California Environmental Protection Agency

Air Resources Board

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR PROPOSED RULEMAKING

PROPOSED AMENDMENTS TO THE LOW CARBON FUEL STANDARD

Stationary Source Division
Transportation Fuels Branch
Alternative Fuels Branch

October 2011

State of California
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR PROPOSED RULEMAKING

Public Hearing to Consider

PROPOSED AMENDMENTS TO THE LOW CARBON FUEL STANDARD REGULATION

To be considered by the Air Resources Board on December 15, 2011, at:

California Environmental Protection Agency
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1001 "I" Street
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Glossary

List of Acronyms and Abbreviations

ARB or Board	California Air Resources Board
BEV	Battery Electric Vehicle
CA-GREET	California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
CARBOB	California Reformulated Gasoline Blendstock for Oxygenate Blending
CBI	Confidential Business Information
CEQA	California Environmental Quality Act
CI	Carbon Intensity
CO_2, CO_2e	Carbon Dioxide, Carbon Dioxide Equivalent
CCS	Carbon Capture and Sequestration
CNG	Compressed Natural Gas
DGS	Distillers Grains with Solubles
EERs	Energy Economy Ratios
EO	Executive Officer
EWG	Electricity Workgroup
EV	Electric Vehicle(s)
EVSE	Electric Vehicle Service Equipment
EVSPs	Electric Vehicle Service Provider(s)
FCV	Fuel Cell Vehicle
gCO_2e/MJ	Grams of CO_2 Equivalent per Megajoule
gge	Gasoline Gallon Equivalent
GHG	Greenhouse Gas
HCICO	High Carbon-Intensity Crude Oil
iLUC	Indirect Land-use Change
ISOR	Initial Statement of Reasons
LCA	Lifecycle Assessment
L-CIS	LCFS Central Information System
LCFS	Low Carbon Fuel Standard
LNG	Liquefied Natural Gas
LRT	LCFS Reporting Tool
OPIS	Oil Price Information Service
$MMTCO_2e$	Million Metric Tons of CO_2 Equivalent
$MTCO_2e$	Metric Ton of CO_2 Equivalent
PHEV	Plug-in-Hybrid Electric Vehicles
RFS2	Renewable Fuel Standard 2
RINs	Renewable Identification Numbers
TOU	Time-of-Use
ULSD	Ultra Low Sulfur Diesel

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TABLE OF CONTENTS

APPENDICES

LIST OF TABLES

LIST OF FIGURES

Executive Summary

The California Air Resources Board (ARB or Board) staff is proposing amendments to the Low Carbon Fuel Standard (LCFS) regulation.[1] The primary objectives of the proposed amendments are to clarify, streamline, and enhance certain provisions of the regulation. It should be emphasized that the proposal primarily involves refining and improving certain aspects of the regulation and that the vast majority of the regulation remains unchanged by this proposal. Therefore, this Initial Statement of Reasons (ISOR or Staff Report) builds on the comprehensive and extensive work that was done in support of the original 2009 LCFS rulemaking.[2] Accordingly, the rulemaking record and supporting materials for that original rulemaking generally remain applicable to this staff proposal, and this Staff Report addresses only the incremental changes related to the proposed amendments.

Staff developed these proposed amendments to support the overall purpose of the LCFS, which is to reduce greenhouse gas emissions (GHG) by reducing the full fuel-cycle, carbon intensity (CI) of the transportation fuel pool used in California.[3] The proposed amendments address several aspects of the regulation, including: reporting requirements, credit trading, regulated parties, opt-in and opt-out provisions, definitions, and other clarifying language. A summary description of each of the proposed amendments is provided later in this section.

After the Board approved the LCFS for adoption on April 23, 2009, the regulation entered into full effect on April 15, 2010. Implementation of the CI-reduction requirements and compliance schedules began on January 1, 2011. Since the regulation went into effect, regulated parties have operated under the LCFS program with no significant compliance issues.

In short, the LCFS is working as designed and intended. Regulated parties are using the LCFS Reporting Tool (LRT) to submit electronically their quarterly progress and annual compliance reports with no known significant problems. Further, fuel producers are innovating and achieving material reductions in their fuel pathways' carbon intensities, an effect the LCFS regulation is expressly designed to encourage, which is reflected in the large number of applications submitted under the "Method 2A/2B" process. Indeed, 26 submittals for Method 2A/2B applications, representing over 100 individual new or modified fuel pathways with substantially lower carbon intensities

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[1] Codified at title 17, California Code of Regulations (CCR), sections 95480 through 95490.
[2] See the initial statement of reasons (http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf and http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor2.pdf) and final statement of reasons (http://www.arb.ca.gov/regact/2009/lcfs09/lcfsfsor.pdf) for the original 2009 LCFS rulemaking, all of which are incorporated herein by reference.
[3] Adopted pursuant to California Global Warming Solutions Act of 2006 (AB 32) and codified at Health and Safety Code, sections 38500 through 38599.

have been posted to date by staff on the LCFS portal.[4] Substantial credit generation also indicates a successful implementation of the program; in the first quarter of 2011 alone, regulated parties reported generating about 225,000 metric tons (MT) of LCFS credits versus about 150,000 MTs of deficits.

To the extent questions from stakeholders have arisen, they have been addressed through a series of regulatory advisories[5] broadcast to stakeholders subscribed to the LCFS email notification list serve. Staff also provided a LCFS Guidance Document[6] that addresses frequently asked questions, and communicated with individual stakeholders on their specific questions.

With that said, most complex regulations like the LCFS can generally benefit from further refinements. Based on feedback from regulated parties as well as other stakeholders, and by reviewing lessons learned since implementation began, staff identified specific areas of the regulation for clarification and other improvements. These proposed improvements are expected to better ensure the successful implementation of the LCFS program.

To develop these proposed amendments, ARB staff conducted three public workshops, held numerous meetings and discussions with interested parties, and worked closely with stakeholders, including transportation fuel providers and importers, environmental groups, academia, and other interested parties. Materials presented and discussed by staff and other parties at the public meetings were made available for public review on ARB's main LCFS informational portal.[7]

Concurrent with the development of these amendments, ARB staff conducted the first review of the LCFS program. Section 95489 of the regulation requires the Executive Officer (EO) to establish an advisory panel and conduct two reviews of the implementation of the LCFS program through a public process. The reviews are required to address a broad range of implementation topics, including the program's progress against LCFS targets, whether adjustments to the compliance schedule are needed, advances in fuels and production technologies, hurdles or barriers and recommendations for addressing such barriers, and other relevant topics.
Section 95489(a) of the regulation defines the minimum scope of each review. Several of the amendments proposed in this Staff Report take into consideration discussions with the advisory panelists on related topics.

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[4] Pursuant to LCFS Regulatory Advisory 10-04, regulated parties are permitted to use the Method 2A/2B pathways and carbon intensities when they are posted by ARB staff prior to a hearing by the Executive Officer to consider taking action on such proposed pathways. See http://www.arb.ca.gov/fuels/lcfs/122310lcfs-rep-adv.pdf.

[5] See Advisories 10-02, 10-03, 10-04, and 10-04A at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm.

[6] See http://www.arb.ca.gov/fuels/lcfs/LCFS_Guidance_(Final_v.1.0).pdf.

[7] See www.arb.ca.gov/fuels/lcfs/lcfs.htm and www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm.

Further, it should be noted that the proposal does not reflect the staff's ongoing work to update the indirect land-use change analysis (iLUC),[8] which was considered too preliminary at the time of this Staff Report's release to serve as the basis for a proposed amendment on the iLUC carbon intensity values. This ongoing work is expected to be completed during the latter half of 2012, at which time the staff expects to propose regulatory amendments, if appropriate, for the Board's consideration to reflect the completed update.[9]

Summary of Proposed Amendments

The proposed amendments include revisions to specific provisions and requirements of the regulation. The following is a summary description of each of the proposed amendments:

Opt-In and Opt-Out Provisions

Various low-carbon and exempted fuel providers with fuels already meeting the 2020 carbon intensity standards have expressed their intent and desire to opt into the LCFS program as a regulated party, but they are unsure of the process and if they can opt out in the future. To address this concern, staff is proposing to add specific opt-in and opt-out provisions in the regulation. These provisions would specify the process and information submittals needed for a fuel provider to opt in or opt out as a regulated party.

In addition, several out-of-state fuel producers and some in-state fuel suppliers expressed the desire to opt into the program as regulated parties. The current regulation does not confer regulated party status to these out-of-state entities because of jurisdictional concerns. These parties are further upstream and closer to the starting point of fuel production than currently designated regulated parties (i.e., fuel importers and California producers). Staff is proposing regulatory amendments that would permit such entities to voluntarily elect to become regulated parties and become subject to California jurisdiction. These proposed opt-in provisions are intended to work in tandem with the enhanced regulated party changes described below.

Enhanced Regulated Party

Staff has identified a couple ways to enhance the regulated party definitions so that more fuel producers and suppliers can become regulated parties. First, staff is proposing to amend the definitions of "producer," "importer," and "import facility" to

[8] See Chapter IV, section C, of the 2009 LCFS staff report (http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf) at IV-16 through IV-48 for a general discussion of iLUC analysis. The current work is evaluating advancements in the iLUC analysis for corn ethanol, sugarcane ethanol, and soybean biodiesel.

[9] See http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm for presentations and materials discussed to date related to the iLUC work.

include out-of-state and intermediate entities, such as fuel distributors, suppliers, and marketers as regulated parties. This would have the effect of conferring initial regulated party status to those entities that own title to a fuel and actually deliver or cause delivery of a transportation fuel to California. Second, as noted above, several out-of-state fuel providers and intermediate entities have expressed their desire to be able to opt in as a regulated party under the regulation. Further, several gas utilities have expressed a desire to opt into the program when a person, who would normally be qualified to opt in as a regulated party for compressed natural gas (CNG), decides not to do so. Staff is proposing language to permit these entities to opt into the regulation under specified conditions.

Method 2A/2B Certification

The approval of new or modified fuel pathways (i.e., "Method 2A/2B approval") under the regulation currently requires a formal rulemaking. A formal rulemaking is a lengthy and resource-intensive undertaking, requiring an "initial statement of reasons"; a 45-day comment period; a "final statement of reasons," in which comments received on the proposed rulemaking are responded to; and a public hearing. This formal process typically takes about six months to a year. Based on the potential efficiency gains and in recognition that the activities to process and evaluate Method 2A/2B applications are becoming more routine, the Board directed staff under Resolution 09-31 to investigate the feasibility of converting the rulemaking process for the approval of new or modified pathways into a more streamlined certification process.[10] Based on this investigation, staff proposes to convert the current application process into a certification program to facilitate more expeditious reviews of Method 2A/2B submittals. The staff's proposal maintains transparency and accountability by including provisions retaining the public's ability to review and comment on proposed certifications.

Credit Trading

The current regulatory text permits regulated parties to trade and transact LCFS credits, but it does not specify ARB's role in the transactions, information about the credit market to be published by ARB, and other relevant provisions and requirements. Therefore, staff is proposing a new section to be added to the LCFS regulation to provide more detail on how credits and deficits will be tracked. The proposal also specifies the process for regulated parties to use for acquiring, banking, transferring, and retiring credits. Other provisions relevant to credit trading are also proposed.

High Carbon-Intensity Crude Oil (HCICO)

The current regulation contains a provision requiring regulated parties of petroleum-based fuels to account for their use of high carbon-intensity crude oil (HCICO) in their crude slates. The existing regulation employs a simple "bright line" approach to assigning carbon intensities to petroleum transportation fuels in California

[10] See http://www.arb.ca.gov/regact/2009/lcfs09/res0931.pdf.

(i.e., a crude is determine to either be a HCICO or a non-HCICO). Although the current approach has the benefit of being relatively simple, it has been suggested that, to reflect current market realities, a better approach be developed to account for a continuum of crude oil carbon intensities.

Accordingly, staff is proposing a new accounting approach that would require such regulated parties to account for: (1) the difference in carbon intensity between the LCFS compliance schedules and a specified baseline (i.e., the “baseline deficit”), and (2) the incremental difference in carbon intensity between the specified baseline and the actual carbon intensity of petroleum fuels used in California within a specified timeframe (i.e., the “incremental deficit”). In essence, this approach would require the California petroleum-refining sector to not only account for the carbon-intensity reduction that the compliance schedules would otherwise require relative to a specified baseline, but it would also require this sector to account for changes in the actual carbon intensity of petroleum fuels due to the use of HCICO feedstocks.

The proposal described above calls for the new approach to go into effect on January 1, 2013. Because there could be a lag between implementation of the new approach and the existing “HCICO/non-HCICO” provisions, the proposal also specifies a list of crude oils that the Executive Office has determined, in consultation with stakeholders and sister agencies, to be clearly non-HCICO feedstocks. This list would sunset when the new approach described above goes into effect.

Electricity Regulated Party Revisions

The Board directed staff in Resolution 09-31 to review the provisions applicable to regulated parties for electricity and propose amendments if appropriate. Since the regulation was approved by the Board, the markets for electric vehicles (EV) and EV fueling infrastructure have evolved and continue to evolve. To reflect this market evolution, staff is proposing amendments that would better define the potential regulated parties for electricity and the order of priority in which that status would be conferred. The proposal would apply to potential regulated parties such as electric utilities, non-utilities installing electric vehicle service equipment (EVSE) with a customer contract, fleet operators, and business owners.

Energy Economy Ratios

In Resolution 09-31, the Board directed staff to reevaluate the Energy Economy Ratios (EERs) for heavy-duty vehicles burning CNG or liquefied natural gas (LNG) vehicles and update them if appropriate. Accordingly, staff has reevaluated those EERs and proposes to revise them to reflect updated information. In addition, staff has reevaluated and proposes revisions to the EERs for light-duty battery electric vehicles (BEV), plug-in-hybrid electric vehicles (PHEV), and light-duty fuel cell vehicles. These proposed changes to the EERs, along with proposed changes to how they are used in the calculations specified in the regulation, reflect engine efficiency and fuel economy data that were not available during the original 2009 rulemaking.

<u>Reporting Requirements</u>

Staff proposes several amendments to various reporting requirements to simplify the provisions, including elimination of reporting energy volumes in “gasoline gallon equivalent” units and the reporting of renewable identification numbers (RINs). Similarly, staff also proposes to simplify reporting of significant figures by requiring such figures to be expressed in nearest whole units. Finally, staff proposes to require the use of the LCFS Reporting Tool (LRT) for reporting purposes. Although the current regulatory text does not explicitly require use of the LRT, it has become the *de facto* standard for reporting purposes, and staff’s proposal would simply formalize this.

<u>Miscellaneous Changes</u>

The proposal contains a number of miscellaneous changes. This includes deleting the reference to the alternative fuel specification in the definitions of “compressed natural gas,” “biogas,” and “liquefied natural gas.” Staff proposes this change to better reflect the GHG basis of the regulation. Further, staff proposes amendments that would codify a number of provisions specified in the LCFS regulatory advisories released to date. Finally, staff proposes a number of grammatical, typographical, or other non-substantial corrections.

Impacts of Proposed 2011 Amendments to LCFS Regulation

<u>Environmental Impacts</u>

The environmental analysis published in the 2009 LCFS ISOR focused on the significant GHG emission reductions that the regulation would achieve through the production and use of lower-CI transportation fuels. Staff estimated that a reduction of about 16 million metric tons of CO_2-equivalent ($MMTCO_2e$) would come solely from the combustion of transportation fuels in California in 2020. A thorough description of the estimated environmental impacts of the LCFS can be found in the 2009 LCFS ISOR; the assumptions and resulting analyses contained therein are still considered valid.

For the proposed amendments, staff has estimated that there are no significant adverse environmental impacts. Most of the proposed amendments – opt-in/opt-out, enhanced regulated party, credit trading mechanism, Method 2A/2B certification, etc. – are related to making the implementation of the LCFS run more smoothly. There may be environmental benefits related to additional credits generated and introduced into the LCFS credit market, as these credits may obviate the need for additional fuels to be produced at biorefineries. However, as a result of the proposed amendments we do not anticipate a substantive change in GHG emission reductions (there may be a slight increase in reductions due to changes to the baseline). Further, as a result of the proposed amendments, we do not anticipate local adverse environmental impacts.

Economic Impact

Staff estimates that the proposed amendments will generally have a positive economic impact on regulated parties, largely due to additional credits expected to be introduced into the LCFS credit market. Clarifications on opting into the LCFS, a credit-trading mechanism, enhanced regulated parties, and who gets electricity credits are all expected to attract additional credits to the LCFS program. These additional credits should keep credit prices lower than they would otherwise be, thus reducing compliance costs.

The proposed Method 2A/2B certification process will streamline the approval process for stakeholders while maintaining a transparent process. Staff expects the proposed amendments will have no fiscal impacts for federal, state, or local governments.

Analysis of Alternatives

Staff evaluated several alternatives to the proposed amendments. The alternatives are presented below:

1. Take no action (i.e., leave current regulatory language as is). As discussed in Chapter VII, Analysis of Alternatives, this alternative was deemed not feasible because it would not effectuate the various clarifications and enhancements contained in the staff proposal. Consequently, implementation of the regulation would not be as successful as it could be with the staff's proposed changes.

   For example, as noted previously, the proposed enhanced regulated party definitions and opt-in and opt-out provisions are intended to help encourage additional entities to participate in the LCFS regulation. In a number of cases, those proposed changes would help capture and bring into the LCFS credit market those credits that might otherwise be "orphaned" because their generators did not choose to enter into the program. Other refinements that would be foregone in a "no action" alternative would include updates to the EERs, changes to clarify and make transparent credit trading, and the streamlining benefits of converting the Method 2A/2B approval process from a rulemaking to a certification process.

   The two major substantive portions of the staff's proposal that would be adversely affected under a "no action" alternative would be the proposal's changes to the electricity regulated party provisions and the provisions for addressing the carbon intensity of petroleum crude oils and fuels derived from such crude oils. The no-action alternative would prevent the staff's proposed improvements to the electricity regulated party provisions. As noted earlier, the staff's proposal with regard to electricity regulated parties would better reflect the evolution of the EV sector since the 2009 approval of the LCFS regulation. Under the no-action alternative, these evolutionary changes in the EV market would not be reflected in the regulation, thereby depriving credits to those entities that would otherwise qualify for regulated party status under the staff's proposed changes. The no-action alternative would also deprive consumers with the public education and other value-added benefits called for under the staff's proposal.

For petroleum regulated parties, the no-action alternative would mean that those entities would need to continue to meet the existing requirements for high intensity crude oil (HCICO). Because the HCICO provisions are tied to a 2006 crude slate or "basket," the no-action alternative would preclude adjustments to the HCICO provisions that would better reflect the petroleum market that has evolved since the original 2009 rulemaking. Just as important, the no action alternative would preclude the more accurate accounting of carbon intensities for petroleum crude that would occur under the staff's proposal versus the "bright line" HCICO approach in the current regulation that is based on the grandfathered 2006 crude basket approach.

For the above reasons, staff has determined that a no-action alternative is not feasible and would not accomplish the same objectives as the staff's proposal at the same or lower costs.

2. Staff evaluated the following options for designating the potential electricity regulated parties:

    - Designate electric utilities as potential regulated parties for all EV charging.
    - Designate EV owners as potential regulated parties for electricity delivered to their vehicles.
    - Omit potential default regulated parties.

    When evaluating these alternatives, staff kept three goals in mind. The first goal was to keep the proposed language simple to avoid confusion in regulated party designation and maintain relevancy as the EV-charging market evolves in future years. The second goal was to limit the number of regulated parties to increase the possibility that credits will be captured and made available to other regulated parties. The final goal was to maximize the number of credits captured and available for purchase.

    The first option – designate electric utilities as potential regulated parties for all EV charging – goes against the goal of maintaining relevancy as the EV charging market evolves in future years. Such designation cannot benefit potential charging equipment installers such as non-utility electric vehicle service providers, business owners, and EV fleet owners; therefore, this approach would discourage their efforts to establish the public and private charging networks which are critical to the future EV market.

    The second option – designate individual EV owners as potential regulated parties for electricity delivered to their vehicles – goes against the goal of limiting the number of regulated parties to increase the possibility that credits will be captured and made available to other regulated parties. It is much more difficult to keep track of the credits from individual EV customers than from larger entities, such as the utilities.

The third option – designate a hierarchy of potential regulated parties without designating a default party – goes against the goal of maximizing the number of credits captured and available for purchase. Given the recordkeeping and other requirements in the LCFS regulation, there is a potential for significant amounts of credits to be "orphaned" or otherwise not captured and put into the credit trading market if the designated regulated party, such as a business owner with an onsite charger, fails to opt in. On the other hand, electric utilities have an inherent interest in being able to generate credits for electricity used for transportation. For this reason, among others, staff proposes to designate electric utilities as the default regulated party to ensure that credits are not orphaned.

3. Staff evaluated several alternative approaches for the treatment of HCICOs in the LCFS regulation:

   a. Current Approach with Amendments: Staff applies a screening mechanism to market crudes to identify crudes that are clearly non-HCICOs, then assigns a default CI value for crudes that are potential-HCICOs. Staff develops a process besides Method 2B to determine if potential-HCICOs are either non-HCICOs or HCICOs.

      Staff determined that this approach offered little benefit over the current approach.

   b. Hybrid California Average/Company-Specific Approach: The base deficit for individual companies is calculated the same as in the current regulation; however, individual companies only incur an incremental deficit if their own crude slate becomes more carbon-intensive over time relative to their crude slate refined in the baseline year.

      Although there is likely greater flexibility to purchase worldwide crude supplies for some companies than the current approach, this approach makes implementation more complicated due to the need for company-specific CI values each year. Staff does not have sufficient company-specific data to fully assess the impacts of this approach on individual oil companies.

   c. Company-Specific Approach: Each oil company would have distinct Lookup Table values and compliance targets for CARBOB and diesel, which are based on the crude slate refined by that company in California in the baseline year. Individual companies only incur an Incremental Deficit if their own crude slate becomes more carbon-intensive over time.

      As with the Hybrid Approach, this approach requires company-specific data that staff does not have. Furthermore, each oil company having its own CI values for

CARBOB and Ultra Low Sulfur Diesel (ULSD) in the market would be unnecessarily complex and discriminatory.

d. Worldwide Average Approach: This approach bases the average Lookup Table CI values for CARBOB and diesel and the compliance schedule on worldwide average crude oil production and refining emissions in the baseline year. An Incremental Deficit is applied to all companies if the worldwide average crude production and refining becomes more carbon intensive over time.

   Since crudes used by California refineries would have little, if any, impact on the CI value of the world average, this approach could result in significantly greater amounts of HCICO being used at California refineries because there is no effective incentive to avoid their use.

e. California Baseline Approach (Eliminate Consideration of HCICOs in the LCFS): All CARBOB and diesel would use the existing CI values in the Look Up Table. Regulated parties would only calculate and be subject to the Base Deficit for all CARBOB and diesel regardless of the crude oil used for refining. The Look-Up Table values for CARBOB and diesel would not be updated.

   This approach would eliminate the current HCICO provision. It does not account for, track, or mitigate increases in upstream emissions from crudes used by California refineries, and is therefore inconsistent with the lifecycle analysis basis of the LCFS. This approach could result in significantly greater amounts of HCICO being used at California refineries because there is no incentive to avoid their use.

I. INTRODUCTION

In this chapter, ARB staff provides a brief overview of the LCFS, information on the implementation of the LCFS program, and the regulatory process and actions taken to develop the staff's proposed amendments.

As noted, ARB staff is proposing various amendments to the LCFS regulation. The primary objectives of the amendments are to further clarify and enhance certain aspects of the regulation. These proposed amendments support the primary purpose of the LCFS, which is to reduce greenhouse gas (GHG) emissions by reducing the carbon intensity of transportation fuels used in California by 10 percent by 2020.

Additional information on the LCFS regulation and its underlying principles can be found in the 2009 staff report prepared for the adoption of the LCFS regulation.

A. Overview of the LCFS Regulation

On April 23, 2009, the Board approved the LCFS for adoption. The regulation became effective on January 12, 2010; additional provisions became effective on April 15, 2010. The first year of the program, 2010, was intended solely as a reporting year (i.e., for regulated parties to begin acclimating to the recordkeeping, reporting, and other administrative provisions by using the LCFS Reporting Tool (LRT), filing demonstrations of pathways, etc.). Actual implementation of the carbon intensity requirements and compliance schedules began on January 1, 2011.

The LCFS establishes two sets of performance standards that regulated parties must meet each compliance year. One set of annual standards is for gasoline and the alternative fuels that substitute for gasoline. The second set of standards is for diesel fuel and its substitutes. Each set of standards (i.e., "compliance schedule") is set to achieve an average 10 percent reduction in the carbon intensity of the statewide mix of transportation fuels by 2020.

The LCFS is based on the premise that each fuel has a "lifecycle" GHG emission value; subjecting this lifecycle GHG rating to a declining standard for the transportation fuel pool in California would result in a decrease in the fuel's lifecycle GHG levels. This lifecycle assessment (LCA) represents the GHG emissions associated with the production, transportation, and use of a given fuel in motor vehicles. The LCA includes direct emissions associated with producing, transporting, and using the fuels, as well as significant indirect effects on GHG emissions, such as changes in land use for some biofuels and other effects.

The LCFS standards are expressed in terms of the "carbon intensity" of gasoline and diesel fuel and their substitutes. Depending on the circumstances, GHG emissions from each step can include carbon dioxide (CO_2), methane, nitrous oxide (N_2O), and other GHG contributors. Moreover, the overall GHG contribution from each particular step is a function of the energy that the fuel contains. Thus, carbon intensity is expressed in terms of grams of CO_2 equivalent per megajoule (g CO_2e/MJ).

Fuels Included in the LCFS

The LCFS applies, either on a compulsory or opt-in basis, to most types of fuels used for transportation in California, including:

- California reformulated gasoline;
- California ultra low sulfur diesel fuel;
- Compressed or liquefied natural gas;
- Electricity;
- Compressed or liquefied hydrogen;
- Any fuel blend containing hydrogen;
- Any fuel blend containing greater than 10 percent ethanol by volume;
- Any fuel blend containing biomass-based diesel;
- Neat denatured ethanol;
- Neat biomass-based diesel; and
- Any other liquid or non-liquid fuel not otherwise exempted from the regulation.

Fuel Pool Carbon Intensity Standards

The LCFS achieves GHG emission reductions by incrementally reducing the allowable carbon intensity of transportation fuel used in California. The LCFS does not limit the carbon intensity of individual batches of fuels, but it does require regulated parties to comply with an annual standard for the transportation fuel pool they provide. As noted, this annual standard is expressed as carbon intensity in units of g CO_2e/MJ. The allowable carbon intensity of transportation fuels decreases each year, starting in 2011, until the carbon intensities of gasoline and diesel transportation fuels (and their substitutes) in 2020 are each reduced by 10 percent relative to 2010. Gasoline and diesel follow similar carbon-intensity reduction curves from 2011 through 2020 and beyond.

