

Detailed California-Modified GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California



Stationary Source Division
Release Date: April 22, 2008
Version 1.0

The Staff of the Air Resources Board developed this preliminary draft version as part of the Low Carbon Fuel Standard Regulatory Process

The ARB acknowledges contributions from the California Energy Commission, TIAX, and Life Cycle Associates during the development of this document

When reviewing this document, please submit comments directly to:

Anil Prabhu: aprabhu@arb.ca.gov

Chan Pham: cpham@arb.ca.gov

Michelle Werner: mwerner@arb.ca.gov

These comments will be compiled, reviewed, and posted to the LCFS website in a timely manner.

TABLE OF CONTENTS

Table of Contents.....	1
List of Figures.....	2
List of Tables.....	3
SUMMARY.....	1
CA-GREET Model Pathway for CARBOB from Average Crude Refined In California	2
WTT Details-Crude Recovery	7
WTT Details-Crude Transport and Storage.....	8
WTT Details-Crude Refining	8
WTT Details-CARBOB Transport and Storage	9
TTW - Tank to Wheel Energy and GHG Emissions Summary	10
APPENDIX A.....	11
Section 1. CRUDE RECOVERY.....	13
1.1 Energy Use for Crude Recovery	14
1.2 GHG Emissions from Crude Recovery.....	16
Section 2. CRUDE TRANSPORT	25
2.1 Energy Use for Crude Transport.....	26
2.2 GHG Emissions for Crude Transportation.....	28
Section 3. CRUDE REFINING	31
3.1 Energy Use for Crude Refining	32
3.2 GHG Emissions from Crude Refining.....	34
Section 4. CARBOB TRANSPORT AND DISTRIBUTION.....	41
4.1 Energy Use for Transport and Distribution of CARBOB	42
4.2 GHG Emissions from Transportation and Distribution of CARBOB.....	45
Section 5. CARBON EMISSIONS FROM CARBOB COMBUSTION.....	47
5.1 Combustion Emissions from Fuel.....	48
APPENDIX B.....	49
CARBOB Pathway Input Values.....	49
Average Crude Oil to California Refineries to Make CARBOB.....	50

LIST OF FIGURES

<i>Figure 1. Discrete Components of Crude to CARBOB Pathway</i>	<i>4</i>
<i>Figure 2. Energy and Emissions Contribution for CARBOB.....</i>	<i>6</i>
<i>Figure 3. Efficiency of Various Fuel Products.....</i>	<i>32</i>

LIST OF TABLES

Table A. Energy Use and GHG Values for the CARBOB Pathway	5
Table B. Total Energy Use for Crude Recovery	7
Table C. Total GHG Emissions from Crude Recovery	7
Table D. Energy Consumed for Crude Transport.....	8
Table E. Total GHG Emissions Crude Transport and Distribution.....	8
Table F. Energy Required for Crude Refining to CARBOB.....	9
Table G. GHG Emissions from Crude Refining to CARBOB.....	9
Table H. Energy Use for CARBOB Transportation and Distribution.....	9
Table I. GHG Emissions from Transporting and Distributing CARBOB.....	9
Table J. Carbon in Fuel Calculations for CARBOB	10
Table 1.01 Details on How Efficiency is Used to Calculate Energy Consumption for Crude Recovery	14
Table 1.02 Adjustment to Values in Table 1.01 to Account for Upstream Losses	15
Table 1.03 Details for Equations in Table 1.02.....	15
Table 1.04 Global Warming Potentials for Gases	16
Table 1.05 CO ₂ Emissions by Fuel Type (does not include other GHGs)	16
Table 1.06 Specific Fuel Shares Contributing to CO ₂ Emissions	17
Table 1.07 Values Used in Table 1.06	18
Table 1.08A CO ₂ Emissions from Diesel.....	19
Table 1.08B CO ₂ Emissions from Natural Gas.....	19
Table 1.09 Detailed CO ₂ Emissions from Feedstock Consumption for Electricity	19
Table 1.10 Energy Breakdown from Electricity (Feedstock Consumption) as Used in Table 1.11	20
Table 1.11 Detailed CO ₂ Emissions from Feedstock Production	21
Table 1.12 Values Used in Table 1.11 Calculations.....	22
Table 1.13 CH ₄ , N ₂ O, VOC and CO Emissions from Crude Recovery.....	23
Table 1.14 Total GHG Emissions from Crude Recovery.....	23
Table 2.01 Crude Oil Transport Details from AB 1007 Work.....	26
Table 2.02 Details of Energy Consumed for Crude Transport.....	27
Table 2.03 Values for Equations Used in Table 2.02	27
Table 2.04 Crude Transport CO ₂ Emissions	28
Table 2.05 Values of Properties Used in Table 2.04.....	28
Table 2.06 Crude Transport CH ₄ Emissions	29
Table 2.07 Total GHG Emissions from Crude Transport and Distribution	29
Table 3.01 Details on How Efficiency is Used to Calculate Energy Needs for Crude Refining.....	33
Table 3.02 Adjustment to Crude Refining.....	33
Table 3.03 Details for Entries in Table 3.02	33
Table 3.04 CO ₂ Emissions by Fuel Type.....	34
Table 3.05 CO ₂ Emissions from Residual Oil Use in Refineries from Table 3.04.....	34

DRAFT – FOR REVIEW

Table 3.06 Values for Use in Table 3.05..... 34
Table 3.07 CO₂ Emissions from Natural Gas from Table 3.04..... 35
Table 3.08 Details of Values Used in Table 3.07 35
Table 3.09 CO₂ Emissions from Electricity from Table 3.04..... 35
Table 3.11 CO₂ Emissions from Electricity..... 36
Table 3.12 CO₂ Emissions from Non-Combustion Sources 36
Table 3.13 CO₂ Emissions from Electricity (feedstock production)..... 37
Table 3.14 Factors and Values for Use in Table 3.13 37
Table 3.15 Energy Breakdown from Electricity (Feedstock Consumption)..... 38
Table 3.16 CO₂ Emissions from Use of Refinery Still Gas 38
Table 3.17 Values Used in Table 3.16 39
Table 3.18 CH₄ Emissions 39
Table 3.19 N₂O Emissions 39
Table 3.20 GHG Emissions from Crude Refining..... 40

Table 4.01 Energy Use for Transport and Distribution via Pipeline 42
Table 4.02 Energy Use for Transportation and Distribution CARBOB via HDD Truck .. 43
Table 4.04 Values of Properties Used in Table 4.03..... 44
Table 4.05 CO₂ from CARBOB Transportation and Distribution 45
Table 4.06 Details of GHG from CARBOB Transportation and Distribution 45

*Table 5.01 Inputs and Assumptions used for Calculating Combustion GHG Emissions*48

SUMMARY



CA-GREET Model Pathway for CARBOB from Average Crude Refined In California

A Well-To-Tank (WTT) Life Cycle Analysis of a petroleum based fuel pathway includes all steps from crude oil recovery to final finished fuel. Tank-To-Wheel (TTW) analysis includes actual combustion of fuel in a motor vehicle for motive power. Together, WTT and TTW analysis are combined to provide a total Well-To-Wheel (WTW) analysis.

A Life Cycle Analysis Model called the **G**reenhouse gases, **R**egulated **E**missions, and **E**nergy use in **T**ransportation (GREET)¹ developed by Argonne National Laboratory has been used to calculate the energy use and greenhouse gas (GHG) emissions generated during the process of transforming crude to produce California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB)². The model however, was modified by TIAX under contract to the California Energy Commission during the AB 1007 process³. Changes were restricted to mostly input factors (electricity generation factors, crude transportation distances, etc.) with no changes in methodology inherent in the original GREET model. This California-modified GREET model forms the basis of this document. The pathway described in this document is for average crude (both in-state production and overseas crude transported to CA) that is refined in CA. The values, assumptions, and equations used in this document are from the CA-modified GREET model (greet1.7ca_v98.xls). This model is available for download from the Low Carbon Fuel Standard website at <http://www.arb.ca.gov/fuels/lcfs/lcfs.htm>. The values shown in this document are preliminary draft values and staff is in the process of evaluating them. The areas that staff may revise include emission factors, energy intensity factors, % fuel shares, transport modes and their shares, agricultural chemical use factors, co-product credit methodologies, etc.

The pathway includes crude recovery, transport, refining of crude in a typical California refinery and transport of finished product (CARBOB). For the CARBOB pathway, the TTW does not truly include combustion since CARBOB can not be used as a fuel per regulations established by the Air Resources Board. A similar analysis of an oxygenate such as ethanol is necessary to allow for combining the necessary energy and GHG contributions to provide for a total WTW analysis of California Reformulated Gasoline (CaRFG), a mixture of ethanol (2.0 wt.% of oxygen) in CARBOB. ARB staff will provide a similar analysis for ethanol which will then be combined with this analysis to provide a WTW analysis for CaRFG. Figure 1 show below details the discrete components that form the CARBOB pathway, from crude recovery through final finished fuel blending component. Utilizing the energy and GHG emissions from each component, a total for the entire CARBOB pathway is then calculated.

