NATIONAL ENERGY TECHNOLOGY LABORATORY

Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels

November 26, 2008

DOE/NETL-2009/1346

Disclaimer

Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels

DOE/NETL-2009/1346

November 26, 2008

NETL Contacts:

Timothy J. Skone, P.E.
Kristin Gerdes
Office of Systems, Analyses and Planning

National Energy Technology Laboratory
www.netl.doe.gov

This page intentionally left blank.

Acknowledgements

This work was funded by the U.S. Department of Energy's National Energy Technology Laboratory (U.S. DOE-NETL). The NETL sponsor for this project was Dan Cicero, Office of Coal and Power R&D, Technology Manager for Hydrogen and Syngas Program. The NETL management team provided guidance and technical oversight for this study.

Contract support was provided by Massood Ramezan and Barbara Bennett, Research and Development Solutions, LLC (RDS) under contract number DE-AC26-04NT 41817.403.01.12A.

NETL would like to acknowledge and thank the contributions of Bill Harrison, U.S. Air Force Research Laboratory; Dr. James Hileman, Massachusetts Institute of Technology; and Dr. Joyce Cooper, University of Washington for their review comments that helped improve the quality of this report. NETL would also like to thank Aaron Levy and Ari Kahan from the U.S. Environmental Protection Agency, Office of Transportation and Air Quality for developing the national average vehicle emissions profile for the year 2005.

Table of Contents

Appendix F: Overview of Allocation Procedures for Petroleum Refining Operations

Appendix G: Cradle-to-Gate GHG Emissions Inventory for Hydrogen Production Via SMR with PSA Purification

Appendix H: Crude Oil and Finished Product Loss Factors

Appendix I: Conversion Factors

Appendix J: Emissions Factors for Various Vehicle Types

Appendix K: LTO Emission Factors and Emissions for Various Aircraft

Appendix L: Study GHG Results Presented in Alternate Units

Attachment 1: Documentation Associated with Profiles Extracted from GaBi 4

List of Tables

List of Figures

Acronyms and Abbreviations

AEO	Annual Energy Outlook (Energy Information Agency)
AGR	Acid Gas Removal
ANL	Argonne National Laboratory
API	American Petroleum Institute
ASU	Air Separation Unit
BA AQMD	Bay Area Air Quality Management District
bbl	Barrel
BEA	Bureau of Economic Analysis
BP	British Petroleum
Btu	British Thermal Unit
bpcd	Barrels per Calendar Day
bpd	Barrels per Day
bpsd	Barrels per Stream Day
CARB	California Air Resources Board
CBM	Coal Bed Methane
CCS	Carbon Capture and Storage
cd	Calendar Day
cf	Cubic feet
CH_4	Methane
CIDI	Compression-Ignition, Direct-Injection
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2E	Carbon Dioxide Equivalent
COE	Cost of Electricity
DF	Diesel Fuel
DOE	Department of Energy
DOT	Department of Transportation
DWT	Dead Weight Ton
EE	Energy Efficiency
EERE	Energy Efficiency and Renewable Energy
EIA	Energy Information Administration

ELCD	European Reference Life Cycle Data
EOR	Enhanced Oil Recovery
EOS	Equation of State
EPA	Environmental Protection Agency
ETE	Effective Thermal Efficiency
EU	European Union
EUCAR	European Council for Automotive R&D
EX	Existing Refinery
FAA	Federal Aviation Administration
FE	Fossil Energy
FEHQ	Fossil Energy Headquarters
FERC	Federal Energy Regulatory Commission
FTE	Full Time Equivalent
G&A	General and Administrative
GHG	Greenhouse Gas
GPM	Gallons per Minute
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
GWP	Global Warming Potential
H_2	Hydrogen
HDSAM	Hydrogen Delivery Scenario Analysis Model
HFO	Heavy Fuel Oil
HHV	Higher Heating Value
hphr	Heat Pump Heat Recovery
HRSG	Heat Recovery Steam Generator
IC	Internal Combustion
IGCC	Integrated Gasification Combined Cycle
IISI	International Iron and Steel Institute
IPCC	Intergovernmental Panel on Climate Change
IPIECA	International Petroleum Industry Environmental Conservation Association
ISO	International Organization for Standardization
kg	Kilogram
kt	Knot

kW	Kilowatt
kWh	Kilowatt-hour
lb	Pound
LC	Life Cycle
LCA	Life Cycle Analysis
LCC	Life Cycle Cost
LCI	Life Cycle Inventory
LCIA	Life Cycle Impact Assessment
LHV	Lower Heating Value
LPG	Liquefied Petroleum Gas
LS	Low Sulfur
LTO	Landing and Takeoff
Mbbl	Thousand Barrels
MJ	Megajoule
MMBtu	Million Btu
MMscf	Million Standard Cubic Feet
Mcf	Thousand cubic feet
MPa	Megapascal
mpg	Miles Per Gallon
MTBE	Methyl Tertiary-Butyl Ether
MTPA	Million Tonnes Per Annum
MWh	Megawatt-hour
N_2O	Nitrous Oxide
NAICS	North American Industry Classification System
NEB	National Energy Board
NEI	National Emissions Inventory
NETL	National Energy Technology Laboratory
NG	Natural Gas
NGL	Natural Gas Liquids
NIST	National Institute of Standards and Technology
NOx	Nitrogen Oxides
NPRA	National Petroleum Refiners Association

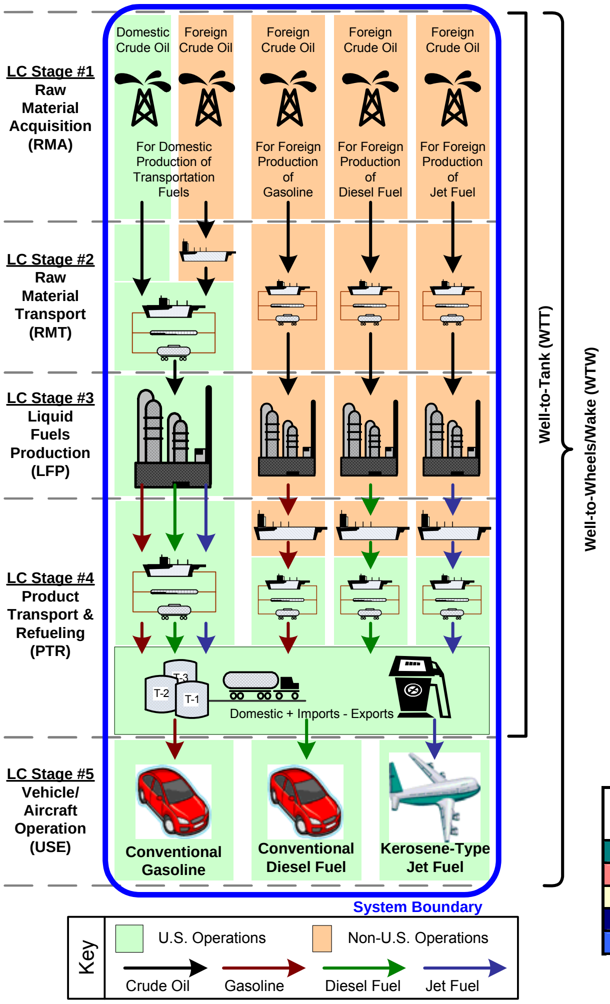
NRC	National Research Council
NREL	National Renewable Energy Laboratory
O&GJ	Oil and Gas Journal
O&M	Operating and Maintenance
ORNL	Oak Ridge National Laboratory
OSAP	Office of Systems and Planning
PADD	Petroleum Administration for Defense District
PM	Particulate Matter
ppm	Parts Per Million
PSA	Pressure Swing Adsorption
psi	Pounds per Square Inch
PV	Present Value
RCRA	Resource Conservation and Recovery Act
ROG	Reactive Organic Gas
SCAQMD	South Coast Air Quality Management District
scf	Standard Cubic Feet
scfb	Standard Cubic Feet per Barrel
scfd	Standard Cubic Feet per Day
SCR	Selective Catalytic Reduction
SMR	Steam Methane Reforming
SOA	State of the Art
SOx	Sulfur Oxides
TOG	Total Organic Gas
TPD	Tons Per Day
TRI	Toxic Release Inventory
ULSD	Ultra Low Sulfur Diesel
U.S.	United States
VOC	Volatile Organic Compound
WTT	Well-to-Tank
WTW	Well-toWheels/Wake

This page intentionally left blank.

Executive Summary

Alternative transportation fuel options are currently being explored or implemented across the nation to (1) reduce climate change impacts from the release of greenhouse gases (GHGs), (2) reduce our reliance on foreign sources of energy, and (3) provide an economically-stable transportation fuel source to reduce price shocks to our economy. The U.S. Department of Energy (DOE), National Energy Technology Laboratory (NETL) is currently evaluating options to produce transportation fuels from coal, coal and biomass, and unconventional fossil energy resources. This study develops a comprehensive and transparent baseline for the life cycle GHG emissions from conventional petroleum-based transportation fuels sold or distributed in the United States in the year 2005. The scope of this study is depicted in Figure ES-1. The results of this study are necessary to benchmark the performance of alternative transportation fuels with respect to climate change impacts. The study goals and scope were aligned to meet the definition of "baseline lifecycle greenhouse gas emissions" as defined in the Energy Independence and Security Act of 2007 (EISA 2007), Title II, Subtitle A, Sec. 201.

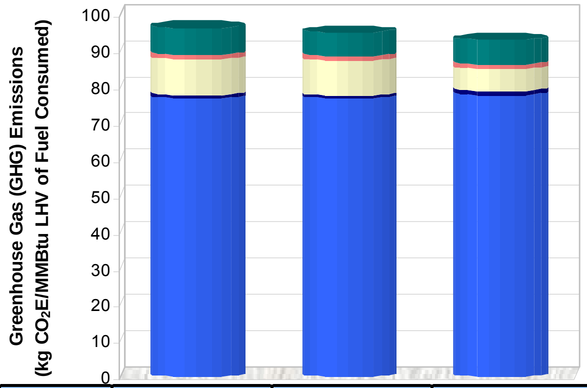
Figure ES-1. Life Cycle of Petroleum-Based Transportation Fuels



Summary Results

Figure ES-2 summarizes the study results for the U.S. average "baseline" life cycle GHG emissions of conventional gasoline, conventional diesel fuel (≤500 parts per million (ppm) sulfur), and kerosene-based jet fuel. The results are reported in terms of carbon dioxide equivalents (CO_2E) per million British Thermal

Figure ES-2. Baseline Life Cycle Greenhouse Gas Emissions for Petroleum Transportation Fuels Sold or Distributed in the U.S. in Year 2005 (kg CO_2E/MMBtu LHV of Fuel Consumed)



Key	Life Cycle Stage	Conventional Gasoline		Conventional Diesel		Kerosene-Based Jet Fuel	
■	#1: RMA	7.3	8%	6.6	7%	6.8	7%
■	#2: RMT	1.4	1%	1.3	1%	1.3	1%
■	#3: LFP	9.8	10%	9.5	10%	6.0	6%
■	#4: PTR	1.1	1%	0.9	1%	1.0	1%
■	#5: Use	76.6	80%	76.7	81%	77.7	84%
	Total:WTT	19.6	20%	18.4	19%	15.1	16%
	Total:WTW	96.3	100%	95.0	100%	92.9	100%

Units (MMBtu), lower heating value (LHV), of fuel consumed. The total contribution in CO_2E of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) are reported based on the 2007 IPCC 100-year global warming potentials. Combustion of the fuel (denoted as "Life Cycle Stage #5: Use" in this study) accounts for 80% of the gasoline and diesel vehicle emissions and almost 84% of the total GHG emissions from the use of jet fuel. The life cycle GHG analysis results, as reported, are modeled based on the 2005 average passenger vehicle as modeled by the U.S. Environmental Protection Agency's MOVES model. Changes to the vehicle or engine type will not change the baseline life cycle GHG emissions profile for conventional gasoline and conventional diesel fuel as reported on a "per MMBtu LHV of Fuel Consumed" basis. Results reported on a "per mile traveled" basis are dependant on the vehicle and engine type modeled. GHG emissions associated with the combustion of kerosene-type jet fuel (Life Cycle Stage #5: Use) are modeled based on the U.S. Federal Aviation Administration (FAA) and Intergovernmental Panel on Climate Change (IPCC) methodology for estimating GHG emissions from aircraft. The composite GHG value used in this study is the same value used by the FAA and U.S. Environmental Protection Agency (EPA) to calculate annual GHG emissions from aircraft operations in the United States.

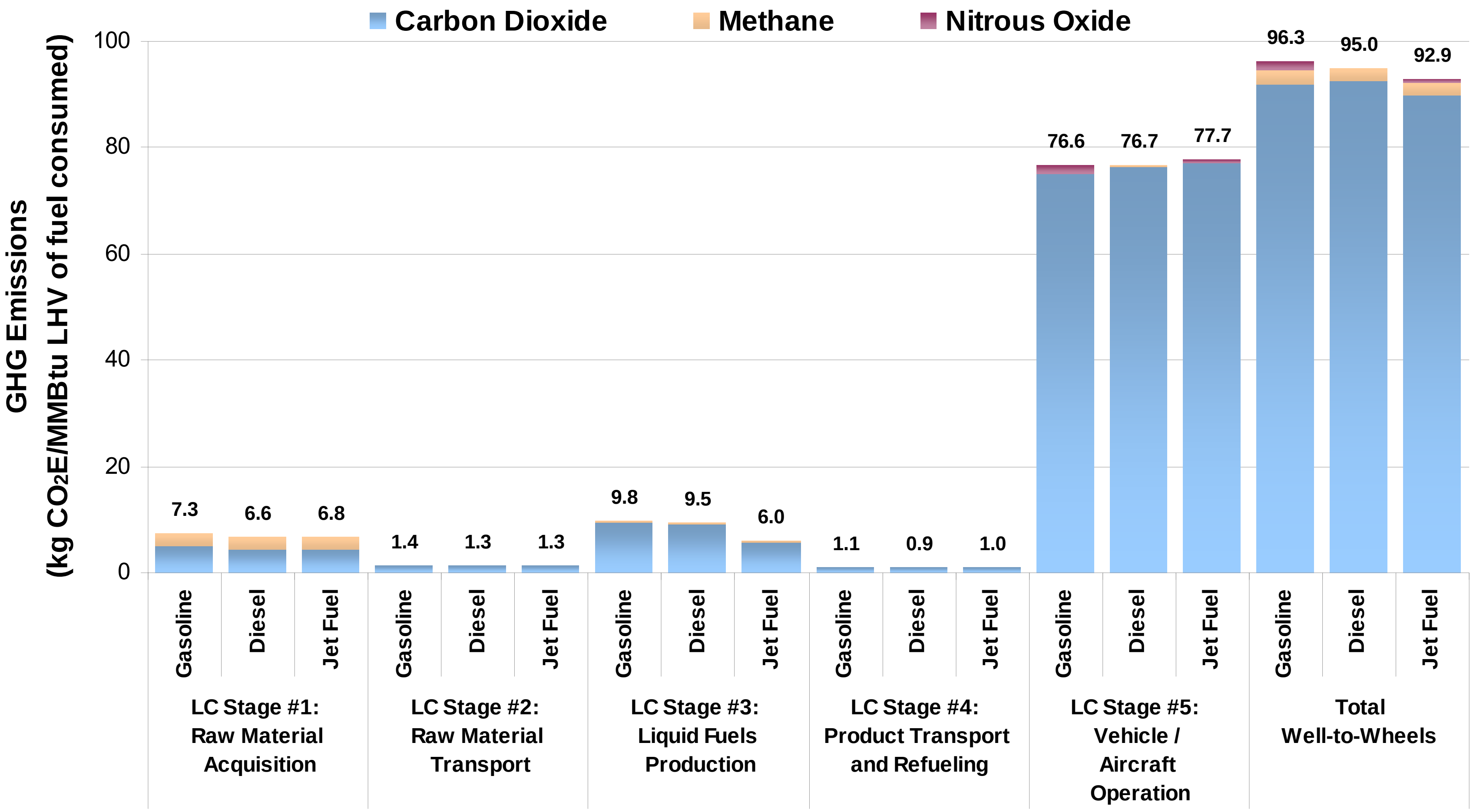
Well-to-tank (WTT) releases of GHGs contribute 20% or less to the total life cycle GHG emissions for each fuel type. Refinery operations (Life Cycle Stage #3: LFP) contribute 10% of the life cycle GHG emissions for conventional gasoline and diesel fuel while the crude oil extraction process (Life Cycle Stage #1: RMA) contributes another 7-8%. Crude oil extraction contributes slighter more GHGs then refining operations for kerosene-type jet fuel (7.3% compared to 6.5%) due to the lower refining energy requirements for producing jet fuel. The remainder for each fuel type, less than 3%, is from crude oil (Life Cycle Stage #2: RMT) and finished product (Life Cycle Stage #4: PTR) transportation and distribution operations. Comparative life cycle stage results for each fuel type are presented in Figure ES-3 by a stacked bar chart showing the relative contribution of GHG emissions on a CO_2E basis.

Opportunities for lowering the life cycle GHG emissions will best be achieved through **improved vehicle efficiency** or **alternative sources of transportation fuels**.

A 7 MPG increase in vehicle efficiency reduces the life cycle GHG emissions by 20% - equal to the total upstream GHG emissions from well-to-tank.

Opportunities for lowering the life cycle GHG emissions from transportation-related fuels will best be achieved through improved vehicle efficiency (e.g., gallons of fuel consumed per mile traveled) or alternative sources of transportation fuels. For example, improving the average gasoline-powered light-duty passenger vehicle efficiency from 21.6 miles per gallon (MPG) to 28.6 MPG, a 7 MPG increase, reduces the life cycle GHG emissions by 20%–equal to the total upstream GHG emissions from well-to-tank. Opportunities for reducing emissions from refining operations are very limited. Petroleum refining operations are one of the most energy efficient chemical conversion processes in the country– averaging around 90% energy efficiency. The U.S. petroleum refining industry, through its trade association the American Petroleum Institute (API), has implemented an aggressive greenhouse gas reduction program entitled "API Voluntary Climate Change Program." This program, and others, should continue to be encouraged to reduce life cycle GHG emissions; however, large-scale reductions can only be achieved through improved vehicle efficiency and alternative sources of transportation fuels.

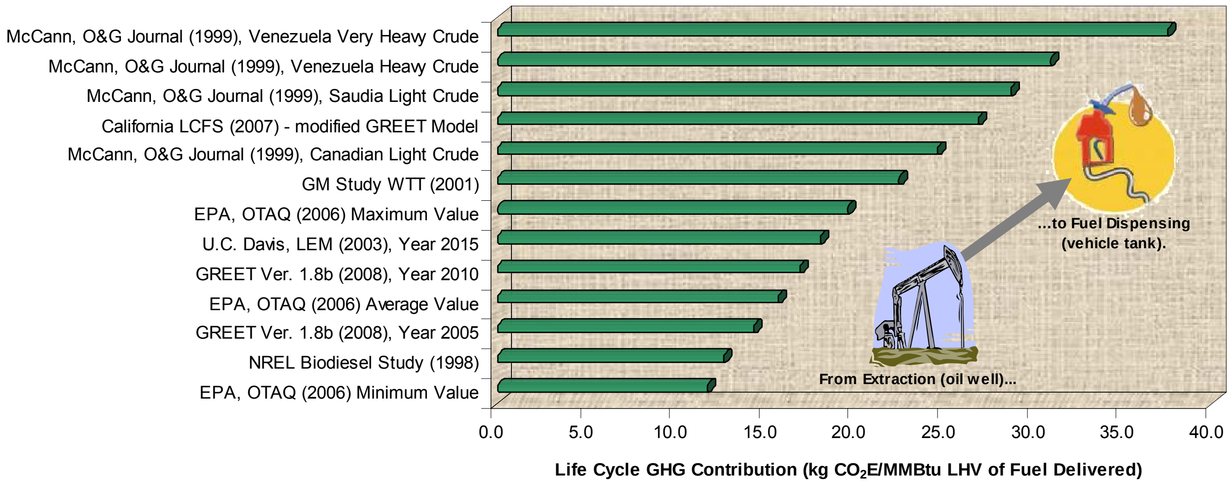
Figure ES-3. Life Cycle GHG Emissions for Conventional Transportation Fuels in kg CO_2E per MMBtu LHV Fuel Consumed



Study Drivers

The production and delivery of transportation fuels has been widely studied in the United States. Over the past 10 years, the increasing emphasis on GHG emissions in the United States and abroad has resulted in a number of well-documented and cited reports on the life cycle emissions of petroleum-based diesel fuel and gasoline. Figure ES-4 illustrates the results from various studies for the production and delivery of diesel fuel on a "well-to-tank" (WTT) basis. The results vary from 11.8 to 37.5 kg CO_2E/MMBtu LHV–a three-fold differential between the minimum and maximum values.

Figure ES-4. Comparison of Diesel Fuel Greenhouse Gas Profiles from Various Studies



This raised the questions "*What is the greenhouse gas (GHG) contribution from the production and delivery of diesel fuel, gasoline and kerosene-based jet fuel in the United States?*" and "*How does one compare alternative fuel options?*" Each of the results presented in Figure ES-4 is appropriate based on the individual study purpose and modeling assumptions employed by the authors. Significant differences in results arise primarily from differences in study boundary conditions, type of data used in the analysis, technology represented, geographical representation of key processes (national average, regional, or site-specific), time-related coverage (age of the data used in the analysis), and/or the allocation procedures used to assign emissions to operations with more than one valuable product (such as in a petroleum refinery).

On January 4, 2007, the EISA 2007 was passed into law. Under Title II, Subtitle A, Sec. 201 of the Act, it calls for the development of baseline lifecycle greenhouse gas emissions for gasoline and diesel sold or distributed as a transportation fuel in the U.S. in 2005. The baseline is to be determined by the U.S. EPA Administrator, after notice and opportunity for comment.

The goals and scope of this study were aligned to meet the above drivers.

EISA 2007, Title II, Subtitle A, Sec. 201

"(C) BASELINE LIFECYCLE GREENHOUSE GAS EMISSIONS- The term 'baseline lifecycle greenhouse gas emissions' means the average lifecycle greenhouse gas emissions, as determined by the Administrator, after notice and opportunity for comment, for gasoline or diesel (whichever is being replaced by the renewable fuel) sold or distributed as transportation fuel in 2005."

Life Cycle Modeling Approach and Data Limitations

This study conforms to the International Standards Organization (ISO) 14040 and 14044 life cycle assessment standards. This study includes all four phases of a life cycle assessment: Goal and Scope Definition, Inventory Analysis, Impact Assessment, and Interpretation. The scope of the life cycle inventory (LCI) is limited to greenhouse gas emissions; as a result, the life cycle impact assessment (LCIA) only determines the global warming potential (GWP) of the GHG emissions based on their relative contribution.

The life cycle GHG emissions are calculated for the following transportation fuel types:

- Conventional Gasoline
- Conventional Diesel Fuel (≤500 ppm sulfur)
- Kerosene-Based Jet Fuel

The physical boundaries of the life cycle include operations that have a significant contribution to the total life cycle GHG emissions. Specifically, the average life cycle GHG profile for transportation fuels sold or distributed in the United States in 2005 is determined based on the weighted average of fuels produced in the U.S. plus fuels imported into the U.S. minus fuels produced in the U.S. but exported to other countries for use.

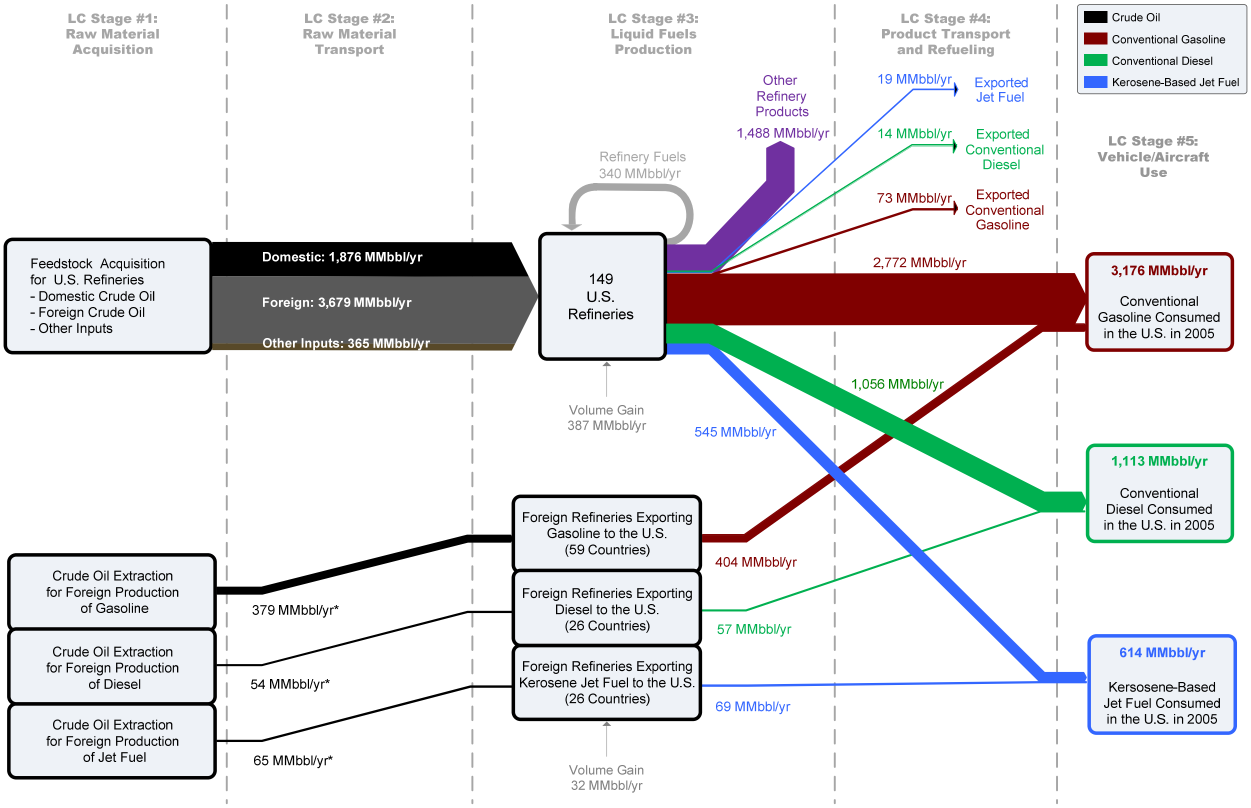
GHG life cycle results are reported in terms of kg CO_2E/MMBtu LHV of fuel consumed. This metric is dependant on the energy content of the fuel and could alternatively be reported in terms of kg CO_2E/mile traveled. The first expression is more commonly accepted for use in comparing well-to-tank and well-to-wheel/wake (WTW) results.

Table ES-1 summarizes the life cycle GHG analysis study design parameters. Figure ES-5 depicts the magnitude of transportation fuels sold or distributed in the U.S. in year 2005.

Table ES-1. Life Cycle Greenhouse Gas Study Design

Life Cycle Boundary	Well-to-Wheels/Wake (Raw Material Extraction thru Fuel Use)
Temporal Representation	Year 2005
Technological Representation	Industry Average
Geographical Representation	Transportation Fuel Sold or Distributed in the United States
Transportation Fuel Life Cycles Modeled	Conventional Gasoline Conventional Diesel Fuel (≤500 ppm Sulfur) Kerosene-Based Jet Fuel
Impact Assessment Methodology	Global Warming Potential, IPCC 2007, 100-year time-frame
Reporting Metric	kg CO_2E/MMBtu LHV of Fuel Consumed
Data Quality Objectives	100% Publically Available Data Full Transparency of Modeling Approach and Data Sources Accounting for 99% of Mass and Energy Accounting for 99% of Environmental Relevance Process-based (“Bottoms-up”) Modeling Approach

Figure ES-5. Year 2005 Petroleum Refinery Feedstock and Product Flows



* ***Crude oil input to FOREIGN refineries include only the portion of crude oil considered to be contributing to gasoline, diesel and jet fuel production***

The physical properties of the final products modeled and the fuel combustion profiles (vehicle/aircraft use) applied to each life cycle have a significant impact on the final results. Table ES-2 summarizes the fuel properties and provides the use profiles used in this study. Application of different physical properties and/or vehicle/aircraft use profiles have been identified as common differences between existing studies that characterize the life cycle GHG emissions from conventional transportation fuels for comparison to alternative transportation fuel options.

Table ES-2. Product Specifications and Vehicle/Aircraft Use Profiles

Property	Conventional Gasoline	Conventional Diesel Fuel	Kerosene-Based Jet Fuel
Lower Heating Value (LHV), MMBtu/bbl	4.892	5.512	5.230
Density, lb/gal	6.16	7.07	6.70
Vehicle Fuel Efficiency, MPG	23.7	31.2	Not Applicable
Vehicle Total Fuel Use, Btu LHV/mile	4,866	3,737	Not Applicable
Use Phase GHG Emissions, kg CO_2E/MMBtu LHV	76.6	76.7	77.7
Use Phase GHG Emissions, kg CO_2E/mile	0.373	0.286	Not Applicable

Data Limitations

The following limitations exist in the body of publicly-available data to characterize the life cycle of conventional transportation fuels sold or distributed in the United States in 2005.

- Crude oil extraction profiles for each country were available for year 2002, not 2005. No significant changes in crude oil extraction practices were identified for the U.S. or foreign countries with the exception of Canada. The magnitude of this limitation was minimized through the development of Canadian crude oil extraction, oil sands production, and bitumen upgrading profiles. The 2005 mix of conventional crude oil, syncrude from oil sands, and blended bitumen imported from Canada was used in this study.
- Level of refinery data collected and reported by the Energy Information Administration (EIA) and other industry sources does not provide detail for all pertinent data to differentiate between different grades of gasoline, distillate fuel oil or kerosene produced when developing a detailed refinery model. The data represents the "average" for the various grades produced. For example, distillate fuel was produced and sold as conventional (also referred to as "low-sulfur") diesel fuel (≤500 ppm sulfur) and off-road diesel fuel (>500 ppm sulfur) in 2005.
- Oxygenates and other additives used in reformulated gasoline blends were excluded from the study. In 2005, oxygenate input accounted for 4% of the total finished motor gasoline volume from U.S. refinery and blender operations (EIA 2008). Development of individual life cycles was determined to add negligible value to the study results when modeled as 100% of the volume from conventional gasoline.
- Foreign refining of conventional gasoline, conventional diesel fuel, and kerosene-based jet fuel is based on the U.S. refining model developed within this study. Significant differences in modeling assumptions and boundary conditions for foreign refining operations characterized in the public data voided the potential use in this study. The impact of this limitation was evaluated in the sensitivity analysis and determined to contribute less than ± 0.4% to the total life cycle GHG results (WTW).
- Vehicle emissions profiles were developed by the U.S. Environmental Protection Agency, Office of Transportation and Air Quality, MOVES model. The profiles represent the average vehicle in operation during the year 2005. The results are reported by vehicle class. Emissions from operation of the vehicle and combustion of the fuel account for 80% of the total life cycle GHG emission. Inherent uncertainties in the use emissions modeling are managed by ensuring consistent and comparable vehicle use profiles are applied when evaluating alternative transportation fuel options.
- A statistical average of the aircraft in operation in 2005 is not available and emissions associated with cruise methane and nitrous oxide emissions are highly uncertain. Furthermore, gross estimates are used to estimate the relative fuel consumption of cruise and landing and take-off. This limitation is also managed by ensuring consistent and comparable aircraft use profiles are applied when evaluating alternative transportation fuel options.

Data Quality Assessment

Table ES-3 assesses the data quality requirements identified by the International Standards Organization (ISO) 14044 “Environmental Management – Life Cycle Assessment – Requirements and Guidelines” as appropriate metrics for evaluating the quality of study results with respect to the study goal and scope.

Table ES-3. Data Quality Assessment of Study Methodology and Results

Quality Metric	Qualitative Assessment
Time-related Coverage	Crude oil extraction profiles for all countries are technologically representative of year 2005 operations. Year 2005 industry data, reported to the EIA, was used to characterize sources of refinery feedstock material, refinery energy usage, refinery production data, and imported product data. Energy intensity and modes of transport were derived from Oak Ridge National Laboratory, Transportation Energy Data Book for year 2005 which are compiled from Department of Transportation statistics. Vehicle emission profiles (from fuel combustion) are based on the average 2005 U.S. passenger vehicle fleet. Aircraft emission profile are not specific to 2005 operations, but are consistent with the aviation standard for reporting GHG emissions for the year 2005.
Geographical Coverage	U.S. specific models were constructed to represent all U.S. operations. Country specific crude oil extraction profiles were used to represent 90% of the total crude oil consumed at U.S. refineries. Foreign refining operations are based on the NETL U.S. Petroleum Refining Model. Results were compared to non-U.S. studies of foreign refining operations. Due to high variability in results of non-U.S. studies, sensitivity analysis was conducted to determine the impact of utilizing the U.S. model.
Technology Coverage	Petroleum refining technology has not changed significantly in the past 15-years. All data was evaluated to accurately represent energy consumption and emission rates relative to year 2005. Petroleum refining unit process capacity utilization data was based on a 1996 survey of the U.S. petroleum industry. Unit process throughput allocation to the product categories was based on a survey of recent literature. Sensitivity analysis was conducted on these parameters and determined to have minimal impact on the final results.
Precision	Precision was managed by subject matter expert review and quality assessment of data sources and subsequent selection of the best available data representing actual operations in year 2005. Key parameters were evaluated through sensitivity analysis to assess the impact to the final results.

Quality Metric	Qualitative Assessment
Completeness	Completeness is achieved within the study's defined cut-off criteria of mass, cost, and environmental relevance consistent with ISO 14044 life cycle assessment standards. This includes analysis and selection of carbon dioxide, methane, and nitrous oxide as the three types of GHG emissions that have environmental relevance to the total life cycle of petroleum-derived transportation fuels. The refinery model was balanced to 100% based on an iterative calculation procedure to balance both the energy and hydrogen values.
Representativeness	The results of this study accurately reflect the 2005 U.S. national average GHG profile for conventional transportation fuels sold or distributed using the highest quality data publically-available.
Consistency	The study methodology and level of modeling detail were applied consistently throughout all aspects of the study. Any deviations were evaluated through sensitivity analysis and determined to have minor impact to the final results.
Reproducibility	The results of this study are 100% reproducible. Proprietary purchased data from PE International were not reported but these data are publically-available and calculated results in terms of CO_2E using the PE International data are fully reported. All documentation for PE International data sets used in this study is included as an attachment for full transparency.
Sources of Data	Industry average data was used as the primary data source. Industry specific data and engineering estimates were used when industry average data was not available. The source of all data is clearly documented in the report for each unit process modeled.
Uncertainty of the Information	Uncertainty is an inherent aspect of performing life cycle based studies. Probability estimates were not determined for each data point used in this study. Key parameters were assessed through sensitivity analysis in place of uncertainty analysis. This analysis has a variance of less than +/- 4% for the well-to-tank results on any single sensitivity parameter. Use phase results are static (+/- 0%) based on a fixed modeling assumption to manage the variance in the study results. The variance in the life cycle total (well-to-wheels/wake) then equates to less than +/- 1% on any single sensitivity parameter.
Study Quality/Applicable Uses	This study reflects the highest quality of life cycle (GHG) analysis based on the study goal and scope. Use of the study results is applicable for all decision types (internal, public, policy, etc.) when used in the appropriate context.

This page intentionally left blank.

1.0 Introduction

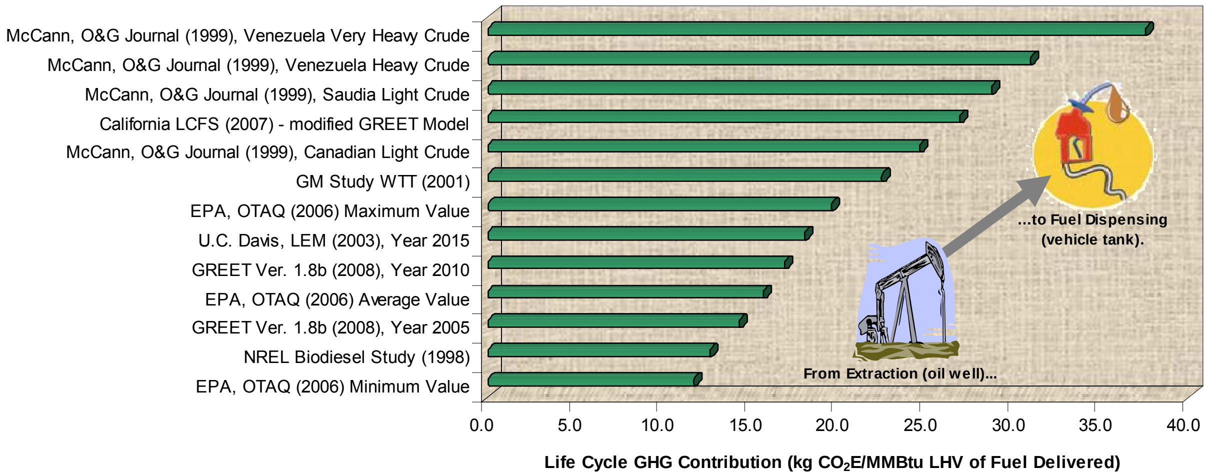
1.1 Background

The Energy Independence and Security Act of 2007 (EISA 2007), Title II, Subtitle A, Sec. 201 calls for the development of baseline life cycle greenhouse gas (GHG) emissions for gasoline and diesel sold or distributed as a transportation fuel in 2005 to be determined by the Administrator of the U.S. Environmental Protection Agency (EPA), after notice and opportunity for comment. That baseline will become the metric against which alternative transportation fuels will be evaluated. Under Title V, Subtitle C, Section 526 of the same act, Federal agencies buying either an alternative or a synthetic fuel can do so only if the life cycle GHG emissions from both the "the production and combustion of the fuel" are less than that from a conventional petroleum pathway.

The key to determining both the eligibility of alternative fuel projects for award and justifying the purchase of biofuels and/or synthetic fuels by Federal agencies is the ability to accurately account for life cycle GHG emissions. A life cycle methodology for quantitatively determining GHG gas emissions for the 2005 petroleum baseline is developed in this study.

The production and delivery of transportation fuels has been widely studied in the United States. Over the past 10 years, the increasing emphasis on GHG emissions in the United States and abroad has resulted in a number of well-documented and cited reports on the life cycle emissions of diesel fuel and gasoline. Figure 1-1 illustrates the results from various studies for the production and delivery of diesel fuel (commonly referred to as a "well-to-tank" (WTT) analysis). The results vary from 11.8 to 37.5 kg CO_2E/MMBtu LHV[1]–a three-fold differential between the minimum and maximum values.

Figure 1-1. Comparison of Diesel Fuel GHG Profiles from Various U.S. Studies



---

[1] "kg CO_2E/MMBtu" = kilograms of carbon dioxide (CO_2) equivalents (E) per million British thermal units (MMBtu) Lower Heating Value (LHV) of diesel fuel dispensed into a vehicle.

The large variability in diesel WTT GHG emission profiles raises the questions "*What is the GHG contribution from the production and delivery of diesel fuel, gasoline, and kerosene-based jet fuel in the United States?*" and "*How does one compare alternative fuel options?*" Each of the results presented in Figure 1-1 may be appropriate based on the individual study purpose and modeling assumptions employed by the authors. Significant differences in results arise primarily from differences in study boundary conditions, type of data used in the analysis, technology represented, geographical representation of key processes (national average, regional, or site-specific), time-related coverage (age of the data used in the analysis), and/or the allocation procedures used to assign emissions to operations with more than one valuable product (such as in a petroleum refinery).

1.2 Purpose & Goal of the Study

The purpose of this study is to develop baseline data, methodologies, and results to determine the life cycle greenhouse gas emissions for liquid fuels (conventional gasoline, conventional diesel, and kerosene-based jet fuel) production from petroleum as consumed in the U.S. in 2005 to allow comparisons with alternative transportation fuel options on the same basis (i.e., life cycle modeling assumptions, boundaries, and allocation procedures).

1.3 Study Boundary and Modeling Approach

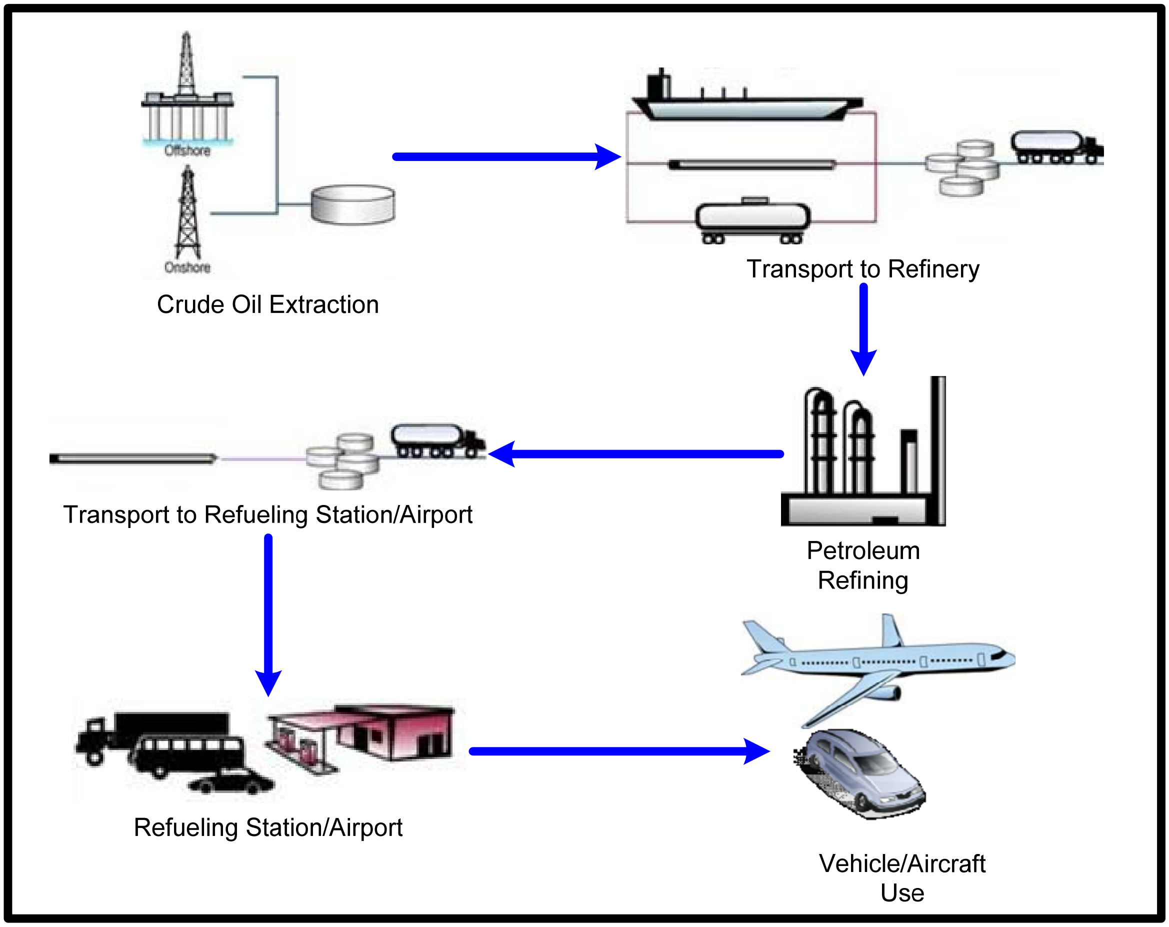
The boundary of this study includes both domestic and foreign extraction of refinery feedstocks and fuels, transport to U.S. and foreign refineries (exporting transportation fuels to the U.S.), processing of petroleum to produce transportation fuels, transport to refueling stations, and consumption in either a light-duty passenger vehicle or a jet aircraft. The life cycle boundary for this study is referred to as "cradle-to-grave." The "cradle" refers to extraction of raw materials from the earth and the "grave" is represented as the combustion of the fuel in a vehicle. Figure 1-2 graphically represents the boundary for petroleum-based fuel production operations included within this study. This conceptual boundary applies to both liquid fuels produced domestically as well as imported liquid fuels.

1.3.1 Scope of the Environmental Life Cycle Analysis

The environmental life cycle analysis (LCA) approach utilizes the International Standards Organization (ISO) 14040 "Environmental Management – Life Cycle Assessment – Principles and Framework." (ISO 2006) This study includes all four phases of a life cycle assessment: Goal and Scope Definition, Inventory Analysis, Impact Assessment, and Interpretation.

The scope of the life cycle inventory (LCI) is limited to quantifying greenhouse gas emissions. As a result, the life cycle impact assessment (LCIA) considers only the global warming potential (GWP) of the GHG emissions based on their relative contribution. Emissions from various greenhouse gases were assessed during a pre-screening assessment to determine the primary emissions of relevance to be tracked and included within the study. Based on analysis of available data, carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) were identified as the three forms of GHG emissions that have environmental relevance to the total life cycle of petroleum-derived transportation fuels.

Figure 1-2. Conceptual Study Boundary



The Intergovernmental Panel on Climate Change (IPCC) publishes the international standard for calculating GWP based on the weighted contribution of various emissions (IPCC 2001; IPCC 2007). The IPCC publishes values for three time-frames: 20, 100, and 500 years. The U.S. standard is based on the 100-year time-frame. GWP were standardized in 1990, 1996, 2001, and in 2007 by the IPCC. Within this study the most current 2007 IPCC values are used. When interpreting older data sources that report GWP, it is necessary to determine which set of IPCC GWP values were used in the calculation. Table 1-1 lists the primary GHGs and their corresponding 100-year global warming potentials reported in mass of CO_2 equivalents for the three most recent set of IPCC values.

Table 1-1. GHG Emissions Included in Study Boundary and their 100-year GWP

Emissions to Air	Abbreviation	1996 IPCC (GWP CO_2E)	2001 IPCC (GWP CO_2E)	2007 IPCC (GWP CO_2E)	This Study (GWP CO_2E)
Carbon Dioxide	CO_2	1	1	1	1
Methane	CH_4	21	23	25	25
Nitrous Oxide	N_2O	310	296	298	298

Nitrogen oxides (NO_x) and their impact to global warming are currently being reviewed by climatologists around the world and there is a lack of agreement about the impact of NO_x in relation to global warming. The 2007 Intergovernmental Panel on Climate Change (IPCC) report entitled "Climate Change 2007: The Physical Science Basis" notes that nitrogen oxides have short lifetimes and complex nonlinear chemistry with opposing indirect effects through ozone enhancements and methane reduction (IPCC 2007). Most current research suggests that the GWP for surface/industrial NO_x emission may be negative. Wild et al. (2001) report a GWP for industrial NO_x emissions of -12. Since there is a lack of agreement on NO_x effects, the IPCC has opted to omit them from consideration.

1.3.2 Cut-off Criteria for the System Boundary

Cut-off criteria define the selection of materials and processes to be included in the system boundary. Following the requirements of International Organization of Standardization (ISO) LCA standard 14044 (ISO 2006), the criteria of mass, cost, and environmental relevance were used for material and energy inputs.

A significant material input is defined as a material input that has a mass greater than 1% of the principal product that is produced by a process. A significant material input is also defined as one that has a relatively high cost (for instance, compared to the cost of the largest, by mass, material input), or has an important environmental relevance (for instance, a high GWP).

A significant energy input is defined as one that contributes more than 1% of the total energy used by the process. As with materials, a significant energy input is also one that has a relatively high cost or has an important environmental relevance.

1.3.3 Exclusion of Data from the System Boundary

All operations are considered pre-existing; therefore, no construction related emissions are included within the scope of this study.

Humans involved in the system boundary have a burden on the environment, such as driving to and from work and production of food they eat, that is part of the overall life cycle. However, this complicates the life cycle tremendously due to the data collection required to quantify the human-related inflows-from and outflows-to the environment and how to allocate them to fuel production. Furthermore, it is assumed that the workforce will be unaffected by the choice of fuel at large-scale production volumes. Issues related to humans, such as the societal impacts of humans in the workforce that need to be addressed through policy and value-based decisions, are outside the scope of this life cycle study.

Low frequency, high magnitude environmental events (e.g., accidental releases) were not included in the system boundary since such circumstances are difficult to predict, quantify, or associate with a particular product. However, where the impact of operational abnormalities is embedded in 2005 data, no attempt was made to account for or quantify the effects. For example, no adjustment was made for the atypical energy usage, feedstock quality and production volumes embedded in reported data in 2005 associated with shut-down of Gulf Coast refineries impacted by hurricanes Katrina and Rita. More frequent, but perhaps lower magnitude events, such as material loss during transport, are included in the system boundary.

1.3.4 Data Reduction and Allocation Procedures

In order to generate a life cycle inventory for each pathway, the vast array of collected secondary data (data not directly usable but which in concert with other data meets the necessary requirements) must be reduced using numerous calculations and equations. These reductions constitute manipulation of the secondary data to conform it to the requirements of the goal and scope of this study (e.g., relating data to a functional unit, data aggregation, allocation of flows/releases, etc.). ISO standards, where appropriate, are used as guidelines in performing data reductions and allocation procedures (ISO 2006).

System expansion and unit process division are the two methods recommended within ISO 14044 for avoiding allocation wherever possible (i.e., avoiding allocation is preferred) and are used within this study. The displacement method, a type of system expansion, is recommended by the U.S. Environmental Protection Agency (EPA) for allocating co-products from energy conversion facilities producing transportation fuels (EPA 2007). The displacement method expands the system boundary to include the production of co-products by other means that would theoretically be avoided as a result of secondary production by the primary process being modeled. When system expansion is determined not to be feasible, then the following shall apply. In general, flows associated with energy carriers or any materials produced for its energy value are allocated based on energy content. All other materials and co-products are allocated based on mass or volume. Allocation by economic value was not performed in this study.

1.3.5 Geography, Technology and Time-frame Represented

The scope of this study is the production and delivery of petroleum-based liquid transportation fuels sold or distributed in the United States in 2005. Consumption of transportation fuels in Puerto Rico and the Virgin Islands is excluded. The technology represents existing operations for 2005.

The primary source of U.S. petroleum refining operations data used in the analysis is the U.S. Department of Energy (DOE), Energy Information Administration (EIA) petroleum industry statistics. Refinery equipment is surveyed annually on January 1st providing a snapshot of refinery operations. Refinery equipment and capacities reported on January 1, 2006, are assumed to be representative of that which was in operation in 2005. Using this data set allows comparison with the Oil & Gas Journal 2005 Worldwide Refining Survey which also presents data as of January 1, 2006.

The vehicle emissions for conventional gasoline and conventional diesel are representative of the average fleet of light-duty passenger vehicles for 2005. This data was obtained from EPA and was extracted from the MOVES model (EPA 2008).

Aircraft emissions estimates were derived from emission factors for typical jet aircraft operation, as reported by the IPCC in 2006 (IPCC 2006).

1.4 Life Cycle Stages

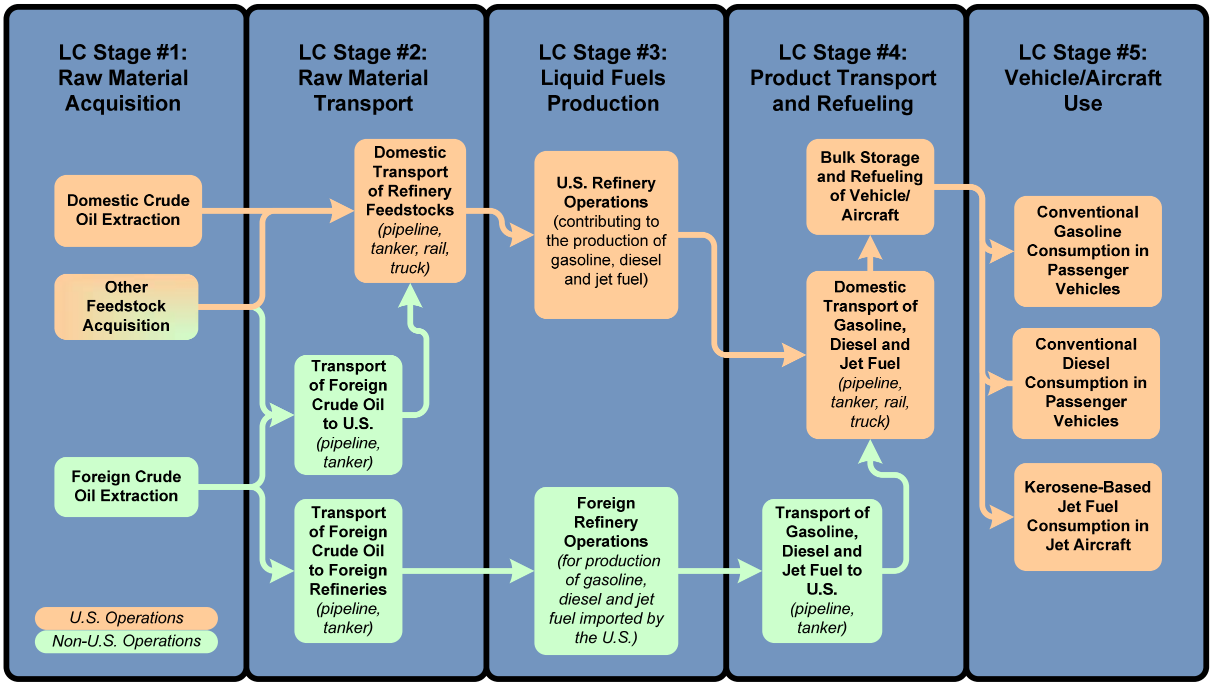
The boundary for this study is from cradle-to-grave or raw material acquisition through the consumption of the fuel by the vehicle/aircraft.

The following five life cycle (LC) stages are used to organize data and report results:

- Life Cycle Stage #1: Raw Material Acquisition
- Life Cycle Stage #2: Raw Material Transport
- Life Cycle Stage #3: Liquid Fuels Production
- Life Cycle Stage #4: Product Transport and Refueling
- Life Cycle Stage #5: Vehicle/Aircraft Operation

Figure 1-3 depicts the flow of petroleum refining feedstocks and products of interest through the life cycle stages and highlights the key activities occurring within the U.S. and in foreign countries.

