exactly match that forecast by CARB staff in the "illustrative compliance scenarios" developed as part the LCFS rulemaking;[2]

3. Forty percent of renewable diesel delivered to California will be used directly by refiners to comply with the requirements of CARB's existing diesel fuel regulations[4] while the remaining 60% will be blended into fuel that complies with the diesel fuel regulations downstream of refineries;

4. The use of biodiesel up to the B20 level in New Technology Diesel Engines[5] (NTDEs, which employ exhaust aftertreatment systems to reduce NOx emissions) will not result in any increase in NOx emissions;

5. The use of biodiesel in heavy-duty diesel engines other than NTDEs—which are referred to by CARB staff as "legacy vehicles"—will increase NOx linearly with increasing biodiesel blend content, up to a 20% increase for B100;

---

[2] See attached emails from Jim Lyons of Sierra to Lex Mitchel and other CARB staff from January 2015.
[3] These are presented in Appendix B to the LCFS ISOR.
[4] Sections 2281 to 2284, Title 13, California Code of Regulations.
[5] Proposed section 2293.3 Title 13 CCR (see Appendix A to the LCFS ISOR) defines a New Technology Diesel Engines as:

a diesel engine that meets at least one of the following criteria:

(A) Meets 2010 ARB emission standards for on-road heavy duty diesel engines under section 1956.8.

(B) Meets Tier 4 emission standards for non-road compression ignition engines under sections 2421, 2423, 2424, 2425, 2425.1, 2426, and 2427.

(C) Is equipped with or employs a Diesel Emissions Control Strategy (DECS), verified by ARB pursuant to section 2700 et seq., which uses selective catalytic reduction to control Oxides of Nitrogen (NOx).

6. The blending of renewable diesel downstream of refineries will reduce NOx emissions from legacy vehicles, with each 2.75 gallons of renewable diesel blended offsetting the emissions increase associated with each gallon of biodiesel used; and

7. During the period from 2018 to 2020, 30 million gallons of biodiesel will be blended to the B20 level for use in legacy vehicles each year, and will therefore be subject to the mitigation requirements of the proposed ADF regulation and will not cause an increase in NOx emissions. Furthermore, this volume will increase to 35 million gallons per year from 2021 to 2023.

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Based on the above assumptions, CARB staff followed the methodology steps outlined below for estimating biodiesel impacts.

1. The fraction of legacy vehicles in a given year is determined by subtracting the percentage of vehicle miles traveled by on-road heavy-duty vehicles with NTDEs from 100%.

2. The fraction of legacy vehicles from Step 1 is multiplied by the total volume of biodiesel assumed to be consumed in a given year to yield the number of gallons of biodiesel used in legacy vehicles in that year.

3. For years 2018 and later, the amount of biodiesel assumed to be sold as emissions-mitigated B20 in a given year is subtracted from the total volume of biodiesel used in legacy vehicles in that year.

4. The total volume of renewable diesel assumed to be sold in a given year is multiplied by the percentage of legacy vehicles in that year and then multiplied by 0.6 to account for renewable diesel used in refineries to yield the amount of renewable diesel creating reductions in NOx emissions from legacy vehicles in that year.

5. The amount of renewable diesel used in legacy vehicles is then divided by 2.75 to determine the number of gallons of biodiesel for which NOx emissions have been offset for that year.

6. The number of gallons of biodiesel for which NOx emissions have been offset, as determined in Step 5, is then subtracted from the amount of biodiesel used in legacy vehicles, as determined in Step 3, to yield the total number of gallons of biodiesel used in legacy vehicles that cause increased NOx emissions for that given year.

7. The biodiesel volume from Step 6 is multiplied by the assumed NOx increase of 20% for B100 and then divided by the total volume of diesel fuel forecast to be used in that year to get the percentage increase in diesel emissions for that year.

8. The value from Step 7 is multiplied by the assumed Diesel Emissions inventory for that year to yield the final estimate of increased NOx emissions due to biodiesel in units of tons per day for the entire state of California.

Using the above methodology, CARB staff estimates that use of biodiesel in California led to a 1.36 ton per day increase in NOx emissions in 2014, and that the proposed ADF regulation will reduce the magnitude of that increase through 2023 down to 0.01 ton per day.[6]

The review of the staff's emission analysis identified two major issues in addition to the lack of documentation regarding how the diesel "Emission Inventory" values used by staff were developed:

1. Assuming that biodiesel use in NTDEs at levels up to B20 will not increase NOx emissions; and

2. Assuming that biodiesel NOx emissions are offset by the use of renewable diesel fuel.

Beginning with NTDEs, it has been demonstrated[7] that the available data indicate not only that NOx emissions from NTDEs will increase with the use of biodiesel in proportion to the amount of biodiesel present in the blend, but also that the magnitude of the increase on a percentage basis will be much greater than that observed for "legacy vehicles." At the B20 level where CARB staff assumed that there will be no NOx increase, the best current estimate is that NTDE NOx emissions will be increased by between 18% and 22%. CARB staff's failure to account for increased NOx emissions from NTDEs renders the staff's emission analysis meaningless in terms of assessing the adverse environmental impacts of the proposed ADF regulation. Another problem with CARB staff's treatment of NTDEs is that they have incorrectly assumed that the penetration of NTDEs into the on-road fleet is equal to that in the non-road fleet. NTDE penetration rates into the non-road fleet will be delayed due to the later effective date of the Tier 4 Final standards, relative to the 2010 on-road standards, and by the fact that while newer trucks dominate on-road heavy-duty vehicle operation, that effect does not occur in the non-road vehicle population.

Similarly, there are fundamental flaws with CARB staff's assumption that the use of renewable diesel will offset increased NOx emissions due to the use of biodiesel. First, it must be noted that there is nothing in either the proposed ADF regulation or the proposed LCFS regulation that mandates the use of any volume of biodiesel in California, much less the use of the exact ratio of renewable diesel to biodiesel assumed by CARB staff in its emissions analysis. Second, based on a review of the ADF and LCFS ISORs and supporting materials, there is no apparent basis for the staff's assumption that 40% of renewable diesel used in California will be used by refiners to aid in compliance with CARB's existing diesel fuel regulations, and that 60% will be blended downstream of refineries. To the extent that fuel producers choose to blend renewable diesel in California, one would expect them to do so by purchasing renewable diesel for use at their

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

[6] Table B-1, Appendix B of the ADF ISOR.
[7] "NOx Emission Impacts of Biodiesel Blends," Rincon Ranch Consulting, February 17, 2015.

refineries where they can benefit from the other desirable properties of this fuel beyond its low carbon intensity (CI) value (e.g., high cetane number and fungibility with diesel fuel at all blend levels), rather than by purchasing LCFS credits generated by downstream blenders of renewable diesel fuel.

To illustrate the magnitude of the significance of CARB's flawed assumptions regarding NTDEs and renewable diesel, if one simply and extremely conservatively assumes that NTDE NOx increases will be the same on a percentage basis as legacy vehicles and eliminates the NOx offsets assumed from renewable diesel, the NOx increases expected from biodiesel increase from 1.35 tons per day statewide in 2014 to approximately 3.44 tons per day—a factor of about 2.65. For 2023, estimated NOx emission increases due to biodiesel rise to about 0.87 tons per day, or about 100 times more than the 0.01 tons per day CARB staff estimated. However, as documented below, a more rigorous analysis indicates that far greater increases in NOx emissions are likely.

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Detailed Analysis of Increases in NOx Emissions from Biodiesel Use

Given the flawed assumptions and undocumented sources of data associated with CARB staff's analysis of the emission impacts associated with biodiesel under the proposed ADF, Sierra Research undertook a detailed analysis of the same issue. The first step in this analysis was identifying the most current methods and tools for estimating NOx emissions from on- and non-road diesel engines operating in California for which biodiesel use is expected to increase NOx emissions.

On-Road Heavy-Duty Diesel Vehicles – On December 30, 2014, CARB officially released the final version of the EMFAC2014 model for estimating on-road emissions in California, which has replaced the now obsolete EMFAC2011 model that CARB staff relied upon for certain elements of its emission analysis. In releasing EMFAC2014, CARB staff noted a number of changes intended to improve the accuracy of the model relative to EMFAC2011. First, EMFAC2014 accounts for CARB's adoption of recent mobile source rules and regulations that lower future NOx emission estimates, including the Advanced Clean Cars program and the 2014 Amendments to the Truck and Bus Regulation. In addition, EMFAC2014 now estimates off-cycle emissions of SCR-equipped vehicles (i.e., NTDEs) by reflecting higher NOx emissions during low speed operation and cold starts.[8]

Given the above, Sierra selected EMFAC2014 for estimating NTDE emissions directly in this assessment. It was used to generate annual average NOx emissions, in tons per day, for the South Coast and San Joaquin Valley Air Basins, and the entire state for the years 2015, 2020, and 2023. Emission estimates were obtained for light-heavy-duty, medium-heavy-duty, and heavy-heavy-duty trucks, as well as school, urban, and transit buses. Output by "model year" was used to differentiate NOx emissions of legacy vehicles from those of NTDEs, which were defined as 2010 and later model-year vehicles consistent with the definition in proposed section 2293.2 Title 13, CCR (see Appendix A to the LCFS ISOR).

[8] Email from ARB EMFAC2014 Team, November 26, 2014.

<u>Off-Road Diesel Equipment and Engines</u> – The process of estimating emissions from off-road equipment and engines in California is much less straightforward than for on-road vehicles, as the most recent CARB models have been separated by equipment type and updated at various points in time as part of the rulemaking process associated with the development of regulations for different source categories.

In addition to having been developed and last updated at different points in time, some of the methodologies do not output data with sufficient detail (e.g., emissions by engine model year) to differentiate between "legacy vehicles" and NTDEs, which, in the case of off-road sources, are defined by CARB staff in proposed section 2293.2 Title 13 CCR as being compliant with Tier 4 final emission standards for non-road compression ignition (i.e., diesel) engines under sections 2421, 2423, 2424, 2425, 2425.1, 2426, and 2427 Title 13 CCR.[9] The effective dates of these standards vary as a function of engine power rating, as shown in Table 1. It should be noted that compliance with the Tier 4 Final standards by engines below 50 horsepower in general does not require the use of the SCR technology[10] that CARB has used to define "NTDEs." Therefore, all engines in this category were assumed to respond to biodiesel in the same way as legacy vehicles, despite the fact that they meet Tier 4 final standards and are technically classified as NTDEs by CARB under the ADF regulation. As discussed below, this again reduced the magnitude of the biodiesel NOx impact.

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Table 1
Effective Dates of Tier 4 Final Standards

Horsepower Range	Model Year
50-75	2013
76-175	2015
176-750	2014
Over 751	2015

Table 2 summarizes current state of CARB inventory models and methodologies for off-road diesel emission sources by equipment/engine sector[11] and indicates which outputs have sufficient detail to differentiate between emissions from legacy vehicles and NTDEs. As shown, only the general off-road equipment (construction, industrial, ground support, and oil drilling equipment), cargo handling equipment, and agricultural equipment sectors could be included in the Sierra analyses for the South Coast and San Joaquin Valley Air Basins. For the statewide inventory, it was possible to include transportation refrigeration units (TRUs) as well. Given that all diesel emission categories could not be included in the Sierra analysis, it should be noted that the results of the analysis presented below are conservative in that they do not account for the full magnitude of the increase in NOx emissions related to biodiesel use in California.

[9] See ISOR Appendix A.
[10] See *http://www.arb.ca.gov/diesel/tru/tru.htm#mozTocId341892.*
[11] All models can be downloaded at *http://www.arb.ca.gov/msei/categories.htm* .

The CARB off-road emissions inventory tools were configured to include the impacts of the most recent regulatory actions in each sector, and were executed to provide estimates of annual average day NOx emissions for both legacy and NTDE vehicles for calendar years 2015, 2020, and 2023 occurring in the South Coast and San Joaquin Valley Air Basins, as well as the entire state.

Key Assumptions: The Sierra analysis of the emission impacts of biodiesel use in California relies on the following two key assumptions:

1. B5 will be in use on a statewide basis in 2015, 2020, and 2023;
2. At the B5 level, NOx emissions from legacy vehicles will be increased by 1%, and by 5% from NTDEs.

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Table 2
Summary of Current California Off-Road Diesel Emission Inventory Methodologies

Category	CARB Model/Database Tool	Capable of Differentiating Legacy Vehicle and NDTE Emissions
In-Use Off-Road Equipment	2011 Inventory Model	Yes
Cargo Handling Equipment	2011 Inventory Model	Yes
Transportation Refrigeration Units	2011 TRU Emissions Inventory	Yes – but not capable of estimating emissions by air basin
Agricultural Equipment	OFFROAD2007	Yes
Stationary Engines	2010 StaComm Inventory Model	No
Locomotives	NA	No
Commercial Harborcraft	2011 CHC/CA Crew and Supply Vessel/CA Barge and Dredge Inventory Databases	No
Ocean-Going Vessels	2011 Marine Emissions Model	No

The assumption regarding B5 was based on the fact that it represents the highest blend allowed under the ADF without mitigation, at least during the summer months. That this assumption is reasonable can be seen by comparing CARB's current and previous assumptions of biodiesel use: in the current LCFS compliance scenario,[3] the staff assumes a range from about B3 in 2015 to about B4 in 2020; in 2009,[12] the staff assumed approximately B1 in 2015 and B5 in 2020; and

[12] CARB, Proposed Regulation to Implement the Low Carbon Fuel Standard, Volume II, Appendices, March 5, 2009.

in 2011,[13] approximately B10 in 2015 and B20 in 2020 were assumed. Furthermore, the Sierra results can be scaled to reflect lower or higher non-mitigated biodiesel levels by multiplying them by the ratio of the assumed biodiesel level to B5.

The assumptions of a 1% and 5% increase at B5 for legacy vehicles and NTDEs, respectively, are based on the analysis of Rincon Ranch Consulting,[7] where 5% represents the mid-point of the range of estimates.

Diesel Emission Inventory and Biodiesel Impacts

The results of the Sierra analysis for the statewide diesel inventory for 2015, 2020, and 2023 are presented in Table 3 along with the undocumented values published by CARB staff.[6] As shown, the Sierra values are lower than those used by CARB staff. This is expected to some degree given that the Sierra analysis does not include, as explained above, some diesel source categories; however, the difference cannot be reconciled given the lack of information made available by CARB staff regarding its analysis.

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Table 3
Statewide Diesel Emissions tons/day

	2015	2020	2023
Sierra Analysis	621	436	277
CARB Table B-1, Appendix B ADF ISOR	863	634	496

Table 4 compares the results of Sierra's analysis with the results of the CARB staff's analysis. As shown, the differences are large and are due primarily to two factors: 1) the staff's assumption regarding biodiesel impacts on NTDE NOx emissions, which is contradicted by the available data; and 2) the differences in the assumed levels of biodiesel use. The impact of the latter difference can also be seen in the results presented in Table 4, where results from the Sierra analysis scaled to reflect the lower biodiesel use rates assumed by CARB staff are presented. Again, even with this adjustment, the results of the Sierra analysis indicate much greater NOx impacts under the proposed ADF. Finally, it should be recalled that because of limitations with CARB's emission inventory methods for off-road sources, not all sources of diesel emissions that could be impacted by biodiesel use under the ADF have been accounted for, and the actual impacts will be greater than those shown in Table 4.

[13] CARB, Low Carbon Fuel Standard 2011 Program Review Report, December 8, 2011.

Table 4 Statewide Increase in NOx Emissions Due to Biodiesel tons/day			
	2015	2020	2023
Sierra Analysis – B5	9.18	9.73	8.75
Sierra Analysis at CARB Assumed Biodiesel Levels from Table B-1	4.70	7.15	6.15
CARB Table B-1, Appendix B ADF ISOR	1.29	0.39	0.01

The results of the Sierra analysis are shown graphically in Figures 1a through c for the entire state as well as the South Coast and San Joaquin air basins, respectively. These figures also show the relative contributions of legacy vehicles and NTDEs to the total estimated for each area and year. As shown, the contributions of NTDEs to increased NOx emissions are substantial in 2015, and dominate the impacts in 2020 and 2023. Further data supporting these results are provided in Tables 6 through 8 at the end of this attachment.

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Figure 1a
Results of Sierra Analysis of Statewide NOx Increases Due to Biodiesel Use under the Proposed ADF Regulation

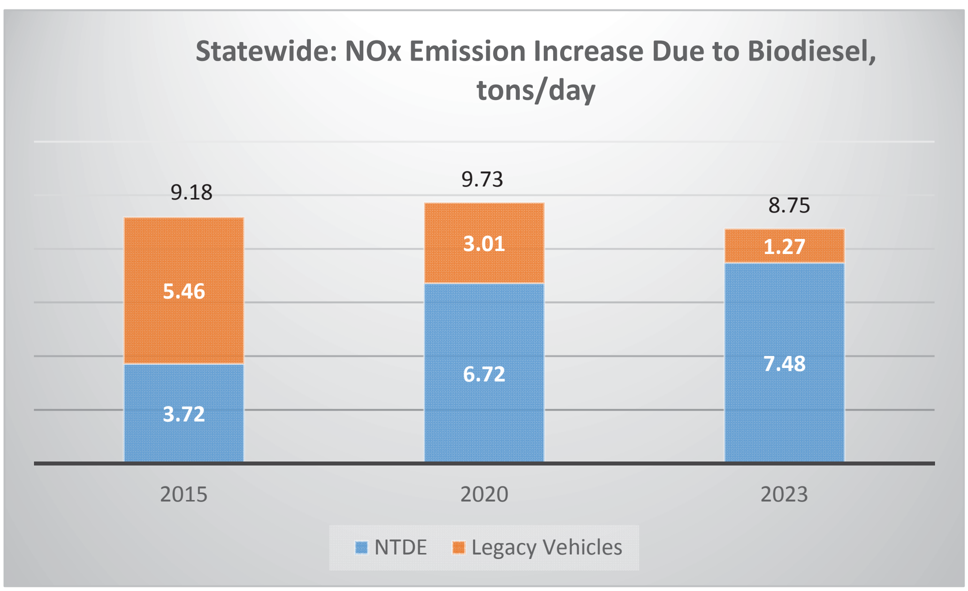


Figure 1b
Results of Sierra Analysis of South Coast Air Basin NOx Increases Due to Biodiesel Use under the Proposed ADF Regulation

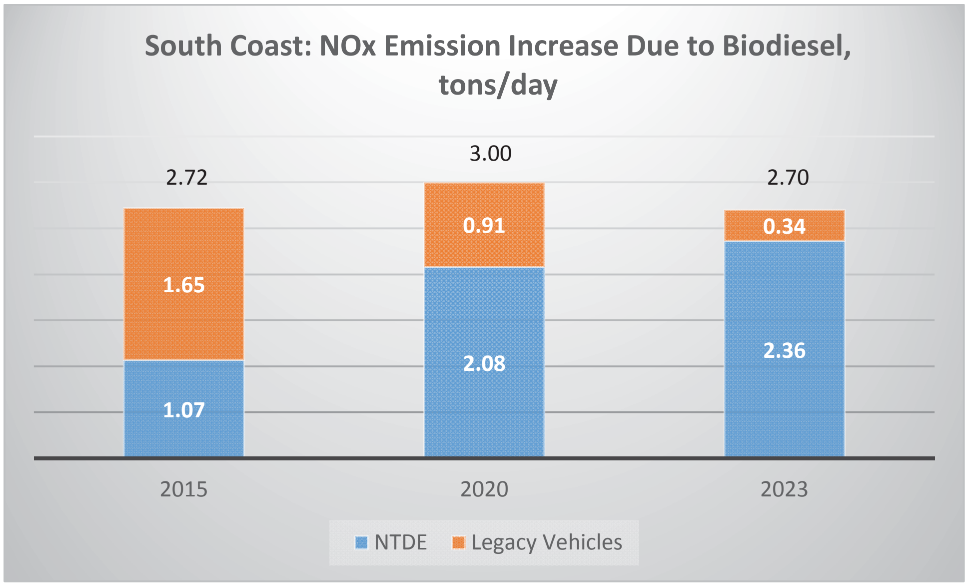
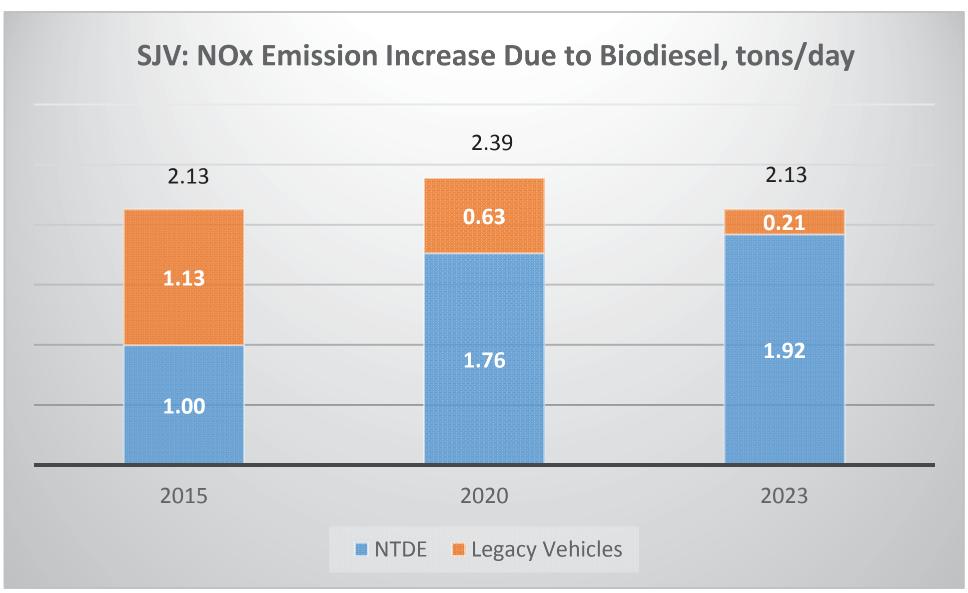


Figure 1c
Results of Sierra Analysis of San Joaquin Valley Air Basin NOx Increases Due to Biodiesel Use under the Proposed ADF Regulation



Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

As indicated above, the Sierra analysis uses the results from an assessment of existing data regarding biodiesel impacts on NOx emissions from NTDEs performed by Rincon Ranch Consulting. The key findings of that analysis are shown in Figure 2 (reproduced with permission), which establishes that the available data for biodiesel impacts on NTDE NOx emissions follow a linear relationship just as they do for legacy vehicles.

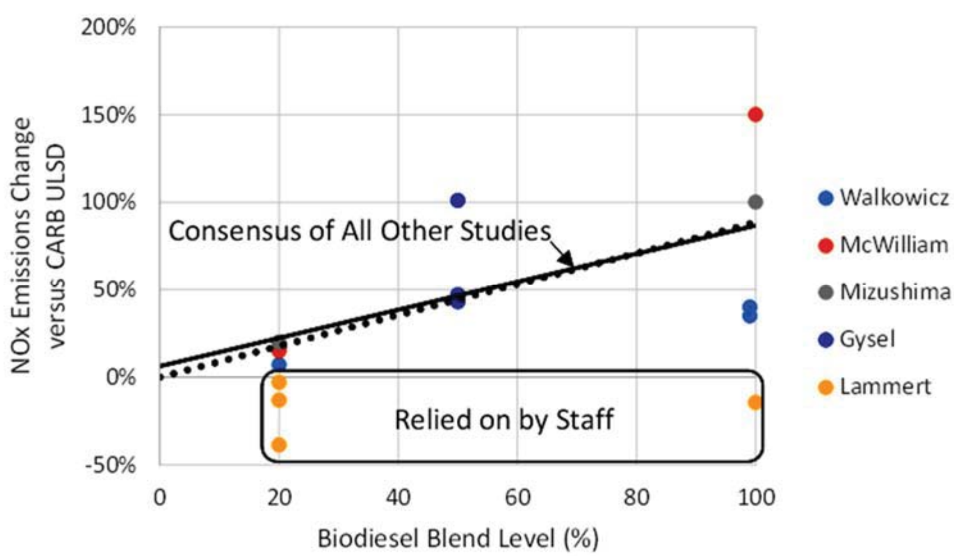
In contrast to the data upon which the Sierra analysis rests, the basis of CARB staff's assumption regarding biodiesel impacts on NTDE emissions rests on the following excerpts from the ADF ISOR:

> *Research also indicates that the use of biodiesel up to blends of B20 in NTDEs results in no detrimental NOx impacts. Therefore, the proposed regulation also includes a process for fleets and fueling stations to become exempted from the in-use requirements for biodiesel blends up to B20 as long as they can demonstrate to the satisfaction of the Executive Officer that they are fueling at least 90 percent light or medium duty vehicles or NTDEs.*
>
> *Staff proposes to take a precautionary approach and in the light of data showing there may be a NOx impact at higher biodiesel blends but not at lower biodiesel blends, staff is limiting the conclusion of no detrimental NOx impacts in NTDEs to blends of B20 and below.*

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Clearly, if CARB staff were truly taking a "precautionary approach" to the issue of biodiesel impacts on NTDE NOx emissions, they would also rely on the results of the analysis summarized in Figure 2.

Figure 2
The Impact of Biodiesel on NTDE NOx Emissions



The assumption made by CARB staff regarding biodiesel impacts on NDTE NOx emissions has additional ramifications beyond those shown above by the results of the Sierra analysis. As set forth in proposed section 2293.6, Title 13 CCR (see ISOR Appendix A), the mitigation requirements for biodiesel up to the B20 level will be dropped when NTDEs account for 90% of heavy-duty vehicle miles travelled in California (expected by staff to be 2023) and use of B20 without mitigation will be allowed in all fleets of centrally fueled vehicles comprised of more than 90% NTDEs. Given this, use of unmitigated biodiesel blends of up to B20 in NTDEs may be common under the proposed ADF regulation. The potential significance of these provisions of the staff proposal with respect to the potential for NOx increases is shown in Figures 3a through 3c, which illustrate the estimated increases in NDTE NOx emissions as a function of biodiesel content up to B20 for the state, the South Coast air basin, and the San Joaquin Valley air basins, respectively, for the years 2015, 2020, and 2023.

As shown, the potential NOx increases from extensive use of higher level biodiesel blends in NTDEs is quite large. Furthermore, although the results shown in Figures 3a through 3c are maximum potential impacts, they can again be simply scaled for other cases. For example, in order to estimate statewide NOx increases from B20 use in 50% rather than 100% of NTDEs, one would simply multiply the value of 30 tons per day by 0.5 (50/100) to arrive at a 15 ton per day increase. Finally, it should be noted that the values in Figures 3a through 3c reflect both on- and off-road NTDEs as described above for the Sierra analysis of B5 impacts.

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Figure 3a
Results of Sierra Analysis of Statewide NOx Increases Due to Biodiesel Use in All NTDEs under the Proposed ADF Regulation

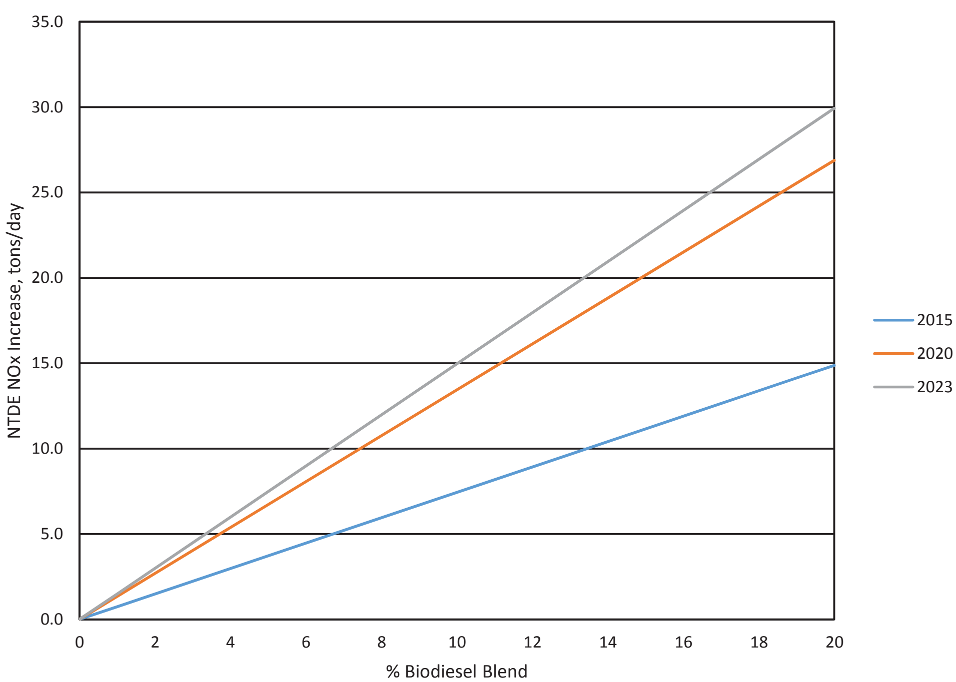


Figure 3b
Results of Sierra Analysis of South Coast Air Basin NOx Increases Due to Biodiesel Use in All NTDEs under the Proposed ADF Regulation

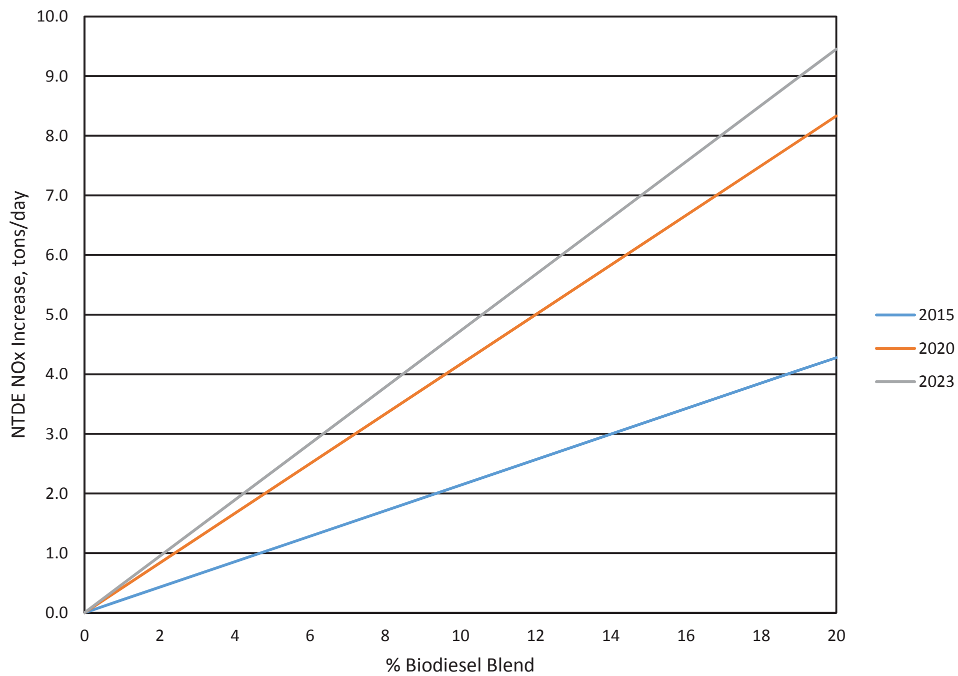
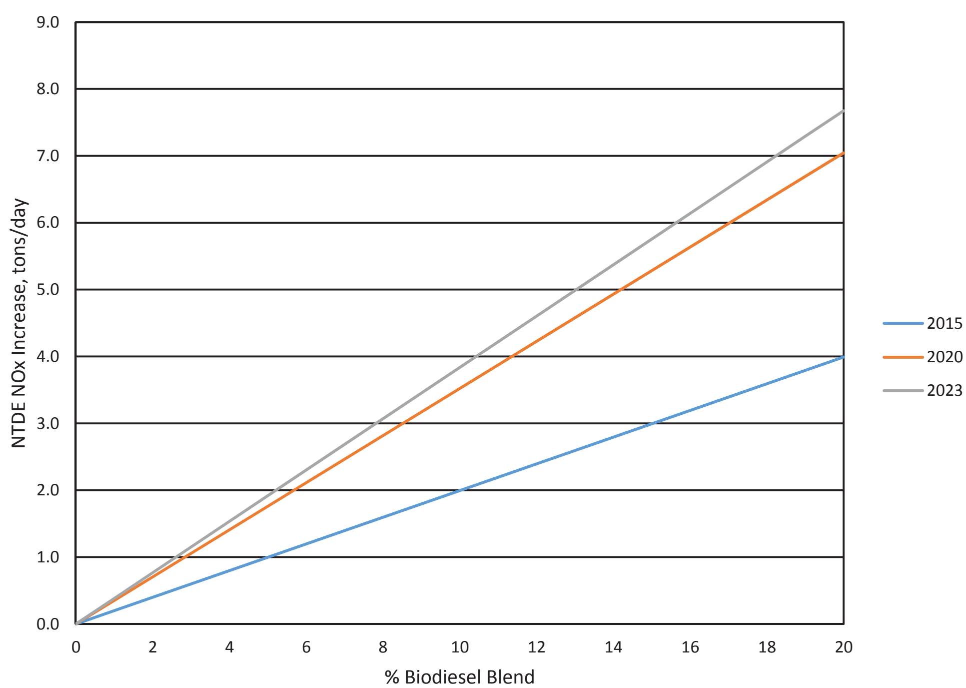


Figure 3C
Results of Sierra Analysis of San Joaquin Valley Air Basin NOx Increases Due to Biodiesel Use in All NTDEs Under the Proposed ADF Regulation



Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Significance of Increases in NOx Emissions Caused by Biodiesel

As illustrated above, the proposed ADF regulations are likely to lead to substantial increases in NOx emissions for the state as a whole, as well as in the South Coast and San Joaquin Valley air basins, which are in extreme nonattainment of the federal standard for ozone and experience the state's highest levels of ozone and other pollutants. The significance of the NOx increases from biodiesel can be seen by comparing those increases with air quality planning documents.

Perhaps the best initial point of reference comes from CARB's "Vision for Clean Air"[14] prepared in conjunction with the South Coast Air Quality Management District and the San Joaquin Valley Unified Air Pollution Control District. This report addresses potential control strategies that will be required to bring these extreme ozone nonattainment areas into compliance. According to the Vision report, NOx emissions will have to be reduced by 80% to 90% from 2010 levels in both the South Coast and San Joaquin Valley areas in order to achieve ozone compliance. Furthermore, in working to identify potential control strategies, the three regulatory agencies chose to focus **only** on ways to reduce NOx emissions (and not hydrocarbon emissions) because, in their words, *"NOx is the most critical pollutant for reducing regional ozone and fine particulate matter."* Given this, CARB staff's proposal to allow any NOx emission increases from the use of biodiesel is difficult to understand.

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

CARB staff's proposal becomes even more difficult to understand when the emission increases from biodiesel are compared to the emission benefits from adopted and proposed control measures. As an illustration, the NOx reductions expected from transportation control measures in the South Coast Basin that are part of the district's Air Quality Plan[15] are compared in Table 5 to estimated NOx emission increases under the ADF based on Sierra's analysis of B5. As shown, the increases due to biodiesel are far larger than the reductions from transportation control measures and completely offset the benefits of those measures that must be implemented as the result of their being included in the Air Quality Plan.

Table 5
Comparison of NOx Reductions from South Coast Transportation Control Measures (TCMs) and Estimated NOx Increases from Biodiesel Under the Proposed ADF Regulation

Calendar Year	NOx Reduction from TCMs, tons/day	NOx Increase due to Biodiesel tons/day
2014/2015	-0.7	2.72
2019/2020	-1.4	3.00
2023	-1.5	2.70

[14] California Air Resources Board, Vision for Clean Air: A Framework for Air Quality and Climate Planning, June 27, 2012.
[15] See South Coast 2012 AQMP. Appendix IV C. *http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2012-air-quality-management-plan/final-2012-aqmp-(february-2013)/appendix-iv-(c)-final-2012.pdf*

Similarly, the approximately two ton per day NOx increase estimated from the use of biodiesel in the San Joaquin Valley under the ADF can be compared to planned and implemented NOx control measures,[16,17] many of which have emission benefits on the order of two tons per day or less. Again, it should also be noted that the potential NOx emission increases allowed under the proposed ADF from extensive use of B20 in NDTEs without mitigation are far greater than the fleetwide impacts associated with the use of B5.

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

[16] San Joaquin Valley Air Pollution Control District, 2007 Ozone Plan and Appendices and Updates.
[17] San Joaquin Valley Air Pollution Control District, 2010 Ozone Mid-Course Review, June 2010.

Table 6
Results of Sierra Research Statewide Analysis

Statewide Total NOx Emissions Inventory, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	493.3	345.0	204.9
Construction/Mining/Drilling	75.8	56.6	43.6
Cargo Handling Equipment (CHE)	4.02	3.13	2.70
Transportation Refrigiration Units (TRU)	13.33	11.25	12.26
Agricultural Equipment	34.35	19.75	13.44
TOTAL	620.8	435.7	276.9

Statewide NTDE NOx Emissions Inventory, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	73.0	127.2	138.2
Construction/Mining/Drilling	0.8	5.5	9.0
Cargo Handling Equipment (CHE)	0.26	0.89	1.22
Transportation Refrigiration Units (TRU)	0.00	0.00	0.00
Agricultural Equipment	0.21	0.85	1.23
TOTAL	74.4	134.4	149.6

Statewide NOx Emissions Increase Due to B5 , tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	7.8550	8.5374	7.5764
Construction/Mining/Drilling	0.7916	0.7850	0.7962
Cargo Handling Equipment (CHE)	0.0506	0.0668	0.0757
Transportation Refrigiration Units (TRU)	0.1333	0.1125	0.1226
Agricultural Equipment	0.3520	0.2317	0.1837
TOTAL	9.18	9.73	8.75

Statewide NTDE NOx Emission Increase Due to B5, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	3.6523	6.3596	6.9092
Construction/Mining/Drilling	0.0424	0.2735	0.4507
Cargo Handling Equipment (CHE)	0.0131	0.0444	0.0609
Transportation Refrigiration Units (TRU)	0.0000	0.0000	0.0000
Agricultural Equipment	0.0106	0.0427	0.0617
TOTAL	3.72	6.72	7.48

Statewide Legacy Vehicle NOx Emission Increase Due to B5, tons/day			
	2015	2020	2023
Trucks (LHD1, LHD2, MHD, HHD, Buses)	4.2027	2.1778	0.6672
Construction/Mining/Drilling	0.7492	0.5115	0.3454
Cargo Handling Equipment (CHE)	0.0375	0.0224	0.0148
Transportation Refrigiration Units (TRU)	0.1333	0.1125	0.1226
Agricultural Equipment	0.3414	0.1890	0.1220
TOTAL	5.46	3.01	1.27

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Table 7
Results of Sierra Research South Coast Air Basin Analysis

South Coast Total NOx Emissions Inventory, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	153.0	107.9	62.3
Construction/Mining/Drilling	28.0	21.5	15.9
Cargo Handling Equipment (CHE)	3.21	2.53	2.20
Agricultural Equipment	2.18	1.23	0.84
TOTAL	186.4	133.1	81.3

South Coast NTDE NOx Emissions Inventory, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	20.8	38.7	42.8
Construction/Mining/Drilling	0.3	2.1	3.3
Cargo Handling Equipment (CHE)	0.24	0.79	1.08
Agricultural Equipment	0.01	0.05	0.07
TOTAL	21.4	41.7	47.3

South Coast NOx Emission Increase Due to B5 , tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	2.3624	2.6270	2.3340
Construction/Mining/Drilling	0.2931	0.2993	0.2929
Cargo Handling Equipment (CHE)	0.0416	0.0568	0.0652
Agricultural Equipment	0.0223	0.0144	0.0113
TOTAL	2.72	3.00	2.70

South Coast NTDE NOx Emission Increase Due to B5, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	1.0410	1.9352	2.1385
Construction/Mining/Drilling	0.0161	0.1056	0.1673
Cargo Handling Equipment (CHE)	0.0118	0.0393	0.0539
Agricultural Equipment	0.0006	0.0026	0.0037
TOTAL	1.07	2.08	2.36

South Coast Legacy Vehicle NOx Emission Increase Due to B5, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	1.3213	0.6918	0.1955
Construction/Mining/Drilling	0.2770	0.1938	0.1256
Cargo Handling Equipment (CHE)	0.0298	0.0175	0.0112
Agricultural Equipment	0.0216	0.0118	0.0076
TOTAL	1.65	0.91	0.34

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

Table 8
Results of Sierra Research San Joaquin Valley Analysis

San Joaquin Valley Total NOx Emissions Inventory, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	103.9	77.1	43.9
Construction/Mining/Drilling	14.0	12.1	9.4
Cargo Handling Equipment (CHE)	0.09	0.06	0.06
Agricultural Equipment	14.81	8.58	5.82
TOTAL	132.8	97.8	59.2

San Joaquin Valley NTDE NOx Emissions Inventory, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	19.7	33.7	35.9
Construction/Mining/Drilling	0.1	1.1	1.9
Cargo Handling Equipment (CHE)	0.00	0.01	0.01
Agricultural Equipment	0.09	0.36	0.53
TOTAL	20.0	35.2	38.4

San Joaquin Valley NOx Emission Increase Due to B5 , tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	1.8277	2.1196	1.8769
Construction/Mining/Drilling	0.1459	0.1661	0.1696
Cargo Handling Equipment (CHE)	0.0010	0.0011	0.0011
Agricultural Equipment	0.1517	0.1003	0.0793
TOTAL	2.13	2.39	2.13

San Joaquin Valley NTDE NOx Emission Increase Due to B5, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	0.9857	1.6862	1.7973
Construction/Mining/Drilling	0.0075	0.0560	0.0941
Cargo Handling Equipment (CHE)	0.0001	0.0005	0.0007
Agricultural Equipment	0.0046	0.0182	0.0264
TOTAL	1.00	1.76	1.92

San Joaquin Valley Legacy Vehicle NOx Emission Increase Due to B5, tons/day			
	2015	**2020**	**2023**
Trucks (LHD1, LHD2, MHD, HHD, Buses)	0.8421	0.4333	0.0796
Construction/Mining/Drilling	0.1384	0.1101	0.0755
Cargo Handling Equipment (CHE)	0.0009	0.0005	0.0004
Agricultural Equipment	0.1471	0.0822	0.0529
TOTAL	1.13	0.63	0.21

Reproduction of Pages 253 - 270 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-24 through ADF 17-35

8_SF_LCFS_GE (Page 191 - 208)

1209. Comment: **Review of CARB Staff Estimates of NOx Emission Increases Associated with the Use of Biodiesel in California Under the Proposed ADF Regulation**

Agency Response: This is the second time this document was submitted. It is a reproduction of comments **ADF 17-24** through **ADF 17-35**. The comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **17_OP_ADF_GE**.

This page intentionally left blank.

Attachment E

Assessment of CARB's Environmental Analysis and ADF Mitigation Requirements

In developing the proposed Alternative Diesel Fuel (ADF) regulation, CARB staff has performed an environmental analysis and included mitigation requirements intended to eliminate the adverse environmental impacts associated with increased NOx emissions resulting from the use of biodiesel under the ADF.

The environmental analysis is fundamentally flawed in that staff incorrectly selected 2014 as the baseline year and performed the analysis in light of biodiesel usage levels in that year. As documented below, CARB staff has long been aware that biodiesel use leads to increases in NOx emissions, and promised but failed to act to address those emissions through enactment of an ADF regulation as early as 2009. There is no basis for an agency to use its failure to promptly act to address an environmental issue of which it was clearly aware as grounds to change the baseline for assessing its' proposed effort to address that issue. This is even more apparent given that CARB staff acknowledges that a key function of the LCFS regulation is to incent low carbon intensity fuels including biodiesel which has to date generated 13% of all credits issued by CARB under the LCFS.[1] Given this, the proper baseline for assessing the ADF regulation should be 2009 when CARB first stated it would regulate biodiesel use and when, by CARB staff's own admission, little biodiesel was used in California and NOx emissions were minimal.

The mitigation requirements of the ADF regulation are equally flawed. First, they are based on CARB's staff's fundamentally flawed emission analysis, and second their implementation is unreasonably delayed until 2018—more than ten years after CARB staff was aware that biodiesel use in California would lead to increased NOx emissions.

Reproduction of Pages 271 - 277 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-36 through ADF 17-44

History of the ADF Regulation

Although the U.S. Environmental Protection Agency (EPA) published a report in 2002 showing that biodiesel use increases NOx emissions linearly with increasing biodiesel content,[2] the earliest document found on the CARB website indicates that agency discussions regarding the need to adopt regulations addressing NOx began at least as early as February 2004.[3] This led to the first meeting of the Biodiesel Work Group in April 2004.[4] A summary of that discussion

[1] See Page III-2 of the LCFS ISOR.

[2] See EPA, A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions (available at http://www.epa.gov/otaq/models/analysis/biodsl/p02001.pdf).

[3] See CARB, Public Consultation Meeting Regulatory and Non-Regulatory Fuels Activities at 26-29 (Feb. 25, 2004) (available at http://www.arb.ca.gov/fuels/diesel/022504arb.pdf).

[4] See CARB Ltr. (Mar. 18, 2004) (available at http://www.arb.ca.gov/fuels/diesel/altdiesel/041204altdslwsh.pdf).

published at the time[5] it occurred indicates that topics discussed included ways to mitigate NOx emission increases associated with biodiesel use.

In 2006, CARB published a draft guidance document regarding the use of biodiesel in California,[6] at which time the agency simply decided not to address increased NOx emissions until biodiesel use became more widespread.[7] At that time, CARB instead could have ensured that there would be no NOx increases from biodiesel use by simply requiring those interested in selling biodiesel in California to demonstrate that they could formulate biodiesel blends in a way that did not increase NOx emissions, which is one of the approaches CARB is now considering.[8]

The first time CARB was scheduled to adopt regulations addressing this issue was in November 2009; this is indicated on page 12 of CARB's 2009 Rulemaking Calendar,[9] which includes the following summary:

> *Staff will propose motor vehicle fuel specifications for biodiesel and renewable diesel. These specifications are necessary for the implementation of the Low Carbon Fuel Standard regulation (to be considered at the March 2009 Hearing).*

No action was taken by CARB in 2009 and the planned adoption date was moved to June 2010; this is evidenced by CARB's 2010 Rulemaking Calendar,[10] which lists the regulatory item on page 11. This time the summary reads:

> *The staff will propose adoption of new motor vehicle fuel specifications for biodiesel and renewable diesel. These specifications are necessary to ensure that the use of these fuels will not increase emissions of criteria and toxic air pollutants when used as a motor vehicle fuel.*

Again, no action was taken by CARB in 2010 and the planned adoption date was moved to November 2011; this is evidenced by CARB's 2011 Rulemaking Calendar,[11] which lists the regulatory item on page 14. This time the summary reads:

Reproduction of Pages 271 - 277 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-36 through ADF 17-44

[5] See *CVS News*, at 27-31 (May 2004) (available at http://www.sierraresearch.com/documents/cvs_news_may_2004.pdf).
[6] See CARB, Draft Advisory on Biodiesel Use (Nov. 14, 2006) (available at http://www.arb.ca.gov/fuels/diesel/altdiesel/111606biodsl_advisory.pdf).
[7] See CARB, Suggested ARB Biodiesel Policy (May 24, 2006) (available at http://www.arb.ca.gov/fuels/diesel/altdiesel/052406arb_prsntn.pdf).
[8] See California Environmental Protection Agency, Discussion of Conceptual Approach to Regulation of Alternative Diesel Fuels (Feb. 15, 2013).
[9] See CARB, 2009 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2009rulemakingcalendar.pdf).
[10] See CARB, 2010 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2010rulemakingcalendar.pdf).
[11] See CARB, 2011 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2011rulemakingcalendar.pdf).

The Low Carbon Fuel Standard incents the use of biodiesel and renewable diesel, for which there are no current emissions–based fuel specifications. Staff will propose fuel specifications for both of these diesel blendstocks.

Yet again, no action was taken by CARB in 2011 and the planned adoption date was moved to November 2012; this is evidenced by CARB's 2012 Rulemaking Calendar,[12] which lists the regulatory item on page 14. This time the summary reads:

Rulemaking to establish commercial fuel specifications for blends of commercial diesel fuel and neat biodiesel in amounts greater than five volume percent.

Yet again, no action was taken by CARB in 2012 and, for the fourth consecutive year, the item was scheduled to be presented to the Board—the CARB Rulemaking Calendar for 2013[13] indicates on page 8 that the Board is currently scheduled to consider adoption of amendments to the agency's Alternative Diesel Fuel Regulations in September 2013. This time the summary reads:

Proposed new motor vehicle alternative diesel fuel specifications and commensurate amendments to the diesel fuel regulations.

Unlike the previous years, during 2013 CARB staff did begin to take action to actually develop a regulation that it purported would address increases in NOx emissions resulting from biodiesel use. The hearing notice[14] and Initial Statement of Reasons[15] for the proposed ADF regulation were published in October 2013, in advance of a Board hearing to be held on December 12-13, 2013. However, that hearing was postponed to until March 20, 2014,[16] and then the entire rulemaking was abandoned prior to the March 2014 hearing.[17]

Reproduction of Pages 271 - 277 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-36 through ADF 17-44

History of Biodiesel Use

Although CARB does not disclose the amounts of biodiesel used in California prior to 72 million gallons estimated in 2014 in the ADF rulemaking documents (see ISOR Appendix B), data for 2005 to 2012 are available from the California Energy Commission.[18] These data are shown in Figure 1 below. As shown, biodiesel use in California increased dramatically in 2006 when CARB staff indicated that it would not regulate biodiesel, and then decreased until the LCFS

---

[12] See CARB, 20012 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2012rulemakingcalendar.pdf).

[13] See CARB, 2013 Rulemaking Calendar Schedule (available at http://www.arb.ca.gov/regact/2013rmcal.pdf).

[14] See http://www.arb.ca.gov/regact/2013/adf2013/adf2013notice.pdf

[15] See http://www.arb.ca.gov/regact/2013/adf2013/adf2013isor.pdf

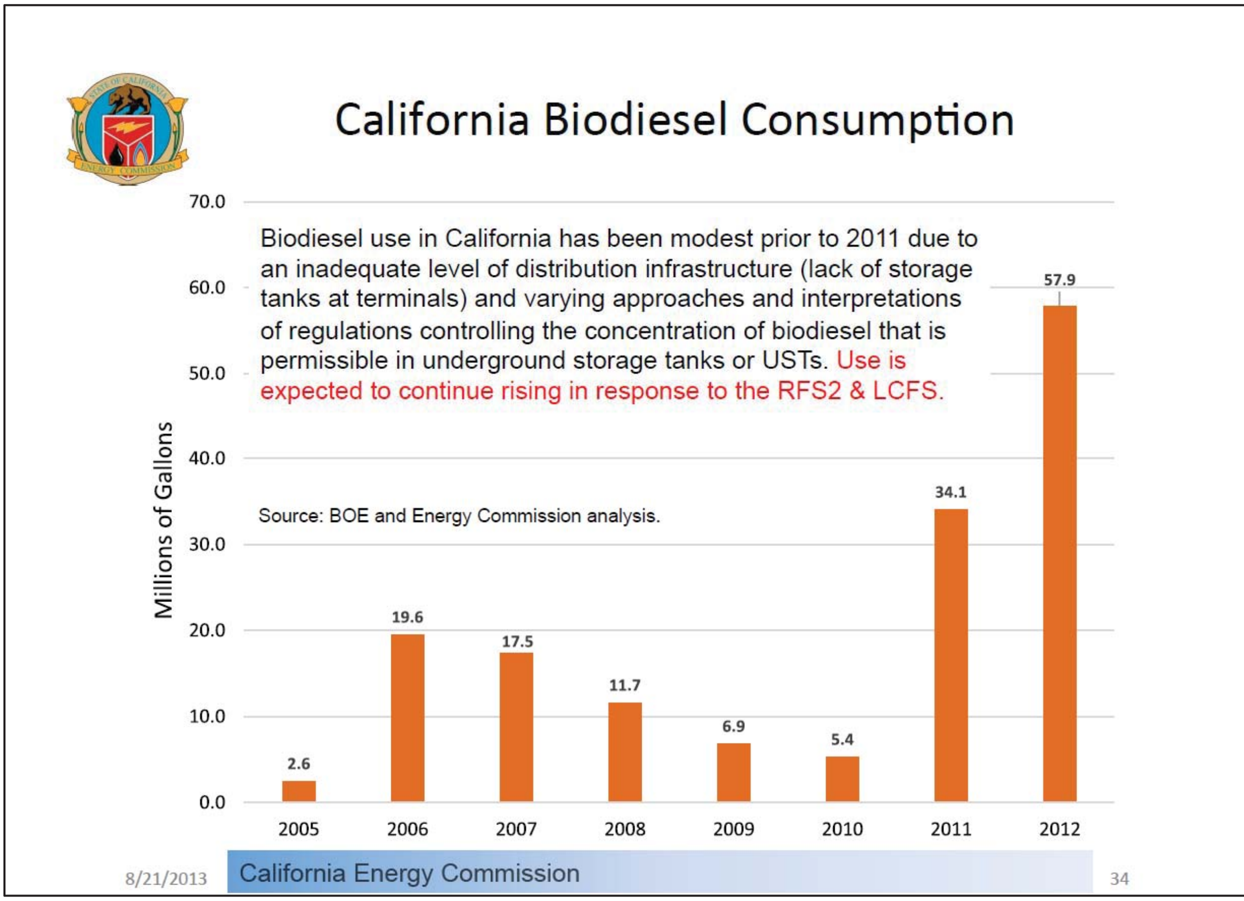
[16] See http://www.arb.ca.gov/regact/2013/adf2013/adf2013postpone.pdf

[17] See http://www.arb.ca.gov/regact/2013/adf2013/NDNPadf2013.pdf

[18] See http://www.energy.ca.gov/2013_energypolicy/documents/2013-08-21_workshop/presentations/06_Schremp_Biofuels.pdf

took effect in 2011 at which point it again increased dramatically. Clearly, the appropriate baseline year for analysis of the ADF regulation is 2009 or 2010 when CARB first committed to adopting a regulation to address biodiesel NOx impacts, not any later year after which substantial increases in biodiesel use occurred in response to the LCFS.

Figure 1
Biodiesel Consumption in California as Reported by the California Energy Commission



Reproduction of Pages 271 - 277 of Comment Letter 46_OP_LCFS_GE / 17_OP_ADF_GE Consisting of Comments ADF 17-36 through ADF 17-44

The NOx increases resulting from CARB's failure to regulate biodiesel during the period from 2005 to 2014 are summarized in Table 1. The values presented are approximate and are based on the Sierra Research methodology for 2015 adjusted to account for differences in biodiesel use as well as the absence of NTDE engines in years prior to 2010. Biodiesel use for 2014 is taken from Appendix B of the ADF ISOR, and the estimated use for 2013 assumed linear growth in biodiesel use from 2012 to 2014. Significant increases in NOx emissions from 2011 to 2014 can be seen from a comparison of the values presented in Table 1 with the values presented in Table B-1 of Appendix B to the ADF ISOR. These increased NOx emissions from 2011 to 2014 total 782, 1032, and 3,463 tons for the San Joaquin Valley, South Coast, and entire state, respectively.

Table 1 Estimated Increases in NOx Emissions Due to Biodiesel Use in California from 2005 to 2014 (tons per year)			
Calendar Year	Statewide	South Coast	San Joaquin Valley
2005	31	9	7
2006	234	70	50
2007	209	63	45
2008	140	42	30
2009	82	25	18
2010	65	19	14
2011	447	134	98
2012	825	246	184
2013	1000	298	227
2014	1191	354	273
Total	4225	1260	945

Proposed ADF Mitigation Requirements

Under the proposed ADF regulation,[19] mitigation is generally required for "low-saturation" biodiesel blends with diesel fuel above B5 (e.g., B6 and higher) during the summer, and above B10 (e.g., B11 and higher) during the winter, unless the fuels are used in vehicles with new technology diesel engines in which case mitigation is not required for levels up to B20. For "high-saturation" biodiesel blends with diesel fuel, mitigation is required year-round above B10 (e.g., B11 and higher) again, unless the fuels are used in vehicles with new technology diesel engines in which case mitigation is not required for levels up to B20. However, no mitigation is required for any biodiesel blend sold in California prior to January 1, 2018.

According to the ADF ISOR,[20] CARB staff selected these levels based on an "analysis" for which no detail or documentation has been provided, and that reportedly included consideration of the impacts of new technology diesel engines (NTDEs) and the use of renewable diesel as "offsetting factors." Although it is impossible to thoroughly review an analysis which is not described in detail, in this case it can still be demonstrated to be fundamentally flawed. As discussed elsewhere, CARB incorrectly assumes that NOx emissions from NTDEs are unaffected by biodiesel despite the fact that available data show statistically significant increases in NOx emissions. Further, CARB cannot rely on the use of renewable diesel as mitigation for NOx increases from biodiesel as there is nothing in the ADF or the LCFS regulation that mandates the use of any volume of renewable diesel in California, nor which links the amount of renewable diesel used to the amount of biodiesel used. Further, neither the ADF nor LCFS regulations ensure that fuel producers will use biodiesel in a manner that provides surplus

Reproduction of Pages 271 - 277 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-36 through ADF 17-44

[19] Proposed section 2293.6 Title 13, CCR in ISOR Appendix A.
[20] Chapter 6, Part H.

reductions[21] in NOx emissions. Given that CARB's reliance on "offsetting factors" is fundamentally flawed, the agency's "Determination of NOx Control Level for Biodiesel" is also fundamentally flawed. Another problem with the "determination" is that CARB staff claims to have performed an "analysis" for which no detail or documentation is provided, indicating that the higher blend level threshold for mitigation that applies to "low-saturation" blends during the winter months will not result in adverse air quality impacts. Again, it is not possible to critically review an analysis which is not described in detail; further, the information provided in this analysis is so insufficient that it is not even possible to develop an appropriate set of comments.

In addition to the flaws in CARB staff's analysis of what mitigation should be applied to address the increased NOx emissions associated with biodiesel use, CARB staff is arbitrarily delaying the date on which mitigation is required by two years from the expected effective date of the ADF regulation. According to ADF ISOR, CARB staff claim the reason for this delay is:

> *ARB is also proposing the in-use requirements come into effect on January 1, 2018, as time is needed to overcome logistical and other issues in implementation of in-use requirements. For example, use of the additive Di-tert-butyl peroxide (DTBP) will require replacement of steel tanks with stainless steel tanks, permitting of hazardous substance storage, approval by local fire agencies, additional additization infrastructure, and logistical business changes to acquire the additive. All of this is expected to take around 2 years to complete. Another method of compliance is re-routing higher blends to NTDEs. Research shows that the use of biodiesel in blends up to B20 in NTDEs results in no detrimental NOx impacts. This and other methods of complying with the in-use requirements, such as certification of additional options are also expected to take 2 years or more. Because compliance with the in-use options would be infeasible during initial implementation on January 1, 2016, only recordkeeping and reporting provisions will be implemented initially. The in-use requirements are proposed to come into effect on January 1, 2018.*

It is not clear why CARB staff believes that a two year delay in the implementation of mitigation requirements is required under the ADF regulation when the maximum delay in the implementation of new requirements under the LCFS regulation, which will much more dramatically impact fuel producers than the ADF requirements, is only one year, until January 1, 2017. Further, as the biodiesel industry has been on notice that CARB intended to impose NOx mitigation requirements for over ten years, it is not clear why such measures cannot be required from the expected January 1, 2016 effective date of the proposed regulation.

The impact of the failure to immediately require Biodiesel mitigation under the ADF regulation is shown in Table 2. These values are based on the Sierra Research emissions methodology which assumes statewide use of B5. As discussed elsewhere, these impacts

Reproduction of Pages 271 - 277 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-36 through ADF 17-44

[21] In order to generate surplus reductions in NOx, renewable diesel would have to be blended into diesel fuel downstream of refineries, and although CARB staff has assumed that this will occur they have provided no basis for that assumption.

are significant in that the increases are as large or larger than those sought from emission control measures implemented of under consideration by CARB and local air pollution control agencies in the South Coast and San Joaquin Valley air basins.

Reproduction of Pages 271 - 277 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-36 through ADF 17-44

Table 2
Potential NOx Increases Due to CARB's Failure to Require Immediate Biodiesel Mitigation Under the ADF
(tons per year)

	Statewide	South Coast	San Joaquin Valley
2016	3405	1013	796
2017	3460	1034	815
Total	6866	2047	1612

This page intentionally left blank.

8_SF_LCFS_GE (Page 209 - 215)

1210. Comment: **Assessment of CARB's Environmental Analysis and ADF Mitigation Requirements**

Agency Response: This is the second time this document was submitted. It is a reproduction of comments **ADF 17-36** through **ADF 17-44**. The comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **17_OP_ADF_GE**.

This page intentionally left blank.

Attachment F

Potential for Actual Biodiesel Blend Levels to Exceed Levels Purported Under the Proposed ADF Regulation

In order to properly understand and mitigate the adverse environmental impacts of biodiesel blends sold in California, it is critical that the actual amount of biodiesel present in a blend be accurately known. Despite this, the proposed ADF regulation fails to adequately ensure that the actual biodiesel content of biodiesel blends—and therefore their adverse environmental impacts—will be accurately known or appropriately mitigated. As discussed below, significant changes are required to definitions used in the proposed LCFS and ADF regulations, and new testing, recordkeeping, and reporting requirements need to be added to the ADF regulation to prevent the blending of biodiesel with fuels that already contain undisclosed amounts of biodiesel.

Reproduction of Pages 278 - 282 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-45 through ADF 17-46

<u>Background</u>

CARB regulations at §2281 and §2282, Title 13, California Code of Regulations apply to vehicular diesel fuel sold in California and define "diesel fuel" as follows:

> *"Diesel fuel" means any fuel that is commonly or commercially known, sold or represented as diesel fuel, including any mixture of primarily liquid hydrocarbons – organic compounds consisting exclusively of the elements carbon and hydrogen – that is sold or represented as suitable for use in an internal combustion, compression-ignition engine."*[1]

The proposed LCFS regulation contains the following definitions that are relevant to biodiesel blends (See ISOR Appendix A):[2]

> *"B100" means biodiesel meeting ASTM D6751-14 (2014) (Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels), which is incorporated herein by reference.*

> *"Biodiesel" means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel meeting all the following:*

[1] 13 CCR §2281(b)(1) and §2282(b)(3)
[2] See proposed §95481, Title 17, California Code of Regulations

(A) Registered as a motor vehicle fuel or fuel additive under 40 Code of Federal Regulations (CFR) part 79;
(B) A mono-alkyl ester;
(C) Meets ASTM D6751-08 (2014), Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, which is incorporated herein by reference;
(D) Intended for use in engines that are designed to run on conventional diesel fuel; and
(E) Derived from nonpetroleum renewable resources.

"Biodiesel Blend" means a blend of biodiesel and diesel fuel containing 6 percent (B6) to 20 percent (B20) biodiesel and meeting ASTM D7467-13 (2013), Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), which is incorporated herein by reference.

"Diesel Fuel" (also called conventional diesel fuel) has the same meaning as specified in California Code of Regulations, title 13, section 2281(b).

"Diesel Fuel Blend" means a blend of diesel fuel and biodiesel containing no more than 5 percent (B5) biodiesel by weight and meeting ASTM D975-14a, (2014), Standard Specification for Diesel Fuel Oils, which is incorporated herein by reference.

Reproduction of Pages 278 - 282 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-45 through ADF 17-46

Finally, the proposed ADF regulation contains the following definitions that are relevant to biodiesel blends:[3]

"Alternative diesel fuel" or "ADF" means any fuel used in a compression ignition engine that is not petroleum-based, does not consist solely of hydrocarbons, and is not subject to a specification under subarticle 1 of this article.

"Biodiesel" means a fuel comprised of mono-alkyl esters of long chain fatty acids derived from vegetable oils or animal fats that is 99-100 percent biodiesel by volume (B100 or B99) and meets the specifications set forth by ASTM International in the latest version of Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels D6751 contained in the ASTM publication entitled: Annual Book of ASTM Standards, Section 5, as defined in California Code of Regulations, title 4, section 4140(a), which is hereby incorporated by reference.

"Biodiesel Blend" means biodiesel blended with petroleum-based CARB diesel fuel or non-ester renewable diesel.

[3] See proposed §2293.2(a), Title 13, California Code of Regulations

"Blend Level" means the ratio of an ADF to the CARB diesel it is blended with, expressed as a percent by volume. The blend level may also be expressed as "AXX," where "A" represents the particular ADF and "XX" represents the percent by volume that ADF is present in the blend with CARB diesel (e.g., a 20 percent by volume biodiesel/CARB diesel blend is denoted as "B20").

"B5" means a biodiesel blend containing no more than five percent biodiesel by volume.

"B20" means a biodiesel blend containing more than five and no more than 20 percent biodiesel by volume.

"CARB diesel" means a light or middle distillate fuel that may be comingled with up to five (5) volume percent biodiesel and meets the definition and requirements for "diesel fuel" or "California nonvehicular diesel fuel" as specified in California Code of Regulations, title 13, section 2281 et seq. "CARB diesel" may include: non-ester renewable diesel; gas-to-liquid fuels; Fischer-Tropsch diesel; diesel fuel produced from renewable crude; CARB diesel blended with additives specifically formulated to reduce emissions of one or more criteria or toxic air contaminants relative to reference CARB diesel; and CARB diesel specifically formulated to reduce emissions of one or more criteria or toxic air contaminants relative to reference CARB diesel.

Reproduction of Pages 278 - 282 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-45 through ADF 17-46

Discussion

The first issue related to the potential for uncertainty and inaccuracy in actual biodiesel content of fuels sold in California involves the different definitions that have been proposed for the term "biodiesel" under the proposed LCFS and ADF regulations. Although the two definitions may be functionally equivalent, they should be made the same under both the LCFS and ADF regulations unless CARB staff can articulate a compelling need for the use of different definitions to describe the same thing.

More importantly, the term "Biodiesel Blend" in the proposed LCFS regulation directly conflicts with the use of the same exact term in the proposed ADF regulation: a "Biodiesel Blend" under the LCFS regulations contains at least 6% biodiesel, while a "Biodiesel Blend" under the ADF is a diesel fuel containing any biodiesel. Furthermore, the LCFS regulation defines "Diesel Fuel Blend" as a blend of diesel fuel and up to 5% biodiesel, while such a fuel would be considered "CARB diesel" under the ADF regulation. Again, this haphazard use of the same term to describe fundamentally different fuels and different terms to describe the same fuel will assuredly lead to confusion in practice regarding the actual content of biodiesel available in California.

Further confusion is created by the definitions of "Biodiesel Blend" and "Blend Level" under the proposed ADF regulation. "Biodiesel Blend" is defined as a mixture of biodiesel and an undefined fuel referred to as "petroleum-based CARB diesel." "Blend

Level" applies to blends of all fuels subject to the ADF regulation, including biodiesel, and is defined as the ratio of an "Alternative diesel fuel" mixed with "CARB diesel." However, as noted above, "CARB diesel" may already contain as much as 5% biodiesel under the proposed ADF regulation. Furthermore, the definition of "Blend Level" includes no reference to the fuel termed "petroleum-based CARB diesel" that appears in the definition of "Biodiesel Blend" under the ADF—instead, it refers to "CARB diesel," which, as noted above, may contain as much as 5% biodiesel. Obviously, the addition of biodiesel to a fuel already containing some amount of biodiesel up to 5% will cause the actual biodiesel content to be higher than the blender expects; this, in turn, will lead to more significant adverse environmental impacts than expected. It is also clear that CARB staff mean for the definition of "Blend Level" to apply to "Biodiesel Blends," as that definition uses an example based on biodiesel (B20) to demonstrate the practical meaning of "Blend Level."

Finally, under the proposed ADF regulation, "B20" is nonsensically defined as a fuel that contains between 6% and 20% biodiesel, which directly contradicts the definition of "Blend Level" in same regulation. There appears to be no need for this definition or the definition of B5 in the proposed ADF regulation.

Reproduction of Pages 278 - 282 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-45 through ADF 17-46

As outlined above, the proposed CARB LCFS and ADF regulations fail completely in clearly defining the four fuels that are of fundamental importance to ensuring that the biodiesel content of a fuels sold in California—and hence the adverse environmental impacts associated with their use—is accurately known. Instead, the proposed regulations make it likely that biodiesel blenders will unknowingly use fuels that already contain an unknown amount of biodiesel (up to 5%) in blending and that the actual biodiesel content of biodiesel blends may be as much as 5% greater than that represented by the blender and reported to CARB under the ADF regulation. This is significant because, as discussed in other attachments to this declaration, the increases in NOx emissions and associated adverse environmental impacts caused by biodiesel blends become larger in direct proportion to the amount of biodiesel present.

Both the LCFS and the ADF regulation must clearly define the four fuels described below.

1. ***"Diesel fuel"* –** This should defined as under 13 CCR §2281(b)(1) and §2282(b)(3).

2. ***"Biodiesel"*** or "***B100"* –** It appears that this could be properly defined through changes to the definitions currently proposed in the LCFS and ADF regulations; this is what should be blended only with "diesel fuel" to create a "Biodiesel Blend."

3. ***"CARB diesel"* –** This is accurately defined under the proposed ADF regulation, but under no circumstances should it be allowed to be blended with biodiesel or any other ADF. It should be renamed to clearly differentiate it from "diesel fuel" such that no reasonable person would understand that it could be legally mixed with any ADF.

4. ***“Biodiesel Blend”*** **–** This should refer to the “Blend Level” and must correspond to the actual amount of “Biodiesel” or “B100” in terms of percentage by volume in the final blend with “diesel fuel.”

In addition to modifying the definitions as described above, the ADF regulation must also be modified to ensure that biodiesel blenders do not intentionally or unintentionally blend biodiesel into fuels that already contain biodiesel. This can easily be achieved by adding requirements to proposed §2293.8 Title 13, CCR, to require that any “diesel fuel” to be used in blending with biodiesel be tested for the presence of biodiesel prior to blending. Similarly, that section should be modified to include reporting and record keeping requirements for biodiesel blenders that document that they have used only biodiesel-free “diesel fuel” in all of their blending operations.

Reproduction of Pages 278 - 282 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-45 through ADF 17-46

This page intentionally left blank.

8_SF_LCFS_GE (Page 216 - 220)

1211. Comment: **Potential for Actual Biodiesel Blend Levels to Exceed Levels Purported Under the Proposed ADF Regulation**

Agency Response: This is the second time this document was submitted. It is a reproduction of comments **ADF 17-45** through **ADF 17-46**. The comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **17_OP_ADF_GE**.

This page intentionally left blank.

Attachment G

The Growth Energy Alternative to Proposed ADF Regulation is the Least-Burdensome Approach that Best Achieves the Project Objectives at the Least Cost That Must be Adopted

As part of the rulemaking process leading to CARB staff's proposed ADF regulation, staff was required to solicit and consider alternatives to the proposed regulation. Growth Energy submitted such an alternative which CARB staff acknowledged provided equivalent or superior reductions in NOx emissions from biodiesel use but rejected as being more costly. However, as is documented in detail below, CARB staff made fundamental errors in its' assessment of the Growth Energy Alternative, which will in fact provide greater reductions in NOx emissions from biodiesel use than the staff's proposed ADF regulation but do so with equal cost-effectiveness. (Equal cost-effectiveness means that the dollars spent per unit mass of NOx emissions eliminated will be the same.) Given that the Growth Energy alternative provides greater environmental benefits, which in turn substantially lessen the ADF's significant impacts, and is equally cost-effective as the staff's proposed ADF regulation, the Growth Energy Alternative rather than the staff proposal should be adopted by CARB.

Reproduction of Pages 283 - 285 of Comment Letter 46_OP_LCFS_GE / 17_OP_ADF_GE Consisting of Comments ADF 17-47 through ADF 17-50

Background

On July 29, 2014, CARB published a "Solicitation of Alternatives for Analysis in the Alternative Diesel Fuel Standardized Regulatory Impact Assessment" which is attached. On August 15, 2014, Growth Energy submitted an alternative regulatory proposal for the ADF regulation (which is attached) to CARB in response to the agency's solicitation. On December 30, 2014, CARB staff published both the ISOR for the ADF regulation as well as a document entitled "Summary of DOF Comments to the Combined LCFS/ADF SRIA and ARB Responses" which is Appendix E to the ADF ISOR, both of which include information related to staff's decision to reject the alternative to the ADF regulation proposed by Growth Energy.

The staff's assessment of the Growth Energy (GE) Alternative published in Appendix E of the ADF ISOR is as follows (emphasis added):

> ***Benefits:***
>
> ***ARB finds that the GE alternative would meet the emissions goals of the ADF proposal and achieve roughly the same emissions benefits as the ADF proposal. The GE alternative may achieve marginally more emissions benefits if biodiesel were to be widely used as an additive under the ADF proposal. Although the GE alternative is simpler than the ADF proposal, the GE alternative is unnecessarily strict; ARB's analysis of the science does not find that there are NO_X increases with B5 animal biodiesel or biodiesel used in NTDEs, so***

requiring mitigation for these does not achieve any additional emissions benefit versus the ADF proposal.

Costs:

The GE alternative would require mitigation of more fuel than the ADF proposal; regulated parties would incur more costs to mitigate non-animal- and animal-based biodiesel similarly and setting the significance level for both at one percent. Additionally, the NTDE exemption would increase the volumes of fuels to be mitigated, further increasing the direct costs on regulated parties.

Economic Impacts:

The REMI results also indicate that the combined LCFS/ADF proposal has no discernible difference from the GE alternative. Employment, GSP, and output differ only slightly and represent a difference of less than one tenth of one percent. Given that the GE alternative has higher direct costs, the combined LCFS/ADF alternative is preferred.

Cost-Effectiveness:

The GE alternative costs more than the ADF proposal, because it requires mitigation of more biodiesel than the ADF proposal. The GE alternative does not result in any more emissions reductions than the ADF proposal and as such is less cost effective than the ADF proposal.

Reason for Rejection:

ARB rejects the GE alternative because it costs more than the ADF proposal and does not achieve additional emissions benefits*.*

The reason for rejection of the Growth Energy (GE) alternative presented in the ADF ISOR itself is as follows:

This alternative proposal retains the same biodiesel NOx mitigation options as the ADF proposal*. However, under the GE alternative, animal and non-animal biodiesel would be treated equally and require NOx mitigation for all biodiesel blends, including blends below B5.* ***ARB rejects this alternative because the costs are significantly higher than the ADF proposal and do not achieve additional emissions benefits.*** *During the development of this regulation, staff considered alternatives to the proposal and determined that the proposal represents the least-burdensome approach that best achieves the objectives at the least cost.*

Finally, it should be noted that the stated intention of the ADF regulation according to CARB staff in the ADF ISOR is as follows (emphasis added):

Reproduction of Pages 283 - 285 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-47 through ADF 17-50

*The ADF regulation is intended to create a framework for these low carbon diesel fuel substitutes to enter the commercial market in California, **while mitigating any potential environmental or public health impacts**.*

Discussion

As indicated above, the stated reason why CARB staff rejected the Growth Energy alternative to the proposed ADF regulation is because CARB staff believed it would require that actions be taken to mitigate increased NOx emissions from biodiesel under circumstances where CARB staff incorrectly assumed there would no increased emissions due to biodiesel use on under the ADF. However, as is clearly demonstrated in another attachment to the declaration of James M. Lyons,[1] CARB staff's analysis and assumptions of the increases in NOx emissions that will result for the ADF regulation is fatally flawed as is CARB's basis for rejection of the Growth Energy Alternative.

Reproduction of Pages 283 - 285 of Comment Letter 46_OP_LCFS_GE/ 17_OP_ADF_GE Consisting of Comments ADF 17-47 through ADF 17-50

As shown by the Sierra emissions analysis, once the flaws in the CARB emissions analysis are corrected, it becomes clear that the ADF regulation will allow significant and unmitigated increases in NOx emissions to occur throughout California including areas such as the South Coast and San Joaquin air basins which experience the worst air quality in the state. As CARB staff itself admits, the Growth Energy alternative would require mitigation in exactly those areas where CARB staff was lead to believe it was not required based on its flawed emissions analysis. CARB staff also admits the Growth Energy alternative is based on the same mitigation options contained in the ADF regulation, which CARB staff has already determined to be technically feasible and cost-effective. However, the Growth Energy Alternative is superior to the ADF regulation because it expands the conditions under which this mitigation has to be applied in order to eliminate the potential for any increase in NOx emissions due to biodiesel use to a less-than-significant level. The Growth Energy Alternative therefore precludes any adverse environmental impacts due to increased NOx emissions, which is exactly what CARB staff has asserted the ADF regulation is intended to do.

Given that the Growth Energy alternative:

1. Provides complete mitigation of potential NOx emission increases due to biodiesel use under the ADF and any associated adverse environmental impacts; and

2. Relies on the same mitigation strategies proposed by CARB staff which staff has found to be technically feasible and cost-effective,

CARB must adopt the Growth Energy alternative as it better achieves the stated project objectives in an equally cost-effective manner.

[1] Review of CARB Staff Estimates of NOx Emission Increases Associated with the Use of Biodiesel in California under the Proposed ADF Regulation.

This page intentionally left blank.

8_SF_LCFS_GE (Page 221 - 223)

1212. Comment: **The Growth Energy Alternative to Proposed ADF Regulation is the Least-Burdensome Approach that Best Achieves the Project Objectives at the Least Cost That Must be Adopted**

Agency Response: This is the second time this document was submitted. It is a reproduction of comments **ADF 17-47** through **ADF 17-50**. The comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **17_OP_ADF_GE**.

This page intentionally left blank.

Attachment 4

NOx EMISSIONS IMPACTS OF BIODIESEL BLENDS

Prepared by:

Rincon Ranch Consulting
2853 S. Quail Trail
Tucson, AZ 85730

Prepared for:

Sierra Research
1801 J. Street
Sacramento, CA 95811

February 10, 2015

NOx EMISSIONS IMPACTS OF BIODIESEL BLENDS

Table of Contents

Page

List of Figures

List of Tables

NOx EMISSION IMPACTS OF BIODIESEL BLENDS

1. EXECUTIVE SUMMARY

The purpose of the Alternative Diesel Fuels (ADF) rulemaking, according to the Air Resources Board (ARB), is to create a regulatory framework that will permit biodiesel and other low-carbon, alternative diesel fuels to "enter the commercial market in California, while mitigating any potential environmental or public health impacts." [1]

The work presented in this report assesses the impacts of biodiesel use on NOx emissions from conventional and new technology diesel engines. It was performed by Rincon Ranch Consulting under subcontract to Sierra Research at the request of Growth Energy.

At present, most diesel fuel and biodiesel is consumed in conventional diesel engines that do not have exhaust gas after-treatment to reduce NOx emissions. The consensus of the literature is that biodiesel will increase NOx emissions by amounts that depend on the blending percentage (how much biodiesel is present in the diesel fuel) and the type of biodiesel feedstock (soy versus animal sources). NOx increases of 1-2% are expected from soy biodiesel at blend levels of B5 to B10 with smaller increases expected, in general, from animal biodiesel at the B5 to B10 level.

Over time, new technology diesel engines (NTDEs) equipped with exhaust gas after-treatment controls for NOx will increasingly make up the heavy duty fleet in response to other ARB programs. While baseline emissions from these engines will be reduced compared to conventional engines, the consensus of the literature available today is that use of biodiesel will still increase NOx emissions above the reduced baseline. At the B20 level, the NOx increase appears to be greater on a percentage basis than would be expected in conventional diesel engines.

The results of this work indicate the following with respect to conventional diesel engines:

- Soy biodiesels will increase NOx emissions at the B5 and B10 levels by approximately 1% and 2%, respectively. This work and Staff's analysis concur in both the conclusion and the estimated levels of NOx increase at B5 and B10. Soy biodiesels in this blend range require NOx mitigation on a per-gallon basis in order to prevent increases in NOx emissions.
- The consensus of the research community is that the effect of soy biodiesel on NOx emissions is continuous and linear with respect to the blending percentage. NOx

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

[1] "Proposed Regulation on the Commercialization of New Alternative Diesel Fuels. Staff Report: Initial Statement of Reason." California Air Resources Board, Stationary Source Division, Alternative Fuels Branch. January 2, 2015. http://www.arb.ca.gov/regact/2015/adf2015/adf15isor.pdf. Page 11.

increases have been observed at levels as low as B1.[2] The statistical analysis performed for ARB by Rocke supports this conclusion and estimates that soy biodiesel will increase NOx emissions by about 0.2% for each 1% biodiesel in the blend (0.99% for each 5% biodiesel).

In spite of this consensus, the Staff proposal requires NOx mitigation for soy-based biodiesel only above the B5 level in summer months and above the B10 level in winter months. Soy biodiesel blended at the B5 and lower levels would not require mitigation in any circumstance. The ADF regulatory framework must require mitigation of soy-based biodiesels at all blend levels if it is to ensure that such fuels do not increase NOx emissions.

- The effect of animal-based biodiesel on NOx emissions is more complicated than for soy-based blends. As the available literature demonstrates, some animal-based biodiesels will increase NOx emissions while other animal biodiesels will not. While Staff's proposal would establish B10 as the control level for animal-based biodiesel (e.g., mitigation would be required year-round for blends above B10), the available data do not support Staff's conclusion that there will not be increases in NOx emissions from B10 and lower blends. Given the Staff proposal, the only way to ensure that animal-based biodiesel does not increase NOx emissions is to require mitigation at all blend levels.

- Staff presents information indicating that animal biodiesels decrease NOx by 0.2% on average and that the emissions change in comparison to CARB diesel fuel is not statistically significant. The average and the test for statistical significance are both flawed by the failure to consider the varying effects that animal feedstocks have on Cetane Number (CN). The absence of CN as a variable in Staff's analysis leads Staff to wrongly conclude that animal biodiesels will not increase NOx below the B10 level.

- It is well established that increasing CN will reduce NOx emissions from diesel engines. Whether an animal biodiesel will increase NOx depends primarily on the extent to which the feedstock blending increases the CN of the blended fuel. Soy and animal biodiesel blends are not categorically different fuels once the differing effect of soy- and animal-feedstocks on CN is taken into account.

With respect to new technology diesel engines (NTDEs):

- Staff is incorrect in concluding that biodiesel use will not increase NOx in NTDEs. This conclusion is based on a highly selective reading of the technical literature (choosing one of four available studies) and relies on the one study in which the laboratory was not well equipped to measure the low levels of tailpipe NOx emissions from NTDEs.

- A fair reading of the technical literature indicates that B20 biodiesel will increase NOx emissions by about 20% in NTDEs. The four best studies estimate that B20 biodiesel

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

---

[2] McCormick 2002 tested a Fisher-Tropsch (FT) base fuel blended at the B1, B20, and B80 levels. Although the very high FT cetane number (≥75) takes it out of the range of commercial diesel fuels, the study nevertheless measured higher NOx emissions at the B1 level than it did on the FT base fuel.

increases NOx by 18-22% in NTDEs and that the increase is statistically significant. This is a greater percentage NOx increase in proportion to blend level than the increase caused by soy biodiesel in conventional diesel engines (1% at B5, 2% at B10 and ~4% at B20).

- The technical literature also indicates that one should expect NOx emissions to increase at blend levels below B20, with the size of the NOx increase being proportionate to blend level. At the B5 level, NOx emissions from NTDEs are expected to increase by about 5%.

- Staff makes no mention of the concern that use of biodiesel fuels in NTDEs may lead to the loss of NOx conversion efficiency in urea-SCR systems by shifting the NO_2/NOx ratio to lower values. Staff's proposal to allow B20 biodiesel to be used in NTDEs without mitigation potentially places at risk the investment in NOx after-treatment systems to meet the stringent NOx certification levels now in effect.

This analysis demonstrates that the proposed regulations will not "ensure that the use of biodiesel due to LCFS will not result in increases in NOx emissions in California." In fact, the regulations will result in increased NOx emissions in California from the following:

- B5 and lower soy biodiesels year round;
- B6 to B10 soy biodiesels in winter;
- At least some B10 and lower animal biodiesels year-round; and
- B20 and lower biodiesels of all types in NTDEs.

To our knowledge, ARB has not formulated a position on the level of NOx increase from alternative diesel fuel that is too small to warrant concern. A point of comparison for the NOx increases permitted by the proposed ADF regulations is the ARB program for Reformulated Gasoline (RFG). The RFG program permits alternative gasoline formulations to be sold in the California market provided they are demonstrated to be emissions equivalent to a reference gasoline using the Predictive Model for RFG. The emissions analysis differs somewhat for winter and summer gasoline, but in no instance may the alternative formulation increase emissions of the pollutants considered by more than 0.05%.

The biodiesel NOx emission increases permitted under the proposed ADF regulations dwarf the 0.05% threshold applied to RFG. Soy biodiesel will increase NOx by more than 0.05% at blend levels above 0.25% biodiesel (B0.25). Some animal biodiesels will increase NOx by 0.05% or more at blend levels twice as high (B0.5). The NOx emissions increase in NTDEs appears to be substantially greater on a percentage basis, so that biodiesels will exceed the 0.05% threshold at much lower blend levels.

In the ISOR, Staff uses the term "low saturation" to refer to soy and other feedstocks with CN < 56 and "high saturation" to refer to feedstocks, including animal sources, with CN ≥ 56. Classification based on saturation is useful because of its association with CN. By itself, however, it does not alleviate the concerns regarding NOx increases from unmitigated fuels.

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

The analysis presented here indicates that CN changes induced by biodiesel blending have a large influence on the size of the NOx increase that is observed. Soy (low saturation) biodiesels adversely affect CN leading to larger NOx increases; animal (high saturation) biodiesels increase CN leading to smaller NOx increases. In fact, soy and animal biodiesels are not categorically different fuels once their differing effect on blend CN is taken into account.

It is strongly recommended that ARB consider as part of the ADF rulemaking a regulatory structure in which the NOx impacts of soy and animal biodiesel are accounted for using a statistical model analogous to the Predictive Model for RFG. The analysis documented in this report provides a possible form for a biodiesel predictive model.

2. NOX EMISSIONS FROM CONVENTIONAL DIESEL ENGINES

2.1 ARB Analysis in Support of the Proposed Regulations

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

In support of the proposed regulations, ARB commissioned an analysis of the available NOx emissions data by David M. Rocke, PhD. The results of the analysis are reported in Appendix G: Supplemental Statistical Analysis[3] to the ISOR. The analysis used NOx emission measurements on ULSD, B5, and B10 fuels in conventional diesel engines from five studies. The dataset is substantially the same as that used by Rincon Ranch Consulting in the analysis presented later in this section.

The Rocke analysis formulated a series of statistical models involving log(NOx) as the dependent variable and used a statistical approach termed Mixed Effects modeling to estimate the coefficient values. The Mixed Effects approach has statistical advantages over more commonly used methods when dealing with unbalanced datasets, as is the case here. A number of different models were specified, estimated, and the results compared in order to ensure that conclusions drawn from the analysis do not depend upon the model specifications.

For soy-based biodiesel, the Rocke study concludes that soy fuels increase NOx by 1% at B5 and by 2% at B10. The study also demonstrated that the NOx increase is linearly related to the blend level. The slope was estimated to be 0.99% for each 5% biodiesel in a blend and was highly significant statistically ($p \ll 0.001$). These results agree with the Rincon Ranch analysis presented later in this report. <u>There is no controversy with regard to the NOx impact of soy-based biodiesel.</u> Soy biodiesel will increase NOx emissions at all blend levels by about 0.2% for each 1% biodiesel in the blend.

With respect to animal biodiesel, the Rocke study concludes that animal biodiesel does not increase NOx emissions at B5 or B10. The emission changes that are observed are not statistically significant. <u>There is controversy here because the Rocke analysis did not account for the effect of feedstock blending on the CN of the tested fuels</u>. The CN change compared to ULSD is a fixed effect that must be accounted for because the four animal feedstocks that have been used in the technical literature show substantially different cetane behavior in blending.

[3] http://www.arb.ca.gov/regact/2015/adf2015/adf15appg.pdf.

The case for cetane as an explanatory variable for NOx emissions in animal blends is made in Section 2.2.4 of this report. It is well established that increasing CN will reduce NOx emissions from diesel engines. For example, ARB has shown that the additive DTBP can be used to raise CN and mitigate NOx increases caused by biodiesel blending. Whether an animal biodiesel will increase NOx depends primarily on the extent to which the feedstock blending increases CN of the blended fuel. The two animal blends that showed the smallest CN gain over ULSD caused statistically significant NOx increases in the engines tested. The one animal blend that showed the largest CN gain was certified to be NOx neutral, while the animal blend with the next largest CN gain may or may not be NOx neutral. Cetane appears to blend linearly when using soy feedstocks, so that the CN gain over ULSD is highly correlated with blend level. The same is not true for animal feedstocks, where highly non-linear blending behavior has been observed.

The Rocke analysis used a Mixed Effects model to estimate the NOx emissions change at B5 and B10. For animal blends, it concluded that the observed emission changes are not statistically significant. Implicit in the approach is the assumption that the fuels being tested are different, individual realizations from a homogenous population. In this instance, the residual variation not accounted for by the blend level is a random effect representing the scatter in test results due to a variety of factors. The statistical significance of the blend level effect (a fixed effect) is judged in comparison to the residual variation. When the residual variation is large in comparison to the fixed effect, the latter is said to be not statistically significant.

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

The assumption of a homogenous population is appropriate for soy-based biodiesels. One soybean is much like the next, and the only appreciable differences among soy fuels will result from the methods of preparation. However, the assumption of homogeneity is not appropriate for animal-based biodiesels, which can be drawn from a variety of animal sources and prepared in different ways. The non-homogeneity is seen most readily in the greatly different cetane responses of biodiesel fuels:

- In the McCormick 2005 and Durbin 2011 studies, the animal feedstocks increased the CN of the biodiesel blends by small amounts. These fuels led to statistically significant increases in NOx.
- In the Durbin 2013A study, blending at the B5 level was sufficient to raise the CN of the blend by 8 numbers to reach the cetane level of the feedstock itself. This fuel was certified as NOx neutral at B5.
- The animal feedstock used in the Karavalakis 2014 study was intermediate in its CN effect and also intermediate in its NOx effect.

Because the ARB and Rocke studies have not included cetane as an explanatory variable for animal-based biodiesels, the residual variation term has been enlarged since a portion of it could be accounted for by including a fixed-effects term for cetane. With an enlarged estimate of the residual variance, the studies more easily find that the fixed effect of blend level is not statistically significant.

The absence of cetane as an explanatory variable also affects other methods of analysis used by Rocke. In a t-test comparison of emission differences between biodiesel and ULSD, Rocke finds two cases in which animal B5 changes NOx by statistically significant amounts (one increasing NOx and the other decreasing NOx) and one such case in animal B10 (decreasing NOx), while the other cases show no statistically significant change compared to the base fuel. The study wrongly concludes that these results demonstrate no or little systematic evidence for B5 or B10 animal to increase NOx emissions. In fact, these cases are systematically related to the CN gain of the animal blends in comparison to the base fuel.

The Rocke analysis was well planned and executed, and we concur with the conclusions drawn for soy-based blends. Because the analysis for animal-based blends is flawed by omission of a cetane variable, it should be revised to address CN gain. We expect that a revised analysis will shed further light on the circumstances in which animal-based biodiesels will and will not increase NOx emissions.

2.2 Rincon Ranch Analysis of ARB NOx Emissions Data

In July 2014, ARB released two datasets that represent the fruit of its efforts to compile the available biodiesel NOx emissions test data on conventional heavy-duty truck (HDT) engines. This report and the companion file *"Biodiesel Emissions Analysis Technical Summary 102014.pdf,"* which is attached to and incorporated in this report, present the results of a statistical analysis of the data sets released by ARB that was performed by Rincon Ranch Consulting at the request of Growth Energy.

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

The analysis presented below focused on whether soy and animal blends will increase NOx at low blend levels in conventional diesel engines. The following issues were examined:

- The NOx impacts of soy and animal blends at B5 and B10;
- The NOx emission differences observed among animal feedstocks and blends;
- For animal blends, the effect on NOx emissions of the CN change relative to base fuel that is caused by blending of the animal feedstock; and
- The development of a cetane-based model of the biodiesel NOx impacts of soy and animal blends.

2.2.1 Data Used in the Analysis

As noted above, in July 2014, ARB released two datasets of NOx emissions data from testing of biodiesel blends in HDT engines. One file ("B5 & B10 Raw NOx Data") contains the subset of testing for B5 and B10 blends (soy and animal). The test data generated in the four ARB-sponsored UCR studies are present in the form of the individual test run measurements. Because test run information was not reported in their publications, the B5 soy data from Nikanjam 2010 and the B10 soy data from Thompson 2010 are present in the form of emission averages. No animal blends have been tested at the B5 or B10 levels except in the ARB-sponsored emissions testing. A second file ("2014 Biodiesel Literature Search Database") contains all of the biodiesel testing available in the literature through the B20 level (soy and animal), including ARB-sponsored testing and the literature search. The data are in the form of emission averages by engine, test cycle, feedstock type, and blend level.

For purposes of this analysis, the following information was added to the ARB datasets:

- The number of test replications for emissions averages for each study (estimated when the source did not report the number);
- The CN for CARB diesel, the biodiesel blends, and the biodiesel feedstocks; and
- Additional NOx emissions testing at the B50 and B100 levels (where available).

Appendix Table A presents a list of the studies included in the dataset and the author references used in citations here.

2.2.2 NOx Emissions from Soy Biodiesel Blends

Most past research on biodiesel emissions has focused on soy blends. As a result, the literature is relatively large and diverse. The dataset assembled by ARB is derived from 10 different studies, covers 13 different vegetable feedstocks (10 soy, 2 used cooking oil [UCO], 1 canola), and was conducted using 7 different test cycles on a wide variety of engines in different labs. Most of the data, in terms of number of data points, are derived from the three UCR studies (Durbin 2011, Durbin 2013B, and Karavalakis 2014) sponsored by ARB.

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

We subjected the soy dataset to a number of different analyses using different statistical techniques and selections of the data to ensure that the conclusions we drew were robust. The statistical analyses included the t-test for the difference in mean values (e.g., between B5 and CARB diesel) and linear regression analysis using several different models. The data subsets were selected to use either individual test runs or emission averages and to contain testing through maximum blend levels of B5, B10, B20, B50, and B100.

Our analyses show that there is a consensus among the studies on the NOx impact of soy biodiesel without regard to the specific analytical methods or data used. Soy biodiesel increases NOx emissions by amounts that can be estimated with good statistical confidence because of the large size of the available dataset. The key conclusions are as follows:

- Soy biodiesel increases NOx emissions by ~1% at B5 and ~2% at B10;
- NOx emissions increase in a linear fashion with increasing blend level to reach ~4% at B20 and proportionately larger values at higher blend levels; and
- There is no evidence in the data for a threshold level below which soy biodiesel does not increase NOx.

These conclusions are supported by all of the available studies and data. None of the studies disagree substantially, and while the results for individual blends, engines, and test cycles will vary to some extent, the evidence across a wide range of engines and test cycles is clear. NOx increases can be expected for UCO, canola, and other vegetable biodiesels, but the data are very limited and it is not possible to draw definitive conclusions for these blends.

2.2.3 NOx Emissions from Animal Biodiesel Blends

The literature on NOx emissions from animal blends is much smaller—it consists of only four studies, three of which (Durbin 2011, Durbin 2013A, and Karavalakis 2014) were sponsored by ARB. Except for the McCormick 2005 study, the emissions testing was conducted at the UCR CE-CERT lab. A variety of test cycles were used, but most of the testing was conducted on the hot-start FTP cycle. Table 1 presents a summary of the emissions studies for animal biodiesel.

Table 1. Scope of Emissions Testing for Animal Biodiesel

	McCormick 2005	Durbin 2011	Durbin 2013A	Karavalakis 2014
Biodiesel Feedstock	Animal #1	Animal #2	Animal #3	Animal #4
Blend Levels Tested	B20	B5, B20, B50, B100	B5	B5, B10
Engines Tested	2 on-road	3 on-road, 1 off-road	1 on-road	1 on-road
Test Cycles	FTP	FTP, UDDS, 50 mph, ISO 8178	FTP	FTP, SET, UDDS
Test Replications on Biodiesel	6	126	26	80
Is NOx Increase Observed?				
At / Below B10	–	Yes	No	No
Above B10	Yes	Yes	–	–

It is important to understand the limitations of this small dataset. Without the ARB-sponsored testing, we would have only the six test replications (individual runs) conducted in the McCormick 2005 study. While the three UCR studies accumulated 232 test replications, the work involved only three different animal feedstocks. Including the McCormick 2005 study, the entire literature on NOx emissions from animal biodiesel is based on only four different animal feedstocks. The small number is an important limitation because animal feedstocks are much less homogenous than soy due the greater variety possible in animal sources and compositions. Further, there are notable differences among the four studies as to whether animal biodiesel increases NOx at the B5 and B10 levels (as indicated by the red circles in the table).

As in the soy analysis, we subjected the animal biodiesel data to a number of different analyses using different statistical techniques and selections of the data to ensure that the conclusions we drew were robust. The t-test is the most direct method to assess whether NOx emissions are higher at B5 compared to CARB diesel. Using the individual test run data available from the three UCR studies, we find the following for animal biodiesel at the B5 blend level:

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

- The animal feedstock used in Durbin 2011 increases NOx in 2 of 3 engines. The increase is highly significant[4] statistically for one engine.

- The animal feedstock used in Durbin 2013A decreases NOx in one engine. The decrease is statistically significant at the p=0.05 level, and the blend was certified as NOx neutral at B5.

- The animal feedstock used in Karavalakis 2014 increases NOx in three of six cases and decreases NOx in the other three cases. None of the changes are statistically significant. The blend may or may not change NOx.

Contrary to Staff's assertion that no NOx increase occurs in B5 animal blends, it is clear that some animal blends will significantly increase NOx emissions, while other animal blends will not. The fundamental issue is then understanding what the NOx impact of a particular animal biodiesel blend will be.

The effect of feedstock blending on the CN of the resulting animal blend is the reason for the apparently discordant results among the studies. Figure 1 plots the four series of animal blends used in the studies, with blend level on the horizontal axis and the change in blend CN (relative to CARB diesel) on the vertical axis. CN blended linearly to B20 for the McCormick feedstock, which showed a much smaller CN benefit than the feedstocks used by UCR—only three numbers at B20 (0.6 numbers at B5). In contrast, all three UCR animal blends achieve a large CN boost at low blending levels in which most or all of the CN benefit of the feedstock is achieved at B5.

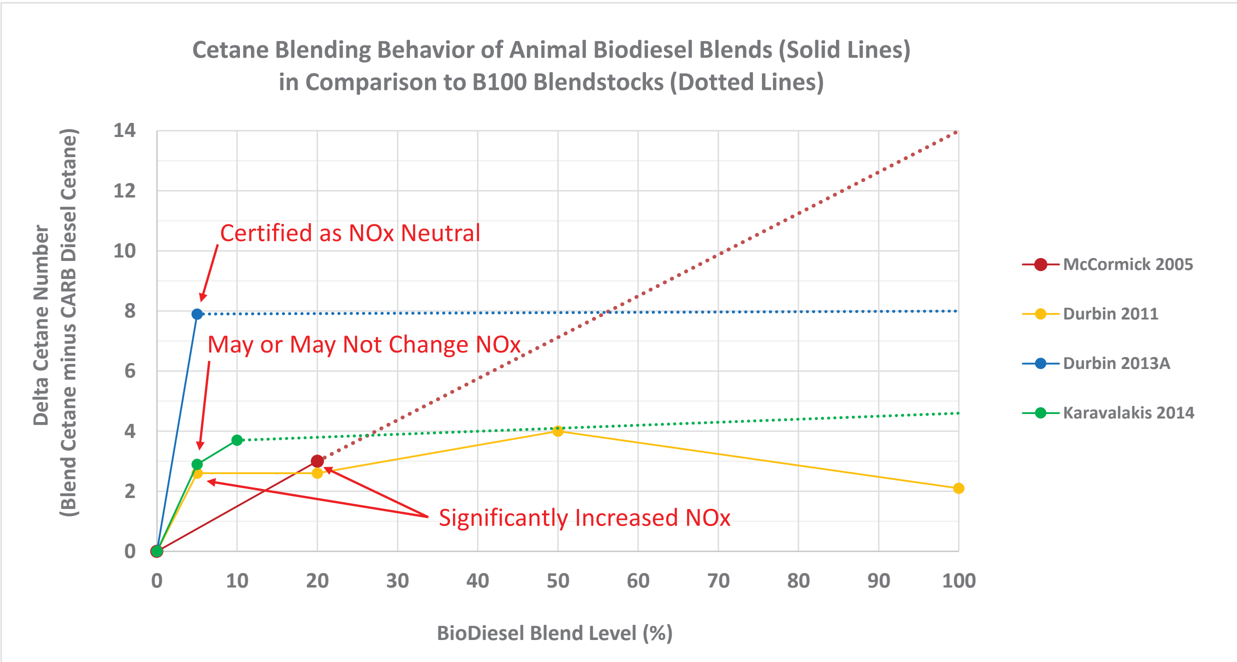
In Durbin 2011, the CNs for the blends are above that of the B100 feedstock. This result is probably caused by lab-to-lab differences (blend CN was determined at CE-CERT, while CN for CARB diesel and the B100 feedstock were determined by an outside lab). The actual CN changes are surely lower than shown here—at or below +2 CNs.

The two animal feedstocks that caused statistically significant NOx increases have the smallest CN benefits: McCormick 2005 (red) at B20 and Durbin 2011 (yellow) at B5. The animal B5 blend that passed certification testing as NOx neutral in Durbin 2013A (blue) has the highest CN benefit, where it achieved the entire B100 CN at just 5% blending. The Karavalakis 2014 B5 blend (green) had an intermediate CN benefit and may or may not change NOx.

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

[4] The term "significant" is used in this report only to refer to statistical significance. When a result reaches the p=0.05 level, we can be 95 percent confident that it is real. In such case, and at smaller p values, the result is said to be statistically significant.

Figure 1. Cetane Blending Behavior of Animal Blends (Solid Lines) Compared to B100 Feedstocks (Dotted Lines)



The blending behavior of the UCR blends is surprising in comparison to the McCormick study, and we find relatively little research on the CN blending behavior of animal feedstocks. All conclusions from this dataset will be influenced by the CN blending behavior of the specific animal feedstocks involved. For such conclusions to be reliable, we must be confident that the large CN boost reported for the UCR blends is both real and representative of all animal feedstocks in California. Also, only limited information is available on the sources and characteristics of the animal feedstocks.

To permit all parties to better understand the animal feedstocks that were tested, ARB should release all information that it has on the following:

- CNs (methods of determination and measured values) for the Durbin 2011 and other UCR studies;
- Physical and chemical properties of the animal feedstocks and biodiesel blends tested;
- The distribution of sources, characteristics, and properties in the population of animal feedstocks that are available for use in the California market; and
- How the specific animal feedstocks tested at UCR were selected, including any information that would demonstrate that the feedstock properties and their CN blending behavior are representative of the animal feedstock population available for use in California.

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

Staff's use of the terms low saturation (for soy) and high saturation (for animal) to classify biodiesel is useful to differentiate between feedstocks that will tend to decrease CN and those that will tend to increase it. However, it is not a sufficient step in that the CN change at each blend level is the determinative factor for NOx emissions, not the CN of the feedstock itself. Soy feedstocks appear to blend linearly with respect to cetane; however, animal feedstocks often lead to a highly non-linear CN response, as shown in Figure 1.

2.2.4 Development of a Cetane-based Model of NOx Impacts from Soy and Animal Biodiesel

The results presented above indicate the important role that CN plays in determining the NOx response for animal blends. Animal feedstocks tend to increase the CN of the blend above that of the CARB diesel and the CN change can be large at low blend levels. Soy feedstocks generally decrease the CN of the blend below that of the CARB diesel; for soy, the CN change at low blend levels can be smaller than the uncertainty in determining CN. The result of our work on a cetane-based model demonstrates that soy and animal blends are not categorically different fuels once their differing effect on CN is taken into accounted. Their NOx impacts can be represented by the same model as a function of blend level and the change in CN compared to CARB diesel.

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

The document that accompanies this report explains the development of the cetane-based model in some detail. In brief, it was developed using conventional linear regression analysis with log(NOx) emissions as the dependent variable. Intercept terms were included to represent the varying emission levels on CARB diesel for each combination of study, feedstock type, engine, and test cycle. A *b* coefficient was included to represent the change in NOx emissions for each one percent biodiesel in a blend at constant CN. A *c* coefficient was included to represent the change in NOx emissions for each one number change in CN compared to CARB diesel at constant blend level. Both soy and animal blends were included in the estimation, along with the small number of canola and UCO data points, at blend levels up to (and including) B20.

The model estimation shows that the *b* and *c* coefficients are highly significant statistically ($p < 0.0001$). The estimation results also show the following:

- The *b* coefficient has a value of +0.00156, which estimates that soy and animal biodiesel will increase NOx emissions by 0.16% for each one percent biodiesel at constant CN or by 0.8% at B5.
- The *c* coefficient estimates that +5 CNs will decrease NOx emissions by 1.5% at constant blend level. This result is completely consistent with earlier work[5] on the relationship between CN and NOx emissions in HDT engines, which also found that +5 CNs will decrease NOx emissions by 1.5% in base fuels with CN ~50.

[5] The Effect of Cetane Number Increase Due to Additives on NOx Emissions from Heavy-Duty Highway Engines. EPA420-R-03-002. February 2004. Figure IV.A-1.

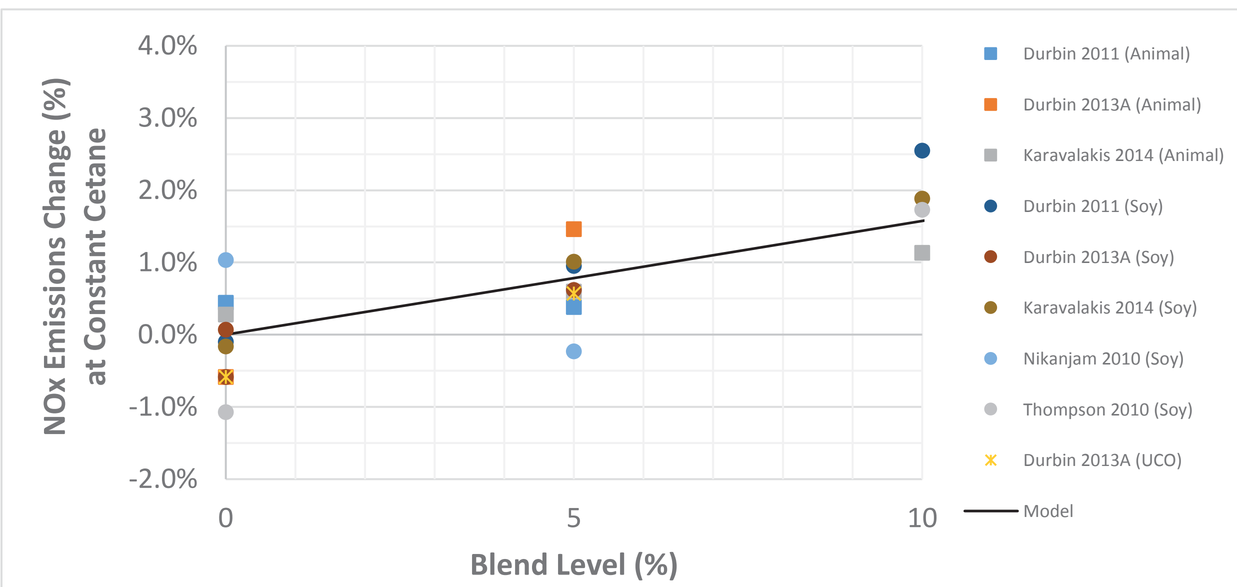
- An increase of -b/c = 0.5 CNs is needed to offset the NOx increase expected from each 1% biodiesel added. For B5, an increase of 2.5 CNs is required to offset the expected NOx increase.

The results explain why soy and animal blends appear to be different fuels. Soy blends have an additional, adverse CN effect that increases their NOx impact to ~1% at B5. Animal blends will generally increase CN and that reduces their NOx impact to about one-half the soy level or less, depending on the CN change caused by blending. The results also explain why some animal blends do not increase NOx emissions. If an animal feedstock increases CN by more than ~0.5 numbers for each 1% biodiesel blended, then the resulting fuel may not increase NOx emissions.

To demonstrate these conclusions, Figure 2 presents NOx emissions as a function of blend level for all fuels used to estimate the model once NOx emissions are adjusted for the CN change observed for each blend. For example, if an animal blend increased CN, then its NOx impact is <u>increased</u> as we return it to the base fuel CN. If a soy blend decreases CN, then its NOx impact is <u>decreased</u> as we return it to the base fuel CN. Once adjusted, percent changes in emissions are calculated. As seen in the figure, there is no discernable difference among feedstock types once CN changes are taken into account. Animal and soy blends scatter on both sides of the regression line, indicating that they obey the same blend level model.

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

Figure 2. There Are No Detectable Differences Among Feedstock Types Once NOx Emissions Are Adjusted to Constant CN



Note: Animal blends are plotted as squares, soy blends as circles, and the non-soy vegetable blends as asterisks.

Note the scatter of points around the regression line (which gives the "average" response). Some of the scatter is due simply to emissions measurement error; however, other factors may be involved in determining the NOx impact for a given feedstock, including differences in the

FAME (fatty acid methyl ester) composition and uncertainty in determining CN for the blends. If ARB were to adopt a predictive model to determine the CN improvement needed to mitigate NOx, it should use the model to evaluate a "worst case" feedstock, meaning a point near the upper end of the range at each blend level.

The most important conclusion of this work is that soy and animal biodiesel blends are not categorically different fuels. Their emissions effects are similar, but they show different NOx impacts because they have different effects on CN. Furthermore, this work provides a potential answer to the problem that some animal blends will significantly increase NOx emissions, while other blends will not, by indicating what individual blends may do.

3. NOX EMISSIONS IN NEW TECHNOLOGY DIESEL ENGINES

Staff's position is that biodiesel will not increase NOx emissions in NTDEs at levels up to and including B20. Its assessment is stated in the ISOR as follows:

> *Engines that meet the latest emission standards through the use of Selective Catalytic Reduction (SCR) have been shown to have no significant difference in NOx emissions based on the fuel used. A study conducted by the NREL looked at two Cummins ISL engines that were equipped with SCR, and found that NOx emissions control eliminates fuel effects on NOx, even for B100 and even in fuels compared against a CARB diesel baseline.*[20] *However, a recent study at UC Riverside tested B50 blends and found a NOx increase with a 2010 Cummins ISX.*[21] *The UC Riverside study did not look at blends below B50. Staff proposes to take a precautionary approach and in the light of data showing there may be a NOx impact at higher biodiesel blends but not at lower biodiesel blends, Staff is limiting the conclusion of no detrimental NOx impacts in NTDEs to blends of B20 and below. Additional studies on NTDEs have been completed, however since they included either retrofit engines or non-commercial engines Staff did not include their results in this analysis*.[22,23,24] (Page 24)

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

Staff's reliance on Lammert 2012 (Ref. 20) is misplaced because the NREL lab was not equipped to measure the low NOx emission levels of the test vehicles, as the abstract of the Lammert paper clearly notes.[6] In fact, none of the emission changes observed in the study (with one exception) were statistically significant due to the high standard errors that necessarily exist when measurements are made close to the level of detection. In this instance, the failure to observe statistically significant NOx emissions increases from biodiesel at the B20 level is not a demonstration that such increases do not exist.

This specific shortcoming of the Lammert study is why its negative results are in conflict with the finding of the UC Riverside study (Gysel 2014) cited by Staff and the three other studies (Walkowicz 2009, McWilliam 2010, Mizushima 2010) that Staff dismissed. With respect to the

[6] "SCR systems proved effective at reducing NOx to near the detection limit on all duty cycles and fuels, including B100." Lammert 2012, Abstract.

three other studies, we see no reason why they should be dismissed. It is not the case that factory-designed NOx after-treatment systems will reduce NOx levels to below the detection limit of well-equipped labs (see Gysel 2014 and engine certification testing). Testing conducted using retrofit NOx after-treatment systems that achieve representative levels of NOx control, as in these studies, is entirely suitable for determining whether biodiesel increases tailpipe NOx emissions on a percentage basis. Having a different absolute level of emissions does not preclude reliable measurement of a percentage change.

When all available studies are included, a consensus of the literature is that biodiesel at the B20 level will increase NOx emissions from NTDEs in most, if not all cases. Lammert 2012 is the one study at odds with the rest of the literature. A range of biodiesel types were used in the studies. NOx increases should be expected at the B20 level for all biodiesel types until such time as additional research indicates differential impacts for biodiesels derived from different sources

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

3.1 Review of the NTDE Literature

The following sections briefly summarize the NTDE testing conducted in the studies and the conclusions drawn on the NOx emissions impact of biodiesel fuels. Testing of conventional diesel engines without NOx after-treatment is not considered, nor is testing on non-California fuels (low aromatics ULSD was considered equivalent to CARB ULSD). Appendix Table B presents a list of the studies included in the NTDE dataset and the author references used in citations here.

Walkowicz 2009. Chassis dynamometer testing was conducted using a 2005 International 9200i tractor equipped with and without a retrofit diesel oxidation catalyst (DOC) and urea-SCR NOx after-treatment system. On-road emissions measurements also were made using a RAVEM portable emissions measurement system. A ULSD base fuel was tested, as were B20 and B99 biodiesel blends. The type of biodiesel (soy or animal) was not specified, but was mostly likely soy-based as this is the feedstock most common in the market and in engine research.

- Under loaded, on-road conditions, biodiesel increased NOx by 17% at B20 and by about 40% at B99. At B20, the increase was marginally significant ($p=0.10$); at B99, the increase was statistically significant ($p=0.05$).
- Chassis dyno testing was done 24 months later at an ARB lab. The vehicle was determined to have high oil consumption, and lubricating oil was likely present in the exhaust stream. On the UDDS cycle, biodiesel increased NOx by 7% at B20 (marginally significant at $p=0.07$) and by 35% at B99 (highly significant, $p<0.01$).

The authors concluded "The use of biodiesel did result in higher NOx emissions than the use of ULSD (in tests with statistical significance)." The B20 test results did not reach the usual $p=0.05$ level for statistical significance, but were marginally significant ($0.05 < p \leq 0.10$).

McWilliam 2010. A Caterpillar 6.61 engine equipped with DOC and urea-SCR NOx after-treatment was tested using the European non-road transient cycle (NRTC). The fuels used were ULSD plus B20 and B100 biodiesels blended from a rapeseed methyl ester. Figure 9 of the paper shows tailpipe NOx emissions of the vehicle in g/kWh units. Reading from the graph because numerical emission values were not given, tailpipe NOx emissions increase ~15% at B20 and ~150% at B100. Based on the narrow error bars shown in the figure, both of these increases are statistically significant.

This study was conducted by Caterpillar because previous work had highlighted the potential for biodiesel to have an adverse impact on the NOx conversion efficiency of urea-SCR after-treatment systems. Thus, reductions in conversion efficiency have the potential to increase NOx emissions by amounts that exceed that caused by the biodiesel itself. At B20, only a 1% loss of conversion efficiency was noted, but a substantial 6% loss was observed at B100.

The authors of this paper concluded "Additional control strategies will be necessary to correct for NOx increases during biodiesel operation on installations requiring compliance regardless of fuel used."

Mizushima 2010. An inline 4-cylinder diesel engine equipped with DOC, diesel particulate trap (DPT), and urea-SCR NOx after-treatment system was tested using the JE-05 exhaust emissions test cycle used for heavy-duty vehicles in Japan. The fuels used were ULSD plus B20 and B100 blended from waste vegetable oil (WVO). Figure 4 of the paper shows tailpipe NOx emissions of the engine in g/kWh units. NOx emissions are highly linear with biodiesel blending level. Reading from the graph because numerical emission values were not given, tailpipe emissions increase ~20% at B20 and ~100% at B100. The paper does not address the statistical significance of these results.

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

With respect to NOx conversion efficiency, the study noted a drop from 76% on ULSD to 47% at B100, with a smaller but still measurable drop at B20. The impact on NOx conversion efficiency was linked to the effect of biodiesel in lowering the overall NO_2/NOx ratio at the SCR inlet leading to reduced conversion efficiency.

The authors drew no conclusions regarding the NOx emissions effects of B20 biodiesel as the focus of their research was on the B100 fuel.

Lammert 2012. The NREL study examined NOx emissions from transit buses on both EPA and CARB diesel fuels, B20 soy blends of each, and B100 soy. Chassis dynamometer testing was conducted using the Manhattan Bus (MAN), Orange County Transit Authority (OCTA) and UDDS test cycles. Two of the buses were NTDEs, including a 2010 Cummins ISL and 2011 Gillig/Cummins ISL. Only the 2010 Cummins was tested using the CARB ULSD base fuel and the biodiesel fuels.

NOx emission results for the 2010 Cummins bus are shown in Figure 10 of the paper. For B20, NOx emissions decreased compared to CARB ULSD on all three cycles (MAN, OCTA, and UDDS), and for B100 on the MAN cycle (OCTA and UDDS were not tested). None of the differences were statistically significant except for B20 on the UDDS cycle, and the standard errors plotted in the figure are large in comparison to the emission averages.

The authors explain the non-significance of their results as follows:

> *For much of the cycle NOx would be at or near the detection limit of the laboratory equipment, which resulted in a 95% confidence interval error that was high relative to the value of the cycle emissions.* (Page 6)

One of the authors' conclusions is that SCR NOx after-treatment appears to nearly negate the effect of fuels on NOx emissions. Another conclusion is that SCR NOx after-treatment also negates any duty cycle effect on NOx. (Page 8) For buses without NOx after-treatment, NOx emissions are strongly related to the kinetic intensity (load) of the test cycle. This result is consistent with all past vehicle and engine research studies, which show that NOx emissions are increased when a diesel engine is operated under increased load. However, no such relationship is observed for SCR-equipped buses. Increased load will increase engine-out NOx levels in an SCR-equipped bus. Unless this is accompanied by an increase in NOx conversion efficiency, tailpipe NOx emissions should also increase. Neither conclusion is reliable because of the study's problems in measuring NOx emissions even on ULSD fuel.

Gysel 2014. A 2010 Cummins ISX-15 equipped with DOC, DPF and urea-SCR NOx after-treatment was tested on CARB ULSD and B50 biodiesel blended from soy, waste cooking oil (WCO) and animal fat feedstocks. Chassis dynamometer testing was performed at CE-CERT using the UDDS test cycle.

Figure 7 of the paper shows the NOx emissions measured on ULSD and the three B50 biodiesel blends. The soy and WCO B50 blends increased NOx by 43% and 101%, respectively, with both increases being highly statistically significant ($p<0.01$). The animal B50 blend increased NOx by 47%, which was marginally significant ($p=0.065$). The authors' conclude that "Overall, NOx emissions exhibited increases with biodiesel for both vehicles with the differences in NOx emissions relative to CARB ULSD being statistically significant for the new Cummins ISX-15 engine." (Page 6)

The authors note the negative results reported by Lammert 2012 as being in contrast to those of their study, "which shows that there is a relatively strong fuel effect with the B50 blends compared to CARB ULSD from the Cummins ISX-15 engine with SCR." (Page 6). They also note the following:

> *The NOx increase with biodiesel for SCR-equipped engines is usually attributed by a reduction of exhaust temperature and the change of NO_2/NO ratio in NOx emissions [38]. In general, the lower exhaust temperatures with biodiesel will lower the oxidation rates of NO to NO_2 from the DOC. It has been shown that a NO_2/NOx ratio below 0.5 significantly changes SCR reaction chemistry lowering the SCR removal efficiency of NOx [39]. Walkowicz et al. [40] found increases in NOx emissions of 7% with B20 and 26% with B99 compared to ULSD for a heavy-duty diesel vehicle equipped with a 2004 Caterpillar 400 hp C13 engine. For the same vehicle equipped with a urea-based SCR system, NOx increases were very similar on a percentage basis, with B20 and B99 having 7% and 27%, respectively, higher NOx than ULSD.* (Page 6)

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

The authors continue to say:

> *The trend of increasing NOx emissions for biodiesel blends is consistent with a wide range of studies found in the literature. Comprehensive investigations conducted by Mueller et al. [41] and Sun et al. [42] confirmed that biodiesel promotes a combustion process that is shorter and more advanced than conventional diesel, which contributes to the formation of thermal NOx. The higher NOx emissions with biodiesel for both vehicles could also be a consequence of the higher oxygen content in biodiesel, which enhances the formation of NOx. The lower volatility of biodiesel compared to diesel fuel could also contribute to decreased fractions of premixed burn, as a result of fewer evaporated droplets during the ignition delay period [43]. Another contributing factor for NOx emissions increase could be the engine control module (ECM), which may dictate a different injection strategy based on the lower volumetric energy content of biodiesel. Eckerle et al. [44] suggested that a higher fuel flow is required with biodiesel compared to diesel fuel for an engine to achieve the same power. The ECM interprets this higher fuel flow as an indicator of higher torque, and therefore makes adjustments to engine operating parameters that, under certain operating conditions, increase NOx emissions.* (Page 6).

The engineering mechanisms described by the authors indicate that <u>biodiesel should be expected to increase NOx emissions in NTDEs at blend levels below the B50 examined in the study</u>. There is no basis in these mechanisms to believe that biodiesel <u>will not</u> increase NOx emissions at B20 but <u>will</u> increase NOx emissions at B50.

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

3.2 Consensus on Biodiesel NOx Impacts

Table 2 presents a summary of the available literature on the NOx emissions impact of biodiesel at the B20 blend level. Four of the five studies tested B20 fuels on NTDEs. Staff choose to rely on the one study in which NOx emissions were at or near the detection limit of the laboratory equipment for much of the test cycle on each fuel and to dismiss the other three studies "… since they included either retrofit engines or non-commercial engines …". The study that was retained did not observe a NOx increase because it had trouble measuring NOx emissions from the NTDE tested. The studies that were dismissed showed consistent NOx emission increases in the range of 10-20% at B20.

Staff notes the Gysel study, which found significantly increased NOx emissions at B50 compared to CARB ULSD, as its reason for setting the biodiesel control level at B20 for NTDEs. However, Staff did not note the study's discussion indicating that the Lammert results were in contrast to their results and to the results of other studies in the literature. Nor did Staff note the discussion of mechanisms by which biodiesel is believed to increase NOx emissions in NTDEs. These mechanisms include a reduction of the NO_2/NOx ratio that leads to loss of NOx conversion efficiency in urea-SCR systems, promotion of a combustion process that contributes to increased formation of thermal NOx, higher NOx emissions due to the oxygen content of biodiesel, and the lower volatility and lower volumetric energy content of biodiesel. <u>These mechanisms indicate that biodiesel can be expected to increase NOx emissions in NTDEs at blend levels below the B50 examined in the study</u>.

