CALIFORNIA
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Low Carbon Fuel Standard

Lookup Table Pathways

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California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) ◆ California Ultra-low Sulfur Diesel Fuel Pathway (ULSD) ◆ Fossil Natural Gas ◆ Electricity ◆ Hydrogen ◆ Fossil Based Propane

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Introduction

This document provides details of the Low Carbon Fuel Standard Lookup Table pathways for the following fuels:

- California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB)
- California Ultra-low Sulfur Diesel Fuel Pathway (ULSD)
- Fossil Natural Gas
- Electricity
  - California average grid electricity supplied to electric vehicles
  - Electricity that is generated from 100 percent solar or wind supplied to electric vehicles in California
- Hydrogen
  - Hydrogen (gaseous and liquefied) from central reforming of fossil-based natural gas
  - Hydrogen (gaseous and liquefied) from central reforming of biomethane from landfills
  - Hydrogen (gaseous) from electrolysis using California grid-average Electricity
  - Hydrogen (gaseous) from electrolysis using solar or wind generated electricity
- Fossil Based Propane

This document is based on CA-GREET 3.0 model. It provides inputs and assumptions related to calculation of well-to-wheel carbon intensities for each of the pathways included in the Lookup Table.

Section A: California Reformulated Gasoline Blendstock for Oxygenate Blending

I. Pathway Summary

California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) pathway carbon intensity includes greenhouse gas emissions from the following life cycle stages: crude oil recovery from all domestic and oversea sources, crude transport to California for refining, refining of the crude to gasoline blendstock in California refineries, transport to blending racks and distribution of the finished fuel, and tailpipe emissions from final combustion[1] in a vehicle. Based on the updated CA-GREET 3.0, the life cycle Carbon Intensity (CI) of CARBOB is calculated to be **101.69** gCO_2e/MJ of CARBOB as shown in Table A.1.

Table A.1. Summary Table of CARBOB CI

Component	Total CI* gCO_2e/MJ
Crude Recovery and Crude Transport	12.31
Refining	15.00
CARBOB Transport	0.44
Tailpipe Emissions	73.94
Total CI	**101.69**

*(Individual values may not sum to the total due to rounding)

II. Pathway Assumptions, Details, and Calculation

1. Crude Oil Recovery and Transport to California:

   Crude oil recovery for the year 2010 is based on the updated Oil Production Greenhouse Gas Emission Estimator (OPGEE) model, version 2.0.[2] The CI is calculated to be **12.31** gCO_2e /MJ.

2. CARBOB Refining:

   Argonne National Laboratory used refinery linear programming models developed by Jacobs Consultancy Inc., which were validated against propriety data from the refining industry and refinery statistical data provided by the Energy Information Administration (EIA). The models were validated against 2012

[1] Tailpipe emissions are determined for California reformulated gasoline (90 percent CARBOB and 10 percent ethanol by volume) and allocated to the blendstock on an energy basis.

[2] Updated Oil Production Greenhouse Gas Emission Estimator (OPGEE) model, version 2.0b : https://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm

refinery capacities. However, when compared with refinery data for 2010 from the EIA, little difference was observed at a PADD level. Based on validation of the linear programming models, Argonne determined energy inputs, refining efficiency and refinery operational details for the production of CARBOB and are shown in Table A.2.

Details of entries in Table A.2:

The total energy inputs for CARBOB is **1,128,160 Btu/MMBtu** of finished product. Refining efficiency is calculated as 1,000,000/1,128,160 and reported as 88.64% if Table A.2. The energy inputs are derived from various inputs based on modeling results and include:

- Energy ratio of crude oil feeds to product: This is the quantity of crude derived feedstock used in the production of CARBOB. From Argonne's modeling, an average California refinery uses 750,105 Btu of crude to produce 1,000,000 Btu of CARBOB.

- Additional energy inputs are derived from purchased feedstock and include residual oil (as a surrogate for purchased unfinished oil and heavy products), natural gas, electricity, hydrogen, butane and blendstock.

For production of CARBOB as modeled, GHG emissions are generated from the use of Pet Coke, refinery still gas and hydrogen and details are provided in Table A.2.

Table A.2. Refining Parameters Used in CARBOB Refining CI Calculations.

Parameter	Value (%)	Btu/MMBtu	Note
Refining Energy Efficiency	88.64% [3]		
Energy ratio of crude oil feeds to product (Btu of crude/MMBtu of CARBOB throughput)	0.750	750,105	Many refineries use crude oil in addition to unfinished oil and heavy products to produce gasoline blendstock. Also, gasoline blendstock is typically blended with butane and other blendstocks from the refinery product streams. This value is the energy ratio of crude inputs to produce finished fuel excluding the unfinished oil, heavy oil, butane and other blendstocks. The upstream of these additional inputs are taken into account with the values below (see residual oil, butane and blendstock).
CARBOB Refining: Energy Inputs			
Residual oil	36.6%	138,368	As a surrogate for purchased unfinished oil and heavy products.
Natural gas	22.6%	85,440	A portion of natural gas is converted into H2 by on-site SMR while the rest is mixed with fuel gases and combusted to produce heat and electricity (see refinery still gas).
Electricity	1.3%	4,915	
Hydrogen	0.7%	2,646	
Butane	20.4%	77,123	Butane is used mainly as a blendstock for gasoline. Assumes butane refining requires 1/3 of gasoline refining energy.
Blendstock	18.4%	69,562	Other purchased blendstock (alkylates, reformates and natural

[3] Forman, Grant, Stephen, Vincent B. Divita, Jeongwoo Han, Hao Cai, Amgad Elgowainy, and Michael Q. Wang. "Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries" May 2014. https://greet.es.anl.gov/publication-energy-efficiency-refineries

			gasoline) produced elsewhere. Assumes blendstock refining requires 2/3 gasoline refining energy.
Feed loss	0.0%	0.0%	
Total Energy Input, Btu/MMBtu CARBOB	**100%**	**1,128,160**	Total energy inputs 1,128,160 Btu for 1 MMBtu of CARBOB production
CARBOB Refining: Intermediate Product Combustion			
		Btu/MMBtu	
Pet Coke		19,855	On-site combustion of FCC coke. Since FCC coke is intermediate product derived from external inputs (crude oil, unfinished oil, heavy products, etc.), only the combustion emissions of FCC coke are taken into account.
Refinery Still Gas		94,100	Refinery still gas is a mix of purchased natural gas and internally produced fuel gas. Since refinery still gas is derived from external inputs, only the combustion emissions of refinery still gas are taken into account.
Hydrogen from SMR (Steam Reforming Reactor)		1,113	

The CI of refining from CA-GREET 3.0 is calculated to be **15.00** gCO_2e/MJ.

3. <u>CARBOB Transport and Distribution:</u>

    - Transportation: CARBOB is transported to the blending terminal and is blended with ethanol. 80% is assumed to be transported by pipeline for 50 miles to a blending terminal and 20% is blended at the refinery and distributed 50 miles by Heavy Duty Diesel (HDD) truck (emissions for HDD distribution is accounted in the distribution step).

    - Distribution: Finished gasoline is distributed to gas stations and is assumed to be a total 50 miles by HDD Truck.