Figure 1-3. Flow of Petroleum Refining Feedstock and Products through the Life Cycle Stages



The following briefly describes the boundary of each LC stage. Environmental modeling assumptions applied to each of the LC stages are documented in Sections 2.0 to 6.0 of this document.

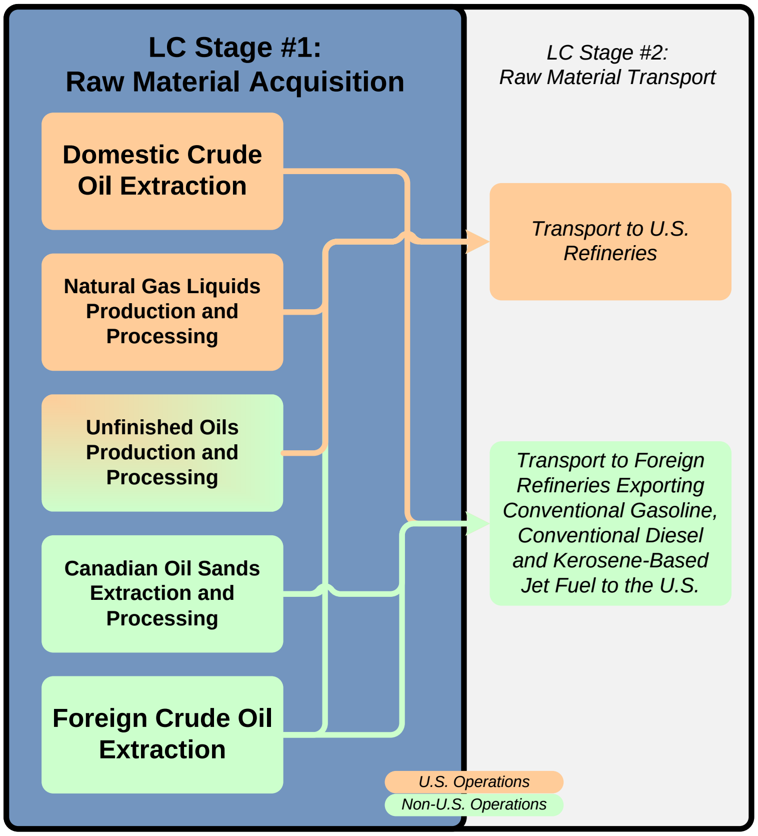
- Life Cycle Stage #1: Raw Material Acquisition
    - Boundary includes extraction of raw feedstocks from the earth and any partial processing of the raw materials that may occur.
    - Feedstocks include foreign and domestic crude oil, natural gas liquids, unfinished oils, and unconventional hydrocarbons (e.g. oil sands).

- Life Cycle Stage #2: Raw Material Transport
    - Boundary begins at the end of extraction/processing of the raw materials and ends at the entrance to the petroleum refineries.
    - Feedstocks are transported from both domestic and foreign sources to U.S. and foreign refineries.
- Life Cycle Stage #3: Liquid Fuels Production
    - Boundary starts at the entrance of the petroleum refinery with the receipt of crude oil (and other feedstock inputs) and ends at the entrance to the petroleum pipeline used to transport the liquid fuels to the bulk fuel storage depot.
    - Petroleum refinery operations are both foreign and domestic.
    - Emissions associated with acquisition and production of indirect fuel inputs such as purchased power and steam, purchased fuels such as natural gas and coal, and fuels produced in the refinery and subsequently consumed therein are included in this stage.
    - Emissions associated with on-site and off-site hydrogen production are included in this stage, including emissions associated with raw material acquisition for hydrogen plant feedstock and fuel.
    - Production of oxygenates is excluded from the scope of this study.
- Life Cycle Stage #4: Product Transport and Refueling
    - Boundary starts at the exit of the petroleum refinery and ends with dispensing the fuel into the vehicle/aircraft.
    - Boundary includes the operation of the bulk fuel storage depot for gasoline and diesel and the airport fuel storage tanks.
    - Boundary includes the operation of liquid fuel tanker trucks used to transfer the gasoline/diesel from the depot to the vehicle fueling stations and the transport of jet fuel from the airport fuel storage tanks to the aircraft by a refueling truck.
- Life Cycle Stage #5: Vehicle/Aircraft Operation
    - Boundary starts at the vehicle/aircraft fuel tank and ends with the combustion of the liquid fuel.

2.0 LC Stage #1: Raw Material Acquisition

LC Stage #1 consists of extraction of raw refinery feedstocks (crude oil and equivalent, natural gas liquids, and unfinished oils) from the earth and associated post-extraction-processing required to derive a feedstock-quality input. This section describes the environmental modeling assumptions associated with this LC stage for feedstocks for U.S. petroleum refineries and for foreign petroleum refineries producing gasoline, diesel and kerosene-based jet fuel imported by the U.S. in 2005. Figure 2-1 depicts the activities and flow of feedstocks for LC Stage #1.

Figure 2-1. Flow Diagram of Raw Material Acquisition Activities



2.1 Raw Material Acquisition for Domestic Petroleum Refineries

Table 2-1 shows the daily refinery input of feedstocks in barrels (bbl) to U.S. refineries in 2005 (excludes refining operations in the Virgin Islands and Puerto Rico). Emissions profiles associated with extraction and processing for the following petroleum refinery feedstocks are included in this stage:

- Crude oil and other hydrocarbons fed to refineries as synthetic crude (i.e. from Canadian oil sands)
- Natural Gas Liquids
- Unfinished Oils

Table 2-1. Daily Refinery Feedstock Input in 2005 (EIA 2008)

Feedstock	Input (thousand bbl/day)
Crude Oil	15,220
Natural Gas Liquids	432
Unfinished Oils (net)	569

Each raw material acquisition process is described below.

2.1.1 Crude Oil Acquisition

The crude oil mix fed to U.S. refineries includes domestic and foreign crude oil. Extraction profiles are modeled for the foreign sources shown in Table 2-2 which (when added to the U.S. resources) account for over 90% of the total crude input to U.S. refineries in 2005.

Table 2-2. Sources of Crude Oil Utilized at U.S. Petroleum Refineries in 2005

U.S. Crude Oil Sources	Production/Import as % of Refinery Crude Input (Year 2005, EIA)
U.S. Crude Oil	33.8%
Canada Crude Oil	10.7%
Canada Oil Sands	
Mexico Crude Oil	10.2%
Saudi Arabia Crude Oil	9.4%
Venezuela Crude Oil	8.1%
Nigeria Crude Oil	7.1%
Iraq Crude Oil	3.4%
Angola Crude Oil	3.0%
Ecuador Crude Oil	1.8%
Algeria Crude Oil	1.5%
Kuwait Crude Oil	1.5%
Total	**90.5%**

2.1.1.1 Crude Oil Extraction GHG Profiles

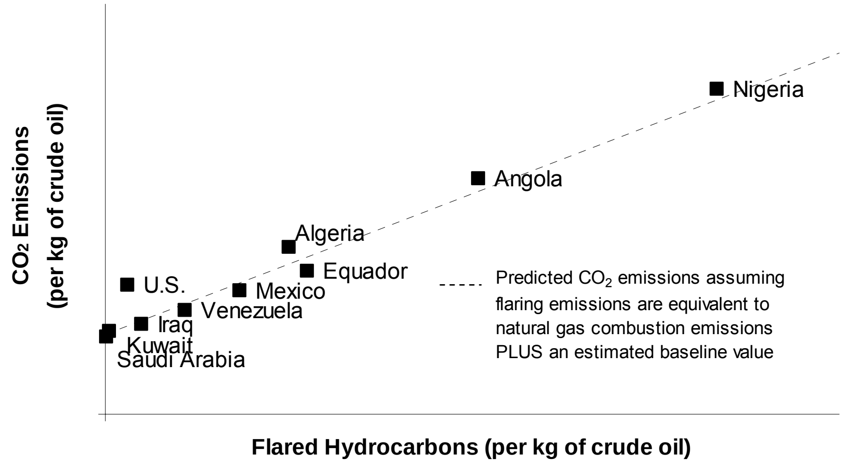
Country-specific crude oil extraction profiles were purchased from PE International (2008) for the U.S. crude oil sources listed in Table 2-2, with the exception of Canada. The Canadian profile was derived independently by NETL. The global warming potential in CO_2 equivalents (utilizing the factors in Table 1-1) associated with the purchased extraction profiles is shown in Table 2-3. The data are representative of 2002 rather than 2005 but this temporal difference is expected to result in minor differences in the upstream profile for conventional crude oil extraction.

Table 2-3. GHG Emissions Consistent with Extraction of Crude Oil in Countries Exporting to U.S. Petroleum Refineries in 2005

Crude Oil Source	GHG Emissions (kg CO_2E/bbl of crude oil)
U.S. Crude Oil	24.5
Saudi Arabia Crude Oil	13.6
Mexico Crude Oil	38.4
Venezuela Crude Oil	24.2§
Nigeria Crude Oil	128.6
Iraq Crude Oil	19.6
Angola Crude Oil	81.8
Ecuador Crude Oil	31.3
Algeria Crude Oil	35.1
Kuwait Crude Oil	16.5

Differences in the extraction profiles from country-to-country are significant. Much of the variability can be explained by the reported flaring and venting rates consistent with crude oil extraction in each of the countries. Figure 2-2 shows the relationship between flaring rate and CO_2 emissions. A dotted line is added to show what the expected CO_2 emissions would be if the gas flared is assumed to be natural gas. Figure 2-3 shows the relationship between venting rate and CH_4 emissions. A dotted line is added to show what the expected methane emissions would be assuming the vented gas if 75% by weight methane is assumed. Flaring and venting data presented in these figures are consistent with the values reported in the documentation associated with the crude oil extraction profiles (Attachment 1).§

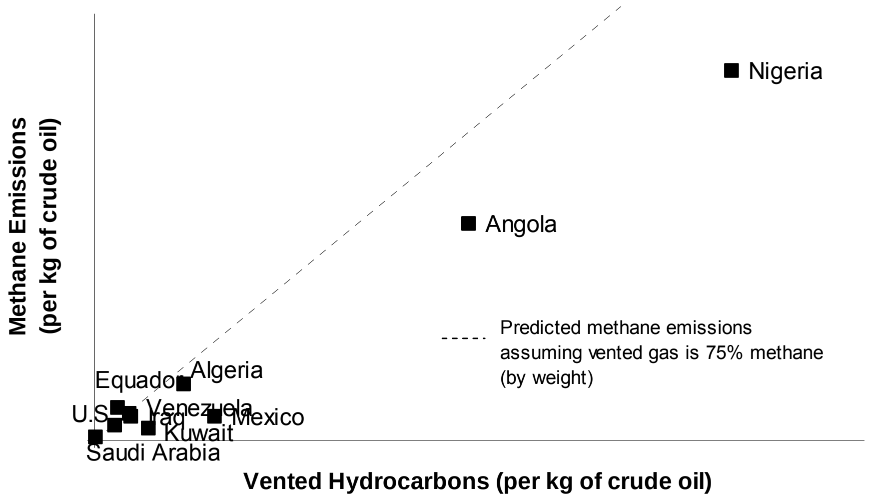
Figure 2-2. Country-Specific CO_2 Emissions Associated with Crude Oil Extraction Relative to Reported Flaring



---

§ A sensitivity analysis was performed on these parameters.

Figure 2-3. Country-Specific Methane Emissions Associated with Crude Oil Extraction Relative to Reported Venting



2.1.1.2 Canadian Crude Oil Mix Extraction GHG Profile

For Canada, the crude oil mix extraction profile will vary significantly based on the assumed mix of oil sands and conventional crude oil. As Canada was the largest foreign contributor of crude oil to U.S. refineries in 2005, this variability can have a significant impact on the final U.S. composite extraction profile. For this reason, separate profiles for Canadian conventional crude oil extraction and Canadian oil sands extraction and processing were developed to allow for increased quality and transparency.

Conventional Canadian Crude Oil

Determining an emissions profile for Canadian conventional crude oil extraction is challenged due to the inclusion of oil sands activities in many reported data. The Canadian Association of Petroleum Producers (CAPP) sponsored the development of a report determining a GHG emissions inventory for upstream oil and gas operations. However, in this report indirect emissions from purchased power and steam were not fully quantified. CAPP noted that convenient and reliable sources of these data generally do not exist (CAPP 2004).

The U.S. crude oil extraction GHG emissions profile has been adjusted for use as an estimate for the Canada crude oil extraction profile. Because of the strong relationship between flaring and venting rates associated with crude oil extraction and the CO_2 and methane emissions profiles, the U.S. profile was modified to account for the differences in reported flaring and venting for U.S. and Canada extraction activities. Assuming that the gas flared is natural gas, and the gas vented is 75% by weight methane, the resulting Canada profile is as shown in Table 2-4. The U.S. profile is provided for reference.

Table 2-4. GHG Emissions Consistent with Extraction of Canadian Conventional Crude Oil Based on Adjusted U.S. Crude Oil Extraction Emissions Profile

Crude Oil Source	GHG Emissions (kg CO_2E/bbl of crude oil)
Canadian Crude Oil	35.2
U.S. Crude Oil	24.5

Canadian Oil Sands

The Canadian crude oil mix exported to the U.S. in 2005 included conventional crude oil as well as oil sands products (either diluted crude bitumen or synthetic crude produced from extracted bitumen). In 2005, the U.S. refinery crude feedstock mix contained 3.5% oil sands (NEB 2006). Of this amount, 43% was input as blended bitumen, 35% as light synthetic crude, and 21% as heavy synthetic crude (NEB 2006). The environmental emissions and GHG profile is significantly higher for oil sands than for conventional crude oil and there is variation in the oil sands profile depending upon the method of extraction and final quality of the material.

Table 2-5 shows the GHG emissions profiles used for crude bitumen and synthetic crude from oil sands as well as the composite profile for input to U.S. refineries in 2005. These values were derived using actual emissions reported by two primary producers, Imperial Oil and Syncrude, and their estimated 2005 production rates, as reported by the respective operators. Together, these two operations accounted for approximately 33% of the Canadian oil sands bitumen production in 2005 (AEUB 2006).

Table 2-5. GHG Emissions Consistent with Extraction and Processing of Canadian Oil Sands§

Source	Emissions (kg/bbl synthetic crude oil)			References/Comments
	CO_2	CH_4	N_2O	
Crude Bitumen	80.8	0.00943	0.00114	(EnvCan 2008); estimated using Imperial Oil Cold Lake data; (Imperial Oil 2006)
Synthetic Crude from Oil Sands	122	0.426	0.00410	(EnvCan 2008); (Syncrude 2006)
Study Value for Input to U.S. Refineries	**104**	**0.247**	**0.00283**	**43% Crude Bitumen & 57% Synthetic Crude**

2.1.1.3 Crude Oil Mix Composite Extraction GHG Profiles

Figure 2-4 compares the global warming potential for crude oil extraction based on the purchased profiles, the developed Canadian conventional and oil sands profiles, the profile used for the remaining foreign import sources, and the U.S. composite profile. The extraction profile for the remaining foreign import sources (9.5%) has been approximated by assuming that the GHG profile is equivalent to the average profile for the foreign sources listed in Table 2-2 (excluding Canadian oil sands).§

---

§ A sensitivity analysis was performed on these parameters.

The GHG emissions associated with extraction operations for the 2005 composite crude oil input to U.S. refineries are reported in Table 2-6.

Figure 2-4. GHG Emissions Consistent with Extraction of Crude Oil Input to U.S. Refineries in 2005

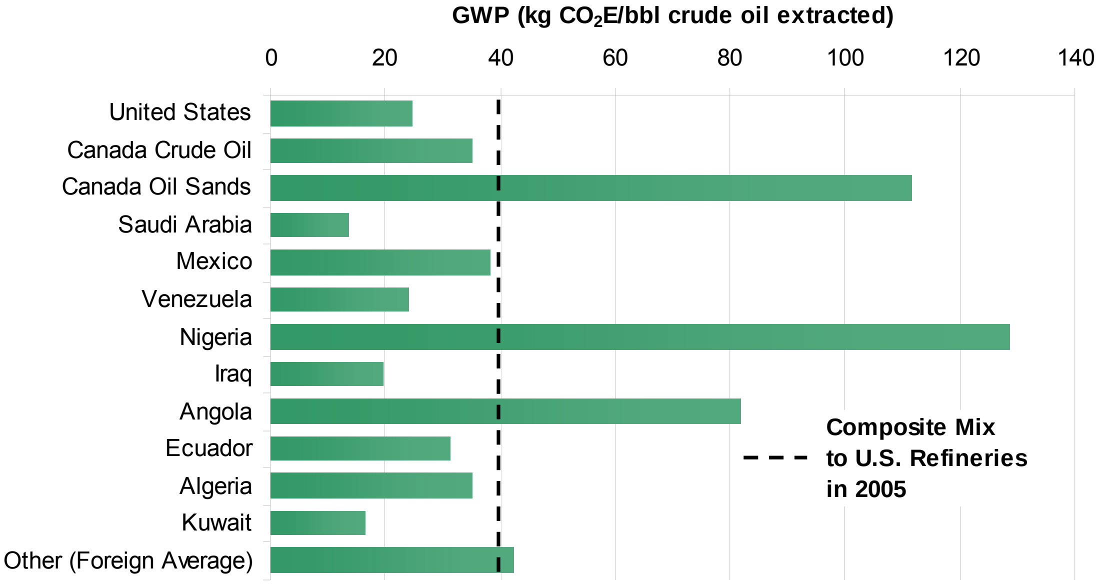


Table 2-6. GHG Emissions Consistent with Extraction of Composite U.S. Crude Oil Mix for 2005

Source	Emissions (kg/bbl crude oil)		
	CO_2	CH_4	N_2O
Conventional Crude Oil Only	23.5	0.525	0.000641
Crude Oil and Canadian Oil Sands	26.3	0.515	0.000717

2.1.2 Natural Gas Liquids Extraction and Processing

Natural gas liquids (NGL) are hydrocarbons extracted from a reservoir during natural gas recovery. Natural gas liquids include primarily ethane, propane, butanes, and pentanes and are separated from the natural gas (methane) during processing.

The emissions profile for natural gas liquids has been estimated using Canadian data for upstream oil and gas operations. The emissions profile generated is for natural gas liquids produced from a natural gas well (NGL processing from an associated oil and gas production operation may differ due to the different processing options available). Table 2-7 shows emission factors for natural gas production and processing in Canada in 2000 (CAPP 2004). No significant technology differences/advances occurred in the field of oil and gas extraction in the years between 2000 and 2005 and therefore the data meets the quality objectives for this study.

Table 2-7. Emissions from Natural Gas Production and Processing (CAPP 2004)

Source	Emissions (tonnes/million m^3 raw natural gas produced)		
	CO_2	CH_4	N_2O
Natural Gas Production	42.7	2.34	0.0040
Natural Gas Processing	90.4	0.29	0.0032
Total	**133**	**2.63**	**0.0072**

Since NGL are produced via the same general mechanisms as natural gas (NG), the volume of NG that is extracted and processed to produce a quantity of NGL is allocated to the NGL component. Based upon EIA's Natural Gas Annual 2005 Table 7, NGL production totaled 619,884 thousand barrels (Mbbl) in the U.S. and this resulted in an apparent NG extraction volumetric loss of 876,497 million cubic feet (cf). Thus, for every barrel of NGL produced, 1,414 cf of NG is extracted and processed.

Applying the Canadian emission factors to the above quantity of NG extracted/processed, an emissions profile for NGL is generated, as shown in Table 2-8.

Table 2-8. Emissions from Natural Gas Liquids Production and Processing

Source	Emissions (kg/bbl natural gas liquids produced)		
	CO_2	CH_4	N_2O
Natural Gas Liquids	5.33	0.105	0.000288

2.1.3 Unfinished Oils Extraction and Processing

Unfinished oils are modeled in a similar manner to crude oil but have an additional emission component associated with atmospheric/vacuum distillation column operation. EIA reports the unfinished oils input to refineries in barrels per day (bpd) by fraction, as shown in Table 2-9.

Table 2-9. Unfinished Oils Net Input to U.S. Refineries in 2005 (EIA 2008)

Composition	Input (bpd)	Percent of Total
Naphthas and Lighter	74,759	13%
Kerosene and Light Gas Oils*	-10,575	-2%
Heavy Gas Oils	382,592	67%
Residuum	122,351	21%
Unfinished Oils (net)	**569,126**	**100%**

* Negative value due to inventory accounting

The extraction profile is modeled to be the same as the U.S. composite crude oil profile (excluding Canadian oil sands) generated in Section 2.1.1.

The minimum additional processing for the unfinished oils is assumed to be atmospheric distillation separation for all components. Residuum is anticipated to also pass through the vacuum distillation column. Energy usage, and associated emissions, consistent with performing these operations (see Life Cycle Stage #3) are added to the crude oil composite to generate a total for the unfinished oils fraction as shown in Table 2-10.

Table 2-10. Emissions for Unfinished Oils Extraction and Processing

Source	Emissions (kg/bbl unfinished oils)		
	CO_2	CH_4	N_2O
Extraction	23.6	0.526	0.000643
Processing	14.7	0.0177	0.000258
Total	**38.3**	**0.544**	**0.000901**

2.1.4 LC Stage #1 Summary for Domestic Refineries

The following table summarizes the upstream GHG emissions profiles for the U.S. refinery feedstocks for 2005. The results are based on the feedstock volumes delivered to U.S. refineries and thus the additional crude oil extraction required to account for losses and the associated emissions are incorporated here. Additional information on the loss factors applied are detailed in Appendix H.

Table 2-11. GHG Emissions from Feedstock Extraction for Input to Domestic Refineries in 2005

Feedstock	Input (bpd)	Emissions (kg/day)		
		CO_2	CH_4	N_2O
Crude Oil	14,692,542	346,326,430	7,734,105	9,448
Canadian Oil Sands	527,545	55,276,887	130,421	1,495
Natural Gas Liquids	432,044	2,302,453	45,496	125
Unfinished Oils (net)	569,126	21,804,399	309,632	513
Total	**16,221,258**	**425,710,170**	**8,219,654**	**11,581**

2.2 Raw Material Acquisition for Foreign Petroleum Refineries

Refined petroleum products were imported in 2005 and contributed to the overall U.S. liquid fuels GHG footprint. Upstream emissions for those materials imported to the U. S. were estimated and added to the U.S. refining upstream profile to gain a comprehensive view of the GHG emissions consistent with use of liquid fuels in the U.S. in 2005.

Crude oil was refined in and finished products exported from a distinct set of foreign countries for each fuel–gasoline, diesel and jet fuel. Feedstock extraction modeling was conducted and results compiled for each of these sets of foreign countries. Appendix A outlines the specific sources for imported gasoline (and associated blendstocks), diesel (≤ 500 ppm sulfur), and kerosene-based jet fuel as reported by EIA. Table 2-12 shows the import quantities and the percent of U.S. consumption for 2005 that the import quantity represents. Significant proportions of gasoline and jet fuel are imported but only a small fraction of diesel fuel.

Table 2-12. Import Quantities of Petroleum Fuels in 2005 and Percent of 2005 U.S. Consumption

	Import Quantity (bpd)	Imports as a % of 2005 U.S. Consumption
Conventional Gasoline	1,106,712	12.7%
Conventional Diesel	157,164	5.2%
Kerosene-Based Jet fuel	190,049	11.3%

All countries which exported finished products of interest to the U.S. in 2005 are shown in Table 2-13. Data for the raw material extraction process is divided into three categories depending upon data availability for crude oil extraction profiles.

Table 2-13. Petroleum Products Import Sources and Data Availability for Raw Material Extraction GHG Emissions

Exporting Country	Country-Specific Crude Oil Extraction Profile Used	Country-Specific Delivered Crude Oil Profile Used	Surrogate Profile
Algeria	Yes		
Angola	Yes		
Argentina			FA
Aruba			FA
Australia		Yes	
Bahamas			FA
Belgium		Yes	
Brazil		Yes	
Bulgaria			FA
Canada			Individually Developed
Chile			FA
China, Peoples Rep		Yes	
Colombia			FA
Congo (Brazzaville)			FA
Denmark			EU-15
Ecuador	Yes		
Egypt			FA
Estonia			EU-25
Finland		Yes	
France		Yes	
Gabon			FA
Georgia			FA
Germany		Yes	
Ghana			FA
India			FA
Indonesia			FA

Exporting Country	Country-Specific Crude Oil Extraction Profile Used	Country-Specific Delivered Crude Oil Profile Used	Surrogate Profile
Iraq	Yes		
Ireland			EU-15
Italy		Yes	
Japan		Yes	
Kazakhstan			FA
Korea, South			Saudi Arabia
Kuwait	Yes		
Latvia			EU-25
Lithuania			EU-25
Malaysia			FA
Martinique			FA
Mexico	Yes		
Netherlands		Yes	
Netherlands Antilles			FA
Nigeria	Yes		
Norway		Yes	
Peru			FA
Philippines			FA
Poland			EU-25
Portugal		Yes	
Qatar			FA
Romania			FA
Russia		Yes	
Saudi Arabia	Yes		
Singapore			FA
Spain		Yes	
Sweden		Yes	
Taiwan			FA
Thailand			FA
Trinidad & Tobago			FA
Turkey			FA
Turkmenistan			FA
United Kingdom		Yes	
Uruguay			FA
Venezuela	Yes		
Virgin Islands, U.S.			Individually Developed

FA = Foreign Average (Average of Australia, Belgium, Brazil, China, EU-15, EU-25, Finland, France, Germany, Italy, Japan, Netherlands, Norway, Portugal, Russia, Spain, Sweden, and United Kingdom)

EU-15 includes Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Sweden and the United Kingdom

EU-25 includes EU-15 plus Cyprus, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Malta, Poland, Slovakia, and Slovenia

Country-Specific Crude Oil Extraction Profiles

Emissions data for crude oil extraction for the top countries supplying crude oil to the U.S. were purchased from PE International (2008). Of the foreign countries for which extraction information was obtained, Angola, Ecuador, Iraq, Kuwait, Mexico, Nigeria, Saudi Arabia, and Venezuela report no crude oil imports for 2005 (IEA 2008). Algeria imports a small quantity of crude oil (less than 0.5% of the produced quantity) (IEA 2008). For all of the aforementioned countries it is assumed that the country-specific extraction profile is representative of the crude oil being fed to refineries in these countries.

Country-Specific Delivered Crude Oil Profile

Country-specific "free-to-customer" or in-country delivered crude oil mix profiles were extracted from GaBi 4 Life Cycle Assessment Software, Professional Database (2007), when available. Delivered "free-to-customer" country-specific profiles include an embedded transport component in the GHG profile. The extraction contribution to the total GHG profile has been estimated by determining the GHG contribution of the extraction step to the total U.S. delivered GHG profile and assuming that the same relative contribution of the extraction component is applicable to foreign crude oil mixes. For crude oil delivered to domestic refineries, 75% of the CO_2, 99% of methane, and 80% of nitrous oxide is attributable to raw material acquisition. The embedded transport component which is excluded here is incorporated in LC Stage #2 modeling.

Canada Profile

The Canada composite profile was individually developed, as it is a primary liquid fuel exporter to the U.S. and its refineries import a significant portion of their feedstocks. Table 2-14 lists the refinery feedstocks—both foreign and domestic—input to Canadian refineries in 2005. Over 50% of the Canadian refinery feedstocks for 2005 were attributable to foreign crudes.

Table 2-14. Canadian Refinery Feedstocks for 2005 (StatCan 2008)

Country/Crude Source	Quantity (thousands m^3)	% of Total Crude Oil and Equivalent	Quantity (bpd)
Imports			
Algeria	9,469	8.8%	163,170
Angola	908	0.8%	15,652
Iraq	3,803	3.6%	65,531
Nigeria	1,426	1.3%	24,570
Saudi Arabia	4,386	4.1%	75,574
Venezuela	2,805	2.6%	48,342
Russia	1,263	1.2%	21,759
Norway	13,961	13.0%	240,579
United Kingdom	8,461	7.9%	145,808
United States	1,226	1.1%	21,130
Mexico	2,153	2.0%	37,103
Ecuador	351	0.3%	6,054
Other Countries	3,574	3.3%	61,587
Total Imports	**53,786**	**50.2%**	**926,860**

Country/Crude Source	Quantity (thousands m^3)	% of Total Crude Oil and Equivalent	Quantity (bpd)
Domestic Production			
Canada Crude (light + heavy)	32,402	30.3%	558,370
Synthetic Crude Oil (light)	14,836	13.9%	255,663
Crude Bitumen	4,065	3.8%	70,056
Condensates and pentanes +	2,024	1.9%	34,885
Total Domestic	**53,328**	**49.8%**	**918,974**
Total Imports + Domestic	**107,114**	**100.0%**	**1,845,833**

Country-specific extraction profiles obtained for PE International (2008) were utilized for all foreign crude oil sources with the exception of Russia, Norway and the United Kingdom. For the three latter countries, the delivered crude oil profile is used after removing the estimated transport component. The underlying assumption in using these profiles is that the GHG extraction profile for the crude oil mix utilized in these countries is equivalent to the profile for the crude oil exported from those countries.

For Canadian conventional crude oil, the extraction profile was developed as described in Section 2.1.1.1. For Canadian oil sands, Table 2-6 lists the upstream emissions on a per-barrel-oil-equivalent basis. For this profile, synthetic crude oil (light) upstream emissions were taken from Syncrude emissions reports for 2005 (EnvCan 2008), (Syncrude 2006) and crude bitumen upstream emissions were approximated by assuming Imperial Oil Cold Lake bitumen production emissions are representative of all 2005 crude bitumen production operations. Condensates and pentanes plus were modeled the same as U.S. NGL (see Section 2.1.2).

The resulting extraction profile for feedstocks to Canadian refineries in 2005 is shown in Table 2-15.

Table 2-15. GHG Emissions Consistent with Extraction of Crude Oil Mix to Canadian Refineries in 2005

Source	Emissions (kg/bbl crude oil)		
	CO_2	CH_4	N_2O
Crude Oil Mix Average	35.0	0.366	0.00102

Virgin Islands Profile

The Virgin Islands profile was also developed individually as it is a primary liquid fuel exporter to the U.S. and its refineries import all of their feedstocks, as shown in Table 2-16.

Table 2-16. Virgin Islands Refinery Feedstocks for 2005 (EIA 2008)

Country/Crude Source	Import Quantity (bpd)	% of Total Crude Oil and Equivalent
Angola	7,984	1.7%
Colombia	8,858	1.9%
Ivory Coast	2,584	0.6%
Gabon	65,479	14.2%
Iraq	1,233	0.3%
Nigeria	29,945	6.5%
Norway	28,162	6.1%
Peru	989	0.2%
United Kingdom	8,395	1.8%
Venezuela	307,767	66.7%
Total	**461,395**	100.0%

As available, country-specific extraction profiles obtained for PE International (2008) were utilized for all foreign crude oil sources. Colombia was modeled using Venezuela as a surrogate profile, Peru was modeled using Ecuador as a surrogate profile, and the Ivory Coast and Gabon were modeled using Angola as a surrogate profile. The resulting extraction profile for feedstocks to Virgin Island refineries in 2005 is shown in Table 2-17.

Table 2-17. GHG Emissions Consistent with Extraction of Crude Oil Mix to the Virgin Islands Refinery in 2005

Source	Emissions (kg/bbl crude oil)		
	CO_2	CH_4	N_2O
Crude Oil Mix Average	23.0	0.634	0.000590

Surrogate Profiles

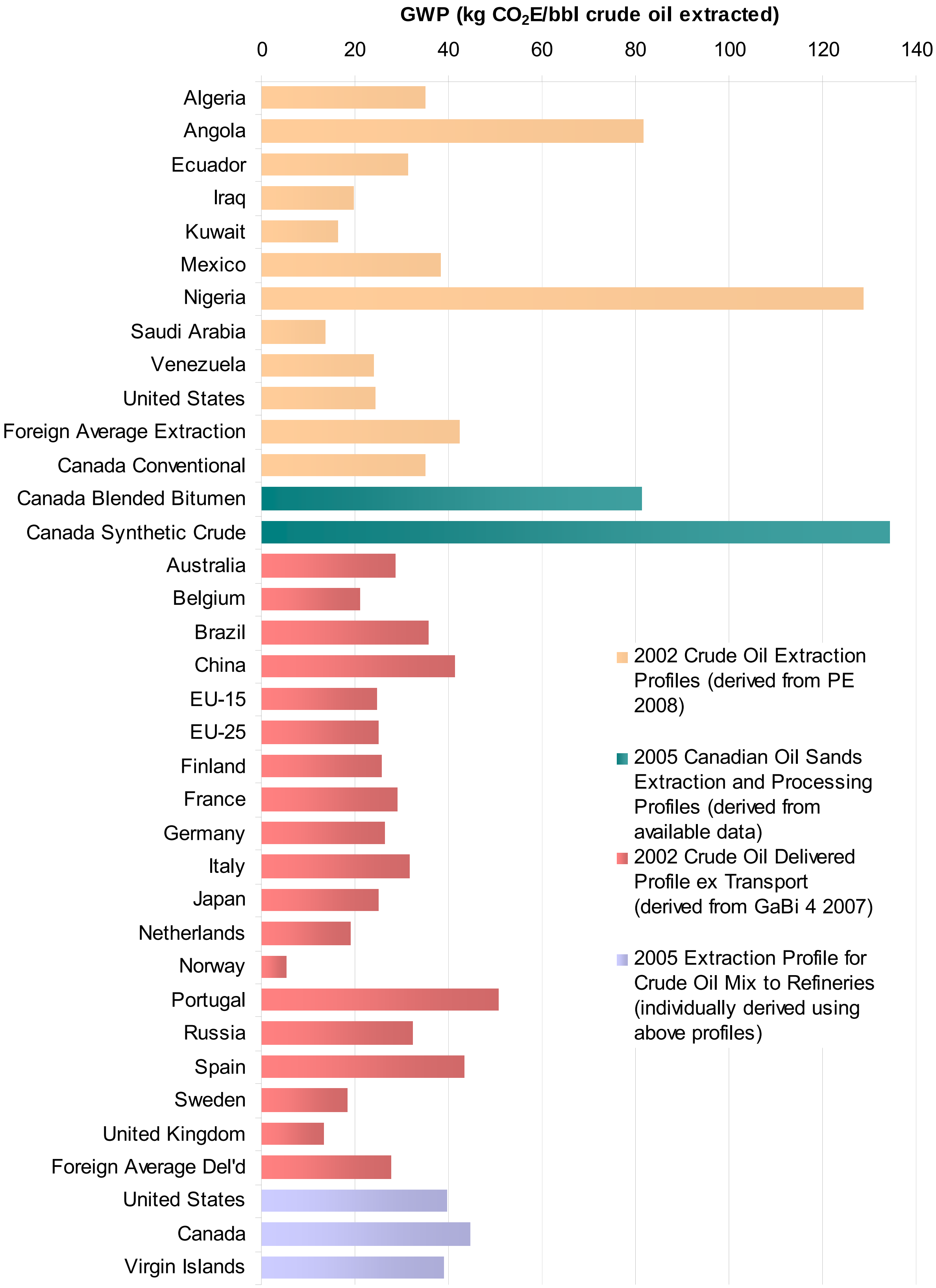
For other countries, a surrogate profile was chosen based upon either geographic location or primary crude source. For any European country for which a country-specific delivered profile was not available, the EU-15 or EU-25 delivered profile was utilized. For South Korea, the crude source is primarily Saudi Arabia (EIA 2008). For all other countries, the crude oil profile is estimated as simply a foreign average (FA) of the delivered profiles. § The foreign average is used for 9% of the gasoline crude oil mix, 12% of the diesel crude oil mix, and 22% of the jet fuel crude oil mix. With the exception of Saudi Arabia, these profiles represent the GHG emissions for delivered crude oil and the embedded transport component was removed as previously described.

Table 2-13 lists the export countries and the upstream profile used to determine the crude oil extraction emissions. Figure 2-5 shows the global warming potential (calculated using the factors in Table 1-1) for each of the profiles utilized and developed. For the delivered crude oil profiles, the transport component was excluded.

---

§ A sensitivity analysis was performed on these parameters.

Figure 2-5. GHG Emissions Consistent with Crude Oil Extraction



2.2.2 Raw Material Extraction for Gasoline Imports

Imported motor gasoline and associated blendstocks amounted to 14.2% of domestic gasoline production in 2005. Imports come from many different countries, as shown in Appendix A. Canada (15.8%), the Netherlands (10.5%), Virgin Islands (10.5%), the United Kingdom (10.3%), and Venezuela (7.6%) were the top exporters of gasoline (and associated blendstocks) to the U.S. in 2005. The composite GHG emissions profile consistent with extraction of the crude oil mix used in refining of gasoline imported to the U.S. in 2005 is shown in Table 2-18.

Table 2-18. GHG Emissions Consistent with Extraction of Composite Crude Oil Mix for Foreign Gasoline Refining in 2005

Source	Emissions (kg/bbl crude oil extracted)		
	CO_2	CH_4	N_2O
Crude Oil Mix Average	19.3	0.429	0.000497

2.2.3 Raw Material Extraction for Diesel Imports

Diesel is imported primarily from Canada and the Virgin Islands and these two sources make up 68.5% of the total U.S. diesel imports (≤ 500 ppm sulfur). European countries (Belgium, Denmark, Estonia, France, Germany, Latvia, Lithuania, Netherlands, Sweden, and the United Kingdom) make up an additional 11.5%. The origin of U.S. distillate imports for 2005 is shown in Appendix A along with the quantity imported. The composite GHG emissions profile consistent with extraction of the crude oil mix used in refining of diesel fuel imported to the U.S. in 2005 is shown in Table 2-19.

Table 2-19. GHG Emissions Consistent with Extraction of Composite Crude Oil Mix for Foreign Diesel Refining in 2005

Source	Emissions (kg/bbl crude oil extracted)		
	CO_2	CH_4	N_2O
Crude Oil Mix Average	25.0	0.437	0.000676

2.2.4 Raw Material Extraction for Jet Fuel Imports

The primary import sources for jet fuel in 2005 were South Korea (21.9%), followed by the Virgin Islands (16.7%) and Venezuela (15.7%). The origin of U.S. jet fuel imports for 2005 is shown in Appendix A along with the quantity imported. The composite GHG emissions profile consistent with extraction of the crude oil mix used in refining of kerosene-based jet fuel imported to the U.S. in 2005 is shown in Table 2-20.

Table 2-20. GHG Emissions Consistent with Extraction of Composite Crude Oil Mix for Foreign Jet Fuel Refining in 2005

Source	Emissions (kg/bbl crude oil extracted)		
	CO_2	CH_4	N_2O
Crude Oil Mix Average	18.0	0.315	0.000448

2.3 Summary of Life Cycle Stage #1 GHG Emissions Profiles

Table 2-21 summarizes the emissions profiles associated with acquisition of petroleum refining feedstocks for U.S. refineries and foreign refineries producing gasoline, diesel and jet fuel imported by the U.S. in 2005. Emissions are presented per barrel of feedstock extracted. Emissions associated with Canadian oil sands extraction and processing are included in the crude oil extraction profile.

Table 2-21. Summary of GHG Emissions Consistent with Extraction of Crude Oil and Other Feedstocks for U.S. and Foreign Refineries in 2005

Source	Emissions (kg/bbl extracted)		
	CO_2	CH_4	N_2O
Feedstock Extraction for U.S. Refineries			
Crude Oil	26.3	0.515	0.000717
NGL	5.33	0.105	0.000288
Unfinished Oils	38.3	0.544	0.000901
Crude Oil Extraction for Foreign Refineries			
Gasoline Imports	19.3	0.429	0.000497
Diesel Imports	25.0	0.437	0.000676
Jet Fuel Imports	18.0	0.315	0.000448

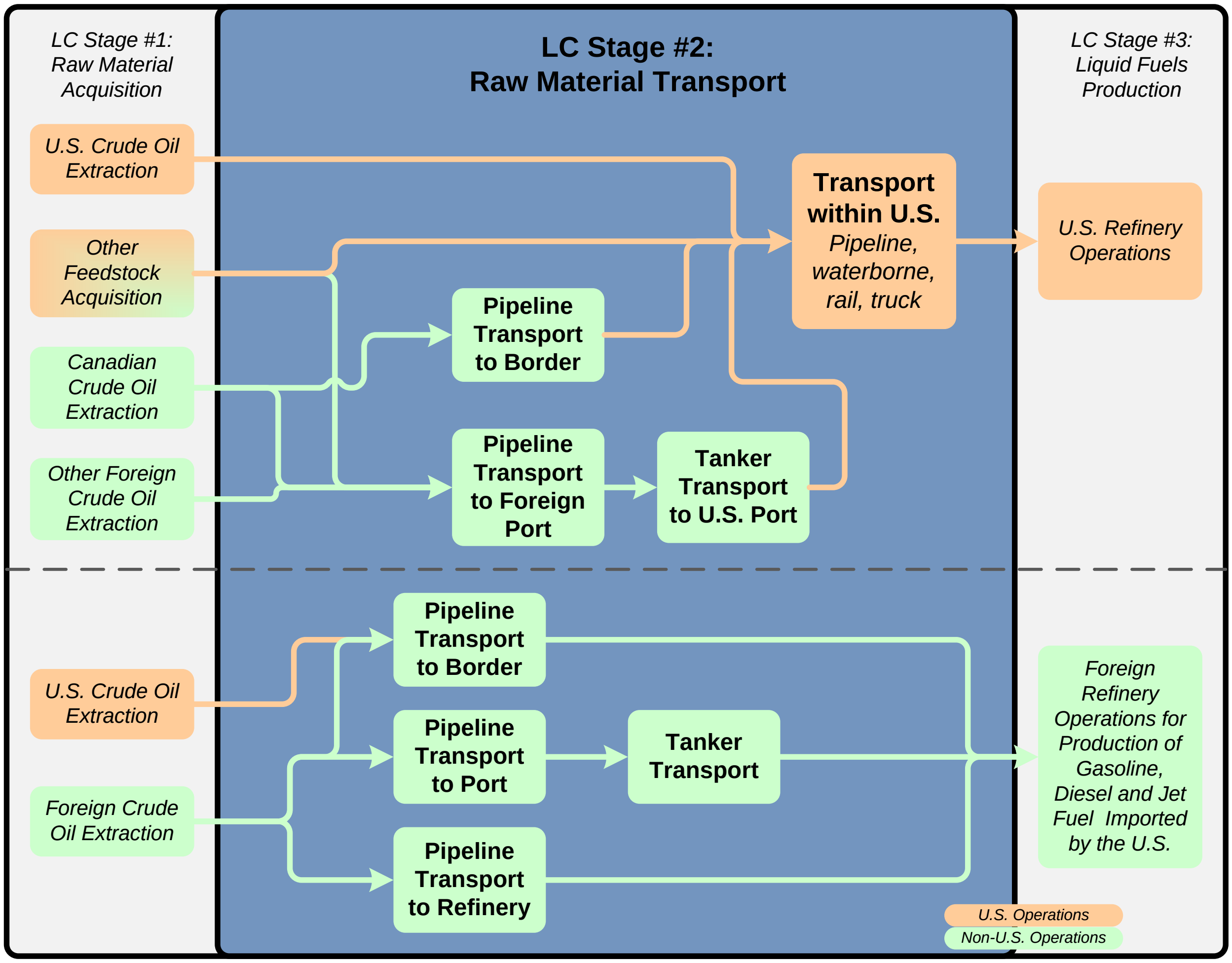
3.0 Life Cycle Stage #2: Raw Material Transport

Emissions profiles associated with transportation for the following petroleum refinery feedstocks are included in this stage:

- Crude oil and other hydrocarbons (i.e. from Canadian oil sands) fed to refineries as synthetic crude
- Natural Gas Liquids
- Unfinished Oils

Figure 3-1 depicts the activities and flow of feedstocks for LC Stage #2.

Figure 3-1. Flow Diagram of Raw Material Transport Activities



3.1 Crude Oil Mix Transport

Crude oil transport includes transport of foreign and domestic crude oil from the point of extraction to the refinery. Crude oil transport is modeled for delivery to domestic refineries and foreign refineries for processing into finished imports. Transport emissions are based on the amount input to a transport operation (amount extracted). Losses are then assessed at the end of the transport operation (Appendix H).

3.1.1 Crude Oil Mix Transport to Domestic Refineries

Crude oil transport to U.S. refineries includes pipeline transport within the exporting country, ocean tanker transport to the U.S., and domestic crude oil transport to refineries via a combination of pipeline, water carrier, rail, and truck.

3.1.1.1 Crude Oil Transport within Exporting Country

For all foreign crude sources for U.S. refineries, the crude is assumed to be transported 100 miles via pipeline to an ocean port or U.S. border.§

The energy intensity for pipeline transport is assumed to be 260 Btu/ton-mile (Wang 2008) and electricity is assumed to be the power source. The emissions associated with pipeline transport are estimated using emissions from the U.S. power grid as a surrogate profile for that of foreign countries (Appendix B).§ This is noted as a data limitation but the overall impact to the life cycle emissions is minimal. The resulting emissions profile per barrel of crude oil imported is shown in Table 3-1.

Table 3-1. GHG Emissions Associated with Transport of Imported Crude Oil from Point of Extraction to Foreign Ports

Emissions Source	Emissions (kg/bbl extracted)		
	CO_2	CH_4	N_2O
Pipeline Transport	0.863	1.00E-03	1.12E-05

3.1.1.2 Crude Oil Mix Ocean Transport to Domestic Ports

The energy requirement for transporting crude oil via tanker is calculated by multiplying the quantity shipped by the distance traveled in nautical miles and the energy intensity for transport. The return trip is assumed to require the same amount of energy. The values are summed for each of the different import sources and the emissions associated with consumption of that quantity of energy (as heavy fuel oil) is determined.

Table 3-2 outlines the performance specifications for various sizes and types of crude carriers. The energy intensity ranges from 4.2 to 7.5 Btu per barrel-nautical mile of crude transported. The assumed study value for crude tanker transport operations is 5.5 Btu per barrel-nautical mile.§

The heavy fuel oil (HFO) used to power tanker operations is essentially residual fuel oil and therefore the GHG emissions profile consistent with combustion of residual fuel oil in marine

---

§ A sensitivity analysis was performed on these parameters.

engines is used to determine the ship emissions during international transport. GHG emissions from heavy fuel oil are presented in Table 3-3. Emissions are per million Btu higher heating value (HHV) of fuel combusted.

Table 3-2. Performance Specifications for Various Crude Tankers

Designation	Formosapetro Discovery VLCC (IHI 2008a)	Sky Wing (IHI 2008b)	VLCC (IHI 2008c)	Suezmax Oil Tanker (Brodosplit 2008)	Oil Tanker (Brodosplit 2008)	Oil Tanker (Brodosplit 2008)
Service Speed (kt)	15	15.8	16.3	15.5	15.3	15.52
Fuel Oil Consumption (tonnes/day)	75.4	97.3	89.7	56.7	52.3	51.2
Cargo Volume (m^3)	328,458	340,218	350,000	185,447	126,210	126,211
Deadweight (MT)	281,434	299,997	300,500	166,300	114,000	108,000
Product Volume (bbl)	2,065,938	2,139,907	2,201,434	1,166,426	793,837	793,843
Energy Intensity: Btu/bbl-nautical mile	**4.24**	**5.02**	**4.36**	**5.47**	**7.51**	**7.25**

Table 3-3. GHG Emissions from Combustion of HFO (Residual Fuel Oil) in Ships (EIA 2007)

Emissions Source	Emissions (kg/MMBtu HHV)		
	CO_2	CH_4	N_2O
HFO Combustion in Ships	78.8	5.75E-03	2.00E-03

Table 3-4 lists the foreign crude sources for 2005 and the exporting port(s) with associated average ocean travel distance in nautical miles. EIA reports crude oil volumes, receiving ports, and country of origin for each shipment imported in 2005. Portworld distance calculator (2008) was used along with the EIA data to determine port-to-port travel distances for all crude oil shipments for the top ten crude oil importing countries. Transport through the Panama Canal, Suez Canal, and Bosporus Strait was disallowed. Canadian exports entering the U.S. through ocean or lake ports are assumed to travel via water while all others are assumed to be transported via pipeline. Based on this assumption, approximately 28% of the imports from Canada are waterborne. For shipments received from countries other than those listed in Table 3-4, the one-way travel distance is assumed to be 10,000 nautical miles.§

Table 3-4. Sources of U.S. Crude Input to Refineries, Exporting Port, and Country-Specific Average Ocean Travel Distance

U.S. Crude Oil Sources	Import as % of Refinery Crude Input (Year 2005, EIA)	Exporting Port	Country-Specific Average One-WayTravel Distance (nautical miles)
Canada Waterborne	2.99%	Vancouver/Hibernia	675*
Canada Pipeline	7.70%	NA	NA

---

§ A sensitivity analysis was performed on these parameters.

U.S. Crude Oil Sources	Import as % of Refinery Crude Input (Year 2005, EIA)	Exporting Port	Country-Specific Average One-WayTravel Distance (nautical miles)
Mexico Crude Oil	10.2%	Cayo Arcas	1,061
Saudi Arabia Crude Oil	9.4%	Ras Tanura	12,018
Venezuela Crude Oil	8.1%	Amuay/Cardon	1,789
Nigeria Crude Oil	7.1%	Bonny Island	5,672
Iraq Crude Oil	3.4%	Umm Qasr	12,370
Angola Crude Oil	3.0%	Luanda	6,736
Ecuador Crude Oil	1.8%	Balao	5,653
Algeria Crude Oil	1.5%	Arzew	4,452
Kuwait Crude Oil	1.5%	Mina al-Ahmadi	12,526
Other	9.5%		10,000

*Weighted average based on assumed waterborne import volumes only.

Table 3-5 lists the GHG emissions associated with tanker transport of waterborne crude oil from foreign ports to the U.S. in 2005.

Table 3-5. GHG Emissions Associated with Ocean Tanker Transport of Waterborne Imported Crude Oil to Domestic Ports

Emissions Source	Emissions (kg/bbl exported)		
	CO_2	CH_4	N_2O
Tanker Transport to U.S. Port	5.54	4.04E-04	1.41E-04

3.1.1.3 Crude Oil Mix Domestic Transport

Crude oil mix within the U.S. is transported via pipeline, water carrier, rail, and truck. Table 3-6 summarizes U.S. crude petroleum domestic transportation modes for years 2000 through 2004.

Table 3-6. Total *Crude Petroleum* Carried In Domestic Transportation (Billions of Ton-Miles) and Percent of Total Carried by Mode of Transportation (AOP 2006)

Year	Total Products	Pipelines*		Water Carriers		Motor Carriers**		Railroads	
	Ton-miles	Ton-miles	% of Total	Ton-miles	% of Total	Ton-miles	% of Total	Ton-miles	% of Total
2000	376.0	283.4	75.4	91.0	24.2	1.2	0.3	0.4	0.1
2001	376.6	277.0	73.6	98.1	26.0	1.1	0.3	0.4	0.1
2002	384.0	286.6	74.7	95.7	24.9	1.2	0.3	0.5	0.1
2003	380.4	284.5	74.8	94.1	24.8	1.3	0.3	0.5	0.1
2004	374.1	283.7	75.9	88.7	23.7	1.2	0.3	0.5	0.1

* The amounts carried by pipeline are based on ton-miles of crude and petroleum products for federally-regulated pipelines (84 percent) plus an estimated breakdown of crude and petroleum products in units of ton-miles for pipelines that are not federally regulated (16 percent).

** The amounts carried by motor carriers are estimated.

The Oak Ridge National Laboratory (ORNL) Transportation Energy Data Book (2007), Table 2.4, outlines the domestic consumption of transportation energy by mode and fuel type. These data were used to determine the fuel powering the aforementioned transportation operations. Based upon the ORNL Transportation Energy Data Book, Table 2.4, in 2004, natural gas and electricity were the primary fuels for effecting pipeline transport. Since natural gas is used primarily for fueling natural gas pipeline transport, all crude oil and petroleum product transport via pipeline is assumed to be fueled by electricity. Similarly, diesel fuel is shown to be the exclusive fuel source for Class I freight railroad operations. Water carriers transporting freight are powered by diesel fuel and residual fuel oil (30.5 % diesel fuel and 69.5% residual fuel oil on an energetic basis). Medium/heavy trucks were powered primarily (90%) by diesel fuel and all petroleum tanker trucks in this study are assumed to be powered exclusively by diesel fuel.

Table 3-7. Energy Intensity of Transport Activities

Transport Mode	Energy Intensity (One-way)	Unit	Reference Year	Reference
Petroleum Pipeline	260	Btu/ton-mile	2008	Wang 2008
Water Carriers	514	Btu/ton-mile	2005	ORNL 2007, Table 2.16
Railroad	337	Btu/ton-mile	2005	ORNL 2007, Table 2.16
Heavy single-unit and combination trucks	20,539	Btu/Vehicle-Mile	2005	ORNL 2007, Table 2.16
Heavy single-unit and combination trucks	822*	Btu/ton-Mile	2005	ORNL 2007, Table 2.16

* Assuming a 25-ton tanker truck capacity

The data from Table 3-6 and Table 3-7 are then combined to determine a quantity of energy (by transport type) expended for crude petroleum transport in 2004. This energy/resource usage is then allocated to the 5,675,365,000 barrels of crude oil (sum of 2004 imported crude oil and 2004 U.S. crude oil production). The transportation energy usage relative to barrels transported is assumed to be the same for 2005. Results of the energy usage allocation are summarized in Table 3-8.