Table 2. Summary of NTDE Literature on NOx Emissions Impact of B20

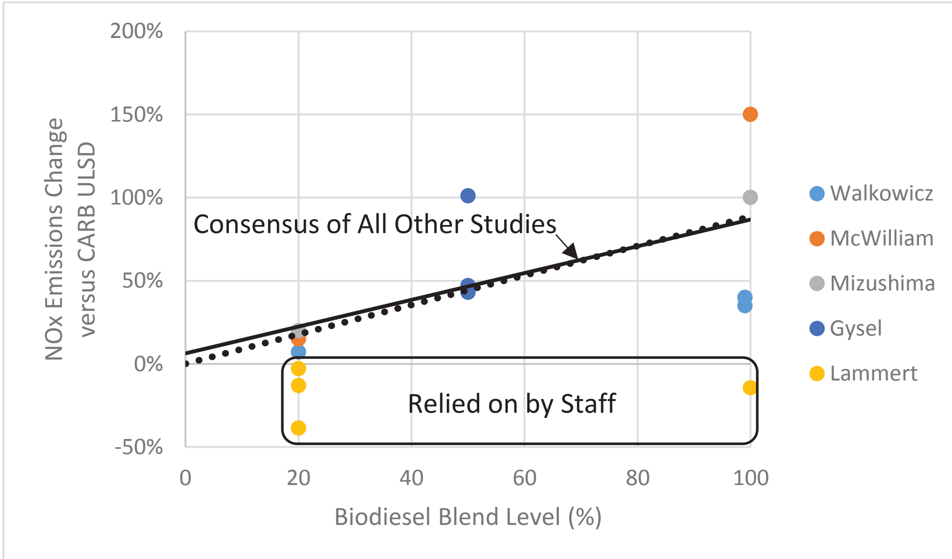
	B20 NOx Emissions Change (%) versus CARB ULSD	Comments
Studies Relied on by Staff		
Lammert 2012	NOx emissions decrease on three cycles	UDDS cycle decrease is statistically significant. NOx emissions on all fuels were at or near the detection limit of the laboratory equipment.
Gysel 2014	B20 not tested	The paper discusses how biodiesel effects NOx emissions. These mechanisms suggest that biodiesel <u>should</u> increase NOx emissions at levels below B50.
Studies Dismissed by Staff		
Walkowicz 2009	+17% on-road + 7% chassis dyno	Both results are marginally significant ($0.10 \leq p < 0.05$)
McWilliam 2010	~15% increase	European transient cycle
Mizushima 2010	~20% increase	Japanese heavy-duty test cycle

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

Figure 3 summarizes the impact of biodiesel on NTDE NOx emissions at all blend levels. The four studies (excluding Lammert 2012) establish a linear relationship between NOx emissions and blend level. The first trend line (solid black) passes very nearly through the origin without being constrained to do so. The second trend line (dotted black) is constrained to pass through the origin. While there is substantial scatter around the trend lines, the consensus of the four studies is that biodiesel increases NOx by 18-22% at B20, by 45-50% at B50, and by 90-100% at B100.

In spite of this consensus, Staff chose to rely only on the Lammert 2012 study, which shows that biodiesel <u>decreases</u> NOx emissions at both the B20 and B100 blend levels. This is the study that had difficulty measuring NOx emissions because NOx was at or near the detection limit of the laboratory equipment for much of the test cycle on all fuels.

Figure 3. The Impact of Biodiesel on NTDE NOx Emissions



To test the statistical significance of the trend lines shown in the figure, conventional regression analysis was conducted using the data reported by four of the studies (Lammert 2012 excluded) as summarized in Table 3. Regression A corresponds to the figure's solid trend line and is not constrained to pass through the origin. Its slope is +0.80% increase per 1% biodiesel in the blend; it is statistically significant at the $p=0.035$ level. Regression B corresponds to the dotted trend line and is constrained to pass through the origin. Its slope is +0.89% increase per 1% biodiesel, and it is statistically significant at the $p<0.001$ level. The two regression models predict a 22% and 18% increase, respectively, in NOx emissions at B20 in NTDEs.

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

Table 3. Statistical Significance of Biodiesel NOx Effect in NTDEs

	Intercept	Significance	Slope (% NOx Increase per 1% biodiesel)	Significance	Predicted NOx Increase at B20
Regression A	6.4	p = 0.80	+0.80% (±0.32%)	p = 0.035	22%
Regression B	None	n/a	+0.89% (±0.16%)	p <0.001	18%

A fair reading of the technical literature would lead Staff to expect that biodiesel will increase NOx emissions in NTDEs by about 20% at B20 and by proportionately smaller amounts at blend levels below B20. At the B5 level, the impact is expected to be an increase in NOx emissions of about 5%. At the B20 level, the NOx increase appears to be greater on a percentage basis than would be expected in conventional diesel engines (1% at B5, 2% at B10, and ~4% at B20). The loss of NOx conversion efficiency when biodiesel fuels are used is one likely reason for the greater impact.

4. SUMMARY AND CONCLUSIONS

The key conclusions of this study are summarized below with respect to conventional diesel engines and new technology diesel engines.

Conventional Diesel Engines

- Soy and animal blends are not categorically different fuels once their differing effect on blend CN is taken into account.
- There is no evidence in the data of a threshold level below which biodiesel fuels as a group do not increase NOx, whether soy or animal. As shown here, the magnitude of the NOx impact observed depends on both the blend level and the change in CN that results from blending of the biodiesel feedstock.
- Soy blends clearly and significantly increase NOx by ~1% at B5 and by ~2% at B10. The effect is continuous and linear with respect to the blend level at all levels above ULSD. Soy blends require mitigation at all levels to offset increased NOx emissions.
- Staff's proposal requires NOx mitigation in summer months for soy fuels at blend levels greater than B5. Because soy fuels increase NOx at all blend levels, mitigation should be required for B5 and lower blends to prevent increased NOx emissions.
- Animal blends are more complicated. The current research is limited, and the evidence is mixed. At least one B5 animal blend significantly increased NOx, while another has been certified as NOx neutral. Other B5 animal blends may or may not increase NOx depending on their CN effect (and possibly other factors).
- Staff's assertion that no NOx increase occurs at B5 in animal blends is incorrect: some animal blends will significantly increase NOx emissions, while other animal blends will not.
- Animal blends cannot be assumed to have no impact on NOx emissions without a demonstration that feedstock blending raises CN enough to offset potential NOx increases.

New Technology Diesel Engines

- Staff is incorrect in concluding that biodiesels will not increase NOx in NTDEs. The Staff conclusion is based on a highly selective reading of the technical literature that relies on the one study in which the laboratory was not well equipped to measure the low levels of tailpipe NOx emissions from NTDEs.

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

- There is greater reason to exclude the study Staff relied on than the three studies that Staff excluded. If that is done, there are no test data at the B20 level or below in NTDEs and no basis whatsoever to permit biodiesel fuels in NTDEs in California.

- While the available data are limited, the four best studies (excluding Lammert 2012) support the conclusion that biodiesel increases NOx by 18-22% at B20 and that the increase is statistically significant. Staff has no basis to claim that no NOx impacts are associated with biodiesel at the B20 level and below in NTDEs.

- A fair reading of the technical literature would lead Staff to expect that biodiesel will increase NOx emissions by about 20% at B20 and by proportionately smaller amounts at lower blend levels. This is a greater percentage NOx increase in proportion to blend level than the increase caused by soy biodiesel in conventional diesel engines (1% at B5, 2% at B10, and ~4% at B20).

- Staff makes no mention of the concern that the use of biodiesel fuels may lead to the loss of NOx conversion efficiency in urea-SCR after-treatment systems by shifting the NO_2/NOx ratio to lower values. Conversion losses were observed at B20 in two of the studies.

Based on the results summarized above, it is strongly recommended that ARB consider as part of the ADF rulemaking a regulatory structure in which the NOx impacts of soy and animal biodiesel are accounted for using a statistical model analogous to the Predictive Model for RFG. We see the cetane-based model presented here as a possible draft for a biodiesel predictive model, but substantial additional work is needed to:

- Demonstrate that blends mitigated using DTBP obey the same model; and

- Further assess the impacts of biodiesel produced from animal feedstocks on both CN gain in blends as well as NOx emissions.

Further, more advanced statistical techniques should be used as was done in developing the Predictive Model for California Reformulated gasoline. The dataset used here is unbalanced, meaning that there are varying numbers of data points for each combination of study, feedstock type, engine, and test cycle. In fact, only a fraction of all possible study/feedstock/engine/test cycle cells are represented by one or more data points. Mixed Effects modeling is appropriate in such cases and its use will assure that coefficient estimates are not biased by the unbalanced distribution of the data.

###

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

APPENDIX TABLE A: REFERENCES TO LITERATURE ON CONVENTIONAL DIESEL ENGINES

Author	Title	Feedstocks Studied	Blends Studied
Clark 1999	Transient Emissions Comparisons of Alternative Compression Ignition Fuel	Soy	B20
McCormick 2002	Fuel Additive and Blending Approaches to Reducing NOx Emissions from Biodiesel	Soy, UCO	B20
McCormick 2005	Regulated Emissions from Biodiesel Tested in Heavy-Duty Engines Meeting 2004 Emissions	Soy, Canola, Animal	B20
Eckerle 2008	Effects of Methyl Ester Biodiesel Blends on NOx Emissions	Soy	B20
Nuszkowski 2009	Evaluation of the NOx emissions from heavy duty diesel engines with the addition of cetane improvers.	Soy	B20
Nikanjam 2010	Performance and emissions of diesel and alternative diesel fuels	Soy	B5, B20
Thompson 2010	Neat fuel influence on biodiesel blend emissions	Soy	B10, B20
Durbin 2011	Biodiesel Characterization and NOx Mitigation Study	Soy, Animal	B5, B10, B20
Durbin 2013A	CARB B5 Preliminary and Certification Testing	Animal	B5
Durbin 2013B	CARB B20 Biodiesel Preliminary and Certification Testing	Soy, UCO	B20
Karavalakis 2014	CARB Comprehensive B5/B10 Biodiesel Blends Heavy-Duty Engine Dynamometer Testing	Soy, Animal	B5, B10

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

APPENDIX TABLE B: REFERENCES TO LITERATURE ON NEW TECHNOLOGY DIESEL ENGINES

Author	Title	Feedstocks Studied	Blends Studied
Walkowicz 2009	On-road and In-Laboratory Testing to Demonstrate Effects of ULSD, B20 and B99 on a Retrofit Urea-SCR Aftertreatment System	Soy?	B20, B99
McWilliam 2010	Emissions and Performance Implications of Biodiesel Use in an SCR-equipped Caterpillar C6.6	Rapeseed	B20, B100
Mizushima 2010	Effect of Biodiesel on NOx Reduction Performance of Urea-SCR System	WVO	B20, B100
Lammert 2012	Effect of B20 and Low Aromatic Diesel on Transit Bus NOx Emissions Over Driving Cycles with a Range of Kinetic Intensity	Soy	B20, B100
Gysel 2014	Emissions and Redox Activity of Biodiesel Blends Obtained from Different Feedstocks from a Heavy-Duty Vehicle Equipped with DPF/SCR Aftertreatment and a Heavy-Duty Vehicle without Control Aftertreatment	Soy, WCO, animal	B50

Reproduction of Pages 531 -558 of Comment Letter 12_B_LCFS_GE/3_B_ADF_GE Consisting of Comments ADF B3-153 through ADF B3-197

3593

This page intentionally left blank.

8_SF_LCFS_GE (Page 224 - 250)

1213. Comment: **NOx Emission Impacts Of Biodiesel Blends**

Agency Response: This is the second time this document was submitted. It is a reproduction of comments **ADF B3-153** through **ADF B3-197**. The comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

This page intentionally left blank.

Attachment 5

NOx Emissions Impact of Soy- and Animal-based Biodiesel Fuels: A Re-Analysis

December 10, 2013

Prepared for:

Sierra Research
1801 J Street
Sacramento, CA 95811

Prepared by:

Robert Crawford
Rincon Ranch Consulting
2853 South Quail Trail
Tucson, AZ 85730-5627
Tel 520-546-1490

NOX EMISSIONS IMPACT OF SOY- AND ANIMAL-BASED BIODIESEL FUELS: A RE-ANALYSIS

prepared for:

Sierra Research, Inc.

December 10, 2013

prepared by:

Robert Crawford
Rincon Ranch Consulting
2853 South Quail Trail
Tucson, AZ 85730-5627
Tel 520-546-1490

NOX IMPACT OF SOY- AND ANIMAL-BASED BIODIESEL FUELS: A RE-ANALYSIS

Table of Contents

Page

List of Tables

Table | Page

List of Figures

1.ĀEXECUTIVE SUMMARY

1.1ĀBackground on the Proposed Rule

The California Air Resources Board (CARB) has proposed regulations on the commercialization of alternative diesel fuel (ADF) that were to be heard at the December 2013 meeting of the Board. The proposed regulations seek to "… create a streamlined legal framework that protects California's residents and environment while allowing innovative ADFs to enter the commercial market as efficiently is possible."[1] In this context ADF refers to biodiesel fuel blends. Biodiesel fuels are generally recognized to have the potential to decrease emissions of several pollutants, including hydrocarbons (HC), carbon monoxide (CO), and particulate matter (PM), but are also recognized to have the potential to increase oxides of nitrogen (NOx) unless mitigated in some way. NOx emissions are an important precursor to smog and have historically been subject to stringent emission standards and mitigation programs to prevent growth in emissions over time. A crucial issue with respect to biodiesel is how to "… safeguard against potential increases in oxides of nitrogen (NOx) emissions."[2]

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

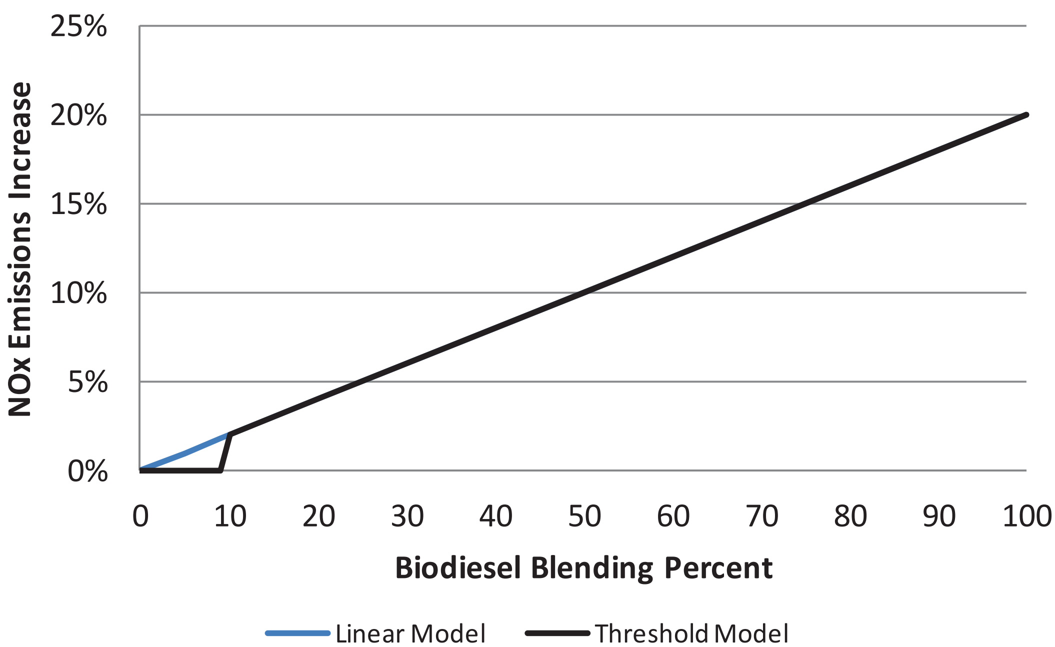
The proposed regulations are presented in the Staff Report: Initial Statement of Reasons (ISOR) for the Proposed Regulation on the Commercialization of New Alternative Diesel Fuels[3] (referenced as ISOR). Chapter 5 of the document describes the proposed regulations, which exempt diesel blends with less than 10 percent biodiesel (B10) from requirements to mitigate NOx emissions:

> *There are two distinct blend levels relative to biodiesel that have been identified as important for this analysis. Based on our analysis to date, we have found that diesel blends with less than 10 percent biodiesel by volume (<B10) have no significant increase in any of the pollutants of concern and therefore will be regulated at Stage 3B (Commercial Sales not Subject to Mitigation). However, we have found that biodiesel blends of 10 percent and above (≥B10) have potentially significant increases in NOx emissions, in the absence of any mitigating factors, and therefore those higher blend levels will be regulated under Stage 3A (Commercial Sales Subject to Mitigation).*[4]

[1] "Notice of Public Hearing to Consider Proposed Regulation on the Commercialization of New Alternative Diesel Fuels." California Air Resources Board, p. 3. *http://www.arb.ca.gov/regact/2013/adf2013/adf2013notice.pdf*.
[2] Ibid. p. 3.
[3] "Proposed Regulation on the Commercialization of New Alternative Diesel Fuels. Staff Report: Initial Statement of Reason." California Air Resources Board, Stationary Source Division, Alternative Fuels Branch. October 23, 2013. *http://www.arb.ca.gov/regact/2013/adf2013/adf2013isor.pdf*.
[4] Ibid, p. 22.

Existing research on the NOx emission effects of biodiesel has consistently been conducted under the hypothesis that the emission effect will be linearly proportional to the blending percent of neat biodiesel (B100) with the base diesel fuel. The Linear Model that has been accepted by researchers is shown as the blue line in Figure 1-1. The Staff position cited above is that biodiesel fuels do not increase NOx emissions until the fuel blend reaches 10% biodiesel. This so-called Staff Threshold Model departs from the Linear Model that underlies past and current biodiesel research by claiming that NOx emissions do not increase until the biodiesel content reaches 10 percent.

Figure 1-1
Linear and Staff Threshold Models for Biodiesel NOx Impacts



The Staff Threshold model is justified by the statement: "*Based on our analysis to date, we have found that diesel blends with less than 10 percent biodiesel by volume (<B10) have no significant increase in any of the pollutants of concern.*" Other portions of the ISOR state that Staff will track "… the effective blend level on an annual statewide average basis until the effective blend level reaches 9.5 percent. At that point, the biodiesel producers, importers, blenders, and other suppliers are put on notice that the effective blend-level trigger of 9.5 percent is approaching and mitigation measures will be required once the trigger is reached."[5] Until such time, NOx emission increases from biodiesel blends below B10 will not require mitigation.

Section 6 of the ISOR presents a Technology Assessment that includes a literature search the Staff conducted to obtain past studies on the NOx impact of biodiesel in heavy-duty

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

[5] Ibid, p. 24.

engines using California diesel (or other high-cetane diesel) as a base fuel. Section 6.d presents the results of the literature search with additional technical information provided in Appendix B. The past studies include the Biodiesel Characterization and NOx Mitigation Study[6] sponsored by CARB (referenced as Durbin 2011).

The results of the Staff literature search are summarized in Table 1-1, which has been reproduced from Table 6.1 of the ISOR. For B5 and B20, the data represent averages for a mix of soy- and animal-based biodiesels, which tend to have different impacts on NOx emissions (animal-based biodiesels increase NOx to a lesser extent). For B10, the data represent an average for soy-based biodiesels only. Staff uses the +0.3% average NOx increase at B5 in comparison to the 1.3% standard deviation to conclude:

> *Overall, the testing indicates different NOx impacts at different biodiesel percentages. Staff analysis shows there is a wide statistical variance in NOx emissions at biodiesel levels of B5, providing no demonstrable NOx emissions impact at this level and below. At biodiesel levels of B10 and above, multiple studies demonstrate statistically significant NOx increases, without additional mitigation.*[7]

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Table 1-1
Results of Literature Search Analysis

Biodiesel Blend Level	NOx Difference	Standard Deviation
B5	0.3%	1.3%
B10[a]	2.7%	0.2%
B20	3.2%	2.3%

Source: Table 6.1 of Durbin 2011
Notes:
[a] Represents data using biodiesel from soy feedstocks.

<u>The Staff conclusion is erroneous because it relies upon an apples-to-oranges comparison among the blending levels</u>. Each of the B5, B10, and B20 levels include data from a different mix of studies, involving different fuels (soy- and/or animal-based), different test engines, and different test cycles. The B5 values come solely from the CARB Biodiesel Characterization study, while the B10 values come solely from other studies. The B20 values are a mix of data from the CARB and other studies. The results seen in the table above are the product of the uncontrolled aggregation of different studies that produces incomparable estimates of the NOx emission impact at the three blending levels.

[6] "CARB Assessment of the Emissions from the Use of Biodiesel as a Motor Vehicle Fuel in California: Biodiesel Characterization and NOx Mitigation Study." Prepared by Thomas D. Durbin, J. Wayne Miller and others. Prepared for Robert Okamoto and Alexander Mitchell, California Air Resources Board. October 2011.
[7] ISOR, p. 32.

As will be demonstrated in this report, the Staff conclusion drawn from the data in Table 1-1 is not supported by past or current biodiesel research, including the recent testing program sponsored by CARB. In fact, past and current studies indicate that biodiesel blends at any level will increase NOx emissions in proportion to the blending percent unless specifically mitigated by additives or other measures.

1.2 Summary and Conclusions

The following sections of this report examine the studies cited by CARB one-by-one. As evidenced from this review, it is clear that the data do not support the Staff conclusion and, indeed, the data refute the Staff conclusion in some instances. Specifically:

- There is no evidence supporting the Staff conclusion that NOx emissions do not increase until the B10 level is reached. Instead, there is consistent and strong evidence that biodiesel increases NOx emissions in proportion to the biodiesel blending percent.

- There is clear and statistically significant evidence that biodiesel increases NOx emissions at the B5 level in at least some engines for both soy- and animal-based biodiesels.

Considering each of the six past studies obtained from the technical literature and their data on high-cetane biodiesels comparable to California fuels, we find the following:

1. None of the six studies measured the NOx emissions impact from biodiesel at blending levels below B10. Only two studies tested a fuel at the B10 level. All other testing was at the B20 level or higher. Because none tested a B5 (or similar) fuel, none of them *can* provide direct evidence that NOx emissions are not increased at B5 or other blending levels below B10.

2. These studies provide no data or evidence supporting the validity of the Staff's Threshold Model that biodiesel below B10 does not increase NOx emissions. In fact, all of the studies are consistent with the contention that biodiesel increases NOx emissions in proportion to the blending percent.

3. Two of the studies present evidence and arguments that the NOx impact from biodiesel is a continuous effect that is present even at very low blending levels and will increase at higher levels in proportion to the blending percentage.

Considering the CARB Biodiesel Characterization report, we find that:

4. For the three engines where CARB has published the emission values measured in engine dynamometer testing, all of the data demonstrate that biodiesel fuels significantly increase NOx emissions for both soy- and animal-based fuels by amounts that are proportional to the blending percent. This is true for on-road and off-road engines and for a range of test cycles.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

5. Where B5 fuels were tested for these engines, NOx emissions were observed to increase. NOx emission increases are smaller at B5 than at higher blending levels and the observed increases for two engines were not statistically significant by themselves based on the pair-wise t-test employed in Durbin 2011.[8] However, the testing for one of the engines (the 2007 MBE4000) showed statistically significant NOx emission increases at the B5 level for both soy- and animal-based blends.

By itself, the latter result is sufficient to disprove the Staff's contention that biodiesel blends at the B5 level will not increase NOx emissions.

Based on examination of all of the studies cited by CARB as the basis for its proposal to exempt biodiesels below B10 from mitigation, it is clear that the available research points to the expectation that both soy- and animal-based biodiesel blends will increase NOx emissions in proportion to their biodiesel content, including at the B5 level. CARB's own test data demonstrate that B5 will significantly increase NOx emissions in at least some engines.

Based on data in the CARB Biodiesel Characterization report, soy-based biodiesels will increase NOx emissions by about 1% at B5 (and 2% at B10), while animal-based biodiesels will increase NOx emissions by about one-half as much: 0.45% at B5 (and 0.9% at B10). All of the available research says that the NOx increases are real and implementation of mitigation measures will be required to prevent increases in NOx emissions due to biodiesel use at blending levels below B10.

Finally, we note that CARB has not published fully the biodiesel testing data that it relied on in support of the Proposed Rule and thereby has failed to adequately serve the interest of full public disclosure in this matter. The CARB-sponsored testing reported in Durbin 2011 is the sole source of B5 testing cited by CARB as support for the Proposed Rule. Durbin 2011 publishes only portions of the measured emissions data in a form that permits re-analysis; it does not publish any of the B5 data in such a form. It has not been possible to obtain the remaining data through a personal request to Durbin or an official public records request to CARB and, to the best of our knowledge, the data are not otherwise available online or through another source.

CARB should publish all of the testing presented in Durbin 2011 and any future testing that it sponsors in a complete format that allows for re-analysis. Such a format would be (a) the measured emission values for each individual test replication; or (b) averages across all test replications, along with the number of replications and the standard error of the individual tests. The first format (individual test replications) is preferable because that would permit a full examination of the data including effects such as test cell drift over time. Such publication is necessary to assure that full public disclosure is achieved and that future proposed rules are fully and adequately informed by the data.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

---

[8]As discussed in Section 3.3, the pair-wise t-test is not the preferred method for demonstrating statistical significance.

1.3Ā Review of 2013 CARB B5 Emission Testing

In December 2013, after the release of the ISOR and in response to an earlier Public Records Act request, CARB released a copy of new CARB-sponsored emission testing conducted by Durbin and others at the University of California CE-CERT[9]. The purpose of the study was "*... to evaluate different B5 blends as potential emissions equivalent biodiesel fuel formulations for California.*"[10] Three B5 blends derived from soy, waste vegetable oil (WVO), and animal biodiesel stocks were tested on one 2006 Cummins ISM 370 engine using the hot-start EPA heavy-duty engine dynamometer cycle. A preliminary round of testing was conducted for all three fuels followed by emissions-equivalent certification testing per 13 CCR 2282(g) for two of the fuels. As noted by Durbin: "*[t]he emissions equivalent diesel certification procedure is robust in that it requires at least twenty replicate tests on the reference and candidate fuels, providing the ability to differentiate small differences in emissions.*"[11]

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Soy and WVO B5 Biodiesel

The B5-soy and B5-WVO fuels were blended from biodiesel stocks that were generally similar to the soy-based stock used in the earlier CARB Biodiesel Characterization Study (Durbin 2011) with respect to API gravity and cetane number. In the preliminary testing, the two fuels "*...showed 1.2-1.3% statistically significant [NOx emissions] increases with the B5-soy and B5-WVO biodiesel blends compared to the CARB reference fuel.*"[12] The B5-WVO fuel caused the smaller NOx increase (1.2%) and was selected for the certification phase of the testing. There, it "*... showed a statistically significant 1.0% increase in NOx compared to the CARB reference fuel*"[13] and failed the emissions-equivalent certification due to NOx emissions.

Animal B5 Biodiesel

The B5-animal derived fuel was blended from an animal tallow derived biodiesel that was substantially different from the animal based biodiesel used in the earlier Durbin study, and was higher in both API gravity and cetane number. The blending response for cetane number was also surprising, in that blending 5 percent by volume of a B100 stock (cetane number 61.1) with 95% of CARB ULSD (cetane number 53.1) produced a B5 fuel blend with cetane number 61.

In preliminary testing, the B5-animal fuel showed a small NOx increase which was not statistically significant, causing it to be judged the best candidate for emissions-equivalent certification. In the certification testing, it "*...showed a statistically*

[9] "*CARB B5 Biodiesel Preliminary and Certification Testing*." Prepared by Thomas D. Durbin, G. Karavalakis and others. Prepared for Alexander Mitchell, California Air Resources Board. July 2013. This study is not referenced in the ISOR, nor was it included in the rule making file when the hearing notice for the ADF regulation was published in October 2013.
[10] Ibid, p. vi.
[11] Ibid, p. viii.
[12] Ibid, p. 8.
[13] Ibid, p. 9.

significant 0.5% reduction in NOx compared to the CARB reference fuel"[13] and passed the emissions-equivalent certification. The NOx emission reduction for this fuel blend appears to be real for this engine, but given the differences between the blendstock and the animal based biodiesel blendstock used in the earlier Durbin study it is unclear that it is representative for animal-based biodiesels in general..

Summary

The conclusions drawn in the preceding section are not changed by the consideration of these new emission testing results. For plant-based biodiesels (soy- and WVO-based), the new testing provides additional and statistically significant evidence that B5 blends ***will*** increase NOx emissions at the B5 level. The result of decreased NOx for the B5 animal-based blend stands out from the general trend of research results reviewed in this report. However:

- The same result – reduced NOx emissions for some fuels and engines – has sometimes been observed in past research, as evidenced by the emissions data considered by CARB staff in ISOR Figure B.3 (reproduced in Figure 2.1 below). As shown, some animal-based B5 and B20 fuels reduced NOx emissions while others increased NOx emissions with the overall conclusion being that NOx emissions increase in direct proportion to biodiesel content of the blends and that there is no emissions threshold.

- Increasing cetane is known to generally reduce NOx emissions and has already been proposed by CARB as a mitigation strategy for increased NOx emissions from biodiesel[14]. The unusual cetane number response in the blending and the high cetane number of the B5-animal fuel may account for the results presented in the recently released study.

Considering the broad range of plant- and animal-based biodiesel stocks that will be used in biodiesel fuels, we conclude that the available research (including the recently released CARB test results) indicates that unrestricted biodiesel use at the B5 level will cause real increases in NOx emissions and that countermeasures may be required to prevent increases in NOx emissions due to biodiesel use at blending levels below B10.

###

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

[14] For example, see Durbin 2011 Section 7.0 for a discussion of NOx mitigation results through blending of cetane improvers and other measures.

2.Ā CARB LITERATURE REVIEW

The Staff ISOR explains that the Appendix B Technology Assessment is the basis for CARB's conclusion that biodiesels below B10 have no significant impact on NOx emissions. The assessment is based on data from seven studies (identified in Table 2-1) that tested high-cetane diesel fuels. The first study (Durbin 2011) is the Biodiesel Characterization Study that was conducted for CARB, while the others were obtained through a literature search.

Table 2-1
List of Studies from High-Cetane Literature Search

Primary Author	Title	Published	Year
Durbin	Biodiesel Mitigation Study	Final Report Prepared for Robert Okamoto, M.S. and Alexander Mitchell, CARB	2011
Clark	Transient Emissions Comparisons of Alternative Compression Ignition Fuel	SAE 1999-01-1117	1999
Eckerle	Effects of Methyl Ester Biodiesel Blends on NOx Emissions	SAE 2008-01-0078	2008
McCormick	Fuel Additive and Blending Approaches to Reducing NOx Emissions from Biodiesel	SAE 2002-01-1658	2002
McCormick	Regulated Emissions from Biodiesel Tested in Heavy-Duty Engines Meeting 2004 Emissions	SAE 2005-01-2200	2005
Nuszkowski	Evaluation of the NOx emissions from heavy duty diesel engines with the addition of cetane improvers	Proc. I Mech E Vol. 223 Part D: J. Automobile Engineering, 223, 1049-1060	2009
Thompson	Neat fuel influence on biodiesel blend emissions	Int J Engine Res Vol. 11, 61-77.	2010

Source: Table B.2 of Durbin 2011

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Figure 2-1 reproduces two exhibits from Appendix B that show increasing trends for NOx emissions with the biodiesel blending level. Based on the slopes of the trend lines,

Figure 2-1
NOx Emission Increases Observed in Biodiesel Research Cited in Staff ISOR

Figure B.2: NOx Impact of Soy Biodiesel Blended in High Cetane Base Fuel

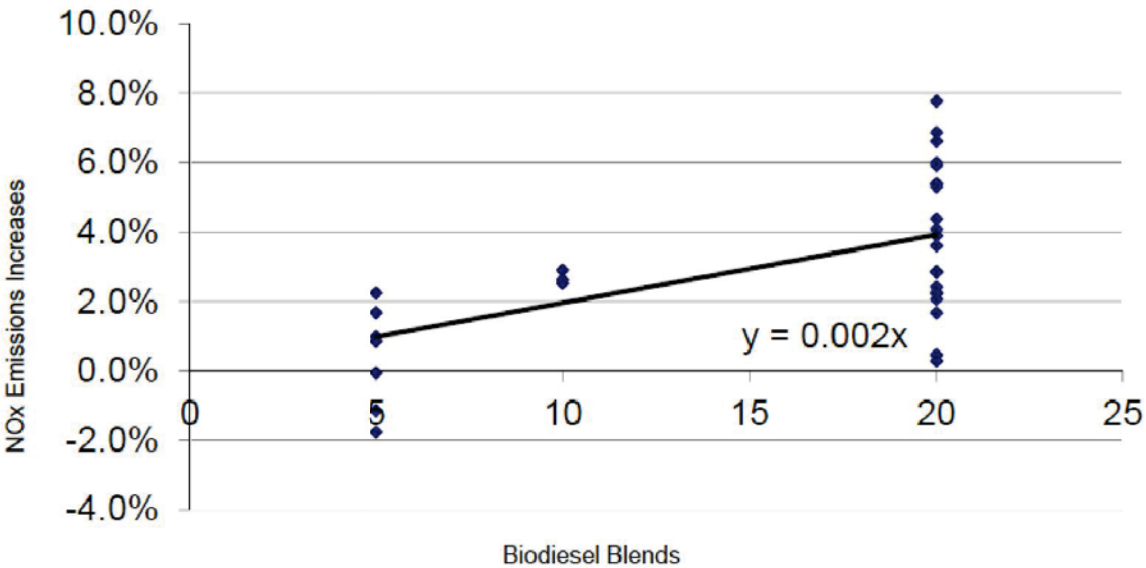
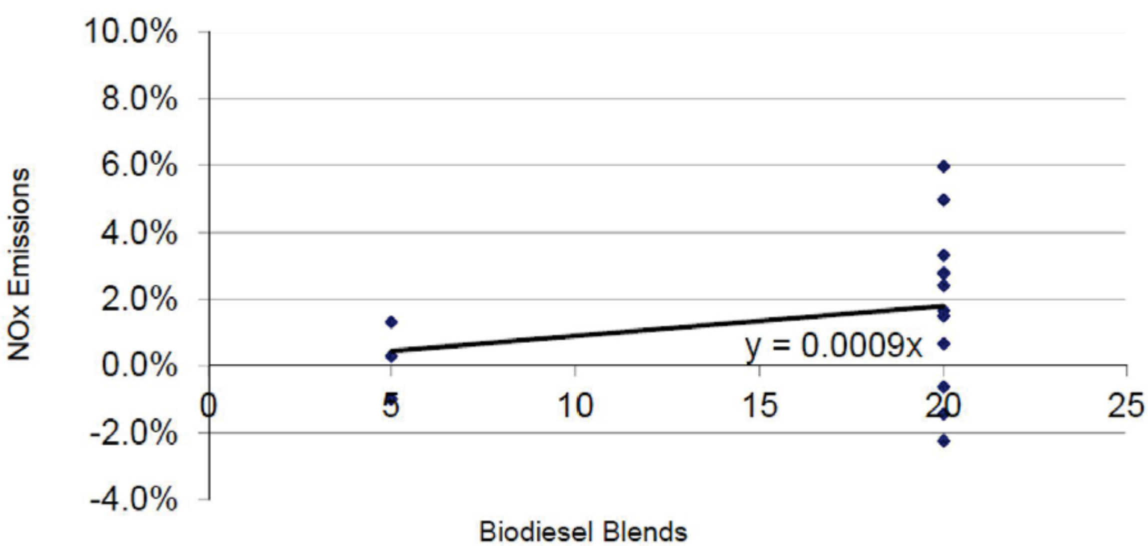


Figure B.3: NOx Impact of Animal Biodiesel Blended in High Cetane Base Fuel



Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Source: Figures B.2 and B.3 of Appendix B: Technology Assessment

soy-based biodiesels are shown to increase NOx emissions by approximately 1% at B5, 2% at B10, and 4% at B20. Animal-based biodiesels are shown to increase NOx emissions by about one-half as much: 0.45% at B5, 0.9% at B10, and 1.8% at B20. Although there is substantial scatter in the results, these data do not appear to support the Staff Threshold Model that biodiesel does not increase NOx emissions at B5 but does so at B10.

We will examine the Durbin 2011 study at some length in Section 3. In this section, we look at each of the other studies cited by the Staff to find out what the studies say about NOx emissions impacts at and below B10.

2.1 Review of Literature Cited in the ISOR

The Staff literature search sought and selected testing that used fuels with cetane levels comparable to California diesel fuels; the Staff does not, however, list those fuels or provide the data that support the tables and figures in Appendix B of the ISOR. Therefore, we have necessarily made our own selection of high-cetane fuels in the course of reviewing the studies. The key testing and findings of each study are summarized below, with a specific focus on what they tell us about NOx emission impacts at B10 and below.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

2.1.1 Clark 1999

This study tested a variety of fuels on a 1994 7.3L Navistar T444E engine. Of the high-cetane base fuels, one base fuel (Diesel A, off-road LSD) was blended and tested at levels of B20, B50, and B100. NOx emissions were significantly increased for all of the blends. The other base fuel (CA Diesel) was tested only as a base fuel. Its NOx emissions were 12% below that of Diesel A, making it is unclear whether Diesel A is representative of fuels in CA. <u>This study conducted no testing of the NOx emissions impact from biodiesels at the B10 level or below</u>.

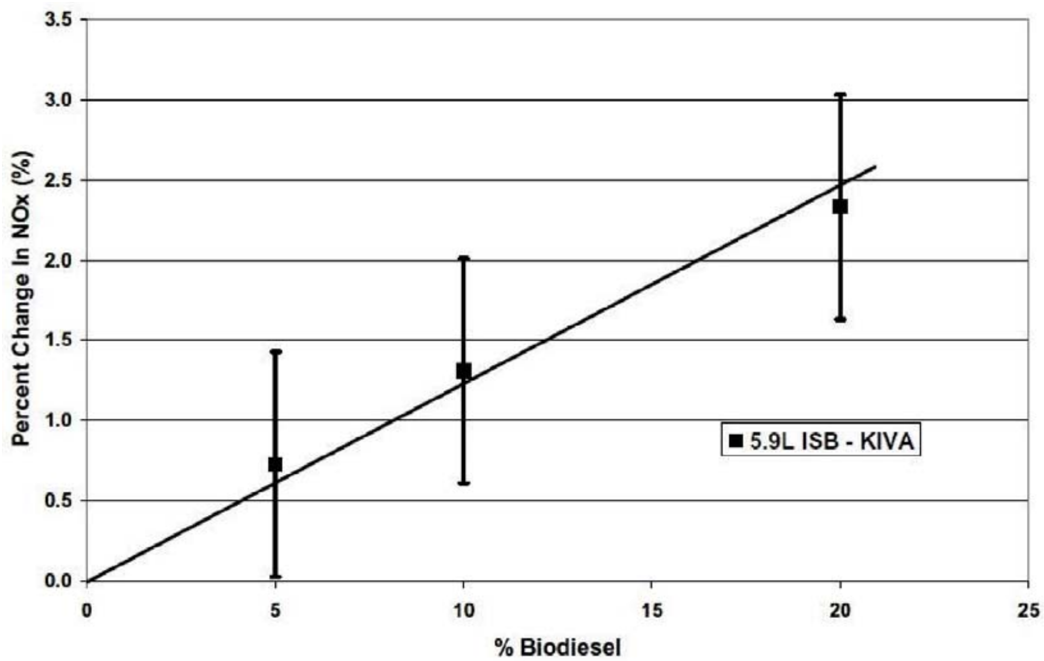
2.1.2 Eckerle 2008

This study tested low and mid/high-cetane base fuels alone and blended with soy-based biodiesel at the B20 level. The Cummins single-cylinder test engine facility was used in a configuration representative of modern diesel technology, including cooled EGR. Testing was conducted under a variety of engine speed and load conditions. FTP cycle emissions were then calculated from the speed/load data points. The test results show that B20 blends increase NOx emissions compared to both low- and high-cetane base fuels. <u>This study conducted no testing of the NOx emissions impact from biodiesels at the B10 level or below</u>.

The study notes that two other studies "show that NOx emissions increase nearly linearly with the increase in the percentage of biodiesel added to diesel fuel." Eckerle's Figure 21 (reproduced below as Figure 2-2) indicates a NOx emissions increase at B5, which is the basis for the statement in the abstract that "Results also show that for biodiesel blends containing less than 20% biodiesel, the NOx impact over the FTP cycle is proportional to

the blend percentage of biodiesel." The authors clearly believe that biodiesel fuels have NOx emission impacts proportional to the blending percent at all levels including B5.

Figure 2-2
Impact of Biodiesel Blends on Percent NOx Change for the 5.9L ISB Engine Operation Over the FTP Cycle



Source: Figure 21 of Eckerle 2008

2.1.3 <u>McCormick 2002</u>

This study tested low- and mid-cetane base fuels alone and blended with soy- and animal-based biodiesel at the B20 level. The testing was conducted on a 1991 DDC Series 60 engine using the hot-start U.S. heavy-duty FTP. NOx emission increases were observed for both fuels at the B20 level. Mitigation of NOx impacts was investigated by blending a Fisher-Tropsch fuel, a 10% aromatics fuel and fuel additives. <u>This study conducted no testing of the NOx emissions impact from commercial biodiesels at the B10 level or below</u>.

This study also tested a Fisher-Tropsch (FT) base fuel blended at the B1, B20, and B80 levels. Although the very high cetane number (≥75) takes it out of the range of commercial diesel fuels, it is interesting to note that the study measured higher NOx emissions at the B1 level than it did on the FT base fuel and substantially higher NOx emissions at the B20 and B80 levels. While the B1 increase was not statistically significant given the uncertainties in the emission measurements (averages of three test runs), <u>it is clear that increased NOx emissions have been observed at very low blending levels</u>.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

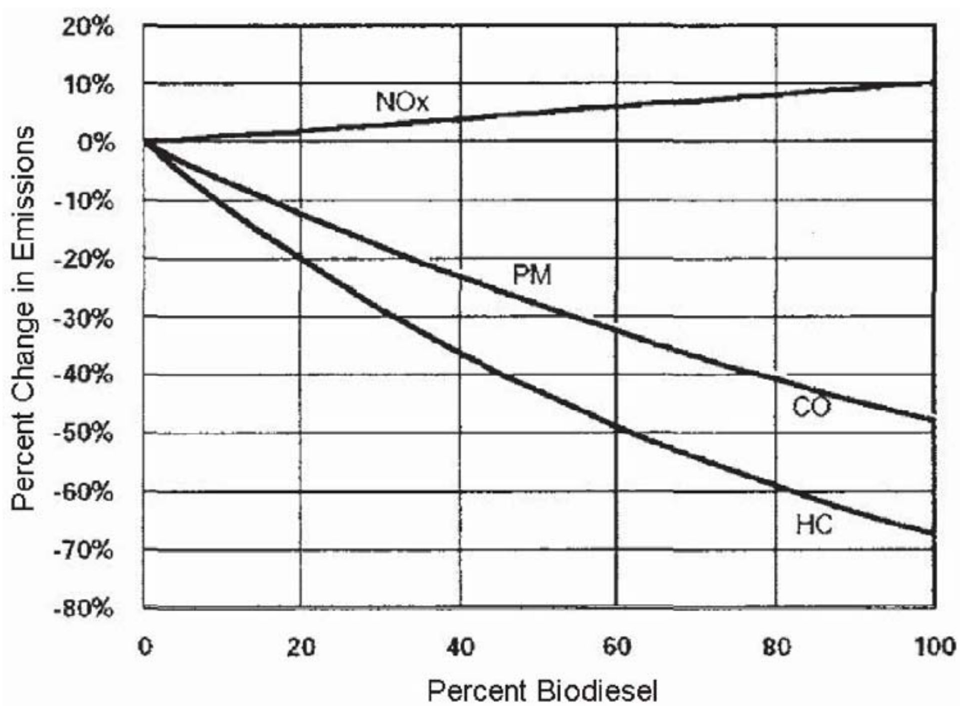
2.1.4 McCormick 2005

This study tested blends of soy- and animal-based biodiesels with a high-cetane ULSD base fuel at B10 levels and higher. Two engines were tested – a 2002 Cummins ISB and a 2003 DDC Series 60, both with cooled EGR. The hot-start U.S. heavy-duty FTP test cycle was used. The majority of testing was at the B20 level with additional testing at the B50 and B100 levels. One soy-based fuel was tested at B10. The study showed NOx emission increases at B10, B20, and higher levels. The study also investigated mitigation of NOx increases. This study conducted no testing of the NOx emissions impact from biodiesels below the B10 level.

The authors present a figure (reproduced as Figure 2-3) in their introduction that shows their summary of biodiesel emission impacts based on an EPA review of heavy-duty engine testing. It shows NOx emissions increasing linearly with the biodiesel blend percentage.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Figure 2-3
Trend in HC, CO, NOx and PM Emissions with Biodiesel Percent



Source: McCormick 2005

2.1.5 Nuszkowski 2009

This study tested five different diesel engines: one 1991 DDC Series 60, two 1992 DDC Series 60, one 1999 Cummins ISM, and one 2004 Cummins ISM. Only the 2004 Cummins ISM was equipped with EGR. All testing was done using the hot-start U.S. heavy-duty FTP test cycle. The testing was designed to test emissions from fuels with and without cetane-improving additives. Although a total of five engines were tested, the base diesel and B20 fuels were tested on only two engines (one Cummins and one DDC Series 60) because there was a limited supply of fuel available. NOx emissions increased on the B20 fuel for both engines. A third engine (Cummins) was tested on B20 and B20 blended with cetane improvers to examine mitigation of NOx emissions. This study conducted no testing of the NOx emissions impact from biodiesels at the B10 level or below.

2.1.6 Thompson 2010

This study examined the emissions impacts of soy-based biodiesel at the B10 and B20 levels relative to low-cetane (42), mid-cetane (49), and high-cetane (63) base fuels using one 1992 DDC Series 60 engine. The emissions results were measured on the hot-start U.S. heavy-duty FTP cycle. The study found that NOx emissions were unchanged (observed differences were not statistically significant) at B10 and B20 levels for the low- and mid-cetane fuels. NOx emissions increased significantly at B10 and B20 levels for the high-cetane fuels. This study conducted no testing of the NOx emissions impact from biodiesels at levels below B10.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

2.2 Conclusions Based on Studies Obtained in Literature Search

From the foregoing summary of the studies cited by Staff, we reach the conclusions given below.

1. None of the six studies measured the NOx emissions impact from commercial-grade biodiesel at blending levels below B10, and only two studies tested a fuel at the B10 level. All other testing was at the B20 level or higher. Because none tested a B5 (or similar) fuel, none is capable of providing direct evidence regarding NOx emissions at B5 or other blending levels below B10.

2. These studies provide no data or evidence supporting the validity of Staff's Threshold Model that biodiesel below B10 does not increase NOx emissions. In fact, all of the studies are consistent with the contention that biodiesel increases NOx emissions in proportion to the blending percent.

3. Two of the studies present evidence and arguments that the NOx impact from biodiesel is a continuous effect that is present even at very low blending levels and will increase at higher levels in proportion to the blending percentage. One study tested a Fischer-Tropsch biodiesel blend at B1 and observed NOx emissions to increase (but not by a statistically significant amount).

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

###

3. CARB BIODIESEL CHARACTERIZATION STUDY

3.1 Background

CARB sponsored a comprehensive study of biodiesel and other alternative diesel blends in order "… to better characterize the emissions impacts of renewable fuels under a variety of conditions."[15] The study was designed to test eight different heavy- duty engines or vehicles, including both highway and off-road engines using engine or chassis dynamometer testing. Five different test cycles were used: the Urban Dynamometer Driving Schedule (UDDS), the Federal Test Procedure (FTP), and 40 mph and 50 mph CARB heavy-heavy-duty diesel truck (HHDDT) cruise cycles, and the ISO 8178 (8 mode) cycle. Table 3-1 (reproduced from Table ES-1 of Durbin 2011) documents the scope of the test program. Because the Staff relied only on engine dynamometer testing in its Technology Assessment, only the data for the first four engines (shaded) are considered here.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Table 3-1
A Breakdown of the Test Engines for the Different Categories of Testing

2006 Cummins ISM[a]	Heavy-duty on-highway	Engine dynamometer	
2007 MBE4000	Heavy-duty on-highway	Engine dynamometer	
1998, 2.2 liter, Kubota V2203-DIB	Off-road	Engine dynamometer	
2009 John Deere 4.5 L	Off-road	Engine dynamometer	
2000 Caterpillar C-15	Heavy-duty on-highway	Chassis dynamometer	Freightliner chassis
2006 Cummins ISM	Heavy-duty on-highway	Chassis dynamometer	International chassis
2007 BME4000	Heavy-duty on-highway	Chassis dynamometer	Freightliner chassis
2010 Cummins ISX15	Heavy-duty on-highway	Chassis dynamometer	Kenworth chassis

Source: Table ES-1 of Durbin 2011, page xxvi
Notes:
[a] Data for the first four engines (shaded) are considered in this report.

[15] Durbin 2011, p. xxiv.

The original goal of this report was to subject all of the NOx emission testing in Durbin 2011 to a fresh re-analysis. However, it was discovered that Durbin 2011 did not report all of the data that were obtained during the program and are discussed in the report. The chassis dynamometer testing was conducted at the CARB Los Angeles facility. Emission results for the chassis dynamometer testing are presented in tabular and graphical form, but the report does not contain the actual emissions test data. For the engine dynamometer testing, some of the measured emission values are not reported even though the emission results are reported in tabulated or graphical form. Requests for the missing data were directed to Durbin in a personal request and to CARB through an official records request. No information has been provided in response and we have not been able to obtain the missing data from online or other sources.

For this report, we have worked with the data in the forms that are provided in Durbin 2011 as being the best-available record of the results of the CARB study. Because Staff used only data obtained in engine dynamometer testing, the analysis presented in this report has done the same. Nevertheless, the results of the chassis dynamometer testing are generally supportive of the results and conclusions presented here. Durbin 2011 notes:

> *"… The NOx emissions showed a consistent trend of increasing emissions with increasing biodiesel blend level. These differences were statistically significant or marginally significant for nearly all of the test sequences for the B50 and B100 fuels, and for a subset of the tests on the B20 blends."*[16]

Durbin notes that emissions variability was greater in the chassis dynamometer testing, which leads to the sometimes lower levels of statistical significance. There was also a noticeable drift over time in NOx emissions that complicated the results for one engine.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

3.2 Data and Methodology

Table 3-2 compiles descriptive information on the engine dynamometer testing performed in Durbin 2011. The experimental matrix involves four engines, two types of biodiesel fuels (soy- and animal-based), and up to four test cycles per engine. However, the matrix is not completely filled with all fuels tested on all engines on all applicable test cycles. The most complete testing is for the ULSD base fuel and B20, B50, and B100 blends. There is less testing for the B5 blend, and B5 is tested using only a subset of cycles. For this reason, we first examine the testing for ULSD, B20, B50, and B100 fuels to determine the overall impact of biodiesels on NOx emissions. We then examine the more limited testing for B5 to determine the extent to which it impacts NOx emissions.

This examination is limited by the form in which emissions test information is reported in Durbin 2011. A complete statistical analysis can be conducted only for the two on-road engines for which Appendices G and H of Durbin 2011 provide measured emissions, and for a portion of the testing of the Kubota off-road engine for which Appendix I provides

[16] Durbin 2011, p. 126.

Table 3-2
Experimental Matrix for Heavy-Duty Engine Dynamometer Testing Reported in Durbin 2011

Engine	Biodiesel Type	Fuels Tested	Test Cycles	Notes
On-Road Engines				
2006 Cummins ISM	Soy	ULSD, B20, B50, B100, B5	UDDS, FTP, 40 mph, 50 mph	B5 tested on 40 mph and 50 mph cruise cycles
	Animal	ULSD, B20, B50, B100, B5	UDDS, FTP, 50 mph	B5 tested only on FTP.
2007 MBE4000	Soy	ULSD, B20, B50, B100, B5	UDDS, FTP, 50 mph	B5 tested only on FTP.
	Animal	ULSD, B20, B50, B100, B5		B5 tested only on FTP.
Off-Road Engines				
1998 Kubota V2203-DIB	Soy	ULSD, B20, B50, B100, B5	ISO 8178 (8 Mode)	none
	Animal	Not tested		
2009 John Deere	Soy	ULSD, B20, B50, B100	ISO 8178 (8 Mode)	B5 not tested
	Animal	ULSD, B20, B5		none

measured emissions. The data needed to support a full re-analysis consist of measured emissions on each fuel in gm/hp-hr terms, which are stated in Durbin 2011 as averages across all test replications along with the number of replications and the standard error of the individual tests. With this information, the dependence of NOx emissions on biodiesel blending percent can be determined as accurately as if the individual test values had been reported and the appropriate statistical tests for the significance of results can be performed.

Regression analysis is used as the primary method of analysis. For each engine and test cycle, the emission averages for each fuel are regressed against the biodiesel blending percent to determine a straight line. The regression weights each data point in inverse proportion to the square of its standard error to account for differences in the number and reliability of emission measurements that make up each average. The resulting regression line will pass through the mean value estimated from the data (i.e., the average NOx emission level at the average blending percent), while the emission averages for each fuel may scatter above and below the regression line due to uncertainties in their measurement. The slope of the line estimates the dependence of NOx emissions on the blending percentage.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Where the data points closely follow a straight line and the slope is determined to be statistically significant, one can conclude that blending biodiesel with a base fuel will increase NOx emissions in proportion to the blending percent. The regression line can then be used to estimate the predicted emissions increase for a given blending percent. The predicted emissions increase is the value one would expect on average over many measurements and is comparable to the average emissions increase one would expect in a fleet of vehicles.

The same level of analysis is not possible for the testing on B5 fuel, which is reported as a simple average for the on-road engines and is not reported at all for the off-road engines. For the B5 fuel, Durbin 2011 presents emission test results in a tabulated form where the percentage change in NOx emissions has been computed compared to ULSD base fuel. This form supports the presentation of results graphically, but it does not permit a proper statistical analysis to be performed. Specifically, the computation of percentage emission changes will perturb the error distribution of the data, by mixing the uncertainty in measured emissions on the base fuel with the uncertainties in measured emissions on each biodiesel blend, and it can introduce bias as a result of the mixing. Further statistical analysis of the computed percent values should be avoided because of these problems. Therefore, a more limited trend analysis of the NOx emissions data for B5 and the John Deere engine is conducted.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

3.3Ā2006 Cummins Engine (Engine Dynamometer Testing)

Table 3-3 shows the NOx emission results for the 2006 model-year Cummins heavy-duty diesel engine based on a re-analysis of the data for this report. As indicated by highlighting in the table, the relationship between increasing biodiesel content and increased NOx emissions for soy-based biodiesel is statistically significant at >95% confidence level[17] in all cases. For the animal-based biodiesel, the relationship is statistically significant at the 92% confidence level for the UDDS cycle, the 94% confidence level for the 50 mph cruise, and the >99% confidence level for the FTP cycle.

For the soy-based fuels, the R^2 statistics show that the emissions effect of biodiesel is almost perfectly linear with increasing biodiesel content over the range B20, B50, and B100. Although not as high for the animal-based fuels (because the emissions effect is smaller and measurement errors are relatively larger in comparison to the trend), the R^2 statistics nevertheless establish a linear increase in NOx emissions with increasing biodiesel content over the same range. The linearity of the response with blending percent is well supported by the many NOx emissions graphs contained in Durbin 2011.

The table also gives the estimated NOx emission increases for B5 and B10 as predicted by the regression lines. For soy-based fuels, the values are 1% for B5 (range 0.8% to 1.3% depending on the cycle) and 2% for B10 (range 1.6% to 2.6% depending on cycle).

[17] A result is said to be statistically significant at the 95% confidence level when the p value is reported as $p \leq 0.05$. At the $p \leq 0.01$ level, a result is said to be statistically significant at the 99% confidence level, and so forth.

Table 3-3
Re-Analysis for 2006 Cummins Engine (Engine Dynamometer Testing)
Model: NOx = A + B · BioPct
Using ULSD, B20, B50, and B100 fuels

Biodiesel Type	Test Cycle	R^2	Intercept A	BioPct Slope B		Predicted NOx Increase for B5	Predicted NOx Increase for B10
			Value	Value	p value	Pct Change	Pct Change
Soy-based							
	UDDS	0.997	5.896	0.0100 [a]	0.001	0.8%	1.7%
	FTP	0.995	2.024	0.0052	0.003	1.3%	2.6%
	40 mph	1.000	2.030	0.0037	<0.0001	0.9%	1.8%
	50 mph	0.969	1.733	0.0028	0.016	0.8%	1.6%
Animal-based							
	UDDS	0.847	5.911	0.0021 [b]	0.080	0.2%	0.4%
	FTP	0.981	2.067	0.0031	0.001	0.7%	1.4%
	50 mph	0.887	1.768	0.0011	0.058	0.3%	0.6%

Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better.
[b] Orange highlight indicates result is statistically significant at the 90% confidence level or better.

For animal-based fuels, the values are approximately one-half as large: 0.4% for B5 (range 0.2% to 0.7%) and 0.8% for B10 (range 0.4% to 1.4%). These predicted increases are statistically significant to the same degree as the slope of the regression line from which they are estimated. That is, the NOx increases predicted by the regression line for soy-based fuels are statistically significant at the 95% confidence level (or better) on all cycles and the predicted NOx increases for animal-based fuels are statistically significant at the 90% confidence level (or better) on all cycles and at the >99% confidence level for the FTP.

Because the limited data on B5 were not used to develop the regression lines for each cycle, and no test data on B10 are available, use of the lines to make predictions for B5 and B10 depends on their linearity over the range between ULSD and B20. Based on the R^2 statistics and the graphs in Durbin 2011, the slopes observed between ULSD and B20 are the same as the slopes observed between B20 and B100 for each of the test cycles. We believe that the linearity of the response with blending percent for values over the range ULSD to B100 would be accepted by the large majority of researchers in the field, as would the use of regression analysis to make predictions for B5 and B10.

The Durbin 2011 report takes a different approach for determining the statistical significance of NOx emission increases for each fuel. For each fuel tested, it computes a percentage change in emissions for NOx (and other pollutants) relative to the ULSD base fuel. It then determines the statistical significance of each observed change using a conventional t-test for the difference of two mean values (2-tailed, 2 sample equal

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

variance t-test). The t-test is conducted on the measured emission values before the percentage emission change is computed.

The t-test would be the appropriate approach for determining statistical significance if only two fuels were tested. However, it is a simplistic approach when three or more fuels are tested because it is applied on a pair-wise basis (B5 vs. ULSD, B20 vs. ULSD, etc.) and does not make use of all of the data that is available. It will have less power than the regression approach to detect emission changes that are real. This limitation is in one direction, however, in that the test is too weak when 3 or more data points are available, but a finding of statistical significance is valid when it occurs. As long as the linear hypothesis is valid, the regression approach should be the preferred method for analysis and for the determination of whether biodiesel blending significantly increases NOx emissions.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Because emission changes will be smallest for B5 (because of the low blending volume), the pair-wise t-test is most likely to fail to find statistical significance at the B5 level. In cases where the pair-wise t-test for B5 says that the emission change vs. ULSD is not statistically significant – but slope of the regression line <u>is</u> statistically significant – the proper conclusion is that additional B5 testing (to improve the precision of the emission averages) would likely lead to the detection of a statistically significant B5 emissions change using the t-test. In this case, <u>the failure to find statistical significance using the t-test is not evidence that B5 does not increase NOx emissions</u>.

For this engine, soy-based B5 was tested on the 40 mph and 50 mph cruise cycles and animal-based B5 was tested on the FTP. To examine this matter further, Table 3-4 reproduces NOx emission results reported in Tables ES-2 and ES-3 of Durbin 2011. Soy-based B5 was shown to increase NOx emissions on the 40 mph cruise cycle, but not on the 50 mph cruise cycle. Animal-based B5 was shown to increase NOx emissions on the FTP. Durbin 2011 noted (p. xxxii) that "[t]he 50 mph cruise results were obscured, however, by changes in the engine operation and control strategy that occurred over a segment of this cycle." Therefore, we discount the 50 mph cruise results and do not consider them further. Neither of the remaining B5 NOx emission increases (for the 40 mph Cruise and FTP cycles) were found to be statistically significant using the t-test, although the 40 mph cruise result for soy-based fuels comes close to being marginally significant (it would be statistically significant at an 86.5% level). The NOx emission increases at higher blending levels were found have high statistical significance (>99% confidence level).

This format, used throughout Durbin 2011 to report emission test data and to show the effect of biodiesel on emissions, is subject to an important statistical caveat. The percent changes are computed by dividing the biodiesel emission values by the emissions measured for the ULSD base fuel. Therefore, measurement errors in the ULSD measurement are blended with the measurement errors for each of the biodiesel fuels. The blending of errors in each computed percent change can bias the apparent trend of emissions with increasing biodiesel content. As will be shown in Section 3.3.2, we can see this problem in the animal-based B5 test data for this engine.

Table 3-4 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 2006 Cummins Engine (Engine Dynamometer Testing)						
	Soy-based Biodiesel				Animal-based Biodiesel	
	40 mph Cruise		50 mph Cruise		FTP	
	NOx % Diff	p value	NOx % Diff	p value	NOx % Diff	p value
B5	1.7%	0.135	-1.1%	0.588	0.3%	0.298
B20	3.9% [a]	0.000	0.5%	0.800	1.5%	0.000
B50	9.1%	0.000	6.3%	0.001	6.4%	0.000
B100	20.9%	0.000	18.3%	0.000	14.1%	0.000

Source: Table ES-2 and ES-3 of Durbin 2011, p. xxviii
Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on the pair-wise t-test.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

3.3.1 NOx Impact of Soy-based Biodiesel at the B5 Level

Figures 3-1a and 3-1b display the trend of NOx emissions with blending percent for the soy-based biodiesel on the 40 mph cruise cycle. Figure 3-1a plots the percentage increases as reported by Durbin 2011 in contrast to two different analytical models for the relationship:

- Ā The Linear Model shown by the blue line; and
- Ā The Staff Threshold model (black line), in which the NOx emission change is zero through B9 and then increases abruptly to join the linear model.

In Figure 3-1a, the linear model is an Excel trendline for the computed percent changes. While the data violate a key assumption for the proper use of regression analysis, this approach is the only way to establish a trendline given the form in which Durbin 2011 tabulates the data and presents the results of its testing.

Figure 3-1b plots the actual measured emission values in g/bhp-hr terms in contrast to the same two analytical models. Here, the linear model line is determined through a proper use of regression analysis, in which each emission average in g/bhp-hr terms is weighted inversely by the square of its standard error, using the data for ULSD, B20, B50 and B100 (i.e., excluding the B5 data point). In the case of this engine and biodiesel fuel, both forms of assessment show generally the same trend for NOx emissions as a function of blending percent. Although the NOx emission increases for B5 may fail the t-test for significance, emissions are increased at B5 and the B5 data point is fully consistent with the Linear Model. The Threshold model is clearly a less-satisfactory representation of the test data.

Figure 3-1a
Durbin 2011 Assessment: 40 mph Cruise Cycle NOx Emissions Increases for Soy-Biodiesel Blends (2006 Cummins Engine)

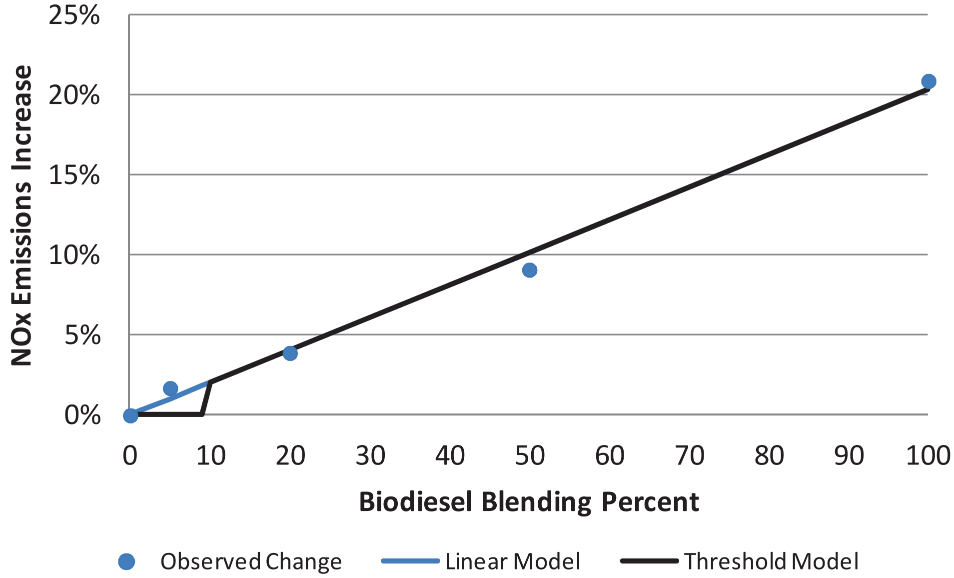
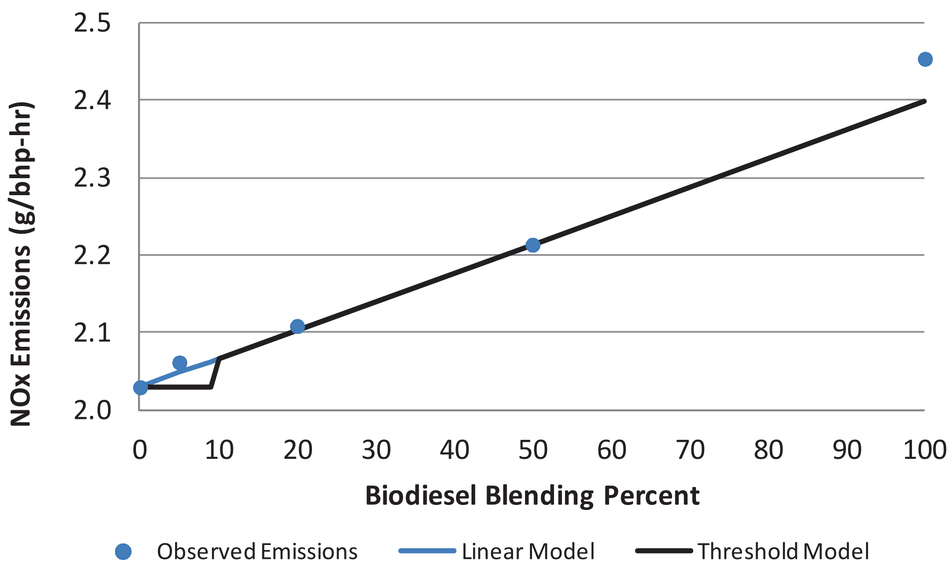


Figure 3-1b
Re-assessment of 40 mph Cruise Cycle NOx Emissions Increases for Soy-Biodiesel Blends (2006 Cummins Engine)



Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Note that the slope of the trendline (Figure 3-1a) is greater than the slope of the regression line (Figure 3-1b). In the latter figure, the B100 data point stands above the regression line, which passes below it. The regression line (but not the trendline) is fit in

a manner that accounts for the uncertainties in each data point, so that the line will pass closer to points that have smaller uncertainties and farther from points that have greater uncertainties. For these data, the B100 data point has the largest uncertainty (±0.026 g/bhp-hr) followed by the B20 data point (±0.025 g/bhp-hr). The other three data points (ULSD, B5, and B50) have uncertainties less than ±0.001 g/bhp-hr. The B20 data point happens to fall on the line, but the B100 data point is found to diverge above. Because the regression analysis can account for the relative uncertainties of the data points, it provides a more accurate and reliable assessment of the impact on NOx emissions.

3.3.2 NOx Impact of Animal-based Biodiesel at the B5 level

Figures 3-2a and 3-2b display the trend of NOx emissions with blending percent for the animal-based biodiesel on the FTP test cycle as reported by Durbin 2011 and as re-assessed in this report using regression analysis, respectively. As Figure 3-2a shows, the NOx percent change values reported by Durbin 2011 appear to follow the Staff Threshold model in that NOx emissions are not materially increased at B5, but are increased significantly at B20 and above. As a result, the blue trendline in the figure (fit from the B20, B50 and B100 data points) has a negative intercept.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Figure 3-2b paints a very different picture from the data. Here, the ULSD and B5 data points stand above the weighted regression line (blue) developed from the data for ULSD, B20, B50 and B100. In the data used to fit the regression line, the ULSD data point has the largest uncertainty (±0.013 g/bhp-hr) while the other three data points (B20, B50, and B100) have uncertainties of ±0.002 g/bhp-hr (one case) and ±0.001 g/bhp-hr (two cases). Considering all of the data, the B5 data point has the second highest uncertainty (±0.007 g/bhp-hr). The regression line closely follows a linear model with a high R^2 (0.981) considering the weighted errors, while the ULSD and B5 points lie above it.

Because the ULSD data point is subject to more uncertainty and appears to be biased high compared to the regression line, the NOx percent changes computed by Durbin 2011 are themselves biased. The trendline result in Figure 3-2a that appeared to be supportive of the Staff Threshold model now appears to be the result of biases in the ULSD and B5 emission averages.

Two important conclusions can be drawn from the foregoing:

1. Accurate and reliable conclusions regarding the impact of B5 on NOx emissions cannot be drawn from the computed percent changes that are reported in Durbin 2011. Nor can accurate and reliable conclusions be drawn from visual inspection of graphs that present such data. Weighted regression analysis of the measured emission values (g/bhp-hr terms) must be performed so that the uncertainties in emissions measurements can be fully accounted for.

2. When a weighted regression analysis is performed using the testing for this engine, there is no evidence that supports the conclusion that B5 blends will not increase NOx emissions. In fact, the data are consistent with the conclusion that biodiesel increases NOx emissions in proportion to the blending percent.

Figure 3-2a
Durbin 2011 Assessment: FTP NOx Emissions Increases for Animal-based Biodiesel Blends (2006 Cummins Engine)

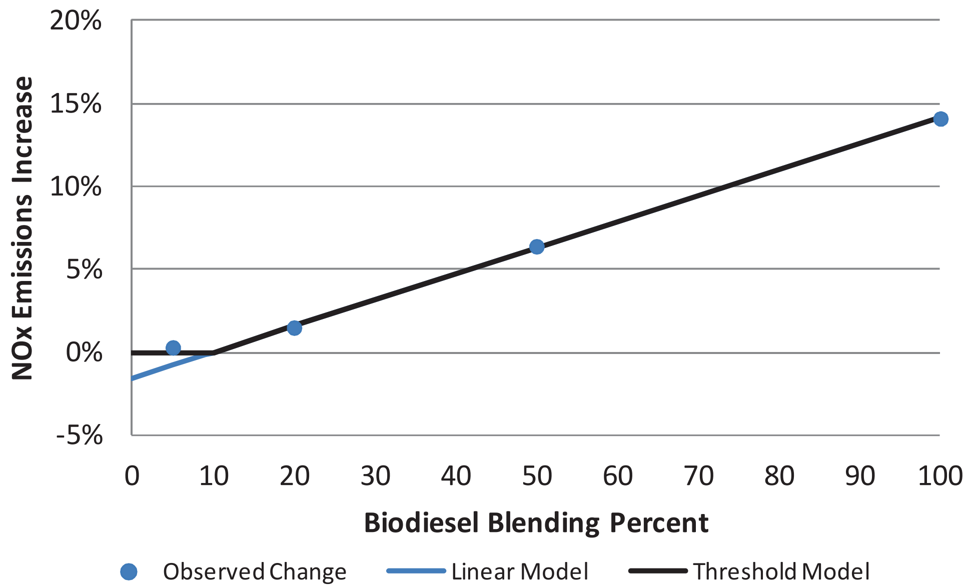
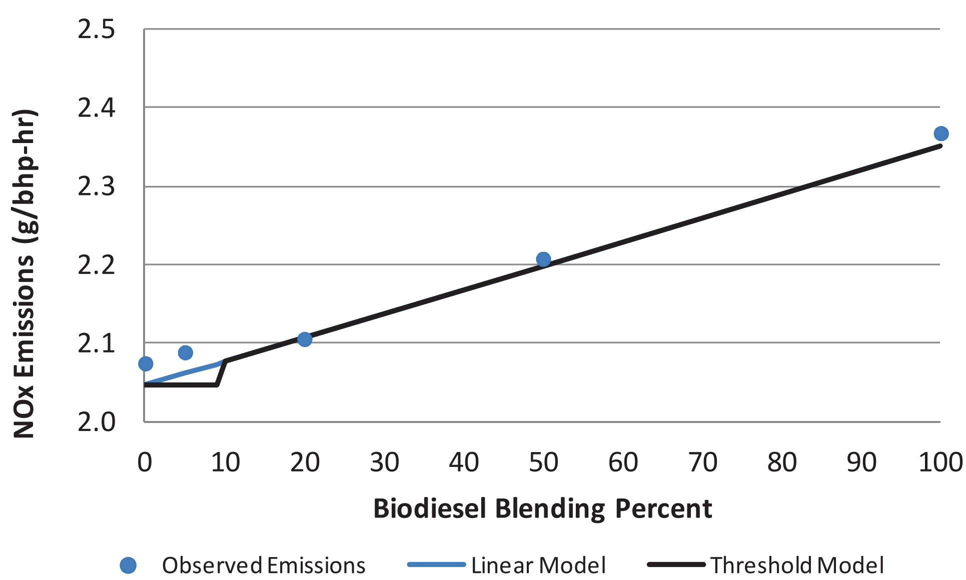


Figure 3-2b
Re-assessment of FTP NOx Emissions Increases for Animal-based Biodiesel Blends (2006 Cummins Engine)



Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

3.4 2007 MBE4000 Engine (Engine Dynamometer Testing)

To analyze the data for the 2007 MBE4000 engine, it has proved necessary to remove two data points, one for the soy-based B20 fuel on the 50 mpg cruise cycle and one for the animal-based B50 fuel on the FTP test cycle:

- Appendix H reports the 50 mph cruise emission average for soy-based B20 to be 0.014 ± 0.020 g/bhp-hr. This value is implausible and wholly inconsistent with the NOx emission change of +6.9% reported in Table ES-4 of Durbin 2011, which would imply a NOx emission average of 1.21*1.069 = 1.30 g/bhp-hr.

- Appendix H reports the FTP emission average for the animal-based B50 fuel to be 2.592 ± 0.028 g/bhp-hr, which stands well above the other test data on animal-based biodiesel. This value is also inconsistent with the NOx emission change of +12.1% reported in Table ES-4 of Durbin 2011, which would imply a NOx emission average of 1.29*1.121 = 1.45 g/bhp-hr.

We believe these reported values are affected by typographical errors and have deleted them from the dataset used here.

With these corrections, Table 3-5 shows the results of the NOx emissions analysis for the 2007 model-year MBE4000 heavy-duty diesel engine. As indicated by highlighting in the table, the relationship between increasing biodiesel content and increased NOx emissions is statistically significant at >99% confidence level in two cases for soy-based biodiesel (the UDDS and FTP cycles) and at the 90% confidence level in one case (the 50 mph cycle). For the animal-based biodiesel, the relationship is statistically significant at the 96% confidence level for the UDDS cycle, the 98% confidence level for the FTP cycle, and >99% confidence level for the 50 mph cycle.

Durbin 2011 again notes a problem with the 50 mph cruise test results, saying (p. xxxii) that "[the NOx] trend was obscured, however, by the differences in engine operation that were observed for the 50 mph cruise cycle." Therefore, we will focus the discussion on the UDDS and FTP results.

For the soy-based fuels, the R^2 statistics show that the emissions effect of biodiesel is almost perfectly linear with increasing biodiesel content over the range from ULSD to B20, B50, and B100 for all cycles (including the 50 mph cruise). That is, the NOx emissions increase between ULSD and B20 shares the same slope as the NOx emissions increase between B20 and B100. For the animal-based biodiesel, the R^2 statistics also establish a linear increase in NOx emissions with increasing biodiesel content over the same range. The linearity of the response with blending percent is also well supported by the many NOx emissions graphs contained in Durbin 2011.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Table 3-5 **Re-Analysis for 2007 MBE4000 Engine (Engine Dynamometer Testing)** Model: NOx = A + B · BioPct Using ULSD, B20, B50, and B100 fuels							
Biodiesel Type	Test Cycle	R^2	Intercept A	BioPct Slope B		Predicted NOx Increase for B5	Predicted NOx Increase for B10
			Value	Value	p value	Pct Change	Pct Change
Soy-based							
	UDDS	0.989	2.319	0.0090 [a]	0.005	4.6%	9.1%
	FTP	0.998	1.268	0.0049	0.006	2.5%	5.0%
	50 mph	0.979	1.198	0.0054 [b]	0.092	2.7%	5.5%
Animal-based							
	UDDS	0.913	2.441	0.0036	0.044	2.0%	4.0%
	FTP	0.999	1.288	0.0038	0.020	2.5%	5.0%
	50 mph	0.994	1.205	0.0049	0.003	2.5%	5.0%

Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better.
[b] Orange highlight indicates result is statistically significant at the 90% confidence level or better.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

The table also gives the estimated NOx emission increases for B5 and B10 as predicted by the regression lines. For soy-based fuels, the values are ~3.5% for B5 (range 2.5% to 4.6% depending on the cycle) and ~7.5% for B10 (range 5.0% to 9.1% depending on cycle). For animal-based fuels, the values are approximately two-thirds as large: ~2.3% for B5 (range 2.0% to 2.5%) and ~4.5% for B10 (range 4.0% to 5.0%). The predicted increases are statistically significant to the same degree as the slope of the regression line from which they are estimated. That is, the predicted NOx increases are statistically significant at the >99% confidence level for soy-based fuels on the UDDS and FTP cycles and at the >95% confidence level for animal-based fuels on all cycles. The predicted NOx increase is statistically significant at the 90% confidence level for soy-based fuels on the 50 mph cruise cycle.

For this engine, soy- and animal-based B5 were tested on the FTP. Table 3-6 reproduces the NOx emission results reported in Tables ES-4 and ES-5 of Durbin 2011. While there are caveats on use of the pair-wise t-test, the FTP test data for this engine show NOx emissions at the B5 level for both soy- and animal-based fuels that are statistically significant at the 99% confidence level (or better) in this case. That is, <u>the test data for this engine as reported by Durbin 2011 refute the Staff Threshold Model that biodiesel blends below B10 do not increase NOx emissions</u>.

Table 3-6 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 2007 MBE4000 Engine (Engine Dynamometer Testing)				
	Soy-Based Biodiesel FTP		Animal-Based Biodiesel FTP	
	NOx % Diff	p value	NOx % Diff	p value
B5	0.9% [a]	0.007	1.3%	0.000
B20	5.9%	0.000	5%	0.000
B50	15.3%	0.000	12.1	0.000
B100	38.1%	0.000	29%	0.000

Source: Table ES-4/5 of Durbin 2011, p. xxix
Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on pair-wise t-test.

Figures 3-3a and 3-3b below compare the FTP data for this engine to the regression line representing the linear model (blue) and the Staff Threshold model (black) for both soy- and animal-based biodiesel. In both cases, the regression line was developed using the data for ULSD, B20, B50, and B100 (i.e., excluding the B5 data point). For both soy- and animal-based biodiesels, the data point for B5 falls on the established line, while the Staff Threshold model is inconsistent with the data. For this engine, it is clear that soy- and animal-based biodiesels increase NOx emissions at all blending levels.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Figure 3-3a
Re-assessment of FTP Cycle NOx Emissions Increases for Soy-based Biodiesel Blends (2007 MBE4000 Engine)

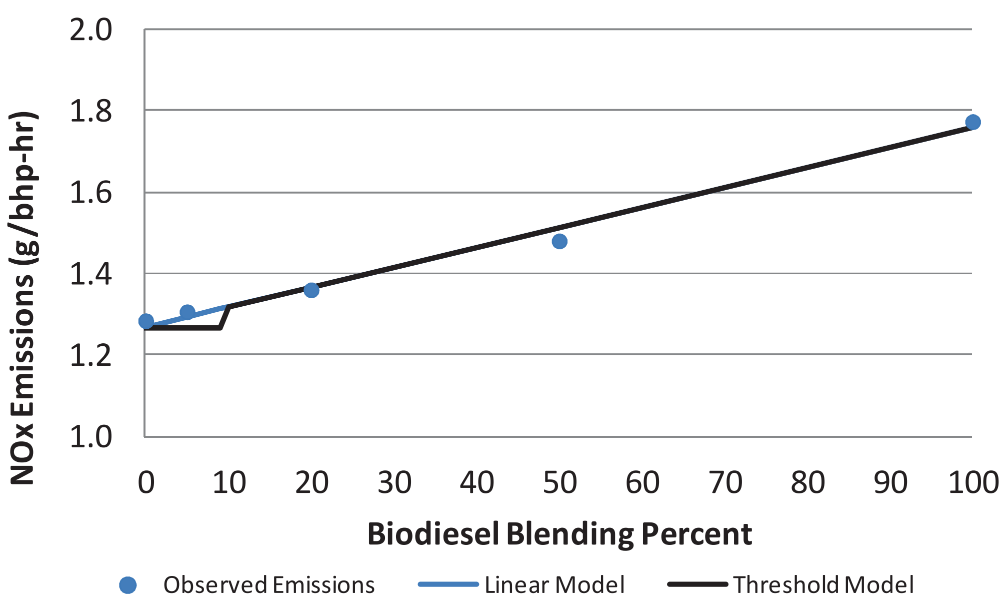
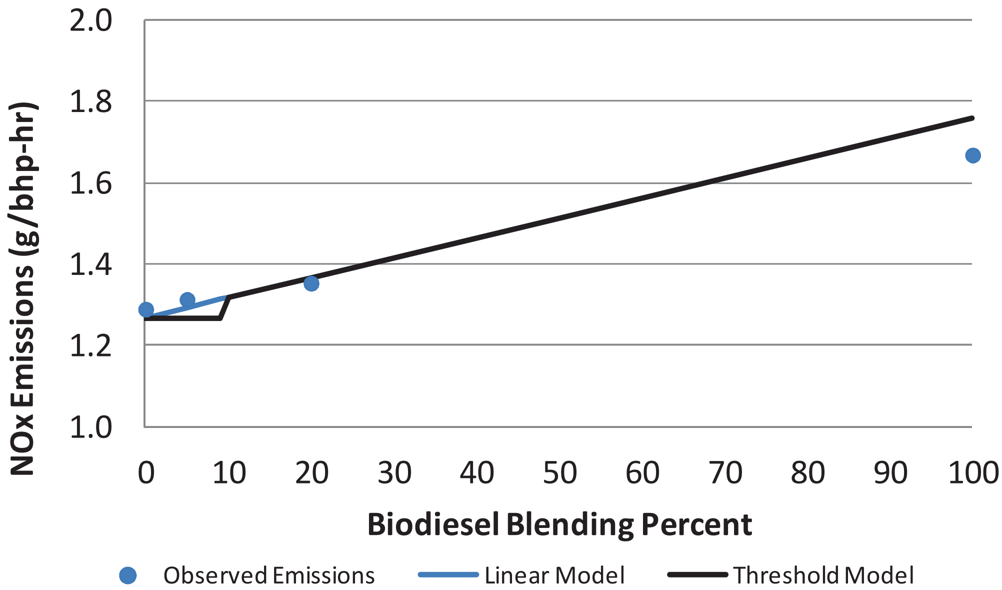


Figure 3-3b
Re-assessment of FTP Cycle NOx Emissions Increases for Animal-based Biodiesel Blends (2007 MBE4000 Engine)



Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

3.5Ā1998 Kubota TRU Engine (Engine Dynamometer Testing)

The 1998 Kubota V2203-DIB off-road engine was tested on the base fuel (ULSD) and soy-based biodiesel at four blending levels (B5, B20, B50, B100) in two different series using the ISO 8178 (8-mode) test cycle. Appendix I reports the measured emissions data only for the first series (ULSD, B50, B100). Using this subset of data, Table 3-7 summarizes the results of the re-analysis for this engine.

As for the other engines, the results of the analysis demonstrate the following:

- Ā The high R^2 statistic shows that the emissions effect of biodiesel is almost perfectly linear over the range B50 and B100. That is, the slope from ULSD to B50 is the same as the slope from B50 to B100. The slope of the regression line is statistically significant at the 99% confidence level.

- Ā NOx emissions are estimated to increase by 1.0% at the B5 level and by 2.1% at the B10 level. These estimated NOx emission increases are statistically significant to the same high degree as the regression slope on which they are based.

Table 3-7 Re-Analysis for 1998 Kubota V2203-DIB Engine (Engine Dynamometer Testing) Model: NOx = A + B · BioPct Using ULSD, B50, and B100 fuels							
Biodiesel Type	Test Cycle	R^2	Intercept A	BioPct Slope B		Predicted NOx Increase for B5	Predicted NOx Increase for B10
			Value	Value	p value	Pct Change	Pct Change
Soy-based	ISO 8178	0.999	12.19	0.0256 [a]	0.01	1.0%	2.1%

Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better.

The second test series involved ULSD, B5, B20, and B100 fuels. Measured emissions data are not given in Appendix I, so we must work with the calculated percent changes in NOx emissions tabulated in Durbin 2011. Table 3-8 reproduces the NOx emission results reported in Table ES-8 of Durbin 2011 for the two test series. For the second test series, biodiesel at the B5 level increased NOx emissions, but the result fails the pair-wise t-test for statistical significance. The NOx emission increase at the B20 level was statistically significant at the 90% confidence level, and the increase at the B100 level was statistically significant at the >99% confidence level. The significance determinations use the pair-wise t-test, which is subject to caveats, but this is the only method available to gauge significance because re-analysis of the computed percentage changes is not possible.

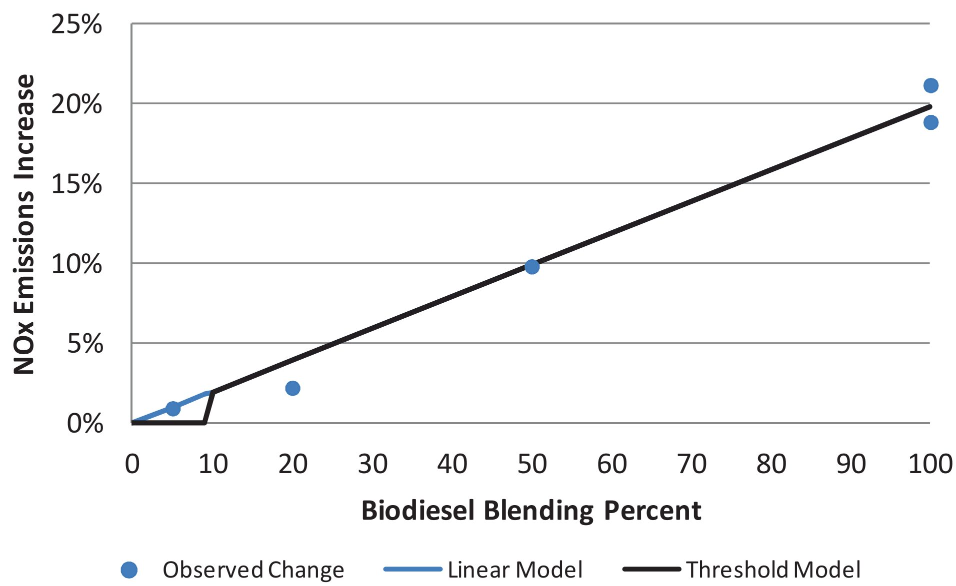
Table 3-8 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 1998 Kubota TRU Engine (Engine Dynamometer Testing)				
	Soy-Based Biodiesel Series 1 ISO 8178		Soy-Based Biodiesel Series 2 ISO 8178	
	NOx % Diff	p value	NOx % Diff	p value
B5	Not tested		0.97%	0.412
B20	Not tested		2.25% [a]	0.086
B50	7.63% [b]	0.000	Not tested	
B100	13.76%	0.000	18.89%	0.000

Source: Table ES-8 of Durbin 2011, p. xxxviii
Notes:
[a] Orange highlight indicates result is statistically significant at the 90% confidence level or better based on pair-wise t-test.
[b] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on pair-wise t-test

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Figure 3-4 displays the trend of NOx emissions with blending percent for the first and second test series combined. As the figure shows, the available data points scatter around the trendline determined from the emission change percentages (not from regression analysis). The B20 data point falls below the trend line while the two B100 data points bracket the trend line. It is not possible to explain the divergence of the B20 data point

Figure 3-4
Durbin 2011 Assessment: ISO 8178 Cycle NOx Emissions Increases for Soy-based Biodiesel Blends (1998 Kubota Engine, Test Series 1 and 2 Combined)



because the emissions data for the second test series are not published in Durbin 2011. The B5 data point clearly supports the Linear Model and is inconsistent with the Staff Threshold Model.

3.6Ā2009 John Deere Off-Road Engine (Engine Dynamometer Testing)

The only information on the 2009 John Deere off-road engine comes from the tabulation of calculated percentage emission changes. Table 3-9 reproduces these data from Table ES-7 of Durbin 2011. For the soy-based biodiesel, NOx emissions are significantly increased at the B20 and higher blend levels. The increase for B20 is statistically significant at the 90% confidence level and the increases for B50 and B100 are statistically significant at the >99% confidence level based on the pair-wise t-test. A soy-based B5 fuel was not tested.

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

Table 3-9 Percentage Change in NOx Emissions for Biodiesel Blends Relative to ULSD: 2009 John Deere Engine (Engine Dynamometer Testing)				
	Soy-Based Biodiesel ISO 8178		Animal-Based Biodiesel ISO 8178	
	NOx % Diff	p value	NOx % Diff	p value
B5	Not tested		-3.82	0.318
B20	2.82% [a]	0.021	-2.20	0.528
B50	7.63%	0.000	Not tested	
B100	13.76%	0.000	4.57	0.000

Source: Table ES-7 of Durbin 2011, p. xxxviii
Notes:
[a] Blue highlight indicates result is statistically significant at the 95% confidence level or better based on pair-wise t-test.

For animal-based biodiesel, the testing shows the unusual result that B5 and B20 appear to decrease NOx emissions, while B100 increases NOx. The B5 and B20 decreases are not statistically significant, while the B100 increase is statistically significant at the >99% confidence level. Durbin 2011 concludes:

> *The animal-based biodiesel also did not show as great a tendency to increase NOx emissions compared to the soy-based biodiesel for the John Deere engine, with only the B100 animal-based biodiesel showing statistically significant increases in NOx emissions.*[18]

Durbin 2011 does not discuss these results further and does not note any problems in the testing, making further interpretation of the results difficult. Figure 8-1 of Durbin 2011 presents the NOx results for this engine with error bars. First, we note that the figure appears to suggest that NOx emissions were increased on the B20 fuel in contradiction to the table above. Second, it is clear that the error bars are large enough that no difference in NOx emissions can be detected among ULSD, B5, and B20 fuels. Overall, this result could be consistent with the Staff Threshold Model through B5, but the failure to detect a NOx emission increase at B20 is not. Without further information, it is not possible to determine whether the result seen here is a unique response of the John Deere engine to animal-based biodiesel or is the result of a statistical fluctuation or an artifact in the emissions data.

3.7 Conclusions

The Biodiesel Characterization report prepared by Durbin et al. for CARB is an important source of information on the NOx emissions impact of biodiesel fuels in heavy-duty engines. It is the sole source of information on the NOx impact of B5 blends cited in the ISOR. When the engine dynamometer test data are examined for

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

[18] Durbin 2011, p. xx.

the three engines for which emissions test data have been published, we find clear evidence that biodiesel increases NOx emissions in proportion to the blending percent. Where B5 fuels were tested for these engines, NOx emissions are found to increase above ULSD for both soy- and animal-based blends in all three engines and by statistically significant amounts in one engine.

Specifically, a re-analysis of the NOx emissions test data demonstrates the following:

1. For the 2006 Cummins engine, biodiesel fuels are found to significantly increase NOx emissions for both soy- and animal-based blends by amounts that are proportional to the blending percent. This result indicates that biodiesels will increase NOx emissions at blending levels below B10. When B5 fuels were tested, NOx emissions were observed to increase but by amounts that fail to reach statistical significance according to the pair-wise test.[19] Graphical analysis demonstrates that NOx emissions measured for B5 fuels are consistent with the Linear Model, but not the Staff Threshold Model.

2. For the 2007 MBD4000 engine, biodiesel fuels are found to significantly increase NOx emissions for both soy- and animal-based blends by amounts that are proportional to the blending percent. This result indicates that biodiesels will increase NOx emissions at blending levels below B10. When B5 fuels were tested, NOx emissions were observed to increase and by amounts that are found to be statistically significant using the pair-wise t-test.[13] This result alone is sufficient to disprove the Staff Threshold Model. Graphical analysis demonstrates that NOx emissions measured for B5 fuels are consistent with the Linear Model, but not the Staff Threshold Model.

3. For the 1998 Kubota TRU (off-road) engine, soy-based biodiesel fuels are found to significantly increase NOx missions. Animal-based biodiesel was not tested. When a soy-based B5 fuel was tested, NOx emissions were observed to increase but by amounts that fail to reach statistical significance according to the pair-wise test.[13] Graphical analysis demonstrates that NOx emissions measured for B5 fuels are consistent with the Linear Model, but not the Staff Threshold Model.

The measured emissions test data for the other off-road engine (2009 John Deere) are not contained in the Durbin 2011 report and CARB has not made them publicly available. Thus, a re-analysis was not possible. Based on the tables and figures in Durbin 2011, soy-based biodiesel fuels were shown to significantly increase NOx emissions at B20 levels and higher, but B5 was not tested. Testing of animal-based blends shows no change in NOx emissions at B5 and B20 levels, but B100 is shown to significantly increase NOx emissions. Durbin 2011 discusses this result only briefly, and it is unclear what conclusions can be drawn from it.

###

Reproduction of Pages 168 -209 of Comment Letter 12_B_LCFS_GE/ 3_B_ADF_GE Consisting of Comments ADF B3-46 through ADF B3-92

[19] As discussed in Section 3.3, the pair-wise t-test is not the preferred method for demonstrating statistical significance.

8_SF_LCFS_GE (Page 251 - 288)

1214. Comment: **NOx Emission Impacts Of Biodiesel Blends**

Agency Response: This is the fourth time this document was submitted by Growth Energy. It is a reproduction of comments **ADF B3-46** through **ADF B3-92**. The comments are responded to in the Alternative Diesel Regulation Final Statement of Reasons under comment letter **3_B_ADF_GE**.

This page intentionally left blank.

APPENDIX AĀ

RESUME OF ROBERT W. CRAWFORD

Education

1978 Doctoral Candidate, ScM. Physics, Brown University, Providence, Rhode Island
1976 B.A. Physics, Pomona College, Claremont, California

Professional Experience

1998-Present Independent Consultant

Individual consulting practice emphasizing the statistical analysis of environment and energy data with an emphasis on how data and statistics are properly used to make scientific inferences. Mr. Crawford provides support on statistical, data analysis, and modeling problems related to ambient air quality data and emissions from mobile and stationary sources.

Ambient Air Quality and Mobile Source Emissions – Mr. Crawford has worked with Sierra Research on elevated ambient CO and PM concentrations in Fairbanks AK and Phoenix AZ, including the effect of meteorological conditions on ambient concentrations, the relationship of concentrations to source inventories, and the use of non-parametric techniques to infer source location from wind speed and direction data. Ongoing work is employing Principal Components Analysis to elucidate the relationship between meteorology and $PM_{2.5}$ concentrations in Fairbanks. In the past year, this work led to creation of the AQ Alert System, a tool used by air quality staff to track $PM_{2.5}$ monitor concentrations during the day and to prepare AQ alerts over the next 3 days based on the meteorological forecast.

In past work for Sierra, he has also conducted studies of fuel effects on motor vehicle emissions for Sierra. For CRC, he determined the relationship between gasoline volatility and oxygen content on tailpipe emissions of late model vehicles at FTP and cold-ambient temperatures. For SEMPRA, he determined the relationship between CNG formulation and tailpipe emissions of criteria pollutants and a range of air toxics. Other work has included the design of vehicle surveillance surveys and determination of sample sizes, development of screening techniques similar to discriminant functions to improve the efficiency of vehicle recruitment, the analysis of vehicle failure rates measured in inspection & maintenance programs, and the statistical evaluation of data collected on freeway speeds using automated sensors.

Stationary Source Emissions – Over the past 5 years, Mr. Crawford has worked with AEMS, LLC on EPA's MACT and CISWI rulemakings for Portland Cement plants, in which significant issues related to data quality, data reliability, and emissions variability are evident. Key issues include the need to properly account for uncertainty and emissions variability in setting emission standards. He also supported AEMS in the

current EPA rulemaking on reporting of greenhouse gas emissions from semiconductor facilities, where the proper characterization of emission control device performance was a key issue. He is currently supporting AEMS in a regulatory process to re-determine emission standards for an industrial facility where the new standard will be enforced by continuous emissions monitoring (CEMS). At issue is how to set the standard in such a way that there will be no more than a small, defined risk that 30-day emission averages will exceed the limitations while emissions remain well-controlled .

Advanced Combustion Research – In recent work for Oak Ridge National Laboratory, Mr. Crawford conducted a series of statistical studies on the fuel consumption and emissions performance of Homogenous Charge Compression Ignition (HCCI) engines. One of these studies was for CRC, in which fuel chemistry impacts were examined in gasoline HCCI. In HCCI, the fuel is atomized and fully-mixed with the intake air charge outside the cylinder, inducted during the intake stroke, and then compressed to the point of spontaneous combustion. The timing of combustion is controlled by heating of the intake air. If R&D work can demonstrate a sufficient understanding of how fuel properties influence engine performance, the HCCI combustion strategy potentially offers the fuel economy benefit of a diesel engine with inherently lower emissions.

1979-1997 Energy and Environmental Analysis, Inc., Arlington, VA. Director & Partner (from 1989).

<u>Primary work areas</u>: Studies of U.S. energy industries for private and institutional clients emphasizing statistical analysis, business planning and computer modeling/forecasting. Responsible for the EEA practice area that provided strategic planning and forecasting services to major energy companies. Primary topical areas included: U.S. energy market analysis and strategic planning; gas utility operations; and natural gas supply planning.

<u>U.S. Energy Market Analysis</u>

During 1995-1997, Mr. Crawford directed EEA’s program to provide comprehensive energy supply and demand forecasting for the Gas Research Institute (GRI) in its annual *Baseline Projection of U.S. Energy Supply and Demand*. Services included: development of U.S. energy supply, demand, and price forecasts; sector-specific analyses covering energy end-use (residential, commercial, industrial, transportation), electricity supply, and natural gas supply and transportation; and the preparation of a range of publications on the forecasts and energy sector trends.

From 1989 through 1997, he directed the use of EEA's Energy Overview Model in strategic planning and long-term market analysis for a client base of major energy producers, pipelines, and distributors in both the United States and Canada. The Energy Overview Model was used under his direction as the primary analytical basis for the 1992 National Petroleum Council study *The Potential for Natural Gas in the United States*. Mr. Crawford also provided analysis for clients on a wide range of other energy market issues, including negotiations related to an LNG import project intended to serve U.S. East Coast markets. This work assessed the utilization and economic value of seasonal

gas deliverability in order to develop LNG pricing formulas and evaluate the project's viability.

Other topical areas of work during his period of employment with EEA include:

Gas Load Analysis and Utility Operations – Principal investigator in a multi-year research program for the Gas Research Institute (GRI) that examined seasonal gas loads, utility operations, and the implications for transmission and storage system reliability and capacity planning.

Gas Transmission and Storage – Principal investigator for a study of industry plans for expansion of underground gas storage capacity in the post-Order 636 environment, including additions of depleted-reservoir and salt-formation storage, an engineering analysis of capital and operating costs for the projects, and unbundled rates for new storage services.

Natural Gas Supply Planning – Mr. Crawford was EEA's senior manager and lead analyst on gas supply planning issues for both pipeline and distribution companies, which included technical and analytic support in development and justification of gas supply strategies; and identification of optimal seasonal supply portfolios for Integrated Resource Planning proceedings.

Transportation Systems Research

Mr. Crawford also had extensive experience in motor vehicle fuel economy and emissions while at EEA. He participated for five years in a DOE research program on fuel economy, with emphasis on the evaluation of differences between laboratory and on-road fuel economy. His work included analysis of vehicle use databases to understand how driving patterns and ambient (environmental) conditions influence actual on-road fuel economy. He also developed a software system to link vehicle certification data systems to vehicle inspection and testing programs and participated in a range of studies on vehicle technology, fuel economy, and emissions for DOE, EPA, and other governmental agencies.

SELECTED PUBLICATIONS (emissions and motor vehicle-related topics)

Statistical Assessment of $PM_{2.5}$ and Meteorology in Fairbanks, Alaska: 2013 Update. Crawford and Dulla. Prepared for the Alaska Department of Environmental Conservation. (forthcoming).

Statistical Assessment of $PM_{2.5}$ and Meteorology in Fairbanks, Alaska. Crawford and Dulla. Prepared for the Alaska Department of Environmental Conservation. March 2012.

Principal Component Analysis: Inventory Insights and Speciated $PM_{2.5}$ Estimates. Crawford. Presentation at Air Quality Symposium 2011, Fairbanks and North Star Borough, Fairbanks, AK. January 2011.

Influence of Meteorology on $PM_{2.5}$ Concentrations in Fairbanks Alaska: Winter 2008-2009. Crawford. Presentation at Air Quality Symposium 2009, Fairbanks and North Star Borough, Fairbanks, AK. July 2009.

Analysis of the Effect of Fuel Chemistry and Properties on HCCI Engine Operation: A Re-Analysis Using a PCA Representation of Fuels. Bunting and Crawford. 2009. Draft Report (CRC Project AFVL13C)

The Chemistry, Properties, and HCCI Combustion Behavior of Refinery Streams Derived from Canadian Oil Sands Crude. Bunting, Fairbridge, Mitchell, Crawford, et al. 2008. (SAE *08FFL 28)*

The Relationships of Diesel Fuel Properties, Chemistry, and HCCI Engine Performance as Determined by Principal Components Analysis. Bunting and Crawford. 2007. (SAE 07FFL 64).

Review and Critique of Data and Methodologies used in EPA Proposed Utility Mercury MACT Rulemaking, prepared by AEMS and RWCrawford Energy Systems for the National Mining Association. April 2004.

PCR+ in Diesel Fuels and Emissions Research. McAdams, Crawford, Hadder. March 2002. ORNL/TM-2002/16.

A Vector Approach to Regression Analysis and its Application to Heavy-duty Diesel Emissions. McAdams, Crawford, Hadder. November 2000. ORNL/TM-2000/5.

A Vector Approach to Regression Analysis and its Application to Heavy-duty Diesel Emissions. McAdams, Crawford, Hadder. June 2000. (SAE 2000-01-1961).

Reconciliation of Differences in the Results of Published Shortfall Analyses of 1981 Model Year Cars. Prepared by Energy and Environmental Analysis, Inc. for the U.S. Department of Energy under Contract DE-AC01-79PE-70045. October 1985

Short Test Results on 1980-1981 Passenger Cars from the Arizona Inspection and Maintenance Program. Darlington, Crawford, Sashihara. August 1984.

Seasonal and Regional MPG as Influenced by Environmental Conditions and Travel Patterns. Prepared by Energy and Environmental Analysis, Inc. for the U.S. Department of Energy under Contract DE-AC01-79PE-70045. March 1983.

Comparison of EPA and On-Road Fuel Economy – Analysis Approaches, Trends, and Impacts. McNutt, Dulla, Crawford, McAdams, Morse. June 1982. (SAE 820788)

Regionalization of In-Use Fuel Economy Effects. Prepared by Energy and Environmental Analysis, Inc. for the U.S. Department of Energy under Contract DE-AC01-79PE-70032. April 1982.

1985 Light-Duty Truck Fuel Economy. Duleep, Kuhn, Crawford. October 1980. (SAE 801387)

PROFESSIONAL AFFILIATIONS

Member, Society of Automotive Engineers.

HONORS AND AWARDS

2006 Barry D. McNutt Award for Excellence in Automotive Policy Analysis. Society of Automotive Engineers.

US Patent 7018524 (McAdams, Crawford, Hadder, McNutt). Reformulated diesel fuels for automotive diesel engines which meet the requirements of ASTM 975-02 and provide significantly reduced emissions of nitrogen oxides (NO_x) and particulate matter (PM) relative to commercially available diesel fuels.

US Patent 7096123 (McAdams, Crawford, Hadder, McNutt). A method for mathematically identifying at least one diesel fuel suitable for combustion in an automotive diesel engine with significantly reduced emissions and producible from known petroleum blend stocks using known refining processes, including the use of cetane additives (ignition improvers) and oxygenated compounds.

###

8_SF_LCFS_GE (Page 289 - 293)

1215. Comment: **Robert Crawford's Resume**

Agency Response: This is submittal four of four of Robert Crawford's resume. It does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

Attachment 6

Proposed Regulation on the Commercialization of Alternative Diesel Fuels

Staff Report: Initial Statement of Reasons




Industrial Strategies Division

Oil and Gas and GHG Mitigation Branch & Transportation Fuels Branch

Release Date: January 2, 2015

To Be Considered by the Board: February 19 or 20, 2015

This page intentionally left blank

State of California
Air Resources Board

Staff Report: Initial Statement of Reasons for Proposed Rulemaking

Proposed Regulation on the Commercialization of Alternative Diesel Fuels

Date of Release: January 2, 2015
Scheduled for Consideration: February 19 or 20, 2015

Location:

California Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

This page intentionally left blank

Acknowledgments

This report was prepared with the assistance and support from many individuals within the Air Resources Board. Staff would like to acknowledge the cooperation from numerous State, governmental, and local air pollution control agencies that have provided assistance throughout the rulemaking process. Staff would also like to acknowledge the invaluable contributions from our key stakeholders including the National Biodiesel Board, California Biodiesel Alliance, Western States Petroleum Association, Kinder Morgan, and others.

Air Resources Board

Principal Contributors

Industrial Strategies Division

Susie Chung
Aubrey Gonzalez
Alexander “Lex” Mitchell
Jose Saldana
Jim Peterson

Research Division
Chantel Crane

Supporting Contributors

Office of Legal Affairs
Stephen Adams
William Brieger
Christina Morkner Brown

Enforcement Division
Herman Lau

CEQA
Cathi Slaminski
Ascent Environmental

Research Division
Fereidun Feizollahi
Jeff Austin

Reviewed by:

Richard W. Corey, Executive Officer
Edie Chang, Deputy Executive Officer
Floyd Vergara, Chief, Industrial Strategies Division
Jack Kitowski, Assistant Chief, Industrial Strategies Division
Mike Waugh, Chief, Transportation Fuels Branch
Elizabeth Scheehle, Chief, Oil and Gas and GHG Mitigation Branch
Jim Aguila, Manager, Substance Evaluation Section
Alexander “Lex” Mitchell, Manager, Emerging Technology Section

This page intentionally left blank

Table of Contents

Table of Appendices:

Table of Figures:

This page intentionally left blank

EXECUTIVE SUMMARY

The staff of the Air Resources Board (ARB or Board) is proposing a regulation to govern the commercialization of motor vehicle alternative diesel fuels (ADF) in California. Through California's fuel policies, consumers are beginning to see increasingly cleaner fuels as well as more options for fueling their motor vehicles. The ADF regulation is intended to create a framework for these low carbon diesel fuel substitutes to enter the commercial market in California, while mitigating any potential environmental or public health impacts. ADFs are those alternative diesel fuels that do not have an established ARB fuel specification in effect prior to January 1, 2016. The proposed regulation consists of two major parts:

1) A three stage process for ADFs to be introduced into the California market including, if necessary, a determination of mitigation measures to ensure no degradation in air quality.
2) In-use requirements for biodiesel as the first ADF

Although this will be a new regulation, the proposal consolidates many current administrative and regulatory practices into one regulation that provides a clear framework for commercialization of ADFs. The formal framework is necessary for two primary reasons. First, programs such as California's Low Carbon Fuel Standard (LCFS) and the federal Renewable Fuels Standard (RFS) are expected to incentivize the rapid development of ADFs. Many of these fuels provide criteria pollutant and toxic air contaminant emission reductions in addition to their greenhouse gas (GHG) benefit. Second, some ADFs may have adverse effects under certain circumstances. For these reasons, ARB is proposing the regulation to ensure that ADFs are commercialized in California under specific requirements and conditions that avoid potential adverse impacts while realizing the benefits that ADFs can provide.

The first ADF that will be subject to in-use requirements under this framework is biodiesel. Fuel specifications and other requirements for future ADFs will be incorporated into this regulation through additional rulemakings. Biodiesel has particulate matter (PM) and GHG benefits, however testing by ARB and others show that biodiesel can increase oxides of nitrogen (or NOx) under certain circumstances and without considering offsetting factors. These effects are only observed in older (pre-2010) vehicles. As new technology diesel engines are phased in through other ARB programs such as the Truck and Bus Regulation, the NOx impacts will be reduced until they are negligible. ARB expects the in-use specifications to sunset around 2023. Until that time, the in-use specifications will reduce NOx from current levels and Californians will continue to experience the PM and GHG benefits.

There has been confusion between biodiesel and renewable diesel; however, these are two distinct fuels. Renewable diesel and biodiesel are both biomass based diesel fuel replacements and can be confused with each other, but the distinctions are important. Although the two fuels use the same feedstocks (e.g. animal tallow, used cooking oil, soybean oil), they are produced using different production processes with resulting products having different chemical properties and environmental attributes. Renewable diesel is not considered an ADF as it consists solely of hydrocarbons and is chemically indistinguishable from conventional diesel. Renewable diesel has been shown to decrease emissions of GHGs, PM, hydrocarbons, and carbon monoxide and, in contrast to biodiesel, renewable diesel has also been shown to reduce NOx. Because renewable diesel is not an ADF, it would not be subject to in-use requirements and is expected to increase significantly over time, with associated co-benefits of reduced air pollutants.

The availability of both renewable diesel and biodiesel will help fulfill our climate goals, provide fuel diversity, contribute PM emission reduction benefits, and, with the implementation of this regulation, have no degradation of air quality from current levels.

What are we proposing?

The proposed regulation would require an ADF to proceed through a three-stage process that evaluates the fuel for environmental impacts prior to use above a minimum threshold amount in California. As part of that evaluation process, the regulation establishes measures that apply to maintain current air quality protections. Many of the provisions in this regulation are already required under existing State law. The three stages of this process are described below.

Stage 1: Pilot Program. In this stage, an ADF applicant(s) would apply to ARB for a pilot program under which no more than 1 million gallons total of the ADF could be used in the State in well-defined fleets within a year. During that time, the applicant would conduct required testing and emissions evaluations. The application process includes disclosure of the chemical composition of the ADF, as well as other important information, which would enable staff to conduct a screening analysis. This screening analysis is intended to help staff determine whether use of the ADF presents a potential adverse impact to the public health or environment. Advancement to Stage 2 requires the ADF applicant to fulfill the Stage 1 requirements and enter into an agreement with the Executive Officer (EO) to complete and satisfy specified terms and conditions, such as additional emissions testing, which will apply during the second stage.

Stage 2: Fuel Specification Development. In this stage, an ADF proponent(s) would apply for a broader, but still limited, agreement allowing use of up to 30 million gallons of that ADF per year in a larger fleet. The larger volume and sample fleet would allow for more comprehensive testing and analyses that would inform a multimedia evaluation; help develop consensus standards for the ADF; identify what circumstances, if any, could result in an adverse impact on public health or the environment; and, if necessary, determine appropriate mitigation options. During this stage, ARB staff would determine, if necessary, a pollutant control level for a particular pollutant of concern.

Stage 3: Commercial Sales. This stage is split into Stage 3A and Stage 3B. Stage 3A is applicable to ADFs for which ARB staff has identified a pollutant control level. An ADF sold in California under this stage would be subject to potential sales conditions and mitigation measures that are based on the pollutant control level(s) determined in

Stage 2. By contrast, Stage 3B is applicable to ADFs for which no pollutant control level is necessary. Accordingly, ADFs in Stage 3B can be used at any blend level and without any conditions of use or mitigation measures.

An ADF subject to Stage 3A is subject to enhanced monitoring and recordkeeping. The ARB staff would use such monitoring and records, along with other market and fleet data, to determine whether the pollutant control level has been reached.

Staff has determined that certain blends of biodiesel, the first ADF to be subject to the proposed regulation, can increase NOx under certain circumstances and in the absence of offsetting factors. However, ARB staff has also determined that NOx associated with these biodiesel blends are offset by a number of factors. Accordingly, ARB staff has designed the proposed regulation to ensure that biodiesel can be commercialized without an increase in NOx. The proposed regulation provides for a proper accounting of offsetting factors already occurring in the California market and the appropriate application of in-use requirements.

Accounting for feedstock saturation and offsetting factors such as renewable diesel usage and fuel use by newer heavy duty trucks, biodiesel can be used in lower blends levels without triggering in-use specifications. In-use specifications are necessary above a five percent blend level (B5) for low saturation biodiesel and a B10 level for high saturation biodiesel during ozone season and above B10 for all biodiesel in low ozone season.

Why are we taking this action?

Consumption of ADFs, such as biodiesel, is expected to increase in the coming years due to a variety of policy incentives including the RFS, LCFS, and potentially the continuance of federal blending tax credits. These fuels will help California meet its climate and petroleum reduction goals, provide fuel diversity, and contribute PM benefits. As such, it is important to ensure that the full commercialization of these fuels do not increase air pollution or cause other environmental concerns. The proposed regulation will ensure this by subjecting new ADFs to a rigorous, phased environmental review with specific terms and conditions. As part of the environmental review, staff will determine whether the ADF has a “pollutant control level” for the pollutant of concern, which is defined to be that level of ADF use which could lead to an increase in the pollutant of concern. In that case, staff will identify the terms of the pollutant control level and define the specific in-use requirements, when conditions warrant mitigation. This regulation will ensure that ADFs avoid potential adverse impacts while realizing the benefits that ADFs can provide in terms of reductions in GHGs and PM and increase in fuel diversity in the state.

Who is affected by this proposed regulation?

The regulation applies primarily to producers and importers of alternative diesel fuels. If necessary, the applicant producer or importer would be responsible for applying any mitigation measures that may be required under a Stage 3A scenario. Retail marketers and distributors of alternative diesel fuels are generally not affected by the in-use requirements unless they are also conducting fuel blending. Retailers and distributors may be required to do some of the required recordkeeping and monitoring, but these generally would apply to the higher blends of an ADF (e.g., for marketers of biodiesel in blends above B10).

What are the costs of this proposed regulation?

Staff expects the costs directly attributable to this proposed regulation to be minimal. Regulatory costs are primarily due to some increases in reporting, recordkeeping and testing of ADFs, as well as costs for in-use requirements affecting some biodiesel blends. Many of the requirements of this regulation already exist under other State law, and, as such, are not an additional cost of this regulation. For example, much of the reporting associated with this regulation is already required to comply with the LCFS regulation or other State or federal programs. The requirement for a multimedia evaluation of new ADFs is already required by ARB pursuant to Health and Safety Code (H&SC) section 43830.8, and development of consensus standards is already required by existing regulations implemented by the California Department of Food and Agriculture. The differences between existing law and this proposed regulation is primarily the enhanced monitoring required and a more streamlined route to the commercial market.

Staff also estimated potential costs of in-use control for biodiesel use. Staff's analysis shows that with full implementation of the in-use requirements in 2018, biodiesel used in B5 blends incur no in-use requirement costs, only minimal recordkeeping costs. Higher blends above B5 may have a small cost per gallon. For 2018, the projected costs for complying with the in-use requirements are about $3 million on 180 million gallons of biodiesel, or less than two cents per gallon. Beyond 2018, the cost for biodiesel blends above B5 is projected to decrease to zero because the in-use requirement will sunset upon near full fleet penetration of new technology diesel engines in California.

CHAPTER 1. INTRODUCTION

A. Air Quality

Due to its unique geography, California has unique air pollution challenges. Ambient air quality standards designed to protect public health have been established for several pollutants in the State. Although California has made substantial progress, in many parts of the State air pollution exceeds these ambient air quality standards. To attain the ambient air quality standards, the California Air Resources Board (ARB or Board) has designed a multi-faceted strategy, including emission reductions from mobile sources and motor vehicle fuels. The ARB uses its legal authority to regulate emissions from motor vehicle fuels in the State when appropriate to reduce air pollution. To date, ARB has developed fuel quality standards for gasoline, diesel and several alternative motor vehicle fuels.

In anticipation of increasing biodiesel use and additional alternative motor vehicle fuels in California, ARB staff recognizes the need for a new regulation to maintain air quality benefits for future commercial substitute diesel fuels.

B. Alternative Motor Vehicle Fuels

There is a trend in California toward increasing consumption of alternative motor vehicle fuels in place of conventional petroleum-based gasoline and diesel fuels. This trend is primarily due to economic incentives and policies at the State and national level that incent the use of lower polluting, less toxic, and lower carbon intensity fuels in the commercial market. A more detailed discussion of these new fuels is presented in Chapters 2 through 4. As a result of this diversification, some diesel fuel substitutes have started to enter commerce in California without clear regulatory requirements to ensure there are no detrimental impacts to air pollution as a result of their use. In response to this, ARB staff is proposing a new Alternative Diesel Fuel (ADF) regulation that will put the proper regulatory structure into place to ensure no detrimental impacts to air quality as California moves toward increased alternative motor vehicle fuels consumption.

C. Alternative Diesel Fuels Overview

In general, alternative diesel fuels are a category of motor vehicle fuels that are not conventional diesel and do not solely consist of hydrocarbons. While there are a few alternative diesel fuels in existence today, biodiesel is by far the most prevalent. While renewable diesel is also an innovative diesel fuel replacement, it consists solely of hydrocarbons and is virtually indistinguishable from conventional diesel; therefore, renewable diesel is not considered an alternative diesel fuel under this proposed regulation.

Biodiesel and renewable diesel are both low carbon fuels that can be produced domestically. Using conventional feed stocks, these fuels provide carbon intensities about 25 percent lower than petroleum diesel fuel. Using waste feedstocks, the carbon intensity can be as much as 80 percent lower than petroleum diesel fuel. Biodiesel and renewable diesel also decrease emissions of harmful air pollutants. Blends of biodiesel and renewable diesel have been shown to decrease the emission rates of particulate matter, hydrocarbons and carbon monoxide. Renewable diesel has also been shown to reduce NOx.

1. Biodiesel

Biodiesel has already been in use in California for several decades. Waste restaurant grease is frequently confused with biodiesel. Grease is referred to as straight vegetable oil (SVO), which has a long history of use in diesel engines. Peanut oil, a type of SVO, was the fuel that powered Rudolph Diesel's original compression ignition engine at the 1911 World Fair.

Although SVO can be used in most diesel engines, its use leads to durability issues, such as clogging of fuel injectors and fatty engine deposits. To create a fuel that is more appropriate for the modern diesel engine, SVO must be chemically converted to a form that has improved combustion properties through a process called transesterifcation. In order to accomplish this conversion, the SVO, or other feed stock, is chemically converted to fatty acid methyl esters (FAME) by reacting the SVO with methanol and a catalyst. The resulting FAME biodiesel is much cleaner burning and less viscous, reducing or eliminating many of the problems caused by SVO.

Biodiesel feed stocks such as animal tallow and waste vegetable oil contain high concentrations of triglycerides, which is the main component of fats and oils. These feed stocks can be processed into biodiesel and depending upon the specific feed stock, there may be a range of emissions effects. For example, soybean oils tend to produce higher NOx emitting biodiesel than animal tallow.

2. Renewable Diesel

In addition to biodiesel, ARB considered renewable diesel during this rulemaking. Renewable diesel uses essentially the same feed stocks that are used to make biodiesel, but instead of the transesterification reaction, renewable diesel is produced by hydroprocessing, which results in a fuel containing pure hydrocarbons, paraffinic compounds and nearly no aromatics. Renewable diesel has few of the disadvantages normally associated with biodiesel such as poor cold weather performance, biological degradation or oxidation stability. However, renewable diesel exhibits poor lubricity and generally must be used in a lubricated mixture or have a lubricity additive incorporated in the fuel. Finally, renewable diesel is generally more homogeneous and does not exhibit the chemical variability of biodiesel made from different production feedstocks.

D. Low Carbon Fuel Standard Litigation

On July 15, 2013, the State of California Court of Appeal, Fifth Appellate District (Court) issued its opinion in POET, LLC versus California Air Resources Board (2013) 218 Cal.App.4th 681. Among the issues in the lawsuit was the treatment of biodiesel in the original LCFS regulation. The judge's opinion was that ARB did not adequately address biodiesel NOx emissions that could potentially result from implementation of the LCFS. The Court held that the LCFS would remain in effect and that ARB can continue to implement and enforce the 2013 regulatory standards while it takes steps to cure California Environmental Quality Act and Administrative Procedure Act issues associated with the original adoption of the regulation. In addition to the general impetus of this regulation to protect air quality, it is also designed to fulfill the court's requirements and to remedy issues with NOx emissions from biodiesel. Implementation of this regulation will ensure that the use of biodiesel due to LCFS will not result in increases in NOx emissions in California.

E. Development Process for the Proposed Regulation

Staff evaluation of ADFs and biodiesel began in the early 2000s. During the informal rulemaking process, ARB staff conducted numerous meetings of the Multimedia Working Group (MMWG), multiple public workshops, and numerous meetings with individual stakeholders to discuss a proposed regulation. The MMWG is an inter-agency group responsible for oversight of multimedia evaluations. Below is a timeline of the public actions taken leading up to this proposal, each of the meetings below included opportunities for public comment, which were considered when developing the proposed ADF regulation.

Table 1.1: ADF Regulatory Development Timeline

Date	**Meeting**
2004-2005	Two Biodiesel Work Group Meetings
2006-2007	Five Meetings of the Biodiesel Work Group
2008-2009	Six Meetings of the Biodiesel Work Group
2010	Two Biodiesel Rulemaking Workshops
December 8, 2010	Multimedia Evaluation Meeting
October 4, 2011	Released Biodiesel Guidance Document
February 15, 2013	ADF Concept Paper
April 23, 2013	ADF Rulemaking Workshop
June 13, 2013	ADF Rulemaking Workshop
September 5, 2013	ADF Rulemaking Workshop
February 13, 2014	ADF Rulemaking Workshop
April 17, 2014	ADF Rulemaking Workshop
July 1, 2014	Webinar/Biodiesel Emissions Characteristic Study
October 20, 2014	ADF Rulemaking Workshop
November 21, 2014	Final ADF Rulemaking Workshop and Proposed Draft Regulatory Language

For each of the rulemaking meetings above, over 7,000 individuals or companies were notified and invited to participate. Each of these meetings was well attended by a variety of stakeholders including refiners, oil marketers, alternative fuel producers, non-governmental organizations, academia, and other State agencies. Notices for the workshops, and associated materials, were posted to ARB's biodiesel and renewable diesel webpage at: http://www.arb.ca.gov/fuels/diesel/altdiesel/biodiesel.htm, and emailed to subscribers of our "altdiesel" listserve. Rulemaking workshops were made available to remote attendees by either webcast or webinar in all cases.

In addition to the public meetings, staff had many meetings with stakeholders, attended trade meetings, and exchanged technical information on a regular basis with staff from other State agencies, academia, industry groups, and non-governmental organizations. As a result of this extensive communication with the affected entities, the proposal contained herein is based upon feedback from nearly every corner of the regulated industry as well as other impacted organizations and individuals that are affected by actions concerning or regulate the fuels industry.

Staff also conducted a Standardized Regulatory Impact Assessment (SRIA) in combination with the LCFS. As required by Senate Bill 617 (Chapter 496, Status of 2011), ARB conducted a SRIA and received public feedback and comments from the Department of Finance.