4. <u>Tailpipe Emissions:</u>

    Since CARBOB is a blendstock and not a final finished fuel, vehicle tailpipe emissions represent the portion of California Reformulated Gasoline (CaRFG) emissions allocated to CARBOB. The tailpipe emissions are based on CARB's EMFAC 2010 model[4], and results are shown in Table A.3:

Table A.3. Tailpipe Emissions from CARBOB

GHG	Tailpipe GHG from gasoline vehicles, g/MMBtu	gCO_2e/MJ
CH_4	5.87	0.14
N_2O	3.22	0.91
CO_2	76,904.65	72.89
Total $gCO_2e/MMBtu$	78,010.83	
Total CI		**73.94**

[4] California Air Resources Board. May 2014. California's 2000-2012 Greenhouse Gas Emissions Inventory Technical Support Document. State of California Air Resources Board. Air Quality Planning and Science Division. https://www.arb.ca.gov/cc/inventory/doc/methods_00-12/ghg_inventory_00-12_technical_support_document.pdf

Table A.4 provides a comparison of inputs to produce CARBOB in the GREET 2.0 and CA-GREET 3.0 models.

Table A.4. Comparison of CIs and Refining Details for CARBOB Production between CA-GREET 2.0 and CA-GREET 3.0 GREET

CARBOB	CA-GREET 2.0 (2010)	CA-GREET 3.0 (2014)	Difference
1) Crude Recovery	1-US Average Mix		
Efficiency	92.58%	92.58%	
CI, g/MJ	**11.98**	**12.31** [5]	**0.33**
2) Crude Refining to CARBOB	3-CAMX Mix		
Efficiency	89%	88.64%[6]	
Residual oil	24.9%	36.6%	
Diesel fuel	0.9%	0.0%	
Gasoline	0.0%	0.0%	
Natural gas	37.40%	22.6%	
LPG	8.01%	0.0%	
Electricity	3.5%	1.31%	
Hydrogen	26.2%	0.7%	
Butane	0.0%	20.4%	
Blendstock	0.0%	18.4%	
Feed loss	0.0%	0.0%	
CI, g/MJ	**13.45**	**15.00**	**1.55**
3) CARBOB Transport	1-US Average Mix		
80% pipeline to blending terminal (miles)	50	50	
20% on-site blending and distributed by HDD truck	0	0	
Distributed by HDD Truck	50	50	
CI, g/MJ	**0.41**	**0.44**	**0.03**
4) Tailpipe Emissions	**73.94**	**73.94**	**0.00**
Methane (CH4), g/MJ	0.14	0.14	
N2O, g/MJ	0.91	0.91	
CO2, g/MJ	72.89	72.89	
Total CI, g/MJ	**99.78**	**101.69**	**1.91**

[5] Updated Oil Production Greenhouse Gas Emission Estimator (OPGEE) model, version 2.0b: https://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm.

[6] Aggregated data from Argonne for each process in refinery for CA. See Energy Consumption provided in Table 3: Ignasi Palou-Rivera, Jeongwoo Han, and Michael Wang. "Updates to Petroleum Refining and Upstream Emissions", Argonne National Laboratory, October 2011. https://greet.es.anl.gov/publication-petroleum.

Section B: California Ultra Low Sulfur Diesel (ULSD) Fuel Pathway

I. Pathway Summary

The California Ultra-low Sulfur Diesel (ULSD) pathway carbon intensity assessment includes greenhouse gas emissions from the following well-to-wheel life cycle stages: crude oil recovery from all domestic and overseas sources, crude transport to California for refining, refining of the crude to ultra-low sulfur diesel in California refineries, transport to blending racks and distribution of the finished fuel, and tailpipe emissions from final combustion of the fuel in a vehicle. Based on the updated CA-GREET 3.0 model, the life cycle Carbon Intensity (CI) of California ULSD is calculated to be **101.05** gCO_2e/MJ as shown in Table B.1.

Table B.1. Summary Table of California ULSD CI

Aggregated Impact	Total CI* gCO_2e/MJ
Crude Recovery and Crude Transport	12.31
Crude Oil Refining	13.51
ULSD Transport	0.38
Tailpipe Emissions	74.86
Total CI	**101.05**

*(Individual values may not sum to the total due to rounding)

II. Pathway Assumptions, Details, and Calculation

1. Crude Oil Recovery and Transport to California:

   Crude oil recovery for the year 2010 is based on the updated Oil Production Greenhouse Gas Emission Estimator (OPGEE) model, version 2.0b.[7] The CI for this phase of the life cycle assessment is calculated to be **12.31** gCO_2e /MJ.

2. ULSD Refining:

   Argonne National Laboratory used refinery linear programming models developed by Jacobs Consultancy Inc., which were validated against propriety data from the refining industry and refinery statistical data provided by the Energy Information Administration (EIA). The models were validated against 2012

[7] Updated Oil Production Greenhouse Gas Emission Estimator (OPGEE) model, version 2.0b : https://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm

refinery capacities. However, when compared with refinery data for 2010 from the EIA, little difference was observed at a PADD level. Based on validation of the linear programming models, Argonne determined energy inputs, refining efficiency and refinery operational details for the production of ULSD are shown in Table B.2.

Details of entries in Table B.2:

The total energy inputs for ULSD is modeled to be **1,164,551 Btu/MMBtu** of finished product. Refining efficiency is calculated as 1,000,000/1,164,551 and reported as 85.87% if Table B.2. The energy inputs are derived from various inputs based on modeling results and include:

- Energy ratio of crude oil feeds to product: This is the quantity of crude derived feedstock used in the production of ULSD. From Argonne's modeling, an average California refinery uses 978,161 Btu of crude to produce 1000,000 Btu of ULSD.

- Additional energy inputs are derived from purchased feedstock and include residual oil (as a surrogate for purchased unfinished oil and heavy products), natural gas, electricity, hydrogen and butane.

The total energy inputs for ULSD is modeled to total 1,164,551 Btu for 1 MMBtu of finished product. For production of ULSD as modeled, GHG emissions are generated from the use of Pet Coke and refinery still gas and details are provided in Table B.2.

Table B.2. Refining Parameters Used in ULSD Refining CI Calculations[8]

Parameter	Value (%)	Btu/MMBtu	Notes
Refining Energy Efficiency	85.87%[9,10]	N/A	
Energy ratio of crude oil feeds to product (Btu of crude/MMBtu of ULSD throughput)	0.978	978,161	Many refineries use crude oil in addition to unfinished oil and heavy products to produce diesel blendstock. This value is the energy ratio of crude inputs to produce finished fuel excluding the unfinished oil, heavy oil and other blendstocks. The upstream of these additional inputs are taken into account with the values below (see residual oil and butane).
USLD Refining: Energy Inputs			
Residual oil	20.8%	38,769	As a surrogate for purchased unfinished oil and heavy products
Natural gas	71.7%	133,642	A portion of NG is converted into H_2 by on-site SMR while the rest is mixed with fuel gases and combusted to produce heat and electricity (see refinery still gas).
Electricity	3.7%	6,896	
Hydrogen	3.6%	6,710	
Butane	0.2%	373	
Feed loss	0.0%	0.0%	
Total Energy Input, Btu/MMBtu ULSD	100%	1,164,551 Btu/MMBtu	Total energy inputs (1,164,551 Btu) – 1 MMBtu in CARB Diesel
ULSD Refining: Intermediate Product Combustion			
Pet Coke		7,076	On-site combustion of FCC coke. Since FCC coke is intermediate product derived from external inputs (crude oil, unfinished oil, heavy products, etc.), only the combustion emissions of FCC coke are taken into account.