Table 3-8. Energy Usage for Crude Petroleum Transport Activities

Transport Mode	Total Energy Usage (Billion Btu HHV)	Energy Usage (Btu HHV/bbl of Crude Petroleum Transported)	Fuel Source
Petroleum Pipeline	73,762	12,997	Electricity
Water Carriers	91,184	16,067	30.5% Diesel Fuel 69.5% Residual Fuel Oil
Railroad	337	59	Diesel Fuel
Heavy single-unit and combination trucks	1,972	347	Diesel Fuel

In order to determine emissions associated with the estimated fuel consumption for crude oil transport, appropriate emissions factors are applied to the quantities of fuels consumed (as shown in Table 3-8) for transport. Table 3-9 provides a summary of the emissions factors applied for each mode of fuel product transportation. The emissions factors for diesel fuel and residual fuel oil are for combustion of the fuel only. The upstream emissions associated with production of secondary fuels contribute only minimally to the final results for the scenarios of interest.

Table 3-9. Crude Oil Transportation Modes and Associated Emission Factors

Transport Mode	Energy Usage (Btu HHV /bbl of Petroleum Transport)	Fuel Source	Fuel Energy Content (MMBtu HHV/ bbl)	CO_2 Emissions (g CO_2 /gallon)	CH_4 Emissions (g CH4 /gallon)	N_2O Emissions (g N_2O /gallon)	Emission Factor References
Pipeline	12,997	Electricity	N/A	217*	0.251*	0.00281*	EPA, 2007 (eGRID); GaBi 4, 2007
Water Carriers	4,900	Diesel Fuel	5.825	10,147	0.74	0.26	EIA 2007
Water Carriers	11,166	Residual Fuel Oil	6.287	11,793	0.86	0.3	EIA 2007
Railroad	59	Diesel Fuel	5.825	10,147	0.8	0.26	EIA 2007
Heavy single-unit and combination trucks	347	Diesel Fuel	5.825	10,147	0.57	0.3	API 2004 Table 4-9

* Emission factor units are kg/MMBtu for electricity

Calculated specific transit GHG emissions associated with each of the aforementioned modes of crude oil transportation are reported in Table 3-10. The total GHG emissions per barrel factors are applied to all crude oil fed to U.S. refineries.

Table 3-10. GHG Emissions Associated with Crude Oil Transport within U.S.

Transport Mode	Emissions (kg/bbl extracted)		
	CO_2	CH_4	N_2O
Pipeline	2.81	3.27E-03	3.65E-05
Water Carriers (Diesel)	0.359	2.61E-05	9.19E-06
Water Carriers (Residual Fuel Oil)	0.880	6.42E-05	2.24E-05
Railroad	0.00434	3.43E-07	1.11E-07
Heavy single-unit and combination trucks	0.0254	1.43E-06	7.52E-07
Total	**4.08**	**3.36E-03**	**6.90E-05**

3.1.2 Crude Oil Mix Transport to Foreign Refineries

Crude oil transport is estimated from the point of extraction to the foreign refineries producing imported liquid fuels. The methods utilized for each country exporting finished fuels to the U.S. vary by country.

Delivered Country-Specific Profiles

Countries for which the crude oil delivered "free-to-customer" country-specific profiles are available are detailed in Table 2-13. These profiles include an embedded transport component in the GHG profile. The transport contribution to the total GHG profile for these countries has been estimated by determining the GHG contribution of the transport step to the total U.S. delivered GHG profile and assuming that the same relative contribution of the transport component is applicable to foreign crude oil mixes. For crude oil delivered to domestic refineries, 25% of the CO_2, 1% of methane, and 20% of nitrous oxide is attributable to transport operations.

Pipeline Transport

An average pipeline transport distance of 100 miles from the point of extraction to an in-country refinery is assumed for all countries where a country-specific extraction profile was used.§

The energy intensity for pipeline transport is assumed to be 260 Btu/ton-mile (Wang 2008) and electricity is assumed to be the power source. The emissions associated with pipeline transport are estimated using emissions from the U.S. power grid as a surrogate profile for that of foreign countries (Appendix B). This is noted as a data limitation but the overall impact to the life cycle emissions is expected to be minimal. The resulting emissions profile per barrel of crude oil transported by pipeline is shown in Table 3-11.

Table 3-11. GHG Emissions Associated with Transport of Foreign Crude to Foreign Refineries/Ports

Source	Emissions (kg/bbl exported)		
	CO_2	CH_4	N_2O
Pipeline Transport	0.863	1.00E-03	1.12E-05

Tanker Transport

Canada and the Virgin Islands import significant quantities of foreign crudes for refinery processing. Transport of crude oil to South Korea is also assumed to be 100% by tanker transport. Portworld distance calculator (2008) was used along with the EIA data to determine port-to-port travel distances for crude oil shipments. Transport through the Panama Canal, Suez Canal, and Bosporus Strait was disallowed. The emissions associated with ocean transport of crude was determined as outlined in Section 3.1.1.2 and are shown in Table 3-12 along with the weighted average travel distance determined for each country. It was assumed that all crude imports to Canada from the U.S. were by pipeline. Crude oil mix transport within Canada, the Virgin Islands and South Korea is assumed to be negligible because refineries receiving crude are located at a port.

---

§ A sensitivity analysis was performed on these parameters.

Table 3-12. GHG Emissions and One-Way Travel Distance Assumptions Associated with Ocean Tanker Transport of Foreign Crude to Foreign Refineries/Ports

Receiving Country	Weighted Average Travel Distance One Way (nautical miles)*	Emissions (kg/bbl exported)		
		CO_2	CH_4	N_2O
Canada	4,967	4.31	3.14E-04	1.09E-04
Virgin Islands	1,729	1.50	1.09E-04	3.81E-05
South Korea	6,190	5.37	3.91E-04	1.36E-04

*Weighted average based on assumed waterborne import volumes only.

Composite Transport GHG Emissions to Foreign Refineries

Combining the ocean transport, pipeline transport and the transport portion of the delivered country-specific profiles for the countries exporting gasoline, diesel and jet fuel to the U.S. results in GHG emissions per barrel of crude oil as shown in Table 3-13.

Table 3-13. GHG Emissions Associated with All Modes of Transport of Foreign Crude to Foreign Refineries

Source	Emissions (kg/bbl crude oil exported)		
	CO_2	CH_4	N_2O
Conventional Gasoline	3.87	2.38E-03	7.01E-05
Conventional Diesel	3.45	1.59E-03	6.80E-05
Kerosene-Based Jet Fuel	3.69	1.80E-03	7.33E-05

3.2 Natural Gas Liquids Transport

NGL transport has been modeled the same as petroleum products transport in Life Cycle Stage #4 (see Section 5.1.2 for detailed modeling assumptions). Table 3-14 lists the estimated GHG emissions consistent with NGL transport.

Table 3-14. GHG Emissions Associated with NGL Transport

Source	Emissions (kg/bbl exported)		
	CO_2	CH_4	N_2O
NGL Transport	4.54	2.81E-03	8.93E-05

3.3 Unfinished Oils Transport

The unfinished oils transport component is modeled the same as an equivalent volume of imported crude oil. Refer to Section 3.1.1 for further detail. Table 3-15 lists the estimated GHG emissions consistent with unfinished oils transport.

Table 3-15. GHG Emissions Associated with Unfinished Oils Transport

Source	Emissions (kg/bbl exported)		
	CO_2	CH_4	N_2O
Unfinished Oils Transport	7.92	4.27E-03	1.59E-04

3.4 Summary of Life Cycle Stage #2 GHG Emissions Profiles

Table 3-16 summarizes the emissions profiles associated with transport of petroleum refining feedstocks for U.S. refineries and foreign refineries producing the gasoline, diesel and jet fuel imported by the U.S. in 2005. The increase in transport activity required to deliver each barrel of crude oil (due to transport losses detailed in Appendix H are applied and emissions are presented per barrel delivered to refineries.

Table 3-16. Summary of GHG Emissions Consistent with Transport of Crude Oil and Other Feedstocks for U.S. and Foreign Refineries in 2005

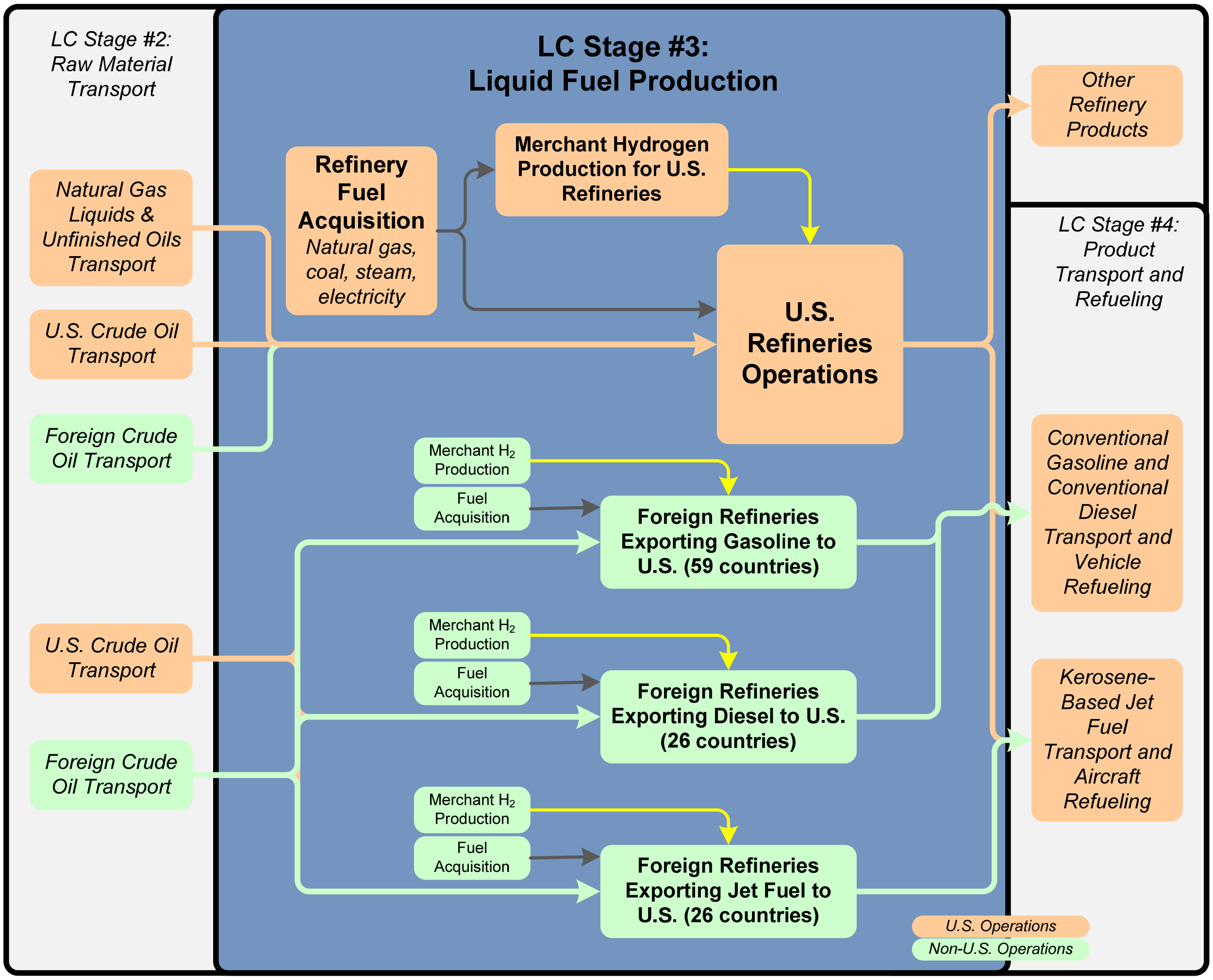
Source	Emissions (kg/bbl delivered)		
	CO_2	CH_4	N_2O
Feedstock Transport to U.S. Refineries			
Crude Oil	7.92	4.27E-03	1.59E-04
NGL	4.54	2.81E-03	8.93E-05
Unfinished Oils	7.92	4.27E-03	1.59E-04
Crude Oil Transport to Foreign Refineries			
Gasoline Imports	3.88	2.39E-03	7.03E-05
Diesel Imports	3.46	1.60E-03	6.82E-05
Jet Fuel Imports	3.70	1.80E-03	7.36E-05

4.0 Life Cycle Stage #3: Liquid Fuels Production

The boundary of LC Stage #3 starts at the entrance of the petroleum refinery with the receipt of feedstocks and ends at the entrance of the petroleum pipeline or tanker used to transport the liquid fuels to a bulk fuel storage depot. Modeling assumptions and methodology are described for both domestic refineries and foreign refineries providing imported gasoline, diesel and jet fuel. Production of oxygenates is excluded from the scope of this study.

Figure 4-1 depicts the activities and flow of feedstocks for LC Stage #3.

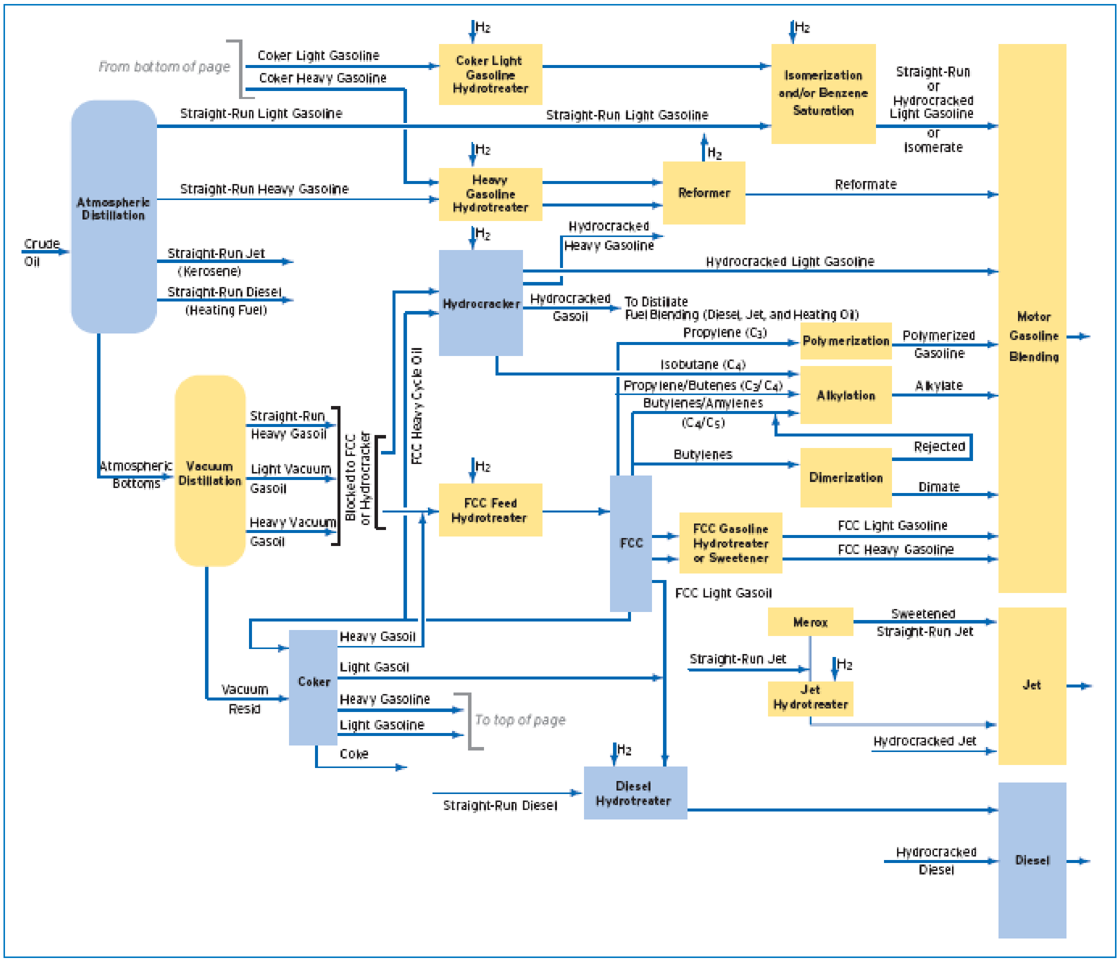
Figure 4-1. Flow Diagram of Liquid Fuels Production Activities



4.1 General Description of a Petroleum Refinery

Petroleum refining is an extremely complicated, highly integrated process where the equipment and unit operations are tailored to specific feed properties. The complexity level of refineries is increasing with time due to decreasing crude oil input quality (heavier crude oils with higher sulfur contents) resulting in increased upgrading and processing requirements. Figure 4-2 depicts a typical U.S. refinery operation.

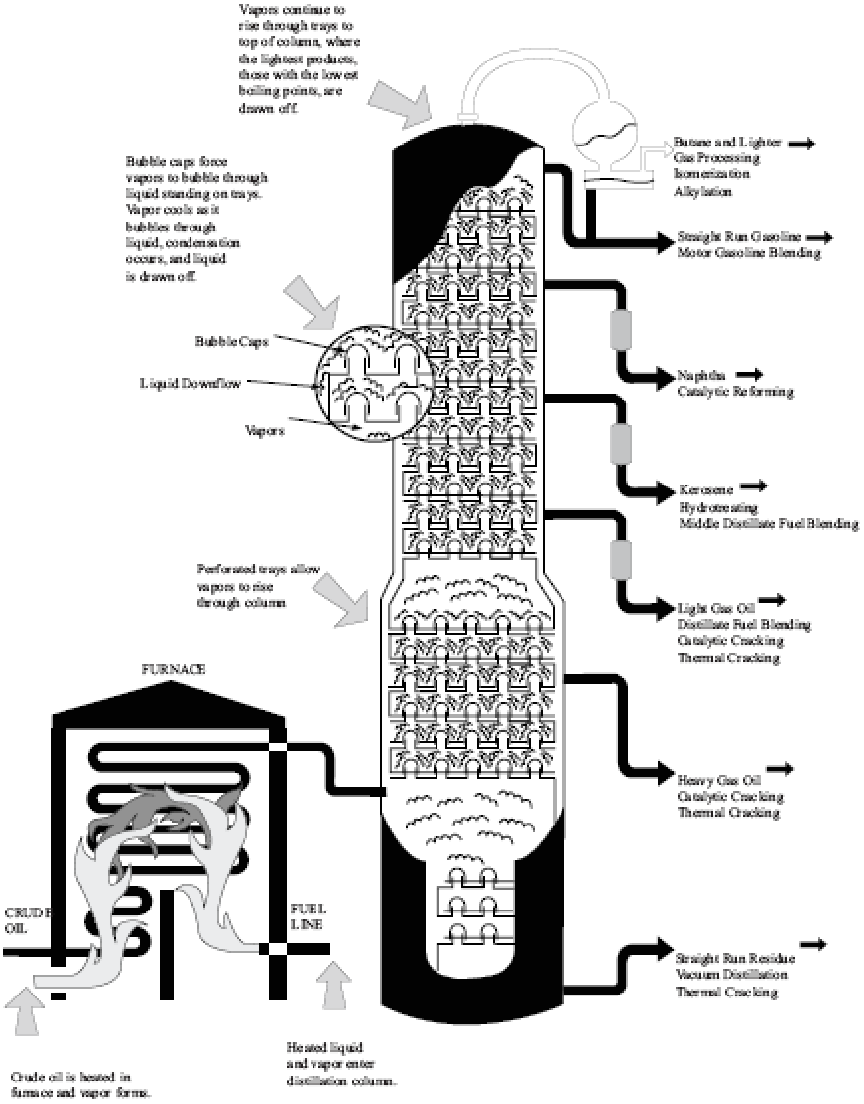
Figure 4-2. Modern Oil Refinery (Chevron 2007)



The following sections outline the basic operations that constitute a modern refinery and provide brief descriptions of those operations. Specialized operations that contribute solely (or primarily) to upgrading of hydrocarbon materials not intended for liquid transportation fuels (i.e. lubricants, etc) are not discussed.

Atmospheric and Vacuum Distillation: The first and most basic operation associated with a refinery is distillation. The atmospheric distillation column fractionates the crude oil input into various fractions with different boiling point ranges. Figure 4-3 shows the generalized operation of a distillation column and the various product cuts obtained. Table 4-1 shows a simplified breakdown of the boiling point cuts.

Figure 4-3. Atmospheric Distillation Column (EIA 1999)



The vacuum distillation process takes the heavy (high-molecular weight) fraction from the atmospheric distillation column and further separates the components by distillation under vacuum conditions.

Table 4-1. Crude Oil Boiling Point Range for Product Slate (Energetics 2007)

Fraction	ASTM Boiling Range, ºF
Light Straight-Run Gasoline	90-220
Naphtha	108-400
Kerosene	330-540
Light Gas Oil	420-640
Atmospheric Gas Oil	520-830
Heavy Residue	650+
Vacuum Gas Oil	750+

Catalytic Cracking: Catalytic cracking processes involve heating high-molecular weight hydrocarbons in the presence of a catalyst to break the molecules down into lighter components. This operation helps increase the gasoline and diesel fractions at the expense of the less-desirable residual fraction. Catalytic cracking is the most widely used crude oil upgrading process.

Catalytic Hydrocracking: Catalytic hydrocracking is similar to catalytic cracking except that hydrogen is added to facilitate molecular decompositions while simultaneously removing undesirable heteroatomic species (sulfur, nitrogen, etc.).

Coking: Coking processes are refining operations in which solid carbonaceous material (known as coke) is produced when the heavy hydrocarbon fraction from the vacuum distillation columns is thermally devolatilized. The low-molecular weight species produced during coking can be used as fuel gas, gasoline blendstocks, distillate blendstocks, or feedstocks for secondary upgrading/reforming processes. The solid coke can be either marketed or used as a refinery fuel.

Coking operations in the U.S. are primarily delayed coking with a small number of fluid coking processes. Delayed coking produces large coke grains suitable for electrode manufacture while fluid coking produces coke particulates. Delayed coking is a semi-batch process while fluid coking is a continuous process.

Desulfurization/Hydrotreating: The desulfurization/hydrotreating process is very similar to hydrocracking in that a hydrocarbon stream is reacted with hydrogen to remove sulfur species from the stream. This process is often distinguished from hydrocracking by the severity of the processing conditions. Since the purpose of the process is to remove sulfur and not significantly alter the molecular composition and species profile, it is often performed under milder conditions.

Catalytic Reforming: The catalytic reforming operation takes less desirable naphtha streams and chemically reconfigures the compounds. The primary operations are dehydrogenation of napthenes to produce aromatic species, isomerization, dehydrocyclization (transforming a straight-chain compound into a ring structure while dehydrogenating the same), and hydrocracking (Energetics 2007). While catalytically-reformed liquid fuels contribute primarily to the gasoline fraction, hydrogen is produced as a by-product of the reforming operations. This hydrogen may be used for desulfurization of products not contributing directly to the gasoline slate.

Isomerization: Isomerization is a process where straight-chain hydrocarbons (paraffins) are converted into branched isomers. The isoparaffins are produced through a series of molecular rearrangements in the presence of a catalyst. The branched paraffins are superior to the straight chain species because they have a higher octane number and thus contribute primarily to the gasoline product slate.

Alkylation: Alkylation is a process where isobutane, isopentane, and/or isohexane are alkylated with low-molecular-weight alkenes (primarily a mixture of propylene and butylene) in the presence of a strong acid catalyst, either sulfuric acid or hydrofluoric acid. The product of the reaction is a mixture of branched chain paraffins which are used as gasoline additives.

4.2 Liquid Fuels Production at Domestic Petroleum Refineries

The emissions profile associated with U.S. petroleum refining operations in 2005 consists of emissions from fuels acquisition, fuels combustion, hydrogen production, flaring, and venting and fugitive emissions. These refinery operations result in the production of a variety of finished products including gasoline, diesel fuel, kerosene-based jet fuel, and other petroleum-based products. The methodology for developing the GHG emissions profile and for allocating GHG emissions to the various co-products is discussed in detail in this section.

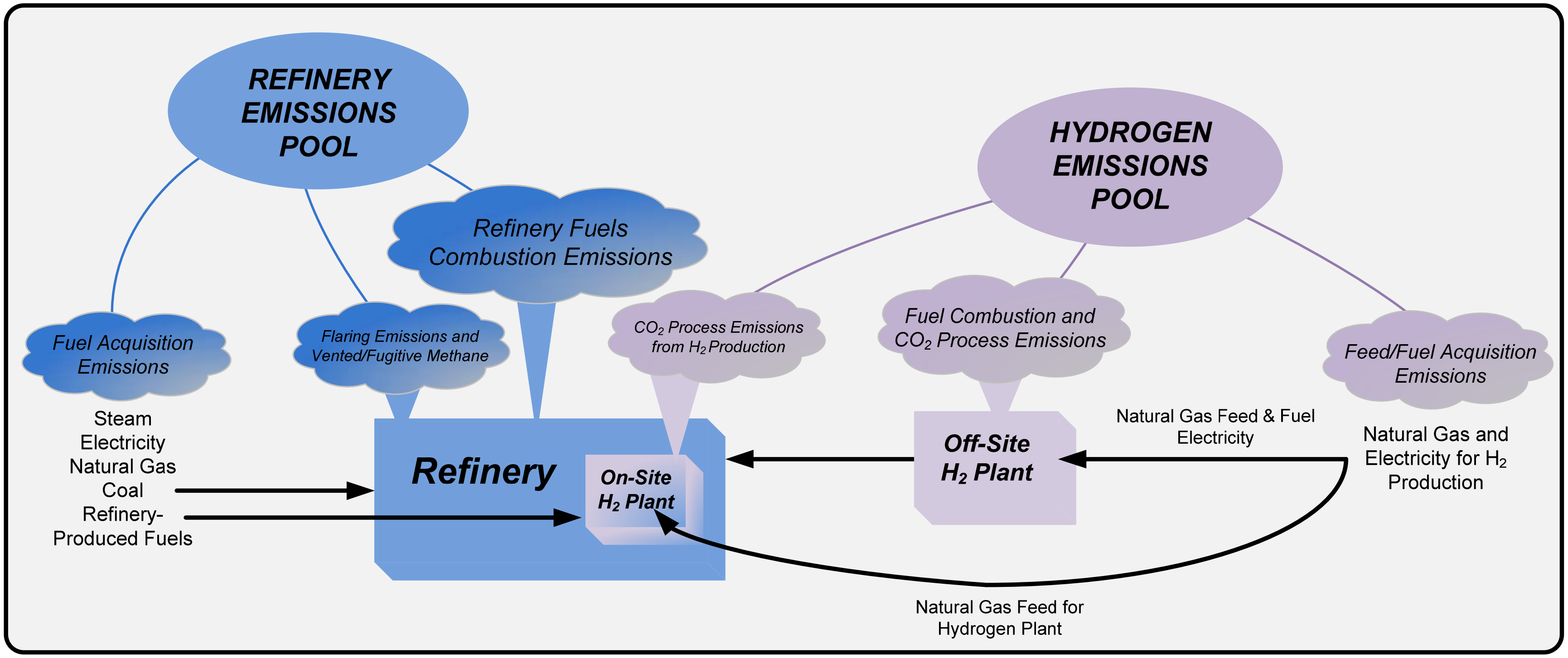
The GHG emissions profile associated with U.S. petroleum refining operations in 2005 consists of emissions from the following activities/sources:

- Acquisition of fuels
    - Indirect emissions associated with purchased power and steam
    - Emissions associated with the acquisition of coal and natural gas purchased and consumed at the refinery as fuels
    - Emissions associated with production of fuels at the refinery which are subsequently consumed as fuels (i.e. still gas, petroleum coke)
- Combustion of fuels at the refinery
- Hydrogen production (on-site and off-site)
    - Upstream emissions associated with natural gas feed
    - CO_2 process emissions from steam methane reforming (SMR)
    - Fuel combustion and upstream emissions associated with natural gas fuel and indirect (electricity) emissions for *off-site* hydrogen production
- Flaring
- Venting and fugitive emissions

The emissions above will be organized into a refinery emissions pool and a hydrogen emissions pool and subsequently allocated between the various refinery products. There are no individual assignments of energy sources to unit operations or refinery products. For example, emissions associated with acquisition and combustion of natural gas will not be allocated based on the unit operations where the natural gas is consumed.

Figure 4-4 depicts the two emissions pools, refinery and hydrogen, developed in this section. Fuels for use at the refinery enter from the left of the diagram while hydrogen produced off-site enters the refinery from the right of the diagram. As shown, a portion of the emissions associated with on-site hydrogen production are embedded in the refinery emissions profile while the remaining is included in the hydrogen emissions pool. This is discussed in detail in subsequent sections.

Figure 4-4. Depiction of Refinery and Hydrogen Emissions Pools



4.2.1 Reported Refinery Data

The primary source of information used to determine greenhouse gas emissions for petroleum refineries is the EIA dataset compiled for U.S. refineries from individual government-mandated refinery surveys. EIA collects and compiles petroleum production and processing data from U.S. refineries and publishes most of the information on their website for public use. While some refinery-specific information is available, refinery operational data are generally aggregated to avoid disclosing proprietary information.

4.2.2 Refinery Energy Usage

Fuels consumed data are presented by EIA on an annual basis and aggregated data at the regional Petroleum Administration for Defense Districts (PADD) level represent the highest level of detail available for this information. Refinery fuels consumed for 2005 are shown in Table 4-2 for the U.S. This information is used to estimate the refinery energy consumption and associated emissions. Puerto Rico and the Virgin Islands refineries are not included in these data.

Table 4-2. Refinery Fuels Consumed for 2005

Fuel	Annual Consumption (thousand bbl)
Crude Oil	0
Liquefied Petroleum Gases	4,175
Distillate Fuel Oil	755
Residual Fuel Oil	2,207
Still Gas	238,236
Petroleum Coke	89,652
Marketable Petroleum Coke	2,242
Catalyst Petroleum Coke	87,410
Other Petroleum Products	5,329
Natural Gas (Million Cubic Feet)	682,919
Coal (Thousand Short Tons)	41
Purchased Electricity (Million Kilowatt-hours)	36,592
Purchased Steam (Million Pounds)	63,591

Refinery energy consumption is calculated by multiplying the energy content of the various fuels, as reported in Table 4-3, by the quantity used and summing to obtain a total refinery energy usage. The energy usage profile is shown in Table 4-4.

Table 4-3. Refinery Fuels Energy Content (HHV)

Refinery Fuel	Energy Content (HHV)	Units	References
Liquefied Petroleum Gases (LPG)	3.616	MMBtu/bbl	EIA 2008
Distillate Fuel Oil	5.825	MMBtu/bbl	EIA 2008
Residual Fuel Oil	6.287	MMBtu/bbl	EIA 2008
Still Gas	6.000	MMBtu/bbl	EIA 2008
Petroleum Coke	6.024	MMBtu/bbl	EIA 2008
Other Petroleum Products*	5.796	MMBtu/bbl	EIA 2008
Natural Gas	1,027	MMBtu/Mcf	EIA 2008
Coal**	27	MMBtu/ton	API 2004 Table 3-5
Purchased Electricity	3,412	Btu/kWh	
Purchased Steam	1,200	Btu/lb	ConEdison, 2007; GaBi 4, 2007

* Includes pentanes plus, other hydrocarbons, oxygenates, hydrogen, unfinished oils, gasoline, special naphthas, jet fuel, lubricants, asphalt and road oil, and miscellaneous products.

** Assume bituminous coal; API average energy content for bituminous coal of 13,500 Btu HHV/lb

Table 4-4. Refinery Fuels Energy Usage Profile for 2005 (HHV)

Fuel Consumed	Energy Usage (MMBtu HHV/day)
Liquefied Petroleum Gases (LPG)	41,361
Distillate Fuel Oil	12,049
Residual Fuel Oil	38,015
Still Gas	3,916,208
Petroleum Coke	1,479,626
Other Petroleum Products*	84,622
Natural Gas	1,921,528
Coal**	3,033
Purchased Electricity	342,060
Purchased Steam	209,066
Total	**8,047,569**

* Includes pentanes plus, other hydrocarbons, oxygenates, hydrogen, unfinished oils, gasoline, special naphthas, jet fuel, lubricants, asphalt and road oil, and miscellaneous products.

** Assume bituminous coal; API average energy content for bituminous coal of 13,500 Btu HHV/lb

4.2.3 Fuels Acquisition

Each of the fuels consumed and indirect fuel inputs for refineries have an emissions profile associated with extraction/production of those fuels/energy sources. These fuel inputs include:

- Indirect fuel inputs including purchased electricity and steam
- Purchased fuels including coal and natural gas
- Produced fuels from the refinery operations which includes all other fuels reported by refineries to EIA

4.2.3.1 Purchased Electricity and Steam

The tables below list CO_2, CH_4, and N_2O emissions factors consistent with refinery usage of purchased power and steam. Emissions consistent with purchased electricity were estimated using eGRID data with U.S. average emissions, as applicable (refer to Appendix B) for further discussion). The emissions from the U.S. power grid mix are representative of 2004 emissions due to unavailability of 2005 data at the time the study was performed.

Table 4-5. Refinery Fuels and Associated Indirect CO_2 Emissions

Refinery Fuel	CO_2 Emissions (kg CO_2/MMBtu HHV)	References
Purchased Electricity	217§	EPA 2007 (eGRID); GaBi 4 2007
Purchased Steam	92.7	ConEdison 2007; GaBi 4 2007

Table 4-6. Refinery Fuels and Associated Indirect Methane Emissions

Refinery Fuel	CH_4 Emissions (kg CH_4/MMBtu HHV)	References
Purchased Electricity	0.251§	EPA, 2007 (eGRID); GaBi 4, 2007
Purchased Steam	0.132	ConEdison, 2007; GaBi 4, 2007

Table 4-7. Refinery Fuels and Associated Indirect N_2O Emissions

Refinery Fuel	N_2O Emissions (kg N_2O/MMBtu HHV)	References
Purchased Electricity	0.00281§	EPA 2007 (eGRID); GaBi 4 2007
Purchased Steam	0.00104	ConEdison 2007; GaBi 4 2007

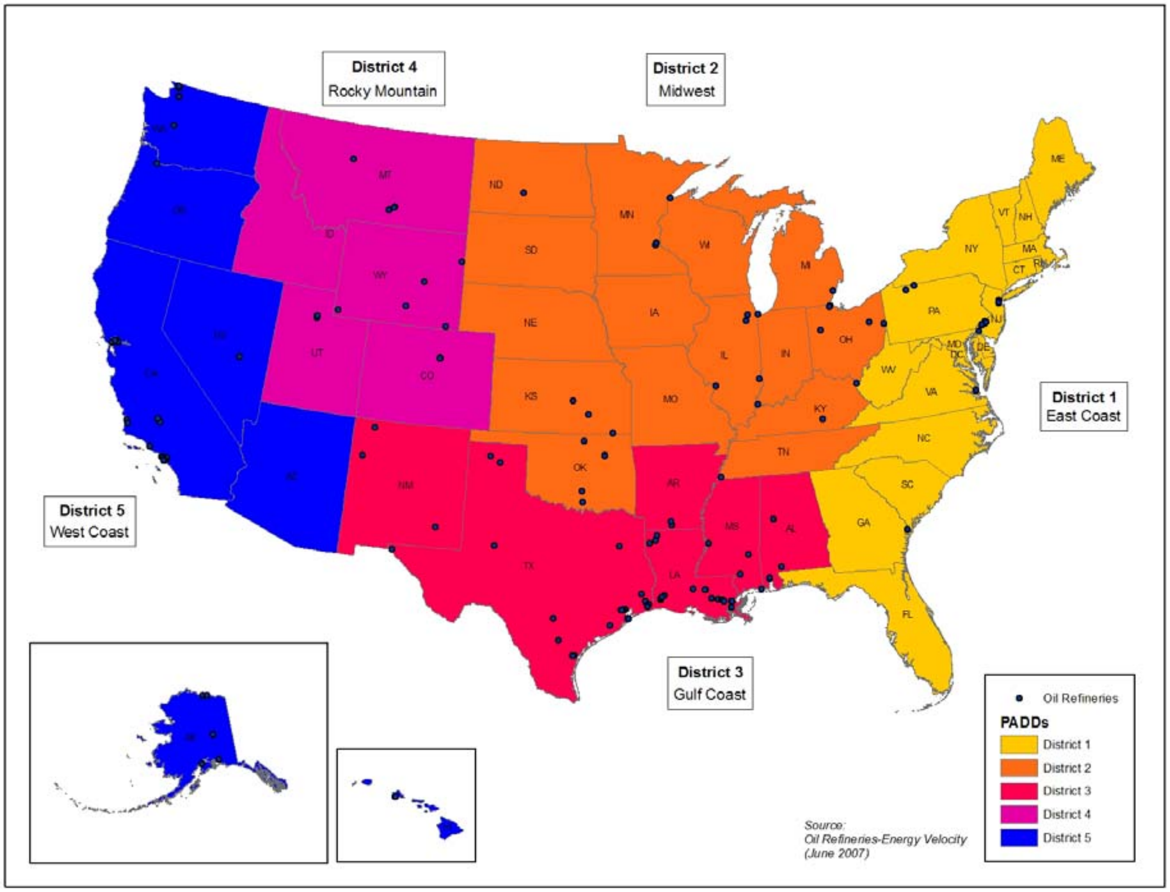
---

§ A sensitivity analysis was performed on these parameters.

4.2.3.2 Coal

Coal was used as a refinery fuel in PADD 1 and 2 in 2005. A total of 41,000 short tons of coal was consumed in 2005—33,000 short tons in PADD 1 and 8,000 in PADD 2 (EIA 2008). Figure 4-5 shows the location of the regional PADDs in the United States and the location of refineries. Given that PADD 1 refineries are located primarily in the northeast, it is assumed that the coal used as a refinery fuel is a bituminous coal extracted by underground mining.

Figure 4-5. Map of the United States Showing Petroleum Administration for Defense Districts and Refinery Locations (Energy Velocity 2007)



Source:
Oil Refineries-Energy Velocity
(June 2007)

There are three primary emissions components that contribute to the greenhouse gas emissions profile for coal acquisition: (1) energy usage (fuels consumed) for mining and preparation, (2) mine methane emissions, and (3) transport of coal to the refineries.

Coal Mining and Preparation

Data for fuels consumed and resulting emissions were derived from 2002 Census Data (USDOC 2004) for Bituminous Coal Underground Mining (included preparation). No major technology advances occurred in the field of coal mining in the years between 2002 and 2005 and therefore it is assumed that these data meets the quality objectives for this study. Table 4-8 lists the fuels used for extraction and preparation of bituminous coal recovered by underground mining in 2002. Emission factors for fuel consumption are shown in Table 4-9 thru Table 4-11.

Table 4-8. Underground Mining Energy Inputs Required for Extraction and Preparation of 371.4 Million Tons of Bituminous Coal (USDOC 2004)

Fuel	Value	Units	Comments
Coal (produced & used in same plant as fuel)	179.8	[1,000 tons]	
Distillate (light) grade numbers 1, 2, 4, and light diesel fuel	655.9	[1,000 bbls]	(data from 1997 survey—2002 data unavailable)
Residual (heavy) grade numbers 5 and 6 and heavy diesel fuel	178.3	[1,000 bbls]	
Gas (natural, manufactured, and mixed)	0.5	[billion cubic feet]	(data from 1997 survey—2002 data withheld)
Gasoline	1.5	[million gallons]	
Purchased Electricity	6,287,072	[1,000 kWh]	

Table 4-9. Underground Bituminous Coal Mining/Preparation Fuels and Associated CO_2 Emission Factors

Fuel	CO_2 Emissions (kg CO_2/MMBtu HHV)	References
Coal*	93.1	API 2004 Table A-3
Distillate Fuel Oil	73.2	API 2004 Table 4-1
Residual Fuel Oil	78.8	API 2004 Table 4-1
Natural Gas	53.1	API 2004 Table 4-1
Gasoline	70.9	API 2004 Table 4-1
Purchased Electricity	217	EPA, 2007 (eGRID); GaBi 4, 2007

* Assume bituminous coal; API average energy content for bituminous coal of 13,500 Btu HHV/lb

Table 4-10. Underground Bituminous Coal Mining/Preparation Fuels and Associated CH_4 Emission Factors

Fuel	CH_4 Emissions (kg CH_4/MMBtu HHV)	References
Coal*	7.65E-04	NEB 1999, Table A10.1
Distillate Fuel Oil	5.45E-03	NEB 1999, Table A10.1
Residual Fuel Oil	4.32E-03	NEB 1999, Table A10.1
Natural Gas	1.34E-03	NEB 1999, Table A10.1
Gasoline	0.137	API 2004 Table 4-5
Purchased Electricity	0.251	EPA, 2007 (eGRID); GaBi 4, 2007

* Assume bituminous coal; API average energy content for bituminous coal of 13,500 Btu HHV/lb

Table 4-11. Underground Bituminous Coal Mining/Preparation Fuels and Associated N_2O Emission Factors

Fuel	N_2O Emissions (kg N_2O/MMBtu HHV)	References
Coal*	2.37E-03	NEB 1999, Table A10.1
Distillate Fuel Oil	3.51E-03	NEB 1999, Table A10.1
Residual Fuel Oil	3.26E-03	NEB 1999, Table A10.1
Natural Gas	5.70E-04	NEB 1999, Table A10.1
Gasoline	1.17E-04	API 2004 Table 4-5
Purchased Electricity	2.81E-03	EPA, 2007 (eGRID); GaBi 4, 2007

* Assume bituminous coal; API average energy content for bituminous coal of 13,500 Btu HHV/lb

Mine Methane Emissions

An approximation was developed for mine methane emissions by considering available estimates of coal bed methane (CBM) in-situ productivity for basins containing large bituminous coal reserves, and adding estimated methane emissions that would be released if that mined coal were removed and processed, such as would be the case in mining and post-mining processing.

Table 4-12 reports values or ranges of estimated extractable CBM for several large bituminous coal basins in the conterminous United States. These data, reported from various sources, all describe the estimated extractable methane using best available CBM extraction technologies and do not represent the total volume of methane that would be expected to be released if coal were extracted and processed at the surface. It is assumed herein that these CBM estimates are comparable to coal methane released during only the preliminary coal extraction phase (initial mining being considered roughly equivalent to fracturing and depressurizing the coal seam, as is the case in in-situ CBM extraction).

In the absence of more geospatially detailed data that would allow development of a more rigorous methodology, a simplistic approach of estimating a mean bituminous CBM productivity has been adopted. The reported estimated CBM values (or averages of reported productivity ranges) have simply been averaged with equal weighting for all formations. Using this simplified estimation method, an estimated mean bituminous CBM specific productivity value of approximately 260 standard cubic feet (scf) per ton was determined.

A publication by the American Petroleum Institute in 2004 reports mining and post-mining methane emissions factors for underground and surface mining operations. While these data (summarized in Table 4-13) are average values and do not break down emissions as a function of coal type, the reported underground mining methane emissions value of 250 scf CH_4 per short ton of coal (vented and degassed) compares favorably with the aforementioned estimated mean bituminous CBM productivity value of 260 scf/short ton bituminous coal.

Table 4-12. Summary of Coal Bed Methane Productivity Estimates

Coal Basin	**CBM Estimate (scf/ton coal)** *mean of ranges noted parenthetically*	**References**
Northern Appalachian	150	GTI 2002
Central Appalachian	300	GTI 2002
Warrior Basin	350	Lee 2007
San Juan Basin	400	Lee 2007
Illinois Basin	100-150 (mean 125) 83.3-188.7 (mean 138.5) mean of two means: 131.75)	U.S. DOE 2007; Eble, et al. 2005
Cherokee Basin (SE Kansas)	185-325 (225)	Tedesco 2004
Forest City Basin	50-450 (250)	Tedesco 2004
Study Value	**260***	

* Excludes post-mining emissions

Table 4-13. Coal Mining Methane Emissions Factors (API 2004)

Activity	**Methane Emission Factor**			
	scf CH_4/short ton coal	**lb CH_4/short ton coal**	**Tonnes CH_4/ tonne coal**	**Percent of total methane released**
Underground Mining (Ventilation and Degasification)	250	10.6	0.00528	76.6%
Underground Post-mining (Coal Handling)	76.2	3.22	0.00161	23.4%
Surface Mining	32.1	1.36	0.000679	85.7%
Surface Post-Mining (Coal Handling)	5.35	0.23	0.000113	14.3%

In addition to methane emitted at the point of underground mining, the API report also gives an average value for methane released during post-mining processing of coal mined from an underground mine of 76.2 scf CH_4/short ton. Based on these data, approximately 77% of coal methane is released during coal mining (in the case of longwall mining, at the shearing point), while the remaining 23% of the coal methane is released during post-mining processing. Post-mining methane emissions are not, as previously discussed, considered to be represented in the CBM specific productivity values. To account for the post-mining methane emissions (analogous to methane that remains in the formation following in-situ CBM extraction), it is assumed that an additional 23% of the reported bituminous CBM value (260 scf/ton) would be released following mining of the same coal; an additional 60 scf/ton would be released during post-mining processing resulting in total methane emissions from bituminous coal of 320 scf/ton. A value of 320 scf/ton is therefore used for methane emissions from bituminous coal mining, assuming that voluntary best-management practices are not employed at underground bituminous coal mines.

Coal Transportation

Transport of the coal from the mine or preparation plant to the refinery is assumed to be 100% by rail. The assumed transport distance is 400 miles (round trip) and energy intensity values for rail transport for 2005, extracted from the Transportation Energy Data Book (ORNL 2007), is used for determining transport emissions from locomotive transport operations. According to the Transportation Energy Data Book, locomotives for freight transport are fueled 100% by diesel fuel. Assumptions made to construct the coal transportation portion of the coal extraction/transport upstream profile for use in petroleum refineries are reported in Table 4-14. Table 4-15 outlines the GHG emissions associated with coal transport via rail.

Table 4-14. Summary of Assumptions for Coal Rail Transportation

Parameter	Value	Units	Reference
Trip from Product Origin to Destination	337	Btu HHV/ton-mile	ORNL 2007, Table 2.16
Trip from Product Destination Back to Origin	337	Btu HHV/ton-mile	ORNL 2007, Table 2.16
Round-trip Distance for Coal Transport	400	Miles	Study Assumption
Locomotive Fuel	Diesel	-	ORNL 2007, Table 2.4

Table 4-15. GHG Emissions Consistent with Coal Transport by Rail (EIA 2007)

Source	Energy Usage (Diesel) in Btu HHV/ton	Diesel Emissions (kg/MMBtu HHV diesel fuel)			Transport Emissions (kg/ton bituminous coal)		
		CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
Coal Transport	134,800	73.2	0.00577	0.00187	9.86	7.78E-04	2.53E-04

Table 4-16 shows the GHG emissions for bituminous coal mining from an underground mine, associated mine methane emissions, and estimated emissions consistent with railroad transport of the coal to petroleum refineries.

Table 4-16. Summary of GHG Emissions Consistent With Coal Acquisition

Source	Emissions (kg/ton Coal)		
	CO_2	CH_4	N_2O
Coal Mining & Preparation	14.8	0.0147	2.41E-04
Mine Methane Emissions	N/A	6.12	N/A
Coal Transport	9.86	7.78E-04	2.53E-04
Total	**24.7**	**6.14**	**4.93E-04**

4.2.3.3 Natural Gas

The emissions profile for natural gas used as a refinery fuel/feedstock was extracted from GaBi 4 (2008). The profile includes emissions associated with extraction, processing, and transport of natural gas to the final consumer. The data are representative of the U.S. natural gas mix delivered to customers in 2002 (GaBi data set dated September 15, 2006). The GHG emissions consistent with natural gas consumed by refineries are shown in Table 4-17. No significant technology differences/advances occurred in the field of natural gas extraction and processing in the years between 2002 and 2005 and therefore the data meet the quality objectives for this study.

Table 4-17. GHG Emissions Consistent with Delivered Natural Gas in the U.S.

Basis/Quantity	GHG Emissions (kg CO_2E)
kg Natural Gas	0.516
scf Natural Gas	0.00984

4.2.3.4 Refinery-Produced Fuels

The upstream emissions profile for fuels that are produced in the refinery and subsequently combusted therein are equivalent to the cradle-to-gate emissions associated with production of that fuel as if it were a refinery product. For example, the emissions associated with production of still gas include the emissions associated with refinery feedstock acquisition and transport and all refinery operations as allocated to still gas. For that reason, a preliminary calculation of the entire LC Stage #3 profile (excluding acquisition of refinery-produced fuels) must be determined prior to incorporating the upstream emissions of these fuels.

Appendix C details the development of this profile. A summary of the upstream emissions profile is shown in Table 4-18.

Table 4-18. Summary of GHG Emissions Consistent with Acquisition of Refinery-Produced Fuels

Fuel	Quantity Input (bpd)	Emissions (kg/day)		
		CO_2	CH_4	N_2O
LPG	11,438	696,439	5,886	15
Distillate	2,068	171,312	1,122	3
Residual Fuel Oil	6,047	409,065	3,165	8
Still Gas	652,701	39,740,582	335,879	850
Petroleum Coke	245,622	18,267,585	130,326	380
Other Products	14,600	1,095,456	7,768	22
Total		**60,380,439**	**484,146**	**1,278**

4.2.3.5 Refinery Fuels Acquisition Emissions Profile

Table 4-19 provides a summary of the GHG Emissions profiles for each of the fuel acquisition categories.

Table 4-19. Summary of GHG Emissions Consistent with Acquisition of Petroleum Refinery Fuels

Source	Emissions (kg/day)		
	CO_2	CH_4	N_2O
Indirect Inputs	93,451,488	113,716	1,178
Purchased Fuels	14,134,109	168,565	277
Produced Fuels	60,380,439	484,146	1,278

4.2.4 Refinery Fuels Combustion

The primary source of GHG emissions at a refinery is from fuels combustion. Emissions are determined for all of the fuels consumed during the refining operations. All hydrocarbon species are assumed to be combusted in industrial-scale equipment. The following sections outline the emission factors associated with consumption of the various refining fuels. Total emissions are determined by multiplying the emission factor by the quantity of fuel consumed.

Since it is not possible to accurately ascribe fuel types, combustion equipment and the resulting emissions to the various refinery operations, a composite energy usage/emissions profile was determined for all refining operations. The GHG emissions associated with the fuels consumed are allocated equivalently for each unit of energy consumed.

4.2.4.1 CO_2 Emissions from Refinery Fuels Combustion

Refinery CO_2 emissions are determined by multiplying the quantity of fuel consumed by the appropriate CO_2 emissions factor for fuel consumption. Table 4-20 shows the various hydrocarbon fuels consumed at refineries and lists the CO_2 emissions consistent with combustion of the individual species.

4.2.4.2 Methane Emissions from Refinery Fuels Combustion

Methane emissions have been quantified for standard combustion processes using finished fuels, but off-spec refinery still gas and coke combustion emission factors are not as precise and estimates vary. In the absence of detailed process and equipment information for the refining facilities, the uncertainty of the methane estimates from combustion emissions is high. Due, in part, to this high level of uncertainty, the Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions (IPIECA et al. 2003) do not consider methane produced by fuel combustion in any of its GHG estimation tiers for refining operations (see Appendix D).

The Canadian National Energy Board has estimated methane emission factors for combustion of various standard and non-standard hydrocarbon fuels (NEB 1999) and those values have been used to determine methane emissions consistent with refinery combustion operations. The methane emission factors utilized in this study for fuel combustion are presented in Table 4-21.

Table 4-20. Refinery Fuels and Associated CO_2 Emissions from Fuel Combustion

Refinery Fuel	CO_2 Emissions (kg CO_2/MMBtu HHV)	References
Liquefied Petroleum Gases (LPG)	62.3	API 2004 Table 4-1
Distillate Fuel Oil	73.2	API 2004 Table 4-1
Residual Fuel Oil	78.8	API 2004 Table 4-1
Still Gas	64.2§	API 2004 Table 4-1
Petroleum Coke	102.1	API 2004 Table 4-1
Other Petroleum Products*	72.1	API 2004 Table A-3
Natural Gas	53.1	API 2004 Table 4-1
Coal**	93.1	API 2004 Table A-3

* Includes pentanes plus, other hydrocarbons, oxygenates, hydrogen, unfinished oils, gasoline, special naphthas, jet fuel, lubricants, asphalt and road oil, and miscellaneous products. CO_2 emissions estimate consistent with API Compendium emission factor or “miscellaneous petroleum products and crude” (see API 2004 Appendix A).

** Assume bituminous coal; API average energy content for bituminous coal of 13,500 Btu HHV/lb and 93.1 kg CO_2 emitted per MMBtu HHV

Table 4-21. Refinery Fuels and Associated Methane Emissions from Fuel Combustion

Refinery Fuel	CH_4 Emissions (kg CH_4/MMBtu HHV)	References
Liquefied Petroleum Gases (LPG)	0.00118	NEB 1999, Table A10.1
Distillate Fuel Oil	0.00545	NEB 1999, Table A10.1
Residual Fuel Oil	0.00432	NEB 1999, Table A10.1
Still Gas*	0.00134	NEB 1999, Table A10.1
Petroleum Coke	0.00299	NEB 1999, Table A10.1
Other Petroleum Products**	0.00545	NEB 1999, Table A10.1
Natural Gas	0.00134	NEB 1999, Table A10.1
Coal***	0.00076	NEB 1999, Table A10.1

* Methane emissions from still gas combustion are assumed to be the same as for combustion of natural gas.

** Includes pentanes plus, other hydrocarbons, oxygenates, hydrogen, unfinished oils, gasoline, special naphthas, jet fuel, lubricants, asphalt and road oil, and miscellaneous products; methane emissions are assumed to be similar to that of diesel fuel.

*** Assume U.S. bituminous coal

4.2.4.3 N_2O Emissions from Refinery Fuels Combustion

Current estimates for N_2O emissions from combustion operations, as determined by the U.S. Environmental Protection Agency (EPA) AP-42 emission factors, are only determined for typical operations using petroleum refinery products—not petroleum intermediates such as still gas. Similarly, EPA emission factors have not been developed for petroleum coke combustion. Ignoring the effects of still gas and coke combustion would dramatically underestimate N_2O

---

§ A sensitivity analysis was performed on these parameters.

production. Emission factors for refinery operations using standard fuels are shown in Appendix E.