Several general descriptions and clarification of terminology used throughout this document are:

¹ <http://www.transportation.anl.gov/software/GREET/>

² RFG is actually blended with 5.7% ethanol. Ethanol free RFG is potentially also a fuel, but the fuel cycle energy inputs would differ somewhat from CARBOB. In CA, CARBOB by itself can not be used as a motor vehicle fuel but needs to be blended with an oxygenate before use

³ <http://www.energy.ca.gov/ab1007/>

DRAFT – FOR REVIEW

- GREET employs a recursive methodology to calculate energy consumption and emissions. To calculate WTT energy and emissions, the values being calculated are often utilized in the calculation. For example, crude oil is used as a process fuel to recover crude oil. The total crude oil recovery energy consumption includes the direct crude oil consumption AND the energy associated with crude recovery (which is the value being calculated).
- Btu/mmBtu is the energy input necessary in Btu to produce or transport one million Btu of a finished (or intermediate) product. This description is used consistently in GREET for all energy calculations. There are 1055 million Btu in one MJ of energy, so in order to convert one million Btu into MJ, multiply the million Btu by 1055.
- gCO₂e/MJ provides the total greenhouse gas emissions on a CO₂ equivalent basis per unit of energy (MJ) for a given fuel. Methane (CH₄) and nitrous oxide (N₂O) are converted to a CO₂ equivalent basis using IPCC global warming potential values and included in the total.
- GREET assumes that VOC and CO are converted to CO₂ in the atmosphere and includes these pollutants in the total CO₂ value using ratios of the appropriate molecular weights.
- Process Efficiency for any step in GREET is defined as:

$$\text{Efficiency} = \text{energy output} / (\text{energy output} + \text{energy consumed})$$

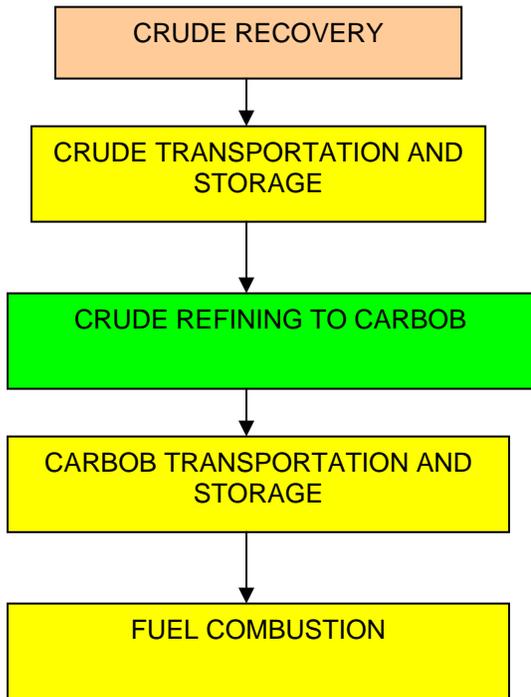


Figure 1. Discrete Components of Crude to CARBOB Pathway

Table A provides a summary of the Well-To-Tank (WTT) and Tank-To-Wheel (TTW) energy use and GHG emissions for this pathway. Note that rounding of values has not been performed in several tables in this document. This is to allow stakeholders executing runs with the GREET model to compare actual output values from the CA-modified model with values in this document.

DRAFT – FOR REVIEW

Table A. Energy Use and GHG Values for the CARBOB Pathway

	Energy Required (Btu/mmBtu)	% Energy Contribution	Emissions (gCO₂e/MJ)	% Emissions Contribution
Crude Recovery	86,477	6.6%	6.6	6.9%
Crude Transport	10,076	0.8%	2.2	2.4%
Crude Refining (CA)	208,621	15.9%	13.1	13.8%
CARBOB Transport	4,309	0.3%	0.3	0.3%
Total (Well To Tank)	309,483	23.6%	22.2	23.4%
(Tank to Wheel)	1,000,000	76.4%	72.9	76.6%
Total (Well To Wheel)	1,309,483	100%	95.2	100%

Note: percentages may not add to 100 due to rounding

From Table A, the WTW analysis of CARBOB indicates that 1,309,483 Btu of energy is required to produce 1 (one) mmBtu of available fuel energy delivered to the vehicle. From a GHG perspective, 95.2 gCO₂e of GHG emissions are released during the production of 1 (one) MJ of CARBOB. The value reported within this document varies from previously reported values of ~92 for several reasons: The current value includes both N₂O and CH₄ emissions and the crude recovery efficiency is 93.9%, which has been modified from 98.0%. For a more detailed explanation of the difference in crude recovery efficiency, see Section 1.1. The transportation of crude via ocean tanker and pipeline is also weighted to reflect average crude available in California.

Note that WTW values calculated in Table A do not represent a true WTW option since CARBOB is prohibited from being used as a fuel in a motor vehicle. Only the carbon in fuel which is transformed into CO₂ is included in the WTW analysis in this document and the calculations are provided in Appendix A. A complete WTW analysis would include not only the CO₂ generated from carbon in the fuel but would also account for N₂O and CH₄. Using a similar analysis for ethanol (used as an oxygenate), staff will provide details of a WTW analysis for CARBOB blended with ethanol. Both the ethanol and the CaRFG documentation can be found online.

The values in Table A are pictorially represented in Figure 2, showing specific contributions of each of the discrete components of the fuel pathway. The charts are shown separately for energy use and GHG emissions. From an energy use viewpoint, energy in fuel (76.4%), crude refining (15.9%) and crude recovery (6.6%) dominate the WTW energy use. From a GHG perspective, carbon in fuel (76.6%), crude refining (13.8%), and crude recovery (6.9%) dominate the GHG emissions for this pathway.

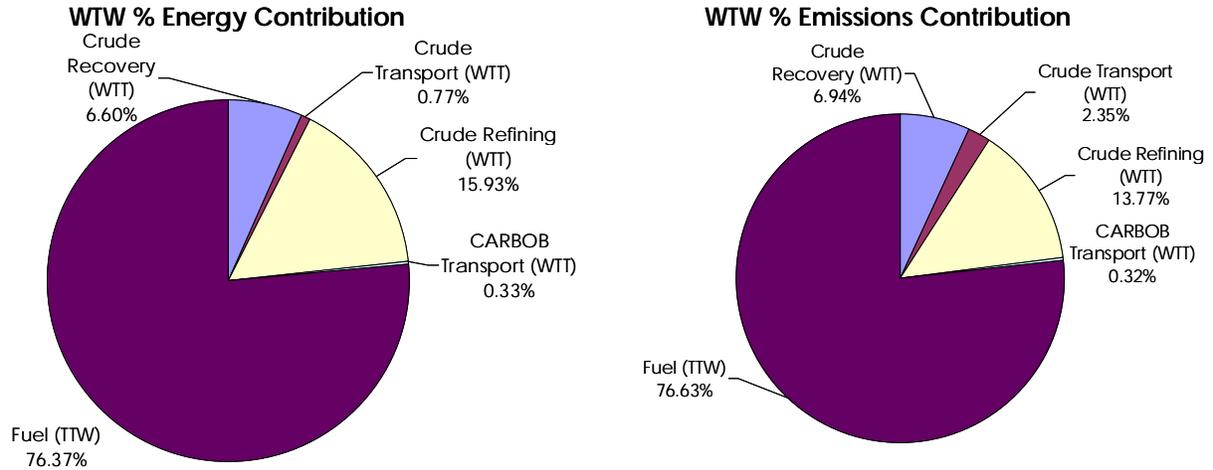


Figure 2. Energy and Emissions Contribution for CARBOB

The section below provides an expanded view of the summary results presented here. Appendix A provides detailed description of the assumptions, input values and equations used in the model. Appendix B provides a table of input values used in the calculations in this document.

WTT Details-Crude Recovery

Table B provides a breakdown of energy use for crude recovery. Crude recovery utilizes process energy which GREET depicts as being derived from a combination of several fuel types to include crude itself, residual oil, diesel, gasoline, natural gas and electricity. As an example, natural gas is combusted in a boiler to generate heat which then runs a turbine to generate electricity. This feature is captured in the electricity fuel share part of the energy mix. The table indicates that 86,477 Btu of energy is required to recover crude containing 1 mmBtu of energy. Detailed calculations are provided in Appendix A.

Table B. Total Energy Use for Crude Recovery

Fuel Type	Btu/mmBtu
Crude oil	704
Residual oil	758
Diesel	12,074
Gasoline	1,664
Natural gas	43,165
Electricity	28,083
Feed Loss	28
Total energy for crude recovery	86,477

The GHG emissions associated with the transformation of fuel sources to useful process energy for crude recovery is shown in Table C below. During the crude recovery step of this pathway 6.60 grams of CO₂ e GHG emissions are generated. Additional details are provided in Appendix A.

Table C. Total GHG Emissions from Crude Recovery

GHG Emissions	gCO₂e/MJ
CO ₂	6.08
CH ₄ (combustion)	0.39
CH ₄ (non-combustion)	0.05
N ₂ O	0.03
CO	0.04
VOC	0.01
Total GHG emissions	6.6

Note: Non-combustion methane leaks during recovery operations

WTT Details-Crude Transport and Storage

Table D shows the energy necessary for transporting crude via ocean tanker and pipeline to California refineries. The proportional split between these two modes of transport are calculated from the average crude mix arriving in California, both from within the state as well as from overseas. Detailed breakdown of proportions utilized in the calculations are provided in Appendix A. A small energy loss attributable to feed losses is also captured in this analysis. As shown in Table D, crude transport utilizes 10,076 Btu of energy for every 1 mmBtu of crude transported.

Table D. Energy Consumed for Crude Transport

	Btu/mmBtu
Feed Loss	62
Ocean Tanker	5,845
Pipeline	4,169
Total	10,076

Table E shows GHG emissions from crude transport in ocean tankers and pipelines. The fuel consumption and other specifics necessary for this calculation are detailed in Appendix A. Crude transport by the two types of transport weighted proportionally generates 2.24 gCO_{2e} GHG emissions for every 1 MJ of crude transported.

Table E. Total GHG Emissions Crude Transport and Distribution

GHG	gCO_{2e}/MJ
CO ₂	0.71
CH ₄	1.53
N ₂ O	0
CO	0
VOC	0
Total GHG emissions	2.24

WTT Details-Crude Refining

As can be seen in the Table F below, 208,621 Btu of energy is required to produce 1 mmBtu of finished CARBOB. Again, each source of fuel has associated GHG emissions in its transformation into useful energy and these are shown in Table G below. The refining process generates 11.87 gCO_{2e} per MJ of finished CARBOB. This is combined with non-combustion methane which adds an additional 1.23 gCO_{2e} providing for a total of 13.1 gCO_{2e} per MJ of fuel. Details of all the calculations are presented in Appendix A.

DRAFT – FOR REVIEW

Table F. Energy Required for Crude Refining to CARBOB

Fuel Type	Btu/mmBtu
Residual Oil	12,868
Natural Gas	78,783
Electricity	16,725
Refinery still gas	100,244
Total energy for refining	208,621

Table G. GHG Emissions from Crude Refining to CARBOB

GHG	gCO₂e/MJ
CO ₂	11.50
CH ₄ (combustion)	0.29
CH ₄ (non-combustion)	1.23
N ₂ O	0.04
CO	0.01
VOC	0.00
Total	13.1

WTT Details-CARBOB Transport and Storage

Table H provides a summary of the energy expended to transport finished CARBOB via pipeline and Heavy Duty Diesel (HDD) truck from refineries to a blending station. From Table H, this component of the pathway utilizes 4,309 Btu of energy for every 1 mmBtu of CARBOB transported. The transportation through pipeline and HDD truck generates GHG emissions which are shown in Table I below. A total of 0.3 gCO₂e GHG emissions are generated for every 1 MJ of CARBOB transported.