As part of the SRIA process, ARB solicited public input on alternative ADF approaches, including any approach that may yield the same or greater benefits than those associated with the proposed regulation, or that may achieve the goals at lower cost. Alternative approaches submitted to ARB were considered as staff prepared a SRIA. The combined SRIA of Low Carbon Fuel Standard and ADF summary is posted at: http://www.dof.ca.gov/research/economic_research_unit/SB617_regulation/2014_Major_Regulations/documents/ADF_DF_131_SUMMARY.PDF

F. Organization of This Report

This report is organized into twelve chapters with five appendices. We start with four chapters of background and introduction followed by chapters for description of the proposed regulation, alternatives considered, technology assessment, environmental assessment, multimedia assessment, economic impacts analysis of this proposed regulation and concluding with a summary and rationale for the regulation as well as a references chapter. The five appendices include Proposed Regulation Order, Technology Assessment, Economic Assessment, Standardized Regulatory Impact Assessment and California Environmental Quality analysis.

CHAPTER 2. CALIFORNIA MANDATES ON AIR QUALITY

A. Ambient Air Quality Standards

Ambient air quality standards (AAQS) are established to protect even the most sensitive individuals in our communities. An air quality standard defines the maximum amount of a pollutant that can be present in outdoor air without harm to the public's health. Both the ARB and the U.S. Environmental Protection Agency (U.S. EPA) are authorized to and have set ambient air quality standards. California has established AAQS standards for certain pollutants such as fine particulate matter (PM_{10}), ozone, carbon monoxide and sulfur dioxide, which are more protective of public health than federal ambient air quality standards. California has also set standards for some pollutants that are not addressed by federal standards in addition to six criteria pollutants that are on National AAQS list.

Air pollution harms the health of California residents, damages agricultural crops, forests and other plants, and creates the haze that reduces visibility. A large body of scientific evidence associates air pollution exposure with a variety of harmful health effects. To address air pollution, both the California ARB and the U.S. EPA have adopted ambient (outdoor) air quality standards. These legal limits on outdoor air pollution are designed to protect the health and welfare of Californians.

B. Greenhouse Gases and Climate Change

California Global Warming Solutions Act of 2006 (AB 32) outlined the process by which the Board would reduce GHG emissions in California to 1990 levels by 2020 - a reduction of approximately 30 percent by 2020, and then an 80 percent reduction below 1990 levels by 2050. Required actions are codified in H&SC section 38500 through 38599, and Executive Orders S-3-05 and B-16-2012. Some specific provisions of AB 32 included the following responsibilities of ARB:

- Prepare and approve a scoping plan for achieving the maximum technologically feasible and cost-effective reductions in GHG emissions from sources or categories of sources of GHG by 2020 (H&SC §38561); and
- Identify the statewide level of GHG emissions in 1990 to serve as the emissions limit to be achieved by 2020 (H&SC §38550); and
- Adopt a regulation requiring the mandatory reporting of GHG emissions (H&SC §38530); and
- Identify and adopt regulations for discrete early actions that could be enforceable on or before January 1, 2010 (H&SC §38560.5).

AB 32 also requires ARB to develop a Scoping Plan (H&SC §38561) which lays out California's strategy for meeting the GHG reduction goals. The Scoping Plan must be updated every five years and in December 2008, the Board approved the initial Scoping Plan, which included a suite of measures to sharply cut GHG emissions. In May 2014, ARB approved the First Update to the Climate Change Scoping Plan (Update), which builds upon the initial Scoping Plan with new strategies and recommendations. The Update highlights California's progress toward meeting the near-term 2020 GHG emission reduction goals, highlights the latest climate change science and provides direction on how to achieve long-term emission reduction goal described in Executive Order S-3-05. Low Carbon Fuel Standard Program was one of the discrete early actions identified by ARB pursuant to AB 32.

CHAPTER 3. CALIFORNIA MOTOR VEHICLE DIESEL FUEL POLICIES

This chapter provides a summary of various State policies that affect motor vehicle diesel fuel and specifically the development of the ADF regulation. These policies broadly include statutes, regulations, or initiatives that impact the development of the ADF regulation.

A. California Health and Safety Code

California Senate and Assembly bills pertinent to motor vehicle diesel fuels are codified in the California Health and Safety Code (H&SC). These statutes are then administered as rules and regulations in the California Code of Regulations (CCR). The relevant statutes and regulations are provided below but are primarily contained in H&SC Division 26, Parts 1, 2, and 5; and CCR Division 3, Titles 13 and 17.

1. Development of Diesel Fuel Regulations

H&SC Sections 39600, 39601, 43013, 43018, 43101, and 43833 authorize the Board to adopt motor vehicle diesel fuel regulations. Section 43013 is the primary source of ARB's legal authority to adopt and implement motor vehicle fuel specifications, motor vehicle emission standards, and in-use performance standards for the control of air contaminants and sources of air pollution which the Board has found to be necessary, cost effective, and technologically feasible.

Section 43018 expands ARB's authority to adopt whatever control measures pertaining to fuels that are technologically feasible, cost-effective, and necessary to attain the state AAQS by the earliest practicable date.

2. Fuels Multimedia Evaluation

H&SC section 43830.8 requires the state Board to conduct a multimedia evaluation before adopting any regulation that establishes motor vehicle fuel specifications. Section 43830.8(b) defines "multimedia evaluation" as "the identification and evaluation of any significant adverse impact on public health or the environment, including air, water, or soil, that may result from the production, use, or disposal of the motor vehicle fuel that may be used to meet the state board's motor vehicle fuel specification."

Section 43830.8 also requires the California Environmental Policy Council (CEPC or Council) to review the multimedia evaluation and determine if any significant adverse impact on public health or the environment may result from a proposed regulation. If the Council determines that the proposed regulation will cause a significant adverse impact on public health or the environment, or that alternatives exist that would be less adverse, the Council shall recommend alternative or mitigating measures to reduce the adverse impact on public health and the environment.

B. Low Carbon Fuel Standard

In January 2007, Executive Order S-01-07 called for a low carbon fuel standard for transportation fuels to be established for California. The Executive Order specifies a reduction of at least 10 percent in the average carbon intensity of the State's transportation fuels by 2020.

The Executive Order instructed the California Environmental Protection Agency to coordinate activities between the University of California (UC), the California Energy Commission (CEC), and other state agencies to develop and propose a draft compliance schedule to meet the 2020 target. Furthermore, it directed ARB to consider initiating regulatory proceedings to establish and implement the LCFS. The ARB identified the LCFS as a discrete early action measure and approved it on April 23, 2009. The LCFS regulation reduces the carbon intensity of transportation fuels used in the State by an average of 10 percent by the year 2020 to be in line with Executive Order S-01-07.

California's LCFS is expected to reduce GHG emissions from the transportation sector in California by about 16 million metric tons (MMT) in 2020. These reductions account for almost 20 percent of the total GHG emission reductions needed to achieve the State's mandate of reducing GHG emissions to 1990 levels by 2020. In addition, the LCFS is designed to reduce California's dependence on petroleum, create a lasting market for clean transportation technology, and stimulate the production and use of alternative, low carbon fuels in California.

The LCFS is designed to provide a framework that uses market mechanisms, based on carbon intensity – a full lifecycle accounting of a fuel's carbon emissions relative to its energy potential, to spur the steady introduction of lower carbon fuels. The framework establishes performance standards that fuel producers and importers must meet each year beginning in 2011. Since the regulation went into effect, regulated parties have operated under the LCFS program with no significant compliance issues.

To date, the LCFS is working as designed and intended. Fuel producers are innovating and achieving reductions in their fuel pathway carbon intensities, an effect the LCFS regulation is expressly designed to encourage.

The LCFS, as well as other policies and incentives, are prompting the development and use of new ADFs in the State. As such, it is important to ensure that the full commercialization of these fuels do not adversely affect air quality or cause other environmental concerns. The proposed ADF regulation helps ensure this by subjecting new ADFs to rigorous environmental review and a comprehensive multimedia evaluation. In response to the LCFS, biodiesel production is projected to increase. As the LCFS and other policies continue to incentivize the use of ADFs, the proposed regulation will maintain air quality protections and address potential environmental and public health impacts.

Under the LCFS, biodiesel and emerging ADFs represent an important strategy for meeting annual compliance standards and will continue to be an essential part of California's fuel pool. The ADF regulation not only provides regulatory certainty for biodiesel and biodiesel blends, but also provides a clear pathway to streamline the commercialization of new ADFs in the future.

1. ADF Role within the Low Carbon Fuel Standard Program

The proposed ADF regulation is separate and not a part of the LCFS regulation, however the two are interconnected. The LCFS (among other policies and regulations) is expected to drive demand for biodiesel, renewable diesel, and other low carbon fuels. As a result of the increased use of biodiesel in recent years, interest has developed on the impacts of these fuels, especially as it relates to NOx emissions which had been identified as a potential concern. As such the proposed ADF regulation is a response in part to the LCFS and increased demand for biodiesel, as well as potential future demand for other ADFs.

2. Low Carbon Fuel Standard Litigation

Since the initial adoption of the LCFS in 2009, ARB has been involved with two separate lawsuits. The first, Rocky Mountain Farmers Union vs. Corey, relates to a federal lawsuit that challenges the LCFS on the grounds that the regulations were preempted by the federal Clean Air Act and the federal Energy Independence and Security Act and violated the dormant Commerce Clause. On December 29, 2011, the District Court granted Rocky Mountain Farmers Union's request for a preliminary injunction and American Fuels & Petrochemical Manufacturers Association's partial motion for summary judgment, concluding that the LCFS violated the dormant Commerce Clause of the U.S. Constitution. On September 18, 2013, the Ninth Court of Appeals reversed the District Court's opinion that held that the LCFS violated the dormant Commerce Clause and remanded the case for trial. The Ninth Circuit reversed on all but the Clean Air Act preemption claims and remanded for entry of partial summary judgment in favor of ARB.

A second lawsuit, POET, LLC vs. CARB was initiated on December 23, 2009, on the grounds that ARB violated the Administrative Procedure Act (APA) and California Environmental Quality Act (CEQA) during the adoption process. On July 15, 2013, the State of California Court of Appeal, Fifth Appellate District (Court) issued its opinion in POET, LLC v. California Air Resources Board (2013) 218 Cal.App.4th 681. The Court held that the LCFS would remain in effect and that ARB can continue to implement and enforce the 2013 regulatory standards while it takes steps to comply with APA and CEQA statutes.

Among the issues in the POET, LLC vs. CARB lawsuit was the treatment of biodiesel in the original LCFS regulation. The Court concluded that ARB violated CEQA by deferring the formulation of mitigation measures for NOx emissions from biodiesel without committing to specific performance criteria for judging the efficacy of the future mitigation measures. In addition to the general impetus of this ADF regulation to protect air quality, it is also designed to fulfill the court's requirements and to address issues with NOx emissions from biodiesel. Implementation of this proposed regulation will ensure that the use of biodiesel subject to LCFS will not result in increases in NOx emissions in California relative to current conditions.

Also, in response to the Court's directive, ARB staff will propose re-adoption of the LCFS regulation in 2015. This will allow ARB to comply with all procedural requirements imposed by CEQA and the APA. As stated earlier, the Court held the 2013 regulatory standards in place until the LCFS regulation can be re-adopted. Since the LCFS is scheduled to be presented to the Board in early 2015, the new LCFS requirements are schedule to go into effect January 1, 2016. As part of the LCFS re-adoption effort, new elements and amendments are also being considered.

C. California Diesel Fuel Programs

Diesel and biodiesel are regulated by multiple state agencies in California. This section gives an overview of major state regulations affecting ADF use in California.

1. ARB Regulations

As the state air pollution agency, ARB is authorized to adopt standards, rules, and regulations to achieve the maximum degree of emission reduction possible from vehicular and other mobile sources in order to accomplish the attainment of the State ambient air quality standards at the earliest practicable date. ARB regulations can be found under California Code of Regulations (CCR) Division 3, Titles 13 and 17.

a. California Reformulated Diesel Fuel

In November 1988, the Board approved regulations limiting the aromatic hydrocarbon content to 10 percent by volume with a 20 percent limit for small refiners. These diesel fuel regulations, which became effective in 1993, are a necessary part of the State's strategy to reduce air pollution through the use of clean fuels, lower-emitting motor vehicles, and off-road equipment. The regulation includes provisions that enable diesel fuel producers and importers to comply through alternative diesel formulations that may cost less. The alternative specifications must result in the same emission benefits as the 10 percent aromatic standard (or in the case of small refiners, the 20 percent standard).

On July 24, 2003, the Board approved amendments to the California diesel fuel regulations. The amendments reduced the sulfur content limit from 500 ppmw to 15 ppmw for diesel fuel sold for use in California in on-road and off-road motor vehicles starting in mid-2006. The lower sulfur limit aligned the California requirement with the on-road diesel sulfur limit adopted by the U.S. EPA, but expanded the limit to include off-road motor vehicle diesel fuel. The new sulfur standard enabled the use of the emissions control technology, such as particulate filters, used for 2007 and subsequent model-year heavy-duty engines and vehicles.

In 2005, the Board also adopted a measure that applied the diesel fuel standards to harborcraft and intrastate locomotives.

b. Alternative Fuels

"Alternative fuel" generally means any motor vehicle transportation fuel that is not gasoline or diesel fuel. This includes, but is not limited to, those fuels that are commonly or commercially known or sold as one of the following: M-100 fuel methanol, M-85 fuel methanol, E-100 fuel ethanol, E-85 fuel ethanol, biodiesel, compressed natural gas (CNG), liquefied natural gas (LNG), liquefied petroleum gas (LPG), or hydrogen.

The quality of alternative motor vehicle fuels is subject to ARB-approved composition specifications under Title 13, California Code of Regulations, Sections 2292.1 through 2292.6, as follows:

- M-100 fuel methanol (13 CCR §2292.1),
- M-85 fuel methanol (13 CCR §2292.2),
- E-100 fuel ethanol (13 CCR §2292.3),
- E-85 fuel ethanol (13 CCR §2292.4),
- compressed natural gas (13 CCR §2292.5), and
- liquefied petroleum gas (13 CCR §2292.6).

Biodiesel is considered to be an alternative diesel fuel, but there are currently no ARB standards for biodiesel fuel.

2. SWRCB Regulations

The California State Water Resources Control Board (SWRCB) regulates the storage of diesel and biodiesel in Underground Storage Tanks (UST). These tanks must undergo compatibility testing by an independent certification lab, such as Underwriters Laboratory, for any new fuel that may be stored in them. B5 has undergone such a certification. Fuels above B6 have not undergone independent certification and there is no current activity to obtain certification, as such B6-B20 blends of biodiesel are generally stored above ground.

3. CDFA Regulations

The Division of Measurement Standards (DMS) of the California Department of Food and Agriculture (CDFA) regulates diesel and biodiesel for compliance with California specifications and measurement. DMS is statutorily obligated to adopt specifications for new fuels when an independent specification organization, such as ASTM, sets specifications for that fuel.

In 2008, ASTM international developed three biodiesel specifications. First, ASTM updated its specifications for B-100 blendstock, D6751-08, “Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels.” Second, ASTM approved revisions to D975-08, “Standard Specification for Diesel Fuel Oils,” which would subject biodiesel blends from B1 to B5 to the same specification as regulation diesel fuel. Finally, ASTM adopted new fuel specifications for B-6 to B-20 in D7467-08, “Standard Specification for Diesel Fuel Oil Biodiesel Blend (B6 to B20).”

DMS conducted a rulemaking to adopt ASTM D6751 Standard Specification for Biodiesel fuel Blend Stock (B100) for use in Middle Distillate Fuels. DMS has also adopted ASTM D7467 Standard Specification for Diesel Fuel Oil, Biodiesel Blends (B6-B20). ASTM D975, Standard Specification for Diesel Fuel Oils, allows up to B5 to be used and has also been adopted by ASTM.

4. OSFM Regulations

The Office of the State Fire Marshal regulates diesel and biodiesel storage, dispensing, and vapor recovery. All diesel and biodiesel facilities must follow California building and fire code and adhere to the specific provisions regarding diesel and biodiesel.

5. Air Quality Improvement Program (AB 118)

The *California Alternative and Renewable Fuel, Vehicle Technology, Clean Air, and Carbon Reduction Act of 2007* (Assembly Bill (AB) 118) establishes two funding programs for alternative fuels and vehicle technologies.[1] The Air Quality Improvement Program (AQIP) is a voluntary incentive program administered by the ARB. Through AQIP, ARB invests in clean vehicle and equipment projects that reduce criteria pollutant and air toxic emissions, often with concurrent climate change benefits. For current information on annual funding plans and guidelines, please visit ARB’s Air Quality Improvement Program website at http://www.arb.ca.gov/msprog/aqip/aqip.htm.
The Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP), administered by the CEC, is a competitive grant program that provides as much as $100 million annually towards innovative transportation and fuel technologies. The CEC’s program is governed by its AB 118 Investment Plan, through which the CEC has provided nearly $415 million to date in funding for production and infrastructure projects involving diesel substitutes, including biodiesel and renewable diesel.[2] For more information on total funding amounts and clean transportation projects to date, please visit the CEC’s ARFVTP website at http://www.energy.ca.gov/drive/index.html.

[1] Assembly Bill 118; Núñez, Chapter 750, Statutes of 2007
[2] California Energy Commission, *2014-2015 Investment Plan Update for the Alternative and Renewable Fuel and Vehicle Technology Program*, p. 1, April 2014

CHAPTER 4. FEDERAL POLICIES AFFECTING MOTOR VEHICLE DIESEL FUEL

This chapter summarizes various Federal policies that affect motor vehicle diesel fuel and may specifically impact the ADF regulation. The policies covered in this chapter include pertinent federal fuel regulations, standards, and requirements.

A. Federal Fuel Registration

U.S. EPA regulations establish fuel registration and formulation requirements.
U.S. EPA requires that all diesel fuels and fuel additives for on-road motor vehicle use be registered in accordance with 40 Code of Federal Regulation (CFR) Part 79. To become registered, a new fuel must apply for registration and meet “substantially similar” requirements as either conventional gasoline or diesel fuel. The “substantially similar” requirement means that the fuel must be of mostly the same composition as the fuel it is displacing, which in the cases depicted under this regulatory proposal would be diesel fuel. Any biodiesel used in California must also be registered as a fuel with U.S. EPA.

The registration requirements for diesel fuels apply to fuels composed of more than 50 percent diesel fuel by volume, and their associated fuel additives. Manufacturers may enroll a fuel or fuel additive in a group of similar fuels and fuel additives through submission of jointly-sponsored testing and analysis conducted on a specific product, for which additives would be measured in parts per million (ppm). In addition, the regulation requires a cetane index of at least 40 or an aromatic hydrocarbon content of no greater than 35 volume percent. All on-road motor vehicle diesel fuel sold or supplied in the United States, except in Alaska, must comply with representative specifications for all products in that group.

B. Federal Regulations Affecting Diesel Fuel Quality

U.S. EPA motor vehicle diesel fuel standards, contained in 40 CFR Part 80 Subpart I, requires on-road motor vehicles diesel fuel to have a sulfur content of no greater than 15 ppmv.

The diesel fuel sulfur regulations require refiners, importers, distributors, and retailers who produce, import, sell, store, or transport diesel fuel to meet the standards specified in the diesel regulations. Sulfur standards were phased in from 2006 to 2010, and were designed to ensure widespread availability of highway diesel fuel containing 15 ppm sulfur or less.

C. Federal Renewable Fuels Standard

Congress adopted the Renewable Fuels Standard (RFS) in 2005 and strengthened it (RFS2) in December 2007 as part of the Energy Independence and Security Act of 2007 (EISA). The RFS2 contains, among other provisions, requirements for increasing volumes of biofuels every year, up to a required volume of 36 billion gallons by 2022. New categories of renewable fuel were also established with separate volume requirements for each category.

Successful implementation of the RFS2 will result in significant quantities of low carbon intensity biofuels that could be used toward compliance with California's LCFS. In addition, successful implementation would also signal that the necessary technological breakthroughs to produce second and third generation biofuels have occurred.

1. Renewable Fuel Volume Requirements

The RFS2 requires fuel producers to use a progressively increasing amount of biofuel, culminating in at least 36 billion gallons of biofuel by 2022[3]. The U.S. EPA must establish regulations to ensure that the transportation fuel sold in, or imported into, the United States contains a minimum volume of renewable fuels as required under the EISA of 2007. Responsible parties under the U.S. EPA regulations relating to biofuels include refiners, blenders, and importers of transportation fuels.[4] RFS2 differentiates between "conventional biofuel" (corn-based ethanol) and "advanced biofuel." Advanced biofuel is renewable fuel, other than corn-based ethanol, with lifecycle greenhouse gas emissions that are at least 50 percent less than greenhouse gas emissions produced by gasoline or diesel. Starting in 2009, a progressively increasing portion of renewable fuels must be advanced biofuels, such as cellulosic ethanol.

2. Renewable Fuels GHG Requirements

The RFS2 requires GHG reductions for the various categories of renewable fuels, but only in discrete "bins" (e.g., both advanced biofuel and biomass-based diesel must achieve a life-cycle GHG emission-reduction threshold of 50 percent).[5] This federal program does not use a carbon intensity standard like the LCFS. As noted, there are specific requirements for the different classifications of renewable fuels. In general, these specifications are set relative to the baseline lifecycle GHG emissions for gasoline and diesel fuel sold or distributed in 2005. The lifecycle GHG emissions are specifically defined as:

> *"The term 'lifecycle greenhouse gas emissions' means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate*

---

[3] *Energy Independence and Security Act of 2007,* section 202 (a)(2)(B)(i)(I)

[4] U.S. Environmental Protection Agency, Office of Transportation and Quality. *EPA Finalizes Regulations for the National Renewable Fuel Standard Program for 2010 and Beyond,* EPA-420-F-10-007. February 2010

[5] U.S. Environmental Protection Agency, Office of Transportation and Quality. *EPA Lifecycle Analysis of Greenhouse Gas Emissions from Renewable Fuels,* EPA-420-F-10-006. February 2010

consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential."[6]

There are four general classifications of renewable fuels defined in RFS2: renewable fuels, advanced biofuels, cellulosic biofuels, and biomass-based diesel.

3. Renewable Biomass Definition

The RFS2 defines renewable fuel as fuel that is produced from renewable biomass. Renewable biomass is then defined as each of the following[7]:

- Planted crops and crop residue harvested from agricultural land cleared or cultivated at any time prior to the enactment of this sentence that is either actively managed or fallow, and nonforested.
- Planted trees and tree residue from actively managed tree plantations on non-federal land cleared at any time prior to enactment of this sentence, including land belonging to an Indian tribe or an Indian individual, that is held in trust by the United States or subject to a restriction against alienation imposed by the United States.
- Animal waste material and animal byproducts.
- Slash and pre-commercial thinnings that are from non-federal forestlands, including forestlands belonging to an Indian tribe or an Indian individual, that are held in trust by the United States or subject to a restriction against alienation imposed by the United States, but not forests or forestlands that are ecological communities with a global or State ranking of critically imperiled, imperiled, or rare pursuant to a State Natural Heritage Program, old growth forest, or late successional forest.
- Biomass obtained from the immediate vicinity of buildings and other areas regularly occupied by people, or of public infrastructure, at risk from wildfire.
- Algae.
- Separated yard waste or food waste, including recycled cooking and trap grease

One aspect of the definition of renewable biomass is that there are significant federal incentive funds for producing advanced biofuels. To qualify for these incentives, the renewable fuels must be produced from renewable biomass.

4. U.S. EPA Rulemakings Implementing the RFS2

U.S. EPA is responsible for implementing the volume requirements in the RFS2. Section 211(o) of the Clean Air Act (CAA or the Act), as amended, requires the

[6] *Energy Independence and Security Act of 2007*, Title II-Energy Security Through Increased Production of Biofuels; Subtitle A Section 201 (1)(H).
[7] *Energy Independence and Security Act of 2007*, Title II-Energy Security Through Increased Production of Biofuels; Subtitle A Section 201 (1)(I).

U.S. EPA Administrator to annually determine a renewable fuel standard and publish the standard in the Federal Register. Based on this standard, each obligated party determines the volume of renewable fuel that it must ensure is consumed as motor vehicle fuel. This standard is calculated as a percentage, by dividing the amount of renewable fuel that the Act requires to be blended into gasoline for a given year by the amount of gasoline expected to be used during that year, including certain adjustments specified by the Act.

a. RFS2 Volume Requirement - 2013

In August 2013, U.S. EPA finalized the 2013 renewable fuel standards which established the 2013 annual percentage standards for cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel.[8]: Note that the 16.55 billion gallons of renewable fuel required in 2013 was projected to include approximately 1.7 billion gallons of biodiesel and renewable diesel. In April 2014, U.S. EPA took direct final action to revise the 2013 cellulosic biofuel standard. The final 2013 volumes are shown in Table 4.1 below.

Table 4.1: Volumes Used to Determine the Final 2013 Percentage Standards

Category	Volume*
Cellulosic Biofuel	810,185 gal
Biomass-based Diesel	1.28 billion gal
Advanced Biofuel	2.75 billion gal
Renewable Fuel	16.55 billion gal

*All volumes are ethanol-equivalent, except for biomass-based diesel which is actual.

The U.S. EPA also used the applicable volumes that are specified in the statute to set the percentage standards for advanced biofuel and total renewable fuel for 2013.[9] The percentage standards required under the RFS program represent the ratio of renewable fuel volume to non-renewable gasoline and diesel volume. The 2013 standards are shown in Table 4.2 below.

Table 4.2: Final Percentage Standards for 2013

Category	Percent
Cellulosic Biofuel	0.0005%
Biomass-based Diesel	1.13%
Advanced Biofuel	1.62%
Renewable Fuel	9.74%

b. RFS2 Volume Requirements - 2014

[8] U.S. Environmental Protection Agency, Office of Transportation and Quality. *EPA Finalizes 2013 Renewable Fuel Standards,* EPA-420-F-13-042. August 2013
[9] U.S. Environmental Protection Agency, Office of Transportation and Quality. *EPA Issues Direct Final Rule for 2013 Cellulosic Standard,* EPA-420-F-14-018. April 2014

In November 2013, U.S. EPA proposed 2014 percentage standards for cellulosic biofuel, biomass-based diesel, advanced biofuel, and renewable fuels.[10] The projected 2014 volumes used to determine the proposed percentage standards are shown in Table 4.5 below:

Table 4.3: Volumes Used to Determine the Proposed 2014 Percentage Standards

Category	Proposed Volume*	Projected Range
Cellulosic Biofuel	17 million gal	8-30 million gallons
Biomass-based Diesel	1.28 billion gal	1.28 billion gallons**
Advanced Biofuel	2.20 billion gal	2.0-2.51 billion gallons
Renewable Fuel	15.21 billion gal	15.00-15.52 billion gallons

* All volumes are ethanol-equivalent, except for biomass-based diesel which is actual
** U.S. EPA is requesting comment on alternative approaches and higher volumes

The percentage standards represent the ratio of renewable fuel volume to non-renewable gasoline and diesel volume. The proposed 2014 standards are shown in Table 4.6 below.

Table 4.4: Proposed Percentage Standards for 2014

Category	Percent
Cellulosic Biofuel	0.010%
Biomass-based Diesel	1.16%
Advanced Biofuel	1.33%
Renewable Fuel	9.20%

The proposed 2014 standards were submitted to the Office of Management and Budget of interagency review in August 2014. However, in November 2014, the U.S. EPA announced that it will not be finalizing the 2014 standards until 2015.

D. Federal Trade Commission Labeling Requirements

The EISA of 2007 required Federal Trade Commission (FTC) to adopt regulations pertaining to the labeling of biodiesel and biomass-based diesel at retail dispensing outlets. This regulation was enacted under Title 16, Code of Federal Regulations, Part 306.12. The regulation requires labeling of biodiesel and biomass-based diesel if the blend level is above 5 percent. Specifically it requires labeling of blend B6 to B20 and blends above B20 are required to be labeled by the exact amount of biodiesel for example B63. Biomass-based diesel labeling requirements are parallel but independent of biodiesel volume.

[10] U.S. Environmental Protection Agency. *2014 Standards for the Renewable Fuel Standard Program; Proposed Rule.* Federal Register. Volume 78, No. 230. Part II. 40 CFR 80. November 29, 2013

This page intentionally left blank

CHAPTER 5. DESCRIPTION OF PROPOSED REGULATION

A. Overview of Proposed Regulation

The primary purpose of the proposed regulation is to create a framework that allows for innovation and diversity in the California diesel fuel pool while ensuring the introduction of ADFs is managed responsibly by setting up a three stage process to evaluate environmental impacts of ADFs. Additionally, this rulemaking will establish in-use specifications for biodiesel as part of Stage 3A requirements of the proposed regulation.

B. Applicability

The proposed regulation will apply to all producers, importers, blenders and distributors of ADFs in the State of California. Fuel that meets a specification under the alternative fuels regulation 13 CCR 2292 are not considered ADFs and are thus not subject to this regulation. It is ARB's intention that this proposed regulation be in effect at all points of sale, offer, or supply in the California fuel distribution infrastructure.

C. Definitions

For the purposes of sections 2293 through 2293.9, the definitions in H&SC sections 39010 through 39060 shall apply, except as otherwise specified in subarticle 1:

Section (a) covers the definitions in the proposed regulation.

Section (b) is a glossary of acronyms used in the proposed regulation.

D. Applicable Requirements for Alternative Diesel Fuels

It is the goal of this proposed regulation to ensure that there are no adverse environmental impacts of ADFs as they are introduced into California. This proposed regulation relies on a three-stage introduction of ADFs, through which the environmental impacts will be determined and, if necessary, any adverse impacts minimized.

1. Stage 1 (Pilot Program)

The first stage of this proposed regulation is referred to as a pilot program. Any new ADF proponent may apply to setup a pilot program in order to begin testing of their fuel in California. The pilot program will limit the amount of a new ADF, not to exceed the energy equivalent of one million gallons of diesel fuel, used in well-defined fleets. The pilot program will last for one year, with three opportunities to renew for six months each. The application for a pilot program includes public disclosure of many properties of the fuel that may affect its impact to the environment (e.g., density, distillation curve, and water-octanol partition coefficient). The EO will use this information to conduct a preliminary review of the fuel to determine whether it is appropriate for use in California and if any potential risks resulting from the use of the fuel in a pilot program are outweighed by any potential benefits of the fuel. The EO will issue an Executive Order if the pilot program application is approved. The Executive Order will contain the necessary terms and conditions of additional testing based on the properties of the fuel. Completion of the terms of the Executive Order will be required prior to advancing to Stage 2. Applicants under a Stage 1 Executive Order will also be required to submit quarterly reports on how much fuel is being used.

2. Stage 2 (Fuel Specification Development)

Once an ADF applicant completes the terms of a Stage 1 Executive Order, they may apply for an updated Executive Order to move to Stage 2. The Stage 2 Executive Order will include a limit on the amount of that fuel that may be sold in California, to be determined by the EO but not to exceed the energy equivalent of 30 million gallons of diesel.

During Stage 2, an ADF applicant would be required to: (1) complete a multimedia evaluation, (2) achieve adoption of consensus standards, (3) obtain approval for use from 75 percent of engine manufacturers who produce engines in which the ADF is expected to be used, and (4) identify appropriate specifications for the fuel.

During Stage 2, ARB would make a determination of potential adverse emissions impacts from use of the ADF in question, using emissions data assembled during a multimedia evaluation. If it is determined that an ADF has been shown to have no potential adverse emissions impacts, the ADF would then be eligible to apply to advance to Stage 3B. If, however, it has determined there are potential adverse emissions impacts for the ADF or ADF blends, the ADF would be eligible to apply to advance to Stage 3A.

3. Stage 3 (Commercial Sales)

After completing the requirements of Stage 2, an ADF proponent may apply to the EO to move their fuel to Stage 3. If a determination of potential adverse emissions impacts was made under Stage 2, the EO may declare intent to advance the fuel to Stage 3A where an evaluation to determine whether there are adverse emissions impacts considering the effects of offsetting factors will commence. If the EO determines there are adverse emissions impacts the appropriate specifications and/or in-use requirements will be established by rulemaking. Throughout the course of a Stage 3A rulemaking, the volume limits from Stage 2 shall apply. In a Stage 3A rulemaking the EO shall consider, at a minimum, the offsetting effects of feedstocks, other fuel use, and vehicle effects when determining the appropriateness of establishing specifications and/or in-use requirements.

If the ADF was found to have no potential adverse emissions impacts, the EO may advance the ADF to Stage 3B by issuing an Executive Order with the specific provisions of the no potential adverse impacts determination. In Stage 3B, there are no limits on the fuel volume a proponent may sell or supply for use in California. Stage 3B consists of reporting and recordkeeping for an ADF.

E. Biodiesel as an Alternative Diesel Fuel

Biodiesel will have completed all of the relevant steps that are outlined in Stage 2 of the proposed regulation by the time this proposed regulation is in full effect. Potential adverse impacts have been identified. As such, ARB is proposing to regulate biodiesel at stage 3A. Because of the potential adverse emissions impacts identified for NOx emissions, ARB is proposing to establish specifications and in-use requirements for biodiesel and its blends.

ARB is also proposing the in-use requirements come into effect on January 1, 2018, as time is needed to overcome logistical and other issues in implementation of in-use requirements. For example, use of the additive Di-tert-butyl peroxide (DTBP) will require replacement of steel tanks with stainless steel tanks, permitting of hazardous substance storage, approval by local fire agencies, additional additization infrastructure, and logistical business changes to acquire the additive. All of this is expected to take around 2 years to complete. Another method of compliance is re-routing higher blends to NTDEs. Research shows that the use of biodiesel in blends up to B20 in NTDEs results in no detrimental NOx impacts. This and other methods of complying with the in-use requirements, such as certification of additional options are also expected to take 2 years or more. Because compliance with the in-use options would be infeasible during initial implementation on January 1, 2016, only recordkeeping and reporting provisions will be implemented initially. The in-use requirements are proposed to come into effect on January 1, 2018.

Staff's statistical analysis found that for certain vehicles biodiesel has potential adverse emissions impacts on NOx in any blends of low saturation biodiesel (un-additized CN <56) but not in blends of high saturation biodiesel (un-additized CN ≥56) up to B10. Staff has also found that there exist offsetting factors, in the form of renewable diesel and NTDEs that are expected to reduce and eventually eliminate any NOx increase from low level blends (B5 or less) of low saturation biodiesel. In order to ensure that the use of higher blends of biodiesel do not increase NOx emissions, staff is proposing NOx control levels above which per gallon in-use requirements would be instituted. Table 5.1 below shows the proposed NOx control levels based on feedstock and time of year.

Table 5.1: NOx Control Levels

	Control Level (April 1 to October 31)	Control Level (November 1 to March 31)
Low Saturation BD	B5	B10
High Saturation BD	B10	B10

In the period between November 1 and March 31, NOx control for reduction of ozone is less necessary. In order to maximize the PM reductions from biodiesel and allow increased flexibility for the biodiesel industry, ARB is proposing a control level of B10 for all biodiesel during this period.

Staff expects increasing use of NTDEs to eliminate biodiesel's NOx impact over time, thus the proposed biodiesel provisions include a sunset provision. ARB is proposing that the NOx control levels would sunset when EMFAC 2011 (ARB's model for estimating emissions from California on-road vehicles) shows more than 90 percent of Vehicle Miles Travelled (VMT) by NTDEs. The sunset provision is expected to trigger in 2023. However, staff has also proposed a review to be completed by December 31, 2019 in order to make sure that the offsetting factors are on track and that the in-use requirements for biodiesel are operating as expected.

Research indicates that the use of biodiesel in light- or medium-duty vehicles results in no detrimental NOx impacts. Research also indicates that the use of biodiesel up to blends of B20 in NTDEs results in no detrimental NOx impacts. Therefore, the proposed regulation also includes a process for fleets and fueling stations to become exempted from the in-use requirements for biodiesel blends up to B20 as long as they can demonstrate to the satisfaction of the Executive Officer that they are fueling at least 90 percent light or medium duty vehicles, or NTDEs.

CHAPTER 6. TECHNOLOGY ASSESSMENT

A. Introduction

This chapter summarizes the process by which ARB developed the conclusions on the NOx impacts of the use of biodiesel. This process includes the studies that ARB has sponsored, the additional studies upon which we based our analysis, as well as the statistical methods and study selection criteria that we used.

B. Emissions Studies Literature Review

Multiple studies have looked at the impact of biodiesel on heavy-duty diesel vehicle NOx emissions. The National Renewable Energy Lab (NREL) and the U.S. EPA have both examined the literature to determine these effects. Neither of these databases focused primarily on the effects of using CARB diesel as the base fuel. To fill this knowledge gap, ARB staff conducted a literature search that addresses the impacts of biodiesel use on NOx emissions in heavy duty engines using California diesel as the base fuel. It is important to focus on studies which use CARB diesel as the baseline, since multiple studies, such as the NREL and EPA studies referenced above, have found that base fuel impacts the presence and magnitude of a biodiesel NOx impact.

1. Criteria for Choosing Relevant Studies

The literature search focused on biodiesel blends B20 and below and characterized studies by their baseline fuel properties. Studies looking at B20 and below were chosen as the focus, since these are the fuels which are currently legal commercially. Studies that used either explicitly CARB diesel or a diesel fuel that was tested to have a cetane number of at least 49 were included in the analysis. Non-CARB diesel that had a cetane number of at least 49 was determined by staff to be similar enough to CARB diesel in NOx emissions to treat as CARB diesel for the purposes of this analysis, including showing similar emissions result when testing biodiesel blends derived from these fuels.

The studies included in this analysis were all performed using an engine dynamometer with commercially available engines, and no engine modifications. Engine dynamometer data were chosen over chassis dynamometer data because they eliminate some variability and as such are able to get a more accurate representation of true fuel to fuel variances. For example, since chassis dynamometer requires a person driving who would attempt to match an acceleration curve and engine dynamometer curves are performed by a computer, driver to driver variability is eliminated. Studies using test cycles based on a single speed and mode were excluded from this analysis because their results do not transfer well to real world emissions. Instead studies that used test cycles such as the Federal Test Procedure (FTP) or Urban Dynamometer Drive Schedule (UDDS) were selected because these cycles vary load and engine speed over the cycle in order to approximate real world operation.

2. Major Studies

Below is a list of the studies that met the stated criteria for inclusion in this analysis from our literature search.

Table 6.1: Major Studies from Literature Search

Author	Title	Publication	Year
Clark	Transient Emissions Comparisons of Alternative Compression Ignition Fuels	SAE 1999-01-1117	1999
Durbin	Biodiesel Characterization and NOx Mitigation Study	UC Riverside, prepared for CARB	2011
Durbin	CARB B5 Biodiesel Preliminary and Certification Testing	UC Riverside, prepared for CARB	2013
Durbin	CARB B20 Biodiesel Preliminary and Certification Testing	UC Riverside, prepared for CARB	2013
Eckerle	Effects of Methyl Ester Biodiesel Blends on NOx Emissions	SAE 2008-01-0078	2008
Karavalakis	CARB B5 Biodiesel Characterization Study	UC Riverside, prepared for CARB	2014
McCormick	Fuel Additive and Blending Approaches to Reducing NOx Emissions from Biodiesel	SAE 2002-01-1658	2002
McCormick	Regulated Emissions from Biodiesel Tested in Heavy-Duty Engines Meeting 2004 Emissions	SAE 2005-01-2200	2005
Nikanjam	Performance and Emissions of Diesel and Alternative Diesel Fuels in a Heavy-duty Industry-Standard Older Engine	SAE 2010-01-2281	2010
Nuzkowski	Evaluation of the NOx Emissions from Heavy Duty Diesel Engines with the Addition of Cetane Improvers	Proc. I Mech E Vol. 223 Part D: J. Automobile Engineering: 1049-1060	2009
Thompson	Neat Fuel Influence on Biodiesel Blend Emissions	Int J Engine Res Vol. 11: 61-77	2010

In order to better understand emissions from biodiesel, ARB considered NOx data from literature studies as well as ARB studies from a wide range of vehicles feedstocks and test cycles. Table 6.2 below summarizes the testing matrix that was completed in studies included in the literature search.

Table 6.2: Summary of Testing Included in Literature Search

Application	Engine	Feedstocks	Test Cycles
On-road chassis	Caterpillar C15 Cummins ISM DDC MBE4000 Cummins ISX	Animal Soy Renewable diesel GTL	UDDS FTP 40mph Cruise 50mph Cruise
On-road HD engine	Cummins ISM DDC MBE4000 DDC Series 60	Animal Soy	UDDS FTP SET
Non-road engine	John Deere 4084 Kubota TRU	Animal Soy	ISO 8178-4

These studies found that most of the emissions from biodiesel are reduced from the CARB diesel baseline, including PM, CO, HC, and most toxic species. However, NOx was found to increase for certain biodiesel blend levels and feedstocks. Generally, it was found that soy based biodiesel blends had greater NOx emissions than those derived from animal based biodiesel. The results of these studies apply specifically to heavy-duty vehicles that do not use post-exhaust NOx emissions control, therefore the results of this study should not be extended to NTDEs or Light-duty and Medium-duty vehicles.

3. Effect of Base Fuel on Emissions

EPA 2002[11] examined the effect that base fuel has on the emissions results of biodiesel blends and found that using clean base diesel, such as CARB diesel, may impact the results in NOx emissions from biodiesel. As a result of this conclusion, ARB staff began looking into the effect that biodiesel might have on blends used within the State of California specifically. California's diesel fuel tends to be lower in aromatic hydrocarbon content and higher in cetane number than federal diesel. These two properties are important in the formation of NOx. After extensive testing and review, staff confirms EPA's original analysis and finds that the effects of biodiesel on NOx with CARB diesel as a base fuel are greater than the effects using federal diesel as a base fuel. As an example, EPA 2002 found NOx increases of about two percent in B20 derived from soy when federal diesel is the base fuel, whereas ARB's literature review finds NOx increases of about four percent in B20 derived from soy when CARB diesel is the base fuel. These results are discussed more in section C of this chapter.

C. NOx Emissions Data Analysis

ARB staff re-analyzed original data from three engine dynamometer studies that look at B5 to examine whether biodiesel blends yield different NOx emissions from conventional diesel fuel.[12,13,14] Staff chose to focus on engine studies because the

[11] U.S. Environmental Protection Agency, *A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions*, 2002
[12] Durbin et al., *Biodiesel Characterization and NOx Mitigation Study,* October 2011

variability in emission measurements is smaller than for vehicles. A small change in emissions due to biodiesel would require a larger sample size to detect if vehicle data were used.

Our analysis focused primarily on soy B5, since soy is expected to be the dominant feed stock, and the existence of a significant effect at the 5% blend level would imply the existence of an effect at higher blend levels. Staff analyzed each blend level separately, and did not make any assumptions about whether the relationship between blend level and NOx emissions is linear or not.

Engine type and drive cycle have a significant impact on NOx emissions, and differences from one study to another can lead to large variations in emissions. We therefore controlled for these three variables in the statistical model. Out of several possible ways to reflect this in the model, we chose a simple approach: we treated the combination of engine type, drive cycle and study as a single categorical variable which we called the "experiment", and considered each experiment as yielding an independent estimate of the difference in NOx emissions between soy B5 and conventional diesel.

Past experience with emissions data suggests that transforming emissions by taking logarithms (or equivalently, working with percent differences instead of absolute differences) is appropriate. Staff confirmed this with model diagnostics.

Staff used a linear mixed effects model, with experiment as a random effect, fuel type as a fixed effect, and the natural logarithm of NOx emissions as the response, to estimate the difference in NOx emissions from soy B5 relative to CARB diesel.[15,16] Staff used R statistical software, specifically the `lmer` model fitting routine from R's `lme4` package.[17,18] The result: B5 yields approximately 1% higher NOx emissions than CARB diesel, and the increase is highly statistically significant (confidence level > 99.9999%).

Staff performed numerous sensitivity checks on the results. Staff tried several different formulations of the mixed model, as well as other statistical models. Staff also experimented with including other data sets that were not used for the final analysis. In each case soy B5 yielded around 1% higher NOx emissions than CARB diesel, and in each case the result was statistically significant.

---

[13] Durbin et al., *CARB B5 Biodiesel Preliminary and Certification Testing*, April 2013
[14] Karavalakis et al., *CARB Comprehensive B5/B10 Biodiesel Blends Heavy-Duty Engine Dynamometer Testing*, June 2014
[15] Nester et al.,(1996). *Applied Linear Statistical Models*, Fourth Edition, Irwin. US
[16] Draper N, Smith H (1998). *Applied Regression Analysis*. Third Edition, Wiley Interscience. US
[17] R Core Team (2013). R: A language and environment for statistical computing. R Foundation for Statistical Computing, Vienna, Austria. ISBN 3-900051-07-0. http://www.R-project.org/
[18] Bates et al., (2014). lme4: Linear mixed-effects models using Eigen and S4. R package version 1.1-7 http://CRAN.R-project.org/package=lme4

As a further check against ARB staff's results, ARB contracted with Prof. David Rocke of U.C.Davis to analyze the same data set and derive independent conclusions. Prof. Rocke's analysis is attached as Appendix F. His results matched ARB staff's: soy B5 yielded approximately 1% higher NOx emissions than CARB diesel. The increase was highly statistically significant (confidence level > 99.9999%).

Further analysis of other biodiesel blends yielded the following results:

Soy B10	approximately 2% higher than CARB diesel
Animal B5	no statistical difference
Animal B10	no statistical difference

These results are consistent with a linear relationship between blend level and NOx emissions for soy blends in the 5-10% range. However, no data were available for blend levels below 5%, and it is not possible to establish whether the relationship is linear in the 0-5% range.

It should be noted that this testing demonstrates the results of a specific fuel formulation on specific engines in controlled laboratory conditions. To translate this to any potential real-world emission impact requires consideration of many factors (e.g., number of NTDE engines, amount of renewable and other low-NOx diesel, amount of low saturation vs high saturation biodiesel, and any NOx-reducing additives).

The complex mechanisms creating NOx increases at different biodiesel levels are not completely understood. The NOx emissions appear to be affected primarily through thermodynamic interactions, yet other factors have also been proposed. For example, Bunce et. al.,[19] looked at engine factors such as air to fuel ratio, EGR fraction, rail pressure and start of injection, as well as cetane number, soot radiation, bulk modulus, Engine Control Module feedback, and adiabatic flame temperature as factors that could serve to control engine NOx emissions. The complex interactions created by the fuel and engine system demonstrate the uncertainty inherent in translating the results of laboratory testing to real world emissions effects. The consistent and highly significant findings for NOx give certainty that there is an effect compared to CARB diesel.

D. Biodiesel Emissions in Heavy-Duty Diesel Engines

Below staff presents emissions effects of biodiesel based on the literature search described in section B of this chapter. The average data below are based on averages of the data found in the literature search and are not weighted as they were in the statistical analysis above. These results should thus be used as estimates of the effect of biodiesel as no attempt was made to weight them according to representativeness of the engines tested in the California Heavy duty vehicle fleet. For the rest of this chapter staff refers to soy biodiesel as low saturation biodiesel, and animal biodiesel as high saturation biodiesel. This is explained more fully in section 4.

---

[19] Bunce et al, *Stock and Optimized Performance and Emissions with 5% and 20% Soy Biodiesel Blends in a Modern Common Rail Turbo-Diesel Engine,* Energy Fuels, 2010, *24* (2), pp 928–939

1. NOx Emissions

Biodiesel blend level was found to be directly related to NOx emissions level. Additionally, the NOx emissions from biodiesel were found to be dependent upon the saturation level of the biodiesel feedstock: high saturation feedstocks (animal in the studies) had less NOx emissions than low saturation feedstocks (soy and other lower cetane number feedstocks). Engine and duty cycle did not have substantial impacts on the NOx emissions. Table 6.3 below shows NOx emissions based on biodiesel blend levels and feedstock saturation.

Table 6.3: Biodiesel NOx Emissions by Blend Level and Feedstock Saturation

(ΔNOx Emissions)	**B5**	**B10**	**B20**
Low Saturation	1.1%	1.8%	4.0%
High Saturation	-0.2%	0.1%	1.5%

2. PM Emissions

Biodiesel blend level was found to be inversely correlated to PM emissions. Biodiesel feedstock or test method did not seem to substantively affect PM emissions. In 2007 and later engines equipped with PM filters, it was difficult to identify any meaningful differences in PM emissions between CARB diesel and biodiesel. Table 6.4 below shows PM emissions results by blend level.

Table 6.4: PM Reductions by Biodiesel Blend Level in pre-2007 Engines

(ΔPM Emissions)	**B5**	**B10**	**B20**
Pre-2007 Engines	-4.7%	-8.9%	-19.0%

3. VOC Emissions

Biodiesel blends generally had lower VOC emissions than CARB diesel, however in 2007 and later engines with PM filters it was difficult to identify any trends, likely because PM filters generally also include diesel oxidation catalysts which are designed to reduce VOCs. Effects of feedstocks and test cycles were not clear. Table 6.5 below shows VOC emissions in pre-2007 engines.

Table 6.5: VOC Emissions by Biodiesel Blend Level in pre-2007 Engines

(ΔVOC Emissions)	**B5**	**B10**	**B20**
Pre-2007 Engines	-2.2%	-3.1%	-10.1%

4. Effect of Biodiesel Properties on Emissions

NOx emissions from biodiesel are influenced by the feedstock from which the biodiesel is produced. Chemically the main properties of the biodiesel that are related to NOx appear to be the level of saturation and the chain length. Biodiesel is produced in such a way that several properties of the feedstock (e.g., saturation level, chain length) are retained in the biodiesel product. These chemical properties influence physical properties in fuel delivery and combustion that are important to the way the engine operates and thus relate to NOx emissions. The physical properties of interest include modulus of incompressibility, fuel atomization, and ignition delay; these properties are intercorrelated.

Rather than specifying feedstocks and their specific relationship with NOx emissions, which can pose technical and logistical difficulties for determination and tracking, it is preferable to separate biodiesel feedstocks and their NOx emissions potential using performance based properties. Staff is aware of two performance properties that have been shown to be reasonably well correlated to NOx emissions differences between feedstocks: Cetane number and iodine value. Neither of these properties are direct indicators of NOx emissions, but are surrogate values for predicting the chemical and physical properties which are related to NOx emissions. Cetane number has been shown to be a better indicator of NOx emissions differences than iodine number, but has problems when the fuels are additized with cetane enhancing additives.

Durbin 2011 showed that use of the cetane enhancing additive DTBP mitigated the NOx increases from a soy biodiesel. That same study showed that another cetane enhancing additive, 2-ethylhexyl nitrate (2-EHN), did not mitigate the NOx increases from a soy biodiesel. In fact, there were no differences between unnaditized biodiesel blends and additized biodiesel blends using 2-EHN. This result shows that the difference in NOx emissions from biodiesel is not based solely on cetane number of the mixture but on the properties of the biodiesel. Therefore, if cetane is used as an indicator of the NOx differences between biodiesel feedstocks, it should be measured prior to addition of cetane enhancing additives.

Alternatively, iodine number may be used to predict NOx differences between biodiesel feedstocks since it is not sensitive to cetane enhancing additives and is a measure of saturation of a fuel. Iodine number also has potential issues since it only addresses biodiesel saturation, and does not include the important effects of biodiesel chain length. However, this may not be an issue as the currently most frequently used feedstocks are very similar in chain length (primarily C16 and C18), and is not likely to become a problem unless more exotic feedstocks such as coconut oil (primarily C12) become popular. Staff proposes to use unadditized cetane number as the determinant of saturation level, since it is more frequently tested for by biodiesel producers and is more closely correlated to NOx emissions than iodine number.

5. Comparison of Vehicle Chassis to Engine Data

Vehicle chassis dynamometer and engine dynamometer are two popular methods of measuring the work exerted during emissions testing. In both cases, the goal is to relate the amount of emissions to some relevant value, generally grams/mile for chassis dynamometer and gram/brake horsepower hour for engine dynamometer. While chassis dynamometer certainly has its place and is able to better distinguish vehicle to vehicle differences, due to the use of the whole vehicle in testing, it adds greatly to the variability of testing, due to the driver, transmission and other sources of variability not present in engine testing. Therefore, when testing for fuel specific effects it is most appropriate to use engine dynamometer testing. As such, staff's analysis of specific numeric quantification of biodiesel emissions testing relies upon engine dynamometer studies.

It should be noted that although chassis dynamometer studies were not relied upon for quantification of emissions effects of biodiesel, staff examined several studies that included results using chassis dynamometer and they were directionally similar to the results staff got using engine data.

6. Emissions in New Technology Diesel Engines

Engines that meet the latest emission standards through the use of Selective Catalytic Reduction (SCR) have been shown to have no significant difference in NOx emissions based on the fuel used. A study conducted by the NREL looked at two Cummins ISL engines that were equipped with SCR, and found that NOx emissions control eliminates fuel effects on NOx, even for B100 and even in fuels compared against a CARB diesel baseline.[20] However, a recent study at UC Riverside tested B50 blends and found a NOx increase with a 2010 Cummins ISX.[21] The UC Riverside study did not look at blends below B50. Staff proposes to take a precautionary approach and in the light of data showing there may be a NOx impact at higher biodiesel blends but not at lower biodiesel blends, staff is limiting the conclusion of no detrimental NOx impacts in NTDEs to blends of B20 and below. Additional studies on NTDEs have been completed, however since they included either retrofit engines or non-commercial engines staff did not include their results in this analysis.[22,23,24]

7. Renewable Diesel NOx Emissions

Renewable diesel (as well as Gas-to-liquid diesel) has been found to decrease NOx emissions relative to CARB diesel. Durbin 2011 found that use of pure renewable diesel or GTL fuel reduced NOx emissions by about 10 percent relative to CARB diesel, and was found to be fairly linear according to blend level. Additionally as part of the

---

[20] Lammert et al., *Effect of B20 and Low Aromatic Diesel on Transit Bus NOx emissions Over Driving Cycles with a Range of Kinetic Intensity*, SAE Int. J Fuels Lubr., 5(3):2012

[21] Gysel et al., *Emissions and Redox Activity of Biodiesel Blends Obtained from Different Feedstocks from a Heavy-Duty Vehicle Equipped with DPF/SCR Aftertreatment and a Heavy-Duty Vehicle without Control Aftertreatment,* SAE 2014-01-1400 Published 04/01/2014

[22] McWilliam et al., Emission and Performance Implications of Biodiesel Use in an SCR-equipped Caterpillar C6.6 2010-012157 Published 10/25/2010

[23] Mizushima et al., *Effect of Biodiesel on NOx Reduction Performance of Urea-SCR System* 2010-01-2278 Published 10/25/2010

[24] Walkowicz et al., *On-Road and In-Laboratory Testing to Demonstrate Effects of ULSD, B20, and B99 on a Retrofit Urea-SCR Aftertreatment System*, SAE Int. 2009-01-2733

mitigation testing in that study, it was found that blends containing at least 2.75 gallons of renewable diesel per gallon of biodiesel were NOx neutral compared to CARB diesel.

E. Biodiesel Effects in Light and Medium Duty Vehicles

Light-duty and medium-duty vehicles have been found not to experience increases in NOx due to the use of biodiesel. For example, a study performed on three light-duty vehicles using different biodiesel blends found no significant and consistent pattern in NOx emissions based on blend levels across the different engines, blends and cycles.[25,26]

F. Biodiesel Effects in Non-road and Stationary Engines

1. Emissions from Non-road Engines

Durbin 2011 included two non-road engines in its test matrix, a John Deere 4084 and a Kubota TRU engine. Generally, the trends and magnitude of emissions for these engines were similar to those for the study as a whole. In general, NOx emissions increased, PM and HC emissions decreased with increasing biodiesel blend levels. The table below shows selected emissions for the John Deere and Kubota TRU engines, from a soy feedstock.

Table 6.6. Emissions from non-road engines on soy biodiesel

Engine	Blend Level	NOx	p-value	PM	p-value	HC	p-value
John Deere	B20	2.82%	0.021	-23.25%	0.028	-5.22%	0.498
	B50	7.63%	0.000	-31.75%	0.013	-15.12%	0.104
	B100	13.76%	0.000	-55.93%	0.000	-27.54%	0.001
Kubota TRU	B20	2.25%	0.086	-6.91%	0.011	-5.68%	0.153
	B100	18.89%	0.000	-40.30	0.000	-58.53%	0.000

2. Emissions from Stationary Engines

Stationary engines were not tested as part of staff's studies on biodiesel and no data were found on them during the literature search. As a conservative measure staff assumes that biodiesel also increases NOx at similar rates in stationary engines as in on-road and non-road engines.

G. NOx Emission Control Techniques

As a result of the Mitigation Study completed by UC Riverside and ARB, several technically feasible options were identified that would ensure no NOx increase as a

[25] Nikanjam et al, *Performance and Emissions of Diesel and Alternative Diesel Fuels in Modern Light-Duty Vehicles*, SAE 2011-24-0198, 2011
[26] Durbin et al., *Regulated Emissions from Biodiesel Fuels from On/Off-road Applications*, Atmospheric Environment, Volume 41, p. 5647-5658, 2007

result of biodiesel use. The options that were identified reduce NOx to parity with conventional CARB diesel by using additives or altering the baseline fuel.

The Mitigation study found that a blend of 1 percent di-tert butyl peroxide in B20 yielded NOx emissions that were equivalent to the CARB diesel baseline. Additionally, the Mitigation Study found that a blend of 55 percent renewable diesel, 25 percent CARB diesel and 20 percent biodiesel was equivalent to the CARB diesel baseline. Additionally, 2-ethylhexyl nitrate (2-EHN) was tested to determine whether it would also be able to mitigate the NOx from biodiesel blends since it is also a cetane improver. However, the fuels containing 2-EHN had essentially the same NOx emissions as those without additives. The difference between the NOx emissions of these blends compared to baseline CARB diesel is shown in the Table 6.3 below.

Table 6.7: NOx Emissions of Mitigation Measures

Fuel Blend	NOx Diff % from CARB diesel	p-value
B20 1%DTBP	0.0 %	0.959
C25 R55 B20	-0.8 %	0.029
B20 1% 2-EHN	6.3 %	0.000

In addition to the use of additives, staff is including certification procedures to allow for innovation and to allow the market to determine the best option for mitigation while ensuring no increase in NOx from the use of biodiesel. The certification option is based on the CARB diesel certification procedures under title 13 CCR section 2282(g). The certification requires a minimum of 20 tests each on a CARB diesel reference fuel and a candidate fuel. This number of replicates ensures that any emissions differences between the candidate fuel and the reference diesel are detected if they exist.

H. Determination of NOx Control Level for Biodiesel

Staff considered several factors in the analysis of what level of NOx control would be appropriate for biodiesel, primarily:

- NOx increase associated with biodiesel,
- Effects of high vs low saturation feedstocks,
- NOx reducing impacts of renewable diesel,
- Penetration rate of NTDEs,
- Reductions in emissions of pollutants other than NOx, and
- Feasibility of control methods.

When considering the impacts of biodiesel by feedstock, ARB determined that most of the biodiesel used in California would be low saturation biodiesel, which was found to have NOx increases at B5 with no clear point of NOx neutrality with CARB diesel. To be conservative, ARB has assumed that all blends containing low saturation biodiesel caused NOx increase.

ARB considered the range of factors which affect NOx emissions from diesel engines in the commercial market. NTDEs, which are increasing in number in California, do not show increased NOx from biodiesel use up to B20. Additionally, renewable diesel, which is increasing in California in response to the LCFS, reduces NOx. Given their impact on NOx emissions, renewable diesel and NTDEs are considered offsetting factors. Staff's analysis was designed to determine the appropriate blend level considering the Nox controls achieved by the above offsetting factors. Staff's analysis concluded that existing trends regarding use of NTDEs and renewable diesel as well as other factors supports a NOx control level of B5 for low saturation and B10 for high saturation biodiesel from April 1st to October 31st, and B10 for low and high saturation biodiesel from November 1st to March 31st.

For biodiesel blends below the NOx control level no in-use requirements are proposed because their use would not increase NOx emissions in the environment above current conditions after considering offsetting factors. In-use requirements will, under staff's proposal, be required for use of blends higher than NOx control level. These requirements could be met through the use of the additive DTBP, targeting exempt fleets, or certification of alternative options. The proposal addresses the seasonality of potential detrimental air quality impacts primarily related to summer-time ozone, and therefore allows a higher B10 blend for both low and high-saturation biodiesel during the low ozone season. Staff's analysis suggests that there will likely be no secondary PM detriment from the higher blends allowed in the low ozone season and may be benefits due to the direct PM reductions from biodiesel.

The net impacts of the proposal reduce NOx impacts from biodiesel, even assuming increased biodiesel volumes over the subsequent years. Estimated impacts under the proposal are less than the baseline (current year) and will continue to decrease as NTDE use increases in California. This proposal provides the maximum feasible level of mitigation while still achieving GHG and PM emission reductions.

This page intentionally left blank

CHAPTER 7. AIR QUALITY AND ENVIRONMENTAL JUSTICE

A. Introduction

This chapter outlines the expected air quality impacts of the proposed regulation as well as an analysis of potential effects of the ADF regulation on environmental justice and local communities. The CEQA related requirements and findings are discussed in Chapter 8 as well as the attached Environmental Analysis document attached in Appendix D.

B. Air Quality

One of the primary goals of the ADF regulation is to ensure no significant environmental impacts as a result of the use of ADFs. As such ARB is proposing an environmental review process through the three stage evaluation of ADFs, as well as provisions for biodiesel as the first commercial ADF. Biodiesel provides important air quality benefits, primarily in the form of PM and GHG emissions reductions. Use of biodiesel is expected to contribute to ARB's short and long term air quality and climate goals.

Biodiesel has been found to increase NOx emissions in some circumstances, depending on feedstock, blend level, and vehicle technology. Staff anticipates that over the long term offsetting factors, such as NTDEs and renewable diesel, will grow as a result of other ARB regulations and will eliminate any adverse NOx impacts associated with the use of biodiesel. However, until the offsetting factors reach a critical point (90 percent of on-road heavy-duty VMTs operated by NTDE) there is a risk that use of higher blends of biodiesel (greater than B5) could result in NOx emissions higher than the current levels in 2014. In order to eliminate this risk, ARB is proposing a NOx control level that varies depending on the saturation level of the biodiesel feedstock and the time of year.

In 2014, staff estimates that approximately 72 million gallons of biodiesel and 120 million gallons of renewable diesel were consumed in California. These volumes combined with the use of NTDEs resulted in an increase in NOx of about 1.3 tons per day (TPD) and a decrease in PM of about 0.8 TPD statewide compared to use of CARB diesel alone. Once the proposed ADF and LCFS regulations are adopted staff anticipates that NOx emissions will decrease from current levels. As a result of the in-use requirements on biodiesel, staff expects that use of biodiesel above B5 will not result in NOx impacts. Table 7.1 shows the expected NOx impacts of biodiesel compared to 2014, including offsetting factors.

Table 7.1: Fuel Volumes and Resulting NOx emissions relative to 2014 levels

Million gallons	2014	2015	2016	2017	2018	2019	2020	2021	2022
Low Saturation B5	72	97	129	160	150	150	150	150	150
RD	120	180	250	300	320	360	400	500	550
NTDE VMT %	40%	51%	60%	66%	71%	75%	80%	85%	89%
Net NOx TPD	0.0	-0.06	-0.08	-0.09	-0.51	-0.75	-0.9	-1.17	-1.26

The result of staff's analysis concludes that the proposed LCFS and ADF regulations will have long term air quality benefits with reductions in NOx expected as well as reductions in PM and GHG emissions.

C. Environmental Justice and Local Communities

Government Code section 65040.12(e) defines environmental justice as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies. ARB is committed to supporting the achievement of environmental justice. In 2001, the Board adopted a framework for incorporating environmental justice into the ARB's programs consistent with the directives of State law. [27] Although ARB's environmental justice policies apply to all communities in California, they recognize that environmental justice issues have been raised more often in the context of low-income and minority communities.

As a result of ARB's work with the public, the business sector, local government, and air districts, California's ambient air is the cleanest since air quality measurements have been recorded.[28] Whereas the Los Angeles area experienced 148 smog alerts in 1970, by the year 2000, there was not a single smog alert.[29] However, large numbers of Californians live in areas that continue to experience episodes of unhealthy concentrations of ozone and PM2.5.

For this analysis, we note as an initial matter that any community in proximity to operations involving diesel fueled vehicles is already experiencing incremental risks from exposure to diesel particulate matter (PM). In 1998, ARB identified diesel PM as a toxic air contaminant with no safe threshold of exposure, which means that any diesel PM exposure may increase lifetime cancer risk for affected communities. Consequently, ARB embarked on a comprehensive diesel risk reduction program in the

[27] California Air Resources Board, Report, *Policies and Actions for Environmental Justice*, 2001
[28] California Air Resources Board, *History of Air Resources Board*, Website, http://www.arb.ca.gov/knowzone/history.htm, November 16, 20120 (accessed October 4, 2013)
[29] California Air Resources Board, Video file, *Clearing California Skies Updated*, http://www.arb.ca.gov/videos/clskies.htm (accessed October 4, 2013)

early 2000s, implementing a number of stationary, mobile, and portable diesel engine standards; fleet emission controls; and diesel fuel requirements designed to address such risks.

This proposed rulemaking is designed to maintain the air quality protections already in place under ARB's existing diesel fuel regulations. This includes, but is not limited to, maintaining protections in the only two areas nationwide whose air quality nonattainment status has been classified as "extreme," the San Joaquin Valley Air Basin and the South Coast Air Basin. Both areas have active environmental justice groups that have lobbied ARB to take aggressive action in pursuit of reduced toxic emission releases and attainment of ambient standards to ease air quality-related health burdens on their communities.

The air quality impacts of this regulatory proposal promote environmental justice by maintaining current protections for California's air quality in areas that are simultaneously the most adversely affected with respect to ground level ozone and home to many minority and low-income groups. At the same time, the proposed rulemaking provides a clear legal pathway to the commercialization of innovative, lower carbon diesel fuel substitutes. These innovative substitutes will reduce GHG emissions, and many of them also provide benefits in the form of additional reductions in PM, CO, NOx, toxic air contaminants, and other air pollutants.

As noted in Chapter 6, ADFs have the potential to reduce exposure to pollutants when used as a replacement for conventional diesel. To the extent that the proposed regulation expedites the introduction of ADFs as replacements for conventional diesel, all communities will benefit from improved air quality. In general, staff anticipates that any impacts resulting from the proposed regulation will be beneficial in nature, as a result of introducing new, lower-emitting ADFs.

To further ensure maintenance of air quality protections at the community level, the proposed regulation contains provisions that require a new ADF proponent to disclose comprehensive information about the ADF and the proponent's plan for limited fleet testing of that fuel. This comprehensive and detailed level of information required to be submitted before testing begins will permit ARB staff to assess the potential impacts such vehicle fleet studies could have on the most sensitive communities. Pertinent to the sensitive communities is a provision in the proposal that requires disclosure, in the Stage 1 and Stage 2 phases, of the ZIP codes in which the applicant proposes to conduct the limited vehicle fleet testing. The ARB staff will consider the proposed ZIP codes, along with the feasibility of conducting the fleet tests in alternative locations, as part of the Stage 1 and Stage 2 approval process. Depending on a number of factors, including the nature of the candidate ADFs and the extent of the fleet test, ARB staff may suggest or require a different location for the study as appropriate and feasible.

Based on staff's assessment of current and future ADFs, such as biodiesel and dimethyl ether, it is likely that new ADFs will exhibit less PM emissions relative to conventional diesel. In such cases, communities will benefit from lower cancer risk associated with the replacement of diesel fuel with ADFs. Likewise, communities will also benefit from any reductions in other criteria and toxic air pollutants associated with ADF use. The State mandated multimedia assessment will determine whether future ADFs will exhibit any increases in other toxic compounds, which may warrant additional controls. Moreover, since the proposed regulation provides for a more orderly process than currently exists towards commercialization, ARB would have more oversight over the approval of any ADF use in local communities and can ascertain whether additional requirements should apply to safeguard against any adverse impacts.

In addition to governing the approval and use of future ADFs, the proposed regulation would also explicitly identify biodiesel as the first ADF commercialized under this regulation. Biodiesel has an extensive history of environmental evaluation and consensus standard development. Indeed, much of the proposed regulation is modeled on ARB staff's experience in evaluating biodiesel over the years. As a result, the proposed regulation would explicitly identify biodiesel as a Stage 3A ADF, "Commercial Sales Subject to Mitigation," in recognition of the fact that biodiesel already has effectively undergone the requirements in Stage 1 and 2.

As discussed in Chapter 6 and the multimedia evaluation, biodiesel has been shown to reduce PM, HC, CO and greenhouse gases from diesel engines. Therefore, replacing diesel with biodiesel provides an immediate reduction in toxic cancer risk that is proportional to the percent reduction in PM emissions. Likewise, reductions in HC and CO also help communities by lowering near source and regional concentrations of ozone and CO.

Being the first commercially recognized ADF under the proposed regulation, biodiesel will have positive long term overall air quality impacts and benefits for all communities, and near term benefits to PM and GHG emissions. Staff expects that in the longer term (post 2022) no NOx mitigation will be necessary for biodiesel blends up to B20 due to the adoption of NTDEs.

In conclusion, the proposed ADF regulation is designed to ensure that the introduction and use of innovative ADFs in California, including biodiesel, will have no significant adverse environmental or public health impacts, as the heavy duty diesel fleet transitions to NTDEs. This conclusion applies at the State level as a whole, at the various air basin and regional levels, and at the local community level. As a result, the proposed regulation maintains the environmental and human health protections that are already provided under the existing diesel fuel regulations.

CHAPTER 8. ENVIRONMENTAL ANALYSIS

The Air Resources Board (ARB), as the lead agency for the proposed regulation, has prepared an environmental analysis under its certified regulatory program (17 CCR 60000 – 60008) to comply with the requirements of the California Environmental Quality Act (CEQA). ARB's regulatory program, which involves the adoption, approval, amendment, or repeal of standards, rules, regulations, or plans for the protection and enhancement of the State's ambient air quality has been certified by the California Secretary for Natural Resources under Public Resources Code section 21080.5 of CEQA (14 CCR 15251(d)). ARB, as a lead agency, prepares a substitute environmental document (referred to as an "Environmental Analysis" or "EA") as part of the Staff Report to comply with CEQA (17 CCR 60005).

The Draft Environmental Analysis (EA) for the proposed regulation is included in Appendix D to this Staff Report.   The Draft EA provides a single coordinated programmatic environmental analysis of an illustrative, reasonably foreseeable compliance scenario that could result from implementation of the proposed Alternative Diesel Fuel (ADF) regulation and the proposed re-adoption of the Low Carbon Fuel Standard (LCFS) regulation. The proposed ADF and LCFS regulations have two separate regulatory notices and staff reports and will be considered by the Board in separate proceedings. This approach is consistent with CEQA's requirement that an agency consider the whole of an action when it assesses a project's environmental effects, even if the project consists of separate approvals (14 CCR 15378(a)).

The Draft EA states that implementation of the proposed regulations could result in beneficial impacts to GHGs through substantial reductions in emissions from transportation fuels in California from 2016 through 2020 and beyond, long-term beneficial impacts to air quality through reductions in criteria pollutants, and beneficial impacts to energy demand. The Draft EA also states the proposed regulations could result in less than significant or no impacts to mineral resources, population and housing, public services, and recreation; and potentially significant and unavoidable adverse impacts to aesthetics, agriculture resources, biological resources, cultural resources, geology and soils, hazards and hazardous materials, hydrology and water quality, land use and planning, noise, transportation and traffic, and utilities, and short-term construction-related air quality impacts primarily related to the construction projects and minor expansions to existing operations that are reasonably foreseeable as a result of the proposed regulations.

Written comments on the Draft EA will be accepted starting January 2, 2015 through 5 p.m. on February 17, 2015. The Board will consider the Final EA and responses to comments received on the Draft EA before taking action to adopt an ADF regulation.

This page intentionally left blank

CHAPTER 9. MULTIMEDIA EVALUATION

H&SC section 43830.8 prohibits ARB from adopting any regulation that establishes motor vehicle fuel specifications unless that regulation is subject to a multimedia evaluation and reviewed by the CEPC. Pursuant to Public Resources Code section 71017(b), the CEPC was established as a seven-member body comprised of the Secretary for Environmental Protection; the Chairpersons of the ARB and SWRCB; and the Directors of the Office of Environmental Health Hazard Assessment (OEHHA), the Department of Toxic Substances Control (DTSC), the Department of Pesticide Regulation (DPR), and the Department of Resources Recycling and Recovery (CalRecycle). Key components of the evaluation process are the identification and evaluation of significant adverse impacts on public health or the environment and the use of best available scientific data.

A. General Overview

"Multimedia evaluation" means the identification and evaluation of any significant adverse impact in public health or the environment, including air, water, and soil, that may result from the production, use, and disposal of a motor vehicle fuel that may be used to meet the state board's motor vehicle fuel specifications (H&SC §43830.8(b)).

1. Multimedia Working Group

The California Environmental Protection Agency (Cal/EPA) formed the interagency multimedia working group (MMWG) to oversee the multimedia evaluation process. The MMWG includes representatives from the ARB, SWRCB, OEHHA, and DTSC. The MMWG also consults with other Cal/EPA agencies and experts as needed.

During a multimedia evaluation, ARB staff are responsible for the air quality impact assessment and overall coordination of the MMWG. SWRCB staff are responsible for the evaluation of surface water and groundwater quality and potential impacts. OEHHA staff are responsible for evaluating potential public health impacts. DTSC staff are responsible for evaluating potential hazardous waste and soil impacts.

2. California Environmental Policy Council

Before ARB adopts a regulation that establishes new fuel specifications, the CEPC must determine if the proposed fuel specification poses a significant adverse impact on public health or the environment. In making its determination, the CEPC must consider the following:

- emissions of air pollutants, including ozone-forming compounds, particulate matter, toxic air contaminants, and greenhouse gases,
- contamination of surface water, groundwater, and soil,
- disposal of waste materials, including agricultural residue, forest biomass, and municipal solid waste, and

- MMWG staff report and peer review comments.

The CEPC must complete its review of the evaluation within 90 calendar days following notice from ARB that it intends to adopt the regulation. If the CPEC determines that the proposed regulation will cause a significant adverse impact on public health or the environment, or that alternatives exist that would be less adverse, the CEPC shall recommend alternative measures to reduce the impact.

3. External Scientific Peer Review

H&SC section 43830.8(d) requires an external scientific peer review to be conducted on the multimedia evaluation in accordance with H&SC section 57004. The purpose of the peer review is to determine whether the scientific portions of the staff report are based upon "sound scientific knowledge, methods, and practices (HSC section 57004(d)(2))."

B. Summary of the Biodiesel and Renewable Diesel Multimedia Evaluation

As part of the ADF regulation, staff intends to establish fuel quality specifications for biodiesel. Therefore, a multimedia evaluation of biodiesel and renewable diesel fuel was conducted pursuant to H&SC section 43830.8 and the *Guidance Document and Recommendations on the Types of Scientific Information Submitted by Applicants for California Fuels Environmental Multimedia Evaluations,* ("Multimedia Evaluation Guidance Document").[30]

The MMWG prepared two staff reports entitled, "*Draft Staff Report: Multimedia Evaluation of Biodiesel*" (Biodiesel Staff Report)[31] and "*Draft Staff Report: Multimedia Evaluation of Renewable Diesel*" (Renewable Diesel Staff Report).[32] The draft staff reports consist of the MMWG's assessment of the biodiesel and renewable diesel multimedia evaluations conducted by the UC Berkeley and UC Davis, and the MMWG's analysis of potential significant adverse impacts on public health and the environment.

The MMWG's conclusions and recommendations are based on the results of the multimedia evaluation and the information provided in the UC final reports entitled, "*California Biodiesel Multimedia Evaluation Final Tier III Report*" (Biodiesel Final Report)[33] and "*California Renewable Diesel Multimedia Evaluation Final Tier III Report*" (Renewable Diesel Final Report).[34]

---

[30] U.C. Berkeley, U.C. Davis, Lawrence Livermore National Laboratory, *Guidance Document and Recommendations on the Types of Scientific Information Submitted by Applicants for California Fuels Environmental Multimedia Evaluations*, June 2008
[31] Multimedia Working Group, California Environmental Protection Agency. *Staff Report: Multimedia Evaluation of Biodiesel"* November 2013
[32] Multimedia Working Group, California Environmental Protection Agency. *Staff Report: Multimedia Evaluation of Renewable Diesel"* November 2013
[33] U.C. Berkeley, U.C. Davis, *California Biodiesel Multimedia Evaluation Final Tier III Report*, May 2013
[34] U.C. Berkeley, U.C. Davis, *California Renewable Diesel Multimedia Evaluation Final Tier III Report*, April 2012

1. Biodiesel Multimedia Evaluation

The MMWG completed their assessment of the biodiesel multimedia evaluation and potential impacts on public health and the environment. The evaluation is a relative comparison between biodiesel and CARB diesel.

The MMWG concludes that the use of biodiesel fuel in California, as specified in the biodiesel multimedia evaluation, does not pose a significant adverse impact on public health or the environment relative to CARB diesel.

Each agency's individual assessments and conclusions are summarized below:

- Air Emissions Evaluation. ARB staff assessed potential air quality impacts and made conclusions based on their assessment of various emissions test results and air quality data, including criteria pollutants, toxic air contaminants, and greenhouse gas emissions data. ARB staff concludes that biodiesel reduces PM, CO, and HC emissions and may increase NOx emissions in some blends.

- Water Evaluation. SWRCB staff assessed potential surface water and groundwater impacts and made conclusions based on their assessment of potential water impacts and materials compatibility, functionality, and fate and transport information. SWRCB staff concludes that there are minimal additional risks to beneficial uses of California waters posed by biodiesel than that posed by CARB diesel.

- Public Health Evaluation. OEHHA staff assessed potential public health impacts and made conclusions based on their assessment of potential impacts on atmospheric carbon dioxide and combustion emissions results. OEHHA staff concludes that the substitution of biodiesel for CARB diesel reduces the rate of addition of carbon dioxide to the atmosphere and reduces the amount of PM, benzene, ethyl benzene, and polycyclic aromatic hydrocarbons (PAHs) released into the atmosphere, but may increase emissions of NOx for certain blends. Limited emission testing resulted in a non-statistical increase in acrolein for a higher B50 biodiesel blend level (i.e., confidence interval less than 95%). Furthermore, the statistical analysis for acrolein emission results was compared to only one data point for the control sample.

- Soil and Hazardous Waste Evaluation. DTSC staff assessed soil and hazardous waste impacts and made conclusions based on their evaluation of hazardous waste generation and potential impacts on the fate and transport of biodiesel fuel in the subsurface soil from unauthorized spills or releases. DTSC concludes that biodiesel aerobically biodegrades more readily than CARB diesel, has potentially higher aquatic toxicity for a small subset of tested species, and generally has no significant difference in vadose zone infiltration rates.

2. Renewable Diesel Multimedia Evaluation

The MMWG completed their assessment of the renewable diesel multimedia evaluation in support of low NOx standard. The evaluation is a relative comparison between renewable diesel and CARB diesel.

The MMWG concludes that the use of renewable diesel fuel in California, as specified in the renewable diesel multimedia evaluation, does not pose a significant adverse impact on public health or the environment relative to CARB diesel.

Each agency's individual assessments and conclusions are summarized below:

- Air Emissions Evaluation. ARB staff assessed potential air quality impacts and made conclusions based on their assessment of various emissions test results and air quality data, including criteria pollutants, toxic air contaminants, and greenhouse gas emissions data. ARB staff concludes that renewable diesel does not pose a significant adverse impact on public health or the environment from potential air quality impacts.

- Water Evaluation. SWRCB staff assessed potential surface water and groundwater impacts and made conclusions based on their assessment of potential water impacts and materials compatibility, functionality, and fate and transport information. SWRCB staff concludes that there are minimal additional risks to beneficial uses of California waters posed by renewable diesel than that posed by CARB diesel.

- Public Health Evaluation. OEHHA staff assessed potential public health impacts and made conclusions based on their analysis of toxicity testing data and combustion emissions results. OEHHA staff concludes that PM, benzene, ethyl benzene, and toluene in combustion emissions from diesel engines using hydrotreated vegetable oil renewable diesel are significantly lower than CARB diesel.

- Soil and Hazardous Waste Evaluation. DTSC staff assessed soil and hazardous waste impacts and made conclusions based on their evaluation of hazardous waste generation and potential impacts on the fate and transport of biodiesel fuel in the subsurface soil from unauthorized spills or releases. DTSC concludes that renewable diesel is free of ester compounds and has low aromatic content. The chemical compositions of renewable diesel are almost identical to that of CARB diesel. Therefore, the impacts on human health and the environment in case of a spill to soil, groundwater, and surface waters would be expected to be similar to those of CARB diesel.

C. Biodiesel and Renewable Diesel Peer Review

The peer review process was initiated by submittal of a request memorandum to the manager of the Cal/EPA Scientific Peer Review Program. The memorandum was prepared by ARB as the lead agency of the MMWG and included a summary of the nature and scope of the requested review, descriptions of the scientific issues to be addressed, and a list of recommended expertise. Upon approval, the University of California, through an interagency agreement with Cal/EPA, identified seven reviewers to complete the review of the biodiesel and renewable diesel multimedia evaluations.

The MMWG requested reviewers to address the Biodiesel and Renewable Diesel Staff Reports separately. Therefore, each reviewer completed two separate reviews, accordingly, for a total of 14 reviews.

In general, the peer reviewers determined that the conclusions and recommendations made by the MMWG were based upon sound scientific knowledge, methods, and practices, including the overall finding that the use of biodiesel and renewable diesel fuel in California, as specified in the biodiesel and renewable diesel multimedia evaluation, respectively, do not pose a significant adverse impact on public health or the environment relative to CARB diesel.

The complete set of peer review comments are posted on the *Fuels Multimedia Evaluation Meetings and Documents* webpage.[35] Individual peer review comments are categorized under the following general topics:

- Air quality
- Public health
- Water quality
- Soil and hazardous waste
- Multimedia evaluation
- Staff report
- Source reports
- Proposed regulation

The MMWG are preparing written responses to each of the comments. The complete set of peer review comments and MMWG responses will be included in the staff reports as new chapters, including any revisions to the staff reports that were made to address comments, where appropriate.

D. Current Status and Next Steps

The Biodiesel Staff Report is currently undergoing supplemental external peer review and internal MMWG analysis. Upon completion of the MMWG's review and

[35] Air Resources Board. *Fuels Multimedia Evaluation Meetings and Documents* webpage: http://www.arb.ca.gov/fuels/multimedia/meetings/meetings.htm

assessment of additional biodiesel studies and comments from the initial peer review, ARB intends to update and modify the Biodiesel Staff Report.

The supplemental external peer review of biodiesel will focus on the modifications to the MMWG's assessment of the biodiesel multimedia evaluation and the scientific basis for which the proposed modifications are based.

The supplemental peer review is currently scheduled from January to February 2015. Once all peer review comments are received, the MMWG will prepare written responses and make any revisions to the staff report, as needed. After all comments have been addressed, the MMWG will finalize the staff reports for submittal to the CEPC. The Cal/EPA will then convene a public meeting of the CEPC to consider the results of the peer reviews and the overall multimedia evaluation of biodiesel and renewable diesel fuel. Based on the evaluation and public comments, the CEPC will determine if the proposed regulation will cause a significant adverse impact on public health or the environment.

CHAPTER 10. ECONOMIC IMPACTS ASSESSMENT

A. Summary of Economic Impacts

In preparing this economic analysis, staff considered the costs of complying with the general provisions prescribed for Stage 1, Stage 2, and Stage 3 (as described in Chapter 5) of the proposed regulation. The compliance costs are determined on a fuel-by-fuel basis and will depend on whether a new ADF achieves full commercial development and successfully completes all three stages. Full commercialization of new ADFs in California will depend on successful resolution of a myriad of technical issues including, but not limited to, vehicle performance, fuel infrastructure compatibility, public health and environmental issues. If a new ADF completes all three prescribed stages, then only minimal recordkeeping and reporting above and beyond requirements that are already required under other State and Federal mandates will be the costs attributable to this regulation. These reporting requirements would be satisfied with reporting currently done through the Low Carbon Fuel Standard Reporting Tool (LRT) used to claim LCFS credits.

Because the majority of the provisions in all three stages are already required under existing State and Federal programs, staff estimates that the overall cost of the regulation to commercialize a future ADF will be minimal for the majority of ADF producers or distributors and would mainly account for additional, or “enhanced,” recordkeeping. Other than biodiesel, no other ADF has undergone more than a preliminary analysis akin to Stage 1 of this proposal. The environmental impacts of those potential fuels are unknown, as that is determined in Stage 2 during the multimedia evaluation. For an ADF under Stage 3B, there will be minimal costs attributable to the proposed regulation because those ADFs would be subject to the same reporting requirements as all other commercial motor vehicle fuels, and no costs if reporting is done via the LRT. Without knowing the type of ADF and associated volumes that may come to market in the future, pollutant control costs cannot be estimated for those fuels commercialized under Stage 3A. Since biodiesel is the first commercialized ADF to be regulated under this proposal, the cost for biodiesel suppliers to comply with the regulation is addressed in this chapter as the costs of the regulation.

As noted, biodiesel has already undergone the equivalent of the proposal’s Stages 1 and 2. Accordingly, biodiesel would be sold in the California market under Stage 3A upon this proposed regulation becoming effective. Staff propose to incorporate certain provisions in Stage 3A to ensure NOx emissions from biodiesel use do not cause any significant adverse impacts. These include per gallon NOx emission control requirements from April 1st through October 31st, for low saturation biodiesel blends above B5, as well as for blends above B10 for high saturation biodiesel. From November 1st through March 31st, the in-use requirements are relaxed and permit both low and high saturation biodiesel blends up to B10 for use without these in-use requirements. The current California biodiesel market currently uses and is projected to continue using the majority of the biodiesel produced in the state to create blends below B5, and therefore, we project limited costs due to NOx control requirements.

Biodiesel and biodiesel blends are being currently sold in California without regulatory oversight to safeguard against potential adverse emissions impacts, including NO_x. As such, the biodiesel industry has not invested in the additive blending infrastructure required for NO_x emissions controls, nor have they pursued certifications of low NO_x emissions biodiesel formulas. This absence of any NOx emissions controls infrastructure was brought up in the National Biodiesel Board's (NBB) submittal of an alternative to the proposed regulation, which also recommended a lead-in period. Given the current lack of NO_x emissions controls infrastructure, staff proposes that the in-use requirements not take effect until 2018, or two years after the implementation date of the regulation. Staff believes that two years is sufficient to provide the biodiesel industry with time to invest in the infrastructure necessary for additive handling and blending; to develop and pursue certifications for new NOx reduction options; and to adopt potential commercial changes such as focusing on exempted NTDE fleets. Also, this two year period is in keeping with established ARB policy, as many other ARB regulations have also provided similar grace periods to their affected industries; allowing them time to adjust their business practices and minimize adverse fiscal impacts, especially in cases where no regulatory oversight existed before.

The proposed regulation is not expected to have a significant adverse economic impact on California businesses or their competitiveness. However, the proposed ADF regulation will have some minimal economic costs to ADF fuel providers, including producers, distributors, and possibly retailers. In addition, consumers and government agencies that opt to fuel their fleets with biodiesel blends requiring NO_x emissions controls may experience an increase in fuel costs provided their fleets consist of heavy duty vehicles without NTDEs, though these costs are small. ARB determined that the regulation does not pose any requirements that will have an adverse economic impact. The highest cost year of the regulation is 2018 with a cost of $3,071,000 to produce both B10 and B20 blends. This represents less than one-one hundredth of the economic activity in California in 2018. Additionally, the direct costs to the industry are a small portion of the industry revenues and can likely be absorbed by either the ADF business or passed along to consumers. Finally, these additional costs will likely be offset by the revenue from credit generation in the LCFS program and therefore not impact the regulated entities significantly.

B. Major Regulations

ARB is subject to two separate major regulation requirements, identified below:

For a major regulation proposed on or after November 1, 2013, a standardized regulatory impact assessment (SRIA) is required. A major regulation is one "that will have an economic impact on California business enterprises and individuals in an amount exceeding fifty million dollars ($50,000,000) in any 12-month period between the date the major regulation is filed with the Secretary of State through 12 months after the major regulation is estimated to be fully implemented, as estimated by the agency." (Govt. Code Section 11342.548). This requirement is triggered if either the direct, indirect and induced costs, or taken separately, the benefits exceed $50 million. The economic impacts of this regulation may exceed $50 million, and therefore the regulation is treated as major according to the Government Code. In response, ARB prepared and submitted a SRIA to the Department of Finance[36].

For purposes of Health and Safety Code Section 57005(b), “major regulation” means any regulation that will have an economic impact (compliance cost) on the state’s business enterprises in an amount exceeding ten million dollars ($10,000,000), as estimated by the board, department, or office within the agency proposing to adopt the regulation in the assessment required by subdivision (a) of Section 11346.3 of the Govt. Code. This regulation may impose compliance costs that exceed $10 million and therefore the regulation is treated as major for the Health and Safety Code.

C. Economic Impacts Assessment

As discussed in Chapter 5, biodiesel is currently the only ADF identified as subject to the proposed regulation. Given the fact that biodiesel currently has consensus standards, is completing a multimedia assessment, and has an identified NOx emissions impact and in-use pollutant control strategies, staff proposes to recognize biodiesel as a Stage 3A commercial ADF subject to in-use requirements under specified conditions.

Therefore, only the cost of biodiesel compliance in Stage 3A would be attributable to the proposed regulation, and drives all the actual costs of the regulation. This means that the cost of biodiesel as the first commercial ADF will be primarily the cost of enhanced monitoring with minor costs due to in-use requirements. As staff discussed in Chapter 6, in-use requirements for NO_x control are unlikely to be utilized for most of the biodiesel sold in the state. In the unlikely scenario of blends requiring NO_x controls reaching wide scale market share in the future, the cost of these controls would also be attributable to the proposed regulation. NO_x control costs are presented in Appendix C.

Staff projects the same overall volumes of pure biodiesel (B100) will be produced as in business as usual. However, the blend levels will be adjusted downward to meet the provisions outlined in this regulation. Staff identified the following options that may occur in reaction to the ADF regulation:

Option 1: Businesses will use NO_x emissions controls and continue selling at the same level. Staff believes the majority of businesses will not opt to use NO_x emissions controls given that other options are less costly and therefore more feasible. These businesses will have an option to sell biodiesel blends up to B10 in the winter months.

Option 2: Businesses will continue selling blends with in-use requirements such as B20 at existing volumes by targeting NTDE fleets with exemptions from the in-use requirements. Many of the existing retailers (and therefore distributors), are already working with functionally exempt fleets. For example, staff discovered that many B20

[36] SRIA: http://www.dof.ca.gov/research/economic_research_unit/SB617_regulation/2014_Major_Regulations/

fueling pumps cannot accommodate HDVs because of low ceiling clearance and inaccessible facilities. As such, these retailers could seek exemptions that allow them to continue selling B20 to the medium and light duty vehicles, which these retail pumps are designed to accommodate. For the retailers that can accommodate HDVs, some change in their business practices will have to occur, such as establishing a dedicated lane for NTDEs that wish to use biodiesel blends such as B20. These business will also the option to sell biodiesel blends up to B10 in the winter months

Option 3: Businesses will stop selling B20 and only offer lower blends. For the retailers they may lose some business, which is likely negligible as the consumers of these fuels will likely transition from B20 to lower blends. The distributors will be able to stay in business, but have to change their business practices to accommodate a change to lower blends. For instance: they will likely have to distribute lower blends by truck, potentially leading to increased truckloads. These business also will have an option to sell biodiesel blends up to B10 in the winter months

Staff believes the reality will be a mix of these options. This chapter assumes the following scenario, which is evaluated in detail in this chapter:

Staff estimates that in 2018 the market share of biodiesel blends requiring NO_x controls will be around 17 percent (30 million gallons out of 180 of the total biodiesel volumes sold in the state), with volumes projected to remain steady until 2021 when total biodiesel volumes increase to 185 million gallons. These volumes then remain at 185 million gallons until 2023 when NTDE VMT exceeds 90 percent of total VMT in EmFAC 2011. At that point the in-use requirements will sunset and use of B20 will be allowed without in-use requirements.

- For all seasons, high saturation biodiesel has a NOx emissions control requirement at the level of B10. Staff assumes high saturation biodiesel will be sold at B10 with only the cost of testing to verify the high saturation exemption to the requirement for NOx emissions controls at the B5 level.
- The projection of VMT by NDTEs is 71 percent in 2018. Assuming some portion of these vehicles will be targeted by the B20 industry, coupled with additional B20 use in light and medium-duty vehicles, staff calculates 8 million gallons of B100 used in B20 will be exempted for all seasons in 2018. The VMT by NTDE's increases in the subsequent years from 75 percent in 2019 to 98 percent in 2023. As the VMT of the NTDE fleets increases, so will the proportion of biodiesel volumes with exemptions to the in-use requirements.
- The final 9 million gallons of low saturation biodiesel will be divided between winter and summer. Assuming slightly less biodiesel is used in the winter; staff assumes 4 million gallons in winter and 5 million in summer. The summer use will require a NOx emissions control of 5 percent DTBP per gallon of B100. The remaining 4 million will be used in winter as B10 without any in-use requirements.

This scenario is summarized in the table below, using volumes projected for 2018:

Table 10.1 Summary of Costs for 2018

Million Gallons of biodiesel blended above B5	**Category of Use**	**Requirement**	**Cost in 2018**
5	High-saturation use in summer as B10	Testing to verify high saturation*	$215,000
8	Low-saturation used in exempted fleets and vehicles in all seasons	Use in exempted fleets such as NTDEs, medium and light duty vehicles	Recordkeeping (included as part of $56,000.00)
5	Low-saturation use in summer as B20	5% DTBP per gallon of B100	$2,800,000
12	Low-saturation use in winter as B10	No NOx controls in winter for B10 and below (Nov 1-March 31)	Recordkeeping (included as part of $56,000.00)
Total: 30 million gallons			Total: $3,071,000**

* See Appendix C for testing costs methodology

** Includes reporting and recordkeeping costs for 150 million gallons of B100 used for blends below

As mentioned earlier, staff assumes the volumes of biodiesel with NO_x controls to decrease as the volumes of biodiesel used in exempted fleets such as NTDEs, medium and light duty vehicles increase each year. The table below reflects the changing scenario on increased NTDEs and the subsequent reduction in costs. Table 10.2 demonstrates how the volumes, and associated costs, of high saturation biodiesel for summer use and NO_x controls for low saturation biodiesel decreased while the volumes of low saturation biodiesel blends in exempted fleets increased; when compared to table 10.1. In 2023, only the cost of recordkeeping and reporting would apply due to the sunset provision.

In addition to the in-use requirement costs listed in Tables 10.1 and 10.2, the industry will face additional recordkeeping costs, which are outlined below. Following this discussion, this chapter will identify the costs as indicated in the table above.

Table 10.2 Summary of Costs for 2021

Million Gallons of biodiesel blended above B5	Category of Use	Requirement	Cost in 2021
2	High-saturation use in summer as B10	Testing to verify high saturation*	$86,000
14	Low-saturation used in exempted fleets and vehicles in all seasons	Use in exempted fleets such as NTDEs, medium and light duty vehicles	Recordkeeping (included as part of $56,000.00)
2	Low-saturation use in summer as B20	5% DTBP per gallon of B100	$1,120,000
12	Low-saturation use in winter as B10	No NOx controls in winter for B10 and below (Nov 1-March 31)	Recordkeeping (included as part of $56,000.00)
30			$1,262,000**

* See Appendix C for testing costs methodology
** Includes reporting and recordkeeping costs for 150 million gallons of B100 used for blends below

1. Cost of Enhanced Recordkeeping

Because staff is proposing to allow commercialization of biodiesel under Stage 3A with in-use requirements for low and high saturation biodiesel blends, detailed market sales and related information would be required from biodiesel producers to track blend levels and compliance with the in-use requirements. We anticipate similar compliance costs if pollutant controls are identified for future ADFs that are approved for commercialization under this regulation. For an ADF with no such controls identified, there will be no costs attributable to the proposed regulation because those ADFs would be subject to the same reporting requirements as all other commercial motor vehicle fuels. Biodiesel retailers will not experience any quantifiable costs for enhanced recordkeeping once a transition from Stage 3A to Stage 3B occurs.

As shown in Table 10.3, staff estimates that a typical cost for enhanced recordkeeping for each producer will be about $1,600 annually. For the 12 producers and 23 blender distributors we are aware of, we estimate the total cost for recordkeeping to be $56,000 per year. This number was reached using the prevailing wage for an environmental engineer of $40.00 an hour and an estimate of 40 hours needed to comply with the enhanced recordkeeping.

Table 10.3: Estimate of Annual Cost of Enhanced Recordkeeping*

Increased Annual Recordkeeping Hrs.	Cost per Hr**	Annual Cost per Producer and Blender/Distributor	Total Annual Cost for all Recordkeeping
40	$40.00	$1,600	$56,000

* Enhanced monitoring consists of: monthly biodiesel sales volumes by blend (B5, B10, B20, B100); geographic location of respective biodiesel blend sales; Sales of biodiesel produced from animal tallow feedstocks

** Prevailing wage for environmental engineer (source: http://www.bls.gov/ooh/architecture-and-engineering/environmental-engineers.htm)

2. Cost of NOx Emissions Controls for Biodiesel

a. High-saturation for use in all seasons

The 2018 projected biodiesel volumes of 180 million gallons consist of 150 million B100 gallons dedicated to biodiesel blends below the blend levels requiring NO_x emissions controls and 30 million B100 gallons used to create blends above that level. Of these 30 million gallons, 5 million gallons are potential high saturation biodiesel due to their marketability as B10 with only the cost of testing required (cost of testing is laid out in Appendix B). Staff expects most of this high saturation biodiesel to be sold as B10, which does not require more expensive NOx controls. So the resultant cost would be:

5 million gallons * $0.043/ gallon = $215,000

b. Low-Saturation Use in Summer

This will require DTBP additization at the cost of $0.112 per gallon of B20 (see Appendix C for the per gallon calculation). Staff assumes, that in 2018, 5 million gallons of low saturation B100 will be used in the summer and require NOx emissions controls. This means that 5 million gallons of B100, or 25 million gallons of B20 will cost the industry:

$0.112 per gallon. (B20 * 25 million gallons = $2,800,000)

Based on the analysis presented in Chapter 6, staff concludes that using additives such as DTBP is the least likely compliance option for blends with NOx emissions control requirements, due to the high cost of additives and infrastructure needed for additization blending. However, due to demand for these blends by certain government agencies and companies with policies that encourage “green” fuels, some additization will occur. A detailed cost analysis of the NOx control option using additive, as well as the certification option, can be found in Appendix C and is summarized in Table 10.4. The cost of ADF certification is not included as a direct cost because biodiesel producers are not required to pursue that option. It would be a producer’s decision to develop a certified low-NOx formula under a research and development protocol, which can be viewed as the cost of doing business.

c. Low-Saturation Use in Winter

Because the requirement for the winter allows a higher blend, the producers would likely not use additives for NOx controls but instead sell at the B10 blend level. Therefore, no additional costs above the recordkeeping would be incurred in the winter. Due to cloud point issues with biodiesel in cold weather, business as usual is typically the use of blends with a lower percentage than 20 percent by volume. However, because California has a fairly mild climate, blends of B10 in areas such as Southern California and the San Francisco Bay Area would not be expected to decrease in the winter. These areas also happen to be where the majority of biodiesel is consumed.

3. Potential Adverse Economic Impacts Directly Affecting Business

Biodiesel industries downstream from the producers such as blenders or jobbers, distributors, and retailers, are not expected to experience any costs during the first two years of the regulation. However, in 2018, when in-use requirements for certain biodiesel blends take effect, businesses that did not modify their business practices or seek exemptions to in-use requirements for blends above B5 for low saturation biodiesel, or B10 for high saturation biodiesel, can be expected to incur costs and/or losses. These costs or losses may include: costs of additizing the blends they sell, the costs of adopting new business practices, and the loss of business from not offering B20.

In addition to the measures businesses can take to reduce any adverse economic impacts resulting from the 2018 requirements of the proposal, others may find increased opportunities. Staff does not expect total biodiesel volumes in the State to decrease as a result of the regulation, but rather to be diverted from blends with in-use requirements to blends below B5, or to exempt fleets.

4. Impacts on Small Business

Tables 10.4 and 10.5 on the next page list several businesses that support biodiesel use in California, including 12 biodiesel producers and 23 biodiesel distributor/blenders operating in the State. Twenty-two of these are small businesses, seven are not, and six are unknown, based on the definition for small businesses (GC 11342.610). The list of producers and distributors was derived from Biodiesel magazine[37] and National Biodiesel Board's lists of biodiesel producers[38] and distributors[39].

---

[37] Biodiesel Magazine, *USA Plants* http://www.biodieselmagazine.com/plants/listplants/USA/page:1/sort:state/direction:asc (accessed November 4, 2014)
[38] National Biodiesel Board, *Biodiesel Plants Listing*, http://www.biodiesel.org/production/plants/plants-listing (accessed November 4, 2014)

Table 10.4: Biodiesel Producers

Biodiesel Producers	Small Business
Baker Commodities, Inc.	No
Bay Biodiesel, LLC	Yes
Biodiesel Industries of Ventura, LLC	Yes
Community Fuels	unknown
Crimson Renewable Energy, L.P.	Yes
Geogreen Biofuels, Inc.	Yes
Imperial Western Products, Inc.,	Yes
New Leaf Biofuel, LLC	No
Noil Energy Group, Inc.	Yes
North Star Biofuels, LLC	unknown
Simple Fuels Biodiesel	Yes
Yokayo Biofuels	Yes

Table 10.5: List of Distributors

Biodiesel Distributors	Small Business
Argo Energy	Unknown
Beck Oil, Inc	Unknown
Downs Energy	Yes
Eel River Fuels, Inc.	Yes
General Petroleum Corporation	No
Goodspeed Auto-Fuel Systems, Inc.	No
Inter-State Oil Co.	No
Interstate Oil Company	Yes
Lee Escher Oil Co	Yes
NAPA Valley Petroleum, Inc.	No
New West Petroleum	Unknown
New West Petroleum	Yes
Pearson Fuels	Yes
Promethean Biofuels Cooperative Corporation	Unknown
Ramos Oil Company Inc.	Yes
Royal Petroleum Company	Yes
RTC Fuels, LLC (Pearson)	Yes
SC Fuels	Yes
Sirona Fuels	No
Southern Counties Oil Co.	Yes
Supreme Oil Co.	Yes
Tom Lopes Distributing, Inc.	Yes
W. H. Breshears, Inc.	No

[39] National Biodiesel Board, *Biodiesel Distributor Listings*, http://www.biodiesel.org/using-biodiesel/finding-biodiesel/locate-distributors-in-the-us/biodiesel-distributor-listings (accessed November 4 , 2014)

Many of the biodiesel fuel providers will take advantage of the two-year grace period to change business practices and thus incur minimal costs from recordkeeping. For instance, retail fuel providers that sell B20 at fueling stations that only accommodate light duty vehicles could work with a biodiesel producer to target customers of light duty vehicle fleets. This would allow the fuel producers and fuel providers to continue selling blends up to B20 at said stations.

5. Total Cost of Biodiesel Under Proposed Regulation

The total cost of the biodiesel regulation is identified for two time periods. The first time period addresses costs in 2016 and 2017 which are the years before the in-use requirement provisions take effect. The second time period is from 2018 through 2023 when provisions for in-use requirements, including NOx emissions controls, take effect until the sun setting of the regulation.

Based on the estimates above, we expect the total cost of biodiesel as the first commercial ADF regulation to be the cost of enhanced monitoring at $1,600 per year per producer and blender/distributor, or $56,000 total cost per year for all producers and distributors, and the cost of using NOx controls. Upon implementation of the ADF regulation in 2016, the annual biodiesel production is projected to be 129 million gallons (see Appendix B, Table B1) for an incremental biodiesel cost of less than one cent per gallon. These costs would remain steady through 2017.

In 2018, the projected volume increases to 180 million gallons for an incremental cost of less than one cent per gallon for recordkeeping. However, in 2018, in-use requirements take effect for NOx emissions control on certain biodiesel blends. From 2019 through 2020, projected volumes remain steady at 180 million gallons and from 2021 until the sunset provision in 2023, the volumes remain steady at 185 million gallons. However, it should be noted that from 2019 through 2023, the VMT of NTDEs is projected to increase considerably, due to other CARB regulations, which will allow for more biodiesel blends to be sold to exempted fleets with costs for in-use requirements. This would reduce the overall costs of NOx controls. The total cost of the regulation in 2018 is expected to reach $3,071,000. Each year thereafter, starting in 2019 will result in a reduction in costs from the previous year because of the increasing exemptions from NTDE fleets.

6. Potential Economic Costs to Consumers

As noted, we expect individual consumers would incur minimal or no costs as a result of the proposed regulation. Fuel suppliers already blend up to five percent biodiesel by volume in the CARB diesel that is offered throughout the state. Higher blends of biodiesel are currently sold at a price premium relative to CARB diesel, but such premiums exist in the absence of the proposed regulation. Therefore, the proposal should not adversely affect retail prices for biodiesel blends based on the anticipated minimal costs discussed above. Consumers that own either light or medium duty vehicles will not likely experience an increase in cost for biodiesel blends up to B20, because these fleets qualify for exemptions from in-use requirements.

D. Cost Effectiveness

Cost effectiveness is typically defined as the dollars spent to reduce a unit mass of a specified pollutant. Because the proposal is designed to maintain current environmental protections rather than achieve additional air pollution reductions, the concept of cost-effectiveness does not apply to the proposal. Nevertheless, upon implementation of the proposed ADF regulation in 2016, the regulatory costs of compliance (up to the low tens of thousands of dollars per year), if passed on to the consumer, would yield a per-gallon impact that is small (e.g., $56,000 per year /129 million gallons per year or less than one cent per gallon with full pass-through).

In 2018, when in-use requirements take effect the cost on a per gallon basis would increase, then go back down in subsequent years (e.g., $3,071,000 per year /180 million gallons per year or less than 2 cents per gallon increase if full pass-through).

No alternative considered by the agency would be more effective in carrying out the purpose for which the regulation is proposed or would be as effective as or less burdensome to affected private persons than the proposed regulation.

F. Reasons for Adopting Regulations Different from Federal Regulations

A main objective of the proposed ADF regulation is to consolidate existing requirements, supplemented with minor additional data requirements and enhanced recordkeeping provisions, to provide a clear, legal pathway to commercialization for new ADFs. As noted, many of the proposed regulatory requirements already exist in various State and federal programs.

Table 10.6 shows the existing applicable mandates, which require the same information required under the proposed regulation. However, under the proposed regulation, information generally would be required early in the phase-in process and before the ADF is commercialized in California to allow for screening of environmental and public health impacts. For purposes of this cost analysis, staff did not consider the costs of meeting the existing applicable mandates that overlap with the requirements under the proposal.

For example, H&SC section 43830.8 currently requires a multimedia evaluation to be conducted for any fuel before the ARB can establish motor vehicle fuel specifications for any particular fuel. Thus, while a multimedia evaluation is required under Stage 2 of the proposed regulation, the cost of that evaluation is not attributable to this rulemaking.

Table 10.6: Applicable Requirements from Various State and Federal Mandates

	Proposed Regulation	FTC[1] Labeling	DMS Fuels[2] Authority	DMS Fuel[3] Variance	H&S Code 43830.8[4]
Test Program Application	x			x	
- Test Plan (vehicle ID, fuels, duration, etc.)	x			x	
- Fuel Chemical Properties	x			x	
- U.S.EPA Registration[5]	x				
- Reporting & Recordkeeping	x	x	x	x	
Consensus Fuel Specification Development	x			x	
Enforcement of ASTM Stds.			x		
Fuel Quality Testing	x		x	x	
Pump Labeling (biodiesel blends)		x			
Multimedia Evaluation[6]	x				x
Determination of Pollution Control Levels	x				x
Enhanced Reporting	x				

1. Federal Trade Commission regulation on biodiesel pump labeling under 16 CFR Part 306.
2. CA Dept. of Food & Ag.-Div. of Measurement Stds. authority to enforce ASTM fuel quality stds. under CCR, title 4, §§ 4140, 4148, 4200, 4202-4205.
3. CDFA-DMS administration of developmental fuel variance program under CCR, title 4, §§4144, 4147 - 4148.
4. Multimedia evaluation requirements under Health & Safety Code §43830.8.
5. USEPA fuels and additives registration program under 40 CFR Part 79.
6. Also requires lifecycle analysis, release scenarios & emissions testing.

Another set of State mandates affecting the enforcement of potential ADFs pertains to regulatory requirements promulgated by the California Department of Food and Agriculture, Division of Measurement Standards (DMS). Under California Code of Regulations (CCR), Title 4, sections 4140-4149 and 4200-4205, DMS has the responsibility to enforce the consensus (ASTM) standards for the fuels listed therein, including biodiesel. Therefore, costs for meeting the ASTM standards or developing consensus standards for future ADFs are attributable to the DMS regulations.

The DMS also administers a program that is similar to the proposed Stage 1 requirements. Known as the developmental fuel variance (DFV), this program is authorized under Title 4 CCR, Sections 4144, 4147 and 4148. The DFV program allows unconventional motor vehicle fuels to be used in limited quantities to develop data in support of the development of consensus standards for those fuels. Stage 1 of the proposed regulation requires the same information as that required under the DFV, as well as some additional information. Thus, staff's analysis for the proposal does not consider the portion of the costs that would already be incurred under the DFV program.

Two federal programs also apply to ADFs that would be subject to the proposal. First, U.S. EPA requires a gasoline, diesel, or additive supplier to register under 40 CFR 79 prior to the sale or supply of such fuel products in California. Similarly, the proposed regulation would require U.S. EPA registration before an ADF could be sold or supplied in California under Stage 1. Second, the FTC specifies particular labeling requirements on individual pumps that dispense B6-B20 and blends above B20 (no labeling requirements for B5 and below). For enforcement purposes, fuel marketers are required to maintain volume sales and other fuel content records for these labeled pumps. The proposed regulation contains recordkeeping, testing, and reporting requirements that would piggyback on these existing federal requirements.

Alternative diesel fuels that meet the criterion for a Stage 3A will be required to conduct enhanced recordkeeping to monitor progress towards meeting any pollutant emissions levels that would require pollutant controls. The level of enhanced recordkeeping, and the cost of the pollutant controls (when applicable), will be a case-by-case determination because different ADFs have different chemistries.

G. Impacts to California State or Local Agencies

Several state agencies operate large fleets, often with many alternative fuel vehicles included in their fleet. Staff contacted several State agencies to determine biodiesel usage and received responses from some, but not all of the agencies contacted. Those that did respond did not indicate any usage of biodiesel blends with in-use requirements, and thus higher cost. During this period, staff became aware that Caltrans was the State agency using the most biodiesel. According to a 2013 report, "Caltrans Activities to Address Climate Change[40]", Caltrans is the biggest user of biodiesel in the State and is only using B5 blends currently; although they've used B20 blends in the past. As such, Caltrans would not incur any additional costs due to this regulation. In addition, the University of California system was contacted and staff was informed that the majority of their biodiesel use was B5, and that the majority of their fleet was vehicles eligible for an exemption to in-use requirements.

[40] Department of Transportation *Caltrans Activities to Address Climate Change Reducing Greenhouse Gas Emissions and Adapting to Impacts*, April 2013

Staff also contacted local municipalities and found that with the exception of San Francisco, all of the municipalities that responded did not use biodiesel blends above B5. Anecdotal evidence suggests that some school districts may be using biodiesel blends with in-use requirements. Therefore only those few agencies opting to use biodiesel blends with in-use requirements may incur some minor costs; though these can likely be absorbed in existing budgets. If these same agencies opt to use CARB diesel or lower blends of biodiesel, they could incur a costs savings.

CHAPTER 11. ANALYSIS OF REGULATORY ALTERNATIVES

As required by Senate Bill 617 (Chapter 496, Status of 2011), State agencies must conduct a Standardized Regulatory Impact Assessment (SRIA) when a proposed regulation has an economic impact exceeding $50 million in any 12-month period between the date the major regulation is estimated to be filed with the Secretary of State through12 months after the regulation is estimated to be fully implemented. The Department of Finance is required to review the completed SRIA submitted by agencies and provide comment(s) to the agency on the extent to which the assessment adheres to the regulations adopted by Finance. Rules implementing these requirements are found at title 1, sections 2000-2004 of the California Code of Regulations.

As part of the SRIA process, ARB solicited public input on alternative ADF approaches, including any approach that may yield the same or greater benefits than those associated with the proposed regulation, or that may achieve the goals at lower cost. Alternative approaches submitted to ARB were considered as staff prepared a SRIA. The combined SRIA of Low Carbon Fuel Standard and ADF summary is posted at: http://www.dof.ca.gov/research/economic_research_unit/SB617_regulation/2014_Major_Regulations/documents/ADF_DF_131_SUMMARY.PDF

Staff solicited public input and received two alternatives to the proposal that were considered as part of the SRIA process. The full analysis and comparison is located in Appendix D. The alternatives are summarized below:

A. Alternative Submitted by Growth Energy

The first alternative considered was submitted by Growth Energy (GE). Key provisions are listed below, along with the reason for rejecting this alternative in the following paragraphs.

- Treating animal- and non-animal-based biodiesel the same: setting the significance level for both at zero percent, as compared to the ADF proposal, which sets the significance level at B5 for non-animal-based biodiesel and B10 for animal-based biodiesel; and
- Eliminating the provisions for exemptions based on the use of NTDEs, as compared to the ADF proposal, which provides exemptions for biodiesel used in NTDEs; and
- Eliminating the sunset provision of the ADF proposal, whereas the ADF proposal would likely end mitigation for biodiesel in 2024.

This alternative proposal retains the same biodiesel NOx mitigation options as the ADF proposal. However, under the GE alternative, animal and non-animal biodiesel would be treated equally and require NOx mitigation for all biodiesel blends, including blends below B5. ARB rejects this alternative because the costs are significantly higher than the ADF proposal and do not achieve additional emissions benefits. During the development of this regulation, staff considered alternatives to the proposal and determined that the proposal represents the least-burdensome approach that best achieves the objectives at the least cost.

B. Alternative Submitted by National Biodiesel Board

The second alternative considered was submitted by the National Biodiesel Board (NBB). Key provisions are listed below, along with the reason for rejecting this alternative in the following paragraphs.

- Setting a significance level threshold for biodiesel at 10% biodiesel blend (B10) for all biodiesel feedstocks;
- Establishing an effective blend level that accounts for the impact of NTDEs, RD, and animal biodiesel, vs per-gallon mitigation in the ADF proposal; and
- Including a three-year phase-in period for the regulation.

This alternative would treat animal- and non-animal-based biodiesel the same by setting a significance level for both at 10 percent annually by volume. The alternative also includes a three-year phase-in period; accordingly, there are no costs for biodiesel mitigation in the first three years. For this alternative, mitigation would not be necessary until the statewide biodiesel content is up to 10 percent; after which the 10 percent any additional biodiesel would be mitigated using the same options available in the ADF proposal.

Because this alternative achieves substantially fewer emissions benefits than the ADF proposal, it does not meet the goals of the ADF proposal and ARB rejects the NBB alternative.

C. Conclusions

No alternatives were presented that would achieve the same emissions benefits and lessen any adverse impact on small businesses that may occur due to the regulation. However, the phase-in period suggested in the NBB proposal was modified to two years and included in the regulation to ensure ample time for small businesses to prepare and alter their business models to minimize their costs.

CHAPTER 12. SUMMARY AND RATIONALE

The Proposed ADF regulation is designed to allow a streamlined path to commercialization for alternative diesel fuels, while ensuring no increase in air pollution from those fuels. This section discusses the requirements and rationale for each provision of the proposed regulation.

Subarticle 1. Specifications for Alternative Motor Vehicle Fuels

Summary and Rationale for Subarticle 1
Article 1 is being renamed Subarticle 1 as part of splitting the article for clarity. Additionally, minor changes were made to accommodate the subarticle renaming and authority cited was added for clarity.

Subarticle 2. Commercialization of Alternative Diesel Fuels

Section 2293 Purpose
Summary of section 2293
Section 2293 states the purpose of the proposed regulation.

Rationale for section 2293
This section is needed to inform the regulated public and other market participants of the proposed regulation’s intent.

Section 2293.1 Applicability
Summary of section 2293.1
Subsection(a) establishes January 1, 2016, as the effective date of the proposed regulation, as well as laying out general requirements for alternative diesel fuels (ADFs) in California.

Rationale for section 2293.1
This section is needed to establish the implementation date, and general requirements that will apply to ADFs in California.

Section 2293.2 Definitions
Summary of section 2293.2
This section introduces definitions to the terms used in the regulation as well as the acronyms used in the proposed regulation.

Rationale for section 2293.2
It is necessary that ARB defines terms as applicable to the Alternative Diesel Fuels regulation. Several of these terms are used in the same manner as other articles and titles in the California Code of Regulations, Government Code sections or statutes. It is necessary for ARB to be consistent with existing definitions to the extent that they apply to this regulation.

Section 2293.3 Exemptions

<u>Summary of section 2293.3</u>
Section 2293.3 introduces the list of exemptions that apply to this proposed regulation.

<u>Rationale for section 2293.3</u>
This section is necessary for clarity of which fuels or additives are not subject to the regulation. The exempted fuels are already regulated elsewhere.

Section 2293.4 General Requirements Applicable to All ADFs

<u>Summary of section 2293.4</u>
This section outlines the provisions that apply to all ADFs in California

<u>Rationale for section 2293.4</u>
This section is necessary to ensure that it is clear that other applicable local, State, and federal requirements, including some specifically listed requirements, apply in addition to the provisions outlined in the proposed regulation.

Section 2293.5 Phase-In Requirements

<u>Summary of section 2293.5</u>
Section 2293.5 states that ADFs intended for use in motor vehicles that do not meet the requirements of this regulation by having a fuel specification or approved Executive Order in place cannot be sold without being in violation of this regulation.

<u>Rationale for section 2293.5</u>
This section is necessary to introduce the different stages of the regulation and the Executive Order requirements in Stage 1. The goal of this comprehensive process is to foster the introduction of new, lower polluting ADF fuels by allowing the limited sales of innovative ADFs in stages while emissions, performance, and environmental impacts testing is conducted. This testing is intended to develop the necessary real-world information to quantify the environmental and human health benefits from using new ADFs, determine whether these fuels have adverse environmental impacts relative to conventional CARB diesel, and identify any vehicle/engine performance issues such fuels may have.

<u>Summary of section 2293.5(a)</u>
Subsection (a) outlines the requirements of Stage 1: Pilot Program. This is the first in a series of 3 stages leading to potential commercialization of ADFs, and includes an initial analysis, submittal of relevant data, and a limited use of ADF allowed.

<u>Rationale for section 2293.5(a)</u>
This section is needed to communicate clearly the requirements for application, acceptance, and completion of Stage 1 for ADF proponents who are initially proposing an ADF for use. The purpose of this stage is to allow limited, small fleet use of innovative fuels while requiring screening tests and assessments to quickly determine whether there will be unreasonable potential impacts on air quality, the environment and vehicular performance. Such data will help inform more extensive testing and analysis

to be conducted in Stage 2. This Stage 1 is modeled after the existing ARB regulation that provides limited, fuel test program exemptions under 13 CCR 2259. The required submittals allow ARB and the public to evaluate the rigor of any proposed testing plan.

Summary of section 2293.5(b)
Subsection (b) outlines the requirements of Stage 2: Development of Fuel Specification. This is the second in a series of 3 stages leading to potential commercialization of ADFs, and includes rigorous environmental testing, development of standards, determination of environmental impacts, and increased use of ADF allowed.

Rationale for section 2293.5(b)
Subsection (b) is needed to communicate clearly the requirements for application, acceptance, and completion of Stage 2 for ADF proponents who are getting closer to commercial operation. The purpose of this stage is to allow limited but expanded fleet use of an ADF that has successfully undergone the Stage 1 pilot program. Stage 2 candidate ADFs undergo additional emissions and performance testing to better characterize potential impacts on air quality, the environment and vehicular performance. This testing and assessment will be conducted pursuant to a formal multimedia evaluation leading to the development of a fuel specification, as appropriate. Further, the multimedia evaluation will be the basis for determining whether the candidate ADF has potential adverse emissions impacts. The determination of potential adverse emissions impacts determines whether the candidate ADF can proceed to Stage 3A or Stage 3B. The required submittals will allow ARB and the public to evaluate the rigor of the proposed testing.

Summary of section 2293.5(c)
Subsection 2293.5(c) outlines the requirements of Stage 3A: Commercial Sales Subject to in-use Requirements. This is the culminating stage for ADFs that have been found to have potential adverse emissions impacts, and includes provisions for determination of in-use requirements and or fuel specifications if they are determined to be necessary.

Rationale for section 2293.5(c)
Subsection (c) is needed to communicate clearly the requirements for full commercialization of ADFs that have been found to have potential adverse emissions impacts.

Summary of section 2293.5(d)
Subsection 2293.5(d) outlines the requirements of Stage 3B: Commercial Sales Not Subject to In-use Requirements. This is the culminating stage for ADFs that have either been found to have no potential adverse emissions impacts or that have been found in Stage 3A to have no adverse emissions impacts. ADFs subject to this stage have limited reporting requirements.

Rationale for section 2293.5(d)
Subsection (d) is needed to communicate clearly the requirements for full commercialization of ADFs that will have no adverse emissions impacts relative to conventional CARB diesel. The provision makes the reporting consistent with reporting requirements in place for existing motor vehicle fuels.

Section 2293.6 In-use Requirements for Specific ADFs Subject to Stage 3A
Summary of section 2293.6
Section 2293.6 includes provisions for any ADF that has undergone the 3-stage process for commercialization and has been determined to be in Stage 3A with in-use requirements.

Rationale for section 2293.6
This section is needed to implement the provisions of Stage 3A once an ADF has completed the 3-stage commercialization process.

Summary of section 2293.6(a)
Subsection 2293.6 (a) contains the in-use requirements that apply to biodiesel as the first commercial ADF. This subsection includes a phase-in period, pollutant control levels, provisions for feedstock differences, a sunset provision, a process for exemption from the in-use requirements for biodiesel, and a mid-term review of the biodiesel provisions.

Rationale for section 2293.6(a)
Subsection (d) is needed to implement the solutions to the adverse emissions impacts associated with biodiesel. These adverse emissions impacts vary based on feedstock and engines, as such specific provisions for each of these are included.

Section 2293.7 Specifications for Alternative Diesel Fuels
Summary of section 2293.7
Section 2293.7 is a lead sentence to be completed in subsections 2293.7(a) and (b) that provide the specifications that must be met by ADFs, if not under a mitigation strategy in effect.

Rationale for section 2293.7
This section is needed to provide a framework for subsequent subsections.

Summary of section 2293.7(a)
Section 2293.7(a) is a title line for biodiesel the specification subsection.

Rationale for section 2293.7(a)
This section is needed to provide a framework for subsequent subsections.

Section 2293.8 Reporting and Recordkeeping

Summary of section 2293.8

Section 2293.8 (a) states that the applicable sampling methodology set forth in 13 CCR section 2296 shall be used for sampling of fuel properties as required by the Executive Order.

Rationale for section 2293.8

This subsection is needed to provide the applicant with guidance regarding their sampling requirements.

Section 2293.9 Severability

Summary of section 2293.9

Section 2293.8 states that each part of this subarticle shall be deemed severable, and in the event that any part of this subarticle is held to be invalid, the remainder of this subarticle shall continue in full force and effect.