The Canadian National Energy Board has estimated N_2O emission factors for combustion of various non-standard hydrocarbon fuels (NEB 1999) and those values have been used to determine N_2O emissions consistent with refinery combustion operations. The N_2O emission factors utilized in this study are presented in Table 4-22.

Table 4-22. Refinery Fuels and Associated N_2O Emissions from Fuel Combustion

Refinery Fuel	N_2O Emissions (kg N_2O/MMBtu HHV)	References
Liquefied Petroleum Gases (LPG)	0.00950	NEB 1999, Table A10.1
Distillate Fuel Oil	0.00351	NEB 1999, Table A10.1
Residual Fuel Oil	0.00326	NEB 1999, Table A10.1
Still Gas	0.00065	NEB 1999, Table A10.1
Petroleum Coke	0.00322	NEB 1999, Table A10.1
Other Petroleum Products*	0.00351	NEB 1999, Table A10.1
Natural Gas	0.00057	NEB 1999, Table A10.1
Coal**	0.00237	NEB 1999, Table A10.1

* Includes pentanes plus, other hydrocarbons, oxygenates, hydrogen, unfinished oils, gasoline, special naphthas, jet fuel, lubricants, asphalt and road oil, and miscellaneous products; emissions are assumed to be similar to diesel fuel.

** Assume bituminous coal

4.2.4.4 Refinery Fuels Combustion Emissions Profile

Refinery GHG emissions attributable to fuels combusted on a daily basis are presented in Table 4-23.

Table 4-23. GHG Emissions Associated with Daily Fuels Input to Refineries

Refinery Fuel	Quantity Input	Units	Emissions (kg/day)		
			CO_2	CH_4	N_2O
LPG	11,438	bpd	2,576,796	49	393
Distillate Fuel Oil	2,068	bpd	881,985	66	42
Residual Fuel Oil	6,047	bpd	2,995,568	164	124
Still Gas	652,701	bpd	251,420,568	5,247	2,562
Petroleum Coke	245,622	bpd	151,069,859	4,418	4,761
Other Petroleum Products	14,600	bpd	6,101,217	462	297
Natural Gas	1,871	MMcfd	102,033,150	2,575	1,095
Coal	112	tons/day	282,361	2	7
Total			**517,361,504**	**12,983**	**9,281**

4.2.5 Hydrogen Production

Refineries are the largest consumers of hydrogen in the United States (CEH 2004). Hydrogen at refineries comes primarily from three different sources—hydrogen by-product from catalytic reforming, on-site hydrogen plants, and purchased hydrogen produced off-site. For this study all hydrogen produced on-site and off-site is assumed to be generated by steam methane reforming using natural gas as both a feedstock and fuel.

While all three of the aforementioned sources contribute to the emissions profile for the refining industry, their GHG accounting differs. The energy used to produce hydrogen via catalytic reforming—and hence the emissions associated with this activity—are embedded in the total refinery energy usage estimation calculated in the previous section. The fuel and associated utilities for on-site hydrogen production at a dedicated hydrogen plant are also included in the refinery fuels-consumed tally, but the natural gas used as a feedstock is explicitly excluded. The energy/resource usage and environmental effects of hydrogen produced and purchased from an off-site or third party supplier are not accounted for in the refinery fuels consumed estimate. Table 4-24 outlines these hydrogen accounting issues.

Table 4-24. Refinery Hydrogen Sources and Emissions Accounting Summary

Hydrogen Source	Included in Refinery Fuels Consumed Emissions Profile	Not Included in Refinery Fuels Consumed Emissions Profile
Catalytic Reformer	Complete accounting in refinery fuels used tally; Resource, energy used, and associated emissions embedded in refinery total	None
On-Site H_2 Production	Partial accounting in refinery fuels used tally; Fuel/utilities and associated emissions embedded in refinery total	Feedstock (natural gas) input and GHG emissions (primarily CO_2) consistent with H_2 production not included
Off-Site (3rd party) H_2 Production	None	Complete cradle-to-gate LCA inventory/profile must be generated for H_2 production and delivery

To ensure complete accounting of emissions for hydrogen production, the following must be determined:

- Refinery energy/fuels consumed for catalytic reforming and allocation to liquid fuels and hydrogen, as appropriate
- Refinery energy/fuels consumed for the on-site hydrogen plant
- Feedstock quantity of natural gas fed to the on-site hydrogen plant and associated cradle-to-gate emissions consistent with production and delivery of that quantity of natural gas
- Process emissions from the on-site hydrogen plant
- A full cradle-to-gate LCA inventory/profile for off-site H_2 production and delivery
- Allocation of emissions associated with hydrogen production (detailed in subsequent sections)

To simplify the issue of hydrogen accounting, the concept of a hydrogen "pool" has been developed. This pool consists of excess hydrogen from the catalytic reformer and hydrogen produced on- and off-site via steam methane reforming. All hydrogen gets input into the pool and hydrogen needed for refinery unit operations is pulled indiscriminately from the pool. Each hydrogen-contributing source is allotted an emburdened usage for that fraction.

4.2.5.1 Hydrogen Production Via Steam Methane Reforming (SMR)

Hydrogen for refinery usage in the United States is produced predominantly by steam methane reforming (SMR) of natural gas and this study assumes both on-site and off-site hydrogen production utilize this method. The amount of hydrogen produced at on-site hydrogen plants is assumed to be 85% of the installed hydrogen production capacity reported by EIA (as of January 1, 2006).§ The amount of hydrogen input to the refinery from an external source is estimated to be 1,220 million standard cubic feet per day (scfd) based on the 2004 Chemical Economics Handbook Marketing Report for Hydrogen (CEH 2004).§ This source reports a value for 2003 which was extrapolated using the percentage growth in off-site hydrogen production for refineries from 1999 to 2003.

Hydrogen Plant Feedstock Requirements

Hydrogen plants are being built/retrofitted to handle increasingly heavier hydrocarbon feedstocks and fuels but this study assumes that hydrogen production in the U.S. operates solely using natural gas as both a fuel and feedstock. The SMR stoichiometry for converting hydrocarbons (primarily methane) to hydrogen is shown in Equation 1. From the stoichiometry, it can be seen that for pure methane and 100% conversion, the theoretical minimum necessary feedstock requirements would be 0.0048 kg (231 Btu LHV, 256 Btu HHV) methane per scf of hydrogen.

$$C_xH_{(2x+2)} + 2xH_2O \rightarrow (3x+1)H_2 + xCO_2 \qquad (1)$$

The actual amount of natural gas used as a feedstock must be determined to estimate the upstream and process emissions for the on-site hydrogen plant. The following table shows a survey of total feedstock input to SMR processes for every standard cubic foot of hydrogen produced and their associated references. Natural gas lower heating value is assumed to be 918 Btu/ft^3 and higher heating value is assumed to be 1020 Btu/ft^3 (API 2004). The average density is assumed to be 23.8 ft^3 per pound (API 2004). In this study, the hydrogen plant feedstock requirement for natural gas is assumed to be 352 Btu HHV/scf H_2 (0.006581 kg natural gas per scf H_2).

Hydrogen Plant CO_2 Process Emissions

The CO_2 process emissions consistent with on-site SMR operation must be determined from the above feedstock specific input. Table 4-26 shows the average U.S. natural gas composition that is assumed to be representative of the natural gas input for all cases in this study.

---

§ A sensitivity analysis was performed on these parameters.

Table 4-25. Specific Natural Gas Input as Feedstock to SMR Hydrogen Plants

Feedstock Input (Btu LHV/scf H_2)	Feedstock Input (Btu HHV/scf H_2)	Reference	Comments
275	306	Boyce 2004	Old style--methanation process with amine purification
317	352	Boyce 2004	Modern—PSA purification
331	368	NREL 2001	
338	376	FW 2001	
	352§	**Study Value**	

Table 4-26. Composition of U.S. Pipeline Quality Natural Gas (API 2004)

Compound	Average Volume %
Methane	93.07
Ethane	3.21
Propane	0.59
Higher hydrocarbons*	0.32
Non-hydrocarbons**	2.81

* Higher molecular weight hydrocarbons were represented by C5 in calculating the CO_2 and hydrogen production rates.

** The non-hydrocarbons are assumed to contain 0.565 volume % CO_2 based on an average natural gas composition from Perry's Chemical Engineers Handbook.

Based upon the natural gas composition shown in Table 4-26, hydrogen plant process CO_2 emissions have been calculated, consistent with the rigorous API methodology that uses the average U.S. pipeline natural gas specifications (API 2004). Natural gas is estimated to be 76 weight percent carbon (API 2004) and CO_2 process emissions are estimated to be 0.01879 kg CO_2 per scf H_2 produced (2.855 kg CO_2 per kg of natural gas feed input). Complete combustion of natural gas is assumed and thus there are negligible methane process emissions. The use of hydrogen process waste gas streams recycled to the hydrogen plant reformer furnaces as a fuel gas are assumed to be unaccounted for in the EIA refinery fuels-consumed estimate.

To bound the above determined process CO_2 emissions estimate and determine the absolute minimum CO_2 emissions, the simplified approach for determining CO_2 process emissions was also evaluated. This method considers the stoichiometry shown in Equation 1 and determines the CO_2 production consistent with a given rate of H_2 production. Using this method, the minimum CO_2 process emissions for a hydrogen plant using the above pipeline quality natural gas would be 0.0134 kg CO_2 per scf H_2.

Hydrogen Plant Energy Usage

Table 4-27 shows a survey of reported total energy usage (including feedstock energy) for hydrogen production from various vendors and the literature. It is important to note that all but one of the estimates considers modern pressure swing adsorption (PSA) as the purification

---

§ A sensitivity analysis was performed on these parameters.

technology. This technology is less energy intensive than the older style plant which uses amine-based purification and methanation technology (Boyce 2004). Thus, these estimates may be more conservative and underestimate the energy requirements for older plants. The average energy usage (including natural gas for feedstock and fuel use) for production of hydrogen in this study is estimated to be 388 Btu HHV/scf H_2.

Table 4-27. Estimated Energy Consumption for Hydrogen Production

Estimated Energy Usage (Fuel + Feed + Power – Steam) in Btu HHV/scf H_2	Technology Supplier	Reference	Comments
370	Uhde GmbH	HP 2006	This estimate does not include power consumption; Energy usage reported as 333 MMBtu/MMscf and assumed to be LHV and adjusted to HHV basis
389	Technip	HP 2006	
430	Haldor Topsøe A/S	HT 2008	HTCR Technology
506	Chicago Bridge & Ironworks (CBI)	Boyce 2004	Old style--methanation process with amine purification; steam valued at 1,200 Btu/lb
388	Chicago Bridge & Ironworks (CBI)	Boyce 2004	Modern—PSA purification; steam valued at 1,180 Btu/lb
354	Foster Wheeler	Meyers 2004	Feed and fuel energy usage assumed to be HHV basis; Energy usage = 400 Btu/scf if feed/fuel usage reported on LHV basis
385		NREL 2001	Steam valued at 1,200 Btu/lb
388	**Study Value**		

For hydrogen purchased from an external supplier, the entire life-cycle inventory from the cradle-to-gate must be determined. This inventory includes emissions from natural gas acquisition, transport, conversion to hydrogen, and subsequent hydrogen transport to the refinery.

The cradle-to-gate GHG emissions profile for natural gas is necessary to estimate the upstream emissions associated with the natural gas feedstock input to the refinery hydrogen plant (the natural gas input to the refinery fuels consumed tally is discussed in Section 4.2.3.3). The GHG life cycle inventory for natural gas is shown in Table 4-17.

The cradle-to-gate life cycle inventory for hydrogen production using SMR with PSA purification technology has been derived and is presented in Appendix G. Table 4-28 summarizes the results for this process.

Table 4-28. Cradle-to-Gate GHG Emissions Inventory for Hydrogen Production via SMR with PSA Purification

Basis/Quantity	Emissions (kg)		
	CO_2	CH_4	N_2O
scf H_2 Produced	0.0204	2.98E-05	1.03E-07

4.2.5.2 Hydrogen Produced from Catalytic Reformer

It has been estimated that hydrogen produced during catalytic reforming accounts for more than 60% of refinery hydrogen needs (Aitani 1996). In addition to producing high-octane reformate for gasoline blending, catalytic reforming also produces an off-gas that is typically 80-85% hydrogen by volume (CEH 2004). Table 4-29 shows the quoted hydrogen production quantities from reforming operations cited from various sources. This study assumes that catalytic reforming operations produce 1,000 standard cubic feet of hydrogen per barrel (scfb) of feed, on average.§

Table 4-29. Specific Hydrogen Production from Catalytic Reformer

Specific Hydrogen Production (scf H_2 per bbl of Reformer Feed)	Reference	Comments
600 – 1,600	CEH 2004	
1,481	Energetics 2007	
1,085	HPP 2006	Semiregenerative
1,709	HPP 2006	Continuous Catalyst Regeneration
1,150	HP 2006	CB&I Licensor
950 – 1,500	UOP 2003	
1,000	**Study Value**	

For the estimated catalytic reformer throughput of 3,419,000 bpd (detailed in Section 4.2.9.1), this results in a net hydrogen production from the catalytic reformer of 3,419 million standard cubic feet per day (MMscfd) of hydrogen production. This corresponds to approximately 49% of the total refinery hydrogen requirements being met by the reformer hydrogen output. The feed to the catalytic reformer requires hydrotreating to remove sulfur prior to entering the catalytic reformer. The hydrogen used in this operation is a recycle stream from the hydrogen produced in the catalytic reformer and is considered to be integral to the catalytic reformer operation (Maples 1993). Thus, the hydrogen recycle stream is subtracted from the catalytic reformer hydrogen output and the remaining hydrogen from the reformer is then allocated to the hydrogen pool. Table 4-30 demonstrates catalytic reformer contributions to the hydrogen pool. Hydrotreating the catalytic reformer/naphtha stream utilizes approximately 19% of the hydrogen produced by the reformer.

Table 4-30. Catalytic Reformer Net Hydrogen Output

Source	Estimated Unit Operation Input (thousand bpd)	Specific H_2 Production (Consumption) (scfb feed)	Daily H_2 Production (Consumption) (MMscfd)
Catalytic Reformer	3,419	1,000	3,419
Reformer Feed Hydrotreating*	3,419	(186)	(637)
Catalytic Reformer—Net Contribution to H_2 Pool		**814**	**2,782**

* Hydrogen use for hydrotreating will be discussed in greater detail in subsequent sections

---

§ A sensitivity analysis was performed on these parameters.

Hydrogen produced from the catalytic reformer must be allocated a portion of the unit operation energy burden. This burden is expressed as "energy used" to operate the catalytic reformer. The total energetic burden (the energy used to operate the catalytic reformer and reformer feed hydrotreater) must be allocated to the co-products of the operation, gasoline and hydrogen. Typical methods for allocation considered are examined below:

- Historically the catalytic reformer burden has been assigned principally—if not entirely—to the gasoline fraction. However, hydrogen usage is now a critical component for meeting regulatory requirements regarding sulfur content.
- If the energetic burden is divided between the reformate and hydrogen based on the energetic content of the species, then the reformate (gasoline) bears the lion's share of the energy burden. The value of the hydrogen is not as an energy carrier, but rather as a reactant. This distinction in the intrinsic value of hydrogen prevents straight-forward comparison to the reformate.

Alternatively, this study uses "system expansion" to determine the "value" of hydrogen. If the catalytic reformer was not sufficient/operational/present to meet the hydrogen needs, hydrogen would need to be produced by the next best method—steam methane reforming. Therefore, the energetic burden associated with producing hydrogen via steam methane reforming is allocated to hydrogen from the catalytic reformer as though it were produced by SMR. One salient difference is that the hydrogen stream from a dedicated hydrogen plant is of higher purity—generally 97+% hydrogen while hydrogen from a catalytic reformer is estimated to be 80-85% hydrogen (CEH 2004).

The estimated specific energy consumption for the catalytic reformer and reformer hydrotreater used in this study is 312 MBtu/barrel (Energetics 2007). This corresponds to a daily energy consumption for the reformer of 384 Btu/scf H_2 net output from the reformer. This is lower than the 388 Btu/scf H_2 required to produce hydrogen via SMR (from Table 4-27). Therefore, reformate—a high-quality gasoline blendstock—and hydrogen are both produced during the operation with less energy consumption than would be needed to simply produce the same quantity of hydrogen by SMR.

In the absence of a more equitable method for allocating the catalytic reformer burden to the reformate and hydrogen co-products, the system expansion methodology calls for the hydrogen contributed to the pool to be burdened with 100% of the energetic requirement for the catalytic reformer, 384 Btu/scf. All operations/products that draw hydrogen from that pool are then equally burdened.

Appendix F provides additional discussion on the allocation rationale and methodology employed in this study.

4.2.5.3 Summary of Hydrogen Pool

Table 4-31 provides the estimated hydrogen production rate and relative contribution to total refinery production from the various sources for 2005.

Table 4-31. Hydrogen Production for U.S. Refineries in 2005

Source	Contribution Amount (MMscfd H_2)	Percent Contribution
Catalytic Reformer	2,782	43.4%
On-Site H_2 Plant	2,400	37.5%
Off-Site H_2 Plant	1,222	19.1%
Total	**6,404**	**100%**

Table 4-32 summarizes the *refinery* energy burden for hydrogen produced from the three aforementioned sources. The energy usage for on-site hydrogen production reported by U.S. refineries to the EIA specifically excludes the energy contained in the natural gas feedstock and is calculated as shown in Appendix G. The total refinery energy used for hydrogen production is used as part of the allocation process for the refinery fuels combustion profile.

Table 4-32. Refinery Energy Used for Hydrogen Production for U.S. Refineries in 2005

Source	Refinery Energy Used for Hydrogen Production (MMBtu HHV per day)
Catalytic Reformer	1,068,397
On-Site H_2 Plant	87,472
Off-Site H_2 Plant	0
Total	**1,155,866**

Table 4-33 summarizes the emissions burden for the hydrogen produced from the three sources. Note that the GHG profile here does not include emissions associated with fuels consumed at the refinery. Those emissions are captured in the refinery fuels combustion emissions presented in a previous section.

Table 4-33. GHG Emissions Not Included in Refinery Energy Usage for Hydrogen Production for U.S. Refineries in 2005

Source	Emburdened Usage	Emissions (kg/day)		
		CO_2	CH_4	N_2O
Catalytic Reformer		0	0	0
On-Site H_2 Plant	NG feedstock cradle-to-gate GHG emissions + CO_2 *process* emissions from H_2 production	51,350,819	74,346	123
Off-Site H_2 Plant	Complete cradle-to-gate LCA inventory/profile for H_2 production and delivery	24,936,718	36,440	126
Total		**76,287,537**	**110,786**	**249**

4.2.6 Flaring Operations

Flare operations and associated emissions are not generally tracked for petroleum refineries across the United States. For this study, U.S. refinery flare operations and emissions have been estimated by taking data from two air quality districts in California—which require refineries to report flaring operations—and extrapolating that data to the U.S. as a whole.

A flaring summary was compiled for selected petroleum refineries in two air quality basins in California for a one-year period. The two basins selected were the Bay Area Air Quality Management District[2] (BA AQMD) and the South Coast Air Quality Management District[3] SCAQMD). The BA AQMD data included methane, whereas the SCAQMD data did not.

Flare gas flow for selected California refineries during 2005 in the BA AQMD and during 2006 in SCAQMD are illustrated in Table 4-34. These data were extracted from the BA AQMD and SCAQMD websites and totaled. The total flare gas flow was divided by the total refinery atmospheric distillation column capacity for those refineries in order to apply a metric by which to scale the refineries' flaring activities. Table 4-34 shows the flare gas flow in standard cubic feet and the flare gas output in terms of standard cubic feet per barrel of atmospheric distillation capacity. For this study, the average U.S. refinery flare gas flow is assumed to be 5.65 standard cubic feet per barrel (scfb).§

Using California data for flare operations and extrapolating those values to all U.S. refineries is expected to underestimate the emissions for total U.S. refinery flaring operations. California—and the BA AQMD and SCAQMD in particular—have more stringent environmental regulations than most other locations. The SCAQMD requires refineries to have flare minimization plans and report their performance. Refineries located in other regions will not likely have such strict anti-flaring operational mandates.

4.2.6.1 CO_2 Emissions

Given that the composition of flared gas is unknown, it is necessary to estimate CO_2 combustion emissions without an understanding of the composition of the gas. The minimum CO_2 emissions consistent with flaring would result from the combustion of flare gas composed entirely of natural gas (since it has the lowest carbon-to-hydrogen ratio). For a flare gas flow rate of 5.65 scfb, using the natural gas energy content and emission factor for combustion shown in Table 4-20, refinery CO_2 emissions from flaring would be 0.308 kg CO_2 per barrel of atmospheric distillation capacity. This represents the minimum CO_2 emissions produced by flare activities.

4.2.6.2 Methane Emissions

In addition to presenting the flare gas flow, the BAAQMD data include methane emissions, whereas the SCAQMD data do not. BAAQMD flare data are shown in Table 4-35.

---

[2] http://www.baaqmd.gov/enf/flares/index_2005.htm

[3] http://www.aqmd.gov/comply/1118/emissiondata.htm

§ A sensitivity analysis was performed on these parameters.

Table 4-34. Flaring Summary for Selected California Refineries

Refinery (Location)	Flare Gas Flow (scf)	Flare Flow per Unit of Atmospheric Distillation Capacity (scfb)	Year	Reference
Chevron (Richmond)	73,168,477	0.83	2005	BA AQMD 2008
ConocoPhillips (Rodeo)	58,545,909	2.11	2005	BA AQMD 2008
Shell (Martinez)	144,843,539	2.55	2005	BA AQMD 2008
Tesoro (Martinez)	298,309,759	4.92	2005	BA AQMD 2008
Valero (Benicia)	67,533,365	1.28	2005	BA AQMD 2008
Chevron (El Segundo)	402,340,700	4.24	2006	SCAQMD 2008
Ultramar (Wilmington)	122,149,430	4.14	2006	SCAQMD 2008
BP (Carson/LA)	714,386,630	7.53	2006	SCAQMD 2008
ExxonMobil (Torrance)	270,100,637	4.95	2006	SCAQMD 2008
Paramount (Paramount)	222,424,303	12.19	2006	SCAQMD 2008
ConocoPhillips (Wilmington)	1,178,351,730	23.23	2006	SCAQMD 2008

Table 4-35. Flaring Summary for Selected California Refineries 2005 (BA AQMD 2008)

Refinery (Location)	Flare Gas Flow (scf)	CH_4 Emissions per Unit of Atmospheric Distillation Capacity (scfb)	Flare Flow per Unit of Atmospheric Distillation Capacity (scfb)
Chevron (Richmond)	73,168,477	0.0027	0.83
ConocoPhillips (Rodeo)	58,545,909	0.0120	2.11
Shell (Martinez)	144,843,539	0.0090	2.55
Tesoro (Martinez)	298,309,759	0.0144	4.92
Valero (Benicia)	67,533,365	0.0042	1.28

If methane combustion emissions are estimated as if the flare gas was natural gas, as above, then the refinery methane emissions are significantly lower than if we use the refinery-reported methane flare emissions. Table 4-36 shows the estimate for refinery flare emissions if natural gas is considered to be the flare gas, as well as the actual (reported) refinery methane emissions. As can be seen, the reported value is much larger than the estimated value. The reported refinery methane emissions are used to estimate U.S. total refinery methane emissions from flaring activities.

Table 4-36. Estimate of GHG Emissions Consistent with Flaring Activities 2006

Source/Method	CH_4 Emitted from Flares (kg CH_4 per bbl of Distillation Capacity)
Estimated from Flare Rate	7.77E-06
Reported	1.46E-04
Study Value	**1.46E-04**

4.2.6.3 N_2O Emissions

For a flare gas flow rate of 5.65 scfb, using the natural gas energy content and emission factor for combustion shown in Table 4-22, refinery N_2O emissions from flaring would be 3.306E-06 kg N_2O per barrel of atmospheric distillation capacity.

4.2.7 Vented/Fugitive Emissions

The primary source of methane emissions from refineries is vented emissions, with smaller amounts of unburned CH_4 in process heater stack emissions and unburned CH_4 in engine exhausts and flares (EPA 2007b). Methane emissions from refinery operations have not generally been tracked or estimated and very little information is available regarding estimation procedures and data for estimates. The Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions (IPIECA et al. 2003) does not consider methane in any of its GHG estimation tiers for refining operations (see Appendix D). Due to the small contribution of methane to total GHG emissions from refineries and the uncertainty associated with the methane estimate, direct methane emissions are often ignored when compiling GHG totals for refineries.

Methane emissions from refinery operations for the 2005 U.S. GHG Inventory have been estimated and extrapolated from 1996 and 1999 EPA studies (EPA 1996; EPA 1999) of refinery process unit methane emissions. Table 4-37 shows the EPA estimates of methane emissions from petroleum refinery operations for 2005.

For the purpose of this study, methane emissions associated with asphalt blowing have not been included in the refinery methane emissions which are allocated to liquid fuel production. Asphalt blowing emissions are one of the primary sources of refinery methane emissions but these operations are not attributable to liquid fuels production and thus should be allocated exclusively to asphalt production.

It is important to note that environmental regulations and industry responsible care has increased in the interim since 1996 and 1999 when the estimates for process emissions were developed. Thus, these values may be inflated for refineries currently in operation today. Methane venting and fugitive emissions for liquid fuels production in 2005, as derived from the data in Table 4-37, were assumed to be 0.861 Bcf/year (vented emissions, excluding asphalt blowing, plus fugitive emissions). §

4.2.8 Refinery Emissions Profile

Table 4-38 summarizes the refinery emissions from fuels consumption (direct fuel combustion emissions as well as indirect emissions), hydrogen production, flaring, and methane venting/fugitives.

The indirect refinery emissions listed in Table 4-38 include upstream emissions associated with purchased power and steam. The emissions associated with extraction of the raw materials from the earth, transport of those material to an energy conversion facility, energy conversion, and transport to the consumer are embedded in the GHG estimates shown in that table. The direct emissions shown in Table 4-38 account for the upstream emissions associated with acquisition of the purchased coal and natural gas.

---

§ A sensitivity analysis was performed on these parameters.

Table 4-37. 2005 Methane Emissions from Petroleum Refining (EPA 2007c)

Activity/Equipment	Emission Factor Units	Activity Factor Units	Emissions (Bcf/yr)
Vented Emissions			**1.252**
Tanks	20.6 scf CH_4/Mbbl	1,951 Mbbl/cd heavy crude feed	0.015
System Blowdowns	137 scf CH_4/Mbbl	15,204 Mbbl/cd refinery feed	0.760
Asphalt Blowing	2,555 scf CH_4/Mbbl	510 Mbbl/cd production	0.477
Fugitive Emissions			**0.086**
Fuel Gas System	439 Mcf CH_4/refinery/yr	142 Refineries	0.062
Floating Roof Tanks	587 scf CH_4/floating roof tank/yr	767 No. of floating roof tanks	0.000
Wastewater Treating	1.88 scf CH_4/Mbbl	15,204 Mbbl/cd refinery feed	0.010
Cooling Towers	2.36 scf CH_4/Mbbl	15,204 Mbbl/cd refinery feed	0.013
Combustion Emissions			**0.094**
Atmospheric Distillation	3.61 scf CH_4/Mbbl	15,479 Mbbl/cd refinery feed	0.021
Vacuum Distillation	3.61 scf CH_4/Mbbl	6,966 Mbbl/cd feed	0.009
Thermal Operations	6.02 scf CH_4/Mbbl	2,181 Mbbl/cd feed	0.005
Catalytic Cracking	5.17 scf CH_4/Mbbl	5,239 Mbbl/cd feed	0.010
Catalytic Reforming	7.22 scf CH_4/Mbbl	3,222 Mbbl/cd feed	0.008
Catalytic Hydrocracking	7.22 scf CH_4/Mbbl	1,340 Mbbl/cd feed	0.003
Hydrorefining	2.17 scf CH_4/Mbbl	2,167 Mbbl/cd feed	0.002
Hydrotreating	6.50 scf CH_4/Mbbl	9,941 Mbbl/cd feed	0.023
Alkylation/Polymerization	12.6 scf CH_4/Mbbl	1,111 Mbbl/cd feed	0.005
Aromatics/Isomeration	1.80 scf CH_4/Mbbl	992 Mbbl/cd feed	0.001
Lube Oil Processing	0.00 scf CH_4/Mbbl	185 Mbbl/cd feed	0.000
Engines	0.006 scf CH_4/hp-hr	1,187 MMhp-hr/yr	0.007
Flares	0.189 scf CH_4/Mbbl	15,204 Mbbl/cd refinery feed	0.001
		Total	**1.432**
		Total Vented + Fugitive (excluding asphalt blowing)	**0.861**

Table 4-38. Refining GHG Emissions Sources

Source	Emissions (kg/day)		
	CO_2	CH_4	N_2O
Fuels Combustion	517,361,504	12,983	9,281
Fuels Acquisition*			
Indirect Energy Inputs	93,451,488	113,716	1,178
Purchased Fuels	14,134,109	168,565	277
Flare Emissions	76,287,537	110,786	249
H_2 Production Emissions**	5,337,947	2,524	57
CH_4 Vented/Fugitive Emissions***	0	45,159	0
Total	**706,572,586**	**453,732**	**11,042**

* Excludes emissions associated with refinery-produced fuels

** Does not include emissions associated with H_2 production embedded in the refining profile

*** Does not include methane emissions from asphalt blowing

Emissions from all fuels consumed (combustion and acquisition) and flaring and vented/fugitive emissions are combined to determine a total refinery emissions pool. There are no individual assignments of energy sources to unit operations. This particular modeling aspect is well-suited to allocation of refinery emissions to energy consumers. However, it should be noted that energy sources have very different upstream emissions profiles. For example, coal extraction, processing, and transport emits 6.60 kg CO_2E per MMBtu of coal delivered while natural gas extraction, processing, and transport emits 9.58 kg CO_2E per MMBtu delivered.

The emissions associated with hydrogen production create a second pool. These pools will be allocated to various petroleum refinery products as discussed in the next section.

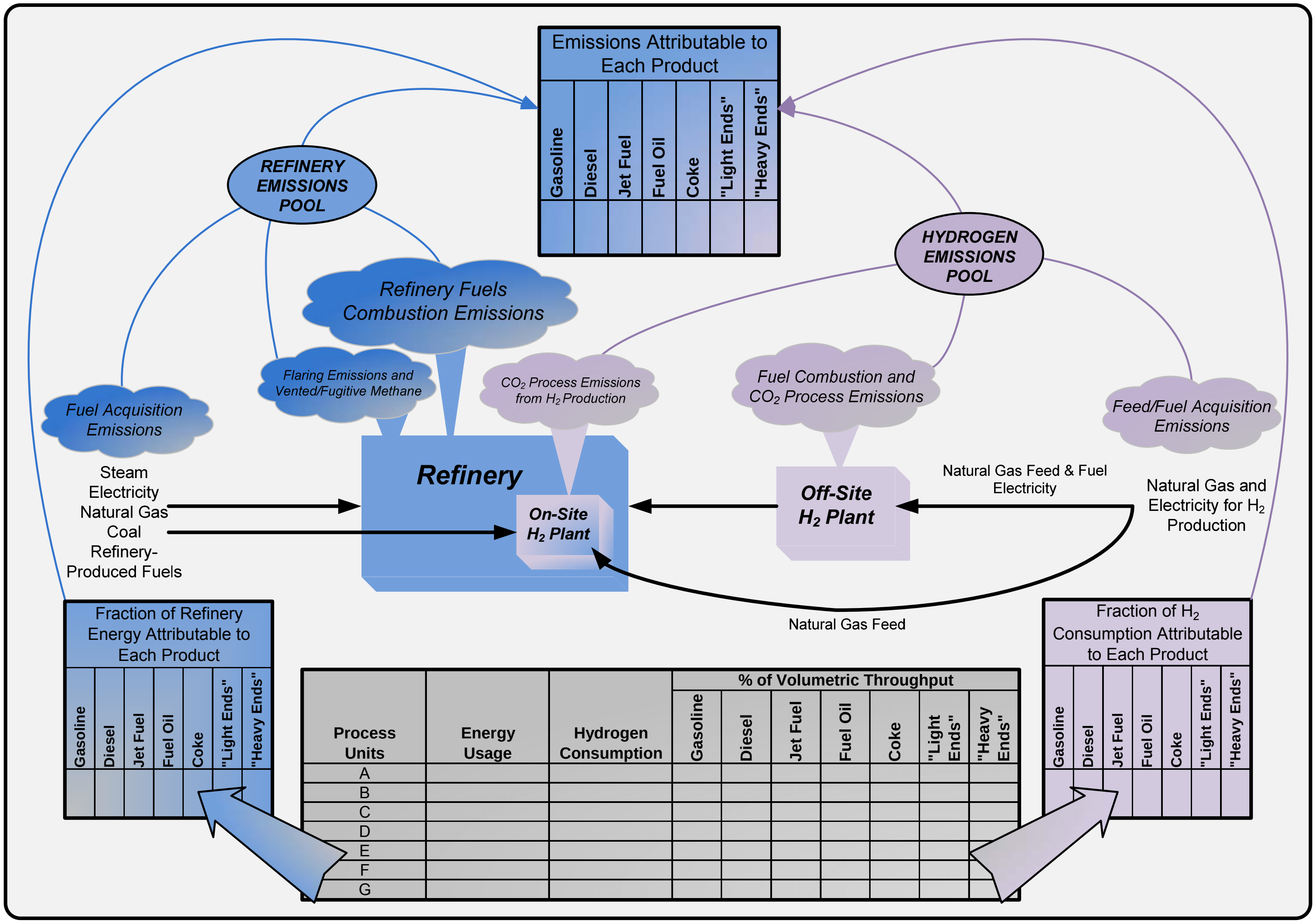
4.2.9 Refinery Process Unit Data Modeling and GHG Allocation to Products

Refinery emissions and emissions associated with hydrogen production are allocated to products based upon each product's consumption of resources (hydrocarbon feedstocks, fuels/energy, and hydrogen). To do this, the individual unit operations within the refineries are modeled using the following steps:

1. Capacity/throughput is determined for each of the unit processes
2. Energy requirements are determined for each of the unit processes
3. Hydrogen consumption is determined for each of the unit processes
4. Contribution of each of the unit processes to the final product slate is determined
5. Resource usage (energy and hydrogen) is allocated to the product slate

Figure 4-6 depicts the allocation of the refinery emissions and hydrogen production emissions pools developed in this section. Additional information on the selection of the allocation technique is provided in Appendix F.

Figure 4-6. Representation of Allocation of Life Cycle Stage #3 Emissions to Product Categories



Process Units	Energy Usage	Hydrogen Consumption	% of Volumetric Throughput						
			Gasoline	Diesel	Jet Fuel	Fuel Oil	Coke	"Light Ends"	"Heavy Ends"
A									
B									
C									
D									
E									
F									
G									

4.2.9.1 Process Unit Capacity and Throughput

EIA compiles data annually for U.S. refineries which include unit operation capacities in barrels per stream day and/or barrels per calendar day. Barrels per stream day (bpsd) is defined as the maximum number of barrels input to a unit operation which can be processed within a 24-hour period when running at full capacity under optimal crude and product slate conditions with no allowance for downtime. Barrels per calendar day (bpcd) is defined as the amount of input that a unit operation can process in one day under usual operating conditions. Thus, barrels per calendar day is representative of actual operating conditions and barrels per stream day is representative of a theoretical maximum capacity. Table 4-39 shows U.S. refineries total unit operation capacities in barrels per stream day and barrels per calendar day (where reported) for 2005 (plant capacities reported as of January 1, 2006). It is assumed that plant capacity reported on January 1, 2006, is representative of the capacity available for the entire year of 2005.

Table 4-39. U.S. Total Refinery Unit Operations Capacities in 2005* (EIA 2008)

Process	Unit Operation Capacity in 2005 (bpsd)	Unit Operation Capacity in 2005 (bpcd)
Atmospheric Distillation	18,307,502	17,338,814
Vacuum Distillation	8,398,470	Not Reported
Catalytic Cracking (Fresh Feed)	6,187,883	5,799,582
Catalytic Hydrocracking	1,637,200	1,474,986
Distillate	516,600	473,515
Gas Oil	920,200	824,171
Residual	200,400	177,300
Coking	2,510,910	2,330,100
Delayed	2,305,510	2,141,600
Fluid	205,400	188,500
Hydrotreating	14,807,986	Not Reported
Naphtha/Reformer Feed	4,400,484	Not Reported
Gasoline	2,056,470	Not Reported
Heavy Gas Oil	2,557,040	Not Reported
Distillate Fuel Oil	4,784,852	Not Reported
Kerosene/Jet Fuel	960,700	Not Reported
Diesel Fuel	2,950,792	Not Reported
Other Distillate	873,360	Not Reported
Residual Fuel Oil/Other	1,009,140	Not Reported
Residual Fuel Oil	327,100	Not Reported
Other	682,040	Not Reported
Catalytic Reforming	3,859,070	Not Reported
Alkylation**	1,238,479	Not Reported
Isomerization**	708,357	Not Reported
Isobutane	230,714	Not Reported
Isopentane/Isohexane	477,643	Not Reported

Process	Unit Operation Capacity in 2005 (bpsd)	Unit Operation Capacity in 2005 (bpcd)
Aromatics**	319,250	Not Reported
Asphalt & Road Oil**	893,249	Not Reported
Fuels Solvent Deasphalting	386,290	Not Reported
Lubricants**	219,840	Not Reported
Hydrogen** (MMcf)	2,823	Not Reported
Sulfur** (short tons)	32,421	Not Reported

* Refinery capacities were based on operational capacity as of January 1, 2006

** Production Capacity rather than downstream charge capacity

In order to better quantify the gas oil fractions, EIA has defined fractional cuts by boiling point range. Table 4-40 shows the boiling point ranges for the gas oil fractions noted in Table 4-39.

Table 4-40. Boiling Range for Various Petroleum Intermediates (EIA 2008)

Fraction	Boiling Range (^{o}F)
Naphtha	122 - 400
Kerosene and Light Gas Oils	401 – 650
Heavy Gas Oils	651 – 1,000
Residuum	> 1,000

Visbreaking and other thermal cracking capacity were excluded from the thermal cracking/coking category because the total visbreaking plus other capacity amounts to less than 1% of the coking capacity. In addition, visbreaking unit operation capacity is decreasing in the U.S. and there was an 11% reduction between January 1, 2006, and January 1, 2007. Actual capacity utilization is therefore questionable and has been excluded from this life cycle study.

Aromatics, asphalts, and fuels solvent deasphalting are also excluded and thus are not captured in the refinery modeling for liquid fuels production. It is not practical to attempt to estimate throughput and energy consumption associated with these downstream operations due to the variability in refinery designs, unspecified final product qualities, and a general lack of publicly available information to characterize the operation of these processes. It is acknowledged that liquid fuels will, therefore, bear some burden for these operations.

Unit operation capacities are not reported for all unit operations in barrels per calendar day, as indicated in Table 4-39. The actual daily operating capacity for unit operations—as a percent of the stream day capacity—varies by operation. The atmospheric distillation column capacity in barrels per calendar day is 94.7% of stream day capacity, catalytic cracking is 93.7%, catalytic hydrocracking is 90.1%, and coking is 92.8%.

Data on the actual downstream (subsequent process units) input into certain key refinery unit operations are collected by EIA. The actual inputs (in barrels per calendar day) into the atmospheric distillation column, catalytic cracking units, catalytic hydrocracking units, and delayed and fluid coking units are reported by EIA. Table 4-41 shows the actual input to these unit operations for refineries in the U.S. in 2005.

Table 4-41. Unit Operation Capacity, Actual Input, and Utilization Rate for Key U.S. Refinery Operations in 2005 (EIA 2008)

Unit Operation	Unit Capacity (bpcd)	Unit Actual Input (bpd)	Operable Utilization Rate (%)
Atmospheric Distillation	17,338,814	15,578,000	89.8
Catalytic Cracking (Fresh Feed)	5,799,582	5,269,000	90.9
Catalytic Hydrocracking	1,474,986	1,172,000	79.5
Delayed and Fluid Coking	2,330,100	2,054,000	88.2

In order to estimate the energy consumption associated with individual unit operations, it is necessary to determine the input to those operations. The actual throughputs/inputs for the atmospheric distillation column, catalytic cracking units, catalytic hydrocracking units and delayed and fluid coking units are known but the inputs to the vacuum distillation, hydrotreating, catalytic reforming, alkylation, and isomerization units must be approximated. Table 4-42 shows the actual or estimated input for each of the refinery unit operations listed in Table 4-39. The actual hydrocracking input has been sub-divided into distillate, gas oil, and residual inputs according to the relative installed unit operation capacities. Similarly, the total coking input has been ratioed to delayed and fluid coking units based upon the installed capacities.

A 1996 American Petroleum Institute (API)/National Petroleum Refiners Association (NPRA) survey of refinery operations and product quality (API 1997) was used to estimate the actual inputs to the vacuum distillation, hydrotreating, catalytic reforming, alkylation, and isomerization units. The survey details the "percent capacity utilization" for the aforementioned units but the API/NPRA survey (API 1997) definition of "percent capacity utilization" is slightly different than that of EIA. The API/NPRA survey definition of percent capacity utilization is ({Actual Unit Daily Charge or Production/Stream Day Capacity} x 100). Hence the capacity reduction associated with the stream day to calendar day conversion (optimum to usual), as well as the decrease in utilization from the capacity at usual operating conditions to actual throughput, is included in this factor. The 1996 API/NPRA survey shows the percent utilization for hydrotreating operations at U.S. refineries (excluding California) averaged 79%. Most hydrotreating operations are therefore estimated, for the purpose of this model, to have operated at an 80% utilization rate in 2005 (slightly higher utilization rate since crude oil sulfur content has increased significantly since 1996 and sulfur requirements in finished products has become more stringent). Table 4-42 shows the 1996 API/NPRA reported operation utilization rate and the estimated 2005 unit operation utilization rate.

In 2005, there was 168,000 bpd of lubricant production (EIA 2008) resulting in a unit operation utilization rate of 76.3% (unknown quantity of process input since EIA only tracks production for this operation).

Table 4-42. U.S. Total Refinery Unit Operations Capacities in 2005*

Process	Actual or Estimated Unit Operation Input in 2005 (bpd)	API/NPRA 1996 Unit Operation Utilization Rate (%)	2005 Unit Operation Utilization Rate (%)
Atmospheric Distillation**	15,578,000	92.4	89.8
Vacuum Distillation	7,138,700	84.7	85.0§
Catalytic Cracking (Fresh Feed)**	5,269,000	91.2	90.9
Catalytic Hydrocracking**	1,172,000	89.9	79.5
Distillate	376,247		79.5
Gas Oil	654,873		79.5
Residual	140,880		79.5
Coking**	2,054,000	89.1	88.2
Delayed	1,887,836		88.2
Fluid	166,164		88.2
Hydrotreating	11,846,389		
Naphtha/Reformer Feed***	3,520,387	82.4	80.0§
Naphtha***	101,251		
Reformer Feed***	3,419,136		
Gasoline	1,645,176		80.0§
Heavy Gas Oil	2,045,632	83.6	80.0§
Distillate Fuel Oil	3,827,882		80.0§
Kerosene/Jet Fuel	768,560	75.5	80.0§
Diesel Fuel	2,360,634	78.8	80.0§
Other Distillate	698,688		80.0§
Residual Fuel Oil/Other	807,312		80.0§
Residual Fuel Oil	261,680	74.3	80.0§
Other	545,632	79.1	80.0§
Catalytic Reforming	3,419,136	86.1	88.6
Alkylation	1,052,707	84.4	85.0
Isomerization	521,553		
Isobutane	177,650	76.6	77.0
Isopentane/Isohexane	343,903	71.3	72.0
Lubricants	168,000	Not Reported	76.4
Sulfur (short tons)	22,695	Not Reported	70.0

* Refinery capacities were based on operational capacity as of January 1, 2006

** Actual throughput as reported by EIA, all others are estimated; utilization rate based on bpcd capacity rather than bpsd (as for all other operations)

*** Reformer feed hydrotreating assumed equal to reformer throughput with balance to naphtha hydrotreating

---

§ A sensitivity analysis was performed on these parameters.

4.2.9.2 Refinery Unit Operations' Energy Consumption

In order to allocate refinery energy usage and associated emissions, it is first necessary to determine the energy requirements for the individual unit operations found in refineries. Energy utilization for each of the operations outlined in Table 4-43 has been estimated in the DOE study *Energy and Environmental Profile of the U.S. Petroleum Refining Industry* (Energetics 2007). All energy consumption data is on the basis of thousands Btu (MBtu) per barrel of feed input to the operation. The specific energy use is based on the estimated utility requirements for a range of technologies. The report breaks the unit processes energy requirements down into estimates from various energy sources, such as electricity and hydrocarbon fuels, and reports total energy requirements after incorporating exported energy and electricity losses. The unit process energy requirements used from the report specifically exclude energy associated with hydrogen production and consumption.

The estimated net electricity requirements (based on Energetics unit operation electrical requirements combined with the 2005 actual and estimated throughputs from the previous section) yields an electricity requirement of approximately 33.5% more power than the EIA reported quantity of purchased power for refineries in 2005 (see Section 4.2.2). It is therefore assumed that 33% of the refineries' electricity is produced on site in combined heat and power (CHP) units or other power generation activities. To account for the thermodynamic inefficiency associated with producing electricity from hydrocarbon species, the 33% power component is multiplied by a factor of 2.5. At a practical level, this means that for every MMBtu of electricity produced on site that is used by a unit operation, 2.5 MMBtu of thermal energy is necessary as a refinery input.

Table 4-43 shows the original ranges and averages reported by Energetics including all electricity losses and the adjusted values incorporating only those electricity losses associated with power generation occurring at the refinery. The study values align with the manner in which EIA reports fuels consumption.

4.2.9.3 Refinery Unit Hydrogen Consumption

The primary use for hydrogen in refineries is for removal of sulfur (desulfurization) to meet product quality requirements. Hydrotreating also removes nitrogen, oxygen, halides, and metals from petroleum fractions. U.S. refineries have the capacity to hydrotreat a combined volume equivalent to approximately 81% of the atmospheric distillation capacity. Hydrocracking—a more severe hydrotreating process which simultaneously hydrotreats and breaks down larger hydrocarbons— can treat a volume equivalent to approximately 9% of the atmospheric distillation capacity. Together, these processes can treat a volume equivalent to 90% of the total refinery atmospheric distillation capacity.

Table 4-43. Estimated Energy Use by Refining Process (Energetics 2007) and Study Value with Electricity Loss Adjustment

Process	Range of Unit Operation Specific Energy Usage (MBtu/bbl)*	Average Unit Operation Specific Energy Usage (MBtu/bbl)*	Study Unit Operation Specific Energy Usage (MBtu/bbl)
Atmospheric Distillation	82 - 186	114	110
Vacuum Distillation	51 - 113	92	89.7§
Fluid Catalytic Cracking	209	209	189
Catalytic Hydrocracking	159 - 321	168	107
Coking			
Delayed	114 - 230	166	147§
Fluid***	258	260	98.9
Catalytic Hydrotreating	61 - 164	88	59§
Catalytic Reforming	213 - 342	269	253§
Alkylation**	330 - 340	335	270
Isomerization			
Isobutane	359	359	343
Isopentane/Isohexane	102-236	175	166
Lubricants	1,506	1,506	1,410
Sulfur (per short ton)	389	389	190

* Specific energy usage is inflated to include electricity generation and transmission losses

** Specific energy usage is inflated to include electricity generation losses associated with power generation occurring at the refinery

*** Energetics fluid coking category encompasses traditional fluid coking and flexicoking. The traditional fluid coking specific energy requirement is used here.

**** Alkylation assumes the sulfuric acid process which has a higher specific energy requirement than hydrofluoric acid process

The amount of hydrogen consumed during hydrotreating is a function of the species being treated and the sulfur content of the fraction. Generally, for straight-run fractions, the heavier the hydrocarbons, the more hydrogen is required to remove heteroatoms. Lower boiling point compounds are desulfurized more readily than higher-boiling point fractions and the difficulty of sulfur removal increases in the following order: paraffins, naphthenes, aromatics (Gary 2007). Straight-run species require less hydrogen than cracked species because much of the hydrogen used for desulfurizing cracked species is uptaken for hydrogenation of these compounds. Figure 4-7 shows the increasing hydrogen requirement as the hydrotreated fraction becomes heavier and demonstrates the variability in hydrogen requirements for a particular fraction. Table 4-44 shows the average hydrotreating hydrogen requirements for various fractions, as quoted from different sources. A broad range of hydrogen consumption values is quoted for each fraction and there is often large variability between quoted estimates for the same fraction from different sources. The estimation of hydrogen utilization is further complicated by the fact that the total required hydrogen is generally higher than the chemical consumption.

---

§ A sensitivity analysis was performed on these parameters.

Figure 4-7. Hydrogen Consumption for Hydrotreating Operations (Jechura 2008)

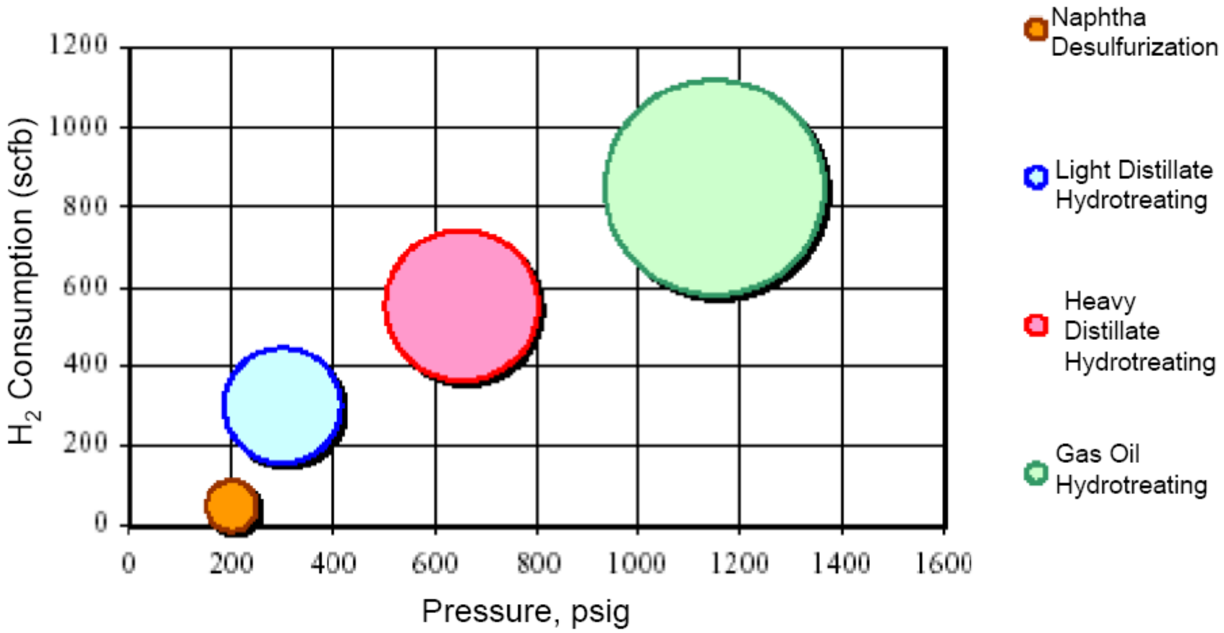


Table 4-44. Chemical Hydrogen Consumption for Various Petroleum Fractions

Fraction	Hydrogen Consumption (scfb)	References
Naphtha	10-50	Maples 1993
	20-200	O&GJ 2007
FCC Gasoline	20-200	O&GJ 2007
Kerosene	25-140	Maples 1993
Distillate	200-600	O&GJ 2007
Diesel	50-200	Maples 1993
Light Gas Oil	100-200	Maples 1993
Heavy Gas Oil	200-300	Maples 1993
FCC Feed	200-1,000	O&GJ 2007

Hydrogen requirements for hydrocracking are usually more severe than for hydrotreating. The requirements increase as the feedstock becomes heavier and the degree of hydrocracking increases. Hydrogen consumption for hydrocracking generally ranges between 1,000 and 2,500 scfb depending upon the feed and desired degree of conversion to lighter species (Maples 1993). Hydrocracking hydrogen consumption has been recently estimated to be 1,120 scfb (Energetics 2007). The estimated hydrogen consumption for hydrocracking operations used in this study is shown in Table 4-45.

Table 4-45. Estimated Hydrogen Consumption for Hydrocracking Operations

Hydrocracking Operation	Estimated Hydrogen Consumption (scfb)§
Distillate	1,000
Gas Oil	1,200
Residual	1,400

Hydrogen input to unit operations for hydrotreating/hydrocracking includes the hydrogen chemically consumed as well as excess hydrogen for operation and hydrogen lost as a dissolved species in the liquid product. Not all produced hydrogen is used as a reactant. When a hydrogen stream is sufficiently depleted of hydrogen so as to be unacceptable for use in hydrotreating operations or too difficult/costly to purify, the stream is used as a fuel gas. This quantity is considered part of the "refinery gas" or "still gas" fuels. The emission factor for still gas should include the presence of hydrogen. Additionally, combustion of hydrogen results in production of water and there should be no extraneous emissions consistent with utilization of the hydrogen stream as a fuel gas.

For this study, a mass balance determines the hydrogen requirements for hydrotreating. The quantity of hydrogen produced was detailed in Section 4.2.5 and this hydrogen is then distributed to the hydrotreating and hydrocracking operations. The quantities of hydrogen used for hydrocracking were chosen as shown in Table 4-45. The remaining hydrogen, as shown in Table 4-46, has been assigned to the hydrotreating operations.

Table 4-46. Hydrogen Consumption Mass Balance

Source	Hydrogen Consumption (MMscfd H_2)	Reference
Hydrocrackers	1,359	Table 4-45 & Table 4-42
Hydrotreaters	5,681	Balance
Total (including reformer feed hydrotreating)	**7,041**	**Table 4-31 & Table 4-30**

The allocation of this hydrogen to the hydrotreater subcategories is based on a ratio (relative to naphtha) of hydrogen consumption estimated from Table 4-44 and other hydrotreating data/trends. The ratios are reported in Table 4-47.