A graphical representation of the compliance schedules is presented in Figures 1 and 2. Table 1 shows the compliance schedules for gasoline and diesel fuel.

Figure 1

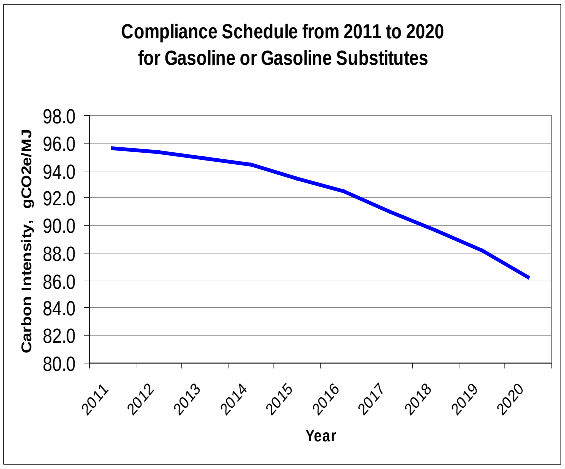

Figure 2

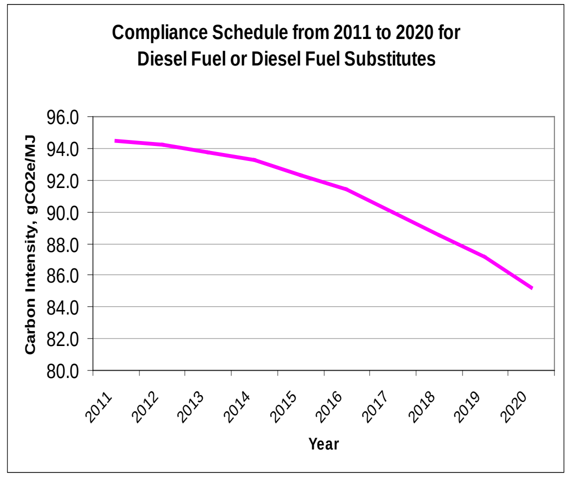

Table 1
LCFS Compliance Schedule

Year	Carbon Intensity for Gasoline and Fuels Substituting for Gasoline (g/MJ)	Gasoline and Fuels Substituting for Gasoline % Reduction	Carbon Intensity for Diesel and Fuels Substituting for Diesel (g/MJ)	Diesel and Fuels Substituting for Diesel % Reduction
2010	Reporting Only			
2011	95.61	0.25%	94.47	0.25%
2012	95.37	0.5%	94.24	0.5%
2013	94.89	1.0%	93.76	1.0%
2014	94.41	1.5%	93.29	1.5%
2015	93.45	2.5%	92.34	2.5%
2016	92.50	3.5%	91.40	3.5%
2017	91.06	5.0%	89.97	5.0%
2018	89.62	6.5%	88.55	6.5%
2019	88.18	8.0%	87.13	8.0%
2020 and subsequent years	86.27	10.0%	85.24	10.0%

Under the LCFS, the carbon intensity for alternative fuels (biofuels, natural gas, hydrogen, electricity) would be judged against either the gasoline or diesel carbon intensity standards, depending on whether the alternative fuel is used for light- or medium-duty vehicles or for heavy-duty vehicles, as specified in the regulation. In each year, the carbon intensity of each fuel is compared to the LCFS standard for that year.

Fuels that have carbon intensity levels below the standard generate credits. Fuels with carbon intensity above the standard create deficits. To comply with the LCFS for a given year, a regulated party must show that its banked total amount of credits equal or exceed the deficits incurred. Credits can be banked or sold to other regulated parties.

Determination of Carbon Intensity Values

The carbon intensity values represent the currency upon which the LCFS is based. The carbon intensity is determined in two parts. The first part represents the direct GHG emissions associated with producing, transporting, and using the fuel. This involves determining the amount of GHG emissions emitted per unit of energy for each of the steps in the fuel pathway. For example, these steps may involve the following for the production of ethanol:

- Farming practices (e.g., frequency and type of fertilizer used).
- Crop yields.
- Harvesting of the crop.
- Collection and transportation of the crop.
- Type of fuel production process.
- Fuel used in the production process (e.g. coal/CNG/biomass).
- Energy efficiency of the production process.
- The value of the co-products generated (e.g. distillers grain).
- Transport and distribution of the fuel.
- Combustion of the fuel in vehicles.

The second part considers any other significant effects, both direct and indirect, that are caused by the change in land use or other market-mediated effects. For some crop-based biofuels, staff has identified land-use change as a significant source of additional GHG emissions. No other significant indirect effects that result in large GHG emissions have been identified that would substantially affect the LCFS framework for reducing the carbon intensity of transportation fuels.

A more complete description of how the LCFS regulation is designed to work, as well as its underlying scientific and economic principles, can be found in the initial and final statements of reasons for the original 2009 rulemaking.[11]

B. Implementation Status of the LCFS Program

Since the LCFS was approved by the Board in April 2009, staff undertook several collaborations with stakeholders to help ensure the smooth launch of the program. First, staff convened an Expert Workgroup to compile and assess subsequent developments in the field of indirect effects analysis. The Expert Workgroup provided

[11] See www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf, www.arb.ca.gov/regact/2009/lcfs09/lcfsisor2.pdf, and www.arb.ca.gov/regact/2009/lcfs09/lcfsfsor.pdf.

recommendations on how best to incorporate such developments into the next iteration of the LCFS regulation. These efforts have helped focus staff's work on updating the indirect land-use change (iLUC) carbon-intensity values, which as noted below, will be proposed in a 2012 rulemaking after that work has been completed. Second, the staff convened a working group to evaluate developments in the field of sustainability. While it is unclear at this time whether the final deliverable of that ongoing effort will be regulatory or advisory in nature, the important work being conducted by that working group will help inform future versions of the LCFS. Third, as discussed in more detail later in this chapter, staff convened the LCFS Advisory Panel in early 2011. While the mandate of this panel is to evaluate and advise staff on high-level policies related to the LCFS, several of those evaluations helped inform the changes that staff is proposing in this Staff Report.

As noted, implementation of the compliance schedules and carbon intensity requirements began on January 1, 2011. Since early 2010, the LCFS has mandated that all regulated parties report required data on a quarterly and annual basis. To facilitate the electronic reporting of vast amounts of transactional data, ARB staff developed an on-line LCFS Reporting Tool (LRT) for the reporting of fuel volumes and other data to the State. The LRT is a secure, web-based data collection and report generation application designed to accommodate the submittals of all required information and help regulated parties meet the reporting requirements of the LCFS.

The LRT has been operational since early 2010 and has been used by regulated parties in its full production mode since December 2010. The LRT is readily accessible for electronic reporting by all regulated parties.[12] To date, a total of 70 entities have registered as regulated parties and have used the LRT exclusively for reporting during 2010 and the first quarter of 2011. These regulated parties have used the LRT for both manual fuel-transaction data entry via the user interface and through XML data file upload submission. Because the LRT has been the only means regulated parties have used for LCFS reporting, it has become the *de facto* method for electronic reporting.

Based on staff's review of reported first quarter 2011 data, it appears that regulated parties are able to generate substantial LCFS credits at this early stage of the program. During the first quarter of 2011, regulated parties reported generating about 225,000 metric tons of LCFS credits. On the other hand, regulated parties reported incurring about 150,000 metric tons of LCFS deficits. Additional results from staff's review of first quarter 2011 reports from the LRT are shown in Appendix B.

A healthy LCFS program depends on having a robust credit market and participants with confidence in a market that has clarity, certainty, transparency and accountability. Despite the number of credits generated in first quarter 2011, staff has determined that additional clarity and improvements to certain aspects of the regulation are needed to ensure an even more successful implementation of the program.

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[12] See www.arb.ca.gov/lcfsrt.

To this end, the proposal's inclusion of specific opt-in/opt-out procedures, as well as enhancements to the biofuel and electricity regulated-party provisions, should increase both participation in the LCFS program and the generation of LCFS credits. Similarly, the proposal's credit trading provisions will provide certainty, clarity, transparency, and accountability to credit transactions, thereby increasing confidence in the credit market. Further, the proposal's certification procedure for taking action on Method 2A/2B submittals, without invoking a full rulemaking process, is expected to encourage further innovations that reduce carbon intensities. This, in turn, should help widen the range of biofuels and alternative fuels available for regulated parties to choose for their transportation fuel pools. Finally, the proposed update to the EER values and the HCICO refinements will help ensure that the regulation reflects the most up-to-date information and accounting/screening techniques.

C. Development Process for the Proposed Amendments

During the rulemaking process, ARB staff conducted three public workshops, several workgroup meetings, and numerous meetings with individual stakeholders to discuss the proposed amendments and address various concerns that were raised. ARB staff provided ample opportunities for stakeholders to comment on and present information about the proposed amendments. Meeting attendees included transportation fuel providers and importers, environmental groups, academia, and other interested persons. These individuals participated both by reviewing draft regulations and supporting documentation, providing data, and participating in workgroup meetings.

As noted, ARB staff established a number of workgroups, including the electricity, crude oil screening, and LCFS Reporting Tool workgroups, to address topic-specific concerns and suggested improvements raised by stakeholders during the rulemaking process.[13] Table 2 on the following page lists dates for the meetings that were held to apprise the public about the proposed amendments and other related developments.

[13] See http://www.arb.ca.gov/fuels/lcfs/workgroups/workgroups.htm for a compilation of the workgroups convened by ARB staff and the materials presented to and discussed with the workgroups.

Table 2: LCFS Workshop/Workgroup and Public Outreach Meetings

Meeting	Date	Location	Time
LCFS Proposed Amendments Public Workshops			
First Public Workshop	July 22, 2011	Cal/EPA Building, Coastal Hearing Room	9:00 a.m.
Second Public Workshop	September 14, 2011	Cal/EPA Building, Sierra Hearing Room	1:00 p.m.
Third Public Workshop	October 14, 2011	Cal/EPA Building, Sierra Hearing Room	1:00 p.m.
LCFS Electricity Workgroup (EWG) Meetings			
EWG Meeting	July 14, 2010	Cal/EPA Building, Conference Room 610	1:00 p.m.
EWG Meeting	October 26, 2010	Cal/EPA Building, Conference Room 610	1:00 p.m.
EWG Meeting	July 11, 2011	Cal/EPA Building, Conference Room 610	2:00 p.m.
LCFS High Carbon Intensity Crude Oil (HCICO) Screening Workgroup Meetings			
HCICO Workgroup Meeting	March 29, 2010	Cal/EPA Building, Conference Room 620	12:00 p.m.
HCICO Workgroup Meeting	May 6, 2010	Cal/EPA Building, Conference Room 620	9:00 a.m.
HCICO Workgroup Meeting	June 16, 2010	Cal/EPA Building, Conference Room 620	12:30 p.m.
HCICO Workgroup Meeting	July 14, 2010	Cal/EPA Building, Conference Room 610	3:30 p.m.
HCICO Workgroup Meeting	September 9, 2010	Cal/EPA Building, Conference Room 620	9:00 a.m.
HCICO Workgroup Meeting	February 17, 2011	Cal/EPA Building, Conference Room 620	9:00 a.m.

Over 7,100 individuals or companies were notified for each workshop/hearing. Notices for the public meetings were posted to ARB's LCFS websites (informational portal and public meetings/workshops) and e-mailed to subscribers of the "LCFS" list serve. The public workshops were webcast live whenever possible. In addition, ARB staff participated in numerous stakeholder meetings, presenting information on the implementation of the current regulation and the proposed amendments.

To increase public participation and enhance the information flow between ARB and interested parties, staff created the LCFS informational portal website (http://www.arb.ca.gov/fuels/lcfs/lcfs.htm). Since that time, staff has consistently made available online materials related to this rulemaking, including meeting presentations and draft regulatory language. The website has also provided background information on the LCFS, workshop and meeting notices and materials; other GHG related information; and links to other websites with related information.

Beyond the public and workgroup meetings noted above, staff's outreach efforts also included numerous personal contacts via telephone, electronic mail, regular mail, surveys, facility visits, and individual meetings with interested parties. These contacts included regulated parties, transportation fuel providers, marketers, importers, environmental, community, public health organizations, and other entities.

As noted previously, ARB staff also worked in parallel with the LCFS Advisory Panel. Its mandate is to assist ARB staff in reviewing specific aspects of the LCFS program's implementation; staff is to present the results of its two program reviews, with the Advisory Panel's input, to the Board by January 1, 2012 and January 1, 2015.

The staff's work with the Advisory Panel is ongoing. Because the Advisory Panel's purview generally covers high-level policy topics, it was not an appropriate forum for discussing technical details and minutiae in the LCFS regulation. Nevertheless, the discussions with the Advisory Panel were helpful in focusing staff's work to refine the proposal's changes to the regulatory text in a number of areas.

Finally, it should be noted that the proposal does not reflect the staff's ongoing work to update the indirect land-use change analysis (iLUC),[14] which was considered too preliminary at the time of this Staff Report's release to support a proposed amendment to the indirect carbon intensity values. This ongoing work is expected to be completed during the latter half of 2012, at which time the staff expects to propose regulatory amendments, if appropriate, to reflect the completed update.[15]

[14] See Chapter IV, section C, of the 2009 LCFS staff report (http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf) at IV-16 through IV-48 for a general discussion of iLUC analysis. The current work is evaluating advancements in the iLUC analysis for corn ethanol, sugarcane ethanol, and soybean biodiesel.

[15] See http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm for presentations and materials discussed to date related to the iLUC work.

II. NEED FOR PROPOSED AMENDMENTS

As noted, the primary objectives of the proposed amendments are to clarify, streamline, and enhance certain provisions of the regulation. It should be emphasized that the proposal involves refining and improving certain aspects of the regulation and that the vast majority of the regulation remains unchanged by this proposal. Therefore, this ISOR builds on the comprehensive and extensive work that was done in support of the original 2009 LCFS rulemaking,[16] which generally remains applicable to this proposal, and this ISOR addresses only the proposal's incremental changes.

Staff developed these proposed amendments to support the overall purpose of the LCFS. The proposed amendments address several aspects of the regulation, including: reporting requirements, credit trading, regulated parties, opt-in and opt-out provisions, definitions, and other clarifying language. A summary description of each of the proposed amendments is provided in Chapter IV, Proposed Amendments.

After the Board approved the LCFS for adoption on April 23, 2009, the regulation entered into full effect on April 15, 2010. Implementation of the carbon intensity reduction requirements and compliance schedules began on January 1, 2011. As noted, implementation of the LCFS has generally been without significant issues. However, as with most complex regulations, there is always room to improve the LCFS.

There are several factors driving the staff's proposed amendments. First, based on stakeholder comments received in the original 2009 rulemaking, the Board directed staff in Resolution 09-31 to consider revisions to the regulation in a number of specific areas. These included updates to the Energy Economy Ratios (EERs), conversion of Method 2A/2B reviews into a certification process, and a reevaluation of the electricity regulated-party provisions. Second, staff solicited and encouraged feedback from regulated parties and other stakeholders throughout the LCFS' implementation. This feedback directly informed the staff's refinements contained in this proposal. Finally, staff conducted internal reviews of lessons learned since implementation began. For example, these reviews lead to the proposal to enhance the regulated party definitions and provisions, credit trading provisions, and opt-in/opt-out procedures.

With the above drivers, staff was able to identify specific areas of the regulation for clarification and other improvements. These proposed improvements are expected to better ensure the successful implementation of the LCFS program. Beyond this proposal, staff will continue to monitor implementation of the LCFS and developments in fields, such as credit trading, land use change analysis, and high carbon intensity crudes, to help shape further refinements in future iterations of the LCFS.

[16] See the initial statement of reasons (http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf and http://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor2.pdf) and final statement of reasons (http://www.arb.ca.gov/regact/2009/lcfs09/lcfsfsor.pdf) for the original 2009 LCFS rulemaking, all of which are incorporated herein by reference.

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III. TECHNOLOGY ASSESSMENT

The staff report for the original LCFS rulemaking clearly showed the basic regulation to be technologically feasible.[17] Accordingly, this chapter discusses the technical feasibility of meeting the proposed amendments. Because there are no new fuel pathways and no new scientific modeling in this proposal, the amendments do not require regulated parties to use new technologies in order to comply. Staff has identified no technological barriers that would prevent regulated parties from meeting the proposed changes. As noted, the proposal is generally aimed at streamlining the LCFS, increasing its flexibility, and making the program implementation operate more smoothly. The following summarizes the technological feasibility of the major proposed changes; additional details are provided in Chapter IV, Proposed Amendments.

Opt-In/Opt-Out and Enhanced Regulated Party Provisions

The current regulation allows for regulated parties of low CI fuels to opt into the program. However, there are no provisions explaining how opting in is to be accomplished. The staff's proposed changes are intended to address this and bring more voluntary participants into the program. The proposed changes will clarify the circumstances under which existing participants would be designated as the regulated party for a specific volume of fuel.

There are no complex technologies required for a regulated party to opt in. Under the proposal, opting into the LCFS program simply requires registration as a regulated party through the LRT online program. As noted previously, the LRT is readily accessible through ARB's website (https://ssl.arb.ca.gov/lcfsrt/Login.aspx). Regulated parties can use a standard web browser to access the LRT, such as Firefox®, Internet Explorer®, Safari®, Opera®, and other popular browsers. For those eligible, opting out of the regulation would only require that email and hardcopy notices be submitted to ARB staff for confirmation. Based on these considerations, this proposed amendment was found to be technologically feasible.

Mandatory LRT Use

As noted, the LRT has become the *de facto* method for regulated parties to electronically submit their required quarterly and annual reports. ARB staff is not aware of any regulated party's inability to access and use the LRT through ARB's website.

The next generation LRT is under development. Currently, known as the LCFS Central Information System (L-CIS), it will be a more interactive workspace for regulated parties to meet their regulatory needs. The system will be designed to incorporate Method 2A/2B submittals, credit transactions, and voluntary biorefinery and opt-in fuel producer registrations. Until the L-CIS is operational, regulated parties can provide the

[17] See Staff Report: Initial Statement of Reasons, Proposed Regulation to Implement the Low Carbon Fuel Standard, Vol. I (March 5, 2009), at ES-7 and III-1 through III-22.

required information via electronic or regular mail submittals; the proposal does not refer to or otherwise rely on the existence of the L-CIS.

Method 2A/2B Certifications

The proposal to convert the current rulemaking process for approving Method 2A/2B submittals into a certification process does not involve any technological requirements other than the requirement for applications to be electronically submitted. Such submittals are readily achieved through the use of standard email programs or by submitting an application package on a compact disk or other electronic media.

Credit Trading

The information required to be reported under the proposed amendments will, in the short term, be processed manually by ARB staff. Upon receipt of the required information (via electronic or regular mail submittal), staff will process the information and manually input the relevant transactional data into the LRT accounts for both buyers and sellers. As noted, the next-generation LRT (L-CIS) will be designed to handle this transactional information electronically and automatically, but there are no requirements in the proposed amendments that refer to or otherwise rely on the L-CIS.

Electricity Regulated Party Provisions

The proposal specifies requirements for various entities to qualify for electricity credits. Depending on the circumstances, these requirements may include one or more of the following:

- Use all credit proceeds as direct benefits for current electric vehicle (EV) customers.
- Provide rate options that encourage off-peak-charging and minimize adverse impacts to the electric grid.
- Educate the public on the benefits of EV transportation through outreach efforts such as holding public meetings, providing EV dealership flyers, utility customer bill inserts, radio or television advertisements, and publishing EV-relevant webpage content.
- Report annually a summary of the above efforts, as well as an accounting of the number of EVs known to be operating in the service territory.

The above list does not impose requirements involving any technologies above and beyond standard telecommunications, word processing, and internet/web publishing programs that are readily accessible to the general public and businesses.

HCICO

The HCICO provisions in the proposal simply dictate how a regulated party, with HCICO-derived fuel in its fuel pool, would account for that HCICO when calculating its credits and deficits. There are no special technologies required to conduct the proposed changes to the crude oil CI accounting. Typically, such regulated parties would be a small group of petroleum refineries and marketers. Thus, the HCICO provisions basically entail nothing more complicated than careful recordkeeping, reporting, and accounting, which refineries presumably do already using currently available accounting software. While regulated parties may need to better understand the origins of their HCICO-derived fuels, staff is unaware of any special technologies that would be required for a regulated party to perform these actions.

EER Updates

The energy economy ratio (EER) refers to the unitless multiplier that is used to account for differences in energy efficiency among different types of fuels and vehicles. The EER is defined as the ratio of the number of miles driven per unit energy consumed for a fuel of interest to the miles driven per unit energy for a reference fuel. For purposes of the LCFS, the reference fuel is gasoline for light- and medium-duty vehicles, and diesel for heavy-duty vehicles. Thus, the EER for light-duty vehicles for a given fuel is defined as the ratio of the miles driven per energy consumed for that fuel to the miles driven per energy consumed for a comparable vehicle using gasoline. Therefore, the EER for gasoline is always 1.0 for light- and medium-duty gasoline-powered vehicles; similarly, the EER for diesel is always 1.0 for diesel-fueled heavy-duty vehicles.

In this proposal, staff is updating the EERs for a number of alternative fuels, including battery electric vehicles (BEV), plug-in hybrid electric vehicles (PHEV), fuel cell vehicles, and heavy-duty compressed natural gas (CNG) or liquefied natural gas (LNG) vehicles.[18] In the original 2009 rulemaking, the data for these fuels were relatively limited.[19] Since then, a number of vehicles have come into the market using these fuels. This influx of new alternative-fueled vehicles has allowed staff to use more real-world, fuel-economy data for those vehicles to update their EERs. This is explained in more detail in Chapter IV, Proposed Amendments.

Because staff's proposal is based on actual alternative-fueled vehicles that are commercially available, the proposed changes to the EERs are clearly technologically feasible. Moreover, there are no technologies required for regulated parties to meet these updated EER values; the values are simply inputs in the credit/deficit calculations specified in the regulation.[20] Because the LCFS does not regulate the EERs but simply lists them, there are no technologies required to be used by vehicle or engine manufacturers.

[18] These EERs can be found in Cal. Code Regs., tit. 17,§ 95485(a)(3), Table 5.
[19] See Staff Report: Initial Statement of Reasons, Proposed Regulation to Implement the Low Carbon Fuel Standard, Vol. I (March 5, 2009), at ES-18.
[20] See Cal. Code Regs., tit. 17,§ 95485(a)(3)(A) and (B).

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IV. PROPOSED AMENDMENTS

In this chapter, we provide a discussion of each of the major proposed amendments. All section references are to the LCFS regulation (13 CCR 95480-95490) unless otherwise noted.

A. Opt-In and Opt-Out Provisions

Section 95480.1(b) currently identifies specific low-CI fuels that are exempt from the LCFS program. Although the language allows providers of these fuels to opt into the program to generate credits, it does not specify a procedure for voluntarily opting in or opting out. Consequently, there are a number of providers of biogas and other exempted, low-CI fuels (i.e., those that already meet the 2020 CI standards) that want to opt into the LCFS but are reluctant to do so at this time; among the reasons they cite for their reluctance is the lack of a specified opt-in/opt-out procedure.

In addition, there are a number of out-of-state producers and intermediates that have expressed a similar desire to voluntarily opt into the regulation in order to become regulated parties. However, the existing regulatory text does not allow such out-of-state entities to become regulated parties due to jurisdictional concerns. Because such producers are not currently able to become regulated parties, they must sell their fuels without the ability to retain the compliance obligation (and hence retain the credits); if the product is sold to an importer to California, that importer would be designated the regulated party under the existing rule. If these producers and intermediates are allowed to voluntarily enter the LCFS program as regulated parties, they would be able to sell their fuels and retain all or part of the credits generated from their low-CI fuels.

Accordingly, staff is proposing changes that would address these concerns. First, staff proposes to include a new section 95480.2, which would identify and establish specific criteria for voluntarily entering the LCFS program (i.e., criteria that would apply to persons wishing to opt into the program). In addition to the fuel providers specified in section 95480.1(b), this new section would allow out-of-state producers of oxygenate (e.g., ethanol) or biomass-based diesel to opt into the program. Further, the new section would allow intermediate entities downstream of the out-of-state producer to also opt into the program under prescribed conditions. Finally, this new section would allow for gas suppliers to opt into the program, under specified conditions, in lieu of California compressed natural gas (CNG) fueling station owners, if such station owners have not otherwise elected to opt into the program. Allowing the gas suppliers to opt into the program under the specified conditions will help ensure that potential LCFS credits are not “orphaned” if the fueling station owners choose not to opt into the program.

Second, staff proposes a new section 95480.3, which would specify the actual procedure for opting into and out of the LCFS program. This procedure would be available for those persons who are qualified to opt in under new section 95480.2.

Opting in would simply require a qualified person to register as the regulated party for the fuel of interest.

This new section 95480.3 would also specify the options available for the opt-in regulated party to select the applicable CI value for its fuel. Basically, in addition to the standard options (Methods 1, 2A, and 2B) that are available to other regulated parties, opt-in regulated parties for low-CI fuels subject to section 95480.1(b) would have a third option of choosing the 2020 endpoint CI values for the gasoline or diesel compliance schedules. In other words, if an opt-in regulated party for CNG, for example, does not want to choose Method 1 (or there are no applicable CI values in the Lookup Table), and it wants to avoid submitting a Method 2A/2B application for a new/modified fuel pathway, the regulated party can choose either the 2020 CI target for gasoline (86.27 gCO2e/MJ) or diesel (85.24 gCO2e/MJ), whichever applies. This is because the fuels, including CNG, which are subject to section 95480.1(b) are presumed to already meet the 2020 CI standards.

As noted, new section 95480.3 would specify the procedure for opting out. The proposed procedure would specify 90-day pre-opt out notification, verification that the opt-out occurred on that date, and post-op-out notification and reporting requirements. The proposal would also require recordkeeping consistent with the recordkeeping requirements already specified in the regulation for all regulated parties.

Third, the expansion of potential opt-in entities, especially for qualified intermediates, raises the possibility of multiple parties inadvertently registering and reporting themselves as the regulated party for the same volume of fuel. Therefore, staff proposes a new section 95480.4 that would establish a clear procedure for the Executive Officer (EO) to use in determining which party can validly claim to be the regulated party in that situation. Essentially, the proposal would look first at any contracts between the parties of interest to see if the agreements identify the proper regulated party. In the absence of clear contract language, the EO would then look at the regulatory language and apply the priority scheme contained therein. Finally, in case neither of these approaches works, the proposal would assign regulated party status based on a specified default. While the EO's determination is underway, any credits subject to multiple claims of regulated party status will be held in escrow for a maximum of 30 business days.