Table H. Energy Use for CARBOB Transportation and Distribution

Transport mode	Btu/mmBtu
Feed Loss	210
CARBOB transported by pipeline	631
CARBOB Distribution by HDD truck	3476
Total	4,309

Table I. GHG Emissions from Transporting and Distributing CARBOB

Transportation Mode	CO₂e (g/MJ)
Pipeline	0.04
HDD Truck	0.26
Total	0.3

TTW - Tank to Wheel Energy and GHG Emissions Summary

Since CARBOB can not be used as a fuel per Air Resources Board regulations (no oxygenate in CARBOB), actual TTW calculations can not be made for CARBOB to account for CO₂, CH₄, CO, N₂O and VOC emissions. Table J below provides a summary of the carbon in fuel calculations, details of which are provided in Appendix A. The carbon content of CARBOB generates 72.91 gCO₂ per MJ, which in effect represents perfect combustion of the carbon in the CARBOB to CO₂.

Table J. Carbon in Fuel Calculations for CARBOB

$\text{CO}_2 \text{ from fuel} = \text{Density} * \text{carbon ratio in gasoline} / (\text{C factor} * \text{Lower Heating Value}) =$ $72.9 \text{ g CO}_2\text{e/MJ}$
--

DRAFT – FOR REVIEW

APPENDIX A

DRAFT – FOR REVIEW

(This page intentionally left blank.)

SECTION 1. CRUDE RECOVERY



1.1 Energy Use for Crude Recovery

Energy requirements in GREET for this component utilizes a crude recovery efficiency which is used to calculate energy needs for this process. The crude recovery efficiency used here is a weighted average and takes into consideration crude extracted in California as well as crude recovered overseas. The default value in GREET is 98% which reflects an average crude processed in the United States. The 93.9% value represents an estimate of a mix of conventional oil recovery and Thermally Enhanced Oil Recovery (TEOR) as detailed in the AB1007 analysis. TEOR requires steam to be injected into the reserves and therefore uses more energy than conventional oil reserves. Natural gas is most commonly the fuel used to generate steam. Table 1.01 provides details on how this efficiency is used to calculate energy requirements for this part of the pathway. Here, fuel shares describe a breakdown of how different fuels are used as an energy source for various operations used in crude recovery (e.g. natural gas share of energy input is 62%). The fuel shares are default GREET values. Note that the inverse of efficiency is multiplied by 10^6 since we calculate Btu per million Btu of fuel. For flared natural gas, the GREET default value is 16,800 Btu/mmBtu.

Table 1.01 Details on How Efficiency is Used to Calculate Energy Consumption for Crude Recovery

Fuel Type	Fuel Shares	Relationship of Recovery Efficiency and Fuel Shares	Btu/mmBtu CARBOB
Crude oil	1%	$(10^6)(1/0.939 - 1)(0.01) = 648$	648
Residual oil	1%	$(10^6)(1/0.939 - 1)(0.01) = 648$	648
Diesel fuel	15%	$(10^6)(1/0.939 - 1)(0.15) = 9,726$	9,726
Gasoline	2%	$(10^6)(1/0.939 - 1)(0.02) = 1,297$	1,297
Natural gas	62%	$(10^6)(1/0.939 - 1)(0.62) = 40,201$	40,201
Electricity	19%	$(10^6)(1/0.939 - 1)(0.19) = 12,320$	12,320
Feed Loss	0.043%	$(10^6)(1/0.939 - 1)(0.00043) = 28$	28
Natural Gas Flared		GREET Default Value	16,800

Note: Crude Recovery Efficiency in GREET is defined as energy in crude recovered / (energy in crude recovered + energy consumed to recover crude)

The values in Table 1.01 are then adjusted to account for upstream losses in the WTT energy use. Table 1.02 depicts the adjustments to the values from the table above for each fuel type, accounting for loss factors associated with the WTT energy for each fuel used during crude recovery operations. Table 1.03, which follows Table 1.02, provides values and descriptions for the equations used in Table 1.02.

DRAFT – FOR REVIEW

Table 1.02 Adjustment to Values in Table 1.01 to Account for Upstream Losses

Fuel Type	Formula	Btu/mmBtu
Crude oil	$648 (1 + A/10^6)$	704
Residual oil	$648 (1 + (B*D+ C)/ 10^6)$	758
Diesel fuel	$9,726 (1 + (B*F + E)/ 10^6)$	12,074
Gasoline	$1,297 (1 + (B*H + G)/ 10^6)$	1,664
Natural gas	$40,201 (1 + I/10^6)$	43,165
Electricity	$12,320 (K+ J)/ 10^6$	28,083
Feed Loss	28	28
Total WTT energy for crude recovery		86,477

Table 1.03 Details for Equations in Table 1.02

Quantity	Description
A = 86,477	WTT energy in Btu for crude recovery at the oil field. This value calculated as the total WTT energy for crude recovery in Table 1.02 above. It is also an input the total WTT energy calculation This is one instance of a “recursive” ¹ calculation in GREET.
B = 92,986	WTT energy of crude in Btu consumed to recover one million Btu as feedstock used in US refineries. This is a GREET calculation that includes losses and delivery to the oil refinery.
C = 76,209	WTT energy in Btu required to produce 1 million Btu of residual oil. This is calculated from the WTT analysis of residual oil similar to the CARBOB calculations being detailed in this document.
D = 1.0002	Loss factor ² residual oil which is a GREET default value.
E = 148,433	WTT energy required in Btu to produce one million Btu of diesel. This value is calculated from the WTT analysis of diesel from GREET similar to the CARBOB calculations being detailed in this document.
F = 1.0002	Loss factor ² for diesel fuel which is default GREET value.
G = 189,960	WTT energy in Btu to produce one million Btu of gasoline. This value is calculated from the WTT analysis of gasoline from GREET similar to the CARBOB calculations being detailed in this document.
H = 1.00019	Loss factor ² for gasoline which is default GREET value.
I = 73,741	WTT energy in Btu used to produce natural gas as stationary fuel. This is a GREET calculated value.
J = 2,173,356	Total energy required in Btu to produce one million Btu of electricity. This is derived from the electricity analysis by GREET.
K = 106,317	Total energy required Btu to produce one million Btu of electricity feedstock. This is derived from the electricity analysis by GREET.

¹ GREET employs a recursive methodology to calculate energy consumption and emissions. To calculate WTT energy and emissions, the values being calculated are often utilized in the calculation. For example, crude oil is used as a process fuel to recover crude oil. The total crude oil recovery energy consumption includes the direct crude oil consumption AND the energy associated with crude recovery (which is the value being calculated).

² Loss factors for petroleum fuels include refueling spillage plus evaporative losses from vehicle fueling and fuel transfer operations.

1.2 GHG Emissions from Crude Recovery

For Greenhouse Gas (GHG) emissions, GREET only accounts for CO₂, CH₄ and N₂O. The Global Warming Potentials (GWP) for all gases are from the IPCC guidelines and are default GREET values listed in Table 1.04. For CO and VOC the model uses adjustment factors to calculate their CO₂ equivalents and the conversion calculations is provided as a note below.

Table 1.04 Global Warming Potentials for Gases

Species	GWP (relative to CO ₂)
CO ₂	1
CH ₄	23
N ₂ O	296

Note: Values from mmBtu to MJ have been calculated using 1055 mmBtu = 1MJ
 GREET uses a specific methodology to account for GHG emissions related to VOCs and CO:
 Carbon ratio of VOC = 0.85 which is then converted as gCO₂e/MJ = g VOC*(0.85)*(44/12) = 3.1
 Carbon ratio of CO = 0.43 which is then converted as gCO₂e/MJ = g CO*(0.43)*(44/12) = 1.6

The transformation of various fuel types into energy generates emissions, specific to each type of fuel and the equipment used in the transformation. An example is natural gas being combusted to generate electricity in turbines. Table 1.05 details only CO₂ emissions for each fuel type used in crude recovery. CH₄, N₂O, VOC and CO contributions to total GHG emissions are detailed later in this section. Additional details for each specific fuel type are provided in sections to follow. The table provides GHG values both in gCO₂e/mmBtu and gCO₂e/MJ. As an example, the use of diesel fuel in crude recovery generates 0.87 gCO₂e/MJ.

Table 1.05 CO₂ Emissions by Fuel Type (does not include other GHGs)

Fuel Type	gCO ₂ /mmBtu	gCO ₂ /MJ
Crude oil	54	0.05
Residual oil	63	0.06
Diesel fuel	917	0.87
Gasoline	92	0.09
Natural Gas	2,521	2.39
Electricity	1,792	1.70
Natural Gas (flared)	975	0.92
Total	6,416	6.1

Note: 1055 mmBtu = 1MJ

DRAFT – FOR REVIEW

Table 1.06 utilizes the energy use by fuel type from Table 1.01 and calculates GHG emissions utilizing emission factors which are provided in Table 1.07. The CO₂ emission factors represent the carbon in fuel minus carbon emissions associated with VOC and CO emissions. Thus, the emission factors are different among equipment types such as engines and turbines. The carbon in fuel factors are GREET default values, except for natural gas, which is slightly different based on the AB1007 analysis. The calculations shown reflect the estimated direct emissions of CO₂ from the different equipment types excluding the carbon in VOC and CO. Note that energy use is used from Table 1.01 of this document (as an example, the value 648 is from Table 1.01 for crude oil). Table 1.06 essentially provides details on how CO₂ emissions were calculated and provided in Table 1.05.