Given these relative hydrogen requirements, the quantity of hydrogen required for refinery operation is estimated for each of the hydrotreating operations. This method balances refinery consumption with hydrogen production. Table 4-48 shows the calculated (estimated) hydrotreating hydrogen requirements for the various fractions. Note that the mass balance results in hydrogen requirements that are within the bounds presented in Figure 4-7.

---

§ A sensitivity analysis was performed on these parameters.

Table 4-47. Estimated Hydrogen Requirements for Hydrotreating (Relative to Naphtha)

Hydrotreater	Relative Hydrogen Consumption
Naphtha/Reformer Feed	1.0
Gasoline	2.25
Heavy Gas Oil	4.0
Distillate Fuel Oil	
Kerosene/Jet Fuel	2.5
Diesel Fuel	3.0
Other Distillate	3.5
Residual Fuel Oil/Other	
Residual Fuel Oil	4.5
Other	4.5

Table 4-48. Estimated Hydrogen Requirements for Hydrotreating

Hydrotreater	Hydrogen Consumption (scfb)
Naphtha/Reformer Feed	186
Gasoline	419
Heavy Gas Oil	745
Distillate Fuel Oil	
Kerosene/Jet Fuel	466
Diesel Fuel	559
Other Distillate	652
Residual Fuel Oil/Other	
Residual Fuel Oil	839
Other	839

4.2.9.4 Contribution of Unit Operation to Product Categories

Allocation of refinery emissions are made to seven different product categories: gasoline, diesel, kerosene and kerosene-based jet fuel, residual fuel oil, coke, "light ends," and "heavy ends." The light ends category is composed of still gas, liquefied refinery gases (LRG), special naphtha, and petrochemical feedstocks. The heavy ends category is composed of asphalt and road oil, lubricants, waxes, and a miscellaneous fraction.

Production Volumes by Product Category

Table 4-49 shows the quantity of domestically refined petroleum products for 2005 for each of the categories. This information is reported by EIA (2008). The gasoline category includes all formulations of motor gasoline and aviation gasoline, as well as gasoline blendstocks produced at the refineries (but which was not yet blended to produce finished gasoline). Diesel includes all types of distillate fuel oil (with varying sulfur content). Residual fuel oil includes all types (with varying sulfur content). Coke includes both catalyst and marketable coke. This table also shows the portion of each product category that is associated with the liquid fuels of interest: conventional gasoline, conventional diesel and kerosene-based jet fuel. When determining the contribution of each of the unit operations to the product categories, no differentiation is made between these subcategories. For gasoline and kerosene, the subcategory for the fuel of interest makes up more than 95% of the category. For diesel, however, conventional diesel makes up only 75% of the of the distillate production.

Table 4-49. Product Categories and Amount Produced in 2005

Product Category	Amount Produced (thousand bpd)
Gasoline	7,816
Conventional Gasoline	7,794
Aviation Gasoline	22
Diesel	3,954
Conventional Diesel (≤500 ppm sulfur)	2,933
All Other Diesel	1,022
Kerosene and Kerosene-Based Jet Fuel	1,611
Kerosene-Based Jet Fuel	1,546
Kerosene	66
Residual fuel oil	628
Coke	835
Light ends	1,684
Heavy ends	754

Primary Basis for Unit Operation Allocation to Product Categories

Historical information from 1996 serves as the primary basis for allocation of the contribution of various unit operations to the finished liquid fuels product slate. The 1996 API/NPRA refining survey took a detailed look at refining operations and product quality for a 4-month time frame (API 1997). These data have been adjusted to account for the changes in feedstock quality since that time, changes in environmental emissions requirements, changes in product quality/slate, and modified refinery operations.

Refinery feedstocks are, on average, becoming lower quality. In 1996, the weighted U.S. average sulfur content of crude oil input to refineries was 1.15% (EIA 2008). In 2005, the average sulfur content was 1.42%—a 23% increase in sulfur. The average API gravity for crude oil inputs was 31.14 degrees in 1996 and was 30.20 in 2005—a 0.94 degree drop in API gravity (indicating heavier crude oil).

Diesel production has increased since 1996 and the product slate is moving towards lower sulfur products. Ultra low sulfur diesel (ULSD) was not produced in 1996 and accounted for less than 1% of distillate production in 2005. Table 4-50 shows diesel production and product sulfur contents in 1996 and 2005.

Table 4-50. Diesel Production and Sulfur Content in 1996 and 2005 (EIA 2008)

Diesel Production	1996	2005
Total Production (1,000 bbls)	1,213,563	1,443,348
Ultra Low Sulfur Diesel, <15 ppm S (%)	0.00%	0.60%
Low Sulfur Diesel, 15-500 ppm S (%)	63%	74%
High Sulfur Diesel, >500 ppm S (%)	37%	26%

Table 4-51 summarizes the data presented in the 1996 API/NPRA survey report and presents the estimates used in this study for 2005. Data are presented for catalytic cracking, coking, catalytic hydrocracking, and hydrotreating operations detailing the percentage of the final product that goes through the selected refinery operations.

Table 4-51. 1996 Reported and 2005 Estimated Unit Operation Contributions to Diesel, Gasoline, and Kerosene Fractions

Unit Operation	1996 Contribution (%) to Low-Sulfur Diesel*	1996 Contribution (%) to All Diesel*	Estimate of 2005 (%) Contribution to Diesel	1996 Contribution (%) to US Gasoline*	Estimate of 2005 (%) Contribution to Gasoline	1996 Contribution (%) to Kerosene /Jet Fuel	Estimate of 2005 (%) Contribution to Kerosene/ Jet Fuel
Catalytic Cracking	22.5	22.4	25	31.0**	40.4**	4.3	5.0
Coking	9.2***	7.9	23.4	0.25	2.6	1.4	6.4
Catalytic Hydrocracking	4.0	5.9	9.0	--	8.0	5.4	8.4
Hydrotreating	79.4	64.1	82.6	--	89.4	44.8	52.7

Source: Final Report: 1996 American Petroleum Institute/National Petroleum Refiners Association Survey of Refining Operation and Product Quality

* Total U.S. data, excludes California

** Catalytic cracked gasoline amounts to approximately 60% of the catalytic cracking unit feed

*** In California, coking contributes 40.5% to the low-sulfur diesel fraction

Individual Unit Operation Allocations to Product Categories

The volumetric capacities of the individual unit operations have been assigned to the seven product categories based upon the relative contribution of the throughput of that operation to the final product category. Table 4-52 summarizes the volumetric throughput allocations to the final product fractions. The rationale for the individual unit operations' capacity assignments to product categories is described in greater detail below.

Table 4-52. Summary of Unit Operation Contribution to End Products

	Gasoline	Diesel	Kerosene/ Kerosene-Based Jet Fuel	Residual Fuel Oil	Coke	Light Ends	Heavy Ends
Atmospheric Distillation	Relative to final product slate						
Vacuum Distillation	Equal to catalytic cracking throughput contribution for Gasoline, Diesel or Kerosene plus the remainder (after fuel oil, coke, heavy ends is assigned) ratioed to Gasoline, Diesel and Kerosene relative to respective throughput contribution of coking units			Equal to final product slate			Equal to final product slate
Catalytic Cracking	60% of throughput	25% of diesel produced	5% of kerosene produced		All catalyst coke	Balance	
Distillate Hydrocracking	75%	10%	15%				
Gas Oil Hydrocracking	50%	40%	10%				
Residual Hydrocracking	Balance	40%	10%				51.3 Mbpd
Delayed Coking	10% of throughput	45% of throughput	5% of throughput		All marketable coke distributed based on throughput	Balance	
Fluid Coking							
Naphtha Hydrotreating	95% of throughput					5% of throughput	
Reformer Feed Hydrotreating*	95% of throughput*					5% of throughput*	
Gasoline Hydrotreating	All						
Heavy Gas Oil Hydrotreating	1,850 kbbl/day is catalytic cracker feed hydrotreating and is distributed as in catalytic cracking; remainder to diesel fraction						
Kerosene/Jet Fuel Hydrotreating			All				
Diesel Fuel Hydrotreating		All					
Other Distillate Hydrotreating	Relative to final product slate						
Residual Fuel Oil Hydrotreating				All			
Other Hydrotreating	Balance relative to final product slate						115 Mbpd
Catalytic Reforming*	95% of throughput*					5% of throughput*	
Alkylation	All						
Isomerization	All						
Lubricants							All
Sulfur							All

* Allocations for reformer feed hydrotreating and catalytic reforming include only energy requirements remaining after assigning energy to the hydrogen pool

Atmospheric Distillation

Since all refinery products pass through the atmospheric distillation column in the form of the initial feedstock, the atmospheric distillation capacity is divided among all seven product categories according to that product category's fraction of the total refinery output (includes fuels produced and consumed in the refinery).

Vacuum Distillation

The vacuum distillation column separates the bottoms from the atmospheric distillation column into additional boiling-point cuts for appropriate downstream treating. The primary downstream operations used to upgrade the heavy vacuum distillation cuts are the coking and catalytic cracking units. All coke, residual fuel oil, and heavy ends production is assumed to pass through the vacuum distillation column.

A large volume of the vacuum distillation column throughput is heavy oils destined for the catalytic cracking unit. The vacuum distillation column capacity is ratioed to the products from the catalytic cracking unit relative to that unit's contribution to the final product slate. For example, based on the 1996 API/NPRA refining survey (API 1997), 60% of the catalytic cracker input is slated to go to the gasoline fraction; therefore, 60% of the catalytic cracker throughput is slated to go through the vacuum distillation column to the gasoline fraction. The vacuum distillation contribution to the diesel and kerosene/jet-fuel fractions is calculated relative to the catalytic cracking contribution in the same manner (as described above for gasoline) for those species.

The remaining vacuum distillation column capacity, after subtracting out the above contributions, is then ratioed to gasoline, diesel, and kerosene/jet-fuel in the same ratio as the liquid product allocation from the coking unit—16.7% to gasoline, 75% to diesel, and 8.3% to kerosene/jet fuel (see subsequent discussion of the coking operations).

Catalytic Cracking

The catalytic cracking unit breaks large hydrocarbon molecules down into smaller, more useful, species. The primary recipient of the products from this operation is the gasoline fraction.

Based on the 1996 API/NPRA refining survey (API 1997), 60% of the catalytic cracker input went to the gasoline fraction; therefore, 60% of the catalytic cracker input in 2005 has been slated to go to the gasoline fraction.§

The 1996 API/NPRA refining survey (API 1997), reported that 22.4% of 15-500 ppm diesel was cracked in 1995. Considering that crude stocks have gotten heavier in the interim, it was estimated that 25% of diesel fuel total production would be cracked in 2005.§

The 1996 API/NPRA refining survey (API 1997), reported that 4.3% of kerosene/jet fuel production is cracked. In 2005, 5% of kerosene/jet fuel total production is estimated to be cracked.§

EIA reports that 239,000 bpd of catalyst coke was produced in 2005. The catalytic cracker is assumed to be the sole producer of this catalyst coke and thus 239,000 bpd has been allocated to the coke fraction.

---

§ A sensitivity analysis was performed on these parameters.

The remaining unaccounted for catalytic cracking capacity (after coke, gasoline, diesel, and kerosene/jet fuel fractions have been accounted for) has been assigned to the light ends.

Catalytic Hydrocracking

The catalytic hydrocracking operation is divided into three sub-categories based on the feed input: distillate, gas oil, and residual. The severity of the hydrocracking operation, as well as the feed quality, determines the product quality/category. The hydrocracking throughput allocations to the final products have a high degree of uncertainty.

Distillate hydrocracking is assumed to produce predominantly gasoline; 75% of distillate hydrocracking capacity has been assigned to gasoline, 15% to kerosene/jet fuel, and 10% to diesel fuel.

Gas oil hydrocracking is a more severe (higher pressure and higher hydrogen consumption) process than distillate hydrocracking. The throughput capacity for this operation has been allocated 50% to gasoline, 40% to diesel, and 10% to kerosene/jet fuel.[§]

Residual hydrocracking is the most severe of the three types listed. According to the Oil and Gas Journal Worldwide Refining Survey (O&GJ 2005) there was 57,000 bpcd of installed hydrocracking capacity for lube oil manufacturing. Assuming a 90% utilization rate, this results in 51,300 bpcd of capacity allocated to the heavy ends product fraction. Forty percent of the residual hydrocracking capacity has been allocated to the diesel fraction and 10% has been allocated to the kerosene/jet fuel fraction. The remainder (14%) has been allocated to the gasoline fraction.

Coking

The coking operation is divided into two types, delayed and fluid. The total coking annual input is reported and the capacity is allocated to the delayed and fluid coking operations according to the ratio of the installed capacities. In 2005, a total of 596,000 bpd of marketable petroleum coke was produced and the production was allocated to the coke fraction (delayed and fluid) in the same ratio as their respective installed capacity. The allocation of the remaining capacity was performed using information derived from Petroleum Refining Technology and Economics Table 5.11 (Gary 2007). The yield on fresh feed is reported to be approximately 10% naphtha, 50% gas oil, and 10% gases. Therefore, the gasoline fraction was assigned 10% of the coking throughput, diesel was assigned 45% (reported yield is designated as gas oil and so it was assumed that 45% would be allocated to diesel and 5% to kerosene), kerosene/jet fuel was assigned 5%, coke was assigned 596,000 bpd (29%), and light ends made up the remainder (11%).

Catalytic Reforming

Using system expansion, it was determined in Section 4.2.5 that the energy associated with the catalytic reformer would be assigned entirely to the hydrogen pool. However, for various sensitivity analysis cases, this same methodology calls for a portion for the catalytic reformer energy to be assigned to the liquid products. Note that the allocation detailed here applies only

---

[§] A sensitivity analysis was performed on these parameters.

to any portion of the catalytic reformer energy requirement that is assigned to the reformate after energy requirements are distributed to the hydrogen pool.

In addition to hydrogen, the catalytic reformer produces reformate, which goes exclusively to the gasoline fraction, and light hydrocarbons which are assigned to the light ends. It is assumed that 95% of the catalytic reforming unit capacity is attributable to the gasoline fraction and 5% is attributable to the light ends (due to decomposition and removal of miscellaneous hydrocarbon gases during the reforming operation).

Hydrotreating

The hydrotreating operations are subdivided into several categories based upon the species being hydrotreated. The hydrotreating categories are broken down as follows: naphtha/reformer feed, heavy gas oil, kerosene/jet fuel, diesel fuel, other distillate, residual fuel oil, and other.

Reformer feed hydrotreating capacity has been assigned to the final product slate based on the catalytic reformer output assignments. Hence, after allocation to the hydrogen pool, 95% of the reformer feed hydrotreating capacity is attributable to the gasoline fraction and 5% is attributable to the light ends. Naphtha hydrotreating capacity has been assigned as 95% to the gasoline fraction and 5% to the light ends fraction.

Heavy gas oil hydrotreating is assumed to be attributed primarily to catalytic cracking unit feed hydrotreating. This is consistent with the Oil and Gas Journal Worldwide Refining Survey (O&GJ 2005) citing that in 2005, 2,056,437 bpcd of capacity existed for pretreatment of catalytic cracker feeds. Assuming a 90% utilization rate this results in 1,850,793 bpcd of catalytic cracker hydrotreating. Hence, 1,850,793 bpcd is allocated to the products from the catalytic cracking unit and the remaining 194,839 bpcd is allocated to the diesel fraction.

Kerosene/jet fuel hydrotreating capacity has been assigned exclusively to the kerosene/jet fuel final product fraction.

Diesel fuel hydrotreating capacity has been allocated exclusively to the diesel fuel product fraction.

Other distillate hydrotreating capacity has been allocated to the gasoline and diesel fuel fractions based upon the relative production volume of gasoline and diesel, due to a lack of information allowing a more definitive classification.

Residual fuel oil hydrotreating capacity has been allocated exclusively to the residual fuel oil product fraction.

Other hydrotreating capacity is somewhat ill-defined and thus assumptions must be made to distribute throughput among the product fractions. Hydrogen is used for lube oil “polishing” and according to the Oil and Gas Journal Worldwide Refining Survey (O&GJ 2005) there was 128,450 bpcd of installed capacity for lube oil polishing. Therefore, 115,605 bpcd (based on an assumed 90% utilization rate) has been assigned to the heavy ends product fraction. The remainder of "other" hydrotreating capacity has been assigned to gasoline, diesel, and kerosene/jet fuel based on their relative production quantities.

Alkylation

The alkylation operations and the throughput for those operations are assigned exclusively to the gasoline fraction.

Isomerization

Isomerization is further categorized into isobutane or isopentane/isohexane isomerization. The products of this operation are assumed to contribute exclusively to the gasoline fraction.

Summary

Table 4-52 shows a summary of the allocation data described above. Figure 4-8 shows the resulting percentages of volumetric throughput for each unit operation that is being allocated to each end product. Catalytic reforming operations are excluded from this figure due to the separate allocation process with hydrogen.

4.2.9.5 Resources and Emissions Allocation to Product Fractions

A refinery performance summary with allocation of refining energy use and hydrogen production/consumption has been developed for the seven product fractions discussed previously. This performance summary is then used to allocate the emissions associated with refinery fuels, hydrogen production, flaring and venting/fugitive methane emissions to the final product categories.

Product Fractions Performance Summary

The refinery energy consumption has been estimated for the seven categories by multiplying the throughput for contributing unit operations by the specific energy usage, in thousands Btu per barrel (see Table 4-43), and summing for each product category. For catalytic reforming and reformer feed hydrotreating, the entire specific energy usage is allocated to hydrogen output (see Section 4.2.5.2 for further discussion).

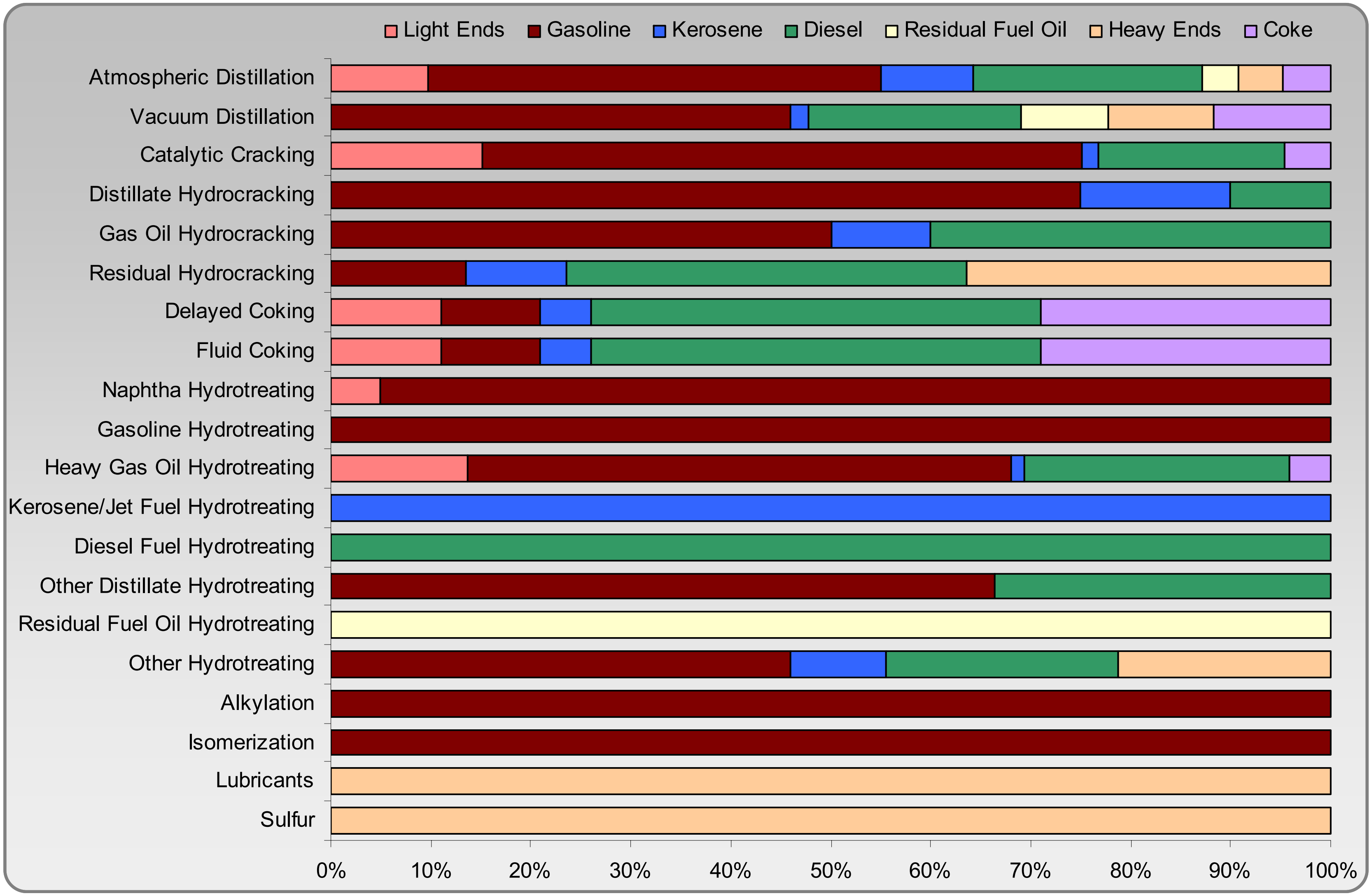
Hydrogen requirements are determined for the seven product categories by multiplying the process input/throughput for each operation by the specific hydrogen consumption and summing. Hydrogen requirements for the reformer feed hydrotreating operation are excluded from this total because hydrogen used for pretreatment of the reformer feed (recycle stream) is subtracted from the reformer output prior to contribution to the hydrogen pool.

The concept of a refinery hydrogen pool was developed earlier and is described in Section 4.2.5. Hydrogen extracted from that "pool" has a *refinery* energy requirement associated with it, as well as a GHG emissions profile. Energy consumption consistent with hydrogen consumption is calculated by multiplying the total refinery energy associated with hydrogen from Table 4-32 by the fraction of the total hydrogen requirement for each of the categories.

The total refining energy requirement is a sum of the process unit energy requirements and the energy requirements for producing hydrogen consumed by refinery operations across all seven product categories. The fraction of the total refinery energy that is attributable to the product slate is determined by summing the refining process unit energy requirements and the hydrogen production energy requirements for each category and dividing by the total energy requirements for the entire refinery.

Note that the refinery energy requirement calculated here is based on estimated unit operation throughput and energy usage and only includes those operations modeled. This total is approximately 75% of the total energy input calculated from the fuels consumed as reported by refiners to EIA.

Figure 4-8. Percent of Volumetric Throughput Allocated to End Products



A refinery performance summary with allocation of refining energy use and hydrogen production/consumption has been calculated for the product fractions outlined above. Table 4-54 summarizes the refinery performance.

Fuels Combustion and Acquisition Emissions Allocation to Product Fractions

Fuels-consumed emissions are assigned to the product fractions based upon the fractional energy usage required to produce these products. Table 4-54 reports the fraction of total refinery energy consumption attributable to the seven product categories. The GHG emissions consistent with fuels consumption is then multiplied by the appropriate energy consumption fraction for each category.

Hydrogen Production Emissions Allocation to Product Fractions

Hydrogen production emissions associated with operations not included in the refinery energy and emissions profile have been assigned to the product fractions according to each category's hydrogen consumption fraction.

Flaring and Methane Venting/Fugitive Emissions Allocation to Product Fractions

Refinery flaring and methane venting/fugitive emissions have been allocated to product fractions based upon the fraction of the total refinery energy usage required for production of each product category.

4.2.10 Summary of LC Stage #3 for Domestic Refineries

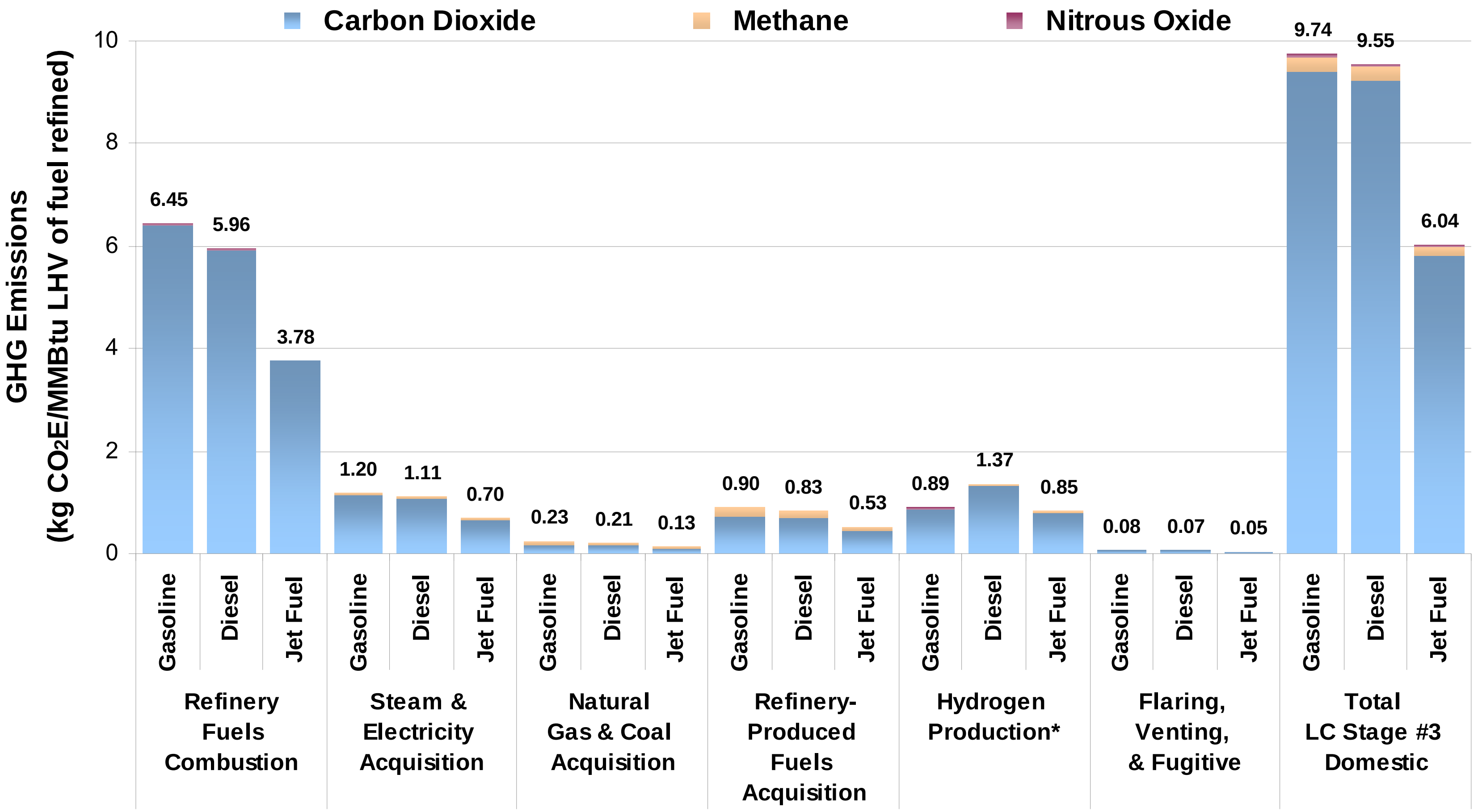
The resulting emissions profile for each product category per barrel and per million Btu LHV of product refined are shown in Table 4-55 and Table 4-56 including a breakdown for various sub-categories. Heating values in Appendix I were utilized to convert from a volumetric to an energetic basis. Figure 4-9 shows the information for the refinery products of interest on a CO_2 equivalent basis.

Table 4-53 provides the CO_2, methane and nitrous oxide emissions on a per barrel refined basis for the transportation fuels of interest.

Table 4-53. LC Stage #3 GHG Emissions for Transportation Fuels Produced in Domestic Refineries

Source	Emissions (kg/bbl refined)		
	CO_2	CH_4	N_2O
Conventional Gasoline	46.0	0.0562	7.45E-04
Conventional Diesel	50.8	0.0627	7.85E-04
Kerosene-Based Jet Fuel	30.5	0.0376	4.72E-04

Figure 4-9. Life Cycle Stage #3 GHG Emissions for Domestic Refineries - Key Products



* Does not include fuel usage at the refineries (and associated emissions) that is attributable to hydrogen production

Table 4-54. Refinery Performance Summary for Product Fractions

Properties	Gasoline	Diesel	Kerosene & Kerosene-Based Jet Fuel	Residual Fuel Oil	Coke	Light Ends	Heavy Ends
H_2 Requirement (MMscfd) [Excluding reformer feed hydrotreating]	2,751	2,414	577	219	63	210	169
Fraction of H_2 Consumption Requirement	0.430	0.377	0.090	0.034	0.010	0.033	0.026
Refinery Energy Requirement for H_2 Production (MMBtu HHV/day)	496,515	435,814	104,213	39,612	11,295	37,956	30,463
Estimated Energy Requirement for Refining Unit Operations Modeled (MMBtu HHV/day) [excludes H_2 production energy consumption]	2,378,144	1,077,947	267,077	134,126	293,143	367,615	396,018
Estimated Energy Requirement for Refining Unit Operations Modeled (MMBtu HHV/day) [includes H_2 production energy consumption]	2,874,660	1,513,760	371,290	173,738	304,438	405,571	426,482
Fraction of Refinery Energy Consumed Attributable to Refinery Unit Operations Modeled	0.47	0.25	0.06	0.03	0.05	0.07	0.07
Total Refinery Energy Usage Attributable to Product Category (MMBtu HHV/day) [Based on total fuels consumed for 2005]	3,811,449	2,006,952	492,258	230,343	403,625	537,708	565,432
Fraction of Total Refinery Production Attributable to Products (volumetric)	0.45	0.23	0.09	0.04	0.05	0.10	0.04

Table 4-55. Life Cycle Stage #3 GHG Emissions for Domestic Refineries by Activity Sub-Category

Source	Gasoline	Diesel	Kerosene & Kerosene-type Jet Fuel	Residual Fuel Oil	Coke	Light Ends	Heavy Ends
CO_2 Emissions (kg/bbl Refined Product)	**46.0**	**50.8**	**30.5**	**35.7**	**42.4**	**28.9**	**67.0**
Refinery Fuels Combustion	31.4	32.6	19.6	23.6	31.1	20.5	48.2
Purchased Steam and Electricity	5.66	5.89	3.55	4.26	5.61	3.71	8.70
Acquisition of Natural Gas & Coal	0.86	0.89	0.54	0.64	0.85	0.56	1.32
Acquisition of Refinery-Produced Fuels	3.66	3.81	2.29	2.75	3.63	2.40	5.62
Hydrogen Production*	4.19	7.27	4.27	4.17	0.89	1.49	2.67
Flaring, Vented & Fugitive	0.32	0.34	0.20	0.24	0.32	0.21	0.50
CH_4 Emissions (kg/bbl Refined Product)	**5.62E-02**	**6.27E-02**	**3.76E-02**	**4.38E-02**	**5.10E-02**	**3.50E-02**	**8.09E-02**
Refinery Fuels Combustion	7.87E-04	8.19E-04	4.93E-04	5.92E-04	7.80E-04	5.15E-04	1.21E-03
Purchased Steam and Electricity	6.89E-03	7.17E-03	4.32E-03	5.19E-03	6.83E-03	4.51E-03	1.06E-02
Acquisition of Natural Gas & Coal	1.02E-02	1.06E-02	6.40E-03	7.69E-03	1.01E-02	6.69E-03	1.57E-02
Acquisition of Refinery-Produced Fuels	2.93E-02	3.05E-02	1.84E-02	2.21E-02	2.91E-02	1.92E-02	4.51E-02
Hydrogen Production*	6.09E-03	1.06E-02	6.20E-03	6.05E-03	1.30E-03	2.16E-03	3.87E-03
Flaring, Vented & Fugitive	2.89E-03	3.01E-03	1.81E-03	2.17E-03	2.86E-03	1.89E-03	4.44E-03
N_2O Emissions (kg/bbl Refined Product)	**7.45E-04**	**7.85E-04**	**4.72E-04**	**5.64E-04**	**7.28E-04**	**4.84E-04**	**1.13E-03**
Refinery Fuels Combustion	5.62E-04	5.85E-04	3.52E-04	4.23E-04	5.58E-04	3.68E-04	8.64E-04
Indirect Energy Inputs	7.14E-05	7.43E-05	4.47E-05	5.37E-05	7.08E-05	4.68E-05	1.10E-04
Acquisition of Purchased Fuels	1.68E-05	1.75E-05	1.05E-05	1.26E-05	1.66E-05	1.10E-05	2.58E-05
Acquisition of Refinery-Produced Fuels	7.75E-05	8.06E-05	4.85E-05	5.83E-05	7.68E-05	5.07E-05	1.19E-04
Hydrogen Production*	1.37E-05	2.37E-05	1.39E-05	1.36E-05	2.91E-06	4.86E-06	8.71E-06
Flaring, Vented & Fugitive	3.47E-06	3.61E-06	2.17E-06	2.61E-06	3.44E-06	2.27E-06	5.33E-06

Source	Gasoline	Diesel	Kerosene & Kerosene-type Jet Fuel	Residual Fuel Oil	Coke	Light Ends	Heavy Ends
GWP in CO_2E (kg/bbl Refined Product)	**47.7**	**52.6**	**31.6**	**36.9**	**43.9**	**29.9**	**69.4**
Refinery Fuels Combustion	31.5	32.8	19.8	23.7	31.3	20.7	48.5
Purchased Steam and Electricity	5.86	6.10	3.67	4.41	5.81	3.84	9.00
Acquisition of Natural Gas & Coal	1.12	1.16	0.70	0.84	1.11	0.73	1.72
Acquisition of Refinery-Produced Fuels	4.42	4.60	2.77	3.32	4.38	2.89	6.79
Hydrogen Production*	4.35	7.55	4.43	4.32	0.93	1.54	2.77
Flaring, Vented & Fugitive	0.40	0.41	0.25	0.30	0.39	0.26	0.61

* Does not include fuel usage at the refineries (and associated emissions) that is attributable to hydrogen production

Table 4-56. Life Cycle Stage #3 GHG Emissions for Domestic Refineries by Sub-Category

Source	Gasoline	Diesel	Kerosene & Kerosene-type Jet Fuel
GWP in CO_2E (kg CO_2E/MMBtu LHV of Refined Product)	**9.74**	**9.55**	**6.04**
Refinery Fuels Combustion	6.45	5.96	3.78
Purchased Steam and Electricity	1.20	1.11	0.70
Acquisition of Natural Gas & Coal	0.228	0.211	0.134
Acquisition of Refinery-Produced Fuels	0.903	0.834	0.529
Hydrogen Production*	0.889	1.369	0.847
Flaring, Vented & Fugitive	0.081	0.075	0.048

* Does not include fuel usage at the refineries (and associated emissions) that is attributable to hydrogen production

4.3 Liquid Fuels Production at Foreign Refineries

Determining emissions consistent with refining operations for foreign entities is not a trivial matter due to the inherent variability in feedstocks and technologies employed, as well as different product emphasis and environmental regulations. Information extracted from foreign studies of gasoline and diesel production vary widely due to differences in study assumptions, system boundaries, and information sources. Three publicly available sources of information for gasoline and diesel production emissions are discussed briefly below, two for European refining operations and one for Brazilian refinery operations. The Brazilian source also details emissions consistent with kerosene production.

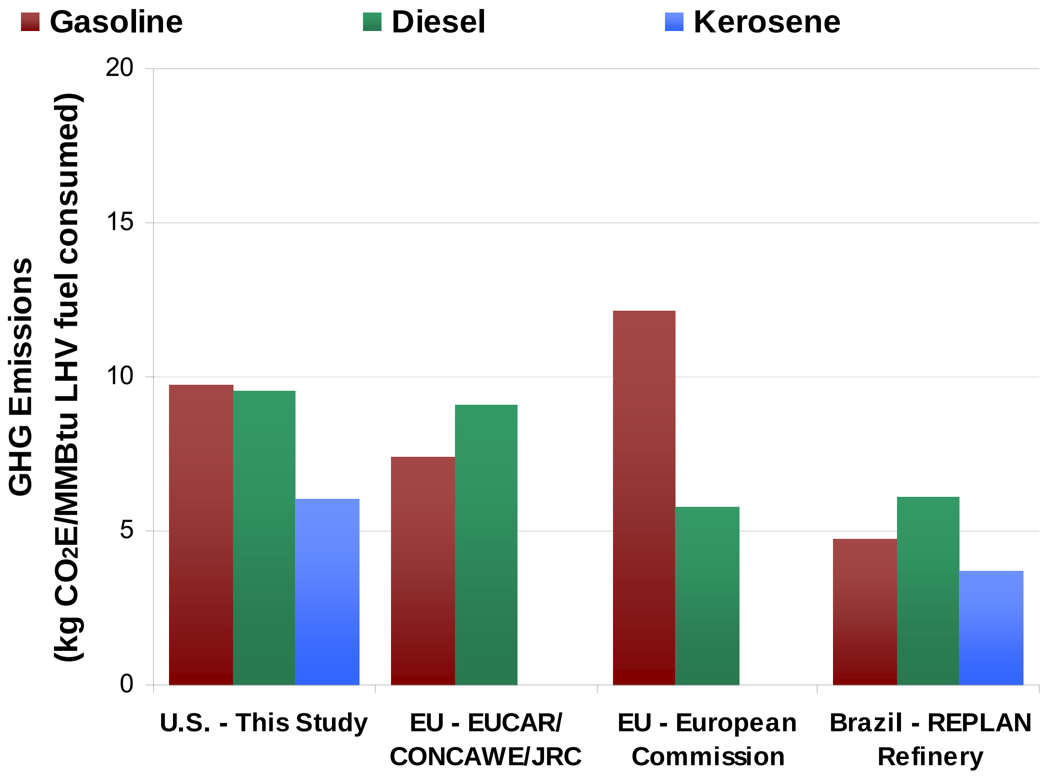
EUCAR/CONCAWE/JRC Study: An analysis of European well-to-tank emissions for petroleum products was performed jointly by representatives of EUCAR (the European Council for Automotive R&D), CONCAWE (the oil companies' European association for environment, health and safety in refining and distribution) and JRC/IES (the Institute for Environment and Sustainability of the EU Commission's Joint Research Centre), assisted by personnel from L-B-Systemtechnik GmbH (LBST) and the Institut Français de Pétrole (IFP). The study is entitled "Well-to-Wheels analysis of future automotive fuels and powertrains in the European context: WELL-TO-TANK Report" (EUCAR 2007).

European Commission Life Cycle Inventory Data: The European Commission maintains the "European Reference Life Cycle Data System" (ELCD) of Life Cycle Inventory (LCI) data sets (ELCD 2008). Life cycle inventory information is publicly available for gasoline and diesel production (cradle-to-gate). These data were used to determine the refining emissions consistent with gasoline and diesel production by subtracting the crude oil free-to-customer emissions for EU-15 crude oil mix (GaBi 4 2007) from the profile assuming a ratio of 0.94 bbl inputs/bbl of product (the same ratio determined for U.S. refineries).

Brazilian National LCI Database: The cradle-to-gate life cycle inventory is publicly available for the largest petroleum refinery in Brazil—REPLAN Refinery (Refinaria de Paulínia) located in Sao Paulo Brazil (BNLD 2008). Refinery experts deemed that refinery to be a "representative Brazilian refinery" (BNLD 2008). Life cycle inventory data is available for gasoline (200 ppm sulfur), diesel (500 ppm sulfur), and kerosene (2,000 ppm sulfur) production in 2005, as well as other refinery products. These data were used to determine the refining emissions consistent with gasoline, diesel, and kerosene production by subtracting the crude oil free-to-customer emissions for the 2002 Brazilian crude oil mix (GaBi 4 2007) from the profile assuming a ratio of 0.94 bbl inputs/bbl of product (the same ratio determined for U.S. refineries).

Figure 4-10 shows a comparison of this study's results for gasoline and diesel refining with that of the three aforementioned foreign studies modeling gasoline and diesel production. Figure 4-10 also shows a comparison of this study's results for kerosene-based jet fuel with Brazilian results for kerosene production. The results are presented in CO_2E. Due to the wide variability between studies modeling refining operations, the U.S. domestic refining emissions profile (shown in Table 4-53) developed herein has been used as a surrogate for foreign refinery operations.

Figure 4-10. Comparison of Refining GHG Emissions Between Studies



4.4 Summary of Life Cycle Stage #3 GHG Emissions Profiles

Table 4-57 summarizes the emissions profiles associated with petroleum refining operations for production of gasoline, diesel and jet fuel. The profile here is used for both U.S. and non-U.S. operations. Emissions are presented as per barrel refined.§

Table 4-57. Summary of GHG Emissions Consistent with Refining of Gasoline, Diesel and Jet Fuel at U.S. and Foreign Refineries in 2005

Fuel Type	Emissions (kg/bbl refined)		
	CO_2	CH_4	N_2O
Conventional Gasoline	46.0	0.0562	7.45E-04
Conventional Diesel	50.8	0.0627	7.85E-04
Kerosene-Based Jet Fuel	30.5	0.0376	4.72E-04

---

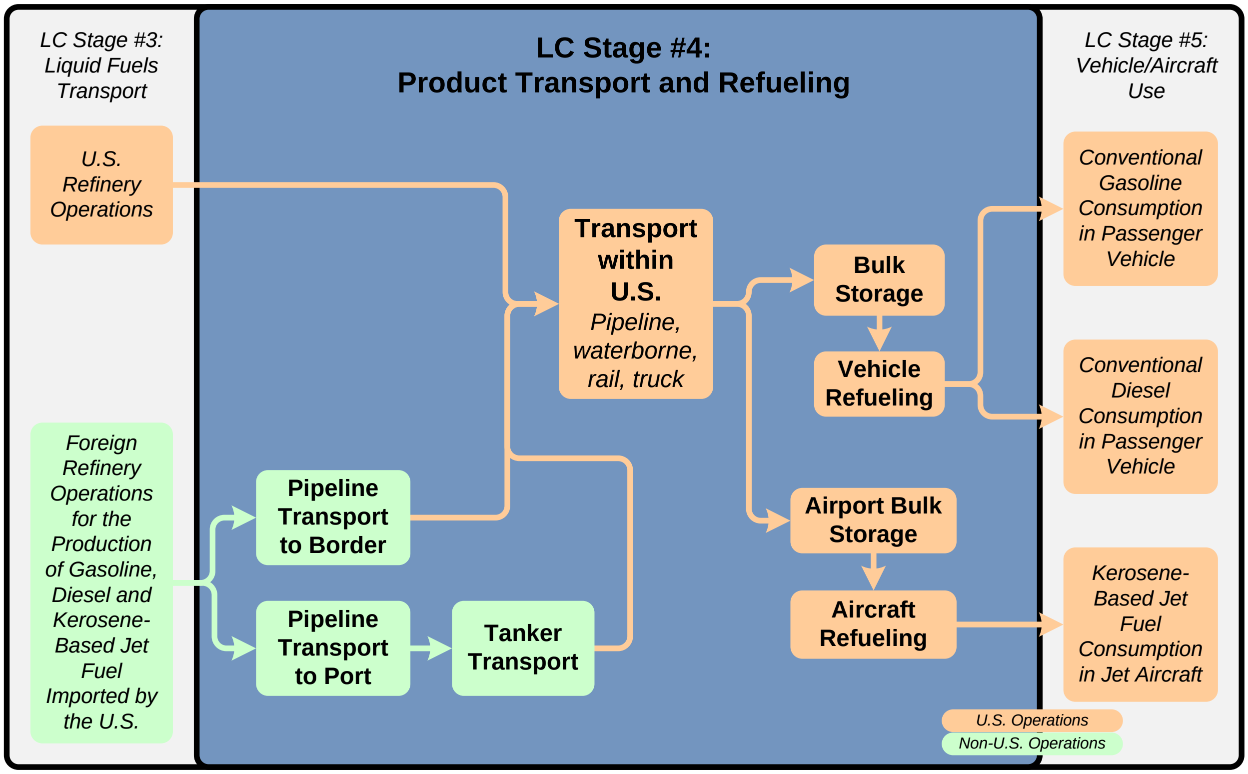
§ A sensitivity analysis was performed on these parameters.

5.0 Life Cycle Stage #4: Transport of Liquid Fuels to Vehicle Refueling Station or Airport and Refueling of Vehicle/Aircraft

Life Cycle Stage #4 begins where liquid fuels exit foreign and domestic refineries and end with fueling of the vehicle/aircraft. This stage includes product transport to bulk storage, bulk storage at terminals or the airport, transport of jet fuel to aircraft, and refueling operations.

Figure 5-1 depicts the activities and flow of feedstocks for LC Stage #3.

Figure 5-1. Flow Diagram of Product Transport and Refueling Activities



5.1 Product Transport

Product transport includes transport of imported liquid fuels from the exporting nations to the U.S. as well as domestic transport of both imported fuels and domestically produced liquid fuels.

5.1.1 Foreign Transport

Product transport includes tanker and/or pipeline transport of imported products to the U.S. receiving port. Emissions associated with tanker/pipeline operation are the primary GHG emission sources. Losses during product transport indirectly add to GHG emissions by necessitating more product be produced to meet end use requirements.

Petroleum products are assumed to be shipped an average of 10 miles by pipeline to either a port for ocean transport or to the U.S. border. The energy intensity for pipeline transport is assumed to be 260 Btu/ton-mile (Wang 2008) and electricity is assumed to be the power source. The emissions associated with pipeline transport are estimated using emissions from the U.S. power grid as a surrogate profile for that of foreign countries (Appendix B).§ This is noted as a data limitation but the resulting impact to the overall life cycle emissions is minor.

The energy requirement for transporting liquid fuels via tanker is calculated by multiplying the number of barrels of fuel shipped by the distance traveled in nautical miles and the energy intensity for transport. The return trip is assumed to require the same amount of energy. The values are summed for each of the different import sources and the emissions associated with consumption of that quantity of energy (as heavy fuel oil) are determined.

Table 5-1 outlines the performance specifications for various sizes and types of petroleum product tankers. The energy intensity ranges from 7.4 to 10.9 Btu per barrel-nautical mile of fuel transported. The assumed study value for product tanker transport operations is 10 Btu per barrel-nautical mile.§

Table 5-1. Performance Specifications for Various Petroleum Product Tankers (Brodosplit 2008)

Designation	Product Tanker	Product Tanker Ice-1A Class	Product Tanker	Oil Product/ Chemical Tanker	Handy Size Oil Product Tanker
Service Speed (kt)	15.8	16.3	14.9	15.7	15.3
Fuel Oil Consumption (tonnes/day)	49.0	49.2	41.0	33.6	31.8
Cargo Volume (m^3)	116,032	85,950	70,255	55,423	53,000
Deadweight (MT)	95,000	74,999	65,200	45,000	45,000
Product Volume (bbl)	729,819	540,610	441,891	348,600	333,360
Energy Intensity: Btu/bbl-nautical mile	**7.4**	**9.8**	**10.8**	**10.7**	**10.9**

The heavy fuel oil (HFO) used to power tanker operations is essentially residual fuel oil and therefore the GHG emissions profile consistent with combustion of residual fuel oil in marine engines is used to determine the ship emissions during international transport. GHG emissions from heavy fuel oil are presented in Table 5-2.

Table 5-2. GHG Emissions from Combustion of HFO (Residual Fuel Oil) in Ships (EIA 2007)

Source	Emissions (kg/MMBtu HHV)		
	CO_2	CH_4	N_2O
HFO Combustion in Ships	78.8	5.75E-03	2.00E-03

---

§ A sensitivity analysis was performed on these parameters.

Product losses from marine transport operations were estimated using EPA AP-42 emission factors and a detailed discussion of loss factors is presented in Appendix H.

5.1.1.1 Gasoline Transport to the U.S.

EIA (2008) reports more than 3,000 import shipments of gasoline and gasoline blendstocks in 2005 totaling 403,950,000 barrels. Gasoline is imported to 89 different U.S. ports from 59 different sources. 80.7% of these imports were received by PADD 1. Import source and quantity of imports are shown in Appendix A.

The average density of all gasoline types and gasoline blendstocks is assumed to be the same at 2.79 kg per gallon (EPA 2008). This yields 372 million Btu HHV per day of energy consumed for the assumed 10 miles of foreign pipeline transport of gasoline. The GHG emissions associated with this energy consumption are shown in Table 5-3.

Specific port-to-port travel distances were estimated for imports from Canada (98% of gasoline imports received via waterborne transit) and the Virgin Islands because of their high volume of exports to the U.S. Given the complexity involved in determining transit distances for all other import shipments, all other imports were estimated to travel 5,000 nautical miles to their U.S. destination. The transit time for imports from Canada and the Virgin Islands was calculated assuming an average ship speed of 15 knots (kt). All other imports are assumed to have a two week transit time (effectively assuming an average speed of approximately 15 kt).§

Tanker transport emissions for gasoline imported to the U.S. is shown in Table 5-3, along with the foreign pipeline transport emissions and the total foreign transport emissions.

Table 5-3. GHG Emissions Associated with Transport of Imported Gasoline to Domestic Ports

Source	Emissions (kg/bbl refined)		
	CO_2	CH_4	N_2O
Pipeline Transport	0.073	8.46E-05	9.45E-07
Tanker Transport to U.S. Port	4.90	3.57E-04	1.24E-04
Total Foreign Transport	**4.97**	**4.41E-04**	**1.25E-04**

5.1.1.2 Diesel Transport to the U.S.

Diesel is imported primarily from Canada (82% of diesel imports received via waterborne transit) and the Virgin Islands and these two sources make up 69% of the total U.S. conventional diesel imports (≤ 500 ppm S). European countries (Belgium, Denmark, Estonia, France, Germany, Latvia, Lithuania, Netherlands, Sweden, and the United Kingdom) make up an additional 11%. The origin of U.S. distillate imports for 2005 is shown in Appendix A along with the quantity imported.

The average density of diesel (EPA 2008) is 3.21 kg per gallon. This yields 60.6 million Btu HHV per day of energy consumed for the assumed 10 miles of foreign pipeline transport of

---

§ A sensitivity analysis was performed on these parameters.

diesel fuel. The GHG emissions associated with this energy consumption are shown in Table 5-4.

Specific port-to-port travel distances were estimated for imports from Canada and the Virgin Islands because they represent the primary sources for diesel imports to the U.S. in 2005. Given the complexity involved in determining transit distances for all other import shipments, all other imports were estimated to travel 5,000 nautical miles to their U.S. destination. The transit time for imports from Canada and the Virgin Islands was calculated assuming an average ship speed of 15 kt. All other imports are assumed to have a two week transit time (effectively assuming an average speed of approximately 15 kt).§

Table 5-4. GHG Emissions Associated with Transport of Imported Diesel to Domestic Ports

Source	Emissions (kg/bbl refined)		
	CO_2	CH_4	N_2O
Pipeline Transport	0.084	9.70E-05	1.08E-06
Tanker Transport to U.S. Port	2.97	2.16E-04	7.54E-05
Total Foreign Transport	**3.05**	**3.13E-04**	**7.65E-05**

5.1.1.3 Kerosene-Based Jet Fuel Transport to the U.S.

Kerosene-based jet fuel is imported primarily from South Korea, the Virgin Islands, and Venezuela. The origin of U.S. jet fuel imports for 2005 is shown in Appendix A along with the quantity imported.

The average density of jet fuel is 3.04 kg per gallon (DESC 2005). This yields 69.5 million Btu HHV per day of energy consumed for the assumed 10 miles of foreign pipeline transport of jet fuel. The GHG emissions associated with this energy consumption are shown in Table 5-5.

Given the complexity involved in determining transit distances for import shipments, imports from Canada and the Virgin Islands were assumed the have the same effective waterborne transport distance as diesel imports; all remaining imports were estimated to travel 5,000 nautical miles to their U.S. destination. All imports (with the exception of Canada and the Virgin Islands) are assumed to have a two week transit time (effectively assuming an average speed of approximately 15 kt).§

Table 5-5. GHG Emissions Associated with Transport of Imported Kerosene-Based Jet Fuel to Domestic Ports

Source	Emissions (kg/bbl refined)		
	CO_2	CH_4	N_2O
Pipeline Transport	0.079	9.20E-05	1.03E-06
Tanker Transport to U.S. Port	4.99	3.64E-04	1.27E-04
Total Foreign Transport	**5.07**	**4.56E-04**	**1.28E-04**

---

§ A sensitivity analysis was performed on these parameters.

5.1.2 Domestic Transport

Liquid fuels are transported within the U.S. via five primary mechanisms: pipeline, ocean tanker, barge, railroad, and truck. Table 5-6 summarizes the U.S. petroleum products' domestic transportation modes.

The Oak Ridge National Laboratory (ORNL) Transportation Energy Data Book, Table 2.4, outlines the domestic consumption of transportation energy by mode and fuel type. These data were used to determine the fuel powering the aforementioned transportation operations. Based upon the ORNL Transportation Energy Data Book, Table 2.4, in 2004 natural gas and electricity were the primary fuels for effecting pipeline transport. Since natural gas is used primarily for fueling natural gas pipeline transport, all crude oil and petroleum product transport via pipeline is assumed to be fueled by electricity. Similarly, diesel fuel is shown to be the exclusive fuel source for Class I freight railroad operations. Water carriers transporting freight are powered by diesel fuel and residual fuel oil (30.5 % diesel fuel and 69.5% residual fuel oil on an energetic basis). Medium/heavy trucks were powered primarily (90%) by diesel fuel and all petroleum tanker trucks in this study are assumed to be powered exclusively with diesel fuel.