Rationale for section 2293.9

This subsection is needed to inform the applicant of their responsibility to adhere to all applicable requirements of this regulation, in the event that any part of this subarticle shall be deemed severable.

Subarticle 3. Ancillary Provisions

Section 2294. Equivalent Test Methods

Summary of and Rationale for section 2294

This is former section 2293 renumbered to section 2294 and grouped under new subarticle 3 for consistency and ease of reading.

Section 2295. Exemptions for Alternative Motor Vehicle Used in Test Programs

Summary of and Rationale for section 2295

This is former section 2293.5 renumbered to section 2295 and grouped under new subarticle 3 for consistency and ease of reading.   This section facilitates innovation and testing for new fuels.

Appendix 1 In-use Requirements for Pollutant Emissions Control

Summary of Appendix 1

Appendix 1 outlines the in-use requirements that apply to ADFs operating under Stage 3A.

Rationale for Appendix 1

Appendix 1 is needed to identify the options that are available for complying with the provisions of Stage 3A

Summary of Appendix 1 (a)

This section includes the in-use requirement options that are available to biodiesel, currently additive blending and certification procedures.

Rationale for Appendix 1 (a)

This section is needed to convey the amount of additive needed to comply with in-use requirements for biodiesel based on time of year, feedstock, and blend level. The certification procedures are needed to provide flexibility for new in-use options that can be rigorously demonstrated to be effective.

This Page Left Intentionally Blank

CHAPTER 13. REFERENCES

Note: The references are listed according to the footnote they correspond to in the ISOR. Not all footnotes are references and are only listed here to maintain the numbering system used for the ISOR footnotes. The footnotes that are not references are listed as "Explanatory Footnote."

Chapter 1. Introduction

No Reference Cited

Chapter 2. California Mandates on Air Quality

No Reference Cited

Chapter 3. California Motor Vehicle Diesel Fuel Policies

1. Assembly Bill 118; Núñez, Chapter 750, Statutes of 2007

2. California Energy Commission, *2014-2015 Investment Plan Update for the Alternative and Renewable Fuel and Vehicle Technology Program*, p. 1, April 2014

Chapter 4. Federal Policies Affecting Motor Vehicles Diesel Fuel

3. *Energy Independence and Security Act of 2007*, section 202 (a)(2)(B)(i)(I)

4. U.S. Environmental Protection Agency, Office of Transportation and Quality. *EPA Finalizes Regulations for the National Renewable Fuel Standard Program for 2010 and Beyond*, EPA 420-F-10-007. February 2010

5. U.S. Environmental Protection Agency, Office of Transportation and Quality. *EPA Lifecycle Analysis of Greenhouse Gas Emissions from Renewable Fuels*, EPA 420-F-10-006. February 2010

6. *Energy Independence and Security Act of 2007*, Title II-Energy Security Through Increased Production of Biofuels; Subtitle A Section 201(1)(H)

7. *Energy Independence and Security Act of 2007*, Title II-Energy Security Through Increased Production of Biofuels; Subtitle A Section 201 (1)(I).

8. U.S. Environmental Protection Agency, Office of Transportation and Air Quality. *EPA Finalizes 2013 Renewable Fuel Standards*, EPA-420-F-13-042. August 2013

9. U.S. Environmental Protection Agency, Office of Transportation and Air Quality. *EPA Issues Direct Final Rule for 2013 Cellulosic Standard*, EPA-420-F-14-018 April 2014

10. U.S. Environmental Protection Agency. *2014 Standards for the Renewable Fuel Standard Program; Proposed Rule*. Federal Register. Volume 78, No. 230. Part II. 40 CFR 80. November 29, 2013

Chapter 5. Description of Proposed Regulation

No Reference Cited

Chapter 6. Technology Assessment

11. U.S. Environmental Protection Agency, *A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions*, 2002

12. Durbin, Thomas et al., *Biodiesel Characterization and NOx Mitigation Study,* October 2011

13. Durbin, Thomas et al., *CARB B5 Biodiesel Preliminary and Certification Testing*, April 2013

14. Karavalakis, Georgios et al., *CARB Comprehensive B5/B10 Biodiesel Blends Heavy-Duty Engine Dynamometer Testing*, June 2014

15. Nester, John et al., *Applied Linear Statistical Models,* Fourth Edition Irwin. US, 1996

16. Draper, Norman and Smith, Harry, *Applied Regression Analysis*, Third Edition Wiley Interscience. US, 1998

17. R Core Team, R: A language and environment for statistical computing. R Foundation for Statistical Computing, Vienna, Austria. ISBN 3-900051-07-0, 2013, http://www.R-project.org/.

18. Bates, Douglas et al., lme4: Linear mixed-effects models using Eigen and S4. R package version 1.1-7, 2014, http://CRAN.R-project.org/package=lme4

19. Bunce, Michael et al, *Stock and Optimized Performance and Emissions with 5% and 20% Soy Biodiesel Blends in a Modern Common Rail Turbo-Diesel Engine*, Energy Fuels, 2010, 24 (2), pp 928–939

20. Lammert, Michael et al., *Effect of B20 and Low Aromatic Diesel on Transit Bus NOx Emissions Over Driving Cycles with a Range of Kinetic Intensity*, SAE Int. J Fuels Lubr., 5(3):2012

21. Gysel, Nicholas et al., *Emissions and Redox Activity of Biodiesel Blends Obtained from Different Feedstocks from a Heavy-Duty Vehicle Equipped with DPF/SCR Aftertreatment and a Heavy-Duty Vehicle without Control Aftertreatment*, SAE 2014-01-1400, Published 04/01/2014

22. McWilliam, Lyn and Zimmermann, Anton, *Emission and Performance Implications of Biodiesel Use in an SCR-equipped Caterpillar C6.6*, 2010-012157 Published, 10/25/2010

23. Mizushima, Norifumi and Nurata, Yutaka, *Effect of Biodiesel on NOx Reduction Performance of Urea-SCR system*, SAE 2010-01-2278, Published 10/25/2010

24. Walkowicz, Kevin et al., *On-Road and In-Laboratory Testing to Demonstrate Effects of ULSD, B20, and B99 on a Retrofit Urea-SCR Aftertreatment System*, SAE 2009-01-2733

25. Nikanjam, Manuch, et al., *Performance and Emissions of Diesel and Alternative Diesel Fuels in Modern Light-Duty Vehicles*, SAE 2011-24-0198, 2011, Published 09/11/2011

26. Durbin, Thomas et al., *Regulated Emissions from Biodiesel Fuels from On/Off-road Applications*, Atmospheric Environment, Volume 41, p. 5647-5658, 2007

Chapter 7. Air Quality and Environmental Justice

27. California Air Resources Board, Report, *Policies and Actions for Environmental J ustice*, 2001

28. California Air Resources Board, *History of Air Resources Board*, Website, http://www.arb.ca.gov/knowzone/history.htm, Oct 22, 2014 (accessed December 10, 2014)

29. California Air Resources Board, Video file, *Clearing California Skies Updated*, http://www.arb.ca.gov/videos/clskies.htm (accessed December 10, 2014)

Chapter 8. Environmental Analysis

No Reference Cited

Chapter 9. Multimedia Evaluation

30. U.C. Berkeley, U.C. Davis, Lawrence Livermore National Laboratory, *Guidance Document and Recommendations on the Types of Scientific Information Submitted by Applicants for California Fuels Environmental Multimedia Evaluations*, June 2008

31. Multimedia Working Group, California Environmental Protection Agency. *Staff Report: Multimedia Evaluation of Biodiesel*, November 2013.

32. Multimedia Working Group, California Environmental Protection Agency. *Staff Report: Multimedia Evaluation of Renewable Diesel*, November 2013.

33. U.C. Berkeley, U.C. Davis, *California Biodiesel Multimedia Evaluation Final Tier III Report*, May 2013

34. U.C. Berkeley, U.C. Davis, *California Renewable Diesel Multimedia Evaluation Final Tier III Report*, April 2012

35. Air Resources Board. *Fuels Multimedia Evaluation Meetings and Documents* http://www.arb.ca.gov/fuels/multimedia/meetings/meetings.htm.

Chapter 10. Economic Impacts Assessment

36. Standardized Regulatory Impact Assessments (SRIA): http://www.dof.ca.gov/research/economic_research_unit/SB617_regulation/2014Major_Regulations/

37. Biodiesel Magazine, USA Plants http://www.biodieselmagazine.com/plants/listplants/USA/page:1/sort:state/direction:asc (accessed November 4 , 2014)

38. National Biodiesel Board, Biodiesel Plants Listing, http://www.biodiesel.org/production/plants/plants-listing (accessed November 4, 2014)

39. National Biodiesel Board, Biodiesel Distributor Listings, http://www.biodiesel.org/using-biodiesel/finding-biodiesel/locate-distributors-in-the-us/biodiesel-distributor-listings (accessed November 4, 2014)

40. Department of Transportation, *Caltrans Activities to Address Climate Change Reducing Greenhouse Gas Emissions and Adapting to Impacts*, April 2013

Chapter 11. Analysis of Regulatory Alternatives

No Reference Cited

Chapter 12. Summary and Rationale

No Reference Cited

Attachment 7

APPENDIX B

TECHNICAL SUPPORTING INFORMATION

This Page Left Intentionally Blank

1. Biodiesel NOx Emissions Calculation

As part of staff's determination of the effect of biodiesel on NOx emissions a methodology was developed that takes into account varying factors including offsetting effects. As part of this analysis staff takes the illustrative fuel volumes from the LCFS re-adoption and the projected Vehicle Miles Travelled (VMT) of NTDEs in EmFAC 2011. The renewable diesel volumes are adjusted by the amount expected to be consumed by refineries. These factors are used to determine the total NOx emissions impacts of biodiesel compared to the use of CARB diesel, as shown in the table below.

After January 1, 2018, biodiesel used above B5 (assumed to be B20) is controlled by in-use requirements and does not cause NOx. Thus this volume is subtracted from total biodiesel to determine the amount of biodiesel (BD) potentially causing NOx. The next step is to determine the amount of biodiesel used in legacy vehicles (non-NTDE). This is important because the NOx increase is seen in legacy vehicles not NTDE vehicles. The proportion of legacy vehicles is determined by subtracting the percentage of NTDEs from 100% to determine the percentage of legacy vehicles. The amount of fuel used in legacy vehicles is then determined by multiplying the percentage of legacy vehicles by the volume of biodiesel potentially causing NOx. The same calculation is then completed for RD. Staff assumed that 40 percent of renewable diesel is used in refineries, and as such does not reduce NOx since refineries may use the NOx benefit of RD in their CARB diesel formulations. The calculated RD used in legacy vehicles is divided by 2.75 to get the amount of RD offsetting BD. As discussed earlier, renewable diesel decreases NOx and the NOx increase from one gallon of biodiesel is offset by the NOx decrease from 2.75 gallons of renewable diesel. The amount of biodiesel offset by legacy RD is then subtracted from the BD amount used in legacy to result in the amount of biodiesel causing NOx. That total is divided by the liquid diesel demand and multiplied by the NOx increase of B100 to determine a %NOx increase from BD. The total change is then multiplied by the diesel portion of the emissions inventory to get NOx increase from biodiesel.

Table B-1: Biodiesel NOx Emissions Calculations

(Million gallons)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total Biodiesel	72	97	129	160	180	180	180	185	185	185
B20 (No NOx post 2018)					30	30	30	35	35	35
BD Potentially causing NOx	72	97	129	160	150	150	150	150	150	150
RD Volume	120	180	250	300	320	360	400	500	550	600
Liquid Diesel Demand	3732	3788	3845	3903	3961	4021	4081	4142	4204	4267
	NOx emissions Calculations									
%NTDE (EmFAC 2011) (VMT)	40.09%	50.86%	59.87%	66.35%	71.26%	75.00%	79.78%	85.03%	88.74%	98.44%
BD used in legacy vehicles	43.1	47.7	51.8	53.8	43.1	37.5	30.3	22.5	16.9	2.3
%NOx increase (B100)	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RD used in legacy	72	88	100	101	92	90	81	75	62	9
%RD used in refineries	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
Legacy RD not used in refineries	43	53	60	61	55	54	49	45	37	6
Legacy BD offset by Legacy RD	16	19	22	22	20	20	18	16	14	2
%NOx increase from BD	0.15%	0.15%	0.16%	0.16%	0.12%	0.09%	0.06%	0.03%	0.02%	0.00%
Emissions Inventory (Diesel TPD)	916	863	818	772	726	680	634	588	542	496
NOx increase from BD (TPD)	1.35	1.29	1.27	1.26	0.84	0.60	0.39	0.17	0.09	0.01
Net NOx increase (from 2014)	0.00	-0.05	-0.08	-0.09	-0.50	-0.74	-0.95	-1.17	-1.26	-1.34
NOx increase from BD (TPY)	492	472	464	459	308	221	144	63	32	3

2. Biodiesel Emissions B5 and B10 Testing Results

As part of staff's determination of biodiesel impacts of low biodiesel blends, we released a spreadsheet of data gathered from all testing we were aware of from B5 and B10 biodiesel blends using a CARB diesel baseline. Those emissions results are included in Table B-2. These data are also available at: http://www.arb.ca.gov/fuels/diesel/altdiesel/20140725B5&B10studies_raw_all_pollutants_%20data.xlsx

Table B-2: Biodiesel B5 and B10 Blends Emissions Testing Results

All raw data on B5 and B10 from animal and soy feedstocks. Values are in g/bhp-hr.									
Fuel	Cycle	Engine	Work	THC	CO	NOx	PM	CO2	BSFC (gal/bhp-hr)
Durbin 2011- Biodiesel Characterization and NOx Mitigation Study									
B5 - Soy	CRUISE - 40mph	2006 Cummins ISM	42.980	0.249	0.613	2.079	0.045	586.063	0.060
			43.210	0.248	0.617	2.044	0.045	579.506	0.059
CARB ULSD	CRUISE - 40mph	2006 Cummins ISM	43.146	0.247	0.582	2.040	0.046	569.448	0.058
			43.372	0.249	0.618	2.012	0.048	573.429	0.058
			43.150	0.257	0.607	2.031	0.049	577.056	0.059
B5 - Soy	CRUISE - 50mph	2006 Cummins ISM	34.379	0.180	0.451	1.776	0.049	539.299	0.055

			34.238	0.181	0.511	1.674	0.054	548.853	0.056
			34.210	0.184	0.481	1.790	0.051	541.312	0.055
			34.193	0.183	0.479	1.791	0.050	542.130	0.055
			34.302	0.184	0.472	1.660	0.052	547.319	0.056
			34.214	0.183	0.474	1.669	0.051	550.718	0.056
CARB ULSD	CRUISE - 50mph	2006 Cummins ISM	34.367	0.181	0.475	1.767	0.052	537.155	0.055
			34.285	0.179	0.458	1.777	0.052	540.383	0.055
			34.265	0.182	0.454	1.757	0.053	538.915	0.055
			34.345	0.190	0.464	1.826	0.053	547.919	0.056
			34.283	0.191	0.505	1.676	0.056	552.006	0.056
			34.249	0.190	0.481	1.677	0.056	552.186	0.056
B5-Soy	FTP	2006 Cummins ISM	26.570	0.300	0.742	2.146	0.074	633.678	0.065
			26.715	0.295	0.676	2.139	0.066	630.990	0.064
			26.556	0.295	0.694	2.146	0.067	635.459	0.065
			26.488	0.282	0.687	2.155	0.066	631.014	0.064
			26.616	0.284	0.686	2.157	0.066	629.410	0.064
			26.621	0.287	0.686	2.137	0.066	631.529	0.064
CARB ULSD	FTP	2006 Cummins ISM	26.650	0.280	0.698	2.076	0.072	624.986	0.064
			26.598	0.286	0.694	2.067	0.072	625.364	0.064
			26.457	0.288	0.710	2.090	0.074	630.497	0.064
			26.525	0.293	0.715	2.076	0.073	629.674	0.064
			26.603	0.297	0.690	2.092	0.073	633.139	0.064
			26.676	0.293	0.673	2.093	0.077	631.495	0.064
			26.593	0.296	0.705	2.097	0.073	634.048	0.064
			26.703	0.289	0.673	2.083	0.070	623.705	0.063
			26.589	0.294	0.681	2.088	0.071	630.334	0.064
			26.656	0.296	0.691	2.068	0.071	627.629	0.064
			26.590	0.298	0.714	2.113	0.072	630.587	0.064
			26.640	0.298	0.689	2.110	0.070	632.011	0.064
			26.639	0.300	0.703	2.112	0.072	633.399	0.064
			26.688	0.306	0.730	2.123	0.073	635.859	0.065
			26.797	0.302	0.686	2.105	0.070	631.540	0.064
			26.675	0.304	0.698	2.104	0.072	633.093	0.064
			26.720	0.298	0.673	2.092	0.070	627.904	0.064
			26.655	0.299	0.682	2.128	0.071	633.331	0.064
			26.660	0.301	0.699	2.106	0.070	631.359	0.064

			26.600	0.293	0.698	2.114	0.071	629.096	0.064
			26.476	0.296	0.717	2.109	0.072	630.787	0.064
			26.691	0.300	0.698	2.099	0.072	628.385	0.064
			26.558	0.289	0.716	2.093	0.071	633.251	0.064
			26.637	0.295	0.725	2.078	0.073	633.116	0.064
			26.662	0.294	0.735	2.080	0.080	632.255	0.064
			26.559	0.294	0.747	2.104	0.073	636.271	0.065
			26.574	0.295	0.693	2.105	0.072	634.493	0.065
			26.605	0.289	0.713	2.109	0.070	633.036	0.064
			26.544	0.290	0.711	2.113	0.071	635.431	0.065
			26.580	0.292	0.711	2.130	0.069	634.065	0.064
			26.620	0.297	0.691	2.105	0.070	636.511	0.065
			26.714	0.293	0.699	2.118	0.071	633.708	0.064
			26.611	0.296	0.683	2.128	0.071	635.402	0.065
B5 - Soy	FTP	2007 MBE4000	28.647	0.005	0.070	1.309	0.000	578.991	0.059
			28.679	0.006	0.046	1.303	0.000	578.899	0.059
			28.535	0.006	0.065	1.312	0.000	581.532	0.059
			28.667	0.005	0.066	1.305	0.000	580.041	0.059
			28.606	0.005	0.065	1.307	0.000	581.602	0.059
			28.674	0.006	0.051	1.306	0.001	580.839	0.059
CARB ULSD	FTP	2007 MBE4000	28.638	0.003	0.073	1.305	0.001	580.798	0.059
			28.535	0.004	0.074	1.295	0.000	579.591	0.059
			28.635	0.003	0.078	1.291	0.000	578.233	0.059
			28.611	0.005	0.067	1.295	0.001	580.980	0.059
			28.542	0.005	0.073	1.295	0.001	580.184	0.059
			28.569	0.004	0.091	1.293	0.001	580.473	0.059
B10-Soy	FTP	2006 Cummins ISM	26.629	0.274	0.707	2.149	0.062	632.076	0.065
			26.643	0.277	0.665	2.154	0.059	630.411	0.064
			26.726	0.277	0.692	2.152	0.054	631.084	0.064
			26.697	0.276	0.679	2.150	0.060	628.027	0.064
			26.689	0.275	0.699	2.164	0.062	629.416	0.064
			26.544	0.282	0.700	2.164	0.062	634.349	0.065
CARB ULSD	FTP	2006 Cummins ISM	26.650	0.280	0.698	2.076	0.072	624.986	0.064
			26.598	0.286	0.694	2.067	0.072	625.364	0.064
			26.457	0.288	0.710	2.090	0.074	630.497	0.064
			26.525	0.293	0.715	2.076	0.073	629.674	0.064

			26.603	0.297	0.690	2.092	0.073	633.139	0.064
			26.676	0.293	0.673	2.093	0.077	631.495	0.064
			26.593	0.296	0.705	2.097	0.073	634.048	0.064
			26.703	0.289	0.673	2.083	0.070	623.705	0.063
			26.589	0.294	0.681	2.088	0.071	630.334	0.064
			26.656	0.296	0.691	2.068	0.071	627.629	0.064
			26.590	0.298	0.714	2.113	0.072	630.587	0.064
			26.640	0.298	0.689	2.110	0.070	632.011	0.064
			26.639	0.300	0.703	2.112	0.072	633.399	0.064
			26.688	0.306	0.730	2.123	0.073	635.859	0.065
			26.797	0.302	0.686	2.105	0.070	631.540	0.064
			26.675	0.304	0.698	2.104	0.072	633.093	0.064
			26.720	0.298	0.673	2.092	0.070	627.904	0.064
			26.655	0.299	0.682	2.128	0.071	633.331	0.064
			26.660	0.301	0.699	2.106	0.070	631.359	0.064
			26.600	0.293	0.698	2.114	0.071	629.096	0.064
			26.476	0.296	0.717	2.109	0.072	630.787	0.064
			26.691	0.300	0.698	2.099	0.072	628.385	0.064
			26.558	0.289	0.716	2.093	0.071	633.251	0.064
			26.637	0.295	0.725	2.078	0.073	633.116	0.064
			26.662	0.294	0.735	2.080	0.080	632.255	0.064
			26.559	0.294	0.747	2.104	0.073	636.271	0.065
			26.574	0.295	0.693	2.105	0.072	634.493	0.065
			26.605	0.289	0.713	2.109	0.070	633.036	0.064
			26.544	0.290	0.711	2.113	0.071	635.431	0.065
			26.580	0.292	0.711	2.130	0.069	634.065	0.064
			26.620	0.297	0.691	2.105	0.070	636.511	0.065
			26.714	0.293	0.699	2.118	0.071	633.708	0.064
			26.611	0.296	0.683	2.128	0.071	635.402	0.065
B5 - Animal	FTP	2006 Cummins ISM	26.756	0.286	0.677	2.079	0.070	621.722	0.065
			26.676	0.292	0.681	2.093	0.070	625.282	0.065
			26.590	0.297	0.685	2.085	0.069	626.072	0.066
			26.570	0.297	0.683	2.093	0.068	627.470	0.068
			26.652	0.300	0.715	2.099	0.071	624.219	0.068
			26.672	0.299	0.674	2.087	0.069	623.306	0.068
CARB ULSD	FTP	2006 Cummins ISM	26.453	0.299	0.724	2.099	0.076	628.314	0.066
			26.585	0.305	0.693	2.087	0.075	628.067	0.066
			26.583	0.308	0.742	2.085	0.076	629.575	0.066

			26.577	0.302	0.713	2.089	0.072	626.206	0.064
			26.629	0.302	0.710	2.074	0.079	623.568	0.063
			26.629	0.302	0.710	2.062	0.079	623.568	0.063
B5 - Animal	FTP	2007 MBE4000	28.601	0.005	0.062	1.311	0.001	581.793	0.059
			28.574	0.008	0.074	1.308	0.001	583.817	0.059
			28.605	0.006	0.070	1.313	0.000	583.982	0.059
			28.480	0.006	0.068	1.316	0.001	587.733	0.060
			28.571	0.005	0.080	1.319	0.000	585.563	0.060
			28.508	0.005	0.077	1.317	0.000	585.178	0.059
CARB ULSD	FTP	2007 MBE4000	28.575	0.004	0.076	1.295	0.001	584.790	0.059
			28.609	0.005	0.073	1.289	0.000	583.101	0.059
			28.545	0.008	0.069	1.290	0.000	584.206	0.059
			28.589	0.006	0.096	1.301	0.001	581.388	0.059
			28.639	0.004	0.089	1.301	0.000	581.705	0.059
			28.524	0.004	0.083	1.307	0.000	583.545	0.059
TRU Study (part of 2011 Biodiesel Characterization and NOx Mitigation Study)									
B5-Soy	ISO 8178-4 C1	1999 Kubota TRU	No data	1.381	6.054	8.635	1.584	619.027	No data
			No data	1.472	6.304	9.000	1.602	621.212	No data
			No data	1.374	5.825	8.784	1.383	621.924	No data
			No data	1.325	5.671	9.109	1.531	621.025	No data
			No data	1.334	6.162	8.538	1.491	622.661	No data
			No data	1.135	6.371	8.671	1.630	626.671	No data
			No data	1.287	6.299	8.592	1.573	630.638	No data
			No data	1.252	6.101	8.692	1.570	629.242	No data
CARB ULSD	ISO 8178-4 C1	1999 Kubota TRU	No data	1.336	5.944	9.055	1.549	620.206	No data
			No data	1.475	5.697	8.987	1.513	619.158	No data
			No data	1.292	5.673	8.714	1.390	623.035	No data
			No data	1.375	6.363	8.816	1.496	624.634	No

									data
			No data	1.343	5.658	8.622	1.506	622.925	No data
			No data	1.241	6.486	8.503	1.585	622.932	No data
			No data	1.243	6.602	8.393	1.608	628.286	No data
			No data	1.134	6.594	8.648	1.615	625.054	No data
			No data	1.204	6.147	8.574	1.428	626.399	No data
			No data	1.117	6.345	8.328	1.610	625.471	No data
			No data	1.335	6.568	8.711	1.723	632.989	No data
John Deere Study (part of 2011 Biodiesel Characterization and NOx Mitigation Study)									
B5 - Animal	ISO 8178-4 C1	2009 John Deere 4045HF	58.025	0.140	1.249	2.640	0.108	654.301	No data
			59.576	0.175	1.166	2.694	0.095	648.814	No data
			59.050	0.129	1.178	2.538	0.100	640.811	No data
			59.298	0.137	1.242	2.694	0.105	654.543	No data
			58.674	0.132	1.310	2.626	0.113	653.924	No data
			57.484	0.143	1.222	2.651	0.098	664.292	No data
CARB ULSD	ISO 8178-4 C1	2009 John Deere 4045HF	58.862	0.169	1.187	2.690	0.076	642.608	No data
			59.538	0.159	1.267	2.685	0.106	646.342	No data
			59.098	0.156	1.214	2.699	0.106	652.373	No data
			58.744	0.217	1.311	2.612	0.107	660.206	No data
			59.672	0.129	1.148	2.648	0.109	637.148	No data
			58.530	0.133	1.323	2.632	0.114	655.929	No data
			58.890	0.135	1.239	2.647	0.099	651.141	No data

			58.841	0.141	1.264	2.722	0.124	649.127	No data
Durbin 2013 - CARB B5 Preliminary and Certification Testing									
B5 - Soy	FTP	2006 Cummins ISM	26.212	0.324	0.816	2.070	0.061	635.115	0.064
			26.128	0.330	0.805	2.067	0.063	636.837	0.064
			26.179	0.335	0.824	2.071	0.063	636.466	0.064
			26.215	0.332	0.801	2.061	0.062	636.491	0.064
			26.214	0.337	0.827	2.065	0.064	636.176	0.064
			26.125	0.339	0.795	2.086	0.063	637.625	0.064
CARB ULSD	FTP	2006 Cummins ISM	26.174	0.317	0.807	2.035	0.067	631.578	0.064
			26.205	0.320	0.813	2.051	0.064	631.097	0.064
			26.267	0.325	0.813	2.034	0.066	631.778	0.064
			26.315	0.317	0.792	2.034	0.066	630.574	0.063
			26.263	0.317	0.787	2.044	0.065	633.602	0.064
			26.157	0.322	0.797	2.064	0.065	635.144	0.064
B5-Animal	FTP	2006 Cummins ISM	26.252	0.347	0.802	1.999	0.062	636.928	0.065
			26.227	0.340	0.780	2.049	0.063	635.310	0.065
			26.202	0.341	0.815	2.055	0.065	637.443	0.065
			26.076	0.309	0.807	2.062	0.062	636.773	0.065
			26.147	0.312	0.807	2.060	0.062	638.336	0.065
			26.207	0.312	0.789	2.050	0.064	638.461	0.065
CARB ULSD	FTP	2006 Cummins ISM	26.174	0.317	0.807	2.035	0.067	631.578	0.064
			26.205	0.320	0.813	2.051	0.064	631.097	0.064
			26.267	0.325	0.813	2.034	0.066	631.778	0.064
			26.315	0.317	0.792	2.034	0.066	630.574	0.063
			26.263	0.317	0.787	2.044	0.065	633.602	0.064
			26.157	0.322	0.797	2.064	0.065	635.144	0.064
B5 - Animal	FTP	2006 Cummins ISM	26.141	0.317	0.734	2.054	0.064	640.411	0.065
			26.235	0.317	0.747	2.059	0.064	637.502	0.065
			26.201		0.710	2.035	0.062	637.357	
			26.237		0.745	2.024	0.066	637.880	

			26.193	0.309	0.731	2.023	0.064	637.041	0.065
			26.269	0.315	0.766	2.022	0.065	636.276	0.065
			26.243	0.303	0.751	2.028	0.065	636.613	0.065
			26.222	0.303	0.714	2.019	0.063	637.752	0.065
			26.267	0.307	0.769	2.030	0.064	635.646	0.064
			26.181	0.291	0.738	2.047	0.064	640.168	0.065
			26.197	0.326	0.740	2.036	0.065	637.503	0.065
			26.184	0.332	0.713	2.032	0.065	638.464	0.065
			26.287	0.308	0.750	2.014	0.064	636.100	0.065
			26.288	0.312	0.808	2.049	0.067	637.861	0.065
			26.241	0.327	0.711	2.035	0.065	630.743	0.064
			26.353	0.323	0.722	2.022	0.064	627.978	0.064
			26.213	0.310	0.758	2.039	0.064	638.419	0.065
			26.232	0.311	0.719	2.031	0.064	640.299	0.065
			26.270	0.326	0.702	2.030	0.064	632.213	0.064
			26.154	0.323	0.708	2.056	0.065	635.355	0.064
CARB ULSD	FTP	2006 Cummins ISM	26.173	0.322	0.771	2.044	0.068	638.055	0.064
			26.245	0.339	0.755	2.040	0.069	630.006	0.063
			26.246	0.283	0.780	2.044	0.067	635.655	0.064
			26.302		0.760	2.036	0.067	634.929	
			26.283		0.771	2.033	0.067	635.720	
			26.320	0.336	0.757	2.046	0.067	635.816	0.064
			26.235	0.312	0.803	2.051	0.065	636.990	0.064
			26.326	0.329	0.809	2.049	0.067	634.778	0.064
			26.249	0.325	0.799	2.031	0.067	638.402	0.064
			26.268	0.341	0.777	2.056	0.067	633.363	0.064
			26.262	0.337	0.805	2.051	0.070	632.077	0.064
			26.239	0.349	0.781	2.044	0.069	630.199	0.063
			26.332	0.315	0.795	2.037	0.066	635.121	0.064
			26.363	0.335	0.760	2.033	0.067	628.785	0.063
			26.192	0.332	0.773	2.046	0.067	633.752	0.064
			26.176	0.350	0.784	2.069	0.068	638.577	0.064
			26.246	0.321	0.793	2.046	0.064	635.479	0.064
			26.300	0.335	0.780	2.044	0.068	637.581	0.064
			26.321	0.336	0.810	2.043	0.068	636.569	0.064
			26.278	0.350	0.804	2.043	0.071	635.689	0.064
Karavalakis and Durbin 2014 - CARB Comprehensive B5/B10 Biodiesel Blends Heavy-Duty Engine Dynamometer Testing									
B5 -	FTP	2006	26.609	0.158	0.672	2.109	0.064	626.926	0.064

Soy		Cummins ISM							
			26.590	0.157	0.675	2.108	0.064	625.733	0.064
			26.705	0.172	0.675	2.103	0.065	621.435	0.064
			26.623	0.168	0.683	2.106	0.065	623.839	0.064
			26.801	0.161	0.686	2.101	0.063	622.351	0.064
			26.621	0.161	0.671	2.094	0.074	624.650	0.064
			26.653	0.175	0.651	2.114	0.064	624.660	0.064
			26.614	0.171	0.665	2.122	0.064	627.011	0.064
CARB ULSD	FTP	2006 Cummins ISM	26.656	0.144	0.680	2.091	0.066	626.286	0.063
			26.666	0.172	0.674	2.083	0.067	623.633	0.063
			26.659	0.167	0.702	2.080	0.070	622.790	0.063
			26.718	0.179	0.666	2.079	0.068	620.006	0.063
			26.683	0.149	0.675	2.087	0.068	625.166	0.063
			26.509	0.175	0.680	2.081	0.069	625.365	0.063
			26.623	0.171	0.667	2.093	0.068	624.758	0.063
			26.620	0.177	0.683	2.092	0.021	623.524	0.063
B5 - Soy	UDDS	2006 Cummins ISM	5.341	0.428	1.979	6.075	0.101	805.284	0.083
			5.318	0.425	1.958	6.089	0.115	806.198	0.083
			5.285	0.454	1.995	6.140	0.118	803.728	0.082
			5.388	0.436	1.912	5.829	0.114	789.118	0.081
			5.327	0.414	1.929	6.160	0.110	802.930	0.082
			5.300	0.406	2.054	6.171	0.120	815.394	0.084
			5.395	0.462	1.982	5.915	0.116	786.343	0.081
			5.376	0.438	1.861	6.096	0.119	793.979	0.081
CARB ULSD	UDDS	2006 Cummins ISM	5.401	0.393	1.845	6.024	0.086	795.862	0.081
			5.389	0.443	1.878	6.102	0.113	791.042	0.080
			5.367	0.474	2.093	5.844	0.113	793.163	0.080
			5.232	0.461	1.903	6.076	0.109	814.959	0.083
			5.331	0.463	1.921	6.064	0.115	796.322	0.081
			5.306	0.396	1.881	6.042	0.099	804.611	0.082
			5.298	0.443	2.069	5.978	0.111	806.123	0.082
			5.378	0.429	1.848	5.940	0.113	788.578	0.080
			5.339	0.460	1.963	5.874	0.109	789.834	0.080
B5 - Soy	SET	2006 Cummins	124.510	0.058	0.353	1.866	0.035	527.587	0.054

		ISM							
			124.719	0.059	0.354	1.875	0.035	528.600	0.054
			124.548	0.067	0.351	1.863	0.036	527.730	0.054
			124.543	0.064	0.354	1.852	0.036	529.935	0.054
CARB ULSD	SET	2006 Cummins ISM	124.399	0.067	0.352	1.861	0.036	530.775	0.054
			124.586	0.071	0.371	1.842	0.039	531.263	0.054
			124.570	0.065	0.363	1.847	0.038	529.526	0.053
			124.546	0.072	0.356	1.862	0.039	530.713	0.054
B5 - Soy	FTP	1991 DDC60	24.041	0.056	1.566	4.460	0.124	549.100	0.056
			24.060	0.056	1.548	4.450	0.061	550.680	0.056
			24.108	0.054	1.522	4.423	0.060	545.378	0.056
			23.885	0.059	1.527	4.460	0.061	547.776	0.056
			24.152	0.054	1.571	4.477	0.059	546.983	0.056
			24.089	0.054	1.548	4.479	0.061	547.319	0.056
			24.003	0.054	1.521	4.468	0.060	545.599	0.056
			24.088	0.054	1.514	4.429	0.059	543.807	0.056
CARB ULSD	FTP	1991 DDC60	24.090	0.056	1.659	4.413	0.067	551.036	0.056
			23.956	0.056	1.602	4.421	0.066	550.577	0.056
			24.055	0.056	1.586	4.401	0.066	549.490	0.056
			24.054	0.056	1.582	4.411	0.067	546.202	0.055
			24.109	0.054	1.615	4.399	0.064	546.887	0.055
			23.999	0.057	1.585	4.432	0.065	547.842	0.055
			24.110	0.055	1.556	4.416	0.059	542.331	0.055
			24.030	0.055	1.549	4.394	0.066	543.799	0.055
B5 - Soy	UDDS	1991 DDC60	3.914	0.208	2.123	11.206	0.039	686.604	0.070
			3.922	0.214	2.162	11.344	0.052	687.872	0.071
			3.936	0.213	2.102	11.378	0.036	682.080	0.070
			3.825	0.226	1.984	12.080	0.046	706.644	0.072
			3.940	0.202	2.107	11.191	0.037	682.656	0.070
			3.955	0.208	2.004	11.181	0.043	677.613	0.070
			3.808	0.217	2.212	11.851	0.036	711.225	0.073
			3.883	0.206	1.929	12.027	0.042	692.957	0.071
CARB ULSD	UDDS	1991 DDC60	3.907	0.196	2.138	11.177	0.033	687.912	0.070
			3.966	0.207	1.925	11.003	0.026	671.689	0.068
			3.940	0.216	1.951	11.457	0.043	688.026	0.070
			3.960	0.214	1.999	11.107	0.036	676.508	0.069

			3.995	0.197	1.976	10.903	0.026	670.123	0.068
			4.026	0.195	1.919	10.843	0.028	665.558	0.067
			3.985	0.210	1.987	11.529	0.042	677.009	0.069
			3.901	0.209	1.863	11.404	0.028	685.082	0.069
B5 - Soy	SET	1991 DDC60	96.561	0.024	1.501	7.415	0.018	472.264	0.048
			96.527	0.024	1.532	7.353	0.019	472.815	0.049
			96.736	0.023	1.471	7.420	0.019	471.757	0.048
			96.716	0.023	1.522	7.354	0.019	471.178	0.048
CARB ULSD	SET	1991 DDC60	96.754	0.023	1.546	7.381	0.020	475.016	0.048
			96.564	0.025	1.558	7.308	0.023	472.114	0.048
			96.621	0.024	1.543	7.410	0.020	473.600	0.048
			96.522	0.024	1.524	7.324	0.019	470.655	0.048
B10 - Soy	FTP	2006 Cummins ISM	26.689	0.159	0.675	2.126	0.061	626.427	0.064
			26.710	0.156	0.677	2.128	0.060	625.609	0.064
			26.610	0.171	0.673	2.128	0.061	625.517	0.064
			26.643	0.167	0.665	2.121	0.061	625.227	0.064
			26.669	0.165	0.676	2.104	0.060	622.391	0.063
			26.686	0.164	0.674	2.116	0.060	623.945	0.063
			26.689	0.173	0.665	2.104	0.059	620.955	0.063
			26.679	0.074	0.696	2.068	0.062	624.381	0.063
CARB ULSD	FTP	2006 Cummins ISM	26.569	0.150	0.690	2.086	0.069	628.285	0.063
			26.643	0.174	0.698	2.081	0.068	624.724	0.063
			26.681	0.171	0.695	2.085	0.068	623.383	0.063
			26.644	0.182	0.690	2.093	0.070	624.493	0.063
			26.687	0.156	0.677	2.064	0.067	623.122	0.063
			26.643	0.179	0.680	2.061	0.068	621.981	0.063
			26.634	0.176	0.680	2.061	0.069	623.280	0.063
			26.696	0.067	0.700	2.041	0.069	620.977	0.063
B10 - Soy	UDDS	2006 Cummins ISM	5.286	0.441	1.868	6.189	0.110	833.226	0.085
			5.209	0.427	2.058	6.249	0.115	821.626	0.084
			5.276	0.464	1.926	6.192	0.120	798.438	0.081
			5.452	0.429	1.835	5.969	0.114	773.917	0.079
			5.257	0.428	2.105	6.166	0.114	812.722	0.083

			5.329	0.438	1.962	6.114	0.118	803.185	0.082
			5.383	0.431	1.989	6.032	0.107	782.687	0.080
			5.263	0.431	2.035	6.174	0.120	806.079	0.082
CARB ULSD	UDDS	2006 Cummins ISM	5.418	0.406	2.076	5.701	0.091	777.837	0.079
			5.371	0.448	1.834	5.802	0.107	783.911	0.079
			5.377	0.451	1.791	5.966	0.113	785.636	0.080
			5.425	0.501	1.799	5.795	0.114	771.695	0.078
			5.322	0.394	1.929	6.061	0.092	797.735	0.081
			5.284	0.463	2.055	6.051	0.117	800.415	0.081
			5.213	0.459	1.918	5.976	0.118	810.873	0.082
			5.290	0.487	1.917	6.036	0.124	795.973	0.081
B10 - Soy	SET	2006 Cummins ISM	124.050	0.069	0.335	1.891	0.033	532.803	0.054
			124.267	0.065	0.340	1.895	0.034	530.683	0.054
			124.366	0.055	0.342	1.905	0.033	531.303	0.054
			124.334	0.066	0.344	1.893	0.033	534.490	0.054
CARB ULSD	SET	2006 Cummins ISM	124.516	0.071	0.361	1.857	0.042	528.103	0.053
			124.296	0.072	0.360	1.864	0.039	531.702	0.054
			124.589	0.058	0.329	2.057	0.035	528.118	0.053
			124.394	0.071	0.362	1.844	0.039	533.069	0.054
B10 - Soy	FTP	1991 DDC60	23.951	0.051	1.466	4.535	0.040	545.347	0.056
			23.950	0.051	1.447	4.545	0.055	546.778	0.056
			24.100	0.053	1.424	4.480	0.057	542.826	0.055
			23.874	0.053	1.446	4.535	0.059	549.990	0.056
			24.133	0.048	1.443	4.487	0.054	545.646	0.056
			24.125	0.051	1.445	4.495	0.055	546.297	0.056
			23.966	0.052	1.407	4.489	0.058	547.050	0.056
			24.127	0.053	1.437	4.468	0.059	545.045	0.056
CARB ULSD	FTP	1991 DDC60	23.997	0.053	1.549	4.446	0.066	544.742	0.055
			24.077	0.052	1.521	4.493	0.063	543.284	0.055
			24.037	0.056	1.486	4.458	0.066	543.312	0.055
			24.024	0.053	1.495	4.421	0.065	544.388	0.055
			23.994	0.051	1.572	4.399	0.064	547.771	0.055
			24.008	0.051	1.554	4.449	0.067	548.299	0.056
			24.107	0.057	1.470	4.440	0.067	543.195	0.055

			24.149	0.055	1.498	4.386	0.067	545.515	0.055
B10 - Soy	UDDS	1991 DDC60	3.892	0.282	2.067	11.537	0.033	688.438	0.070
			4.019	0.235	2.035	11.222	0.051	673.671	0.069
			3.969	0.187	1.973	11.338	0.030	671.496	0.068
			4.025	0.188	1.911	11.408	0.042	668.260	0.068
			3.919	0.206	2.061	11.316	0.026	684.954	0.070
			3.831	0.218	2.106	11.710	0.035	701.493	0.072
			3.894	0.206	2.009	11.373	0.027	685.500	0.070
			3.953	0.211	1.937	11.523	0.034	678.714	0.069
CARB ULSD	UDDS	1991 DDC60	3.851	0.240	2.184	11.454	0.048	633.992	0.064
			3.967	0.184	1.916	10.878	0.032	655.914	0.066
			3.941	0.193	1.900	11.356	0.035	674.042	0.068
			3.889	0.179	2.038	11.332	0.038	680.864	0.069
			3.919	0.206	1.932	11.252	0.037	683.429	0.069
			3.898	0.207	1.997	11.152	0.026	678.309	0.069
			3.906	0.220	1.967	11.528	0.041	685.783	0.070
			3.790	0.214	2.079	11.620	0.032	702.421	0.071
B10 - Soy	SET	1991 DDC60	96.569	0.022	1.452	7.533	0.019	476.304	0.049
			96.443	0.024	1.509	7.559	0.020	475.018	0.048
			96.856	0.021	1.435	7.554	0.018	475.960	0.048
			96.720	0.022	1.477	7.512	0.003	478.397	0.049
CARB ULSD	SET	1991 DDC60	96.725	0.022	1.591	7.483	0.022	474.525	0.048
			96.788	0.032	1.589	7.376	0.022	469.362	0.048
			96.725	0.022	1.547	7.465	0.020	476.633	0.048
			96.700	0.024	1.518	7.435	0.020	475.701	0.048
B5 - Animal	FTP	2006 Cummins ISM	26.576	0.168	0.683	2.120	0.064	630.523	0.064
			26.534	0.168	0.674	2.105	0.065	630.943	0.064
			26.624	0.164	0.683	2.125	0.063	632.268	0.064
			26.642	0.164	0.672	2.114	0.064	630.484	0.064
			26.568	0.182	0.673	2.045	0.065	631.032	0.064
			26.633	0.188	0.689	2.059	0.065	628.851	0.064
			26.614	0.176	0.699	2.090	0.065	626.289	0.064
			26.567	0.173	0.658	2.094	0.063	629.711	0.064
CARB ULSD	FTP	2006 Cummins	26.503	0.151	0.688	2.115	0.068	634.665	0.064

		ISM							
			26.569	0.171	0.731	2.084	0.070	629.277	0.064
			26.529	0.180	0.746	2.100	0.072	628.960	0.064
			26.529	0.176	0.687	2.102	0.069	630.814	0.064
			26.528	0.181	0.698	2.061	0.068	632.022	0.064
			26.686	0.178	0.688	2.093	0.067	626.835	0.063
			26.581	0.177	0.677	2.157	0.069	629.277	0.064
			26.566	0.185	0.675	2.098	0.067	628.862	0.064
B5 - Animal	UDDS	2006 Cummins ISM	5.276	0.398	1.791	5.879	0.047	793.351	0.081
			5.261	0.404	1.910	6.131	0.066	801.409	0.082
			5.276	0.417	1.890	5.842	0.048	785.816	0.080
			5.391	0.402	2.031	5.796	0.071	778.393	0.079
			5.339	0.387	1.953	5.783	0.052	785.094	0.080
			5.316	0.404	1.799	5.866	0.068	789.823	0.080
			5.363	0.426	1.906	5.753	0.048	778.155	0.079
			5.311	0.423	1.813	5.838	0.068	791.837	0.081
CARB ULSD	UDDS	2006 Cummins ISM	5.407	0.384	1.856	5.901	0.065	772.271	0.078
			5.258	0.432	1.851	6.103	0.050	787.975	0.080
			5.230	0.431	2.213	6.220	0.069	807.599	0.082
			5.200	0.464	1.967	6.016	0.054	800.607	0.081
			5.306	0.351	1.853	5.990	0.056	787.114	0.080
			5.311	0.429	1.861	5.866	0.049	783.355	0.079
			5.432	0.422	1.862	5.786	0.066	777.663	0.079
			5.379	0.422	1.792	5.800	0.050	776.020	0.079
B5 - Animal	SET	2006 Cummins ISM	124.369	0.072	0.336	1.872	0.035	529.411	0.054
			124.429	0.070	0.354	1.805	0.036	529.477	0.054
			124.482	0.060	0.341	1.891	0.034	527.182	0.054
			124.577	0.061	0.343	1.870	0.035	528.558	0.054
CARB ULSD	SET	2006 Cummins ISM	124.284	0.069	0.356	1.866	0.039	535.371	0.054
			124.604	0.074	0.362	1.859	0.039	528.769	0.053
			124.719	0.072	0.357	1.830	0.038	529.177	0.053
			124.748	0.063	0.358	1.873	0.037	529.000	0.053
B5 -	FTP	1991	24.184	0.048	1.433	4.428	0.056	535.039	0.054

Animal		DDC60							
			24.091	0.048	1.456	4.456	0.057	539.868	0.055
			24.108	0.055	1.442	4.438	0.059	541.703	0.055
			24.045	0.054	1.450	4.425	0.059	544.376	0.055
			23.872	0.051	1.481	4.480	0.058	545.117	0.056
			24.105	0.051	1.409	4.434	0.056	542.039	0.055
			24.018	0.052	1.449	4.446	0.057	542.838	0.055
			24.071	0.051	1.426	4.419	0.057	542.198	0.055
CARB ULSD	FTP	1991 DDC60	24.018	0.052	1.591	4.476	0.063	541.193	0.055
			24.103	0.049	1.494	4.408	0.063	539.320	0.055
			24.066	0.049	1.511	4.412	0.064	535.697	0.054
			23.942	0.055	1.551	4.485	0.067	544.347	0.055
			24.117	0.052	1.514	4.453	0.062	551.908	0.056
			24.167	0.062	1.517	4.411	0.063	539.619	0.055
			24.113	0.053	1.522	4.417	0.063	540.678	0.055
			23.983	0.048	1.531	4.439	0.063	545.836	0.055
B5 - Animal	UDDS	1991 DDC60	3.914	0.188	1.955	11.164	0.029	684.679	0.070
			3.952	0.200	1.925	11.201	0.041	682.338	0.070
			3.932	0.266	2.049	11.114	0.036	676.580	0.069
			3.937	0.186	1.779	11.579	0.042	670.579	0.068
			3.980	0.183	1.840	10.813	0.033	670.036	0.068
			3.957	0.193	1.876	10.997	0.045	676.072	0.069
			3.879	0.214	1.884	11.208	0.026	680.907	0.069
			4.021	0.195	1.818	11.382	0.031	656.703	0.067
CARB ULSD	UDDS	1991 DDC60	3.824	0.196	2.213	11.417	0.035	696.574	0.071
			3.916	0.214	2.079	11.407	0.032	682.352	0.069
			4.051	0.200	1.885	11.370	0.041	661.985	0.067
			3.998	0.202	1.937	11.162	0.027	666.428	0.068
			3.978	0.182	1.985	10.971	0.035	663.656	0.067
			3.919	0.203	2.017	11.148	0.040	679.634	0.069
			3.929	0.217	1.886	11.558	0.041	684.333	0.069
			3.906	0.207	1.963	11.320	0.023	676.747	0.069
B5 - Animal	SET	1991 DDC60	96.721	0.023	1.439	7.463	0.019	470.279	0.048
			96.704	0.024	1.456	7.416	0.019	471.616	0.048
			96.746	0.022	1.433	7.446	0.019	471.109	0.048
			96.738	0.023	1.473	7.378	0.019	467.864	0.048
CARB ULSD	SET	1991 DDC60	96.632	0.024	1.500	7.451	0.019	472.005	0.048

			96.712	0.024	1.485	7.398	0.020	470.693	0.048
			96.574	0.024	1.496	7.462	0.020	474.082	0.048
			96.677	0.024	1.472	7.354	0.021	470.321	0.048
B10 - Animal	FTP	2006 Cummins ISM	26.651	0.160	0.638	2.104	0.057	630.806	0.064
			26.578	0.156	0.645	2.100	0.058	631.728	0.064
			26.605	0.171	0.658	2.090	0.058	627.752	0.064
			26.494	0.167	0.645	2.117	0.052	633.290	0.065
			26.508	0.181	0.644	2.091	0.058	627.280	0.064
			26.505	0.178	0.643	2.082	0.060	627.336	0.064
			26.598	0.170	0.640	2.095	0.058	626.243	0.064
			26.667	0.192	0.648	2.080	0.061	625.159	0.064
CARB ULSD	FTP	2006 Cummins ISM	26.525	0.153	0.682	2.097	0.068	634.590	0.064
			26.655	0.171	0.670	2.072	0.065	622.399	0.063
			26.560	0.175	0.673	2.086	0.067	626.814	0.063
			26.504	0.187	0.688	2.083	0.069	628.489	0.064
			26.544	0.181	0.719	2.109	0.072	636.609	0.064
			26.611	0.202	0.699	2.016	0.069	624.279	0.063
			26.610	0.193	0.667	2.067	0.067	624.932	0.063
			26.513	0.212	0.675	2.088	0.068	625.125	0.063
B10 - Animal	UDDS	2006 Cummins ISM	5.245	0.453	1.703	5.926	0.046	796.750	0.081
			5.340	0.464	1.715	5.737	0.063	784.883	0.080
			5.279	0.503	1.697	5.692	0.047	782.658	0.080
			5.262	0.488	1.764	5.981	0.055	796.833	0.081
			5.368	0.390	1.669	5.743	0.050	786.368	0.080
			5.213	0.420	1.786	5.994	0.068	814.041	0.083
			5.268	0.419	1.755	5.954	0.045	795.621	0.081
			5.174	0.428	1.752	5.950	0.067	813.832	0.083
CARB ULSD	UDDS	2006 Cummins ISM	5.300	0.440	1.911	5.813	0.059	781.133	0.079
			5.277	0.423	1.813	5.986	0.048	788.031	0.080
			5.285	0.443	1.900	5.860	0.065	790.256	0.080
			5.311	0.454	1.826	5.785	0.046	779.762	0.079
			5.357	0.410	1.934	5.792	0.052	786.706	0.080
			5.267	0.451	1.861	5.879	0.051	797.890	0.081
			5.233	0.460	1.971	6.181	0.066	811.293	0.082

			5.379	0.450	1.813	5.743	0.035	774.032	0.078
B10 - Animal	SET	2006 Cummins ISM	124.261	0.069	0.345	1.827	0.034	531.664	0.054
			124.348	0.064	0.333	1.867	0.033	529.263	0.054
			124.357	0.065	0.341	1.884	0.032	530.668	0.054
			124.476	0.064	0.329	1.873	0.032	528.502	0.054
CARB ULSD	SET	2006 Cummins ISM	124.729	0.058	0.369	1.853	0.037	527.956	0.053
			124.731	0.070	0.364	1.849	0.038	530.162	0.054
			124.532	0.067	0.368	1.858	0.037	534.031	0.054
			124.313	0.073	0.357	1.845	0.037	533.580	0.054
B10 - Animal	FTP	1991 DDC60	24.124	0.047	1.473	4.424	0.056	542.028	0.055
			24.060	0.048	1.453	4.452	0.054	544.795	0.056
			24.051	0.048	1.421	4.448	0.054	542.634	0.055
			24.006	0.048	1.386	4.457	0.053	544.899	0.056
			23.872	0.054	1.449	4.499	0.054	549.573	0.056
			24.088	0.053	1.450	4.461	0.054	544.840	0.056
			24.070	0.050	1.423	4.436	0.055	543.600	0.056
			24.151	0.050	1.395	4.423	0.054	542.167	0.055
CARB ULSD	FTP	1991 DDC60	24.166	0.050	1.652	4.391	0.066	543.834	0.055
			24.049	0.050	1.522	4.412	0.062	542.739	0.055
			24.091	0.050	1.531	4.421	0.062	543.979	0.055
			24.111	0.050	1.523	4.415	0.062	542.676	0.055
			24.034	0.057	1.596	4.429	0.064	546.817	0.055
			24.123	0.054	1.521	4.415	0.062	541.290	0.055
			24.125	0.051	1.519	4.411	0.062	542.416	0.055
			24.021	0.053	1.523	4.429	0.064	544.966	0.055
B10 - Animal	UDDS	1991 DDC60	3.964	0.204	1.909	10.964	0.027	674.078	0.069
			3.861	0.212	1.878	11.397	0.034	688.934	0.070
			3.940	0.204	1.811	11.029	0.025	677.519	0.069
			3.956	0.202	1.893	11.185	0.037	678.280	0.069
			4.004	0.187	1.949	10.819	0.027	670.699	0.069
			3.900	0.200	1.873	11.328	0.043	688.469	0.070
			3.827	0.207	1.983	11.625	0.020	703.553	0.072
			3.948	0.212	1.890	11.596	0.022	680.697	0.070
CARB	UDDS	1991	3.973	0.208	2.006	11.178	0.040	678.454	0.069

ULSD		DDC60							
			3.918	0.210	2.012	11.319	0.031	683.226	0.069
			3.965	0.215	1.920	11.300	0.040	673.661	0.068
			3.898	0.205	2.034	11.343	0.027	685.868	0.070
			3.972	0.188	1.960	11.107	0.025	675.660	0.068
			3.820	0.216	2.066	11.425	0.024	693.672	0.070
			4.011	0.199	1.840	11.435	0.029	672.133	0.068
			3.908	0.209	1.908	11.408	0.018	685.454	0.069
B10 - Animal	SET	1991 DDC60	96.519	0.022	1.415	7.531	0.019	476.564	0.049
			96.458	0.022	1.442	7.489	0.019	477.808	0.049
			96.573	0.022	1.435	7.488	0.019	476.079	0.049
			96.341	0.021	1.477	7.432	0.019	476.800	0.049
CARB ULSD	SET	1991 DDC60	96.834	0.022	1.536	7.484	0.020	475.231	0.048
			96.733	0.024	1.510	7.402	0.020	471.576	0.048
			96.747	0.023	1.580	7.485	0.021	474.469	0.048
			96.647	0.023	1.582	7.362	0.022	476.991	0.048
2010 Performance and emissions of diesel and alternative diesel fuels									
Raw data were not available to ARB, average data are shown below where available. Study is available in published literature.									
B5 - Soy	FTP	1991 DDC60	Not Avail.	Not Avail.	Not Avail.	4.514	Not Avail.	Not Avail.	Not Avail.
CARB ULSD	FTP	1991 DDC60	Not Avail.	Not Avail.	Not Avail.	4.596	Not Avail.	Not Avail.	Not Avail.
B5 - Soy	SET	1991 DDC60	Not Avail.	Not Avail.	Not Avail.	7.528	Not Avail.	Not Avail.	Not Avail.
CARB ULSD	SET	1991 DDC60	Not Avail.	Not Avail.	Not Avail.	7.532	Not Avail.	Not Avail.	Not Avail.
Thompson 2010 - Neat Fuel Influence on Biodiesel Blend Emissions									
Raw data were not available to ARB, average data are shown below where available. Study is available in published literature (BSFC is in g/bhp-hr)									
B10 - Soy	FTP	1992 DDC60	Not Avail.	0.086	2.685	4.500	0.201	Not Avail.	169.2 77
CARB Like	FTP	1992 DDC60	Not Avail.	0.087	2.811	4.370	0.223	Not Avail.	167.0 40
B10 - Soy	SET	1992 DDC60	Not Avail.	Not Avail.	Not Avail.	8.662	0.0729	Not Avail.	Not Avail.
CARB	SET	1992	Not	Not	Not	8.446	0.0855	Not Avail.	Not

Like		DDC60	Avail.	Avail.	Avail.				Avail.

8_SF_LCFS_GE (Page 294 - 404)

1216. Comment: **Alternative Diesel Fuel Regulation Initial Statement of Reasons**

Agency Response: This document does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

Exhibit G to Declaration of James M. Lyons

Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

Catherine H. Reheis-Boyd
President

June 22, 2015

Secretary Matthew Rodriquez, Chair
Environmental Policy Council
1001 I Street, P.O. Box 2815
Sacramento, CA 95812
Via electronic mail: cepc@calepa.ca.gov

Dear Secretary Rodriguez:

Re. Western States Petroleum Association Comments for June 23, 2015 CEPC Meeting Consideration of the Multi-Media Working Group staff reports - Multi-Media Evaluation of Biodiesel and Staff Report: Multi-Media Evaluation of Renewable Diesel

The Western States Petroleum Association (WSPA) is a non-profit trade association representing twenty-five companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California and 5 western states.

WSPA appreciates the opportunity to provide our comments and requests for CEPC action in the attached set of comments.

If there are any questions or a need for additional clarification of our comments, please contact Gina Grey of my staff (ggrey@wspa.org) to arrange for further dialogue with WSPA.

Sincerely,

c.c. Alex Mitchell, CARB

1415 L Street, Suite 600, Sacramento, California 95814
(916) 498-7752 ▪ Fax: (916) 444-5745 ▪ Cell: (916) 835-0450
cathy@wspa.org ▪ www.wspa.org

Summary

WSPA supports the use of full Multi-Media Evaluations (MME) to assess the environmental impacts of fuels and fuel additives prior to their introduction. However, the current MME for biodiesel blends is not complete since it did not consider: LCFS SF8-14

- The use of di-tertiary butyl peroxide (DTBP), the sole additive proposed for mitigating NOx increases in biodiesel blends, at the concentrations required in the proposed Alternative Diesel Fuel (ADF) regulation, which can be 10 times those envisioned for DTBP use as a diesel cetane improver.
    - Concerns include the fate and transport of DTBP (soil, surface and ground water), potential toxicological impacts, safety (e.g., peroxide stability), and materials compatibility (e.g., metallurgy, engine compatibility). LCFS SF8-15

  The auto manufacturers are normally concerned about any fuel additives and the potential impact on vehicle systems, and in this case fuel stability impacts associated the higher dosage of DTBP. Testing should be completed at the higher concentration levels proposed in the ADF which has not been fully evaluated in the current MME.

- Water demands in biofuel production for the Low Carbon Fuel Standard (LCFS).
    - As Fulton and Cooley[1] state in a 2015 publication: "Although early LCFS policy assessments raised the issue of water demands and impacts from increased biofuel production, any subsequent efforts to track or address those impacts through policy have been lacking."

The allocation of water resource analysis proposed here is not within the traditional scope of California's MME process. However, we feel the scope of the MME segment should be broader given the scarcity of California's water resources to include water use/consumption/allocation consideration and, more particularly, the shifts in those brought about by regulatory action such as LCFS. Thus, we respectfully request that these two items be addressed by the Multimedia Working Group (MMWG) and the California Environmental Policy Council (CEPC) prior to the approval of this MME. LCFS SF8-16

Di-Tertiary Butyl Peroxide

WSPA is concerned that an adequate MME has not been performed with regard to the use of DTBP at the concentrations currently required for mitigation in the proposed Alternative Diesel Fuel (ADF) regulations. A review of the "STAFF REPORT - Multimedia Evaluation of Biodiesel" dated May 2015, only includes an evaluation of combustion air emissions impact (i.e. NOx reduction) due to the use of the DTBP additive. LCFS SF8-15 cont.

[1] Cooley, H., Fulton, J. The Water Footprint of California's Energy System, 1990–2012. Environmental Science and Technology. 2015. 49. 3314–3321.

The MMWG recommendations include a provision/condition that fuel formulations and additives that were not included within the scope of this multimedia evaluation must be reviewed by the MMWG for consideration of appropriate action. However, it is not clear the MMWG has adequately considered what the environmental impacts of those additives may be, and whether the types, concentrations, and use specifications differ from those used in conventional diesel.

The significance of these caveats involving the use of additives in the MME reports is particularly noteworthy for WSPA members who have previously pointed out to Air Resources Board (ARB) staff that a thorough assessment of DTBP, the sole additive included as a NOx mitigation measure in the proposed ADF regulation, has yet to be conducted. While air emissions impacts were considered for the use of DTBP, there is no documentation in the MME that other potential impacts of DTBP were evaluated, including, but not limited to: LCFS SF8-15 cont.

- Full multimedia evaluation of environmental impacts (e.g. fate and transport including soil, surface water & ground water and non-combustion air emissions),
- Toxicological impacts,
- Safety impacts (e.g. peroxide stability and interactions with other additives such as antioxidants), and,
- Materials compatibility impacts (e.g. OEM approval, metallurgical compatibility in distribution storage, piping, and fueling equipment).

We note that the State Water Resources Control Board's (SWRCB) review was limited to the differences between biodiesel and CARB diesel[2]. In addition, the Department of Toxic Substance Control (DTSC) performed fate and transport studies with biodiesel, CARB diesel, and biodiesel blends, and with two additives (a biocide and antioxidant). However, they did not test a biodiesel blend with DTBP. The DTSC also noted:

"If new or different additives from those tested are proposed for use, appropriate evaluation through the MMWG process should occur."

While DTBP is clearly being proposed for use, it does not appear that either a SWRCB or DTSC review of biodiesel blends containing DTBP was performed as part of the MME. Both agencies clearly indicated that newly proposed additives would need further evaluation, but there is no discussion in the MME as to why DTBP was not included in their reviews. LCFS SF8-17

Review of the MMWG response to Peer Review comments, indicates that the SWRCB evaluation assumed that the additives used in biodiesel and biodiesel blends will employ the same additives currently used in CARB diesel, and recommended that other additives used be evaluated separately by the MMWG[3]. However, DTBP, as proposed in the ADF, will be used for a purpose other than the one it was originally intended for (which was cetane enhancement)

---

[2] 2015 Biodiesel MME (page 12, Section B).
[3] 2015 Biodiesel MME (Appendix J, Page 31, Response to Comment E-9).

and at levels (0.25-1.00 volume percent) substantially higher than the range that it is typically used for cetane enhancement (0.1-0.3 volume percent – Society of Automotive Engineers Technical Series Paper No. 982574). The DTSC's response to Peer Review comments indicate that it is important to understand the real life fate and transport behaviors associated with additive packages relevant to biodiesel/CARB diesel blends[4], which was not done here.

LCFS SF8-17 cont.

In addition, a review of the MSDS for DTBP from two manufacturers[5,6] indicates there are specific issues regarding DTBP that are not discussed in ARB's MME. We feel the MME should include an evaluation of the DTBP specific issues listed below prior to approving the use of DTBP at the recommended concentrations:

- DTBP decomposes at approximately 80°C; recommended maximum storage temperature 40°C[4,5]
- Flash point of 6°C, highly flammable at room temperature[4,5];
- Precautions are needed to guard against electrostatic discharge[4,5]
- Control of vapor space, such as nitrogen blanketing, may be required or recommended[5]
- Segregation of DTBP from accelerators, stabilizers, acids, bases, and heavy metals is highly recommended[4,5]
- Use only stainless steel 316, polypropylene, polyethylene, or glass lined equipment for storage[5]
- Must avoid contact with rust, iron and copper[5]

LCFS SF8-18

We request that the CEPC recommend the MMWG fully re-examine the use of DTBP as proposed, to ensure all potential impacts associated with its use are reviewed and evaluated, and feel this request is consistent with the recommendations included in the MME.

LCFS SF8-19

Other Water Impacts

In addition to the DTBP evaluation included above, we have concerns that the MMWG has not sufficiently evaluated potential impacts to water in the US and the State of California.

- In the MME Conclusions of Water Impacts[7], SWRCB staff concludes there are minimal additional risks to use of California waters posed by biodiesel.
- Given the severe drought conditions California currently faces, the MME must take into account the significant water demands associated with the use of biofuels, which are outlined in in the recently published peer-reviewed study by Julian Fulton of the Energy and Resources Group at U.C. Berkeley and Heather Cooley of the Pacific Institute[8].

LCFS SF8-20

[4] 2015 Biodiesel MME (Appendix J, Page 23, Response to Comment D-1).
[5] United Initiators MSDS for DTBP from: http://www.united-initiators.com/products/details/di-tert-butyl-peroxide/
[6] Azko Nobel TRIGONOX B MSDS from: https://www.akzonobel.com/polymer/msds/
[7] 2015 Biodiesel MME (III.B, page 17).
[8] Cooley, H., Fulton, J. The Water Footprint of California's Energy System, 1990–2012. Environmental Science and Technology. 2015. 49. 3314–3321.

- We feel the SWCRB MME conclusion of minimal additional risks should be further evaluated relative to the conclusions drawn by Fulton and Cooley: "Although early LCFS policy assessments raised the issue of water demands and impacts from increased biofuel production, any subsequent efforts to track or address those impacts through policy have been lacking." **LCFS SF8-20 cont.**

8_SF_LCFS_GE (Page 405 - 410)

The commenter attaches a comment letter that was written by WSPA and submitted by WSPA to the CEPC public hearing. Although this document was not submitted as an objection or suggestion on the proposal, ARB staff responded where appropriate.

1217. Comment: **LCFS SF8-15 through LCFS SF8-17, LCFS SF8-19, and LCFS SF8-20**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

1218. Comment: **LCFS SF8-14**

The comment states that the multimedia evaluation is not complete and continues to list specific topics not considered.

Agency Response: Please see responses **LCFS SF8-15** and **LCFS SF8-16** in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

1219. Comment: **LCFS SF8-18**

The comment states that the multimedia evaluation should include an evaluation of specific issues regarding DTBP prior to approval.

Agency Response: Please see response **ADF F1-4** in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

This page intentionally left blank.

ATTACHMENT B

Declaration of Thomas L. Darlington

CALIFORNIA ENVIRONMENTAL PROTECTION AGENCY

CALIFORNIA AIR RESOURCES BOARD

DECLARATION OF THOMAS L. DARLINGTON

I, Thomas L. Darlington, declare as follows:

1. I am an engineer with training and expertise in lifecycle emissions analysis; the use of models to estimate lifecycle emissions and to attribute emissions to the production, distribution and use of various fuels; and the use of regulations to control mobile-source emissions. My areas of expertise also include land-use change ("LUC") modeling and the application of econometric models to attributional and consequential lifecycle emissions analysis. Following my graduation from the University of Michigan in 1979, I served for eight years as an Engineer and Project Manager at the United States Environmental Protection Agency's Motor Vehicle Emissions and Fuels Laboratory in Ann Arbor, Michigan. Thereafter I worked at Detroit Diesel Corporation and General Motors Corporation, and as the Director of Mobile Source Programs at Systems Application International. I am the President of Air Improvement Resource ("AIR"), a company formed in 1994 to provide mobile source emission modeling to government and industry. A copy of my CV is attached to this Declaration as Exhibit "B."

2. I have participated on behalf of renewable fuels producers in the public consultation and rulemaking processes at the California Air Resources Board ("ARB" or "the Board") to consider, adopt and revise the low-carbon fuel standard ("LCFS") regulation since 2008. I testified at the Board's February 2015 hearing concerning proposed amendments to the LCFS regulation. I am fully familiar with the models released by CARB to establish and implement the LCFS regulation, including the versions of the Global Trade Analysis Project ("GTAP") modeling systems used by CARB or proposed for use by the CARB staff as part of the current and proposed LCFS regulation.

3. I make this Declaration based upon my personal knowledge, my training and expertise, and my familiarity with the subjects that I address here.

A. Documentation for Perennial Reversion GHG Emissions for Sugarcane

4. The land use change emissions (LUC) for sugarcane have decreased from 46 gCO2e/MJ in the current LCFS to 11.8 gCO2e/MJ in the proposed LCFS. A factor that is important in this drop in LUC emissions for cane is the "perennial reversion GHG emissions" for cane. These emissions describe the carbon stored in a field when cane is planted after forest is removed for cane.

5. ARB has a report that describes the emissions released when various types of land are converted from one use to another.[1] AIR reviewed this report but there is no documentation or description for the perennial reversion emissions for various perennials, LCFS SF8-21

[1] *Agro-Ecological Zone Emission Factor Model (v52)*, Plevin, Gibbs, Duffy, et al, December 11, 2014.

including cane. AIR also reviewed Appendix I of the ISOR, which also contains details on the LUC estimates for various feedstocks.[2] This document also did not describe the perennial reversion emissions for various perennials. Finally, AIR emailed ARB on several occasions to determine how ARB estimated these emissions.[3] However, the information on how ARB developed these important emissions was not provided, so AIR was unable to satisfactorily review how the cane LUC emissions were developed. (See Exhibit "A," which provides copies of the text of email exchanges I had on this issue with CARB staff.)

LCFS SF8-21 cont.

B. Requirement for One Quarter's Plant Operating Data For Prospective LCFS Applications

6. For Provisional Pathways, ARB in its proposal requires one calendar quarter of plant operating data to be submitted with the application.

> As set forth in sections 95488 (c)(3) and (c)(4)(l)(2), LCFS pathways are generally developed for fuels that have been in full commercial production for at least two years. In order to encourage the development of innovative fuel technologies, however, applicants may submit New Pathway Forms, as set forth in section 95488(c)(1), covering Tier 2 facilities that have been in full commercial operation for less than two years, provided they have been in full commercial operation for at least one full calendar quarter.

7. In the current LCFS rule, ARB accepts engineering estimates for inputs that are based on pilot data. Under either regulation, plants must produce biofuels at CIs that are at or below their assigned value; therefore, requiring one calendar quarter of data is an unnecessary requirement in the current proposal. I believe the current proposal should be amended to allow the use of engineering estimates for process fuel use, ethanol and coproduct production, and other inputs needed to estimate the CI using CaGREET2.0.

LCFS SF8-22

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 8th day of July, 2015 in Holland, Michigan.

Thomas L. Darlington

Thomas L. Darlington

---

2 Appendix I of Initial Statement of Reasons.

3 See Exhibit A for email string.

Exhibit A to Declaration of Thomas L. Darlington

Exhibit "A"
Emails Concerning LUC of Cane

1. Text of Darlington's inquiry on February 6, 2015

Tom, I'm forwarding your request to Anil. Jim Duffy 916-599-9364 -----Original Message----- From: Tom Darlington [mailto:tdarlington@airimprovement.com] Sent: Friday, February 06, 2015 1:06 PM To: Duffy, James@ARB Subject: aez-ef model Jim - how were the forest-to-perennial and cropland pasture-to-perennial emission factors developed in the worksheet "EF" in the AEZ-EF model? I did not see a description of that in the AEZ-EF report. Tom

2. Email Received By Darlington on February 6, 2015 from Anil Prabhu

Tom, Please see below responses to your questions: For forest-to-perennial, the emissions: deforested_fraction_GHG * (biomass_loss_GHG + foregone_seq_GHG) + (1 - deforested_fraction) * -1 * perennialReversion_GHG We assume no change in soil carbon. For pasture-to-perennial, emissions: biomass_loss_GHG + foregone_seq_GHG Again, no change in SOC, and in this case, not weighted by deforestation vs afforestation. Hope this helps. Regards, Anil

3. Darlington's follow-up email on April 29, 2015

From: Tom Darlington [mailto:tdarlington@airimprovement.com]
Sent: Wednesday, April 29, 2015 9:12 AM
To: Prabhu, Anil@ARB
Cc: Sahay, Shailesh
Subject: Fwd: Re: aez-ef model

Anil - I still cannot find where the perennial reversion GHG emissions are discussed for sugar cane. Can you direct me to the proper documentation for that? Thanks.

Tom

4. Response Received By Darlington from Anil on April 30, 2015

Tom,

This is what we have. Hope it helps.

Regards,

Anil

There is no specific treatment for sugarcane: both oil palm and sugarcane are treated the same. The difference between perennials and annuals is that perennial-to-forest is assumed to not gain soil C, whereas crop-to-forest does gain soil C.

Reversion to forest by perennials is assumed to result in a gain of the "biomass regrowth C" minus the understory and deadwood and a portion of the litter for forest in the given AEZ-Region, as these pools would take more time to accumulate.

This page intentionally left blank.

8_SF_LCFS_GE (Page 411 – 415)

1220. Comment: **LCFS SF8-21**

The commenter believes there is no documentation or description for the perennial reversion emissions for various perennials.

Agency Response: See response to **LCFS SF8-1** in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

1221. Comment: **LCFS SF8-22**

The commenter believes that requiring one calendar quarter of data is an unnecessary requirement in the current proposal.

Agency Response: Please see response to **LCFS FF56-2**.

This page intentionally left blank.

Exhibit B to Declaration of Thomas L. Darlington

Thomas L. Darlington

President, Air Improvement Resource Inc.

Profile

Thomas L. Darlington is President of Air Improvement Resource, a company formed in 1994 specializing in mobile source emission modeling. He is an internationally recognized expert in mobile source emissions modeling, lifecycle analysis, and land use modeling.

Professional Experience

1994-Present	President, Air Improvement Resource
1993-1994	Director, Mobile Source Programs, Systems Application International
1989-1994	Senior Engineer, General Motors Corporation, Environmental Activities
1988-1989	Senior Project Engineer, Detroit Diesel Corporation
1979-1988	Project Manager, U.S. EPA, Ann Arbor, Michigan

Recent Major Projects

- Developed Life Cycle reports and complete applications for 8 plants for the California Low Carbon Fuel Standard; six are currently registered, two plants are pending. Five plants were corn ethanol plants, one is sorghum and two are cellulose.
- Participated in and provided written comments on ARB's three 2014 iLUC workshops
- With Purdue and Don O'Connor, conducted study of iLUC emissions of rapeseed and other oilseeds in 2013 utilizing an updated version of GTAP
- Reviewed EPA's palm oil iLUC emissions in 2013
- Submitted comments on ARB's new GREET2.0 model
- Reviewed CARB's land use emissions for soybean biodiesel
- Reviewed the land use impacts of the RFS2 from EPA, including the notice of Proposed Rule, Regulatory Impact Analysis, and approximately one hundred documents in the rulemaking docket.
- Completed a land use study for Renewable Fuels Association and reviewed California Air Resource Board's Initial Statement of Reasons for the Low Carbon Fuel Standard
- Represented three stakeholders in the recent development of the ARB Predictive Model for reformulated gasoline in California (Alliance of Automobile Manufacturers, Renewable Fuels Association and Western States Petroleum Association)
- Represented two stakeholders in EPA's development of the MOVES on-highway emissions model (Alliance of Automobile Manufacturers and Engine Manufacturers Association)

- Developed the effects of ethanol permeation on on-highway and off-highway mobile sources in California and other states for the American Petroleum Institute
- Studied gasoline and diesel fuel options for Southeast Michigan (for SEMCOG, API and Alliance of Automobile Manufacturers)

Recent Publications

"Study of Transportation Fuel Life Cycle Analysis: Review of Economic Models Use to Assess Land Use Effects", CRC-E-88-3, July 2014.

"Land Use Change Greenhouse Gas Emissions of European Biofuel Policies Utilizing the Global Trade Analysis Project Model", Darlington, Kahlbaum, O'Connor, and Mueller, August 30, 2013.

"A Comparison of Corn Ethanol Lifecycle Analyses: California Low Carbon Fuels Standard (LCFS) Versus Renewable Fuels Standard (RFS2)", June 14, 2010. Renewable Fuels Association and Nebraska Corn Board. This study compared and contrasted the corn ethanol lifecycle analyses performed by both CARB (as a part of the LCFS) and the EPA (as a part of RFS2).

"Review of EPA's RFS2 Lifecycle Emissions Analysis for Corn Ethanol", September 25, 2009. Conducted for Renewable Fuels Association. This study reviewed EPA's land use GHG emissions assessment for corn ethanol, including the FASOM and FAPRI models and Winrock land-use types converted and emission factors by ecosystem type. The study made many recommendations for improving the land-use and emissions modeling.

"Review of CARB's Low Carbon Fuel Standard Proposal", April 15, 2009. Conducted for Renewable Fuels Association. This study reviewed CARB's analysis of land use emissions using GTAP6 and CARB's overall lifecycle emissions for corn ethanol. This study made many recommendations for improving the land use and lifecycle emissions of corn ethanol.

"Emission Benefits of a National Clean Gasoline", August 2008. Conducted for the Alliance of Automobile Manufacturers. This study evaluated the nationwide criteria pollutant emission reductions of a national clean gasoline standard.

"Land Use Effects of Corn-Based Ethanol", February 25, 2009. Conducted for Renewable Fuels Association. This study evaluates possible land use changes and GHG emissions associated with these land use changes as a result of the renewable fuel standard mandated 15 billion gallons of corn ethanol required by calendar year 2015. The study utilized projections of land use in the US and rest of world performed by Informa Economics, LLC, as well as newer estimates of the land use credits of co-products produced by ethanol plants to evaluate possible land use changes.

"On-Road NOx Emission Rates From 1994-2003 Heavy-Duty Trucks", SAE2008-01-1299, conducted for the Engine Manufacturers Association. This study examined

manufacturers consent decree emissions data to determine on-road NOx emission rates, and deterioration in emissions from heavy-duty vehicles. (Peer reviewed publication)

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act - Part 2: CO2 and GHG Impacts", SAE2008-01-1853, conducted for the Alliance of Automobile Manufacturers. This paper evaluated the comparison of greenhouse gases from cars and light trucks in the US under both the Federal and California GHG policies. (Peer reviewed publication)

"Effectiveness of the California Light Duty Vehicle Regulations as Compared to Federal Regulations", June 15, 2007. Conducted with NERA Economic Consulting and Sierra Research for The Alliance of Automobile Manufacturers. This study compares the emission benefits of the California and Federal light duty vehicle regulations for HC, CO, NOx, PM, SOx, and Toxics taking into account the difference in emission standards, new vehicle costs and its effect on fleet turnover, new vehicle fuel economy and its effect on vehicle miles traveled, and other factors. Both the EPA MOBILE6 and ARB EMFAC on-road emissions models were used to estimate changes in emissions inventories.

"The Case for a Dual Tech 4 Model Within the California Predictive Model", May 20, 2007. Conducted with ICF International and Transportation Fuels Consulting for the Renewable Fuels Association (RFA). This study developed separate emissions vs fuel property models for lower and higher Tech 4 (1986-1995) vehicles, and showed that utilizing this alternative Predictive Model would result in a higher compliance margin for fuels containing higher volumes of ethanol. It was thought that this could lead to higher ethanol concentrations in the state, but even if the dual model is not used, it is a better representation of the 2015 inventory than the ARB single model.

"Updated Final Report, Effects of Gasoline Ethanol Blends on Permeation Emissions Contribution to VOC Inventory From On-Road and Off-Road Sources, Inclusion of E-65 Phase 3 Data and Other Updates", June 20, 2007. Conducted for the American Petroleum Institute. This report updates the earlier March 3, 2005 report for API utilizing data collected by CRC and others since of the time of the earlier report.

Final Report, Development of Technical Information for a Regional Fuels Strategy, February 28, 2006. Conducted for the Lake Air Directors Consortium (LADCO). This report provided guidance to the LADCO states (Midwestern states) concerning how to model different types of fuel control programs (in particular) using EPA mobile source models, and how to set up the baseline input files so that results are consistent between the different states.

"Emission Reductions from Changes to Gasoline and Diesel Specifications and Diesel Engine Retrofits in the Southeast Michigan Area", February 23, 2005. Conducted for the Southeast Michigan Council of Governments (SEMCOG), the Alliance of Automobile Manufacturers, and the American Petroleum Institute. This study examined the on-road and off-road emission benefits of many different possible gasoline and diesel fuel

specifications that the state could adopt to help meet the 8-hour ozone standards. This study formed the basis for the state's move to lower RVP summer gasoline.

"Examination of Temperature and RVP Effects on CO Emissions in EPA's Certification Database, Final Report", CRC Project No. E-74a, April 11, 2005. Conducted for the Coordinating Research Council. This study compared CO vs temperature results from the MOBILE6 model to the certification data, and recommended further testing, which is being conducted by the CRC at this time.

"Effects of Gasoline Ethanol Blends on Permeation Emissions Contribution to VOC Inventory From On-Road and Off-Road Sources" March 3, 2005. Conducted for the American Petroleum Institute (API). Using data from the CRC-E-65 program, and data collected by the California EPA and Federal EPA, this study estimated the impacts of ethanol use on increasing permeation VOC emissions from on-road vehicles, off-road equipment and vehicles, and from portable containers. Emission inventory estimates were made for a number of geographical areas including the state of California, and results showed that the permeation effect increases anthropogenic VOC inventories by 2-4%.

Review of EPA Report "A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions", February 11, 2003. Conducted for the American Petroleum Institute. This study critically examined the methods that EPA used to develop the impacts of biodiesel fuels on HC, CO, NOx, and PM emissions.

"Well-To Wheels Analysis of Advanced Fuel/Vehicle Systems – A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions", May 2005. Conducted for General Motors Corporation, with Argonne National Labs. This study examined many different well to wheels pathways for various fuels, and their impacts on GHG and criteria pollutant emissions.

"Potential Delaware Air Emission Impacts of Switching From MTBE to Ethanol in the Reformulated Gasoline Program", May 26, 2005. Conducted for Lyondell Chemical Company. This study examined the HC, CO, and NOx impacts of switching from MTBE to ethanol.

"Potential Massachusetts Air Emission Impacts of Switching From MTBE to Ethanol in the Reformulated Gasoline Program" June 17, 2005. Conducted for Lyondell Chemical Company. This study is similar to the Delaware study above.

"Potential Maryland Air Emission Impacts of a Ban on MTBE in the Reformulated Gasoline Program", October 18, 2005. Conducted for Lyondell Chemical Company. This study is similar to the Delaware study above.

"MOBILE6.2C with Ethanol Permeation and Ethanol NOx Effects", February 8, 2005. Conducted for Health Canada. This study modified the MOBILE6.2C model for ethanol permeation VOC and ethanol NOx effects.

Education

B. Sc., (Materials and Metallurgical Engineering), University of Michigan, Ann Arbor, 1979
Post Graduate Courses (Business Administration), University of Michigan, Ann Arbor, 1982

8_SF_LCFS_GE (Page 416 - 421)

1222. Comment: **Tom Darlington's Resume**

Agency Response: This is a submittal of Tom Darlington's resume. It does not constitute an objection or suggestion on the proposal.

This page intentionally left blank.

Comment letter code: 9-SF-LCFS-CNGVC

Commenter: Carmichael, Tim

Affiliation: California Natural Gas Vehicle Coalition

The following letter was submitted to the LCFS Docket during the Second 15-day comment period.

This page intentionally left blank.

9_SF_LCFS _CNGVC

July 8, 2015

Richard Corey
Executive Officer
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Re: Comments on ARB's "Attachment A: Second 15-Day Modified Regulation Order" (LCFS)

Dear Executive Officer Corey:

The California Natural Gas Vehicle Coalition (CNGVC), NGVAmerica (NGVA), and the Coalition for Renewable Natural Gas (RNGC)[1] are pleased to provide these joint comments regarding ARB's proposed re-adoption of the Low Carbon Fuel Standard (LCFS) regulation. Specifically, this letter provides our detailed joint comments on ARB's "Attachment A: Second 15-Day Modified Regulation Order," which was released for public comment on June 23, 2015.

Below, we present our joint, detailed comments and recommendations. Many of these comments reiterate issues that were raised in our June 19th letter regarding the previous 15-day comment period. While ARB has addressed the critical issue of "provisional credits," we remain concerned about many issues that were not addressed in the most recent Modified Regulation Order.

We want to be clear that our three organizations continue to support ARB's proposed re-adoption of the LCFS regulation. We greatly appreciate the time and effort put forth by ARB staff over the last several months to meet with our representatives and address our specific concerns. ARB has made several changes that corrected erroneous information and updated obsolete inputs in early drafts of the proposed CA-GREET model revision (version 2.0). We remain committed to continue working closely with ARB staff, right up until the LCFS program re-adoption is anticipated at the Board's July 23, 2015 meeting.

A. Comments on Proposed LCFS Regulatory Changes

Our detailed comments regarding ARB's proposed LCFS regulatory changes are presented below, in six specific areas.

1. Provisional Pathway Process

We would like to thank Staff for addressing the concerns of many stakeholders by allowing the credits generated under the Provisional Pathway process to be immediately and fully tradeable. This change is crucial to support the continued development of low carbon fuels in the California marketplace. LCFS SF9-1

[1] For more information about our three organizations and respective memberships, please refer to the many previous formal comment letters that we uploaded over the last nine months to the ARB LCFS comments website.

2. Temporary FPC Values

Table 7 of the regulation proposes temporary carbon intensities for fuels where a specific fuel pathway cannot be identified. These may also potentially be used as "default" values for facilities awaiting application approval or in the beginning stages of the Provisional Pathway process. Hence, the values in Table 7 have a material impact on the credits and deficits generated under the LCFS. Despite the importance of these values, ARB staff have not provided information regarding the underlying assumptions used to determine most of the values in Table 7 (excluding the CIs for diesel and CARBOB, which are clearly documented elsewhere). We believe that the values in Table 7 are not consistent with typical values expected for natural gas pathways providing fuel to California. In fact, values for LNG from North American natural gas, and CNG or LNG derived from landfill gas are significantly higher than the illustrative values provided by ARB staff at the April 3rd workshop at which updates to CA-GREET 2.0 were extensively discussed.

LCFS SF9-2

In sum, the currently proposed revisions to Table 7 further increase the CIs for natural gas pathways above values previously proposed by staff, and these increases do not appear to be explainable by documented revisions to the CA-GREET model. We believe that it is inappropriate to further increase the values in Table 7 without providing details on the assumptions underlying these changes. Consequently, we request that ARB staff not modify the values in Table 7 from the values proposed in February. At the very least, we believe that any modifications to the values in Table 7 should be clearly linked to documented changes and updates to the CA-GREET model.

3. Application Review Timeline

Section 95488(c)(5)(B) proposes to eliminate the 60-day deadline for ARB staff to review an application and notify the applicant about its completeness. However, Staff is not proposing to modify the 180-day deadline for an applicant to provide a complete application. Staff notes that this change is being proposed to eliminate "unrealistic deadlines" during times when Staff will be working to recertify hundreds of existing pathways.

This removal of the 60-day deadline may be acceptable for applications covered by an existing pathway and able to generate credits as late as December 31, 2016. However, the proposed change <u>is not acceptable for new applications</u>. It is crucial that ARB continue to provide timely feedback to applicants regarding the completeness of their applications and any deficiencies that must be addressed. Delays in the review process can translate directly into lost credit generation, the associated revenue, and verified carbon reductions.

LCFS SF9-3

Further, we note that the removal of the 60-day requirement is not limited to the 2016 timeframe. It is inappropriate to establish a regulation in which Staff have no obligation to complete a timely review of an application but where the applicant is simultaneously constrained to a fixed deadline and dependent on Staff's review of the application.

Similarly, Staff propose to remove the 15-day deadline for review and notification of completeness of a fuel transport mode as defined in Section 95488(e)(5). We have similar concerns and objections to the removal of this requirement for timely review of the fuel transport mode application as we do for the pathway application review process in Section 95488(c)(5).

We urge Staff to retain the 60-day and 15-day deadlines in Sections 95488(c)(5)(B) and 95488(e)(5), respectively, and to provide the LCFS program the necessary resources to conduct timely review of applications during the 2016 timeframe. It is critically important that industry has a process for application review that includes firm deadlines for ARB's actions. LCFS SF9-3 cont.

4. Treatment of Business Confidential Information

Staff are proposing to eliminate language providing protection of credit transaction data as Business Confidential information. Section 95487(c)(1)(B) currently requires ARB to treat all data reported in Credit Transfer Forms as business confidential, with limited exceptions for reporting of aggregated data described in Section 95487(d).

Credit Transfer Forms contain a number of sensitive pieces of information including, but not limited to:

- Names and contact information of individuals at companies involved in the transaction;
- Parties to specific transactions;
- Price and number of credits involved with a specific transaction. LCFS SF9-4

There is no basis for broad public disclosure of the names and contact information of private persons, particularly when they are acting simply in an administrative role for a private organization. Further, the disclosure of the parties, pricing, types of credits, and number of credits associated with a particular transaction can be damaging to the business interests of regulated parties. The disclosure of such sensitive information is not consistent with other regulatory programs including the US EPA's Renewable Fuel Standard.

It should also be noted that, while the regulation allows brokers to facilitate "blind transactions," the disclosure of data in the Credit Transfer Forms would undermine blind transactions for any transactions where the broker does not first aggregate the credits from multiple buyers or sellers.

We urge Staff to retain the Business Confidential protection language in Section 95487(c)(1)(B). Confidentiality provisions are the industry standard for commodity transactions. However, we can support providing information for the sole purpose of calculating a published index.

5. Definition of L-CNG and Bio-L-CNG

The proposed regulatory text currently defines L-CNG as "LNG that has been liquefied and transported to a dispensing station where it was then re-gasified and compressed to a pressure greater than ambient pressure."

Similarly, Bio-L-CNG is defined as "biogas-derived biomethane which has been compressed, liquefied, re-gasified, and re-compressed into L-CNG, and has performance characteristics at least equivalent to fossil L-CNG." LCFS SF9-5

In both definitions, it is assumed that L-CNG is created by gasifying LNG and then compressing the resulting gas to pressures suitable for CNG, typically 3,600 psi. This is not an accurate description for most L-CNG and Bio-L-CNG facilities. The pumping of liquids to high pressures is much less energy intensive than the compression of gas. Most L-CNG facilities take advantage of this fact by first pumping LNG to high pressures and then re-gasifying the LNG at pressure, ultimately producing CNG without the need for a gas compression process. Such a distinction is important because it has a meaningful impact on the carbon intensity for L-CNG fuels. We note that this issue was raised in our comments submitted to ARB on December 15, 2014. Following that submission, Staff updated the CA-GREET model to reflect the typical operation of L-CNG stations. LCFS SF9-5 cont.

We recommend that Staff modify the definition of L-CNG and Bio-L-CNG to be consistent with the processes modeled in CA-GREET 2.0. Specifically, by eliminating the text asserting that L-CNG and Bio-L-CNG necessarily involve "compression" or "re-compression" of natural gas at the station.

6. Retroactivity

Section 95486(a)(2) limits the generation of retroactive credits to a maximum of two quarters; the quarter in which the complete application was submitted and the quarter in which the Executive Officer approves the application. Exceptions are made for provisional credits generated during the period that the applicant is accruing two years of operational data.

While the two-quarter limit on retroactive credit generation appears reasonable, it is predicated on the assumption that the Executive Officer will approve a complete application by the end of the quarter following submission of the application. Considering that Staff acknowledge the likelihood of significant delays in application processing during 2016, and in light of the proposed elimination of the 60-day and 15-day review deadlines discussed in item 3 above, we believe that retroactivity should not be constrained by a two-quarter limit. Specifically, we propose that retroactive credit generation should apply from the quarter the applicant submits a completed application or demonstration to the quarter in which the Executive Officer approves the application or demonstration. Hence, if the approval of the application or demonstration by the Executive Officer requires more than one quarter, the applicant does not lose credits due to delays outside the applicant's control. LCFS SF9-6

This proposed change is both reasonable and important. However, we do not believe it is worth delaying the adoption of the LCFS, provided that Staff ensures the timely review of applications as noted in our comments under Item 3, above. Instead, we strongly urge Staff to consider making this change in a future update to the LCFS, retain the 60-day and 15-day deadlines for review in the current rulemaking (or alternative reasonable timeline with a firm deadline), and ensure that the LCFS program has sufficient resources to provide timely review of applications.

B. Comments on CA-GREET Model Update

We would like to thank Staff for their efforts to address our concerns related to the draft CA-GREET 2.0 model over the last nine months. These interactions have resulted in important improvements to the model.

In the latest draft of CA-GREET, Staff incorporated estimates of Tank to Wheels (TTW) methane and nitrous oxide emissions from natural gas vehicles, based on a recent whitepaper from Argonne National Laboratory

(ANL).[2] The whitepaper provides estimated emissions for various vehicle types and applications, including combination long haul trucks, combination short haul trucks, refuse trucks, buses, heavy duty trucks and vans, and medium duty vehicles. Staff rely on the emissions rates in the ANL report, combined with estimates of the composition of the natural gas vehicle fleet, to calculate fleet-averaged TTW emissions rates for CNG and LNG.

The emissions rates calculated by ARB staff are not insignificant. As shown in Table 1, ARB assumes that the fleet-averaged emissions of methane and nitrous oxide for CNG and LNG vehicles are 4.90-4.91 gCO2e/MJ. This represents a 6% increase in pathway emissions for CNG and LNG from fossil sources, and potentially more than 25% of emissions from renewable natural gas pathways. However, as shown, emissions from some vehicle types are much lower than the calculated fleet average.

Table 1. Non-CO2 GHG emissions assumptions for natural gas vehicles

Vehicle Type	Non-CO2 vehicle emissions
ARB CNG Fleet Average	4.90 gCO2e/MJ
Light-Duty/Medium Duty	0.99 gCO2e/MJ
Heavy-Duty Class 8b	2.42 gCO2e/MJ
ARB LNG Fleet Average	4.91 gCO2e/MJ

Both heavy-duty class 8b vehicles and light/medium duty vehicles are estimated to have much lower TTW emissions than the fleet-average. Because of such wide variation in the emissions from vehicle types, the fleet-averaged emissions are very sensitive to the assumed fleet composition. Overestimating the fraction of the fleet in higher emitting applications raises the fleet average and potentially penalizes lower emitting applications.

We raise two specific concerns here, as described below.

1. Basis for the Current Fleet Mix

Staff calculates the current mix of applications consuming CNG and LNG based on data from the US Energy Information Administration's (EIA) Alternative Fuel User Database. The latest year for available data is 2011. We note that the data are both out of date, and inconsistent with other industry specific data sources. As an example, we note that ARB staff estimate that transit buses consume 60% of the 55 million gallons of LNG sold in 2014. This equates to nearly 22 million GGE, or 150% more LNG for transit buses than reported by EIA. The National Transportation Database (NTDB) reports that California transit fleets consumed only 7 million gallons of LNG, or approximately 4.6 million GGE in 2011; roughly half of the fuel consumption reported by EIA. Finally, it is unclear to what extent reported LNG consumption actually reflects LNG delivered to an LCNG station.

LCFS
SF9-7

The dominant purchasers of LNG in California for transit applications are Orange County Transportation Authority (OCTA) and Santa Monica's Big Blue Bus (BBB). These two agencies represent almost 95% of LNG purchased in 2011, according to the NTDB. Examination of a recent LNG purchase contract from OCTA reveals

[2] Cai, H. et al, The GREET Model Expansion for Well-to-Wheels Analysis of Heavy-Duty Vehicles, 2015

that the agency consumes roughly 22,000 gallons of LNG per weekday, or approximately 5.5 million LNG gallons per year.[3] A city council report on the BBB LNG fuel procurement for 2010-2011 reported that BBB purchases roughly 200,000 LNG gallons per month to serve a mix of BBB vehicles as well as city vehicles and the Santa Monica Unified School District.[4] BBB operates a mix of CNG and LNG buses, supplying the CNG buses through their LCNG station. Consequently, only a fraction of the BBB LNG purchases are actually used in transit applications. In total, the two largest purchasers of LNG for transit applications only represented less than 7.7 million LNG gallons in 2011. Again, this value is much lower than that reported by EIA.

Such disparities between EIA and other data sources make it clear that EIA is not a reliable basis upon which to develop a fleet-average emissions rates.

2. Evolving Fleet Mix

EIA's last available estimate of the population of NGVs in the US is 121,650 vehicles in 2011. Based on industry sales data, NGVA estimates that the current population of NGVs is in excess of 155,000 and growing. New deployments show growth in sales of Class 8 trucks in addition to sales in more traditional transit and refuse applications. It is clear that the mix of NGVs is changing and that it is not possible to accurate predict the future fleet mix. Further, because of the relatively small number of NGVs in the state (relative to traditional petroleum fueled vehicles), modest growth in any application could significantly alter the fleet mix.

LCFS SF9-7 cont.

Recommendations Regarding CA-GREET Update

Based on the two concerns described above – and the fact that the TTW emissions rates employed by ARB have non-trivial variations based on the vehicle type/application – we request that ARB allow fuel producers the option to adjust their pathway carbon intensities based on the vehicle type receiving the fuel. For example, a CNG or LNG station owner that documents the volume of fuel dispensed to Class 8b trucks would adjust their pathway CI based on non-CO2 TTW emissions of 2.42 gCO2e/MJ, rather than the fleet average of 4.90 or 4.91 gCO2e/MJ.

This option would help incentivize the deployment of NGVs in the lowest emitting categories by recognizing their specific emissions profiles and would require minimal changes to the data tracked in the LRT. Currently light and medium-duty natural gas consumption is tracked separately from heavy-duty natural gas fuel consumption in the LRT. Implementing the proposed recommendation would only require the separation of Class 8b fuel consumption from the remaining heavy-duty vehicle applications. Where the vehicle type cannot be determined or is not documented, the credit generator would continue to use the fleet-averaged TTW emissions rates.

[3] Orange County Transportation Authority, Award of Liquefied Natural Gas Contract – Staff Report, 2013 http://atb.octa.net/AgendaPDFSite/10775_Staff%20Report.pdf

[4] City of Santa Monica, LNG Fuel for the Big Blue Bus, Agenda Item 3-E, February 8, 2011. http://www.smgov.net/departments/council/agendas/2011/20110208/s2011020803-E.htm

Closing Comment

Our three organizations support re-adoption of the LCFS regulation. We genuinely appreciate the cooperation that ARB staff have shown in working with our industry representatives to improve the program, especially the critically important CA-GREET model. Leading up to the July 23 Board meeting, we urge you to expeditiously address the issues identified in this letter. LCFS SF9-8

Thank you for the opportunity to comment. If we can provide additional information, please contact any of us.

Sincerely yours,

Tim Carmichael

Tim Carmichael, President
California Natural Gas Vehicle Coalition
916-448-0015

Matthew Godlewski

Matthew Godlewski, President
NGVAmerica
202-824-7360

David Cox

David Cox, Director of Operations & General Counsel
Coalition for Renewable Natural Gas
916-678-1592

This page intentionally left blank.

9_SF_LCFS_CNGVC

1223. Comment: **LCFS SF9-1**

The commenter supports the regulatory language modifications in the second 15-day comments which effectively remove the restriction on the sale of LCFS credits based on the provisional pathway. The commenter thanked the Air Resources Board staff for regulatory language modifications in the second 15-day comments which effectively remove the restriction on the sale of LCFS credits based on the provisional pathway. They believe that the change is crucial to support the continued development of low carbon transportation fuels in California.

Agency Response: ARB staff appreciates the support for the modification of the provisional pathways.

1224. Comment: **LCFS SF9-2**

The commenter believes that the values in Table 7 are not consistent with typical values expected for natural gas pathways providing fuel to California.

Agency Response: This comment was submitted July 8, 2015 during the comment period for the Second 15-Day Modified Regulation Order, but relates to a change proposed in the First 15-Day Modified Regulation Order proposed on June 4, 2015. The comment duplicates a comment submitted during the first comment period; Staff believes that the response to CNGVC's comment **LCFS FF35-6** sufficiently addresses this comment.

1225. Comment: **LCFS SF9-3**

The commenter states that the elimination of 60-day deadline for staff to advise the applicant that application is complete or incomplete is not acceptable for new pathways.

Agency Response: This comment was submitted July 8, 2015 during the comment period for the Second 15-Day Modified Regulation Order, but relates to a change proposed in the First 15-Day Modified Regulation Order proposed on June 4, 2015. The comment duplicates a comment submitted during the first comment period; Staff believes that the response to CNGVC's comment **LCFS FF35-7** sufficiently addresses this comment.

1226. Comment: **LCFS SF9-4**

The commenter recommends retaining language in section 95487 that deems data in credit transaction forms confidential.

Agency Response: See response to comment **LCFS FF35-10**.

1227. Comment: **LCFS SF9-5**

The commenter recommends that staff modify the definition of L-CNG and Bio-L-CNG to be consistent with the processes modeled in CA-GREET 2.0. Specifically, by eliminating the text asserting that L-CNG and Bio-L-CNG necessarily involve “compression” or “re-compression” of natural gas at the station.

Agency Response: Because CA-GREET 2.0 correctly reflects the processing described by the comment, no further change is needed; the fuels in question will receive a correct CI.

1228. Comment: **LCFS SF9-6**

The commenter proposes that retroactive credit generation should apply from the quarter the applicant submits a completed application or demonstration to the quarter in which the Executive Officer approves the application or demonstration.

Agency Response: See response to comment **LCFS FF35-12**.

1229. Comment: **LCFS SF9-7**

The commenter states that disparities between EIA and other data sources make EIA an unreliable basis upon which to develop fleet-average emissions rates.

Agency Response: See responses to **LCFS FF35-13**, **LCFS FF35-14**, and **LCFS FF35-15**.

1230. Comment: **LCFS SF9-8**

The commenter supports the re-adoption of the LCFS regulation and urges staff to expeditiously address the issues identified in their letter.

Agency Response: ARB staff appreciates the support of the commenters. After the Board Hearing, staff will continue conducting workshops, providing guidance, and seeking stakeholder feedback regarding pathway processing.

Comment letter code: 10-SF-LCFS- WE

Commenter: Tijong, Carol

Affiliation: White Energy

The following letter was submitted to the LCFS Docket during the Second 15-day comment period.

This page intentionally left blank.

WHITE ENERGY
CLEAN ENERGY FOR A CLEAN FUTURE.

10_SF_LCFS_WE

July 8, 2015

California Air Resources Board
1001 I Street
Sacramento, CA 95812

RE: LCFS Re-adoption, 2nd 15-day notice

Dear Mary Nichols & Staff:

Thank you for the Second 15-Day Modified Regulation Order posted June 23, 2015. We are submitting comments for which we would appreciate ARB's consideration.

Our comment involves the proposed regulation regarding provisional pathways. We greatly appreciate ARB's proposed modification to Section 95488(d)(2) to allow the sale or transfer of credits generated under provisional pathways. However, if the regulations intend that these provisional credits (which we'd appreciate making a defined term for purposes of clarity) may not be utilized for compliance purposes by a regulated party [95486(a)(2)], such a prohibition may create hesitancy in customer acceptance of a fuel with a new fuel technology, and thus reduce feasibility, marketability, and potential benefit under LCFS to drive investment. We acknowledge ARB's need to adjust a provisional CI and appreciate ARB's willingness to allow provisional CIs, but if ARB intents to also adjust a provisional CI outside of a producer's account, we would prefer an alternate method to account for any adjustment necessary for any potential negative differences of CI upon the completion of the full two years of commercial operation. For example, if a provisional CI is changed to a higher operational CI, then any provisional credits *still in our account as producer* would be adjusted to the operational CI but the *accumulated difference* between the provisional CI and the operational CI for *any provisional CI already transferred to a third party* would be debited to our account, for which we would be obligated to clear (perhaps through purchasing credits on the open market or via any other credit balance in our account). LCFS SF10-1

Please feel free to contact me to clarify the provisions or to discuss further. We are excited to work with ARB to help meet its increasing GHG targets and provide a lower carbon intensity product for our customers. Thank you for the opportunity to comment and provide feedback.

Sincerely,

Carol Tjiong

Carol Tjiong
Vice President

2745 N. Dallas Parkway, Suite 670, Plano, TX 75093
Telephone 972.715.6490, Fax 214.751.2595
www.white-energy.com

This page intentionally left blank.

10_SF_LCFS_WE

1231. Comment: **LCFS SF10-1**

The commenter urges ARB to implement an alternative method for adjusting any potential negative balances at the end of the provisional period.

Agency Response: See response to **LCFS SF6-3**.

This page intentionally left blank.

Comment letter code: 11-SF-LCFS-DuPont

Commenter: Koninckx, Jan

Affiliation: DuPont

The following letter was submitted to the LCFS Docket during the Second 15-day comment period.

This page intentionally left blank.

11_SF_LCFS _DuPont

DUPONT®

July 8, 2015

Samuel Wade
California Air Resources Board
Branch Chief, Transportation Fuels Branch
1001 I Street
Sacramento, CA 95814

Re: Second Notice of Proposed 15-day Regulation Order containing Modified Text and Availability of Additional Documents and Information for the Proposed Re-Adoption of the Low Carbon Fuel Standard

Dear Samuel Wade:

On behalf of DuPont, thank you for the opportunity to comment on the Second Notice of Proposed Modified Text for the LCFS. DuPont has significant investments in advanced biofuels that meet the specified greenhouse gas reduction threshold. These fuels will make transformative contributions to our nation's energy security, reduce greenhouse gas emissions and strengthen rural economies. These fuels represent a tremendous shift in how we energize our planet and are being commercialized due in large part to visionary state fuels programs like the CA Low Carbon Fuel Standard.

We look forward to doing business in California; however, DuPont has remaining concerns with the Second Notice of proposed modification to Obtaining and Using Fuel Pathways in Section 95488(d). The current proposed text is an improvement over the previous version which would have required a provisional status for new fuel producers for two years without the ability to transfer credits. In Section 95488 (d)(1)(D), the updated version appears to allow assigning a temporary fuel production code carbon intensity (CI) that could apply for two quarters. The issue with this approach is that the temporary CI could expire prior to a fuel pathway being approved. A new fuel producer must have 3 months of operational data before submitting a new pathway request pursuant to Section 95488 (d)(2). Completing and submitting an application form after the first 3 months of operation will take several weeks. We are concerned that the fuel pathway approval process could extend beyond the period of time covered by the temporary fuel production code. It is incredibly important for new advanced biofuel producers to be able to sell into the CA market from the first day of operation and continue without a lapse in valid carbon credits. In addition, DuPont recognizes the importance of accurate CI values and believes the Air Resources Board should develop a mechanism to compensate fuel producers or regulated parties when a fuel's CI value is adjusted upwards or downwards to include any change from the temporary fuel production code CI.

LCFS SF11-1

LCFS SF11-2

Therefore, DuPont recommends that the regulations be modified to: (1) allow the Air Resources Board flexibility to extend the period of time for temporary fuel production codes as long as a new fuel producer is actively seeking a fuel pathway approval; and (2) provide for an audit mechanism to debit or credit for adjusting CI values to fuel producers and regulated parties as needed to accurately account for changing CI values.

LCFS SF11-1 cont.

LCFS SF11-2 cont.

Introduction

DuPont is an industry leader in providing products for agricultural energy crops, feedstock processing, animal nutrition, and biofuels. Our three-part approach to biofuels includes: (1) improving existing ethanol production through differentiated agriculture seed products, crop protection chemicals, as well as enzymes and other processing aids; (2) developing and supplying new technologies to allow conversion of cellulose to ethanol; and (3) developing and supplying next generation biofuels with cellulosic ethanol and biobutanol.

We bring the perspective of a company deeply involved in the agricultural and biofuels industries. Our seed business DuPont Pioneer sells corn seed to farmers growing for a variety of end-use markets, including grain ethanol production. Our intimate relationship with our farmer customers and our extensive research provides us significant insight into the agronomics of the harvest and management of corn stover as a cellulosic feedstock. We provide a variety of products for the grain ethanol business as well, including saccharification enzymes and fermentation processing aids, and so have an intimate knowledge of the operation of these relevant sugar fermentation operations.

DuPont began its research into cellulosic technology a decade ago. What started as a lab scouting project grew into a full scale commercialization effort. In 2009, DuPont opened a demonstration facility in eastern Tennessee producing cellulosic ethanol from both corn stover and switchgrass. For the past four years, we have brought together growers, academia, public institutions like the USDA and custom equipment makers to conduct harvest trials on corn stover. All this work culminated in the groundbreaking of a 30 million gallon per year facility in December of 2012 in Nevada, Iowa, located approximately 40 miles north of Des Moines. I am happy to report that we are in the very final stages of construction, commissioning has been initiated and we will be open for business later this year. We anticipate that a number of other companies in addition to DuPont will bring cellulosic volumes to the market. Multiple companies are constructing, starting up or operating facilities producing renewable fuels from a wide variety of cellulosic feedstocks including corn stover, switchgrass, wheat straw, municipal solid waste and wood fiber. Many of these are large, well-capitalized, sophisticated companies with long track records in designing, constructing and operating manufacturing facilities. This diversity of operations provides a high level of confidence for multiple technologies succeeding at commercial scale.

In addition to cellulosic ethanol, DuPont is pursuing another advanced renewable fuel with our partner BP in a 50/50 joint venture called Butamax™. The joint venture has developed and extensively tested bio-butanol, a higher alcohol fuel produced by fermenting biomass. Biobutanol has excellent fuel properties, with higher energy density than ethanol and the ability to be distributed via the existing gasoline infrastructure, including pipelines. It also reduces volatility, allowing butanol gasoline blends to be used in the summer in regions that currently require waivers from air quality regulation for the use of ethanol-gasoline blends. Because butanol has less affinity for water and is a weaker solvent than ethanol, it will be more compatible with existing equipment, including small engines.

The proposed modification to Provisional Pathways

In the Proposed 15-day Regulation Order containing the Second Notice of Modified Text and Availability of Additional Documents and Information for the Proposed Re-Adoption of the Low Carbon Fuel Standard, the Air Resources Board proposes the following in Section 95488 (d)(1)(D) and (d)(2):

DUPONT

(D) A temporary FPC approved for use by the Executive Officer will be permitted for LRT-CBTS reporting purposes for up to two quarters. Reporting will be granted only for the quarter during which a temporary FPC is approved for use and the subsequent full quarter.

* * *

(2) Provisional Pathways. As set forth in sections 95488(c)(3) and (c)(4)(I)2., LCFS fuel pathways are generally developed for fuels that have been in full commercial production for at least two years. In order to encourage the development of innovative fuel technologies, however, applicants may submit New Pathway Request Forms, as set forth in section 95488(c)(1), covering Tier 1 and Tier 2 facilities that have been in full commercial operation for less than two years, provided they have been in full commercial production for at least one full calendar quarter. If that form is subsequently approved by the Executive Officer, as set forth in section 95488(c)(2), the applicant shall submit operating records covering all prior periods of full commercial operation, provided those records cover at least one full calendar quarter. The following subsections govern the development, evaluation, and post-certification monitoring of such provisional pathways.

Analysis and Recommendations

The proposed text is overly restrictive and burdensome for both California and biofuels interests that are set to bring new technologies and fuels to market in California. DuPont fully appreciates the need for accurate CI values for fuel that is sold pursuant to the LCFS while also encouraging production and growth for the advanced biofuels sector. For this reason, we are highlighting the following concerns with the Second Notice of proposed modified text from above:

1. The current proposed text would by default assign a temporary, conservative CI value to these fuels that can only be applied for two quarters. This means that the temporary CI credits could lapse before the fuel pathway is approved. Any waiting period that prevents these fuels from receiving CI credit is fundamentally unfair and is not based on principles of sound science.

2. Any waiting period that prevents a biofuels producer from receiving CI credits will prevent and delay fuel from being sold in California. DuPont's cellulosic ethanol is being manufactured in Iowa. Without the benefit of the CI credit, it would be unreasonable for us to make special arrangements to ship our fuel to California. In addition, obligated parties in California would have no reason to purchase fuel without CI credits. Given their obligations under the LCFS, they would need to purchase fuel with CI credits.

3. Any waiting period that prevents a biofuels producer from receiving CI credits would create an unfair competitive advantage for existing fuel producers. These producers would not be required to wait to receive CI credits thereby rewarding current producers.

LCFS SF11-1 cont.

4. New facilities need to be able to sell fuel for full market value from initial production and on a continuous basis in order to survive. Biofuels facilities do not have storage capacity beyond one or two days of fuel production. In addition, encouraging growth in the cellulosic and advance biofuels sector can only be achieved with supportive federal and state biofuels policies. A waiting period for CI credits would discourage rather than encourage growth. LCFS SF11-1 cont.

5. The temporary fuel production code CI for cellulosic ethanol is 41.05 as set forth in Table 7 in Section 95488. There is a very high probability that after one quarter of production and subsequent quarters of energy data submitted, that the CI value for this fuel will be reduced significantly. Therefore, we respectfully request a process for which any documented change in the CI value, in either the positive or negative direction, enables fuel producers to receive credit or require a debit for the change in CI value. LCFS SF11-2 cont.

Given the concerns above, DuPont recommends that the regulations be modified to provide the Air Resources Board the requisite flexibility to extend the assigned temporary fuel production code CI value as long as necessary while the new producer is actively pursuing a new pathway approval. LCFS SF11-1 cont. New producers should then be able to revise the CI value as quarterly energy collection data warrants with a debit or credit applied that reflects the change in CI value. LCFS SF11-2 cont.

Thank you for the opportunity to comment on the Second Notice of the Proposed 15-day Regulation Order for the Proposed Re-Adoption of the Low Carbon Fuel Standard as this is an important issue for DuPont's biofuels business. Please contact me at Jan.Koninckx@dupont.com if you have any questions about the comments provided.

Sincerely,

Jan Koninckx

Jan Koninckx, Global Business Director for Biorefineries
DuPont Industrial Biosciences

11_SF_LCFS_DuPont

1232. Comment: **LCFS SF11-1**

The commenter believes that the fuel pathway certification process could extend beyond the period of time covered by the temporary fuel pathway codes (FPC).

Agency Response: The burden to furnish complete applications rests on the applicant. The time-limited availability of the FPC serves to limit the applicant from "application grid-lock" where requested missing information is not furnished by the applicant, nor can staff proceed further with processing the application without the missing information.

1233. Comment: **LCFS SF11-2**

This comment is related to compensating the fuel producers or regulated parties as a result of provisional CIs being determined to be higher or lower than the values assigned by the temporary Fuel Pathway Code (FPC).

Agency Response: The temporary FPCs have been conservatively estimated, are deemed to be valid, and final. To the extent that they are viewed as too high, that is meant to motivate a prompt application for an individualized CI. Allowing downward adjustments could result in endless and numerous requests for adjusted CI's – a workload that ARB staff could not keep up with.

This page intentionally left blank.

Comment letter code: 12-SF-LCFS-RFA

Commenter: Cooper, Geoff

Affiliation: Renewable Fuels Association

The following letter was submitted to the LCFS Docket during the Second 15-day comment period.

This page intentionally left blank.

12_SF_LCFS _RFA

RFA RENEWABLE FUELS ASSOCIATION

July 8, 2015

Mary Nichols
Chairwoman
California Air Resources Board
1001 "I" Street
Sacramento, CA 95812

Dear Chairwoman Nichols,

The Renewable Fuels Association (RFA) appreciates the opportunity to comment on proposed regulatory changes associated with the re-adoption of the Low Carbon Fuels Standard (LCFS) (Second Notice of Public Availability of Modified Text, June 23, 2015).

We are encouraged that the Air Resources Board (ARB) is revising several problematic elements of the first 15-day notice (released June 4, 2015) based on feedback from RFA and other interested stakeholders. A number of provisions in the first 15-day notice regarding establishment of fuel pathways were simply unworkable and we commend ARB for taking steps to address stakeholder concerns.

However, while the second 15-day notice represents a marked improvement over the initial proposed modified text, RFA believes ARB must make additional changes to ensure the pathway approval process is efficient and presents minimal administrative burden for both low carbon fuel producers and ARB staff. In addition, RFA again urges ARB to revise its indirect land use change (ILUC) analysis to reflect the best available science and data. Our comments and concerns on the second 15-day notice are detailed below.

1. **We support the new language added to section 95488(a)(2) allowing fuel producers to request re-certification of "legacy pathways" that were certified under prior versions of the LCFS.**

Under the first 15-day notice, the requirement that all low carbon fuel producers with existing certified pathways must entirely re-apply for those pathways was unnecessarily burdensome and duplicative. Thus, we welcome ARB's proposed modifications to section 95488 to streamline the re-certification process by allowing fuel producers to request re-certification of existing pathways by ARB staff using CA-GREET 2.0. We agree that, in most cases, ARB staff "already has all of the information needed to conduct recertification without any submission of additional data by the applicant…", and we support the use of a simple, straightforward electronic form through the LRT system to request re-certification. We assume that the key variables that influenced an individual ethanol producer's existing pathway carbon intensity (CI) score (e.g., natural gas use, transportation distances, ethanol yield, etc.) will be retained by ARB staff for the re-certification using CA-GREET 2.0. However, it is somewhat unclear how LCFS SF12-1

ARB will handle producer-specific inputs in CA-GREET 2.0 that were not included in approved pathway petitions based on CA-GREET 1.8 (e.g., yeast and enzymes). We encourage CARB to include fields for any additional information needed for re-certification on the online form. LCFS SF12-1 cont.

2. **RFA supports the proposed prioritization of fuel pathway re-certifications for "batch processing."**

LCFS SF12-2

Based on the volumes of distinct renewable fuels delivered to the California market, and the different roles certain fuels have played in helping regulated parties achieve compliance, we agree with ARB's proposed prioritization of fuel types for "batch processing" of re-certification requests.

3. **The description of "Tier 1" fuels in section 95488(b)(1) remains somewhat confusing and ambiguous. ARB should clarify that the "Tier 1" classification applies to specific *fuels* not specific *facilities* or *individual pathways*.**

ARB describes Tier 1 fuels as being "[c]onventionally-produced alternative fuels of a type that has been in full commercial production, excluding start-up or ramp-up phase, for at least three years, and for which certified LCFS pathways have existed for at least three years shall be classified into Tier 1." This language has caused much confusion amongst conventional ethanol producers. Many producers have interpreted this description as applying to individual facilities or specific Method 2 pathways; and some producers who have had an approved Method 2 pathway for fewer than three years have interpreted this language as meaning their fuel cannot be classified as "Tier 1." ARB should clarify that the "Tier 1" classification applies to specific *fuels*—not specific facilities—that have existed commercially for at least three years. In other words, ARB should clarify that all starch-based ethanol produced using conventional methods is "Tier 1" fuel. LCFS SF12-3

4. **"Tier 1" fuels should be excluded from the "Provisional Pathways" requirements described in section 95488(d)(2).**

For unexplained reasons, the second 15-day notice inserted Tier 1 fuels into the section governing provisional pathways. Because ARB is highly familiar with the feedstocks and production technologies associated with Tier 1 fuels, it is completely unnecessary to apply the same provisional pathway conditions to new Tier 1 fuel producers that are applied to new Tier 2 fuels. New facilities producing Tier 1 fuels should receive final approval of their CI scores by the Executive Officer based on one quarter of operational records, as facility operations and the fuel CI would not be expected to change following start-up. LCFS SF12-4

5. **Investment in the development of new "Tier 2" fuels is discouraged by the "Provisional Pathway" requirements described in 95488(d)(2). ARB should allow provisional CI scores to be based on pilot-scale data, rather than requiring operational data for a full quarter of commercial production.**

LCFS SF12-5

Developers of new and innovative low-carbon fuels will likely find it difficult to attract financing for scale-up due to ARB's requirement that new "Tier 2" facilities must have operational data for one full quarter of commercial production before even submitting a new pathway petition.

Developers of “Tier 2” fuel facilities are unlikely to raise the necessary capital for construction of commercial-scale facilities without the ability to show potential investors or lenders a provisional CI score that has been approved by ARB.

We agree that ARB can and should verify provisional CI scores using actual operational data once the Tier 2 facility is up and running. Further, if actual operational data indicates that the actual CI of the fuel is higher than the provisional CI score, we agree that the Executive Officer should “adjust the number of credits or reverse any provisional credit in the producer’s account without a hearing.” However, we strongly believe provisional CI scores should be approved on the basis of pilot-scale data provided by Tier 2 fuel developers so that the LCFS regulation encourages—rather than discourages—investment in new and innovative low-carbon fuels. LCFS SF12-5 cont.

6. **RFA again urges ARB to revise its indirect land use change (ILUC) analysis to reflect the best available science and data.**

RFA continues to strongly dispute the analyses underlying the ILUC values in ARB’s re-adoption proposal (Table 5). We have commented numerous times on ARB’s most recent ILUC analysis and provided volumes of new information and data from independent sources that support much lower ILUC values for corn ethanol. To that end, we are re-attaching our recent comments to ARB on the staff’s flawed ILUC analysis. LCFS SF12-6

* * * * *

Thank you again for the opportunity to comment and please do not hesitate to contact me with any questions.

Sincerely,

Geoff Cooper

Geoff Cooper
Senior Vice President

RENEWABLE
FUELS
ASSOCIATION

February 16, 2015

Mary Nichols
Chairwoman
California Air Resources Board
1001 "I" Street
Sacramento, CA 95812

Dear Chairwoman Nichols,

The Renewable Fuels Association (RFA) appreciates the opportunity to provide comment on the California Air Resources Board's (CARB) Initial Statement of Reasons (ISOR) regarding re-adoption of the Low Carbon Fuel Standard (LCFS). While the proposal for re-adoption marks a slight improvement over the current regulation, we remain deeply concerned by several aspects of the proposal and believe it threatens the long-term durability of the LCFS program. Thus, RFA believes the ISOR needs significant revision before it can be presented to the Board for approval.

Grain-based ethanol has made a substantial contribution to LCFS compliance in the first four years of the program. Indeed, ethanol has accounted for **59% of total credits** generated from 2011Q1 through 2014Q3, and 95% of the ethanol used for compliance has been grain-based ethanol, according to CARB reporting data. If not for the LCFS credits generated by grain-based ethanol, deficit generation would have certainly outpaced credits by now, and compliance with the program would be extremely difficult, if not impossible. Thus, it is not an exaggeration to state that the LCFS has endured so far **only because of the contributions of grain ethanol**. Yet, the ISOR proposes to continue punitive carbon intensity (CI) penalties for grain ethanol and other crop-based biofuels based on purported indirect land use change (ILUC) emissions. If finalized, the proposed re-adoption regulation will make the use of most grain ethanol infeasible for compliance as early as 2016. Why would CARB use flawed and prejudicial analysis to purposely diminish the compliance viability of the low-carbon fuel that has provided the largest volume of credits to date?