[8] See Energy Consumption provided in Table 3: Ignasi Palou-Rivera, Jeongwoo Han, and Michael Wang. "Updates to Petroleum Refining and Upstream Emissions", Argonne National Laboratory, October 2011. https://greet.es.anl.gov/publication-petroleum

[9] Forman, Grant Stephen, Vincent B. Divita, Jeongwoo Han, Hao Cai, Amgad Elgowainy, and Michael Q. Wang. "Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries" May 2014. https://greet.es.anl.gov/publication-energy-efficiency-refineries

[10] Calculations based on personal communication with Argonne (will be separately released accompanying the release of this document and includes details for both CARBOB and ULSD).

Refinery Still Gas		115,219	Refinery still gas is a mix of purchased NG and internally produced fuel gas. Since refinery still gas is derived from external inputs, only the combustion emissions of refinery still gas are taken into account.

The CI for ULSD refining is calculated from CA-GREET 3.0 to be **13.51** gCO_2e/MJ.

3. ULSD Transport and Distribution:

   - Transportation: After refining, ULSD is transported to the distribution terminal. The assumed transport route is 80% by pipeline for 50 miles, and 20% is directly transported by truck to a filling station (50 miles considered in distribution leg).

   - Distribution: Finished diesel is distributed from a diesel terminal to filling stations and this distance is assumed to be 50 miles by HDDT.

4. Tailpipe Emissions:

   The tailpipe emissions are based on CARB's EMFAC 2010 model,[11] and results are shown in Table B.3:

Table B.3. ULSD Tailpipe Emissions

GHG	Tailpipe GHG Emissions from Diesel-fueled Vehicles ($gCO_2e/MMBtu$)	gCO_2e/MJ
CH_4	1.39	0.03
N_2O	2.56	0.72
CO_2	76,068.43	74.10
Total $gCO_2e/MMBtu$	79,866.31	
Total CI		**74.86**

Table B.4 provides a comparison of inputs to produce ULSD in the GREET 2.0 and CA-GREET 3.0 models.

[11] California Air Resources Board. May 2014. California's 2000-2012 Greenhouse Gas Emissions Inventory Technical Support Document. State of California Air Resources Board. Air Quality Planning and Science Division. http://www.arb.ca.gov/cc/inventory/doc/methods_00-12/ghg_inventory_0012_technical_support_document.pdf

Table B.4. Comparison of CIs and Refining Details for ULSD Production between CA-GREET 2.0 and CA-GREET 3.0 GREET

ULSD	CA-GREET 2.0 (2010)	CA-GREET 3.0 (2014)	Differences	Notes
1) Crude Recovery	1-US Average Mix			
Efficiency	92.58%	92.58%		
CI, g/MJ	**11.98**	**12.31** [12]	**0.33**	
2) Crude Refining to ULSD	3-CAMX			
Efficiency	88%	85.87% [13]		
Residual oil	24.9%	20.8%		
Diesel fuel	0.9%	0.00%		
Gasoline	0.0%	0.00%		
Natural gas	37.40%	71.7%		
LPG	8.01%	0.0%		
Electricity	3.5%	3.7%		
Hydrogen	26.2%	3.6%		
Butane	0.0%	0.2%		
Feed loss	0.0%	0.0%		
CI, g/MJ	**14.83**	**13.51**	**-1.32**	
3) ULSD Transport	1-US Average Mix			
80% pipeline to blending terminal, miles	50	50		
20% pipeline directly to blending terminal, miles	0	0		
Distributed by HDD Truck	50	50		
CI, g/MJ	**0.34**	**0.38**	**0.04**	
4) Tailpipe Emissions	74.85	74.86	**-0.01**	
Methane (CH_4), g/MJ	0.03	0.03		
N_2O, g/MJ	0.724	0.724		
CO_2, g/MJ	74.1	74.1		
Total CI, g/MJ	**102.01**	**101.05**	**-0.96**	

[12] Updated Oil Production Greenhouse Gas Emission Estimator (OPGEE) model, version 2.0b : https://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm

[13] Aggregated data from Argonne for each process in refinery for CA. See Energy Consumption provided in Table 3: Ignasi Palou-Rivera, Jeongwoo Han, and Michael Wang. "Updates to Petroleum Refining and Upstream Emissions", Argonne National Laboratory, October 2011. https://greet.es.anl.gov/publication-petroleum.

Section C. Fossil Natural Gas

I. Pathway Summary

The Fossil Natural Gas (NG) pathway includes natural gas from shale formations (50.2%) and from conventional fossil NG (49.8%) wells.

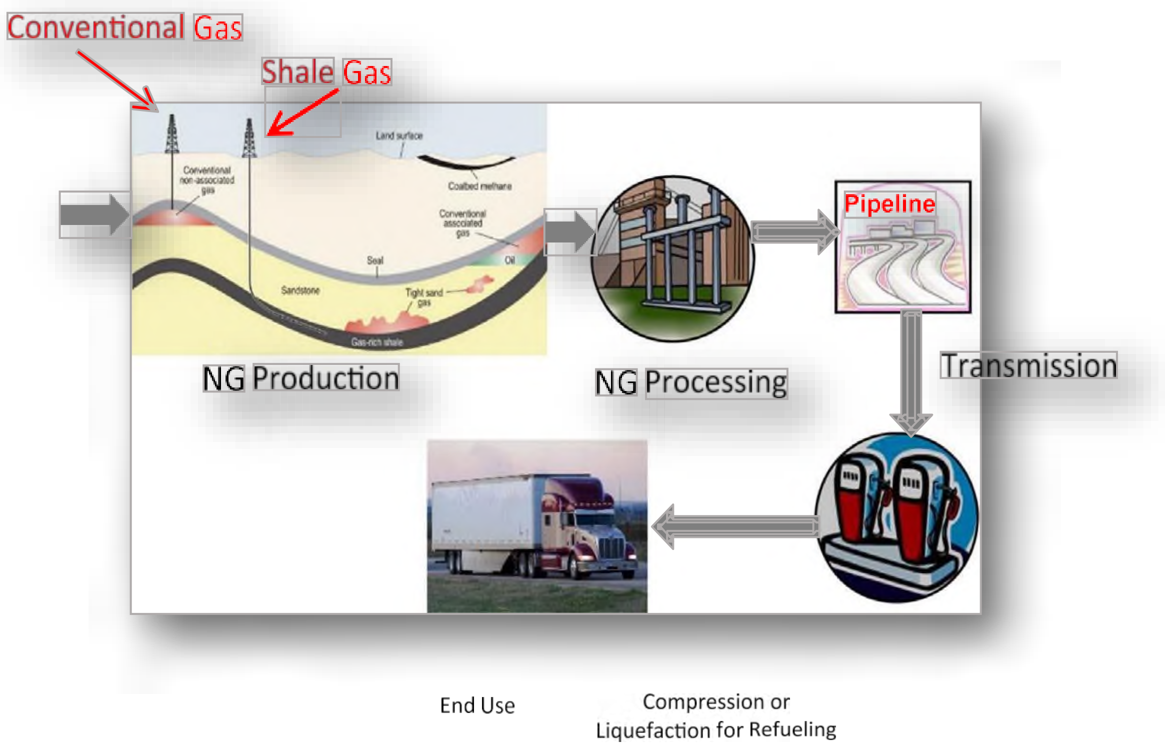

Figure C1: Life cycle Natural Gas Production and Use (Courtesy of Argonne National Lab)

Shale gas is recovered from seven large shale gas wells in the country. Conventional NG is recovered from various sources. About 90% of fossil natural gas is imported to California from Canada, the Rocky Mountain Basin and from the San Juan Basin in Texas and 10% is produced from in-state.[14] Figure 2 shows sources of NG imported into California.