Table 5-6. Total *Petroleum Products* Carried In Domestic Transportation (Billions of Ton-Miles) and Percent of Total Carried by Mode of Transportation (AOP 2006)

Year	Total Products	Pipelines*		Water Carriers		Motor Carriers**		Railroads	
	Ton-miles	Ton-miles	% of Total	Ton-miles	% of Total	Ton-miles	% of Total	Ton-miles	% of Total
2000	497.3	293.9	59.1	153.4	30.8	30.1	6.1	19.9	4.0
2001	493.2	299.1	60.6	145.9	29.6	29.7	6.0	18.5	3.8
2002	480.6	299.6	62.3	131.9	27.5	29.4	6.1	19.7	4.1
2003	502.9	305.7	60.8	146.0	29.1	31.9	6.3	19.3	3.8
2004	528.4	315.9	59.8	158.2	29.9	33.2	6.3	21.1	4.0

* The amounts carried by pipeline are based on ton-miles of crude and petroleum products for federally-regulated pipelines (84 percent) plus an estimated breakdown of crude and petroleum products in units of ton-miles for pipelines that are not federally regulated (16 percent).

** The amounts carried by motor carriers are estimated.

The above data were then combined to determine a quantity of energy expended for petroleum products transport and the fuel type powering the operation for the whole U.S. for 2004. In the absence of a better method for allocating transportation energy to petroleum products[4], the total energy consumption for transport of petroleum products in 2004 and their associated emissions are allocated to the volume of petroleum products produced or imported in 2004. This total volume is 7,781,225 Mbbl and was computed as follows: total refinery products minus refinery products used on-site as a fuel minus petrochemical feedstocks plus total imported petroleum

---

[4] The U.S. Department of Transportation Federal Highway Administration notes that shipments of petroleum products "are significantly underestimated" in the U.S. Commodity Flow Survey (CFS) which tracks gasoline and aviation turbine fuels, fuel oils, and other petroleum products. The CFS is conducted as part of the Economic Census by the U.S. Census Bureau in partnership with the Bureau of Transportation Statistics of the U.S. Department of Transportation. http://ops.fhwa.dot.gov/freight/freight_analysis/faf/faf2_reports/reports6.htm

products plus natural gas liquids production.§ This transportation energy is assumed to be the same for 2005. Results of this energy usage allocation are summarized in Table 5-6.

Table 5-7. Energy Intensity of Transport Activities

Transport Mode	Energy Intensity (One-way)	Unit	Reference Year	Reference
Petroleum Product Pipeline	260	Btu/ton-mile	2008	Wang 2008
Water Carriers	514	Btu/ton-mile	2005	ORNL 2007, Table 2.16
Railroad	337	Btu/ton-mile	2005	ORNL 2007, Table 2.16
Heavy single-unit and combination trucks	20,539	Btu/Vehicle-Mile	2005	ORNL 2007, Table 2.16
Heavy single-unit and combination trucks	822*	Btu/ton-Mile	2005	ORNL 2007, Table 2.16

* Assuming a 25-ton truck tanker capacity

Table 5-8. Energy Usage for Petroleum Product Transport Activities

Transport Mode	Energy Usage (Billion Btu HHV)	Energy Usage (Btu HHV/bbl of Petroleum Products Transported)	Fuel Source
Petroleum Product Pipeline	82,134	10,555	Electricity
Water Carriers	162,630	20,900	30.5% Diesel Fuel/69.5% Residual Fuel Oil
Railroad	14,221	1,828	Diesel Fuel
Heavy single-unit and combination trucks	54,552	7,011	Diesel Fuel

In order to determine emissions associated with the estimated fuels consumption for petroleum products transport, appropriate emissions factors are applied to the quantities of fuels consumed (as shown in Table 5-8) for transport. Table 5-9 provides a summary of the emissions factors applied for each mode of fuel product transportation. The emissions factors for diesel fuel and residual fuel oil take into account combustion of the fuel only. The upstream emissions associated with production of these secondary fuels contribute only minimally to the final results for the scenarios of interest.

---

§ A sensitivity analysis was performed on these parameters.

Table 5-9. Petroleum Product Transportation Modes and Associated Emission Factors

Transport Mode	Energy Usage (Btu HHV/bbl of Petroleum Products Transported)	Fuel Source	Fuel Energy Content (MMBtu HHV/ bbl)	CO_2 (g CO_2/ gallon)	CH_4 (g CH_4 /gallon)	N_2O (g N_2O/ gallon)	Emission Factor Reference
Pipeline	10,555	Electricity	N/A	217*	0.251*	0.00281*	EPA, 2007 (eGRID); GaBi 4, 2007
Water Carriers	6,375	Diesel Fuel	5.825	10,147	0.74	0.26	EIA 2007
Water Carriers	14,526	Residual Fuel Oil	6.287	11,793	0.86	0.30	EIA 2007
Railroad	1,828	Diesel Fuel	5.825	10,147	0.80	0.26	EIA 2007
Heavy single-unit and combination trucks	7,011	Diesel Fuel	5.825	10,147	0.57	0.30	API 2004 Table 4-9

* Emission factor units are kg/MMBtu for electricity

Calculated specific transit emissions associated with each of the aforementioned modes of petroleum product transportation are reported with the associated emissions in Table 5-10. Losses from transport are not incorporated here.

Table 5-10. Emissions Associated with Petroleum Products Transport

Transport Mode	Emissions (kg/bbl)		
	CO_2	CH_4	N_2O
Pipeline	2.29	2.65E-03	2.97E-05
Water Carriers (Diesel)	0.47	3.40E-05	1.20E-05
Water Carriers (Residual Fuel Oil)	1.14	8.35E-05	2.91E-05
Railroad	0.13	1.05E-05	3.43E-06
Heavy single-unit and combination trucks	0.51	2.88E-05	1.52E-05
Total	**4.54**	**2.81E-03**	**8.93E-05**

5.2 Vehicle/Aircraft Refueling

5.2.1 Vehicle Refueling

The vehicle fueling station is defined as the fuel storage tank, fuel pumps, and dispensing stations.

Emissions consistent with energy consumption to transfer fuel from the underground storage tank and meter the fuel into the vehicles were estimated. Electricity is the primary power source for this motive action and emissions consistent with the power consumption were modeled using the U.S. power grid mix developed using the U.S. EPA eGRID database (EPA 2007a). A discussion of the power-related GHG emissions is presented in Appendix B.

Evaporative losses (see Appendix H) consistent with unloading the fuel from the tanker truck and refueling the vehicle at the station occur in this stage.

5.2.1.1 Gasoline Refueling Operations

Electricity usage at service station to pump liquid fuels from the underground storage tank and meter them into vehicles is relatively minor. The electrical consumption for a gasoline dispensing unit was calculated based on assumptions made about the dispensing unit and the amount of fuel it dispensed. The power output for the motor in the dispensing unit is rated at 750 W (CHG 2008). The EPA regulated flow rate of gasoline dispensing units is 10 gal/min or 600 gal/hr. By taking the power and dividing it by the flow rate, the amount of energy consumed by the motor for an hour per gallon is found. Dispensing gasoline into vehicles required 0.00125 kWh per gallon of gasoline dispensed.

GHG emissions associated with vehicle refueling operations are summarized in Table 5-11.

Table 5-11. Greenhouse Gas Emissions Associated with Vehicle Refueling Operations

Source	Emissions (kg/bbl delivered to refueling station)		
	CO_2	CH_4	N_2O
Gasoline Dispenser Operation	0.0388	4.50E-05	5.03E-07

5.2.1.2 Diesel Refueling Operations

The electricity needed to effect fuel transfer operations for diesel is calculated the same as for gasoline transfer. Hence the electricity requirement for dispensing diesel fuel is 0.00125 kWh per gallon of diesel dispensed. Table 5-11 shows the emissions associated with the fuel pump and dispenser operation.

5.2.2 Aircraft Refueling

Aircraft fueling operation includes transfer of jet fuel from the airport tank farm to a tanker truck followed by aircraft refueling from the tanker. Aircraft refueling emissions consistent with transport of the jet fuel from airport storage to the aircraft via tanker truck are assumed to be included in the product transport emissions profile.

5.3 Summary of Life Cycle Stage #4 GHG Emissions Profiles

Table 5-12 summarizes the emissions profiles associated with transport of gasoline, diesel and jet fuel. The foreign transport profile is applicable only to imported fuels. The domestic transport and refueling profiles are applicable to both domestically-produced and imported transportation fuels. The increase in transport activity required to deliver each barrel of product (due to transport losses detailed in Appendix H) are applied. Emissions for the transport profiles are presented as per barrel delivered to U.S. ports/borders for foreign transport and per barrel delivered to the airport or refueling station for domestic transport. Refueling emissions are presented as per barrel delivered to the vehicle tank.

Table 5-12. Summary of GHG Emissions Consistent with Transport of Gasoline, Diesel and Jet Fuel in 2005

	CO_2	CH_4	N_2O
Foreign Transport	**Emissions (kg/bbl delivered to U.S.)**		
Conventional Gasoline	4.97	4.40E-04	1.25E-04
Conventional Diesel	3.05	3.13E-04	7.65E-05
Kerosene-Based Jet Fuel	5.07	4.56E-04	1.28E-04
Domestic Transport	**Emissions (kg/bbl delivered to refueling station)**		
Conventional Gasoline	4.55	2.82E-03	8.95E-05
Conventional Diesel	4.54	2.81E-03	8.93E-05
Kerosene-Based Jet Fuel	4.54	2.81E-03	8.93E-05
Refueling	**Emissions (kg/bbl delivered to tank)**		
Conventional Gasoline	0.0388	4.51E-05	5.04E-07
Conventional Diesel	0.0388	4.50E-05	5.03E-07
Kerosene-Based Jet Fuel	Included in transport profile		

6.0 Life Cycle Stage #5: Vehicle/Aircraft Operation

This LC stage comprises of combustion of the fuel in the vehicle or aircraft. This is the last LC stage in the study. Routine maintenance of the vehicle over the useful lifespan is excluded from the study boundary.

6.1 Vehicle Operation

This LC stage starts when refueling of the vehicle is complete and continues as the fuel is burned for the energy it provides. The primary focus of analysis in this stage is the emissions which are created during the combustion process.

Vehicle use profiles for gasoline and diesel fuel consumption for the 2005 average fleet were calculated by the U.S. EPA, Office of Transportation and Air Quality, Motor Vehicle Emission Simulator (MOVES) model (EPA 2008). A conventional internal combustion engine for HPMS passenger car vehicle class is utilized in this study for reporting of use emissions for conventional gasoline and conventional diesel. Table 6-1 shows the fuel efficiency and vehicle use emissions on a per-mile and per-MMBtu LHV-fuel-burned basis for gasoline and diesel-powered passenger cars. The vehicle use profile on a kg/MMBtu LHV basis is equivalent for all vehicle types as reported.[5] Results calculated and reported on a "per-mile" basis are dependant on each vehicle class's fuel efficiency (i.e., fuel consumed per mile traveled) and are therefore only applicable to the applied vehicle class. Appendix J provides the emissions factors for the 2005 average fleet for other vehicle classifications.

Table 6-1. Conventional Diesel and Conventional Gasoline Operational Parameters and Emissions for 2000 Model Passenger Cars (EPA 2008)

Property	Units	Conventional Gasoline	Conventional Diesel
Fuel Efficiency	MPG	23.9	35.1
Total fuel use	Btu LHV/mile	4,866	3,737
Emissions:			
CO_2	kg/mile	0.365	0.286
CH_4	kg/mile	2.37E-05	2.99E-07
N_2O	kg/mile	2.43E-05	6.53E-07
CO_2	kg/MMBtu LHV	75.0	76.6
CH_4	kg/MMBtu LHV	4.9E-03	8.0E-05
N_2O	kg/MMBtu LHV	5.0E-03	1.7E-04

---

[5] Differences in vehicle engine efficiency result in different methane and nitrous oxide emissions, however, the contribution to the total GWP, on a CO_2 equivalent basis, is orders of magnitude smaller than the CO_2 emissions.

6.2 Aircraft Operation

The LC stage starts when refueling of the aircraft is complete. The stage continues as the fuel is burned for the energy it provides. The primary focus of analysis in this stage is the emissions which are created during the combustion process. The U.S. Federal Aviation Administration (FAA 1997) Air Quality Handbook, Appendix D: Aircraft Emission Methodology, outlines emissions estimation techniques for aircraft.

Aircraft-specific emissions are available for landing and take-off (LTO) operations but not for the cruise component of flights. Appendix K shows the LTO emissions for various aircraft.

The IPCC methodology for estimating aircraft emissions for both LTO and cruise are utilized in this study. The CO_2 cruise emissions—like LTO emissions—assume all carbon in the fuel is converted to CO_2 and CO_2 emissions are estimated to be 3.16 kg CO_2 per kg of fuel (IPCC 2006). The cruise emission estimates are considered highly uncertain for methane and nitrous oxide (IPCC 2006). IPCC (2006) reports that in-flight methane emissions are considered negligible and assumed to be zero. A composite CH_4 emission factor has been generated by the IPCC (2006) for flights assuming that the LTO emission factor is 5 kg/TJ (0.005 kg CH_4/MMBtu LHV) (10% of total VOC factor) and that globally about 10% of the total fuel is consumed during LTO cycles, resulting in a fleet averaged CH_4 emission factor of 0.5 kg/TJ (0.0005 kg CH_4/MMBtu LHV). N_2O emissions are computed indirectly and the default value is 2 kg/TJ LHV (0.002 kg/MMBtu LHV) for flight operations (LTO plus cruise). Table 6-2 lists the total average flight emissions in kg per MMBtu LHV of jet fuel consumed. Appendix I provides the heat content and densities for jet fuel.

Table 6-2. GHG Emissions Consistent with Average Flight Operations

Source	Emissions (kg/MMBtu LHV)		
	CO_2	CH_4	N_2O
Average Flight Operations (LTO + Cruise)	77.1	0.0005	0.002

6.3 Life Cycle Stage #5 Summary

Table 6-3 summarizes the emissions profiles associated with consumption of gasoline, diesel and jet fuel.

Table 6-3. Summary of GHG Emissions Consistent with Consumption of Gasoline, Diesel and Jet Fuel in 2005

Petroleum Product	Emissions (kg/MMBtu LHV consumed)		
	CO_2	CH_4	N_2O
Conventional Gasoline	75.0	4.88E-03	4.99E-03
Conventional Diesel	76.6	8.00E-05	1.75E-04
Kerosene-Based Jet Fuel	77.1	5E-04	2E-03

7.0 Results and Discussion

The U.S. liquid fuels GHG profile for 2005 includes domestically-produced petroleum products as well as imported petroleum products (either as a finished product or blendstock). The following sections detail the GHG profile for the product mix (foreign and domestically produced) consumed in the U.S. in 2005 for each of the following fuels:

- Conventional motor gasoline
- Conventional diesel (≤500 ppm sulfur)
- Kerosene-based jet fuel

7.1 Construction of Life Cycle Emissions Profiles

CO_2, CH_4, and N_2O emission profiles were developed for each life cycle stage associated with both U.S. and foreign petroleum feedstock acquisition and transport, refining, and transport of gasoline, diesel and jet fuel to and within the U.S. in 2005. The final results are presented as GHG emissions per million Btu of fuel consumed in a vehicle or aircraft. This requires relating the emissions profiles in each life cycle stage to this functional unit. The individual life cycle stages report emissions as a function of the output for the individual operations. For example, emissions associated with crude oil extraction are reported on a per-barrel-of-crude-oil-extracted basis. The following factors must be taken into account when relating the profiles from each life cycle stage to the functional unit (one million Btu of fuel consumed): (1) allocation of crude oil acquisition and transport emissions to petroleum refinery products; (2) the relationship between imported and domestically produced fuels; (3) losses occurring during transport of the crude oil and the finished product and the necessary increase in feedstock acquisition and liquid fuel production to meet the specified consumption (1 MMBtu); and (4) the heating values for the transportation fuels.

Allocation of Feedstock Acquisition and Transport Emissions to Refinery Products

The acquisition and transport emissions for the crude oil mix, NGL, and unfinished oils have been allocated to the refinery products based on each product categories' volumetric contribution to total production (rather than energy contribution). This allocation method was selected based on the fact that the volumetric output of the species is more closely correlated with the volumetric input of crude oil than with the energy content (and not all refinery products are valued for their energy content). EIA reports refinery yield in volume percent and most unit operation product data are expressed in volume percent of feed. The product categories' volumetric contribution to total production is shown in Table 4-54 of Section 4.2.9.5. This allocation method results in emissions for each of the products being equivalent on a per-barrel-refined basis (but varying on an energetic basis). As reported by EIA, total refinery product volume in 2005 was 17,281 Mbbl per day while input to the refineries (crude oil mix, unfinished oils and natural gas liquids) was 16,221 Mbbl per day. This yields a ratio of 0.939 barrels of input per barrel of product which has been used to relate the feedstock acquisition emissions to refinery products. This ratio calculated using U.S. refining data is assumed to also be applicable to foreign refinery operations.

Volumetric Representation of Imported and Domestically-Produced Fuels

Figure 7-1 shows an overview of the volumetric flows of feedstock and products for U.S. refineries and imported and exported conventional gasoline, conventional diesel and kerosene-based jet fuel. Figure 7-2 thru Figure 7-4 show the feedstock and product requirements necessary for each activity to result in one thousand barrels of fuel consumed in the U.S. in 2005 for conventional motor gasoline, conventional diesel fuel and kerosene-based jet fuel. The relationship between imported and domestically-produced transportation fuels discussed in Appendix A and loss factors developed and discussed in Appendix H were utilized in development of these figures.

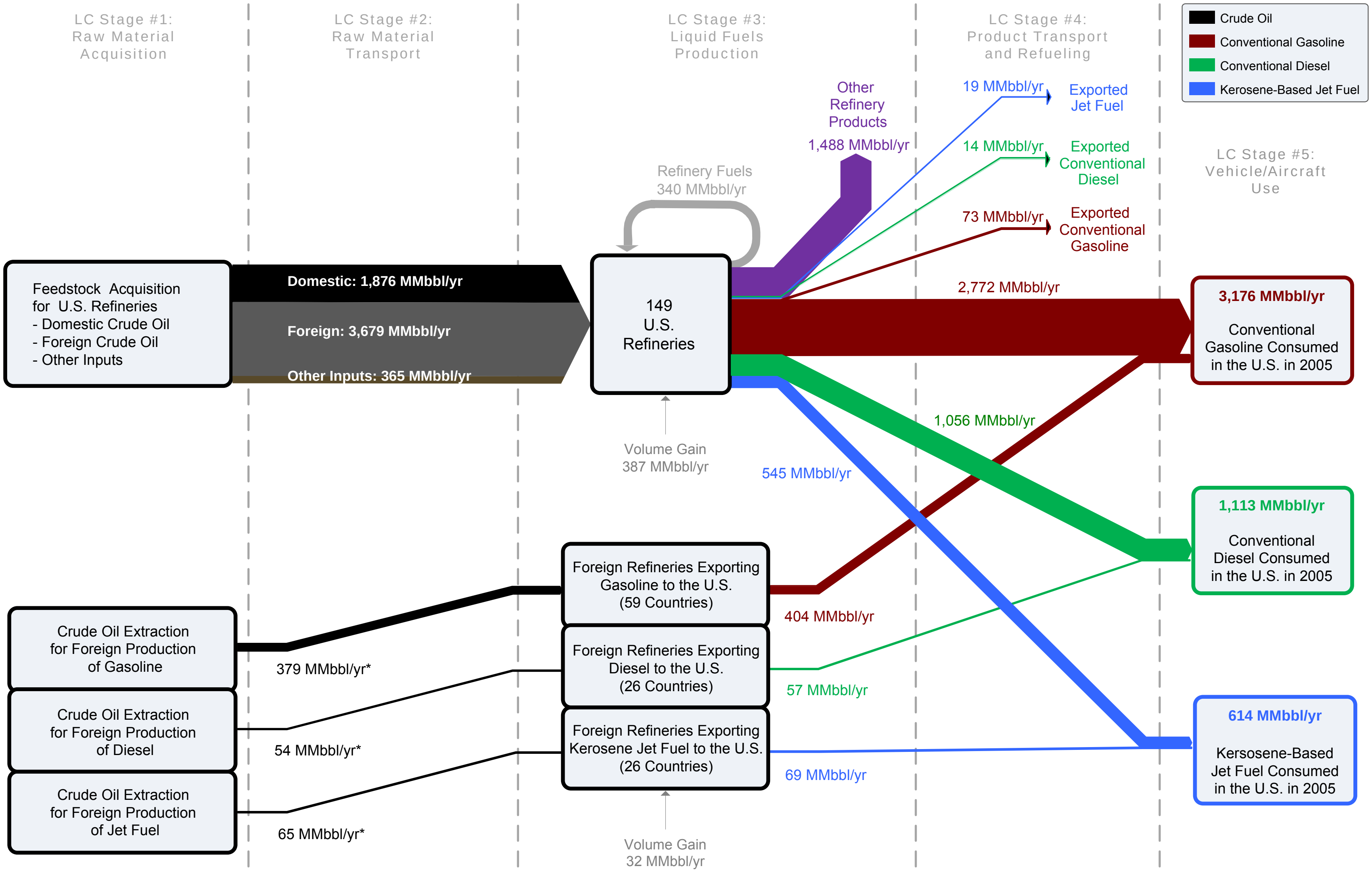
Conversion to Energetic Basis

After the emissions factors for each activity in each LC Stage are combined with the volumetric flows associated with each activity, the final profile is converted to a LHV basis using the energy contents in Table 7-1.

Table 7-1. Heat Content of Petroleum Products

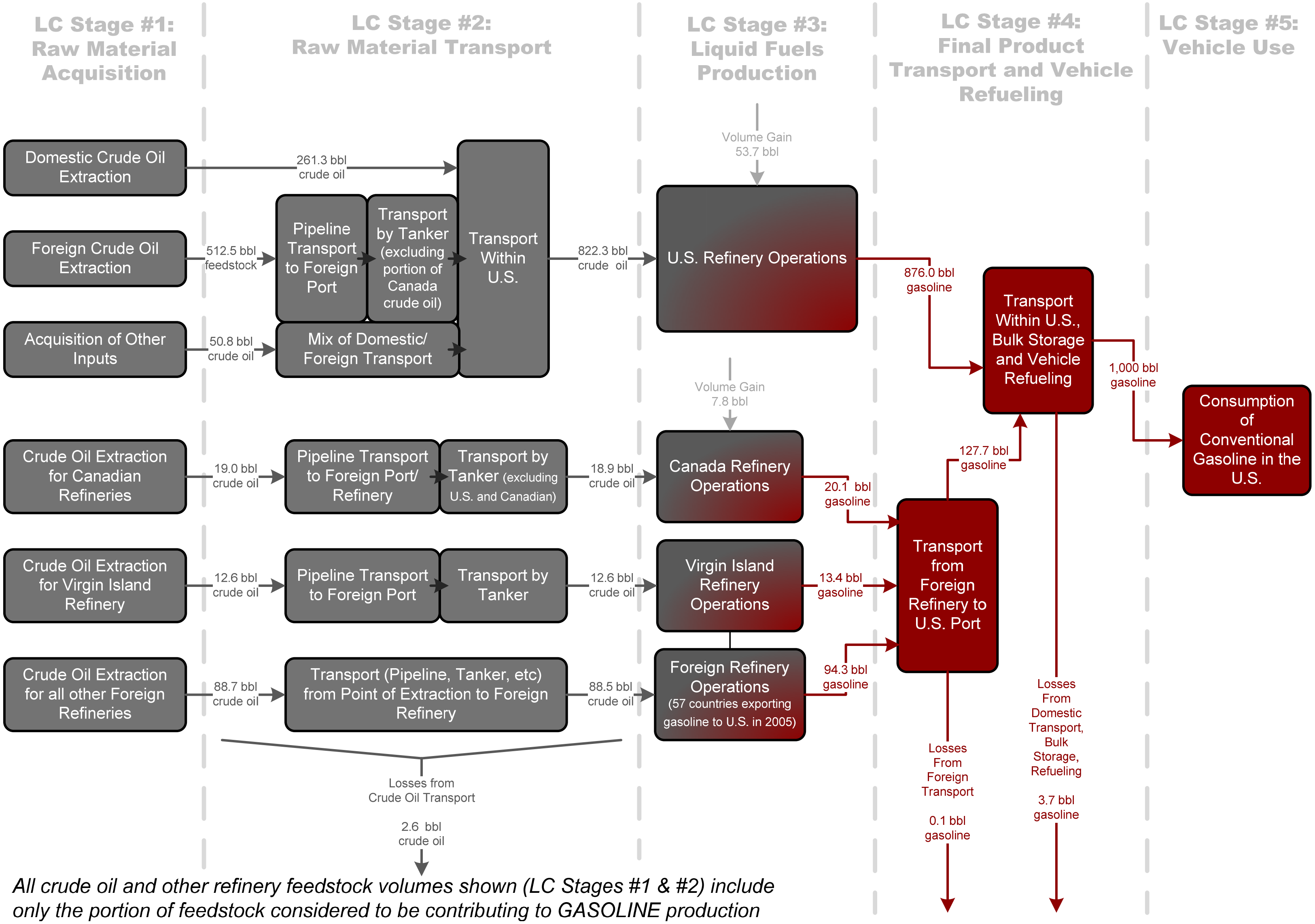
Petroleum Product	Heat Content (MMBtu LHV per bbl)	Reference
Conventional Gasoline	4.89	EPA 2008
Conventional Diesel	5.51	EPA 2008
Kerosene-Based Jet Fuel	5.23	DESC 2008

Figure 7-1. Feedstock and Product Volumetric Flows for Consumption of Conventional Gasoline, Conventional Diesel and Kerosene-Based Jet Fuel in the U.S. in 2005



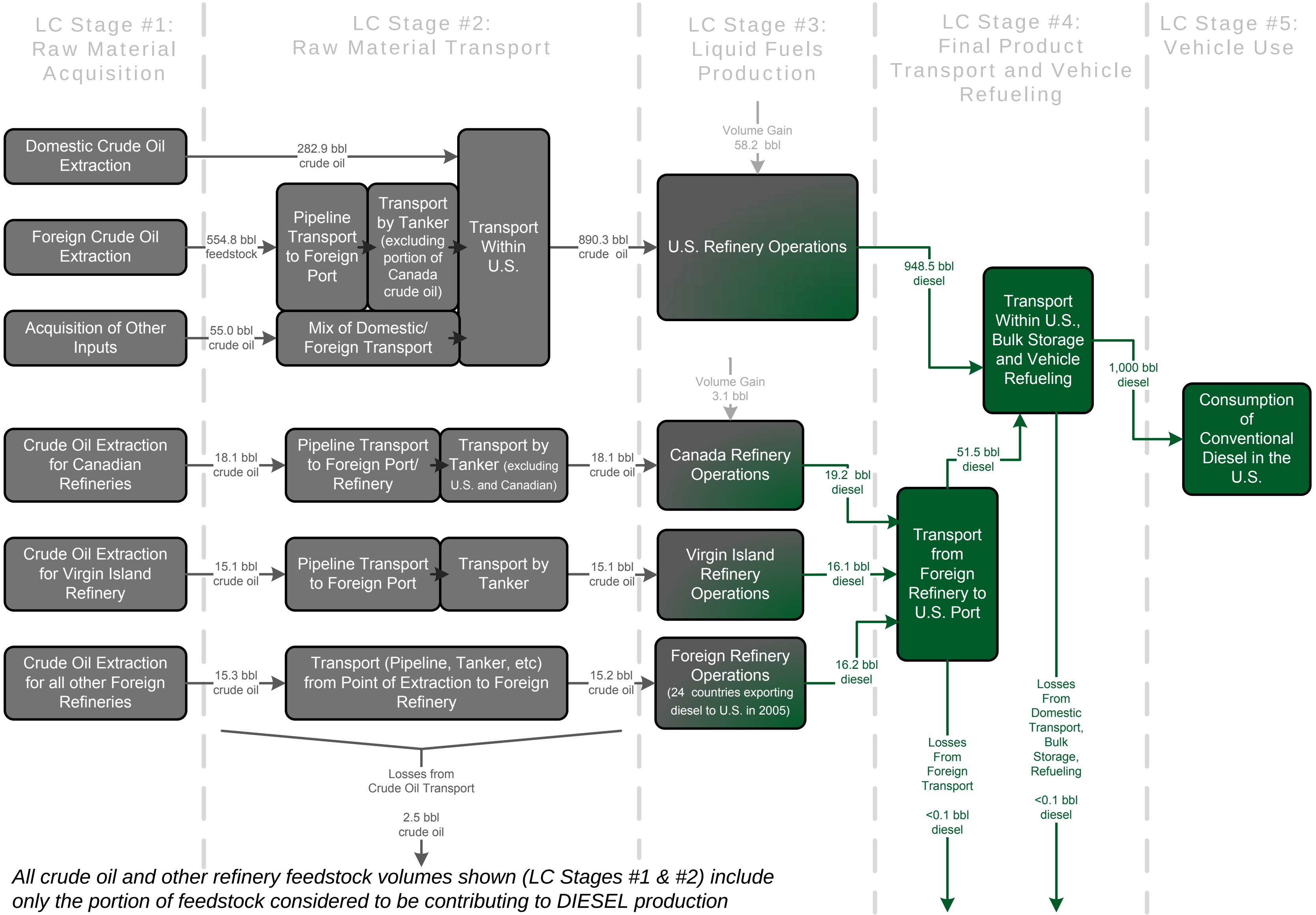
Crude oil input to FOREIGN refineries include only the portion of crude oil considered to be contributing to gasoline, diesel and jet fuel production

Figure 7-2. Feedstock and Product Requirements Consistent with One Thousand Barrels of Conventional Gasoline Consumed in the U.S. in 2005



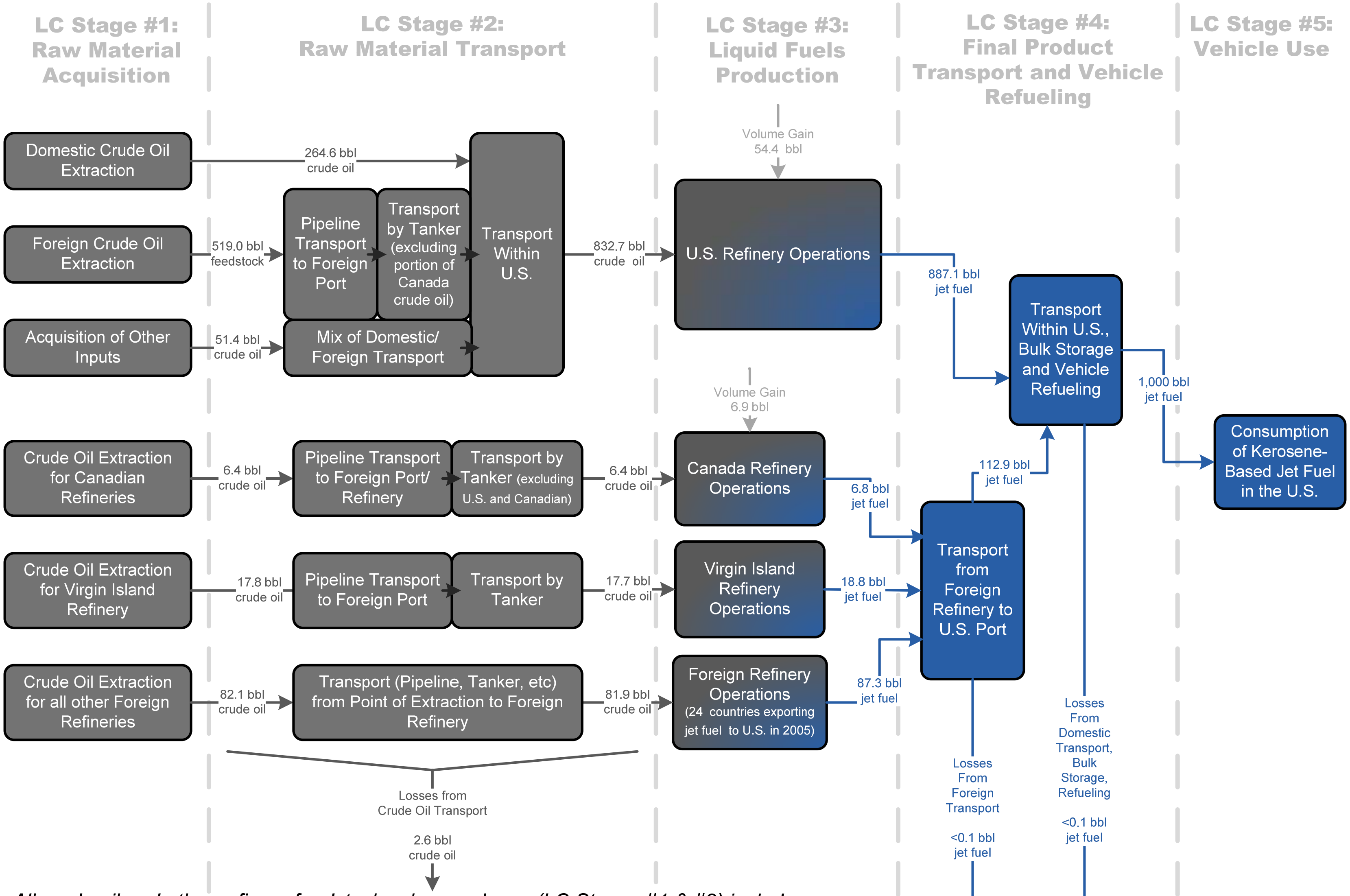
All crude oil and other refinery feedstock volumes shown (LC Stages #1 & #2) include only the portion of feedstock considered to be contributing to GASOLINE production

Figure 7-3. Feedstock and Product Requirements Consistent with One Thousand Barrels of Conventional Diesel Consumed in the U.S. in 2005



All crude oil and other refinery feedstock volumes shown (LC Stages #1 & #2) include only the portion of feedstock considered to be contributing to DIESEL production

Figure 7-4. Feedstock and Product Requirements Consistent with One Thousand Barrels of Kerosene-Based Jet Fuel Consumed in the U.S. in 2005



All crude oil and other refinery feedstock volumes shown (LC Stages #1 & #2) include only the portion of feedstock considered to be contributing to JET FUEL production

7.2 Life Cycle GHG Emissions Associated with Finished Transportation Fuels Consumed in the U.S. in 2005

CO_2, CH_4, and N_2O emission profiles were developed for the mix of the domestically-produced and imported fuels of interest for 2005. The results from the first four life cycle stages are applicable to any source consuming these petroleum-based fuels. Vehicle/aircraft operation (LC Stage #5) represents the carbon content of the fuel, on a MMBtu basis, being converted to carbon dioxide during combustion.[6] These results are only applicable on a "per-MMBtu" basis as reported. Also, these results are not applicable to any fuel mix containing non-petroleum based fuels, off-road diesel fuel (>500 ppm sulfur), aviation gasoline or kerosene for other than aircraft use.

Table 7-2 shows the GWP for production and consumption of the three liquid fuels on a per-MMBtu-LHV-consumed basis using the global warming potentials for CO_2, CH_4, and N_2O listed in Table 1-1. To help demonstrate the contributions each GHG species makes to the total GWP, the contribution of CO_2, CH_4, and N_2O (in CO_2E) is also presented for each liquid fuel under the total. Appendix L presents the data from Table 7-2 in alternate units (GHG emissions on a kg-per-barrel-consumed basis and kg-per-GJ-fuel-consumed basis) and in alternate IPCC global warming potential values based on the 1996 and 2001 technical reports.

Table 7-2 thru Table 7-4 show the individual GHG species and their emissions for the five life cycle stages for conventional motor gasoline, conventional diesel, and kerosene-based jet fuel on a per-MMBtu-LHV-consumed basis.

Table 7-2. GHG Emissions for Liquid Fuels Production

	LC Stage #1: Raw Material Acquisition	LC Stage #2: Raw Material Transport	LC Stage #3: Liquid Fuels Production	LC Stage #4: Product Transport and Refueling	LC Stage #5: Vehicle / Aircraft Operation	Total Well-to-Wheels
Conventional Gasoline (kg CO_2E/ MMBtu LHV fuel consumed)						
Total	**7.32**	**1.44**	**9.78**	**1.09**	**76.6**	**96.3**
CO_2	4.89	1.41	9.45	1.07	75.0	91.9
CH_4 (CO_2E)	2.39	0.0193	0.288	0.0149	0.12	2.84
N_2O (CO_2E)	0.0394	0.0084	0.0456	0.0065	1.49	1.59
Conventional Diesel (kg CO_2E/ MMBtu LHV fuel consumed)						
Total	**6.64**	**1.32**	**9.55**	**0.88**	**76.7**	**95.0**
CO_2	4.46	1.30	9.22	0.86	76.6	92.4
CH_4 (CO_2E)	2.14	0.0175	0.285	0.0130	0.0020	2.46
N_2O (CO_2E)	0.0361	0.0078	0.0424	0.0051	0.0521	0.143
Kerosene-Based Jet Fuel (kg CO_2E/ MMBtu LHV fuel consumed)						
Total	**6.76**	**1.35**	**6.04**	**1.00**	**77.7**	**92.9**
CO_2	4.54	1.32	5.83	0.978	77.1	89.8
CH_4 (CO_2E)	2.18	0.0178	0.180	0.0137	0.013	2.40
N_2O (CO_2E)	0.0366	0.0079	0.0269	0.0059	0.629	0.706

---

[6] See Section 6.0 for detailed explanation of vehicle and aircraft emission factors from fuel combustion.

Table 7-3. Methane Emissions for Liquid Fuels Production

Petroleum Product	LC Stage #1: Raw Material Acquisition	LC Stage #2: Raw Material Transport	LC Stage #3: Liquid Fuels Production	LC Stage #4: Product Transport and Refueling	LC Stage #5: Vehicle / Aircraft Operation	Total Well-to-Wheels
	kg CH_4/MMBtu LHV fuel consumed					
Conventional Gasoline	0.0977	0.000774	0.0117	0.000608	0.00411	0.115
Conventional Diesel	0.0891	0.000713	0.0117	0.000542	0.000581	0.103
Kerosene-Based Jet Fuel	0.0886	0.000711	0.00725	0.000548	0.0131	0.110

Table 7-4. Nitrous Oxide Emissions for Liquid Fuels Production

Petroleum Product	LC Stage #1: Raw Material Acquisition	LC Stage #2: Raw Material Transport	LC Stage #3: Liquid Fuels Production	LC Stage #4: Product Transport and Refueling	LC Stage #5: Vehicle / Aircraft Operation	Total Well-to-Wheels
	kg N_2O/MMBtu LHV fuel consumed					
Conventional Gasoline	1.32E-04	2.82E-05	1.53E-04	2.17E-05	4.99E-03	5.33E-03
Conventional Diesel	1.21E-04	2.60E-05	1.42E-04	1.70E-05	1.75E-04	4.81E-04
Kerosene-Based Jet Fuel	1.23E-04	2.66E-05	9.03E-05	1.98E-05	2.11E-03	2.37E-03

Passenger vehicle emissions are presented on the basis of one mile traveled in Table 7-5. This metric is important since gasoline and diesel-powered vehicles have different fuel efficiencies.

Table 7-5. Well-to-Wheels GHG Emissions in a Passenger Vehicle

GHG	Conventional Gasoline	Conventional Diesel
	kg/mile traveled	
CO_2	0.447	0.345
CH_4	5.52E-04	3.68E-04
N_2O	2.59E-05	1.80E-06
GHG, CO_2E	0.468	0.355

Figure 7-5 thru Figure 7-8 graphically portray the individual GHG species and their emissions for the five life cycle stages for conventional motor gasoline, conventional diesel, and kerosene-based jet fuel on a per-MMBtu-LHV-consumed basis. Appendix L presents the data from Figure

7-5 in alternate units (GHG emissions on a kg-per-barrel-consumed basis and kg-per-GJ-fuel-consumed basis) and in alternate IPCC global warming potential values based on the 1996 and 2001 technical reports.

To allow a more detailed examination of upstream fuels processing and their resulting emissions, well-to-tank emissions for gasoline, diesel, and jet fuel are shown in Figure 7-9.

The percent contributions of each life cycle stage are displayed graphically in Figure 7-10. This allows a quick assessment of the relative impact of the various life cycle stages on the total emissions.

Figure 7-5. GHG Emissions for Liquid Fuels' Individual Life Cycle Stages and Complete Well-to-Wheels Life Cycle

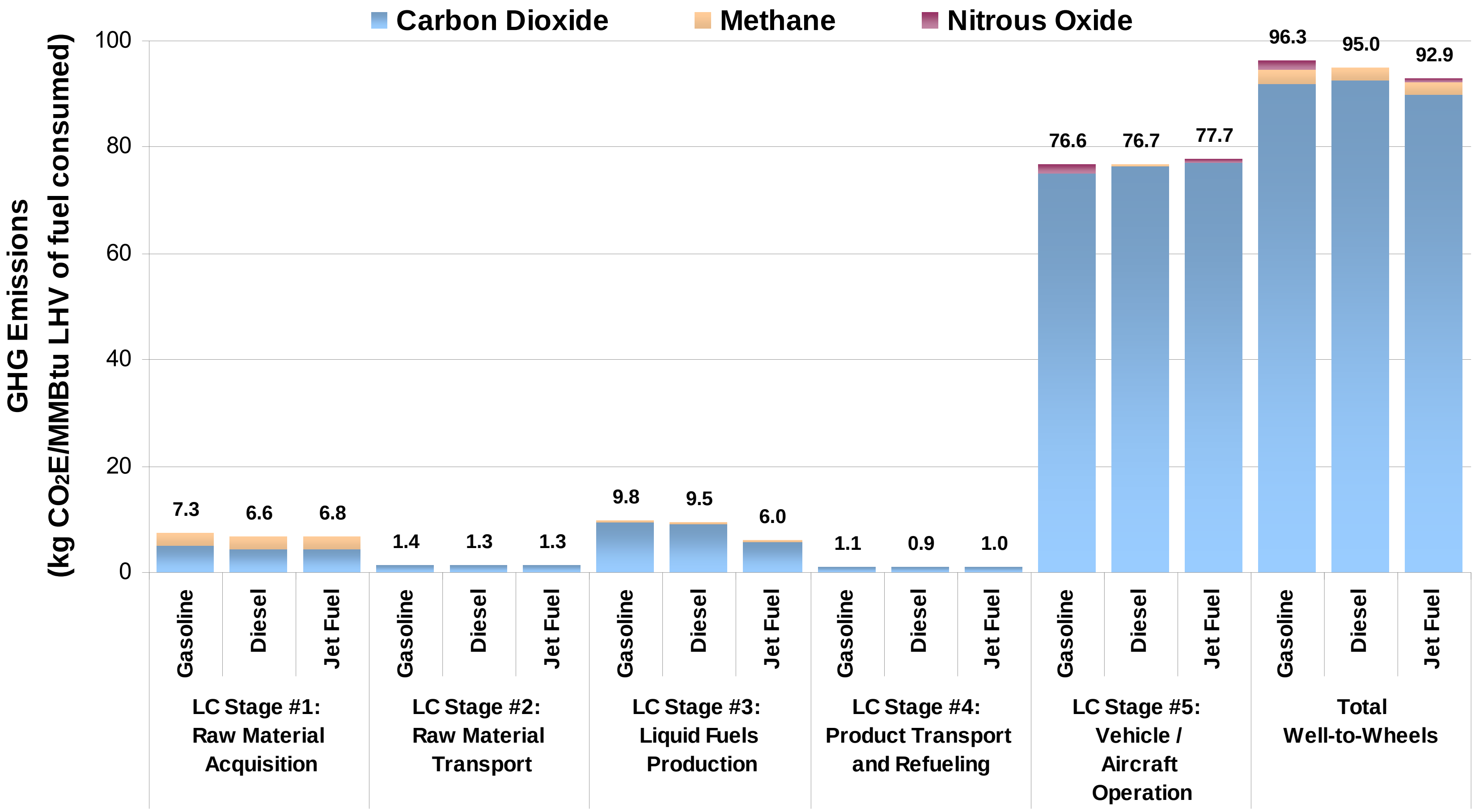


Figure 7-6. Carbon Dioxide Emissions for Liquid Fuels' Individual Life Cycle Stages and Complete Well-to-Wheels Life Cycle

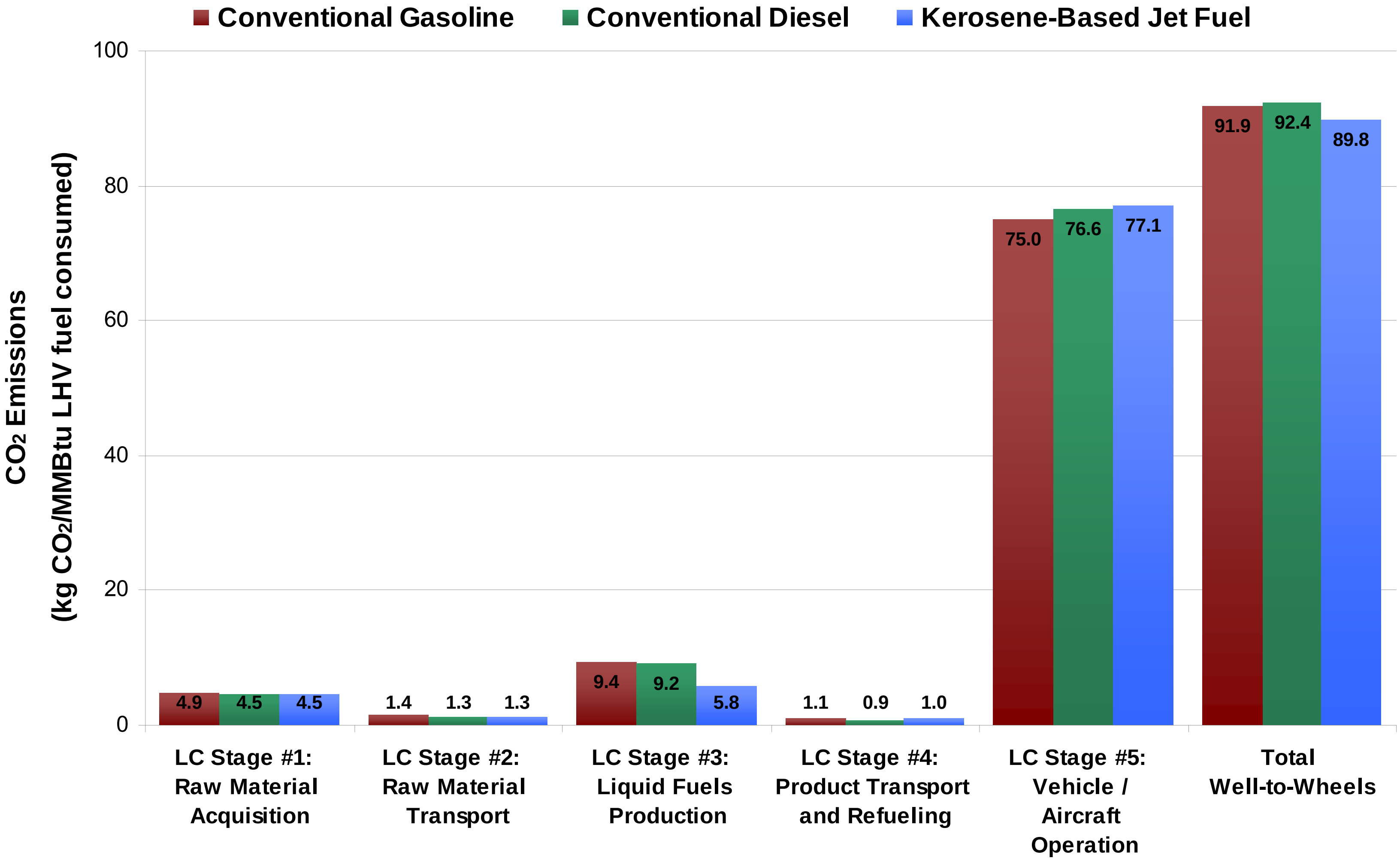


Figure 7-7. Methane Emissions for Liquid Fuels' Individual Life Cycle Stages and Complete Well-to-Wheels Life Cycle

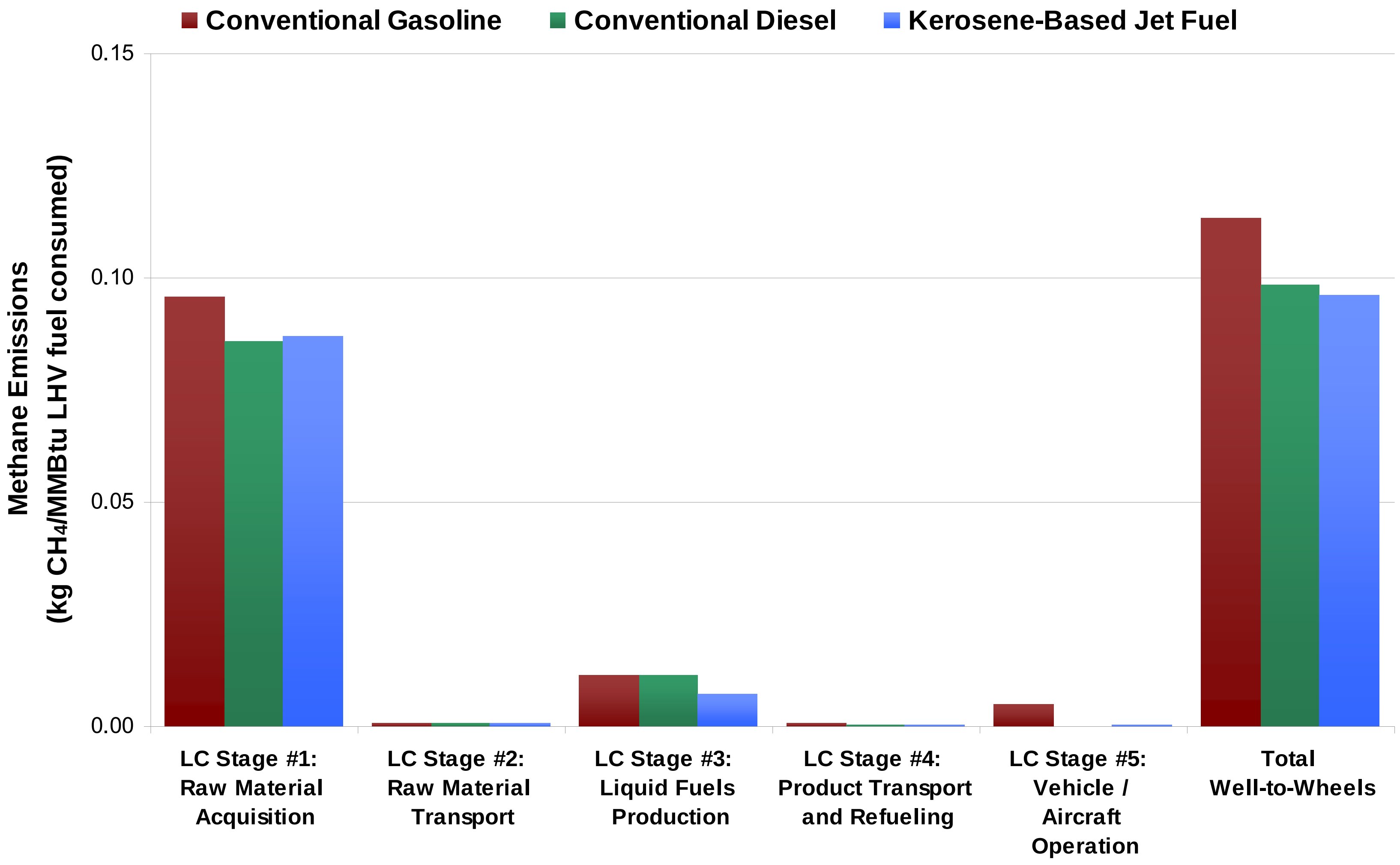


Figure 7-8. Nitrous Oxide Emissions for Liquid Fuels' Individual Life Cycle Stages and Complete Well-to-Wheels Life Cycle