Thus, for fuels produced outside California, the regulatory text would effectively assign initial regulated party status in the following order of priority (unless written contracts between the parties stipulate otherwise):

1. Out-of-state producer (if the producer opts in);

2. Intermediate entity downstream of the out-of-state producer (if the producer transfers compliance obligation to the intermediate and other requirements in 95480.3 are met); and

3. Importer (if neither 1 nor 2 applies).

Finally, staff proposes a new section 95480.5 that would make it clear that registration as a regulated party (in this case, as an opt-in regulated party) would establish that person's consent to be subject to California jurisdiction. This new section would also establish a person's consent to be subject to California jurisdiction if the person receives proceeds from a credit transaction.

B. Enhanced Regulated Party

The existing LCFS regulation places compliance obligations initially on California fuel producers and importers. Section 95484 of the regulation specifies the criteria under which a person would be deemed a regulated party for each particular fuel and how the responsibility for complying with the LCFS can be transferred. As currently worded, the regulation provides for the transfer of compliance obligation to flow "downstream" from the initial regulated party; it does not permit the compliance obligation to flow "upstream" to intermediates and the out-of-state producer.

As noted above in "Opt-In and Opt-Out Provisions," staff is proposing changes that would allow out-of-state producers to voluntarily enter the LCFS program by becoming the initial regulated party. Consistent with this proposal, staff is also proposing to change the definition of "producer" so that it also encompasses out-of-state producers (the current definition includes only California-based producers).

Further, based on stakeholder comments received,[21,22] staff is proposing revisions to the definition of "importer" to include, as potential initial regulated parties, those entities that own title to a product at the point the equipment has entered California. The existing regulation confers initial regulated party status to importers if those persons own title to the fuel when it is received at the "import facility," so this proposed change would impart the regulated party status on the person who owns the product in the transportation equipment that held or carried the product, when it entered California. Staff proposes to delete the definition of "import facility" since the definition of "importer" no longer references "import facility."

C. Method 2A/2B Certification

When the Board approved the LCFS in April 2009, the regulation contained both fuel pathway Lookup Tables and a formal process for adding pathways submitted by stakeholders to those tables. The Lookup Tables (Tables 6 and 7, section 95486(b)(1)) house the carbon intensities of the fuel pathways that the Board approved. Section 95486(c) and (d) establish the procedures regulated parties and other entities must follow in order to add new pathways to the Lookup Tables. Those procedures consist of a formal application process in which the applicant calculates a pathway

[21] Robert Whiteman, POET Ethanol Products, July 29, 2011. Comment letter to ARB providing specific information about how liquid biofuels are currently being delivered into California.
[22] Jessica Wiechman, Renewable Products Marketing Group, Inc. (RPMG), August 5, 2011. Comment letter to ARB regarding Midwest biofuel industry.

carbon intensity value, using the California Greenhouse gases, Regulated Emissions, and Energy use in Transportation (CA-GREET) model, and provides ARB staff with sufficient supporting documentation to recommend the proposed pathway carbon intensity for approval by the EO.

Because the Lookup Tables are contained in the LCFS regulation, making changes to them (i.e., adding a new fuel pathway) would require a full rulemaking process pursuant to the Administrative Procedure Act (APA)[23].

As with most ARB rulemakings, the approval of new or modified fuel pathways for incorporation into the Lookup Tables would require an initial and final statement of reasons, at least one formal comment period (generally a 45-day period), and a public hearing. Substantive changes proposed after the start of the formal comment period would entail additional comment periods. Thus, a typical rulemaking would take from six to 12 months during the formal rulemaking phase. This doesn't include the approximate 30 to 90 days of working with an applicant, before the formal comment period begins, to prepare the application. Based on the potential efficiency gains and in recognition that the activities to process and evaluate Method 2A/2B applications are becoming more routine, the Board directed staff under Resolution 09-31 to investigate the feasibility of converting the rulemaking process for the approval of new or modified pathways into a more streamlined certification process.

While the certification program described in this Chapter was under development, the Board issued Resolution 10-49, which directed staff to develop a process whereby Method 2A and 2B applicants could use their proposed pathway CIs once staff recommended them for approval. Approval recommendations are issued well before the applications can be heard before the EO. Accordingly, guidance clarifying this policy was issued in December of 2010 in the form of LCFS Regulatory Advisory 10-04. Under that Advisory, Method 2A and 2B applicants are able to use their proposed CIs as soon as staff recommends them for approval and posts them to the LCFS web site.

Regulatory Advisory 10-04 allows applicants to temporarily use the CIs for which they apply while the rulemaking process is underway, but does not expedite the final approval process. Nor does it alleviate the substantial ARB staff workload associated with the regulatory change process. Importantly, it also does not fulfill the Resolution 09-31 directive to develop a certification program. As such, the Regulatory Advisory 10-04 process amounts only to a temporary measure.

<u>Proposed Certification Process</u>

This section provides a brief, plain English summary of the major elements of the proposed certification process. Because the certification process itself is highly detailed and comprehensive, the reader is directed to Appendix A (Proposed Regulation Order) for exact details on the proposed regulatory text.

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[23] Government Code section 11340 et seq.

Under the existing regulation, a regulated party can use a CI value from the Lookup Tables that applies to that person's fuel pathway (subject to approval by the EO). Alternatively, the regulated party can submit a Method 2A/2B application for EO certification of the new or modified pathway. As part of the approval process, the EO would issue an Executive Order for the fuel pathway covered by the certification. The Executive Order would apply only to the applicant and its certified fuel pathway(s).

1. *Application Submission Requirements*

The staff's proposal would require applications, in order to be deemed complete, to contain extensive and detailed information about the applicant's proposed fuel pathway. As noted, the detailed information that would be required in the submittal is specified in the proposed regulatory text.[24] This high level of detail is derived from ARB staff's experience with the Method 2A/2B review process to date. Based on that experience, the staff's proposal specifies a level of detail in the required information that staff believes is necessary for the EO to make the determination that the application is based on robust, scientifically defensible and credible information. Further, for Method 2A applications, the information is necessary for the EO to make the determination that the application represents an innovation that meets the regulation's substantiality requirements.

A primary concern in the application process is the protection from disclosure of confidential business information (CBI). On the other hand, this concern must be balanced with the need to maintain transparency and give the public a meaningful opportunity for comment and review of the proposed fuel pathway. To balance these concerns, the proposed application process would require the applicant to submit a fully detailed application, including all required information, for ARB staff's review. At the same time, the proposal would require the applicant to also submit a version of the application with the CBI redacted to the extent that would still allow for meaningful public review. The process would require applicants to clearly identify the specific information for which confidentiality is sought.

2. *Application Evaluation Procedure*

The proposal specifies that, within 30 calendar days after receiving an application designated by the applicant as a final, evaluation-ready copy, ARB staff will advise the applicant in writing that it is either complete or that specified additional information is required to make it complete. Within 30 calendar days from the request for additional information, ARB staff will again advise the applicant in writing that the application is either complete or that specified additional information is still required before it can be deemed complete. The proposal does not specify how many times this cycle can be repeated, but the application can be denied if staff determines that the required information is not forthcoming. Even if an application packet has been deemed complete, the proposal provides ARB staff with the ability to request additional

[24] See section 95486(f)(3)(C) of the proposed regulation order.

information and clarification, if needed, as staff's analysis of the application packet proceeds. This may be needed, for example, if staff's analysis of an application already deemed complete raises additional issues that need to be addressed.

The proposal specifies that the formal evaluation will last no more than 90 calendar days. Because each application is unique and may present unforeseen challenges, the proposal provides for the possibility of pausing staff's evaluation while staff works with the applicant to resolve such issues. This allows the evaluation process, once the issues have been resolved, to resume at about the point where it left off.

Under the staff's proposal, the evaluation of complete Method 2A and 2B applications will generally involve the following steps:

- Staff attempts to replicate the applicant's carbon intensity calculations;
- Staff attempts to replicate the energy consumption inputs to the carbon intensity calculations using the energy purchase and fuel production data in the application;
- Staff evaluates the production information submitted by the applicant for consistency, both with itself (internal consistency) and with every other item in the application (external consistency). Consistency is required in all areas, not only those that directly contribute to the calculation of the pathway carbon intensity; and
- Staff evaluates the documentary basis of all data and assumptions that are not verifiably derived from the energy consumption and fuel production data included in the application packet.

If any of the steps outlined above cannot be complete due to a discrepancy or other issue, the evaluation will be suspended until the discrepancy or issue can be resolved.

3. *Pathway-Specific Requirements*

The proposal provides for specific requirements that apply to certain types of pathways. These requirements will minimize the exercise of discretion in the evaluation of the applications in these categories and help assure consistent outcomes across different applicants.

a. Most fermentation-based pathways (e.g., corn ethanol) yield a co-product known as distillers grains with solubles (DGS), which the applicant may sell at varying levels of moisture content. Many fuel operations will vary DGS drying over time to reflect market conditions. In order to assure that all drying energy for different levels of DGS dryness are accounted for, applicants who sell DGS at more than one dryness level will be required to calculate their pathway CI (or CIs) using one of the following methods:

    i. General approach (most applicants): Calculate a single CI that reflects the maximum foreseeable production of fully and partially dried DGS, reflecting the total plant energy consumed while DGS is being dried at the maximum foreseeable rate. The applicant can average plant energy consumption on either a monthly or an annual basis. However, any ethanol associated with the production of dry or partially dry DGS, in excess of the quantities used to calculate the plant's pathway CI, cannot be sold in California under the approved pathway. For example, the approved CI may be based on drying 75 percent of the total DGS stream, calculated as an annual average. After the pathway has been approved, if 80 percent of the ethanol is dried in any given year, the ethanol associated with the production of 80 percent dry DGS cannot be sold in California under the approved CI. The approval issued by the EO will, in fact, include an operational condition stating that the production of dry or partially dry DGS shall never exceed the quantities on which the approved CI is based.

ii. Alternative approach: An applicant with a plant that has DGS dryers equipped with functional and accurate gas gauges may apply for separate CIs for each DGS dryness level. This is provided the applicant is able to accurately associate every gallon of ethanol produced with a specific DGS dryness level. Dryer gas gauge readings will be used to precisely calculate the drying energy consumed for each DGS dryness level. These energy consumption levels will be added to baseline (100 percent wet DGS) levels to calculate DGS-specific carbon intensities. The applicant must then demonstrate, to ARB staff's satisfaction, that each gallon of ethanol produced can be clearly associated with only one DGS dryness level. This association must be credible and accurate, even in plants with continuous DGS production that employ dryers that function in series.[25]

b. Although ARB encourages and is moving to fully account for agricultural practices aimed at reducing GHG emissions, accounting for these practices under the proposed Method 2 certification process is not yet straightforward. Reliable data, with sufficient geographic resolution, on the use of such practices is limited.

For example, it is currently difficult to determine how various planting and disking practices alter equipment use, chemical application rates, erosion, and decomposition of soil organic matter. In other cases, State-level data showing performance improvements over national averages may exist, but no indication of the variance in the data is available. A high variance may mean that the apparent difference isn't actually significantly different from zero. Even if the significance of an apparent difference can be confirmed, there is usually no way to determine farm-to-farm differences (i.e., there is no certainty that practices on the specific farms supplying feedstock to fuel producers seeking LCFS certification actually conform to the state-level averages). Finally, even in cases where farm-level GHG-benefits can be documented on the farms supplying feedstock to pathway applicants, most of the practices are easily reversible. Economic conditions could easily alter the extent to which reduced-emissions practices are maintained from year-to-year.

[25] When dryers are installed in series rather than singly or in parallel, a portion of the DGS stream exiting the first dryer enters a second dryer, where it becomes dry DGS. The portion of the stream that is diverted before it enters the second dryer becomes modified (or partially dry) DGS.

Until a process is developed whereby practices that reduce GHG-emissions are included in the calculated fuel pathway CIs, the Method 2 pathway development process can only credit pathways for low-emissions agricultural practices if:

i. scientifically sound data exist that demonstrate the claimed practices are in use on the specific farms that supply feedstock to the Method 2 applicant, and

ii. the applicant agrees to a process in which ARB can confirm that the beneficial practices remain in place for each crop cycle.

c. Certification applications for sugarcane pathways would need to be backed by verifiable third-party documentation. Acceptable forms of documentation include, but are not limited to, receipts for sales of surplus electricity, sales receipts from ethanol buyers, engineering studies produced by independent and well-established engineering firms, independent audit reports, and published research results. An area in which sugar cane ethanol producers may be able to improve their carbon intensities is by exporting electricity in excess of the 0.96 kWh/gallon of ethanol, which is the basis for the two lowest sugarcane ethanol CIs (66.40 and 58.40 gCO2e/MJ) ARB staff has assessed at this time. Any application claiming exports beyond this level must document that claim with, for example, receipts from the buyers of the surplus electricity, and sales receipts for all ethanol sold over the period covered by the electricity sales receipts. Third party audit and engineering reports may also suffice.

   Additional sugarcane-specific requirements are specified in the staff's proposed amendments. For example, the applicant would need to demonstrate that only the electricity generated from the bagasse associated with the cane used in the ethanol production was counted in the electrical export calculations (i.e., the bagasse from the cane that went to sugar production cannot be counted). Similarly, the electricity sold to the grid from the sugar production operation could not be counted in the calculation of the ethanol electricity export credit. Further, applications that claim credit for mechanical harvesting would need to be supported, with verifiable third-party documentation, that show mechanical harvesting is used on an ongoing basis on the plantations supplying sugarcane to the applicant's mills. This is necessary because a large proportion of plantations still do not employ mechanical harvesting.[26]

Additional carbon intensity determination provisions unrelated to the proposed certification program were also added to Section 95486(a). In 95486(a)(4), a provision

[26] See, for example, Alves de Aguiar, Daniel, Wagner Fernando da Silva, Bernardo Friedrich Theodor Rudorff, Marcos Adami, July 5-7, 2010, "Canasat Project: Monitoring The Sugarcane Harvest Type In The State Of São Paulo, Brazil." In: Wagner W., Székely, B. (eds.): ISPRS TC VII Symposium – 100 Years ISPRS, Vienna, Austria, July 5–7, 2010, IAPRS, Vol. XXXVIII, Part 7B. : http://www.isprs.org/proceedings/XXXVIII/part7/b/pdf/10_XXXVIII-part7B.pdf. The authors found that 50.9 percent of the harvested sugarcane area in the State of São Paulo was burned in 2008/09.

creating default carbon intensity values was added. These values—one for gasoline substitutes and one for diesel substitutes—could be used, with Executive Officer approval, in cases in which the actual carbon intensity cannot be determined. This provision was added to the regulation because carbon intensity defaults currently exist only in Regulatory Advisories 10-04 and 10-04a, both of which are set to expire.

A fuel's carbon intensity cannot be determined if:

- It's production facility cannot be identified, or
- It has neither been registered with Biofuel Producer Registration process, nor received a carbon intensity via the Method 2 process.

This section establishes a default of 99.4 gCO_2e/MJ (the Midwest average from the Lookup Table) for gasoline substitutes, and the current annual ULSD baseline carbon intensity for diesel substitutes

Provisions were also added to 95486(a)(2) and (3) clarifying the procedure by which carbon intensities are determined using the Method 1 process. These new provisions specify that Method 1 can only be used for fuels that are produced using a well-to-wheels production pathway that is substantially similar to the corresponding well-to-wheels pathway described in the pathway document on which an LCFS Lookup Table pathway is based. Although the current regulation accomplishes this, the degree to which the actual fuel pathway and the Lookup Table pathway must be similar may not be clear without reference to 95486(b) in which the pathway documents behind the Lookup Table pathways are referenced. The proposed new language provides full clarity on this point within 95486(a).

D. Credit Trading Provisions

A new section 95488 is proposed to the LCFS regulation to provide more detail on how credits and deficits will be tracked, and to specify the process to be used to acquire, bank, transfer, and retire credits. Furthermore, this section clarifies how a regulated party can use credits acquired in the first quarter of a year to meet a compliance obligation in the previous year. This section would also establish requirements relating to the public release of information concerning deficits and the generation, use and transfer of credits.

Moreover, staff is proposing a number of changes to section 95484(b) of the existing regulation, and proposes to relocate section 95484(b) to new section 95488(a). These changes do not alter the stringency of the LCFS or change a regulated party's compliance obligation. They modify the formulas used to demonstrate compliance, change some of the terminology used, and conform the provisions of section 95488(a) to the proposed provisions of section 95488(b) through (e).

Changes to Previous Section 95484(b)

Section 95484(b) of the existing regulation, which is now relocated to section 95488(a), specifies how to calculate a Credit Balance and how to use the Credit Balance to determine if an annual compliance obligation has been met. The existing rule reflects an approach where "net" credit balance is tracked through quarterly reporting, and compliance is achieved when a regulated party's credit balance is zero or positive at the end of an annual compliance period.

However, as staff investigated a more detailed system for banking and trading credits, they determined that an approach that clearly separates credit generation and tracking from deficit accounting was appropriate. Accordingly, staff proposes several changes to reflect such an approach. The proposed changes, which do not alter the stringency of the LCFS, include:

- A new formula to calculate a regulated party's annual compliance obligation.
- A revised formula to calculate a regulated party's credit balance.
- A provision specifying that a regulated party must retire credits equal to deficits to demonstrate it has met its annual compliance obligation.
- A revised method to determine a regulated party's credit to deficit ratio if the regulated party retires insufficient credits to meet its compliance obligation.

First, the proposal would define a new term—a regulated party's compliance obligation. The compliance obligation would be the sum of all deficits a regulated party generated in the current compliance period plus any deficits that were carried over from a previous period. The proposed approach is no more or less stringent than the existing rule.

Second, the proposal would modify the formula used to calculate credit balance. The revised formula would be based on credit generation and credit acquisition or credit transfer[27] only. Credit balance would be calculated as follows:

$$Credit\ Balance = Sum\ of\ (Credits^{Gen} + Credits^{Acquired}) - Sum\ of\ (Credits^{Retired} + Credits^{Sold} + Credits^{Exported})$$

where:

$Credits^{Gen}$ are the total credits generated pursuant to section 95488;

$Credits^{Acquired}$ are the total credits purchased or otherwise acquired, including carry back credits acquired pursuant to section 95488(b)(3);

[27] Transfers include credit retirement, the transfer of credits to other regulated parties, and the export of credits to other programs.

Credits ^{Sold} are the total credits sold or otherwise transferred;

Credits ^{Exported} are the total credits exported to programs outside the LCFS; and

Credits ^{Retired} are the total credits retired within the LCFS.

The term Credit Balance would be used to determine the total number of credits in a regulated party's credit account. This is the maximum number of credits that can be retired for compliance or, in the case of a proposed credit transfer, the maximum number of credits that can be transferred to another regulated party.

Third, the proposal would add a new section: "Compliance Demonstration." This section specifies that an regulated party must possess and have retired qualifying credits[28] equal to its deficits (as defined by its compliance obligation) by the time the regulated party submits its annual compliance report. The proposed approach is no more or less stringent than the existing rule. The compliance demonstration replaces the term "Credit Balance" currently used in section 95488(a)(2) to determine if deficits exist and must be carried over to the next compliance period.

Fourth, the proposal would establish a new formula to determine if a deficit can be carried over to the next compliance period without penalty. The proposed approach is no more or less stringent than the existing rule. A regulated party is required to retire credits equal to at least 90 percent of its compliance obligation in order to carry over deficits without penalty.

Finally, the proposal would modify some of the terms used in the Deficit Reconciliation section so that this section conforms to the changes made in the preceding subsections.

New Section 95488 - Banking, Transfer and Retirement of Credits

Earning and Using Transferrable Credits

Credits are generated under the LCFS program when the carbon intensity (CI) of a fuel or blendstock supplied for transportation use is below the annual gasoline or diesel standard. The amount of credit generated by fuels with CIs that are lower than the CI of the LCFS depends on both the CI of the fuel and the quantity that is supplied in California. Regulated parties use the LCFS Reporting Tool (LRT) to report the fuels they supply, and the LRT uses this information to calculate both the credits and deficits that are generated for each fuel type. Under the proposed approach, the amount of

[28] Qualifying credits must have been generated by a regulated party prior to the end of an annual compliance period. Credits which are generated in the first quarter of a year may not be retired to meet a previous year's compliance obligation.

credit generated would not be affected by the amount of deficits incurred by the same regulated party[29]. Deficits and credits would be tracked separately in the LCFS. For example, suppose a supplier provides fuel A, B, and C, and fuels A and B generate credits while fuel C generates a deficit. The total credits generated is the sum of credits from fuel A and fuel B, regardless of the deficits generated from fuel C. Figure 3 illustrates how credits are generated by the successful, timely submission of a quarterly report.

Figure 3: Summary of Quarterly Report Showing Credits and Deficit Generated as a Result of Supplying Ethanol to California

Submit Quarterly Report

Organization: Not Applicable **Reporting Period: Quarter 1 , 2011** **Status: Open**

Quarterly Fuel Details

Transaction Details	Fuel Name	Fuel Pathway Code	CI (g/MJ)	EER	Total Obligated Amount	Unit	Credits (MT)	Deficits (MT)	Incremental Deficit (MT)	Fuel Application
Goto Details	Ethanol from Corn	ETHC031	83.70	1	45,454,345	gal	44,126	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Corn	ETHC028	91.70	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Corn	ETHC027	88.50	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Corn	ETHC026	88.50	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Corn	ETHC025	92.40	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Corn	ETHC008	90.10	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Corn	ETHC004	98.40	1	444,334	gal	0	101	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Sorghum	ETHG006	84.36	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles
Goto Details	Ethanol from Sorghum	ETHG002	85.81	1	0	gal	0	0	0	Light Duty or Medium Duty Vehicles

Total quarterly credits generated and banked* **Total Credits/Deficits Generated (MT): 44,025**

***** The total number of credits banked and available for trade is determined from the sum of all credits generated from the supply of fuels that exceed the performance of the standard.

In Figure 3, a regulated party has submitted a quarterly status report showing the supply of two ethanol fuels. In the LRT, a quarterly summary page containing an overview of the reported information is displayed to the user. The summary page shows all credits

[29] Staff had considered using the net credits to limit the amount of credit a regulated party could bank or transfer or trade. However, after reviewing the existing LCFS regulation, it was determined that the concept of limiting the number of credits that could be banked or traded to the net credits was not consistent with the adopted regulation, and that maintaining a separate accounting process for credits and deficits was preferable.

calculated from the supply of fuel below the standard in the column labeled "Credits (MT)." Similarly, a column called "Deficits (MT)" contains all deficits associated with fuels above the standard.

On a quarterly basis, upon the successful, timely submission of a report, a total value representing the sum of all credits and a total value representing the sum of all deficits are separately tracked in the LCFS Credit Accounting system. The sum of all credits, independent of the sum of all deficits, is the amount of credits earned for the quarter. These credits would then be added to the regulated party's credit account balance. Once in the credit account the credits can be banked, transferred, or retired for compliance.

The LRT also calculates the sum of all credits and deficits on a quarterly basis. This "net" credit or deficit balance, labeled as "Total Credits/Deficits Generated (MT)," is listed on the LRT summary page for each regulated party. However, while generated credits will be transferred to a regulated party's credit account on a quarterly basis, deficits will be accumulated as an annual obligation, and the regulated party is not required to possess sufficient credits to offset its deficits until it makes its annual compliance demonstration.

Extended Credit Purchase Period

For regulated parties that may have a credit shortfall[30] in a given compliance year, staff proposes to provide an additional period in which additional credits may be purchased or otherwise acquired. Beginning 2012, a regulated party may acquire credits between January 1 and March 31, also called an "extended credit purchase period," and elect to carry back a portion or all of the purchased credits for the purpose of meeting the regulated party's compliance obligation of the year immediately prior. Credits purchased during the extended period must be generated in a previous compliance year(s) to be used to meet a previous year's compliance obligation. For example, for 2014, the additional credits purchased must have been generated between 2011 and 2013.

Continuing with the same example, a regulated party may, under certain conditions, elect to carry back all or some of the credits purchased between January 1 and March 31, 2014, and apply those credits for the 2013 compliance year. The credits are called "carry-back credits" and may only be used as part of the regulated party's compliance demonstration for the prior year. The credits carried back are considered as additional acquired credits as part of the regulated party's annual compliance demonstration.

[30] Shortfall here means that the regulated party has fewer qualifying credits in its possession than the sum of the deficits it is obligated to offset for the compliance year.

A regulated party electing to carry back credits must either:

1. Retire enough credits to meet the shortfall of the prior compliance year, or
2. If the shortfall cannot be eliminated, retire all credits eligible for carry-back.

For example, if a regulated party has a deficit balance of 200 MT CO_2e at the end of 2011 and then purchased 500 MT of additional credits eligible for carry back during the extended period in 2012, 200 MT of credits must be carried back and retired to meet the obligation in 2011. However, if a regulated party has a deficit balance of 1,000 MT at the end of 2011, then the entire 500 MT purchased credits must be carried back. Additionally, since the regulated party has a remaining balance of -500 MT in 2011, a credit-to-deficit ratio calculation will be performed to determine the extent of the shortfall.

As an interim solution, prior to the availability of the accounting system in the LRT, staff proposes to maintain the regulated party's credit balance in an external interim account and manually execute the process of accounting for carried-back credits. When the LRT enhancements are completed, both the specification of credit carry-back and account management will be handled electronically by the system. Meanwhile, staff will provide all interim solutions to regulated parties so that they may maintain account balances in parallel. For regulated parties that do not elect to carry back credits, any credits purchased in the first quarter of a year would be banked for future use.

Requirements for a Credit Transfer

A regulated party who wishes to sell or transfer credits ("the Seller") and a regulated party who wishes to purchase or acquire credits ("the Buyer") may enter into an agreement to transfer credits. The Seller may transfer credits provided the number of credits to be transferred by the Seller does not exceed the number of total credits in the Seller's credit account. When a transfer agreement is desired, it is the Seller's responsibility to provide the Buyer with a Credit Transfer Form containing the Seller's signature, date when the signature was entered, and the following information:

- Date of the proposed Credit transfer agreement.
- Names of the Seller and Buyer's Company as registered in the LCFS Reporting Tool.
- The Federal Employer Identification Numbers of the Seller and Buyer's Company as registered in the LCFS Reporting Tool.
- The first name and last name of the person who performed the transaction on behalf of the Seller's Company.
- The phone number and email of the person who performed the transaction on behalf of the Seller's Company.
- The first name and last name of the person who performed the transaction on behalf of the Buyer's Company.