[14] California continues to depend upon out-of-state imports for nearly 90 percent of its natural gas supply from California Energy Commission website (downloaded Oct, 2017) http://www.energy.ca.gov/almanac/naturalgas_data/overview.html

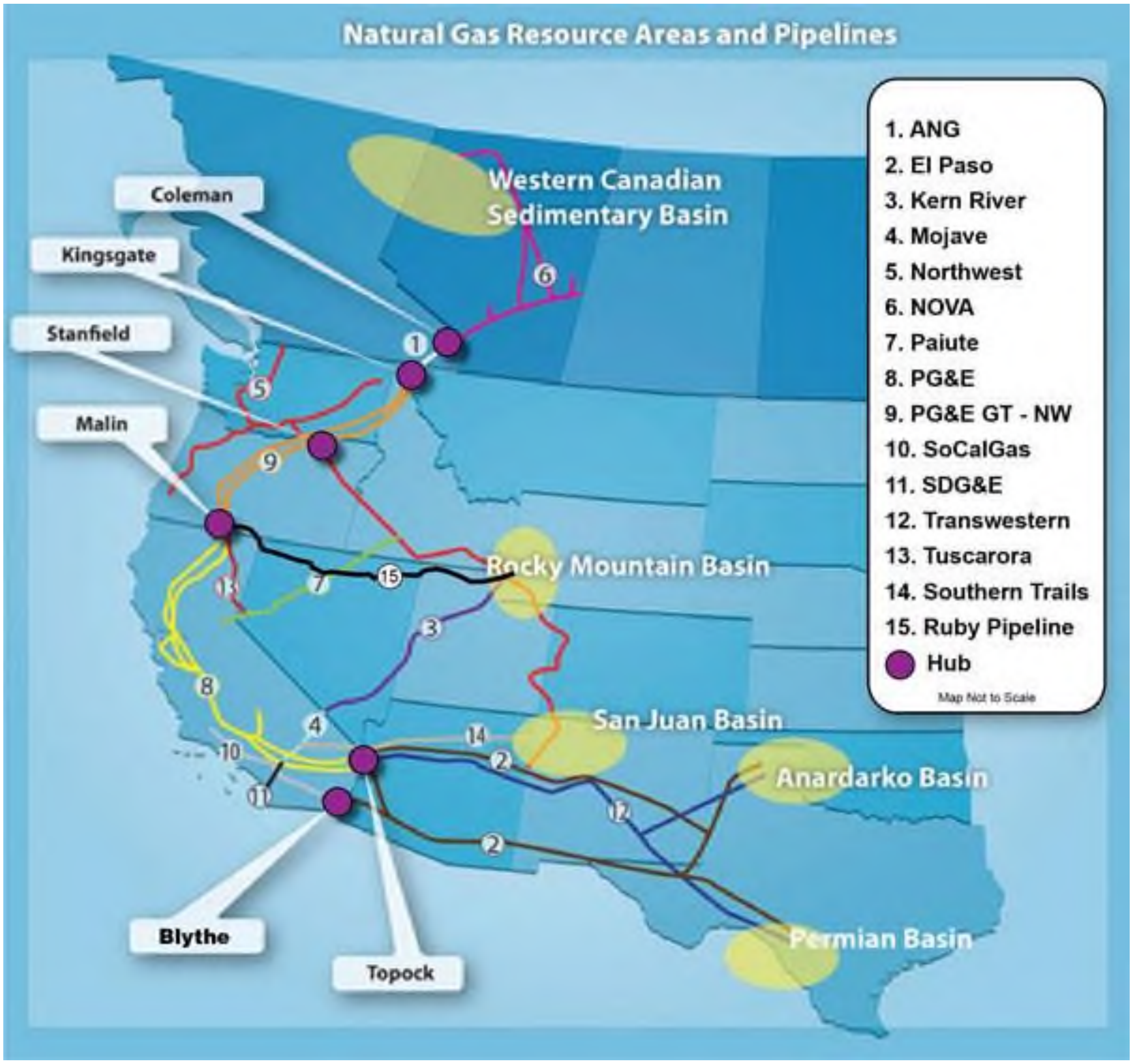

Figure C2: Sources of Natural Gas Imported to California (from California Energy Commission[15])

Extracted NG is processed to meet pipeline specification of around 95% methane content. Processed NG is transported via pipeline to California and based on data available from the CEC website, staff calculated a weighted average distance for out-of-state supplied NG to be approximately 1,200 miles. Due to lack of detailed data for intra-state supplied NG, an overall estimated distance of 1,000 miles was assumed for NG from all sources of NG used in California.

[15] http://www.energy.ca.gov/almanac/naturalgas_data/interstate_pipelines.html

NG is used as a transportation fuel in three separate pathways in the LCFS to-date:

1) Compressed on-site at fueling stations and dispensed as Compressed Natural Gas (CNG);

2) Liquefied at a central liquefaction facility, transported as Liquefied Natural Gas(LNG) and dispensed as LNG;

3) Liquefied at a central liquefaction facility, transported as LNG, subsequently regasified at a fueling station and dispensed as CNG (this pathway is labeled L-CNG).

Based on the CA-GREET 3.0 model, the life cycle Carbon Intensity (CI) of fossil CNG is calculated to be 80.21 gCO_2e/MJ and is detailed in Table C.1.

Table C.1. Summary Table of Fossil NG Carbon Intensity

	Total CI* gCO_2e/MJ
Natural Gas (NG) Recovery	6.09
NG Processing	3.32
NG Transport	6.91
NG Compression	3.16
Tailpipe Emissions	60.73
Total CI	**80.21**

*(Individual values may not sum to the total due to rounding)

II. Pathway Details, Assumptions, and Calculations

Methane Leakage assumptions from extraction to final distribution in CA-GREET 3.0 are the same as Argonne GREET1 2016 and detailed in Table C.2.

Table C.2. Methane Leakage Assumptions

CH_4 leakage rate for each stage in conventional NG and shale gas pathways[16]			vol. % of CH_4 leaked over NG throughput[17]	
Unit (g CH4/MMBtu NG)	Conventional NG	Shale gas	Conventional NG	Shale gas
Recovery - Completion CH_4 Venting	0.5	11.8	0.00%	0.06%
Recovery - Workover CH_4 Venting	0.0	2.4	0.00%	0.01%
Recovery - Liquid Unloading CH_4 Venting	9.0	9.0	0.04%	0.04%
Well Equipment - CH_4 Venting and Leakage	134.9	134.9	0.65%	0.65%
Processing - CH_4 Venting and Leakage	26.2	26.2	0.13%	0.13%
Transmission and Storage - CH4 Venting and Leakage (g CH_4/MMBtu NG/1000 miles)	74.6	74.6	0.36%	0.36%
Distribution - CH_4 Venting and Leakage	17.7	17.7	0.09%	0.09%
		Total	**1.28%**	**1.34%**

Table C.3 provides details of CI calculations for the fossil NG pathway with CA-GREET 3.0. It also includes details of CI calculations for this pathway using factors and inputs in CA-GREET 2.0 to provide a comparison of changes and related impacts in transitioning from CA-GREET 3.0.