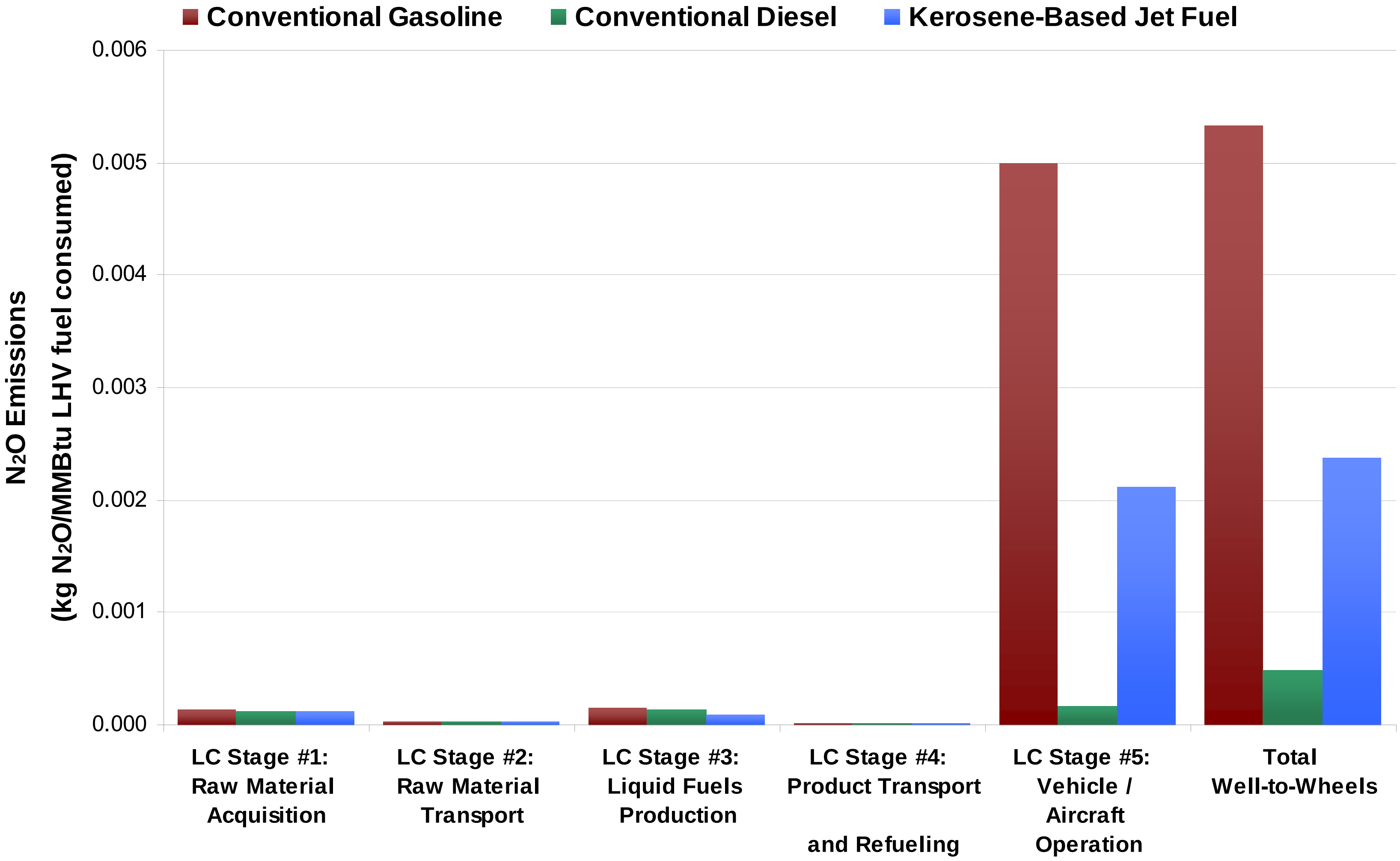


Figure 7-9. Well-to-Tank GHG Emissions for Liquid Fuels

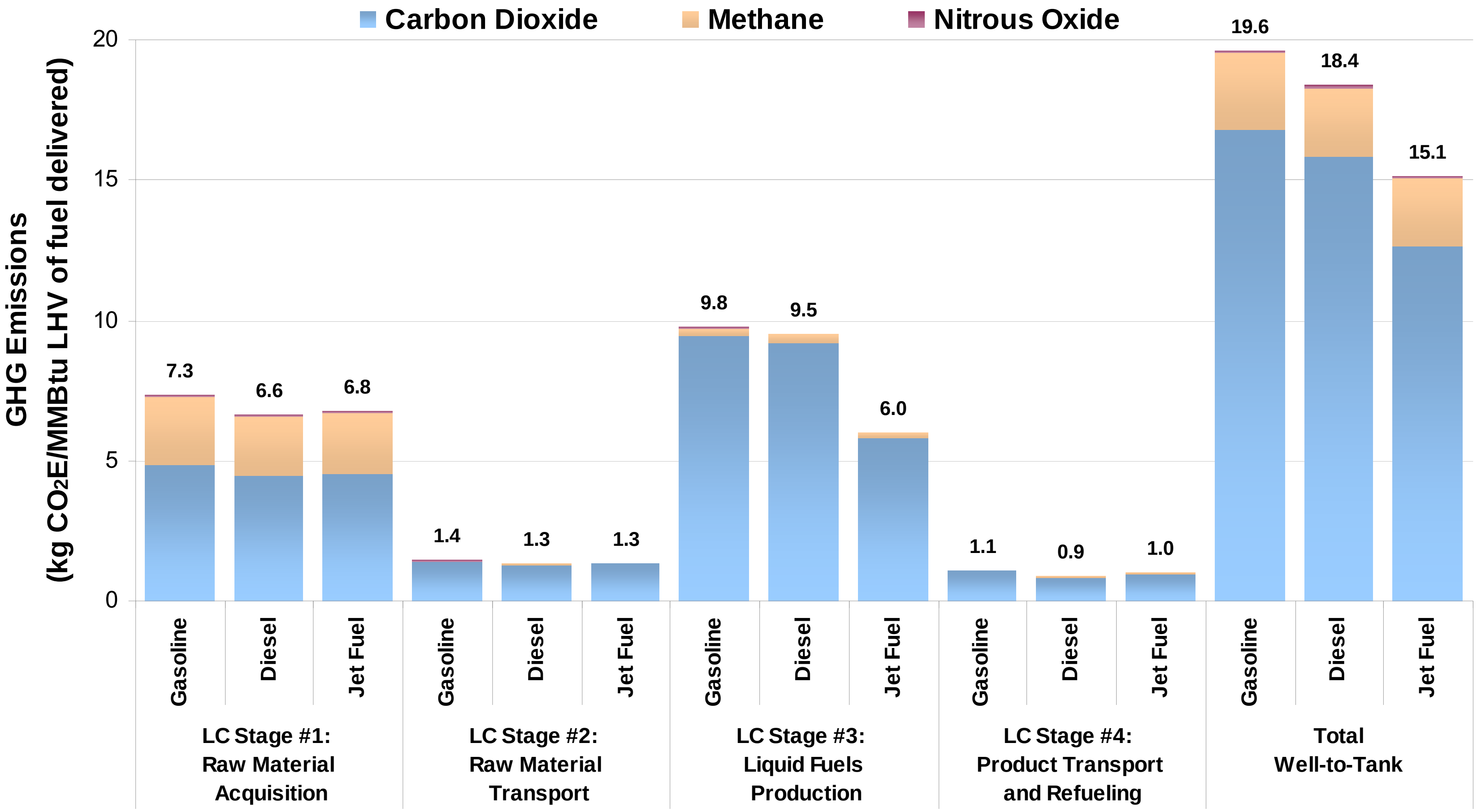
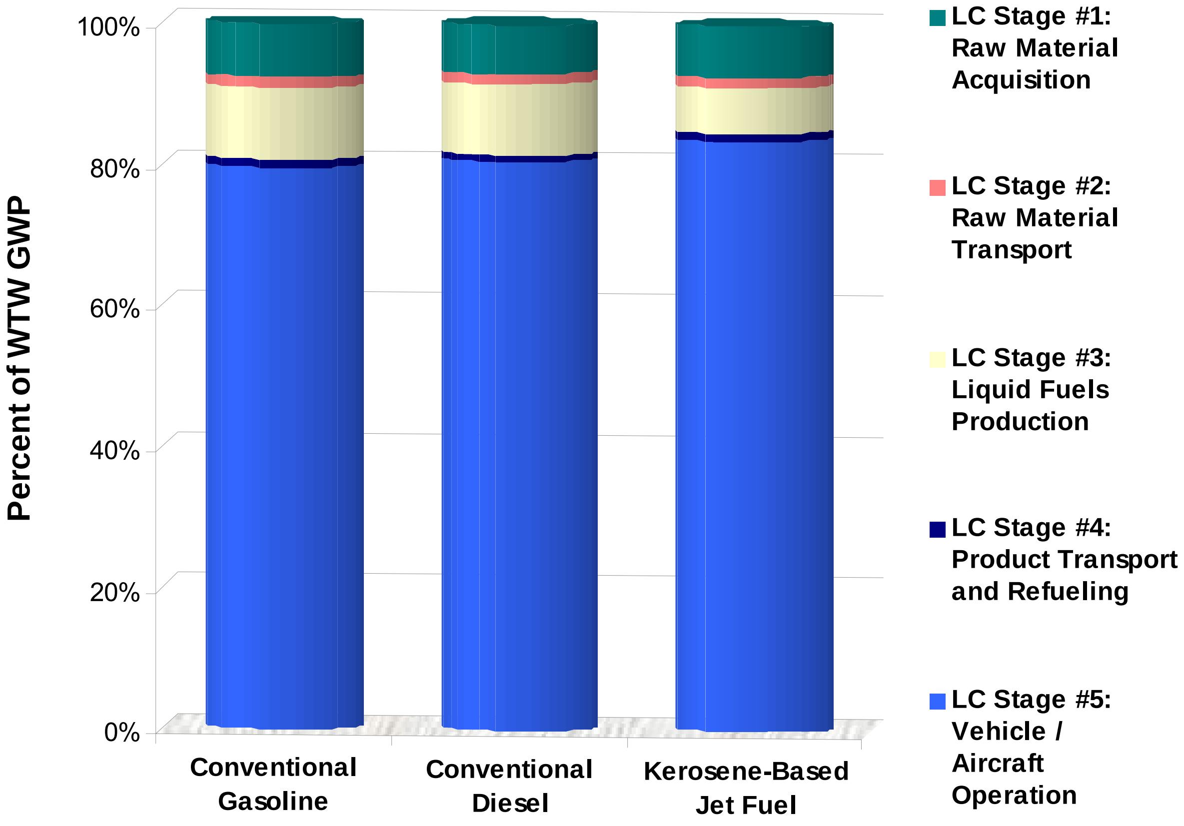


Figure 7-10. Life Cycle Stage Percent Contributions to Total Life Cycle GHG Emissions



7.2.1 Life Cycle Stage #1

Life Cycle Stage #1 includes emissions associated with the extraction and post-extraction processing of refinery feedstocks for U.S. refineries and for foreign refineries providing imported gasoline, conventional diesel and kerosene-based jet fuel. Crude oil mix (conventional and synthetic crude oil/blended bitumen) is the primary feedstock of interest. For U.S. refineries, inputs of NGL and unfinished oils are also included. The primary sources for feedstock acquisition emissions are country-specific crude oil extraction emission profiles (PE 2008) and country-specific delivered crude oil mix emission profiles for foreign refineries (as available) extracted from GaBi 4 (2007). The PE International and GaBi profiles are representative of 2002 rather than 2005 but this temporal difference is expected to only result in minor differences in the upstream profile for conventional crude oil extraction.

The extraction and processing emissions are distributed to all refinery products on a volumetric basis. The relationship between volumetric input and volumetric output at U.S. refineries was also applied to foreign refineries.

Life Cycle Stage #1 contributes a significant amount to the total life cycle emissions for all liquid fuels (7%). This life cycle stage is the primary contributor of methane emissions. Methane from oil and gas extraction operations (primarily associated with venting of light hydrocarbons) accounts for 84-91% of the total life cycle methane emissions. Flare operations contribute significantly to the extraction CO_2 emissions profile.

7.2.2 Life Cycle Stage #2

Life Cycle Stage #2 includes transport of feedstocks from the extraction/processing location to a refinery—either domestic or foreign. Modeling of this transport component includes (1) foreign transport of crude in-country via pipeline to either a port of loading or a refinery (located at a port); (2) ocean transport of foreign crude to a U.S. port or foreign refinery; and (3) U.S. domestic transport of domestically produced feedstocks and foreign imports via a combination of pipeline, waterborne vessel, rail, and truck transport to domestic refineries.

This life cycle stage accounts for 1-2% of the total life cycle GHG emissions. These emissions are primarily CO_2 from fuel combustion.

7.2.3 Life Cycle Stage #3

Life Cycle Stage #3 includes emissions associated with petroleum refinery operations:

- Extraction, transport, and production (collectively acquisition) of refinery fuels and energy inputs including purchased power and steam, purchased coal and natural gas, and fuels produced and subsequently consumed at petroleum refineries
- Combustion of fuels at petroleum refineries
- Cradle-to-gate emissions associated with hydrogen production
- Flaring, venting, and fugitive emissions

Not all GHG emissions for this life cycle stage are actually occurring at the refinery and thus are not being emitted from the refineries. The actual GHG emissions being emitted locally at refineries is 63-67% of the total emissions for LC Stage #3. The remaining 33-37% is attributable to upstream fuel acquisition emissions, merchant hydrogen production, and indirect emissions associated with purchased steam and electricity. Quantities of fuels consumed are reported by U.S. refineries in 2005 (EIA 2008), but a wide range of sources are utilized for combustion emissions factors, development of fuels and hydrogen acquisition GHG emissions profiles, and estimation of emissions from flaring and venting and fugitive methane emissions.

Because petroleum refineries convert crude oil to a range of co-products, an allocation process is necessary to distribute the emissions associated with petroleum refinery operations between the various refinery products. The allocation used here is based on the relative energy and hydrogen usage attributable to the production of each of the products, as determined through process unit-level analysis. Capacities, volumetric throughput, energy usage, and hydrogen consumption and production are estimated for 11 process unit categories. The contribution of each process unit to each of the product categories is determined, combined with the above, and the result is the fraction of energy and hydrogen usage attributable to each product. Throughput capacities of process units are as reported by U.S. refineries for January 1, 2006 (EIA 2008), but a wide range of sources are utilized to determine capacity utilization, energy usage, hydrogen usage and contribution of process unit operations to end products. Refinery data are aggregate U.S. data and the refineries were modeled for steady-state operation. Start-up, shut-down, systemic anomalies and perturbations are difficult to quantify and thus excluded from this modeling effort.

Refinery energy estimations using unit operation energy requirement for the processes modeled accounted for approximately 75% of the actual fuels/energy consumption reported by EIA. There are two primary reasons that the total modeled energy consumption does not agree with the actual energy consumption. First, the energy estimates used to model the aggregate refinery operations are average values. There will be variability due to differences in processing schemes, efficiency/age of process units, differing feedstock qualities, etc. Secondly, there are miscellaneous other downstream operations that are not tracked by EIA that contribute to the total refinery energy consumption (e.g. Merox process unit, etc.) It is acknowledged that liquid fuels will, therefore, bear some burden for these operations.

Foreign refineries producing petroleum products for export to the U.S. have been assumed to have the same refining GHG profile as U.S. refineries. There is a lack of publicly available, accurate information for foreign refinery operations that covers the appropriate system boundary (i.e. indirect emissions associated with electricity usage and hydrogen inputs). The refining GHG profile developed for this study was compared to three foreign studies (refer to Section 4.3), however, U.S. refining results were used as a surrogate for foreign refinery operations to maintain transparency. This assumption is noted as a data limitation.

This life cycle stage represents 6.5% of the total GHG emissions profile for kerosene-type jet fuel and 10% for both gasoline and diesel fuel.

7.2.4 Life Cycle Stage #4

Life Cycle Stage #4 consists of emissions and product losses associated with transport of liquid fuels from the refinery to either the vehicle refueling station or the airport followed by aircraft/vehicle refueling. This includes ocean tanker and/or pipeline transport of petroleum products from a foreign refinery to the U.S. and domestic transport of foreign imports and domestically produced liquid fuels via a combination of pipeline, waterborne vessel, rail, and truck transport to refueling facilities.

Life Cycle Stage #4 does not include any emissions consistent with blender operations (other than bulk storage). Since only conventional gasoline is modeled, blender operations necessary to add oxygenates or other fuel additives, or create boutique fuel blends would not be required.

Life Cycle Stage #4 also includes emissions associated with refueling operations for passenger vehicles and aircraft. For gasoline and diesel, the only direct GHG emissions are the result of power requirements to operate the dispenser (pump and meter).

Transport losses occurring during transport and refueling are a function of the liquid fuel's volatility. Hence, gasoline—which is the most volatile of the three primary transportation fuels—will experience the largest evaporative losses. These evaporative losses do not have an associated GHG emissions profile. However, they do indirectly increase GHG emissions minimally because more upstream product refining (and refinery feedstock acquisition) is required to meet a specified final need. For this study, the delivery requirements are 1 MMBtu (LHV) consumed by a vehicle or aircraft.

Transportation and refueling operations are not a significant contributor to the total life cycle GHG emissions (approximately 1%).

7.2.5 Life Cycle Stage #5

Life Cycle Stage #5 is the use stage for the three liquid fuels modeled. As expected, combustion emissions generated during the use phase are the primary contributors to the total life cycle GHG emissions. The use phase ranges from 79.6% to 83.7% of the total life cycle GHG emissions for the three fuels modeled.

Vehicle use profiles for gasoline and diesel fuel consumption for the 2005 average fleet were calculated by the U.S. EPA, Office of Transportation and Air Quality, Motor Vehicle Emission Simulator (MOVES) model (EPA 2008). A conventional internal combustion engine for HPMS passenger car vehicle class is utilized in this study for reporting of use emissions for conventional gasoline and conventional diesel. The vehicle use profile on a kg/MMBtu LHV basis is equivalent for all vehicle types as reported.[7] Results calculated and reported on a "per-mile" basis are dependant on each vehicle class's fuel efficiency (i.e., fuel consumed per mile traveled) and are therefore only applicable to the applied vehicle class.

The IPCC methodology for estimating aircraft emissions for both LTO and cruise are utilized in this study. The CO_2 cruise emissions—like LTO emissions—assume all carbon in the fuel is converted to CO_2 and CO_2 emissions are estimated to be 3.16 kg CO_2 per kg of fuel (IPCC 2006). The cruise emission estimates are considered highly uncertain for methane and nitrous oxide (IPCC 2006). IPCC (2006) reports that in-flight methane emissions are considered negligible and assumed to be zero. A composite CH_4 emission factor has been generated by the IPCC (2006) for flights assuming that the LTO emission factor is 5 kg/TJ (0.005 kg CH_4/MMBtu LHV) (10% of total VOC factor) and that globally about 10% of the total fuel is consumed during LTO cycles, resulting in a fleet averaged CH_4 emission factor of 0.5 kg/TJ (0.0005 kg CH_4/MMBtu LHV). N_2O emissions are computed indirectly and the default value is 2 kg/TJ LHV (0.002 kg/MMBtu LHV) for flight operations (LTO plus cruise).

---

[7] Differences in vehicle engine efficiency result in different methane and nitrous oxide emissions, however, the contribution to the total GWP, on a CO_2 equivalent basis, is orders of magnitude smaller than the CO_2 emissions.

7.3 GHG Emissions Associated with Liquid Fuels Produced at U.S. Refineries in 2005: Comparison to Foreign Imported Fuels

Figure 7-11 and Figure 7-12 show the life cycle GHG emissions for domestically-produced liquid fuels.

Figure 7-13 thru Figure 7-15 compare the life cycle stage GHG emissions for U.S. fuel production and consumption with that of imported fuels. Life Cycle Stage #1 emissions for U.S. fuel production is higher than that for imports, due in part to the U.S. import of Canadian oil sands which has a significantly higher GHG extraction profile. LC Stage #2 emissions for refinery feedstock transport for U.S. fuel production are approximately twice as high as for imported fuel production. This is due to the fact that the U.S. imports a significant amount of the refinery feedstocks from foreign destinations while foreign production of imported liquid fuels utilizes a greater proportion of local crude oil feedstocks. LC Stage #3 emissions for refinery operation are the same for both U.S. and foreign refining (study assumption). LC Stage #4 emissions for foreign imports are higher than for U.S. production because of the additional foreign transport operations (primarily ocean tanker transport). LC Stage #5 emissions will be the same for both fuel sources since it is assumed that there is no difference in final fuel quality between U.S. and foreign fuel sources.

Figure 7-11. GHG Emissions for Liquid Fuels Produced Domestically

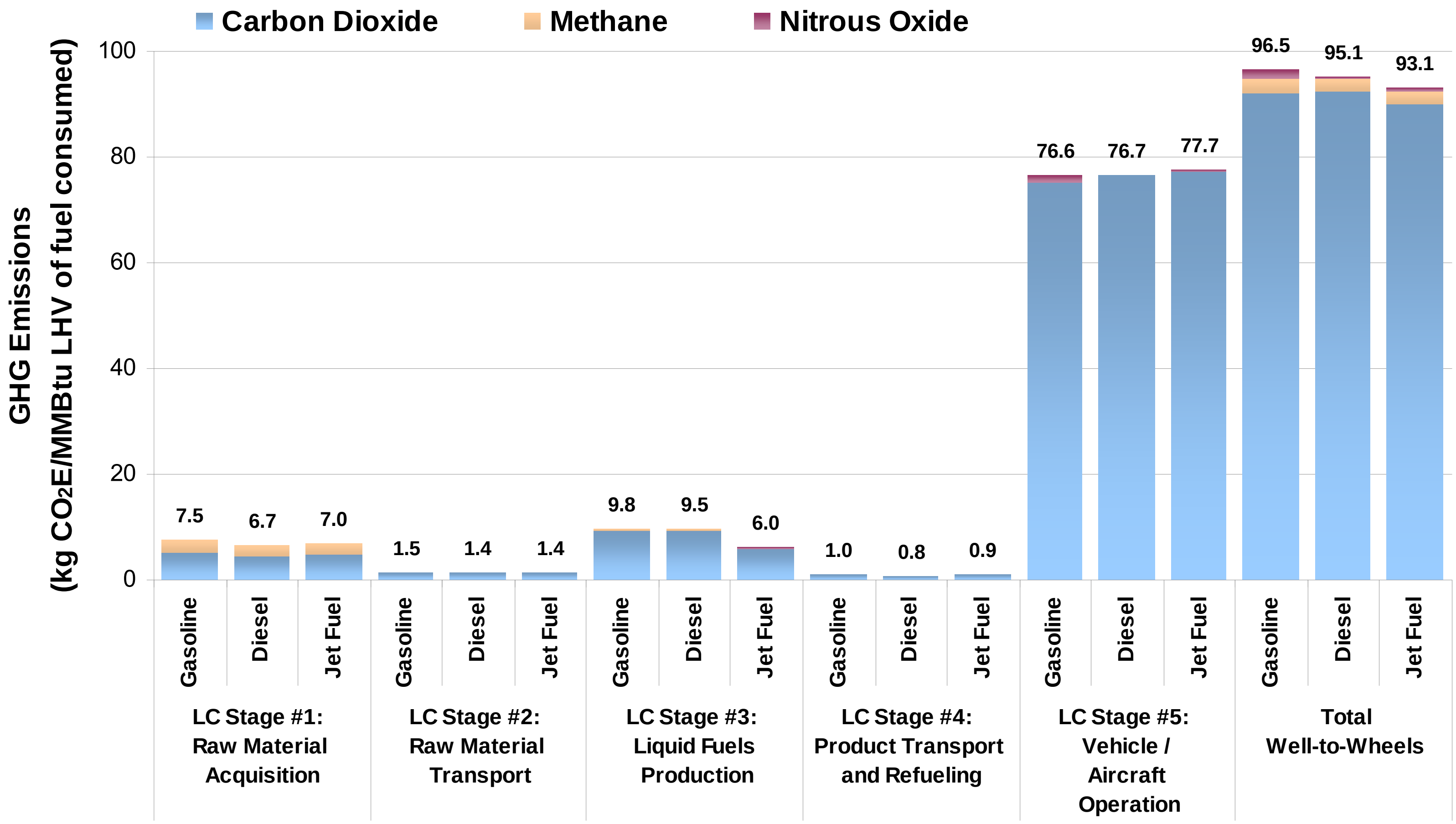


Figure 7-12. Well-to-Tank GHG Emissions for Liquid Fuels Produced Domestically

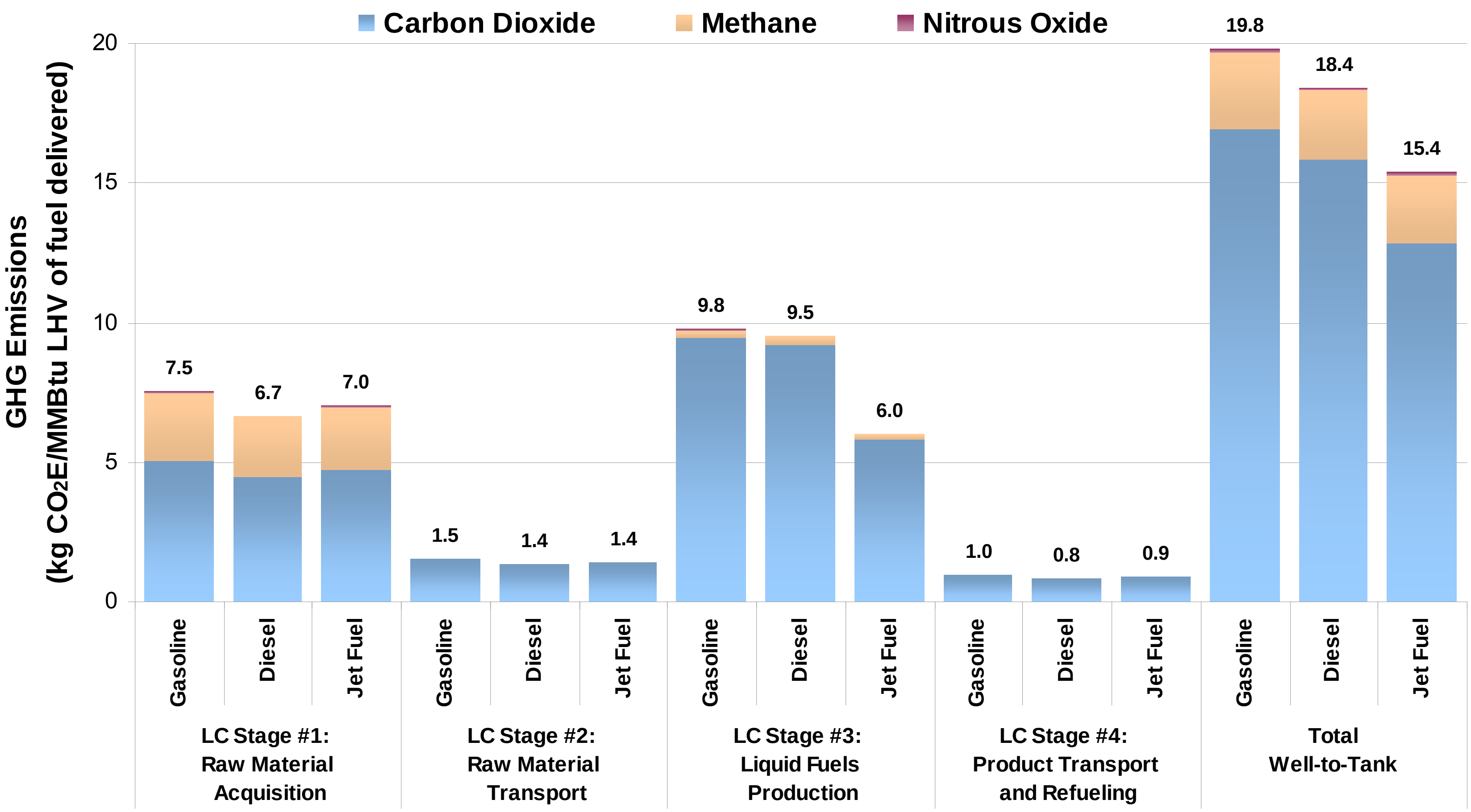


Figure 7-13. Comparison of GHG Emissions for Conventional Gasoline Produced at U.S. Refineries and Imported from Foreign Refineries

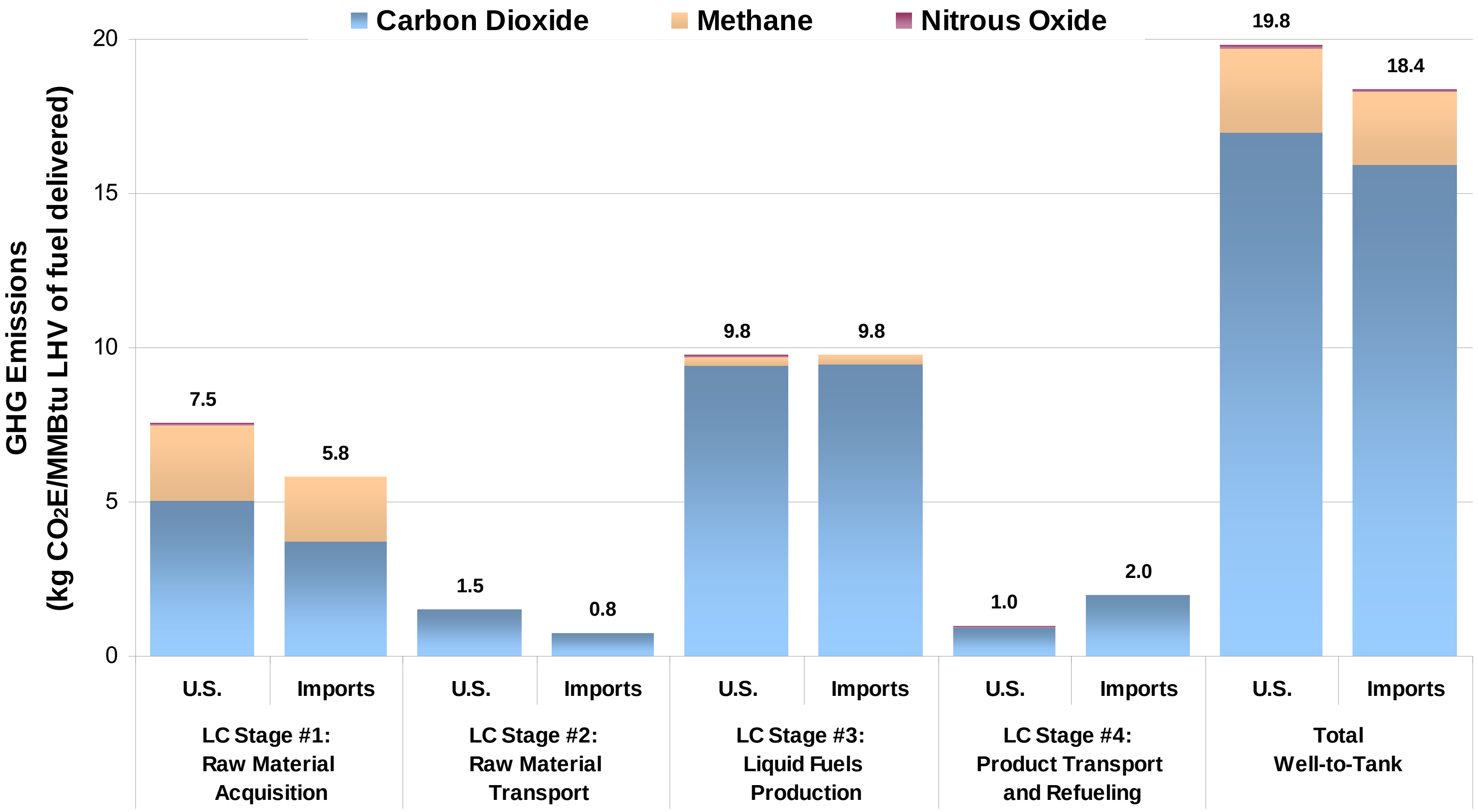


Figure 7-14. Comparison of GHG Emissions for Conventional Diesel Fuel Produced at U.S. Refineries and Imported from Foreign Refineries

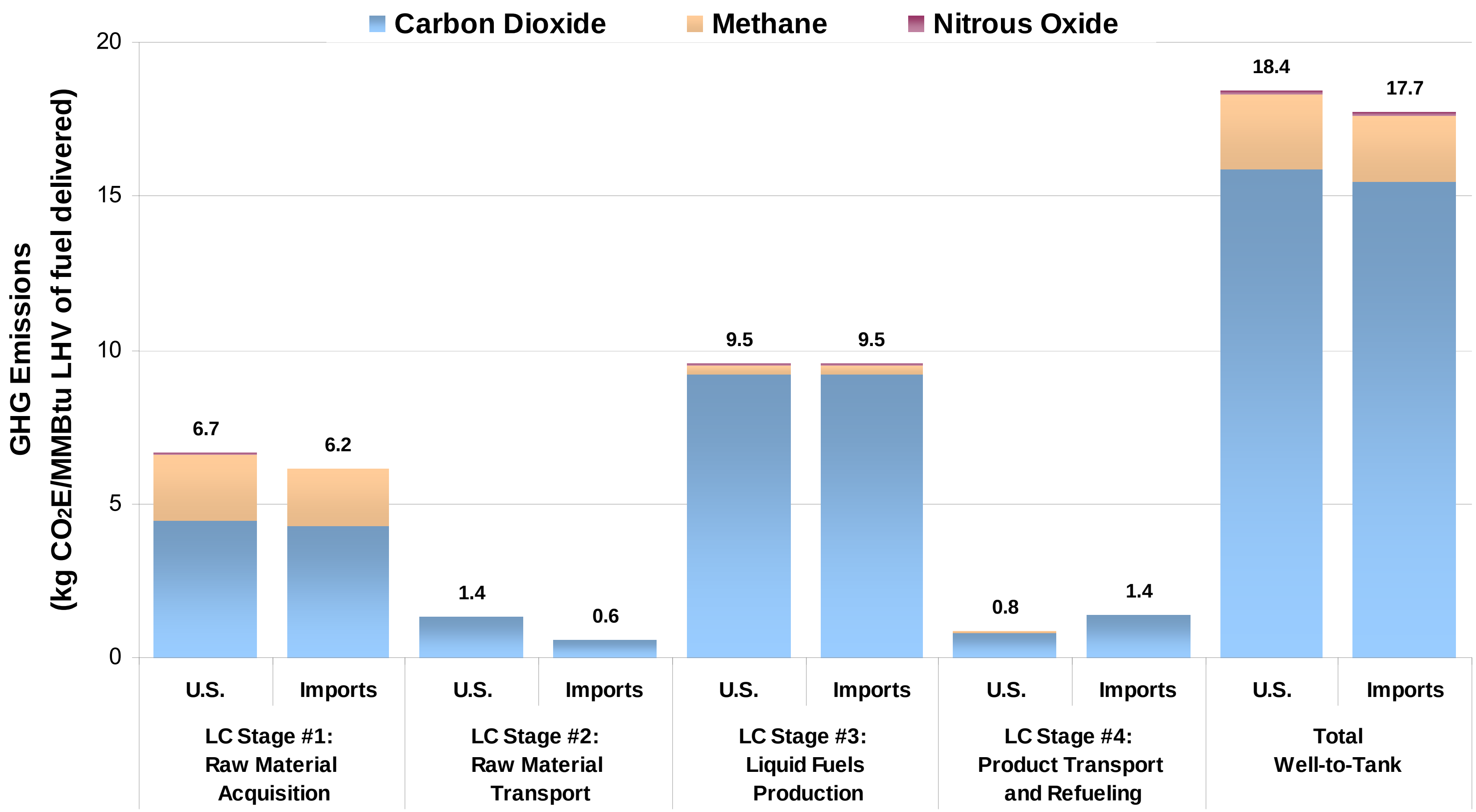
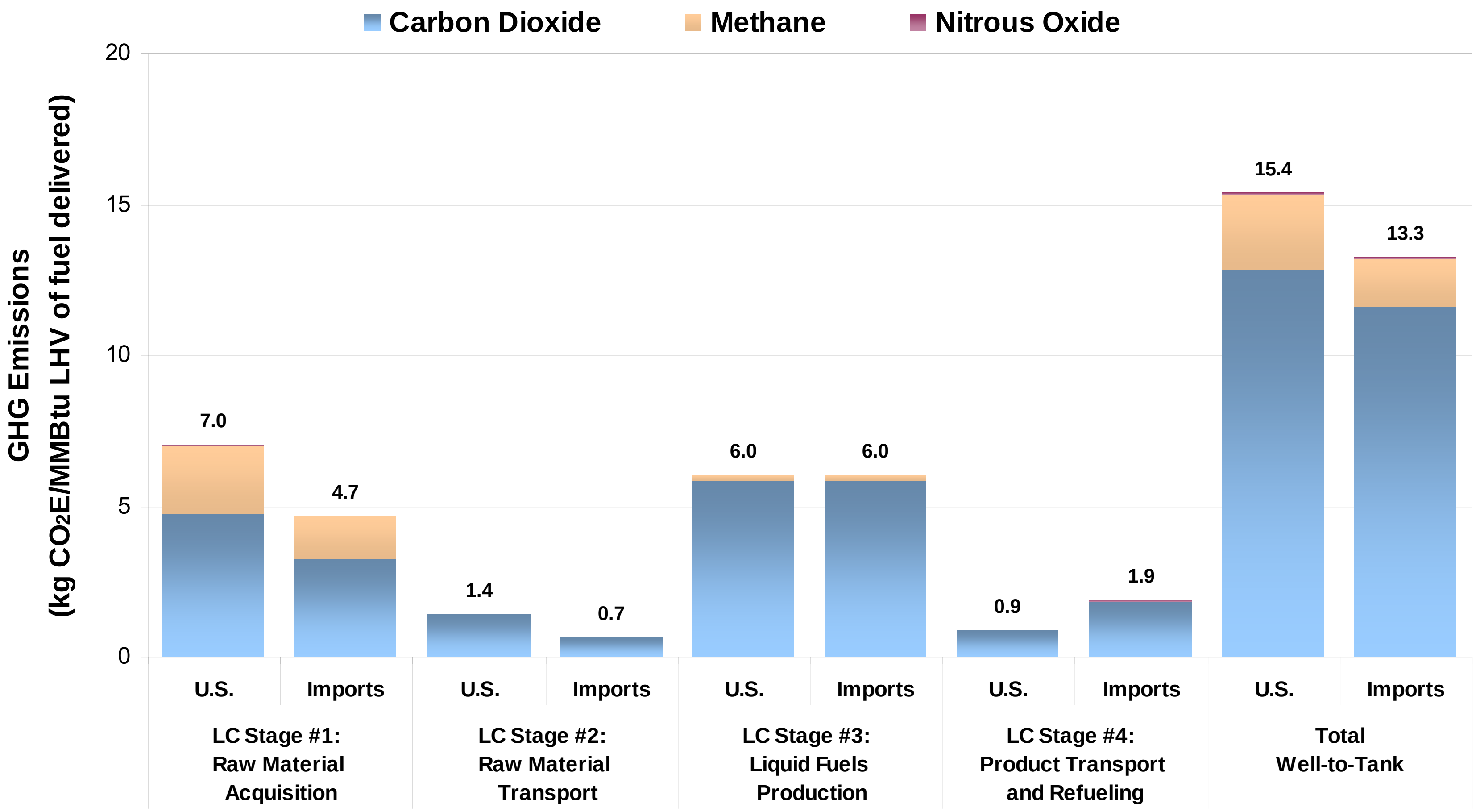


Figure 7-15. Comparison of GHG Emissions for Kerosene-Based Jet Fuel Produced at U.S. Refineries and Imported from Foreign Refineries



8.0 Data Quality and Sensitivity Analysis

Applicability of data for the study year 2005, level of detail available (i.e. due to the country where the activity occurs), absence of data, and fitness of data sources are all factors that effect the overall quality of the results of this study. The impact of lower quality data or necessary assumptions and estimations on the final results will vary based on the relative contribution of the associated activity to the final emissions profile. To understand and quantify the effects of such uncertainty, a data quality assessment is discussed and associated sensitivity analysis results are presented for each life cycle stage.

Sensitivity analyses are shown in terms of well-to-tank GHG emissions and have not been conducted for the vehicle/aircraft use phase of the fuel cycle. While this stage contributes a significant portion of the total life cycle GHG profile, the variability can simply be represented by modifying the LC Stage #5 results. In general for well-to-tank GHG emissions, greater variability occurs for raw material acquisition and liquid fuels production stages, since these stages account for a much higher fraction of the well-to-tank profile.

8.1 Life Cycle Stage #1

LC Stage #1 includes emissions associated with the extraction and post-extraction processing of refinery feedstocks for U.S. refineries and for foreign refineries providing imported gasoline, conventional diesel and kerosene-based jet fuel. Figure 8-1 thru Figure 8-3 show the results of the sensitivity analysis for LC Stage #1 activities for each liquid product of interest: conventional motor gasoline, conventional diesel fuel and kerosene-based jet fuel. The figures show the variability in the well-to-tank GHG emissions profiles for several factors. The baseline value is represented by the dotted line.

8.1.1 Crude Oil Extraction Profiles

Crude oil extraction accounts for approximately 87% of the GHG emissions in LC Stage #1 and between 31 and 39% of the entire well-to-tank profiles. The country of origin for crude oil imported by the U.S. and by the Virgin Islands is as reported by EIA and is specific to the year 2005. A similar level of detail is available for crude oil inputs to Canadian refineries in 2005. Country-specific crude oil GHG emissions profiles, either for extraction by country of origin (PE 2008) or delivered profiles (Gabi 4 2007), were used as available. These profiles are representative of 2002 operations and, where delivered crude oil profiles were used for foreign refineries, representative of crude oil mixes in 2002.

Use of Crude Oil Profiles

As discussed in Section 2.1.1.1, the country-specific crude oil extraction profiles are highly dependent on flaring and venting and, while a linear relationship between CO_2 emissions and flaring is apparent, the U.S. profile is above the CO_2 emissions predicted from this relationship. Because U.S. data is often more readily available and transparent, the higher U.S. value relative to the trend for GHG emissions associated with crude oil extraction in the foreign countries could lead to the conclusion that the foreign data are underestimated. Assuming that half of the difference is due to this (and the other half is due to different extraction technologies, mix of onshore/off-shore, maturity of fields, etc), all of the foreign extraction profiles would be increased by 3.4 kg CO_2E/bbl.

The extraction profiles for all countries are representative of 2002 rather than 2005. Significant changes in the flaring and venting rates relative to crude oil production in the countries of interest would change the profiles. Assuming Mexico, Algeria, Angola, and Nigeria all reduced their flaring and venting by one fourth would result in an overall reduction of emissions associated with this life cycle stage.

The impact of these two scenarios is shown in Figure 8-1 as "Baseline adjustment in line with U.S. profile" and "Reduced flaring/venting." The impact of reduction in flaring and venting has the greatest impact on the GHG profile for this life cycle stage, but results in less than 5% percent reduction in the well-to-tank profiles and less than 1% percent reduction in the well-to-wheels profiles.

While not quantified here, it is important to note that the impact of flaring and venting highlights the substantial reliance on country-reported flaring and venting rates, although to a lesser degree in countries where multi-national companies operate the crude oil and natural gas production.

Foreign Average Crude Oil Extraction Profile

Country-specific crude oil extraction profiles for the countries contributing over 90% of the crude oil input to U.S. refineries in 2005 are modeled with the remaining assumed to be a foreign average. This foreign average is also used for 3.3% of the crude oil fed to Canadian refineries. Figure 8-1 thru 8-3 show the impact of varying the foreign average extraction profile study value from 58% (equal to the U.S. profile) to 125% (65% of the Angola profile) on WTT GHG emissions. The GHG profile varies less than ±2% with these changes.

Foreign Average Delivered Crude Oil Profile

Country-specific delivered profiles or extraction profiles were used for foreign refineries producing conventional gasoline, conventional diesel, or kerosene-based jet fuel imported by the U.S. in 2005. A foreign average delivered profile was used as a surrogate for the crude input to foreign refineries in countries where crude oil extraction profiles were not available. For imported fuels, the foreign average is used for 9% of the gasoline crude oil mix, 12% of the diesel crude oil mix, and 22% of the jet fuel crude oil mix. The sensitivity of the well-to-tank profiles assuming the delivered foreign profile study value is varied from 67% (equal to Sweden's delivered profile) to 151% (equal to China's delivered profile) was found to be insignificant.

8.1.2 Oil Sands/Heavy Oils GHG Emissions Profiles

Oil sands and other heavy oils and synthetic crude oil are emerging as unconventional feedstocks to refineries and the extraction process and subsequent upgrading associated with these oils are more energy intensive than traditional crude oil extraction. The specific quantity of Canadian oil sands utilized by U.S. refineries in 2005 is available, however, data are limited for other countries that may have supplied similar unconventional feedstocks to U.S. refineries.

Canadian Oil Sands

When determining the GHG emissions profile for Canadian oil sands, the 2005 reported GHG emissions from a company producing blended bitumen and another producing synthetic crude oil were used and assumed to be representative of the industry. While these companies are well established and represented approximately 33% of the Canadian oil sands bitumen production in 2005 (AEUB 2006), it is expected that there is uncertainty in this profile of Canadian oil sands. The GHG well-to-tank emissions profile for each of the fuels is shown in the sensitivity analysis for a scenario where the Canadian oils sands GHG profile is varied between 75% and 125% of the study value. This change in the Canadian oil sands GHG profile results in a 1% or less change in the GHG profile for each of the petroleum products.

Venezuelan Crude Oil Extraction Profile

Heavy oil extraction and upgrading is a growing piece of Venezuelan oil production. However, due to limited availability of information, the extraction emissions profile used does not incorporate such activities. The sensitivity analysis shows what the well-to-tank emissions profile would be if 25% of the Venezuelan crude oil input to U.S. and foreign refineries were set equal to the Canadian oil sands extraction profile (50/50 mix of synthetic crude oil and blended bitumen). Increasing Venezuelan crude oil extraction emissions increases the WTT GHG emissions by less than 3%.

Figure 8-1. Sensitivity Analysis of Life Cycle Stage #1 Activities on the Well-to-Tank GHG Emissions Profile for Conventional Gasoline Consumed in the U.S. in 2005

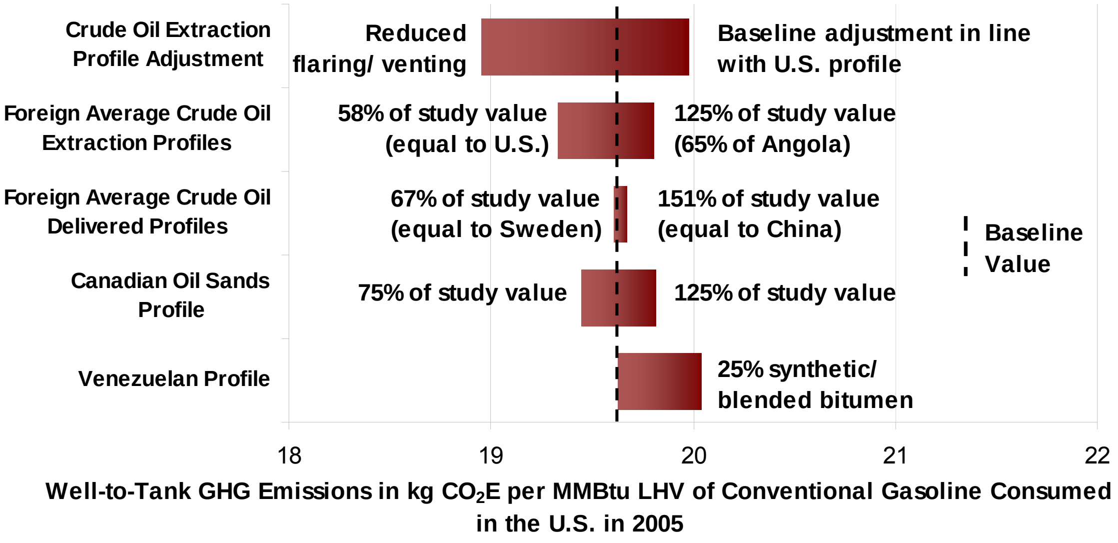


Figure 8-2. Sensitivity Analysis of Life Cycle Stage #1 Activities on the Well-to-Tank GHG Emissions Profile for Conventional Diesel Consumed in the U.S. in 2005

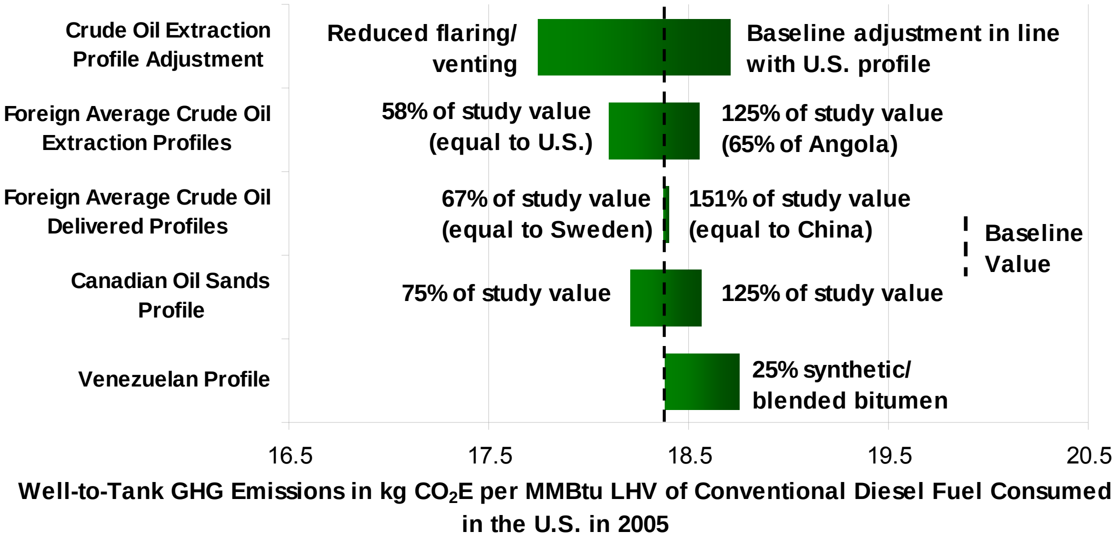
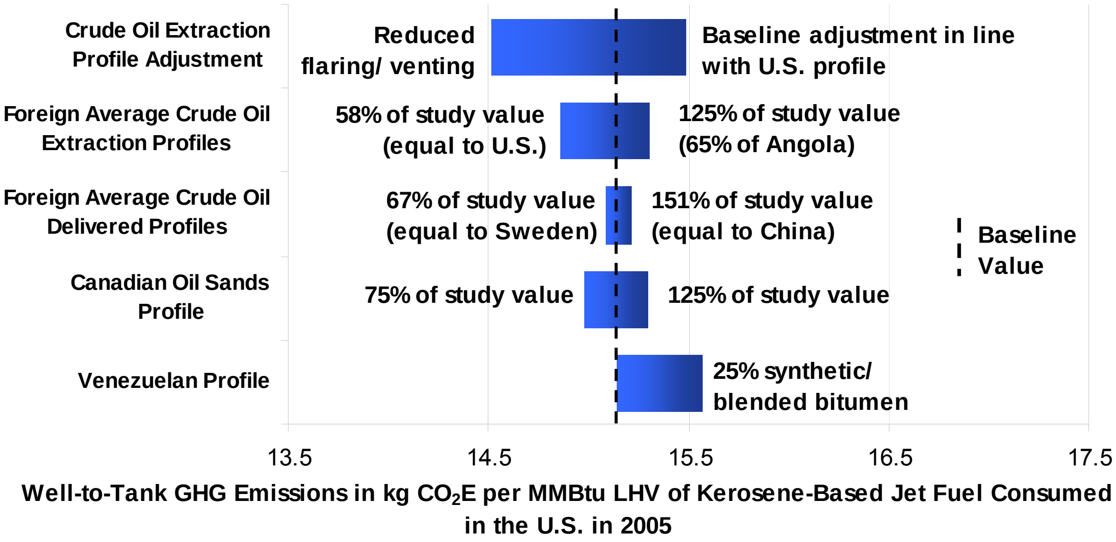


Figure 8-3. Sensitivity Analysis of Life Cycle Stage #1 Activities on the Well-to-Tank GHG Emissions Profile for Kerosene-Based Jet Fuel Consumed in the U.S. in 2005



8.2 Life Cycle Stage #2

LC Stage #2 includes emissions associated with the transport of crude oil and other feedstocks from the point of extraction to the refinery that processes the crude oil. This is applicable to both crude oil for use in U.S. refineries and for foreign refineries providing imported gasoline, conventional diesel, and kerosene-based jet fuel. Figure 8-4 thru Figure 8-6 show the results of the sensitivity analysis for LC Stage #2 activities for each liquid product of interest: conventional motor gasoline, conventional diesel fuel and kerosene-based jet fuel. The figures show the variability in the well-to-tank GHG emissions profile for several factors. The baseline value is represented by the dotted line.

8.2.1 Waterborne Transport

Transport of crude oil by tanker from foreign ports to refineries in the U.S., Canada, Virgin Islands and South Korea was modeled. EIA volume and receiving port data are available for each shipment received by the U.S. and Virgin Islands in 2005. While specific ports of receipt were not available for Canada, a similar approach was used for distance traveled calculations.

For foreign countries where a delivered crude oil profile was not available, any waterborne transport associated with shipment of crude oil is embedded in that profile and thus is not impacted by the sensitivity analysis.

Crude Oil Carrier Energy Intensity

A crude oil carrier energy intensity factor was determined after conducting a survey of crude oil vessels. The energy intensity factor will be specific to the tanker characteristics and capacity. For this sensitivity analysis, the crude oil water carrier energy intensity was varied from 4.25 to 7.25 Btu/bbl-nautical mile (study value of 5.5 Btu/bbl-nautical mile) in line with the range occurring in the survey of tankers conducted as part of this study. The resulting variability in the well-to-tank GHG emissions profile is minor (±1%).

Crude Oil Waterborne Transport Distances

Modeling of the transport of crude oil by tanker from foreign ports to refineries in the U.S., Canada, Virgin Islands and South Korea used estimated port-to-port travel distances assuming no crude oil tanker transport through various canals. For 9.5% of the crude oil to U.S. refineries and 3.3% of the crude oil to Canadian refineries, assumed average transport distances are 10,000 and 5,000 nautical miles, respectively. To simulate uncertainty in the use of these averages and restriction of canal usage, a sensitivity analysis varied all waterborne distances from 90% to 115%. This results in a range in the well-to-tank GHG emissions profile of minor consequence.

8.2.2 Pipeline Transport

All transport from the point of extraction to port/border of export or refinery was assumed to be 100 miles by pipeline and a GHG emissions profile for the U.S. power grid was applied to the power consumed for pipeline operation. The impact of these two assumptions is negligible, as shown by the sensitivity analysis where the pipeline mileage is varied from 50 to 200 miles and the electricity profile for foreign transport is simultaneously varied from 80% to 120%.

For foreign countries where a delivered crude oil profile was not available, any pipeline movements associated with crude oil transport is embedded in that profile and thus is not impacted by the sensitivity analysis.

8.2.3 Crude Oil Loss Factor

Losses associated with crude oil transport will vary based on crude oil type, duration of transport, and modes of transport. For this reason, data on average loss factors is not available. The loss factor used is based on that reported by a European company for 2005 that imports a majority of its crude oil (Eni 2006). This loss factor was applied to all crude oil transported. The sensitivity analysis shows that varying the crude oil loss factor from 50% to 200% of the base value has an insignificant impact on the final well-to-tank emissions profile. Note that crude oil losses occur during LC Stage 2 activities, but impact the profile of both LC Stage #1 and #2.