Table 1.06 Specific Fuel Shares Contributing to CO₂ Emissions

Fuel	Calculations	CO₂ emissions (gCO₂/mmBtu)
Crude Oil	648 *(crude oil emissions factor + total CO ₂ emissions from crude recovery)/ 10 ⁶	54
Residual Oil	648 *(Fraction of residual oil consumed in a commercial boiler*emissions factor of a commercial boiler + emissions from crude*loss factor for emissions from crude + total emissions from residual oil)/ 10 ⁶	63
Diesel fuel	9,726*(percentage from diesel boiler*emission factor for diesel boiler + percentage from stationary diesel engine*emissions factor for diesel engine + percentage from stationary diesel turbine*emission factor of diesel turbine + emissions from crude*loss factor + total emissions from diesel)/ 10 ⁶ (see Table 1.08A for further details)	917
Gasoline	1,297*(emissions factor of reciprocating engine + crude emissions* loss factor + emissions from conventional gasoline)/ 10 ⁶	92
Natural Gas	40,201*(percentage of natural gas used in an engine*emissions factor for natural gas engine + percentage of natural gas used in a small industrial boiler*emissions factor for small industrial boiler + emissions from natural gas as a stationary fuel)/ 10 ⁶ (see Table 1.08B for further details)	2,521
Electricity	12,320*(emissions from producing feedstock + emissions from consuming feedstock)/ 10 ⁶	1,792
Natural Gas (flared)	16,800*(emissions factor for natural gas flaring)/10 ⁶	975

DRAFT – FOR REVIEW

Table 1.07 Values Used in Table 1.06

Fuel	Calculations
Crude Oil	crude oil emissions factor = 77,264 (gCO ₂ /mmBtu) which is a GREET default.
	CO ₂ emissions from crude recovery = 6,416 (gCO ₂ /mmBtu) which is recursively calculated from Table 1.06.
Residual Oil	fraction of residual oil consumed in a commercial boiler = 1.00 which is a GREET default value.
	emissions factor of a commercial boiler = 85,049 in gCO ₂ /mmBtu which is a GREET calculated value.
	emissions factor from crude = 6,963 in gCO ₂ /mmBtu which is a GREET calculated value.
	loss factor for emissions from crude = 1.000 also a GREET default value.
	total emissions from residual oil = 5,141 a GREET calculated value.
Diesel fuel	percentage from diesel boiler = 0.25 a default value from GREET.
	emission factor for diesel boiler = 78,167 gCO ₂ /mmBtu, a GREET calculated value.
	percentage from stationary diesel engine = 0.5, a GREET default value.
	emissions factor for diesel engine = 77,349 gCO ₂ /mmBtu, a calculated value from GREET.
	percentage from stationary diesel turbine = 0.25 a default GREET value.
	emission factor of diesel turbine = 78,179 gCO ₂ /mmBtu, a GREET calculated value.
	emissions from crude = 6,963 gCO ₂ /mmBtu, calculated from GREET.
	loss factor for emissions from crude = 1.000, a default value from GREET.
total emissions from diesel = 9,610 gCO ₂ /mmBtu, a GREET calculated value.	
Gasoline	emissions factor of reciprocating engine = 1,297 gCO ₂ /mmBtu a GREET default value.
	emissions from crude = 6,963 gCO ₂ /mmBtu, a GREET calculated value.
	loss factor for emissions from crude = 1.000, a GREET default value.
	emissions from conventional gasoline = 13,884 gCO ₂ /mmBtu, GREET calculated value.
Natural Gas	percentage of natural gas used in an engine = 0.5, GREET default.
	emissions factor for natural gas engine = 56,551 gCO ₂ /mmBtu, a GREET calculated value
	percentage of natural gas used in a small industrial boiler = 0.5, a GREET default.
	emissions factor for small industrial boiler = 58,176 gCO ₂ /mmBtu, a GREET calculated value
	emissions from natural gas as a stationary fuel = 5,349 gCO ₂ /mmBtu, a GREET calculated value.
Electricity	emissions from producing feedstock = 7,737 gCO ₂ /mmBtu, a GREET calculated value from electricity pathway.
	emissions from consuming feedstock = 137,734 gCO ₂ /mmBtu, a GREET calculated from electricity pathway.
Natural Gas (flared)	emissions factor for natural gas flaring =58,048 gCO ₂ /mmBtu, a GREET default value.

Tables 1.08A and 1.08B provide additional details on emissions coming from diesel, natural gas and electricity generation. Carbon dioxide emissions from crude oil, residual oil, and gasoline combustion cannot be further broken down according to equipment type because they are used in only one equipment type: industrial boilers (crude oil and residual oil) and reciprocating engines (gasoline). The values from crude oil, residual oil, and gasoline combustion are provided by the emission factors for these fuels as detailed in Tables 1.06 and 1.07. In Tables 1.08A and 1.08B, details for CO₂ emissions are provided for diesel and natural gas used as a fuel in crude recovery operations. All values in Tables 1.08A and 1.08B are GREET default values and subsequent GREET calculated values. Note that Tables 1.08A and 1.08B detail how values reported in Table 1.06 for diesel and natural gas are calculated.

DRAFT – FOR REVIEW

Table 1.08A CO₂ Emissions from Diesel

Equipment Type	Equipment Shares	Emissions Factor	gCO₂/mmBtu
Commercial Boiler	25%	78,167	190.06
Stationary Reciprocating Engine	50%	77,349	376.15
Turbine	25%	78,179	190.09
Crude Oil and Diesel Production			161.19
Total			917

Table 1.08B CO₂ Emissions from Natural Gas

Equipment Type	Equipment Shares	Emissions Factor	gCO₂/mmBtu
Stationary Reciprocating Engine	50%	56,551	1,137
Small Industrial Boiler	50%	58,176	1,169
As Stationary Fuel		5,349	215
Total			2,521

Tables 1.09 through 1.12 detail CO₂ emissions from electricity generation. They essentially detail how electricity values are calculated in Table 1.06. The emissions factor are GREET calculations. For electricity, it is broken down into emissions from feedstock production (recovering feedstock such as coal from mines and transporting to a facility) and feedstock consumption (actual use in a boiler). Table 1.09 details CO₂ emissions from feedstock consumption and values used here are provided in Table 1.10.

Table 1.09 Detailed CO₂ Emissions from Feedstock Consumption for Electricity

Feedstock As Fuel	Calculation	gCO₂/mmBtu
Natural Gas	1,697*(A/G) (note: this is a recursive calculation and all in this column)	941
Coal	1,697*(B/G)	383
Biomass	1,697*(C/G)	29
Nuclear	1,697*(D/G)	126
Residual Oil	1,697*(E/G)	1
Other Sources*	1,697*(F/G)	217
Total		1,697

*Other sources include hydro, wind, geothermal etc.

DRAFT – FOR REVIEW

Table 1.10 Energy Breakdown from Electricity (Feedstock Consumption) as Used in Table 1.11

Fuel	Conv. Efficiency	Generation Mix	Relationship of Conversion Efficiency and Energy Use	Energy Use (Btu/mmBtu)	Factor	Description
Residual Oil	34.8%	0.05%	$(10^6/0.348) * (1/1-0.081) * 0.0005$	1,563	E	Energy used as residual oil (Btu/mmBtu), a GREET calculation.
Natural Gas	38.9%	43.1%	$(10^6/0.389) * (1/1-0.081) * 0.431$	1,204,871	A	Energy used as natural gas (Btu/mmBtu), a GREET calculation.
Coal	34.1%	15.4%	$(10^6/0.341) * (1/1-0.081) * 0.154$	490,460	B	Energy used as coal (Btu/mmBtu), a GREET calculation.
Biomass	32.1%	1.1%	$(10^6/0.321) * (1/1-0.081) * 0.011$	37,288	C	Energy used as biomass (Btu/mmBtu), a GREET calculation.
Nuclear	100%	14.8%	$(10^6/1.00) * (1/1-0.081) * 0.148$	161,262	D	Energy used as nuclear (Btu/mmBtu), a GREET calculation.
Other	100%	25.5%	$(10^6/1.00) * (1/1-0.081) * 0.255$	277,911	F	Energy used as other sources (Btu/mmBtu), a GREET calculation.
Total energy used to produce electricity (Btu/mmBtu), GREET calculation				2,173,356	G	

“Other” is a combination of hydro, wind, geothermal, etc.

Table 1.11 provides information on CO₂ emissions from feedstock production related to electricity. The values used to perform the calculations in Table 1.11 are provided in Table 1.12. All values are GREET calculations. The values in Tables 1.09 and 1.11

DRAFT – FOR REVIEW

provide the total for electricity which adds to $1697 + 95 = 1,792$ gCO₂/mmBtu, shown for electricity in Table 1.06.

Table 1.11 Detailed CO₂ Emissions from Feedstock Production

Feedstock	Calculation	gCO₂/mmBtu
Natural Gas	$95*(A*B/C)/10^6$	80
Coal	$95*(D*E/C)/10^6$	7
Biomass	$95*((F*G)/H*I)/C$	1
Nuclear	$95*(J*K/(L*1000*3412))/C$	7
Residual Oil	$95*M*(N*O +P/C)/10^6$	0
Total		95

DRAFT – FOR REVIEW

Table 1.12 Values Used in Table 1.11 Calculations

Variable	Value	Description	Reference
A	1,204,871	Energy used as natural gas (Btu/mmBtu)	REET calculation
B	73,741	Energy used as natural gas for electricity generation (Btu/mmBtu)	REET calculation
C	106,137	Total energy used to produce feedstocks (Btu/mmBtu)	REET calculation
D	490,460	Energy used as coal (Btu/mmBtu)	REET calculation
E	16,930	Energy used as coal gas for electricity generation (Btu/mmBtu)	REET calculation
F	37,288	Energy used as biomass (Btu/mmBtu) REET default	REET default
G	548,999	Sum of energy used from fertilizers, pesticides, farming, and transportation for producing biomass (Btu/dry ton)	REET default
H	16,811,000	Low heating value of farmed trees (Btu/ton)	REET default
I	100 %	Shares of woody biomass	REET default
J	161,262	Energy used as nuclear fuel (Btu/mmBtu)	REET calculation
K	1,099,450	Energy used as nuclear fuel for electricity generation (Btu/mmBtu)	REET calculation
L	6.926	Conversion factor for nuclear power plants	REET default
M	1,563	Energy use from residual oil as a stationary source (Btu/mmBtu)	REET calculation
N	92,986	Energy used from crude oil (Btu/mmBtu)	REET calculation
O	1.0	Loss factor for residual oil	REET default
P	76,209	Energy used as residual oil for electricity generation (Btu/mmBtu)	REET calculation

Table 1.13 provides details on CH₄, N₂O, VOC and CO emissions generated during the combustion of the different fuels listed in these tables. These values are calculated from default REET values for sources that are used in crude recovery.

DRAFT – FOR REVIEW

Table 1.13 CH₄, N₂O, VOC and CO Emissions from Crude Recovery

	CH₄ Emissions	N₂O Emissions	VOC Emissions	CO Emissions
Fuel Type	(gCH ₄ /mmBtu)	(gN ₂ O/mmBtu)	(gVOC/mmBtu)	(gCO/mmBtu)
Crude oil	0.012	0.00	0.0003	0.034
Residual oil	0.063	0.00	0.0006	0.032
Diesel fuel	1.00	0.02	0.513	2.174
Gasoline	0.30	0.00	2.322	17.141
Natural gas	13.0	0.04	1.139	7.946
Electricity	2.90	0.03	0.186	1.194
Natural gas (flared)	0.80	0.02	0.042	0.436
Total (without non-combustion)	18.075	0.107	4.214	28.829
Non-combustion	2.255	0.00	0.702 (bulk terminal)	0.000
Total	20.33	0.11	4.92	28.83

Table 1.14 summarizes the total GHG emissions for crude recovery. The total is calculated as gCO₂e where non-CO₂ GHG gasses have been converted to CO₂ equivalents using their GWP detailed earlier. It also shows how GREET accounts for CO and VOC emissions in its calculation of pathway GHG emissions.