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

As the attached comments show, CARB's ILUC analysis remains technically and methodologically flawed, and grossly overstates the land use impacts associated with biofuels expansion. A November publication by the Center for Agricultural and Rural Development (CARD) at Iowa State University makes a remarkably important contribution to the debate over ILUC modeling. The report marks the first time that actual land use changes over the past decade (i.e., the period in which commodity crop prices rose to record levels) have been quantified and discussed in the context of CARB's ILUC modeling results. The CARD/ISU paper, which is discussed in detail in the attached comments, found that "[t]he pattern of recent land use changes suggests that **existing estimates of greenhouse gas emissions caused by**

land conversions due to biofuel production are too high because they are based on models that do not allow for increases in non-yield intensification of land use." In essence, the authors found that the primary response of the world's farmers to higher crop prices "…**has been to use available land resources more efficiently rather than to expand the amount of land brought into production**."

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

The CARD/ISU research was submitted to CARB in early December. However, CARB's ISOR fails to even mention or acknowledge the work in any way. For the first time, we have real-world data that provides important insight into actual market responses to increased biofuels demand and higher crop prices. As described in the attached comments, we believe CARB must take into account the new CARD/ISU research and use it to immediately re-calibrate the GTAP model.

We appreciate CARB's consideration of our attached comments, which also address CA-GREET model revisions and assumptions used in CARB's illustrative compliance scenarios. We welcome further dialog on this subject and look forward to responses to any of the comments offered in the attached document.

Sincerely,

Geoff Cooper

Geoff Cooper
Senior Vice President

RENEWABLE FUELS ASSOCIATION

COMMENTS OF
THE RENEWABLE FUELS ASSOCIATION
IN RESPONSE TO THE CALIFORNIA AIR RESOURCES BOARD
STAFF REPORT: INITIAL STATEMENT OF REASONS
TO CONSIDER
RE-ADOPTION OF THE LOW CARBON FUEL STANDARD (LCFS)

The Renewable Fuels Association (RFA) offers the following comments in response to the California Air Resources Board's (CARB) release of its Initial Statement of Reasons (ISOR) proposing re-adoption of the Low Carbon Fuel Standard (LCFS)

I. Indirect Land Use Change Analysis

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

CARB continues to rely on a fundamentally flawed approach to predicting indirect land use change (ILUC) that favors hypothetical modeling results over empirical data, real-world observations, and improved assessment methods.

Nearly six years have passed since CARB originally adopted the LCFS, which included carbon intensity (CI) penalties for certain biofuels for predicted ILUC. In the intervening years since the program was adopted, the scientific understanding of land use change has significantly progressed. Retrospective analyses of global agricultural land use have been conducted, actual market responses to increased demand and higher commodity prices have been observed and characterized, the reliability of predictive economic models has been improved, and new data has emerged to better guide certain modeling assumptions.

Yet, in spite of these advances in the science, CARB continues to rely on the narrow—and completely unsubstantiated—view that "[a] sufficiently large increase in biofuel demand in the U.S. would cause non-agricultural land to be converted to cropland both in the U.S. and in countries with agricultural trade relations with the U.S."

CARB's entire approach to ILUC is founded on the notion that farmers are limited to only two responses to increased demand for crops. While CARB recognizes four potential market responses to heightened demand for crops, its predictive modeling framework essentially allows only two of these responses to play out. The four potential market responses acknowledged by CARB are shown below.

- **Response 1**: "Grow more biofuel feedstock crops on existing crop land by reducing or eliminating crop rotations, fallow periods, and other practices which improve soil conditions";
- **Response 2**: "Convert existing agricultural lands from food to fuel crop production";
- **Response 3**: "Convert lands in non-agricultural uses to fuel crop production"; or
- **Response 4**: "Take steps to increase yields beyond that which would otherwise occur."

CARB theorizes that there is essentially no crop yield response to increased demand (Response 4 above), and an artificially low elasticity value is used to reflect this belief in CARB's economic model. Further, the CARB modeling framework does not allow double-cropping or reduction of fallow/idle cropland; thus, Response 1 above is also eliminated. *As a result, CARB assumes increased demand for crops can only be met through displacement of animal feed and conversion of non-agricultural lands to crop production (Responses 2 and 3 above).* Not coincidentally, Responses 2 and 3 have the most significant GHG impacts.

CARB has produced no evidence whatsoever that such land conversions have actually occurred on a meaningful scale in response to the LCFS or growth in U.S. biofuels demand. Indeed, empirical evidence suggests that demand growth has been primarily met through Responses 1 and 4 above, which are effectively excluded from CARB's modeling framework.

Instead of tuning the modeling framework to reflect these observed market responses, CARB continues to rely on conjectural assumptions and model predictions to penalize biofuels for hypothetical market outcomes. In essence, CARB is using the exact same approach to estimating ILUC emissions that it used six years ago, making only minor adjustments to certain model parameters based on "judgment calls."

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

RFA believes the principles of sound policymaking and regulation demand that CARB recognize and incorporate the best available science and data in the LCFS process, particularly when empirical data is available to fill important knowledge gaps.

a. A New Publication by Babcock & Iqbal Has Important Implications for CARB's ILUC Analysis. CARB Should Give Serious Consideration to the Findings of the Paper, and Adjust its ILUC Estimation Methodology Accordingly

In mid-November, Babcock & Iqbal at the Center for Agricultural and Rural Development (CARD) published Staff Report 14-SR 109, "Using Recent Land Use Changes to Validate Land Use Change Models."[1] The paper (Attachment 1) makes a remarkably important contribution to the debate over ILUC modeling. The report marks the first time that actual global land use changes over the past decade (i.e., the period in which commodity crop prices rose to record levels) have been quantified and discussed in the context of CARB's ILUC modeling results. <u>The report was submitted to CARB staff in early December 2014, yet there is not a single mention of the paper (nor is there a response to its findings) in the ISOR.</u>

Babcock & Iqbal examined historical global land use changes from 2004-2006 to 2010-2012 and determined that "…the primary land use change response of the world's farmers from 2004

[1] Babcock, B.A. and Z. Iqbal (2014), Using Recent Land Use Changes to Validate Land Use Change Models. Center for Agricultural and Rural Development Iowa State University Staff Report 14-SR 109. Available at: http://www.card.iastate.edu/publications/synopsis.aspx?id=1230

to 2012 has been to use available land resources more efficiently rather than to expand the amount of land brought into production."[2] Among other important revelations, the paper shows that key regions where CARB's GTAP analysis predicts biofuels-induced conversion of forest and grassland have actually experienced substantial *losses* of cropland.

Unfortunately, CARB's GTAP analysis does not take into account the methods of intensification (e.g., double-cropping, increases in the share of planted area that is harvested, return of fallowed land to production) that have been observed in the real world over the past decade. According to Babcock & Iqbal, GTAP and other models "…do not capture intensive margin land use changes so they will tend to ***overstate land use change at the extensive margin and resulting emissions***."[3] This finding is corroborated by Langeveld et al (2013) (Attachment 2), who found GTAP and other models have "…limited ability to incorporate changes in land use, ***notably cropping intensity***," and "[t]he increases in multiple cropping have often been overlooked and should be considered more fully in calculations of (indirect) land-use change (iLUC)."[4]

Ultimately, the Babcock & Iqbal work calls into question the plausibility of CARB's GTAP results and demonstrates that CARB's ILUC results are directionally inconsistent with real-world data and observed market behaviors in many regions. The data and discussion presented in the paper challenge the very underpinnings of CARB's analysis and are simply too important for the agency to ignore. Thus, as described more fully in the comments below, we believe CARB should move immediately to calibrate its GTAP model using the real-world land use data made available by Babcock & Iqbal.

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

b. Countries and regions where cropland has decreased and/or forestland and grassland have increased over the past decade should be presumed to not have converted pasture or forest to crops in response to biofuel-induced higher prices. CARB should calibrate its GTAP model to reflect the absence of extensive land use change in these countries and regions.

At the outset, it is important to note that the lack of a "counterfactual case" to compare to the real-world data (i.e., the *ceteris paribus* principle) is not sufficient reason to ignore the Babcock & Iqbal results. CARB has stated that comparing GTAP results to real-world data is "not productive," because it is not possible to compare real-world data to a counterfactual case in which biofuel expansion did not occur. Appendix I to the ISOR further states:

> GTAP-BIO is not predicting the *overall aggregate* market trend—only the incremental contribution of a single factor to that trend. If GTAP-BIO projects reduced exports, for example, this should be understood to mean that exports will be lower than what they would have been in

[2] *Id,* Executive Summary.
[3] *Id,* Executive Summary. (emphasis added)
[4] Langeveld, J. W.A., Dixon, J., van Keulen, H. and Quist-Wessel, P.M. F. (2014), Analyzing the effect of biofuel expansion on land use in major producing countries: evidence of increased multiple cropping. Biofuels, Bioprod. Bioref., 8: 49–58. doi: 10.1002/bbb.1432. (emphasis added)

> the absence of the effect being modeled (increased ethanol production, in this case). It is the difference between predicting an absolute change and a relative change.[5]

This statement by CARB seems to misunderstand the recommendation from stakeholders to consider and integrate empirical data and observed outcomes into CARB's modeling work. *RFA and other stakeholders fully understand that CARB's GTAP modeling exercise is meant to isolate only the impacts of biofuels expansion on land use.* However, empirical data can be useful for checking the directional consistency and general reasonableness of model predictions. According to the Babcock & Iqbal, "…the historical record of land use changes can be used to provide insight into the types of land that were converted…"[6]

Comparing empirical land use data to GTAP predictions is particularly useful in regions where cropland has contracted over the past decade. That is, if cropland in a certain region *decreased* according to historical data, then there is no justification for asserting—as GTAP does—that biofuel expansion caused extensive margin conversion of natural forest and grassland in that region. In other words, if there was no cropland expansion resulting from biofuels expansion *and all other factors combined* (i.e., in aggregate), then there certainly is no rationale for arguing that biofuels expansion in isolation of other factors led to cropland expansion.

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

That is not to say, however, that biofuels expansion did not have an impact on land use in the region. Indeed, cropland may have contracted *even more* in a "world without biofuels" (i.e., the counterfactual case). In other words, some additional cropland might have gone out of production in the absence of biofuels, and the function of biofuels demand may have been to keep that cropland engaged in production. Thus, the appropriate question for regions that have experienced cropland *contraction* over the past decade is whether there was foregone sequestration because of biofuels—***not*** whether there was extensive conversion of forest and grassland and soil carbon loss because of biofuels. According to Babcock & Iqbal:

> The countries in Figure 8 that either had negligible or negative extensive land use changes **should be presumed to not have converted pasture or forest to crops in response to biofuel-induced higher prices**. Rather, the presumption should be that **any predicted change in land used in agriculture came from cropland that did not go out of production**.[7]

Figure 8 from Babcock & Iqbal is embedded below. Note that many countries and regions for which CARB's latest GTAP analysis predicts extensive change from forest and grassland to crops actually showed cropland losses or no change. This includes Canada, EU, Japan, China, India, Russia, the U.S., and Oceania. Further, the amount of corn ethanol-induced conversion of

[5] ISOR, Appendix I at I-20.
[6] Babcock, B.A. and Z. Iqbal (2014) at executive summary.
[7] *Id*. at 26.

forest and grassland in the U.S. predicted by CARB's GTAP model is two to four times larger than the actual extensive land use change in the U.S. driven by ***all factors in aggregate***.

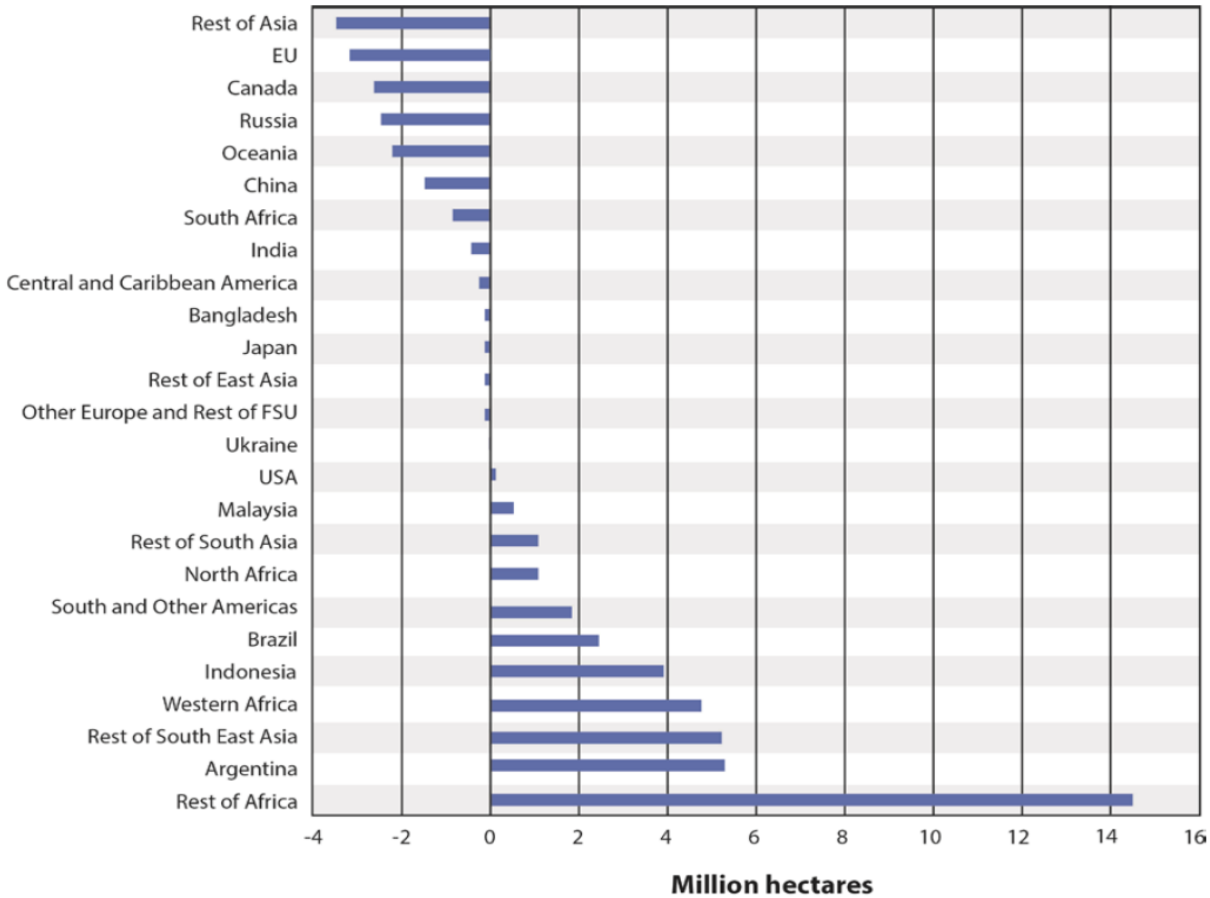


Figure 8. Change in Arable Land Plus Permanent Crops: 2004–2006 to 2010–2012

According to Babcock & Iqbal, the land use emissions implications in countries and regions where cropland decreased or stayed the same are that:

> …the type of land converted to accommodate biofuels was not forest or pastureland but rather **cropland that did not go out of production**. Calculation of foregone carbon sequestration depends on what would have happened to the cropland if it did not remain in crops which, in turn, depends on where the cropland is located and the potential alternative uses. **The magnitude of the change in estimated CO2 emissions from cropland that is prevented from going out of production relative to forest that is converted to cropland is potentially large.**[8]

Unfortunately, CARB's GTAP analysis suggests there was conversion of forest and grassland to crops in regions where real-world data show cropland actually contracted. The disagreement

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

[8] *Id.*

between GTAP predictions and real-world data highlights the implausibility of GTAP results for certain regions. CARB can—and should—correct its analysis to better align with real-world land use patterns. The following section provides a method for calibrating CARB's GTAP model to better reflect observed land use changes.

c. CARB should use data from Babcock & Iqbal (2014) to immediately calibrate its GTAP model to reflect real-world land use change patterns in key regions.

As stated in the Babcock & Iqbal paper, CARB should not presume that higher crop prices have caused conversion of forest and grassland to crops in countries and regions where cropland has actually decreased over the past 10 years. Thus, we believe CARB should calibrate its GTAP model to disallow forest and grassland conversion in AEZs and regions for which empirical data show forest or grassland expansion and/or cropland contraction. This can be easily accomplished by excluding GTAP predicted land conversions for the countries in Figure 8 of Babcock & Iqbal that show negative extensive change (i.e., loss of cropland). A more detailed method for accomplishing this calibration is available in comments submitted to CARB by Air Improvement Resource on Dec. 4, 2014.[9]

It could be argued that these countries should still be subject to emissions penalties for foregone sequestration, in that biofuels demand may have caused some cropland to remain in production that may otherwise have transitioned to some other use. But this should only be done if it can be demonstrated that the alternative use of the land would have resulted in carbon sequestration that is greater than the sequestration achieved if the land remained engaged in crop production.

For the countries in Figure 8 that *do* show extensive land use change over the past 10 years, CARB can continue to rely on GTAP predictions, but should also conduct more intensive research to better understand the precipitating causes of land conversions at the extensive margin in those countries. For example, while Sub-Saharan Africa (excluding South Africa) shows significant extensive change over the past decade, it is likely unrelated to biofuels expansion in the U.S. According to Babcock & Iqbal, "The extent to which extensive expansion in African countries was caused by high world prices is likely small for the simple reason that higher world prices were not transmitted to growers in many African countries."[10]

In the longer term, CARB should migrate to the soon-to-be-released dynamic version of GTAP that contains updated baseline economic data. Further, CARB should closely monitor efforts to validate and back-cast the new version of GTAP and be prepared to consider new results from these exercises.

d. CARB's GTAP Analysis Should Adopt CA-GREET2.0 Assumptions for Co-products Displacement Rates

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

[9] Air Improvement Resources comments available at: http://www.arb.ca.gov/fuels/lcfs/regamend14/air_12042014.pdf
[10] Babcock, B.A. and Z. Iqbal (2014) at 16.

The recently released CA-GREET2.0 model correctly assumes that distillers grains from ethanol production displace both corn and soybean meal in livestock and poultry rations.[11] The total mass of corn, soybean meal, and urea displaced by 1 pound of distiller grains is 1.111 pounds. While this assumption has modest impacts for the direct emissions associated with corn ethanol's lifecycle, the impacts on land use are significant. We have detailed these impacts in many previous comments to CARB, dating back to 2008.

Unfortunately, CARB's GTAP analysis continues to assume 1 pound of distillers grains displaces only 1 pound of corn. This is problematic for at least two reasons: 1) CARB's assumptions and boundary conditions for estimates of direct and indirect emissions should be consistent and uniform, 2) CARB's current GTAP assumptions on distillers grains displacement are simply inconsistent with the reality of how distillers grains are fed.

We are fully aware that there is no simple method for setting displacement ratios in GTAP, as interactions amongst the various sectors in the model are characterized in terms of economic values (e.g., expenditures, receipts, etc.). However, the economic values representing ethanol co-products in CARB's GTAP model are based on the 2004 database. Obviously, there have been significant changes in the distillers grains market since 2004; the ways in which these co-products are traded, priced, and fed have evolved dramatically. As we have discussed in previous comments to CARB, the agency can better reflect real-world feeding practices (i.e., some displacement of soybean meal) by adjusting the economic values associated with co-product trade in GTAP. RFA believes CARB must make this adjustment to ensure consistent boundaries and assumptions across its direct and indirect emissions analysis.

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

e. CARB <u>Still</u> Has Not Justified its Proposal to Use a Yield-Price Elasticity Value That is Lower than Recommended by Both Purdue and CARB's Own Expert Work Group. CARB Should Use 0.25 as the Central Value, Not the Proposed Value of 0.185.

Despite new data and published scientific papers supporting the use of a range for YPE of 0.14-0.53, CARB continues to propose using a range of 0.05-0.35. CARB staff has continued to ignore input from stakeholders, academia, and its own Expert Work Group on this parameter, instead relying on input from paid contractors at UC Davis and its own "expert judgment."

In Appendix I, CARB states that "[a]n expert from UC Davis, contracted to conduct a review and statistical analysis of data from a few published studies also concluded that YPE values were small to zero." Yet, it is quite clear from the brief (and somewhat unclear) report from the UC Davis contractor that the YPE response was examined only over the short term (i.e., 1-2 years).

This is inappropriate and scientifically indefensible, as demonstrated by previous stakeholder comments and remarks from Purdue University. For example, during the March 11 workshop on

[11] The latest version of CA-GREET2.0 is available at: http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm

ILUC, Purdue University Prof. Wally Tyner explained why it is inappropriate to include short-run estimates in the range used for CARB's analysis, stating:

> The yield-price elasticity is a *medium-term elasticity*…and we normally think of that as about 8 years. I personally think, and our group thinks, that any of those papers in the literature that represent one year are *totally irrelevant* to this. They may be fine for a one-year estimate, but a one-year estimate is totally irrelevant. Most of the short-term estimates are very low and most of the medium-term [estimates] were much higher—in the range of the 0.25 that we currently use.[12]

Tyner underscored this point again in a note to CARB following the March 11 workshop: "The yield to price elasticity does not measure changes over one crop year. In fact, ***any estimate done over one year would be totally inappropriate for GTAP and should be excluded from consideration in determining appropriate values for the parameter***."[13]

Babcock and other members of the Expert Work Group's Elasticity Subgroup agreed that the use of a short-run elasticity is inappropriate for the purposes of CARB's GTAP scenario runs:

> …to the extent that existing studies provide reliable one-year estimates, they underestimate the long-run response of yields to price. There are sound theoretical reasons for believing that there are lags in the response to higher crop prices. Farmers have an incentive to adopt higher-yielding seed technologies and other management techniques with higher prices. Switching from one seed variety or technology such as seed-planting populations, may require more than a single season to accomplish. And there are likely five to 15 year lags involved in developing new seed varieties and new management techniques that may be only profitable under high prices.[14]

The Schlenker work, which has served as the basis of CARB's use of inappropriately low YPE values, was critiqued by the EWG's Elasticities Subgroup. The subgroup raised several concerns with the Schlenker data, none of which (to our knowledge) have been adequately addressed by CARB staff. In short, the Elasticities Subgroup found that, "[t]he Roberts and Schlenker (2010) results provide ***no evidence that there is not a price-yield relationship***,

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

---

[12] Audio of Prof. Tyner comments are available at: http://domesticfuel.com/2014/03/12/carb-stresses-iluc-update-is-preliminary/. (emphasis added)

[13] See Appendix B of March 11, 2014 RFA comments, available at: http://www.arb.ca.gov/fuels/lcfs/regamend14/rfa_04092014.pdf. (emphasis added)

[14] ARB Expert Work Group. 2011. "Final Recommendations from the Elasticity Values Subgroup." Available at: http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/010511-final-rpt-elasticity.pdf

they just find evidence that any short-run price yield relationship is overwhelmed by variations in yields caused by weather."[15]

f. The GTAP model's inability to explicitly consider double-cropping further justifies the use of a higher range of price-yield elasticity values.

As explained by CARB's EWG, "…higher prices give farmers a greater incentive to double crop."[16] Indeed, Babcock & Iqbal adds to the body of empirical evidence that double-cropping has significantly increased during the recent period of higher commodity prices (see also Babcock & Carriquiry[17]). Unfortunately, GTAP simulations do not explicitly allow increased demand for agricultural commodities to be satisfied through increased double-cropping. <u>While we believe the best way to account for the impact of double-cropping is to calibrate the GTAP model to the Babcock & Iqbal data (as described in previous sections), and alternative method would be to raise the yield-price elasticity in regions where double-cropping is known to occur</u>.

The EWG Elasticities Subgroup recommended that the price-yield elasticity parameter could be used to partially account for double-cropping responses. In its final report, the subgroup explained that "the reality of double cropping" *by itself* justified the use of a positive (i.e., non-zero) value for the price-yield elasticity.[18] The subgroup recommended that "…for countries that have the opportunity to double crop, such as the U.S., Brazil, Argentina, and some Asian rice producing countries such as Thailand…an additional increment should be given to the price-yield elasticity."[19] To date, CARB staff has failed to account for increased double-cropping in its GTAP modeling scenarios. At a minimum, 0.25 should be used as an average value, and an additional increment of 0.1 should be added (total = 0.35) for regions where double-cropping is known to occur.

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

II. The New CA-GREET2.0 Model Marks a Major Improvement Over CA-GREET1.8b. However, Certain Improvements to CA-GREE2.0 Are Still Needed to Better Reflect the Direct Carbon Intensity of Ethanol Pathways

In general, RFA supports CARB's decision to revise and update its CA-GREET model based on the Argonne National Laboratory GREET1_2013 model. We believe Argonne's GREET1_2013 model contains a number of important improvements and updated inputs that more accurately reflect the current CI performance of corn ethanol and many other fuel pathways. Much has changed since CARB released the original CA-GREET model more than six years ago; ethanol and feedstock producers have rapidly adopted new technologies and practices that have significantly reduced the fuel's lifecycle CI impacts. Thus, it is encouraging to see the CA-

[15] *Id*. (emphasis added)
[16] *Id*.
[17] Babcock, B. A. and M. Carriquiry, 2010. "An Exploration of Certain Aspects of CARB's Approach to Modeling Indirect Land Use from Expanded Biodiesel Production." Center for Agricultural and Rural Development Iowa State University Staff Report 10-SR 105.
[18] ARB Expert Work Group. 2011. "Final Recommendations from the Elasticity Values Subgroup." Available at: http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/010511-final-rpt-elasticity.pdf
[19] *Id.*

GREET model finally catching up to the actual state of the industry. However, we believe the CA-GREET2.0 model could be further improved by adopting the recommendations below.

a. CARB Should Reduce Denaturant Content in Fuel Ethanol to 2.49% to Reflect Real-World Conditions

In order to comply with Federal requirements, ethanol producers limit the denaturant content of commercial fuel ethanol to 2.49% or less. GREET1_2013, upon which CA-GREET2.0 is based, appropriately assumes denaturant content is 2%. However, Appendix C to the ISOR specifies that CA-GREET2.0 assumes the non-ethanol content of denatured fuel ethanol is 5.4%, with 2.5% being denaturant, 1% being water, 0.5% being methanol, and 1.4% being "other." While denatured fuel ethanol does contain trace amounts of water (1% or less), methanol and "other" components are generally absent from the fuel or present in amounts below those specified by CARB. Further, CARB assumes that all non-ethanol constituents of denatured fuel ethanol—including <u>*water*</u> and "other"—have the same carbon intensity as CARBOB. This is an unsubstantiated and unfair assumption. CARB should fix the denaturant content at 2.49% and treat any remaining non-ethanol constituents (which would be mostly water) as having the same CI as the ethanol.

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

b. CARB Should Include the GREET1_2013 Default Value for Enteric Fermentation Impacts in the Corn Ethanol Pathway

For the CA-GREET2.0 model, CARB is proposing to exclude the GREET1_2013 credit for methane emissions reduction resulting from feeding DDGS. We strongly disagree with this proposal and CARB's rationale for the exclusion. We recommend that CARB adopt the GREET1_2013 methane emissions reduction credit for use in CA-GREET2.0.

CARB states that an "expanded system boundary" would be required for inclusion of methane emission reductions resulting from feeding DDGS to livestock. This implies that CARB views methane emissions reductions as a potential indirect or consequential effect. It could be argued that reduced methane emissions from livestock are a direct effect of corn ethanol expansion (via increased DDGS feeding). Nonetheless, even if we accept the argument that methane emission reductions are an *indirect* effect, CARB has no defensible reason for excluding these emission reductions. That is because CARB <u>*already has expanded the boundary conditions for its corn ethanol pathways to include consequential/indirect effects such as purported land use changes*</u>. CARB has also proposed to include indirect emissions associated with irrigation constraints, and at one point CARB was considering inclusion of hypothetical emissions that would indirectly result from "holding food consumption constant." Thus, CARB is proposing to include a number of potential indirect/consequential emissions sources in the corn ethanol lifecycle, but plans to selectively exclude potential emissions reductions (i.e., credits). This reflects inconsistent and asymmetrical boundary conditions (and possible bias) in CARB's analysis of corn ethanol emissions.

III. CARB's Compliance Scenario Assumptions Regarding the Availability of Sugarcane Ethanol and Related Credit Generation Seem Highly Implausible

CARB's new compliance scenarios continue to grossly over-estimate the amount of imported sugar-derived ethanol that is likely to be available to the U.S. and California marketplace in the future. As a result, CARB adopts an overly optimistic view of potential LCFS credit generation in the 2015-2020 timeframe.

In Appendix B, CARB states that its sugarcane ethanol estimate is derived from the Food and Agricultural Policy Research Institute's (FAPRI) World Agricultural Outlook. It should be noted that due to budget constraints, FAPRI has not produced a comprehensive World Agricultural Outlook report since 2011. It is unfathomable that CARB would rely on the 2011 FAPRI publication for its projections of sugarcane ethanol availability when more current projections are available from multiple sources.

Indeed, FAPRI itself continues to publish annual "Projections for Agricultural and Biofuel Markets."[20] These projections are published in March of every year. Much has changed in the Brazilian and world sugar and ethanol sectors since 2011, and FAPRI has since significantly revised its outlook for U.S. imports of sugarcane ethanol.

FAPRI's 2014 projections include yearly estimates of U.S. ethanol imports through 2023. FAPRI projects that U.S. ethanol imports will average **182 mg per year** in the 2015-2023 timeframe, with exports never exceeding 197 mg in any single year. *Importantly, these projections include the effects of the California Low Carbon Fuel Standard*. According to FAPRI:

- "Sugarcane ethanol imports from Brazil continue to decline in 2014 before leveling out."
- "Lower RFS requirements for advanced biofuel could imply reduced ethanol imports."
- "However, *low-carbon fuel requirements in California provide some incentive for continued ethanol imports*."

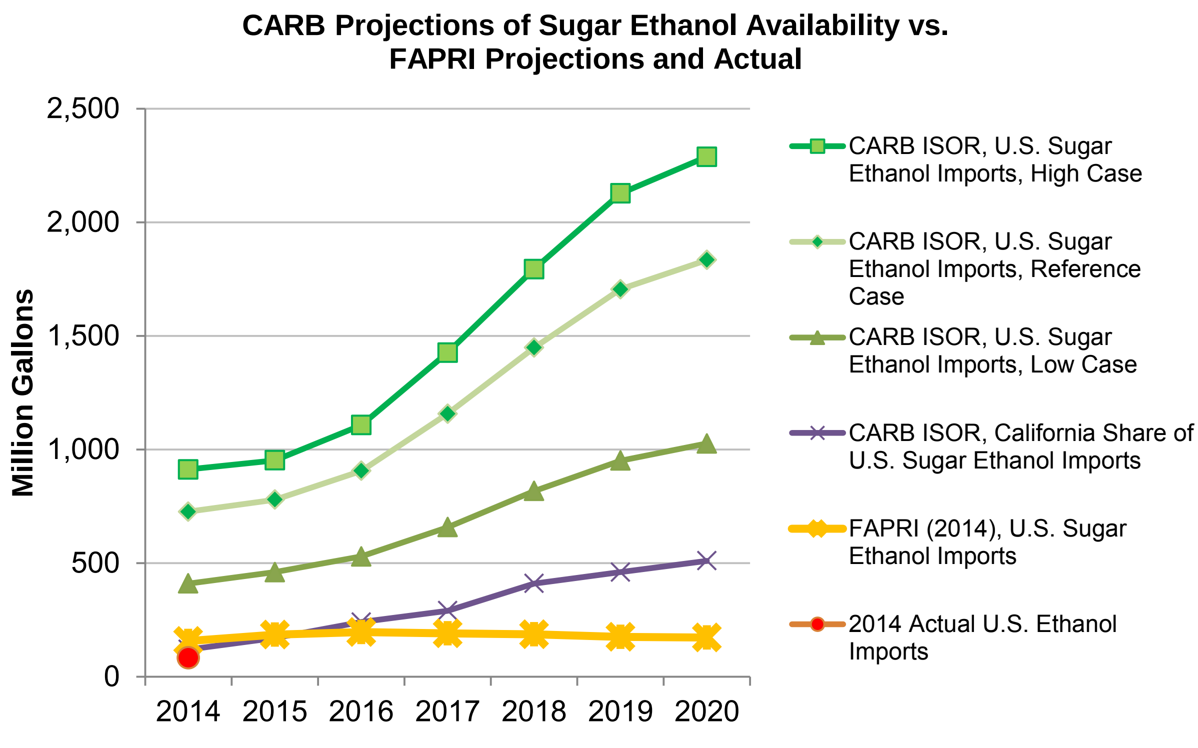
Thus, CARB's current 2020 projections (Appendix B reference, high and low cases) of sugarcane- and molasses-based ethanol are roughly 6-13 times higher than FAPRI's current outlook, which *do* take into the account the likely "pull" from the LCFS. Further, total ethanol imports to the entire United States (most of which were sugar-derived) were just 84 million gallons in 2014, compared to CARB's compliance scenario assumption of 410-912 million gallons. In fact, CARB's projection that California would receive 120 million gallons of sugar-related ethanol in 2014 is 42% larger than actual imports to the entire U.S. Of the 84 million gallons imported by the U.S., only 7.96 million gallons—or 9.5% of the U.S. total—entered through California ports. Thus, actual California imports in 2014 were equivalent to just 6.6% of the volume anticipated by CARB.

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

[20] 2014 FAPRI Baseline available here: http://www.fapri.missouri.edu/outreach/publications/2014/FAPRI_MU_Report_02_14.pdf

Similarly, CARB's projection that California will receive 510 million gallons of sugar-derived ethanol in 2020 compares to FAPRI's projection that the entire U.S. will receive only 172 million gallons of sugar ethanol that year.

CARB has suggested that higher LCFS credit values could lure larger volumes of sugar ethanol to California than projected by FAPRI. However, empirical data from the past four years show no discernible relationship between credit values and sugarcane ethanol imports to California.[21] It is also worth noting that Brazil is soon increasing its ethanol blend rate, which will further reduce the amount of sugarcane ethanol that is available to export.



We strongly recommend that CARB refine its estimates of sugar-related ethanol and use FAPRI's latest projections of sugarcane ethanol availability when conducting its analysis of potential fuel availability.

* * * * *

Thank you for considering RFA's comments on the ISOR for the re-adoption of the LCFS. We would be pleased to address any questions you may have regarding the contents of these comments or any other issues related to ethanol's role in the LCFS.

Reproduction of Comment Letter 8_OP_LCFS_RFA Comments LCFS 8-1 through LCFS 8-14

[21] See analysis of sugarcane ethanol import response to LCFS credit prices at: http://www.ethanolrfa.org/exchange/entry/the-california-lcfs-and-sugarcane-ethanol-wheres-the-flood/

APPENDIX A:

Babcock, B.A. and Z. Iqbal (2014), Using Recent Land Use Changes to Validate Land Use Change Models. Center for Agricultural and Rural Development Iowa State University Staff Report 14-SR 109.

Using Recent Land Use Changes to Validate Land Use Change Models

Bruce A. Babcock and Zabid Iqbal

Staff Report 14-SR 109

Center for Agricultural and Rural Development
Iowa State University
Ames, Iowa 50011-1070
www.card.iastate.edu

Bruce A. Babcock is Cargill Chair of Energy Economics, Department of Economics, Iowa State University, 468H Heady Hall, Ames, IA 50011. *E-mail*: *babcock@iastate.edu.*

Zabid Iqbal is a graduate research assistant, Department of Economics, Iowa State University, 571 Heady Hall, Ames, IA 50011. E-mail: zabid@iastate.edu.

This publication is available online on the CARD website: *www.card.iastate.edu*. Permission is granted to reproduce this information with appropriate attribution to the author and the Center for Agricultural and Rural Development, Iowa State University, Ames, Iowa 50011-1070.

The authors gratefully acknowledge research support provided to Iowa State University by the Renewable Fuels Foundation and the Bioindustry Industry Center.

For questions or comments about the contents of this paper, please contact Bruce A. Babcock, *babcock@iastate.edu.*

Iowa State University does not discriminate on the basis of race, color, age, ethnicity, religion, national origin, pregnancy, sexual orientation, gender identity, genetic information, sex, marital status, disability, or status as a U.S. veteran. Inquiries can be directed to the Interim Assistant Director of Equal Opportunity and Compliance, 3280 Beardshear Hall, (515) 294-7612.

Executive Summary

Economics models used by California, the Environmental Protection Agency, and the EU Commission all predict significant emissions from conversion of land from forest and pasture to cropland in response to increased biofuel production. The models attribute all supply response not captured by increased crop yields to land use conversion on the extensive margin. The dramatic increase in agricultural commodity prices since the mid-2000s seems ideally suited to test the reliability of these models by comparing actual land use changes that have occurred since the price increase to model predictions. Country-level data from FAOSTAT were used to measure land use changes. To smooth annual variations, changes in land use were measured as the change in average use across 2004 to 2006 compared to average use across 2010 to 2012. Separate measurements were made of changes in land use at the extensive margin, which involves bringing new land into agriculture, and changes in land use at the intensive margin, which includes increased double cropping, a reduction in unharvested land, a reduction in fallow land, and a reduction in temporary or mowed pasture. Changes in yield per harvested hectare were not considered in this study. Significant findings include:

- In most countries harvested area is a poor indicator of extensive land use.
- Most of the change in extensive land use change occurred in African countries. Most of the extensive land use change in African countries cannot be attributed to higher world prices because transmission of world price changes to most rural African markets is quite low.
- Outside of African countries, 15 times more land use change occurred at the intensive margin than at the extensive margin. Economic models used to measure land use change do not capture intensive margin land use changes so they will tend to overstate land use change at the extensive margin and resulting emissions.
- Non-African countries with significant extensive land use changes include Argentina, Indonesia, Brazil, and other Southeast Asian countries.
- Given the lack of a definitive counterfactual, it is not possible to judge the consistency of model predictions of land use to what actually happened in each country. Some indirect findings are that model predictions of land use change in Brazil are too high relative to other South American countries; and model predictions of increasing extensive land use that are larger than what actually occurred are consistent with actual land use changes only if cropland was kept from going out of production rather than being converted from forest or pasture.

The contribution of this study is to confirm that the primary land use change response of the world's farmers from 2004 to 2012 has been to use available land resources more efficiently rather than to expand the amount of land brought into production. This finding is not necessarily new and it is consistent with the literature that shows the value of waiting before investing in land conversion projects; however, this finding has not been recognized by regulators who calculate indirect land use. Our conclusion that intensification of agricultural production has dominated supply response in most of the world does not rely on higher yields in terms of production per hectare harvested. Any increase in yields in response to higher prices would be an additional intensive response.

Using Recent Land Use Changes to Validate Land Use Change Models

In the mid-2000s prices for major agricultural commodities began a long, sustained increase. Prices increased dramatically due to growth in demand for food and biofuel producers, underinvestment in agricultural infrastructure and technology, and poor growing conditions in major producing regions. Figure 1 shows the percent change in inflation-adjusted prices received by US producers for corn, soybeans, wheat, and rice relative to the previous five-year average.[1] The predominance of negative changes shows that since 1960 average real prices for these commodities have dropped. These figures show that the commodity price boom in the early 1970s resulted in the largest increase in real prices, but the recent increase in prices since 2006 resulted in the longest sustained increase, especially for corn and soybeans. For wheat and rice, real prices increased sharply in the mid-2000s and have stayed high even though the year-over-year increases were not as long lasting as for corn and soybeans. The magnitude of these real price increases after such a prolonged and sustained period of flat or falling prices presents a unique opportunity to quantify how world agriculture responds to incentives to produce more.

The United States, California, and the EU have enacted regulations based in part on model predictions of agricultural supply response to price increases induced by increased biofuel production. The model predictions of land use changes are called indirect land use changes because the predicted changes are due to a modeled response to higher market prices rather than a direct response to the need to grow more feedstock for biofuel production. Thus, for example, the corn used to produce corn ethanol in the United States was met by US corn production; however, the diversion of corn from other uses increased corn prices and crop prices of other commodities that compete with corn for market share and land. Because corn and other commodities are traded on world markets, prices in other countries also increase. The response in the US and in other countries to these higher prices is what the models measure.

[1] Prices are average annual prices received by US farmers adjusted by the US CPI.

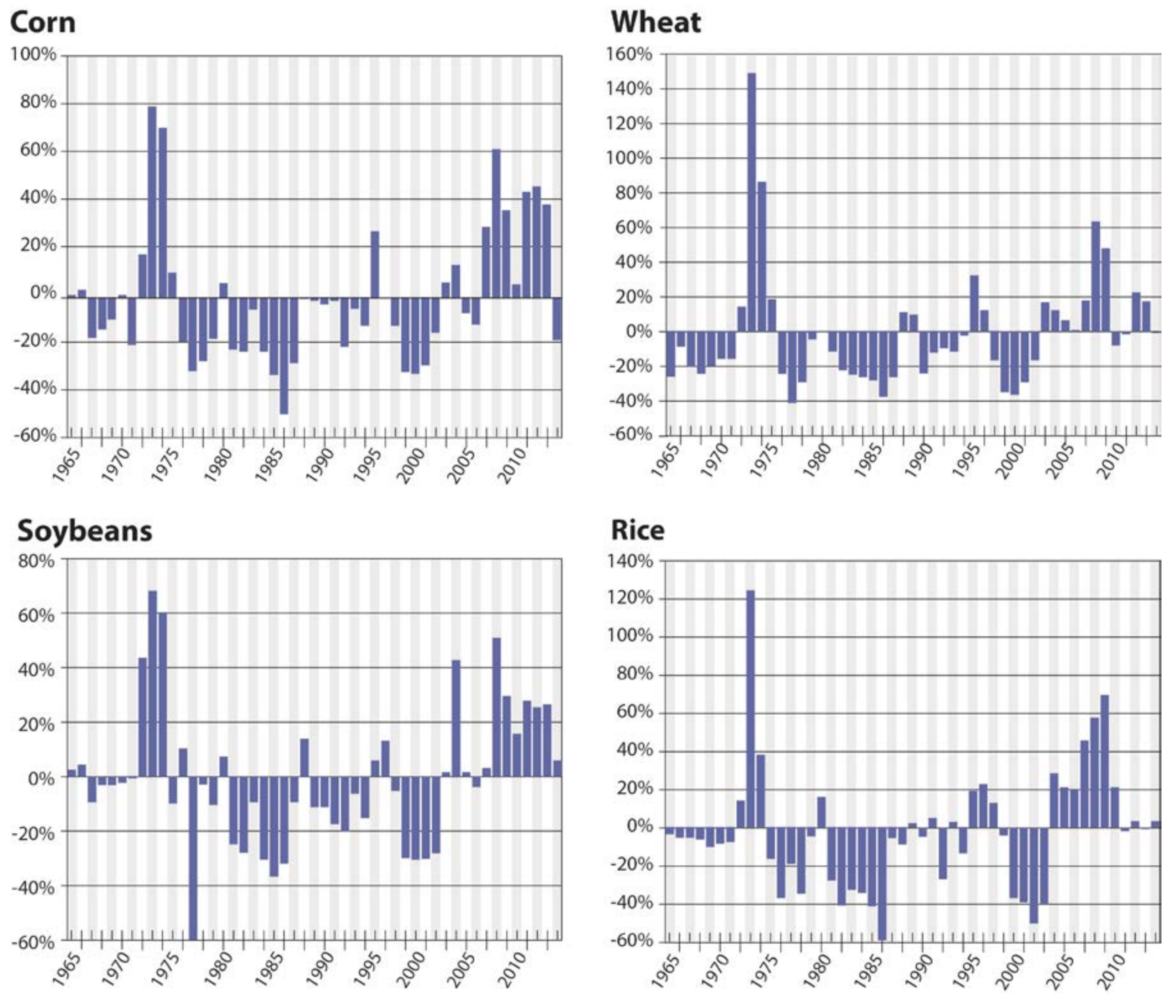


Figure 1. Deviations in Real US Commodity Price Levels from Lagged Five-Year Average Measuring World Land Use Changes

Some portion of the higher prices since the mid-2000s was caused by increased biofuel production. For example, Fabiosa and Babcock (2011) estimate that 36% of the corn price increase from 2006 to 2009 was due to expanded ethanol production. Carter, Rausser, and Smith (2010) estimate that 34% of the corn price increase between 2006 and 2012 was due to the US corn ethanol mandate. This implies that a portion of the actual response of land use since this price increase is due to US ethanol production. Other factors such as crop shortfalls and other sources of increased demand account for the rest of the price increase.

Because indirect land use is a response to higher market prices, model predictions of land use change should be similar whether the higher prices came from increased biofuel production, increased world demand for beef, or from a drought that decreased supply in one or more major producing areas. This implies that the pattern of actual land use changes that we have seen since the mid-2000s should be useful to determine the reliability and accuracy of the models that have been used to measure indirect land use. The purpose of this paper is to look at what has happened over approximately the last 10 years in terms of land use changes and to determine whether and how these historical changes can provide insight into the reliability of model-predicted changes in land use. We address the following questions in this paper:

- How has cropland changed around the world in approximately the last 10 years?
- What were the major drivers of observed land use changes?
- When can actual land use changes be compared with model predictions?
- What can be said about the types of land that were actually converted?

How Has Harvested Area Changed Since 2004?

The most complete source of data on annual cropland is from the Statistics Division of FAO (FAOSTAT), which measures annual harvested area by crop and country. These data have been widely used to measure the impact of biofuel production on expansion of land used in agriculture (Roberts and Schlenker 2013) and to calibrate the land cover change parameter in the GTAP model (Taheripour and Tyner 2013). Figure 2 shows the change in harvested land according to FAO. The data are smoothed by calculating the change in harvested area as the average in 2010, 2011, and 2012 minus the average in 2004, 2005, and 2006. The earlier period measures harvested area before the large increase in price. The later period represents harvested area after prices had increased substantially. India, China, Africa, Indonesia and Brazil had the largest increase in harvested land. These data seem to suggest that these countries had the largest increase in land conversion; however, harvested land is not equal to planted land. Harvested land will deviate from planted land when a portion of planted land is not harvested and when a portion of land is double or triple cropped.

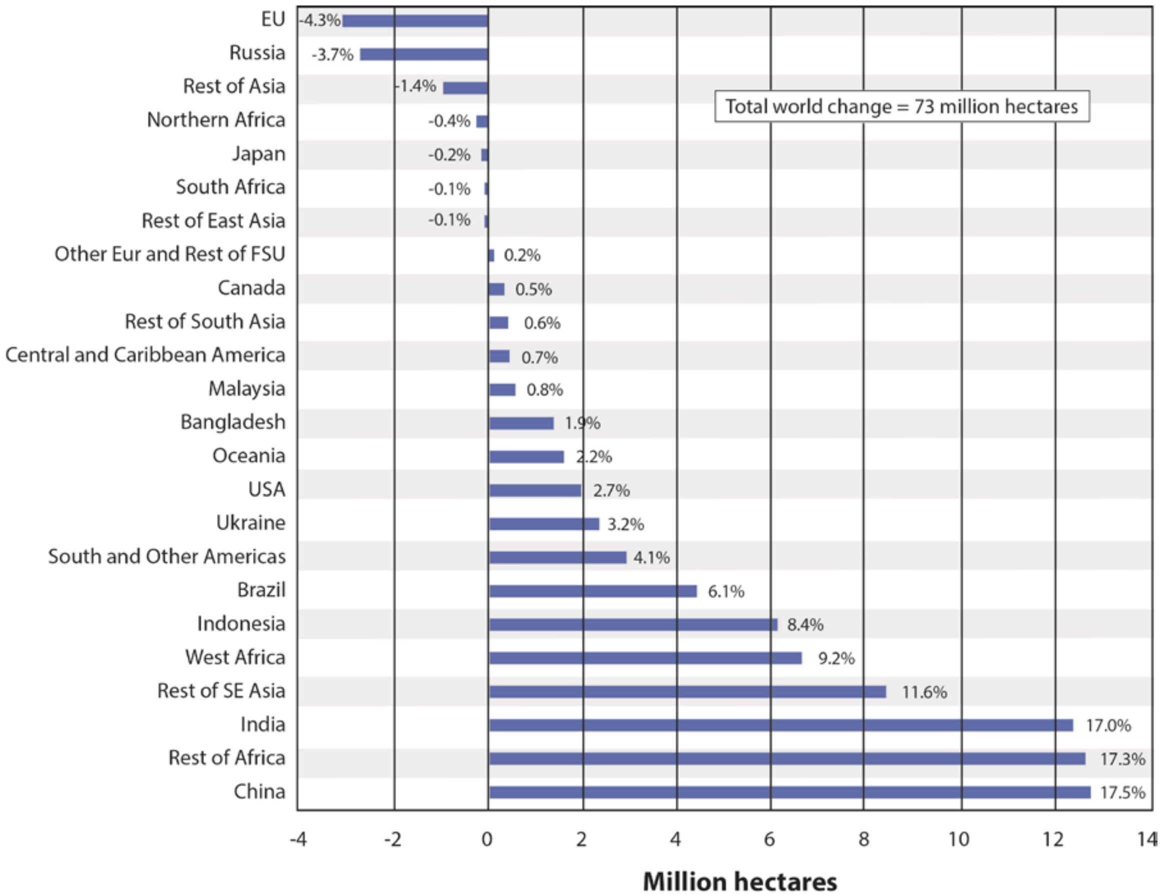


Figure 2. Change in Harvested Land 2010–2012 Average Minus 2004–2006 Average and Country's Share of Total World Change
Source: FAOSTAT

Suppose that a portion of land that is planted to a first crop is not harvested and that a portion of first crop land that is harvested in a country is double-cropped, which simply means that a second crop is planted on land that was already planted to a crop in the same year.[2] By definition, total harvested land, H, equals total harvested land from the first crop, H_1, plus total harvested land from the second crop, H_2. Total harvested land from the first crop equals total land planted to the first crop, P_1 minus land that was planted but not harvested, a_1. Thus we have in any year t

$$P_{1,t} = H_t - H_{2,t} + a_{1,t}$$

[2] Throughout this article land the phrase double crop should be interpreted as two or more crops being grown on a single parcel of land.

For the purpose of greenhouse gas emissions from land use changes, it is most relevant to calculate the change in planted area between two time periods $t = T$ and $t = 0$. Thus, we have

$$P_{1,\mathrm{T}} - P_{1,0} = (H_T - H_0) - (\mathrm{H}_{2,\mathrm{T}} - H_{2,0}) + (a_{1,\mathrm{T}} - a_{1,0})$$

If second crop acreage has increased over time, then use of FAO data on total harvested land overstates land use change by this amount. If the change in first crop land that is not harvested also increases over time, then at least some portion of this upward bias in measuring land use change is overcome. If, instead, the amount of unharvested land has decreased over time then the upward bias is increased. A more in-depth examination of data available for a few countries gives insight into the extent to which use of FAO harvested area data provides a good indication of land use changes.

United States

Figure 3 illustrates that reliance on harvested area as an indicator of land use change can lead to a large bias, and shows annual changes in harvested and planted land to corn in

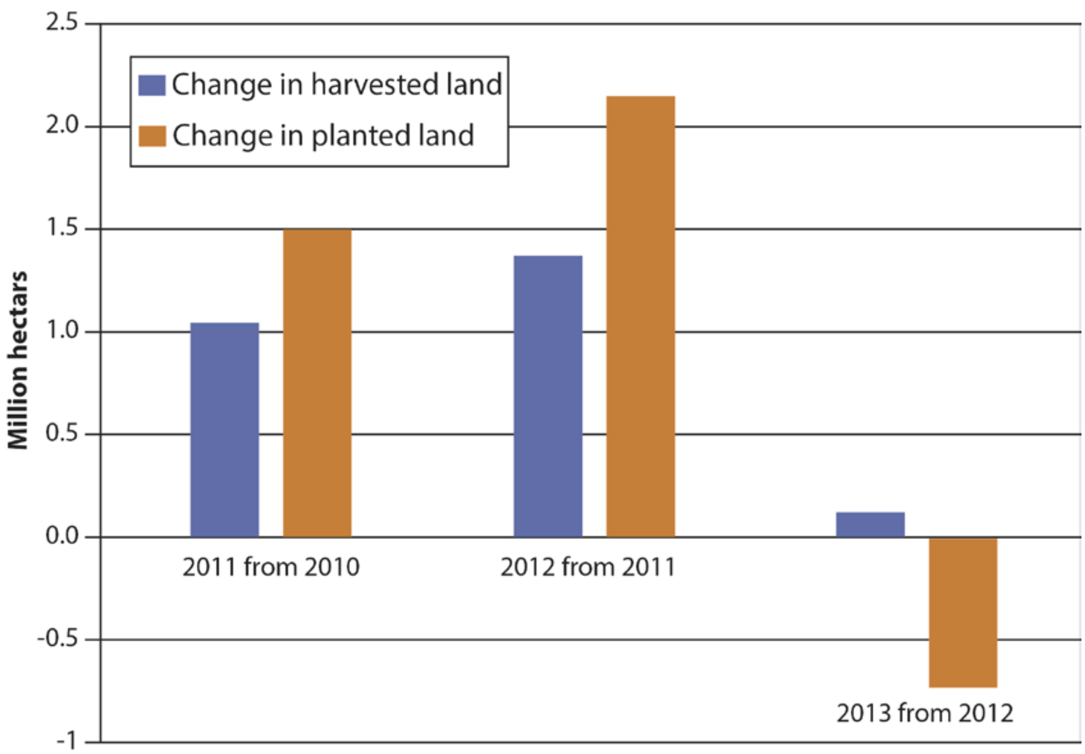


Figure 3. Annual Change in Harvested and Planted Corn Land in the United States

the United States from 2011 to 2013. A widespread drought in the United States resulted in an increase in the amount of planted land that was not harvested. Thus in 2012, use of harvested land to measure land use change understates land use change, whereas in 2013, it overstates land use change. Taking average changes over some time period will reduce the impact of an outlier like 2012, but it will not eliminate it. Thus, use of 2012 harvested data in the United States will tend to understate land use change relative to an earlier period and overstate it relative to a later period. Because data on US planted land is available from USDA's National Agricultural Statistics Service, it makes much more sense to use these data rather than FAO harvested land data.

Brazil

Brazil is another country that collects data on both harvested and planted land.[3] In addition, Brazil collects data on land that is double cropped. Figure 4 shows total harvested land and total harvested land from double cropped land. The axes have been set to the same scale to show that a large proportion of the increase in Brazilian harvested land is a result of increased double cropping. The change in total harvested land from 2004–2012 is 5.4

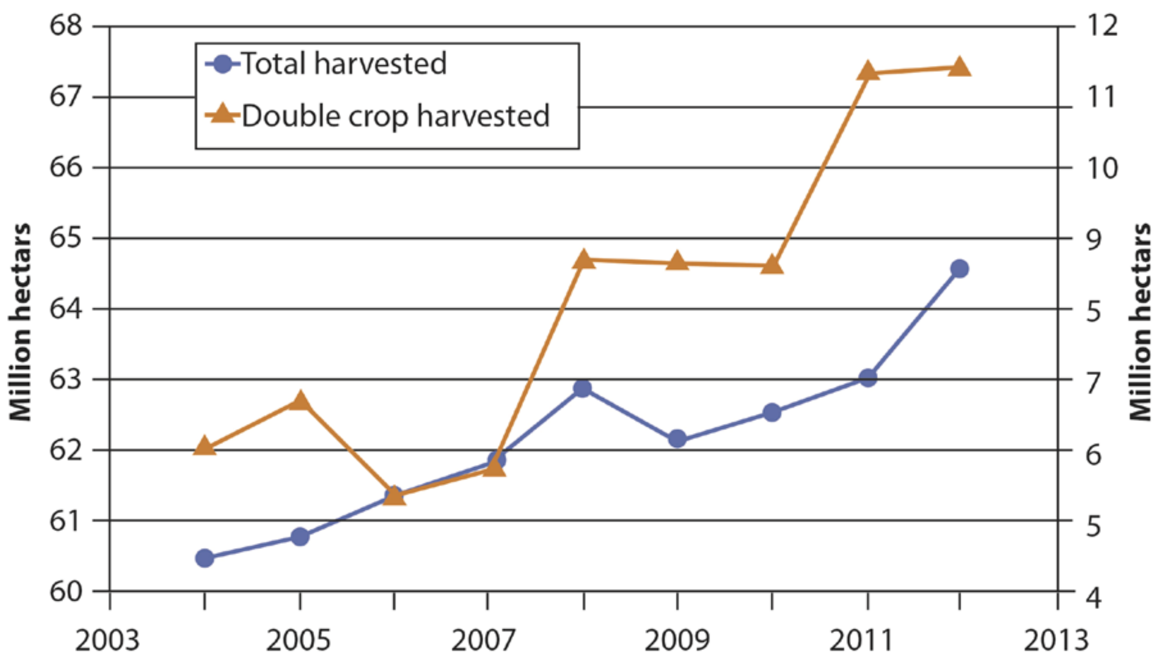


Figure 4. Brazil Harvested Land Data

[3]Brazilian IBGE data is available at http://www.sidra.ibge.gov.br/bda/pesquisas/pam/default.asp?o=27&i=P

million hectares. The change in double cropped land is 4.1 million hectares. Thus, more efficient use of land accounts for 76% of the change in harvested land in Figure 4.

India

Figure 2 shows that India increased harvested area by 6.8% from 2004–2006 to 2010–2012 which is 12.4 million hectares. Given India's long agricultural history it seems unlikely that so much land would be suitable for conversion to crops in such a relatively short time. India collects data on both planted and harvested land as well as double cropped land (India Ministry of Agriculture). Figure 5 shows that the variation in multiple crop area explains most of the variation in total planted area, which includes double cropped area. Subtracting double cropped area from total planted area shows that net planted area decreased by 147,000 hectares between 2004–2006 and 2010–2012. What then accounts for the increase in harvested area? Figure 6 shows that the proportion of planted area that is harvested has increased dramatically over this time period. An examination of previous years' data shows that the wide gap between planted and harvested

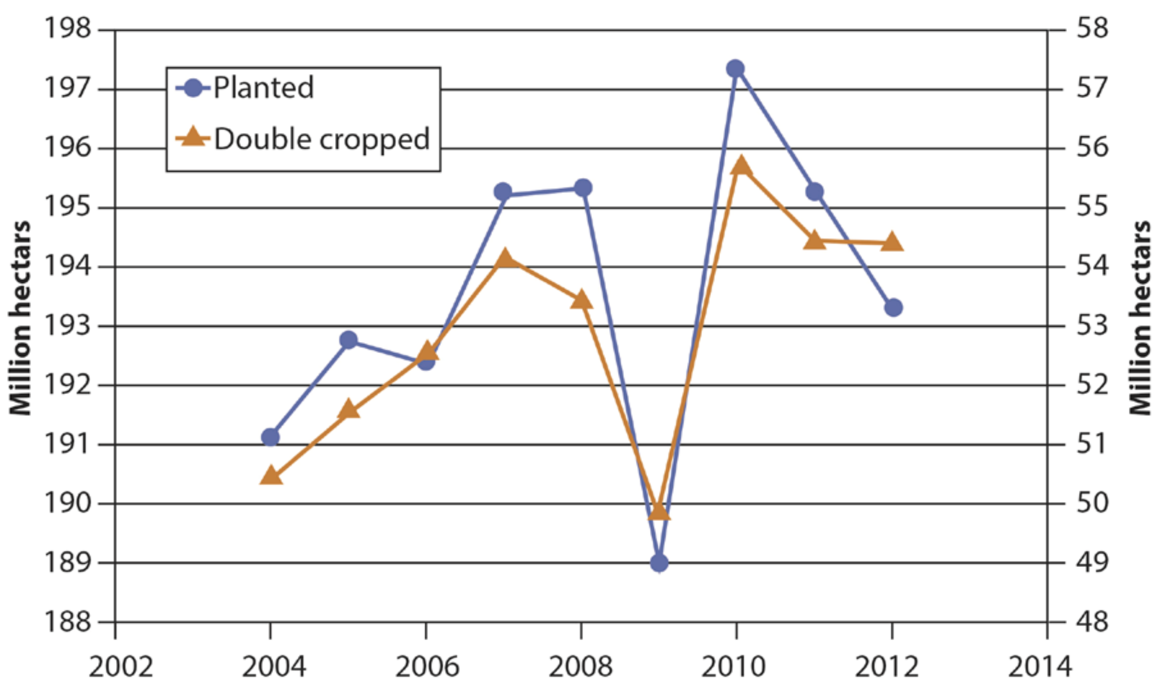


Figure 5. Total Planted and Multiple Crop Area in India

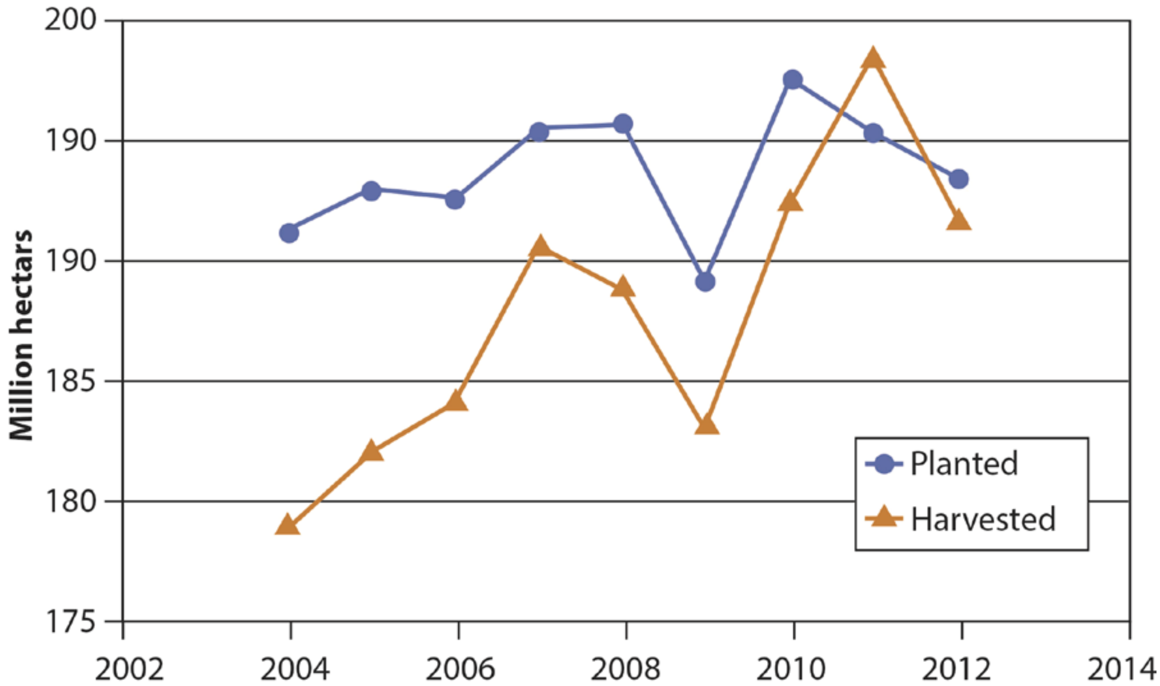


Figure 6. Total Planted and Harvested Area in India

area shown in Figure 6 from 2004 to 2006 was typical. For example, the 2004–2006 gap averages 10.6 million hectares, and the gap from 1992 to 2000 averages 10.4 million hectares. The average gap in 2010 and 2012 is 3.4 million hectares. Thus, an increase in double cropped area accounts for about 3.5 million hectares of the increase in harvested area, and a decrease in non-harvested area accounts for another 7 million hectares. Thus, all of the increase is harvested area is accounted for by intensification of land use. One reason why non-harvested area has increased so much is the 6 million hectare increase in irrigated area from 2004 to 2011. More irrigation allows a greater proportion of planted area to grow to maturity, thereby making it worth harvesting. In addition, India increased support prices and input subsidies in the mid-2000s to combat stagnant growth in the agricultural sector. These actions, combined with the expansion of irrigation, increased the opportunity cost of not harvesting land.

China

FAO harvested area data shows an increase of 8% from 160 million hectares to 173 million hectares from 2004–2006 to 2010–2012. Figure 2 in Cui and Kattumuri (2012) shows that total cultivated land in China dropped from about 130 to about 122 million hectares from 1996 to 2008. The four reasons cited for the loss of agricultural land are urbanization, natural disasters, ecological restoration, and agricultural structural adjustment, with restoration and urbanization accounting for about 80% of losses. Cui and Kattumuri (2012) claim that the loss of agricultural land slowed down in 2004 and 2005 only because of "…stringent land protection policies" (p. 14). Based on this conclusion, it seems that economic forces in China were trying to reduce cultivated land, not increase it, in the mid-2000s. If correct, then it seems highly unlikely that a significant portion of the increase in harvested area was caused by an increase in the amount of land cultivated. If both FAO harvested area data and data used by Cui and Kattumuri (2012) are correct, then at least 38 million hectares of harvested area came from double cropped land in 2004–2006 and 51 million hectares of harvested area came from double cropped areas in 2010–2012.

Sub-Saharan African Countries

Figure 2 shows that sub-Saharan African countries have been large contributors to increases in harvested land. With some exceptions, much of African crop production is carried out by small-scale producers without use of modern technologies. While differences exist between countries, typically most production is consumed domestically and most commercial trade occurs between adjoining African countries (Minot 2010). Sub-Saharan African countries account for 34 of the top 50 countries in the UN data base in terms of population growth rates in 2010.[4] The average population growth rates for these 34 countries in 2010 was 2.93%. Leliveld et al. (2013) show that food production in Tanzania has just about matched population growth and that almost all of the food production increase has been due to an increase in the amount of land planted. Although it is possible to plant more than one crop in many African countries by developing shorter-season varieties and better management (Ajeigle et al. 2010), a lack of access to technology and capital is one defining characteristic of traditional agriculture in sub-Saharan Africa, so there is no evidence that double cropping is widely adopted. Thus, the change in harvested land shown in Figure 2 for African countries is likely a better measure of the change in planted land than in other countries.

[4] Population growth rates are available at http://data.worldbank.org/indicator/SP.POP.GROW/countries?display=default

Indonesia

Figure 7 shows the change in area harvested from 2004–2006 to 2010–2012 for the top eight crops and for all other crops in Indonesia according to FAOSTAT. As shown most of the expansion has occurred in rice and palm oil fruit. Because perennial crops do not generally produce more than one crop per year, the extent to which FAO harvested land data overstates the change in planted land is limited. Adding the change in harvested land of palm, rubber, coffee, coconuts, and cocoa together accounts for 54% of the change in harvested area. According to USDA-FAS (2012) the availability of suitable rice-growing land is severely restricted in Indonesia. Most of the increase in harvested rice area that has been achieved has come about from investment in irrigation facilities that allow two or three crops of rice to be planted on the same land rather than a single crop. The extent to which intensification explains the 1.4 million hectare increase in rice harvested area shown in Indonesia cannot be determined by harvested area data alone. However, given that Indonesia is one of the world's most densely populated countries, and 1.4 million hectares represents a 12% increase in harvested production, it is unlikely that a significant portion of this 1.4 million hectares is new land. According to USDA-FAS (2012) about

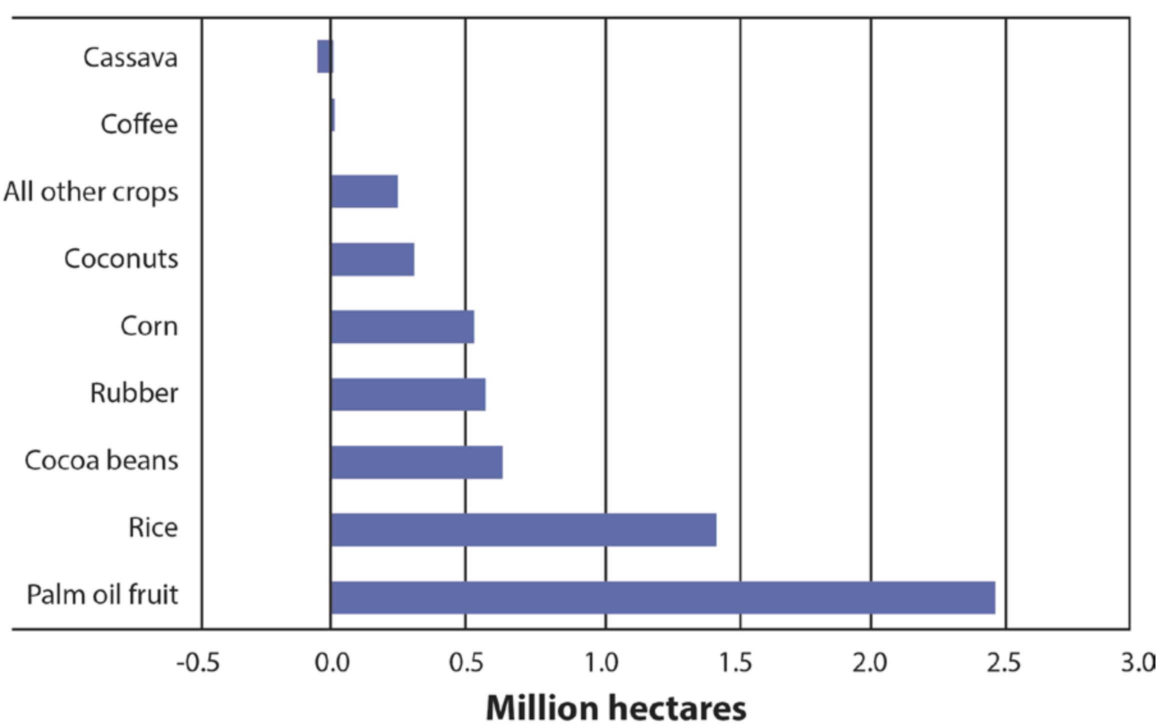


Figure 7. Change in Harvested Area by Crop for Indonesia as Reported by FAO

50% of Indonesian rice area grew rice in both the rainy and dry seasons in 2011, which implies that there is significant room for harvested area growth with greater irrigation. Thus it is likely that most of the increased rice area in Indonesia is accounted for by increased double and triple cropping.

Swastika et al. (2004) explain that most corn production in Indonesia is grown on land that produces two crops. Corn is typically grown with tobacco, cassava, another corn crop, or sometimes with rice. Given land constraints in Indonesia and the significant expansion of palm oil production, which has been accomplished by converting forestland and cropland (Susanti and Burgers 2013; Koh and Wilcove 2008), it is likely that a significant portion of the corn production increase came about by increasing double cropped area.

An Alternative Measure of Land Use Change

Use of harvested area to measure land use change can lead to a large bias in estimates of how much land has been converted to crops from other uses. While this may be an obvious point, it is too often missed in analysis of land use changes. Reliable country-specific data, such as in the United States, that can measure the change in net planted area should be used when available. Where it is not available, land cover data can be used. For global coverage FAOSTAT data on arable land and land planted to permanent crops are available. The FAO definition of arable land is "the land under temporary agricultural crops (multiple-cropped areas are counted only once), temporary meadows for mowing or pasture, land under market and kitchen gardens, and land temporarily fallow (less than five years). The abandoned land resulting from shifting cultivation is not included in this category."[5] This definition is different than the common meaning of arable land—land that is capable of producing a crop rather than land that is actually in crop production. Adding FAO's measure of arable land to land that is in permanent crop provides a measure of land use that is appropriate to use in determining the amount of new land that has been brought into production. Figure 8 reproduces Figure 2 using this measure with the exception of the United States, for which USDA's NASS planted area data is used. For the United States, total planted area of principal field crops minus double crop area is

[5] http://faostat.fao.org/site/375/default.aspx

used instead of FAOSTAT data because FAOSTAT reports a 9 million hectare loss in total cropland because of a sharp reduction in temporary pasture.

The implications of Figure 8 are strikingly different than Figure 2. Furthermore the Figure 8 data is much more consistent with the country-specific data in China, India, Brazil, Indonesia, and Africa. Figure 8 data suggest that the net change in global cropland over this period is 24 million hectares. African countries increased cropland by 20 million hectares. Other countries with more than a million-hectare increase include Argentina, Indonesia, Brazil, Rest of Southeast Asia, Rest of South Asia, and South and Other Americas. Countries with significant reductions in cropland include the EU, Canada, China, Russia, and South Africa.

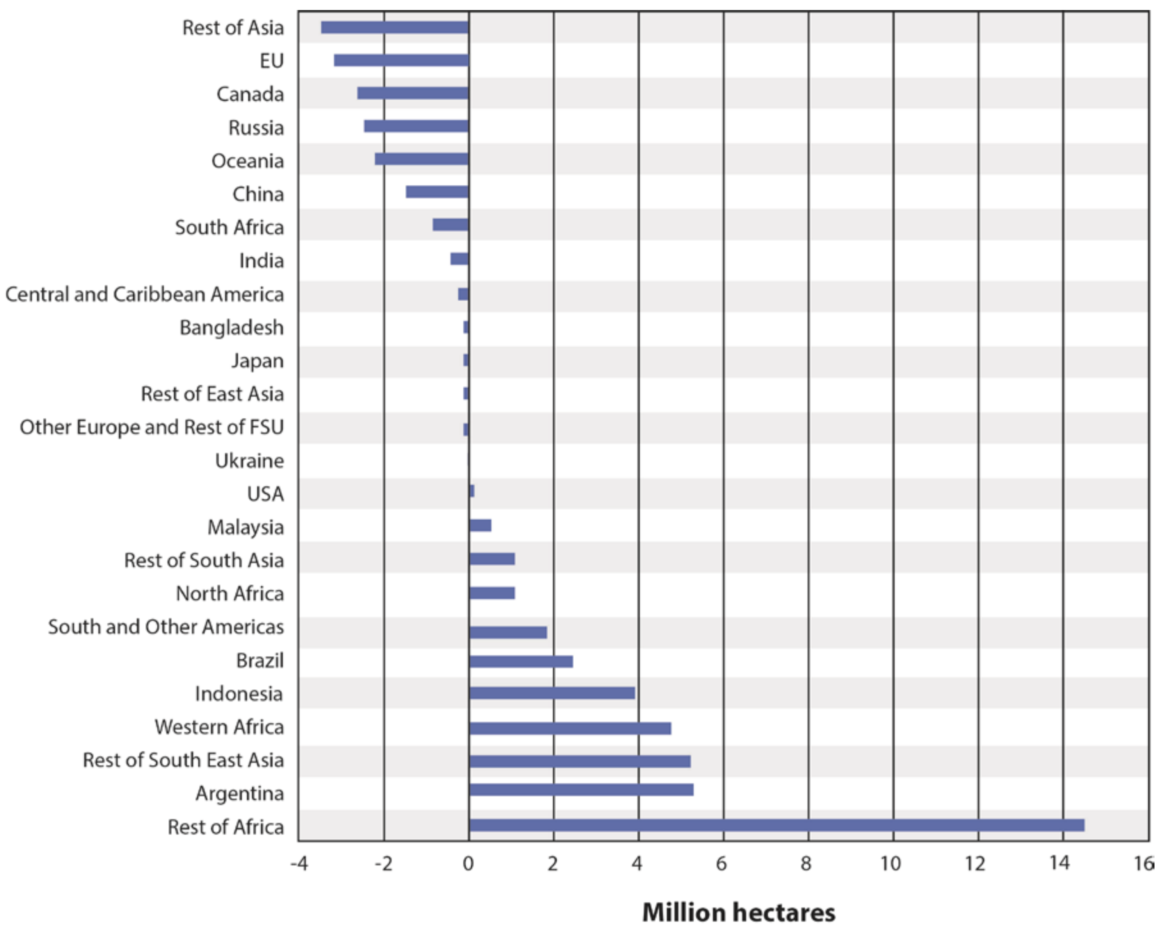


Figure 8. Change in Arable Land Plus Permanent Crops: 2004–2006 to 2010–2012

The data in Figures 2 and 8 can be used to determine the relative importance of land use changes at the intensive and extensive margin. Intensive margin changes are changes in double cropped area and a reduction in land that is available to plant but that is not harvested. The total change in harvested area in Figure 2 is the sum of extensive changes and intensive changes to land use. Thus, intensive changes equal the total change in harvested area from Figure 2 minus the changes in cropland given in Figure 8.[6] Both intensive and extensive changes are shown in Figure 9. Countries are sorted from the left according to their level of extensive acreage changes.

Most of the change in land use in African countries and Argentina is at the extensive margin. Most or all of the response in the developed world, India, China, South Africa, and the rest of Asia is at the intensive margin. The response in Indonesia and Brazil is mixed.

Major Drivers of Recent Land Use Changes

Broadly speaking, the land use changes shown in Figure 9 are consistent with a model of the world in which countries that have available land to convert to agriculture will have relatively more extensive land use change than countries that have long histories of agricultural development and limitations on available land. Thus, one major driver of recent land use changes is the availability of land to convert to agriculture. Most developed countries, along with China and India, have little land available, however, countries in Africa and South America have abundant land resources. There are striking differences, however, in land use indicated by Figure 9 that must be due to other drivers.

Growing demand for soybean imports was a major driver of land use decisions in Argentina, Brazil and the United States. The increased demand for soybeans resulted mainly from China's decision to meet its domestic needs for soybeans through imports rather than domestic production. This decision freed up resources in China to devote to production of other commodities and led to much higher soybean area in Argentina, Brazil, and the United States. Higher demand for high-protein foods in China and other developing countries increased the demand for soybean meal.

[6]One other use of this measure as an indicator of the amount of land that is used in agriculture is OECD-FAO (2014) when total agricultural land is discussed.

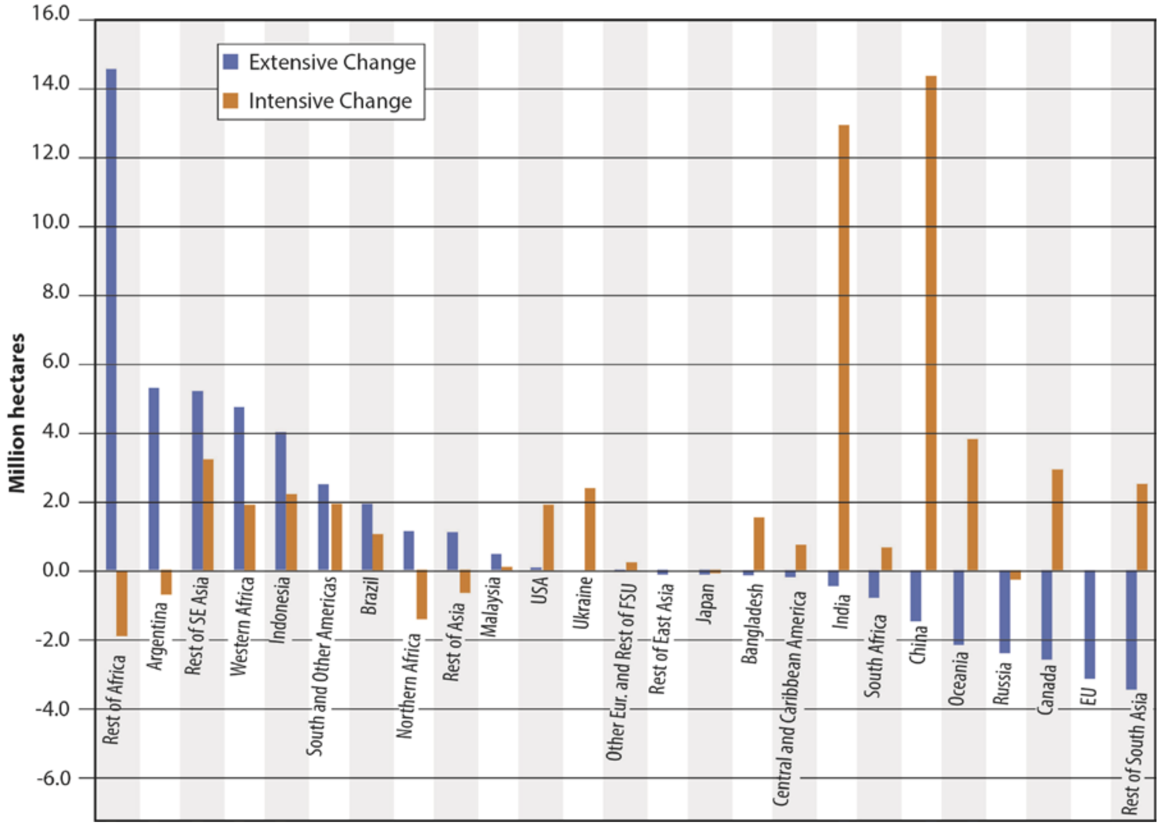


Figure 9. Extensive and Intensive Land Use Changes: 2004–2006 to 2010–2012

Increased demand for vegetable oils for food production, cooking, and biodiesel increased the demand for soybean oil.

Brazil responded to this increased soybean demand by expanding soybean area, however, a second crop of corn was planted on a good portion of expanded soybean acreage. This expansion in double cropping reduced the amount of corn area planted to the first crop of corn. Thus, Brazil expanded at both the extensive and intensive land use margins.

Argentina also expanded soybean area, but it did so at the extensive margin rather than by intensifying land use. The prime soybean production areas in Argentina are farther south than in Brazil, which shortens the time period available for double cropping. However, a second crop of soybeans can be planted in Argentina after winter wheat is harvested in December. One explanation for a lack of intensification is that Argentine area planted to wheat has declined from about 6 million hectares in 2005 to 3.6 million hectares in 2012. This decline simply means that there is less land available for double cropping soybeans after wheat. Therefore, if soybean area needs to increase, less wheat land means less land available for double cropping, thus, soybean first crop area by definition must increase. The decline in wheat area has been mainly driven by government policy interventions in the form of export taxes and export subsidies that were implemented in a way that favored soybeans over corn and wheat (Nogues 2011). This suggests that government policy is what caused a lack of an intensive land use response in Argentina, in contrast to the significant intensive response shown in Figure 9 in Brazil and other South American countries.

As discussed, Indonesian expansion of palm production was accomplished at least in part at the extensive margin. This expansion resulted from increased investment drawn to the industry due to higher profit margins caused by higher prices and higher yields. The higher prices resulted from an overall increase in demand for vegetable oil, driven by increased demand for food production, cooking oil, biodiesel, and other uses. The data show that Indonesian expansion of rice and corn harvested area was done at the intensive margin because the area devoted to perennial crops in Figure 7 is greater than the total extensive expansion shown in Figure 9.

Sugarcane and soybeans account for nearly all of the land expansion in Brazil. Increased sugarcane production was used to meet growing demand for sugar and to meet growing domestic demand for ethanol. The number of flex vehicles in Brazil grew by 20 million from 2005 to 2012. If all of these vehicles used ethanol, Brazilian consumption of ethanol in 2012 would have exceeded 24 billion liters just from these vehicles, and additional consumption would have come from the 15 million gasoline vehicles in Brazil. Actual consumption in Brazil was about 18 billion liters.[7] These figures demonstrate that the growth in sugarcane area was primarily driven by the Brazilian government policy that increased the sales of flex vehicles in Brazil. The expansion in Brazilian soybean area was driven by increased world demand for soybean imports, which was mainly driven by China, as previously discussed. The ability to plant a second crop of corn after soybean due to adoption of shorter-season soybeans and agronomic advances reduced the amount of new land that was needed to accommodate this expansion.

[7] All figures on Brazilian vehicle numbers and ethanol consumption were obtained from UNICA: http://www.unicadata.com.br/?idioma=2

In China, India, and most of the developed world, agricultural land resources are limited. Limited land resources means that expansion at the extensive margin is costly relative to expansion at the intensive margin. Thus, we see a large response in both China and India at the intensive margin rather than the extensive margin. Cui and Kattumuri (2012) argue that Chinese intensification would have been even greater but for the government policy objective of maintaining a minimum of 120 million hectares of land in agriculture. India's intensification was facilitated by government investment in irrigation facilities and price subsidies that increased agricultural profitability (OECO-FAO 2014).

The lack of a large extensive response in Ukraine, Russia, and other FSU countries is somewhat surprising given the availability of land. The lack of response at the extensive margin could be due to a lack of investment in the agricultural sectors of these countries.

How much of the changes in land use shown in Figure 9 can be attributed to high commodity prices cannot be known precisely without observing an alternative history in which the run-up in commodity prices did not occur. Economic theory suggests that some portion of the changes in Figure 9 came about because of high prices in those countries where high world prices were transmitted to farmers. However, some of the changes in land use would have occurred even if prices had remained constant at their 2004–2006 levels.

The extent to which extensive expansion in African countries was caused by high world prices is likely small for the simple reason that higher world prices were not transmitted to growers in many African countries. Minot (2010) concludes that domestic grain prices in Tanzania bear little relationship to world prices. In a more complete study, Minot (2011) studies price transmission in multiple markets in Ethiopia, Ghana, Uganda, Zambia, Mozambique, Tanzania, Kenya, South Africa, and Malawi. Of the 62 markets studied, he found that only 13 showed a statistically significant long-run relationship with world prices. He found some evidence of a linkage in large urban centers and in coastal markets, which is consistent with markets in cities and in coastal ports being more integrated with world markets. However, given his overall findings, these limited linkages to world prices did not find their way through to rural areas where most crops are grown. With such weak evidence supporting price transmission to rural areas one can conclude that the main driver of land expansion in many African countries was not higher world prices.

Empirical Measures of Land Use Changes

Aggregating land use changes across all countries, the aggregate world extensive change was a net increase of 24 million hectares from 2004–2006 to 2010–2012. The aggregate world intensive land use change was 49.1 million hectares. Thus, across all countries, more intensive use of existing land was double the change from more extensive use of land. Outside of African countries, the aggregate intensive change in land use was almost 15 times as large as extensive changes. This wide disparity between more intensive use of land and more extensive use means that the reliability of current models used to estimate indirect would be dramatically increased if they were modified to account for non-yield intensification of land use.

The recent historical changes in land use can provide some guidance about the effect of dramatically higher prices on land use change over an eight-year period. An estimate of the amount of extensive land use change that can be attributed to higher commodity prices can be made under fairly restrictive assumptions.

First is assuming that land use change at the extensive margin due to high prices is zero in those countries or regions in Figure 9 that had negative extensive changes. This assumption implies that the forces that caused countries to lose agricultural land during this time would have caused the same amount of loss even without the high prices. Clearly, it would seem that at least some land in these countries was kept in production from the high prices, so this assumption understates land use change at the extensive margin. From a greenhouse gas perspective, this assumption is equivalent to saying that the net amount of carbon sequestration that would have occurred on land that was kept in production by high prices in these countries is negligible.

Second is assuming that all the extensive margin changes in Figure 9 in countries and regions that have positive changes are due to high world prices. This too is an extreme assumption because some land would have been brought into production even if commodity prices had not increased. Thus this assumption overstates the response of land use at the extensive margin.

If we include extensive changes in Africa, then world extensive land use changes equals 41.2 million hectares, which represents a 2.68% increase over the average level of land in production in 2004–2006. If we assume that the extensive land use changes in

Africa were primarily caused by internal domestic food demand from growing populations and income, and they would have occurred even without high world commodity prices, then the extensive land use increase equals 20.7 million hectares or 1.35%.

It is instructive here to make a rough estimate of the response of the world extensive margin to aggregate higher commodity prices. The average real prices of corn, soybeans, wheat, and rice received by US farmers increased by 123%, 85%, 59%, and 47% respectively in 2010–2012 relative to 2004–2006. A simple average of these price increases is 78%. With this real price increase, the elasticity of the world extensive margin is 0.034 if African extensive response is included, and 0.017 if the African extensive response is not included.

Similarly, if the intensive response in countries and regions where the response is negative is set to zero, then the aggregate intensive response to high prices is 49.1 million hectares if we attribute all the intensive response to higher prices. Without the African country response, the aggregate response is 47.2 million hectares. The resulting elasticities of intensive response are 0.041 and 0.039. Thus, if we attribute all the African extensive land use changes to high prices, then the world intensive elasticity is 19% higher than the extensive elasticity. If none of the African response is attributed to higher prices than the non-African intensive elasticity is almost three times as great as the extensive response.

These rough estimates demonstrate that the primary land use change response of the world's farmers in the last 10 years has been to use available land resources more efficiently rather than to expand the amount of land brought into production. This finding is not new and is consistent with the literature that finds significant option value in waiting to convert land (Song et al. 2011). OECD-FAO (2009) recognized that intensive land use change has been the driving force behind higher production levels, however, this finding has not been recognized by regulators who calculate indirect land use. Note that our measure of more efficient land use does not include higher yields in terms of production per hectare harvested. Any increase in yields would be an additional intensive response. Rather the intensive response measured here is due to increased multiple cropped area, a reduction in unharvested planted area, a reduction in fallow land, and a reduction in temporary pasture. Because greenhouse gas emissions associated with an intensive response are much lower than emissions caused by land conversions (Burney, Davis, and Lobell 2010), ignoring this intensive response overstates estimates of emissions associated with land use change because most of the land use change that has occurred is at the intensive rather than extensive margin.

Comparison of Actual Land Use Changes with Model Predictions

Model predictions of land use change from increased biofuel production are conceptually appealing. This is because the effects of higher biofuel production on land use are measured in isolation—the effects of everything else that influences agriculture are held constant. Thus, the effects of biofuel production alone can, at least conceptually, be measured. The way that the models assume increased production impacts land use is through higher prices. Thus, if the actual changes in land use in Figure 9 were the result of a response to the large increase in commodity prices that actually occurred, then it seems reasonable to compare model predictions to the actual changes that occurred. However reasonable this seems, we simply do not know with certainty what land use changes would have occurred without the increase in commodity prices. What needs to be compared to model predictions is the difference in land use with the commodity price increase relative to what it would have been without the commodity price increase.

What information then can be gleaned from a comparison of model predictions with actual changes? At one extreme, if none of the observed changes in extensive land use were the result of high prices, then we know that indirect land use is not empirically important because land use changes are caused by other forces. At the other extreme, if extensive land use would have stayed constant at base period levels if prices had not increased then all of the observed changes resulted from high prices. In this case it would be valid to judge the accuracy of model predictions with observed changes, because both would be caused by price responses. Reality likely falls somewhere in between these two extremes in that land use in 2012 would have been different than in 2004 even without the price increase, and that at least some portion of the observed changes we see can be attributed to higher prices. Taheripour and Tyner (2013) use observed land use changes as a guide to selection of a key model parameter in GTAP in an attempt to reconcile model predictions with observed changes. Hence, they assume that observed changes in land use are a useful guide to determine how the GTAP model should predict how land use changes in response to a change in commodity prices.

The two most widely used international models used in the United States to predict land use changes associated with increased biofuel production are GTAP and FAPRI (Gohin 2014). Both models allowed crop yields to respond to higher prices, and neither model allowed land use intensity, as measured here, to increase. Given that the primary way that non-African countries have increased effective agricultural land was through intensification, both models have an upward bias in their predictions of land use change at the extensive margin in non-African countries.[8]

Figure 10 shows the predicted increases in cropland from the FAPRI model that was used by the Environmental Protection Agency to determine greenhouse gas emissions

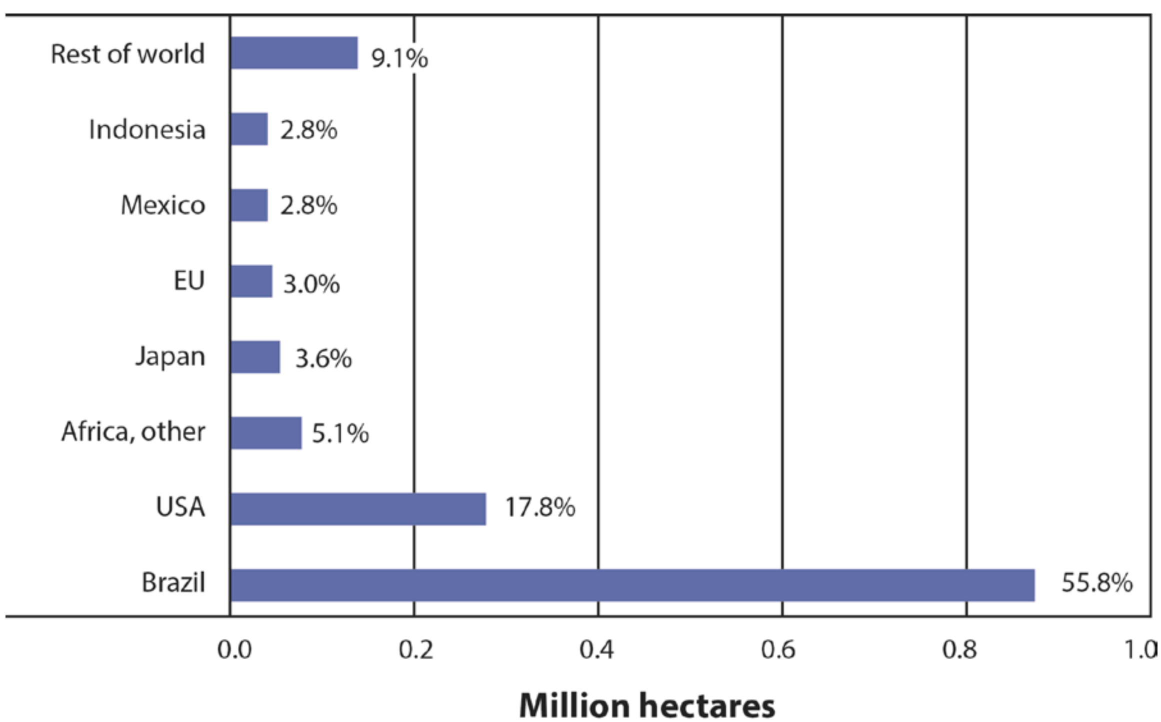


Figure 10. Predicted Land Use Change in EPA "All Biofuel" Scenario: Hectares and Share of World Total

[8] One way that production per unit of agricultural land can increase in the GTAP model is through its yield elasticity, therefore at least some of the upward bias in GTAP's prediction of extensive land use changes is offset by using a yield elasticity value that is higher than can be supported empirically.

associated with land use changes from increased biofuels. What is illustrated is the difference between EPA's "Control Case" that includes levels of biofuels in the RFS and EPA's "AEO Reference Case," which contains lower levels of biofuels (EPA 2010). This scenario simulated increases in many different biofuels including biodiesel made from vegetable oil and waste greases, corn ethanol, sugarcane ethanol, and cellulosic ethanol. How these land use changes were calculated is that the FAPRI predictions of land use in the AEO Reference Case were subtracted from the predictions in the Control Case. The total predicted world change in land use is 1.45 million hectares.

What is striking about Figure 10 is the concentration of predicted land use change in Brazil and the United States. These two countries account for almost 75% of the total predicted change in land use, with Brazil alone accounting for more than half of all change in the world at the extensive margin. In the AEO Reference Case total cropland in Brazil is increasing, thus the predicted increase in area must come from conversion of land that would have been devoted to other uses.

The first valid comparison that can be made between the CARD-FAPRI model prediction and what actually occurred is that the predicted land use change in Brazil due to higher prices is far too high relative to land use changes that actually occurred at the extensive margin in Argentina and other South American countries. As shown in Figure 9 Argentina and other South American countries together increased land use at the extensive margin by almost four times as much as did Brazil. The CARD-FAPRI model results used by EPA predicted almost no land use change in Argentina and other South American countries due to higher prices. It is notable that the CARD-FAPRI model predicted that growth in Brazil cropland from 2002 to 2009 would be about 9.1 million hectares, whereas Argentina's growth would be 3.7 million hectares in the Reference Case. Thus, the larger increase in agricultural area in Argentina that actually occurred cannot be attributed to the model being right about predicting a larger baseline increase in Argentina than in Brazil. The first conclusion one can draw from this comparison is that the CARD-FAPRI model dramatically over-predicted land use change in Brazil relative to Argentina and other South American countries.

The CARD-FAPRI prediction that the United States would account for about 18% of the world's increase in extensive land use seems inconsistent with the large changes that occurred in African countries and Argentina. The only way that the US land use prediction is consistent with the historical record is if cropland in the United States would have dropped by a large amount in the absence of the large price increase. The CARD-FAPRI model predicted that US crop area would decline in both the Reference and Control Cases.

The CARD-FAPRI model includes some South African production and a limited number of other crops in a limited number of African countries. The CARD-FAPRI model implicitly assumes that most of African agricultural production of major crops is isolated from world markets. As discussed above if this isolation is in fact a correct characterization of African agriculture, then the large land use changes in African countries shown in Figure 9 would have occurred even without the high commodity prices. The only other conclusion that can be drawn regarding African countries is that the CARD-FAPRI model underpredicts land use changes there to the extent that land use in African countries responded to world prices.

The commodity price increases that led to the Figure 10 predicted changes in land use were a 3.1% increase in corn prices and a 0.8% increase in soybean prices. These simulated price changes are dwarfed by the actual price changes that have occurred as shown in Figure 1. The FAPRI model prediction of a small increase in extensive land use in Japan and the EU due to small changes in price seems inconsistent with the fact that land use in Japan has been largely unchanged over the last 10 years and the EU has experienced a decline in land use. Again, it is not possible to know the extent to which a small increase in world commodity prices would have kept a small amount of land in production in the EU.

The small model-predicted change in Indonesia in extensive land use is generally consistent with observed changes if we assume that no changes would have occurred except for the higher market prices that actually occurred and not from government development priorities.

Figure 11 shows predicted land use changes by the GTAP model. [9] GTAP predicts that 38% of land use changes occur in the United States. As discussed, although

[9] GTAP model predictions of land use changes associated with biofuels vary across publications. Figure 11 land use change predictions were taken from Hertel et al. (2009) which were published about the same time that California's Air Resources Board was making their determination of greenhouse gas emissions from land use change that relied on GTAP model predictions. For the purposes of this paper, we assume that the

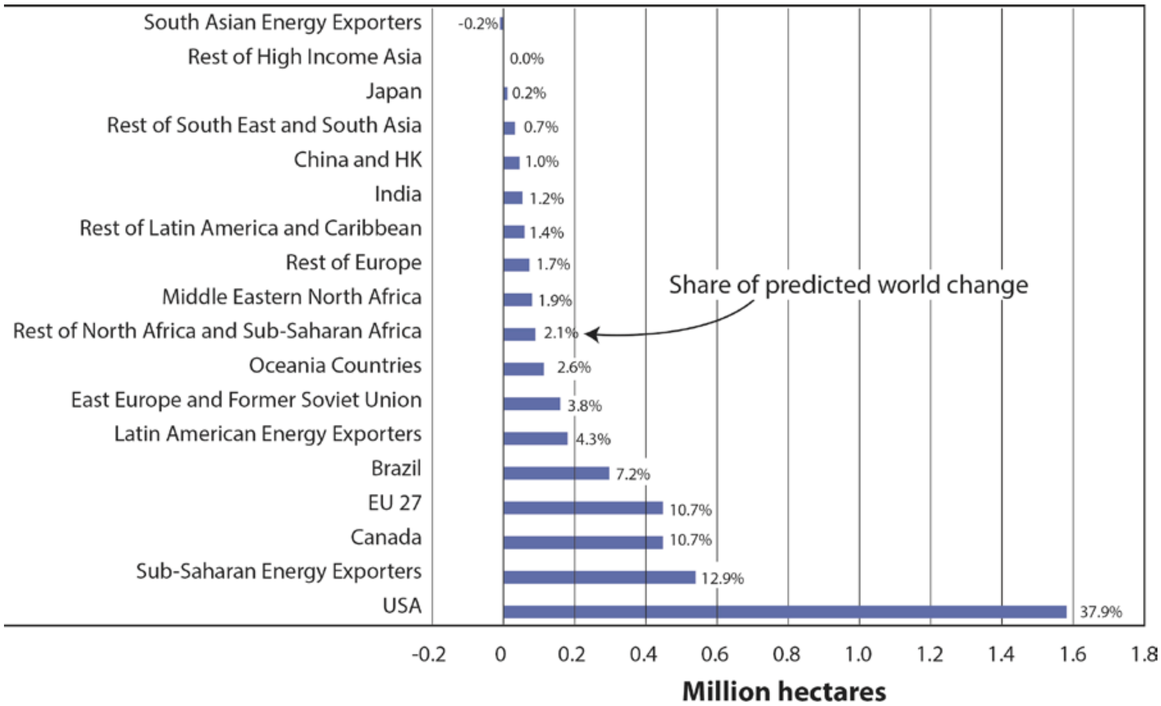


Figure 11. GTAP Predictions of Indirect Land Use Change from Corn Ethanol
Source: Hertel et al. (2009)

this seems like a large over-prediction of the US contribution, it is not possible to say this prediction is inconsistent with the recent historical data given that we cannot observe what land use would have been without the price increase. However, for this prediction to be true, the fairly small price increase simulated by GTAP would have kept a sizeable amount of land in production in the United States.

As with the CARD-FAPRI model, GTAP over-predicts the land use change for Brazil relative to other Latin American countries assuming that the baseline in Hertel et al. (2009) shows Brazil's area increasing more than agricultural area in the rest of Latin America. This baseline level of data was not available for inspection but GTAP's baseline was developed using 2001 data that incorporates land use changes that occurred in previous years. Brazil's agricultural land was expanding in this prior period, so it is reasonable to assume that Brazil's land use in the baseline was increasing more than in

Figure 11 land use changes are consistent with those used by California. There exist many GTAP-based estimates of land use change due to biofuels. An alternative estimate was provided by Tyner (2010). First and Second Generation Biofuels: Economic and Policy Issues, Presented at the Third Berkeley Bioeconomy Conference, June 24, 2010, http://www.berkeleybioeconomy.com/wpcontent/uploads//2010/07/TYner%20Berkeley%20June%202010.pdf.

other South American countries. This would imply that the predicted change in Brazil relative to the rest of Latin America is too large.

Despite the large discrepancies between model predictions and the actual land use changes that have occurred since 2004 it simply is not possible to conclude with certainty that the model predictions have been proven wrong and should be disregarded. For example, the Hertel et al. (2009) prediction that large land use changes from output price increases resulting from US corn ethanol production would occur in the United States, Europe, and Canada seems inconsistent with the fact that cultivated land decreased in the EU and Canada and stayed constant in the United States despite price changes that were many times larger than those predicted by the model. However, it could be that the amount of actual land reduction that would have occurred in the EU and Canada would have been much larger without the commodity price boom and that if actual land use changes were calculated relative to what would have happened without the price impact then the GTAP model predictions would be consistent with what we observe. Thus, without being able to observe the alternative history that did not contain the commodity price boom, it is not possible to conclude with certainty that the model predictions are wrong. As Babcock (2009) pointed out, economists who run models to predict future land use changes are in the enviable position that skeptics of the predictions will find it difficult to use the actual land use change data to prove that the model predictions were wrong. However the historical record of land use changes can be used to provide insight into the types of land that were converted assuming that the model predictions are correct.

Using the Historical Record to Guide Estimates of Land Conversion

Table 1 below presents some GTAP results that were used by California's Air Resources Board to calculate CO_2 emissions associated with land conversion due to corn ethanol production. By regressing emissions on the amount of land converted, it is possible to obtain a rough estimate of how each of the four land conversions affect estimated emissions separately. Table 2 provides the regression results.

An increase in land conversion increases GTAP's estimates of emissions. Conversion of a million hectares of forest increases emissions much more than conversion of pasture. How to interpret these coefficients is that a one million hectare increase in, for

Table 1. GTAP Model Predictions of Land Conversion and Associated GHG Emissions

	Forest Converted		Pasture Converted		
Scenario	U.S.	ROW[a]	U.S.	ROW	LUC Emissions
		million hectares			*gCO_2e/MJ*
A	0.70	0.34	1.04	1.96	33.6
B	0.36	0.01	0.79	1.53	18.3
C	0.82	0.64	1.19	2.83	44.3
D	0.81	0.08	1.31	2.34	35.3
E	0.48	0.52	0.66	1.35	27.1
F	0.46	0.27	1.00	2.10	27.4
G	0.40	0.15	0.92	2.18	24.1

Source: Provided by staff at the Renewable Fuels Association
[a]ROW means Rest of World

Table 2. Impact on CO_2 Emissions of a Million Hectare Increase in Land Conversion

Land Type Converted	Impact on Emissions
	gCO_2e/MJ
US Pasture	6.17
ROW Pasture	3.08
US Forest	22.69
ROW Forest	14.41

Source: Estimated from Table 1.

example, US pasture to crops, leads to a 6.17 increase in emissions measured by grams CO_2 per MJ of gasoline energy replaced by corn ethanol. Across all seven scenarios the average prediction of forest conversion in the United States is 0.58 million hectares.

Multiplying 0.58 by 22.69, which is the coefficient relating conversion of forest to emissions, results in an estimate of the average contribution of US forest conversion to the final CO_2 emission number. The result is that GTAP estimates that conversion of US forests contributes 13.06 gCO_2/MJ or 43% of total estimated emissions.

As shown in Figure 8, US cropland did not appreciably increase at the extensive margin in response to higher prices on average in 2010–2012 relative to 2004–2006.[10] As

[10] A more detailed examination of US data is provided in the next section, which shows there is some evidence of an increase in planned area to be planted from 2007 to 2013. The 2004–2006 and 2010–2012 time periods were used to make US data consistent with available data for other countries.

discussed in the previous section, it is not possible to conclude whether the GTAP model prediction that US cropland would be 1.6 million hectares higher due to higher prices is inconsistent with what actually happened, because it could be that US cropland would have declined from 2004 to 2012 if the higher prices had not occurred. For example, if US cropland would have declined by 5 million hectares if the high prices had not occurred, then the GTAP prediction that 1.6 million of these hectares would have been kept in production is consistent with the historical record. More formally, a necessary condition for consistency of the model prediction of an increase in US cropland due to higher prices is that US cropland would have declined by at least the amount of the model prediction were it not for the higher prices that actually occurred.

So suppose that there would have been a 5 million hectare decline in US cropland were it not for the higher prices and the GTAP prediction is correct that 1.6 million hectares of this land would have been kept in production because of higher prices caused by corn ethanol production. This means that the type of land converted to accommodate biofuels was not forest or pastureland but rather cropland that did not go out of production. Calculation of foregone carbon sequestration depends on what would have happened to the cropland if it did not remain in crops which, in turn, depends on where the cropland is located and the potential alternative uses. The magnitude of the change in estimated CO_2 emissions from cropland that is prevented from going out of production relative to forest that is converted to cropland is potentially large. For example, from Table 2, converting one million hectares of grassland instead of forest would reduce land-based CO_2 emissions by 11.3 gCO_2e/MJ in the rest of the world and by 16.5 gCO_2e/MJ in the United States. If foregone carbon sequestration is less than the amount of carbon lost from converting pasture to crops then the magnitude of the emission reduction would be larger.

The countries in Figure 8 that either had negligible or negative extensive land use changes should be presumed to not have converted pasture or forest to crops in response to biofuel-induced higher prices. Rather, the presumption should be that any predicted change in land used in agriculture came from cropland that did not go out of production. From Figure 11 this would include Canada, the EU, Russia, the Ukraine, and India.

The countries in Figure 8 that had significant extensive land increases cannot be presumed to have only kept cropland in production because of biofuels. Whether the expanded cropland due to the portion of the actual price increase attributable to biofuels expansion came from cropland that would have gone out of production or from pasture is an accounting decision. For these countries that expanded extensive land use, the historical pattern of where in the country the land use expansion occurred provides insight into the type of land that was converted to crops.

Brazil is one country that expanded extensive land use and has data on where this expansion occurred. Figure 12 shows each state's share of extensive land use change in Brazil measured by the change in the 2010–2012 average from the 2010–2012 average.[11] Not surprisingly extensive land use increased the most in Mato Grosso. Expansion of sugarcane area in Sao Paulo explains its increase. The states of Goias, Maranhao,

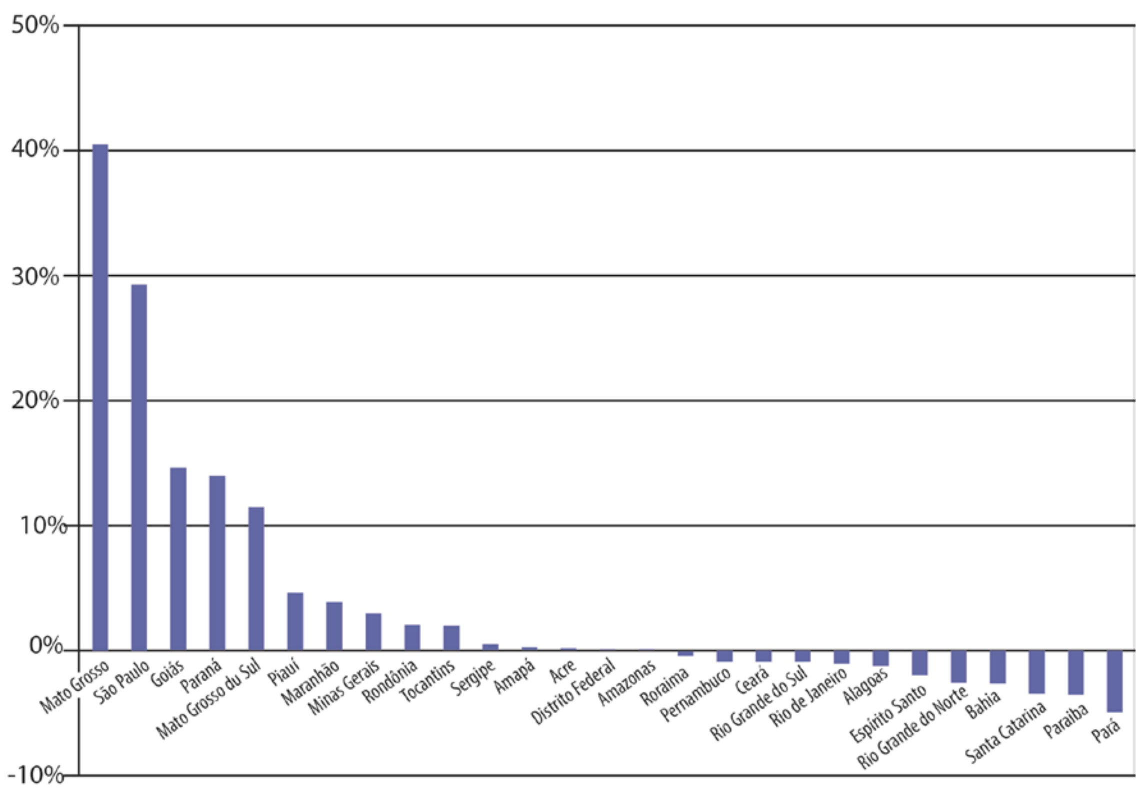


Figure 12. State Share of Brazil's Change in Extensive Land Use from 2004–2006 to 2010-2012.

[11]Only land that was planted to crop was considered in calculating each state's share of extensive land use change. The cropland planted data comes from the IBGE website: http://www.sidra.ibge.gov.br/bda/acervo/acervo9.asp?e=c&p=PA&z=t&o=11. Total planted cropland in Brazil is less than FAOSTAT data on arable land plus permanent crops that was used to determine extensive and internsive land use changes in Figure 10 and 11.

Tocantins, and Piaui all have large land areas in the vast Brazilian Cerrado biome which has also seen large-scale development (The Economist). Rondonia is the only state in the Amazon biome that shows an increase in cropland. Where cropland has expanded in Brazil (and in other countries where data allows) can be used as a guide to determine if model predictions of the type land converted are accurate.

A More Detailed Look at US Extensive Area Data

Figure 13 shows what has happened to one measure of US cropland from 1993 to 2013. This measure is area planted to US principle crops as measured by USDA-NASS, less double cropped harvested area, plus fallow cropland. This measure reached its peak in 1996. In 2007, this measure increased after a long downturn, suggesting some impact of higher prices. However, in 2010 it fell below 130 million hectares before increasing in 2011 and 2012. It is somewhat surprising that total land in agriculture has not increased more than indicated since 2006 because land enrolled in the Conservation Reserve

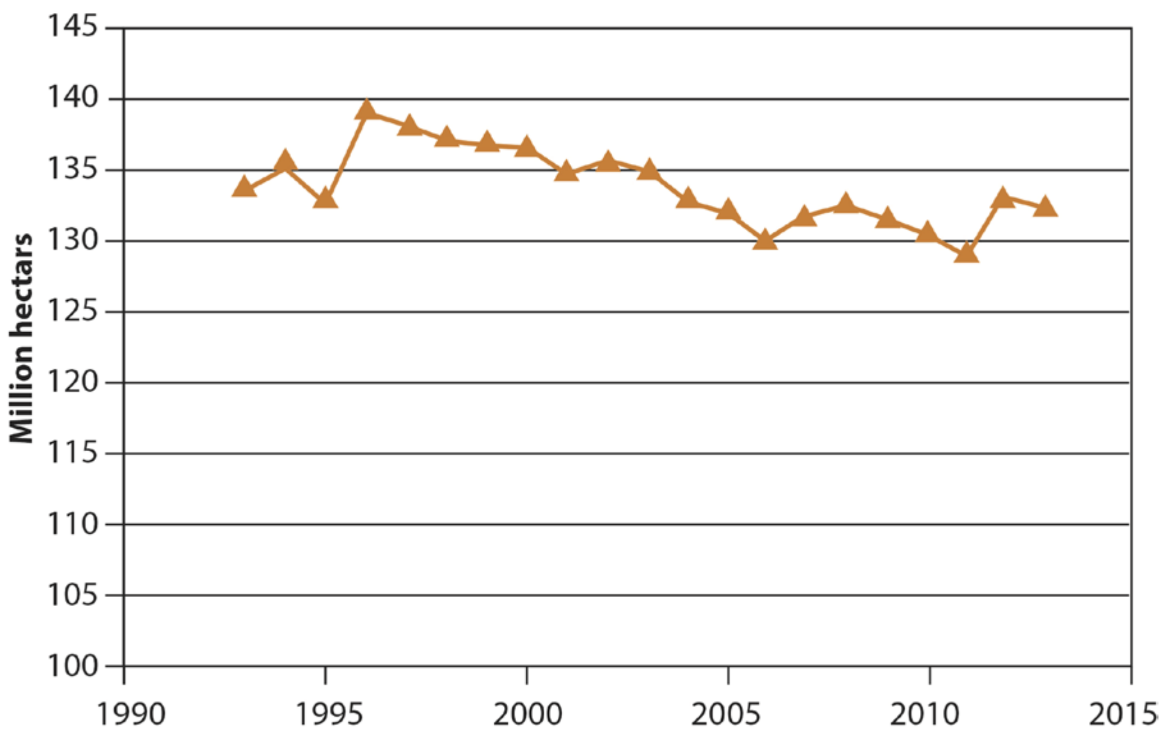


Figure 13. US Cropland Since 1993

Program (CRP) declined by 4 million hectares from 2007 to 2013. One explanation for a lack of response in this measure of land use could be an increase in area that is reported as prevented planting area.

The US crop insurance program creates an incentive for farmers to report area that they had planned to plant but were not able to due to adverse weather. This land is called prevented planted acres. Farmers who buy crop insurance receive a crop insurance payment on these acres. Aggregate data on the amount of prevented planted acres can be added to the Figure 13 data to measure how much land US farmers intend to plant each year. Data on the area designated as prevented planting area are available since 2007.[12] Figure 14 shows the change in CRP land since 2007 (grey line), the change in US cropland since 2007 (blue line calculated from Figure 13), and the change in intended planted land since 2007 (orange line). It is striking how close the change in intended

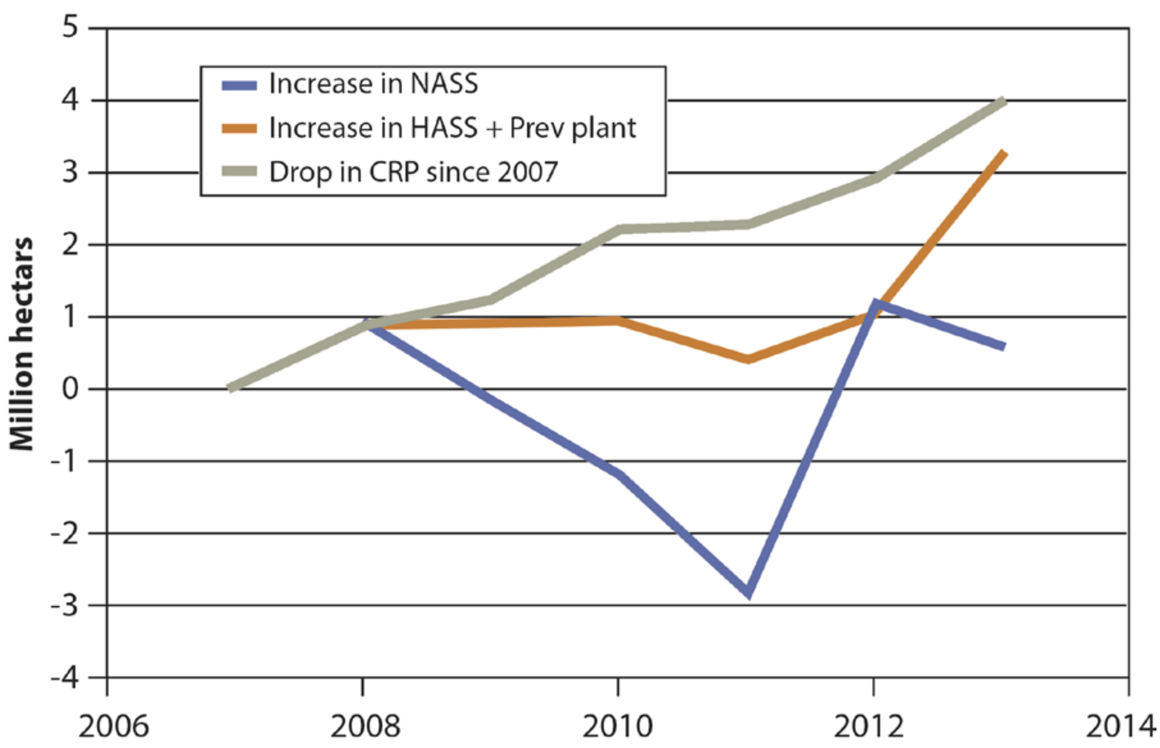


Figure 14. CRP Land Showing up as Increased Prevented Planting Acres

[12] Prevented planting has been part of the US crop insurance program before 2007 but data on total area designated as prevented planting are not readily available.

planted land is to the reduction in CRP, and it is also striking how little of the land that is no longer enrolled in CRP shows up as land in production.

What can be concluded from this more detailed examination of extensive land use in the United States is that the data seem to indicate a reversal of a long-term trend of declining total US cropland since 1996 beginning in 2007—the first crop planted in response to significantly higher prices for US corn and soybeans. The large reduction in land enrolled in CRP is much greater than the amount of land that is reported as being in productive use in crop production. This suggests that there is an abundance of ex-CRP land that is available for planting or that a large proportion of ex-CRP land has not yet been available for crop production and is being reported as having been prevented from being planted. The data are consistent with any increase in extensive land use since prices increased in 2006 as coming from a stock of available land that had been planted to crops previously or from land that was enrolled in CRP. This finding is consistent with USDA (2013), which found that the only net contributor to US cropland from 2007 to 2010 was a reduction in CRP land. There was no net increase in cropland from conversion of forests, from conversion of urban land, or from conversion of pasture.

Conclusions

That countries primarily responded to higher world prices by intensifying land use rather than by converting land from forests and pastures should not be surprising. Many countries, such as China and India, simply do not have available land to bring into agriculture. In countries with land suitable for crops, the investment and other transaction costs of developing new land make the process quite costly relative to the cost of increasing the intensity of land use. In addition, the value of waiting to invest in land conversion projects is large, which leads to a significant delay in land conversions.

The pattern of recent land use changes suggests that existing estimates of greenhouse gas emissions caused by land conversions due to biofuel production are too high because they are based on models that do not allow for increases in non-yield intensification of land use. Intensification of land use does not involve clearing forests or plowing up native grasslands that lead to large losses of carbon stocks.

The recent data on land use changes reveals the importance of policy in determining land use decisions. In Argentina, higher export taxes and quotas on corn and wheat relative to soybeans caused soybean area to increase and wheat area to decrease. The drop in wheat area limits the availability of land on which soybeans can be double cropped which means that expansion of soybeans can only take place by replacing existing crops or by expanding onto new lands. In Brazil, increased enforcement of laws restricting clearing of forests and the resulting drop in the rate of deforestation is consistent with Brazil expanding land use at both the intensive and extensive margin.

It might be argued that recent data are a poor indicator of what we should expect to happen if more time passes because supply response is always larger in the long-run than in the short-run. Land conversion takes time but the time gap used here to measure land use change is long enough to allow a significant amount of change to happen. In addition, the incentive to expand agricultural supply between 2006 and 2012 was as strong as any period since at least 1960. Furthermore, if the recent sharp declines in commodity prices continue then the incentive to expand supplies in the future will be muted.

We plan on extending our analysis of land use changes by attempting to develop a statistical model to explain more systematically why some countries expanded land use more at the extensive margin and others expanded more at the intensive margin. Such a model could provide better insights into the role that policy, price transmission, and resource availability plan in determining agricultural supply response. Improved understanding could be useful to future attempts at estimating greenhouse gas emissions caused by extensification of agricultural production.

References

Babcock, B.A. and J.F. Fabiosa. 2011. "The Impact of Ethanol and Ethanol Subsidies on Corn Prices: Revisiting History." CARD Policy Brief 11-PB5.

Babcock, B.A. 2009. "Measuring Unmeasurable Land Use Changes from Biofuels." *Iowa Ag Review* 15: 4–11.

Barr, K.J., B.A. Babcock, M.C. Carriquiry, A.M. Nassar, and L. Harfuch. 2011. "Agricultural Land Elasticities in the United States and Brazil." *Applied Economic Perspectives and Policy* 33: 449–62.

Berry, Steven T. 2011. "Biofuels Policy and the Empirical Inputs to GTAP Models." California Air Resources Board Expert Workgroup Working Paper.

Burney, J.A., J.D. Steven, and B.L. David. 2010. "Greenhouse Gas Mitigation by Agricultural Intensification." *Proceedings of the National Academy of Sciences* 107: 12052–12057.

Carter, C., G.C. Rausser, and A. Smith. 2010. "The Effect of the US Ethanol Mandate on Corn Prices." *unpublished paper, University of California.*

"The Miracle of the Cerrado." 2010. The Economist. http://www.economist.com/node/16886442

EPA. 2010. "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Final Rule, March 26, 2010." 40 CFR Part 80: 14669–15330.

EPA. 2010. "Renewable Fuel Standard Regulatory Impact Analysis." EPA-420-R-10-006, February 2010.

Gohin, A. 2014. "Assessing the Land Use Changes and Greenhouse Gas Emissions of Biofuels: Elucidating the Crop Yield Effects." *Land Economics* 90: 575–86.

Ajeigbe, H.A., B.B. Singh, A. Musa, J.O. Adeosun, R.S. Adamu, and D. Chikoye. 2010. "Improved Cowpea–Cereal Cropping Systems: Cereal–Double Cowpea System for the Northern Guinea Savanna Zone." *International Institute of Tropical Agriculture (IITA), pp. 17.*

Hertel T.W., A.A. Golub, A.D. Jones, M. O'Hare, R.J. Plevin, and D.M. Kammen. 2009. "Global Land Use and Greenhouse Gas Emission Impacts of U.S. Maize Ethanol: The Role of Market Mediated Responses." GTAP Working Paper No. 55.

India Ministry of Agriculture. 2014. Directorate of Economics and Statistics, Department of Agriculture and Cooperation. http://eands.dacnet.nic.in/

USDA-FAS. 2012. “Indonesia: Stagnating Rice Production Ensures Continued Need for Imports.” *USDA-FAS Commodity Intelligence Reports - South East Asia.* http://www.pecad.fas.usda.gov/highlights/2012/03/Indonesia_rice_Mar2012/

Koh, L.P and D.S. Wilcove. 2008. “Is Oil Palm Agriculture Really Destroying Biodiversity?” *Conservation Letters* 1: 60–64.