- The phone number and email of the person who performed the transaction on behalf of the Buyer's Company.
- The number of credits proposed to be transferred and the credit identification numbers, if any, assigned to the credit(s) by the board.
- The price, if any, per metric ton of credit proposed for transfer, excluding any fees.

After receiving the Credit Transfer Form from the Seller, it would be the Buyer's responsibility to confirm the accuracy of the information contained in the Credit Transfer Form by signing and dating the Credit Transfer Form. The Buyer is responsible for the submission of the Credit Transfer Form with all of the required information to the EO. The EO will process the transfer request, and will update the account balance of the Seller and Buyer to reflect the proposed transfer unless the EO determines that one or more of the requirements for credit transfers has not been met. The Credit Transfer Form is provided in Appendix G.

Credits may be transferred between a Seller and Buyer on a frequency that is agreed upon between the two parties. A Seller or Buyer may elect to use a non-regulated party (a credit facilitator) to facilitate the transfer of credits for the Seller, the Buyer, or both. The credit facilitator may include, but is not limited to, a credit transfer service agency or broker who assists in arranging the transfer of credits. However, a credit facilitator cannot own or otherwise exercise control over the credits.

Retirement of Credits to Meet Obligation

At the end of a compliance year, staff proposes that a regulated party responsible for fuels that have incurred deficits must retire a sufficient number of credits to offset the deficit. If excess credits remain after meeting the obligation, those credits remain in the regulated party's credit account. If a regulated party cannot retire a sufficient number of credits to meet its compliance obligation, then all credits that are eligible to meet the compliance obligation and which are within the possession of the regulated party must be retired.

Specification of Credits to be Retired

As part of its annual compliance report, a regulated party that has met 100 percent of its compliance obligation may specify which credits are to be retired. The specification of which credits are to be retired is voluntary. If a regulated party does not make a specification, staff will use a default retirement hierarchy (see Appendix G). Under the default approach, all credits the regulated party acquired as carry-back credits (if any) during the extended period of January 1 to March 31 of the following year would be retired first. Credits the regulated party acquired during a previous compliance year would then be retired in order of purchase date (oldest first). Finally, credits the regulated party generated in previous compliance years would be retired in order of the credits were generated (oldest first).

Public Disclosure of Information and Transparency

Staff proposes to add a new subsection titled, "*Public Disclosure of Credit and Deficit Balances and Credit Transfer Information,"* to the LCFS rule. The purpose of this section is to make clear to the public and market participants that there will be routine, periodic releases of information on credit and deficit generation as well as trading activity. This subsection would permit the EO, no less frequently than quarterly, to provide public reports containing a summary of credit generation and transfer information including, but not limited to:

- Total deficits and credits generated or incurred in the most recent quarter for which data are available, including information on the types and quantities of fuels used to generate credits.
- Total deficits and credits generated or incurred in all previous quarters of the most recent year for which data are available, including information on the types and quantities of fuels used to generate credits.
- Total credits in possession of regulated parties and the total number of outstanding deficits carried over by regulated parties from a previous compliance year.
- Information on the credits transferred during the most recent quarter for which data is available including, but not limited to, the total number of credits transferred, the number transfers, the number of parties making transfers and the monthly average credit price for transfers that reported a price.
- Total credits transferred and used as carry-back credits during the first quarter of the current compliance period.

In addition, ARB staff intends to publish, at least monthly, information that would be helpful to the functioning of a credit market. Such reports may include recent information on credit transfer volumes, credit prices and price trends, and other information determined by the EO to be of value to market participants and the public. By necessity, the report would need to be limited to a level of detail that does not compromise confidential information submitted by regulated parties. Finally, the staff intends to establish a schedule for the routine release of these reports.

E. High Carbon-Intensity Crude Oil (HCICO) Provisions

<u>Background</u>

There are many production techniques for crude oil recovery. Some of the techniques require more energy or emit more GHGs to produce and pre-process the oil. Thermally enhanced oil recovery, bitumen mining, upgrading, and excessive flaring of associated gas are examples of production methods and practices that lead to increased GHG emissions. Since the LCFS regulation takes into account full lifecycle GHG emissions for fuel pathways, including all stages of feedstock production and distribution, the upstream emissions from energy-intensive crude recovery methods need to be accounted for in the regulation. The purpose of the HCICO provisions is to ensure that increases in the overall CI of CARBOB (California Reformulated Gasoline Blendstock for Oxygenate Blending) and ULSD (Ultra Low Sulfur Diesel) that might occur over time due to the use of more carbon intensive crudes are mitigated and do not diminish the emission reductions anticipated from the LCFS regulation.

The existing provisions address this issue by requiring accounting of GHG emissions associated with crude oils with high upstream emissions. The existing HCICO provisions provide a specific method for treating crude oils with high upstream emissions that were not from geographic areas substantially used in 2006.[31] A HCICO, as defined in Section 95486(b)(2)(A) of the LCFS regulation, is any crude oil which 1) was not produced in one of the countries excluded from the HCICO provision and 2) has a total production and transport carbon intensity (CI) value greater than 15 gCO2e/MJ[32].

Currently, the crude oil mix refined in CA in the year 2006 is used as the baseline to calculate average Lookup Table CI values for CARBOB and ULSD pathways. Gasoline compliance targets are calculated relative to CI for CaRFG (California Reformulated Gasoline; 90 percent CARBOB and 10 percent average ethanol); diesel compliance targets are calculated relative to CI for ULSD. Section 95486(b)(2)(A) of the LCFS regulation specifies the requirements for using the Lookup Table to determine CI values for CARBOB, gasoline, and diesel fuel used under the program. A regulated party is required to use the average CI value shown in the Lookup Table if the fuel/blendstock is derived from crude oil that is either not a HCICO, or was included in the 2006 California baseline crude mix (i.e., originated from a location which contributed two percent or more of the total crude oil refined in California in 2006 ["crude basket"]). A crude oil that does not satisfy both of these conditions is referred to as non-basket HCICO.

For fuel/blendstock made from non-basket HCICOs, the regulated party is required to use the Lookup Table CI values associated with the specific HCICO pathways and to calculate and report the associated deficits from these sources. The purpose of this requirement is to account for additional emissions generated beyond the 2006 gasoline and diesel baseline from the use of HCICOs and to encourage emission-reduction activities from these sources. If those CI values have not yet been determined and published in the Lookup Tables, the regulated party is required to propose a new pathway under Method 2B for its HCICO and obtain approval of the Executive Officer. For HCICOs, the average CI values from the Lookup Table may be used if the oil is produced using innovative methods, such as carbon capture and storage (CCS) or other methods, that reduce the CI to less than 15 gCO2e/MJ.

[31] Defined as countries or states that provided two percent or more of California's crude supplies in 2006. The countries include: Angola, Brazil, Ecuador, Iraq, Mexico, Saudi Arabia and the States include California and Alaska.

[32] In comparison, the average crude production and transport CI included in the overall CI for the CARBOB (CI = 95.86 gCO_2e/MJ) and ULSD (CI = 94.71 gCO_2e/MJ) fuel pathways is 8.07 gCO_2e/MJ, a little more than half the value of a minimum HCICO.

All regulated parties for gasoline (diesel) calculate a “base” deficit using the difference between the average Lookup Table value for CARBOB (ULSD) and the compliance target in that year. An incremental deficit is applied only to those regulated parties that supply fuels derived from non-basket HCICOs. The incremental deficit is calculated using the difference between the Lookup Table CI values for CARBOB (ULSD) and the CI value for the specific HCICO pathway.

Summary of Crude Screening Workgroup

When the Board approved the LCFS regulation on April 23, 2009, it directed staff, through Resolution 09-31, to work with stakeholders to develop an informal screening process for assessing the CI of new or modified fuel pathways. In response to the Board’s direction, staff convened the Crude Screening Workgroup in March 2010 to address new fuel pathways for HCICOs. The intended outcome of the screening process was to identify those crudes that are clearly not HCICO, thereby reducing the number of crudes that would be subject to the more rigorous technical analyses under Method 2B.

The Crude Screening Workgroup was comprised of industry, government, environmental, and academic representatives with an objective to assist in developing a screening process for determining the CI value of crude oil sources under the LCFS. The workgroup met six times, and a smaller subgroup met weekly over a period of six weeks to discuss details of the screening process. Working with the Crude Screening Workgroup, ARB staff developed an interim process[33] for determining which non-basket crude oil sources are non-HCICO, while assigning an appropriate default carbon intensity value to those sources that are determined to be “potential-HCICO.” The intent is that the interim process will remain in place until a standardized tool/method that can be used to calculate CI values for all crude sources is developed and approved.

The interim screening process was applied, with the assistance of California Energy Commission (CEC) staff[34], to approximately 250 crude sources, of which approximately 80 percent were identified as non-HCICO. The remaining sources, which are designated as potential-HCICO, are those produced using thermal recovery methods, bitumen mining, excessive flaring, or upgrading.

Regulatory Advisory 10-04 and Supplemental Advisory 10-04A

On November 18, 2010, staff presented to the Board an update on LCFS implementation activities, including the development of a screening process for HCICOs. Through Resolution 10-49, the Board directed staff to issue guidelines

[33] Air Resources Board, February 11, 2011. Draft - Determining Carbon Intensity Values for Fuels Derived From Crude Oil. Interim Crude Oil Screening Process.

[34] Results of Initial Screening Process to Identify Potential HCICOs. Shremp, Gordon. Senior Fuels Specialist, California Energy Commission. Powerpoint Presentation at Crude Oil Screening Workgroup Meeting, February 17, 2011.

regarding the implementation of the LCFS in 2011. Staff issued two regulatory advisories that, in addition to other LCFS implementation guidance, provided clarifications related to HCICO provisions.

Regulatory Advisory 10-04, issued in December 2010, provided an extension through June 30, 2011, for the use of interim CI values for fuels derived from potential-HCICOs. The advisory stated that ARB staff will continue to work with stakeholders to develop guidelines addressing the generation and banking of credits during 2011, as potentially affected by crude oil purchases that are not part of the 2006 basket.

Supplemental Regulatory Advisory 10-04A, issued in July 2011, provided another extension through the end of 2011 for the use of interim CI values for fuels derived from potential-HCICOs. The supplemental advisory provided guidance on the treatment of credits and deficits generated from the blending of CARBOB or ULSD derived from potential-HCICOs, which was noted as a future action in Regulatory Advisory 10-04. Additionally, a list of 160 marketable crude oil names representing crude oil considered non-HCICO was provided as an attachment to the supplemental advisory to assist the regulated parties in identifying potential-HCICOs. This list of non-HCICOs to be used during the advisory period was developed using the interim screening process and is subject to change based on further ARB staff review and analysis.

Reasons for Considering Amendments to the Current HCICO Provisions

Petroleum refiners in California assert that the current HCICO provisions are overly burdensome to their industry, discriminatory toward sources of crude oil, will result in global crude-shuffling that increases GHG emissions, and would put California refiners at an economic disadvantage to out-of-state refiners. Therefore, they have requested that the 2006 baseline value be used for all production of CARBOB, and diesel fuel regardless of the type of crude supplies used by a refiner (i.e., no differentiation between the carbon intensities of crude oils). On the other hand, other stakeholders are equally as adamant that the LCFS should continue to prevent increases in lifecycle carbon emissions that could occur if higher intensity crudes are used to replace existing supplies. These parties generally support approaches that discourage or fully mitigate the refining of HCICOs in California and incentivize carbon emission mitigation techniques for oil production. ARB staff agreed to work with all interested stakeholders to explore alternatives to the current adopted approach to addressing HCICO in the LCFS. The goal of this effort was to determine if there were better options that would both meet the intent of the regulation (to ensure that the LCFS benefits are not diminished due to increases in GHG emissions from higher carbon intensity crude supplies) and address, to the extent possible, the concerns laid out by the various stakeholders.

<u>Discussion of Proposed Modifications</u>

Staff is proposing significant revisions to the current regulation relative to the treatment of HCICO.

Current Regulatory Requirements Related to HCICO

As stated previously, the purpose of the HCICO provisions of the LCFS regulation is to ensure that increases in the overall CI of CARBOB and ULSD that might occur over time due to the use of more carbon intensive crudes are mitigated and do not diminish the emission reductions anticipated from the LCFS regulation. The LCFS standard becomes more stringent over time, and the amount of deficits incurred per MJ of fuel supplied increase proportionately. For example, in 2011 CARBOB incurs a deficit of 0.25 gCO_2e/MJ; by 2020 the CARBOB deficits increase to 9.59 gCO_2e/MJ. Currently, the portion of the pathways attributable to the production and transport of crude oil is 8.07 gCO_2e/MJ, which comprises 8.4 percent of the CI for CARBOB and 8.5 percent of the CI for ULSD. If not mitigated, any significant increase in the CI of crude supplies used by California would reduce the anticipated benefits of the LCFS. For example, a 10 percent increase in the average CI of crude oil (from 8.07 gCO_2e/MJ to 8.88 gCO_2e/MJ) would reduce the program's effectiveness in reducing emissions from 10 percent to 9.15 percent.

Under the LCFS, regulated parties that supply CARBOB or ULSD generate deficits whenever these fuels are used in California. The amount of deficits incurred is determined by the difference between the LCFS standard in a given year and the CI of the CARBOB or ULSD. Section 95486(b)(2)(A) of the LCFS regulation specifies the procedures used to determine CI values for CARBOB and ULSD subject to the program. A regulated party is required to use the average CI value shown in the Lookup Table if the fuel/blendstock is derived from crude oil that is either not a HCICO (because it was determined to have a CI equal to or less than 15 gCO2e/MJ), or was included in the 2006 California baseline crude mix.

A crude oil that does not satisfy both of these conditions is treated as a HCICO. For fuel/blendstock made from HCICOs, the regulated party is required to apply a CI value determined for the specific HCICO pathways and to calculate and mitigate (through retirement of a similar amount of credits) the deficits incurred due to use of the HCICO. If the CI values of a HCICO have not yet been determined and published in the Lookup Tables, the regulated party is required to propose a new pathway under Method 2B for its HCICO and obtain approval of the Executive Officer.

The application of this requirement accounts for and requires mitigation of additional emissions generated beyond the 2006 gasoline and diesel baseline from the use of HCICOs. The adopted approach also encourages emission-reduction activities from sources of potential HCICO to reduce production and transport emissions to less than or equal to 15 gCO2e/MJ.

Proposed Changes to Regulatory Requirements Related to HCICO

Staff is proposing significant changes to the way increased emissions associated with HCICO fuels would be mitigated under the LCFS regulation. Most of the existing approach would be replaced with new regulatory requirements. The proposed approach would:

- Revise the portion of the CIs for CARBOB and ULSD due to the production and transport of crude oil to California refineries to reflect crude supplies used in the most recent year currently available, 2009. This would:
  - Increase the CI value attributable to the production and transport of crude oil from the current 8.07 gCO2e/MJ to a higher value of 9.72 gCO_2e/MJ;
  - Change the base CI values for CARBOB and ULSD from 95.86 gCO2e/MJ and 94.71 gCO2e/MJ to 97.51 gCO2e/MJ and 96.36 gCO2e/MJ, respectively; and
  - Require a corresponding change in the annual LCFS standards to reflect a higher CI baseline for CaRFG and ULSD. These changes would apply to fuels supplied between 2013 and 2020.

- Rescind the current approach for mitigating emissions greater than a baseline by:
  - Removing any distinctions in how crudes included in the 2006 baseline mix are treated relative to crudes from sources outside of that mix;
  - Eliminating requirements that CI increases for crudes that are classified as HCICOs be individually calculated and mitigated; and
  - Eliminating a provision that non-baseline crudes can qualify as non-HCICOs if it is demonstrated that the crude has a production and transport CI value equal to or less than 15 gCO2e/MJ.

- Establish a modified approach for mitigating higher emissions attributable to increases in crude production and transport CI by:
  - Establishing a California average crude production and transport CI based on the crude slate refined in California during 2009;
  - Performing an annual calculation, beginning in 2013, using data from calendar year 2012, of the “current” California average crude production and transport CI using the crude slate refined in California during the year. This calculation would include all crude supplied to California refineries regardless of the location of production;
  - Determining if an increase has occurred between the base year average crude CI and the annual average crude CI; and
  - Requiring that increases due to higher annual average CI be mitigated.

- Implement the mitigation requirements by:
  - Including a baseline crude average CI ($CI^{XD}_{BaselineCrudeAvg}$) and an annual crude average ($CI^{XD}_{20XXCrudeAvg}$) in the LCFS Lookup Table;
  - Requiring that if the annual crude average CI in a given year is greater than the baseline crude average CI, the incremental CI be used in the following year to calculate the additional deficits to be incurred by regulated parties that supply CARBOB and ULSD;
  - Calculating the amount of the incremental deficits for each regulated party by multiplying the incremental CI for a given year by the total amount of megajoules of CARBOB and ULSD reported by regulated parties for that year;

- Adding the incremental deficits to the compliance obligation of regulated parties for the affected compliance period; and
- Requiring that each affected regulated party retire sufficient credits by the end of the compliance period to offset the added incremental deficits.

- Establish a method whereby a regulated party could earn LCFS credits if it obtains crude from sources that have implemented innovative methods such as carbon capture and sequestration to reduce emissions for crude recovery. Under this provision:
  - The methods used to create the credits must be approved by the Executive Officer;
  - Implementation of the innovative method must have occurred during or after the year 2010;
  - The method must result in a reduction in carbon intensity for crude oil recovery (well-to-refinery entrance gate) of 5.00 gCO2e/MJ or greater;
  - The number of credits will be equal to the emissions reduction achieved by the innovative method; and
  - To avoid double counting carbon emissions, crude oil used to produce CARBOB or diesel for which a credit is allowed will be included in the Annual Crude Average carbon-intensity calculations for that year based on the carbon intensity of the crude oil prior to calculation of any innovative credits allowed.

Proposed Modifications to the Compliance Schedule and Lookup Tables

Staff is proposing revisions to Table 1 and Table 2 (the LCFS annual standards for gasoline and diesel) and Table 6 and Table 7 (the Carbon Intensity Lookup Table) of the current regulation to adjust values in those tables to align with corresponding increases in the CI of CARBOB and ULSD diesel that are proposed as part of the revised HCICO provisions of the LCFS.

i. Proposed Changes to the Average Carbon Intensity Requirements for Gasoline and Diesel

Staff is proposing to adjust the LCFS annual standards contained in the tables listing the "Average Carbon Intensity Requirements for Gasoline and Diesel" to reflect revised base year (2010) CI values for CARBOB and ULSD that occur when the base year CI for crude oil used in California refineries is changed from 2006 to 2009 (See "Proposed Changes to the Carbon Intensity Values for CARBOB and ULSD in the Lookup Tables" below). The proposed revised CI attributed to the production and transport of crude oil to California refineries results in a 1.65 gCO_2e/MJ increase in the CIs for both CARBOB and ULSD diesel, and a concurrent increase in the CI for CaRFG of 1.54 gCO_2e/MJ. This would change the base values used to determine the LCFS annual standards, which are designed to achieve specified percentage reduction in carbon intensity from the base year (2010). Staff is therefore proposing to adjust the annual standards for CARBOB and ULSD to reflect the revised CI values. This would be accomplished by applying the current percent reduction targets listed in Tables 1 and 2 to the revised values for CaRFG and ULSD diesel. This change would affect compliance periods for 2013 and beyond. No change is proposed for 2011 or 2012. The proposed revisions are shown in Tables 3 and 4 below:

Table 3. LCFS Compliance Schedule for 2011 to 2020 for Gasoline and Fuels Used as a Substitute for Gasoline.

Year	Average Carbon Intensity (gCO2E/MJ)	~~% Reduction~~
2010	Reporting Only	
2011	95.61	~~0.25%~~
2012	95.37	~~0.5%~~
2013	96.42 ~~94.89~~	~~1.0%~~
2014	95.93 ~~94.41~~	~~1.5%~~
2015	94.95 ~~93.45~~	~~2.5%~~
2016	93.98 ~~92.50~~	~~3.5%~~
2017	92.52 ~~91.06~~	~~5.0%~~
2018	91.06 ~~89.62~~	~~6.5%~~
2019	89.60 ~~88.18~~	~~8.0%~~
2020 and subsequent years	87.65 ~~86.27~~	~~10.0%~~

Table 4. LCFS Compliance Schedule for 2011 to 2020 for Diesel Fuel and Fuels Used as a Substitute for Diesel Fuel.

Year	Average Carbon Intensity (gCO2E/MJ)	~~% Reduction~~
2010	Reporting Only	
2011	94.47	~~0.25%~~
2012	94.24	~~0.5%~~
2013	95.40 ~~93.76~~	~~1.0%~~
2014	94.91 ~~93.29~~	~~1.5%~~
2015	93.95 ~~92.34~~	~~2.5%~~
2016	92.99 ~~91.40~~	~~3.5%~~
2017	91.54 ~~89.97~~	~~5.0%~~
2018	90.10 ~~88.55~~	~~6.5%~~
2019	88.65 ~~87.13~~	~~8.0%~~
2020 and subsequent years	86.72 ~~85.24~~	~~10.0%~~

These changes are needed to maintain the current stringency of the LCFS and to preserve the program's goal of reducing the carbon intensity of California' transportation fuels by 10 percent by 2020. Overall, these changes to the compliance schedules would have several impacts, such as:

- Maintaining consistency between the method used to calculate lifecycle emissions and the regulatory requirements of the LCFS;

- Providing adequate lead time for a smooth transition from the current annual standards to adjusted standards in 2013;
- Maintaining the balance and stringency in the current program relative to the rate at which carbon intensity of transportation fuels must improve and the ability of obligated parties to create sufficient LCFS credits to meet their compliance obligation; and
- Yielding a modest increase in the GHG reductions achieved under the LCFS when combined with the changes in the CIs for CARBOB and ULSD proposed in the Lookup Tables.

ii. Proposed Changes to the Carbon Intensity Values for CARBOB and ULSD in the Lookup Tables

Staff is proposing changes to Tables 6 and 7 (the Carbon Intensity Lookup Tables) of the current regulation to adjust the CI values of CARBOB and ULSD in those tables to align with corresponding increases in the CI that are proposed as part of the revised HCICO provisions of the LCFS. The CI values for CARBOB and ULSD would increase from 95.86 gCO_2e/MJ and 94.71 gCO_2e/MJ, respectively, to 97.51 gCO_2e/MJ and 96.36 gCO_2e/MJ, respectively. These revisions reflect the increase in the average CIs for CARBOB and ULSD related to the production and transport of crude oil to California refineries in the most recent year currently available (2009) and the revised calculation methodology of the proposal. The increase the CI value attributable to the production and transport of crude oil from the current 8.07 gCO_2e/MJ to 9.72 gCO_2e/MJ. As with the revisions to the annual LCFS standards, this change would affect compliance periods for 2013 and beyond.

iii. Calculation of Revised CI Values for CARBOB and ULSD

Baseline Year and Data Availability

The LCFS regulation considers 2010 as the baseline year against which a ten percent reduction in GHG emissions is mandated by 2020.[35] The compliance schedule targets for gasoline and its substitutes are based on the carbon intensity value for CaRFG, which in the year 2010 contained approximately ten percent ethanol by volume.

Because data for crude oil supplied to California refineries in 2010 was not available during development of the original regulation, Lookup Table carbon intensity values for CARBOB and diesel were based on available crude supply data for the year 2006. At the time, an assumption was made that the carbon intensity for recovery of crude oil supplied to California refineries would not change substantially between 2006 and the 2010 baseline year. This assumption turned out to be incorrect as the percentages of

[35] Air Resources Board. Proposed Regulation to Implement the Low Carbon Fuel Standard Volume I. Staff Report. Initial Statement of Reasons. March 5, 2009. at page V-7

crude recovered using thermal methods, mining, and upgrading have increased.[36,37] Therefore, as part of these proposed regulatory amendments, ARB staff is proposing updates to the baseline carbon intensity values for CARBOB and diesel using the most recently available comprehensive set of crude oil supply data from the year 2009. Furthermore, it is ARB staff's intention to revise these values again in 2012 as part of a 15-day change to these regulatory amendments. In 2012, comprehensive crude oil supply data should be available for the year 2010. ARB staff will be recalculating the "California average" annually to reflect the most current crude slate. To assist in this effort, staff is working with Professor Adam Brandt at Stanford University to develop a lifecycle assessment tool for calculating carbon intensity values for crude oil recovery.

Calculation Methodology for the Baseline Crude Average Carbon Intensity Value

We used a simple approach to calculate the Baseline Crude Average carbon intensity value (see Appendix C for details). For crude sources produced using thermally enhanced oil recovery (TEOR), bitumen mining or upgrading, a single carbon intensity value of 20 gCO2/MJ was assigned. All other crudes were assumed to be produced using conventional primary or secondary recovery methods. For these crude sources, we assumed a common "base" carbon intensity value that accounts for extraction, venting, and fugitive emissions and added to this country-specific values for flaring and transportation emissions. Crude oil produced in California, Canada, Venezuela, and Oman was recovered using a mixture of production methods. In California, approximately half of the crude was produced using TEOR.[38] The CEC data shows that 89 percent of Canadian crude was produced using TEOR, mining or upgrading; 51 percent of Venezuelan crude was produced with upgrading; and 18 percent of crude from Oman was produced using TEOR.[39,40] The resulting carbon intensity values are shown in Table 5 based on state or country of origin. The Baseline Crude Average carbon intensity, 9.72 gCO_2/MJ, was calculated by weighting these values by the percentage contribution to total crude oil supplied to California refineries.

This value is greater than the value presented in the CARBOB and ULSD pathway documents, 8.07 gCO_2/MJ, for two reasons. First, the calculation methodology is different and results in a slightly greater carbon intensity estimate. Applying the methodology described here to the 2006 crude data results in a carbon intensity for crude recovery and transport of 8.57 gCO_2/MJ. This increase is primarily the result of explicitly accounting for flaring emissions by state or country using NOAA data. Crude

[36] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.
[37] California Energy Commission, October 10, 2011, Email Correspondence: Data on Canadian and Venezuelan crude oil production.
[38] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.
[39] California Energy Commission, October 10, 2011, Email Correspondence: Data on Canadian and Venezuelan crude oil production.
[40] Schremp, G., California Energy Commission, 2011, Presentation for Crude Screening Workgroup: Results of Initial Screening Process to Identify Potential HCICOs, revised March 3, 2011.

produced in Alaska, Ecuador, Iraq, Angola, and Oman has flaring emissions that are much greater than assumed in the pathway documents. Second, the percentages of TEOR, mining, or upgrading have increased from 2006 to 2009. For example, California TEOR has increased from 14.43 percent of total California crude in 2006 to 19.48 percent in 2009. Canadian, Venezuelan, and Omani crude imports have also increased.