[16] Burnham – October 2016 – Updated Fugitive Greenhouse Gas Emissions for Natural Gas Pathways in the GREET1_2016 Model – Table 3 – Page 6 – Retrieved October 2017: https://greet.es.anl.gov/publication-updated-ghg-2016

[17] CA-GREET 3.0 – Input Tab

Table C.3. Fossil CNG Pathway CIs (comparison of CI CA-GREET 2.0 and CA-GREET 3.0)

Fossil NG	CA-GREET 2.0 (2010)		CA-GREET 3.0 (2014)		Differences
	Conventional NG	**Shale NG**	**Conventional NG**	**Shale NG**	
Shares of NG	77.20%	22.80%	49.78%	50.22%	
1) NG Recovery	**1-US Average Mix**				
Efficiency	97.18%	97.07%	97.50%	97.62%	
Residual oil	0.88%	0.81%	1.00%	1.00%	
Diesel fuel	9.71%	8.87%	11.00%	11.00%	
Gasoline	0.88%	0.81%	1.00%	1.00%	
Natural gas	77.23%	76.43%	86.00%	86.00%	
Electricity	0.88%	0.81%	1.00%	1.00%	
Feed loss	10.41%	12.28%			
Natural Flared	8,370	8,292	10,486	10,327	
CI, g/MJ	**3.98**		**6.09**		**2.11**
2) NG Processing	**1-US Average Mix**				
Efficiency	97.35%		97.35%		
Residual oil	0.0%		0.0%		
Diesel fuel	0.9%		1.0%		
Gasoline	0.0%		0.0%		
Natural gas	90.07%		96.0%		
Electricity	4.5%		3.0%		
Feed loss	4.5%		0.0%		
CI, g/MJ	**3.380**		**3.32**		**-0.06**
3) NG Transport	1-US Average Mix				
Pipeline Miles	1,000		1,000		
CI, g/MJ	**8.17**		**6.91**		**-1.26**
4) Compression	**3-CAMX**				
Efficiency	97%		97%		
CI, g/MJ	**3.25**		**3.16**		**-0.09**
5) Tailpipe Emissions	**60.69**		**60.73**		**0.04**
Total CI, g/MJ	**79.46**		**80.21**		**0.75**
Comparison Methane Leakage of NA NG		CA-GREET 2.0		CA-GREET 3.0	
	Unit	Conventional NG	Shale gas	Conventional NG	Shale gas

Recovery - Completion CH4 Venting	g CH4/MMBtu NG	0.543	12.384	0.54	11.84
Recovery - Workover CH4 Venting	g CH4/MMBtu NG	0.008	2.477	0.01	2.37
Recovery - Liquid Unloading CH4 Venting	g CH4/MMBtu NG	10.357	10.357	9.00	9.00
Well Equipment - CH4 Venting and Leakage	g CH4/MMBtu NG	51.345	51.345	134.88	134.88
Processing - CH4 Venting and Leakage	g CH4/MMBtu NG	26.710	26.710	26.2	26.2
Transmission and Storage - CH4 Venting and Leakage	g CH4/MMBtu NG/680 miles	81.189	81.189	74.6	74.6
Distribution - CH4 Venting and Leakage	g CH4/MMBtu NG	63.635	63.635	17.70	17.7
	Total, g/MJ	**4.28**	**1.34**	**3.10**	**3.29**

Tailpipe Emissions from Compressed NG vehicles are calculated using emission factors from the Argonne GREET 1 2016 model for Methane (CH_4) and Nitrous Oxide (N_2O). For CO_2, it is calculated based on Carbon in NG. CI of tailpipe emissions is calculated to be **60.73** g/CO2/MJ. The detailed calculations are provided in a supplemental document for CA-GREET 3.0 and is included with the publication of this document.

Section D. Electricity Pathways

I. Pathway Summary

There are two electricity pathways in the Lookup Table and they are summarized in Table D.1 with calculated pathway CIs.

Table D.1. Electricity Lookup Table Pathways

	Fuel Pathway Description	Total CI gCO_2e/MJ
1.	California average grid electricity supplied to electric vehicles	**93.05**
2.	Electricity that is generated from 100 percent solar or wind supplied to electric vehicles in California	**0.00**

II. Pathway Details, Assumptions, and Calculations

California average grid electricity supplied to electric vehicles

Average California Electricity Generation Mixes in CA-GREET 3.0 is based on eGRID[18] published by U.S. EPA for the 2014 data year. The weighted carbon intensity of the feedstock mix is **16.63** gCO_2e/MJ. The CI of electricity generation in California Power plant is calculated to be **81.86** gCO_2e/MJ.[19]

Based on the updated CA-GREET 3.0 model, the life cycle Carbon Intensity (CI) of average California Electricity is calculated to be **98.49** gCO_2e/MJ and is detailed in Table D.1.

Table D.1. Summary Table of California Grid-Average Electricity Resource Mix CI

Regional Resources	Feedstock Production Resource Share	Emission Factors of Feedstock Production, gCO_2e/MJ	Feedstock Contribution to CI, gCO_2e/MJ	Electricity Production Resource Share	Emission Factors of Power Generation gCO_2e/kWh	Electricity Production Contribution to CI, gCO_2e/MJ
	U.S average			California		
Residual Oil	1.84%	14.61	0.90	0.79%	865.43	2.036
Natural Gas	26.44%	13.80	**8.51**	62.47%	421.73	**78.26**
Coal	38.61%	5.23	6.22	0.43%	988.64	1.25
Biomass	1.82%	2.886	0.26	3.43%	30.53	0.31
Nuclear	20.19%	81.44	0.74	8.98%		0
Hydroelectric	4.85%		0	8.41%		0
Geothermal	0.01%		0	4.35%		0
Wind	4.53%		0	6.54%		0
Solar PV	0.87%		0	4.28%		0
Others	0.83%		0	0.34%		0
Sub Total	**100%**		**16.63**			**81.86**
Tailpipe Emissions			0			0
Total CI						**98.49**

(Values may not round to sum due to rounding)

[18] eGRID: Emissions & Generation Resource Integrated Database 2014 from US EPA website, extracted 01/2017: https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid

[19] assumes an average transmission loss from power lines is 6.5% for the U. S. from GREET 1 2016

Examples of calculation in Table D-1 above:

For Natural as Feedstock Production:

$$\frac{26.44\% \times 13.80\ gCO2e/MJ}{45.87\% \times (1 - 6.5\%)} = \mathbf{8.51}\ gCO2e/MJ$$

where:

Feedstock resource share of NG = 26.44%

EF of NG use in power plant = 13.8 gCO_2e/MJ (cell C114 in NG Tab)

Power Plant Energy Conversion Efficiency = 45.87% (cell C64 – Electric tab)

Loss in electricity transmission = 6.5%

For Natural Gas in Electricity Production:

$$\frac{62.47\% \ \times 421.73\ \mathrm{gCO2e/kWh}}{1 - 6.5\%} \times \frac{\mathrm{kWh}}{3412.14\ \mathrm{Btu}} \times \frac{\mathrm{Btu}}{0.001055\mathrm{MJ}} = \mathbf{78.26}\ \mathrm{gCO2e/MJ}$$

where:

Loss in electricity transmission = 6.5%

EF of Electricity generation from NG = 421.73 gCO_2/MJ (cell BA101 in NG tab)

Share of NG = 62.47%

Electricity that is generated from 100 percent solar or wind supplied to electric vehicles in California

For electricity that is generated from 100 percent solar or wind and supplied to electric vehicle charging, the pathway CI is **0.0** g/MJ. Electricity has to meet requirements in 95488.7(i)(B). The total electricity generated in kWh from either source should meet or exceed total electricity used for electric vehicle charging when electricity is reported to generate credits in the LCFS program.