Minot N. 2010. “Staple Food Prices in Tanzania.” Presented at Comesa policy seminar on ‘Variation in Staple Food Prices, Causes, Consequence, and Policy Options.” Maputo, Mozambique 25–26 January 2010.

Minot, N. 2011. “Transmission of World Food Price Changes to Markets in Sub-Saharan Africa.” *Discussion Paper 01059. International Food Policy research Institute.*

OECD-FAO Agricultural Outlook. 2009. “Chapter 5: Can Agriculture Meet the Growing Demand for Food?” http://www.oecd-ilibrary.org/agriculture-and-food/oecd-fao-agricultural-outlook-2009/can-agriculture-meet-the-growing-demand-for-food_agr_outlook-2009-5-en

OECD-FAO Agricultural Outlook. 2014. “Chapter 2: Feeding India: Prospects and Challenges in the Next Decade.” http://www.oecd-ilibrary.org/agriculture-and-food/oecd-fao-agricultural-outlook-2014/feeding-india-prospects-and-challenges-in-the-next-decade_agr_outlook-2014-5-en

Roberts, Michael J., and Wolfram Schlenker. 2013. “Identifying Supply and Demand Elasticities of Agricultural Commodities: Implications for the US Ethanol Mandate.” *American Economic Review* 103(6): 2265–95.

Shunji, Cui, and Ruth Kattumuri. 2010. “Cultivated Land Conversion in China and the Potential for Food Security and Sustainability.” Asia Research Centre Working Paper 35.

U.S. Department of Agriculture. 2013. “Summary Report: 2010 National Resources Inventory.” Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa.

Song F., J. Zhao, and S.M. Swinton. 2011. “Switching to Perennial Energy Crops under Uncertainty and Costly Reversibility.” *American Journal of Agricultural Economics* 93: 768–83.

Susanti, A., G. Mada, and P. Burgers. 2012. “Oil Palm Expansion in Riau Province, Indonesia: Serving People, Planet, and Profit?” Background paper to the European Report on Development 2011/2012: Confronting Scarcity: Managing Water, Energy and Land for Inclusive and Sustainable Growth.

Swastika, D.K.S., F. Kasim, K. Suhariyanto, W. Sudana, R. Hendayana, R.V. Gerpacio, and P.L. Pingali. 2004. “Maize in Indonesia: Production Systems, Constraints, and Research Priorities.” Mexico, DF: CIMMYT.

Taheripour F. and W.E. Tyner. 2013. “Biofuels and Land Use Change: Applying Recent Evidence to Model Estimates.” *Applied Science* 3(1): 14–38.

Tyner, Wally. 2010. “First and Second Generation Biofuels: Economic and Policy Issues.” Presented at the Third Berkeley Bioeconomy Conference, June 24, 2010. http://www.berkeleybioeconomy.com/ wpcon-tent/uploads//2010/07/TYner%20Berkeley%20June%202010.pdf.

Data Sources

Brazil: http://www.sidra.ibge.gov.br/
India: http://eands.dacnet.nic.in/
FAO: Area harvested: http://faostat3.fao.org/download/Q/QC/E
FAO: Land Cover: http://faostat3.fao.org/download/R/RL/E
USA: USDA-NASS: http://quickstats.nass.usda.gov

APPENDIX B:

Langeveld, J. W.A., Dixon, J., van Keulen, H. and Quist-Wessel, P.M. F. (2014), Analyzing the effect of biofuel expansion on land use in major producing countries: evidence of increased multiple cropping. Biofuels, Bioprod. Bioref., 8: 49–58. doi: 10.1002/bbb.1432.

Biofpr Biofuels Bioproducts & Biorefining

Analyzing the effect of biofuel expansion on land use in major producing countries: evidence of increased multiple cropping

Johannes W.A. Langeveld, Biomass Research, Wageningen, the Netherlands
John Dixon, Australian Centre for International Agricultural Research (ACIAR), Canberra, Australia
Herman van Keulen, Wageningen University and Research Centre, Wageningen, the Netherlands
P.M. Foluke Quist-Wessel, Biomass Research, Wageningen, the Netherlands and AgriQuest, Heteren, the Netherlands

Received May 21, 2013; revised June 17, 2013; and accepted June 24, 2013
View online at Wiley Online Library (wileyonlinelibrary.com); DOI: 10.1002/bbb.1432;
***Biofuels, Bioprod. Bioref.* (2013)**

Abstract: Estimates on impacts of biofuel production often use models with limited ability to incorporate changes in land use, notably cropping intensity. This review studies biofuel expansion between 2000 and 2010 in Brazil, the USA, Indonesia, Malaysia, China, Mozambique, South Africa plus 27 EU member states. In 2010, these countries produced 86 billion litres of ethanol and 15 billion litres of biodiesel. Land use increased by 25 Mha, of which 11 Mha is associated with co-products, i.e. by-products of biofuel production processes used as animal feed. In the decade up to 2010, agricultural land decreased by 9 Mha overall. It expanded by 22 Mha in Brazil, Indonesia, Malaysia, and Mozambique, some 31 Mha was lost in the USA, the EU, and South Africa due to urbanization, expansion of infrastructure, conversion into nature, and land abandonment. Increases in cropping intensity accounted for 42 Mha of additional harvested area. Together with increased co-product availability for animal feed, this was sufficient to increase the net harvested area (NHA, crop area harvested for food, feed, and fiber markets) in the study countries by 19 Mha. Thus, despite substantial expansion of biofuel production, more land has become available for non-fuel applications. Biofuel crop areas and NHA increased in most countries including the USA and Brazil. It is concluded that biofuel expansion in 2000–2010 is not associated with a decline in the NHA available for food crop production. The increases in multiple cropping have often been overlooked and should be considered more fully in calculations of (indirect) land-use change (iLUC). © 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

Keywords: biofuels; land use change; iLUC; food vs. fuel; ethanol; biodiesel; co-products; Brazil; USA; EU; China.

Correspondence to: Johannes W.A. Langeveld, Biomass Research, P.O. Box 247, 6700 AE Wageningen, the Netherlands.
E-mail: hans@biomassresearch.eu

SCI

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

Introduction

Increased biofuel production has led to criticism and concerns about food availability while it is feared that rising demand for cropland will lead to deforestation, grassland conversion and increased Greenhouse Gas (GHG) emissions from these land use changes. The main criticism is based on expected impacts of biofuel production following the introduction of dedicated biofuel targets and policies.[1–3]

Commonly used economic models in biofuel policy evaluation include multimarket partial equilibrium models such as the FAPRI-CARD, ESIM, and IMPACT model, and computable general equilibrium (CGE) models such as the Global Trade Analysis Project (GTAP), LEITAP and the Modeling International Relationships in Applied General Equilibrium (MIRAGE) model. Most models were originally developed to evaluate agriculture or climate policies and were later adapted to incorporate biofuel production.[4–6] This has consequences for the way the models have been implemented. Early applications, for example, did not consider generation of co-products (by-products of the biofuel production process which are mostly used as animal feed)[1,7] while second-generation biofuel production technology, at least in early applications, was not included.[4]

Other restrictions include limited ability to adjust to accelerations in yield improvement[7] or to changes in crop rotation.[9] Most models do not consider double-cropping (cultivation of two or more crops on the same plot within a given year), while changes in fallow or other unmanaged land can only be accommodated to a limited extent,[8] which is considered a significant drawback of model results.[7] Changes in programs offering farmers compensation for not cultivating arable land (Conservation Reserve Program (CRP) in the USA and Set-Aside in the EU), for example, were often not adequately represented. Further, models do not fully incorporate impacts of trade policies (e.g. preferential biofuel imports[8]), crop tillage,[10] or agro-ecological conditions in crop production areas.

While the exact consequences of these limitations remain unclear, there is a risk that relevant changes in crop production patterns, partly triggered by biofuel policies, may not be sufficiently covered in the analysis. Scenarios for future crop production published by the Food and Agriculture Organization (FAO) suggest that increasing cropping intensity will be an important source of additional crop biomass. According to Nachtergaele *et al.*,[11] cropping intensity is projected to increase by a total of 4% in developing countries between 2006 and 2050. For developed countries, however, the forecast increase is 7%. Global average is projected to increase by 6%.

Central to the debate on the impact of biofuel production is the question to what extent current policies are causing alienation of land from food and feed production. At the core is the way increased biomass requirements are to be met by area expansion, yield improvement or by increased cropping intensity. Bruinsma[12] estimated that 80% of the projected growth in crop production in developing countries up to 2050 would come from intensification in the form of yield increases (71%) and higher cropping intensities (8%). Higher shares are projected in land-scarce regions such as South Asia and the Near East/North Africa where increases in yield would need to compensate for the expected decline in the arable land area. Arable land expansion will remain an important factor in crop production growth in many countries of sub-Saharan Africa and Latin America; although less so than in the past.

Given the large (albeit possibly temporary) increases in crop prices, the general expectation that biofuels will permanently push up demand for food crop biomass plus the fact that farmers in the past have shown to be able to respond effectively to changes in crop demand might have to be moderated. Especially the projected increases in cropping intensity may be on the low side. Using data for 1962–2007, OECD-FAO[13] for example calculated that half of the realized increases in the harvested area were attributable to increased cropping intensity (the other half have been related to area expansion).

More recently, reduction of (fodder and) CRP area and increased double-cropping have been reported for the USA.[14] For example, about 16% of 2008 corn and soybean farms had brought new acreage into production since 2006. This new, formerly uncultivated, land accounted for approximately 30% of the reported farm's expansion in total harvested acreage. Most acreage conversion came from uncultivated hay. Some 15% of corn and soybean farms reported a harvested acreage (summing up all crops) exceeding their arable area in 2008, implying an increase in double-cropping. These farms reported greater expansion in harvested biofuel crop acreage than other farms, suggesting double-cropping is a quick and effective strategy to generate additional biofuel crop biomass.

Given the above limitations, economic model impact assessments of biofuel policies should be considered with care. Consequences of the limitations on the modeling outcome are difficult to assess but they may be considerable. The introduction of co-products in a GTAP evaluation of US and EU biofuel policies, for example, was

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

assessed to reduce the need for land conversion with 27%.[6] According to Croezen and Brouwer,[15] scenarios including second-generation biofuel technologies resulted in land-use requirements that were 50% lower as compared to scenarios which did not include lignocellulosic biofuel conversion technologies.

In summary, the use of estimates of biofuel scenarios based on incomplete information could generate misleading estimates. Another risk is the inadequate input use, which could give an incorrect impression with respect to day-to-day crop management practices such as input use efficiency. Consequently, perspectives for (sustainable) biomass production for biofuel and food/feed applications may be estimated incorrectly.

With a view to improving the accuracy of data for evaluations of biofuel policy impacts, this paper assesses data from different sources of biomass production of eight major biofuel producers. We analyze biofuels and feedstock increases of major biofuel feedstocks between 2000 and 2010, and their impacts on land use in Brazil, the USA, the EU, China, Indonesia, Malaysia, South Africa, and Mozambique. Together, these countries represent a large majority of global biofuel production. Local conditions for crop and biofuel production will be described in a generalized way. In order to determine the impact of biofuel policies, production volumes will be compared to those of 2000, clearly before most countries introduced biofuel-related policy measures. An important distinction will be made between the amount of biomass (crop feedstocks) that is used to generate biofuels, the amount of land that is needed to produce the biomass, and the average number of harvests that can be generated from arable land (resulting from the prevalence of fallow and double-cropping in a given region). The paper will make use of the following concepts:

- Harvested area: the crop area that is harvested in a country or region in a given year. This differs from the amount of arable land, as land may be harvested several times, while fallow land is not harvested at all.
- Agricultural area in a given country or region. This includes arable land (cultivated with arable crops, i.e. food and feed crops), permanent grassland and agricultural tree crops (fruits, beverages, stimulant crops)
- Cropping intensity: the ratio of harvested crop area to the amount of arable land.*

The relation between these concepts is the following equation:

- Harvested area = arable area * cropping intensity (1)

In our analysis, we estimate land and biomass balances. Based on the volume of biofuels produced, the equivalent amount of biomass and the required area of land is calculated. These estimates are based on detailed material collected and analyzed for a book on biofuel crop production systems currently in preparation. The review is organized as follows. First, it describes available land resources in the study countries. Next, it presents biofuel production in 2010 which is compared to that in 2000. Implications of biofuel expansion for land use are given, as are other changes in land use that have been observed. This is followed by a discussion and some conclusions.

Land resources

An overview of land cover and land use in the study countries is presented in Table 1. China, Brazil, and the USA are the largest countries, Brazil having the largest forest area (nearly 40% of the study countries total). Agricultural area is high in China, the USA and (on a relative scale) the EU, Mozambique, and South Africa. Most arable land is found in the USA, China, and the EU, permanent grasslands being important in China (hosting more than one-third of the study area grassland), the USA, and Brazil. We calculated cropping intensity, expressed as the sum of all harvested crop area during a given year divided by the total arable land (the Multiple Cropping Index or MCI). MCI was originally introduced as a measure for cropping intensity of tropical farming systems,[16] but can be calculated for temperate regions as well.[12] MCI in the study countries varies between 0.53 in South Africa, 1.45 in China. It is around 0.8 in Brazil, the USA, and the EU.

Biofuel production

Sugarcane is the predominant feedstock for ethanol production in tropical regions (Table 2). In temperate areas, ethanol is mostly made from cereals (corn in the USA and China, wheat in the EU and China). Main biodiesel feedstocks are soybean (Brazil, USA), rapeseed (EU), and oil palm (Indonesia and Malaysia). There are other feedstocks of minor importance, such as castor beans in Brazil, sunflower in the EU and Jatropha in Mozambique, but these are not included in the analysis.

Large differences exist in the way fields are prepared for biofuel production. There are a number of practices which

*Note: this is not similar to the intensity of crop production (amount of inputs used per ha or amount of yield realized per ha).

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

Table 1. Land cover and land use (million ha).

Region	Land area	Forest	Agricultural area	Permanent grassland	Arable area	Multiple Cropping Index (-)
Brazil	846	520	273	196	50	0.86
USA	914	304	411	249	160	0.82
EU	418	157	187	68	107	0.84
Indonesia and Malaysia	214	115	62	11	25	1.21
China	933	207	519	393	111	1.45
Mozambique	88	39	49	44	5	1.08
South Africa	121	9	97	84	13	0.53

Source: FAOSTAT (2013).[18]

Table 2. Biofuel production chains included in the analysis.

Region	Feedstock	Biofuel	Field preparation	Input use
Brazil	Sugarcane	Ethanol	Pre-harvest burning is phased out	Moderately low
Brazil	Soybean	Biodiesel	Mostly no-till	Low
USA	Corn	Ethanol	Mostly plowed	High
USA	Soybean	Biodiesel	Half under no-till	Moderately low
EU	Wheat	Ethanol	Plowing	High
EU	Rapeseed	Biodiesel	Plowing	High
EU	Sugarbeet	Ethanol	Plowing	Moderately high
Indonesia and Malaysia	Palm oil	Biodiesel	Pre-harvest burning	Moderately low
China	Corn	Ethanol	Plowing	Very high
China	Wheat	Ethanol	Plowing	Very high
Mozambique	Sugarcane	Ethanol	Pre-harvest burning	Moderately high
South Africa	Sugarcane	Ethanol	Pre-harvest burning	High

determine the performance of the biofuel production chain including pre-harvest burning of sugarcane leaves and plowing for arable crops. Burning leaves of sugarcane is common practice before manual harvesting in order to avoid injuries to laborers. This causes a considerable loss of leaf material and soil organic matter, while emissions of particulate matter cause a threat to the laborers' lungs. This practice is gradually being phased out in Brazil where mechanical green harvesting is becoming more common. Plowing arable fields, causing loss of soil carbon, is common in the EU and in China, but less so in the Midwest of the USA and soybean cultivation in Brazil, who have adopted conservation agriculture. Use of fertilizers and agro-chemicals is highly variable. Input use in feedstock production is low to moderately low in Brazil and in the USA (corn), Indonesia, Malaysia and Southern Africa. It is high in the production of cereals (USA, EU, and China) and rapeseed. Sugarbeet holds an intermediate position.

The main output data are presented in Table 3. Crop yield is high for sugarcane (Brazil, South Africa), sugarbeet, and oil palm. Cereal yields are high for corn in the USA, but less so for corn and wheat in the EU and China. Rapeseed and soybean yields are modest. Ethanol yields are highest for sugarbeet, and sugarcane (Brazil). Highest biodiesel yields were observed for oil palm (Indonesia, Malaysia). Generation of co-products is also quantified, as these can be applied in the livestock industry. Major biofuel crops are well established feed crops, which holds especially for corn and soybean. Co-products considered in this study include dried distillers' grains with solubles (DDGS), soy meal, rapeseed meal, beet pulp, and palm meal. It was decided to use a simple mass balance approach to distinguish between crop biomass used for biofuel production and for feed applications. Biofuel land claims were calculated by allocating a share of total land use according to the ratio of total crop feedstocks used for biofuels. Co-product yields were calculated using conversion data and converted into tons per ha equivalent

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd | *Biofuels, Bioprod. Bioref.* (2013); DOI: 10.1002/bbb

Table 3. Crop, biofuel and coproduct yields.

Region	Feedstock	Crop yield (ton/ha)	Biofuel yield (l/ha)	Biofuel yield (GJ/ha)	Co-product yield (ton/ha)
Brazil	Sugarcane	79.5	7200	152	–
Brazil	Soybean	2.8	600	18	1.8
USA	Corn	9.9	3800	80	4.2
USA	Soybean	2.8	600	18	1.8
EU	Wheat	5.1	1700	37	2.7
EU	Rapeseed	3.1	1300	43	1.7
EU	Sugarbeet	79.1	7900	168	4.0
Indonesia and Malaysia	Palm oil	18.4	4200	90	4.2
China	Corn	5.5	2200	46	2.9
China	Wheat	4.7	1700	36	2.5
Mozambique	Sugarcane	13.1	1100	23	–
South Africa	Sugarcane	60.0	5000	107	–

Source: crop yields calculated from FAOSTAT (2013),[18] biofuel and co-product yields calculated from literature.

which allows better comparison. Co-product yields are high for corn (USA), oil palm, and sugarbeet. Yields are low for rapeseed and soybean, while no co-products for the food or feed market are generated by sugarcane-ethanol.

Ethanol production in the study countries, amounting to 17 billion litres in 2000, rose to 86 billion litres in 2010 (Table 4). Most of the increase was realized in the USA, which was responsible for a production of 50 billion litres in 2010. Brazil is the second-largest producer with 28 billion litres, followed by the EU and China. Increases have been relatively high in China, the USA, and the EU. Biodiesel production rose from 0.8 to 15 billion litres. The EU is the highest producer, followed by Brazil and the USA. Indonesia, Malaysia, Mozambique, or South Africa are not producing significant amounts of biofuels, although they may be important producers in their respective regions. Biofuel production in the study countries (86 and 15 billion litres of ethanol and biodiesel, respectively) represents 97% and 77% of the global total production level. Thus, conclusions of global significance can be drawn from the analysis of the study countries.

Table 4. Biofuel production in the study countries (billion l).

	Ethanol			Biodiesel		
	2000	2010	Increase	2000	2010	Increase
Brazil	9.7	27.6	17.9	Neg.	2.1	2.1
USA	6.1	49.5	43.4	Neg.	2.1	2.1
EU	1.5	6.4	4.9	0.8	10.3	9.5
Indonesia and Malaysia	N.i.	N.i.	N.i.	Neg.	0.2	0.2
China	Neg.	2.1	2.1	Neg.	0.4	0.4
Mozambique	Neg.	0.02	0.02	Neg.	0.05	0.05
South Africa	Neg.	0.02	0.02	Neg.	0.05	0.05
All	17.3	85.6	68.3	0.8	15.1	14.3

Notes: N.i. = not included; Neg. = negligible.

Land use

Land used for biofuel expansion was calculated by dividing increased biofuel production presented in Table 4 by biomass to biofuel conversion rates taken from literature. Since 2000, biofuel expansion in the study countries has claimed an additional 25 million ha of cropland (Table 5). As 11 million ha is allocated to co-products, net biofuel expansion amounts to 14 million ha. Over 85% of area expansion occurred in the USA, where increased biofuel production has occupied over 5 million ha, and in the the EU and Brazil. Co-product generation is relatively high in the USA and the EU. The main crops used to produce biofuels (corn, wheat, soybean, and rape), are dominant feed crops whose nutritive characteristics have long been known. Low co-product ratio in Brazil is explained by the high share of sugarcane, whose residues are mostly used in the production of biofuels or electricity (co-generation). Vinasse is recycled and used as fertilizer.

Since 2000, countries of the study area have seen a net decline in agricultural area by 9 million ha. Loss of agricultural area in the USA, the EU, China, and South Africa amounted to 31 million ha, which is mostly compensated

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd | *Biofuels, Bioprod. Bioref.* (2013); DOI: 10.1002/bbb

Table 5. Net changes in land availability.

	Increased land requirement (mln ha)	Associated with co-products (mln ha)	Net biofuel area increase (mln ha)	Changes in agricultural area (mln ha)	Extra harvested area due to increased MCI (mln ha)	Change in NHA (mln ha)
Brazil	4.9	1.8	3.1	12.0	4.9	13.8
USA	11.0	5.9	5.1	–3.5	10.9	2.3
EU	6.6	3.2	3.4	–11.5	3.6	–11.2
Indonesia, Malaysia	0.02	0.01	0.01	8.9	2.0	10.9
China	2.2	0.4	1.8	–13.4	20.3	5.1
Mozambique	0.13	0.03	0.1	1.3	0.9	2.0
South Africa	0.12	0.04	0.1	–2.7	–1.2	–4.0
All	24.9	11.4	13.5	–9.0	41.5	19.0
Global total				–47.8	91.5	

by expansion of agricultural land in Brazil (plus 12 million ha), Indonesia/Malaysia (plus nine million ha), and Mozambique. Net global loss of agricultural area amounted to 48 million ha. In many cases, loss of agricultural area has been much larger than net expansion of biofuel area. This was the case in the EU, China, and South Africa. It is only in the USA that biofuel expansion is the dominant cause of agricultural land use loss.

Increasing the cropping frequency on arable land – reflected by an increase of the MCI – allows farmers to increase the harvested area on shrinking agricultural areas. This has facilitated *additional* crop harvests equivalent to 42 million ha. More than half of this expansion was realized in China, where government policy has been oriented toward improving (maintaining) food production capacity. MCI also added considerable harvested areas in the USA, Brazil, the EU, Indonesia, and Malaysia. The role of MCI in improving agricultural output since 2000 can hardly be overemphasized. Global increases, equivalent to 92 million ha of harvested crops, have been more than sufficient to compensate for losses of agricultural area.

Improvement of MCI in all but one case is more than sufficient to compensate for expansion of biofuel area: this is the case in Brazil (where MCI generated 5 million ha while biofuels required 3 million ha – a positive balance of nearly 2 million ha), the USA (11 *vs.* 5 million ha), EU (0.2 million ha balance), Indonesia/Malaysia (plus 2 million ha), China (19 million ha) and Mozambique (0.8 million ha). South Africa, which noted a decline of MCI, is the exception to the rule of increased cropping intensity.

The combined effect of biofuel expansion, changes in agricultural area, and improvement of MCI generally is positive. Together, countries included in the study increased harvested area for non-biofuel purposes of 19 million ha. This increase allowed improved availability of crop production for traditional food, feed, and fiber (FFF) markets. Net FFF area increased in most of the cases, except for the EU and South Africa.

Discussion

Following changes in biofuel policies in the course of the first decade of the twenty-first century, a strong expansion in biofuel production was observed in the USA, the EU, China, and many other countries. The 34 study countries realized an increase in ethanol production of 68 billion litres and 14 billion litres of biodiesel in 2010 as compared to 2000. These increases, however, were not sufficient to fully satisfy biofuel policy objectives in the USA and the EU. China, Indonesia, and Malaysia have adjusted policies in response to substantial consumption of food cereals and high palm oil prices, respectively. For the near future, further expansion of biofuel production is expected especially in the USA, Brazil, Argentina, and the EU. Smaller, but significant, development may be expected elsewhere.

Land devoted to biofuel production was calculated at 32 million ha in 2010, an increase of 25 million ha as compared to 2000. Of this increase, 11 million ha can be allocated, using standard conversion rates, to co-products. This means that nearly half of the increase in biofuel area in fact is used to generate crop biomass for the livestock feed market. Clearly, ignoring co-product generation in early biofuel impact assessments has led to an overestimation of land requirements, in most cases by 40% or more. The contribution of feed co-products is relatively high in the USA, China, and the EU due to the large share of cereals with high feed yields. It is low in Brazil where ethanol production is dominated by sugarcane which generates no

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd | *Biofuels, Bioprod. Bioref.* (2013); DOI: 10.1002/bbb

feed co-products. However, it should be noted that the co-generation of electricity from sugar cane residues has not been included in the calculations.

Biomass used for biofuel production, calculated from biofuel literature and FAO statistics, amounted to 527 million ton in 2010. This is an increase of 334 million ton, of which 80 million tons is for co-product generation. Biofuel expansion therefore required 254 million tons of crops. Area expansion, amounting to 25 million ha (including co-products), has been relatively stronger due to a shift from high yielding (ton per ha) sugarcane to cereals like corn and wheat and to oil crops like soybean and rapeseed all which have much lower yields than sugarcane. Implications for land use will, however, also depend on the role of yield improvement. In literature, different assumptions on yield improvement can be found. For US corn, for example, Searchinger *et al.*[19] assumed a maximum of 20% yield improvement in 30 years. Others have suggested that a considerable share of corn used in biofuels in the USA could be generated by yield improvements.[20] One should be extremely careful comparing crop yields as these tend to show large year-to-year variations. However, US corn yields calculated from FAOSTAT data suggest that a significant part of these yield improvements already has taken place between 2000 and 2010. Indicative yield improvements (3-year averages) during this period of sugarcane in Brazil and wheat in the EU have been 17% and 11%, respectively.

The changes in land use that were reported are most revealing. The loss of agricultural area due to urbanization, etc., in industrial countries (USA, EU, South Africa) is two times larger than biofuel expansion (31 *vs.* 14 million ha). Expansion of agricultural area in other countries (Brazil, Indonesia, Malaysia, and Mozambique) amounted to 22 million ha. Changes in intensification of arable cropping are even larger. On a global scale, the MCI increased by 7% in a period of ten years. This may not seem high, but as it applies to an area of 1.4 billion ha, the implications are enormous. In the study area, improvement of cropping intensity has been variable. It rose by 14% in China, 10% in Brazil and Mozambique, and 4% in the EU. Other countries take an intermediate position.

For the entire study area, 42 million ha of crop harvested area has been generated. Consequently, the reduction of unutilized arable land (CRP in the USA, set-aside in the EU plus fallow) and an increase in double-cropping has been sufficient to generate nearly three times the amount of biofuel land expansion. Both fallow reduction and double-cropping seem to have been largely ignored in the debate so far which is a serious omission. Improved MCI was identified as a major source of increased harvested area by OECD-FAO,[12] but the consequences for land availability vis-à-vis future biofuel expansion tend to have been overlooked. Bruinsma[11] focused mainly on yield improvement. Economic models used in evaluation of biofuel policies appear to have neglected the potential contribution of MCI.

In the future, MCI may be expected to show further increases. The magnitudes will, however, depend on crops and farming systems. Tropical regions have a larger potential for double-cropping (provided sufficient water is available). Cereals and pulses, having relatively short growing cycles, provide good perspectives. Sugarcane, occupying land year round, has limited potential for increased MCI. Climate change may, however, also offer new opportunities for temperate regions, for example, when temperatures in spring allow early harvesting of winter cereals.[17]

The approach that was followed has a number of advantages. Calculating full biomass balances allowed the assessment of biofuel feedstocks available for animal feed and – consequently – gives a realistic assessment of the amount of feedstocks required for biofuel production. Requirements of biofuel production for biomass and land resources were calculated with local data, thus incorporating a realistic assumption of cultivation practices, crop rotations, yields, and conversion efficiencies. The use of full land balances has put land demand for biofuels in perspective, integrating many processes which affect land requirement and changes in land use. Limitations of the approach are related to the large number of data that are needed. Data on crop rotations and cultivation practices often have a local nature which makes it difficult to obtain a more generic picture at the national level. Data on double-cropping and biomass to biofuel conversion are extremely difficult to obtain while the exact relation between biofuel production and increased MCI needs to be investigated. Calculations, finally, have been restricted to major biofuel feedstocks.

Notwithstanding these limitations, the implications of the findings are substantial. The impact of the increases in cropping intensity can hardly be overemphasized. On the one hand, observed MCI improvement since 2000 demonstrates that projected biofuel crop areas (estimated up to 50 million ha in 2050) can easily be compensated. In one decade, enhanced cropping intensity generated as much as 92 million ha of extra harvested crops worldwide. This is surprisingly high, and the consequences are clear. While biofuel production may occupy a significant amount of crop land in the future, there are strong drivers of crop area expansion which may be able to generate similar – or larger – additional harvested areas

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd | *Biofuels, Bioprod. Bioref.* (2013); DOI: 10.1002/bbb

in biofuel countries. Thus, there is little reason to expect that biofuel expansion will lead to substantial reductions of area of food/feed production. For the first decade of the twenty-first century, net harvested area for traditional (non-biofuels) biomass markets in the study area increased by 19 million ha.

The outcomes of this study are relevant to the debates related to biofuel production. Our review clearly shows that biofuel expansion has not been the major factor causing land-use change. Loss of arable land due to urbanization, etc., has claimed over twice as much land. This loss is almost certainly permanent, which is not the case for biofuel production. Further, increased intensity of arable land use has generated more than sufficient harvested area to fully compensate biofuel expansion. This makes claims of land-use changes caused by biofuel expansion (as caused by biofuel policies) less convincing.

Consider, for example, projected land use change caused by EU biofuel policies. In 2020, an additional area of 0.5 million ha has been projected to be devoted to biofuels in Brazil.[2] Only 15% of this is associated with deforestation. These are small figures, which suggest that the role of biofuel expansion as a major driving force for deforestation in Brazil needs to be reconsidered (26 million ha of forest was lost since 2000). Projected land-use change due to EU policies should also be compared to the increase of MCI observed in Brazil, generating almost (five million ha or) *ten* times the amount lost to EU biofuel exports in just one decade. In the light of these figures it is hard to imagine that biofuel policies alone are the dominant source of land-use change or deforestation.

The food *versus* fuel debate, further, needs to be enriched. While biofuel expansion in the study area has claimed 14 million ha of arable land, this area is more than compensated for by increased cropping intensity. FAOSTAT data clearly show that harvested area for food/feed markets has increased. They also show that biomass availability for food and feed applications has gone up. Further, it is not biofuel expansion but loss of agricultural land due to urbanization, etc., that is the major threat to land (biomass) availability. All this needs to be considered in the debate. The outcomes of this study show that it is essential for policy impact analyses to use statistical data to check model projections. Further, the analysis should be based on full – and not partial – biomass and land balances. Initial restrictions in model applications, ignoring co-product generation, seem to have given strongly misleading conclusions. Excluding double-cropping or cropping intensity in biofuel policy analysis has been another limitation which has had a major impact on the results. It is suggested, therefore, to incorporate local and national data on crop cultivation (e.g. crop rotations) in assessment studies of biofuel policies.

Keeney and Hertel[8] indicated that forecasting environmental impacts of biofuel policies requires both careful model formulation as well as sufficient empirical knowledge of supply and demand. Currently, only a few key parameters (e.g. yield elasticity, acreage response elasticity) determine the outcome of land-use change modeling studies. It should be checked to what extent popular analytical models correctly predicted adjustments in crop production and land-use practices. Essential elements that may have been lacking include changes in fallow and double-cropping, accelerations in yield improvement, and loss of agricultural land due to urbanization, infrasructure and industry.

Special attention is merited for cropping intensity, as well as non-biofuel crop yield improvement.[7] In this process, predicted changes in crop production and land use should be critically evaluated. Keeney and Hertel,[8] for example, predicted an increase of crop production to coincide with a reduction of forest and pasture areas in the USA, the EU, and Latin America. FAO statistics have shown that, during the last decade, forest area in the USA and EU has *increased* while grassland area remained constant in the USA and in Brazil.

The implication of this analysis for estimations of GHG emissions from biofuel production is potentially substantial. Very high assessments of carbon releases due to indirect land-use changes[2,18] have been used to underpin adjustments in biofuel policies in the EU. This review shows that a careful reconsideration of the generally assumed view that biofuels are important causes of indirect land use change is in place. Whereever feasible, this should be done using observed – rather than modeled – data.

Conclusion

This review addressed the impact of increased biofuels production on land use in major biofuel producing countries using full land balances based on land and crop statistics. Biofuel expansion is often considered a major threat for biomass availability for food and feed production and an important source of land use change. However, this analysis based on FAO statistics on crop production and land use in the period 2000 to 2010 shows that the impact of biofuel expansion on land use has been limited. An increase of 14 million ha was noted in 34 major biofuel producing nations over a period of a decade.

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

During the same period, increased cropping intensity generated over 42 million ha of extra crop land – three times the biofuel expansion. Further, an area of 31 million ha of agricultural area was lost (amongst other due to urbanization) in the USA, the EU, China, and South Africa. Consequently, there are strong drivers for expansion of land availability for traditional food and feed markets which has led to increased food and feed crop area. With the exception of the USA, biofuel expansion has not made up more than a quarter of the total loss of agricultural land.

This information should be considered in discussions on food vs. fuel debate and land-use change caused by biofuel policies. Existing frameworks need to be reconsidered. For example, biofuels *cannot* be identified as the most important or single global cause of land-use change. Other drivers have caused more (and more permanent) loss of agricultural area including process of urbanization, infrastructure development, tourism and even conversion into nature (an additional 8 million ha of forest have been established in the USA and the EU since 2000). Observed changes in land use caused by biofuel policies are very small in comparison to other changes.

Models used to evaluate biofuel policies should be enriched by incorporating more and better information on (changes in) land use and local cropping patterns, as well as differences in current and potential productivities in different agro-ecologies and farming systems. Finally, the relation between increased multiple cropping and biofuel production should be further investigated.

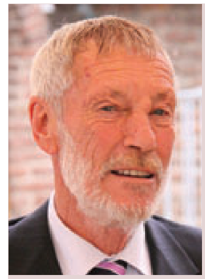
References

1. Banse M, van Meijl H, and Woltjer G, Biofuel policies, production, trade and land use. In: H. Langeveld , J. Sanders and M. Meeusen (eds.), *The Biobased Economy. Biofuels, materials and chemicals in the post-oil era.* Earthscan, London, pp. 244–258 (2010).
2. Al-Riffai P, Dimaranan B, and Laborde D, Global trade and environmental impact study of the EU biofuels mandate. International Food Policy Research Institute, Washington DC, (2012).
3. Elobeid AE, Carriquiry MA, and Fabiosa JF, Land-use change and greenhouse gas emissions in the FAPRI-CARD model system: addressing bias and uncertainty. *Climate Change Economics* **3:**1250014 (2012). DOI: 10.1142/S2010007812500145
4. Pérez Domínguez I and Müller M (eds), Modelling of energy crops in agricultural sector models. A review of existing methodologies. Joint Research Centre/Institute for Prospective Technological Studies, Seville, Spain (2008).
5. *CBES Land-Use Change and Bioenergy*: Report from the 2009 workshop. [Online]. US Department of Energy, Office of Energy Efficiency and Renewable Energy and Oak Ridge National Laboratory, Center for Bioenergy Sustainability Oak Ridge National Laboratory (2009). Available at: http://www.ornl.gov/sci/ees/cbes/workshops/LandUse_Report.pdf [July 8, 2013].
6. Khanna M and Zilbermann D, Modeling the land-use and greenhouse-gas implications of biofuels. *Climate Change Economics* **3:**1250014 (2012).
7. Golub AA and Hertel ThW, Modeling land-use change impacts of biofuels in the GTAP-BIO framework. *Climate Change Economics* **3:**1250015 (2012). DOI: 10.1142/S2010007812500157
8. Keeney R and Hertel ThW, The indirect land use impacts of US biofuel policies: The Importance of acreage, yield, and bilateral trade responses. GTAP Working Paper No. 52. Purdue University, Lafayette, Indiana (2008).
9. Beach BH, Zhang YW, and McCarl BA, Modeling bioenergy, land use, and GHG emissions with FASOMGHG: model overview and analysis of storage cost implications. *Climate Change Economics* **3:**1250012-1-1250012-34 (2012). DOI: 10.1142/S2010007812500121
10. Rosegrant MW, Ewing M, Msangi S, and Zhu T, Bioenergy and global food situation until 2020/2050. WBGU, Berlin (2008).
11. Nachtergaele F, Bruinsma J, Valbo-Jorgensen J and Bartley D, Anticipated trends in the use of global land and water resources. Food and Agricultural Organization of the United Nations, Rome (2011).
12. Bruinsma J, The resource outlook to 2050: By how much do land, water use and crop yields need to increase by 2050? [Online]. 33 pp. *Expert Meeting on How to Feed the World in 2050.* FAO and ESDD, Rome (2009). Available at ftp://ftp.fao.org/docrep/fao/012/ak542e/ak542e06.pdf [16 January 2012]
13. OECD-FAO, *Agricultural outlook 2009-2018.* OECD, Paris; FAO, Rome (2009).
14. Wallander S, Claassen R, and Nickerson C, *The ethanol decade. An expansion of U.S. Corn production, 2000-09*. [Online]. United States Department of Agriculture, Washington DC (2011). Available at http://www.ers.usda.gov/media/121204/eib79.pdf . [April 9, 2013].
15. Croezen H and Brouwer F, *Estimating indirect land use impacts from by-products utilization*. CE, Delft (2008).
16. Beets WC, Multiple cropping and tropical farming systems. Gower, Aldershot, UK (1982).
17. Nafziger E, Cropping systems*. Illinois Agronomy Handbook*. [Online]. (2008). Available at: http://extension.cropsci.illinois.edu/handbook/ [8 March 2013]
18. FAOSTAT, [Online]. (2013) Available at: http://faostat.fao.org/site/291/default.aspx [May 10, 2013].
19. Searchinger T, Heimlich R, Houghton RA, Dong F, Elobeid A, Fabiosa J *et al*., Supporting online material for 'Use of U.S. Croplands for Biofuels Increase Greenhouse Gases Through Emissions from Land-Use Change'. *Science* **319**: 1238 (2008). DOI: 10.1126/science.1151861
20. Gallagher P, Corn ethanol growth in the US without adverse foreign land use change: defining limits and devising policies. *Biofuels Bioprod Bioref* **4:2**96–309 (2010).

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

Hans Langeveld

Hans Langeveld, agronomist, develops and evaluates bioenergy and biobased production chains. His main focus is on feedstock availability, land use change, soil carbon dynamics and GHG emissions. He studied sustainable land use in five continents and co-authored many scientific papers as well as books on farming systems and the biobased economy.



Herman van Keulen

Herman van Keulen was trained as a soil scientist and production ecologist at Wageningen University. During his carreer, he wrote many crop growth models. Herman developed innovative concepts in soil water modelling and sustainability research and has been an expert on crop growth, animal production systems and sustainable land use for over four decades.

John Dixon

John Dixon is Principal Regional Adviser, Asia and Africa, Australian Centre for International Agricultural Research. He has over 30 years of developing country experience with agricultural research and development, including cropping systems, economics and natural resource management with the CGIAR system and the FAO UN.

Foluke Quist-Wessel

Foluke Quist-Wessel is senior agronomist and director of AgriQuest. She holds an MSc. in Tropical Crop Science (Wageningen University) and focuses on agricultural production systems, rural development, food security and chain development. Previously, she worked at Plant Research International (Wageningen UR), and Biomass Research.

© 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

This page intentionally left blank.

12_SF_LCFS_RFA

1234. Comment: **LCFS SF12-1**

The commenter is supportive of ARB's proposed modifications to section 95488 which streamline the re-certification process. The commenter however points out that it is somewhat unclear how ARB staff would handle the producer-specific inputs demanded by the CA-GREETv2.0 life cycle analysis model.

Agency Response: ARB staff appreciates the support provided by the commenter. In response to the Commenter's concern with regards to producer-specific inputs, staff is presently developing an administrative approach to processing re-certification of legacy pathways. Guidance will be provided on re-certification issues at a public workshop to be conducted after the proposed Board Hearing.

1235. Comment: **LCFS SF12-2**

The commenter supports the proposed prioritization of fuel pathway re-certifications for "batch processing."

Agency Response: ARB staff appreciates the support for the pathway re-certifications.

1236. Comment: **LCFS SF12-3**

This Comment is related to the definition and interpretation of a "Tier 1" fuel.

Agency Response: Please see response to **LCFS FF44-13**.

1237. Comment: **LCFS SF12-4**

Tier 1 fuels should be excluded from the Provisional Pathway requirements described in section 95488(d)(2).

Agency Response: Please see response to **LCFS SF4-1.**

1238. Comment: **LCFS SF12-5**

The commenter believes the requirement of one quarter of operational data for a provisional pathway will discourage investment and recommends allowing approval based on pilot plant data.

Agency Response: See response **LCFS FF56-2**.

1239. Comment: **LCFS SF12-6**

The commenter urges ARB to revise its indirect land use change (ILUC) analysis to reflect the best available science and data.

Agency Response: The comment is not relevant to any of the 15 day changes presented. However, ARB's response to this comment is:

The iLUC analysis as currently proposed by ARB is based on the latest and best available scientific and economic information. These values were developed by accounting for updates in land use change science and methodologies in economic modeling of such effects. See responses to **LCFS 8-1** through **LCFS 8-14**.

1240. Comment: **RFA Comment Letter**

Agency Response: Page 4 – 65 is a reproduction of comment letter **8_OP_LCFS_RFA** comments **LCFS 8-1** through **LCFS 8-14**.

Comment letter code: 13-SF-LCFS-SI

Commenter: Ellis, Graham

Affiliation: Solazyme

The following letter was submitted to the LCFS Docket during the Second 15-day comment period.

This page intentionally left blank.

13_SF_LCFS _SI

July 8, 2015

VIA ELECTRONIC FILING

Clerk of the Board
Air Resources Board
I00I I Street
Sacramento, CA 95814

Re: The Proposed Re-Adoption of the Low Carbon Fuel Standard

COMMENTS OF SOLAZYME, INC. ("So1azymc")

Solazyme appreciates the opportunity to comment on the California Air Resources Board's (ARB's) proposal for the 2015 Re-Adoption of the Low Carbon Fuel Standard (LCFS), and we are supportive of the LCFS. Solazyme was founded in California over 12 years ago and is based in South San Francisco. We are in commercial production and already selling biofuel to private fleets in the US, and we are eager to supply advanced biofuels for the California market.

Introduction to Solazyme

Solazyme has pioneered an industrial biotechnology platform that harnesses the prolific oil-producing ability of microalgae. Our platform is feedstock flexible and can utilize a wide variety of plant-based sugars such as sugarcane-based sucrose, corn-based dextrose, and sugar from other biomass sources including cellulosics. By growing our proprietary microalgae in the absence oflight using fermentation tanks to convert photosynthetic plant sugars into oil, we are in effect utilizing "indirect photosynthesis." Solazyme develops and manufactures products for the food, skin-care, industrial chemical and lubricants, and industrial/military fuels sectors.

Solazyme is Currently Producing Advanced Biofucls

At Solazyme, we are creating clean, low carbon, renewable algae-derived advanced biofl.tels. The company's tailored oils are refined into cost-effective, high-quality, on-spec "drop-in" replacements for diesel and jet fuels. Solazyme's algae-derived fuels are compatible with existing infrastructure, meet industry specifications, and can be used with fact01y-standard engines, without modifications. The company has worked with Chevron, UOP Honeywell, and other industry leading refining partners, to produce SoladieselRn®renewable diesel, Soladiesel® renewable diesel, and Solajet® renewable jet fuel for both military and commercial application testing.

After extensive work with the US Department of Defense, the US Navy, United Airlines, Volkswagen, and others, Solazyme is now producing blends of its fuels for private users in the United States. In fact, we have supplied more than four million gallons for fuel blends to private fleet operators to date. This work has shown that we can supply at scale in an efficient, cost-effective way and we are looking to expand our supply base. A well-designed LCFS would help significantly in allowing us to introduce this innovative fuel to California.

Advanced Biofuel Products

- SoladieselnD® is a I00% algae-derived biodiesel that can be used with facto1y-standard diesel engines without modification. The fuel is fully compliant with the ASTM D 6751 specifications for Fatty Acid Methyl-Esther based (FAME) fuel that meets ASTM D 975, and significantly outperforms ultra-low sulfur diesel in total THC, carbon monoxide and particulate matter tailpipe emissions. SoladieselBD®also demonstrates better cold temperature properties than any commercially available biodiesel.
- SoladieselRD® is a I00% algae-derived renewable diesel fuel. It is a drop-in altemative to standard diesel fuels that meets ASTM D 975. Chemically indistinguishable from petroleum-based diesel, the fuel's tailpipe emissions also release fewer particulates and meet the new American Society for Testing and Materials (ASTM) standards for ultra-low sulfur diesel.
- Solajet® is a renewable aviation fuel refined from Solazyme's algal oil. It is the world's first microbially-derived jet fiJel to meet key industry specifications for commercial aviation, ASTM D 1655. Solajet is compatible with existing infrastructure while offering key benefits, including a faster, farther and greater payload; reduced wing heat stress; lower flammability; lower smoke emissions; longer storage life; and ultimately, lower maintenance cost.
- Since 2008, Solazyme has partnered with the US Navy and the Department of Defense to develop, test and ce11ify advanced drop-in renewable fuels that meet their strictest standards. Specifically, Solazyme has developed jet fuel, marine diesel and on-road diesel that have been rigorously tested by the U.S. Navy and shown to meet its HRD-76 and HRJ-5 military specifications. We are proud that Solazyme fuels were used as the reference fuels during the Navy's successful multi-year certification process for renewable marine diesel fuel.

General Comments

Provisional Pathways (pg. 91-92)

The language in Section 95488, and specifically 95488(d)(2), is greatly conceming to Solazyme because of the upfront requirements for a new pathway. The latest language has made necessary improvements, such as the removal of the 2 year monetization hold, but there are still real issues for innovative producers looking to enter the market. For instance, the proposal still requires applicants to have been in full commercial production for at least one fi.Jll calendar quarter before applying for a new pathway. This timeline is not feasible for two reasons. First, biofuel refiners use or blend a broad array of feedstocks when making biodiesel or renewable diesel (e.g., cooking oil, tallow, soy oil, etc.). The dynamic nature of feedstocks processed at a facility over the course of one quarter would make it near impossible to generate consistent data for one new feedstock, even though most new feedstocks are very similar chemically and would provide very similar data. LCFS SF13-1

In addition, this timeline does not match the natural course of the commercialization process for a new biofuel. It is standard practice for biofuel refiners to take time to scale up a new feedstock while it is introduced, typically by running small batches over time. That means that the refiners will not generate a qumier's worth of consistent data on the new feedstock during its early adoption. This requirement will therefore significantly delay the opportunity for a new pathway and delay advanced biofuels from being introduced into California. It creates an undue administrative burden on the refiners to test and qualifY new feedstocks. This will greatly reduce their enthusiasm to incorporate new feedstocks and unfairly drives down the value of these new feedstocks. Instead, this requirement rewards incumbents.

Furthermore, as new feedstock producers enter the California market, this will create a proliferation of pathways for ARB staff to handle. Most feedstock providers will partner with numerous refiners to produce the end product: biodiesel or renewable diesel. This means there will be a two year process for each refiner, as well as a new pathway application for each refiner, for the ARB to review.

California and the ARB have typically lead adoption for new technologies, and we hope this legacy continues, particularly at a time when so many technologies are poised to enter the market.

Batch Processing in2016 (pg. 58)

Solazyme would also like clarification on the process outlined in Section 95488(a)(3). We understand that there are a large number of existing pathways to recertify and we support efforts to expedite this process. That said, the current language seems to indicate that each fuel type would get recetiified at different times. This does not provide a level playing field for the various fuel types and all those who have worked hard to participate in the LCFS. By applying new numbers to fuel types at different times, the ARB would inherently give an advantage to the groups that are recertified first. Instead, the new numbers should be applied at the same time.

Conclusion

Solazyme understands that lack of verification for CI data for already approved pathways is an important concern. We appreciate the revisions made in the June 4 draft rule to remove the 2 year monetization hold and reinforce the authority of the ARB Executive Officer to, instead, enforce CI verification compliance. This is a much fairer approach than upfront requirements that would punish new producers. There is still work to be done, however, in ensuring that the additional upfront requirements to establish a pathway do not significantly delay (or halt) the entry of advanced biofuels to the California market.

We appreciate having this opportunity to provide comments. Please contact me if you have any questions or require additional information.

Sincerely,

Graham Ellis
Vice-President of Business Development and Fuels
Solazyme, Inc.
225 Gateway Boulevard
South San Francisco, CA 94080
650-780-4777 x5155
gellis@solazyme.com

13_SF_LCFS_SI

1241. Comment: **LCFS SF13-1**

This comment is related to the 'full quarter of operations' requirement specifically as it applies to multiple feedstocks used to make transportation fuel, commercialization and scale-up of processes, and prioritization of processing of pathway applications.

Agency Response: See response to **LCFS FF56-2, LCFS SF12-5, and LCFS SF8-22**.

Because different feedstocks may have different upstream direct and indirect GHG emissions impacts, ARB would prefer the fuel pathway to be based on a specific feedstock used (or feedstock most commonly expected to be used) to produce the transportation fuel. Alternatively, the applicant can demonstrate worst-case scenario modeling and selectively base the application on one feedstock.

With regards to the commenter's comments on priority processing of applications for re-certification in batches based on fuel type (pursuant to section 95488(a)(3) of the modified regulation order), staff responds that the prioritization was based on the largest volumes of low carbon fuels (by fuel type) reported in the LCFS Registration System or LRT. Staff believes that for most applicants seeking re-certification, the transition to a newer CI would be seamless.

This page intentionally left blank.

F. COMMENTS RECEIVED DURING THE THIRD 15-DAY COMMENT PERIOD, JULY 31 – AUGUST 17, 2015

Two comment letters were received during the third 15-day comment period. Each comment letter is reproduced below with responses following.

This page intentionally left blank.

Comment letter code: 1-TF-LCFS-DuPont

Commenter: Koninckx, Jan

Affiliation: DuPont

The following letter was submitted to the LCFS Docket during the Third 15-day comment period.

This page intentionally left blank.

1_TF_LCFS _DuPont

August 17, 2015

Samuel Wade
California Air Resources Board
Branch Chief, Transportation Fuels Branch
1001 I Street
Sacramento, CA 95814

Re: Third Notice of Proposed 15-day Regulation Order containing Modified Text and Availability of Additional Documents and Information for the Proposed Re-Adoption of the Low Carbon Fuel Standard

Dear Samuel Wade:

On behalf of DuPont, thank you for the opportunity to comment on the Third Notice of Proposed Modified Text for the LCFS. DuPont has significant investments in advanced biofuels that meet the specified greenhouse gas reduction threshold. These fuels will make transformative contributions to our nation's energy security, reduce greenhouse gas emissions and strengthen rural economies. These fuels represent a tremendous shift in how we energize our planet and are being commercialized due in large part to visionary state fuels programs like the CA Low Carbon Fuel Standard.

We look forward to doing business in California; however as raised in prior comments, DuPont has one significant remaining concern with the Third Notice of proposed modification to Obtaining and Using Fuel Pathways in Section 95488(d). In Section 95488 (d)(1)(D), the proposed text would allow assigning a temporary fuel production code carbon intensity (CI) that could apply for two quarters. The issue with this approach is that the temporary CI could expire prior to a fuel pathway being approved. This limitation is unnecessary and overly restricts the Air Resources Board's ability to be flexible when needed. A new fuel producer must have 3 months of operational data before submitting a new pathway request pursuant to Section 95488 (d)(2). Completing and submitting an application form after the first 3 months of operation will take several weeks. We are concerned that the fuel pathway approval process could extend beyond the period of time covered by the temporary fuel production code. It is incredibly important for new advanced biofuel producers to be able to sell into the CA market from the first day of operation and continue without a lapse in valid carbon credits.

Therefore, DuPont recommends that the regulations be modified to allow the Air Resources Board flexibility to extend the period of time for temporary fuel production codes, when circumstances warrant an extension or when a new fuel producer is actively seeking a fuel pathway approval.

LCFS TF1-1

Introduction

DuPont is an industry leader in providing products for agricultural energy crops, feedstock processing, animal nutrition, and biofuels. Our three-part approach to biofuels includes: (1) improving existing ethanol production through differentiated agriculture seed products, crop protection chemicals, as well as enzymes and other processing aids; (2) developing and supplying new technologies to allow conversion of cellulose to ethanol; and (3) developing and supplying next generation biofuels with cellulosic ethanol and biobutanol.

We bring the perspective of a company deeply involved in the agricultural and biofuels industries. Our seed business DuPont Pioneer sells corn seed to farmers growing for a variety of end-use markets, including grain ethanol production. Our intimate relationship with our farmer customers and our extensive research provides us significant insight into the agronomics of the harvest and management of corn stover as a cellulosic feedstock. We provide a variety of products for the grain ethanol business as well, including saccharification enzymes and fermentation processing aids, and so have an intimate knowledge of the operation of these relevant sugar fermentation operations.

DuPont began its research into cellulosic technology a decade ago. What started as a lab scouting project grew into a full scale commercialization effort. In 2009, DuPont opened a demonstration facility in eastern Tennessee producing cellulosic ethanol from both corn stover and switchgrass. For the past four years, we have brought together growers, academia, public institutions like the USDA and custom equipment makers to conduct harvest trials on corn stover. All this work culminated in the groundbreaking of a 30 million gallon per year facility in December of 2012 in Nevada, Iowa, located approximately 40 miles north of Des Moines. I am happy to report that we are in the very final stages of construction, commissioning has been initiated and we will be open for business later this year. We anticipate that a number of other companies in addition to DuPont will bring cellulosic volumes to the market. Multiple companies are constructing, starting up or operating facilities producing renewable fuels from a wide variety of cellulosic feedstocks including corn stover, switchgrass, wheat straw, municipal solid waste and wood fiber. Many of these are large, well-capitalized, sophisticated companies with long track records in designing, constructing and operating manufacturing facilities. This diversity of operations provides a high level of confidence for multiple technologies succeeding at commercial scale.

In addition to cellulosic ethanol, DuPont is pursuing another advanced renewable fuel with our partner BP in a 50/50 joint venture called Butamax™. The joint venture has developed and extensively tested bio-butanol, a higher alcohol fuel produced by fermenting biomass. Biobutanol has excellent fuel properties, with higher energy density than ethanol and the ability to be distributed via the existing gasoline infrastructure, including pipelines. It also reduces volatility, allowing butanol gasoline blends to be used in the summer in regions that currently require waivers from air quality regulation for the use of ethanol-gasoline blends. Because butanol has less affinity for water and is a weaker solvent than ethanol, it will be more compatible with existing equipment, including small engines.

The proposed modification to Provisional Pathways

In the Proposed 15-day Regulation Order containing the Third Notice of Modified Text and Availability of Additional Documents and Information for the Proposed Re-Adoption of the Low Carbon Fuel Standard, the Air Resources Board proposes the following in Section 95488 (d)(1)(D):

> (D) A temporary FPC approved for use by the Executive Officer will be permitted for LRT-CBTS reporting purposes for up to two quarters. Reporting will be granted only for the quarter during which a temporary FPC is approved for use and the subsequent full quarter.

Analysis and Recommendations

The proposed text is overly restrictive on the Air Resources Board preventing any flexibility to extend a temporary FPC beyond two quarters. In detail, our concerns with the proposed approach are as follows:

1. The current proposed text would by default assign a temporary, conservative CI value to these fuels that can only be applied for two quarters. This means that the temporary CI credits could lapse before the fuel pathway is approved. Any waiting period that prevents these fuels from receiving CI credit is fundamentally unfair and is not based on principles of sound science. LCFS TF1-2

2. Any waiting period that prevents a biofuels producer from receiving CI credits will prevent and delay fuel from being sold in California. DuPont's cellulosic ethanol is being manufactured in Iowa. Without the benefit of the CI credit, it would be unreasonable for us to make special arrangements to ship our fuel to California. In addition, obligated parties in California would have no reason to purchase fuel without CI credits. Given their obligations under the LCFS, they would need to purchase fuel with CI credits. LCFS TF1-3

3. Any waiting period that prevents a biofuels producer from receiving CI credits would create an unfair competitive advantage for existing fuel producers. These producers would not be required to wait to receive CI credits thereby rewarding current producers. LCFS TF1-4

4. New facilities need to be able to sell fuel for full market value from initial production and on a continuous basis in order to survive. Biofuels facilities do not have storage capacity beyond one or two days of fuel production. In addition, encouraging growth in the cellulosic and advance biofuels sector can only be achieved with supportive federal and state biofuels policies. A waiting period for CI credits would discourage rather than encourage growth. LCFS TF1-5

5. The temporary fuel production code CI for cellulosic ethanol is 41.05 as set forth in Table 7 in Section 95488. There is a very high probability that after one quarter of production and subsequent quarters of energy data submitted, that the CI value for this fuel will be reduced significantly. Therefore, there should be very little risk in allowing the Air Resources Board the flexibility to extend the temporary FPC if circumstances warrant it. LCFS TF1-6

Given the concerns above, DuPont recommends that the regulations be modified to provide the Air Resources Board the requisite flexibility to extend the assigned temporary fuel production code CI value as long as necessary while the new producer is actively pursuing a new pathway approval.

Thank you for the opportunity to comment on the Third Notice of the Proposed 15-day Regulation Order for the Proposed Re-Adoption of the Low Carbon Fuel Standard as this is an important issue for DuPont's biofuels business. Please contact me at Jan.Koninckx@dupont.com if you have any questions about the comments provided.

Sincerely,

Jan Koninckx

Jan Koninckx, Global Business Director for Biorefineries
DuPont Industrial Biosciences

This page intentionally left blank.

1_TF_LCFS_DuPont Responses

1242. Comment: **LCFS TF1-1 through LCFS TF1-6**

These comments relate to the two-quarter limit on using Temporary Pathway CIs specifically as it applies to commercialization and scale-up of new processes. The commenter sees potential for economic hardship if Temporary Pathways expire before a full pathway application is approved.

Agency Response: ARB staff has recognized the commenter's concerns. The Table 7 is available to any regulated party who has purchased a fuel, but unable to determine its CI associated with that fuel. As stated in the staff Initial Statement of Reasons (ISOR) (Summary of Section 95488(d), p VIII-11):

A fuel provider is seeking to sell a volume of fuel which has no CI associated with it. Section (d) provides a table of temporary default CIs that can be used to report transactions involving such fuel.

Therefore, Table 7 provides the flexibility which allows applicants to sell their fuels in California market while their fuel pathway applications are in the process for its certification. However, staff urges applicants to submit their applications at the same timeframe when a temporary fuel CI code is activated in the LRT-CBTS system for their use and reporting. ARB staff has assessed carefully and determined that two quarters (180 days) should be sufficient enough for staff to complete the certification process without any impact on regulated party to generate some credits for the interim period.

This page intentionally left blank.

Comment letter code: 2-TF-LCFS-GE

Commenter: Willter, Joshua

Affiliation: Growth Energy

The following letter was submitted to the LCFS Docket during the Third 15-day comment period.

This page intentionally left blank.

2_TF_LCFS_GE

Growth Energy's Comments on July 31, 2015, 15-Day Notice for the Proposed Revisions to the LCFS Regulation

Growth Energy submits the following comments on the California Air Resources Board's ("CARB") July 31, 2015, Notice of Public Availability of Modified Text and Availability of Additional Documents (the "Third 15-Day Notice") for CARB's proposed revisions to the Low Carbon Fuel Standard (the "LCFS regulation").

The Third 15-Day Notice represents the third time CARB staff has performed substantive modifications to the proposed LCFS regulation since it initially circulated an Initial Statement of Reasons (the "ISOR") and an Environmental Analysis ("EA") for public review on December 30, 2014. CARB circulated the first 15-day notice for public review on June 4, 2015 (the "First 15-Day Notice"). CARB circulated the second 15-day notice for public review on June 23, 2015 (the "Second 15-Day Notice").

LCFS TF2-1

In light of all the remaining and important open issues, uncertainties, inconsistencies, and procedural errors that have marked this regulatory process, Growth Energy believes that the Board cannot take final action on the now thrice-amended regulatory proposal without publication of a new rulemaking notice that allows 45 days for public comment, leading to a new public hearing. In addition, Growth Energy submits the following comments on the Third 15-Day Notice. Submitted with these comments are the declarations of James M. Lyons and Thomas L. Darlington, which are enclosed as Attachments "A" and "B," respectively.

A. CARB's Assumptions Regarding the Usage of Renewable Natural Gas <u>in Heavy-Duty Vehicles Are Not Supported by Substantial Evidence</u>

1. CARB's Analysis of Renewable Natural Gas is Internally Inconsistent with CARB's Method of Analysis for Electric <u>Vehicles</u>

LCFS TF2-2

As part of its recent 15-day notice, CARB added a spreadsheet entitled "Estimate of Electricity Use by ZEVs" to the rulemaking file. The spreadsheet reveals the assumptions made by CARB staff in estimating the amount of electricity that would be used by light-duty battery electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs). This analysis was used to develop "illustrative compliance scenarios and evaluat[e] potential compliance curves" included in Appendix B of the ISOR (and updates). The assumptions include the values for the number of EVs and PHEVs in operation, vehicle miles traveled, and fuel efficiency, which are generally consistent with the conclusions published by CARB staff in connection with the Zero Emission Vehicle (ZEV) regulation, which requires automobile manufacturers to produce EVs and PEHVs and offer them for sale in California. (Decl. Lyons ¶ 6.) This information is necessary to understand how CARB staff "arrived at its conclusions regarding the use of electricity as a transportation fuel in the light-duty vehicle fleet, which . . . is critical to assessing the veracity of the illustrative compliance scenarios, the environmental analysis of the proposed LCFS regulation and the estimated cost of the regulation." (*Id.* ¶ 8.) CARB has not explained why this information was not included in the original 45-day notice, nor why it waited until now to make the information available for public comment. The 15 days allowed for public review and comment are insufficient, although Growth Energy has attempted to prepare limited, time-constrained comments in Attachment "A." Among other problems, the record does not include any comparable information for the use of renewable natural gas in heavy-duty vehicles. In fact, CARB staff has advised that it "never performed an analysis similar to that disclosed for ZEVs for natural gas usage by heavy-duty vehicles under the LCFS." (Decl. Lyons ¶ 9.) This is surprising and raises serious concerns regarding the validity of the LCFS illustrative compliance scenario and, consequently, the environmental and economic analysis that were based upon that scenario. (See *id.*) "Further, it is impossible for any stakeholder or reviewing body such as the Office of Administrative Law to understand how the staff arrived at its conclusions regarding the use of electricity as a transportation fuel in the light-duty vehicle fleet, which again is critical to assessing the veracity of the illustrative compliance scenarios, the environmental analysis of the proposed LCFS regulation, and the estimated cost of the regulation." (*Id.*)

LCFS TF2-2 cont.

LCFS TF2-3

Because CARB's methods of analysis for EVs/PHEVs and natural gas are internally inconsistent, CARB's conclusions regarding natural gas usage are not supported by substantial evidence. (See, e.g., *Friends of Oroville v. City of Oroville* (2013) 219 Cal.App.4th 832, 844 [concluding that "speculative and contradictory conclusions do not close the evidentiary sufficiency gap involving the City's finding that the Project's GHG emissions will have a less than significant environmental impact after mitigation."]; see also *Vineyard Area Citizens for Responsible Growth, Inc, v. City of Rancho Cordova* (2007) 40 Cal.4th 412, 439 ["Factual inconsistencies and lack of clarity in the FEIR leave the reader – and the decision makers – without substantial evidence for concluding that sufficient water is, in fact, likely to be available for the Sunrise Douglas project at full build-out."].)

Accordingly, before CARB considers the revised LCFS regulation for approval, it should first disclose the assumptions and analysis used to estimate the use of natural gas in heavy-duty vehicles. Under its certified program, the Board must then permit full public comment and conduct a public hearing. (17 Cal. Code Regs., §§ 60000-60007.)

LCFS TF2-4

2. CARB Has Failed to Meet its Information Disclosure Requirements With Respect to the Use of Natural Gas in <u>Heavy Duty Trucks</u>

"CARB's projected increase in natural gas use in heavy-duty vehicles relative to 2014 levels is 2.6 times in 2020 and 4.4 times in 2025." (Decl. Lyons, Exhibit B-1.) To meet these increases, there would need to be "a massive increase in natural gas as a fuel for heavy-

LCFS TF2-5

duty vehicles, which directly implies a similar massive increase in the number of heavy-duty natural gas vehicles in operation in California." (*Id.*, Exhibit B-3.) Notably, however, CARB's analysis includes no estimate of "number of vehicles required" to meet the projected increase in natural gas as a fuel for heavy-duty vehicles, nor is there any evidence in the record "to support that it is reasonably foreseeable that the required number of vehicles will be in operation in California" to correspond to this demand. (*Id.*, Exhibit B-3.)

CARB's failure in this regard has resulted in a flawed and unreliable analysis. First, by (i) failing to estimate the number of vehicles required to meet CARB's projected increase in natural gas, and (ii) failing to include any evidence that it is "reasonably foreseeable" such increase would occur, CARB has failed to meet its information disclosure obligations under CEQA. Specifically, CEQA requires that an environmental analysis "provide sufficient information to enable the "'public [to] discern . . . the 'analytic route . . . from evidence to action . . . .'" (*City of Maywood v. Los Angeles Unif. Sch. Dist.* (2012) 208 Cal.App.4th 362, 393 [quoting *Calif. Oak Found. v. Regents of Univ. of Calif.* (2010) 188 Cal.App.4th 227, 262].) Because CARB staff did not prepare any detailed estimate of natural gas use by heavy-duty vehicles, and CARB's conclusions regarding natural gas usage are "unsupported by empirical or experimental data, scientific authorities, or explanatory information of any kind," the public and the decision makers have been left without any "basis for a comparison of the problems involved with the proposed project and the difficulties involved in the alternatives." (*Citizens to Preserve the Ojai v. County of Ventura* (1985) 176 Cal.App.3d 421, 429.) LCFS TF2-5 cont.

CARB's failure to provide evidence supporting any increase in heavy-duty gas vehicles in California is particularly puzzling here, as any such increase is contrary to the evidence. Analysis by Sierra Research shows "there will be no significant increase in either the heavy-duty natural gas vehicle population or natural gas use by such vehicles unless CARB requires the purchase and use of such vehicles." (Decl. Lyons, Exhibit B-3.) LCFS TF2-6

Specifically, there "are no existing CARB regulations like the ZEV mandate that require dramatic increases in the sale of heavy-duty natural gas vehicles." (*Id.*) "[I]ncreases in the California heavy-duty natural vehicle population will" therefore "be driven by market forces," and "[i]f CARB believes that the market will drive those increases, staff needs to explain why and allow the public to comment on that explanation." (*Id.*, Exhibit B-4.)

Moreover, any projected increase in the entry of a significant number of heavy-duty natural gas vehicles into the market is contradicted by CARB's own data, which show "substantial barriers to increases in heavy-duty natural gas populations." (*Id.*, Exhibit B-4.) These barriers include: (1) Shorter range between refueling; (2) Increased weight; (3) 10 to 15% lower fuel economy; (4) Higher purchase costs which range from $30,000 to $80,000 per vehicle; (5) Higher maintenance costs of 1-2 cents per mile; and (6) a limited number of LCFS TF2-7 publically accessible refueling stations. (*Id.*) There is simply no evidence CARB took these factors into account when it estimated future natural gas use by heavy-duty vehicles. LCFS TF2-7 cont.

If the entry of heavy-duty natural gas vehicles into the market does not materialize, there will also be potentially significant environmental effects, as regulated parties would have to look to other fuels to comply with the LCFS regulation. If heavy-duty users turn to biodiesel, for example, the LCFS regulation has the potential to increase NOx emissions statewide, including "significant increases in NOx emissions in the South Coast and San Joaquin Valley air basins which are already in extreme non-attainment of the federal ozone NAAQS and moderate non-attainment of the federal fine particulate NAAQS." (Decl. Lyons ¶ 13.) LCFS TF2-8

In any event, CARB's analysis relies upon "unsupported speculation that contradicts economic logic and CARB staff assessments of heavy-duty natural gas vehicles outside of the LCFS rulemaking process." (Decl. Lyons ¶ 13.) Because there is no evidence to suggest a significant increase in heavy-duty gas vehicles is "reasonably foreseeable," and in fact the evidence points to the exact opposite conclusion, CARB's analysis does not "provide sufficient information to enable "'public [to] discern . . . the 'analytic route . . . from evidence to action . . . .'" (See *City of Maywood, supra*, 208 Cal.App.4th at 393.) As a result, CARB's environmental analysis should be revised to address whether a significant increase in heavy-duty gas vehicles is truly reasonably foreseeable. LCFS TF2-9

3. CARB Must Revise its Economic Impact Analysis to Account for the Need for California's Heavy-Duty Gas Vehicle Population to More than Quadruple By 2025

Because there is no analysis in the ISOR (or elsewhere) regarding the number of vehicles required to meet CARB's projected increase in natural gas, Sierra Research performed this analysis. According to Sierra Research, to meet CARB's projected increase, the number of California Heavy-Duty Natural Gas Vehicles would need to more than ***quadruple*** in just ten years. California heavy-duty vehicle users would need to spend approximately $2.4 billion to meet CARB's fuel forecast in order to use natural gas instead of diesel vehicles, in addition to increased maintenance costs of between $22 and $44 million per year. (Decl. Lyons, Exhibit B-4.) LCFS TF2-10

These costs were not included by CARB in its economic analysis for the LCFS regulation, as required under the Government Code, including Sections 11346.3 and 11346.5. (Decl. Lyons, Exhibit B-4.) Because CARB's economic analysis does not take into consideration over $2.4 billion in additional costs associated with the need for California businesses to purchase heavy-duty natural gas vehicles to meet CARB's projections of natural gas usage, CARB's economic impact assessments are not adequately supported by "facts, evidence, documents, testimony or other evidence." (Govt. Code, § 11346.5(a)(8).) If CARB does not agree with our cost estimate, it should explain why, and provide a different estimate along with the basis for its different estimate. If CARB does not believe that these costs must be considered in the current rulemaking, it must explain why. LCFS TF2-10 cont.

4. CARB Failed to Address the Potential Environmental Impacts Associated with the Potential Inability to Meet CARB's 2025 Natural Gas Targets

As explained above, CARB's estimates for natural gas usage by heavy-duty vehicles is exceptionally optimistic, and unlikely to be realized. Nevertheless, there is no indication in CARB's environmental document that CARB analyzed the potential impacts associated with the inability to meet those optimistic targets. LCFS TF2-11

Specifically, if there is no demand in California for the $2.4 billion in heavy-duty natural gas vehicles contemplated under the revised LCFS regulation, this will have a substantial impact on CARB's estimation of credits and deficits generated by the proposed LCFS regulation. For example, if demand for natural gas remains at 2014 levels – *i.e.*, 110 million diesel gallon equivalents – during the years 2015 through 2025, natural gas credits will be reduced significantly, while diesel deficits will increase. (Decl. Lyons, Exhibit C-1.) This would result in deficits of -3.85 MMTs in 2025 for the May 22 natural gas compliance scenario alone, along with net total deficits for the LCFS program generally. (*Id.*, Exhibit C-1, C-2.) LCFS TF2-12

Accordingly, CARB must significantly reevaluate the number of credits and deficits that will likely result from the implementation of the LCFS regulation, (Decl. Lyons, Exhibit C-1), and evaluate the potential environmental effects associated with the potential credit imbalance caused by the proposed LCFS regulation. Thereafter, CARB should recirculate both the environmental analysis and the revised LCFS regulation for public review.

B. CARB's Indirect Land Use Change Factor for Corn Ethanol Is Based on Incomplete Data and Faulty Analysis, and Lacks Evidentiary Support

CARB's proposed revisions to the LCFS regulation contemplate a land use change ("LUC") value for corn ethanol of 19.8 gCO_2e/MJ. This value is based, in large part, on the Global Trade Analysis Project Model (the "GTAP Model"). The price-yield elasticity[1] of a particular biofuel "is an important parameter used in the GTAP [M]odel to estimate the LCFS TF2-13

[1] "[P]rice-yield elasticity is a measure of the change in yield with a change in price of a commodity." (Decl. Darlington ¶ 4.) For example, "[a] price-yield elasticity of 0.25 . . . means that if corn prices increase by 1%, corn yield would be expected to increase by 0.25%." (*Id.*) "The increase in yield is brought about by producers using seed types that are resistant to drought and disease, more intensive planting, possibly more fertilizer, irrigation, and other methods." (*Id.*)

magnitude of land use changes" that CARB contends is associated with that biofuel. (Decl. Darlington ¶ 4.)

To calculate the corn ethanol LUC value, CARB staff used the average of five price-yield values [0.05, 0.10, 0.175, 0.25, and 0.35], which is 0.185. (*Id.* ¶ 6.) To select these five values, CARB used (1) input from the expert working group (EWG) on elasticities, (2) its own review of various price-yield studies, and (3) a report by David Rocke reviewing some price-yield studies. The data Rocke relied upon to critique one of the studies, the Perez study, was not provided by ARB for review until August 1, 2015. (Decl. Darlington ¶ 7.) As with the late addition of the ZEV spreadsheet to rulemaking file, CARB's failure to comply with the Government Code's requirements is unexplained, prejudicial, and impossible to correct merely by allowing a brief period for review with no opportunity for the public to address at a hearing by the Board. LCFS TF2-13 cont.

As is now plainly apparent, in light of the late addition of the Rocke data to the rulemaking file, the 0.185 price-yield value is not supported by the evidence. CARB's own Elasticity Values Expert Working Group (EWG) recommended a mid-point value of 0.25.[2] The only report relied upon by CARB to support a lower price-yield value was prepared by David Rocke of UC Davis. The Rocke analysis is based on only one set of data – a 2012 dissertation by Juan Francisco Rosas Perez, who concluded that price-yield response was approximately 0.29. Despite claiming to use that data set, the Rocke study ignored the Perez data, and somehow concluded the price yield should be lower. (*Id.* ¶¶ 16-18.) Until approximately August 1, 2015, the rulemaking file did not contain an explanation as to how the Rocke study reached this conclusion or performed his statistical analysis. (*Id.* ¶ 7.) Once the information was finally made available to the public, it became readily apparent the lower price-yield values were deeply flawed and unsupported by the evidence. Specifically, although the Perez study found a price-yield value of 0.29, Rocke used the same data as Perez to reach an entirely different result, *i.e.*, that "price elasticities of yield" are "small to zero." (Decl. Darlington ¶ 18.) This conclusion is contrary to the evidence, misinterpret the Perez study, and is based on modeling practices that are inconsistent with the methods CARB has used for other rulemakings. LCFS TF2-14

First, in performing his "simple" analysis, Rocke only used "a small part of the Perez data." (Decl. Darlington ¶ 23.) Because Rocke's analysis only uses a small portion of the Perez data, and CARB relied upon the Rocke analysis to depart from the 0.25 price yield value recommended by its own EWG, CARB's use of a price-yield value of 0.185 is unsupported by the evidence. Without public access to the data on which he relied, the public was completely mislead about the nature of Dr. Rocke's analysis and its unreliability. LCFS TF2-15

[2] *Final Recommendations from the Elasticity Values Subgroup*, ARB LCFs Expert Workgroup, *available at* http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/010511-final-rpt-elasticity.pdf

Rocke's conclusions also misinterpret the Perez study, and are thus wholly unreliable. The entire point of the Perez study was to show how "a wide range of related parameters" affect the price yield values. (Decl. Darlington ¶ 20.) Rocke, however, simply took a small subset of the parameters, and determined based on the incomplete data there was no price yield elasticity. (*Id.* ¶ 16-19.) Nothing in the open record from Dr. Rocke or any other source explains why he took that approach. LCFS TF2-16

Rocke's method of modeling is also inconsistent with the methods CARB has used for other rulemakings. (Decl. Darlington ¶ 19.) Rocke's simple modeling focuses only on one parameter, which has a higher likelihood of resulting in conclusions suggesting a certain parameter is statistically insignificant. (*Id.*) Reliable and scientifically defensive modeling practices include a full range of inputs that could influence vehicle emissions; for example, CARB's Predictive Model for gasoline estimates emissions from cars and trucks in response to a number of gasoline inputs, including sulfur, benzene, T50, T90, aromatics, olefins, volatility, and total oxygen. (*Id.* ¶ 19 n.14.) Rather than relying upon Rocke's conclusions based on incomplete data, CARB should instead rely upon the conclusions of its own EWG, and studies LCFS TF2-17 that are internally consistent with the methodologies it uses in other contexts. Among other steps that CARB must take now, Dr. Rocke's analysis, including the data on which he relied, must receive the external scientific review mandated by Section 57004 of the Health and Safety Code. One, though by no means the only, indication of the need for external review is the fact CARB's own EWG examined the same issue, yet reached a vastly different result. If CARB does not agree, it should explain its reasons for disagreement in full, and address the following issues: LCFS TF2-18

- Whether CARB believes Rocke's very limited analysis of price and supply data alone constitutes an adequate analysis of the Perez data, when CARB's own typical methods of analyzing data are much more robust than those employed by Rocke.

- Why CARB deviated from the EWG recommendation of 0.25 for a central value or average value for YPE.

- What exactly was wrong with how Perez handled autocorrelation in his analysis.

(See *id.* ¶ 25.)

CARB's improper reliance on the Rocke data has significant real-world consequences. Using a factually-supported price-yield value, such as the 0.25 recommended by CARB's EWG, the LUC for corn ethanol would be 17.3 gCO_2/MJ, compared to the 19.8 gCO_2/MJ using the proposed inputs. (Decl. Darlington ¶ 32.) Although Growth Energy considers the use of indirect LUC factors in the LCFS regulation to be generally unsound, CARB has included LUC factors as a component of the Carbon Intensity ("CI") Value placed on a fuel LCFS TF2-19 by CARB. If CARB inaccurately calculates the LUC (and thus the CI Value) of a fuel – such as corn ethanol – as being too high, it will prevent achievement of reductions in greenhouse gas emissions in the most cost-effective manner possible, which is the purpose of the LCFS regulation and a mandatory duty under the 2006 Global Warming Solutions Act. By reducing the CI value assigned to corn ethanol above a level that is scientifically supportable relative to other renewable fuels, CARB is incentivizing the use of fuels that do not provide the maximum GHG reductions in a cost-effective manner. The LCFS regulation will create incorrect "market signals" contrary to the intended effect of the overall LCFS program.[3] (*Cf. id.* ¶ 33.)

LCFS TF2-19 continued

To avoid these potential adverse consequences, and to develop LUC Values (and thereby CI Values) that are based on scientific data and the facts, the GTAP should use a price-yield value that is no less than 0.25, the amount recommended by CARB's EWG. If CARB does not take this action, it should explain why in a new rulemaking notice and permit testimony at a public hearing.

C. Because the 15-Day Review Period Provides Insufficient Time for Commenting Parties to Evaluate the New Evidence and Modifications to the Revised LCFS Regulation, CARB Should Recirculate the EA

Finally, it bears further emphasis that fifteen calendar days provides insufficient time for the public to review CARB's modifications to the proposed LCFS regulation.

LCFS TF2-20

The 15-Day Notice not only includes substantial modifications to the proposed LCFS regulation, but extensive new information regarding CARB's analyses. This information includes, for example, detailed information underlying CARB's analysis of EVs/PHEVs and information regarding the Rocke analysis. This information appears to have been available since the original 45-day comment period, and Growth Energy's representatives have requested that information on many occasions since that time. The statement in the 15-day notice that CARB is seeking public comment on the additional materials in "the interests of fairness and transparency" is ironic, and misleading. It has taken the pressure of litigation against CARB under the Public Records Act – in which CARB has raised its duties under the rulemaking-file provisions of the Government Code as a type of defense – to force CARB to put the new materials in the rulemaking file. CARB initially resisted that Public Records Act request with dilatory motions practice, until the Court with jurisdiction in that case became fully engaged in the issues. No private party should have to bear the expense of attempting to require a public agency to comply with its information disclosure obligations under the Government Code during the rulemaking process, yet this is exactly what CARB forced Growth Energy to do here.

LCFS TF2-21

3 See CARB, "Staff Report: Initial Statement of Reasons, Proposed Regulation to Implement the Low Carbon Fuel Standard," Vol. I at VI-20 (March 5, 2006), available at http://www.arb.ca.gov/fuels/lcfs/030409lcfs_isor_vol1.pdf.

Rather than providing all interested parties, including Growth Energy, with an adequate opportunity to review these highly relevant documents – which, as explained above, show fundamental flaws in CARB's analysis – CARB instead placed the documents into the rulemaking file concurrently with its third 15-day notice. Fifteen days is simply insufficient for technical experts with relevant knowledge of the subject matter of the proposed LCFS regulation; certainly, a member of the public with no technical or legal background could not meaningfully be asked to provide comments on CARB's modifications and new evidence within this short timeframe. LCFS TF2-22

In light of the foregoing, and the significant new information provided by CARB with respect to its analysis of the revised LCFS regulation, CARB should recirculate both the proposed LCFS regulation and a revised EA for 45-day review. LCFS TF2-23

STATE OF CALIFORNIA

BEFORE THE AIR RESOURCES BOARD

Declaration of James M. Lyons

I, James Michael Lyons, declare as follows:

1. I make this Declaration based upon my own personal knowledge and my familiarity with the matters recited herein. It is based on my experience of nearly 30 years as a regulator, consultant, and professional in the field of emissions and air pollution control. A copy of my résumé can be found in Exhibit A.

2. I am a Senior Partner of Sierra Research, Inc., an environmental consulting firm located at 1801 J Street, Sacramento, California owned by Trinity Consultants, Inc. Sierra specializes in research and regulatory matters pertaining to air pollution control, and does work for both governmental and private industry clients. I have been employed at Sierra Research since 1991. I received a B.S. degree in Chemistry from the University of California, Irvine, and a M.S. Degree in Chemical Engineering from the University of California, Los Angeles. Before joining Sierra in 1991, I was employed by the State of California at the Mobile Source Division of the California Air Resources Board (CARB).

3. During my career, I have worked on many projects related to the following areas: 1) the assessment of emissions from on- and non-road mobile sources, 2) assessment of the impacts of changes in fuel composition and alternative fuels on engine emissions, including emissions of green-house gases, 3) analyses of the unintended consequences of regulatory actions, and 4) the feasibility of compliance with air quality regulations.

4. I have testified as an expert under state and federal court rules in cases involving CARB regulations for gasoline, Stage II vapor recovery systems and their design, factors affecting emissions from diesel vehicles, evaporative emission control system design and function, as well as combustion chamber system design. While at Sierra I have acted as a consultant on automobile air pollution control matters for CARB and for the United States Environmental Protection Agency. I am a member of the American Chemical Society and the Society of Automotive Engineers and have co-authored nine peer-reviewed monographs concerned with automotive emissions, including greenhouse gases and their control. In addition, over the course of my career, I have conducted peer-reviews of numerous papers related to a wide variety of issues associated with pollutant emissions and air quality.

5. This Declaration summarizes the results of my review of the CARB Notice of Public Availability of Modified Text and Availability of Additional Documents for the Proposed Re-Adoption of the Low Carbon Fuel Standard Regulation (the LCFS Regulation) dated July 31, 2015. I have performed this review as an independent expert

for Growth Energy. If called upon to do so, I would testify in accord with the facts and opinions presented here.

6. According to CARB staff, the illustrative compliance scenario published in the ISOR and last updated as part of the May 15-day notice has been used for a number of purposes. These include preparation of the environmental analysis[1] and assessment of economic impacts.[2] In response to a lawsuit under the Public Records Act and discussions between counsel for CARB and Growth Energy, CARB has recently added a spreadsheet entitled "Estimate of Electricity Use by ZEVs" to the rulemaking file. This spreadsheet reveals the assumptions made by CARB staff in estimating the amount of electricity that would be used by light-duty battery electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs) for the purposes of developing illustrative compliance scenarios and evaluating potential compliance curves as documented in Appendix B of the Initial Statement of Reasons (ISOR) and subsequent updates. These assumptions include the number of EVs and PHEVs in operation, as well as the annual number of miles traveled and the fuel efficiency of the vehicles. In general, the assumptions reflect the regulatory requirements of the Zero Emission Vehicle (ZEV) regulation,[3] which requires automobile manufacturers to produce EVs and PEHVs and offer them for sale in California. LCFS TF2-24

7. Once it became clear that CARB was using ZEV vehicle population estimates to estimate the amount of electricity expected to be used as a fuel for light-duty vehicles in developing the LCFS illustrative compliance scenario, Growth Energy renewed earlier requests for similar data used by CARB to estimate of the amount of natural gas that will be used in heavy-duty vehicles under the LCFS. I understand that, since the publication of the July 31 public notice, counsel for CARB has advised counsel for Growth Energy that no heavy-duty natural gas vehicle population estimates were used to prepare the LCFS illustrative compliance scenario. I further understand that CARB staff never performed as analysis similar to that disclosed for ZEVs to estimate natural gas use in heavy-duty vehicles under the LCFS. This is surprising, and raises serious concerns regarding the validity of the LCFS illustrative compliance scenario, and therefore the environmental and economic analyses that were performed based on it.

8. If, unlike the situation with ZEVs, CARB has failed to perform any technical analysis to estimate the amount of natural gas that would be used in heavy-duty vehicles which have been assumed in the illustrative compliance scenario and evaluation of potential compliance curves, the compliance scenario and all conclusions drawn from it cannot be relied upon. Further, it is impossible for any stakeholder or reviewing body LCFS TF2-25

---

[1] See page V-1 of the LCFS ISOR.

[2] See page VII-15 of the LCFS ISOR.

[3] See for example the ZEV population forecasts in Table 3.6 of www.arb.ca.gov/regact/2012/zev2012/zevisor.pdf.

such as the Office of Administrative Law to understand how the staff arrived at its conclusions regarding the use of electricity as a transportation fuel in the light-duty vehicle fleet, which again is critical to assessing the veracity of the illustrative compliance scenarios, the environmental analysis of the proposed LCFS regulation, and the estimated cost of the regulation. LCFS TF2-25 continued

9. Although it is not possible to understand how CARB staff arrived at its estimates of natural gas use in heavy-duty vehicles based on the available information, it is possible to estimate what CARB's assumptions would have been if staff performed the analysis required to provide a technical basis that would justify the forecast use of natural gas in heavy-duty vehicles. Once these estimates are established, it is then possible to assess their implications with respect to the veracity of the illustrative compliance scenarios, the environmental analysis of the proposed LCFS regulation, and the estimated cost of the regulation. LCFS TF2-26

10. I have estimated the increase in the number of heavy-duty natural gas vehicles that would be required to come into operation in California in order to consume the volume of natural gas forecast by CARB staff. I have also performed an analysis to determine if that required increase in vehicle population is reasonably foreseeable. Both analyses are documented in Exhibit B to this declaration. As demonstrated by these analyses, the required increase in the number of heavy-duty natural gas vehicles is large, and the available data and information contradict CARB's unsupported assumptions regarding large increases in the use of natural gas in heavy-duty vehicles.

11. Exhibit B also identifies substantial costs that would be incurred as a result of CARB's natural gas usage assumptions that were not considered in the assessment of the economic impacts of the LCFS regulation. To the extent that CARB staff continues to rely on its current illustrative compliance scenario, which incorporates flawed assumptions regarding natural gas use in heavy-duty vehicles, these costs must be included in the economic impact assessment. LCFS TF2-27

12. The correction of CARB's use of flawed assumptions regarding increased natural gas use in heavy-duty vehicles would significantly impact the results of the illustrative compliance scenario. As shown in Exhibit C, using corrected assumptions that limit natural gas use in heavy-duty vehicles to 2014 volumes and increase the use of diesel fuel, total LCFS credit balances under the compliance scenario become negative for the years 2021 to 2025, indicating that compliance with the LCFS regulation will not be feasible based on the remaining assumptions. LCFS TF2-28

13. CARB staff might try to develop illustrative compliance scenarios based on other assumptions. These other assumptions would likely include greater use of biodiesel in heavy-duty vehicles. As I have shown previously,[4] increased use of biodiesel in LCFS TF2-29

[4] See Appendix I of Growth Energy's February 17, 2015 comments on the Alternative Diesel Fuel and LCFS regulations.

heavy-duty diesel vehicles under the proposed LCFS and Alternative Diesel Fuel regulations will lead to increased NOx emissions, including significant increases in NOx emissions in the South Coast and San Joaquin Valley air basins which are already in extreme non-attainment of the federal ozone NAAQS, and moderate non-attainment of the federal fine particulate NAAQS. However, given CARB's reliance on the original illustrative compliance scenario in performing the environmental analysis and assessment of economic impacts, revisions to those analyses would also have to be performed if CARB revises the illustrative compliance scenario. In any case, at present CARB is relying on unsupported speculation that contradicts economic logic and CARB staff assessments of heavy-duty natural gas vehicles outside of the LCFS rulemaking process.

LCFS TF2-29 continued

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 17th day of August, 2015 at Sacramento, California.

JAMES M. LYONS

Exhibit A to Declaration of James M. Lyons

sierra research
A Trinity Consultants Company
1801 J Street
Sacramento, CA 95811
Tel: (916) 444-6666
Fax: (916) 444-8373
Ann Arbor, MI
Tel: (734) 761-6666
Fax: (734) 761-6755

Résumé

James Michael Lyons

Education

1985, M.S., Chemical Engineering, University of California, Los Angeles

1983, B.S., Cum Laude, Chemistry, University of California, Irvine

Professional Experience

4/91 to present — Senior Engineer/Partner/Senior Partner
Sierra Research

Primary responsibilities include oversight and execution of complex analyses of the emission benefits, costs, and cost-effectiveness of mobile source air pollution control measures. Mr. Lyons has developed particular expertise with respect to the assessment of control measures involving fuel reformulation, fuel additives, and alternative fuels, as well as accelerated vehicle/engine retirement programs, the deployment of advanced emission control systems for on- and non-road gasoline- and Diesel-powered engines, on-vehicle evaporative and refueling emission control systems, and Stage I and Stage II service station vapor recovery systems. Additional duties include assessments of the activities of federal, state, and local regulatory agencies with respect to motor vehicle emissions and reports to clients regarding those activities. Mr. Lyons has extensive litigation experience related to air quality regulations, product liability, and intellectual property issues.

7/89 to 4/91 — Senior Air Pollution Specialist
California Air Resources Board

Supervised a staff of four professionals responsible for identifying and controlling emissions of toxic air contaminants from mobile sources and determining the effects of compositional changes to gasoline and diesel fuel on emissions of regulated and unregulated pollutants. Other responsibilities included development of new test procedures and emission standards for evaporative and running loss emissions of hydrocarbons from vehicles; overseeing the development of the state plan to control toxic emissions from motor vehicles; and reducing emissions of CFCs from motor vehicles.

4/89 to 7/89 Air Pollution Research Specialist
California Air Resources Board

Responsibilities included identification of motor vehicle research needs; writing requests for proposals; preparation of technical papers and reports; as well as monitoring and overseeing research programs.

9/85 to 4/89 Associate Engineer/Engineer
California Air Resources Board

Duties included analysis of vehicle emissions data for trends and determining the effectiveness of various types of emissions control systems for both regulated and toxic emissions; determining the impact of gasoline and diesel powered vehicles on ambient levels of toxic air contaminants; participation in the development of regulations for "gray market" vehicles; and preparation of technical papers and reports.

Professional Affiliations

American Chemical Society
Society of Automotive Engineers

Selected Publications (Author or Co-Author)

"Development of Vehicle Attribute Forecasts for 2013 IEPR," Sierra Research Report No. SR2014-01-01, prepared for the California Energy Commission, January 2014.

"Assessment of the Emission Benefits of U.S. EPA's Proposed Tier 3 Motor Vehicle Emission and Fuel Standards," Sierra Research Report No. SR2013-06-01, prepared for the American Petroleum Institute, June 2013.

"Development of Inventory and Speciation Inputs for Ethanol Blends," Sierra Research Report No. SR2012-05-01, prepared for the Coordinating Research Council, Inc. (CRC), May 2012.

"Review of CARB Staff Analysis of 'Illustrative' Low Carbon Fuel Standard (LCFS) Compliance Scenarios," Sierra Research Report No. SR2012-02-01, prepared for the Western States Petroleum Association, February 20, 2012.

"Review of CARB On-Road Heavy-Duty Diesel Emissions Inventory," Sierra Research Report No. SR2010-11-01, prepared for The Ad Hoc Working Group, November 2010.

"Identification and Review of State/Federal Legislative and Regulatory Changes Required for the Introduction of New Transportation Fuels," Sierra Research Report No. SR2010-08-01, prepared for the American Petroleum Institute, August 2010.

"Technical Review of EPA Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis for Non-GHG Pollutants," Sierra Research Report No. SR2010-05-01, prepared for the American Petroleum Institute, May 2010.

"Effects of Gas Composition on Emissions from Heavy-Duty Natural Gas Engines," Sierra Research Report No. SR2010-02-01, prepared for the Southern California Gas Company, February 2010.

"Effects of Gas Composition on Emissions from a Light-Duty Natural Gas Vehicle," Sierra Research Report No. SR2009-11-01, prepared for the Southern California Gas Company, November 2009.

"Technical Review of 2009 EPA Draft Regulatory Impact Analysis for Non-GHG Pollutants Due to Changes to the Renewable Fuel Standard," Sierra Research Report No. SR2009-09-01, prepared for the American Petroleum Institute, September 2009.

"Effects of Vapor Pressure, Oxygen Content, and Temperature on CO Exhaust Emissions," Sierra Research Report No. 2009-05-03, prepared for the Coordinating Research Council, May 2009.

"Technical Review of 2007 EPA Regulatory Impact Analysis Methodology for the Renewable Fuels Standard," Sierra Research Report No. 2008-09-02, prepared for the American Petroleum Institute, September 2008.

"Impacts of MMT Use in Unleaded Gasoline on Engines, Emission Control Systems, and Emissions," Sierra Research Report No. 2008-08-01, prepared for McMillan Binch Mendelsohn LLP, Canadian Vehicle Manufacturers' Association, and Association of International Automobile Manufacturers of Canada, August 2008.

"Attachment to Comments Regarding the NHTSA Proposal for Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015, Docket No. NHTSA-2008-0089," Sierra Research Report No. SR2008-06-01, prepared for the Alliance of Automobile Manufacturers, June 2008.

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act – Part 1: Impacts on New Vehicle Fuel Economy," SAE Paper No. 2008-01-1852, Society of Automotive Engineers, 2008.

"Basic Analysis of the Cost and Long-Term Impact of the Energy Independence and Security Act Fuel Economy Standards," Sierra Research Report No. SR 2008-04-01, April 2008.

"The Benefits of Reducing Fuel Consumption and Greenhouse Gas Emissions from Light-Duty Vehicles," SAE Paper No. 2008-01-0684, Society of Automotive Engineers, 2008.

"Assessment of the Need for Long-Term Reduction in Consumer Product Emissions in South Coast Air Basin," Sierra Research Report No. 2007-09-03, prepared for the Consumer Specialty Products Association, September 2007.

"Summary of Federal and California Subsidies for Alternative Fuels," Sierra Research Report No. SR2007-04-02, prepared for the Western States Petroleum Association, April 2007.

"Analysis of IRTA Report on Water-Based Automotive Products," Sierra Research Report No. SR2006-08-02, prepared for the Consumer Specialty Projects Association and Automotive Specialty Products Alliance, August 2006.

"Evaluation of Pennsylvania's Implementation of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2006-04-01, prepared for Alliance of Automobile Manufacturers, April 12, 2006.

"Evaluation of New Jersey's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-03, prepared for the Alliance of Automobile Manufacturers, September 30, 2005.

"Evaluation of Vermont's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-02, prepared for the Alliance of Automobile Manufacturers, September 19, 2005.

"Assessment of the Cost-Effectiveness of Compliance Strategies for Selected Eight-Hour Ozone NAAQS Nonattainment Areas," Sierra Research Report No. SR2005-08-04, prepared for the American Petroleum Institute, August 30, 2005.

"Evaluation of Connecticut's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-08-03, prepared for the Alliance of Automobile Manufacturers, August 26, 2005.

"Evaluation of New York's Adoption of California's Greenhouse Gas Regulations On Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-07-04, prepared for the Alliance of Automobile Manufacturers, July 14, 2005.

"Review of MOVES2004," Sierra Research Report No. SR2005-07-01, prepared for the Alliance of Automobile Manufacturers, July 11, 2005.

"Review of Mobile Source Air Toxics (MSAT) Emissions from On-Highway Vehicles: Literature Review, Database, Development, and Recommendations for Future Studies," Sierra Research Report No. SR2005-03-01, prepared for the American Petroleum Institute, March 4, 2005.

"The Contribution of Diesel Engines to Emissions of ROG, NOx, and PM2.5 in California: Past, Present, and Future," Sierra Research Report No. SR2005-02-01, prepared for Diesel Technology Forum, February 2005.

"Fuel Effects on Highway Mobile Source Air Toxics (MSAT) Emissions," Sierra Research Report No. SR2004-12-01, prepared for the American Petroleum Institute, December 23, 2004.

"Review of the August 2004 Proposed CARB Regulations to Control Greenhouse Gas Emissions from Motor Vehicles: Cost Effectiveness for the Vehicle Owner or Operator – Appendix C to the Comments of The Alliance of Automobile Manufacturers," Sierra Research Report No. SR2004-09-04, prepared for the Alliance of Automobile Manufacturers, September 2004.

"Emission and Economic Impacts of an Electric Forklift Mandate," Sierra Research Report No. SR2003-12-01, prepared for National Propane Gas Association, December 12, 2003.

"Reducing California's Energy Dependence," Sierra Research Report No. SR2003-11-03, prepared for Alliance of Automobile Manufacturers, November 25, 2003.

"Evaluation of Fuel Effects on Nonroad Mobile Source Air Toxics (MSAT) Emissions: Literature Review, Database Development, and Recommendations for Future Studies," Sierra Research Report No. SR2003-10-01, prepared for American Petroleum Institute, October 3, 2003.

"Review of Current and Future CO Emissions from On-Road Vehicles in Selected Western Areas," Sierra Research Report No. SR03-01-01, prepared for the Western States Petroleum Association, January 2003.

"Review of CO Compliance Status in Selected Western Areas," Sierra Research Report No. SR02-09-04, prepared for the Western States Petroleum Association, September 2002.

"Impacts Associated With the Use of MMT as an Octane Enhancing Additive in Gasoline – A Critical Review", Sierra Research Report No. SR02-07-01, prepared for Canadian Vehicle Manufacturers Association and Association of International Automobile Manufacturers of Canada, July 24, 2002.

"Critical Review of 'Safety Oversight for Mexico-Domiciled Commercial Motor Carriers, Final Programmatic Environmental Assessment', Prepared by John A Volpe Transportation Systems Center, January 2002," Sierra Research Report No. SR02-04-01, April 16, 2002.

"Critical Review of the Method Used by the South Coast Air Quality Management District to Establish the Emissions Equivalency of Heavy-Duty Diesel- and Alternatively Fueled Engines", Sierra Research Report No. SR01-12-03, prepared for Western States Petroleum Association, December 21, 2001.

"Review of U.S. EPA's Diesel Fuel Impact Model", Sierra Research Report No. SR01-10-01, prepared for American Trucking Associations, Inc., October 25, 2001.

"Operation of a Pilot Program for Voluntary Accelerated Retirement of Light-Duty Vehicles in the South Coast Air Basin," Sierra Research Report No. SR01-05-02, prepared for California Air Resources Board, May 2001.

"Comparison of Emission Characteristics of Advanced Heavy-Duty Diesel and CNG Engines," Sierra Report No. SR01-05-01, prepared for Western States Petroleum Association, May 2001.

"Analysis of Southwest Research Institute Test Data on Inboard and Sterndrive Marine Engines," Sierra Report No. SR01-01-01, prepared for National Marine Manufacturers Association, January 2001.

"Institutional Support Programs for Alternative Fuels and Alternative Fuel Vehicles in Arizona: 2000 Update," Sierra Report No. SR00-12-04, prepared for Western States Petroleum Association, December 2000.

"Real-Time Evaporative Emissions Measurement: Mid-Morning Commute and Partial Diurnal Events," SAE Paper No. 2000-01-2959, October 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," SAE Paper No. 2000-01-2958, October 2000.

"A Comparative Analysis of the Feasibility and Cost of Compliance with Potential Future Emission Standards for Heavy-Duty Vehicles Using Diesel or Natural Gas," Sierra Research Report No. SR00-02-02, prepared for Californians For a Sound Fuel Strategy, February 2000.

"Critical Review of the Report Entitled 'Economic Impacts of On Board Diagnostic Regulations (OBD II)' Prepared by Spectrum Economics," Sierra Research Report No. SR00-01-02, prepared for the Alliance of Automobile Manufacturers, January 2000.

"Potential Evaporative Emission Impacts Associated with the Introduction of Ethanol-Gasoline Blends in California," Sierra Research Report No. SR00-01-01, prepared for the American Methanol Institute, January 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," Sierra Research Report No. SR99-10-03, prepared for the Coordinating Research Council, October 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," SAE Paper No. 1999-01-3676, August 1999.

"Future Diesel-Fueled Engine Emission Control Technologies and Their Implications for Diesel Fuel Properties," Sierra Research Report No. SR99-08-01, prepared for the American Petroleum Institute, August 1999.

"Analysis of Compliance Feasibility under Proposed Tier 2 Emission Standards for Passenger Cars and Light Trucks," Sierra Research Report No. SR99-07-02, July 1999.

"Comparison of the Properties of Jet A and Diesel Fuel," Sierra Research Report No. SR99-02-01, prepared for Pillsbury Madison and Sutro, February 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," Sierra Research Report No. SR98-12-02, prepared for the American Petroleum Institute, December 1998.

"Analysis of New Motor Vehicle Issues in the Canadian Government's Foundation Paper on Climate Change – Transportation Sector," Sierra Research Report No. SR98-12-01, prepared for the Canadian Vehicle Manufacturers Association, December 1998.

"Investigation of the Relative Emission Sensitivities of LEV Vehicles to Gasoline Sulfur Content - Emission Control System Design and Cost Differences," Sierra Research Report No. SR98-06-01, prepared for the American Petroleum Institute, June 1998.

"Costs, Benefits, and Cost-Effectiveness of CARB's Proposed Tier 2 Regulations for Handheld Equipment Engines and a PPEMA Alternative Regulatory Proposal," Sierra Research Report No. SR98-03-03, prepared for the Portable Power Equipment Manufacturers Association, March 1998.

"Analysis of Diesel Fuel Quality Issues in Maricopa County, Arizona," Sierra Research Report No. SR97-12-03, prepared for the Western States Petroleum Association, December 1997.

"Potential Impact of Sulfur in Gasoline on Motor Vehicle Pollution Control and Monitoring Technologies," prepared for Environment Canada, July 1997.

"Analysis of Mid- and Long-Term Ozone Control Measures for Maricopa County," Sierra Research Report No. SR96-09-02, prepared for the Western States Petroleum Association, September 9, 1996.

"Technical and Policy Issues Associated with the Evaluation of Selected Mobile Source Emission Control Measures in Nevada," Sierra Research Report No. SR96-03-01, prepared for the Western States Petroleum Association, March 1996.

"Cost-Effectiveness of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-05, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"Cost of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-04, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"A Comparative Characterization of Gasoline Dispensing Facilities With and Without Vapor Recovery Systems," Sierra Research Report No. SR95-10-01, prepared for the Province of British Columbia Ministry of Environment Lands and Parks, October 1995.

"Potential Air Quality Impacts from Changes in Gasoline Composition in Arizona," Sierra Research Report No. SR95-04-01, prepared for Mobil Corporation, April 1995.

"Vehicle Scrappage: An Alternative to More Stringent New Vehicle Standards in California," Sierra Research Report No. SR95-03-02, prepared for Texaco, Inc., March 1995.

"Evaluation of CARB SIP Mobile Source Measures," Sierra Research Report No. SR94-11-02, prepared for Western States Petroleum Association, November 1994.

"Reformulated Gasoline Study," prepared by Turner, Mason & Company, DRI/McGraw-Hill, Inc., and Sierra Research, Inc., for the New York State Energy Research and Development Authority, Energy Authority Report No. 94-18, October 1994.

"Phase II Feasibility Study: Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley," Sierra Research Report No. SR94-09-02, prepared for the Greater Vancouver Regional District, September 1994.

"Cost-Effectiveness of Mobile Source Emission Controls from Accelerated Scrappage to Zero Emission Vehicles," Paper No. 94-TP53.05, presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, OH, June 1994.

"Investigation of MOBILE5a Emission Factors, Assessment of I/M Program and LEV Program Emission Benefits," Sierra Research Report No. SR94-06-05, prepared for American Petroleum Institute, June 1994.

"Cost-Effectiveness of the California Low Emission Vehicle Standards," SAE Paper No. 940471, 1994.

"Meeting ZEV Emission Limits Without ZEVs," Sierra Research Report No. SR94-05-06, prepared for Western States Petroleum Association, May 1994.

"Evaluating the Benefits of Air Pollution Control - Method Development and Application to Refueling and Evaporative Emissions Control," Sierra Research Report No. SR94-03-01, prepared for the American Automobile Manufacturers Association, March 1994.

"The Cost-Effectiveness of Further Regulating Mobile Source Emissions," Sierra Research Report No. SR94-02-04, prepared for the American Automobile Manufacturers Association, February 1994.

"Searles Valley Air Quality Study (SVAQS) Final Report," Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

"A Comparative Study of the Effectiveness of Stage II Refueling Controls and Onboard Refueling Vapor Recovery," Sierra Research Report No. SR93-10-01, prepared for the American Automobile Manufacturers Association, October 1993.

"Evaluation of the Impact of the Proposed Pole Line Road Overcrossing on Ambient Levels of Selected Pollutants at the Calgene Facilities," Sierra Research Report No. SR93-09-01, prepared for the City of Davis, September 1993.

"Leveling the Playing Field for Hybrid Electric Vehicles: Proposed Modifications to CARB's LEV Regulations," Sierra Research Report No. SR93-06-01, prepared for the Hybrid Vehicle Coalition, June 1993.

"Size Distributions of Trace Metals in the Los Angeles Atmosphere," *Atmospheric Environment*, Vol. 27B, No. 2, pp. 237-249, 1993.

"Preliminary Feasibility Study for a Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley Area," Sierra Research Report No. 92-10-01, prepared for the Greater Vancouver Regional District, October 1992.

"Development of Mechanic Qualification Requirements for a Centralized I/M Program," SAE Paper No. 911670, 1991.

"Cost-Effectiveness Analysis of CARB's Proposed Phase 2 Gasoline Regulations," Sierra Research Report No. SR91-11-01, prepared for the Western States Petroleum Association, November 1991.

"Origins and Control of Particulate Air Toxics: Beyond Gas Cleaning," in Proceedings of the Twelfth Conference on Cooperative Advances in Chemical Science and Technology, Washington, D.C., October 1990.

"The Effect of Gasoline Aromatics on Exhaust Emissions: A Cooperative Test Program," SAE Paper No. 902073, 1990.

"Estimation of the Impact of Motor Vehicles on Ambient Asbestos Levels in the South Coast Air Basin," Paper No. 89-34B.7, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"Benzene/Aromatic Measurements and Exhaust Emissions from Gasoline Vehicles," Paper No. 89-34B.4, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"The Impact of Diesel Vehicles on Air Pollution," presented at the 12th North American Motor Vehicle Emissions Control Conference, Louisville, KY, April 1988.

"Exhaust Benzene Emissions from Three-Way Catalyst-Equipped Light-Duty Vehicles," Paper No. 87-1.3, presented at the 80th Annual Meeting of the Air Pollution Control Association, New York, NY, June 1987.

"Trends in Emissions Control Technologies for 1983-1987 Model-Year California-Certified Light-Duty Vehicles," SAE Paper No. 872164, 1987.

Exhibit B to Declaration of James M. Lyons

Exhibit B

Estimation of the Heavy-Duty Natural Gas Vehicle Requirements Implied by CARB's LCFS Illustrative Compliance Scenario

LCFS TF2-30

As described in detail in the ISOR and Appendix B to the ISOR, in developing proposed revisions to the Low Carbon Fuel Standard (LCFS) regulation, CARB staff has prepared an "illustrative compliance scenario" which, for purposes of its Environmental Assessment, must be "reasonably foreseeable."[1] However, CARB staff has failed to publish many of the assumptions and data that underlie that scenario, making it impossible to understand the technical basis, if any, which supports CARB's claim that the scenario is in fact reasonably foreseeable. In particular, CARB staff has failed to provide any technical basis that supports the large increase in natural gas use by heavy-duty vehicles assumed in the compliance scenario. As documented below, an analysis that estimates the implications of CARB's assumptions regarding natural gas use in heavy-duty vehicles indicates that the CARB assumptions are not in fact reasonably foreseeable. Given this, CARB's environmental analysis and its assessment of the economic impacts of the proposed LCFS regulation are flawed and cannot be used to comply with the California Environmental Quality Act (CEQA) or the rulemaking requirements of the Administrative Procedures Act (APA).

CARB Staff Assumptions Regarding Natural Gas Use in Heavy-Duty Vehicles

CARB staff has published several versions of the compliance scenario during the course of the LCFS rulemaking process. The most recent version is dated May 22, 2015 and is titled "Analysis of Compliance Curve Reflecting the Impact of May 2015 Proposed 15-Day Changes." The CARB assumptions regarding conventional and renewable natural gas to be used in heavy-duty vehicles as a function of time are presented in Table 1 in diesel equivalent gallons. As shown, CARB assumes a dramatic increase in total natural gas use over time, with that gas being derived from "renewable" sources that include landfills and waste digesters. More specifically, CARB's projected increase in natural gas use in heavy-duty vehicles, relative to 2014 levels, is 2.6 times greater in 2020 and 4.4 times greater in 2025.

Required Heavy-Duty Natural Gas Vehicle Populations

Using CARB staff's assumptions regarding natural gas use in heavy-duty vehicles, it is possible to estimate the required number of heavy-duty vehicles as a function of time. This process begins with determining the current population of heavy-duty natural gas vehicles in California. Data regarding that population (exclusive of conversions) in 2013 have been published by the

[1] See pages ES-18 and 19 of the LCFS ISOR.

National Renewable Energy Laboratory.[2] These data can then be used with EMFAC2014 annual mileage accumulation rates and an average natural gas fuel economy value of 5.6 miles per diesel equivalent value for the 2013 fleet[3] to estimate natural gas use. These data and the resulting estimate of natural gas consumption by heavy-duty vehicles in 2013 are presented in Table 2. As shown, the estimated volume of 102 million diesel equivalent gallons for the 2013 fleet is in reasonable agreement with the 2014 CARB assumed value of 110 million.

Assuming that both the relative distribution of heavy-duty natural gas vehicles in the fleet and their fuel economy remain constant, the growth in vehicle population required to satisfy CARB's forecast demand is directly proportional to the growth in that demand. The resulting populations for 2015 to 2025 are shown in Table 3. It should be noted that while the assumption of constant fuel economy is likely to be incorrect, the expected increase in fleet fuel economy would only serve to increase the number of natural gas vehicles required to consume the fuel volumes assumed by CARB for future years.

Table 1
CARB Assumptions Regarding Natural Gas Use In Heavy-Duty Vehicles
(million diesel equivalent gallons)

Year	Conventional	Renewable	Total
2014	86	23	110
2015	70	55	125
2016	75	70	145
2017	75	90	165
2018	75	130	205
2019	75	170	245
2020	55	230	285
2021	35	290	325
2022	35	330	365
2023	35	370	405
2024	35	410	445
2025	35	450	485

[2] See www1.eere.energy.gov/cleancities/pdfs/ngvtf14oct_schroeder.pdf
[3] See www.energy.ca.gov/2013_energypolicy/documents/2013-06-26_workshop/presentations/07_Medium_Heavy_Vehicles_Bob_RAS_22Jun2013.pdf

Table 2 2013 Heavy-Duty Natural Gas Fleet Data and Estimated Fuel Consumption			
Type	Population	Annual Miles	NG Use (million diesel equivalent gallons)
Class 4-6	1,009	18,228	3
Class 7	2,148	20,215	8
Class 8	9,791	52,023	91
Total	12,947	-	102

Table 3 Estimated California Heavy-Duty Natural Gas Vehicle Population Required to Consume Natural Gas Volumes Forecast by CARB (vehicles)				
Year	Class 8	Class 7	Class 4-6	Total
2013	9,791	2,148	1,009	12,947
2015	11,156	2,447	1,149	14,753
2016	12,941	2,839	1,333	17,113
2017	14,726	3,230	1,517	19,474
2018	18,296	4,013	1,885	24,194
2019	21,866	4,796	2,253	28,915
2020	25,436	5,579	2,620	33,636
2021	29,006	6,362	2,988	38,357
2022	32,576	7,146	3,356	43,078
2023	36,147	7,929	3,724	47,799
2024	39,717	8,712	4,091	52,520
2025	43,287	9,495	4,459	57,241
Increase from 2013 to 2025	33,496	7,347	3,451	44,294

Assessment of Required Heavy-Duty Natural Gas Vehicle Populations

As documented above, the CARB illustrative scenario assumes a massive increase in natural gas as a fuel for heavy-duty vehicles, which directly implies a similar massive increase in the number of heavy-duty natural gas vehicles in operation in California. Although, CARB staff might be able to show that it is possible to divert the forecast volume of natural gas intended for other purposes to use as a transportation fuel, staff has apparently not estimated the number of vehicles required nor published any data or analysis to support that it is reasonably foreseeable that the required number of vehicles will be in operation in California. Rather, as is demonstrated below, what is reasonably foreseeable is that there will be no significant increase in either the heavy-duty natural gas vehicle population or natural gas use by such vehicles unless CARB requires the purchase and use of such vehicles.

LCFS TF2-31

It should be noted that while there are several existing CARB regulations that have resulted in the deployment of natural gas vehicles, such as Solid Waste Collection Vehicle rule and the Fleet Rule for Transit Agencies, those regulatory programs are mature and will not lead to further increases in heavy-duty natural gas vehicle use. There are simply no existing CARB regulations like the ZEV mandate that require dramatic increases in the sale of heavy-duty natural gas vehicles. Given this, increases in the California heavy-duty natural vehicle population would have to be driven by market. If CARB believes that the market will drive those increases, staff needs to explain why and allow the public to comment on that explanation. Indeed, CARB's own recent assessment of heavy-duty natural gas vehicle technology[4] compares heavy-duty natural gas vehicles with diesel vehicles and notes that natural gas vehicles suffer from a number of disadvantages including the following: LCFS TF2-32

1. Shorter range between refueling;
2. Increased weight;
3. 10 to 15% lower fuel economy;
4. Higher purchase costs which range from $30,000 to $80,000 per vehicle;
5. Higher maintenance costs of 1-2 cents per mile; and
6. A limited number of publically accessible refueling stations.

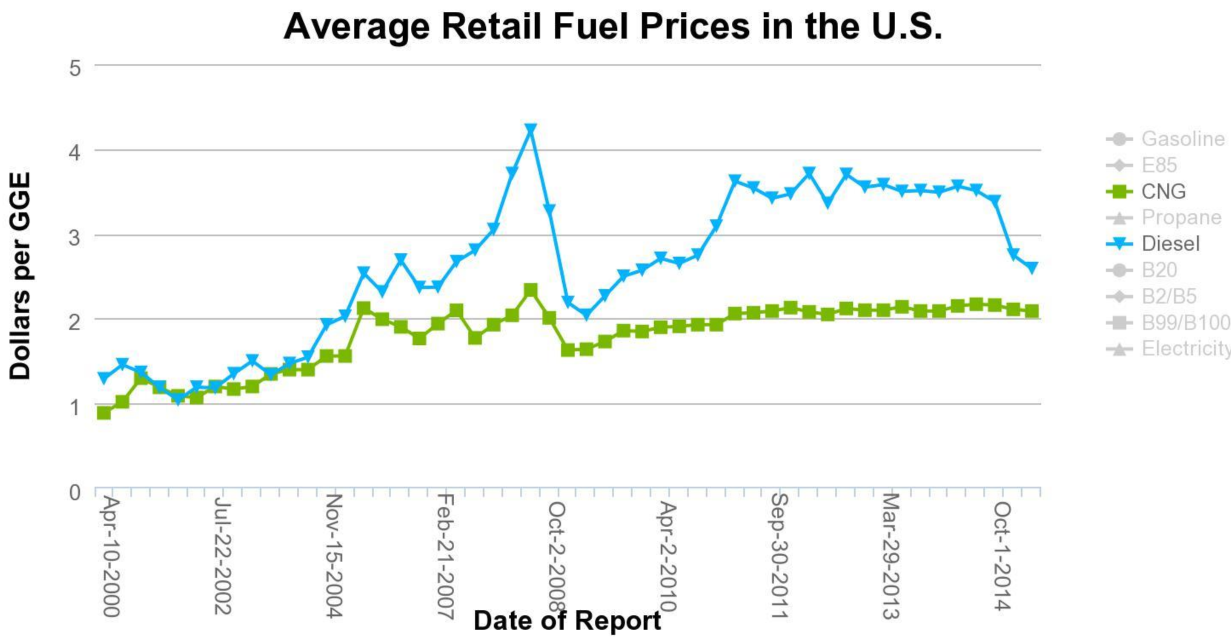
All of these factors serve as substantial barriers to increases in heavy-duty natural gas populations. For example, multiplying the $55,000 mid-point of the range in increased vehicle costs by the estimated 44,924 additional natural gas vehicles that would be required in 2025 to meet CARB's fuel forecast, indicates that an additional $2.4 billion dollars would have to be spent by California heavy-duty vehicle users in order to use natural gas instead of diesel vehicles. Similarly, the increased maintenance costs associated with the additional natural gas vehicles would amount to between $22 and $44 million in 2025 alone. There are also substantial costs associated with installation of natural gas refueling facilities.[5] It should be noted that these costs were not included by CARB staff in its economic analysis of the LCFS regulation.

The two primary advantages associated with natural gas vehicles that have been identified by CARB staff are (1) lower tailpipe emissions of particulate matter and oxides of nitrogen, and (2) lower fuel price. Given that less expensive diesel vehicles will be available, the lower emission levels associated with natural gas vehicles are unlikely to influence the purchasing decisions of vehicle operators. In addition, given the recent changes in the oil prices, the price difference between natural gas and diesel fuel has dropped dramatically as shown in Figure 1, which was obtained from a U.S. Department of Energy website.[6] It should be noted that the price differential shown in Figure 1 does not reflect the 10 to 15% lower fuel economy cited by CARB as a disadvantage of natural gas vehicles, which would further reduce the price differential. Further, current EIA forecasts for diesel fuel prices indicate that lower prices will persist for a considerable period of time.[7] Given this, the advantage associated with lower prices for natural gas does not appear to be a substantial factor. LCFS TF2-33

[4] See www.arb.ca.gov/msprog/tech/presentation/lowernoxfuel.pdf.
[5] See www.afdc.energy.gov/uploads/publication/cng_infrastructure_costs.pdf.
[6] See www.afdc.energy.gov/fuels/prices.html.
[7] See Table 12 at www.eia.gov/forecasts/aeo/tables_ref.cfm.

Overall, as documented above, there are substantial disadvantages associated with heavy-duty natural gas vehicles relative to diesel vehicles, and there is no technical basis that supports CARB's implied assumption that there will be a dramatic increase in the population of such vehicles. This conclusion is supported for the nation as a whole by EIA which forecasts little growth in the number of heavy-duty natural gas vehicles, and a decrease in the total amount of natural gas used by those vehicles over time.[8] CARB's LCFS illustrative compliance scenarios are therefore based on arbitrary and unsupported speculation which is inconsistent with CARB's own analysis outside the LCFS rulemaking process and with EIA's analysis. LCFS TF2-34

Figure 1



[8] See Table 50 at www.eia.gov/forecasts/aeo/tables_ref.cfm.

Exhibit C to Declaration of James M. Lyons

Exhibit C

Impact of CARB's Flawed Assumption Regarding Natural Gas Use in Heavy-Duty Vehicles on CARB Illustrative Compliance Scenario

As described in Attachment B, it has only now become apparent that CARB's LCFS Illustrative Compliance Scenario envisioning dramatic growth in natural gas use by heavy-duty vehicles has no empirical or specific analytic basis. The available information shows now and has long shown that the only reasonable assumption is that there will be little or no growth in natural gas use in heavy-duty vehicles. Given this, it is important to understand the impact associated with correcting CARB's flawed assumptions for the Illustrative Compliance Scenario. LCFS TF2-35

In order to perform this assessment, the May 22 Illustrative Compliance Scenario was used as the starting point, and CARB staff's assumptions regarding the use of conventional natural gas and renewable natural gas were corrected such that the total demand for natural gas remained at 110 million diesel gallon equivalents during the years 2015 through 2025. It was assumed that renewable gas would be used to the maximum degree feasible based on CARB's original forecast up to a maximum of 110 million diesel gallon equivalents. Diesel fuel was assumed to replace the reduced volume of natural gas relative to CARB's original assumptions. LCFS TF2-36

In Table 1, the original May 22 diesel deficit and conventional and renewable natural gas credit volumes are compared to those resulting from the corrected assumptions described above. As shown, the corrected assumptions lead to reduced natural gas credits and increased diesel deficits, relative to the May 22 version.

Table 1
Calendar Year 2014-2025 Diesel Deficit and Natural Gas Credit Volumes
(Flawed vs. Corrected NG Use Assumptions)

	MMTs of Credits or Deficits											
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	May 22 Scenario											
Diesel Deficits	-0.46	-0.45	-0.91	-1.57	-2.23	-3.33	-4.41	-4.30	-4.27	-4.23	-4.26	-4.29
Conv. Natural Gas Credits	0.19	0.15	0.10	0.09	0.07	0.05	0.01	0.01	0.01	0.01	0.01	0.01
Renewable NG Credits	0.18	0.50	0.66	0.85	1.22	1.54	2.01	2.53	2.88	3.23	3.58	3.93
Sum	-0.09	0.20	-0.15	-0.63	-0.94	-1.74	-2.39	-1.76	-1.38	-0.99	-0.67	-0.36
	May 22 Scenario - With Corrected Heavy Duty Natural Gas Assumptions											
Diesel Deficits	-0.46	-0.45	-0.92	-1.60	-2.30	-3.47	-4.65	-4.60	-4.62	-4.64	-4.72	-4.81
Conv. Natural Gas Credits	0.19	0.12	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Renewable NG Credits	0.18	0.50	0.66	0.85	1.03	0.99	0.96	0.96	0.96	0.96	0.96	0.96
Sum	-0.09	0.17	-0.20	-0.72	-1.27	-2.47	-3.69	-3.64	-3.66	-3.68	-3.76	-3.85

A similar comparison of total LCFS program credits and deficits as well as the total credit balance is provided in Table 2. As highlighted in Table 2, with the corrected assumptions, the credit surpluses forecast by CARB for the years 2021 to 2025 become deficits indicating that compliance with the LCFS regulation would not occur. Therefore, CARB's conclusion that compliance with the LCFS regulation is demonstrated by the May 22 version of the Illustrative Compliance Scenario is incorrect and has no empirical or analytical support in the rulemaking file.