Table 5. 2009 Baseline Crude Average Carbon Intensity

Crude Source	Percentage of Total CA Crude	Conventional Crude CI (g/MJ)	Percentage TEOR, Mining, Upgraded	Total CI (g/MJ)
California	39.5	4.38	49.3	12.08
Alaska	15.06	7.28	0	7.28
Saudi Arabia	11.32	6.37	0	6.37
Iraq	8.49	10.39	0	10.39
Ecuador	7.81	8.29	0	8.29
Brazil	4.2	6.40	0	6.40
Columbia	2.61	5.74	0	5.74
Canada	2.31	5.75	89	18.43
Angola	2.28	7.86	0	7.86
Oman	1.58	8.87	18	10.87
Peru	0.95	5.52	0	5.52
Venezuela	0.9	6.54	51	13.41
Others	2.98	7.73	0	7.73
Weighted Average				**9.72**

Calculation Methodology for Baseline Average Carbon Intensity Values for CARBOB and Diesel

Baseline Average carbon intensity values for CARBOB and diesel (ULSD) were determined by substituting the Baseline Crude Average carbon intensity value discussed above for the crude recovery (6.93 gCO_2/MJ) and crude transport (1.14 gCO_2/MJ) values reported in the CARBOB and ULSD pathway documents.[41,42] The resulting values are 97.51 gCO_2/MJ for CARBOB and 96.36 gCO_2/MJ for ULSD.

Assessment of Proposed Changes Related to HCICO

Under the proposed approach, increases in crude CI would be determined and mitigated in the aggregate. The proposal would create incremental deficits only if the

[41] California Air Resources Board, February 27, 2009, Detailed CA-GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California, Version 2.1
[42] California Air Resources Board, February 28, 2009, Detailed CA-GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California, Version 2.1

average crude slate refined in California becomes more carbon-intensive. This aggregate approach differs from the current approach, which mitigates only those increases in crude CI that can be attributed to crudes classified as HCICOs. A second major difference is that the proposed approach allows for "the industry as a whole" to shift its crude slate and not incur additional deficits as long as the average CI of the California crude slate does not increase relative to the baseline year. Finally, the proposed approach necessitates more timely and complete reporting of all of the crude used in California refineries, but eliminates the need for regulated parties to determine the CIs for every crude classified as HCICO.

Staff believes the proposed changes are overall a significant improvement to the current approach and are clearly superior in a number of aspects:

- First, the proposal ensures that all sources of crude supplies are accounted for in a consistent manner in a Statewide average, and assures the mitigation of GHG emissions that result from an increased CI from crude production and transport.
- Second, the current regulation would allow unmitigated CI increases in crude oil supplies from countries in the baseline, and from crudes that have relatively high CIs but are able to demonstrate they do not exceed 15 gCO2e/MJ threshold for HCICO. The proposed approach removes the possibility that such crudes could cause the average CI from production and transport to increase but not be mitigated.
- Third, the proposed approach provides additional flexibility for refiners to:
    - Change crude slates without incurring deficits (assuming the state average carbon intensity does not increase over the baseline average).
    - Avoid the need to prepare and submit to the Executive Officer Method 2B applications, seeking approval of CIs for crudes classified as a potential-HCICO.
- Fourth, the proposal more accurately calculates the 2010 CI baseline for California gasoline and diesel upon which the LCFS is based. Because the revised CI baseline is slightly higher, the ten percent reduction goal of the LCFS will produce greater net GHG emissions reductions under the proposal. For example, the potential incremental GHG benefits under the revised compliance schedules are estimated to be about 259,000 MT CO_2e in 2020; therefore, the total GHG emissions reductions for the LCFS in 2020 are estimated to be about 16.1 MMT CO_2e instead of the original 15.8 MMT CO_2e.

Consideration of Alternatives to the Proposed Changes Related to HCICO

As described above, ARB staff believes that the proposed changes to the HCICO provisions of the LCFS regulation are a significant improvement over the current approach. The proposal provides greater certainty that an increase in the CI of crude will be mitigated, provides greater flexibility to refiners to manage crude slates, is easier to administer once a comprehensive system to assign CIs to crudes is implemented[43], and creates slightly greater GHG reductions from the LCFS program. However, staff is continuing to explore options that could improve the proposal, and may recommend changes by the time the Board considers this matter. Therefore, staff invites comments and suggestions on how the proposal could be improved. Specifically staff solicits suggestions on:

- Alternative methods to allocate incremental deficits so that mitigation responsibility is allocated to those regulated parties most responsible for an increase in the average crude CI.
- Alternative and additional methods of providing incentives for innovation that significantly reduces the CI of non-conventional crudes and crudes that require high-energy production.

Staff is also considering how to address HCICO refined in 2011 and 2012 (e.g., the generation of deficits and potential impacts on credit balances) as well as how to handle the processing of imported intermediate feedstocks, such as cat cracker feed.

F. Electricity Regulated Party Revisions

Overview

In the LCFS regulation, regulated parties for electricity used as a transportation fuel include electric utilities, non-utilities installing electric vehicle service equipment (EVSE) with a customer contract, business owners, and homeowners. The Board directed staff in Resolution 09-31 to review the provisions applicable to regulated parties for electricity and propose amendments if appropriate. Since the Board approved the regulation, the markets for electric vehicles (EV) and EV-fueling infrastructure have evolved and continue to evolve. As a result, staff is proposing modifications to the designation of regulated parties for electricity.

In the regulation, regulated parties for electricity are eligible to receive LCFS credits for delivering electricity for transportation use in California. By providing a lower-carbon fuel relative to gasoline, parties can earn an LCFS credit for each metric ton of CO_2 equivalent ($MTCO_2e$) emissions avoided through the use of electricity—a transportation fuel with much lower carbon intensity (CI) than the 2020 standard specified in the LCFS regulation. The credits will have a monetary value when sold to regulated parties who must offset deficits created by their supply of fuels with CIs that exceed the LCFS standards.

Staff has proposed regulatory amendments to: (1) eliminate ambiguity in some cases of regulated party designation; (2) clearly award potential credits for residential and

[43] A lifecycle assessment tool for calculating carbon intensity values for crude oil recovery is being developed by Professor Adam Brandt at Stanford University under contract with ARB and will be completed in 2012.

public-access vehicle charging; (3) incorporate vehicle charging applications that were not foreseen when the regulation was adopted; and (4) maximize the number of credits available for use in the LCFS program. In the revised language, staff seeks to ensure fair treatment of regulated parties and to incent electric transportation. The proposed changes discussed here are limited to on-road electric refueling.

Regulated parties for electricity are currently opting into the regulation to receive LCFS credits and have submitted reports for fuel transactions for the first two quarters of 2011. The proposed amendments are necessary to align the regulation with current EV charging applications and to reflect staff's intent to award credits in a fair manner.

Current Regulation Hierarchy for Credit Recipients

As allowed in the current regulation, electric utilities can potentially receive credits for electricity delivered through residential charging equipment and for public EVSE they have installed. However, non-utility Electric Vehicle Service Providers (EVSPs) are also installing charging equipment in homes, for public access, and on private business property for employee use. In cases where a non-utility EVSP has installed equipment, the regulation designates the non-utility EVSP as the potential credit recipient rather than the utility. While staff intended non-utility EVSPs to receive credits only for fuel delivered through public charging equipment, the regulation can be interpreted to include residential charging credits to non-utility EVSPs. The regulation allows for two additional potential credit recipients: businesses that provide access to EVSE on their property and homeowners. Business owners and homeowners are eligible to receive LCFS credits only if they have a contract to do so with the appropriate utility.

Proposed Regulation Modifications

Staff is proposing to clarify the regulation to designate electric utilities as the regulated parties for EV charging in single- and multi-family residences. Staff is further proposing to add several requirements that must be met before utilities can receive credit for residential charging. Utilities must:

1. Use all credit proceeds as direct benefits for current EV customers.
2. Provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid.
3. Educate the public on the benefits of EV transportation through outreach efforts.
4. Include in annual reporting a summary of efforts to meet requirements 1, 2, and 3, as well as an accounting of the number of EVs known to be operating in the service territory.

Staff is also proposing to designate non-utility EVSPs and electric utilities as the regulated parties for transportation fuel supplied through public charging equipment that they have installed. For the LCFS regulation, a non-utility EVSP is defined as the entity that installs the EV-charging equipment, or has had an agent install the equipment, and who has a contract with the property owner or lessee where the equipment is located to maintain or otherwise service the charging equipment. The contract must be valid during the corresponding reporting period. For a utility to qualify as the regulated party for public access charging, the utility would also need to have a similar contract valid during the reporting period.

In an effort to maximize the number of credits captured by regulated parties, staff is proposing to add the local utility as the default regulated party if the EVSP elects not to participate in the regulation. Under the proposal, with EO approval, the utility can become eligible to be the regulated party for the electricity supplied by the public access charging equipment.

Staff is also proposing to add requirements that the regulated parties for public access charging must meet to receive credits. The requirements are similar to those specified for utilities for residential charging.

Staff is proposing to add an opportunity for EV fleet operators to become regulated parties. Under the proposal, a company operating a fleet of three or more EVs may opt into the regulation to become a regulated party, while the utility is eligible to be the regulated party for fuel supplied to fleets of less than three EVs. If the fleet operator chooses not to become a regulated party, the electric utility operating in the service territory where the fleet vehicles are charged can become eligible to be the regulated party with EO approval. To receive credit for fuel supplied to an EV fleet, regulated parties must annually report an accounting of the number of EVs in the fleet.

Staff is also proposing to allow employers who offer on-site EV charging equipment to their employees to become regulated parties. Under the proposal, if the employer chooses not to become a regulated party, the electric utility operating in the service territory where the fleet vehicles are charged can become eligible to be the regulated party with EO approval. Staff is further proposing to require regulated parties for employee EV charging to:

1. Educate employees on the benefits of EV transportation.
2. Annually report on the efforts of (1), as well as an accounting of the number of EVs known to be charging at the business.

<u>Current and Expected Near-Term Market for Electric Vehicle Charging</u>

Electric utilities supply the fuel for charging electric transportation. Utilities are also installing separate meters for those residential EV customers who choose an EV time-of-use (TOU) rate structure that encourages EV charging during off-peak hours (generally overnight). In addition, some utilities plan to install EVSE for public access EV charging.

Non-utility EVSPs are installing many EVSEs in single-family homes and also plan to install them in multi-family homes. In addition, non-utility EVSPs are currently installing public access EVSE and establishing contracts with business owners where the equipment is located and contracts with EV owners to access the equipment. The property owner may buy or lease the EVSE.

Justification of Proposal

In preparing the proposal to modify the electricity regulated party language, staff established three goals. First, staff kept the proposed language simple to avoid confusion in regulated party designation and maintain relevancy as the EV charging market continues to evolve. Second, staff limited the number of regulated parties to increase the possibility that credits will be captured and made available to other regulated parties who need to purchase credits. And finally, staff included default regulated parties in the proposed language to maximize the number of credits captured and available for purchase and use for compliance.

Staff is proposing to designate electric utilities as the regulated parties for EV charging in single- and multi-family residences as well as for public access charging equipment they install with a contract. Utilities have been actively preparing for California's EV market. Many utilities have been preparing to accommodate the expected growth in EV population by increasing customer education and outreach, developing EV electricity rate schedules, and evaluating system impacts. As EV customers evaluate their home charging options, some require panel upgrades and the installation of second meters to receive EV TOU rates. In some cases, utilities have replaced transformers as a result of EV charging. Further upgrades to the electric distribution system are anticipated in some areas as the number of EVs operating in California increases. For example, the San Diego Gas & Electric Company has estimated costs to accommodate residential and commercial EV services will range from $1 to $1.5 million annually for 2010 to 2012.[44]

To recover these costs, the CPUC has ruled, in their decision on Phase 2 of the Alternative Fueled Vehicle Proceeding,[45] that until June 30, 2013, "all residential service facility upgrade costs in excess of the residential allowance shall be treated as common facility costs rather than being paid for by the individual plug-in hybrid and electric vehicle customer." Staff is proposing to designate electric utilities as the regulated parties for residential charging to make them eligible to receive LCFS credit revenue that may offset utility costs that are a direct result of the EV market. Staff is further proposing that credit revenue must be returned to EV customers through direct benefits.

Staff is further proposing to designate non-utility EVSPs as the regulated parties for public EV charging that they install. The credit revenue that they will be eligible for will reward them for establishing the public charging network that is required to support a successful EV market.

[44] California Air Resources Board, Utility Survey of SDG & E

[45] California Public Utilities Commission Phase 2 Decision Establishing Policies to Overcome Barriers to Electric Vehicle Deployment and Complying with Public Utilities Code Section 740.2

Stakeholder Outreach

When the Board approved the LCFS regulation in April 2009, they directed staff in Resolution 09-31 to continue working with stakeholders on the electricity regulated party language and to propose language changes if necessary. Staff established an Electricity Workgroup with stakeholders and has held three meetings since the regulation was approved. Participants included representatives from utilities, non-utility EVSPs, oil refineries, the CPUC, the California Energy Commission, and environmental groups. Workgroup members have submitted written comments in addition to participating in the Workgroup meetings.

Value of LCFS Credits

Staff estimates that in 2011, there will be 5,000 to 11,000 electric vehicles operating in California. This includes full-electric vehicles like the Nissan Leaf and Tesla Roadster, and plug-in hybrids like the Chevy Volt. Based on typical annual miles traveled and using electricity supplied from the California grid, a full battery electric vehicle (BEV) could earn on the order of two credits in 2011, while a plug-in hybrid could earn about 1.5 credits in 2011 (one credit is equal to one $MTCO_2e$). The projected total number of credits available in 2011 for the electricity-fueled miles traveled by these vehicles is 8,000 to 22,000. The potential value of the credits for all electric vehicles statewide in 2011, based on a range of $15 to $50 per credit, could range from $114,000 to $1,100,000.

In 2020, when the LCFS CI standard is lower, the potential credits that an electric vehicle could earn are less than 2011 credits, assuming that the EV technology does not significantly improve. Staff predicts that BEVs could earn approximately 1.7 credits per vehicle, while plug-in hybrids could earn 1.3 credits per vehicle. The number of credits projected for the year 2020 varies considerably based on the projected number of electric vehicles. LCFS scenarios are based on 490,000 to 1,780,000 electric vehicles (both battery and plug-in hybrid) in 2020. Based on these scenarios, LCFS credits available in 2020 could be 700,000 to 2,500,000. Compared to the total reduction of CO_2e in 2020 (24 $MMTCO_2e$), credits could be 3 to 10 percent of the total reduction. The potential value of the credits based on a range of $15 to $50 per credit, could range from $10 to $124 million.

G. Energy Economy Ratio (EER) Revisions

Energy Economy Ratios

Staff is proposing three changes to the Energy Economy Ratios (EER). Staff is proposing these changes to reflect the use of engine efficiency and fuel efficiency data that was not available during the original rulemaking in April 2009. The first change is the addition of a new EER of 1.0 for CNG/LNG heavy-duty compression-ignition engines. The EER of 0.9 that is currently in the rule for all CNG/LNG heavy-duty engines would be applicable only to heavy-duty spark-ignition engines. The second proposed change is to change the EER for light duty BEVs and plug-in-hybrid electric vehicles (PHEV) from 3.0 to 3.4. The third proposed change is to change the EER for light-duty fuel cell vehicles (FCVs) from 2.3 to 2.5. The basis for both of the changes being proposed by the staff is the availability of new data on the energy efficiency of heavy-duty engines burning CNG and LPG, BEVs, PHEVs, and FCVs. Furthermore, staff proposes to delete the 1.3 divisor for EVs and FCVs that was originally intended to account for cleaner conventional vehicles in 2016 and beyond. In lieu of the divisor, staff is proposing that the EERs be revisited periodically to account for improvements in all engine and vehicle technologies.

Heavy-Duty CNG/LPG Vehicles

Recent ARB certification data show that the energy efficiency of heavy-duty compression-ignited engines burning CNG and LPG is the same as that of heavy-duty diesel fueled engines of comparable size and horsepower. It is for this reason that the staff is proposing an EER of 1.0 for compression-ignition heavy-duty engines burning CNG and LPG.

Light Duty

Since the publication of the ARB's Initial Statement of Reasons for the Low Carbon Fuel Standard regulation in March 2009, fuel efficiency data has become available for two electric vehicles that are expected to constitute the majority of electric car sales in the next several years. These vehicles are the Chevy Volt and the Nissan Leaf. The fuel economies for these vehicles have been published in the federal Government's Fuel Efficiency Guide. The fuel efficiency for the Chevy Volt, operating in the electric-only mode, was measured at 93 miles per gallon gasoline equivalent, while the fuel efficiency for the Nissan Leaf was measured at 99 miles per gallon gasoline equivalent. For the Chevy Volt, the reference vehicle is the Chevy Cruze. The fuel efficiency for the Chevy Cruze is 28.3 miles per gallon. The corresponding EER for the Chevy Volt (the quotient of its fuel efficiency and that of its reference vehicle) is 3.29. For the Nissan Leaf, the reference vehicle is the Nissan Versa, which has a fuel efficiency of 28.4 miles per gallon. The corresponding EER for the Nissan Leaf is 3.49. The average EER for the Volt and Leaf is 3.39, or 3.4. This EER value would be used in the calculation of all credits originating from the use of electricity in light-duty cars.

Light-Duty Fuel Cell Vehicles

The EER for light-duty fuel cell vehicles is based on the published fuel economies for the 2011 Honda FCX Clarity and the 2011 Mercedes-Benz F-Cell. The published fuel economies for the Clarity and the F-Cell are 60 miles per kilogram of hydrogen, and 53 miles per kilogram, respectively. These translate to about 61 miles per gallon of gasoline equivalent, and about 54 miles per gallon of gasoline equivalent, respectively. The reference vehicle for FCX Clarity is the Honda Accord, while for the F-Cell they are the Mercedes SLK350, SLK300, and C300. The fuel efficiency for the Accord is about 26 miles per gallon, while for the SLK350, SLK300, and C300 the fuel economies are about 21 miles per gallon. The corresponding EER for the Clarity is 2.35, while for the F-Cell it is 2.57. Averaging the EERs of the Clarity and the F-Cell gives an average EER of 2.46, or 2.5, which is proposed to be the EER for purposes of calculating credits.

H. Revisions to Reporting and Recordkeeping Provisions

Designating the LRT for LCFS Quarterly and Annual Reporting

There is no clearly designated single process mandated in the existing LCFS regulation to be used for reporting. The current regulation only specifies that "a regulated party must submit an annual compliance and quarterly progress report by using an interactive, secured internet web-based form." To facilitate such reporting, ARB staff developed the online LCFS Reporting Tool (LRT), which has been operational since early 2010 and in production since December 2010. It is readily accessible at www.arb.ca.gov/lcfsrt for electronic reporting by all regulated parties.

A total of 70 regulated parties have used the LRT for reporting during 2010 and for first quarter 2011 reporting, both for manual entry of fuel transaction data via the user interface and through XML data file upload submission. This has been the only means used for LCFS reporting by all regulated parties; the LRT, therefore, has become the *de facto* standard for electronic submittal of required LCFS reports. Thus, the staff's proposal to mandate the use of the LRT simply codifies the existing standard practice of regulated parties.

As with most industries, the transportation-fuels sector values certainty, and specifying that only the LRT, which is accessible from ARB's website, can be used for reporting ensures such certainty. For similar reasons, the requirement to use the LRT ensures standardization and consistency, which would help facilitate credit trading between regulated parties (especially when the LRT version 2.0 is developed, which will automate credit trades and credit reporting). In addition, because all regulated parties are using the LRT and ARB makes it available for free, there are no additional costs involved with using the LRT for regulated parties. By contrast, the purchase of and training with different, commercially-developed reporting software would almost certainly involve additional costs for regulated parties. For the above reasons, staff proposes to mandate use of the LRT as the only online reporting mechanism for use by regulated parties.

Rounding to Nearest Whole Number, Reporting of Volumes Expressed in GGE

Staff proposes to amend section 95484(c)(5)(C) of the existing regulation, which is now section 95484(b)(5)(C) in the proposed regulation, by eliminating the reporting of fuel volume in terms of "gasoline gallon equivalent (gge)." The use of gge was part of an earlier version of the LCFS regulation in which conversion of fuel volumes to gge values was required as part of fuel transaction reporting. This is no longer needed because the LRT now accepts volume inputs in their native units (i.e., "gallons" for gasoline, diesel and liquid biofuels; “scf” for CNG, LNG and Biogas; “kWh” for electricity; and “kg” for hydrogen). To improve reporting and for consistency in how regulated parties are recording their transactions, staff is also proposing to change the provisions in section 95484(b)(5)(C) for reporting significant figures to simply require reporting to the nearest whole unit.

<u>Renewable Identification Number Reporting</u>

Staff proposes to delete section 95484(b)(3)(A)4. of the existing regulation to no longer require the reporting of “all Renewable Identification Numbers (RINs) that are retired for facilities in California.” Staff determined that this provision was of limited utility and no longer needed. Further, staff proposes to remove the reference to quarterly reporting of RINs in Table 3.

<u>Product Transfer Document</u>

The current regulation uses the term “Product Transfer Document” (PTD) but does not define it; rather, the regulation specifies information that must be contained in the PTD. It is staff’s understanding that PTDs, instead of being a single document, can be a collection of related documents. Thus, staff described a PTD in the LCFS Guidance Document, version 1.0,[46] as a document or documents that may include, but is not limited to, one or more of the following: contract, invoice, bill of lading, RFS2 product transfer document, meter ticket, and rail inventory sheet. The guidance document further describes a PTD as a document or combination of documents that is commonly used and accepted in the industry for the subject fuel. Moreover, if multiple documents are used for an authentication, each document must contain information that identifies their association to each other. To clarify the regulation, some stakeholders have suggested codifying the guidance document’s language into a formal definition for a PTD. Staff agrees and has proposed a definition for PTD accordingly.

<u>Reporting Requirements for Gasoline and Diesel Fuel</u>

Annual Reports

The proposed change is to add to the annual reporting requirements, starting 2012 and for each year thereafter, information on the crude oil supplied to California refineries in a calendar year. These data will be used to estimate the annual average crude oil carbon-intensity. These reporting requirements will be applicable to the producers of CARBOB, gasoline, and diesel. Specifically, the following data for each refinery will be required under this provision:

1. Volume (in gallons) and marketable crude oil name (MCON) of all crude oil supplied to the refinery that was produced in California using thermal enhanced oil recovery (TEOR) methods.

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[46] See http://www.arb.ca.gov/fuels/lcfs/LCFS_Guidance_%28Final_v.1.0%29.pdf, accessed Oct. 9, 2011.

2. Volume (in gallons) and MCON of all crude oil supplied to the refinery in the current compliance period that was produced in California using non-TEOR methods.
3. Volume (in gallons), MCON, and Country (or State) of origin for all crude oil supplied to the refinery in the current compliance period that was imported.

Quarterly Reports

Staff proposes to add, to the quarterly reporting requirements, all imports of petroleum blendstocks, finished fuels, and petroleum intermediates that can be further processed to produce blendstocks or finished fuel. The volumes of such imported products would need to be reported on an individual basis.

I. Miscellaneous

Modifications to the Definitions of "CNG," "LNG," and "Biogas"

The existing regulation defines "compressed natural gas (CNG)," "liquefied natural gas (LNG)," and "biogas (biomethane)," in part, by reference to the existing California motor vehicle fuel specifications for CNG. These fuel specifications are codified at title 13, California Code of Regulations, section 2292.5. Under the original LCFS rulemaking, staff included this reference to the fuel specifications to ensure that only natural gas that was sold, supplied or offered for sale in California for transportation purposes would be credited under the LCFS program. However, staff has determined that the reference to title 13 is unnecessary given that the regulation already explicitly applies only to fuels sold, supplied, or offered for sale for transportation purposes. Further, the title 13 specifications are based on criteria pollutant standards, while the LCFS is based on carbon intensity requirements, so the linkage between the two is superfluous (i.e., the two regulations exist independently). Finally, ARB staff is currently collaborating with local air district staff to update the motor vehicle fuel specifications; thus, staff believes the criteria pollutant aspects of the motor vehicle fuel specifications are more appropriately addressed through the title 13 specifications rather than being linked directly to the LCFS. Based on the above considerations, staff is proposing to eliminate the reference to the motor vehicle fuel specifications from the above definitions.

Codification of LCFS Advisory Provisions

To provide clarity during the early implementation of the LCFS, ARB staff issued a number of advisories.[47] Staff believes a number of these advisories set forth guidance that should be codified in the regulation. For example, it was suggested that the regulation, like the advisories, specify default CI values to be used by regulated parties when faced with purchasing fuel with an unknown CI and fuel pathway. The proposal addresses this scenario and proposes to codify other provisions discussed in the advisories.

[47] See http://www.arb.ca.gov/fuels/lcfs/070111lcfs-rep-adv.pdf, http://www.arb.ca.gov/fuels/lcfs/122310lcfs-rep-adv.pdf, http://www.arb.ca.gov/fuels/lcfs/093010lcfs-rep-adv.pdf, and http://www.arb.ca.gov/fuels/lcfs/070910lcfs-rep-adv.pdf.

V. ENVIRONMENTAL IMPACT ANALYSIS

A. Introduction

This chapter provides an environmental analysis of the proposed regulatory action. Based on ARB's review of the proposed amendments, staff has concluded that the proposed amendments to the Low Carbon Fuel Standard (LCFS) regulation would not have a significant or potentially significant adverse effect on the environment. The analysis in this chapter explains the potential effects that staff examined and the basis for reaching its conclusion.

B. Background on Environmental Review Analysis

ARB is the lead agency for the proposed regulation and has prepared this environmental analysis pursuant to its certified regulatory program. The California Environmental Quality Act (CEQA) at Public Resources Code section 21080.5 allows public agencies with regulatory programs to prepare a plan or other written document in lieu of an environmental impact report or negative declaration once the Secretary of the Resources Agency has certified the regulatory program. ARB's regulatory program has been certified by the Secretary of the Resources Agency.[48] As required by ARB's certified regulatory program, and the policy and substantive requirements of the CEQA, ARB has prepared this environmental analysis to assess the potential for significant long or short term adverse environmental impacts associated with the proposed action and a succinct analysis of those impacts.[49] In accordance with ARB's regulations, the assessment also describes any beneficial impacts.[50] The resource areas from the state CEQA Guidelines environmental checklist were used as a framework for assessing potentially significant impacts.[51] In accordance with ARB's certified regulatory program, for proposed regulations the environmental analysis is included in the Staff Report: Initial Statement of Reasons (ISOR) for the rulemaking. [52]

CEQA requires that when ARB adopts a rule or regulation requiring the installation of pollution control equipment, or a performance standard or treatment requirement, that ARB conduct "an environmental analysis of the reasonably foreseeable methods by which compliance with that rule or regulation will be achieved."[53] The analysis shall include reasonably foreseeable environmental impacts of the methods of compliance, reasonably foreseeable feasible mitigation measures related to significant impacts, and reasonably foreseeable alternative means of compliance that would avoid or eliminate significant impacts. The analysis should not engage in speculation, nor is the detail of a project-level analysis required.