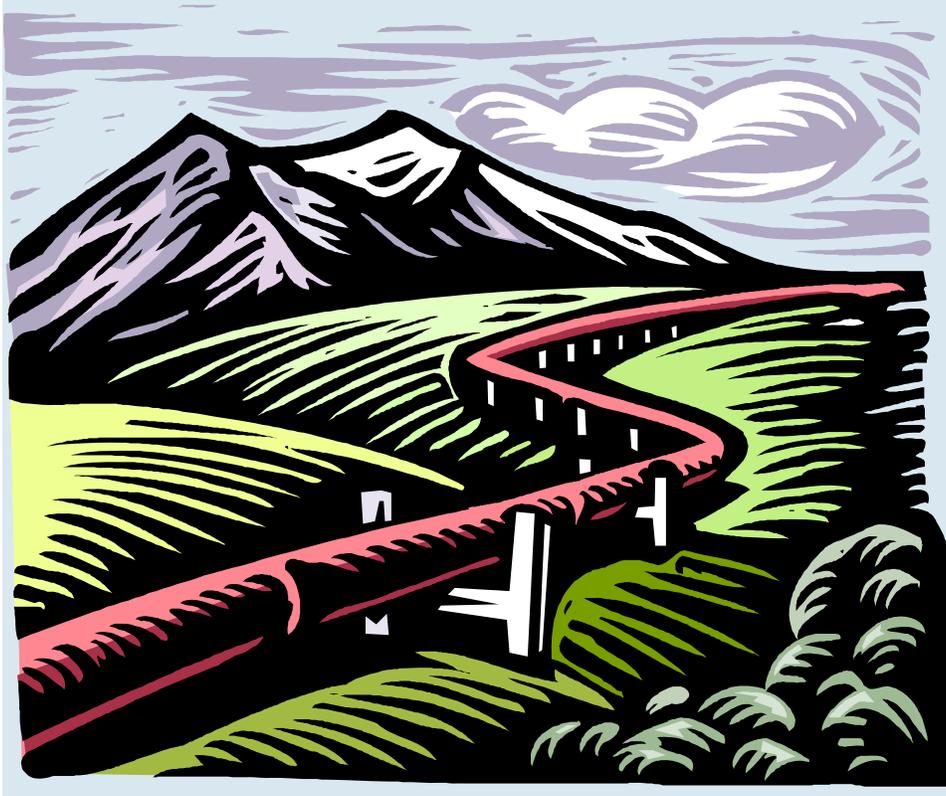
Table 1.14 Total GHG Emissions from Crude Recovery

	(g/mmBtu)	Formula	gCO₂e/mmBtu	gCO₂e/MJ
CO ₂	6,416	6416*1	6,416	6.08
CH ₄	20.33	20.33*23	467.60	0.44
N ₂ O	0.107	0.107*296	31.672	0.03
CO	28.829	28.829*0.43*(44/12)	45.303	0.04
VOC	4.916	4.916*0.85*(44/12)	15.324	0.01
Total GHG emissions			6,976	6.6

DRAFT – FOR REVIEW

(This page intentionally left blank.)

SECTION 2. CRUDE TRANSPORT



2.1 Energy Use for Crude Transport

Crude transportation energy use is based on the weighted mix for crude recovery (average CA crude) and the corresponding transport mode. The transport distances have been calculated to be 266 miles via pipeline and 3,550 miles via oil tanker. These values were utilized by TIAX in their AB 1007 work completed in 2007. Details of how the transport miles were calculated are provided in Table 2.01.

Table 2.01 Crude Oil Transport Details from AB 1007 Work

Crude Supply (2005)	Annual Consumption		Mix	Crude Pipeline		Crude Shipping	
				Destination	Distance	Destination	Distance
Alaska	140	million barrels	21%	Valdez	800	SF	1,700
Domestic	260	million barrels	38%	Refineries	50	--	0
Foreign	280	million barrels	41%	Ras Tanura	200	Long Beach	7,778
Annual Total	680	million barrels			266		3,553

The average pipeline and ocean tanker distances were calculated using the weighted consumption data in Table 2.01 and shown below:

- Pipeline Transport: $266 = (800 \cdot 21\%) + (50 \cdot 38\%) + (200 \cdot 41\%)$
- Ocean Tanker Transport: $3,553 = (1700 \cdot 21\%) + (0 \cdot 38\%) + (7778 \cdot 41\%)$

The two modes of transport are utilized to transport crude to California refineries. Details of how energy use is calculated for both types of modes of transport are detailed in Table 2.02 below with values used in the calculation provided in Table 2.03. Both modes utilize common factors such as lower heating values (LHV) and density of crude, and transport mode specific factors such as energy consumed per mile of transport to calculate energy use for specific distances transported.

DRAFT – FOR REVIEW

Table 2.02 Details of Energy Consumed for Crude Transport

	Detailed Calculations	Btu/mmBtu
Feed Loss	$(1.000062-1)*10^6$	62
Ocean Tanker	$(\text{Density of crude/LHV of crude})*(\text{Energy consumed})*(miles\ traveled)*(1/454)*(1/2000)*(1+0.169)*10^6$	5,845
Pipeline	$(\text{Density of crude/LHV of crude})*(\text{Energy consumed})*(miles\ traveled)*(1/454)*(1/2000)*(2.279)*10^6$	4,169
Total		10,076

Table 2.03 Values for Equations Used in Table 2.02

Description	Value	Source
Loss Factor in Crude T&D	1.000062	GREET Calculation
Miles traveled by Ocean Tanker (miles)	3,550	AB 1007 value
Pipeline transport (miles)	266	AB 1007 value
Density of crude (grams/gallon)	3,205	GREET default
Lower heating value (LHV) of crude (Btu/gallon)	129,670	GREET default
Energy consumed by Ocean Tanker (Btu/ton-mile)	51	GREET calculation based on tanker size
Energy consumed by Pipeline (Btu/ton-mile)	253	GREET default
Conversion from pound to grams	1/454	
Conversion from ton to pounds	1/2000	
WTT Energy Factor for Residual Oil	0.169	GREET calculation
WTT Energy Factor for Electricity including electricity	2.279	GREET calculation

DRAFT – FOR REVIEW

2.2 GHG Emissions for Crude Transportation

Table 2.04 details CO₂ emissions related to crude transport and distribution. The ocean tanker miles used in calculations is 3,550 and for pipeline it is 266 as detailed in the energy calculations section of Crude transport and distribution (section 2.1). Table 2.05 provides values for various terms used in Table 2.04.

Table 2.04 Crude Transport CO₂ Emissions

Mode	Formula	gCO₂/mmBtu	gCO₂/MJ
Ocean Tanker	(Density of crude/LHV of crude)*(miles traveled) *(1/454)*(1/2000)*((Energy intensity on trip from origin to destination*(emission factor for bunker fuel + emission factor for residual oil)) + (Energy intensity on return trip*(emission factor for bunker fuel + emission factor for residual oil))	483	0.46
Pipeline	(Density of crude/LHV of crude)*(Energy intensity of pipeline)*(miles traveled)*(1/454)*(1/2000)*(emission factor for electricity)	266	0.25
Total		749	0.71

Table 2.05 Values of Properties Used in Table 2.04

Parameters	Values	Sources
Miles traveled by Ocean Tanker (miles)	3,550	AB 1007 value
Pipeline transport (miles)	266	AB 1007 value
Density of crude (g/gallon)	3,205	REET default
Lower heating value (LHV) of crude (Btu/gallon)	129,670	REET default
Energy intensity of Ocean Tanker on trip to destination (Btu/ton-mile)	27	REET default
Energy intensity of Ocean Tanker on return trip (Btu/ton-mile)	24	REET default
Energy intensity of Pipeline (Btu/ton-mile)	253	REET default
Conversion from mmBtu to MJ	1/1055	
Emission factor for Bunker Fuel (Carbon in fuel)	84,515	REET default
WTT Emission factor for Residual Oil	12,097	REET default
Emission factor for Electricity	145,220	REET default

DRAFT – FOR REVIEW

Table 2.06 details CH₄ emissions for crude transport and distribution utilizing ocean tanker and pipeline transport modes. The emissions are GREET defaults. VOC and N₂O emissions are small for this group and not detailed but included in the total GHG emissions calculations for this part and shown in Table 2.07.

Table 2.06 Crude Transport CH₄ Emissions

	gCH₄/mmBtu
Ocean Tanker	
Residual oil, combustion	0.503
Pipeline	
Electricity	0.43
Non-combustion	69.54*
Total	70.5

*This is the amount of CH₄ in associated gases and is a GREET default.