Section E. Hydrogen Fuel Pathways

I. Pathway Summary

There are several hydrogen pathways and they are summarized in Table E.1 with calculated CIs.

Table E.1. Hydrogen Fuel Lookup Table Pathways

	Fuel Pathway Description	Total CI gCO_2e/MJ
1.	Compressed gaseous H2 produced in California from central reforming of fossil natural gas	**125.56**
2.	Liquefied H2 produced in California from central reforming of fossil natural gas	**173.42**
3.	Compressed H2 produced in California from central reforming of biomethane from landfills	**100.78**
4.	Liquefied H2 produced in California from central reforming of biomethane from landfills	**149.19**
5.	Gaseous H2 produced in California from on-site electrolysis using California average grid electricity	**165.21**
6.	Gaseous H2 produced in California from on-site electrolysis using solar- or wind-generated electricity	**11.01**

The six hydrogen pathways being proposed have the following pathway characteristics as detailed in Table E.2:

Table E.2. Summary of Production Details and Transport Modes for the Six Hydrogen Fuel Pathways

PROCESS:	Central Plant / SMR	Central Plant / SMR	Central Plant / SMR	Central Plant / SMR	Electrolysis	Electrolysis
Feedstock Types:	Fossil NG	Fossil NG	Biomethane from Landfills	Biomethane from Landfills	Water	Water
Feedstock Transport:	Pipeline	Pipeline	Pipeline	Pipeline	Water delivery infrastructure	Water delivery infrastructure
Process Fuel:	NG and Grid Electricity	NG and Grid Electricity	RNG and Grid Electricity	RNG and Grid Electricity	Grid Electricity	Renewable Electricity
Fuel Type:	Compressed gaseous H2	Liquid H2	Compressed gaseous H2	Liquid H2	Compressed gaseous H2	Compressed gaseous H2
Fuel Transport Mode	Tube Trailer (assumes 4 ton capacity)	Tanker Trailer (assumes 4 ton capacity)	Tube Trailer (assumes 4 ton capacity)	Tanker Trailer (assumes 4 ton capacity)	N/A	N/A
Regasification and Compression:[20]	N/A	Yes	N/A	Yes	N/A	N/A
CI (g CO2e/MJ):	125.56	173.42	100.78	149.19	165.21	11.01[21]

The CIs for each of these pathways is dependent upon specific input parameters in worksheets of the CA-GREET v3.0 model. The stepwise CIs are detailed in Table E.3 for each hydrogen pathway.

[20] Regasification and Recompression is necessary for liquid hydrogen Customers demanding 600+ kg of Hydrogen per day.
[21] Assumes only grid electricity for compression and delivery at filling station.

Table E.3. Step-wise CI details for Hydrogen Pathways

	NG to Gaseous H2 using SMR	NG to Liquid H2 using SMR	Biomethane to Gaseous H2 using SMR	Biomethane to Liquid H2 using SMR	Gaseous H2 from electrolysis (CA e-GRID)	Gaseous H2 from electrolysis (Renewable Grid)
NG Recovery	6.08	6.08				
NG Processing	3.31	3.31				
NG Transport	6.50	6.50				
LFG Recovery			0.8	0.8		
LFG Processing			35.18	35.18		
Biomethane Transport			10.90	10.90		
Gaseous H2 Production	20.82	20.82	20.86	20.86	154.20	0
H2 Production Non-Combustion	64.09	64.09	8.32	8.32		
Liquefaction		70.86		71.11		
Gaseous H2 Transport	13.71		13.71			
Liquid H2 Transport		1.12		1.38		
Gaseous H2 Compression and Precooling	11.01		11.01		11.01	11.01
Liquid H2 Storage		0.63		0.63		
Total CI	**125.56**	**173.42**	**100.78**	**149.19**	**165.21**	**11.01**

II. Pathway Details, Assumptions, and Calculations

Compressed gaseous H2 produced in California from central reforming of fossil natural gas

This pathway uses fossil natural gas used as feedstock and grid-average electricity. From a central reforming station, the hydrogen is assumed to be transported by heavy duty diesel-fueled tube trailers to refueling outlets throughout the State for a distance of 100 miles. The tube pressure is stepped up to 7,000 psi for transport to refueling stations. Once the tube trailer arrives at the refueling station, this pathway assumes a "trans-fill" method for the transfer of gaseous hydrogen loaded tube trailer to the hydrogen storage unit at the refueling station. Once the gaseous hydrogen has been delivered to the refueling station storage unit, it must undergo further compression and precooling to -40 degree Celsius (also -40F) before it can be dispensed into a vehicle. The final discharge pressure for hydrogen fuel is estimated to range between 10,000 and 12,000 psi. Only electrical energy is assumed to be consumed for compression and pre-cooling of the gaseous hydrogen. Table E.3 details inputs and assumptions for this Lookup Table pathway.

Table E.3. Summary of Input Parameters for Gaseous Hydrogen from Fossil Natural Gas

Input Details	Gaseous Hydrogen produced from Steam Methane Reformation (SMR) of Fossil Natural Gas
Plant	Central
Feedstock	Natural Gas
Process Fuel	Natural Gas and Grid Electricity
Finished Fuel	Gaseous Hydrogen
Share of Hydrogen Production	100% Central
Production Efficiency	72%
Gaseous hydrogen Compression Efficiency	90.7%
Electric Generation Mix (Feedstock)	1 (U.S. Ave. Mix)
Electric Generation Mix (Fuel Prod)	1 (California grid-average)
Share of Feedstock as Feed	83%
NG Transport by Pipeline to Central Plant (miles)	1000
Gaseous Hydrogen Bulk Terminal to Refueling Station (miles)	100
Cargo Payload for Hydrogen Transport (tons)	0.4[22]

[22] Assumed capacity of a tube trailer carrying hydrogen fuel from Bulk Terminal to Refueling Station.

Liquefied H2 produced in California from central reforming of fossil natural gas

This pathway uses fossil natural gas used as feedstock and grid-average electricity. It is identical to the gaseous hydrogen from fossil natural gas pathway with the exception of additional steps to produce liquid hydrogen, transporting liquid hydrogen to the dispensing station followed by re-gasification and compression.

Staff assumes that the liquid hydrogen produced at a Central Plant will be transported to refueling stations by heavy duty diesel-fueled tanker trailers over a distance of 100 miles. The pathway assumes that from a Central Plant, 4 ton tankers will be utilized to transport liquid hydrogen. Some natural gas is expended to boil-off hydrogen before recovery and some hydrogen is also lost due to boil-off.

The liquid hydrogen is regasified and stored on site as compressed gaseous hydrogen. The re-compression and precooling requirements prior to dispensing are the same as described in the fossil NG to gaseous hydrogen pathway. Table E.4 details inputs and assumptions for this Lookup Table pathway.