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[48] State CEQA Guidelines Cal. Code Regs., tit. 14,§ 15251 (d); Cal. Code Regs., tit. 17,§, sections 60005-60008.)
[49] Cal. Code Regs., tit. 17,§ 60005, subd. (b).
[50] Cal. Code Regs., tit. 17,§ 60005, subd. (d).
[51] State CEQA Guidelines, Appendix G.
[52] Cal. Code Regs., tit. 17,§ 60005.
[53] PRC section 21159; Cal. Code Regs., tit. 14,§ 15187

CEQA discourages speculation; however, drafting an environmental document necessarily involves some degree of forecasting.[54] While foreseeing the unforeseeable is not possible, an agency must use its best efforts to find out and disclose all that it reasonably can. If after thorough investigation, a lead agency finds that a particular impact is too speculative for evaluation, the agency should note its conclusion and terminate discussion of the impact.

If comments that are received during the public review period raise significant environmental issues, staff will summarize and respond to the comments in writing. The written responses will be included in the Final Statement of Reasons (FSOR) for the proposed regulation amendments. In accordance with ARB's certified regulatory program, prior to taking final action on the proposed regulation amendments, the decision maker will approve the written responses.[55] If the regulation is adopted, a Notice of Decision will be posted on ARB's website and filed with the Secretary of the Natural Resources Agency for public inspection.[56]

C. Summary of 2009 Environmental Analysis

The environmental analysis published in the 2009 LCFS ISOR[57] focused on the significant GHG emission reductions that the regulation would achieve through the production and use of lower-CI transportation fuels. The analysis also included the potential GHG emission reductions realized through changes in the vehicle fleet composition that would be available to use these lower-CI transportation fuels. Staff estimated that a reduction of about 16 million metric tons of CO_2-equivalent ($MMTCO_2e$) would come solely from the combustion of transportation fuels in California in 2020. If the full-fuel-lifecycle is included in the GHG benefits of the LCFS—taking into account GHG reductions outside of California—there would be an estimated reduction of about 23 $MMTCO_2e$.

As part of the analysis, staff estimated the number of potential new transportation fuel facilities that could be built in California. This estimate relied on the volume of biomass available in the State, projects that were undergoing the permitting process at the time of the analysis, and the projected demands of both the LCFS and RFS2 in 2009. Staff estimated that potentially six ethanol facilities, 18 cellulosic ethanol facilities, and six biodiesel facilities could be operational in the State by 2020. In the 2009 analysis, staff assumed that petroleum refining throughput in California would not be affected by the LCFS; California may become a net exporter of transportation fuels rather than the net importer that it currently is when California consumption of petroleum-based fuels declines. As a result, staff did not anticipate any changes in the emissions from petroleum refineries, power plants, or existing corn ethanol facilities over the baseline

[54] Cal. Code Regs., tit. 14,§ 15145; Cal. Code Regs., tit. 14,§ 15144.
[55] Cal. Code Regs., tit. 17,§ 60007, subd (a).
[56] Cal. Code Regs., tit. 17,§ 60007, subd. (b).
[57] Air Resources Board. Proposed Regulation to Implement the Low Carbon Fuel Standard Volume I. Staff Report. Initial Statement of Reasons. March 5, 2009.

projections. In addition, staff assumed that any environmental impacts of additional electricity demand would be offset by the requirements of the 33 percent renewable portfolio standard, and off-peak charging would avert the need for additional power plants. Lastly, at the time of writing the staff report, the California corn ethanol facilities were among the cleanest in the nation, and staff did not anticipate the need to upgrade their facilities within the 2020 time frame. Therefore, any impacts above the baseline were attributed solely to potential new biorefinery facilities operating in the State.

In addition to the GHG benefits, staff also expected the LCFS to result in no additional adverse impacts to California's air quality due to criteria and toxic air pollutants. When calculating the emissions from potential new facilities, staff assumed use of the cleanest conversion and air pollution control technologies. This assumption was based on stringent New Source Review regulations affecting the permitting of these facilities. Staff recommended that any emissions from these facilities, if permitted, would be mitigated and offset, consistent with local air district and CEQA requirements. Staff identified the truck trips associated with the delivery of feedstock and finished fuel as the larger source of criteria pollutant emissions. Staff proposed that these emissions could be mitigated by using newer trucks for the trips, as prescribed by other state and federal regulations (such as LEV and CAFE standards). Furthermore, the emissions could be offset on a statewide basis through the use of these cleaner transportation fuels in California vehicles. Nevertheless, staff recognized that there was still a potential for localized impacts, which prompted a further evaluation as described below.

Staff performed a health risk assessment to estimate the potential cancer risk from a biorefinery. To establish a plausible upper-bound, staff evaluated a scenario consisting of three co-located facilities. Details of this analysis can be found in Chapter VII of the 2009 ISOR. The highest potential cancer risk associated with on-site emission risk was estimated to be 0.4-out-of-a-million at the fence line of the facility. When including both on-site and off-site emissions in the risk analysis, cancer risk was estimated to be 5-out–of-a-million. In addition to the potential cancer risk, staff also analyzed the impacts related to $PM_{2.5}$. This analysis estimated an additional 20 premature deaths, seven hospital admissions, and 314 cases of asthma, acute bronchitis, or lower respiratory symptoms.

Staff further analyzed the ambient ozone impacts and determined that the air quality model could not reliably predict the impact because the concentrations of smog-forming pollutants associated with the LCFS were not statistically significant above the baseline. Lastly, in the 2009 environmental analysis, staff provided qualitative, and in a few cases quantitative, evaluations of impacts on other types of media. Staff included impacts on water use and water quality, agricultural resources, biological resources, geography and soils, hazardous materials, mineral resources and solid waste. Finally, staff provided a brief discussion on the commitment to develop a plan to address sustainability components related to the production of feedstock and transportation fuels.

D. Analysis of Proposed Regulation Modifications

For the proposed amendments, staff analyzed potential environmental impacts in terms of reasonably foreseeable methods of compliance. This section briefly explains each modification provision and the reasonably foreseeable methods by which compliance with the provisions will be achieved.

The proposed provisions include several amendments that are administrative in nature. These include provisions to opt-in and opt-out of the regulation, a provision which mandates use of the LCFS Reporting Tool, and a provision to convert the Method 2A/2B application process to a certification process.

In addition to the administrative provisions, staff is proposing regulation amendments which are more extensive than administrative changes. These include amendments to enhance the regulated party provision by expanding the definition of "producer", specify a credit tracking and trading process, revise the Energy Economy Ratios (EER) for electricity and fuel cell vehicles, add a regulatory approach for High Carbon Intensity Crude Oil (HCICO), and modify the designation of regulated parties for electricity.

<u>Opt-In and Opt-Out Provisions</u>

Staff determined that there are no significant adverse environmental impacts due to this proposal. Staff is proposing to modify language in the regulation to clarify procedures for parties to opt-in and to opt-out of the regulation. The modifications would encourage parties to register for the regulation by providing simple and clear steps to become a regulated party (opt-in) and to cease being a regulated party (opt-out). Compliance with this provision is administrative in nature.

Staff anticipates that the modifications to the opt-in and opt-out provisions could result in a greater number of parties who are eligible to generate credits registering for the regulation. As a result, a greater number of credits could potentially be generated and available on the credit market for purchase by regulated parties seeking to meet compliance obligations. In turn, more credits available for purchase for compliance purposes could potentially deflate credit value and lower overall compliance costs.

<u>Enhanced Regulated Party Provisions</u>

Staff determined that there are no significant adverse environmental impacts due to this proposal. Staff is proposing to expand the definition in the regulation of "producer" to include production facilities located outside California. This modification would allow out-of-state producers to opt into the regulation. Staff is also proposing to expand the definition in the regulation of "import facility" to include the transportation equipment that held or carried the product at the point the equipment entered California. These modifications would allow out-of-state fuel producers and intermediate entities having title of an imported fuel to opt into the regulation, become regulated parties, and therefore generate and hold LCFS credits.

Mandatory LCFS Reporting Tool Use

Staff determined that there are no significant adverse environmental impacts due to this proposal. Currently the LCFS regulation mandates the use of “an interactive, secured internet web-based form” for submitting annual compliance and quarterly progress reports. Since all reporting parties are using ARB’s LCFS Reporting Tool (LRT) as that “interactive, secured internet web-based form,” staff is proposing to modify the regulation to require the LRT be used for all reporting requirements. Compliance with this provision is administrative in nature.

Credit Trading

Staff determined that there are no significant adverse environmental impacts due to this proposal. Staff is proposing to add provisions in the regulation that clarify how credits and deficits are tracked, and to specify the process to be used to acquire, bank, transfer, and retire credits. In the proposal, staff is also including a provision that allows a regulated party to acquire credits in the first quarter of a year to meet a compliance obligation in the previous year, as long as those credits were generated in a previous year. This proposal further seeks to establish requirements relating to the public release of information concerning the generation of deficits and the generation, use, and transfer of credits.

Revised EERs

Staff determined that there are no significant adverse environmental impacts due to this proposal. Staff is proposing three modifications to the Energy Economy Ratios (EERs). First, staff is proposing to add to the regulation an EER of 1.0 for heavy-duty compression-ignited engines fueled with compressed natural gas (CNG) or LPG. Currently, the EER in the regulation for these vehicles is 0.9. Second, staff is proposing to change the EER for the electricity used in light-duty battery electric vehicles and plug-in hybrids from 3.0 to 3.4. Third, staff is proposing to change the EER for light-duty fuel cell vehicles from 2.3 to 2.5.

The proposed changes to EER values have the potential to increase the number of credits generated for CNG/LNG, electricity, and hydrogen transportation fuels. An increase in the number of credits available for regulated parties to purchase could decrease the value of a credit, potentially decreasing compliance costs.

Certification Process for Method 2A/2B

Staff determined that there are no significant adverse environmental impacts due to this proposal. In the current regulation, the process through which a regulated party receives approval to use a carbon intensity value determined through the Method 2A/2B process requires an Executive Officer or Board hearing. Staff is proposing to convert this regulatory process to a certification process to save staff resources, yet maintain the technical rigor and public input of the current requirements. Compliance with this provision is administrative in nature.

High Carbon Intensity Crude Oil (HCICO)

As part of the regulatory amendments for the handling of crude oil, three substantial changes have been proposed. First, the concept of a grandfathered “basket” of crudes would be replaced with a “baseline,” which accounts for the emissions intensity of all crude sources refined in California. Second, the baseline carbon intensity values for CARBOB and ULSD and the associated base deficit attributed to producing these fuels would be referenced to a more recent baseline year to reflect more accurate data than were available for the 2009 rulemaking. Third, the incremental deficit would not apply a 15.00 gCO_2e/MJ bright line for differentiating between high-carbon-intensity-crude-oils (HCICOs) and non-HCICOs. Instead, the proposal would eliminate the distinction entirely and simply require refiners to account for the difference in actual crude carbon intensity values that occur over time relative to a specified baseline. Thus, this would eliminate the “either/or” approach in the current provision and replace it with a continuum-based approach. In the discussion below, we refer to the crude treatment in the current regulation as the “current provision” and the proposed changes as the “California Average Approach.”

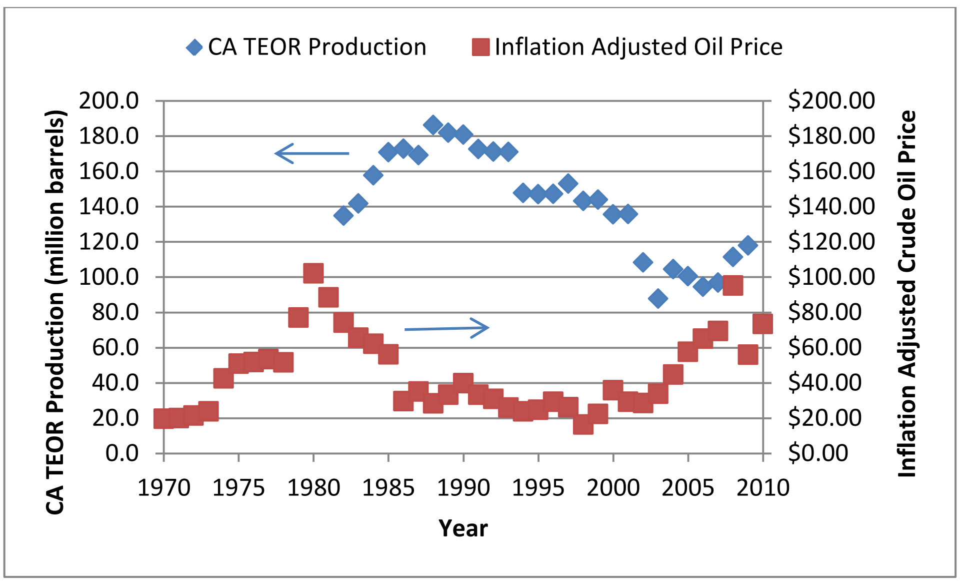
The California Average Approach provides a much more accurate accounting for GHG emissions from all crude oil used by California refineries. This more accurate accounting is necessary to prevent the possibility for backsliding in GHG emissions reductions, which could occur under the current provision. First, by removing the distinction between basket and non-basket crudes, the California Average Approach accurately accounts for emissions associated with increasing production of the basket crudes. Under the current provision, basket crude oil that uses high intensity production methods is assigned the average CI for basket crudes of 8.07 gCO_2e/MJ. Under the California Average approach, this crude would be assigned a CI value more representative of its actual emissions.

Second, the California Average Approach removes the HCICO threshold (15 gCO_2e/MJ) for non-basket crudes. Under the current provision, a non-basket crude with a CI of 14 gCO_2e/MJ will be assigned a CI of 8.07 gCO_2e/MJ, and the excess GHG emissions will not be mitigated. Under the California Average approach, this crude would accurately be assigned a CI of 14 gCO_2e/MJ. This differentiation in carbon intensity values for all crudes may be important because not all crudes produced using thermally enhanced oil recovery (TEOR), mining, or upgrading will have carbon intensity values above 15 gCO_2e/MJ. Moreover, unconventional production methods – such as gas-to-liquids, or enhanced oil recovery methods, such as CO_2 injection, hydrocarbon injection, and chemical injection – and conventional primary or secondary recovery with excessive flaring may also have higher than average CI values that are less than 15 gCO_2e/MJ.

Third, the California Average Approach captures expected increases in emissions intensity of producing conventional crudes as current fields become depleted. The current regulation does not account for GHG emissions increases in conventional crude production unless the CI reaches the unlikely level of 15 gCO_2e/MJ. Further discussion of the implications of more accurate GHG emissions accounting are provided below.

Under the current crude oil provision, there is significant potential for backsliding in the emissions reduction benefits of the regulation due to the grandfathering of basket crude sources. The current crude oil provision was written with the assumption that the use of high-intensity crude from basket sources would likely decrease between 2010 and 2020. This assumption was based on California thermally-enhanced crude (CA TEOR) being the primary source of high-intensity crude within the basket and the annual production of CA TEOR declining significantly from 1990 through 2006 (see Figure 4). The 2006 data were the most recent available to staff on CA TEOR production at the time the current provision was written in 2009.

Figure 4: Trends in CA TEOR Production and Inflation Adjusted Crude Oil Price[58]



As depicted in Figure 4, CA TEOR production shows an overall decline over the past 20 years, but with periods of increasing production occurring in the 1980s and 2006 through 2009. The periods of increasing production correlate well with periods of high oil prices, with a time lag of a few years. High oil prices incent development of new

[58] Spreadsheet containing data from:

- CA TEOR production data from California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, Annual Reports of the State Oil and Gas Supervisor for years 1983 to 2010, available at: http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx
- Crude oil price data obtained from http://inflationdata.com/inflation/inflation_Rate/Historical_Oil_Prices_Table.asp

thermal production, which requires high up-front capital expenditure, and also allow for previously unprofitable wells to be brought back into service. These wells commonly require high steam-to-oil ratios and therefore are only profitable with high oil prices. Between 2006 and 2009, production of CA TEOR increased from 95 to 118 million barrels per year (an average rate of increase of 8 million barrels per year).

The International Energy Agency predicts that oil prices will remain high through 2020 with average prices remaining in the $90 to $100 per barrel range (or higher).[59] Therefore, it is likely that CA TEOR production will remain high and possibly continue to increase through 2020. If the very high growth rate observed over the period of 2006 to 2009 were to continue over the time period for the regulation, an additional 760 million barrels of high-intensity crude would be produced in California as compared to the assumed static 2006 baseline level (95 million barrels per year being maintained over the period of 2010 to 2020).

If refined in California, the current regulation would assign the average carbon intensity of 8.07 gCO_2e/MJ to this additional high intensity crude and therefore excess emissions associated with producing the crude would not be mitigated. If one assumes an average carbon intensity of 20 gCO_2e/MJ for high-intensity crude production, an additional 760 million barrels of high-intensity crude from basket sources would result in approximately 45 million metric tons GHG emissions that do not get mitigated. This is equivalent to approximately three times the expected GHG emissions reductions from the LCFS during the year 2020.

We note that it is not likely that this high growth rate in CA TEOR production will continue through 2020, as reserves of crude oil in California are becoming depleted, but the calculation does inform as to the potential magnitude of the problem and the need to amend the current crude oil provision.

The California Average Approach also improves the accounting of GHG emissions associated with conventional primary or secondary production, which are expected to increase over time. Because the carbon intensity of this crude will not likely exceed the 15 gCO_2e/MJ threshold, the crude will always be assigned a carbon intensity of 8.07 gCO_2e/MJ under the current provision. Therefore, the expected increase in carbon intensity for conventional crude production would go unmitigated under the current regulation.

Crude oil projections presented in the 2010 World Energy Outlook show that in the year 2020, crude recovery from fields currently in production will be in rapid decline and a third of the conventional crude oil will originate from fields yet to be developed and even yet to be discovered.[60] The carbon intensity of conventional crude production in 2020 will likely be greater than today because fields in decline become more carbon-intensive

[59] International Energy Agency, 2010, World Energy Outlook 2010, page 72.
[60] International Energy Agency, 2010, World Energy Outlook 2010, page 122.

as recovery progresses from primary to secondary to tertiary. For example, as fields become depleted, water injection rates increase as indicated by average water-to-oil ratios (WOR) in the U.S. and Canada in excess of 10. An increase in WOR from 3 to 15 results in approximately three times the GHG emissions for crude lifting and water reinjection.[61]

New production is also likely to be more carbon-intensive. Much of the new conventional production is occurring offshore from deep sea wells. Secondary production from deep sea wells using water injection can be very GHG-intensive. Also, offshore production and rapidly developed onshore production (e.g., Bakken field in North Dakota and Montana) is often accompanied by excessive flaring.

By accurately accounting for carbon intensity of all crudes, the California Average Approach provides an incentive, all else being equal, for refiners in California to:

- Purchase crudes produced locally, as these crudes will have lower transportation emissions (more than 1 gCO_2e/MJ difference between crudes from South or Central America and those from Africa or the Middle East);
- Purchase crudes produced with low flaring emissions. Angola and Nigeria both produce light to medium sweet crudes, but flaring in Nigeria contributes over 6 gCO_2e/MJ more to GHG emissions; and
- Purchase thermally-recovered crudes that employ cogeneration or use a lower steam-to-oil ratio.

Although the market signal resulting from this incentive is likely small, it would grow if other jurisdictions adopt an LCFS program with similar provisions.

The regulation is currently structured so that the compliance schedule CI targets are based on average CI values for CaRFG (California Reformulated Gasoline) and ULSD (Ultra-Low-Sulfur Diesel). The CI of CaRFG reflects a mixture of 90 percent CARBOB and 10 percent California Average Corn Ethanol. The average Lookup Table CI values for CARBOB and ULSD are calculated using the average crude oil slate refined in California in the year 2006. Under the proposal, the portion of the CIs for CARBOB and ULSD due to the production and transport of crude oil used in California refineries will be updated to reflect crude supplies used in the most recent year currently available, which is 2009. In effect, this would:

- Increase the CI value attributable to the production and transport of crude oil from the current 8.07 gCO_2e/MJ to a higher value of 9.72gCO_2e/MJ, an increase of 1.65 gCO_2e/MJ;

[61] Jacobs Consultancy and Life Cycle Associates, 2009, Life Cycle Assessment Comparison of North American and Imported Crudes, prepared for Alberta Energy Research Institute.

- Change the base CI values for CARBOB, CaRFG, and ULSD from 95.86 gCO_2e/MJ, 95.85 gCO_2e/MJ, and 94.71 gCO_2e/MJ to 97.51 gCO_2e/MJ, 97.39 gCO_2e/MJ, and 96.36 gCO_2e/MJ, respectively; and
- Require a corresponding change in the annual LCFS standards to reflect a higher CI baseline for CaRFG and ULSD. These changes would apply to fuels supplied between 2013 and 2020.

The 1.65 gCO_2e/MJ increase in production and transport CI of California average crude oil under the proposal is comprised of three components:

- 0.5 gCO_2e/MJ is due to the change in calculation methodology. Applying the methodology used in the proposal to the 2006 crude data would result in a carbon intensity for crude recovery and transport of 8.57 gCO_2/MJ;
- 0.8 gCO_2e/MJ is due to the increase in CA TEOR production from 95 to118 million barrels per year between 2006 and 2009[62,63]; and
- 0.35 gCO_2e/MJ is due to the increase in non-basket HCICO imports from Canada, Venezuela, and Oman. Annual imports of Canadian oil sands and Venezuelan extra-heavy crude have increased between 2006 and 2009, from less than 5 million barrels to over 14 million barrels[64]. An additional small amount of TEOR from Oman was imported in 2009 but actual amounts are unknown.

The increase in CA TEOR production between 2006 and 2009 and related GHG emissions are "grandfathered" in the current approach under the "2006 basket" and therefore would have gone unmitigated regardless of the proposal. However, the current regulation would have required mitigation of the extra GHG emissions from use of the non-basket HCICOs imported from Canada, Venezuela, and Oman in 2009. The proposal provides disincentive for total thermal/mining/upgraded production to increase further, but will allow this additional high intensity crude to remain within the baseline. The overall effect of these factors is that the new 2009 baseline under the proposal would result in a CI increase of 0.35 gCO2e/MJ.

It should be noted that some of this increase in the baseline would be mitigated by the enhanced GHG benefits under the updated compliance schedules of the proposal. Because the revised baseline CI for CaRFG and ULSD is slightly higher (increase of 1.54 gCO_2e/MJ and 1.65 gCO_2e/MJ, respectively) than the current regulation, the ten percent reduction goal of the LCFS from these larger values will produce somewhat greater net emissions. For example, the relative gasoline and diesel CI-reduction

[62] California Department of Conservation, 2007, Division of Oil, Gas, and Geothermal Resources, 2006 annual Report of the State Oil and Gas Supervisor, page 3.
[63] California Department of Conservation, 2010, Division of Oil, Gas, and Geothermal Resources, 2009 annual Report of the State Oil and Gas Supervisor, page 3.
[64] California Energy Commission, October 11, 2011, Email Correspondence: Spreadsheet Data on Canadian and Venezuelan crude oil production.

requirements from the baseline through 2020 would each increase by 0.15 gCO_2e/MJ and 0.16 gCO_2e/MJ under the proposal. Further, the total deficits created with a 1.65 gCO_2e/MJ increase in crude oil CI are on the order of 3.5 percent (approximately 2.3 million MTs more deficits between 2013 and 2020). These effects enhance the GHG benefits expected from the LCFS program under the proposal.

Regulated Parties for Electricity

Staff is proposing modifications to the provisions in the regulation that designate which parties may opt-in as regulated parties for electricity. The proposed provisions clarify which parties are eligible to become regulated parties and receive credits for supplying electricity as a transportation fuel.

Although the proposed provisions alter the recipients of credits for electricity, they do not change the total number of credits that can potentially be generated. However, staff is proposing to include default parties who can potentially receive credits if the first-in-line designated party chooses not to become a regulated party by opting into the LCFS. Staff anticipates that including default parties in the regulation could potentially increase the number of credits captured and offered on the credit market for purchase, thereby decreasing the cost of purchasing credits and reducing compliance costs.

2. Impacts Analysis

    a. GHG and Air Quality Benefits

Opt-in and Opt-out Provisions

The proposed opt-in, opt-out provisions could potentially result in avoided emissions if a regulated party chose to purchase credits from an opt-in fuel producer to meet compliance obligations rather than create an additional demand for biofuels, resulting in the siting and building a new biorefinery.

Staff anticipates no further air quality benefits would result from the opt-in, opt-out regulation modifications.

Enhanced Regulated Party Provisions

As with the proposed opt-in, opt-out provisions described above, the enhanced regulated party provisions could potentially result in a greater number of parties who are eligible to generate credits registering for the regulation. The benefits of additional credits in the LCFS marketplace are similar to those described for opt-in, opt-out provisions.

Staff anticipates no further air quality benefits would result from the enhanced regulated party provisions.

Mandatory LCFS Reporting Tool Use

Staff anticipates no air quality benefits would result from the proposed mandatory LCFS reporting tool provision.

Credit Trading

Staff anticipates no air quality benefits would result from the proposed credit trading provisions.

Revised EERs

The modifications staff is proposing to EER values for electricity and fuel cell vehicles would result in a greater number of credits for regulated parties of these fuels. If the fuels were considered more attractive to regulated parties due to the increase in total credit value, it is conceivable that some shift in fuel use could occur. Because both electricity and hydrogen meet the 2020 carbon intensity standard, there could be air quality benefits if usage shifted from higher carbon intensity fuels.

Certification Process for Method 2A/2B

Staff anticipates no air quality benefits would result from the Method 2A/2B certification process provisions.

High Carbon Intensity Crude Oil (HCICO)

As explained below, staff believes that the proposal would provide a framework for enhanced GHG benefits, and that the proposal would not result in additional adverse impacts to California's air quality relative to the existing regulation.