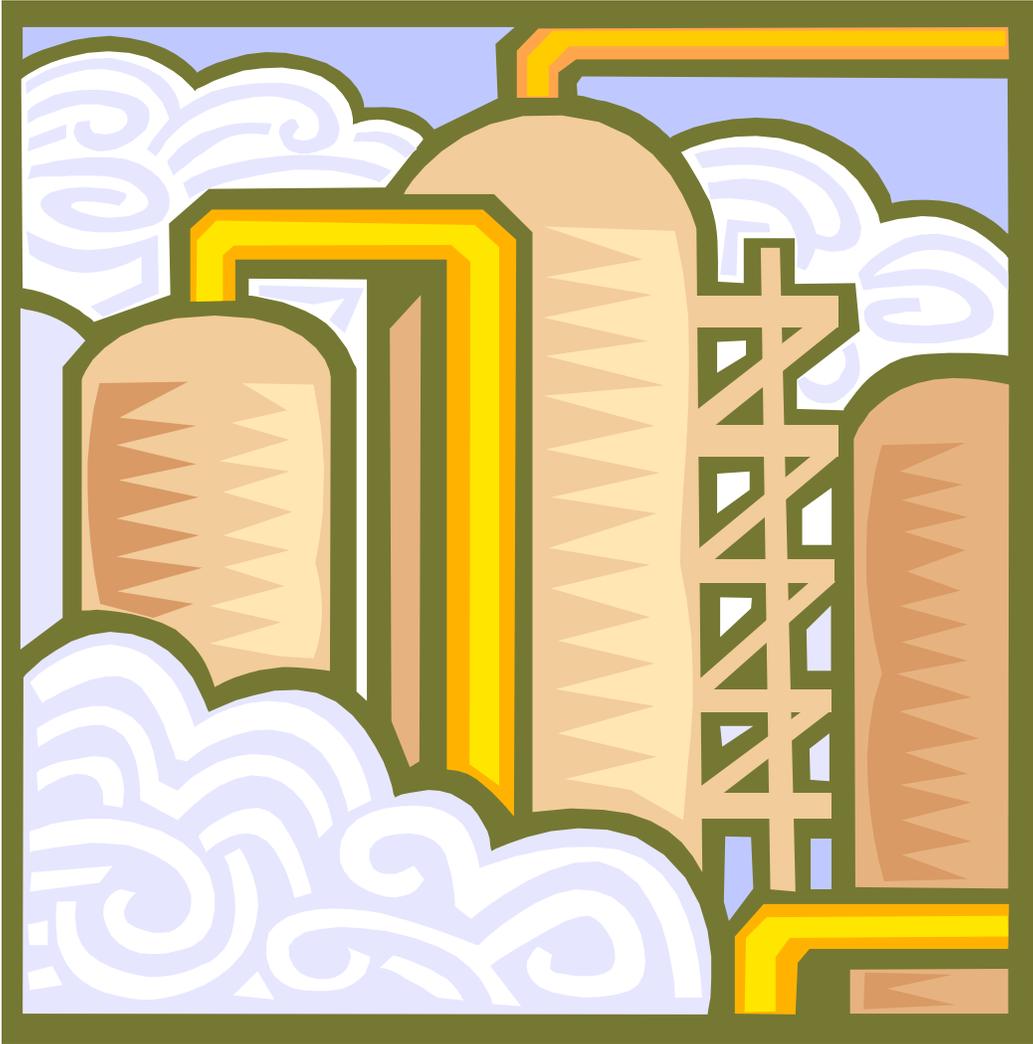
Table 2.07 Total GHG Emissions from Crude Transport and Distribution

GHG	(g/mmBtu)	Formula to convert to CO₂e	gCO₂e/mmBtu	gCO₂e/MJ
CO ₂	749	749*1	749	0.71
CH ₄	70.47	70.47*23	1,620	1.53
N ₂ O	0.015	0.015*296	4.44	0
CO	1.302	1.302*0.43*(44/12)	2.05	0
VOC	0.483	0.483*0.85*(44/12)	1.51	0
Total GHG emissions			2,377	2.2

DRAFT – FOR REVIEW

(This page intentionally left blank.)

SECTION 3. CRUDE REFINING



3.1 Energy Use for Crude Refining

Wang et al.⁴ analyzed refining efficiency on a process allocation basis and, based on this analysis, calculated energy efficiency for the various fuels produced from a crude refining facility. The refinery efficiency is based on a model refinery result combined with EIA data for petroleum production. The 84.5% refinery efficiency value used here is based on the AB 1007 report and is consistent with other well to wheel studies. This refinery efficiency takes into account additional energy used to depentanize gasoline and additional hydrogen required for sulfur removal. This value is used to calculate the energy inputs necessary for gasoline as detailed in Table 3.01.

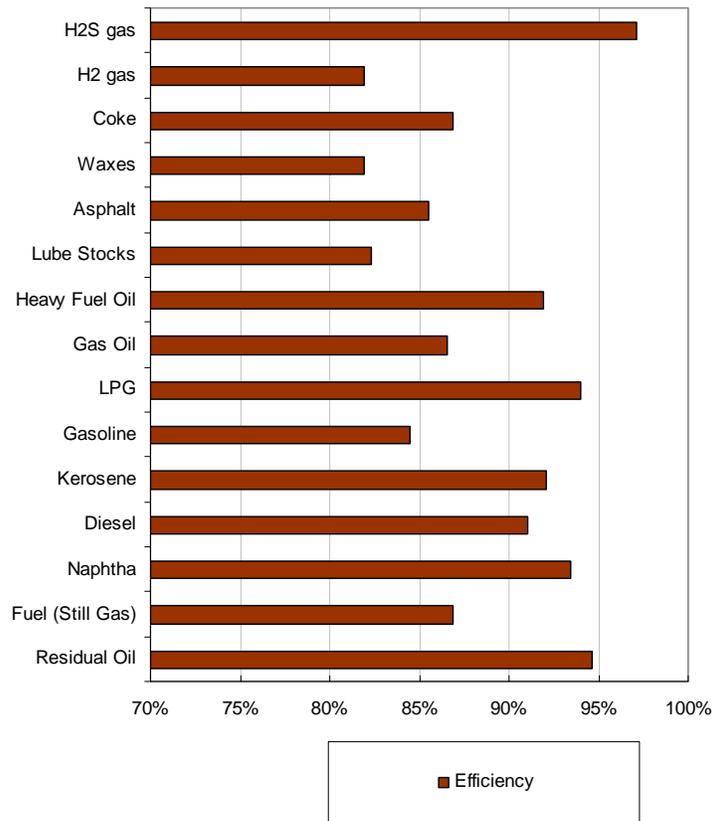


Figure 3. Efficiency of Various Fuel Products

⁴ Refinery Energy Efficiency Allocation Analysis based on: Wang, M., et al. (2004) Allocation of Energy Use in Petroleum Refineries to Petroleum Products Implications for Life-Cycle Energy Use and Emission Inventory of Petroleum Transportation Fuels. LCA Case Studies.

DRAFT – FOR REVIEW

Table 3.01 Details on How Efficiency is Used to Calculate Energy Needs for Crude Refining

Fuel Type	Fuel Shares	Relationship of Refinery Efficiency (0.845) and Fuel Shares	Btu/mmBtu Fuel
Residual Oil	6%	$(1,000,000)(1/0.845 - 1)(0.06)$	11,006
Natural Gas	40%	$(1,000,000)(1/0.845 - 1) (0.40)$	73,373
Electricity	4%	$(1,000,000)(1/0.845 - 1)(0.04)$	7,337
Refinery Still Gas	50%	$(1,000,000)(1/0.845 - 1)(0.50)$	91,716

The values in Table 3.01 are adjusted to account for upstream WTT energy use. Table 3.02 depicts the adjustments to the values from the table above for each fuel type accounting for loss factors associated with the WTT energy for each fuel used during crude refining operations. Table 3.03 details the values and descriptions for the formulas presented in Table 3.02.

Table 3.02 Adjustment to Crude Refining

Fuel Type	Formula	Btu/mmBtu
Residual Oil	$11,006*(1 + (A*B+C/10^6))$	12,868
Natural Gas	$73,373*(1 + D/ 10^6)$	78,783
Electricity	$7,337*((E+F)/ 10^6)$	16,725
Refinery still gas	$91,716*(1 + (A/ 10^6))$	100,244
Total energy for refining		208,621

Table 3.03 Details for Entries in Table 3.02

Quantity	Description
A = 92,986	Energy required to produce crude as feedstock for use in US refineries, a GREET calculated value. (Btu/mmBtu)
B = 1.000	Loss factor, a GREET default.
C = 76,209	Energy in Btu required to produce 1 million Btu of residual oil, a GREET calculated value.
D = 73,741	Energy required to produce natural gas as a stationary fuel, a GREET calculated value.
E = 106,137	Total energy required to produce feedstock for power generation, calculated in GREET electricity analysis.
F = 2,173,356	Energy required in Btu to produce one million Btu of electricity which is calculated in GREET electricity analysis.

3.2 GHG Emissions from Crude Refining

The transformation of energy from the various fuels above to useful energy required in the processing of crude to CARBOB generates equipment specific GHG emissions. GHG emissions include CO₂ as well as non-CO₂ GHG gases. This document first presents the CO₂ emissions, followed by non-CO₂ emissions, which are then converted to CO₂ equivalents and summarized at the end of this section (3.2).

Table 3.04 lists CO₂ emissions by fuel type generated during the refining of crude to CARBOB. Tables 3.05 and 3.06 provide details of CO₂ emissions related to use of residual oil in refineries for processing crude to CARBOB.

Table 3.04 CO₂ Emissions by Fuel Type

Fuel Type	(gCO₂/mmBtu)	(gCO₂e/MJ)
Residual oil	1,069	1.01
Natural gas	4,662	4.42
Electricity	1,067	1.01
Refinery Still Gas	5,337	5.06
Total	12,174	11.5

Table 3.05 CO₂ Emissions from Residual Oil Use in Refineries from Table 3.04

Calculation Details	gCO₂/mmBtu	Reference
11,006*(emissions factor for an industrial residual oil boiler*Percentage of residual oil used in industrial residual oil boiler + emissions from residual oil + emissions from crude oil)/10 ⁶	1,069	REET default

Table 3.06 Values for Use in Table 3.05

Factor	Value	Reference
Emissions factor for an industrial residual oil boiler	85,045 gCO ₂ /mmBtu	REET default
Percentage of residual oil used in industrial residual oil boiler	100%	REET default
Emissions from residual oil	5,137 gCO ₂ /mmBtu	REET default
Emissions from crude oil	6,960 gCO ₂ /mmBtu	REET default

DRAFT – FOR REVIEW

Tables 3.07 and 3.08 provide details on CO₂ emissions from natural gas use in crude refining to CARBOB.

Table 3.07 CO₂ Emissions from Natural Gas from Table 3.04

Calculation details	gCO₂/mmBtu	Reference
73,373*(share from NG engine*emission factor for NG engine)+(share from large turbine*emission factor for large turbine +(share from large industrial boiler*emission factor for large industrial boiler) + (share from small industrial boiler *emission factor for small industrial boiler) + Emissions from natural gas as a stationary fuel/10 ⁶	4,662	GREET default

Table 3.08 Details of Values Used in Table 3.07

	Shares	Emissions factor (gCO₂/mmBtu)	Reference
Share from natural gas engine	0%	56,551	GREET default
Share from large turbine	25%	58,179	GREET default
Share from large industrial boiler	60%	58,198	GREET default
Share from small industrial boiler	15%	58,176	GREET default
Emissions from natural gas as a stationary fuel		5,349	GREET default

Electricity contributions to GHG emissions are provided in Tables 3.09 to 3.15, both for feedstock production and feedstock consumption.

Table 3.09 CO₂ Emissions from Electricity from Table 3.04

	Details Calculation	gCO₂/mmBtu
Electricity as feedstock	7337*7737/10 ⁶	57
Electricity as fuels	Contributed from Residual Oil= 2 Contributed from Natural Gas = 515 Contributed from Coal = 495	1,011
Total		1,067

Note: 7,337 Btu/mmBtu is energy of electricity used in CARBOB refining (see table 3.01)

DRAFT – FOR REVIEW

To calculate CO₂ emissions above:

- CO₂ emission from power plant + VOC and CO emissions conversion from power plant, where:
- CO₂ from power plant = 7337*(Specific Power Plant Emission Factor)* % of generation mix/(1 - % assumed loss in transmission)/10⁶, then convert from g/kWh to gCO₂e/mmBtu by multiplying g/kWhr by (10⁶/3412).
- VOC and CO conversion are from GREET defaults.