Table E.4. Summary of Input Parameters for Liquid Hydrogen from Fossil Natural Gas

Input Details	Liquid Hydrogen produced from Steam Methane Reformation (SMR) of Fossil Natural Gas
	Value (3)
Plant	Central
Feedstock	Natural Gas
Process Fuel	Natural gas and Grid Electricity
Fuel	Liquid Hydrogen
Share of Hydrogen Production	100% Central
Production Efficiency	72%
Hydrogen Liquefaction Efficiency	71%
Boil-Off Effects of liquid Hydrogen	0.30%
Duration of Storage (days)	5
Recovery Rate for Boil-Off Gas	80%
Electric Generation Mix (Feedstock)	1 (U.S. Ave. Mix)
Electric Generation Mix (Fuel Production)	1 (California grid-average mix)
Share of Feedstock as Feed	83%
NG Transport by Pipeline to Central Plant (miles)	1000
Liquid Hydrogen Truck Transport from Terminal to Refueling Station (miles)	100
Cargo Payload for Hydrogen Transport (tons)	4[23]
Gaseous hydrogen Compression Efficiency	90.7%

Compressed H2 produced in California from central reforming of biomethane from landfills

This pathway is analogous to the fossil NG to gaseous hydrogen pathway discussed above with the exception that the feedstock includes renewable natural gas sourced from landfills. Staff assumes a transport distance of 3,200 miles for renewable biomethane sourced from landfills in North America. The upgrading of biogas to biomethane assumes energy use to be similar to energy use in landfill to biomethane pathways certified in the LCFS program from January 2016 through August 2017.

All the hydrogen production, transport and dispensing parameters are the same as detailed in the pathway for gaseous hydrogen from fossil natural gas.

[23] Assumed capacity of a tanker carrying hydrogen fuel from Bulk Terminal to Refueling Station

Since only part of the feedstock (i.e., biomethane) is converted to finished hydrogen, it is critical to establish upstream quantity of biomethane required for every kilogram of hydrogen produced. Calculations using CA-GREET with attendant efficiencies indicate 0.171 MMBtu of biomethane is required for every kilogram of hydrogen produced. Applicants who use this pathway to report hydrogen use in transportation must provide evidence of equivalent quantities of biomethane sourced from landfills. Table E.5 details inputs and assumptions for this Lookup Table pathway.

Table E.5. Summary of Input Parameters for Gaseous Hydrogen from Biomethane from Landfills

Input Details	Gaseous Hydrogen produced from Steam Reformation of Biomethane from Landfills
Plant	Central
Feedstock	Biomethane from Landfills
Process Fuel	Biomethane and Grid Electricity
Finished Fuel	Gaseous Hydrogen
Share of Hydrogen Production	100% Central
Production Efficiency	72%
Gaseous hydrogen Compression Efficiency	90.7%
Electric Generation Mix (Feedstock)	1 (U.S. Ave. Mix)
Electric Generation Mix (Fuel Prod)	1 (California grid-average)
Share of Feedstock as Feed	83%
Biomethane Transport by Pipeline to Central Plant (miles)	3,200
Gaseous Hydrogen Bulk Terminal to Refueling Station (miles)	100
Cargo Payload for Hydrogen Transport (tons)	0.4

Liquefied H2 produced in California from central reforming of biomethane from landfills

This pathway is analogous to the liquid hydrogen pathway from fossil NG. It is identical to the gaseous hydrogen from biomethane pathway with the exception of additional steps to produce liquid hydrogen, transporting liquid hydrogen to the dispensing station followed by re-gasification and compression. Table E.6 details inputs and assumptions for this Lookup Table pathway.

Since only part of the biomethane is converted to finished hydrogen, it is critical to establish upstream quantity of biomethane required for every kilogram of hydrogen produced. Calculations using CA-GREET with attendant efficiencies indicate 0.171 MMBtu of biomethane is required for every kilogram of hydrogen produced. Applicants who use this pathway to report hydrogen use in transportation must provide evidence of equivalent quantities of biomethane sourced from landfills for all of the hydrogen being reported in the LCFS program.

Table E.6. Summary of Input Parameters for Liquid Hydrogen from Biomethane from Landfills

Input Details	Liquid Hydrogen produced from Steam Reformation of Biomethane from Landfill Gas
Plant	Central
Feedstock	Biomethane from Landfills
Process Fuel	Biomethane and Grid Electricity
Fuel	Liquid Hydrogen
Share of Hydrogen Production	100% Central
Production Efficiency	72%
Hydrogen Liquefaction Efficiency	71%
Boil-Off Effects of liquid Hydrogen	0.30%
Duration of Storage (days)	5
Recovery Rate for Boil-Off Gas	80%
Electric Generation Mix (Feedstock)	1 (U.S. Ave. Mix)
Electric Generation Mix (Fuel Production)	1 (California grid-average mix)
Share of Feedstock as Feed	83%
Biomethane Transport by Pipeline to Central Plant (miles)	3200
Liquid Hydrogen Truck Transport from Terminal to Refueling Station (miles)	100
Cargo Payload for Hydrogen Transport (tons)	4
Gaseous hydrogen Compression Efficiency	90.7%

Gaseous H2 produced in California from electrolysis using California grid-average electricity

The feedstock for this production process is primarily water and electricity. There are no transport emissions since the hydrogen is produced on-site. Dispensing parameters are the same as detailed in the pathway for gaseous hydrogen from fossil natural gas. Inputs to the CA-GREET 3.0 model are detailed in Table E.7.

Table E.7. Summary of Input Parameters for Gaseous Hydrogen from Electrolysis using California Grid-Average Electricity

Input Details	Gaseous Hydrogen produced from electrolysis using California grid-average electricity
Feedstock	Water
Process Fuel	California Grid-Average Electricity
Fuel	Gaseous Hydrogen
Share of Hydrogen Production	On-site
Share of Feedstock	100% Electrolysis
Production Efficiency	66.8%
Gaseous Compression Efficiency	90.7%
Electric Generation Mix (Feedstock)	California Grid-Average
Electric Generation Mix (Fuel Prod)	California Grid-Average
Fraction Electricity Used for Gaseous Hydrogen Compression and Precooling	100%

Gaseous H2 produced in California from electrolysis using solar- or wind-generated electricity

The feedstock for this production process is the same as the gaseous hydrogen produced by electrolysis using grid-average electricity. Dispensing parameters are the same as detailed in the pathway for gaseous hydrogen from fossil natural gas. Inputs to the CA-GREET 3.0 model are detailed in Table E.8. The applicant must provide evidence of renewable electricity generation from solar or wind to correspond to hydrogen dispensed (as fuel in transportation) being reported in the LCFS program. 50 kWh of renewable electricity is consumed to produce one kilogram of hydrogen.

Table E.8. Summary of Input Parameters for Gaseous Hydrogen from Electrolysis using Solar- or Wind-generated electricity

CA-GREET v3.0 Worksheet/Parameters	Gaseous Hydrogen produced from electrolysis using solar- or wind-generated electricity
Feedstock	Water
Process Fuel	Solar or Wind Generated Electricity
Fuel	Gaseous Hydrogen
Share of Hydrogen Production	On-site
Share of Feedstock	100% Electrolysis
Production Efficiency	66.8%
Gaseous Compression Efficiency	90.7%
Share of Renewable Electricity	100%
Electric Generation Mix (Feedstock)	100% renewable
Electric Generation Mix (Fuel Prod)	100% renewable
Electric Generation Mix (Compression)	California Grid-Average
Fraction Electricity Used for gaseous Hydrogen Compression and Precooling	100%

Section F: Fossil Based Propane

I. Pathway Summary

Fossil Propane (also termed Liquefied Petroleum Gas or LPG) is a co-product from the refining of crude oil and is also extracted from natural gas and oil production. It is a flammable mixture of hydrocarbon gases predominantly propane and butane. At atmospheric pressures and temperatures, propane will evaporate and is therefore stored in pressurized steel tanks. As a motor vehicle fuel, LPG is composed primarily of propane with varying butane percentages to adjust for vaporization pressure. Less than 3% of propane produced in the U.S. is currently used as a transportation fuel.[24] The LPG pathway in CA-GREET 3.0 assumes 65% of propane is produced from natural gas sources and 35% from petroleum sources[25] in the U.S. The fossil based propane pathway considers gas processed in the U.S., transported 1,000 miles by rail to California and delivered 90 miles by heavy duty truck to end users or stations.