The proposed changes to the handling of crude oil under the LCFS may result in an increase or a decrease in GHG benefits under the LCFS program, depending on projections for crude —specifically, California crudes – supplied to California refineries. Under the current regulation, an increase in California TEOR production would not have to be mitigated because it is grandfathered crude; therefore, the current regulation would be less protective than the proposed amendment, which would account for additional HCICO, domestic or imported. Conversely, if California TEOR production declines by 2020 and is replaced by imported HCICO, the current regulation would impose a CI penalty on the imported HCICO, whereas the proposed amendments would apply no such penalty as long as the total HCICO volume remains the same or declines. Finally, since the proposed amendment will assign lower CI values for California non-TEOR crudes (i.e., a true accounting of crude CIs), their use could mitigate the additional GHG impacts incurred by the additional use of crudes from TEOR production.

Overall, staff believes that the proposed revisions are necessary to properly account for the CI values of all crudes processed in California, irrespective of source. The current regulation does not accomplish this, and grandfathered “basket “crudes that are HCICO could increase in production with no mitigation required, thereby reducing the effectiveness of the LCFS during the remaining period (2013 to 2020) of the LCFS program.

The proposed 2009 baseline CI is slightly higher than the 2006 baseline, so additional volumes of imported, higher-CI crudes may be processed in California refineries. However, since the ten-percent reduction goal of the LCFS will produce greater net GHG emissions reductions under the proposal—10 percent of a larger number is also a larger number—some of the impacts of the higher baseline CI will be mitigated. For example, the potential incremental GHG benefits under the revised compliance schedules are estimated to be about 259,000 MT CO_2e in 2020; therefore, the total GHG emissions reductions for the LCFS in 2020 are estimated to be about 16.1 MMT CO_2e instead of the original 15.8 MMT CO_2e.

Staff expects the proposed HCICO provisions to result in no additional adverse impacts to California’s air quality due to criteria and toxic air pollutants relative to the current regulation. Based on stringent New Source Review regulations affecting the permitting of these facilities, staff recommends that emissions from these facilities be mitigated and offset pursuant to local air district and CEQA requirements.

Regulated Parties for Electricity

Staff anticipates no air quality benefits would result from the modifications to the regulated parties for electricity.

b. Other Potential Impacts

Based on ARB’s review of the proposed regulation, staff concludes that the regulation would not have a significant adverse effect on the environment as explained below. No discussion of alternatives or mitigation measures is necessary because there are no significant adverse environmental impacts identified.

Compliance with all the proposed amendments would not require or result in any physical change to the existing environment, that might involve new development or require modifications to buildings or other structures, or affect operations at existing facilities, or cause any new land use designation. Therefore, these provisions are not expected to result in any adverse impacts to aesthetics, air quality, agricultural and forestry resources, biological resources, cultural resources, geology and soils, greenhouse gases, land use planning, mineral resources, population and housing, public services, recreation, or traffic and transportation. Further, compliance with the proposed modifications to the LCFS does not involve any activity that would involve or affect hazardous material, hydrology and water quality, noise, or population and housing because they do not mandate any action that could affect these resources.

E. Environmental Justice

ARB is committed to integrating environmental justice in all of its activities. On December 13, 2001, the Board approved “Policies and Actions for Environmental Justice,” which formally established a framework for incorporating Environmental Justice into ARB’s programs, consistent with the directive of California state law.[65] Environmental Justice is defined as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies.

The proposed amendments to the LCFS regulation are consistent with the environmental justice policy to reduce health risks from GHG emissions in all communities, especially those with low-income and minority populations, regardless of location. The proposed amendments will continue to reduce GHG emissions from the use of transportation fuels in California.

AB 32 requires that, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emission limit, ARB must consider the potential for direct, indirect, and cumulative emission impacts from market-based compliance, including localized impacts in communities that are already adversely impacted by air pollution, design the program to prevent any increase in emissions, and maximize additional environmental and economic benefits prior to the inclusion of market-based compliance mechanisms in the regulations. As ARB further develops its approach for consideration of these issues, staff will continue to consult with outside experts.

[65] Air Resources Board, 2001, Policies and Actions for Environmental Justice

VI. ECONOMIC IMPACT ANALYSIS

In this chapter, ARB staff analyzed a number of proposed LCFS regulation amendments (as outlined below) and estimated their potential fiscal and economic impacts. The economic analysis includes the costs and savings associated with the economic impacts on businesses, consumers, and government agencies. For a full description of each of the proposed regulatory amendments, please see Chapter IV.

A. Legal Requirements

This section explains the legal requirements that must be satisfied in analyzing the economic impacts of the regulation. Section 11346.3 of the Government Code requires State agencies to assess the potential for adverse economic impacts on California business enterprises and individuals when proposing to adopt or amend any administrative regulation. The assessment shall include a consideration of the impact of the proposed regulation on California jobs, business expansion, elimination or creation, and the ability of California businesses to compete with businesses in other states. Also, State agencies are required to estimate the cost or savings to any State or local agency and school district in accordance with instructions adopted by the Department of Finance. The estimate shall include any non-discretionary cost or savings to local agencies and the cost or savings in federal funding to the State. Finally, Health and Safety Code section 57005 requires ARB to estimate the economic impacts of submitted alternatives to a proposed regulation before adopting any major regulation. A major regulation is defined as a regulation that will have a potential cost to California business enterprises in an amount exceeding ten million dollars in any single year. The following is a description of the methodology used to estimate costs as well as ARB staff's analysis of the economic impacts on California businesses, consumers, and government agencies.

B. Summary of the Economic Impacts

<u>Opt-in, opt-out provisions</u>

Staff will provide clarity to opt-in and opt-out procedures, which could encourage the regulated parties to opt-in, resulting in greater number of LCFS credits generated and available for use by regulated parties. If a regulated party selects to opt-out, then all the available generated credits by the regulated party shall be retired.

Economic Impact: Greater number of LCFS credits generated and available for use could reduce the cost of LCFS credits, thereby reducing compliance costs.

<u>Enhanced Regulated Party Provisions</u>

Allows out-of-state fuel producers and distributors to qualify as regulated parties and generate credits, which could result in greater number of LCFS credits available for use for compliance.

Economic Impact: Greater number of LCFS credits generated and available for use could reduce the cost of LCFS credits, thereby reducing compliance costs.

Mandatory LCFS Reporting Tool Use

Proposed regulatory amendment will require regulated parties to use only the LCFS Reporting Tool (LRT) as the “interactive, secured internet web-based form” required by the current regulation.

Economic Impact: Staff expects no economic impact, as regulated parties are already using the LRT exclusively to comply with LCFS reporting requirements.

Credit Trading

Staff is proposing to add provisions in the regulation that clarify how credits and deficits are tracked and to specify the process to be used to acquire, bank, transfer, and retire credits. In the proposal, staff is also including a provision that allows a regulated party to acquire credits in the first quarter of a year to meet a compliance obligation in the previous year, as long as those credits were generated in a previous year. This proposal further seeks to establish requirements relating to the public release of information concerning the generation of deficits and the generation, use, and transfer of credits.

Economic Impact: By adding certainty to the credit market, credit transactions should increase, thereby lowering the cost of compliance. Both credit sellers and buyers will be more likely to carry out transactions within a rational and predictable framework, improving the efficiency of the LCFS credit market.

Revised EERs

Staff is proposing three modifications to the Energy Economy Ratios (EERs). First, staff is proposing to add to the regulation an EER of 1.0 for heavy-duty compression-ignited engines fueled with compressed natural gas (CNG) or LPG. Currently, the EER in the regulation for these vehicles is 0.9. Second, staff is proposing to change the EER for the electricity used in light-duty battery electric vehicles and plug-in hybrids from 3.0 to 3.4. Third, staff is proposing to change the EER for light-duty fuel cell vehicles from 2.3 to 2.5.

Economic Impact: The proposed changes to EER values have the potential to increase the number of credits generated for CNG/LNG, electricity, and hydrogen transportation fuels. An increase in the number of credits available for regulated parties to purchase can decrease the value of a credit, potentially decreasing compliance costs.

Certification Process for Method 2A/2B

In the current regulation, the process through which a regulated party receives approval to use a carbon intensity value determined through the Method 2A/2B process requires an Executive Officer (EO) or Board hearing. Staff is proposing to convert this regulatory process to a certification process to save staff resources, yet maintain the technical rigor and public input of the current requirements.

Economic Impact: The Method 2A/2B application requirements and the technical analyses conducted by staff during the review of those applications will remain unchanged; therefore, there should be no economic impact on the regulated parties related to the proposed certification process. The benefit of the proposed certification process is a streamlined approval process that reduces staff resources, which then can be redirected to other tasks and program needs. This fiscal cost effects are discussed below in section D.2.

High CI Crude Oil (HCICO)

The proposed LCFS high carbon intensity crude oil (HCICO) amendment departs from the existing HCICO provisions in two fundamental ways. It establishes a new baseline consisting of the 2009 crude mix processed by California refineries, and it assigns a single average CI to every crude oil refined into transportation fuel for sale in California. This California average crude CI would be calculated annually and would apply to the reporting period following its calculation. For example, data for the 2012 crude slate would become available sometime in 2013, at which the California average crude CI would be calculated. This California average crude CI would become applicable on January 1, 2014.

This California average approach to HCICO accounting would replace the existing approach which established a California "basket" containing the crudes processed by California refineries in 2006. The average CI calculated for that basket (8.07 gCO_2e/MJ) was assigned to all crudes contained therein. All crudes *not* in the 2006 basket were to be screened to identify those which are clearly not HCICOs, and those which have the *potential* to be HCICOs. Regulated parties using crudes in the latter category would be required to formally estimate the CI of those crudes using the LCFS Method 2B process. If a Method 2B analysis revealed that the extraction and transportation components of the resulting CI exceeded 15 gCO_2e/MJ, the affected crudes would be deemed to be a HCICO, and would be assigned the CI estimate from its Method 2B analysis.

A shortcoming with the original proposal was that an accurate CI accounting was only required for crudes that exceeded the threshold value of 15 gCO_2e/MJ. Crudes contained in the 2006 basket and crudes with extraction and transportation CIs below the 15 gCO_2e/MJ threshold were able to use the baseline mix CI of 8.07 gCO_2e/MJ. The adoption of the California average approach addresses this shortcoming.

The proposed California Average approach fully accounts every year for the carbon intensity of all crudes processed by California refineries selling transportation fuel into the California market. However, because the California Average approach assigns a single average value to the whole California crude slate, individual refineries processing crudes with CIs that are above the California average will realize a benefit by not having as large a CI deficit to mitigate, while those with CIs that are below the State average will experience a cost by sharing the mitigation of higher-CI crudes that they did not process.

The crude purchasing incentives created by the California average approach vary according to a number of factors. All refiners, however, share the same basic incentive to maintain the California average year-over-year.

Cost Impacts to Fuel Producers

As a result of the differences described above, the HCICO purchasing incentives created by proposed amendments are quite different from the incentives that exist under the current provisions. Under the proposed amendments, the costs incurred depend upon how refiners respond to two potentially competing incentives: the financially driven desire to purchase suitable crudes at least cost and the desire to maintain the California Average. At times, a refinery may find it advantageous from a business perspective to run a HCICO. Doing so, however, risks increasing the California Average. Increases in the California Average must be mitigated by offsetting purchases of lower-CI fuels or the use of credits.

Understanding this dynamic requires that we first understand the case in which the California average is maintained. The proposed California Average approach provides California fuel producers with a number of opportunities to maintain the California Average CI.

1. By using a 2009 baseline, the proposed approach provides more flexibility to fuel producers than does the 2006 baseline used in the existing regulation. Since the 2009 baseline contains higher levels of HCICO than the 2006 baseline, it would allow more flexibility to fuel producers when considering the purchase of higher volumes of HCICOs.
2. The proposed California Average approach provides refiners with the flexibility to substitute one HCICO for another. A HCICO from a newly developed source, such as Canada for example, could be substituted for HCICO from a declining source, such as Venezuela. Under the existing provisions, this substitution would constitute a change from a grandfathered basket crude to a HCICO, triggering an increase in the refiner's CI. This ability to switch among differing HCICOs while maintaining a constant HCICO volume and a constant California Average provides refiners with significant flexibility—flexibility that is unavailable under the current HCICO provisions.
3. Under the proposed amendment, all crudes—including non-HCICOs—are assigned an appropriate and current average value. Under the existing provisions,

non-HCICOs with actual CIs of 15 gCO_2e/MJ or less are assigned a CI of 8.07gCO_2e/MJ. A significant proportion of the California crude slate may fall into this category. The annual California average that would be calculated under the proposed amendment would include the actual CIs of this category of crude oils. These low-CI crudes would at least partially offset the HCICO CIs also included in the average.

The use of a 2009 baseline, the ability to substitute HCICOs without penalty, and the inclusion of low-CI crudes in the California average will result in compliance costs that are no higher than the costs of complying with the existing HCICO provisions. Due to the increased flexibility introduced by the proposed amendments, compliance costs could be lower than they would be under the existing provisions.

Having covered the case in which the California average is maintained year-over-year, it is now necessary to discuss the case in which the California average rises due to a net increase in HCICO purchases. The resulting increase in the average crude CI would need to be mitigated through the increased use of lower-CI fuels and, possibly, the use of credits.

A comparison of the existing and proposed HCICO provisions under a rising average CI scenario requires an examination of the cost impacts of in- and out-of-basket crudes:

1. Crudes that are outside of the California basket.

   Under the current regulation, any HCICO from outside of the California basket results in a CI penalty (in the form a mitigation requirement). Under the proposed amendment, however, some of the non-basket HCICO purchases could be offset by decreases in purchases of in-basket HCICOs. Such offsets will not always occur, of course, but, over the long run, enough offsetting purchases would occur to lower the cost of compliance of under the proposed amendments relative to compliance costs under the existing provisions.

2. Crudes that are in the California basket.

   Unlike the existing provisions, the proposed amendments would require all increased purchases of in-basket HCICOs to be included in the calculation of the California Average. Generally, this represents an increased cost of compliance, which would partially or wholly offset the decreased compliance costs realized for out-of-basket crudes (see section (a), above). In practice, however, reduced purchases of out-of-basket HCICOs would act to reduce the upward pressure from the in-basket purchases. Under the existing provisions, the benefits of reduced purchases of out-of-basket HCICOs would accrue only to the refiners reducing their HCICO use.

Potential Cost Savings

As mentioned above, the current LCFS regulation requires regulated parties using crudes that are “potential-HCICOs” (i.e., those that did not pass the first screening process that would have identified them as clearly non-HCICO) to formally estimate the CI of those crudes using the LCFS Method 2B process. Based on staff experience to date with the Method 2A/2B process, staff estimates that a 2B application would cost the applicant about $20,000. Since 65 market crudes out of 255 did not pass the initial screening process, at $20,000 apiece for a Method 2B application, total costs could be as high as $1.3 million if all of these crudes needed CI values for California use. Under the proposed amendments, ARB staff will calculate the California average crude CI, obviating the need for regulated parties to go through the Method 2B process.

Summary

Where the existing provisions strongly discourage the purchase of out-of-basket HCICOs while simultaneously allowing unlimited, penalty-free purchases of in-basket HCICOs, the proposed amendments generally dis-incent *all* HCICO purchases by all refiners. The differences created by the removal of the California basket under the proposed amendments make any comparison between the existing and proposed provisions a complex undertaking. The analysis presented in this chapter shows, however, that the 2009 baseline, the ability to substitute HCICOs without penalty, and the inclusion of low-CI crudes in the proposed California average will tend to contain compliance costs. Compliance costs under the proposed amendments will be no higher than compliance costs under the existing provisions. The added flexibility that would be created under the proposed amendments could result in reduced compliance costs.

<u>Regulated Parties for Electricity</u>

Staff is proposing modifications to the provisions in the regulation that designate which parties may opt-in as regulated parties for electricity. The proposed provisions clarify which parties are eligible to become regulated parties and receive credits for supplying electricity as a transportation fuel.

Although the proposed provisions alter the recipients of credits for electricity, they do not change the total number of credits that can potentially be generated. However, staff is proposing to include default parties who can potentially receive credits if the first-in-line designated party chooses not to become a regulated party by opting into the LCFS.

Economic Impacts: Staff anticipates that including default parties in the regulation could potentially increase the number of credits captured and offered on the credit market for purchase, thereby decreasing the cost of purchasing credits and reducing compliance costs.

C. Methodology for Estimating Costs

As discussed above, most of the proposed amendments to the LCFS regulation will not result in any fiscal or economic impacts. Staff asserted that several of the proposed amendments would result in additional credits being generated and used within the LCFS program, thereby reducing the cost of credits and reducing compliance costs. Staff did not and could not quantify the benefits of additional available LCFS credits; however, basic economic principles of supply-and-demand support staff's assertions.

D. Potential Costs to Local, State, and Federal Agencies

Fiscal Impact on State, Local, and Federally-Funded Programs

There are no fiscal impacts on these programs.

Other Fiscal Effects on Government

Method 2A and 2B pathway carbon intensities are currently approved through the regulatory change process. Final approval is granted by the Executive Officer at a public hearing. Staff proposes to streamline the approval process by converting the regulatory process to a certification process, thereby reducing staff resources, which then can be redirected to other tasks and program needs. ARB currently runs several effective certification programs, including programs to certify diesel control devices and distributed generation equipment. Staff's proposed certification program will maintain the technical rigor and public input of the current regulatory process, yet realize significant staff utilization efficiencies as estimated in Table 6 below:

Table 6. Fiscal Effects of a Regulatory Change Process

					Totals	
Classification	**Annual PY cost [(a)]**	**Low Hourly Personnel Cost**	**High Hourly Personnel Cost**	**Grand Total Hours devoted to Reg. Change**	**Low**	**High**
Air Pollution Specialist [(b)]	$107,000 - $164,000	$60	$92	272	$16,345	$25,183
Air Resources Engineer [(b)]	$118,000 - $172,000	$66	$97	368	$24,355	$35,572
Air Resources Supervisor 1 [(c)]	$156,000 - $181,000	$88	$102	111	$9,753	$11,301
Air Resources Supervisor 2 [(c)]	$167,000 - $195,000	$94	$110	63	$5,934	$6,899
AGP Video Coordinator [(c)(d)]	N/A	N/A	N/A	N/A	N/A	$6,700
2 Associate Government Program Analyst [(c)(d)]	$110,000 - $124,000	$62	$70	10	$617	$700
2 Students [(c)(d)]	N/A	$13		8	$104	$104
Court Reporting Services [(c)(d)]	N/A	N/A	N/A	N/A	$250	$800
Grand Totals					$57,582	$87,503

[a]: The total costs include salaries and wages, benefits, operating expenses and equipment.
[b]: Information provided by ASD
[c]: Using data from ARB
[d]: Data provided by ARB

VII. ANALYSIS OF ALTERNATIVES

This Chapter provides an analysis of the alternatives to the proposed amendments to the Low Carbon Fuel Standard (LCFS) regulation. The Chapter is divided into two sections. The first section represents an analysis of the status quo alternative—that is, the “no action” alternative. The second section addresses specific alternatives to staff’s proposed amendments. A detailed discussion of each alternative considered follows in the subsections below.

A. “No Action” Alternative

One of the alternatives to the proposed regulatory amendments is to keep the current LCFS regulation as is (i.e., “no action” alternative). ARB staff evaluated this alternative, the analyses of which are summarized below:

1. Energy Economy Ratios (EERs)

Since the publication of the ARB's original LCFS ISOR in March 2009, new fuel economy data have become available for alternative-fueled vehicles. Not revising the EERs values to reflect the most current energy efficiency data available for actual vehicles available in today’s market would result in the LCFS regulation being out-of-date on emerging vehicle technologies. Staff’s proposal to update the EERs values for CNG/LNG burning heavy-duty vehicles and for light-duty vehicles in the battery electric vehicle, plug-in hybrid, and fuel cell-powered categories would reflect current 2011 powertrain efficiencies that were unavailable in 2009 for commercially available cars and heavy duty vehicles.

2. Regulated Party Revisions

Under the current LCFS regulation, a regulated party is defined as a person who ultimately ends up with the carbon intensity obligation for the fuels introduced into the market. Upstream fuel producers and distributors are not regulated parties and therefore cannot generate and maintain LCFS credits, and they are not required to report their fuel sales in the LCFS Reporting Tool (LRT). This current provision may obscure the understanding of the complete lifecycle of imported blendstocks and prevent fuel producers from realizing the full market value of their fuels by disallowing LCFS credit generation. Staff’s proposal would allow upstream producers and distributers to voluntarily opt into the LCFS as regulated parties, reducing fuel pathway uncertainties and generating additional credits for compliance purposes.

3. Reporting Requirements

The current regulation mandates the use of “an interactive, secured internet web-based form” for submitting annual compliance and quarterly progress reports. Since regulated parties are already using the LRT to report, a “no action” alternative to this proposed amendment would not have a real impact today; however, designating the LRT as the mandated reporting form minimizes potential confusion regarding future LCFS reporting.

4. Method 2A/2B Certification

In the current regulation, the process through which a regulated party receives approval to use a carbon intensity value determined through the Method 2A/2B process requires an Executive Officer or Board hearing. This regulatory approach requires considerable staff resources better utilized for other high-priority tasks and programs. Staff is proposing to convert this regulatory process to a certification process to save staff resources, yet maintain the technical rigor and public input of the current requirements. To maintain the current regulatory approach would forfeit the opportunity for greater staff efficiency and productivity.

5. Credit Trading

The current regulation is silent on the mechanism through which LCFS credits may be traded in a robust market, which is essential to the success of the LCFS program. The proposed amendments of the LCFS regulation include a new section to provide more detail on how credits and deficits will be tracked, and to specify the process to be used to acquire, bank, transfer and retire credits. In the proposal, staff is also including a provision that allows a regulated party to acquire credits in the first quarter of a year to meet a compliance obligation in the previous year, as long as those credits were generated in a previous year. This proposal further seeks to establish requirements relating to the public release of information concerning the generation of deficits and the generation, use, and transfer of credits. The “no action” alternative to clarifying the credit trading provisions of the LCFS through proposed regulatory amendments would continue to obscure and inhibit the LCFS credit market.

6. Opt-In/Opt-Out Procedure

The current LCFS regulation allows electricity, hydrogen, CNG, LNG, and biogas to opt in to generate credits. It simply refers to a regulated party electing to generate LCFS credits for the exempted fuels but provides no specificity on how to opt-in or opt-out. There are a number of providers of biogas and other exempted, low-CI fuels (those that already meet the 2020 CI standards) who want to opt into the LCFS but are reluctant to do so because the current regulatory language does not specify what requirements are necessary to opt-out in the future. The proposed amendments to the LCFS regulation include additional language that details how a fuel provider could become a regulated party (opt-in) or later remove them from being a regulated party (opt-out). Providing such specificity should encourage providers of exempt, low-CI alternative fuels who have been reluctant or uncertain about bringing credits to the LCFS market to opt-in. Staff deemed such a proposed amendment necessary and preferred over the current regulation.

7. Regulated Party for Electricity

Since the LCFS was approved by the Board in April 2009, the market dynamics for electric vehicles (EV) and EV-fueling infrastructure have evolved. In the current LCFS regulation, regulated party language for electricity is obsolete and incomplete, needs clarification of key terms, and should reflect current business models for the deployment of EVs. Staff proposes regulatory amendments to clarify which parties are eligible to become regulated parties and receive credits for supplying electricity as a transportation fuel. The “no action” alternative to the proposal would simply maintain the ambiguity and obsolescence of the current language.

8. High Carbon-Intensity Crude Oil (HCICO)

The current LCFS regulation recognizes that additional energy is required to produce some crude oils and, taking a full lifecycle assessment (LCA) into consideration, calculates the carbon intensity deficit for such high carbon intensity crude oils (HCICOs) processed in California refineries. The HCICO provision in the current regulation has been of particular concern for the oil industry, which asserts that the current HCICO provisions result in economic harm to California refineries and environmental harm overall due to crude “shuffling.” On the other hand, other stakeholders are equally as adamant that the LCFS should continue to prevent increases in lifecycle carbon emissions that could occur if higher intensity crudes are used to replace existing supplies. These parties generally support approaches that discourage or fully mitigate the refining of HCICOs in California and incentivize carbon emission mitigation techniques for oil production.

ARB staff has worked with all interested stakeholders to explore alternatives to the current adopted approach to addressing HCICO in the LCFS. Staff proposes regulatory amendments that would more appropriately account for additional emissions from the production and transportation of HCICO processed in California refineries and therefore meets the intent of the regulation (to ensure that the LCFS benefits are not diminished due to increases in GHG emissions from higher carbon intensity crude supplies). At the same time, the staff’s proposal addresses, to the extent possible, the concerns laid out by the various stakeholders.

The “no action” alternative of keeping the current provision has several drawbacks. First, there is the possibility for backsliding in the emissions reduction benefits of the LCFS due to the grandfathering of basket crude sources under current provisions. Second, the current approach limits refiners’ flexibility to purchase crude supplies, as they will have significant incentives to avoid using fuels classified as HCICOs. Third, the current approach is overly burdensome to the regulated parties who need to undergo a technical rigorous Method 2B process for establishing CIs for their HCICOs and obtain approval of the Executive Officer.

9. Designating the LRT for LCFS Quarterly and Annual Reporting

As noted, the alternative to the staff's proposal is the existing regulatory language, "[a] regulated party must submit an annual compliance and quarterly progress report by using an interactive, secured internet web-based form." [Emphasis added.] While this performance-based alternative appears flexible, it has a number of issues that are addressed by the proposal. First, the current language provides little guidance to regulated parties as to what exactly would constitute a compliant interactive, secured internet web-based form. As with most industries, the transportation-fuels sector values certainty, and specifying that only the LRT, which is accessible from ARB's website, can be used for reporting ensures such certainty.

For similar reasons, the requirement to use the LRT ensures standardization and consistency, which would help facilitate credit trading between regulated parties (especially when the LRT version 2.0 is developed, which will automate credit trades and credit reporting). On the other hand, having multiple types of software used for reporting purposes would likely entail compatibility and security issues, both with ARB's database and with credit trading partners.

Finally, because all regulated parties are using the LRT and ARB makes it available for free, there are no additional costs involved with using the LRT for regulated parties. By contrast, the purchase of and training with different, commercially-developed reporting software would almost certainly involve additional costs for regulated parties.

For the above reasons, staff determined that prescribing the use of the LRT as the only online mechanism for use by regulated parties is superior to allowing multiple types of software under the current performance standard.

B. Alternatives to Specific Proposed Amendments

1. Regulated Party for Electricity

Staff evaluated the following options for designating the potential electricity regulated parties:

- Designate electric utilities as potential regulated parties for all EV charging.
- Designate EV owners as potential regulated parties for electricity delivered to their vehicles.
- Omit potential default regulated parties.