Table 3.10 Type of Power Generation Plant and Associated Emission Factors Used in Table 3.09

Power Plant Type	Generation Mix	CO₂ Emission Factor (g/kWhr)	Loss in transmission	Convert to CO₂e (g/mmBtu)
Oil-fired	0.05%	834	8.1%	2
Nat. Gas-fired	43.1%	510	8.1%	515
Coal-fired	15.4%	1,374	8.1%	495

Table 3.11 provides a breakdown of CO₂ emissions from electricity generation into feedstock production and feedstock consumption (as fuels). Production refers to mining or other methods to actually procure the feedstock necessary for use in electricity generation. Feedstock production accounts for about 5.3% of the total emissions and feedstock consumption to generate electricity accounts for the balance of 94.7%.

Table 3.11 CO₂ Emissions from Electricity

	gCO₂/mmBtu	% share
Feedstock Production	7,737	5.3%
Feedstock Consumption	137,734	94.7%
Total	145,471	

CARBOB refining also results in CO₂ emissions from vented sources (non-combustion), as shown in Table 3.12.

Table 3.12 CO₂ Emissions from Non-Combustion Sources

	gCO₂/mmBtu	gCO₂e/MJ
Non-combustion	1,298	1.23

This is calculated from assumed CO₂ vented from bulk terminals (1,172 g/mmBtu) and ratio efficiencies of conventional gasoline refining (86%) on CARBOB refining (84.5%): 1172*(1-86%)/(1-84.5%). Table 3.13 and 3.14 provide details of CO₂ emissions related to feedstock electricity production.

DRAFT – FOR REVIEW

Table 3.13 CO₂ Emissions from Electricity (feedstock production)

Fuel Share	Relationship of Energy Use and CO₂ Emissions	Energy Use Emissions gCO₂/mmBtu
Residual oil	1,563*(crude emission factor*crude loss factor + residual oil emission factor)/10 ⁶	19
Natural gas	1,204,871*(natural gas emission factor)/ 10 ⁶	6,445
Coal	490,460*(coal emission factor)/ 10 ⁶	635
Biomass	37,288*(biomass emission factor)/emissions of farmed trees)	90
Nuclear	161,262*(uranium emission factor)/(conversion factor for nuclear power plants*1000*3412)	482
Other*	VOC emissions*Carbon ration of VOC/Carbon ratio of CO ₂ + CO emissions*Carbon ration of CO/Carbon ratio of CO ₂	67
Total		7,737

*"Other" is a combination of hydro, wind, geothermal, etc.

The numerical values (1,563; 1,204,871; 490,460; 37,288; and 161,262) used in the table above are the energies from those feedstocks used at power plants to generate one mmBtu of electricity at the use site (see detailed calculations in Table 3.15).

Table 3.14 Factors and Values for Use in Table 3.13

Description	GREET default value
Crude emission factor	6,963 gCO ₂ /mmBtu
Crude loss factor	1.000
Residual oil emission factor	5,141 gCO ₂ /mmBtu
Natural gas emission factor	5,349 gCO ₂ /mmBtu
Coal emission factor	1,295 gCO ₂ /mmBtu
Biomass emission factor (sum of factors for farmed trees, fertilizer and pesticides)	40,367 gCO ₂ /mmBtu
Emission of farmed trees	16,811,000 gCO ₂ /mmBtu
Uranium emission factor	70,591 gCO ₂ /mmBtu
Conversion factor for uranium plants	6.926 gCO ₂ /mmBtu
Carbon Ratio of VOC	0.85
Carbon Ratio of CO	0.43
Carbon Ratio of CO ₂ (12/44)	0.27

DRAFT – FOR REVIEW

Table 3.15 shows the relationship between the energies used from feedstocks at a power plant (to produce one mmBtu of electricity to the use site) and the conversion efficiencies of electrical generation for each feedstock used, after taking into account the loss (8.1%) from the transmission of electricity.

Table 3.15 Energy Breakdown from Electricity (Feedstock Consumption)

Fuel Shares	Conversion Efficiency	Generation Mix	Relationship of Conversion Efficiency and Energy Use	Energy Use (Btu/mmBtu)
Residual oil	34.8%	0.05%	$(10^6/0.348)*(1/1-0.081)*0.0005$	1,563
Natural gas	38.9%	43.1%	$(10^6/0.389)*(1/1-0.081)*0.431$	1,204,871
Coal	34.1%	15.4%	$(10^6/0.341)*(1/1-0.081)*0.154$	490,460
Biomass	32.1%	1.1%	$(10^6/0.321)*(1/1-0.081)*0.011$	37,288
Nuclear	100%	14.8%	$(10^6/1.00)*(1/1-0.081)*0.148$	161,262
Other*	100%	25.5%	$(10^6/1.00)*(1/1-0.081)*0.255$	277,911
Total				2,173,355

* "Other" is a combination of hydro, wind, geothermal, etc.

Tables 3.16 and 3.17 detail CO₂ emissions from use of refinery still gas in crude refining operations.

Table 3.16 CO₂ Emissions from Use of Refinery Still Gas

Calculation	(gCO₂/mmBtu)	Reference
Emissions from refinery still gas as a stationary fuel* (share from engine*natural gas engine emission factor) + (share from large turbine*emission factor for large natural gas turbine) + (share from large industrial boiler*emission factor for large industrial boiler) + (share from small industrial boiler *emission factor for small industrial boiler) + (Emissions from natural gas as a stationary fuel)/10 ⁶	5,337	GREET default calculation

DRAFT – FOR REVIEW

Table 3.17 Values Used in Table 3.16

Description	Shares	EF (gCO₂/mmBtu)	Reference
Natural Gas, engine	0	56,551	GREET default
Natural Gas, large turbine	25%	58,179	GREET default
Natural Gas, large Industrial boiler	60%	58,198	GREET default
Natural Gas, small Industrial boiler	15%	58,176	GREET default
Emissions from natural gas as a stationary fuel		5,349	GREET default
Emissions from refinery still gas as a stationary fuel		91,716	GREET default

CH₄ emissions and N₂O emissions from crude refining are shown in Tables 3.18 and 3.19. VOC and CO contributions are small and not further detailed here. They are however included in Table 3.20 below.

Table 3.18 CH₄ Emissions

Fuel	gCH₄/mmBtu
Residual oil	1.09
Natural gas	10.35
Electricity	1.71
Refinery Still Gas	0
Total	13.15

Table 3.19 N₂O Emissions

Fuel	gN₂O/mmBtu
Residual oil	0.01
Natural gas	0.05
Electricity	0.02
Refinery Still Gas	0.06
Total	0.14

Table 3.20 summarizes the total GHG emissions from crude refining. Note that non-CO₂ gases have been converted to CO₂ equivalents using conversion factors detailed earlier in this document.

DRAFT – FOR REVIEW

Table 3.20 GHG Emissions from Crude Refining

GHG	(g/mmBtu)	Conversion to CO₂e	g CO₂e/mmBtu	g CO₂e/MJ
CO ₂	12,136	12136 *1	12,136	11.50
CH ₄ (combustion)	13.15	13.15*23	302.45	0.29
CH ₄ (non-combustion)		1298	1,298	1.23
N ₂ O	0.14	0.14*296	41.44	0.04
CO	5.477	5.477*0.43 *(44/12)	8.61	0.01
VOC	0.963	0.963*0.85*(44/12)	3.00	0.00
Total			13,789	13.1

Note: Non-combustion methane in the crude refining step includes venting and fugitive emissions

SECTION 4. CARBOB TRANSPORT AND DISTRIBUTION



4.1 Energy Use for Transport and Distribution of CARBOB

Table 4.01 shows the energy inputs used in transporting CARBOB to trucking terminals. The energy intensity of 253 Btu/ton-mi is a default GREET value based on a composite of natural gas compressor prime movers. The 50 mile distance is based on an average for California pipeline delivery and is documented in the AB 1007 report. The fuel shares input assumption is 100% electric motors based on the AB 1007 analysis of petroleum infrastructure in California. The energy intensity is multiplied by an adjustment factor for each type of pipeline motor. In this case, the electric motor adjustment factor is 100% (the GREET default value). The total energy is then calculated, including the WTT energy to produce electricity.

Table 4.02 shows the energy inputs for truck transport. The calculation is based on a tanker truck capacity of 9,000 gallons (25 metric tons) and a transport distance of 50 miles. The 50 mile distance is based on a survey of California fuel delivery trucks and is documented in the AB 1007 report. GREET calculates the diesel energy per ton-mile based on the cargo capacity of the truck and its fuel economy.

Table 4.03 shows the total energy calculations used in GREET. Here the pipeline and truck values are weighted by the fraction of fuel delivered by each mode. 80% of the gasoline is assumed to be piped to a blending terminal because some refineries fill trucks at the loading rack adjacent to the refinery. 99.4% of the gasoline is assumed to be transported to fueling stations by delivery trucks. The remaining 0.6% corresponds to the few fueling stations where gasoline is provided directly by pipeline. Table 4.04 details the values used in the formulas presented in Table 4.03. The total transport energy for CARBOB shown in Table 4.03 includes energy associated with feed loss, which is calculated based on the VOC emissions (g/mmBtu) from the bulk terminal and refinery stations (see note below Table 4.03).