According to Energy Information Agency website[26], the supply of ethane and propane, in particular, is expected to grow because of increases in natural gas production in the Marcellus Shale in Pennsylvania and in other shale areas. Pipeline companies plan to add more infrastructure to support LPG exports because of growing oil and natural gas production from shale gas and tight gas resources.

Based on the updated CA-GREET 3.0 model, the life cycle Carbon Intensity (CI) of LPG is calculated to be **82.15** gCO_2e/MJ and is detailed in Table F.1.

[24] California Energy Commission, extracted Oct 2017: http://www.energy.ca.gov/drive/technology/propane.html
[25] The World LPG Association website: shows 60% from NG source and 40% from petroleum sources worldwide: https://www.wlpga.org/about-lpg/production-distribution/
[26] Energy Information Agency (DOE) extracted October 2017: https://www.eia.gov/todayinenergy/detail.php?id=11091

Table F.1. Summary Table of Carbon Intensity of Fossil-Based Propane

	Total CI, gCO_2e/MJ from 100% NG source	Total CI, gCO_2e/MJ from 100% Petroleum source	Total CI* gCO_2e/MJ (weighted based 65/35 ratio of the sources)
Feeds Inputs from NG			
NG Recovery	6.05		3.93
NG Processing	3.30		2.14
NG Transmission	0.32		0.21
Feeds Inputs from Petroleum			
Crude Recovery		9.01	3.15
Crude Transport		0.64	0.22
LPG Refining from NG	3.07		2.0
LPG Refining from Petroleum		10.39	3.63
Non-Combustion Emissions	0.79	0.43	0.66
LPG Transport	1.16	1.16	1.16
LPG Storage			0.0
Tailpipe Emissions	65.03	65.03	65.03
Total CI	**79.46**	**86.39**	**82.15**

*(Values may not sum to total due to rounding)

II. Pathway Details, Assumptions, and Calculations

Since propane is recovered from both natural gas and petroleum sources, the production step includes contributions from both sources and is detailed below. Since 65% is produced from natural gas sources and 35% from petroleum sources, the CIs are proportionally weighted for the total propane produced.

1) Propane Recovery, Processing, and Transport:

Propane recovery from conventional NG and shale gas is assumed to be the same as detailed in the fossil NG Lookup Table pathway (49.78% from conventional gas and 50.22% from shale gas). The use of recovery energy is shown in Table F.2[27]:

[27] C Clark et al – December 2011 – Life-Cycle analysis of Shale Gas and Natural Gas – Retrieved October 2017: https://greet.es.anl.gov/publication-shale_gas

Table F.2. Summary Table of Fossil Natural Gas Recovery and Processing Parameters

	Conventional Natural Gas	Shale Natural Gas	Recovered Natural Gas
Processing	Recovery	Recovery	Processing
Energy Efficiency	97.5%	97.62%	97.35%
Residual oil	1%		
Diesel fuel	11%		1%
Gasoline	1%		
Natural gas	86%		96%
Electricity	1%		3%

Natural gas is processed to remove contaminants to meet pipeline-gas quality prior to pipeline injection. This step is also described in the NG Lookup Table pathway. The clean, processed gas is pipelined 50 miles (assumed) to a LPG plant.

Total carbon intensity of all three steps for LPG production from NG sources: NG recovery (3.93g/MJ), NG processing (2.14g/MJ), and NG transport by pipeline (0.21g/MJ) is calculated to be **6.29** g/MJ (all with 65% allocation).

2) LPG from Crude Recovery, Processing and Transport to a LPG plant:

The average U.S. crude source is used where CI from crude extraction from U.S. sources is 3.15 gCO_2e/MJ and CI from crude transport to LPG plant for 50 miles is 0.22 gCO_2e/MJ. These reflect 35% allocation for propane produced from petroleum sources. The total carbon intensity for LPG production from crude sources is calculated to be **3.37** gCO_2e/MJ (with 35% allocation).

3) LPG Refining from NG and Crude

The energy and efficiency of LPF refining from NG and crude sources is detailed in Table F.3.

Table F.3. LPG Refining Parameters

	NG sources*	Petroleum sources*
Energy Efficiency[28]	96.5%	89.5%
Energy Use Btu/MMBtu LPG		
Diesel	363	113,436
Natural Gas	34,819	47,674
Electricity	1,088	3,177
Hydrogen		7,610
Butane		65,169
CI results after 65/35 allocation	**2.00**	**3.63**

*(Values may not sum to total due to rounding)

Carbon intensity of LPG refining (from NG sources) is calculated to be **2.0** gCO_2e/MJ and LPG refining (from petroleum sources) at **3.63** gCO_2e/MJ as shown in Table F.3.

4) <u>LPG Non-combustion Emissions</u>

CI from Non-combustion emissions is calculated to be 0.51 g/MJ for propane derived from NG sources. This is calculated by adjusting the efficiency difference between NG processing and LPG production. The non-combustion emissions for propane produced from petroleum sources is calculated to be 0.15 g/MJ. Both these values reflect a 65/35 percent allocation for propane sourced from these two sources. Total emissions from non-combustion emissions is calculated to be **0.66 gCO_2e /MJ.**

5) <u>LPG transport:</u>

LPG transport distance is assumed from LPG plants to LPG stations and shown in Table F.4. The mode and mileage are also detailed in Table F.4. The GHG emissions from transport is calculated to be **1.16 gCO_2e /MJ**

[28] A. Elgowainy, J. Han, H. Cai, M. Wang, G. S. Forman, V. B. DiVita – Argonne May 2014 – "Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries" for Propane Energy Efficiency

Table F.4. LPG transport and Distribution

LPG transport and distribution mode	Mileage	CI* gCO_2e /MJ
Transport by Rail	1,000 miles	0.65
Distribution by Heavy Duty Diesel Truck	90 miles	0.52
		1.16

*(Values may not sum to total due to rounding)

6) Tailpipe Emissions:

Tailpipe emissions from the use of fossil-based propane in light duty LPG vehicles are estimated using values from the Argonne GREET1 2016 model for Methane (CH_4) and Nitrous Oxide (N_2O). For CO_2, it is calculated based on Carbon in propane and shown in Table F.5. Total tailpipe emissions calculations are shown in Table F.6.

Table F.5. Summary of Tailpipe CO_2 Emissions for Fossil-Based Propane Vehicles

Components		Note
MPGGE (Miles per Gasoline Equivalent Gallon)	23.4	Similar to Baseline of Gasoline Vehicle
Total LPG Use, Btu/mile	4,795	GREET value
CO_2 in LPG, grams CO_2/mile	326.3	GREET value
Convert to gCO_2/MMBtu	68,052.7	

Table F.6. Summary Table of Vehicles Tailpipe Emissions for Fossil-Based Propane vehicles

	Tailpipe Emissions for Fossil-Based Propane vehicles g/MMBtu	CI* gCO_2e/MJ
CH_4	3.18	0.075
N_2O	1.59	0.45
CO_2	68,052.7	64.50
Total gCO_2e/MMBtu	64,073.17	
Total CI	**68,607.25**	**65.03**

*(Values may not sum to total due to rounding)