When evaluating these alternatives, staff kept three goals in mind. The first goal was to keep the proposed language simple to avoid confusion in regulated party designation and maintain relevancy as the EV-charging market evolves in future years. The second goal was to limit the number of regulated parties to increase the possibility that credits will be captured and made available to other regulated parties. The final goal was to maximize the number of credits captured and available for purchase.

The first option – designate electric utilities as potential regulated parties for all EV charging – goes against the goal of maintaining relevancy as the EV charging market evolves in future years. Such designation cannot benefit potential charging equipment installers such as non-utility electric vehicle service providers, business owners, and EV fleet owners; therefore, this approach would discourage their efforts to establish the public and private charging networks which are critical to the future EV market.

The second option – designate individual EV owners as potential regulated parties for electricity delivered to their vehicles – goes against the goal of limiting the number of regulated parties to increase the possibility that credits will be captured and made available to other regulated parties. It is much more difficult to keep track of the credits from individual EV customers than from larger entities, such as the utilities.

The third option – designate a hierarchy of potential regulated parties without designating a default party – goes against the goal of maximizing the number of credits captured and available for purchase. Given the recordkeeping and other requirements in the LCFS regulation, there is a potential for significant amounts of credits to be "orphaned" or otherwise not captured and put into the credit trading market if the designated regulated party, such as a business owner with an onsite charger, fails to opt in. On the other hand, electric utilities have an inherent interest in being able to generate credits for electricity used for transportation. For this reason, among others, staff proposes to designate electric utilities as the default regulated party to ensure that credits are not orphaned.

2. High Carbon-Intensity Crude Oil (HCICO)

This section includes a discussion of the potential approaches to the treatment of HCICOs in the LCFS regulation, staff's recommended approach, and the rationale for not choosing any of the alternatives.

Potential Approaches

Outlined below are several alternative approaches for the treatment of HCICOs in the LCFS regulation that were explored as this proposed rulemaking was developed. These approaches are a combination of those suggested by stakeholders or identified by ARB staff. An alternative that involves clarifying amendments to the current approach is presented first followed by discussion of five alternatives that would involve significantly different conceptual approaches.

1. Current Approach with Amendments

This approach provides amendments to clarify the regulation requirements and provides details for implementation. Amendments are based on the draft Crude Screening proposal that has been used to generate the list of non-HCICO sources attached to Regulatory Advisory 10-04A. The amendments would:

a. Include Step 1 of the screening process to codify the method used to generate the non-HCICO list. The non-HCICO identifiers are:

- Crude oil produced using recovery techniques other than thermal enhanced oil recovery (steam/hot water injection or in-situ combustion) or crude bitumen; and
- Crude oil produced from a country with an average flaring rate of less than 10 scm/bbl, as determined using the most recent NOAA/NGDC gas flaring rate data together with annual oil production data.

b. Include a provision that a regulated party will not be retroactively penalized if a crude source that has been added to the non-HCICO list is later removed;
c. Include language which sets an interim default HCICO CI for non-baseline crudes that are not on the non-HCICO list (i.e., “potential HCICO”);
d. Briefly outline the process by which a regulated party must get a crude source that “fails” the initial screen either added to the non-HCICO list or determined to be HCICO; and
e. Include a provision that a regulated party can retroactively use the average CI in place of the default HCICO CI if a crude source is later determined to be non-HCICO and put on the non-HCICO list.

2. California Average Approach

In this approach, the base deficit is calculated the same as in the current approach. However, an incremental deficit is applied to all companies if the average crude slate refined in California becomes more carbon intensive over time. This allows for an individual company to shift its crude slate and not be required to mitigate increased emissions as long as the average CI of the California crude slate used by the industry as a whole does not increase over time relative to the baseline year. For the California crude refining industry:

a. Each year of the regulation, a “current” California average CI would be calculated using the crude slate refined in California during a prior year.
b. If the “current” California average CI is greater than the “baseline” California average CI, then a revised incremental CI would be established and all regulated parties that provide California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) and ULSD would incur greater incremental deficits proportional to the amount of fuel they supplied and the difference between the current CI and the baseline CI.
c. An individual company could earn credits if it purchases crude from sources that have implemented innovative methods, such as carbon capture and sequestration (CCS) to reduce emissions for crude recovery. The number of credits will be tied to the emissions reduction achieved by the innovative method.

A variant of this approach[66] could provide the regulated parties the option to report company-specific CI values through an approach analogous to the Hybrid Approach discussed below instead of being subject to the California average CI value in a given year. Those companies opting to report company-specific CIs would be excluded from the California average CI calculation for that year. Any credit generation opportunities would be premised on a company choosing to report their own company specific baseline.

3. Hybrid California Average/Company Specific Approach

The base deficit for individual companies is calculated the same as in the current approach. However, individual companies only incur an Incremental Deficit if their own crude slate becomes more carbon-intensive over time relative to their crude slate refined in the baseline year. This allows individual companies to shift the crude slate they refine in California and not be required to mitigate increased emissions as long as the average CI of their own crude slate does not increase. There are two ways of implementing this approach: by either regulating the volume or the CI of the HCICOs refined by a company. For each oil company:

a. A “baseline” volume (or CI) of HCICO would be determined using the crude slate refined by that company in California during the baseline year.
b. Each year of the regulation, a “current” volume (or CI) of HCICO would be calculated using the crude slate refined by that company in California during a prior year.
c. If the company’s “current” volume (or CI) of HCICO is greater than its “baseline” volume (or CI) of HCICO, then the company will incur an incremental deficit calculated using the difference between the current volume (or CI) and the baseline volume (or CI).
d. An individual company can earn credits if it purchases crude from sources that have implemented innovative methods, such as CCS, to reduce emissions for crude recovery. The number of credits will be tied to the emissions reduction achieved by the innovative method.

4. Company Specific Approach

Each oil company will have distinct Lookup Table values and compliance targets for CARBOB and diesel, which are based on the crude slate refined by that company in California in the baseline year. Individual companies only incur an Incremental Deficit if their own crude slate becomes more carbon-intensive over time. This allows individual companies to shift their crude slates and not be required to mitigate increased emissions as long as the average CI of their own crude slate does not increase. For each oil company:

[66] Simon Mui, NRDC and John Shears, CEERT, September 17, 2011. Comment letter to ARB regarding HCICO Provisions.

a. Each year of the regulation, a “current” CI would be calculated using the crude slate refined by that company in California during a prior year.
b. If the “current” company-specific CI is greater than the “baseline” company-specific CI, then the company will incur an incremental deficit calculated using the difference between its current CI and its baseline CI.
c. An individual company can earn credits if it purchases crude from sources that have implemented innovative methods, such as CCS, to reduce emissions for crude recovery. The number of credits will be tied to the emissions reduction achieved by the innovative method.

5. Worldwide Average Approach

This approach bases the average Lookup Table CI values for CARBOB and diesel and the compliance schedule on worldwide average crude oil production and refining emissions in the baseline year. A Base Deficit is calculated using the difference between the average Lookup Table values for CARBOB (or diesel) and the compliance target for the current year. An Incremental Deficit is applied to all companies if the worldwide average crude production and refining becomes more carbon intensive over time.

All producers of CARBOB and diesel will calculate a Base Deficit using the difference between the average Lookup Table value for CARBOB or diesel and the compliance target in that year. Each year of the regulation, a “current” worldwide average CI would be calculated using the crude slate produced and refined worldwide during the previous year. If the “current” worldwide average CI is greater than the “baseline” worldwide average CI, then all companies will incur an incremental deficit calculated using the difference between the current CI and the baseline CI.

A variant of this approach[67,68] bases the average Lookup Table CI values for CARBOB and diesel and the compliance schedule on California average crude oil production and refining emissions in the baseline year. The other provisions remain the same.

6. California Baseline Approach (Eliminate Consideration of HCICOs in the LCFS)[67,68]

All CARBOB and diesel would use the existing CI values in the Look-Up Table. Regulated parties would only calculate and be subject to the Base Deficit for all CARBOB and diesel regardless of the crude oil used for refining. The Look-Up Table values for CARBOB and diesel would not be updated.

[67] Catherine H. Reheis-Boyd, WSPA, August 8, 2011. Comment letter to ARB regarding LCFS Regulatory Amendments.
[68] Ralph J. Moran, BP America, Inc., July 26, 2011. Comment letter to ARB regarding HCICO Provisions.

Evaluation of Potential Approaches

ARB staff evaluated the potential approaches for regulatory amendments. The guiding principles that formed the basis for our assessment of the alternatives are outlined below. These principles we chosen to assess if the core objectives that lead to the creation of the existing HCICO provision would be preserved.

1. Key Guiding Principles

   a. *Accurate accounting for emissions from production and transport of crude oil:* Since the LCFS regulation takes into account full lifecycle GHG emissions for fuel pathways, including all stages of feedstock production and distribution, the upstream emissions from energy-intensive crude recovery methods need to be accounted for to provide consistent treatment versus other regulated fuels. Establishing an accurate performance-based accounting system will ensure that additional emissions in the carbon intensity of gasoline and diesel fuels from the baseline are captured.

   b. *Discouraging potential increases in emissions and ensure that increases that do occur are mitigated:* An incremental deficit for backsliding with respect to the baseline will ensure that the GHG emission contributions from petroleum fuels do not increase over time without being mitigated.

   c. *Promoting innovation for emission reduction activities:* Providing credits for purchase of crude from production facilities that have implemented innovative methods, such as CCS, to reduce emissions for crude recovery is consistent with the goal of promoting innovation, at the same time accurately accounting for the reduction in upstream emissions. Apart from providing a market signal for cleaner production, credits generated through such activities can provide extra flexibility for meeting LCFS GHG reduction targets.

   d. *Avoiding or limiting incentives to use crude shuffling to generate credits, avoid deficits, or transfer GHG emissions to other jurisdictions to avoid regulation under the LCFS:* Additionally, a program design that can be exported to other jurisdictions will result in minimizing such GHG emission transfers if other jurisdictions adopt consistent programs.

In addition to meeting the above-mentioned key guiding principles to achieve the intended GHG benefits, amendments to the HCICO provision should be designed so as to avoid incremental adverse environmental and economic impacts. Additionally, considerations for a successful implementation, such as simplicity of methodology, availability of data, and administrative burden, as well as other issues such as fuel supply impacts, etc., should reflect on the decision-making process.

2. Qualitative Evaluation of the Potential Approaches

A qualitative evaluation of each approach with respect to the guiding principles is presented below. It should be noted that the current approach in the regulation, as well as some of the alternatives (Worldwide Average Approach and California Baseline Approach) fall short in many areas when assessed under these principles as explained in the following discussion.

a. *Current Approach with Amendments (Option 1):* The current approach accounts for emissions from crude oil production and transport in the “2006 basket” but does not account for emissions changes over time for crudes that are part of that basket. For example, if emissions associated with the production of California crudes using thermally enhanced oil recovery techniques increases — possible if crude prices remain high and the extraction from the fields become more energy intensive but remains economically viable — this approach would not mitigate those additional GHG emissions. Moreover, a non-baseline crude with a CI of 15 g/MJ or less is counted the same as a crude with a CI of 3 g/MJ. These shortcomings in emissions accounting could result in increased upstream emissions from the use of such crudes. This approach provides an incentive for producers of HCICO to reduce emissions to less than 15 g/MJ. However, the incentive is to avoid the mitigation responsibility that is triggered if HCICO are used; it does not provide a credit that might incent even greater reductions. The current approach limits refiners’ flexibility to purchase crude supplies, as they will have significant incentives to avoid using fuels classified as HCICOs. The proposed amendments would assist the industry in identifying crudes that are not HCICOs, increasing their flexibility to use a greater proportion of current crude supplies.

b. *California Average Approach (Option 2):* This approach is the preferred alternative for amendments. It explicitly accounts for and tracks the overall average CI for the transport and production of crudes used by California refineries. The method provides limited incentive for oil companies that produce their own crude oil to reduce emissions (e.g., through flaring reduction or other methods) and promotes innovation. There is likely greater flexibility to purchase worldwide crude supplies than current approach as oil companies have the discretion to shift among crude sources without incurring an incremental deficit, as long as the overall California average CI does not increase. The methodology is simple, providing for a streamlined implementation.

c. *Hybrid California Average/Company Specific Approach (Option 3):* This approach explicitly accounts for all crude used by California refineries and tracks changes over time. It provides greater incentive for oil companies that produce their own crude oil to reduce emissions (e.g., through flaring reduction or other methods) as this will be reflected in their annual CI calculation. There is likely greater flexibility to purchase worldwide crude supplies for some companies than the current approach as oil companies have the discretion to shift among crude sources without incurring an incremental deficit, as long as the overall average CI does not increase. This approach, while providing similar GHG benefits as the California Average Approach, makes implementation more complicated due to the need for company-specific CI values each year. Staff does not have sufficient company-specific data to fully assess the impacts of this approach on individual oil companies.

d. *Company Specific Approach (Option 4):* This approach explicitly accounts for all crude used by California refineries. However, this approach disadvantages those companies that currently refine lower CI crude oil, as their baseline CI value and ability to shift crude supplies would be more limited than those of companies that currently process heavy crudes derived from higher CI production methods. It provides greater incentive for oil companies that produce their own crude oil to reduce emissions (e.g., through flaring reduction or other methods), as this will be reflected in their annual CI calculation. There will be likely greater flexibility to purchase worldwide crude supplies for some oil companies than the current approach, as some companies have the discretion to shift among crude sources without incurring an incremental deficit as long as their overall average CI does not increase. This approach, while providing similar GHG benefits as the California Average Approach, leads to potential uncertainly and confusion in the market due to the need for company-specific compliance schedules. A fuel with the same CI will incur different deficits for different regulated parties under this method. Again, staff does not have sufficient company-specific data to fully assess the impacts of this approach on individual oil companies.

e. *Worldwide Average Approach (Option 5):* This approach has significant drawbacks. It does not explicitly track or account for emissions from crudes used by California refineries. It provides no incentive for oil companies that produce their own oil to reduce emissions (e.g., by reducing flaring) since these reductions will have negligible effect on the worldwide average. There is complete flexibility to purchase worldwide crude supplies, as crudes used by California refineries would have little, if any impacts on the world average. This approach could result in significantly greater amounts of HCICO being used at California refineries because there is no effective incentive to avoid their use. Because it is likely that criteria pollutant emissions increase with greater use of HCICOs — which usually are heavier crudes that typically take additional processing to make clean fuels — this approach could have adverse environmental impacts for the communities located in the vicinity of the refineries.

f. *California Baseline Approach (Option 6):* This approach would eliminate the current HCICO provision, and not replace it with a new approach. It has significant drawbacks. It does not account for, track or mitigate increases in upstream emissions from crudes used by California refineries. This is inconsistent with the LCA basis of the LCFS and undermines the program's goal to achieve a ten percent emission reduction from the 2010 baseline for transportation. It provides no incentive for oil companies that produce their own crude oil to reduce emissions (e.g., by reducing flaring) since these reductions will have no benefit relative to their compliance with the LCFS. There is complete flexibility to purchase worldwide crude supplies, as crudes used by California refineries are not tracked relative to their CIs, and no mitigation would be required if higher crude CIs were to be used. As with the Worldwide Average Approach, this approach could result in significantly greater amounts of harder to refine HCICO being used at California refineries because there is no incentive to avoid their use. Consequently, this approach could have adverse environmental impacts for the communities located in the vicinity of the refineries.

As a result of the above analysis, staff proposes for Board consideration the California Average Approach for the treatment of crude oil under the LCFS. None of the other alternatives considered would be more effective in carrying out the purpose of this high carbon intensity crude oil provision, or would be as effective as, and less burdensome than, the proposed approach.

VIII. SUMMARY AND RATIONALE FOR PROPOSED REGULATIONS

In this chapter, we provide a summary and rationale for each of the affected sections in the regulation:

Section 95480.1. Applicability

<u>Summary of Section 95480.1:</u>

Section 95480.1 specifies which transportation fuels are subject to the LCFS regulation. It also specifies which alternative fuels may generate LCFS credits by electing to opt into the LCFS, and the alternative fuels and specific applications that are exempt from the regulation.

<u>Rationale:</u>

This section is necessary to specifically identify which fuels are subject to the regulation, which fuels are eligible to generate credits by fuel providers opting into the regulation, and which fuels and applications are exempt.

<u>Summary of Subsection 95480.1(b):</u>

This provision specifies the alternative fuels, or “opt-in fuels,” which meet the 2020 carbon intensity standards. The proposed amendment clarifies that an opt-in fuel provider may generate credits only by electing to opt into the LCFS as a regulated party, pursuant to the opt-in and opt-out provisions.

<u>Rationale:</u>

This provision is necessary to identify which fuels are subject to the LCFS regulation and which fuels are exempt. The amendment to this provision is needed to clarify when an alternative fuel provider can generate credits under the opt-in provisions.

Section 95480.2. Persons Eligible for Opting Into the LCFS Program

<u>Purpose of Section 95480.2:</u>

This provision specifies the criteria to be eligible for opting into the LCFS. Staff proposes to add this provision as a new section to the regulation.

<u>Rationale:</u>

This provision is necessary to provide the criteria a person must meet to be eligible for opting into the program. In addition, staff is proposing amendments that would permit out-of-state producers and intermediate entities to be regulated parties. Therefore, these entities are included in this section.

Section 95480.3. Procedure for Opting Into and Opting Out of the LCFS Program

<u>Summary of Section 95480.3:</u>

This section specifies the procedures for opting in and out of the LCFS program. Staff proposes to add opt-in and opt-out procedures, reporting requirements, and selection of CI values.

<u>Rationale:</u>

This section is necessary to specify the procedure and information submittals needed for a fuel provider to opt in or opt out as a regulated party.

Section 95480.4. Multiple Parties Claiming to Be the Regulated Party for the Same Volume of Fuel

<u>Summary of Section 95480.4:</u>

This section establishes the actions taken when more than one party has inadvertently claimed to be the regulated party for the same volume of fuel. Staff proposes to add this as a new section in the regulation.

<u>Rationale:</u>

This section specifies the actions to be taken when more than one party has inadvertently claimed to be the regulated party for the same volume of fuel, including the order credits will be released.

Section 95480.5. Jurisdiction

<u>Summary of Section 95480.5:</u>

This section specifies the actions which establish a person's consent to be subject to the jurisdiction of the State of California, including the administrative authority of ARB and the jurisdiction of the Superior Courts of the State of California.

<u>Rationale:</u>

This section is necessary to implement the enhanced regulated party revisions that would permit out-of-state producers and intermediate entities to voluntarily elect to become regulated parties and, therefore, become subject to California jurisdiction.

Section 95481. Definitions and Acronyms

Summary of Section 95481:

This section provides the specific definitions and acronyms that apply to the regulation. The proposed amendments include revised and new definitions and acronyms.

Rationale:

This section is necessary to specify the definitions and acronyms used in the regulation.

Section 95482. Average Carbon Intensity Requirements for Gasoline and Diesel

Summary of Section 95482:

This section establishes the LCFS compliance schedule from 2011 through 2020 based upon the gasoline and diesel baselines. The proposed amendments revise the compliance schedules for the years 2013 through 2020.

Rationale:

Section 95482 is needed to provide regulated parties with the compliance schedule in which CI requirements are identified. This section is necessary to reflect the proposed revisions to the baseline gasoline and diesel standards, which were first developed in 2006. The intent of the program was to have a 2010 baseline standard and the crude slates have since shifted to require a change in the compliance schedule.

Section 95484. Requirements for Regulated Parties

Summary of Section 95484:

This section establishes the following: 1) criteria by which a regulated party is determined, 2) calculation of credit balance and annual compliance obligation, 3) reporting requirements, 4) recordkeeping and auditing requirements, and 5) violations and penalties. Staff proposes to relocate annual compliance and credit calculation information to the proposed credit trading section 95488.

Rationale:

Section 95484 is needed to provide regulated parties with the requirements and inform them of the penalties for non-compliance. Staff proposes to revise various subsections to implement proposed amendments.

Summary of Section 95484(a):

This subsection establishes the regulated parties for each type of transportation fuel. The proposed amendment revises regulated parties for electricity under section 95484(a)(6).

Rationale:

This section is necessary to provide a clear distinction of which entities can claim title on the credits. This language therefore provides a hierarchy for who may claim the credits and what is required for documentation purposes. The amendment to subsection 95484(a)(6) is needed to identity whom is eligible to claim electricity credits as the regulated party.

Summary of Section 95484(b):

Subsection 95484(b), which is 95484(c) in the existing regulation, provides the reporting requirements for regulated parties. The proposed amendments include mandatory use of the LRT, eliminating the reporting of fuel volume in terms of “gasoline gallon equivalent” (gge), and removal of reporting significant figures to simply report the nearest whole unit.

Rationale:

This subsection is needed to provide regulated parties with the reporting requirements that must be met under LCFS. The proposed amendments to this subsection is necessary to ensure standardization and consistency, which would help facilitate credit trading between regulated parties, and improve how regulated parties are recording their transactions.

Section 95485. LCFS Credits and Deficits

Summary of Section 95485:

This section provides the following information: 1) calculation of credits and deficits, 2) credit generation frequency, 3) credit acquisition, banking, borrowing, and trading, and 4) nature of credits.

Rationale:

Section 95485 is necessary to provide regulated parties with the information needed to calculate the amount of credits and deficits generated, when a regulated party may generate credits, and what a regulated party may or may not do to retain, acquire, transfer, and export credits for compliance.

Summary of Section 95485(a):

This subsection provides regulated parties with the methods that must be used to calculate credits and deficits generated. Staff proposes three changes to the EERs contained in Table 5.

Rationale:

This subsection is needed to provide the calculation methods used to calculated credits and deficits generated. The proposed amendment to the EERs is needed to reflect the use of engine efficiency and fuel efficiency data that was not available during the original rulemaking in 2009.

Section 95486. Determination of Carbon Intensity Values

Summary of Section 95486:

This section provides how CI values for each fuel are determined.

Rationale:

Section 95486 is necessary to provide regulated parties with the information needed to determine the CI values of their fuel.

Summary of Section 95486(a):

Subsection 95486(a) provides the ARB Lookup Table and specifies how a regulated party may select a method and determine CI values. Staff proposes to amend the regulation by adding new subsections 95486(a)(2), (3), and (4).

Subsections 95486(a)(2) and (3) clarifies the procedure by which carbon intensities are determined using the Method 1 process. These new provisions specify that Method 1 can only be used for fuels that are produced using a well-to-wheels production pathway that is substantially similar to the corresponding well-to-wheels pathway described in the pathway document on which an LCFS Lookup Table pathway is based.

Subsection 95486(4) establishes default carbon intensity values.

Rationale:

Subsection 95486(a) is necessary to provide regulated parties the information needed to determine the CI values for each of their fuels or blendstocks. The proposed amendments are needed to clarify the procedure carbon intensities are determined using the Method 1 process, specify that Method 1 can only be used for fuels that are produced using a well-to-wheels production pathway that is substantially similar to the corresponding well-to-wheels pathway from which an LCFS Lookup Table pathway is based, and establish default carbon intensity values.

Summary of Section 95486(b):

Section 95486(b) provides regulated parties the CI lookup table that they may use to select their fuel pathway. The proposed amendment revises how credits are calculated for the incremental credits and deficits associated with high carbon crude oil sources.

Rationale:

This subsection is needed to give regulated parties a location that designates the CI values associated with each fuel pathway. The proposed amendment revises how regulated parties producing gasoline and diesel will handle various crude slates, and the current HCICO provisions have changed from a “bucket method” of crudes to a flexible California average.

Summary of Section 95486(f):

Section 95486(f) provides the requirements for a Method 2A/2B fuel pathway to be processed and approved. The proposed amendment revises how the carbon intensity pathways are evaluated, shifting from a formal rulemaking for each pathway to a certification process.

Rationale:

This subsection is needed to provide the legal support for each pathway that is available for regulated parties to use. The proposed amendment will streamline the process for CI pathways to be incorporated into the regulation by converting the process from an individual rulemaking for each pathway proposed to a certification process. The pathways will then be included into the regulation when the language is revised at a future date.

Section 95488. Banking, Trading, and Purchase of Credits

Summary of Section 95488:

This section provides the following information: 1) calculation of credit balance and annual compliance, 2) generation and acquisition of transferable credits, 3) credit transfers, and 4) mandatory retirement of credits, and 5) public disclosure of credit transfer activity.

Rationale:

Section 95488 is needed as the current regulatory text allows for the transfers of credits, but is silent in the procedure. The proposed language will provide regulated parties with the calculation on how credits are to be banked, the requirements and information that ARB will need to process a credit transfer, the information ARB will need to retire credits at the end of the annual compliance period, and the information that will be disclosed to the public relaying market activity and overall health of the LCFS program.

<u>Summary of Section 95488(a):</u>

Section 95488(a) was relocated from section 95484(b) in the existing regulation. The proposed amendments will provide a clear separation of credit generation and tracking from deficit accounting and provide a revised calculation for annual compliance.

<u>Rationale:</u>

This section is needed to provide regulated parties the definitions and calculations that will be used to determine compliance. The proposed amendments will clearly delineate between credit and deficit generation during the annual compliance period and remove the concept of "net" credit balance upon submission of a quarterly report.

<u>Summary of Section 95488(b):</u>

Section 95488(b) provides a regulated party the procedure on how a credit is generated and validated before it becomes available for trade. It also defines the time that a credit can be purchased after the annual compliance period has ended prior to the submittal of the annual compliance report.

<u>Rationale:</u>

This subsection is needed as the existing regulation is silent on when a credit is available for transfer and to clarify when a regulated party may purchase credits to meet their annual compliance obligation.

<u>Summary of Section 95488(c)</u>

Section 95488(c) provides the requirements that are required by ARB before a credit can be transferred and the associated documentation to confirm the transfer has occurred.

<u>Rationale:</u>

This subsection is needed for ARB to process and confirm trades between regulated parties.

<u>Summary of Section 95488(d):</u>

Section 95488(d) provides a procedure to regulated parties on how their credits at the end of each annual compliance period may be retired.

Rationale:

This subsection is needed if the use of unique IDs is implemented in the reporting tool. Regulated parties will be able to select the credits they wish to retire or allow the default order to be used offset their deficits.

Summary of Section 95488(e):

Section 95488(e) provides a description on the information the public will receive on a monthly basis. The information will include credit and deficit generation by the LCFS program as well as credit market activity.

Rationale:

This subsection is needed as the regulation requires a certain level of transparency. The public and market participants will therefore receive routine, periodic releases of information on credit and deficit generation as well as trading activity to allow the public an overview of LCFS progress.

IX. REFERENCES AND FOOTNOTES

Note: The references are listed according to the footnote they correspond to in the ISOR. Not all footnotes are references and are only listed here to maintain the numbering system used for the ISOR footnotes. The footnotes that are not references are listed as "Explanatory Footnote."

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