Table 4.01 Energy Use for Transport and Distribution via Pipeline

	Energy Intensity (Btu/ton-mile)	Distance from Origin to Destination (miles)	Type of Power Generation	Shares of the type of turbine used	Distributed by pipeline
Pipeline	253	50	Electric Motor	100 %	80%*

*Assumed 20% transported directly from refinery terminal rack

DRAFT – FOR REVIEW

Table 4.02 Energy Use for Transportation and Distribution CARBOB via HDD Truck

	Energy Intensity (Btu/ton-mile)	Distance from Origin to Destination (miles)	Capacity (tons)	Fuel Consumption (miles/gal)	Energy Consumed of HDD truck (Btu/ mile)	Diesel share	Distributed by truck
HDD Truck	1,028	50	25	5	25,690	100%	99.4%*

* Assumed 0.6% CARBOB is transported directly by pipeline to about 50 stations

Table 4.03 Details of Energy Uses for CARBOB Transportation and Distribution

Transport mode	Details Calculations	Btu/mmBtu
Feed Loss	$(\text{Loss Factor} - 1) * 10^6$	201
CARBOB transported by pipeline	$(\text{Density of CARBOB/LHV of CARBOB}) * (1/454) * (1/2000) * (\text{energy consumed by pipeline}) * (\text{miles transported one-way}) * 100\% * 100\% * (2.279) * 80\% * 10^6$	631
CARBOB Distribution by HDD truck	$(\text{Density of CARBOB/LHV of CARBOB}) * (1/454) * (1/2000) * (\text{energy consumed by HDD truck}) * (\text{miles transported one-way} + \text{miles transported one-way backhaul}) * 100\% * (1 + 0.241) * 99.4\% * 10^6$	3,476
Total		4,309

Note: Loss factor = $[(\text{VOC from bulk terminal} + \text{VOC from refinery stations}) / (\text{CARBOB Density}) * (\text{CARBOB LHV} / 10^6)] + 1$

DRAFT – FOR REVIEW

Table 4.04 Values of Properties Used in Table 4.03

Properties	Values	Source
Feed loss (Btu/mmBtu)	201	GREET calculation
Lower heating value of CARBOB (Btu/gallon)	113,300	AB 1007 value
Density of CARBOB (grams/gallon)	2,819	GREET default
Energy consumed by Pipeline (Btu/ton-mile)	253	GREET default
Conversion from pounds to grams	454	
Conversion from tons to pounds	2,000	
Energy intensity of CARBOB transported by HDD truck (Btu/ton-mile)	1,028	AB 1007 value
CARBOB transport one-way (mile)	50	AB 1007 value
Energy consumed in electricity used as transportation fuel in CARBOB Production (Btu/Btu)	2.279	GREET calculation
Energy consumed in diesel used as transportation fuel in CARBOB Production (Btu/Btu)	0.241	GREET calculation
VOC from bulk terminal (g/mmBtu)	1.5	GREET Default
VOC from refinery stations (g/mmBtu)	3.42	GREET Default

Note:

- 2.279 is the WTT energy for electricity calculated in GREET = (energy consumed to produce feedstock + Energy consumed to produce electricity)/106 = (2,173,356+105,317)/10⁶
- 0.241 is the diesel adjustment factor = energy of crude oil transported to the US refineries*loss factor of diesel + WTT energy of conventional diesel.

4.2 GHG Emissions from Transportation and Distribution of CARBOB

Table 4.05 details only CO₂ emissions for the transport and distribution of finished CARBOB.

Table 4.05 CO₂ from CARBOB Transportation and Distribution

	Miles traveled 1-way	Energy Intensity (Btu/mile-ton)	Assumed % usage	gCO ₂ e/mmBtu	gCO ₂ e/MJ
Transported by Pipeline	50	253	80%	40	0.04
Distributed by HDD Truck	50	1028	99.4%	264	0.25
Total				302	0.30

Note:

- For pipeline: assumed shares of power generation are divided as following: turbine 55%, current NG engine 33%, and 12% future NG engine (GREET defaults)
- For HDD Truck: assumed energy consumption at 25,690 Btu/mile, average speed 5 mph, and 25 tons capacity load of CARBOB for delivery to a blending station after taking consideration of 80% and 99.4% shares of pipeline

Table 4.06 provides details for all GHG emissions for CARBOB transport and distribution. This includes CH₄, N₂O, VOC combined with CO₂.

Table 4.06 Details of GHG from CARBOB Transportation and Distribution

	g/mmBtu		g/MJ		Total (gCO ₂ e/MJ)
	Transp.	Distr.	Transp.	Distr.	
CO ₂	40	264	0.038	0.25	0.288
CH ₄ (converted to CO ₂ e)	1.47	6.55	<0.01	<0.01	<0.01
N ₂ O (converted to CO ₂ e)	0.296	1.776	<0.01	<0.01	<0.01
CO (converted to CO ₂)	0.043	0.88	<0.01	<0.01	<0.01
VOC (converted to CO ₂)	0.012	0.25	<0.01	<0.01	<0.01
Total GWI	41.8	271.5	0.04	0.26	0.30

DRAFT – FOR REVIEW

(This page intentionally left blank.)

SECTION 5. CARBON EMISSIONS FROM CARBOB COMBUSTION



5.1 Combustion Emissions from Fuel

GHG emissions from the fuel occur during vehicle operation. The engine burns fuel which primarily forms CO₂. A small fraction of the fuel is emitted as CO, hydrocarbons, methane, or particulate matter. GREET assumes CO and VOC emissions are converted to CO₂ in the atmosphere within a few days and details of this calculation have been provided earlier. However, for the CARBOB pathway, it is not legal in California to be dispensed as a fuel. Hence only CO₂ emissions from carbon in fuel calculations are provided for this pathway. GREET uses the carbon content in the fuel to calculate GHG emissions. The carbon in fuel is calculated from the carbon content in the fuel and fuel density. Table 5.01 provides input values and sources of these values used in calculating carbon emissions from fuel. The average carbon ratio in CARBOB is 85.9% (by weight) which translates to about 76,291 gCO₂ per mmBtu of fuel (72.91 gCO₂/MJ).

Table 5.01 Inputs and Assumptions used for Calculating Combustion GHG Emissions

Description	Value	Reference
Lower Heating Value of CARBOB	113, 300 Btu/gal	AB 1007 value
Density of CARBOB	2,767 g/gal	AB 1007 value
Molecular weight of CO ₂	44 g/mole	
Atomic weight of C	12 g/mole	
C factor	12/44 = 0.27	
Carbon ratio in CARBOB	85.9 % (by weight)	GREET default
MJ to MMBtu conversion	1,055	
Fossil carbon in gasoline: $2,767 * 85.9\% * 44 / 12 / 113,300 * 10^6 = 76,219 \text{ g CO}_2 / \text{MMBtu} = 72.91 \text{ gCO}_2 / \text{MJ}$		
CO ₂ from fuel = Density * carbon ratio in gasoline / (C factor * LHV)		

DRAFT – FOR REVIEW

APPENDIX B

CARBOB PATHWAY INPUT VALUES

DRAFT – FOR REVIEW

Average Crude Oil to California Refineries to Make CARBOB

Parameters	Units	Values	Note
GHG Equivalent			
CO ₂		1	
CH ₄		23	
N ₂ O		296	
VOC		3.1	
CO		1.6	
Crude Recovery			
Efficiency		93.9%	Crude Recovery for 2010 - user input
Process Shares			
<i>Crude</i>		1%	
<i>Residual Oil</i>		1%	
<i>Conventional Diesel</i>		15%	
<i>Conventional Gasoline</i>		2%	
<i>Natural Gas</i>		61.9%	
<i>Electricity</i>		19%	
<i>Feed Loss crude recovery</i>		0.04%	
Equipment Shares			
Commercial Boiler - Diesel		25%	
<i>CO₂ Emission Factor</i>	gCO ₂ /mmBtu	78,167	
Stationary Reciprocating Eng. - Diesel		50%	
<i>CO₂ Emission Factor</i>	gCO ₂ /mmBtu	77,349	
Turbine - Diesel		25%	
<i>CO₂ Emission Factor</i>	gCO ₂ /mmBtu	78,179	
Stationary Reciprocating Eng. - NG		50%	
<i>CO₂ Emission Factor</i>	gCO ₂ /mmBtu	56,551	
Small Industrial Boiler - NG		50%	
<i>CO₂ Emission Factor</i>	gCO ₂ /mmBtu	58,176	
Transportation to CA refineries			
<i>Pipeline shares</i>		42%	by pipeline to CA
<i>Pipeline distance</i>	miles	150	One way
<i>Pipeline Energy Intensity</i>	Btu/mile-ton	253	
<i>Ocean Tanker shares</i>		58%	from Alaska
<i>Average distance traveled</i>	miles	3,300	Energy Intensity 27Btu/mile-ton, 24 for return trip
Transportation to US refineries			
<i>Pipeline distance</i>	miles	266	One way from 48 states, import
<i>Pipeline Energy Intensity</i>	Btu/mile-ton	253	
<i>Ocean Tanker distance traveled</i>	miles	2,100	One way from Alaska
<i>Ocean Tanker Energy Intensity</i>	Btu/mile-ton	27	24 Btu/mile-ton for return trip
Loss Factor in Crude T&D		1.000062	
CARBOB Refining			
Efficiency		84.5%	CARBOB Refining for year 2010 - user input
Process Shares			
<i>Residual Oil</i>		6%	
<i>Natural Gas</i>		40%	
<i>Electricity</i>		4%	
<i>Still Gas</i>		50%	
Equipment shares			
Large Turbine - Natural Gas		25%	
<i>CO₂ Emission Factor</i>	gCO ₂ /mmBtu	58,179	

DRAFT – FOR REVIEW

Parameters	Units	Values	Note
Large Industrial Boiler - Natural Gas		60%	
Parameters	Units	Values	Note
<i>CO₂ Emission Factor</i>	gCO ₂ /mmBtu	58,198	
Small Industrial Boiler - Natural Gas		15%	
<i>CO₂ Emission Factor</i>	gCO ₂ /mmBtu	58,176	
Industrial Boiler - Residual Oil		100%	
<i>CO₂ Emission Factor</i>	gCO ₂ /mmBtu	85,045	
Transportation			
Transportation by pipeline		80%	20% directly from refinery terminal rack
<i>Distance</i>	miles	50	
<i>Energy Intensity</i>	Btu/ton-mile	253	
Distribution by truck		99.4%	0.6% directly supplied by pipeline
<i>Distance</i>	miles	50	
<i>Energy Intensity</i>	Btu/ton-mile	1,028	
<i>Loss Factor in CARBOB T&D</i>		1.000201	
Fuel Properties	LHV (Btu/gal)	Density (g/gal)	
<i>Crude</i>	129,670	3,205	
<i>Residual Oil</i>	140,353	3,752	
<i>Conventional Diesel</i>	128,450	3,167	
<i>Conventional Gasoline</i>	116,090	2,819	
<i>CaRFG</i>	111,289	2,828	
<i>CARBOB</i>	113,300	2,767	
<i>Natural Gas</i>	83,686	2,651	NG Liquids
<i>Ethanol</i>	76,330	2,988	
<i>Still Gas</i>	128,590		
Transportation Modes			
<i>Ocean Tanker</i>	tons	250,000	Crude Oil
	tons	150,000	Gasoline
<i>Heavy Duty Truck</i>	tons	25	Crude Oil
	tons	25	Gasoline