CARB staff could try to formulate other Illustrative Compliance Scenarios that demonstrate compliance based on other assumptions, which would likely include greater use of biodiesel in heavy-duty vehicles. However, use of these different assumptions would require revisions to CARB staff's environmental and economic analyses, which should be made available for public review and comment.

LCFS TF2-36 continued

Table 2
Calendar Year 2014-2025 LCFS Program Credits and Deficits
(Flawed vs. Corrected NG Use Assumptions)

	MMTs of Credits or Deficits											
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	May 22 Scenario											
Total Credits	4.12	5.71	9.00	10.65	12.10	13.09	14.29	17.08	19.08	21.08	22.78	24.44
Total Deficits	-2.35	-2.31	-6.75	-8.68	-11.43	-15.99	-20.38	-19.87	-19.43	-19.02	-18.65	-18.31
Total Credit Balance	4.76	8.16	10.40	12.37	13.04	10.14	4.05	1.26	0.90	2.97	7.10	13.23
	May 22 Scenario - With Corrected Heavy Duty Natural Gas Assumptions											
Total Credits	4.12	5.67	8.95	10.58	11.83	12.49	13.23	15.50	17.15	18.80	20.15	21.46
Total Deficits	-2.35	-2.31	-6.76	-8.71	-11.49	-16.12	-20.62	-20.16	-19.78	-19.42	-19.11	-18.82
Total Credit Balance	4.76	8.12	10.31	12.18	12.52	8.89	1.50	-3.16	-5.80	-6.42	-5.37	-2.74

Exhibit A to Declaration of Thomas L. Darlington

CALIFORNIA ENVIRONMENTAL PROTECTION AGENCY

CALIFORNIA AIR RESOURCES BOARD

DECLARATION OF THOMAS L. DARLINGTON

I, Thomas L. Darlington, declare as follows:

1. I am an engineer with training and expertise in lifecycle emissions analysis, the use of models to estimate lifecycle emissions and to attribute emissions to the production, distribution and use of various fuels, and use of regulations to control mobile-source emissions. My areas of expertise also include land-use change ("LUC") modeling and the application of econometric models to attributional and consequential lifecycle emissions analysis. Following my graduation from the University of Michigan in 1979, I served for eight years as an Engineer and Project Manager at the United States Environmental Protection Agency's Motor Vehicle Emissions and Fuels Laboratory in Ann Arbor, Michigan. Thereafter I worked at Detroit Diesel Corporation and General Motors Corporation, and as the Director of Mobile Source Programs at Systems Application International. I am the President of Air Improvement Resource ("AIR"), a company formed in 1994 to provide mobile source emission modeling to government and industry. A copy of my CV is attached to this Declaration as Exhibit "A."

2. I have participated on behalf of renewable fuels producers in the public consultation and rulemaking processes at the California Air Resources Board ("ARB" or "the Board") to consider, adopt and revise the low-carbon fuel standard ("LCFS") regulation since 2008. I testified at the Board's February 2015 hearing concerning proposed amendments to the LCFS regulation. I am fully familiar with the models released by CARB to establish and implement the LCFS regulation, including the versions of the Global Trade Analysis Project ("GTAP") modeling systems used by CARB or proposed for use by the CARB staff as part of the current and proposed LCFS regulation.

3. I make this Declaration based upon my personal knowledge, my training and expertise, and my familiarity with the subjects that I address here.

A. Overview of LCFS Regulation's Treatment of Price-Yield Elasticity

4. The price-yield elasticity is an important parameter used in the GTAP model[1] to estimate the magnitude of land use changes in response to biofuel expansion. The price-yield elasticity is a measure of the change in yield with a change in price of a commodity. A price-yield elasticity of 0.25, therefore means that if corn prices increase by 1%, corn yield would be expected to increase by 0.25%. The increase in yield is brought

[1] GTAP stands for Global Trade Analysis Project, which is the model ARB uses to develop the land use impacts of biofuels.

about by producers using seed types that are resistant to drought and disease, more intensive planting, possibly more fertilizer, irrigation, and other methods.

5. The increase in investment by producers to achieve a higher yield is justified by the increase in the prices the producer will obtain for the crop. In GTAP, the predicted increase in prices is a result of "shocking" the model with increased demand for feedstocks for biofuels. When the model is shocked with this increase in demand, the model responds by simulating an increase in price of various commodities. This in turn leads to some crop switching (to biofuel feedstocks), higher yields on existing land (due to the YPE elasticity) and conversion of pasture and, to a much lesser extent, forest to cropland.[2]

6. In GTAP, the price-yield parameter (or elasticity) is referred to as YDEL; ARB refers to it as YPE. ARB used five different price-yield elasticities in its analysis of land-use emissions (0.05, 0.1, 0.175, 0.25, and 0.35) for all biofuels.[3] The average of these five values is 0.185.

7. To select these five levels, ARB relied on (1) input from the expert working group (EWG) on elasticities, (2) its own review of various price-yield studies, and (3) a report by David Rocke reviewing some price-yield studies.[4] While the Rocke report was provided by ARB with the ISOR, the data Rocke relied upon to critique one of the studies, the Perez study, was not provided by ARB for review until August 1, 2015.

8. ARB's comments on the Rocke study appear at the end of Attachment 1 to Appendix I of the ISOR. Appendix I discusses the land use emissions estimated by ARB, and Attachment 1 discusses ARB's method for determining YPE values to use in estimating land-use emissions. ARB's summary of the Rocke report is below:

> Staff contacted with David Rocke from the University of California, Davis to perform a statistical analysis of the data used by some of the researchers in Table 1-2. David reviewed analysis (and data where available) for Goodwin et al, Perez, and Berry and Schlenker and additional studies and concluded based on methodologically sound analyses, yield price elasticities are small to zero.

9. Since ARB relied on Rocke's review of recent studies in selecting YPE values, we reviewed Rocke's analysis of the Perez data, and his review of the other studies. In this report, we will show that:

(i) ARB's Elasticity Values Expert Working Group (EWG) recommended a mid-point value of 0.25, not 0.185.

LCFS TF2-37 (cont. on pg 3, bottom)

[2] In the real world, fallow or idled lands are also converted to crops resulting in little real land use change. However, GTAP currently does not currently model the conversion of idle or fallow land.

[3] Table I-4, Appendix I, Detailed Analysis for Indirect Land Use Change, Initial Statement of Reasons, ARB.

[4] *Statistical Issues Related to the Low-Carbon Fuel Standard,* David M. Rocke, PhD, October 31, 2014, under contract 13-405 (2014).

(ii) ARB arbitrarily relied on the Rocke study to select a range of YPE values and a mid-point that were significantly lower than what the EWG recommended. LCFS TF2-38 (cont. on pp 4 -6)

(iii) The Rocke study critically evaluated another study, the Perez study that derived a price yield value of 0.29, which supports the EWG recommendation to ARB. LCFS TF2-39 (cont. on pp 6-7)

(iv) The Rocke study used only part of the Perez data to attempt to duplicate Perez's results. Since the Perez results were not duplicated by Rocke's analysis of the Perez data, Rocke assumed that Perez's results were inappropriately determined. Rocke's analysis constitutes bad modeling practice, is inconsistent with ARB's modeling methodologies used in connection with other regulations, and is unsupported by the evidence in the Perez study. LCFS TF2-40 (cont. on pp 7-8)

(v) Emissions associated with indirect land use change for biofuels are significantly greater (i.e., 15% higher for corn ethanol) with a central YPE value that ARB chose of 0.185 than with the 0.25 that EWG recommended. LCFS TF2-41 (cont. on pp 9-11)

Each of these aspects is discussed further below. As an initial matter, however, it is important to be clear that the time allowed for comment on the new material placed in the docket is not sufficient to prepare all the analysis that could and should be possible in a regular 30- or 45-day comment period. For example, now that the limitations of the Rocke study are known, including the fact that Rocke relied on only a very limited set of the Perez data, stakeholders should be permitted time to conduct studies that use the best available scientific data to assess the relationship between price and yield, and to submit a full price-yield analysis to CARB for consideration in the current rulemaking. AIR has done what is possible in the limited time allowed, but does not understand why it has taken until August 2015 to provide materials that were requested in the fall of 2014. AIR's ability to comment has been limited and prejudiced by this delay. LCFS TF2-42

B. ARB's Elasticity Values Expert Working Group (EWG) <u>Recommended a Mid-Point Value of 0.25, not 0.185</u>

10. The EWG's summary recommendation on price-yield is as follows: LCFS TF2-37 continued

It is not clear if GTAP can assign different elasticities to different crops in different countries. If not then if the long-run price-yield elasticity not accounting for double-cropping is set at 0.175, and if South America and the United States are the countries that contribute the most incremental commodity production in response to higher prices, *then a mid-point value of 0.25 for the price-yield*

> *elasticity seems reasonable* (emphasis added). If differentiation can occur by country, then setting the price-yield elasticity to 0.175 for countries with no double cropping, 0.25 for the U.S. and 0.30 for Brazil and Argentina will provide a more reasonable approximation to reality."[5]

LCFS TF2-37 continued

When ARB varied price-yield, they did this variation for all countries simultaneously, (i.e., they did not utilize separate values for the US and Brazil/Argentina). Thus, the EWG recommendation is clear – the central, or average value used in land use modeling, if regional-specific values are not used, should be 0.25.[6]

C. ARB Arbitrarily Relied on the Rocke Study to Select a Range of YPE Values and a Mid-Point that Were Significantly Lower <u>Than What the EWG Recommended</u>

LCFS TF2-38 continued

11. ARB's Attachment 1 to Appendix I contains a discussion of the EWG recommendations, the Rocke report, and other recent YPE research. ARB summarizes the recent research in the table below, which is taken directly from Attachment 1 of Appendix I of the ISOR.

[5] *Final Recommendations from the Elasticity Values Subgroup*, ARB LCFs Expert Workgroup, http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/010511-final-rpt-elasticity.pdf

[6] In Attachment 1 to Appendix I of the ISOR, ARB quotes the EWG report statement "perhaps a reasonable increment to the short-run elasticity to account for long-run response is 0.05, which brings the average value between 0.10 to 0.25." This seems to support the ARB-selected central value of 0.185. However, the quote is followed by a paragraph where the EWG discusses the impacts of double-cropping on its YPE recommendation. Thus, the range of "between 0.10 to 0.25" was not the EWG's final recommendation on YPE, as the final recommendation is given two paragraphs later. Additionally, the GTAP model ARB used to model land use emissions is capable of having separate price-yield elasticities by region, so ARB could have adopted the EWG recommendation to utilize 0.25 for the US, 0.30 for Brazil/Argentina, and 0.175 for all other countries.

Table 1-2. Updated Literature Estimates of YPEs				
Authors	Period	Elasticity	Crop	Data, Method
Huang and Khanna	1977-2007	0.15	U.S. corn, soybean, wheat	County level data, instrumental variable (IV)
Smith and Sumner	1961-2005	Negative and Significant	U.S. corn	County level data, ordinary least squares (OLS)
Berry and Schlenker	1961-2009	0.1, Net	U.S. corn	Country level data, instrumental variable
Goodwin, et al	1996-2010	0.01 short run, 0.19-0.27 long run	Iowa, Illinois, Indiana Corn	Ordinary least squares
Perez	1960-2004	0.29	Iowa corn and soybeans	Duality-Bayesian

12. The first three studies appear to support low YPEs. The last two studies support the EWG recommendation of a central value of 0.25. With regard to the Smith and Sumner study, ARB notes that it is "a work in progress."[7] It is also worth noting that none of these studies evaluate double-cropping. Double- or multiple-cropping, is the common practice of planting more than one crop on the same land in the same year. Researchers use higher values of YPE to simulate double- or multiple-cropping.

LCFS TF2-38 continued

13. ARB contracted with Rocke to evaluate the last three studies (Berry and Schlenker, Goodwin, and Perez). ARB summarized Rocke's conclusions:

> David (Rocke) reviewed analysis (and data where available) for Goodwin et al, Perez, and Berry and Schlenker and additional studies, and concluded that based on methodologically sound analyses, yield price elasticities are generally small to zero.[8]

14. ARB's conclusion in Attachment 1 to Appendix I is as follows:

> Taking all these (issues) into consideration, and with a wide range of likely values for YPE from published literature, staff used a range of values between 0.05 and 0.35 to conduct scenario runs for all biofuels studied for the LCFS. These input values are used for all

[7] See footnote 55 of Attachment 1 to Appendix I of the ISOR.

[8] Appendix I to ISOR, Attachment 1-5.

crops and regions for the 30 scenario runs conducted for each of the 6 biofuels.[9]

LCFS TF2-38 continued

15. ARB failed to inform the public that its central or average value was 0.185, or 26% less than the EWG recommendation. ARB clearly relied on the Rocke analysis to select a central value that was less than the EWG recommendation.

D. The Rocke Study Critically Evaluated Another Study, the Perez Study, that Derived a Price Yield Value of 0.29, that Supports the EWG Recommendation to ARB

LCFS TF2-39 continued

16. While Rocke reviewed all three studies, he only obtained and analyzed data from one study – the Perez study.[10]

> The data were used in a 2012 dissertation of Juan Francisco Rosas Perez. In these works, the price elasticity of yield was estimated from data on corn (maize) in Iowa for 1960-2004, and was said to be in the range of 0.29. The data set was publicly available so it was used for a re-analysis. The analysis used by Perez was complex, and can be criticized for insufficiently handling autocorrelation in the series. Therefore, a simpler analysis was conducted that should have similar results to the more complex analysis if the latter is not flawed.[11]

17. Rocke performed time-series regressions of corn supply in a given year by corn price in that year, by corn supply in the previous year, and by corn price in the previous year. Rocke used the log of these variables in his regressions, apparently on the premise that the coefficient for price (either the current year or the previous year) would provide a measure of YPE. Rocke failed to find a relationship between yield and price in either the current or previous year. As noted above, Rocke attributes Perez' finding of a YPE of 0.29 to Perez insufficiently handling autocorrelation. Autocorrelation is the concept of supply in the current year being somewhat dependent on supply in the previous year rather than on other factors such as price.

18. In his final statement in the report for ARB, Rocke states:

> As documented in Berry (2011), Berry and Schlenker (2011) and Roberts and Schlenkler (2013), much of the literature providing purported estimates of the price elasticity of yield is deeply methodologically flawed. In addition to the problems of endogenity and autocorrelation that are badly handled, there are other important issues. In Goodwin et al, for example, 15 years of data are multiplied into 405 datapoints by considering 27 different districts. But there

[9] Attachment 1 to Appendix I, 1-6.

[10] *Essays on the environmental effects of agricultural production*, Juan Francisco Rosas Perez, Iowa State University (2012). Graduate These and Dissertations. Paper 12737. http://lib/dr.iastate.edu.etd.

[11] Rocke, page 5.

are still only 15 price values and it is hard to believe that the strong relationships of weather, price, and technology within a given year can be handled by econometric tricks. The analyses, such as those by Roberts and Schlenker (2013) that are methodologically sound all show small to zero price elasticities of yield.[12]

LCFS TF2-39 continued

In other words, Rocke dismisses both Goodwin and Perez as methodologically unsound.

19. We repeated Rocke's simplified analysis of the Perez data. We were able to replicate Rocke's results, using two different statistical packages, in order to establish our ability to work with Rocke's methods. We did not have adequate time to replicate Perez's analysis. Fundamentally, price-yield elasticity cannot be properly estimated with ordinary least squares (OLS) regressions of current price, last year's price, the current supply, and last year's supply only (i.e., the Rocke simplified analysis). Such a narrowly focused analysis is unreliable and is an indefensible modeling practice, and it is not a practice that ARB relies on in other analyses it performs.[13] There are too many other factors influencing yield (supply) that should be accounted for in a reliable prediction model.

E. The Rocke Study Only Used Part of the Perez Data to Attempt to Duplicate Perez's Results

LCFS TF2-40 continued

20. In his 2012 dissertation entitled "Essays on the Environmental Effects of Agricultural Production," Juan Francisco Rosas Perez describes his complex, multi-faceted agricultural prediction system. The mechanics, mathematical, and statistical components of this system cannot be fully addressed in this report, given the limited time since its relevance to the Rocke work and the relevant content of the dissertation have become available and known. Nevertheless, in brief: Perez's model is designed to estimate the impact on supply (and under his assumptions the underlying yield) in relation to a wide range of related parameters. The estimated yields can be determined for corn, soybeans, other crops, and livestock products.

21. The related parameters used by the Perez model are divided into two categories, "inputs," which are usually more time dependent and variable, and so-called "netputs," which are usually more stable. The inputs category includes the quantities and prices for fertilizer, hired labor, and intermediates. The broad intermediate parameters cover seeds, pesticides, energy (petroleum fuels, natural gas, and electricity), and other

[12] Rocke, page 6.

[13] ARB's Predictive Model for gasoline is a good example of the modeling practices that ARB relies on (see www.arb.ca.gov/fuels/gasoline/premodel/premodel.htm.) The Predictive Model estimates emissions from cars and trucks in response to a number of gasoline inputs, including sulfur, benzene, T50, T90, aromatics, olefins, volatility, and total oxygen. All of these inputs are recognized to influence vehicle emissions to varying degrees. If ARB were to analyze the emissions data focusing on only one of these fuel parameters at a time, it would likely find certain fuel parameters to be statistically insignificant. ARB did not do that; it analyzed all of the input parameters that affect emissions simultaneously in creating the Predictive Model. Similarly, ARB should, in determining the impact of price on yield, not rely on analyses that examine only price impacts on yield, but rely on studies that attempt to model as many factors as possible on crop yields.

purchased intermediate inputs (contract labor services, custom machine services, machine and building maintenance and repairs, and irrigation). The "netputs" category includes agricultural capital, Conservation Reserve Program (CRP) land, family labor, farmland, and farm related output. In his analysis, Perez obtained data from 1960-2004 and transformed it to fulfill the requirements of his model.

LCFS TF2-40 continued

22. The results of Perez's model are summarized in the table below, which was taken directly from his report. As can be seen, the elasticity of corn yield to corn price ranges from 0.14 to 0.53, with a median of 0.29.

Table 9. Corn yield elasticities with respect to selected prices and quantities.

	Lower bound	Median	Upper bound
Elasticity of corn yields with respect to:			
Corn price	0.14	0.29	0.53
Hired Labor price	-0.29	-0.12	0.01
Intermediate Inputs price	-0.43	-0.15	-0.01
Fertilizer price	-1.09	-0.17	0.04
Hired Labor quantity	0.000	0.190	0.461
Intermediate Inputs quantity	0.412	0.420	0.429
Fertilizer quantity	0.413	0.422	0.431

Note: Lower and upper bounds represent extremes of the 95% highest probability interval of the marginal posterior density function of each elasticity.

23. Clearly the Perez analysis takes into account many more factors affecting yield than Rocke's simple analysis of only a small part of the Perez data. The fact that Rocke's simple analysis using incomplete data failed to confirm the Perez results does not negate the Perez results. The Perez results also fall in line with the Goodwin et al results. Goodwin et al performed a detailed analysis similar to Perez, where many factors affecting yield were included in the prediction model.

24. Regarding Rocke's criticism of Perez insufficiently handling autocorrelation, Perez does address this issue in the dissertation:

> We assume there is no autocorrelation within equations, but that there is a contemporary correlation among the equation errors. The assumption of autocorrelation absence arises from the fact that, prior to the estimation, we take pseudo-differences of the time-series to remove serial autocorrelation found in the time series.[14]

[14] Perez, page 100.

Either Rocke failed to read this part of the dissertation, or he did read it and disagreed with how Perez handled autocorrelation. In either case, Rocke does not explain in his report for ARB what is wrong with how Perez handled autocorrelation.

LCFS TF2-40 continued

25. Rocke's simple analysis, using only some of the Perez data, is not supported by the evidence, and does not negate the Perez results. ARB's reliance on Rocke's evaluation of the Perez data in selecting price yield values is misplaced. If CARB does not agree with our position on Rocke's analysis, it should explain why, in full detail, and provide us and other stakeholders an adequate opportunity to respond before taking final action on the LCFS regulatory proposal. In particular, CARB should address the following issues:

- Whether ARB believes Rocke's very limited analysis of price and supply data alone constitutes an adequate analysis of the Perez data, when ARB's own methods of analyzing data are much more robust that Rocke's;
- Why ARB deviated from the EWG recommendation of 0.25 for a central value or average value for YPE; and
- What exactly was wrong with how Perez handled autocorrelation in his analysis.

F. LUC Emissions For Biofuels Are Significantly Greater With a Central YPE Value of 0.185, as Opposed to the 0.25 Recommended By the EWG

LCFS TF2-41 continued

26. Emissions attributed to LUC for biofuels are significantly higher, and will be overestimated, with a YPE value of 0.185 than with 0.25.

27. AIR has run the GTAP model that ARB uses to estimate land use change emissions for various biofuels. We were able to replicate many of ARB's land use emission outputs, in order to establish our ability to work with ARB's model.

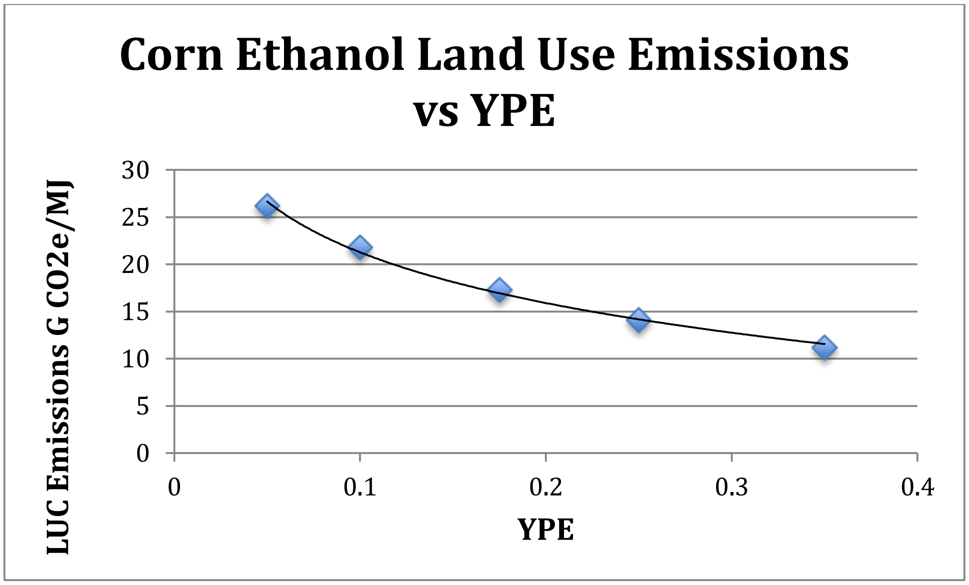
28. ARB ran 30 different GTAP scenarios for each biofuel to estimate LUC emissions. The LUC emissions were estimated as the average of the 30 unique scenarios. For corn ethanol, ARB's average of the 30 scenarios is 19.8 gCO_2/MJ of ethanol. In each of these scenarios, ARB varied several input elasticities, including the price-yield elasticity and two other elasticities. As indicated earlier, there are five input price-yield elasticities, and the average of these is 0.185, which is lower than the central value of 0.25 recommenced by the EWG. To do this correctly, one would have to select five price-yield elasticities whose average is 0.25. One possibility—and one that CARB should either use, or justify not using—would be to select the following elasticities: 0.15, 0.20, 0.25, 0.30, and 0.35.[15] These would be used in place of the current price-yield elasticities, and the input elasticities of the other two inputs would remain the same. The 30 scenarios should

[15] There are many other price-yield elasticities that would average 0.25; this is only one example.

then be re-run and new average emissions would be estimated from the new GTAP runs. This average value would then be compared to the 19.8 gCO_2/MJ.

LCFS TF2-41 continued

29. To illustrate the impact of the price-yield parameter on corn ethanol land use emissions, we provide a chart below which uses ARB's estimate of corn ethanol land use emissions at the five different YPE values. This chart uses scenarios 2, 4, 6, 8, and 10 in ARB's Table I-4. The other elasticities were held constant in these scenarios; only YPE was altered.



30. The chart shows the high degree of sensitivity of land use emissions for corn ethanol to this input parameter. Small changes in the range and average of YPE values chosen for this analysis are important in estimating land use emissions from biofuels.

31. The time allowed for comments on the Rocke report did not allow running 30 new scenarios. Instead, we ran just two scenarios; one using the ARB average inputs, and a second one using 0.25 for price-yield and the average inputs for the other two elasticities. These two scenarios are shown in Table 1. Given the time constraints, we assume that the difference in these two scenarios will approximate the difference between the two averages of 30 scenarios. The actual differences could be either greater or lesser than estimated here.

Table 1. Scenarios Used to Estimate Impact of Difference Between EWG Recommendation and ARB Price-Yield				
Scenario	Price-Yield	PAEL	ETA	Irrigation Constraint
1 – EWG price yield, ARB average for all other	0.25	0.3/0.15	Baseline	On
2 – ARB average	0.185	0.3/0.15	Baseline	On

PAEL = yield elasticity target for cropland/pasture
ETA = elasticity of effective area with respect to harvested area

LCFS TF2-41 continued

32. The land use emissions we obtained for these two scenarios are shown in Table 2. We have used ARB's latest AEZ-EF model with GTAP to estimate emissions for these two scenarios. The corn ethanol LUC emissions difference is 2.5 g CO_2/MJ. Therefore, we would expect that if the 30 scenarios were actually run for both cases, the difference in the averages of the 30 scenarios would be close to 2.5 g/MJ; however, it could be higher because Scenario 2, which represents average ARB inputs, is 17.14 gCO_2e/MJ, and the average of the 30 scenarios for corn ethanol is higher at 19.8 gCO_2e/MJ.

Table 2. Corn Ethanol LUC Emissions (gCO2e/MJ)	
Scenario	LUC Emissions
1 – EWG	14.64
2-ARB	17.14
Difference (2-1)	2.50 (15%)

ARB's corn ethanol land use value is 19.8 gCO_2e/MJ. If the emissions of the 30 scenarios run with new YPE values with an average of 0.25 are 2.5 gCO_2/MJ lower, then the new corn ethanol land use value would be 17.3 gCO_2e/MJ.

33. There would be corresponding changes in all biofuels if ARB adopted the EWG central value of 0.25 for price-yield. In addition, the baseline carbon intensities for 2016-2020 would also change, as well as the annual targets, because 10% corn ethanol is included in the baseline 2016-2020 values.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 17th day of August, 2015 in Holland, Michigan.

Thomas L. Darlington

Exhibit A to Declaration of Thomas L. Darlington

Thomas L. Darlington

President, Air Improvement Resource Inc.

Profile

Thomas L. Darlington is President of Air Improvement Resource, a company formed in 1994 specializing in mobile source emission modeling. He is an internationally recognized expert in mobile source emissions modeling, lifecycle analysis, and land use modeling.

Professional Experience

1994-Present	President, Air Improvement Resource
1993-1994	Director, Mobile Source Programs, Systems Application International
1989-1994	Senior Engineer, General Motors Corporation, Environmental Activities
1988-1989	Senior Project Engineer, Detroit Diesel Corporation
1979-1988	Project Manager, U.S. EPA, Ann Arbor, Michigan

Recent Major Projects

- Developed Life Cycle reports and complete applications for 8 plants for the California Low Carbon Fuel Standard; six are currently registered, two plants are pending. Five plants were corn ethanol plants, one is sorghum and two are cellulose.
- Participated in and provided written comments on ARB's three 2014 iLUC workshops
- With Purdue and Don O'Connor, conducted study of iLUC emissions of rapeseed and other oilseeds in 2013 utilizing an updated version of GTAP
- Reviewed EPA's palm oil iLUC emissions in 2013
- Submitted comments on ARB's new GREET2.0 model
- Reviewed CARB's land use emissions for soybean biodiesel
- Reviewed the land use impacts of the RFS2 from EPA, including the notice of Proposed Rule, Regulatory Impact Analysis, and approximately one hundred documents in the rulemaking docket.
- Completed a land use study for Renewable Fuels Association and reviewed California Air Resource Board's Initial Statement of Reasons for the Low Carbon Fuel Standard
- Represented three stakeholders in the recent development of the ARB Predictive Model for reformulated gasoline in California (Alliance of Automobile Manufacturers, Renewable Fuels Association and Western States Petroleum Association)
- Represented two stakeholders in EPA's development of the MOVES on-highway emissions model (Alliance of Automobile Manufacturers and Engine Manufacturers Association)

Exhibit "B"

- Developed the effects of ethanol permeation on on-highway and off-highway mobile sources in California and other states for the American Petroleum Institute
- Studied gasoline and diesel fuel options for Southeast Michigan (for SEMCOG, API and Alliance of Automobile Manufacturers)

Recent Publications

"Study of Transportation Fuel Life Cycle Analysis: Review of Economic Models Use to Assess Land Use Effects", CRC-E-88-3, July 2014.

"Land Use Change Greenhouse Gas Emissions of European Biofuel Policies Utilizing the Global Trade Analysis Project Model", Darlington, Kahlbaum, O'Connor, and Mueller, August 30, 2013.

"A Comparison of Corn Ethanol Lifecycle Analyses: California Low Carbon Fuels Standard (LCFS) Versus Renewable Fuels Standard (RFS2)", June 14, 2010. Renewable Fuels Association and Nebraska Corn Board. This study compared and contrasted the corn ethanol lifecycle analyses performed by both CARB (as a part of the LCFS) and the EPA (as a part of RFS2).

"Review of EPA's RFS2 Lifecycle Emissions Analysis for Corn Ethanol", September 25, 2009. Conducted for Renewable Fuels Association. This study reviewed EPA's land use GHG emissions assessment for corn ethanol, including the FASOM and FAPRI models and Winrock land-use types converted and emission factors by ecosystem type. The study made many recommendations for improving the land-use and emissions modeling.

"Review of CARB's Low Carbon Fuel Standard Proposal", April 15, 2009. Conducted for Renewable Fuels Association. This study reviewed CARB's analysis of land use emissions using GTAP6 and CARB's overall lifecycle emissions for corn ethanol. This study made many recommendations for improving the land use and lifecycle emissions of corn ethanol.

"Emission Benefits of a National Clean Gasoline", August 2008. Conducted for the Alliance of Automobile Manufacturers. This study evaluated the nationwide criteria pollutant emission reductions of a national clean gasoline standard.

"Land Use Effects of Corn-Based Ethanol", February 25, 2009. Conducted for Renewable Fuels Association. This study evaluates possible land use changes and GHG emissions associated with these land use changes as a result of the renewable fuel standard mandated 15 billion gallons of corn ethanol required by calendar year 2015. The study utilized projections of land use in the US and rest of world performed by Informa Economics, LLC, as well as newer estimates of the land use credits of co-products produced by ethanol plants to evaluate possible land use changes.

"On-Road NOx Emission Rates From 1994-2003 Heavy-Duty Trucks", SAE2008-01-1299, conducted for the Engine Manufacturers Association. This study examined

manufacturers consent decree emissions data to determine on-road NOx emission rates, and deterioration in emissions from heavy-duty vehicles. (Peer reviewed publication)

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act - Part 2: CO2 and GHG Impacts", SAE2008-01-1853, conducted for the Alliance of Automobile Manufacturers. This paper evaluated the comparison of greenhouse gases from cars and light trucks in the US under both the Federal and California GHG policies. (Peer reviewed publication)

"Effectiveness of the California Light Duty Vehicle Regulations as Compared to Federal Regulations", June 15, 2007. Conducted with NERA Economic Consulting and Sierra Research for The Alliance of Automobile Manufacturers. This study compares the emission benefits of the California and Federal light duty vehicle regulations for HC, CO, NOx, PM, SOx, and Toxics taking into account the difference in emission standards, new vehicle costs and its effect on fleet turnover, new vehicle fuel economy and its effect on vehicle miles traveled, and other factors. Both the EPA MOBILE6 and ARB EMFAC on-road emissions models were used to estimate changes in emissions inventories.

"The Case for a Dual Tech 4 Model Within the California Predictive Model", May 20, 2007. Conducted with ICF International and Transportation Fuels Consulting for the Renewable Fuels Association (RFA). This study developed separate emissions vs fuel property models for lower and higher Tech 4 (1986-1995) vehicles, and showed that utilizing this alternative Predictive Model would result in a higher compliance margin for fuels containing higher volumes of ethanol. It was thought that this could lead to higher ethanol concentrations in the state, but even if the dual model is not used, it is a better representation of the 2015 inventory than the ARB single model.

"Updated Final Report, Effects of Gasoline Ethanol Blends on Permeation Emissions Contribution to VOC Inventory From On-Road and Off-Road Sources, Inclusion of E-65 Phase 3 Data and Other Updates", June 20, 2007. Conducted for the American Petroleum Institute. This report updates the earlier March 3, 2005 report for API utilizing data collected by CRC and others since of the time of the earlier report.

Final Report, Development of Technical Information for a Regional Fuels Strategy, February 28, 2006. Conducted for the Lake Air Directors Consortium (LADCO). This report provided guidance to the LADCO states (Midwestern states) concerning how to model different types of fuel control programs (in particular) using EPA mobile source models, and how to set up the baseline input files so that results are consistent between the different states.

"Emission Reductions from Changes to Gasoline and Diesel Specifications and Diesel Engine Retrofits in the Southeast Michigan Area", February 23, 2005. Conducted for the Southeast Michigan Council of Governments (SEMCOG), the Alliance of Automobile Manufacturers, and the American Petroleum Institute. This study examined the on-road and off-road emission benefits of many different possible gasoline and diesel fuel

specifications that the state could adopt to help meet the 8-hour ozone standards. This study formed the basis for the state's move to lower RVP summer gasoline.

"Examination of Temperature and RVP Effects on CO Emissions in EPA's Certification Database, Final Report", CRC Project No. E-74a, April 11, 2005. Conducted for the Coordinating Research Council. This study compared CO vs temperature results from the MOBILE6 model to the certification data, and recommended further testing, which is being conducted by the CRC at this time.

"Effects of Gasoline Ethanol Blends on Permeation Emissions Contribution to VOC Inventory From On-Road and Off-Road Sources" March 3, 2005. Conducted for the American Petroleum Institute (API). Using data from the CRC-E-65 program, and data collected by the California EPA and Federal EPA, this study estimated the impacts of ethanol use on increasing permeation VOC emissions from on-road vehicles, off-road equipment and vehicles, and from portable containers. Emission inventory estimates were made for a number of geographical areas including the state of California, and results showed that the permeation effect increases anthropogenic VOC inventories by 2-4%.

Review of EPA Report "A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions", February 11, 2003. Conducted for the American Petroleum Institute. This study critically examined the methods that EPA used to develop the impacts of biodiesel fuels on HC, CO, NOx, and PM emissions.

"Well-To Wheels Analysis of Advanced Fuel/Vehicle Systems – A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions", May 2005. Conducted for General Motors Corporation, with Argonne National Labs. This study examined many different well to wheels pathways for various fuels, and their impacts on GHG and criteria pollutant emissions.

"Potential Delaware Air Emission Impacts of Switching From MTBE to Ethanol in the Reformulated Gasoline Program", May 26, 2005. Conducted for Lyondell Chemical Company. This study examined the HC, CO, and NOx impacts of switching from MTBE to ethanol.

"Potential Massachusetts Air Emission Impacts of Switching From MTBE to Ethanol in the Reformulated Gasoline Program" June 17, 2005. Conducted for Lyondell Chemical Company. This study is similar to the Delaware study above.

"Potential Maryland Air Emission Impacts of a Ban on MTBE in the Reformulated Gasoline Program", October 18, 2005. Conducted for Lyondell Chemical Company. This study is similar to the Delaware study above.

"MOBILE6.2C with Ethanol Permeation and Ethanol NOx Effects", February 8, 2005. Conducted for Health Canada. This study modified the MOBILE6.2C model for ethanol permeation VOC and ethanol NOx effects.

Education

B. Sc., (Materials and Metallurgical Engineering), University of Michigan, Ann Arbor, 1979
Post Graduate Courses (Business Administration), University of Michigan, Ann Arbor, 1982

2_TF_LCFS_GE

1243. Comment: **LCFS TF2-5, LCFS TF2-8, TF2-9, TF2-11, TF2-12, TF2-19, TF2-23, TF2-29, TF2-30, and TF2-36**

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

1244. Comment: **LCFS TF2-1**

The comment suggests that it is improper to amend a regulatory proposal for a third time, and recommends that ARB start the process over with a new 45-day notice.

Agency Response: ARB staff disagrees, because the APA clearly contemplates that an agency may amend a pending proposal to address an omission or in response to comments from the public.

1245. Comment: **LCFS TF2-2**

The comment relates to a spreadsheet included in the 3rd 15 day notice addressing electricity use estimates included in the illustrative compliance scenario published in the ISOR. The comment states that "CARB has not explained why this information was not included in the original 45-day notice, nor why it waited until now to make the information available for public comment", and argues that the 15 day comment period is insufficient.

Agency Response: ARB staff disagrees that the 15-day period was insufficient in light of the fact that ARB's proposal neither requires nor is predicated on a set amount of electricity usage in transportation. This detail had been sought by and provided to a single stakeholder. ARB determined it should also be made available to the public. ARB placed this material in the record to provide another layer of detail on the inputs to the calculations of electricity consumption used by electric vehicles expected as a result of California's Advanced Clean Cars (ACC) regulation. The relevant part of the information in the spreadsheet was already included in Table B-17 of Appendix B that was released with the ISOR. Table B-17 includes the estimates of the number of electric vehicles anticipated due to the ACC regulation and their corresponding electricity consumption for each year from 2015 through 2020. These estimates were used to quantify light duty vehicle (LDV) electricity use and LCFS credit generation in the

Illustrative Compliance Scenario -- Tables B-22, B-23, and B-24. The more detailed material included in the 3rd 15 Day Notice provides detail on the average e-VMT per ZEV and the average efficiency of ZEVs, shown in the Table B-17. The details provided are consistent with current, publicly-available information on the efficiency and use of ZEVs. The spreadsheet also shows estimates for the full analysis period 2014 through 2025.

ARB staff has not modified its estimates of the number of ZEVs or electricity usage in the updated illustrative compliance scenarios released to demonstrate the impact of the proposed 15 day changes.

1246. Comment: **LCFS TF2-3**

The comment questions why material similar to the electricity use estimates related to natural gas (NG) vehicles was not included in the 3rd 15-day notice.

Agency Response: The comment-is not directed to any material provided for comment in the 3rd 15-day notice, and as such needs no response. ARB staff disagrees with the implication that the rulemaking record is not complete; in light of the fact that ARB's proposal neither requires nor is predicated on a set amount of natural gas usage in transportation. However, for clarity purposes ARB staff is addressing some of the concerns related to NG projections raised in other comments by Growth Energy. Please see responses to **LCFS TF2-5, TF2-6,** and **TF2-7.**

1247. Comment: **LCFS TF2-4**

The comment argues that ARB's treatment of electricity and NG fuel use forecasts are inconsistent and not supported by substantial evidence.

Agency Response: The comment is not directed to any change in the 3rd 15-day notice, and as such needs no response. However, for clarity purposes ARB staff note that the there is no legal or technical rationale for using parallel methodologies when estimating future fuel consumption of different fuels by different vehicle types. The method used for electric vehicles was included only because of one stakeholder's interest in how the anticipated penetration of electric vehicles pursuant to the ACC regulation (which provided an estimate of vehicle numbers but not fuel consumption) translates into fuel use. Forecasts of fuel use and availability were made independent of vehicle numbers for the other fuels included in the illustrative scenarios. See responses to **LCFS TF2-2, TF2-3, TF2-5, TF2-6,** and **TF2-7.**

1248. Comment: **LCFS TF2-6**

These comments argue that ARB has failed to meet disclosure requirements with respect to NG fuel forecasts, has failed to project the number of NG vehicles and has failed to identify the basis for the fuel estimate it used.

Agency Response: See response to **LCFS TF2-5**.

1249. Comment: **LCFS TF2-7**

These comments argue that ARB has failed to meet disclosure requirements with respect to NG fuel forecasts, has failed to project the number of NG vehicles and has failed to identify the basis for the fuel estimate it used.

Agency Response: See response to **LCFS TF2-5**.

1250. Comment: **LCFS TF2-10**

The comment argues that ARB did not include NG vehicle costs in the economic impact analysis.

Agency Response: The comment is not directed to any change in the 3rd 15-day notice, and as such needs no response. However, for clarity purposes ARB staff note that the ISOR is explicit that the LCFS is unlikely to impact, in any significant way, the amount of NG that is consumed by vehicles (ISOR Appendix B pages B-27 and B-28). Therefore there is no reason to perform an economic impact assessment of the LCFS relative to the number of NG vehicles.

1251. Comment: **LCFS TF2-13**

This comment (and those following, through **LCFS TF2-19**) is under the caption: "CARB's Indirect Land Use Change Factor for Corn Ethanol Is Based on Incomplete Data and Faulty Analysis, and Lacks Evidentiary Support." The comment states that in calculating the LUC value for corn ethanol ARB used a variety of inputs. In particular, the commenter refers to two conflicting opinions – both in the ISOR and appendices – one a report by David Rocke and one a student dissertation by Juan Francisco Rosas Perez. The comment then concludes that ARB failed to comply with the Government Code because data was added to the record as part of a 15-day change.

Agency Response: The third 15-day change did not change ARB's iLUC for corn ethanol. That value and the supporting analysis and information were all set forth in the initial notice package for the LCFS re-adoption, and extensively commented on by this commenter and dozens of other parties. No further response is needed regarding the corn ethanol iLUC value, analysis, or supporting information.

The data added to the record was not the basis for the corn ethanol iLUC value. The basis for that value, as the comment itself acknowledges, was in the ISOR. Because the commenter expressed interest in seeing a data set used by both Rosas Perez and Rocke, largely compiled from publicly-available information, ARB added the data set to the record so that all interested parties would have ready access. Now, ironically, the commenter complains that it was improper to share that data set as part of a 15-day notice.

The commenter appears to mistakenly assume that ARB relied on the data set or somehow based the corn ethanol iLUC value on the Rosas Perez data set. In reality, ARB determined the corn ethanol iLUC value as described in the 295-page Staff Report, and the 113-page appendix regarding iLUC.

1252. Comment: **LCFS TF2-14**

The commenter believes that Dr. Rocke misinterpreted the Rosas-Perez study by only analyzing a small subset of parameters (or even one parameter as stated) in contrast with Rosas-Perez who showed that a wide range of parameters affect YPE values. According to the commenter, there is no justification why Dr. Rocke used this approach and Dr. Rocke's simple analysis, which concluded that YPE is small to zero, is deeply flawed, unsupported by evidence, and inconsistent with modeling practices used by ARB for other rulemakings. Also, according to the commenter, , the public was completely misled about Dr. Rocke's approach to estimating YPE using Perez's data because ARB did not make the Rosas-Perez data available and ARB erred in using Dr. Rocke's report to support using a lower yield-price value.

Agency Response: The comment appears aimed at Dr. Rocke's analysis rather than ARB's analysis, and needs no response beyond the extensive responses to the timely comments on the initial notice package. See e.g. **LCFS 8-9**, **LCFS 46-79**, **LCFS 46-86**, and **LCFS 46-102**. Although ARB did not adopt the conclusion reached by either J.F. Rosas Perez or by David Rocke, their respective analyses were included in that initial notice package and comments on those analyses were timely during that initially noticed comment period.

ARB does not agree with the commenter's assertion that ARB's analysis and the information on which it was based was "finally made available to the public" only on "approximately August 1, 2015." In fact, the public, including the commenter, commented extensively on ARB's analysis long before August 1, 2015. See e.g. **LCFS 8-9**, **LCFS 46-79**, **LCFS 46-86**, and **LCFS 46-102**. Further, as the record reflects, the debate about YPE was robust and public. YPE has been the subject of public workshops over several years, and the initial notice package for this rulemaking, released in December 2014, included a 32-page public notice, the 295-page Staff Report, and a 113-page appendix devoted entirely to iLUC

Notably, and as described in the ISOR and its appendices, ARB did not adopt Dr. Rocke's conclusion. In Appendix I, Attachment 1-5, ARB stated "researchers use different econometric methods to derive relationship between yield and price. They sometimes report contrasting values even when using the same data." This is evident from the various studies cited in Appendix I, Attachment 1. Given that there is no consensus in the academic and scientific community about definite values for YPE even when using the same data, ARB used an approach to account for all likely values for YPE. Accordingly, staff used a range between 0.05 and 0.35. This has been document in Attachment 1 of Appendix I of the ISOR. The public was provided ample opportunity to comment on *ARB's* analysis and conclusions.

For the analysis conducted by Dr. Rocke, all years that were included in the Perez data were considered. The variables used were price and supply, and sound modeling principles were used based on Granger Causality. This analysis was used to test whether the complex analysis in Perez was improving elasticity estimates, or whether the Perez results were the artifactual results of using many variables and choosing from among hundreds of possible models with widely varying elasticity estimates in order perhaps to produce an intended result. The commenter's statement is completely contradictory to sound principles of data analysis, where including many variables generally produces false positives, as one could argue Perez's elasticity result would be classified. According to Dr. Rocke, if a reasonable simple analysis produces a null result, but a complex, opaque analysis shows significance, the complex analysis is likely suspect.

See also response to **LCFS TF2-40**, **LCFS FF45-1**, **LCFS 46-12**, **LCFS 46-79**, **LCFS 46-103**, **LCFS 46-102**, **LCFS 46-107**, and **LCFS 8-9.**

1253. Comment: **LCFS TF2-15**

The commenter believes that Dr. Rocke misinterpreted the Perez study by only analyzing a small subset of parameters (or even one parameter as stated) in contrast with Perez who showed that a wide range of parameters affect YPE values. There is no justification why Dr. Rocke used this approach. Dr. Rocke's simple analysis which concluded that YPE is small to zero is deeply flawed, unsupported by evidence, inconsistent with modeling practices used by ARB for other rulemakings. Also, by not making the data available, the public was completely misled about Dr. Rocke's approach to estimating YPE using Perez's data. Finally, ARB used David's report to support using a lower yield-price value.

Agency Response: See responses to **LCFS TF2-13** and **LCFS TF2-14**.

1254. Comment: **LCFS TF2-16**

The commenter believes that Dr. Rocke misinterpreted the Perez study by only analyzing a small subset of parameters (or even one parameter as stated) in contrast with Perez who showed that a wide range of parameters affect YPE values. There is no justification why Dr. Rocke used this approach. Dr. Rocke's simple analysis which concluded that YPE is small to zero is deeply flawed, unsupported by evidence, inconsistent with modeling practices used by ARB for other rulemakings. Also, by not making the data available, the public was completely misled about Dr. Rocke's approach to estimating YPE using Perez's data. Finally, ARB used David's report to support using a lower yield-price value.

Agency Response: See responses to **LCFS TF2-13** and **LCFS TF2-14**.

1255. Comment: **LCFS TF2-17**

The commenter believes that Dr. Rocke misinterpreted the Perez study by only analyzing a small subset of parameters (or even one parameter as stated) in contrast with Perez who showed that a wide range of parameters affect YPE values. There is no justification why Dr. Rocke used this approach. Dr. Rocke's simple analysis which concluded that YPE is small to zero is deeply flawed, unsupported by evidence, inconsistent with modeling practices used by ARB for other rulemakings. Also, by not making the data available, the public was completely misled about Dr. Rocke's approach to estimating YPE using Perez's data. Finally, ARB used David's report to support using a lower yield-price value.

Agency Response: See responses to **LCFS TF2-13** and **LCFS TF2-14**.

1256. Comment: **LCFS TF2-18**

The commenter instructs ARB that it must seek external scientific review of Dr. Rocke's analysis, and must answer a series of interrogatories.

Agency Response: Regarding external review, as required by statute, ARB sent for external review ***ARB's*** findings, conclusions and the assumptions on which the scientific portions of the proposal were based. The pertinent statute does not require ARB to seek separate, expensive, time-consuming scientific review of every ***other party's*** document, submission, conflicting opinion and dataset contained in the vast rulemaking record.

The interrogatories make no recommendation or objection to the third 15-day changes, and need no response.

1257. Comment: **LCFS TF2-20**

The commenter believes that the 15-day public comment period provided was inadequate and that ARB should re-start the entire rulemaking process based on the addition of a handful of technical documents that the commenter itself requested.

Agency Response: ARB disagrees. ARB complied with all requirements of the APA, and ARB's decision to provide materials not covered by the APA's rulemaking file provisions do not indicate otherwise. ARB staff also disagrees with the commenter's characterization of the relevant documents as "extensive new information regarding CARB's analyses." As the commenter indicates, some of the data pertained to "the Rocke analysis," not ARB's analysis, and, as discussed in Response **TF2-2**, the other document contained some background information (the relevant portions of which were provided in the ISOR's Appendix B and none of which represents a new analyses or alters the proposed regulation in any way).

ARB staff also disagree with the commenter's characterization of ARB's actions related to the commenter's Public Records Act as "dilatory" and notes that the court also expressly rejected this characterization in the only ruling (a tentative one) that has been issued in the relevant litigation. In addition, the commenter's opinions concerning ongoing litigation are not directed to any change in the 3rd 15-day notice, and as such need no response.

1258. Comment: **LCFS TF2-21**

The commenter believes that the public comment period established by the California Legislature in Government Code sections 11346.8, subds. (c)(d) and 11347.1 is inadequate, thus ARB should re-start the entire rulemaking process based on the addition of a handful of technical documents that the commenter itself requested. The remainder of the comment consists of complaining about the burdens of litigation that the commenter itself initiated against ARB.

Agency Response: In regard to the public comment period, see response to **LCFS TF2-20**. In regard to ongoing litigation, the comment is not directed to any change in the 3rd 15-day notice, and as such needs no response.

1259. Comment: **LCFS TF2-22**

The commenter believes that the 15-day public comment period was inadequate, thus ARB should re-start the entire rulemaking process based on the addition of a handful of technical documents that the commenter itself requested.

Agency Response: See response to **LCFS TF2-20**.

1260. Comment: **LCFS TF2-24**

The commenter attaches another declaration from Jim Lyons, this one expressing Mr. Lyons' surprise that an estimate of natural gas usage in transportation was not determined based on the number of NGVs in future. For Mr. Lyons that "raises serious concerns" about the validity of ARB's compliance scenario. The declaration includes a conclusory statement that it is "not possible" for anyone to understand how ARB reached conclusions about "the use of electricity as a transportation fuel in the light-duty fleet" in connection with the illustrative scenario.

Agency Response: This comment is not directed to any change in the 3rd 15-day notice, and as such needs no response. However, for clarity purposes ARB staff note that the alleged flaws in the analysis of future natural gas demand (the criticism that ARB staff made no detailed estimate of the number of NGVs), are without merit.

First of all, the proposal does not require the use of NGVs or natural gas. The illustrative scenario was used for various purposes as a reasonably possible forecast, although neither required nor concretely predicted. The illustrative scenario does not bind natural gas producers, natural gas vehicle manufacturers, ARB or anyone else in any way. Indeed, the LCFS—the *regulation* at issue here—is designed to let market participants determine which fuels are used to comply with the LCFS. Any future forecast regarding such a regulation will contain some uncertainty and is not therefor invalid, whatever the commenter means by having serious concerns.

Second, ARB disagrees with the implication that ARB needed to know the NGV population in order to forecast natural gas use. Appendix B of the ISOR contains explicit discussion of how ARB considered estimates of the potential for growth in the use of NG as a fuel independent of any requirement of the LCFS (See pages B-24 to B-26 and B-35). A number of NG growth estimates were available to the ARB as the ISOR was being developed. These included estimates by the California Energy Commission, ICF consulting, the Boston Consulting Group, and the EIA. Each is referenced in the ISOR and was publically available at the time the ISOR was released. These references projected substantial growth in NG use, thus providing ARB staff with the information needed to include NG as a fuel that might be used to comply with the LCFS.

Lyons' declaration includes a conclusory statement that it is "not possible" for anyone to understand how ARB reached conclusions about "the use of electricity as a transportation fuel in the light-duty fleet" in connection with the illustrative scenario. ARB disagrees; the ISOR includes an entire Appendix B, consisting of 41 pages and 31 referenced sources explaining how the illustrative scenario, including for electricity, was developed. The portion of the comment that refers to electric vehicles has also been addressed in the response to **LCFS TF2-3.**

In addition**,** for clarity purposes we have addressed many of the NG related concerns in previous responses. Comments related to the adequacy of ARB's estimates of NG use were addressed in responses **LCFS TF2-5, TF2-6**, and **TF2-7**. Comments related to concerns about economic assessments were addressed in response **LCFS TF2-10**. Comments related to environmental analyses were addressed in response **LCFS TF2-11**.

1261. Comment: **LCFS TF2-25**

The commenter attaches another declaration from Jim Lyons, this one expressing Mr. Lyons' surprise that an estimate of natural gas usage in transportation was not determined based on the number of NGVs in future. For Mr. Lyons, that "raises serious concerns" about the validity of ARB's compliance scenario.

Agency Response: See response to **LCFS TF2-24**.

1262. Comment: **LCFS TF2-26**

The declaration from Jim Lyons challenges assumptions in the illustrative scenario, Appendix B to the ISOR.

Agency Response: See response to **LCFS TF2-24**.

1263. Comment: **LCFS TF2-27**

The declaration from Jim Lyons challenges assumptions in the illustrative scenario, Appendix B to the ISOR.

Agency Response: See response to **LCFS TF2-24**.

1264. Comment: **LCFS TF2-28**

The declaration from Jim Lyons challenges assumptions in the illustrative scenario, Appendix B to the ISOR.

Agency Response: See response to **LCFS TF2-24**.

1265. Comment: **LCFS TF2-31**

The comment, in the form of an "Exhibit B", is used to present calculations of the number of NG vehicles needed to use the fuel projected in the ISOR, and are presented to support the concerns previously expressed in comments **LCFS TF2-4** through **TF2-12.**

Agency Response: These comments are related to the ISOR Appendix B -- issues not included in the 3rd 15 Day notice, and are not directed to any material provided for comment in the 15-day proposal, and as such needs no response.

1266. Comment: **LCFS TF2-32**

The comment, in the form of an "Exhibit B", is used to present calculations of the number of NG vehicles needed to use the fuel projected in the ISOR, and are presented to support the concerns previously expressed in comments **LCFS TF2-4** through **TF2-12.**

Agency Response: These comments are related to the ISOR Appendix B -- issues not included in the 3rd 15 Day notice, and are not directed to any material provided for comment in the 15-day proposal, and as such needs no response.

1267. Comment: **LCFS TF2-33**

The comment, in the form of an "Exhibit B", is used to present calculations of the number of NG vehicles needed to use the fuel projected in the ISOR, and are presented to support the concerns previously expressed in comments **LCFS TF2-4** through **TF2-12.**

Agency Response: These comments are related to the ISOR Appendix B -- issues not included in the 3rd 15 Day notice, and are not directed to any material provided for comment in the 15-day proposal, and as such needs no response.

1268. Comment: **LCFS TF2-34**

The comment, in the form of an "Exhibit B", is used to present calculations of the number of NG vehicles needed to use the fuel projected in the ISOR, and are presented to support the concerns previously expressed in comments **LCFS TF2-4** through **TF2-12.**

Agency Response: These comments are related to the ISOR Appendix B -- issues not included in the 3rd 15 Day notice, and are not directed to any material provided for comment in the 15-day proposal, and as such needs no response.

1269. Comment: **LCFS TF2-35**

The comment, in the form of an "Exhibit C", seeks to support and present the concerns related to credit generation from NG fuel forecasts used in the illustrative compliance scenario previously expressed in comment **LCFS TF2-12.**

Agency Response: This comment is not directed to any change in the 3rd 15-day notice, and as such needs no response.

1270. Comment: **LCFS TF2-37**

The comment states that ARB should explain why 0.25 was not used (EWG recommended value) in a new rulemaking notice and permit testimony at a public hearing.

Agency Response: ARB has explained the approach used in the iLUC analysis in Appendix I of the ISOR; nothing changed in the third 15-day notice. No response to the commenter's renewed critique of iLUC is required

See also responses to **LCFS 8-1**, **LCFS 8-4**, **LCFS 8-9**, **LCFS 46-102**, **LCFS B12-6**, **LCFS B12-32**, **LCFS FF45-1**, **LCFS FF45-1**, and **LCFS TF2-40**.

1271. Comment: **LCFS TF2-38**

The comment states that ARB arbitrarily relied on the Rocke Study to select a range of YPE values and a Mid-Point that were significantly lower than what the EWG recommended.

Agency Response: See response to **LCFS TF2-14**.

1272. Comment: **LCFS TF2-39**

States that Rocke dismissed Goodwin and Perez analyses as methodologically flawed. Repeated and replicated Rocke's results but could not replicate Perez's results. States that Rocke's simplified analysis is not a good measure to estimate YPE and the analysis is unreliable and constitutes indefensible modeling practice (unlike practice used by ARB in other analyses).

Agency Response: Virtually all of this comment critiques Rocke's analysis which was (1) not ARB's conclusion on YPE, and (2) released with the ISOR. Insofar as the comment critiques Rocke's analysis, it is untimely and unrelated to the third 15-day notice.

Insofar as the commenter's expert states that he could not reproduce Perez' results, ARB notes the comment, and further notes that David Rocke attempted to reproduce Perez's results but after spending a large amount of time deciphering the data and information, concluded that the Perez analysis is complex, opaque, and poorly documented that the result is likely not reproducible. See also responses to **LCFS TF2-14** through **LCFS TF2-17**.

1273. Comment: **LCFS TF2-40**

The commenter states that since Dr. Rocke used a simple analysis using incomplete data to invalidate Perez's results, it does not imply that Perez's results are not relevant. The Goodwin results fall in line with Perez's results. If ARB does not agree with commenter's position on the Rocke analysis, staff must address the following:

- Why staff believes Rocke's simple analysis with limited data from the Perez study constitutes an adequate analysis
- Why ARB deviated from the EWG recommendation of 0.25 value for YPE
- What was the issue with Perez's handling of autocorrelation

Agency Response: ARB does not agree with commenter regarding the quality of Dr. Rocke's analysis, except for the prior statement that it could be reproduced. More importantly, ARB does not agree it relied on Dr. Rocke's analysis to determine the YPE values in the iLUC analysis. As explained in ISOR Appendix I, given the disagreement between researchers on specific values (or range) for YPE, ARB used a range of values for YPE between 0.05 and 0.35 to account for all likely values for this elasticity parameter. See also response to **LCFS TF2-14**, **LCFS TF 2-15**, **LCFS TF 2-16**, **LCFS 8-9**, **LCFS 46-12**, **LCFS 46-102**, **LCFS B12-32**, and **LCFS FF45-1**.

ARB is not required to answer the interrogatories constituting the balance of this comment; they are neither recommendations nor objections. See also responses to **LCFS TF2-14** through **LCFS TF2-17**.

1274. Comment: **LCFS TF2-41**

The comment states that the YPE of 0.185 will over estimate iLUC. The use of YPE of 0.25 will result in changes to iLUC values for other biofuels also.

Agency Response: ARB's iLUC and YPE determinations as set forth in the ISOR were extensively commented on by the public, including this commenter during the 45-day comment period, as well as for years preceding this rulemaking. The third 15-day notice did not set forth any analysis, conclusion, support or change regarding ARB's determinations. Commenter's untimely repetition of its views following the third 15-day notice needs no response in this context. Nevertheless, ARB repeats that it does not currently plan to change the iLUC determinations presented in the ISOR. See also responses to **LCFS 8-9**, **LCFS 46-102**, **LCFS B12-32**, and **LCFS FF45-1**.

1275. Comment: **LCFS TF2-42**

In an attached declaration, Mr. Darlington complains that the release of additional data on July 31, 2015 (the dataset used by David Rocke and Juan Francisco Rosas Perez to draw conflicting conclusions) did not give him or the public sufficient time to conduct studies to assess the relationship between price and yield, and to submit an analysis to ARB.

Agency Response: ARB disagrees; the LCFS adoption first began in 2008, and continued in 2009, and has been effective since January 2010. The re-adoption process began in 2014, including a working group on iLUC and a public workshop on iLUC, culminating in a 45-day notice, ISOR, and two Board hearings in 2015. During all of that time, the relationship between price and yield has been hotly, publicly, and thoroughly debated. The suggestion that Mr. Darlington's chance to conduct research or participate in the debate was limited to 15 days in August 2015 is simply wrong.

The following group of comments are from Peer Review.

This page intentionally left blank.

May 5, 2015

Mr. James Aguila
Branch Chief
Program Planning and Management Branch
California Air Resources Board
Industrial Strategies Division
1001 I Street
Sacramento, California 95814

SUBJECT: REQUEST FOR EXTERNAL PEER REVIEW OF STAFF'S METHODOLOGY IN CALCULATING FUEL CARBON INTENSITIES AND USE OF THREE LIFE CYCLE GREENHOUSE GAS EMISSIONS MODELS

Dear Mr. Aguila:

This letter responds to the attached January 21, 2015 request by the California Air Resources Board (ARB) for a external peer review of the staff reports entitled, Staff Report: Calculating Life Cycle Carbon Intensity of Transportation Fuels in California; Calculating Carbon Intensity Values of Crude Oil Supplied to California Refineries; and Calculating Carbon Intensity Values from Indirect Land Use Change of Crop-Based Biofuels.

To begin the process for selecting reviewers, I contacted the University of California, Berkeley (University) and requested recommendations for candidates considered qualified to perform the assignment. The University was provided with the January 21, 2015 request letter to me, and attachments, and no additional material was asked for or forwarded to augment the request. This service by the University includes interviews of each promising candidate and is supported through an Interagency Agreement co-signed by Cal/EPA and the University.

Each candidate who was both interested and available for the review period was asked to send me a completed Conflict of Interest (COI) Disclosure form and Curriculum Vitae to begin the review process. The cover letter for the COI form describes the context for COI concerns that must be taken into consideration when completing the form. "As noted, staff will use this information to evaluate whether a reasonable member of the public would have a serious concern about [the candidate's] ability to provide a neutral and objective review of the work product."

In subsequent letters to candidates approving them as reviewers, I provided the attached January 7, 2009 Supplement to the Cal/EPA Peer Review Guidelines, which, in part serves two purposes: a) it provides guidance to ensure confidentiality through the course of the external review, and, b) it notes reviewers are under no obligation to discuss their comments with third-parties after reviews have been submitted. <u>We recommend they do not</u>. All outside parties are provided opportunities to address a proposed regulatory action, or potential basis for such, through a well-defined rulemaking process.

Later, I sent each reviewer the material to be reviewed and a detailed cover letter to initiate the review (example attached). The letter included as an attachment a summary overview for the many documents and a Disclaimer. The Disclaimer noted supporting documents were either entirely or partially not peer – reviewed, and that reviewers were ultimately responsible for assessing the relevance and accuracy for the content of all information upon which the staff report is based.

Also attached to the cover letter was the January 21, 2015 request for reviewers to me. Its Attachment 2 was highlighted as the focus for the review. Each reviewer was asked to address each conclusion, as expertise allows, in the order given. Thirty days were provided for the review. I also asked reviewers to direct enquiring third-parties to me after they have submitted their reviews.

Reviewers' names, affiliations, curriculum vitae, and reviews are being sent to you now with this letter. All attachments can be electronically accessed through the Bookmark icon at the left of the screen.

Approved reviewers are as follows:

1) Amit Kumar, Ph.D.
Associate Professor
Department of Mechanical Engineering
University of Alberta
5-8M Mechanical Engineering Building
Edmonton, Alberta
Canada T6G 2GB

Telephone: 780-492-7797
Email: amit.kumar@ualberta.com

2) Andres Clarens, Ph.D.
Professor, Environmental and Water Resources
Department of Civil and Environmental Engineering
School of Engineering & Applied Science
University of Virginia
D220 Thornton Hall, 351 McCormick Road
Charlottesville, VA 22903

Telephone: 434-924-7966
Email: aclarens@virginia.edu

3) H. Scott Matthews, Ph.D.
Professor, Civil and Environmental Engineering
Carnegie Mellon University
123A Porter Hall
Pittsburgh, PA 15213-3890

Telephone: 412-268-6218
Email: hsm@cmu.edu

4) Bruce A. McCarl, Ph.D.
University Distinguished Professor
Department of Agricultural Economics
Texas A&M University
College Station, Texas 77843-2124

Telephone: 979-845-1706
Email: mccarl@tamu.edu

If you have questions, or require clarification from the reviewers, please contact me directly.

Regards,

Gerald W. Bowes

Gerald W. Bowes, Ph.D.
Manager, Cal/EPA Scientific Peer Review Program
Office of Research, Planning and Performance
State Water Resources Control Board
1001 "I" Street, 16th Floor
Sacramento, California 95814

Telephone: (916) 341-5567
Fax: (916) 341-5284
Email: GBowes@waterboards.ca.gov

Attachments:
1) January 21, 2015 Request by Jim Aguila for External Scientific Peer Review
2) Example of Letter to Reviewer Initiating the Review
3) January 7, 2009 Supplement to Cal/EPA Peer Review Guidelines

4) Curriculum Vitae:
   a) Amit Kumar, Ph.D. – University of Alberta
   b) Andres Clarens, Ph.D. - University of Virginia
   c) H. Scott Matthews, Ph.D. - Carnegie Mellon University
   d) Bruce A. McCarl, Ph.D. - Texas A&M University

5) External Scientific Peer Reviews
   a) Amit Kumar, Ph.D. – University of Alberta
   b) Andres Clarens, Ph.D. - University of Virginia
   c) H. Scott Matthews, Ph.D. - Carnegie Mellon University
   d) Bruce A. McCarl, Ph.D. - Texas A&M University

cc: Jack Kitowski
jack.kitowski@arb.ca.gov
Assistant Division Chief
Industrial Strategies Division
Air Resources Board

Samuel Wade
samuel.wade@arb.ca.gov
Branch Chief
Transportation Fuels Branch
Air Resources Board

John Courtis
john.courtis@arb.ca.gov
Manager
Alternative Fuels Section
Air Resources Board

Anil Prabhu
anil.prabhu@arb.ca.gov
Air Resources Engineer
Alternative Fuels Section
Air Resources Board

Aubrey Gonzalez
aubrey.gonzalez@arb.ca.gov
Air Resources Engineer
Substance Evaluation Section
Air Resources Board

Matthew Rodriquez
Secretary for Environmental Protection

Air Resources Board

Mary D. Nichols, Chairman
1001 I Street • P.O. Box 2815
Sacramento, California 95812 • www.arb.ca.gov

Edmund G. Brown Jr.
Governor

TO: Gerald W. Bowes, Ph.D., Manager
Cal/EPA Scientific Peer Review Program

FROM: Jim M. Aguila, Chief
Program Planning and Management Branch

DATE: January 21, 2015

SUBJECT: REQUEST FOR EXTERNAL PEER REVIEW OF STAFF'S METHODOLOGY IN CALCULATING FUEL CARBON INTENSITIES AND USE OF THREE LIFE CYCLE GREENHOUSE GAS EMISSIONS MODELS

By way of this memorandum, California Air Resources Board (ARB/Board) staff requests external peer review of the following:

1. *Staff Report: Calculating Life Cycle Carbon Intensity of Transportation Fuels in California*
2. *Staff Report: Calculating Carbon Intensity Values of Crude Oil Supplied to California Refineries*
3. *Staff Report: Calculating Carbon Intensity Values from Indirect Land Use Change of Crop-Based Biofuels*

The reports describe staff's methodology for calculating carbon intensity (CI) values with the use of three life cycle greenhouse gas (GHG) emissions models. Fuel CI is measured on a life cycle basis and represents the equivalent amount of carbon dioxide (CO_2e) emitted over all stages of the fuel's life, from production, to transport, and to use in a motor vehicle. Depending on the fuel, GHG emissions from each step may include carbon dioxide (CO_2), methane, nitrous oxide, and other GHG contributors. The overall GHG contribution from each step may be expressed as a function of the energy that the fuel contains. Thus, CI is expressed in terms of grams CO_2 equivalent per megajoule (CO_2e/MJ). In preparing each report referenced above, staff used the following life cycle GHG emissions model(s) to calculate fuel CI values, respectively:

1. California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET) Model
2. Oil Production Greenhouse Gas Emissions Estimator (OPGEE) Model

The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs, see our website: http://www.arb.ca.gov.

California Environmental Protection Agency

Printed on Recycled Paper

3. Global Trade Analysis Project (GTAP-BIO) Model combined with the Agro-Ecological Zone Emissions Factor (AEZ-EF) Model

For each review topic identified below, staff suggests the following number of reviewers and areas of expertise:

1. Life Cycle Carbon Intensity: Life cycle analysis of transportation fuels.

   A minimum of two reviewers who are familiar with well-to-wheel life cycle analysis related to transportation fuels. Experience with the CA-GREET model is optional.

2. Crude Oil Carbon Intensity: Life cycle analysis of crude oil production methods.

   A minimum of two reviewers who are familiar with crude oil production, developing models for GHG life cycle assessments of crude production, and the application of life cycle analysis models for the assessment of crude production emissions.

3. Indirect Land Use Change: Economic modeling of agricultural impacts, including general expertise with global economic models used to estimate indirect land use effects, carbon emissions inventory, and release of carbon emissions from land conversion.

   A minimum of three reviewers are requested for this complex review. Collectively, reviewers must have expertise in the following areas: econometric modeling, dynamics of land cover change, carbon emissions, and uncertainty analysis. For the uncertainty analysis, the reviewer must be familiar with Monte Carlo simulations. All reviewers must also be familiar with the GTAP model (or similar computable general equilibrium model), its database, application of economic models to estimate land conversions, protocols established by the Intergovernmental Panel on Climate Change or other global agencies for GHG accounting and carbon dynamics in various ecosystems, and changes in carbon stocks resulting from land conversion.

The specific charge or statement of work for each set of reviews is provided in Attachment 2. Peer review comments will be addressed by ARB staff in the final staff reports and submitted to the Board as part of the rulemaking to re-adopt the Low Carbon Fuel Standard (LCFS) regulation by July 2015. The proposed LCFS regulation is scheduled to be presented to the Board on February 19, 2015. The final Board hearing to take action for approval is currently scheduled on July 23, 2015.

The following attachments are enclosed:

1. Attachment 1 - Plain English Summary of Staff's Methodology In Calculating Fuel Carbon Intensities
2. Attachment 2 - Description of Scientific Bases to be Addressed by Peer Reviewers
3. Attachment 3 - List of Participants Associated with the Development of Fuel Carbon Intensities
4. Attachment 4 - References

The staff reports and other supporting documentation will be ready for review by **February 5, 2015**. Staff requests that the peer review be completed and comments from the reviewers be received by **March 10, 2015.**

If you have questions regarding this request, please contact Ms. Aubrey Gonzalez, Air Resources Engineer, Substance Evaluation Section at (916) 324-3334 or by email at aubrey.gonzale@arb.ca.gov.

Thank you for your time and consideration of this request.

Attachments (4)

cc: Aubrey Gonzalez, Air Resources Engineer
Substance Evaluation Section
Industrial Strategies Division

ATTACHMENT 1

Plain English Summary of Staff's Methodology in Calculating Fuel Carbon Intensities

Air Resources Board (ARB) staff prepared three reports entitled:

1. Staff Report: Calculating Life Cycle Carbon Intensity of Transportation Fuels in California
2. Staff Report: Calculating Carbon Intensity Values of Crude Oil Supplied to California Refineries
3. Staff Report: Calculating Carbon Intensity Values from Indirect Land Use Change of Crop-Based Biofuels

The reports describe staff's methodology for calculating fuel carbon intensity (CI) with the use of life cycle greenhouse gas (GHG) emissions models. CI is a measure of the GHG emissions per unit of energy of fuel and is measured in units of grams of carbon dioxide equivalent emissions per mega joule of fuel energy (gCO_2e/MJ).

The determination of fuel CI is fundamental to the reporting and compliance determination provisions of the Low Carbon Fuel Standard (LCFS) regulation.

1. Life Cycle Fuel Carbon Intensities

This section describes the basic methodology for calculating direct life cycle CIs for LCFS fuels. The basic analytical tool for identifying and combining the necessary fuel life cycle data and calculating the direct effects is the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model. Dr. Michael Wang, of the U.S. Department of Energy's Argonne National Laboratory, began developing the GREET model in 1996. Dr. Wang and his colleagues have updated the model several times since the publication of "*GREET 1.0 – Transportation Fuel Cycles Model: Methodology and Use*[1]," which documented the development of the first GREET version of the model. GREET 2014 is the latest version of the model and was released on October 3, 2014.[2]

For purposes of Assembly Bill 1007 and the LCFS, the model was modified to better represent California conditions. The revised version of the Argonne model is referred to as the California-modified GREET (CA-GREET). Staff used the latest version (2.0) of the CA-GREET model to calculate life cycle CIs from direct emissions from transportation fuels in California.

---

[1] Wang, M. Q. *GREET 1.0-: Transportation Fuel Cycles Model: Methodology and Use*. Argonne, IL: Argonne National Laboratory, 1996.

[2] Argonne National Laboratory, U.S. Department of Energy. "GREET Model." Accessed December 12, 2014. https://greet.es.anl.gov/.

The CA-GREET model, like the original GREET model, was developed in Microsoft Excel. The CA-GREET Excel spreadsheet is publicly available at no cost. The model is a sophisticated computational spreadsheet, with thousands of inputs and built-in values that feed into the calculation of energy inputs, emissions, CIs, and other values.

In general, each fuel pathway is modeled in GREET as the sum of the GHG emissions resulting from the following sequence of processes:

- Feedstock production
- Feedstock transport, storage, and distribution (TSD)
- Fuel production
- Production of co-products
- Finished fuel TSD
- Fuel use in a vehicle

The CA-GREET modifications are mostly related to incorporating California-specific conditions, parameters, and data into the original GREET model. The major changes incorporated into the CA-GREET model are listed below:

- Marine and rail emissions reflect in-port and rail switcher activity with an adjustment factor for urban emissions;
- Natural gas transmission and distribution losses reflect data from California gas utilities;
- The fuel properties data for California Reformulated Gasoline Blendstocks for Oxygenate Blending (CARBOB), ultra-low sulfur diesel (ULSD), California reformulated gasoline, natural gas, and hydrogen were revised to reflect California-specific parameters;
- The electricity transmission and distribution loss factor was corrected to reflect California conditions; the electricity mix was also changed to reflect in-State conditions, both for average and marginal electricity mix;
- The California crude oil recovery efficiency was modified to reflect the values specific to the average crude used in California including crude that is both produced in, and imported into, the State;
- Crude refining for both CARBOB and ULSD was adjusted to reflect more stringent standards for these fuels in California;
- Tailpipe CH_4 and N_2O emission factors were adapted for California vehicles where available;
- The process efficiencies and emission factors for equipment were changed to reflect California-specific data; and
- Landfill gas to compressed natural gas (CNG) pathway was coded into the CA-GREET pathway.[3]

[3] California Air Resources Board. *Proposed Regulation to Implement the Low Carbon Fuel Standard Staff Report: Initial Statement of Reasons, Volume I*. March 5, 2009. Pages IV-8–IV-10.

The basis of all fuel pathway CIs under the LCFS is the life cycle inventory (LCI) data contained in the CA-GREET 2.0 spreadsheet. LCI data quantifies the relevant energy, material, and waste flows into and out of the fuel production system. Emission factors and process efficiencies are also used to calculate CIs.

Staff used standard industry assumptions and best practices in applying the model. Examples of the LCI, emissions, and efficiency data found in CA-GREET 2.0 follow:

- *Agricultural Feedstock Production*

    - Argonne National Laboratory (ANL) describes the material and energy flows used in the six cellulosic pathways included in the GREET1 2013[4] version of the model in a document entitled "*Material and Energy Flows in the Production of Cellulosic Feedstocks for Biofuels for the GREET^{TM} Model*.[5]" This document draws on multiple peer-reviewed journal articles and data from the U.S. Department of Agriculture (USDA), U.S. Department of Energy (DOE), National Renewable Energy Laboratory (NREL), U.S. Environmental Protection Agency (U.S. EPA), and other sources.

    - ANL provided background details on its updated life cycle analysis of sorghum ethanol in a 2013 paper entitled "*Life-cycle energy use and greenhouse gas emissions of production of bioethanol from sorghum in the United States*.[6]" This paper draws on information from a wide variety of sources, including the USDA, the United Nations Food and Agricultural Organization, U.S. EPA, and other peer-reviewed literature.

    - The USDA's Economic Research Service reported the results of a 1996 survey of sorghum producers.[7] This report contained information on fertilizer, farm chemical, and on-farm fuel use.

- *Fuel Production*

    - NREL reported on its simulation of the process of converting corn stover to ethanol through dilute-acid pretreatment, enzymatic saccharification, and co-fermentation.[8] NREL's simulation was conducted using the Aspen Plus process modeling software.

[4] Systems Assessment Section, Center for Transportation Researcher, Argonne National Laboratory, 2013.
[5] Wang, Z. *et al*. *Material and Energy Flows in the Production of Cellulosic Feedstocks for Biofuels for the GREET^{TM} Model.* Energy Systems Division, Argonne National Laboratory. October 2013.
[6] Cai, H. *et al.* Biotechnology for Biofuels. *Life-cycle energy use and greenhouse gas emissions of production of bioethanol from sorghum in the United States.* 2013, 6:141.
[7] U.S. Department of Agriculture. Economic Research Service. February 1997.
[8] National Renewable Energy Laboratory and Harris Group. May 2011.

- U.S. EPA published the results of simulations of the energy needed to produce ethanol from sorghum as part of a formal rulemaking under 40 CFR Part 80.[9] These simulations were carried out by USDA and drew on prior simulations of the corn ethanol production process. All simulations were carried out using Aspen process modeling software.

- The energy requirements of producing ethanol from sugar cane were drawn in part from an article entitled "*Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use.*[10]"

- *Feedstock and Fuel Transport*

  ANL describes the updates it has made to the transportation LCI data in the GREET model in a 2013 paper (Dunn et al. October 7, 2013). Revisions to the energy intensity and emissions associated with locomotives, pipelines, heavy-duty trucks, ocean-going vessels, and barges are presented. The updates are based on information from the U.S. Department of Transportation, U.S. Energy Information Administration, U.S. EPA, Journal articles, and other sources.

- *Emission Factors*

  - U.S. EPA's Clearinghouse for Inventories and Emission Factors (Air CHIEF) CD ROM.[11] The Air CHIEF CD contains emission factors and software tools designed to assist with the estimation of emissions from a wide variety of stationary and point sources. It contains Volume I of the Agency's Compilation of Air Pollutant Emission Factors (AP-4), and the latest National Emission Inventory documentation for criteria and hazardous air pollutants.

  - ANL's "Updated Emission Factors of Air Pollutants from Vehicle Operations in GREET™ using Motor Vehicle Emission Simulator (MOVES).[12] This report documents ANL's approach to updating gasoline and diesel vehicle emissions factors to account for changes in engine technology and fuel specifications; deterioration of emission control devices with vehicle age; implementation of emission control inspection and maintenance programs; and the adoption of advanced emission control technologies, such as second-generation onboard diagnostics (OBD II), selective catalytic reduction, diesel particulate filters, and diesel oxidation catalysts. To best capture the effects of these factors, ANL used the U.S. EPA's latest mobile-source emission factor model, the MOVES.

[9] U.S. Environmental Protection Agency. December 17, 2012

[10] Seabra *et al. Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use*. 2011.

[11] U.S. Environmental Protection Agency, Emissions Factor and Inventory Group. 2005.

[12] Cai, et al. September 2013.

Previously, vehicular emission factors were estimated using the U.S. EPA's MOBILE6.2 and the California ARB's EMFAC models.

- The 2010 baseline tailpipe emission factors for CARBOB, California Reformulated Gasoline, and ULSD in the model are from the following sources: CO2 emissions for these fuels were calculated based on the carbon content, assuming complete combustion to CO2, and corrected for carbon emitted as CH4.

- Tailpipe emission factors for CNG-powered light- and heavy-duty trucks are from the U.S. EPA's Emission Inventory.[13]

- Tailpipe emission factors for LNG-powered heavy duty LNG trucks are from U.S. EPA's Emission Inventory.[14]

- The guidelines issued by the Intergovernmental Panel on Climate Change (IPCC) on performing national greenhouse gas inventories.[15] These guidelines provide detailed instructions on the preparation of national GHG inventories, as well as GHG emission factors that can be used in the preparation of those inventories. The GREET model utilizes many of these factors (e.g., N_20 emissions from agriculture).

- Emissions from the generation of grid electricity are calculated using regional electrical generation energy mixes (e.g., natural gas, coal, wind, etc.) from the U.S. EPA's Emissions and Generation Resource Integrated Database (eGRID).[16] The CA-GREET uses energy mixes from the 26 eGRID subregions.

CA-GREET 2.0 is a modified version of the previously peer-reviewed GREET1 2013.[17] Michael Wang and his team at ANL developed GREET1 2013. The software platform for both models is Microsoft Excel. The process for converting ANL's model to a California-specific version consisted primarily of adding the necessary California-specific LCI data and emission factors. A comprehensive list of revisions is maintained on the CA-GREET web site.[18] Among those revisions are the following:

- Crude oil recovery efficiency was modified to reflect the values specific to the average crude used in California, including crude that is both produced in, and imported into, the State;

- Tailpipe CH4 and N20 emission factors were adapted for California vehicle where available, in light of the fact that California has stricter vehicle emissions standards than were assumed in developing GREET1 2013;

[13] U.S. Environmental Protection Agency. 2014b.
[14] U.S. Environmental Protection Agency. 2014b.
[15] Eggleston *et al*. 2006.
[16] U.S. Environmental Protection Agency. 2014a.
[17] Systems Assessment Section, Center for Transportation Research, Argonne National Laboratory, 2013.
[18] http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm

- The U.S. EPA's eGRID[19] was the source of the grid electricity generation energy mixes used in CA-GREET 2.0. An electrical energy generation mix is the mix of energy sources (e.g., natural gas, coal, hydroelectric dams, etc.) used to generate the electricity provided to a regional electrical grid.

Based on staff's assessment of available life cycle inventory sources, emissions, and efficiency data, ARB staff concludes that the assumptions and inputs used in CA-GREET 2.0 to calculate direct life cycle fuel CIs are reasonable and the model was applied appropriately under the LCFS.

2. Crude Oil Carbon Intensity Values

A portion of the CI of gasoline and diesel baseline fuels are the emissions associated with producing and transporting crude oil to a refinery. Staff used the previously peer-reviewed Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model to calculate CIs of all crudes supplied to California refineries. These "well-to-refinery-entrance-gate" emissions estimated by OPGEE can vary significantly depending on the method of production and field-specific production parameters. The CIs calculated using the OPGEE model is combined with the appropriate CIs from the CA-GREET model to calculate a total life cycle CI for gasoline and diesel.

Staff used standard industry assumptions and best practices in applying the model. Figure 1 shows the main input parameter sheet used in OPGEE to estimate CI values for crude production and transport. Figure 1 also indicates whether the parameter is generally known or assumed, based on a smart default, or based on simple default. For each crude source, staff has searched available government, research literature, and internet sources to determine each of these inputs.

Figure 1: OPGEE Main Inputs Sheet

Bulk assessment - Data inputs		
Number of fields	**1**	**Run Assessment**
1 Inputs		
Output variables	**Unit**	**Default**
1.1 Production methods		
Notes: Enter "1" where applicable and "0" where not applicable		
1.1.1 Downhole pump	NA	**Known or** 1
1.1.2 Water reinjection	NA	**Known or** 1
1.1.3 Gas reinjection	NA	**Known or** 1

[19] U.S. Environmental Protection Agency, 2014a.

1.1.4 Water flooding	NA	Known or 0
1.1.5 Gas lifting	NA	Known or 0
1.1.6 Gas flooding	NA	Known or 0
1.1.7 Steam flooding	NA	Known or 0

1.2 Field properties

1.2.1 Field location (Country)	NA	Known
1.2.2 Field name	NA	Known
1.2.3 Field age	yr.	Often Known
1.2.4 Field depth	ft	Often Known
1.2.5 Oil production volume	bbl/d	Often Known
1.2.6 Number of producing wells	[-]	Known/Smart
1.2.7 Number of water injecting wells	[-]	Known/Smart
1.2.8 Well diameter	in	2.775
1.2.9 Productivity index	bbl/psi-d	3
1.2.10 Reservoir pressure	psi	Smart

1.3 Fluid properties

1.3.1 API gravity		deg. API	Known
1.3.2 Gas composition			
	N_2	mol%	2.00
	CO_2	mol%	6.00
	C_1	mol%	84.00
	C_2	mol%	4.00
	C_3	mol%	2.00
	C_4+	mol%	1.00
	H_2S	mol%	1.00

1.4 Production practices

Notes: Enter "NA" where not applicable

1.4.1 Gas-to-oil ratio (GOR)	scf/bbl oil	Known/Smart
1.4.2 Water-to-oil ratio (WOR)	bbl water/bbl oil	Known/Smart
1.4.3 Water injection ratio	bbl water/bbl oil	Smart or NA
1.4.4 Gas lifting injection ratio	scf/bbl liquid	Smart or NA
1.4.5 Gas flooding injection ratio	scf/bbl oil	Smart or NA
1.4.6 Steam-to-oil ratio (SOR)	bbl steam/bbl oil	Usually Known
1.4.7 Fraction of required electricity generated onsite	[-]	Known or 0.00
1.4.8 Fraction of remaining gas reinjected	[-]	Known or assumed
1.4.9 Fraction of produced water reinjected	[-]	Known or 1.00
1.4.10 Fraction of steam generation via cogeneration	[-]	Known or 0.00

1.5	Processing practices		
1.5.1	Heater/treater	NA	Smart
1.5.2	Stabilizer column	NA	Smart
1.5.3	Application of AGR unit	NA	1
1.5.4	Application of gas dehydration unit	NA	1
1.5.5	Application of demethanizer unit	NA	1
1.5.6	Flaring-to-oil ratio	scf/bbl oil	Known/Smart
1.5.7	Venting-to-oil ratio	scf/bbl oil	0.00
1.5.8	Volume fraction of diluent	[-]	Known or 0.00
1.6	Land use impacts		
1.6.1	Crude ecosystem carbon richness		
1.6.1.1	Low carbon richness (semi-arid grasslands)	NA	Assumed
1.6.1.2	Moderate carbon richness (mixed)	NA	Assumed
1.6.1.3	High carbon richness (forested)	NA	Assumed
1.6.2	Field development intensity		
1.6.2.1	Low intensity development and low oxidation	NA	0
1.6.2.2	Mod. intensity development and mod. oxidation	NA	1
1.6.2.3	High intensity development and high oxidation	NA	0
1.7	Non-integrated upgrader	NA	Known or 0
1.8	Crude oil transport		
1.8.1	Fraction of oil transported by each mode		
1.8.1.1	Ocean tanker	[-]	1
1.8.1.2	Barge	[-]	0
1.8.1.3	Pipeline	[-]	1
1.8.1.4	Rail	[-]	0
1.8.2	Transport distance (one way)		
1.8.2.1	Ocean tanker	Mile	Known
1.8.2.2	Barge	Mile	0
1.8.2.3	Pipeline	Mile	Known
1.8.2.4	Rail	Mile	0
1.8.3	Ocean tanker size, if applicable	Ton	250000
1.9	Small sources emissions	gCO_2eq/MJ	0.5

Based on staff's assessment of available government, research literature, and internet sources for each crude source, ARB staff concludes that the assumptions and input parameters used in OPGEE to calculate CI values for crude oil production and transport are reasonable and the model was applied appropriately under the LCFS.

3. Indirect Biofuel Carbon Intensity Values

Current generation of biofuels are mostly derived from crop-based feedstocks (e.g., corn), which traditionally have been used for human consumption or as feed for livestock. The diversion of crops from food or feed markets to biofuel production creates an additional demand to produce the biofuel feedstock. Crop producers in the region which mandates the biofuel, either resort to crop switching (e.g., soybeans to corn) or convert new land to meet the new demand. Any demand that is not met locally[20] is transmitted to the global marketplace and met by production of the agricultural commodity or commodities in other countries. A direct consequence of this 'domino' effect is that new land areas are converted to grow crops. This unintended consequence is termed indirect Land Use Change (iLUC). Converting non-cropland to cropland leads to GHG emissions which are termed "iLUC emissions."

To estimate iLUC emissions, staff selected a global economic model developed by Purdue University called GTAP (Global Trade Analysis Project). In the iLUC analysis, the GTAP model was modified to account for biofuels and their co-products. This model, termed GTAP-BIO represents all sectors of the global economy in an aggregated form, and interactions among various sectors and resources are represented using various internal and external parameters. The model uses a baseline global equilibrium of all sectors in which supply equals demand in all sectors. The model is then "shocked" by increasing biofuel production by an appropriate volume. To meet this new requirement, the model allocates existing resources and also accounts for additional production of crops, ultimately ensuring a new global equilibrium is achieved. The changes in land uses (classified as forestry, pasture, cropland, and cropland-pasture in the model) computed by the model are then used in combination with a carbon emissions model called Agro-Ecological Zone Emission Factor (AEZ-EF) model to estimate the CO_2-equivalent emissions from land-use change.

The AEZ-EF model utilizes soil and biomass carbon stock data for different land types and regions of the world and calculates emission factors for land conversions. The model estimates the CO_2-equivalent GHG flows when land is converted from one type to the other (e.g., forest to cropland). The GHG flows are summed globally and divided by the total quantity of fuel produced to produce a value in grams CO_2e per megajoule of fuel (g CO_2e/MJ). Given the likely range of values for parameters that have the largest influence on model outputs, staff used a scenario approach that used different combinations of input values (within the range derived from literature review and expert

[20] Crop switching leads to local regions producing additional crop required for biofuel production at the expense of another crop not being grown. In the global marketplace, demand for crop that is not grown leads to a different region (or country) that converts new land to agricultural production to satisfy the demand for the crop that has been displaced.

opinion) to estimate output iLUC values for each set of input values. The output iLUC values (CIs) from all the scenario runs was then averaged and proposed to be used as indirect CI for that specific biofuel in the LCFS regulation. For the current analysis, staff has analyzed iLUC emissions for corn ethanol, sugarcane ethanol, soy biodiesel, canola biodiesel (also called rapeseed biodiesel), palm biodiesel, and sorghum ethanol.
The original modeling results were published in 2009 and when the LCFS regulation was adopted, stakeholders raised the issue of uncertainty in the output values for iLUC. Staff, working with the University of California, developed a Monte Carlo approach for estimating total uncertainty of iLUC resulting from variability in individual parameters.

Since 2009, there have been numerous peer-reviewed publications, dissertations, and other scientific literature, that have focused on various aspects of indirect land use changes related to biofuels. Staff has reviewed published articles, contracted with academics, and consulted with experts, all of which have led to significant improvements to the GHG modeling methodologies and analysis completed in 2009.

Specific model and iLUC analysis updates in the current revised modeling include:

- Use of the GTAP 7 database and baseline data for 2004 (the 2009 analysis used a 2001 baseline),
- Addition of cropland pasture in the U.S. and Brazil,
- Re-estimated energy sector demand and supply elasticity values,
- Improved treatment of a corn ethanol co-product (distillers dried grains with solubles - DDGS),
- Improved treatment of soy meal, soy oil, and soy biodiesel,
- Modified structure of the livestock sector,
- Improved method of estimating the productivity of new cropland,
- More comprehensive and spatially explicit set of emission factors that are outside of the GTAP-BIO model,
- Revised yield response to price,
- Revised demand response to price,
- Increased flexibility of crop switching in response to price signals,
- Incorporation of an endogenous yield adjustment for cropland pasture,
- Disaggregated sorghum from the coarse grains sector to allow for modeling iLUC impacts for sorghum ethanol,
- Disaggregated canola (rapeseed) from the oilseeds sector to facilitate modeling of iLUC for canola-based biodiesel,
- Included data for palm in the oilseeds sector to estimate iLUC for palm-derived biodiesel,

- Developed regionalized land transformation elasticities for the model using recent evidence for land transformation[21],
- Split crop production into irrigated versus rain-fed and developed datasets and metrics to assess impacts related to water-constraints in agriculture across the world. Details of the modeling efforts to include irrigation in the GTAP-BIO model is included in a report by Taheriour et al.[22] Determining regions of the world where water constraints could limit expansion of irrigation was developed by researchers at the World Resources Institute (WRI) and is detailed in reports published by WRI[23,24], and
- Disaggregated Yield Price Elasticity (YPE) parameter into regionalized and crop-specific values. For the current analysis, however, the same YPE value is used for all regions and crops.[25]

The primary input to computable general equilibrium models such as GTAP is the specification of the changes that will, by moving the economy away from equilibrium, result in the establishment of a new equilibrium. Parameters, such as elasticities, are used to estimate the extent which introduced changes alter the prior equilibrium. Listed below are the inputs and parameters that the GTAP uses to model the land use change impacts of increased biofuel production levels. Also listed are some of the important approaches used by staff for the current analysis.

- Baseline year: GTAP employs the 2004[26] world economic database as the analytical baseline. This is the most recent year for which a complete global land use database exists.

- Fuel production increase: The primary input to computable general equilibrium models such as GTAP is the specification of the changes that will result in a new equilibrium. “Shock’ corresponds to an increase in the volume of biofuel production used as an input to the model to estimate land use changes.

- Yield Price Elasticity (YPE): This parameter determines how much the crop yield will increase in response to a price increase for the crop. Agricultural crop land is more intensively managed for higher priced crops. If the crop yield elasticity is 0.25, a P percent increase in the price of the crop relative to input cost will result in a percentage increase in crop yields equal to P times 0.25. The higher the

---

[21] Taheripour, F., and Tyner, W. Biofuels and Land Use Change: Applying Recent Evidence to Model estimates, *Appl. Sci.* 2013, *3*, 14-38
[22] F. Taheripour, T. Hertel, and J. Liu, The role of irrigation in determining the global land use impacts of biofuels, Energy, Sustainability, and Society, 3:4, 2013, http://www.energsustainsoc.com/content/3/1/4
[23] F. Gassert, M. Luck, M. Landis, P. Reig, and T. Shiao, Aqueduct Global Maps 2.1: Constructing Decision-Relevant Global Water Risk Indicators, Working Paper, World Resources Institute, April 2014.
[24] F. Gassert, P. Reig, T. Luo, and A. Maddocks, A weighted aggregation of spatially distinct hydrological indicators, Working Paper, World Resources Institute, December 2013.
[25] Staff conducted scenario runs using different values of YPE. For each run, YPE was the same across all regions and crops.
[26] For the 2009 regulation, the baseline year was 2001.

elasticity, the greater the yield increases in response to a price increase. For the 2009 modeling, ARB used a yield-price elasticity value range of 0.2 to 0.6. Purdue researchers have used a single YPE value of 0.25 based on an econometric estimate made by Keeney and Hertel.[27] The Keeney-Hertel estimate of 0.25 is obtained by averaging two values (0.28 and 0.24) from Houck and Gallagher,[28] a value from Lyons and Thompson[29] (0.22) and a value from Choi and Helmberger[30] (0.27). An expert from UC Davis, contracted to conduct a review and statistical analysis of data from a few published studies, also concluded that YPE values were small to zero. Staff conducted a comprehensive review of all available data and reports on YPE and concluded that YPE values were likely small. However, to account for the different values of YPE from recent studies and recommendations from the Expert Working Group (EWG), staff has used values of YPE between 0.05 and 0.35, for the current analysis. Details of the review conducted by staff on YPE are provided in Attachment 1.

- Elasticity of crop yields with respect to area expansion (ETA): This parameter expresses the yields that will be realized from newly converted lands relative to yields on acreage previously devoted to that crop. Because almost all of the land that is well-suited to crop production has already been converted to agricultural uses, yields on newly converted lands are almost always lower than corresponding yields on existing crop lands. For the 2009 regulation, the scenario runs utilized a value of 0.25 and 0.75 for this parameter, based on empirical evidence from U.S. land use and expert judgment on the productivity of the new cropland. For the current analysis, Purdue University used results from the Terrestrial Ecosystem Model (TEM) to derive estimates of net primary productivity (NPP), a measure of maximum biomass productivity. The ratio of NPP of new cropland to existing cropland was used to estimate ETA for a given region/AEZ and is detailed in Taheripour et al.[31] ETA values used in the current analysis are provided in Table 2 on the following page

[27] Keeney, R., and T. W. Hertel. 2008. “The Indirect Land Use Impacts of U.S. Biofuel Policies: The Importance of Acreage, Yield, and Bilateral Trade Responses.” GTAP Working Paper No. 52, Center for Global Trade Analysis, Purdue University, West Lafayette, IN.

[28] Houck, J.P., and P.W. Gallagher. 1976. “The Price Responsiveness of U.S. Corn Yields.” American Journal of Agricultural Economics 58:731–34.

[29] Lyons, D.C., and R.L. Thompson. 1981. “The Effect of Distortions in Relative Prices on Corn Productivity and Exports: A Cross-Country Study.” *Journal of Rural Development* 4:83–102.

[30] Choi, J.S., and P.G. Helmberger. 1993. “How Sensitive are Crop Yield to Price Changes and Farm Programs?” *Journal of Agricultural and Applied Economics* 25:237–44.

[31] F. Taheripour, Q. Zhuang, W. Tyner, and X. Lu, Biofuels, Cropland Expansion, and the Extensive Margin, Energy, Sustainability, and Society, 2:25, 2012, http://www.energsustainsoc.com/content/2/1/25

Table 2. Baseline ETA Values for Each Region/AEZ

ETA	1 USA	2 EU27	3 BRAZIL	4 CAN	5 JAPAN	6 CHIHKG	7 INDIA	8 C_C_Amer	9 S_o_Amer	10 E_Asia
1 AEZ1	1	1	0.914	1	1	1	0.934	1	0.95	1
2 AEZ2	1	1	0.921	1	1	1	0.892	1	0.807	1
3 AEZ3	1	1	0.927	1	1	1	0.859	1	0.896	1
4 AEZ4	1	1	0.893	1	1	1	0.929	1	0.883	1
5 AEZ5	1	1	0.925	1	1	0.9	0.98	0.883	0.895	1
6 AEZ6	1	1	0.911	1	1	0.876	0.982	0.968	0.846	1
7 AEZ7	0.732	1	1	0.889	1	0.805	0.9	0.594	1	1
8 AEZ8	0.71	0.895	1	0.905	1	1	0.711	0.722	0.901	1
9 AEZ9	1	1	1	0.853	1	0.976	0.879	1	0.908	1
10 AEZ10	0.93	0.958	0.881	0.879	0.964	0.84	1	0.887	1	0.93
11 AEZ11	0.955	0.833	1	1	0.936	0.947	0.9	1	0.873	0.838
12 AEZ12	0.888	0.857	0.913	1	0.952	0.916	0.9	1	0.836	1
13 AEZ13	0.922	1	1	0.554	1	1	1	1	1	1
14 AEZ14	0.515	0.891	1	0.796	1	0.921	1	1	1	1
15 AEZ15	0.715	0.902	1	0.829	1	1	1	1	0.64	1
16 AEZ16	1	0.893	1	1	1	1	1	1	0.923	1
17 AEZ17	1	1	1	1	1	1	1	1	1	1
18 AEZ18	1	1	1	1	1	1	1	1	1	1

ETA	11 Mala_Indo	12 R_SE_Asia	13 R_S_Asia	14 Russia	15 Oth_CEE_CIS	16 Oth_Europe	17 MEAS_NAfr	18 S_S_AFR	19 Oceania
1 AEZ1	1	1	1	1	1	1	0.675	0.607	1
2 AEZ2	1	1	1	1	1	1	0.589	1	1
3 AEZ3	1	1	1	1	1	1	1	0.895	0.742
4 AEZ4	0.879	0.888	1	1	1	1	0.863	0.925	0.916
5 AEZ5	0.899	0.908	0.981	1	1	1	1	1	0.955
6 AEZ6	0.885	0.948	0.779	1	1	1	1	1	0.878
7 AEZ7	1	1	0.426	1	0.983	1	0.456	0.801	0.651
8 AEZ8	1	1	0.604	0.844	0.844	1	0.71	0.792	0.861
9 AEZ9	1	1	1	0.941	0.818	1	0.768	0.842	0.931
10 AEZ10	1	1	0.92	0.891	0.888	0.87	0.978	0.876	0.916

GTAP modeling provides an estimate for the amounts and types of land across the world that is converted to agricultural production as a result of the increased demand for biofuels. The land conversion estimates made by GTAP are disaggregated by world region and agro-ecological zones (AEZ). In total, there are 19 regions and 18 AEZs. The next step in calculating an estimate for GHG emissions resulting from land conversion is to apply a set of emission factors. Emission factors provide average values of emissions per unit land area for carbon stored above and below ground as well as the annual amount of carbon sequestered by native vegetation. The amount of "lost sequestration capacity" per unit land area results from the conversion of native vegetation to crops. For the 2009 regulation, staff used emission factor data from Searchinger et al. (2008)[32].

In the 2009 modeling, each of the 19 regions had separate emission factors for forest and pasture conversion to cropland but these emission factors did not vary by AEZ within each region. Because land conversion estimates within each region differ significantly by AEZ and both biomass and soil carbon stocks also vary significantly by AEZ, emission factors specific to each region/AEZ combination provide a more appropriate assessment.

ARB contracted with researchers at UC Berkeley, University of Wisconsin-Madison, and UC Davis to develop the agro-ecological zone emission factor (AEZ-EF) model. The model combines matrices of carbon fluxes ($MgCO_2\ ha^{-1}\ y^{-1}$) with matrices of changes in land use (hectares or ha) according to land-use category as projected by the GTAP-BIO model. As published, AEZ-EF aggregates the carbon flows to the same 19 regions and 18 AEZs used by GTAP-BIO. The AEZ-EF model contains separate carbon stock estimates ($MgC\ ha^{-1}$) for biomass and soil carbon, indexed by GTAP AEZ and region, or "Region-AEZ".[33,34] The model combines these carbon stock data with assumptions about carbon loss from soils and biomass, mode of conversion (i.e., whether by fire), quantity and species of carbonaceous and other greenhouse gas (GHG) emissions resulting from conversion, carbon remaining in harvested wood products and char, and foregone sequestration. The model relies heavily on IPCC greenhouse gas inventory methods and default values (IPCC 2006[35]), augmented with more detailed and recent

[32] This data set is referred to as the "Woods Hole" data because it was compiled by Searchinger's co-author, R. A. Houghton, who is affiliated with the Woods Hole Oceanographic Institute.
[33] Gibbs, H., S. Yui, and R. Plevin. (2014) "New Estimates of Soil and Biomass Carbon Stocks for Global Economic Models." Global Trade Analysis Project (GTAP) Technical Paper No. 33. Center for Global Trade Analysis, Department of Agricultural Economics, Purdue University. West Lafayette, IN.
[34] Plevin, R., H. Gibbs, J. Duffy, S. Yui and S. Yeh. (2014) "Agro-ecological Zone Emission Factor (AEZ-EF) Model (v47)." Global Trade Analysis Project (GTAP) Technical Paper No. 34. Center for Global Trade Analysis, Department of Agricultural Economics, Purdue University. West Lafayette, IN.
[35] http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html

data where available. Details of this model, originally published in 2011 is available in reports submitted to ARB by Holly Gibbs and Richard Plevin.[36,37] In response to stakeholder feedback from workshops, this version was modified and the updates include:

- Contributions to carbon emissions from Harvested Wood Products (HWP) was updated in the model using data compiled by Earles et al.[38]
- Additional modifications to HWP were performed using above-ground live biomass (AGLB) after 30 years in each region
- Updated the peat emission factor to 95 Mg CO_2/ha/yr, using the ICCT report[39]
- Added OilPalmCarbonStock based on Winrock update to RFS2 analysis.[40,41]
- Updated forest biomass carbon, forest area, and forest soil carbon data using latest data from Gibbs et al.[33]
- Updated IPCC_GRASSLAND_BIOMASS_TABLE with data from Gibbs et al.[33]

Based on the iLUC analysis, ARB staff concludes that the assumptions and input parameters used in the GTAP-BIO and AEZ-EF models to estimate indirect land use change for biofuels are reasonable and the models were applied appropriately under the LCFS.

---

[36] Gibbs, H. and S. Yui, September 2011. Preliminary Report: New Geographically-Explicit Estimates of Soil and Biomass Carbon Stocks by GTAP Region and AEZ, posted online at http://www.arb.ca.gov/fuels/lcfs/09142011_iluc_hgreport.pdf

[37] Plevin, R., H. Gibbs, J. Duffy, S. Yui, and S. Yeh, September 2011. Preliminary Report: Agro-ecological Zone Emission Factor Model, posted online at http://www.arb.ca.gov/fuels/lcfs/09142011_aez_ef_model_v15.pdf

[38] Earles J. M., Yeh, S., and Skog, K. E., Timing of carbon emissions from global forest clearance, *Nature Climate Change*, 2012; DOI: 10.1038/nclimate1535

[39] Page, S. E., Morrison, R., Malins, C., Hooijer, A., Rieley, J. O., and Jauhiainen, J., Review of Peat Surface Greenhouse Gas Emissions from Oil Palm Plantations in Southeast Asia, White Paper Number 15, September 2011, www.theicct.org

[40] Harris, N., and Grimland, S., 2011a. Spatial Modeling of Future Oil Palm Expansion in Indonesia, 2000 to 2022. Winrock International. Draft report submitted to EPA.

[41] Harris, N., and Grimland, S., 2011b. Spatial Modeling of Future Oil Palm Expansion in Malaysia, 2003 to 2022. Winrock International. Draft report submitted to EPA.

ATTACHMENT 2

Description of Scientific Bases of the CI Methodology to be Addressed by Peer Reviewers

The statutory mandate for external scientific peer review (H&SC section 57004) states that the reviewer's responsibility is to determine whether the scientific basis or portion of the proposed rule is based upon sound scientific knowledge, methods, and practices.

We request your review to allow you to make this determination for each of the following conclusions that constitute the scientific basis of the staff reports. An explanatory statement is provided for each conclusion to focus the review.

For those work products that are not proposed rules, reviewers must measure the quality of the product with respect to the same exacting standard as if it were subject to H&SC section 57004.

The following conclusions are based on staff's assessment of the results from the life cycle greenhouse gas (GHG) emissions models and information provided in:

1. *Staff Report: Calculating Life Cycle Carbon Intensity of Transportation Fuels in California*
2. *Staff Report: Calculating Carbon Intensity Values of Crude Oil Supplied to California Refineries*
3. *Staff Report: Calculating Carbon Intensity Values from Indirect Land Use Change of Crop-Based Biofuels*

A brief description of each of the models used by staff is provided in Attachment 1.

1. <u>Life Cycle Fuel Carbon Intensities</u>

Based on staff's assessment of available life cycle inventory sources, emissions, and efficiency data, ARB staff concludes that the assumptions and inputs used in CA-GREET 2.0 to calculate direct life cycle fuel CIs are reasonable and the model was applied appropriately under the LCFS.

2. <u>Crude Oil Carbon Intensity Values</u>

Based on staff's assessment of available government, research literature, and internet sources for each crude source, ARB staff concludes that the assumptions and input parameters used in OPGEE to calculate CI values for crude oil production and transport are reasonable and the model was applied appropriately under the LCFS.

3. Indirect Biofuel Carbon Intensity Values

Based on the iLUC analysis, ARB staff concludes that the assumptions and input parameters used in the GTAP-BIO and AEZ-EF models to estimate indirect land use change for biofuels are reasonable and the models were applied appropriately under the LCFS.

4. Big Picture

Reviewers are not limited to addressing only the specific assumptions, conclusions, and findings presented above, and are also asked to contemplate the following questions:

(a) In reading the staff reports and supporting documentation, are there any additional substantive scientific issues that were part of the scientific basis or conclusion of the assessments but not described above? If so, please comment on them.

(b) Taken as a whole, are the conclusions and scientific portions of the assessments based upon sound scientific knowledge, methods, and practices?

Reviewers should note that in some decisions and conclusions necessarily relied on the professional judgment of staff when the scientific data were incomplete (or less than ideal). In these situations, every effort was made to ensure that the data are scientifically defensible.

The proceeding guidance will ensure that reviewers have an opportunity to comment on all aspects of the scientific basis of staff's assessments. At the same time, reviewers also should recognize that the Board has a legal obligation to consider and respond to all feedback on the scientific portions of the assessments. Because of this obligation, reviewers are encouraged to focus their feedback on scientific issues that are relevant to the central regulatory elements being proposed.

ATTACHMENT 3

List of Participants Associated with the Development of Fuel Carbon Intensities

Names and Affiliations of Participants Involved

<u>Air Resources Board</u>

Sam Wade
John Courtis
Anil Prabhu
Farshid Mojaver
Kamran Adili
James Duffy
Wesley Ingram
Kevin Cleary
Hafizur Chowdhury
Todd Dooley
Anthy Alexiades
Chan Pham
Ronald Oineza
Kamal Ahuja
James Aguila
Aubrey Gonzalez

<u>University of California, Berkeley</u>

Mike O'Hare
Richard Plevin (currently with University of California, Davis)
Evan Gallagher
Avery Cohn
Dan Kammen
Yang Ruan
Niels Tomijima
Bianca Taylor

University of California, Davis

Sonia Yeh
Julie Witcover
Sahoko Yui
Nic Lutsey
Hyunok Lee
Eric Winford
Jacob Teter
Gouri Shankar Mishra
Nathan Parker
Gongjing Cao
Quinn Hart
David Rocke

Lawrence Berkeley Laboratory

Andy Jones
Purdue University
Wally Tyner
Tom Hertel
Farzad Taheripour
Alla Golub

Yale University

Steve Berry

University of Wisconsin, Madison

Holly Gibbs

Food and Agricultural Organization, Rome

Kevin Fingerman (currently with Humboldt University)

University of Arizona

Derek Lemoine

Drexel University

Sabrina Spatari

Massachusetts Institute of Technology

John Reilly

Argonne National Laboratory
- Michael Wang
- Hao Cai
- Amgad Elgowainy
- Jeongwoo Han
- Jennifer Dunn
- Andrew Burnham

Stanford University
- Adam Brandt
- Kourosh Vafi
- Scott McNally

Shell Corporation
- Hassan El-Houjeiri

International Council on Clean Transportation
- Chris Malins

University of Toronto
- Heather MacLean

University of Calgary
- Joule Bergerson

Life Cycle Associates, Inc.
- Stefan Unnasch
- Brent Riffel
- Larry Waterland
- Jenny Pont

ATTACHMENT 4

References

All references cited in the staff reports will be provided on a compact disk. For references available online, electronic links will also be provided in the staff reports.

March 25, 2015 **VIA FEDERAL EXPRESS**

H. Scott Matthews, Ph.D.
Professor, Civil and Environmental Engineering
Carnegie Mellon University
123A Porter Hall
Pittsburgh, PA 15213-3890

EXTERNAL PEER REVIEW OF STAFF'S METHODOLOGY IN CALCULATING CARBON INTENSITY VALUES AND USE OF GREENHOUSE GAS EMISSIONS MODELS

Dear Professor Matthews,

The purpose of this letter is to initiate the peer review process. Staff will not communicate with the approved reviewers, such as yourself, nor know their identities, until I formally transmit the reviews to them.

Included in this letter as attachments are the following:

a. **Attachment 1:** Summary Overview of Reports to Review

b. **Attachment 2:** January 21, 2015 Request for External Peer Review of Staff's Methodology in Calculating Fuel Carbon Intensities and Use of Three Life Cycle Greenhouse Gas Emissions Models, including four attachments, signed by Jim Aguila, Branch Chief, Program Planning and Management Branch. ***Please use the enclosed January 21, 2015 letter, and its attachments, as the basis for your review.***

c. **Attachment 3:** January 2009 Supplement to the Cal/EPA Peer Review Guidelines

d. **Attachment 4:** Peer Review Package – Review Materials. Three staff reports are submitted for peer review:

   1. *Staff Report: Calculating Life Cycle Carbon Intensity Values of Transportation Fuels in California* (Staff Report 1)
   2. *Staff Report: Calculating Carbon Intensity Values of Crude Oil Supplied to California Refineries* (Staff Report 2)
   3. *Staff Report: Calculating Carbon Intensity Values from Indirect Land Use Change of Crop-Based Biofuels* (Staff Report 3)

   Hard copies of these reports are provided in the enclosed binder and separated by individual tabs, numbered 1, 2, and 3, and labeled accordingly. For each review topic, reviewers may turn directly to the specific sections in the binder and the corresponding electronic files provided on the enclosed CD, also numbered and labeled accordingly.

All review materials, including the three staff reports (provided as hard copies in the enclosed binder), as well as electronic files (provided as electronic files saved on enclosed CD), including software and program packages, bibliographical references, and supporting documents, are labeled accordingly. ***The complete list of all review materials and corresponding labels are provided below:***

REVIEW MATERIAL	LABEL
1. **Staff Report: Calculating Life Cycle Carbon Intensity Values of Transportation Fuels in California** (Staff Report 1)	**Binder, Tab 1** – *Staff Report 1: Direct Life Cycle Carbon Intensity*
2. **CD** – Electronic Files: References	**CD, Folder 1** – *1. CA-GREET* **Subfolder**: *References*
3. **Staff Report: Calculating Carbon Intensity Values of Crude Oil Supplied to California Refineries** (Staff Report 2)	**Binder, Tab 2** – *Staff Report 2: Crude Oil Carbon Intensity*
4. **CD** – Electronic Files: References	**CD, Folder 2** – *2. OPGEE* **Subfolder:** *References*
5. **Staff Report: Calculating Carbon Intensity Values from Indirect Land Use Change of Crop-Based Biofuels** (Staff Report 3)	**Binder, Tab 3** – *Staff Report 3: Indirect Land Use Change*
6. **CD** – Electronic Files: References, Software and Program Files, Instructions, and Other Background Documents	**CD, Folder 3** – *3. GTAP-BIO_AEZ-EF* **Subfolders:** *I. Software and Program Packages* *II. References* *III. Other Background Documents*

All bibliographical references, supporting files, and other supporting documents are provided on the enclosed CD or as electronic links. If you wish to review references that are not provided as hard copy or live links, please contact me immediately and I will see that you receive them.

<u>Comments on the foregoing</u>:

a. <u>Attachment 1 to the January 21, 2015 request letter provides context for the review</u>. Attachment 1 provides a description for each staff report and is numbered and labeled accordingly.

b. <u>Attachment 2 to the January 21, 2015 request letter provides focus for the review</u>. Attachment 2 provides the conclusion for each staff report and is numbered and labeled accordingly.

c. The January 7, 2009 Supplement. In part, this provides guidance to ensure the review is kept confidential through its course. The Supplement notes reviewers are under no obligation to discuss their comments with third-parties after reviews have been submitted. We recommend they do not. All outside parties are provided opportunities to address a proposed regulatory action through a well-defined regulatory process. Direct third-parties to me.

Disclaimer:

Attachment 1 to this letter places the technical reports and supporting documents in context with respect to the subjects they are addressing. Reviewers may need to scrutinize references and supporting documents in detail. The materials identified as that which must be reviewed (required) and that which should be evaluated (optional) is intended to be helpful guidance by the Air Resources Board (ARB) staff. However, reviewers are ultimately responsible for assessing the relevance and accuracy of the content of all information upon which the staff report to be reviewed is based.

Please return your review directly to me. Questions about the review, or review material, should be for clarification, in writing – email is fine, and addressed to me. My responses will be in writing also. The ARB should not be contacted. I will subsequently forward all reviews together with reviewers' CVs.

I would appreciate your review being completed by Monday, April 27, 2015.

Your acceptance of this review assignment is most appreciated.

Regards,

Gerald W. Bowes

Gerald W. Bowes, Ph.D.
Manager, Cal/EPA Scientific Peer Review Program
Office of Research, Planning and Performance
State Water Resources Control Board
1001 "I" Street, 16th Floor
Sacramento, California 95814

Telephone: (916) 341-5567
FAX: (916) 341-5284
Email: Gerald.Bowes@waterboards.ca.gov

Attachments

1) Attachment 1 – Summary Overview of Reports to Review
2) Attachment 2 – January 21, 2015 Request for External Peer Review
3) Attachment 3 – January 2009 Supplement to the Cal/EPA Peer Review Guidelines
4) Attachment 4 – Peer Review Package – Review Materials

January 7, 2009

Supplement to Cal/EPA External Scientific Peer Review Guidelines – "Exhibit F" in Cal/EPA Interagency Agreement with University of California
Gerald W. Bowes, Ph.D.

Guidance to Staff:

1. Revisions. If you have revised any part of the initial request, please stamp "Revised" on each page where a change has been made, and the date of the change. Clearly describe the revision in the cover letter to reviewers, which transmits the material to be reviewed. The approved reviewers have seen your original request letter and attachments during the solicitation process, and must be made aware of changes.

2. Documents requiring review. All important scientific underpinnings of a proposed science-based rule must be submitted for external peer review. The underpinnings would include all publications (including conference proceedings), reports, and raw data upon which the proposal is based. If there is a question about the value of a particular document, or parts of a document, I should be contacted.

3. Documents not requiring review. The Cal/EPA External Peer Review Guidelines note that there are circumstances where external peer review of supporting scientific documents is not required. An example would be "A particular work product that has been peer reviewed with a known record by a recognized expert or expert body." I would treat this allowance with caution. If you have any doubt about the quality of such external review, or of the reviewers' independence and objectivity, that work product – which could be a component of the proposal - should be provided to the reviewers.

4. Implementation review. Publications which have a solid peer review record, such as a US EPA Criteria document, do not always include an implementation strategy. The Cal/EPA Guidelines require that the implementation of the scientific components of a proposal, or other initiative, must be submitted for external review.

5. Identity of external reviewers. External reviewers should not be informed about the identity of other external reviewers. Our goal has always been to solicit truly independent comments from each reviewer. Allowing the reviewers to know the identity of others sets up the potential for discussions between them that could devalue the independence of the reviews.

6. Panel Formation. Formation of reviewer panels is not appropriate. Panels can take on the appearance of scientific advisory committees and the external reviewers identified through the Cal/EPA process are not to be used as scientific advisors.

7. Conference calls with reviewers. Conference calls with one or more reviewers can be interpreted as seeking collaborative scientific input instead of critical review. Conference calls with reviewers are not allowed.

Guidance to Reviewers from Staff:

1. Discussion of review.

Reviewers are not allowed to discuss the proposal with individuals who participated in development of the proposal. These individuals are listed in Attachment 3 of the review request.

Discussions between staff and reviewers are not permitted. Reviewers may request clarification of certain aspects of the review process or the documents sent to them.

Clarification questions and responses must be in writing. Clarification questions about reviewers' comments by staff and others affiliated with the organization requesting the review, and the responses to them, also must be in writing. These communications will become part of the administrative record.

The organization requesting independent review should be careful that organization-reviewer communications do not become collaboration, or are perceived by others to have become so. The reviewers are not technical advisors. As such, they would be considered participants in the development of the proposal, and would not be considered by the University of California as external reviewers for future revisions of this or related proposals. The statute requiring external review of science-based rules proposed by Cal/EPA organizations prohibits participants serving as peer reviewers..

2. Disclosure of reviewer Identity and release of review comments.

Confidentiality begins at the point a potential candidate is contacted by the University of California. Candidates who agree to complete the conflict of interest disclosure form should keep this matter confidential, and should not inform others about their possible role as reviewer.

Reviewer identity may be kept confidential until review comments are received by the organization that requested the review. After the comments are received, reviewer identity and comments must be made available to anyone requesting them.

Reviewers are under no obligation to disclose their identity to anyone enquiring. It is recommended reviewers keep their role confidential until after their reviews have been submitted.

3. Requests to reviewers by third parties to discuss comments.

After they have submitted their reviews, reviewers may be approached by third parties representing special interests, the press, or by colleagues. Reviewers are under no obligation to discuss their comments with them, and we recommend that they do not.

All outside parties are provided an opportunity to address a proposed regulatory action during the public comment period and at the Cal/EPA organization meeting where the proposal is considered for adoption. Discussions outside these provided avenues for comment could seriously impede the orderly process for vetting the proposal under consideration.

4. Reviewer contact information.

The reviewer's name and professional affiliation should accompany each review. Home address and other personal contact information are considered confidential and should not be part of the comment submittal.

Amit Kumar, PhD, P.Eng.

Position: Associate Professor; NSERC/Cenovus/Alberta Innovates Associate Industrial Research Chair in Energy and Environmental Systems Engineering; Cenovus Energy Endowed Chair in Environmental Engineering

Contact Information: Department of Mechanical Engineering, University of Alberta, Edmonton, Alberta, Canada, T6G 2G8; E-mail: Amit.Kumar@ualberta.ca; Tel: +1-780-492-7797; Admin Office: +1-780-492-3712; Website: http://www.energysystems.ualberta.ca/

Education
PhD - Mechanical Engineering, University of Alberta, Edmonton, Canada - 2004
MEng, 2000, Energy Technology, Asian Institute of Technology, Bangkok, Thailand - 2000
BTech (Hons), 1997, Energy Engineering, Indian Institute of Technology, Kharagpur, India - 1997

Appointments
- Sept. 2012 – Present, NSERC/Cenovus/Alberta Innovates Associate Industrial Research Chair in Energy and Environmental Systems Engineering, University of Alberta, Edmonton, Alberta, Canada
- Sept. 2012 – Present, Cenovus Energy Endowed Chair in Environmental Engineering, University of Alberta, Edmonton, Alberta, Canada
- July 2011 – Present, Associate Professor (tenured), Department of Mechanical Engineering, University of Alberta, Edmonton, Alberta, Canada
- August 2005 – June 2011, Assistant Professor, Department of Mechanical Engineering, University of Alberta, Edmonton, Alberta, Canada

Research Interests: Energy and environmental modeling; life cycle assessment; techno-economic assessment; renewable and non-renewable energy sources

Summary of Supervision Experience Current/Past: Total - 100**;** Direct supervision: 11 PhD, 42 Master's, 12 RAs, 11 PDFs, and 20 undergraduate students (UG). Co-supervision: 3 Master's and 1 UG.

Summary of Student's Examination Committees: 82 examination committees (38 MSc; 44 PhD examination committees).

Publication and Presentations: 56 peer reviewed journal publications; 2 book chapters; 190 conference presentations and publications (33 invited); 53 technical reports.

Research funding: More than C$6 million; more than 30 different funding agencies including industries and government.

Awards and Media Mentions: 7 awards; 20 media mentions

Research Networks – International and National (as member/theme lead): 4

Key Expert Review Panels International/National: European Commission (HORIZON 2020, FP7); National Science Foundation, USA; Natural Sciences and Engineering Research Council of Canada (NSERC).

Chair/Moderator/Organizer Conference and Workshops: More than 30

Publications *(underline indicates graduate students, undergraduate student, research assistants or postdoctoral fellows)*

Book Chapters

1. Olateju, B., Kumar, A. Clean Energy Based Production of Hydrogen – An Energy Carrier. *In:* Yan J. (Ed.). *The Handbook of Clean Energy Systems*, John Wiley & Sons, Ltd., Chichester, U.K., forthcoming (*invited*).
2. Kumar A., Sarkar S. Biohydrogen production from bio-oil. *In:* Pandey A., Larroche C., Gnansounou E., Ricke S.C., Claude-Gilles D. (Eds.). *Biofuels: Alternative Feedstocks and Conversion Processes*, Elsevier Inc., Amsterdam, The Netherlands, 2011, 481-497 (*invited*).

Selected Recent Refereed Journal Publications

1. Nimana B., Canter C., Kumar A. Energy consumption and greenhouse gas emissions in upgrading and refining of Canada's oil sands products, *Energy*, 2015 (in press).
2. Verma A., Kumar A. Life cycle assessment (LCA) of hydrogen production from underground coal gasification (UCG) with carbon capture and sequestration (CCS), *Applied Energy*, 2015 (*in press*).
3. Nimana B., Canter C., Kumar A. Energy consumption and greenhouse gas emissions in the recovery and extraction of crude bitumen from Canada's oil sands, *Applied Energy*, 2015, 143: 189-199.
4. Subramanyam V., Paramshivan D., Kumar A., Mondal, A. Using Sankey diagrams to map energy flow from primary fuel to end use, *Energy Conversion and Management*, 2015, 91: 342–352.
5. Ali B., Kumar A. Development of life cycle water-demand coefficients for coal-based power generation technologies, *Energy Conversion and Management*, 2015, 90: 247-260.
6. Rudra S., Rosendahl L., Kumar A. Development of net energy ratio and emission factor for quad-generation pathways, *Energy Systems*, 2014, 5: 719-735.
7. Rahman M.M., Canter C., Kumar, A. Greenhouse gas emissions from recovery of various North American conventional crudes, *Energy*, 2014, 74, 607-617.
8. Thakur A., Canter C.E., Kumar A. Life cycle energy and emission analysis of power generation from forest biomass, *Applied Energy*, 2014, 128, 246-253.
9. Miller P., Kumar A. Techno-economic assessment of renewable diesel production from canola and camelina, *Sustainable Energy Technologies and Assessments*, 2014, 6, 105-115.
10. Olateju B., Monds J., Kumar A. Large scale hydrogen production from wind energy for upgrading of bitumen from oil sands, *Applied Energy*, 2014, 118 (1), 28-56.
11. Miller P., Kumar A. Development of emission parameters and net energy ratio for renewable diesel from canola and camelina, *Energy*, 2013, 58 (1), 426-437.
12. Olateju B., Kumar A. Techno-economic assessment of hydrogen production from underground coal gasification (UCG) with carbon capture and storage (CCS) for upgrading bitumen from oil sands, *Applied Energy*, 2013, 111, 428-440.
13. Kabir M.R., Kumar A. Comparison of the energy and environmental performances of nine biomass/coal co-firing pathways, *Bioresource Technology*, 2012, 124, 394-405.
14. Olateju B., Kumar A. Hydrogen production from wind energy in western Canada for upgrading bitumen from oil sands, *Energy*, 2011, 36(11), 6326-6329.
15. Kabir M.R., Kumar A. Development of net energy ratio and emission factor for biohydrogen production pathways, *Bioresource Technology*, 2011, 102(19), 8972-8985.
16. Sultana A., Kumar A. Development of energy and emission parameters for densified form of lignocellulosic biomass, *Energy*, 2011, 36(5), 2716-2732.

Andres Clarens
http://cee.virginia.edu/andresclarens/

a. Professional Preparation

University of Virginia	Chemical Engineering	B.S.	1999
University of Michigan	Environmental Engineering	M.E.	2004
University of Michigan	Environmental Engineering	Ph.D.	2008

b. Appointments

2014-present	Associate Professor, Civil and Environmental Engineering, University of Virginia
2008-2014	Assistant Professor, Civil and Environmental Engineering, University of Virginia
2002-2007	Research Assistant, Civil and Environmental Engineering, University of Michigan
2001-2002	Environmental Engineer, Tetra Tech, Fairfax, VA
1999-2001	Environmental Engineer, United State Peace Corps, Dominican Republic

c. Publications

(i) Five most closely related to proposal project

- Middleton, R. S., Clarens, A. F., Liu, X., Bielicki, J. M., and Levine, J. S. (2014). CO_2 Deserts: Implications of Existing CO_2 Supply Limitations for Carbon Management. Environmental Science and Technology, *48*(19), 11713-11720.
- Tao, Z. and A.F. Clarens (2013) "Estimating the carbon sequestration capacity of shale formations using methane production rates" Environmental Science and Technology. *47 (19), pp 11318–11325.*
- Wang, S., T. Zhiyuan, S. Persily, and A.F. Clarens (2013) "CO_2 adhesion on hydrated mineral surfaces" Environmental Science and Technology. *47 (20), pp 11858–11865.*
- Wang, S., I. Edwards, and A.F. Clarens (2013) "Wettability phenomena at the CO_2-brine-mineral interface: Implications for geologic carbon sequestration" Environmental Science and Technology. *47 (1) 234–241.*
- Wang, S. and A.F. Clarens (2012) "The effects of CO_2-brine rheology on leakage processes in geologic carbon sequestration" Water Resources Research. *48, W08516.*

(ii) Five other significant publications

- Clarens, A.F., E.P. Resurreccion, M.A. White, L.M. Colosi. (2010) "Environmental Life Cycle Comparison of Algae to Other Bioenergy Feedstocks" Environmental Science and Technology. 2010, 44, (5), 1813-1819
- Clarens, A.F., H. Nassau, E.P. Resurreccion, M.A. White, L.M. Colosi (2011) "Environmental Impacts of Algae-Derived Biodiesel and Bioelectricity for Transportation" Environmental Science and Technology. 45 (17), 7554–7560
- Liu, X., A.F. Clarens, L.M. Colosi. (2012) "Algae biodiesel has potential despite inconclusive results to date" Bioresource Technology. 104, 803-806

- Clarens, A. F., K. F. Hayes, S. J. Skerlos "Feasibility of Metalworking Fluids Delivered in Supercritical Carbon Dioxide." Journal of Manufacturing Processes. 2006, 8(1) 47-53.
- Clarens, A., A. Younan, P.E. Allaire "Feasibility of Gas-Expanded Lubricants for Increased Energy Efficiency in Tilting-Pad Journal Bearings." ASME - Journal of Tribology. July 2010

d. Synergistic Activities

- Carbon dioxide leakage from deep sequestration sites - Developing fundamental knowledge in the means by which carbon dioxide rises through deep and shallow aquifers as a means by which to estimate and predict significant leakage pathways for storage of CO_2 in the deep subsurface.
- Algae-based CO_2 Sequestration and Bio-based feedstock research - Evaluating the use of algae-based bioenergy processes to remediate existing environmental challenges. Life cycle assessment tools are being used to identify leverage points in the algae production process and study specific ways in which to improve the overall environmental profile of the system. A recent focus has been on wastewater streams to remove estrogenic contaminants and take up nutrients.
- GELs: Gas Expanded Lubricants for energy efficiency - Working to create entirely new concept for delivering tunable mixtures of lubricants and gas a moderate pressures to rotating machinery as a method to improve energy efficiency and reduce lubricant consumption.
- Faculty Advisor, Engineering Students Without Borders (2009-present) Advised student-led group managing multiple national and international service projects using an annual operating budget of $25,000. Continuation of work performed during graduate school as founder of local Engineers With-out Borders chapter.
- University Teaching Fellow (2010-11) - Selected as one of six junior faculty members University wide to engage in intensive year-long pedagogical training program that included redesign of a course and the creation of novel teaching content and tools.

e. Collaborators & Other Affiliations

(i)Collaborators

Lisa Colosi	U. of Virginia	James Rhodes	UC - Davis
Jeffrey Fitts	Princeton	Brian Smith	U. of Virginia
James Lambert	U. of Virginia	Mark White	U. of Virginia
Catherine Peters	Princeton	Fu Zhao	Purdue

(ii) Graduate and Postdoctoral Advisors Kim Hayes, University of Michigan (M.S.E. Advisor); Steven Skerlos, Kim Hayes, Gregory Keoleian, Walter Weber, Jonathan Bulkley, University of Michigan (PhD. Advisors)

(iii) Thesis Advisor and Postgraduate-Scholar Sponsor
MS – 0 (current), 3 (graduated); PhD – 5 (current); 4 (graduated)
Current: Brian Weaver (PhD), Bo Liang (PhD), Tao Zhiyuan (PhD), Lyu Xiaotong (PhD), Rodney Wilkins (PhD)
Graduated: Shibo Wang (PhD), Eleazer Resureccion (PhD), Alec Gosse (PhD), Xiaowei Liu (PhD)

H. SCOTT MATTHEWS
PROFESSOR
DEPARTMENT OF CIVIL AND ENVIRONMENTAL ENGINEERING /
DEPARTMENT OF ENGINEERING AND PUBLIC POLICY
DIRECTOR OF RESEARCH, GREEN DESIGN INSTITUTE
CARNEGIE MELLON UNIVERSITY
PITTSBURGH, PA 15213-3890
Phone: (412) 268-6218 Fax: (412) 268-7357 E-mail: hsm@cmu.edu

PROFESSIONAL PREPARATION

- BS, Computer Engineering and Engineering and Public Policy, Carnegie Mellon, 1992
- MS, Economics; Carnegie Mellon, 1996
- Ph.D., Economics; Carnegie Mellon University, 1999

APPOINTMENTS

- Aug 2010 – Present: Professor, Civil & Environmental Engineering / Engineering & Public Policy
- Aug 2006-2010: Assoc. Professor, Civil & Environmental Engineering / Engineering & Public Policy
- Aug 2002-2006: Asst. Professor, Civil & Environmental Engineering / Engineering & Public Policy
- Jan. 2000-Present: Director of Research, Green Design Institute
- July 2000-July 2002: Research Assistant Professor, Carnegie Mellon University, Pittsburgh, PA
- Jan. 1999-June 2000: Associate Head, Department of Engineering and Public Policy, Carnegie Mellon

PRODUCTS - MOST RELEVANT

1. "Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use", National Research Council, 2009 (member of committee).
2. H. Scott Matthews, Chris T. Hendrickson, and Deanna Matthews, Life Cycle Assessment: Quantitative Approaches for Decisions that Matter (Textbook & Educational Resources), lcatextbook.com, 2014.
3. Ping Chen, Corinne Scown, H. Scott Matthews, James H. Garrett, Chris T. Hendrickson, "Managing Critical Infrastructure Interdependence through Economic Input-output Methods", ASCE Journal of Infrastructure Systems, Volume 15, Issue 3, pp. 200-210 (September 2009).
4. Chung-Yan Shih, Corinne Scown, H. Scott Matthews, James Garrett, Lucio Soibelman, Keith Dodrill, and Sandy McSurdy, "Data Management for Geospatial Vulnerability Assessment of Interdependencies in US Power Generation", ASCE Journal of Infrastructure Systems, Vol. 15, No. 3, September 2009.
5. H. Scott Matthews, Lester Lave, and Heather MacLean, "Life Cycle Impact Analysis: A Challenge for Risk Analysis", Risk Analysis, Vol. 22, No.5, pp. 853-860, 2002.

OTHER SIGNIFICANT PRODUCTS

1. Rachel Hoesly, Mike Blackhurst, H Scott Matthews, Jeffery F. Miller, Amy Maples, Matthew Pettit, Catherine Izard, Paul Fischbeck, "Historical Carbon Footprinting and Implications for Sustainability Planning: a Case study of the Pittsburgh Region", Environmental Science & Technology, 2012, *46* (8), pp 4283–4290, DOI: dx.doi.org/10.1021/es203943q
2. Yeganeh Masayekh, Paulina Jaramillo, Constantine Samaras, Chris T. Hendrickson, Michael Blackhurst, Heather Maclean, and H. Scott Matthews, "Potentials for Sustainable Transportation in Cities to Alleviate Climate Change Impacts", Environmental Science & Technology, 2012, *46* (5), pp. 2529–2537, DOI: 10.1021/es203353q

3. Cliff Davidson, Chris Hendrickson, and H. Scott Matthews, "Sustainable Engineering: A Sequence of Courses at Carnegie Mellon", International Journal of Engineering Education, Vol. 23, No. 2, pp. 287-293, 2007.
4. Chris T. Hendrickson, Gyorgyi Cicas, and H. S. Matthews, "Transportation Sector and Supply Chain Performance and Sustainability", Transportation Research Record No. 1983, 2006.
5. Jon Koomey, H. Scott Matthews and Eric Williams, "Smart Everything: Will Intelligent Systems Reduce Resource Use?", Annual Reviews of Energy and the Environment, Vol, 38, pp. 311-343, 2013, DOI: 10.1146/annurev-environ-021512-110549

SYNERGISTIC ACTIVITIES

- Development of Economic Input-Output Life Cycle Assessment (EIO-LCA) Dataset and Internet Model, http://www.eiolca.net/, 1999-present.
- Development of Green Design Educational Modules, 1998-present (http://gdi.ce.cmu.edu)
- Center for Sustainable Engineering – Head of Educational Module Submission and Dissemination
- IEEE Technical Committee on Sustainable Systems and Technology (formerly TC Electronics and the Environment), Committee Chair (present), Finance Chair (2001-2011), Conference Chair (2004, 2009), Program Chair (2006).
- *Journal of Industrial Ecology* – Associate Editor

COLLABORATORS & OTHER AFFILIATIONS (at Carnegie Mellon unless noted)

Burcu Akinci, Brad Allenby (ASU), Rob Anex (Wisconsin), Ines Azevedo, Mario Berges, Melissa Bilec (U. Pittsburgh), Michael Blackhurst (UT-Austin), Lori Bruhwiler (NOAA), David Dzombak, Paul Fischbeck, James Garrett, W. Michael Griffin, Mohd Hassan (Malaysian Govt), Troy Hawkins (Enviance), Chris Hendrickson, Arpad Horvath (Berkeley), Paulina Jaramillo, Vikas Khanna (Pitt), Jon Koomey (Stanford), Matt Kocoloski (TVA), Amy Landis (ASU), Lester Lave, Reid Lifset (Yale), Joe Marriott (NETL), Deanna Matthews, Heather MacLean (Univ. of Toronto), Aweewan Mangmeechai (Thailand), Jennifer Mankoff, Eric Masanet (Northwestern), Yeganeh Mashayekh (Penn), Francis McMichael, Jeremy Michalek, Kim Mullins (Minnesota), Rachael Nealer (UCS), Stefan Schwietzke (NOAA), Lucio Soibelman, Mili-Ann Tamayao (U of Philippines), Aranya Venkatesh (ExxonMobil), Radisav Vidic (Pitt), Heather Wakeley Healey (TRC Inc.), Eric Williams (RIT)

GRADUATE/THESIS ADVISORS: Dennis Epple, Chris Hendrickson, Lester Lave (Chair), all CMU.

THESIS ADVISEES (all CMU unless noted): Aweewan Mangmeechai (PhD 2009), Chung Yan Shih (PhD 2009), YuShan Anny Huang (PhD 2009), Matt Kocoloski (PhD 2010)*, Mario Berges (PhD 2010), Chris Costello (PhD 2010), Michael Bigrigg (PhD 2011), Michael Blackhurst (PhD 2011)*, Sharon Wagner (PhD 2011), John Matsumura (PhD 2012), Ranjani Theregowda (PhD 2012), Mohd Nohr Azman Hassan (PhD 2012), Brinda Thomas (PhD 2012), Marco Vincenzi (PhD 2012), Aranya Venkatesh (PhD 2012), Kim Mullins (PhD 2012)*, Amy Nagengast (PhD 2012)*, Catherine Izard (PhD 2013), Enes Hosgor (PhD 2013), Yeganeh Mashayekh (PhD 2013), Derrick Carlson (MS 2009, PhD 2013), Stefan Schwietzke (PhD 2013). Total Graduated Students: 40. Asterisks note students also supervised as post-docs. Total post-docs: 9.

Bruce A. McCarl
University Distinguished Professor and Regents Professor
Department of Agricultural Economics
Texas A&M University

Professional Preparation

University of Colorado	Business Statistics	B.S., 1970
Pennsylvania State University	Management Science	Ph.D., 1973

Appointments

2008-present	University Distinguished Professor, Texas A&M University
2002-present	Regents Professor, Texas A&M University
1985-present	Professor, Agricultural Economics, Texas A&M University
1982-1985	Professor, Agric. and Resource Econ., Oregon State Univ.
1980	Visiting Professor, Agric. and Res. Econ., Oregon State Univ.
1979-1982	Associate Professor, Agricultural Economics, Purdue Univ.
1973-1978	Assistant Professor, Agricultural Economics, Purdue Univ.

Publications (Selected from 250+ journal articles)

Chambwera, M., G. Heal, C. Dubeux, S. Hallegatte, L. Leclerc, A. Markandya, B.A. McCarl, R. Mechler, and J. Neumann, "Economics of Adaptation", *IPCC WG II Contribution to The Fifth Assessment Report, Climate Change 2013: Impacts, Adaptation and Vulnerability*, Forthcoming Cambridge University Press, 2014.

Attavanich, W., B.S. Rashford, R.M. Adams, and B.A. McCarl, "Land Use, Climate Change and Ecosystem Services", *Oxford Handbook of Land Economics*, edited by Joshua M. Duke and JunJie Wu, forthcoming, 2014.

Attavanich, W., B.A. McCarl, Z. Ahmedov, S.W. Fuller, and D.V. Vedenov, "Climate Change and Infrastructure: Effects of Climate Change on U.S. Grain Transport", *Nature Climate Change*, on line at doi:10. 1038/nclimate1892, 3, 638-643, 2013.

McCarl, B.A., X. Villavicencio, X.M. Wu, and W.E. Huffman, "Climate Change Influences on Agricultural Research Productivity", *Climatic Change*, 2013.

Aisabokhae, R.A., B.A. McCarl, and Y.W. Zhang, "Agricultural Adaptation: Needs, Findings and Effects", Handbook on Climate Change and Agriculture, Edited by Robert Mendelsohn and Ariel Dinar, Published by Edward Elgar, Northampton, MA, pp 327-341, 2011

Publications (Other)

Zhang, Y.W., A.D. Hagerman, and B.A. McCarl, "How climate factors influence the spatial distribution of Texas cattle breeds", *Climatic Change*, Volume 118, Issue 2, 183-195, 2013.

Joyce, L.A., D.D. Briske, J.R. Brown, H.W. Polley, B.A. McCarl, and D.W. Bailey, "Climate Change and North American Rangelands: Assessment of Mitigation and Adaptation Strategies", *Rangeland Ecology & Management*, 66, 512-528, 2013.

McCarl, B.A., "Some Thoughts on Climate Change as an Agricultural Economic Issue", *Journal of Agricultural and Applied Economics*, vol 44 no 5, 299-305, 2012.

Mu, J.E., B.A. McCarl, and A. Wein, "Adaptation to climate change: changes in farmland use and stocking rate in the U. S", *Mitigation and Adaptation Strategies for Global Change*, doi:10. 1007/s11027-012-9384-4, 2012.

McCarl, B.A., "Vulnerability of Texas Agriculture to Climate Change", *Impact of Global Warming on Texas*, Chapter 6, Second Edition, edited by Jurgen Schmandt, Judith Clarkson and Gerald R. North, University of Texas Press, ISBN: 978-0-292-72330-6, 2011.

Synergistic Activities

Member NAS America's Climate Choices Study, Limiting Panel.
Member Texas Water Development Board Climate Change Panel.
Member of EPA team appraising emissions rules for stationary sources
IPCC Lead Author on economics of adaptation and summary for policy makers on 2013 report
IPCC Mitigation Chapter Lead Author and participant in 2007 Nobel Peace Prize.
Associate Editor, Climatic Change

(v) **Collaborators and Other Affiliations**

(a) *Collaborators*: D. Adams, R. Adams (Oregon State U), W. Parton, D. Ojima, K Paustian (Colorado State U), B. Murray (Duke), W. You , G. Davis (Virginia Tech), P. Smith (Aberdeen), R. Sands (PNNL), J. Smith (Stratus), C. Rosenzweig (Columbia), B. Sohngen(Ohio State), J. Reilly (MIT), S. Rose, EPRI, R. Alig, USDA, J. Baker (Duke), S. Ohrel, J. Creason (EPA), C. Chang, C. Tso, C. Chen (Taiwan), U. Schneider, N. Koleva (U of Hamburg), C. Peacocke (Ireland), R. Chrisman (U. Washington), C.C. Kung (China), R.D. Sands (USDA ERS), Fri, R. (RFF), M. Brown (Georgia Tech), D. Arent (NREL), A. Carlson (UCLA), M. Carter (New York), L. Clarke (PNNL), F. de la Chesnaye (EPRI), G. Eads (RFF), G. Giuliano (USC), A. Hoffman (Michigan), R.O. Keohane (Princeton), L. Lutzenhiser (PSU) , M.C. McFarland (DOW), M.D. Nichols (CARB), E.S. Rubin (Carnegie), T. Tietenberg (Colby), J. Trainham (RTI), L. Geller, A. Crane, T. Menzies, and S. Freeland (NAS), Chambwera, M. (INDP), G. Heal (Columbia), C. Dubeux (Brazil), S. Hallegatte (World Bank), L. Leclerc (Canada), A. Markandya (Spain), R. Mechler (IIASA), J. Neumann (IEC), B.S. Rashford (Wyoming), W. Attavanich (Thailland), Z. Ahmedov (Amer Express), R. Johansson (USDA) W.E. Huffman (Iowa State),Wang, W.W. (Illinois), X. Villavicencio (Ecuador) W.E. Huffman (Iowa state), Aisabokhae, R.A (Dupont, Nogeria)., Y.W. Zhang (IIASA), A.D. Hagerman (USDA, APHIS), Joyce, L.A.(USDA, F.S.), J.R. Brown (New Mexico), H.W. Polley (USDA), D.W. Bailey (New Mexico), Mu, J.E. (Oregon state), A. Wein (USGS)

(b) *Graduate and Postdoctoral Advisors*: G. Kochenberger (Colorado). No postdoctoral Advisors.

(c) *Graduate Students (Ph.D.)*: T. Spreen (Florida), H, Baumes, T. Tice (USDA) C. Chen (Taiwan), L. Elbakidze (Idaho), U. Schneider (Hamburg), M. Kim (Nevada), J. Apland (Minnesota), R. Klemme (Wisconsin), A. Naing (UNDP), D. Barnett (AFDB), Y. Cai (MIT), W Attavanich (Thailand)

Total Supervised: 74 PhD and 19 MS.; presently advising 8 PhDs .

*TO BE PROVIDED

ON TUESDAY, MAY 5, 2015

Review of the Methodology Used in Calculating Fuel Carbon Intensities and of the Use of Three Life Cycle Greenhouse Gas Emissions Models

Amit Kumar, Ph.D., P.Eng.
Associate Professor
Department of Mechanical Engineering
University of Alberta
Edmonton, Alberta, Canada T6X 0A3

May 5, 2015

Background

This response is based on a request for review of staff reports prepared by the Air Resources Board (ARB) of the California Environmental Protection Agency (Cal/EPA). The staff reports focus on the methodology of estimating life cycle greenhouse gas (GHG) emissions from different crude oils processed in California refineries. In light of my expertise, this review is focussed predominantly on the conclusions in Staff Report 2 titled “Calculating Carbon Intensity Values of Crude Oil Supplied to California Refineries” (Memorandum dated January 21, 2015 from Mr. Jim M. Aguila (ARB) to Dr. Gerald W. Bowes (Cal/EPA), Attachment 2). In addition to the specific comments on Staff Report 2, the review comments also include a general assessment of the material provided for review.

Conclusion 2: Crude Oil Intensity Values

Based on staff’s assessment of available government, research literature, and internet sources for each crude source, the ARB staff concludes that the assumptions and input parameters used in OPGEE to calculate CI values for crude oil production and transport are reasonable and the model was applied appropriately under the LCFS.

Comments

In my opinion, the OPGEE model used to estimate the life cycle carbon intensity (CI) of various crude oils refined in California refineries is detailed in terms of the different unit operations involved in the production, transportation, and refining processes of crude oils. The model includes a comprehensive framework for the consideration of the characteristics of production wells, crude oils, refining processes, and crude oil transportation. The estimated CI values are reasonable; however, there are important points that should be taken into account when using these estimates. My comments are given below on various aspects of the methodology, input data, and assumptions, and include suggestions for a path forward.

Methodology: As there are many unit operations considered in an estimation of life cycle GHG emissions from the various crude oils refined in California's refineries, the data for these assessments have been either developed or collected from various sources by the ARB staff. Any variation in these assumptions and input data will have an impact on the overall life cycle GHG footprint. Hence it is very challenging to arrive at a single estimated life cycle GHG emissions value for a particular crude oil. The values in the report (e.g., Table 1, Appendix H) are specific estimates for various crudes. It might be useful if the numbers are associated with some uncertainty or range. This would help address the variations in estimated values found in different studies for a particular crude oil.

PR-1

Effect of GHG emission allocation strategies: The method of allocating refinery and upstream emissions to transportation fuels has a major impact on the life cycle GHG emission results. The process level allocations could be in the form of an energy and/or mass basis. Some of these allocation strategies have been made in an earlier study to understand differences in allocation on refinery levels and sub process levels [1]. In the ARB staff report, there needs to be a justification for the allocation method used. Some consideration should also be given to other allocation strategies, such as the allocation of emissions based on fuel hydrogen content, to study their impact on life cycle GHG emissions. Different existing studies use different allocation techniques and report varying results. A consensus on the allocation strategy is needed to help inform policy formulation and decision making.

PR-2

Use of GHGenius data and assumptions for heavy crude oil from the Canadian oil sands: An LCA is a highly informative but labor-, time-, and research-intensive method. There are several LCA models available [2-5] that would help reduce the workload to perform an LCA for any pathway by providing the basic framework and database. These models provide varying results based on different assumptions, database inventories, and data sources. There are limitations in using these models for the oil sands-based heavier crudes from Canada that are processed in California's refineries. The limitations are specifically related to the assumptions and methodologies built into the model. The ARB report based on the OPGEE model has considered assumptions and inputs from GREET and GHGenius, and the ARB staff report has specifically used the GHGenius model assumptions and input data for a life cycle assessment of transportation fuels from the oil sands.

GHGenius is based on an estimate of GHG emissions with direct input of process fuel consumed per unit of fuel delivered. The direct relationship between mass and volume is used to proceed from one unit operation to the other. For example, one mass unit of synthetic crude oil (SCO) is assumed to be same as one mass unit of bitumen. This may not always be appropriate as the mass of SCO is always less than bitumen and depends on the upgrading operation. GHGenius considers the API (American Petroleum Institute) gravity relations between feeds to be mass additive, which is not fully justified (the density of crude is additive in volume).

Diesel fuel is one of the main sources of energy for bitumen extraction through surface mining. The estimate of diesel required in the OPGEE model, which is based on the GHGenius model, is almost 100 times higher than the values used in the GREET model and up to 7 times higher than the results of another recent study [6]. This assumption needs to be justified in the report as it has an impact in the overall GHG emissions. PR-3

The assumptions in the OPGEE model based on GHGenius regarding electricity production and export from the oil sands are only partially justified. This model uses Alberta's grid electricity ratio for electricity production and electricity export from the oil sands. This assumption is not clear as most of the electricity production in the oil sands is on site and from natural gas. And the extra electricity exported displaces Alberta's grid electricity, of which 53.1% is from coal, 37.4% from natural gas, and the rest from other resources such as hydro, wind, and biomass [7]. This assumption on Alberta's grid electricity ratio for electricity production and export has a significant impact on the overall life cycle GHG emissions of oil sands-based crudes and hence needs further justification. PR-4

Steam Assisted Gravity Drainage (SAGD) is another method of bitumen extraction in the oil sands. One of the key limitations to SAGD in the ARB report (as this is based on GHGenius model) is in the area of electricity and steam generation. The consideration of the cogeneration of electricity and steam is very limited. The limited consideration does not represent the actual scenario in oil sands SAGD operations. The use of cogeneration in SAGD operations is expected to increase in future, and this increase will have a significant impact on the overall life cycle GHG emissions. PR-5

The upgrading of bitumen produced from the oil sands is an energy-intensive process. The requirement of energy is dependent on the techniques used for upgrading. Most of the energy requirement comes from conventional sources of energy (e.g., natural gas and electricity). Coke, which is one of the by-products of the upgrading process, could be used for energy, but its use depends on the different industrial operations. The majority of the coke is stockpiled and not combusted. This stockpiling should be considered in a life cycle GHG emissions assessment as it has a significant impact on the overall estimated values. PR-6

Upgrading operations consume significant quantities of hydrogen to convert bitumen to SCO. There are very limited details on the amount of hydrogen consumed for upgrading bitumen from in situ recovery, and for upgrading bitumen from surface mining there is very limited information found in GHGenius. PR-6 cont

Fugitive emissions: The emissions over the life cycle of the production, processing, and use of the various crude oils are an important factor and have an impact on overall GHG emissions. There has been very limited effort to estimate these emissions. The OPGEE estimates these emissions based on the development of bottom-up parameter-based models; however, a real life measurement of these emissions is needed for a credible estimate. The fugitive emissions for different crudes could vary significantly as there are differences in the extraction, production, transportation, and processing of these oils. The emissions could differ significantly for the conventional and non-conventional sources of crude oils. PR-7

Biomass use for energy and fuels: Different jurisdictions use different sources of biomass to produce energy and fuels. These could be agricultural or forestry sources. The life cycle GHG footprint for various biomass feedstocks (e.g., wheat straw, corn stover, bagasse) depends on the jurisdiction where they are grown and also on the feedstock itself. These life cycle GHG footprints depend on the inputs (e.g., fertilizer, fuels) for biomass production, harvesting, collection, transportation, and conversion. It is very challenging to estimate these parameters for different jurisdictions. The use of different biomass for electricity generation could have an impact on the electricity generation grid mix for various jurisdictions. Hence this should be added as a cautionary note, and a range of life cycle estimates, as stated earlier, may be more appropriate. PR-8

Changing the electricity generation mix with time: The electricity grid GHG emissions for a particular jurisdiction depend on the type of fuels used to produce electricity. The type of fuels could vary significantly from one jurisdiction to another. The electricity grid mix changes continuously with changes in the amount and type of fuel used to produce electricity. For example, in Alberta, recently there has been a significant increase in natural gas-based power generation compared to coal-based power generation. There has also been a significant increase in wind power generation. These sources of power are continuously changing the grid intensity as natural gas- and wind-based electricity have lower GHG footprints than does coal power generation. This lowering of the grid intensity would have an impact on the life cycle GHG emissions of bitumen-based crude oil. There needs to be a system under the LCFS to account for this. PR-9

Future LCA footprints: In the current ARB report, the focus is on life cycle GHG emissions from the different crude oils that are processed in California's refineries. In future, and keeping in mind the current water availability issue in California, it would be important to also look at the life cycle water footprints of the different crude oils processed in California refineries. This could involve the development of methodologies to estimate the life cycle water consumption coefficients for various crude oils. PR-10

References

1. Wang M., Lee H., Molburg J. Allocation of energy use in petroleum refineries to petroleum products – Implications for life-cycle use and emission inventory of petroleum transportation fuels. International Journal of Life Cycle Assessment 2004; 9 (1): 34-44.
2. $(S\&T)^2$. GhGenius model 4.02.Technical report. $(S\&T)^2$ Consultants. Prepared for Natural Resources Canada. 2012.
3. Argonne National Laboratory. GREET 2013 Model. October 25 2013. Available at: https://greet.es.anl.gov/publication-greet-model (accessed on May 4, 2015).
4. PRE consultants. SimaPro software. Amersfoort, Netherlands. 2014. Available at http://www.pre-sustainability.com./ (accessed May 4, 2015).
5. PE INTERNATIONAL. GaBi Software. A product sustainability perfomance solution by PE INTERNATIONAL. Germany. 2014. Available at http://www.pe-international.com/canada/index/ (accessed May 4, 2015).
6. Nimana B., Canter C., Kumar A. Energy consumption and greenhouse gas emissions in recovery and extraction of Canada's oil sands products. Applied Energy 2015; 143:189-199.
7. Alberta Utilities Commission (AUC). Alberta Electric Energy Generation (GWH) by Resource and Interchange. Available at http://www.auc.ab.ca/market-oversight/Annual-Electricity-Data-Collection/Documents/Total_Generation.pdf . 2012. (accessed May 4, 2015).

Andres Clarens
Associate Professor
Civil and Environmental Engineering
University of Virginia
4/30/15

External Peer Review of "**Methodology in Calculating Fuel Carbon Intensities and Use of Three Greenhouse Gas Emissions Models"**

Overall summary statement: After reviewing the three staff reports describing the CI calculation methodology being proposed by CARB, I am confident that the methods are based on sound science and represents the state of the art in CI estimation.

With respect to the three staff reports that I reviewed, I have the following more specific questions and recommendation:

Life Cycle Fuel Carbon Intensities

Page 2. It would be useful to add a sentence or two in this overview report describing efforts by CARB to ensure that there is no double counting of emissions burdens between CA-GREET and the OPGEE modeling estimates. PR-11

Page 5. The CA-GREET model has been updated recently to include cellulosic feedstocks and sorghum. A cellulosic (corn stover) to ethanol pathway is also defined using data obtained using ASPEN plus. Is there any pilot or field data that can be used here to support the findings in the model? Also, is this the only Tier 2 pathway that has emerged in recent years? The report makes it seem like this may be the case. PR-12

Page 7. How do the emissions results from the MOVES model compare to those from the MOBILE6.2 model and the CARB EMFAC model? What prompted the switch other than the fact that the MOVES data is more current? PR-13

Page 8. How is uncertainty propagated through the series of models? I understand how uncertainty is handled in CA-GREET and in GTAP. In the context of the WTW calculations on page 8, does the aggregate carbon intensity value have a reliable uncertainty range associated with it? PR-14

Page 10. The language around the indirect accounting mechanisms as they relate to Tier 1 and Tier 2 fuels is a bit unclear. As written, the report states that the source must be directly consumed in the production process. But this is ambiguous in certain contexts such as those fuels that produce co-products. For example, if a corn feedstock were used to make ethanol and the stover were also used to make fuel (but was not consumed in the same production process) would that not trigger a switch from Tier 1 to Tier 2? It seems like it should but as written it might not. Clarifying this language is key for groups seeking to obtain co-product credit through the CA-LCFS. PR-15

Page 15. The difference between pathway CNG020 and CNG021 is not clear. PR-16

The OPGEE model goes into great detail cataloging the carbon intensity of different crude oils and the results are fascinating. But in light of the significant debate regarding iLUC, there is a big difference between the resolution of data for crude and for agricultural products. The report describes efforts to calculate this using AEZ and this is a strength of the approach. But I wonder whether CA-GREET is able to provide estimates at the same resolution for crop-based biofuel feedstocks coming from different regions of the US and the world? Does the model account for the same crop in difference between rain PR-17 fed and irrigated crops? How does the natural land use cover impact the emissions? What about amount of time the land has been in production? `The staff should consider the resolution of the data across these modeling platforms to ensure that they are comparable. PR-18

To what extent do the CI values from the different crude sources vary year to year? PR-19

The modeling efforts include "elasticity of crop yields with respect to area of expansion". Does it include changes to yield associated with improved technology and year-to-year variability that can come from things like the massive drought in the Midwest? PR-20

Crude Oil Carbon Intensity

How is enhanced oil recovery handled in the OPGEE model and would efforts to develop innovative EOR technologies that sequestered carbon qualify the resulting crude as an innovative pathway? PR-21

I don't know where CARB stands now wrt CO_2 EOR but if there is interest in developing a mechanism for oil producers to gain credit for producing lower CI crude through the LCFS (presumably from outside CA since very little EOR takes place in the state right now I believe), then I strongly encourage CARB to develop a mechanism to track the original source of the CO_2. Most of the CO_2 used in EOR in Texas comes from geologic formations were the carbon capture and sequestration benefits are non-existent. PR-22

The EPA Greenhouse Gas Reporting Program has been collecting data on emissions factors at the facility scale for several years. How do these self-reported emissions from EPA compare to the emissions factors from OPGEE? PR-23

How do significant price swings in crude oil prices (like the drop in prices observed over the past 6 months or a hypothetical spike in prices like the one that occurred in 2008) impact the composition of crude flowing to CA refineries? Are these fluctuations reflected in the CI calculations over such a short timestep? I recognize that this is partially an economic question and that it is therefor somewhat outside the scope of this analysis, but it seems reasonable to ask how the signals might impact the blend, which would impact the CI of the fossil transportation fuels being sold in the state. The report explains the 2010 baseline and how that will be used to lower the compliance target, but I am curious about extraneous market factors that could make meeting those targets unrelated to actual emissions reductions. PR-24

Indirect Land Use Change

This report describes the process by which the staff completed 30 scenarios and averaged the results. Were the scenarios all set up so that they would be equally likely? Additional text here would be useful. PR-25

The GTAP baseline is 2004 but that occurred before the major growth in corn ethanol production in the United States. I understand this has to do with the availability of economic databases. Are there efforts to update the model using more recent economic data? Is there an expectation that new data will provide different estimates based on changes in the biofuels landscape? PR-26

The report does not provide the actual value of the iLUC contribution that CARB is using but I found it online (30 g/MJ) and also learned that there is some disagreement in the community about which value is the most appropriate (and even whether iLUC as a mechanism is the most appropriate to capture the effect of biofuels expansion). I will not weigh in here other than to say that if the intent of CA-LCFS is to be technology-neutral then selecting a value that is at the high end of the distribution will create *de facto* caps that will suppress the development of certain fuels/pathways in the CA market. PR-27

April 25, 2015

Carnegie Mellon University
Department of Civil and Environmental Engineering
5000 Forbes Avenue
Pittsburgh, PA 15213

Gerald W. Bowes, Ph.D.
Manager, Cal/EPA Scientific Peer Review Program
Office of Research, Planning and Performance
State Water Resources Control Board
1001 I Street
Sacramento, CA 95814

Dear Dr. Bowes:

Attached please find my scientific peer review of the materials requested in support of the CA LCFS re-adoption activities.

External to my scientific review, I wanted to note a few small things that might be useful for the staff in terms of making these documents ready for public dissemination.

* Make it clear that LCFS defines the CI units of gCO2e/MJ (p. 2 of CA-GREET Report) PR-28
* Figure 1 is not 'generalized' – one of the arrows refers to biofuel use PR-29
* In the middle of page 8, the VOC and CO factor determination description is hard to follow. I figured out the ratio for CO, and still it could be written more clearly (e.g., describe where the 0.85 and 0.43 values come from – and what specific reference VOC was used to generate the assumed value for 0.85?) PR-30
* There was no text description of Tier 2 Method 1 in the Summary Report PR-31

Thank you again for asking me to participate in this very worthwhile effort.

Sincerely,

H. Scott Matthews
Professor

Peer Reviewer Report
H. Scott Matthews, Carnegie Mellon University

Methodology in Calculating Fuel Carbon Intensities and Use of Greenhouse Gas Emissions Models

April 25, 2015

I was asked by the State of California to review the staff reports and additional materials associated with the work produced in support of the California Low Carbon Fuel Standard (LCFS). It was an honor to be asked to look at this work, as the work done by this evolving team over time has been one of the most impressive scholarly efforts I have seen in my career. This team continues to do excellent work. Likewise, the goal and implementation of the LCFS has been one that has been successful in 'raising the bar' in terms of the expectations of performance in the transportation energy industry, and also in terms of nudging the federal government to adopt similar programs.

The specific statement of task I was given involved various aspects:

My scientific peer review responsibility was "to determine whether the scientific basis or portion of the proposed rule is based upon sound scientific knowledge, methods, and practices." Likewise, the focus is on the methods used to develop the carbon intensity (CI) values, as opposed to the LCFS program in general.

In addition, I was asked to assess the "Big picture" to ensure whether there are scientific issues not described or dealt with in the work.

Finally, I was asked to assess whether, overall, all of the work was based on sound science?

Note that via interactions with the organizers of the peer review, I was asked to focus on the GREET and OPGEE aspects of the work. I thus focused my review into those two components including review of the staff reports as well as the underlying electronic spreadsheets and references. [Note that while I am familiar with the kinds of models used in the GTAP and AEZ component, my review of that part was more cursory, consisting only of a review of the staff reports and a skim of the additional materials provided electronically. However I did not present scientific assessments of that component.]

Finally, I was asked to review the conclusions given by the staff, namely that the CA-GREET and OPGEE models used to calculate carbon intensity values (and GTAP for ILUC) are reasonable and that the models were applied appropriately under the LCFS.

Below I provide detailed review comments separated by the materials associated with the various subcomponents provided.

Three printed staff reports related to CA-GREET, OPGEE, and GTAP models, which are used to estimate the various carbon intensities.

Aside from small issues in terms of the details presented in these summaries, I found no issues of concern related to the high-level goals or methods used in these three domains.

Staff Reports and Plain English Summaries

I note that one thing not provided explicitly in any of the Staff Reports but which would have been useful was a succinct summary (box model diagram) of the three carbon intensity model components, as well as a short summary of the more specific quantitative aspects of the LCFS (10% goal by 2020). For the latter issue, this detail was available in the various links and support provided (e.g., the ISOR). PR-32

The plain English summaries did not seem to be very different than the text in the detailed staff reports. I saw no issues in those summaries for that audience but assume that those documents have been written in conjunction with technical writing experts.

Component 1 - CA-GREET

I found the CA-GREET related Staff Report report to be well organized and written. I note the following issues:

A small issue of concern, where the impact is hard to assess from the material provided, is the use of EPA AP-42 emissions factors. The reference date for the CD-ROM is 2005, but the underlying emissions factors for many processes in that document are much older than that. However there was not enough detail or method listed to give a sense of where those emissions factors were used, for what processes, etc. I trust that staff can develop more robust text that would help to clarify where they were used and any potential scientific impact from them. As a specific example recently noted by EPA (and a change forced by legal action), many of these values are quite old. I was unable to find the specific reference value in GREET/CA-GREET for these parameters but hopefully such changes could be made quickly – or at least added to a holding pile without holding up the re-adoption of LCFS. My first impression is that the net effect on a CO2e basis would be neutral between increasing VOC and decreasing CO emissions factors. (See http://www.epa.gov/ttn/chief/consentdecree/index_consent_decree.html) PR-33

Likewise, a similar concern is related to the version of the EPA MOVES model used. The ANL GREET reference (#13 in staff report) says that MOVES2010b was used (an update to previously using MOBILE6), however, MOVES2014 is available. Are there relevant differences? What is the anticipated update cycle? PR-34

The method uses the IPCC 100-year GWP factors, which I agree are the most relevant values to use. However the report and method should explicitly note that it uses these (rather than the 20 or 500 year values), and why. Too often in the past few years there have been attempts to abuse the GWP method to present results favorable to a particular fuel by cherry-picking higher GWP values that are associated with shorter time horizons. PR-35

The CA-GREET results shown on pages 14-15 (Tables 1 and 2) are presented as 'CI lookup tables'. As presented, it was not clear what these were. However from reading the ISOR my understanding is that these are default values determined ex ante by staff for a generic production of a Tier 2 fuel used for Method 1 (as a default value that would apply for a particular supplier unless they wanted to show a lower value from other use of the methods like 2A or 2B). My lack of understanding has no effect on the scientific merit of the work. PR-36

Although we were only directly provided the underlying GREET 2013 and 2014 Excel models, I was able to find information online related to the CA-GREET project, including downloadable versions of the Tier 1 and Tier 2 CA-GREET Excel spreadsheets. I see no scientific issues with respect to how the CA-specific functionality was added to the base GREET model (which was also presented in the documentation and reports provided).

The results (e.g., CI Lookup Tables) were presented as single values, as opposed to ranges or distributions. I understand that regulatory design is complex, and that providing planning certainty for companies is important, but in the end given the (un-shown) uncertainties it is possible that the actual reduction in greenhouse gas emissions is lower or higher than anticipated. The reports and tools do little to capture this. My scientific concern and how it relates to my focus on the CIs is that, as stated in the ISOR, the new LCFS will require Method 2A pathways to have 5.5 % (or 1 gCO2e/MJ – also about 5%) lower CIs. The uncertainties of the reference flows and the potentially modeled 2A pathways may have uncertainty greater than 5%, which has not been well established in the report. It is also not clear where this "5% threshold" came from. However, I do not view this as an issue with respect to the scientific credibility of the method, just in portraying the magnitude of overall potential benefits of the program and maintaining stakeholder confidence. PR-37

Notes on my review of additional resources listed in documents from Attachment 1 of Bowes' March 25 letter:

- I reviewed the staff's ISOR for the LCFS re-adoption (the Staff Reports provided to us are essentially excerpts of this document). This helped to fill in some of the gaps (identified above) with respect to how the pieces fit together.
- I am familiar with the GREET model since my own research group has used it for various projects in the past. As a result, I did not re-review individual sheets or cells of the spreadsheet model, as I know that this model has been developed with significant research and effort over the past decade.

- The study is based on the ISO LCA Standards. While I was unable to do a full review of every aspect in the comprehensive work, the work done in this study seems to conform to the LCA Standard.

Summary review of CA-GREET component of peer review:

The issues listed above are fairly cosmetic in nature. Thus, with respect to the three aspects I was asked to review:

(1) I agree with the staff's conclusion that "the assumptions and inputs used in CA-GREET 2.0 to calculate direct life cycle CIs are reasonable and the model was applied appropriately under the LCFS." The methods they have followed, including the use of literature sources and references, are consistent with what I would expect to use.

(2) With respect to the big picture issue, I do not believe there are any significant scientific issues that have been neglected in the method descriptions.

(3) Taken as a whole, I believe that all of the work done (including conclusions and scientific assessments) is based on sound science.

Component 2 – OPGEE Model

I again found the Staff Report report to be well organized and written. I was aware of but not familiar with the details of the OPGEE model before undertaking this review – I had only read a few of Professor Brandt's published papers. Unlike the GREET-based analysis, which significantly leverages an existing DOE/ANL model (GREET), most of OPGEE has been developed in the last few years and much has been done with the goal of supporting LCFS specifically. It thus represents a tighter fit to the work needed here. It is truly an impressive and expansive effort, especially given the relatively small research team involved in it as compared to other publicly available life cycle models.

The core results (updated for OPGEE v1.1) are the Lookup Table values as well as those that create the Baseline Crude Average CIs.

I noted the following issues in the OPGEE-related staff report:

Similar to my comments above associated with CA-GREET, I am admittedly uncomfortable in seeing the lookup table CI values represented with 4 significant digits (implying accuracy to the level of 10mg CO_2e/MJ. While the underlying model is comprehensive and rigorous, my concern would be that it is easy for the lookup table / model results to be construed as more exact than they may be (since the uncertainty is not able to be presented as such in these lookup tables). Similar to the fuel pathways above, the "extra digits" may in fact be a target for producers to seek their own pathway approvals because they can show them to be lower when in fact they are mostly just rounded off values (example – 10 instead of 10.35 would be 5% lower yet still within a reasonable uncertainty bound of 10.35). This is not explicitly an issue related to the scientific method used to generate the results (as

PR-38

requested in my peer review charge) but in application in the LCFS becomes an issue. Even removing one of these digits (one after the decimal point) would be an improvement. It is also potentially relevant because the Board has proposed a three-year model version update cycle, which to me suggests that nothing would officially change for 3 years). PR-38 cont

Notes on my review of additional resources listed in documents from Attachment 1 of Bowes' March 25 letter:

- I reviewed Chapter II and Appendix H of the ISOR. This helped to fill in some of the gaps (identified above) with respect to how the pieces fit together. There were too many references in Appendix H to read all of them in this review (some of them already referenced in the published journal papers). I studied a sample of them (Oil and Gas Journal articles, California monthly oil and gas reports, etc.) and agree that they are the relevant types of studies to create parameters or methods in estimating the needed CI values for this project. I note again that the attention to detail in this model, including the identification of production parameters for many foreign countries and fields, is extraordinary.
- The study is based on the ISO LCA Standards. While I was unable to do a full review of every aspect in the comprehensive work, the overall work done in this study seems to conform to the LCA Standard. Several of the main pieces behind OPGEE have already been published in peer-reviewed journal articles.

Summary review of OPGEE component of peer review:

The issues listed above are fairly cosmetic in nature (even my concern about presenting uncertain values). Thus, with respect to the aspects I was asked to review:

(1) I agree with the staff's conclusion that "the assumptions and inputs used in OPGEE to calculate CI values for crude oil production and transport are reasonable and the model was applied appropriately under the LCFS." The methods they have followed, including the use of literature sources and references, are consistent with what I would expect to use.

(2) With respect to the big picture issue, I do not believe there are any significant scientific issues that have been neglected in the method descriptions.

(3) Taken as a whole, I believe that all of the work done (including conclusions and scientific assessments) is based on sound science.

Component 3 – GTAP/Indirect Land Use Model

While my area of expertise is connected with the first two models, I did my best to read through the third modeling area. While I was unable to comprehend the model, data, or inputs at the same level of critical insight, I found nothing associated with that work that caused me to doubt its credibility. I thus agree with the staff's conclusion, have no big picture issues, and have no doubt that the work done was based on sound science.

A peer review as an input to the

EXTERNAL PEER REVIEW OF STAFF'S METHODOLOGY IN CALCULATING CARBON INTENSITY VALUES AND USE OF GREENHOUSE GAS EMISSIONS MODELS

Reviewer: Bruce A. McCarl, Principal, McCarl and Associates and, University Distinguished Professor of Agricultural Economics, Texas A&M University

Review date : April 29, 2015

Preface

As I understand it the peer review is intended to develop external review opinions on whether the CI methodology used by the ARB staff and supporting parties in calculating carbon intensity values and use of greenhouse gas emission models yields a valid scientific basis for the conclusions in the air resources Board staff reports.

I also believe that while I was sent three reports and a plain English version that I am only supposed to review those within my field of expertise which limits me to comment on

Calculating Lifecycle Carbon Intensity Values of Transportation Fuels in California, March 2015 (Staff Report 1)

Calculating Carbon Intensity Values from Indirect Land Change of Crop-Based Biofuels (Staff Report 3)

Additionally I will comment on the attachment entitled *Plain English summary of staff's methodology in calculating fuel carbon intensities*.

Basic findings

In attachment 2 of the request for external peer review originating from Mr. Jim Aguilia I note that I am supposed to express opinions on the conclusions from the staff reports. I will do this for each report separately.

Staff report 1 - lifecycle fuel carbon intensities

The conclusion stated is "based on staff's assessment of available lifecycle inventory sources, emissions, and efficiency data, ARB staff concludes that the assumptions and inputs used in CA-GREET 2.0 to calculate direct lifecycle fuel Cis are reasonable and the model was applied appropriately under the LCFS."

In my reading of the document I developed a number of notes commenting on presentation, assumptions and scientific basis. These appear below. My final opinion after that reading is that I agree with the staff and believe that the sources used, models used, emissions estimates and procedures within CA-GREET 2.0 provide a sound basis for subsequent use of the estimates that arise from its use and that in general the procedure is based on sound scientific knowledge, methods and practices.

Staff report 3 - calculating carbon intensity values from indirect land use change of crop-based biofuels

The conclusion stated is “based on the iLUC analysis, ARB staff concludes that the assumptions and input parameters used in the GTAP-BIO and AEZ– EF models to estimate indirect land use change for biofuels are reasonable and the models were applied appropriately under the LCFS.”

In my reading of the document I developed a number of notes commenting on presentation, assumptions and scientific basis. These appear below. My final opinion after that reading is that I agree with the staff and believe that the assumptions and input parameters used in GTAP-BIO and AEZ– EF plus the way those models were used provides a sound basis for development of results for subsequent use under the LCFS and that in general the whole procedure from assumptions through use is based on sound scientific knowledge, methods and practices.

Specific Comments

The comments below arise from a page by page reading of the staff reports. In places suggestions are made for document improvement. Also given this is a rapidly developing and advancing field some suggestions are made for future analyses with the model as the California rule and staff analysis moves into the future.

Comments arising during a reading of the document staff report 1: calculating lifecycle carbon intensity values of transportation fuels in California, March 2015

On page 3 of the staff report under section C in figure 1 it shows a picture of the life cycle analysis but in this it does not show emissions associated with the inputs to the feedstock production such as fertilizer and pesticides. GREET includes this and inclusion of such items in the Figure might lead to a more accurate portrayal of what's going on in GREET. PR-39

On page 5 a 1996 survey of sorghum producers is referred to as a source of some of the data although I am unclear to what extent this is relied on as substantially newer EPA study is also referenced. I believe in either case newer data could be obtained from the ongoing USDA ERS ARMS survey and the Sorghum Growers Association. There may be some reason to improve assumptions from survey results that are almost 20 years old. In particular the last 20 years in corn production has seen a big increase in yields with little increase in fertilizer. This may also be true for sorghum. Also sorghum yields have increased and with a long the increase in yields probably comes an increase in costs in terms of seed and harvesting effort. . PR-40

On page 6 A particular treatment process for cellulosic biofuels is covered. Today a few companies are just finalizing construction of or are initially operating commercial scale cellulosic biofuel facilities. It would probably be more accurate going into the future to use what can be obtained about those processes as opposed to a lab process using this particular method. I personally am not aware of exactly what methods are being used in those emerging commercial cellulosic plants but the companies may well have created lifecycle estimates for consideration of their fuels under the advanced biofuel category. PR-41

In general use of the GREET assumptions and methodology is scientifically sound as the ANL GREET group is the world leader in life cycle assessment and widely accepted in the government and profession.

On page 9 where tier 1 fuels are listed that perhaps the list should be expanded. In particular given that earlier in the briefing paper text that there is discussion about sugarcane ethanol I would probably have said starch and sugar-based ethanol including that from corn and sugar as those are the two largest sources currently. Under the biodiesel sources I might have listed soybean oil corn oil, canola, and other plant oils. PR-42

On page 10 when the paper mentions carbon capture and sequestration the terminology might be improved. Normally this is called carbon capture and storage. Also I might put in some wording regarding incorporation of carbon capture and storage into processing facilities. PR-43

In figure 2 under tier two generation I might call it ethanol from cellulosic sources. Restricting it to Stover is a pretty narrow set with dedicated bioenergy crops like switchgrass or miscanthus plus use of wood and other things are possible. At some point soon we may also need to list some sources of jet fuel. PR-44

Eventually I might worry some about the assumptions of spatial homogeneity. In particular, I know that for corn in the US there are regions where yields are close to hundred bushels an acre but that in other regions there are yields in excess of 200 bushels per acre. I also know that the fertilizer, seed, pesticides, and tillage requirements plus likely planting density and hauling requirements to get to a processing facility vary widely across regions. This would then lead me to wonder whether the GREET assumptions are appropriately differentiated on a spatial basis to reflect varying greenhouse gas intensity of various operations in various places. I do not think this is the currently the case. I would worry about this and might require people using the default values to justify that those default values would apply to their region in terms of the major ones in production quantities, fossil fuel, fertilizer use and hauling distances. PR-45

I agree with the conclusion the staff states on page 16 that the GREET uses appropriate methods. I believe it is a representation of the state-of-the-art of scientific knowledge and available data. However I must recognize that this is modeling and there almost always are ways models can be manipulated and slightly improved. In the future I might worry some about the sorghum and potential spatial homogeneity assumptions used. Also given the fact that the cellulosic industry is making its first commercial steps this means that the GREET assumptions will likely need to be updated going into the future. PR-46

Comments on staff report three calculating carbon intensity values from indirect land use change of crop-based biofuels

On page 2 I am not totally happy with the chosen wording. In particular the comment is made that the ARB staff has "identified an indirect effect that has a measurable impact on greenhouse gas emissions: land-use change". It's certainly fair to say that scientists and policymakers identified this well before the ARB so I would include some wording to indicate this is not an item uniquely identified by the ARB but rather is identified based on the scientific and policy dialogue. PR-47

In terms of documents scoping I see in the title the word land-use change. I think this is a rather narrow perspective and believe one should not strictly limit consideration of that indirect stimulated greenhouse gas emissions to only land-use change. In particular I believe consideration should involve both land-use change and other sources of emissions leakage. I feel when demand for biofuels increases that it either directly reduces the amount of crops in a region that enter the marketplace or causes a diversion of land away from conventional crop production to bioenergy feedstocks production. Both of these forces reduce the amount of conventional crops in the market place and raises market prices. In turn this would stimulate producers elsewhere to either bring nonagricultural lands into production (ILUC) or to adopt more intensive forms of agricultural production. Both of these actions increase greenhouse gas emissions outside of the target area. PR-48

Thus I would also not limit the discussion and the model GHG accounting to ILUC carbon emissions but would attempt to cover the fact that the excess or leaking GHG emissions include both those from indirect land use change and those from more intense production practices (heavier fertilizer use, more tillage etc). I believe within the GTAP framework that both of these are considered although I am unsure whether the other effects were included in the GHG accounting that ARB used.

On page 2 I agree with the ARB staff conclusion that the land-use impacts are significant and should be included in the fuel carbon intensities.

On page 2 I agree that the staff selected an appropriate global economic model in the form of GTAP.

On page 2 I again have some wording issues. In particular the report states supply equals demand in GTAP. I do not believe this is uniformly true. In general I believe supply is greater than or equal to demand and that in most sectors supply equals demand but cases like corn stalks have more supply than demand. PR-49

I agree with the staff that it's appropriate to shock the model by increasing biofuel production to a higher level of requirement.

On page 2 I do believe it's appropriate to combine GTAP with a more regionally specific emissions model (AEZ) and emissions assumption as was done in the analysts. I do believe in the future that the staff might consider broadening from just ILUC consideration to one that more broadly considers greenhouse gas emissions from any stimulated intensity expansion as discussed above plus, perhaps diminished livestock production (as has been found in my US studies due to increased feed prices). Just to clarify if we reduce corn in the market and Argentina responds by increasing heavily fertilized corn on lands that previously grew a less emitting crop then emissions go up from that source (an intensification response) along with the possibility of expanding cropped land use onto lands that were not previously used for crops. Simultaneously the increased cost of corn may stimulate less livestock production. PR-50

On page 2 I agree with the staff that it's appropriate to use a scenario approach with different combinations of input values to estimate the net greenhouse gas implications.

I believe it is appropriate across these assumptions that the staff average the results and not consider the results from one single scenario. I would note I might use a weighted average if I I had prior beliefs that some situations are closer to reality than others. In this case I would agree that a simple average is appropriate if there are no priors. PR-51

In the current analysis it appears that the staff has appropriately examined the current major liquid fuel sources including ethanol from conventional crops and biodiesel from conventional sources which are our only agricultural sources as of now. I do believe it will be worthwhile in the future to add ethanol from cellulosic sources, jet fuel may also come into the picture. PR-52

On page 5 I again have raised a wording issue. I do not totally agree with the statement that any demand that is not met locally is transmitted to the global marketplace and met by production of the agricultural commodity in other countries. In particular this could be met elsewhere in California, the rest of the US or globally. Also it is possible that this demand is not ever met when the cost in the other countries is more expensive than the result in market price. I might use wording more like where it could be met by production in other countries.

Elaborating I think some of the published findings with GTAP find the demand is not being completely replaced. I also recall a study by Murray and Wear that is references in the Murray, McCarl and Lee leakage piece where 86% of the reduced public timber harvest in the Pacific Northwest is replaced from sources in Canada, the US south and private lands in the Pacific Northwest. This means 14% of the market place reduction was never replaced. PR-53

On page 5 I believe one could elaborate a little bit upon the domino effect that is referred to here to illustrate a little more of the complex cities of the issue. What seems to happen in Brazil is that corn expanded in the far south displacing soybeans, then soybeans moved further north displacing grass and the livestock that were eating that grass. Then the livestock moved into the rain forest areas and land-use change occurred. The point is there may be more than one domino falling in the total process. PR-54

I also again would not solely limit my attention to indirect land use but talk about indirect land use and emissions changes in other emission categories as this ignores a possible intensification and livestock production reduction response. PR-54 cont

On page 4 I again believe it was appropriate for ARB staff to select the GTAP model. I agree it is mature. I believe the model scope description is appropriate. I believe you could strengthen your wording a little and say GTAP is widely used around the world and profession in various forms. PR-55

One page 4 I believe the statements about the AEZ model are appropriate and that this was an appropriate model to use and that it has a strong scientific basis.

I believe the modifications made to the GTAP and AEZ models were appropriate and needed. I believe this is a quite satisfactory modeling platform for the ARB analysis with a strong science and databases and that it has been appropriately modified to meet the needs of the ARB LCFS program requirements.

I believe doing the scenario runs that an average for each biofuel is appropriate.

I do believe that in the future it would be desirable to analyze a slightly wider variety of liquid fuels then appears within the list from corn ethanol to sorghum ethanol that is appears on page 6. In particular I think the staff might begin to address cellulosic ethanol since were just beginning to see commercial production and from what I hear jet fuel is emerging. PR-56

I do believe that the wording could be improved here in this discussion of scenario runs it would be nice to add another sentence or two on what the nature of those scenarios were i.e. alternative yield responses or the like. PR-57

Finally on page 6 I do agree that ARB staff has reached the right conclusions relative to the assumptions and input parameters in the GTAP and the AEZ models. I also believe those models were sound scientifically and data wise and thus were appropriately used to estimate indirect land use. I am unsure whether the analysis is actually broader than a ILUC analysis incorporating use of other inputs and possible livestock reductions. I believe G tab by its very nature would do that analysis but I'm not sure whether or not the ARB GHG accounting picked that up. PR-58

All things considered I agree that the models were applied appropriately to develop estimates relative to indirect land use change that can be used under the LCFS.

Comments based on attachment one plain English summary of staff's methodologies in calculating fuel carbon intensities

On page number one I'm a little confused by the referencing to the GREET model as in the technical memorandum it is referred to as GREET 2013 but here we see GREET 2014. Which one is being used? Or are these two names for the same thing? PR-59

On page number 2 under the bullet for feedstock production I might talk about feedstock production and production of major fossil fuel bearing inputs to include fertilizer, pesticides fossil fuels consumed etc. PR-60

Between page 2 and page 5 there is redundancy in the discussion of the California version of the GREET model. In particular there are two different discussions of what revisions were done and I would think including a single list of them all in one place would be valuable. Also I noticed that in staff report 1 that the shorter list is used. PR-61

On page 9 of the document there's a statement that I think should be more nuanced. In particular you say the diversion of crops from the food or feed markets to biofuel production creates an additional demand to produce the biofuel feedstock. I don't think that diversion create new demand. Rather it competes with existing demand. I would say it creates or it leaves unfilled demands in the food and fuel markets and therefore creates a demand to replace that food and feed from somewhere else. PR-62

Also in the next sentence rather than limiting discussion to the global marketplace I would say to the marketplace outside the region whether it be other areas in the United States, or the globe. Indirect land use does not only occur internationally it can also occur if California reduces production of some goods in favor of bioenergy and production is increased somewhere else in the US potentially on previously unused lands. While this section refers to indirect land use there is also use the possibility of more intense land-use in other regions for example with increased use of double cropping or less abandoned acres, both of which may well increase emissions from additional inputs. All of these would be present in the GTAP model in some form or fashion although it does not potentially do a very good double cropping. PR-63

In the total LCFS analysis in the future I would not dwell solely upon iLUC emissions as the only indirectly stimulated emissions. Rather I would also attempt to account for indirect stimulated emissions coming from other increases and decreases in emissions elsewhere in the world that may come from intensification and livestock use responses. PR-64

I do not believe that GTAP uses a baseline where supply equals demand in all sectors. I believe it is possible in the GTAP structure to have more supply than demand. For example demand for agricultural land in Brazil may not have total supply = total demand rather there may be other lands it can be drawn into agricultural land if the price is high enough and at current prices there may be more land available than is used. This is also true in terms of say corn Stover where the PR-65 current market price is basically just the cost of collecting it in at the farm level the price is zero as there's a greater available supply than there is a demand. PR-65 cont

In GTAP I believe that there also are increases in emissions from intensification (more irrigation or fertilization) so that the characterization of it only in terms of indirect land use change is not accurate. PR-66

In improving the indirect land use analysis when you're looking at corn ethanol byproducts there are also newer developments in terms of extracting corn oil from the DDGs. PR-67

In recent work Bruce Babcock has been looking at how intensity measures such as double cropping and less acreage abandonment have been stimulated by bioenergy prices and this may be something that analysts may want to look into in the future. PR-68

On page 11 I don't like the wording about the economy moving away from equilibrium. Rather I would say save moving the economy away from the current equilibrium to a new equilibrium. PR-69

On page 11 you indicate that irrigation was added to the model and I think this is a good move. I do think it's very important to have the water constraints on maximum use as for example that is a big factor here in the United States in many regions. I also think it may be important to have a maximum irrigable land constraint so that irrigation cannot move on to marginal lands. Generally such lands are distant from water sources and highly unlikely to ever be irrigated. PR-70

On page 11 you specify your fuel production increase and call this a shock. I think it is possible given the energy and corn prices that we may see fuel production move beyond say the limits imposed by the renewable fuel standard. As a consequence I think you might also need a market structure regarding the demand for bioenergy with it substituting in terms of heat content for petroleum-based gasoline. PR-71

On Page 12 there's a discussion of how yields respond to prices which is a good addition. However there might also be a discussion about how input usage and related emissions respond to yield increases. In particular in work I have done the elasticity of input usage response to yield increases is about 0.5 meaning that if you increase yields by 10% that you have a 5% increase in inputs including pesticides, harvest and probably fossil fuel inputs. Note You wouldn't, given recent US history, have much of an increase in US fertilizer use say for corn, but you might well for other crops. There also is likely to be an increase in double cropping and a reduction in idle acres particularly in international settings as shown in the recent work by Babcock. PR-72

In terms of the expansion on to marginal lands I believe that it would be good to have in the future a more rapid diminishing yield productivity as the marginal lands expand. The lands that I see around where I live that are marginal would clearly have diminishing productivity as you used more and more of them. Also I believe that it may well be necessary to restrict marginal PR-73 land production to only certain crops like energy crops like switchgrass rather than prime agricultural crops like rice, wheat and corn. PR-73 cont

On page 14 I think it’s highly appropriate to have the localized AEZ emission factor data that was developed.

On page 15 I find myself in concurrence that the ARB staff concluded that the assumptions are reasonable and that the models were applied appropriately. Naturally in a modeling exercise it’s also was possible to spend more money and improve some of the assumptions and I’ve entered a few suggestions above. I do believe at this point of the model is appropriate, scientifically sound and well grounded in the data and that this means it is scientifically valid for use.

II. Peer Review

Health and Safety Code Section 57004 sets forth requirements for peer review of identified portions of rulemakings proposed by entities within the California Environmental Protection Agency, including ARB. Specifically, the scientific basis or scientific portion of a proposed rule may be subject to this peer review process. In January 2015, ARB requested an external peer review of staff's methodology in calculating fuel carbon intensities and use of three life cycle greenhouse gas emissions models, including the California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET) Model, Oil Production Greenhouse Gas Emissions Estimator (OPGEE) Model, and Global Trade Analysis Project (GTAP-BIO) Model combined with the Agro Ecological Zone Emissions Factor (AEZ-EF) Model. The peer review was completed in April 2015. The ARB staff would like to thank the reviewers for their time and input. The written reviews submitted by the peer reviewers are posted at the following web page: http://www.arb.ca.gov/fuels/lcfs/peerreview/peerreview.htm

To complete ARB's peer review request, the University of California chose four reviewers from a pool of qualified and interested candidates. The reviewers commented on GREET, iLUC and OPGEE models, and submitted their comments to ARB staff who, in turn, responded to the reviewers' comments in the pages below.

A. Agency Response to Peer Review Comments

1. Comment: **PR-1**

The reviewer recommends that the carbon intensity value for each crude oil include an uncertainty range.

Agency Response: The structure of the LCFS requires that each fuel pathway and each crude oil be assigned a single estimate for CI. Because of this, we use the best available data to estimate CI values and do not present uncertainty ranges associated with these values. However, Adam Brandt at Stanford University has published a few papers on the topics of model uncertainty and comparison of OPGEE model results to other LCA models as described in response to **LCFS 37-5**.

2. Comment: **PR-2**

The reviewer suggests giving consideration to alternative co-product allocation strategies to help in arriving at a consensus on allocation strategies.

Agency Response: For co-products of crude oil recovery, OPGEE provides the user with two alternative emissions accounting systems, co-product displacement, and allocation by energy content. The default method, and method used for the LCFS, is co-product displacement. All emissions are assigned to crude oil, and any co-products that are sold separately from the produced oil (e.g., natural gas, electricity, NGL) are assigned a coproduction credit for emissions avoided from the system that they displace. The approach here can therefore be described as a co-product emissions assessment via system boundary expansion rather than via allocation between products. In all cases, the energy consumption and GHG emissions of the displaced production system are calculated using GREET. For co-products produced as part of crude oil recovery, staff believes that co-product displacement is more appropriate than allocation by energy, mass, economic value, hydrogen content, or any other metric for allocating emissions. ISO guidelines also support the use of co-product displacement over allocation where possible.

3. Comment: **PR-3**

The reviewer states that the OPGEE value for diesel consumption during oil sands mining is an overestimate and requests a justification for the value.

Agency Response: As noted by the reviewer, energy consumption (or export) and fugitive emissions values in OPGEE for oil sands mining are based on data extracted from the GHGenius model. These are default values to be used in the absence of field-specific energy consumption data. If an oil sands producer does not believe that these defaults accurately represent their operations, they can provide field-specific energy consumption data to ARB for use in modeling the crude. As to the specific comment about diesel usage for mining operations, the OPGEE default intensity for integrated mines and upgraders is 0.074 MMBTU/bbl. At a heating value of ~5.5 MMBTU/bbl, this amounts to 0.013 MMBTU/MMBTU or 0.013 GJ/GJ. We can compare to a recent report updating the GREET model treatment of oil sands for Argonne National Laboratory (Englander and Brandt 2014)[60]. In this report which uses monthly data for all oil sands operations reported to the Alberta Energy Regulator, diesel use (mean) was 0.02 GJ per GJ of SCO delivered,

[60] Englander and Brandt (2014). Oil Sands Energy Intensity Analysis for GREET Model Update. Argonne National Laboratory, May 4th, 2014.

with a p10-p90 range of 0.01 to 0.03 GJ/GJ (Englander and Brandt, 2014, Table 9, p. 29). If anything, OPGEE diesel use may be low.

In mid-2014, ARB issued a contact to Adam Brandt of Stanford University together with Joule Bergerson at the University of Calgary and Heather MacLean at the University of Toronto. The project scope includes revisions to the treatment of oil sands mining and bitumen upgrading. Treatment of oil sands mining in the new model will be based on the GHOST model developed at the University of Calgary. Newly available data, such as for diesel fuel consumption suggested by the reviewer, will be considered in developing the revised model treatment of oil sands mining.

4. Comment: **PR-4**

The reviewer requests further justification for the assumptions in the OPGEE model regarding electricity production and export from the oil sands.

Agency Response: As noted by the reviewer, electricity import (or export) values in OPGEE for oil sands mining are based on data extracted from the GHGenius model. However, we do not assume the oil sands operators only generate power at grid average GHG intensities. The reported values in GHGenius are net imports or exports, after any on-site generation is consumed. Emissions from onsite electricity generation are accounted for through the import and combustion of natural gas. Moreover, the net electricity import or export values in OPGEE are default values to be used in the absence of field-specific energy consumption (or export) data. If an oil sands producer does not believe that these defaults accurately represent their operations, they can provide field-specific energy consumption data to ARB for use in modeling the crude.

For electricity import, OPGEE assumes a default grid electricity mix. If an oil sands producer can demonstrate that all electricity is produced onsite, then the modeling can be customized using the field-specific information.

For electricity export, the default allocation method is substitution for natural gas based electricity. While OPGEE allows for displacement of grid electricity, staff has decided to use displacement of natural gas based electricity in all cases, irrespective of production location. This method prevents achieving unreasonably large credits for operations with significant power export.

5. Comment: **PR-5**

The reviewer claims that the OPGEE treatment of cogeneration of steam and electricity is limited for the in situ extraction method of steam assisted gravity drainage (SAGD).

Agency Response: In OPGEE the modeling of fields that use steam injection can be done using either the steam injection worksheet of the standard model or using the bitumen extraction and upgrading worksheet. As noted by the reviewer, the bitumen extraction and upgrading worksheet is based on GHGenius and has limited functionality with regard to cogeneration of steam and electricity. However, for the LCFS crude oil CI calculations, ARB staff has chosen to model all thermally enhanced oil recovery (i.e. steam flooding, cyclic steam stimulation, and steam assisted gravity drainage) using the steam injection worksheet of the standard model. Using this approach, cogeneration can be varied from zero to 100 percent of the steam supply for crude production, with the remaining fraction produced using once-through-steam-generators. While the default is set to zero percent cogeneration, we welcome data from operators on the fraction of steam produced using cogeneration and will customize the modeling if appropriate data are provided.

6. Comment: **PR-6**

The reviewer recommends considering the stockpiling of coke in the assessment of emissions from upgrading of bitumen. The reviewer also comments on the limited details presented on the consumption of hydrogen for upgrading bitumen.

Agency Response: As per GHGenius model inputs, we assume only part of the coke is combusted. In OPGEE "Bitumen Extraction" sheet cell D227, the default value for consumption of coke for integrated mining operations is 0.205 MMBTU per bbl. At a heating value of ~5.5 MMBTU/bbl, this represents a fractional energy consumption of 0.037 MMBTU coke per MMBTU SCO produced or 0.037 GJ/GJ. The Argonne Laboratory Report cited above (Englander and Brandt 2014, Table 9, p. 29) gives the mean coke consumption for integrated operations of 0.03 GJ/GJ, with a P10-P90 range of 0.02 to 0.05 GJ/GJ. OPGEE coke consumption is therefore directly in line with reported AER coke consumption rates.

As to the production and consumption of hydrogen, future expansion of the model will treat hydrogen in more detail. As of now, hydrogen generation is treated as in the GHGenius model, which includes NG consumed as reported to regulators.

7. Comment: **PR-7**

The reviewer comments that fugitive emissions are important, that there has been very limited effort to estimate fugitive emissions, that fugitive emissions for different crudes could vary significantly, and that real life measurement of fugitive emissions would prove very helpful

Agency Response: Because on-site fugitive emissions data are generally not available for crudes produced worldwide we have based OPGEE default estimates for fugitive emission sources on published emission factors for crude production operations in the United States and California. Staff is very interested in obtaining additional data on fugitive emissions estimates for evaluation and incorporation into the model. Again, oil producers are encouraged to provide data supporting field-specific values for these emission factors.

8. Comment: **PR-8**

The reviewer comments that GHG emissions for biomass-based electricity can vary greatly depending on source of biomass.

Agency Response: We agree with the reviewer that the lifecycle emissions of biomass used for electricity can vary substantially depending on source of biomass and inputs for biomass growth, harvesting, collection, transport, and conversion. However, the default grid electricity mix used in OPGEE, and assumed for all crude modeling under the LCFS, assumes only 0.3 percent electricity from biomass, and therefore these differences in lifecycle emissions will have little effect on the carbon intensity of crude production.

9. Comment: **PR-9**

The reviewer states that the GHG emissions for electricity are highly dependent on the source of electricity and can change substantially over time, thereby affecting the carbon intensity of crude oil production in a given jurisdiction.

Agency Response: While we agree with much of the reviewer’s comment, OPGEE does not provide an automatic lookup table with differentiated grid electricity mixes for all oil producing regions worldwide. Therefore, ARB staff has chosen to use the OPGEE default grid electricity mix for all crudes, irrespective of production location.

10. Comment: **PR-10**

The reviewer comments that in addition to GHG emissions from crude production, ARB should estimate lifecycle water impacts of various crude oils.

Agency Response: While we agree that lifecycle water footprint may be an important issue for some oil producing regions, the LCFS is based on comparison of GHG emissions and therefore differences in water footprint are not germane to the regulation.

11. Comment: **PR-11**

The reviewer recommends that ARB document efforts to ensure that there is no double counting of emissions burdens between CA-GREET and OPGEE.

Agency Response: Staff acknowledges the need to be clear when discussing how the three models interact. Appendix C of the ISOR is explicit in the way that OPGEE interacts with CA-GREET 2.0. On page C-3, under, "Summary of Major Changes to GREET1 2013 to Produce CA-GREET 2.0", staff states:

"Staff modified GREET1 2013 to use the Oil Production Greenhouse Gas Emissions Estimator Version 1.1 Draft D (OPGEE) as the data source for estimating the carbon intensity (CI) of the crude oil used in California refineries. OPGEE estimates crude production and transport carbon intensities (CIs) based on oil field location and crude extraction technology. The use of OPGEE resulted in revisions to the refining efficiencies used for CARBOB and ultra-low sulfur diesel produced in California. For these two California fuels, we are currently modeling the process fuels mix and refining efficiencies using PADD 5 specific values (CARBOB: Table 31, pg. 60, CA ULSD: Table 35 pg. 65). It is necessary for staff to determine the CI of CARBOB and ultra-low sulfur diesel as accurately as possible, rather than using the US average, because these fuels are LCFS baseline fuels. We are not modifying gasoline or diesel processing for the rest of the US. Staff added crude oil recovery processing and emissions in CA-GREET 2.0 to closely approximate the carbon intensity determined by OPGEE (Table 27 page 56). The CA crude CI modeled in CA-GREET 2.0 matches the carbon intensity determined by OPGEE and approximates the fuel mix and efficiency determined for CA crude recovery by OPGEE."

Staff further refers to Table 27 on page 56 to detail how OPGEE is used for the upstream (non-refining stage) to determine the CI of the crude oil entering California refineries. In Table 27, staff states that the crude refining process has an input (crude oil CI from OPGEE) into the modeling of refining (done in CA-GREET 2.0). Staff further states, "Staff also added a CA Crude Recovery column that closely approximates the inputs to OPGEE and produces a petroleum crude CI equal to OPGEE. This allows the upstream emissions that are calculated during the refining process modeled in CA-GREET 2.0 for CARBOB and ULSD to be more accurate. See Petroleum Tab column beginning at cell D61." Staff further references the CARBOB and California ULSD refinery modeling as receiving the crude CI input from OPGEE rather than the crude CI that would be calculated by GREET1 2013 (the primary model basis for CA-GREET 2.0). Reviewing the model shows that the crude recovery and transportation is not double counted between OPGEE and CA-GREET 2.0. Appendix C is the basis for the, "CA-GREET 2.0 Supplemental Document[61]", which is incorporated by reference in the 15-day change package for the LCFS re-adoption and contains this information.

12. Comment: **PR-12**

The comment questions pilot data that could be used for modeling pathways and asks about corn stover being the only Tier 2 pathway modeled in recent years.

Agency Response: The commenter mentions that CA-GREET has been recently updated to include cellulosic feedstocks and sorghum. If more detailed information is needed regarding grain sorghum to ethanol LCA in CA_GREET 2.0, please refer to Appendix C of the ISOR or the latest update to the CA-GREET 2.0 Supplemental Document.[61]

There is data available for the corn stover to ethanol pathway provided in Appendix C of the ISOR. To more precisely address the commenter's question, the corn stover to ethanol pathway is a Tier 2 pathway. The regulation calls for Tier 2 pathways to be scrutinized from well (field) to wheels because staff is not as familiar with these

[61] The latest updates to the CA-GREET 2.0 Supplemental Document is available at the following site: http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm

pathways. Applicants will supply all of the relevant information to use in conjunction with CA-GREET 2.0, Tier 2. Tier 2 pathways reduce the necessity of relying on general information from the scientific literature or other sources in advance of staff receiving a corn stover to ethanol pathway application or other Tier 2 pathway application. The Tier 2 application process and calculation of carbon intensity is as specific as scientifically possible to the applicant applying.

13. Comment: **PR-13**

The comment inquires about the differences between emissions results from MOVES, MOBILE6.2, and the CARB EMFAC model, and what factors prompted the switch to MOVES emission factors.

Agency Response: ARB staff adopted the heavy and medium duty transportation vehicle emission factors (EF) from GREET1_2014 to account for transport of feedstocks and fuel in pathway modeling. Those EFs were generated by Argonne National Laboratory (ANL) using the Motor Vehicle Emission Simulator (MOVES) (EPA, 2013) model. ANL provides rationale for its choice to update EFs in its paper, *Updated Emission Factors of Air Pollutants from Vehicle Operations in GREET™ Using MOVES* (Cai, Hao et al., 2013), stating:

> "*MOVES2010b replaces MOBILE6.2, the previous model for estimating on-road mobile-source emissions, as EPA's best available tool for quantifying criteria pollutant and precursor emissions from light- and heavy-duty vehicles*"

According to EPA (2013), the advances featured in the MOVES model, relative to its predecessor, MOBILE, include:

- Improved vehicle classification system: by mode of operation rather than by weight rating;
- Updated and improved particulate matter emission data; and
- Incorporation of additional emission measurement data from heavy-duty diesel crankcase ventilation and from extended idling.

Cai, Hao et al., 2013. Updated Emission Factors of Air Pollutants from Vehicle Operations in GREET™ Using MOVES. Energy Assessment Section, Energy Systems Division, Argonne National Laboratory. September 2013. https://greet.es.anl.gov/publication-vehicles-13

EPA, 2013. Motor Vehicle Emission Simulator (MOVES). http://www.epa.gov/otaq/models/moves.

14. Comment: **PR-14**

The commenter asks how uncertainty is propagated through the series of models, states they understand how uncertainty is handled in CA-GREET and GTAP, and questions if there is a reliable uncertainty range in the final carbon intensity.

Agency Response: The aggregate carbon intensity uncertainty based upon the three models - OPGEE, CA-GREET 2.0, and GTAP is not characterized in the scientific literature to-date. Each of these models incorporates various data types, each with their own levels of uncertainty. The uncertainty of every datum in each model is currently unknown. It is theoretically possible to determine an aggregate uncertainty or at least take the initial necessary steps if the scientific community selected specific pathways, identified the most uncertain and certain data, and determined whether there is a reliable or appropriate estimate of uncertainty in a datum or data set. At this time ARB is not aware of any researcher or group that has done this work. In any event, ARB is confident that the relative CI values between fuels are sufficiently accurate to provide an appropriate market signal to accomplish the goals of the LCFS.

15. Comment: **PR-15**

The commenter states that language around the [in the material provided for peer-review] indirect accounting as they relate to Tier 1 and Tier 2 fuels is a bit unclear. The commenter correctly points out or rather questions the difference between a Tier 1 or 2 facility and a Tier 1 or 2 pathway. The commenter goes on to provide an example of a Tier 1 facility producing a Tier 2 fuel, corn ethanol, corn stover ethanol, and co-products.

Agency Response: Please see the staff response to **LCFS FF44-13**. The facility/pathway terminology is also used in the regulation, in addition to the review material provided for peer review.

16. Comment: **PR-16**

The comment states that page 15 (referring to Table 2. Carbon Intensity Lookup Table for Diesel and Fuels that Substitute for Diesel) does not make clear the difference between pathways CNG020 and CNG021.

Agency Response: The two pathways for wastewater treatment sludge to CNG via anaerobic digestion are distinguished in the Staff Report by whether or not excess electricity is produced and exported to the grid. From Table 2, page 15 of the Staff Report (emphasis added):

- "**CNG020** Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling; **export to the grid of surplus cogenerated electricity**. (CI = 7.80 gCO2e/MJ)

- **CNG021** Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling. (CI = 30.98 gCO2e/MJ)."

In addition to this distinction, the Pathway Report specific to these pathways defines the size or capacity of the wastewater treatment facility for each fuel pathway code. CNG020 refers to a "Medium-to-Large" publicly owned treatment works (POTW), which is applicable to a range of wastewater inflow capacities of 21 to 100 million gallons per day (MGD), while CNG021 is relevant for a "Small-to-Medium" POTW with wastewater inflows of 5 to 20 MGD. Other differences in operating conditions and assumptions about energy sources and demand corresponding to the two capacity ranges are also described in this document.

17. Comment: **PR-17**

The commenter questions if GREET is able to provide estimates at the same resolution as the Agro-ecological Zone EmissionFactor (AEZ-EF) Model from different regions of US and the world. The commenter questions if the model accounts for the differences between rain-fed and irrigated crops. The commenter further asks how natural land use impacts the emissions. The commenter suggests to staff that they should consider the resolution of the data across these modeling platforms to ensure that they are comparable.

Agency Response: CA-GREET 2.0 uses inputs for specific parameters, which may in some cases, be able to provide resolution in a specific region. For example, corn grain fertilizer application is modeled as being a national average value based upon data from the USDA through Argonne National Laboratory's technical papers and specifically from the GREET1 2014 model release in this case. It may be possible to model corn grain fertilizer application in a different region or another part of the world within GREET if emission factors and parameters are adjusted appropriately. Sugarcane for ethanol production is modeled in GREET as if sugarcane is produced in Brazil, which would have to be modified to model a different type of cane grown in a more Mediterranean-type climate.

In the case of nitrous oxide emissions from above and below ground biomass, staff applied the IPCC Tier 1 default emissions, which are not specific to soil type, precipitation, topography, temperature, and other factors in a region where a particular biofuel feedstock is grown, but instead is a widely-accepted default "average" emission factor.

18. Comment: **PR-18**

The comment requests that staff consider the resolution of the data across modeling platforms to ensure they are comparable.

Agency Response: Please see response to **PR-17**.

19. Comment: **PR-19**

The reviewer asks about the extent to which crude carbon intensity values vary from year to year.

Agency Response: Carbon intensity values for various crude sources do vary from year to year as production parameters such as steam-oil-ratio, water-oil-ratio, and flaring rate change over time. These changes can be observed by comparing CI values for crudes used to calculate the 2010 baseline (i.e. Table 10 of the proposed regulation) to CI values for the same crudes in the crude lookup table (i.e. Table 8 of the proposed regulation). The CI values for 2010 baseline crudes are based on 2010 crude production data, while CI values for the proposed crude lookup table are based on 2012 crude production data. Future changes in crude CI will be captured by updating the crude lookup table on a three-year cycle.

20. Comment: **PR-20**

This comment inquires if the GTAP model accounts for year-to-year variability in yields and yield improvements resulting from technology improvements.

Agency Response: ARB thanks the peer reviewer for this comment. Since GTAP is a static model, the values used in the analysis cannot capture year-to-year variability from occurrences such as droughts in the Midwest U. S. Technology related yield improvements are implicitly included within the framework of the GTAP model.

21. Comment: **PR-21**

The reviewer asks how carbon dioxide enhanced oil recovery is handled in OPGEE and if CO_2 enhanced oil recovery would qualify as an innovative crude production method.

Agency Response: OPGEEv1.1 does not have the capability to explicitly model CO_2 enhanced oil recovery. During initial model development, this was not considered a priority as very little crude produced using this recovery method is supplied to California. In mid-2014, ARB issued a contact to Adam Brandt of Stanford University. The project scope includes new pathways for carbon capture with CO_2 enhanced oil recovery. These pathways will include both anthropogenic and natural sources of CO_2. The project is expected to be completed in 2016, at which time the draft model will be posted for public review and one or more workshops will be held to discuss the model changes. We intend to propose the new model, OPGEEv2.0, and new crude carbon intensity values for adoption in 2018.

Crude oil produced using carbon capture and sequestration may qualify under the innovative crude provision, provided that the capture of carbon occurs onsite at the crude oil production facility. Moreover, CCS projects must use a Board-approved quantification methodology including monitoring, reporting, verification, and permanence requirements associated with the carbon storage method being proposed for the innovative method. This quantification method is being developed and is expected to be available by 2017. See also the response to **LCFS 37-12.**

22. Comment: **PR-22**

The reviewer recommends that if ARB is considering credit for CO_2 enhanced oil recovery, then the source of carbon dioxide must be determined.

Agency Response: We agree with this comment. Under the LCFS innovative crude provision, credit will only be allowed if the carbon is captured onsite at the oil production facility. See also the response to **PR-21**.

23. Comment: **PR-23**

The reviewer asks how self-reported emissions under the EPA Greenhouse Gas Reporting Program compare to the emission factors used in OPGEE.

Agency Response: OPGEE uses EPA emission factors for several venting and fugitive emissions calculations. However, staff has not performed a detailed comparison of emissions data reported to EPA with emission factors used in OPGEE. Staff encourages individual crude producers to provide field-specific data if they believe that the emission factors or calculations performed in OPGEE do not accurately represent their operations.

24. Comment: **PR-24**

The reviewer asks how significant crude price swings affect the composition of crudes supplied to California refineries and how this may be reflected in the carbon intensity of the crude slate.

Agency Response: While it is true that the CI values for CARBOB and diesel and the LCFS compliance targets are set to a 2010 baseline, the LCFS does include a provision to track and account for changes in crude slate and any increases in average crude carbon intensity over time. Each year California refineries must report crude names and volumes for all crude supplied to each of their refineries. ARB staff then uses this reported data to calculate the Three-year Crude Average Carbon Intensity value (i.e. a rolling average crude CI using the most recent three years of crude supply). If the Three-year Crude Average CI is greater than the 2010 Baseline Crude Average CI, then the refineries are assessed an incremental deficit proportional to the increase in average crude CI.

25. Comment: **PR-25**

The peer reviewer wants clarification on details related to calculating the average iLUC value from the scenario runs (i.e., equal weighting).

Agency Response: Since there is no available information to support greater likelihood of some of the scenarios, ARB staff did not use a weighted approach instead used a simple averaging approach for the results of the 30 scenario runs. See also responses **LCFS 8-9**, **LCFS 46-79**, **LCFS 46-86**, and **LCFS 46-98**.

26. Comment: **PR-26**

Peer reviewer inquires if ARB is committed to updating the database from the 2004 baseline year and if making the change would impact the iLUC values.

Agency Response: The current analysis uses a 2004 GTAP baseline because this is the latest year for which detailed data was available for all sectors and industries used in ARB's version of the model. Purdue is currently in the process of updating the baseline to a 2010 timeframe. When the update is completed, ARB will consider updating the iLUC analysis. Refining the baseline of the model may change the iLUC estimate.

27. Comment**: PR-27**

The peer reviewer conveys his observation that groups within the community question the appropriate value for iLUC and some even question the validity of iLUC applied to biofuels. The reviewer also opines that since the LCFS is technology-neutral, selecting a value that is potentially at the upper end of likely values could create de facto caps which could suppress development of new fuels.

Agency Response: The iLUC value of 30.0 g/MJ for corn ethanol is not relevant to the current analysis. The LCFS program uses the totality of GHG emissions for every transportation fuel used to comply with the program. All fuels are scored on their lifecycle GHG emissions (direct and indirect emissions) and the program is designed to be technology and fuel neutral. The necessity to account for indirect Land Use Change (iLUC) effect has been and has been detailed in response to **LCFS 8-1**. ARB would therefore be remiss if it did not account for indirect land use change effects in the carbon intensities of crop-based biofuels.

The current iLUC value proposed by ARB for corn ethanol is 19.8 g/MJ. This value does not include only the high-end of likely values for iLUC emissions but reflects the average of 30 scenario runs. The 30 scenario runs were completed by utilizing a range of discrete values for each of the most important parameters identified from the Monte Carlo screening analysis. Furthermore, the Monte Carlo analysis uses outputs from hundreds of simulations and is able to isolate parameters in the GTAP model that have the largest impact on model outputs. The mean value estimated from the hundreds of

Monte Carlo simulations was used to corroborate the average value calculated from the scenario runs. The mean estimated from the uncertainty analysis is similar to the average calculated from the scenario runs for all of the 6 biofuels.

28. Comment**: PR-28**

The commenter states some suggestions to staff external to their scientific review. **PR-28** specifically states, "Make it clear that LCFS defines CI units of gCO_2e/MJ (p. 2 of CA-GREET Report)".

Agency Response: A more complete definition of CI is in the ISOR, page III-2, Section B. Definitions and Acronyms. This definition more clearly expresses that the energy units are in gCO_2e/MJ by stating, "Carbon intensity" means the amount of life cycle greenhouse gas emissions, *per unit of energy of fuel delivered*, expressed in grams of carbon dioxide equivalent per megajoule [mega Joule] (gCO_2e/MJ)." In this last definition presented, both the numerator (underlined above) and denominator (*italicized* and underlined above) are better defined than earlier definitions. The mega Joules of energy is the amount of energy (fuel energy) associated with the lifecycle gCO_2e from well (field, etc.) to wheels (WTW). WTW includes all GHG emissions (gCO_2e) involved with, but not necessarily limited to, the production of feedstock, transport of feedstock, production of fuel, delivery of fuel, combustion of the fuel, any indirect emissions (e.g., ILUC), and any co-product credits.

The main point of clarity in response to the comment is that the energy in MJ is the total amount of fuel, as energy, associated with the total lifecycle emissions in gCO_2e. Using an illustrative example, if an entity produced 8 MJ of fuel with the WTW emissions of 2 gCO_2e, the CI of the fuel would have a CI of 0.25 gCO_2e/MJ. In reference to the earlier definitions (in question) of the units of CI (gCO_2e/MJ), the 0.25 gCO_2e/MJ CI shown here as an example can now be used to determine the total emissions under the same conditions that would result if 50 MJ of fuel were produced, rather than 8 MJ. The resulting emissions would be (50 MJ)*(0.25 gCO_2e/MJ) = 12.5 gCO_2e, but the CI of the fuel remains 0.25 gCO_2e/MJ.

29. Comment**: PR-29**

The commenter states some suggestions to staff external to their scientific review. PR-29 states, "Figure 1 is not 'generalized' – one of the arrows refers to biofuel use".

Agency Response: Staff appreciates the recommendation to make the figure more general regarding the type of fuel used in a vehicle. Staff will consider providing more generally labeled components, of general LCA diagrams, in the future.

30. Comment**: PR-30**

The comment questions the reference used for VOCs, how to calculate this value, and states that staff could explain and write this more clearly.

Agency Response: The modeling of VOCs and CO emissions in CA-GREET 2.0 are based upon the assumption that these molecules are relatively short-lived as VOCs and CO and that these species are relatively-rapidly fully oxidized to CO_2.

The ISOR states that, "CA GREET 2.0 assumes that VOC and CO are converted to CO_2 in the atmosphere. It therefore, includes these pollutants in the total CO_2e value using ratios of the appropriate molecular weights. The ratio of the molecular weight of carbon to the molecular weight of CO_2 is 12/44 = 0.273. The CO_2e values of VOCs and CO are, therefore, 0.85/0.273 = 3.12, and 0.43/0.273 = 1.57, respectively." These values were imported from the GREET model from Argonne National Laboratory (ANL) that was used as the basis for CA-GREET 1.8b. The ANL GREET models (GREET1 2013 and GREET1 2014) contain these ratios and the resulting multiplier for global warming potentials (GWP) for CO and VOCs. Staff has used these ratios for CO and VOCs since the LCFS was adopted in 2009 and ANL GREET has as well.

31. Comment**: PR-31**

The commenter states some suggestions to staff external to their scientific review. PR-31 states, "There was no text description of Tier 2 Method 1 in the Summary Report".

Agency Response: The Tier 2 lookup tables (Table 1 and Table 2 in the staff report) are mentioned, which are also Method 1 pathways as discussed in the ISOR and regulation (Appendix A of the ISOR), which were provided for the peer reviewers.

32. Comment: **PR-32**

The commenter would have preferred staff including a summary of how the three models (a box model diagram) integrate into the CI determination of fuels in the LCFS program.

Agency Response: The iLUC analysis includes a graphical representation of the integration of the GTAP and AEZ-EF models in Appendix I of the ISOR. For OPGEE, a graphical representation of the model is provided in Appendix H of the ISOR. There is no graphical representation of the CA-GREET model. ARB acknowledges a graphical representation of the interaction of the three sets of models in estimating the total carbon intensity of a transportation fuel could be helpful.

Regarding GREET, ARB staff agrees with the commenter that a succinct summary (box model diagram) of the three carbon intensity model components, as well as a short summary of the more specific quantitative aspects of the LCFS (10 percent goal by 2020), could be useful. Staff appreciates the time the reviewer took to locate the goals of the LCFS in the ISOR. Staff hopes that Attachment 4 (listed below), which was provided to the peer reviewer, supplied the necessary information even though it was not succinct.

Air Resources Board (ARB) staff prepared three reports entitled:

Attachment 4

- Staff Report: Calculating Life Cycle Carbon Intensity of Transportation Fuels in California
- Staff Report: Calculating Carbon Intensity Values of Crude Oil Supplied to California Refineries
- Staff Report: Calculating Carbon Intensity Values from Indirect Land Use Change of Crop-Based Biofuels

Peer review material is available here for reference and public access: http://www.arb.ca.gov/fuels/lcfs/peerreview/peerreview.htm

33. Comment: **PR-33**

The comment expresses concern about the use of potentially-outdated EPA AP-32 emission factors and the lack of sufficient information provided to determine which values in the model originate from this source.

Agency Response: The purpose of the chapter (II. ASSUMPTIONS AND INPUTS) was not to provide a thorough documentation of values in the model, but rather to impart that the many necessary emission factors in GREET are adopted from widely-accepted, authoritative, standard sources for GHG emission-related factors such as U.S. EPA models (MOVEs, eGRID), International Panel on Climate Change, United Nations Food and Agriculture Organization, etc. The references to U.S. EPA AP-42 emissions factors were found by ARB staff within comments in the GREET model spreadsheet, specifically for small industrial biomass (willow and poplar) boilers.

Users and stakeholders may refer to the 2015 Initial Statement of Reasons (ISOR) Appendix C which thoroughly documents changes made to GREET1_2013 to create the CA-GREET2.0 model and provides many additional references for particular values and calculations used in CA-GREET. For references of values which were “inherited” by CA-GREET, or are not addressed in Appendix C, users must refer to Argonne’s series of publications regarding GREET model updates.

34. Comment: **PR-34**

The comment expresses concern about the use of MOVES2010 although a more recent update, MOVES2014 is available.

Agency Response: Unfortunately, the availability of MOVES2014, the LCFS re-adoption regulatory schedule and limitations on ARB staff resources did not allow a thorough comparison of MOVES2010b and MOVES2014 for all forms of transit. Staff did, however, compare diesel heavy-duty truck emission factors from the two models and found that, while there are significant reductions in all criteria pollutant emissions in MOVES2014, the CO_2 from combustion dominates the emission factor (EF), and the resulting impact in CO_2-equivalent is insignificant. For Class 8 (heavy-heavy duty) trucks, the MOVES2014 EF is 0.5 percent lower (on a gram CO2e per mile basis) than MOVES2010. The EF for Class 6 (medium-heavy duty) trucks was 0.05 percent lower in the newer MOVES version. For a typical transport distance of 100 miles (expected distances vary from 40 to 140 miles) by heavy-duty truck, the impact of using MOVES2010 data is less than 0.002 gCO_2/MJ.

Staff intends to institute a regular review and update cycle for all models used in support of the LCFS; at that time, emission factors from the latest version of MOVES may be utilized.

35. Comment: **PR-35**

The comment advises staff to explicitly note in the Staff Report which GWP factors were used and to supply the rationale for that choice.

Agency Response: ARB staff concurs with and regrets the oversight. The use of Global Warming Potentials from IPCC's AR4, on a 100-year time horizon in CA-GREET2.0 is noted in the Staff Report (page 8) and ISOR (page 106). These values were chosen for consistency with other ARB programs such as the state GHG Inventory.

36. Comment: **PR-36**

The commenter has questions about the CI lookup tables presented in the staff report.

Agency Response: The commenter is correct in their analysis of the purpose of Table 1 and Table 2 in the staff report and in the ISOR. These pathways are available to Tier 2 applicants if they have a fuel (gasoline or diesel) or a fuel substitute that they desire to sell in California that meets the conditions of these fuels in the referenced lookup tables. If a Tier 2 fuel can improve on the CI (reduction in CI) of a fuel in this table by a certain amount (specified in the regulation), then an applicant can apply for a Tier 2 Method 2A pathway using one of the lookup table pathways as a reference/basis pathway. If a lookup table pathway CI does not sufficiently apply to a Tier 2 applicant's fuel, as specified in the regulation; the Tier 2 Applicant must apply under Method 2B for which there is no reference pathway indicated by the lookup table CIs.

37. Comment: **PR-37**

The commenter has questions about the substantiality requirement under Tier 2 for Method 2A applications.

Agency Response: The substantiality requirement between the Tier 2 lookup table (also known as Method 1 reference pathways) and the Tier 2, Method 2A pathway is based upon a percent difference reduction in carbon intensity from the Method 1 lookup table. The ISOR states, "Proposed Method 2A pathways with CIs greater than 20 gCO_2e/MJ must have CIs that are 5.5 percent lower than the CIs of their reference pathways. Proposed pathways with CIs of 20 gCO_2e/MJ or less must have CIs that are at least one gCO_2e/MJ

lower than the CIs of their reference pathways." The purpose of these substantiality requirements is to incentivize reductions in CIs from the lookup table that are substantial and therefore warrant staff time to process Tier 2 applications. In the future, staff may develop Method 1 pathways that would be added to the lookup table (reference pathways) to allow applicants in Tier 2 to use the expedited Tier 2, Method 1 lookup table pathway process.

38. Comment: **PR-38**

The reviewer recommends reporting lookup table CI values to fewer than the currently reported four significant digits.

Agency Response: We realize that, because of the uncertainty in calculations, carbon intensities with fewer significant digits would have advantages. However, in the compliance schedule the incremental carbon intensity reductions of gasoline and diesel fuels are so small, especially in the initial years of the LCFS, that two digits past the decimal point were determined to be necessary to quantify the reductions. As the required CI reduction in the compliance schedule increases over time, we will evaluate the reviewer's suggestion to use fewer significant digits in reporting CI values for both crude oil and finished fuels.

39. Comment: **PR-39**

The commenter suggested that depicting the inputs to feedstock production such as agricultural fertilizers and pesticides lead to a more accurate assessment of how GREET works.

Agency Response: The commenter is correct; agricultural GHG emissions impacts from production of fertilizers and chemicals must be determined to evaluate the overall carbon intensity (CI) of the transportation fuel. While not explicitly depicted in the Figure 1 schematic of the Staff Report, those lifecycle GHG emissions impacts are normally calculated for each well-to-tank CI determination if such agricultural inputs are known to be utilized in the pathway.

40. Comment: **PR-40**

The commenter questions the agricultural data used for sorghum and corn in CA-GREET 2.0.

Agency Response: CA-GREET 2.0 uses corn farming data derived from GREET1 2014 that relies on a variety of data from the USDA and other sources, which were reviewed through Argonne National Lab (ANL) publications and technical reports and used in GREET1 2014.

The grain sorghum agricultural data was updated as referenced in Appendix C of the ISOR based upon collaboration between ARB, ANL and the National Sorghum Producers. Appendix C of the ISOR references the ANL technical memorandum, which is the basis of changes from GREET1 2013 to CA-GREET 2.0 for the grain sorghum to ethanol pathway. Staff notes that the structure of CA-GREET 2.0 is based upon GREET1 2013 even though some data for many pathways were updated from GREET1 2014 (e.g. agricultural inputs for corn production). For further clarification, please see Appendix C of the ISOR or the CA-GREET 2.0 Supplemental Document[62] that is incorporated by reference for the 15-day change package submitted for public comment on June 4, 2015[63].

41. Comment: **PR-41**

The commenter pointed out that the production of cellulosic biofuels is a nascent industry and it would be more accurate to model the lifecycle analysis of fuels using actual process data instead of laboratory scale or pilot plant data.

Agency Response: ARB staff worked closely with two cellulosic ethanol producers and their consultants to develop the LCFS fuel pathways[64] for ethanol derived from cellulosic residues which include sugarcane straw, wheat straw, and corn stover.
The pathways were developed from actual construction details, engineering drawings, process flow diagrams, and material and energy balances of as-built conditions, not laboratory-scale data. Both facilities have long since commenced commercial operation. It is customary for any new process, start-up, or commercial operation at a facility to ramp up production, and eventually reach

[62] CA-GREET 2.0 Model and Documentation: http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm
[63] LCFS, HEARING ACTION AND SUPPLEMENTAL 15-DAY NOTICES http://www.arb.ca.gov/regact/2015/lcfs2015/lcfs2015.htm,
[64] See Abengoa Bioenergy Biomass of Kansas (Hugoton Cellulosic Ethanol Plant) LCFS pathways at http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/abbk-etoh-012915.pdf, and GranBio BioFlex Plant LCFS pathway at http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/gb-102414.pdf.

steady-state. Staff expects that if actual operations are significantly different from design conditions, or deviate on fuel process yields, for example, then the pathway CI would be amended by the applicant.

Staff further believes that enzyme and energy use at cellulosic biofuel production facilities might be verified as ARB develops its monitoring and verification program for the LCFS. Secondly, the proposed LCFS regulation accomplishes what the commenter recommends; what are called "Prospective" pathways is very limited under the new provisions. The plant has to be operating for at least a calendar quarter before a pathway application can be submitted. This means that ARB will be relying much more on operational data going forward.

42. Comment: **PR-42**

The commenter has suggestions for the list of Tier 1 fuels in the staff report.

Agency Response: ARB staff appreciates the commenter's suggestion that the list of Tier 1 fuels in the staff report include, "…starch and sugar-based ethanol including that from corn and sugar as those are the two largest sources currently. Under the biodiesel sources I might have listed soybean oil, corn oil, canola, and other plant oils." Staff reviewed page 9 of the staff report that the commenter references for making these suggestions. Staff found that starch and sugar-based ethanol is included on that page in the staff report, but it does not explicitly say corn and sugarcane ethanol. Staff also found under this same list of, "Tier 1 fuels include, but are not limited to:" for biodiesel and renewable diesel, "(…including but not limited to plant oils, tallow and related animal wastes, and used cooking oil)…" Staff believes that the information provided in the staff report is sufficient.

43. Comment: **PR-43:**

The commenter suggested that the ARB consider re-phrasing the "carbon capture and sequestration" terminology for Tier 2 pathways to "carbon capture and storage."

Agency Response: The Climate Change program of the Air Resources Board (ARB) has utilized both terms sequestration and storage interchangeably,[65] claiming it to be similar. The Carbon Capture and Sequestration stated in the Staff Report refers to the process by which large amounts of carbon dioxide (CO_2) are captured, transported, injected, and stored underground in geological formations such as depleted oil and gas reservoirs, un-mineable coal beds, and saline formations. ARB staff further asserts that there could be instances when carbon dioxide is sequestered but not stored, such as when carbon dioxide emissions from fermentation in ethanol production processes are captured, refined, and re-used in the carbonated beverage industry. In this case, the carbon dioxide is sequestered from one process, and temporarily stored in another.

44. Comment: **PR-44**

The commenter suggests that staff state ethanol from cellulosic sources, rather than corn stover ethanol. The commenter also suggests the need to list sources of jet fuel.

Agency Response: ARB staff appreciates the commenter's suggestion that Figure 2 in the staff report under Tier 2, should be called, "…ethanol from cellulosic sources…" The commenter goes on to say, "Restricting it to Stover [*sic*] is a pretty narrow set with dedicated bioenergy crops like switchgrass or miscanthus plus use of wood and other things are possible. At some point soon we may also need to list some sources of jet fuel." Staff notes that in Figure 2, under Tier 2, Next Generation Fuels that, "cellulosic alcohols" are stated and not only stover as the commenter suggests. Staff notes that under Tier 2 in Figure 2, under cellulosic alcohols, a number of other Tier 2 fuels are listed, one of the listed items is essentially redundant when comparing to cellulosic alcohols, it is, "Ethanol from straw/stover". Aviation fuel is not currently part of the LCFS, thus not analyzed in detail.

45. Comment: **PR-45**

The comment expresses concern about assumptions of spatial homogeneity implicit in the GREET model, citing the examples of wide variation in crop yields, agrochemical application rates, management practices and transportation distances.

Agency Response: Current practice is to use national average parameters in modeling agricultural phase emissions. verification of

[65] See http://www.arb.ca.gov/cc/ccs/ccs.htm

producer- or region-specific agricultural parameters might add costs and regulatory burden on pathway applicants. Applying standard assumptions about energy and material input quantities and crop yield incentivizes the use of crops with high productivity or low-input intensity over incremental improvements in management. This approach also may obscure the advantage some regions have over others, but is advantageous in that it relieves the need for verification of each input.

46. Comment: **PR-46:**

The commenter concurs with the conclusions presented in the Staff Report on the use of the CA-GREET 2.0 model to estimate direct GHG impacts of the fuel pathway. The commenter suggests that, in the future, the model should be open to improvement, and adapt to new feedstocks such as sorghum and cellulosic residues.

Agency Response: Staff believes that for most fuel pathways, the fundamental way to estimate GHG emissions impacts of processes and energy use using the CA-GREET model is likely to remain the same. User defined input parameters are provided for each pathway to the extent possible. For those pathways with new technologies, processes, or unique feedstocks that require a more complex analysis, the Tier 2/Method 2B application process offers more flexibility to the applicant for defining new assumptions, pathway system boundaries, custom calculations, and incorporating new life cycle inventory data.

47. Comment: **PR-47**

The peer reviewer wants staff to acknowledge that iLUC emissions were identified by researchers and policymakers prior to ARB considering including such emissions in its regulatory framework.

Agency Response: ARB staff concurs with the peer reviewer that academics and scientists were the first to publish peer-reviewed articles highlighting GHG emissions attributable to indirect land use effects from biofuel expansion. The language in the ISOR on indirect effects was ARB's effort to highlight that, in consultation with academics at UC Berkeley and UC Davis; the agency recognized the need to consider such effects in the life cycle analysis of transportation fuels and applied this approach in a regulatory context.

48. Comment: **PR-48**

The peer reviewer suggests that GHG accounting should have considered land use change in addition to other sources of emissions leakage. In particular, new land converted and intensification (e.g., fertilizer use, more tillage, etc.) of existing land should be accounted.

Agency Response: The indirect land use change analysis conducted by ARB tries to capture the totality of effects related to increased biofuel production, including land conversion and intensification as referenced by the peer reviewer. However, there are model and data limitations that limit staff's ability to capture all indirect effects. ARB used a modified version of the GTAP model to estimate the effects related to increased demand for biofuels; land conversion in regions near and remote to meet the new demand for the feedstock. One of the effects of intensification -- increased GHG emissions from increased fertilizer use -- has not been included in the current analysis due to lack of detailed data for all crops and regions. Tillage is currently not included as a parameter of influence in the current analysis. These will be considered in future updates to the iLUC estimates. See also **LCFS 46-82**.

49. Comment: **PR-49**

The peer reviewer states that supply does not equal demand in all cases and cites the example of corn stover where potential supply could exceed demand.

Agency Response: The GTAP model is a general equilibrium model and is built on a framework that supply equals demand for all components in the model. The peer reviewer however, highlights the potential for supply of corn stalks to exceed the demand for this product. In the current version of the ARB GTAP model, corn stalks are not considered as a 'commodity' which could be traded or used in the global market. The model therefore does not explicitly apply the supply equals demand constraint for this commodity. The same may apply to other commodities that are outside the model's framework. One or more versions of GTAP (from Purdue University) utilize corn stover and other corn derived products for the production of cellulosic biofuels. In these versions, the supply equals demand constraints are applied.

50. Comment: **PR-50**

The peer reviewer states that ARB should account for intensification of crops due to increased demand to produce a feedstock (for biofuel production) and in addition consider other responses such as decreased livestock production (due to higher feed costs).

Agency Response: The indirect land use change analysis accounts for the production of feedstock in regions remote from where the original feedstock was diverted to produce the biofuel. The GTAP model does account for likely reductions in livestock directly resulting from increased prices for livestock feed. Changes in GHG emissions from changes in livestock have not been included in the current analysis due to lack of detailed data for many regions of the world. Increase in emissions from intensification has also not been included in the present analysis due to lack of detailed data by crop, AEZ, and region.

51. Comment: **PR-51**

The peer reviewer supports ARB's approach with using a simple averaging approach if appropriate information was not available to support weighted averages of iLUC values.

Agency Response: See response to **PR-25**.

52. Comment: **PR-52**

The peer reviewer would like ARB to model emissions related to cellulosic and jet fuels in the future.

Agency Response: ARB staff acknowledges comments by the peer reviewer related to the inclusion of iLUC analysis for cellulosic biofuels and also to consider including jet fuel under the LCFS regulation. ARB plans to modify the GTAP model with additional data to include the capability for modeling iLUC estimates for cellulosic biofuels. Currently, LCFS includes all transportation fuels except jet fuel. ARB has no concrete plan to add jet fuel into the regulatory framework.

53. Comment: **PR-53**

The peer reviewer does not fully agree with the statement that supply equals demand. A study is cited where reduction in timber harvest in one region is not completely met by production in other regions of the world.

Agency Response: The GTAP modeling framework is built on econometrics of supply and demand. When there is a local demand, in the absence of trade, local demand equals local supply. But with national and international trade, local demand is transmitted to other regions which can provide supply to meet the local demand. A primary reason for ARB to use the GTAP model to estimate iLUC effects is that changes in demand at the regional level for food crops to produce biofuels has the effect of transmitting the demand to other regions if economics favor the production in regions remote from the original region. There is also the possibility that prices may change the production or demand of a given commodity or feedstock under a new equilibrium. An example is forest products from the managed forests land cover in the model. In instances where prices of producing forest products far exceed the price for this commodity, the model limits the production of such products.

54. Comment**: PR-54**

The peer reviewer highlights the domino effect of increased feedstock production in the global marketplace and the need to account for intensification and changes in livestock production.

Agency Response: ARB used the GTAP model to account for all potential impacts from the additional production of biofuels. The 'domino' effect as suggested by the peer reviewer is what ARB intended to capture by using an economic model with global coverage for all sectors, industries, and regions. As indicated in responses to **PR-48**, **PR-50**, and **LCFS 46-82**, emissions attributable to intensification was not included due to lack of detailed data by crop and region. As indicated in response to **PR-50**, decreases in livestock due to increase in feed prices is one of the impacts considered in the current analysis. In the future, when detailed data become available, ARB will consider including these elements in the iLUC analysis.

55. Comment**: PR-55**

The peer reviewer requests that ARB highlight the fact that the GTAP model is widely used around the world in various forms.

Agency Response: ARB indicated in the 2009 ISOR that GTAP was selected as a model for use in the iLUC analysis primarily because it was widely used by over 6,000 experts. Though primarily used for evaluating and predicting impacts of econometric policies (e.g., subsidies, tariffs, etc.) in the early years after the model was developed, it is now being used to estimate impacts of various scenarios including impacts of climate change on the global economy.

56. Comment**: PR-56**

The peer reviewer would like ARB to model emissions related to cellulosic and jet fuels in the future.

Agency Response: See response to comment **PR-52**.

57. Comment**: PR-57**

The commenter would have preferred to have additional details related to the scenario runs (e.g., alternative yield responses).

Agency Response: ARB used a Monte Carlo framework to identify important parameters with the greatest impacts on outputs from the GTAP model. The scenario runs used different values for these critical parameters to generate the set of 30 scenario runs used for each biofuel.

58. Comment**: PR-58**

The reviewer states that ARB has reached the right conclusions relative to assumptions and input parameters in the two models. The two models are scientifically sound and include robust data. Here again, the commenter highlights the need to account for other effects such as changes in livestock production.

Agency Response: The GTAP model used by ARB included all relevant inputs and modeling elements to estimate indirect land use change emissions related to the production of food-derived biofuels. The modeling also included likely changes in livestock from changes in feed prices. GHG emissions from changes in livestock were however not considered for the current analysis due to lack of detailed data by type of livestock and region.

59. Comment: **PR-59:**

The commenter expressed confusion at the different references to the GREET model, and was not sure which one was being used, and whether all references implied the same life cycle analysis model.

Agency Response: The CA-GREET 2.0 model being proposed for adoption is the life cycle analysis (LCA) model to be used by ARB staff to determine the GHG emissions impacts and fuel CI under the

LCFS. This model is an upgrade to the CA-GREETv1.8b (December 2009) model presently authorized by the ARB to be utilized for LCA determinations of fuel pathways under the existing LCFS regulation. The CA-GREETv2.0 model was developed using the GREET1_2013 LCA model developed by Argonne National Laboratory (ANL) as a basis. ANL updates their GREET LCA model almost annually, and a newer version of the GREET model (GREET1_2014) has been released to the public. No reference was made in the Staff Report to this version of the GREET model developed by ANL (other than its release date), nor has any part of this model been an influence for the upgraded CA-GREETv2.0 model being proposed for adoption.

60. Comment: **PR-60:**

The commenter suggested staff may wish to elaborate on "Feedstock Production," to include fertilizer in the discussion of how direct GHG impacts are determined.

Agency Response: The mining of crude feedstock for the production of gasoline and diesel was cited as an example for feedstock production-related GHG emissions impacts.
This example was cited for petroleum transportation fuel production. The commenter is correct that some other pathways (for example, crop-based biofuels) may employ the use of agricultural inputs for Feedstock Production; these include fertilizers and pesticides for crops, as well as fossil fuel inputs for farming, harvesting, collection, and transportation equipment, or employ electricity inputs to power irrigation pumps, for example. All of these uses impact Feedstock Production, including the upstream energy expended to manufacture fertilizers, for example.

61. Comment: **PR-61**

The commenter states that there is redundancy in the discussion of the California version of the GREET model between pages 2 and 5.

Agency Response: ARB staff appreciates the commenter's suggestion that there is some redundancy in discussing CA-GREET, on pages 2-5 in the material provided to peer reviewers (and publicly available) titled, "Attachment 1 - Plain English Summary of Staff's Methodology In Calculating Fuel Carbon Intensities". Any redundancy is due to the inclusion of an introduction and overview prior to the specific explanation.

62. Comment: **PR-62**

The peer reviewer would prefer to state that diversion of food crops to produce biofuel creates unfulfilled demands in the food and fuel markets which creates a demand to replace the diverted food or feed.

Agency Response: We agree with the peer reviewer that diversion of food crop to producing biofuel leads to competition between food and fuel industries for the same feedstock. This leads to shortages in the market triggering a demand to produce additional feedstock either regionally or internationally. Land conversions (and corresponding GHG emissions) to produce the additional food crop are estimated by the iLUC analysis conducted by ARB staff.

63. Comment: **PR-63**

The peer reviewer states that land conversion can occur even in local regions. Pressure to produce additional feedstock could incent double-cropping or growing crop on abandoned lands. Increased emissions from fertilizer and other inputs however, have to be captured.

Agency Response: We recognize that indirect effects could occur in regions either regionally or remote from where the demand for additional feedstock is triggered. The iLUC analysis transmits effects either regionally or internationally driven by the economics of producing the feedstock.

ARB staff also acknowledges the peer reviewer's concerns related to increased emissions from changes in agricultural practices. Intensification is captured in the current analysis (double cropping is implicitly considered) but the effects of increased used of fertilizer has not been considered. For response to fallow land see responses to **LCFS 46-83** and for fertilizer emissions, see **LCFS 46-82**. These will be considered in future updates to the iLUC estimates.

See also responses to **PR-48**, **PR-50** and **PR-54**.

64. Comment: **PR-64**

The peer reviewer suggests ARB consider not only iLUC, but other indirect sources of emissions. The reviewer highlights the need to account for changes in emissions from intensification and changes in livestock production.

Agency Response: See response to **PR-48** and **PR-54**.

65. Comment: **PR-65**

The peer reviewer states that supply does not equal demand in all cases.

Agency Response: The GTAP model is a general equilibrium model and is built on a framework that supply equals demand for all components in the model. The modeling framework starts with a baseline equilibrium which when used to estimate land use changes related to increased biofuel production ensures that new demand for agricultural land is met with an equivalent supply of land (from forest or pasture land in the model).

In the current version of ARB's GTAP model, corn stover is not considered a 'commodity' which could be traded or used in the global market. The model therefore does not explicitly apply the supply equals demand constraint for this commodity. The same may apply to other commodities that are outside the model's framework. One or more versions of GTAP (from Purdue University) utilize corn stover and other corn derived products for the production of cellulosic biofuels. In these versions, the supply equals demand constraints are applied.

See also response to comment **PR-49**.

66. Comment: **PR-66**

The peer reviewer requests that the GTAP model include elements to account for emissions from intensification and irrigation.

Agency Response: ARB staff understands that accounting for increases in emissions from intensification is important. Although ARB accounted for yield increases from intensification, it did not account for increases in GHG emissions from the increased use of fertilizers. This was because of lack of detailed data on the use of fertilizers and other agricultural inputs by crop/AEZ/region. The current version of the model does account for changes in GHG emissions from changes in irrigated land across the world.

67. Comment: **PR-67**

The peer reviewer requests that ARB account for corn oil byproduct from corn ethanol production in the iLUC analysis.

Agency Response: The iLUC emissions were estimated for the period 2004-2010 when extracting corn oil from DDGS was not a significant part of the corn ethanol production process. Therefore, the effect of corn oil extraction was not important for the time period under consideration. However, ARB recognizes that since this is a practice adopted by several facilities (beyond 2013), the direct emissions calculated using the CA-GREET model include provisions to account for changes to existing processes by ethanol and other biofuel producers.

68. Comment: **PR-68**

The peer reviewer suggests that, in future updates, ARB may want to consider inclusion of double cropping effects and changes in land abandonment as reported in the Babcock study.

Agency Response: The Babcock study presents the land cover changes across the world resulting from the totality of all effects (i.e., population and economic growth, weather conditions, drought, flooding, reforestation, GHG reduction incentives for agriculture, etc.). In contrast, ARB's analysis estimates land cover changes attributable only to biofuel expansion. It would be challenging to match the two sets of results that use different modeling metrics. In the future, if appropriate modifications can be made to the GTAP model to estimate the effects of all global activities, it may allow for comparison of model outputs to the totality of observed changes in land cover. See also response to **LCFS 8-5**.

69. Comment: **PR-69**

The peer reviewer requests clarity on the modeling protocol description.

Agency Response: ARB staff agrees with the peer reviewer's commenter about clearly specifying the protocol used in the analysis. The modeling estimated impacts in the global economy in moving from an initial equilibrium to a final equilibrium.

70. Comment: **PR-70**

The peer reviewer commends ARB for including irrigated lands and water constraints in the model. Additionally, the peer reviewer wants ARB to set a cap to limit the expansion of irrigable land into marginal land.

Agency Response: ARB staff accounted for limitations in water availability to be a constraint in the expansion of irrigated land in the current analysis. The model in its current form does not include a feature to address maximum irrigable land as suggested by the commenter. In the future, such a feature could be considered in the modeling structure if there is available data to support the inclusion.

71. Comment: **PR-71**

The peer reviewer suggests that fuel production could exceed the federal RFS2 mandates.

Agency Response: ARB staff acknowledges comments by the peer reviewer related to the potential for production of biofuels above the production targets mandated by the Renewable Fuel Standard. ARB has adopted a market structure that is flexible enough to account for production beyond the imposed 'shock' to the transportation energy market. .

72. Comment: **PR-72**

The peer reviewer highlights the need to account for emissions related to increased inputs to boost crop yields. Additionally, the peer reviewer requests that ARB consider double-cropping effects and land abandonment as highlighted in the recent Babcock paper.

Agency Response: ARB staff understands that accounting for increases in emissions from intensification is important. Although ARB accounted for yield increases from intensification, it did not account for increases in GHG emissions from the increased use of fertilizers. See response to **LCFS 46-82** to address the fertilizer use.

For the comment related to the Babcock, see response to **LCFS 8-5**.

See also responses to comments **PR-66** and **PR-68**.

73. Comment: **PR-73**

The peer reviewer suggests that, in future work, ARB account for the decreased productivity of marginal land.

Agency Response: ARB staff acknowledges the peer reviewer's concern related to lower productivity of marginal land. For the current analysis, the Terrestrial Ecosystem Model (TEM) was used to estimate relative productivity of new land (including marginal land) that comes into crop production. In view of peer reviewer's comment, ARB will review literature and published reports and will consider refining the analysis in the future. At that time, ARB will consider limiting marginal land to production of only specific crops such as switchgrass.