Figure 8-4. Sensitivity Analysis of Life Cycle Stage #2 Activities on the Well-to-Tank GHG Emissions Profile for Conventional Gasoline Consumed in the U.S. in 2005

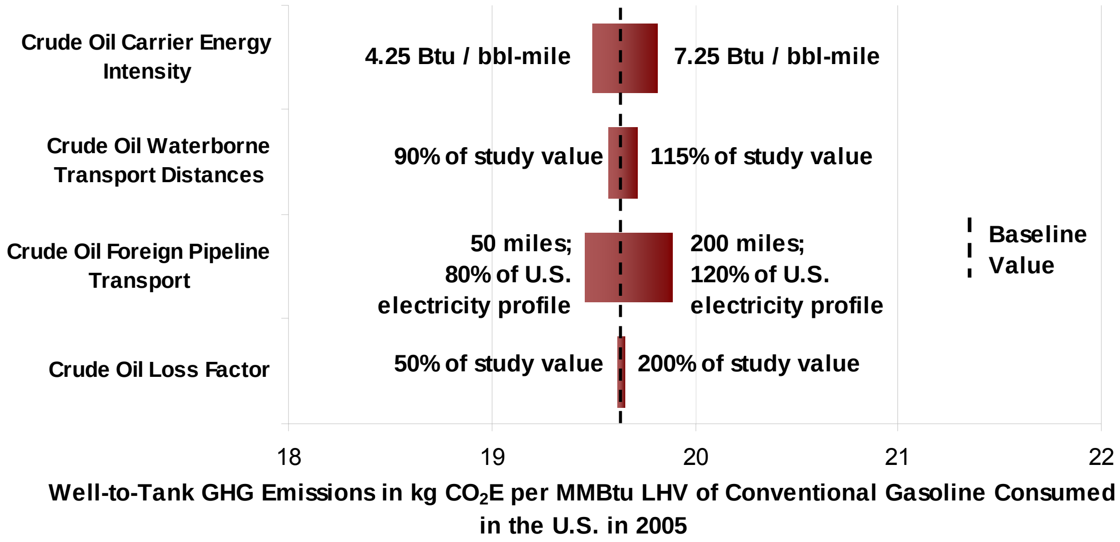


Figure 8-5. Sensitivity Analysis of Life Cycle Stage #2 Activities on the Well-to-Tank GHG Emissions Profile for Conventional Diesel Consumed in the U.S. in 2005

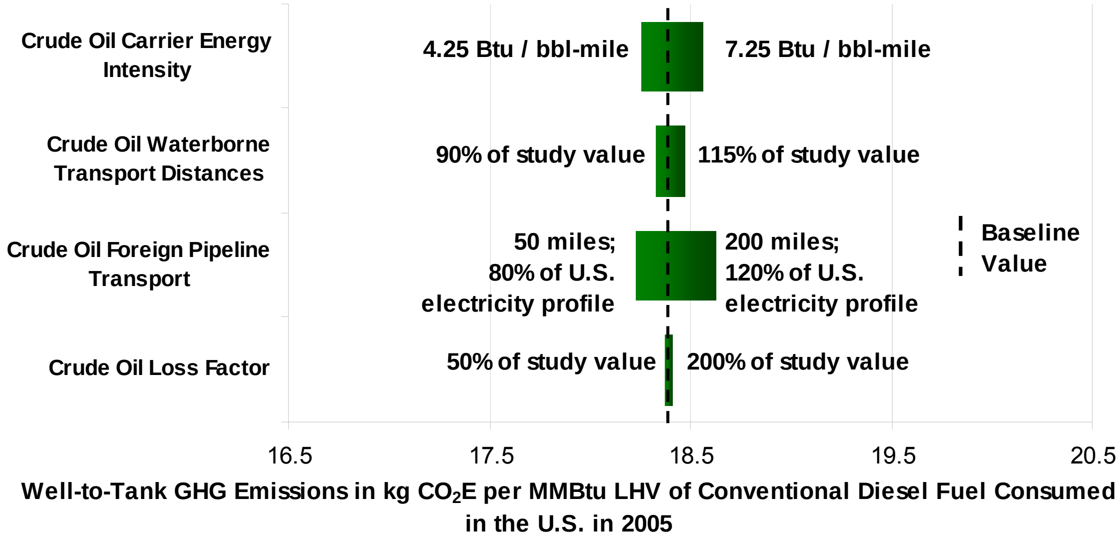
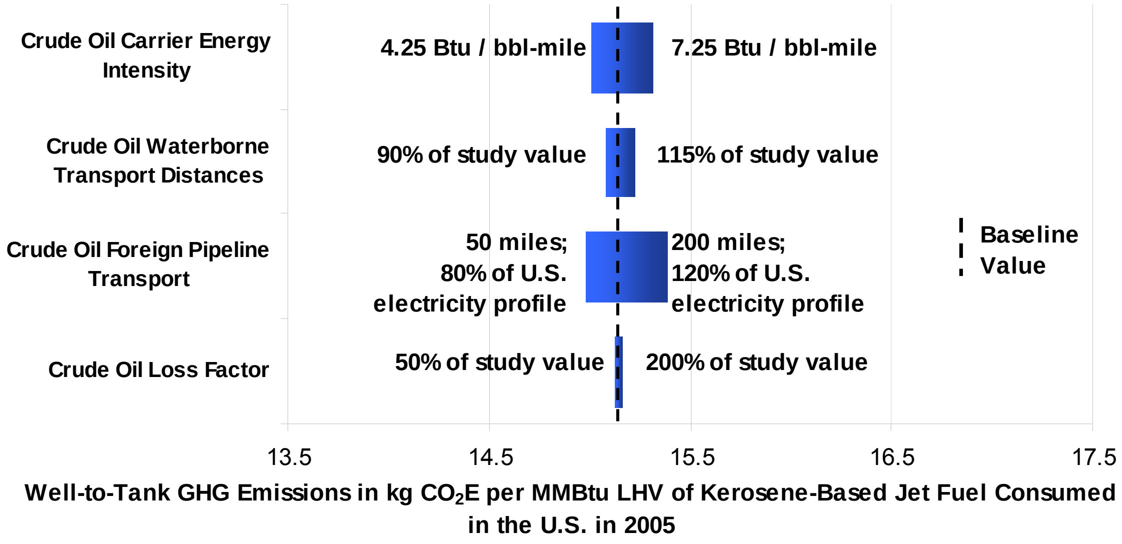


Figure 8-6. Sensitivity Analysis of Life Cycle Stage #2 Activities on the Well-to-Tank GHG Emissions Profile for Kerosene-Based Jet Fuel Consumed in the U.S. in 2005



8.3 Life Cycle Stage #3

Life Cycle Stage #3 includes emissions associated with the following petroleum refinery operations:

- Extraction, transport, and production of refinery fuels and energy inputs
- Combustion of fuels for use as an energy source at petroleum refineries
- Cradle-to-gate emissions associated with hydrogen production
- Flaring, venting and fugitive methane emissions

Figure 8-7 thru Figure 8-9 at the end of the discussion show the results of the sensitivity analysis for LC Stage #3 activities for each liquid product of interest: conventional motor gasoline, conventional diesel fuel and kerosene-based jet fuel. The figures show the variability in the well-to-tank GHG emissions profiles for several factors. The baseline value is represented by the dotted line.

8.3.1 Total Petroleum Refining Emissions

Quantities of fuels consumed in refineries are as reported by U.S. petroleum refineries to EIA in 2005, but a variety of sources not specific to 2005 were used to determine the energy content, emissions profiles for these fuels, flaring and venting at refineries, and energy usage and resulting GHG emissions associated with merchant hydrogen production. Sensitivity analysis on these factors will generally raise or lower the GHG emissions profile for all refinery products.

Still Gas Emissions Factors

Still gas is a mix of light gases from various parts of the refinery and provides nearly half of the energy input to refineries. The quantity of still gas consumed at refineries is reported by EIA and these data are of high quality. One area of uncertainty however, is still gas composition. The carbon content and resulting GHG emissions are not specifically known. However, the impact of varying the CO_2 emissions equal to that from combustion of liquid propane gas to pentanes plus is minor. The emissions factors for liquid propane gas and pentanes plus utilized for this analysis are 62.3 and 66.9 kg CO_2/MMBtu HHV, respectively (API 2004). The still gas study value used is 64.2 kg CO_2/MMBtu HHV.

Electricity Profile for Refineries

The U.S. average mix of electricity sources (coal, nuclear, renewables, etc.) in 2004 was used to represent to GHG emissions profile for electricity purchased and used by U.S. refineries. U.S. refineries are generally located in specific regions of the country and thus the actual electricity source mix may vary from the U.S. average. A sensitivity analysis varying the electricity profile from 90% to 115% of the study value shows minimal impact on the overall profiles.

Hydrogen Plant Feed Input

Hydrogen plant feed input is estimated to be 352 Btu HHV per scf of hydrogen. Based on the survey conducted as part of this study, other reported values vary from 306 to 376 Btu HHV per scf depending on the technology applied. The range evaluated here is 325 to 375 Btu HHV per scf to more accurately represent the range of *average* values for 2005. For diesel fuel and jet fuel, reducing the feed requirements (essentially increasing the efficiency) results in a decrease in the well-to-tank GHG profile. However, gasoline actually shows a slight increase from the baseline profile for both cases. This is due to the system expansion process used for allocation of the catalytic reformer energy. When the model hydrogen plant efficiency is increased, it results in the energy to produce hydrogen from the catalytic reformer being greater than for the model hydrogen plant (SMR). This results in 6% of the catalytic reformer energy requirement being allocated to the reformate and thus to gasoline.

Off-Site Hydrogen Production

Merchant hydrogen consumption by U.S. refineries was estimated using 2003 data and extrapolated based on historical growth rates. Varying the study value between 80% and 125% of the base consumption quantity directly affects the GHG WTT emissions profiles with greater variability for diesel (due to the greater hydrogen consumption associated with its production), but to a small extent (~0.6% difference).

On-Site Hydrogen Plant Capacity Utilization

Hydrogen plant capacity at U.S. refineries is provided by EIA, however the percentage of that capacity that is utilized had to be estimated. The assumed value was 85%. Increasing this value primarily results in an increase in the overall natural gas feed requirements and associated emissions and the CO_2 process emissions associated with production of the hydrogen. Sensitivity analysis for this parameter shows only slight variability in the GHG emissions profiles for each of the fuels through a range of 80% to 90% capacity utilization.

Flaring and Venting/Fugitive Methane Emissions

Emissions associated with flaring at U.S. refineries, as determined in this study, makes up less than 1% of the LC Stage #3 GHG emissions profile. The study value was estimated using flare rates from a group of California refineries for which reporting of such data is required. It was assumed that the flared gas is natural gas. Because California generally has more stringent restrictions on such activities and because combustion emissions from natural gas are expected to underpredict GHG emissions related to refinery flaring, a sensitivity analysis has been conducted to show the impact of a value 300% of the study value. The impact on the overall profile is minor (0.7% or less increase in WTT GHG emissions).

Methane vented and fugitive emissions from refinery operations for the 2005 U.S. GHG Inventory have been estimated and extrapolated from 1996 and 1999 EPA studies (EPA 1996; EPA 1999) of refinery process unit methane emissions. It is important to note that environmental regulations and industry responsible care has increased in the interim since 1996 and 1999. Thus, these values may be inflated for refineries currently in operation today. However, the sensitivity analysis shows an insignificant change to the GHG emissions profiles when the study value is reduced to 25%.

8.3.2 Allocation of Emissions to Petroleum Refining Products

While U.S. petroleum refineries report process unit capacities for January 1st of each year, capacity utilization, unit-specific energy and hydrogen requirements, and the contribution of each process unit to the product categories are all factors that will vary from year to year. Furthermore, if reported values are available, they are typically linked to a technology type rather than a U.S. weighted average. Sensitivity analysis on these factors will generally change the GHG distribution between products.

8.3.2.1 Hydrogen Production and Consumption

Changing factors related to hydrogen production or consumption will impact the energy consumption at the refinery attributable to hydrogen production and thus shift the emissions towards or away from those processes and associated products that consume more hydrogen.

Catalytic Reformer Hydrogen Production

Hydrogen production by the catalytic reformer was assumed to be 1,000 scf/bbl based on a literature survey. While sources showed ranges from 600 to 1,700 scf/bbl, the range of uncertainty is likely smaller based on the average technology and mode of operation for U.S. refineries in 2005. The sensitivity analysis shows the impact on the GHG emissions as the catalytic reformer hydrogen production is varied from 800 to 1,200 scf/bbl. Increasing the hydrogen production by the catalytic reformer slightly skews the distribution of emissions towards those products that consume hydrogen (i.e. diesel). However, decreasing the hydrogen production by the catalytic reformer has a more complex effect and thus a greater impact. This change increases the energy requirements for the catalytic reformer to produce hydrogen to a value greater than that for hydrogen production by SMR. Application of the system expansion methodology described in Section 4.2.5.2 for this scenario results in 21% of the catalytic reformer energy being assigned to reformate production and away from the hydrogen pool. Because reformate is primarily a gasoline blending component, this results in a direct shift of the emissions profile from diesel and kerosene to gasoline.

Reducing the catalytic hydrogen consumption results in one of the larger profile shifts, but it is less than a 3% change from baseline in the well-to-tank profiles.

Hydrocracker Hydrogen Consumption

The hydrocracker hydrogen consumption is fixed and the hydrotreating hydrogen consumption is calculated to balance the system. This means that varying the hydrocracker hydrogen consumption also varies the hydrotreater hydrogen consumption. The results of varying the hydrocracker hydrogen consumption from 80% to 150% of the baseline value for all hydrocracking operations are shown. Varying hydrocracker hydrogen consumption results in only a small deviation of the GHG profile from the study baseline.

8.3.2.2 Capacity Utilization

EIA provides U.S. refinery 2005 actual volumetric throughput for the atmospheric distillation column, catalytic cracking units, hydrocracking units, and coking units. However, for the remaining processing units, capacity utilization must be estimated. A 1996 API/NPRA refinery survey (API 2004) provided capacity utilization factors for various process units and was used as a starting point, but changes in economics, technology, and regulatory requirements, and their resulting impact on capacity utilization is difficult to predict.

Hydrotreating Capacity Utilization

A large volume of intermediate and final products are hydrotreated in refineries to remove sulfur. Furthermore, changes since 1996 have been more than minor due to the processing of heavier, higher sulfur crude oils and lower limits for sulfur content in final products. However, increasing the capacity utilization to 85% (from the study value of 80%) results in only a minor increase in the profile for diesel and an insignificant decrease in the profiles for gasoline and jet fuel.

Vacuum Distillation Capacity Utilization

Increasing the vacuum distillation column capacity utilization results in a shift of GHG emissions from lighter products to heavier products. Varying the vacuum distillation between 80 and 90% (study value is 85%) has a minor impact on the diesel profile, with even less of an impact on the gasoline and jet fuel profiles.

8.3.2.3 Energy Consumption

Process unit-specific energy consumption was used for purposes of allocating between product categories. The average energy consumption for each process unit and ranges for various technologies were shown in Table 4-43 (Energetics 2007). This source draws on the reported energy requirements of multiple licensed technologies employed by U.S. refineries in 2005. The ranges represent different technologies and are not intended to provide a range for the aggregated average value for the year 2005. They are, however, used as a guide for this sensitivity analysis.

Vacuum Distillation Energy Consumption

The vacuum distillation column energy intensity is varied here in the range relative to the study value of 90 MBtu HHV per barrel of throughput. When the energy requirement is increased from the baseline, more energy and associated emissions are allocated to heavier non-transportation fuel products such as lubricants and coke, and less are allocated to gasoline, diesel, and jet fuel.

Delayed Coker Energy Consumption

The delayed coker energy intensity range reported by Energetics is wide (115 MBtu/bbl), representing various technologies and severity of operations. In the sensitivity analysis presented here, for the range evaluated (115 to 175 MBtu HHV per barrel of throughput versus the study value of 147) a minor shift in the emissions profile from lighter to heavier products is observed.

Catalytic Reformer Energy Consumption

The catalytic reformer energy intensity reported range is wide (130 MBtu/bbl), representing various technologies and severity of operations. For the sensitivity analysis presented here, the range evaluated (223 to 283 MBtu HHV per barrel of throughput versus the study value of 253) results in only a minor shift in the emissions profiles. As with the hydrogen production associated with the catalytic reformer, the relationship is not linear due to a shifting of GHG emissions between the hydrogen and reformate.

Hydrotreater Energy Consumption

EIA provides volumetric throughput capacity data on a variety of hydrotreating and hydrocracker subcategories. Energetics (2007) reports average energy intensities for the broad categories of hydrotreating and hydrocracking and the average values are applied across the board to all subcategories. However, energy requirements will vary between these subcategories based on the quantity and type of sulfur in the feed, density of the feed, and product specifications. This sensitivity analysis varies the energy intensities for the subcategories as shown in Table 8-1 to attempt to simulate such variability. The result is a small decrease in GHG emissions for jet fuel, a small increase for diesel, and an insignificant decrease for gasoline. This shift is expected as jet fuel is generally made from a lighter, lower sulfur cut of the crude oil and generally has a less stringent sulfur specification, as compared to gasoline and diesel.

Table 8-1. Adjustments to Hydrotreating Subcategory Energy Consumption Utilized in Sensitivity Analysis

Hydrotreating Subcategory	Study Value	Sensitivity Analysis Value
	Thousand Btu per barrel	
Distillate Hydrocracking	107	85
Gas Oil Hydrocracking	107	115
Residual Hydrocracking	107	130
Naphtha/Reformer Feed Hydrotreating	59.0	45
Gasoline Hydrotreating	59.0	56.5
Heavy Gas Oil Hydrotreating	59.0	75
Kerosene Hydrotreating	59.0	45
Diesel Fuel Hydrotreating	59.0	70
Other Distillate Hydrotreating	59.0	60
Residual Fuel Oil Hydrotreating	59.0	75
Other Hydrotreating	59.0	60

8.3.2.4 Contribution of Unit Operations to Product Categories

An API/NPRA 1996 refinery survey was the primary source used to determine the contribution of each of the process units to the product categories (API 1997). Adjustments were made to the reported values to account for changes in feedstock quality, environmental emissions requirements, product quality/slate, and refinery operations. That report did not consider all unit operations and thus estimates were required in some cases.

Catalytic Cracking Contribution to Product Categories

The API/NPRA refinery study provided the basis for assigning catalytic cracking operational throughput to the final product slate. This assignment also impacts the distribution of energy usage associated with the vacuum distillation column. These two unit operations combined contribute to 27% of the modeled energy consumption. The sensitivity analysis shows that simply shifting the contribution to gasoline between 56% and 64% (study value of 60%) results in one of the more significant changes to the gasoline and diesel emissions profiles. The overall impact on the well-to-tank GHG emissions profiles is around 2%.

Gas Oil Hydrocracking Contribution to Product Categories

Allocation of hydrocracking operations between final products is noted as a data gap in this analysis. For this sensitivity analysis, the allocation of gas oil hydrocracking, which is the greatest subcategory of hydrocracking, was varied between gasoline and diesel. The baseline values of 50% gasoline/40% diesel were varied to 70%/20% and 30%/60%. The resulting change in GHG emissions for gasoline and diesel is less than 2% from the base value. There is no effect on jet fuel.

8.3.3 Refining Profile for Imported Products

The U.S. refining profile for each transportation fuel was used as a surrogate for the foreign refining profiles because of the lack of publically available data that meets the transparency and detail required for this study. Other studies examined showed results that ranged from 60% of this study value for diesel fuel to 95% of this study value for gasoline and from 48% to 125% for diesel. While some of this variability is due to system boundaries and differences in allocation of hydrogen, a portion may also be due to the fuels used and technologies employed at foreign refineries.

All profiles (gasoline, diesel and jet fuel) for foreign refineries are varied from 65% to 130% to characterize the influence of this parameter on the well-to-tank GHG emissions profile. Variation of this parameter has a greater influence on the overall GHG profile for gasoline than for jet fuel or diesel. This is due to the fact that gasoline has the highest import fraction of the three fuels. However, the impact to the gasoline well-to-tank GHG emissions profile is less than 3% and the impact on the well-to-wheels GHG emissions profile is less than 1%.

Figure 8-7. Sensitivity Analysis of Life Cycle Stage #3 Activities on the Well-to-Tank GHG Emissions Profile for Conventional Gasoline Consumed in the U.S. in 2005

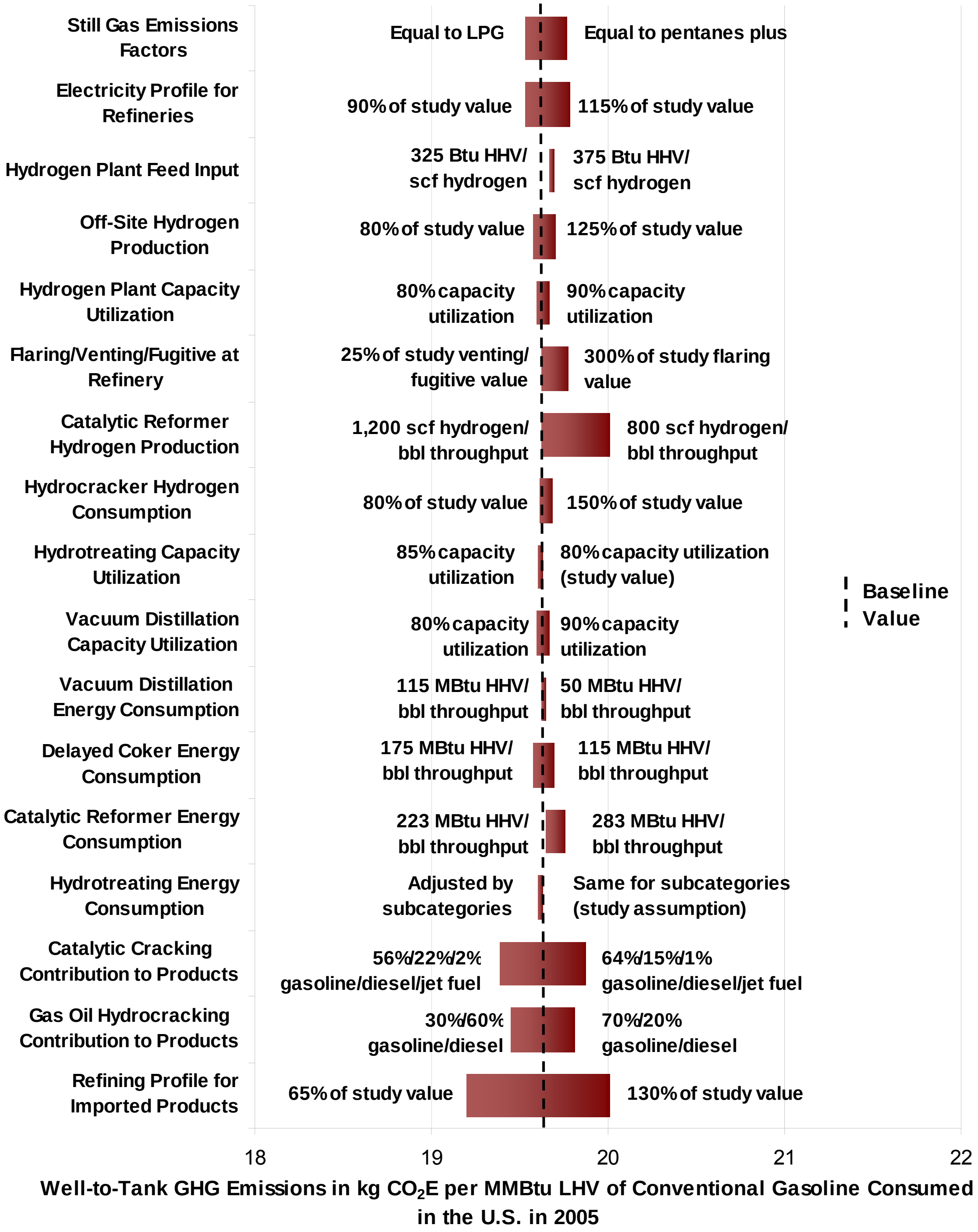


Figure 8-8. Sensitivity Analysis of Life Cycle Stage #3 Activities on the Well-to-Tank GHG Emissions Profile for Conventional Diesel Consumed in the U.S. in 2005

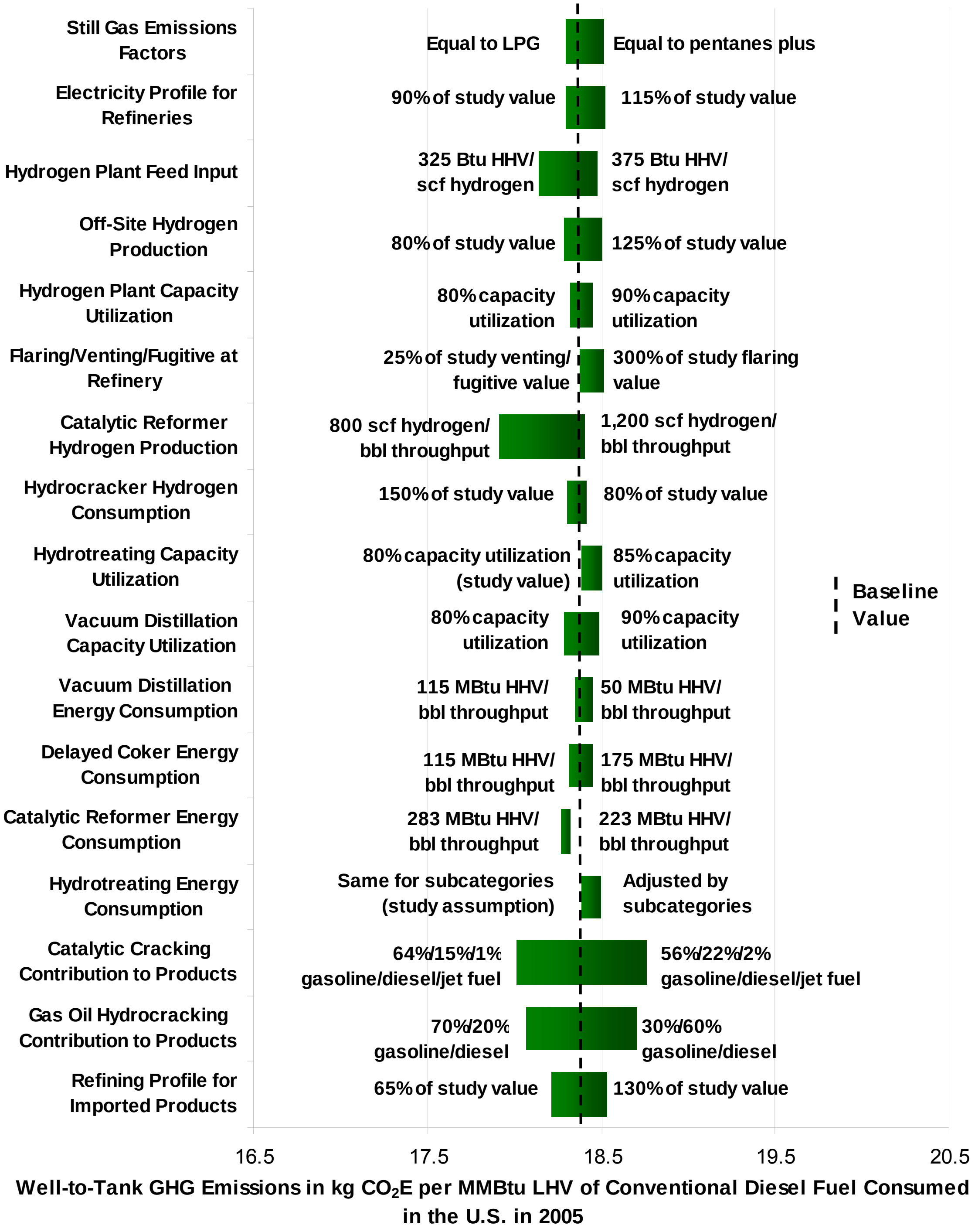
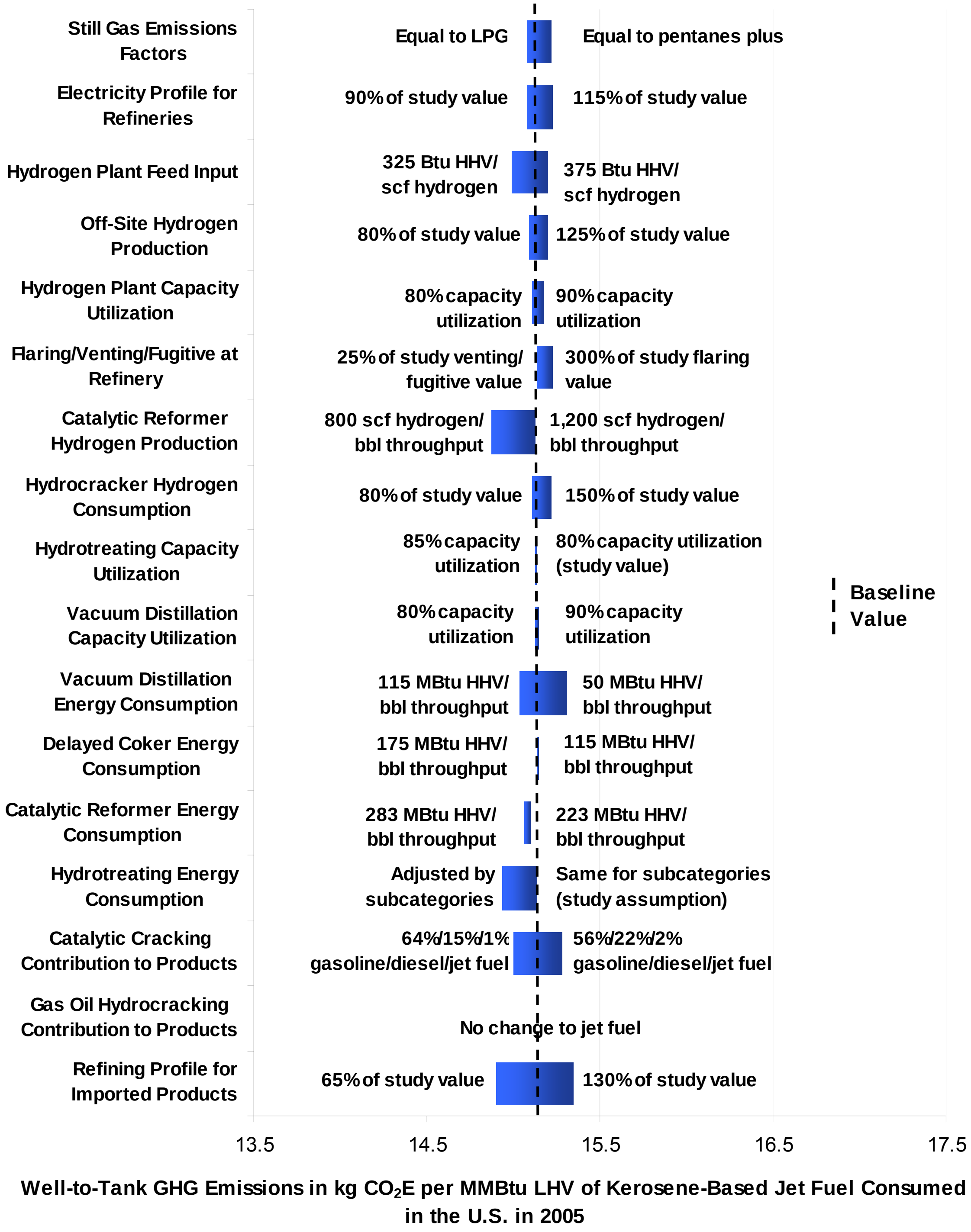


Figure 8-9. Sensitivity Analysis of Life Cycle Stage #3 Activities on the Well-to-Tank GHG Emissions Profile for Kerosene-Based Jet Fuel Consumed in the U.S. in 2005



8.4 Life Cycle Stage #4

LC Stage #4 consists of activities to transport domestically-produced and imported conventional gasoline, conventional diesel, and kerosene-based jet fuel to and within the U.S. and subsequent refueling operations. Modeling of this particular life cycle stage required that multiple simplifying assumptions be made. These assumptions are not expected to have a significant impact on the overall GHG emissions profiles because this profile only contributes 4.8-6.6% to the total well-to-tank profiles.

Figure 8-10 thru Figure 8-12 show the results of the sensitivity analysis for LC Stage #4 activities for each liquid product of interest: conventional motor gasoline, conventional diesel fuel, and kerosene-based jet fuel. The figures show the variability in the well-to-tank GHG emissions profiles for several factors. The baseline value is represented by the dotted line.

Product Water Carrier Energy Intensity

The product water carrier energy intensity was varied based on a survey of tankers conducted as part of this study for transport of imported gasoline, diesel, and jet fuel. For this sensitivity analysis, the petroleum product tanker energy intensity was varied from 7.4 to 10.9 Btu/bbl-nautical mile (study value of 10 Btu/bbl-nautical mile). The resulting variability in the well-to-tank GHG emissions profile is minimal for all profiles, with less of an impact on the profiles which have a smaller fraction of imported products (diesel).

Product Water Carrier Travel Distance

Precise estimates of port-to-port travel distance were determined for petroleum products imported from Canada and the Virgin Islands while a study assumption of 5,000 nautical miles was used for all other imports. Varying all waterborne travel distances between 75% and 140% of the study values results in a minor shift in the GHG emissions profile for gasoline, and an insignificant change to the diesel and jet fuel profiles.

Total Products Transported Domestically

Based on availability of data on transport modes and volumes of petroleum products transported domestically, it was assumed that all petroleum products moved the same distance and by the same mix of modes of transportation. Obviously, this is not going to be the case since solids—like coke—will not be transported via pipeline. Petroleum product additives—such as oxygenates—will also be included in this transport estimate, but it is unknown to what extent.

Volumes of gasoline, diesel, and kerosene-based jet fuel produced at U.S. refineries and the imported products of interest account for 70% of the study value used for total products transported domestically. The sensitivity analysis shows the impact of using 80% of the study value to simulate a shift towards the transportation fuels covered in this study. The impact on all profiles is minor.

Product Loss Factors

Varying all product loss factors from 50% to 200% of the base value results in a minor shift in the gasoline profile, and essentially no change in the diesel and jet fuel profiles due to the relative volatility of the products. While these loss factors are associated with activities in LC Stage #4, they impact the results in stages #1, #2, and #3 as well.

Figure 8-10. Sensitivity Analysis of Life Cycle Stage #4 Activities on the Well-to-Tank GHG Emissions Profile for Conventional Gasoline Consumed in the U.S. in 2005

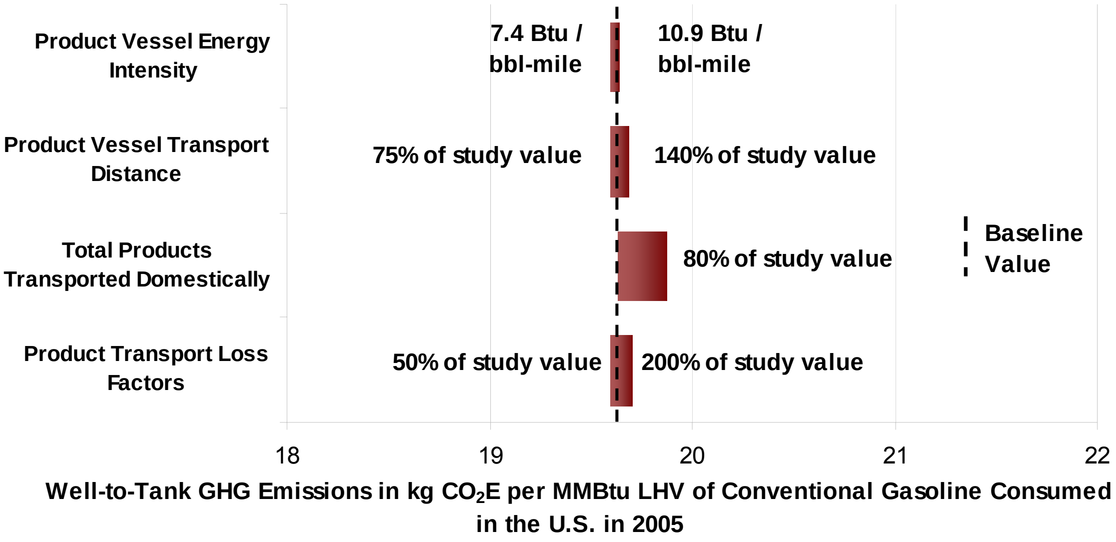


Figure 8-11. Sensitivity Analysis of Life Cycle Stage #4 Activities on the Well-to-Tank GHG Emissions Profile for Conventional Diesel Consumed in the U.S. in 2005

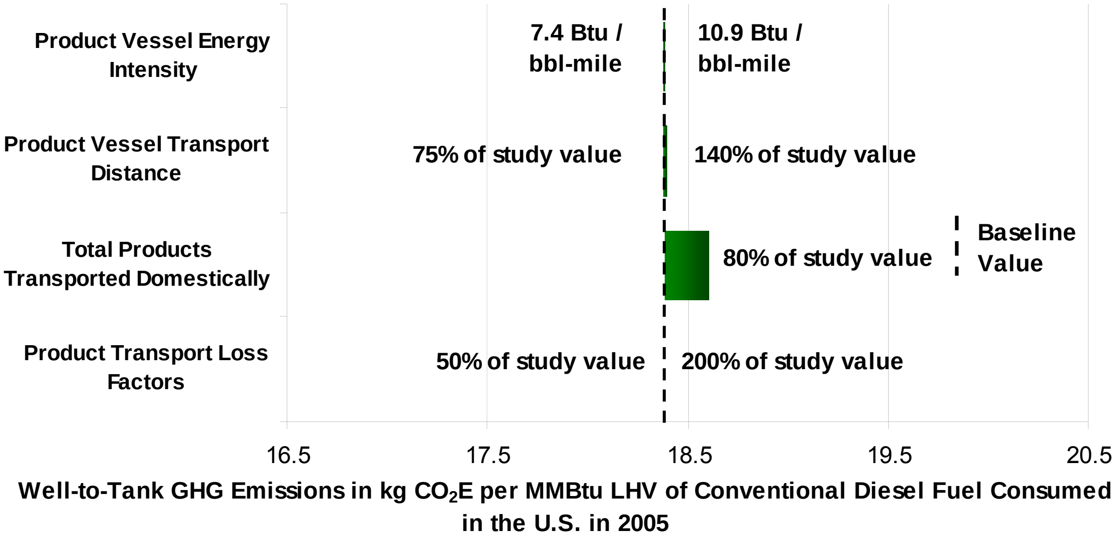
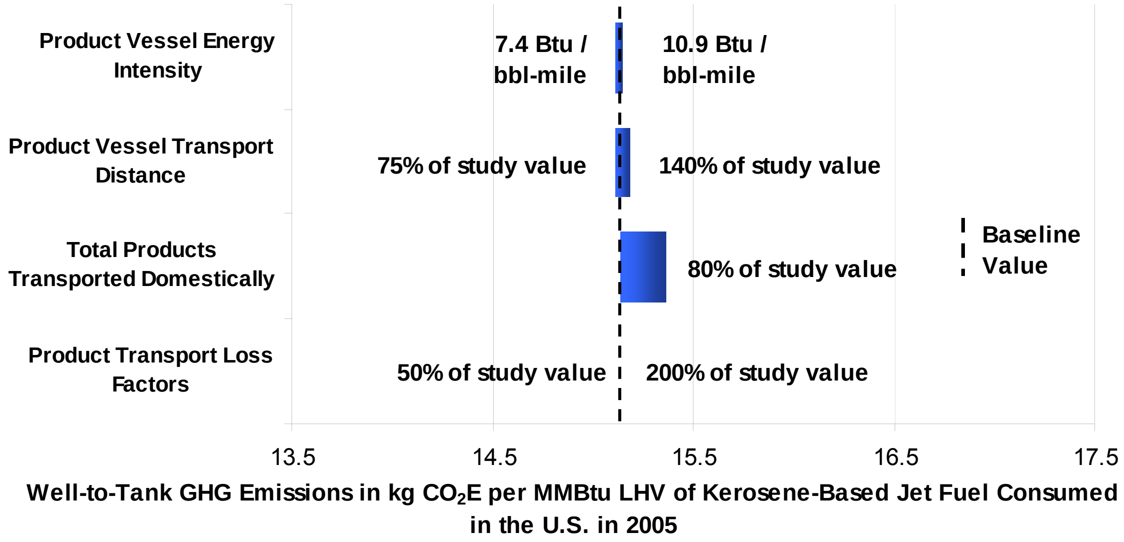


Figure 8-12. Sensitivity Analysis of Life Cycle Stage #4 Activities on the Well-to-Tank GHG Emissions Profile for Kerosene-Based Jet Fuel Consumed in the U.S. in 2005



8.5 Life Cycle Stage #5

The vehicle emissions for conventional gasoline and conventional diesel are representative of the average fleet of passenger car vehicles for 2005. This data was obtained from EPA and was extracted from the MOVES model (EPA 2008).

GHG emissions associated with the combustion of kerosene-type jet fuel are modeled based on average jet aircraft operation. The profile is based on the FAA and IPCC methodology for estimating GHG emissions from aircraft. The CO_2 emissions value used in this study is the same value used by the FAA and EPA to calculate annual GHG emissions from aircraft operations in the United States.

Although it is recognized that improvements and/or adjustments to the vehicle and aircraft use profile will significantly impact the total life cycle GHG results (emissions from the operation of the vehicle and combustion of the fuel account for approximately 80% of the total life cycle GHG emissions), sensitivity analysis was not conducted on these factors. This limitation should instead be managed by ensuring consistent and comparable vehicle use profiles are applied when evaluating alternative transportation fuel options.

8.6 Data Quality and Sensitivity Analysis Summary

Analysis of the data quality and sensitivity studies on parameters in each life cycle stage show that while there are many factors of uncertainty, no single variable shifts the well-to-tank GHG emissions profile by more than ±4% for each of the three transportation fuels modeled. Holding the use profile static, this translates to less than ±1% variance in the well-to-wheels GHG emissions profiles.

References

AEUB 2006	Alberta Energy Utilities Board (AEUB). “Alberta’s Oil Sands 2005.” 2006. http://www.energy.gov.ab.ca/OilSands/pdfs/PUB_osgenbrf2005.pdf
Aitani 1996	Aitani, A. M. *Processes to Enhance Refinery-Hydrogen Production*. International Journal of Hydrogen Energy, Vol. 21, No. 4, pp. 267-271, 1996.
Alireza 2007	Alireza Tehrani Nejad M. Allocation of CO_2 emissions in petroleum refineries to petroleum joint products: A linear programming model for practical application. Energy Economics 29 (2007) 974–997.
AOP	Association of Oil Pipe Lines. Pipelines and Water Carriers Continue to Lead All Other Modes of Transport in Ton-Miles Movement of Oil in 2004, June 2006. http://www.aopl.org/posted/888/Shift_Report_1984_2004.126714.pdf
API 1997	American Petroleum Institute/National Petroleum Refiners Association, *Final Report: 1996 American Petroleum Institute/National Petroleum Refiners Association Survey of Refining Operation and Product Quality*. July 1997.
API 2004	American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*. February 2004.
BA AQMD 2006	Bay Area Air Quality Management District (BA AQMD). *Source Inventory of Bay Area Greenhouse Gas Emissions: Base Year 2002*. November 2006.
BA AQMD 2008	Bay Area Air Quality Management District. “Regulation 12, Rule 11-Flare Monitoring at Petroleum Refineries - 2005 Archive Data.” Bay Area Air Quality Management District. http://www.baaqmd.gov/enf/flares/index_2005.htm (accessed June 1, 2008).
Babusiaux 2007	Babusiaux, Denis and Pierru, Axel. Modelling and allocation of CO_2 emissions in a multiproduct industry: The case of oil refining. Applied Energy 84 (2007) 828–841.
BNLD 2008	Brazilian National LCI Database, Datasets for REPLAN, 2008. http://acv.ibict.br/publicacoes/inventarios-brasileiros/datasets-da-replan-no-inventario-do-diesel-brasileiro/
Boyce 2004	Boyce, Clay A.; Crews, M. Andrew; Ritter, Robin. “Time for a new hydrogen plant?” *Hydrocarbon Engineering*, February, 2004 Vol. 9; Part 2, pages 67-70
BP 2007	British Petroleum. *Statistical Review of World Energy 2007*. www.bp.com (accessed January 28, 2008)
Brodosplit 2008	Brodosplit. Brodosplit Products. 2008. http://www.brodosplit.hr/Portals/44/Brodosplit%20separati.pdf (accessed August 2008).
CAPP 2004	Canadian Association of Petroleum Producers. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen*

	Sulphide (H_2S) Emissions by the Upstream Oil and Gas Industry: Volume 1, Overview of the GHG Emissions Inventory. September 2004. http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=86220
CARB 2000	California Air Resource Board's (CARB). *FACT SHEET #1: Development of Organic Emission Estimates For California's Emission Inventory and Air Quality Models*. August 2000.
CARB 2007	California Air Resources Board. *The California Low-Emission Vehicle Regulations*. Sacramento, California. 2007
CEH 2004	SRI Consulting, Chemical Economics Handbook Marketing Report for Hydrogen, 2004.
Chevron 2007	Chevron. *Diesel Fuels Technical Review*. 2007. http://www.chevron.com/products/ourfuels/prodserv/fuels/documents/Diesel_Fuel_Tech_Review.pdf
CHG 2008	China Hongyang Group. 2008. Explosion Proof Motor Product ID:U701-A. Wenzhou City, China.
ConEdison 2007	ConEdison. *Steam: Cleaner and Greener*. 2007. http://www.coned.com/steam/pdf/SteamEnvironmentalBrochure.pdf
Delucchi 2003	Delucchi, M.D. *A Lifecycle Emission Model(LEM): Lifecycle Emissions from Transportation Fuels, Motor Vehicles, Transportation Modes, Electricity Use, Heating and Cooking Fuels, and Materials*. Research Report UCD-ITS-RR-03-17. Institute of Transportation Studies, University of California, Davis. Davis, CA. December 2003 . www.its.ucdavis.edu/publications/2003/UCD-ITS-RR-03-17-MAIN.pdf
DESC 2005	Defense Energy Support Center. Petroleum Quality Information System (PQIS). 2005. http://www.desc.dla.mil/DCM/DCMPage.asp?pageid=99
Eble 2005	Eble, Cortland; Drahovzal, James; Morse, David; Demir, Ilham; Rupp, John; Mastralerz, Maria; Solano, Wilfrido. Resource Assessment & Production Testing for Coal Bed Methane in the Illinois Basin (Final Report). U.S. DOE Award Number DE-FC26-03NT41876. November, 2005. Accessed 6/5/2008 at: http://www.osti.gov/energycitations/servlets/purl/875823-50fXUq/875823.PDF
EIA 1999	U.S. Department of Energy, Energy Information Agency. *Petroleum: An Energy Profile, 1999.* DOE/EIA-0545(99), p. 26, 1999. http://tonto.eia.doe.gov/FTPROOT/petroleum/054599.pdf
EIA 2006	U.S. Department of Energy, Energy Information Agency. *Energy-Related Carbon Dioxide Emissions in U.S. Manufacturing*, DOE/EIA-0573(2005), November 2006.
EIA 2007	U.S. Department of Energy, Energy Information Agency. *Voluntary Reporting of Greenhouse Gases Program (Technical Assistance): Fuel Emission Factors,* 2007. http://www.eia.doe.gov/oiaf/1605/techassist.html

EIA 2008 U.S. Department of Energy, Energy Information Agency. *Petroleum Navigator*. Web-based, Database Tool. www.eia.gov. (accessed December 2007 thru January 2008)

ELCD 2008 European Commission - DG Joint Research Centre Institute for Environment and Sustainability. "European Reference Life Cycle Data System" (ELCD), v. 1.0.1. 2008. http://lca.jrc.ec.europa.eu/lcainfohub/datasetArea.vm

Energetics 2007 Energetics. *Energy and Environmental Profile of the U.S. Petroleum Refining Industry*, November, 2007.

Eni 2006 Eni. “Eni Fact Book 2005.” 2006. http://www.eni-irl.com/downloads/Fact%20Book%202005.pdf

EnvCan 2008 Environment Canada. Facility GHG Reporting. http://www.ec.gc.ca/pdb/ghg/onlineData/dataSearch_e.cfm (accessed August 2008)

EPA 1995 U.S. Environmental Protection Agency. AP 42, Fifth Edition, Volume I Chapter 5: Petroleum Industry, 1995.

EPA 1996 U.S. Environmental Protection Agency. *Methane Emissions from the U.S. Petroleum Industry (Draft)*. Prepared by Radian. June 1996.

EPA 1999 U.S. Environmental Protection Agency. *Estimates of Methane Emissions from the U.S. Oil Industry (Draft Report)*. EPA, Office of Air and Radiation, Prepared by ICF International. October 1999.

EPA 2006 U.S. Environmental Protection Agency. *Greenhouse Gas Emissions from the U.S. Transportation Sector, 1990-2003*. Office of Transportation and Air Quality (OTAQ). Washington, D.C. March 2006. www.epa.gov/otaq/climate/420r06003.pdf

EPA 2007a U.S. Environmental Protection Agency. Emissions & Generation Resource Integrated Database (eGRID). Updated (April 30, 2007): eGRID2006 Version 2.1. http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html

EPA 2007b U.S. Environmental Protection Agency. *Calculating CO_2 Emissions*. Office of Transportation and Air Quality (OTAQ) web-page. www.epa.gov/otaq/climate/420f05001.htm (accessed August 14, 2007)

EPA 2007c U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2005*. Washington, D.C. April 2007.

EPA 2008 U.S. Environmental Protection Agency; 2005 National Average Vehicle Emissions Profile for Gasoline and Diesel Powered On-road Vehicle Emissions; Developed by U.S. EPA, Office of Transportation and Air Quality for NETL Request for Data from MOVES model; Email transmittal dated November 6, 2008 from Ari Kahan, EPA/OTAQ to Timothy J. Skone, DOE/NETL.

EUCAR 2007 EUCAR (the European Council for Automotive R&D), CONCAWE (the oil companies’ European association for environment, health and safety in refining and distribution) and JRC/IES. “Well-to-Wheels analysis of future

	automotive fuels and powertrains in the European context: WELL-TO-TANK Report" 2007. http://ies.jrc.ec.europa.eu/our-activities/support-to-eu-policies/well-to-wheels-analysis/WTW.html (accessed September 2008)
FAA 1997	U.S. Federal Aviation Administration. Air Quality Procedures For Civilian Airports & Air Force Bases. April 1997. http://www.faa.gov/regulations%5Fpolicies/policy%5Fguidance/envir%5Fpolicy/airquality%5Fhandbook/
Farrell 2007	Farrell, Alexander E, and Sperling, Daniel. *A Low-Carbon Fuel Standard for California, Part 1: Technical Analysis*. Institute of Transportation Studies, University of California, Davis. Research Report UCD-ITS-RR-07-07. Davis, CA. May 2007. http://pubs.its.ucdavis.edu/publication_detail.php?id=1082
FW 2001	Foster Wheeler, *Hydrogen Plants for the New Millenium,* Middle East PETROTECH 2001 Conference and Exhibition, 29-31 October 2001. http://www.fwc.com/publications/tech_papers/files/WARD1109.pdf (accessed March 7, 2008)
GaBi 4 2007	*GaBi 4.0 Life Cycle Assessment Software – Professional Database*. PE International GmbH. Germany. [extracted from Gabi 4 software and data base for Life Cycle Engineering] 2007
Gary 2007	Gary, James; Handwerk, Glenn; Kaiser, Mark. Petroleum Refining Technology and Economics. 5th Edition. CRC Press, 2007.
GM 2001	General Motors Corporation (GM), et. al. *Volume 3, Well-to-Tank Energy Use and Greenhouse Gas Emissions of Transportation Fuels - North American Analysis* -. Detroit, MI. June 2001. www.transportation.anl.gov/pdfs/TA/165.pdf
GTI 2002	GTI E&P Services. Coalbed Methane Alert: Providing the E&P community with the latest information, data and resources for the coalbed methane industry. Feature: Central Appalachian Basin No. 11, May/June 2002. Accessed 6/4/2008 at: http://www.ticora.com/cbmalerts/CBM%20ALERT%20JUNE%202002.pdf
HP 2006	Hydrocarbon Processing®, Refining Processes 2006 www.hydrocarbonprocessing.com ©2006, Gulf Publishing Company
HPP 2006	Jones, David and Pujadó, Peter (ed.). Handbook of Petroleum Processing. Springer, 2006, pp. 217-238.
HT 2008	Haldor Topsøe brochure. Accessed on 3/5/2008 at: http://www.topsoe.com/site.nsf/vALLWEBDOCID/KVOO-5PGFBN/$file/Hydrogen-UK_HTCR.pdf
IEA 2008	International Energy Agency (IEA) Statistics: Oil. 2008. http://www.iea.org/Textbase/stats/prodresult.asp?PRODUCT=Oil
IHI 2008a	IHI Marine United. 280,000 MTDW Double Hull VLCC Formosapetro Discovery. 2008. http://www.ihi.co.jp/ihimu/images/seihin/pl03-1.pdf

IHI 2008b	IHI Marine United. 300,000 MTDW Double Hull VLCC Sky Wing. 2008. http://www.ihi.co.jp/ihimu/images/seihin/pl04_1.pdf
IHI 2008c	IHI Marine United. 300,500 MTDW Double Hull VLCC. 2008. http://www.ihi.co.jp/ihimu/images/seihin/pl05_1.pdf
Imperial Oil 2006	Imperial Oil Ltd. Securities and Exchange Commission (SEC) Filing 8-K, 2006.
IPCC 1996	Intergovernmental Panel on Climate Change. *Climate Change 1995: The Science of Climate Change. Contribution of Working Group I to the Second Assessment Report of the Intergovernmental Panel on Climate Change* [Houghton, J.T.,Meira Filho, Callander, B.A., Harris, H., Kattenberg, A., and Maskell, K. (eds)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA
IPCC 2001	Intergovernmental Panel on Climate Change. *Climate Change 2001: The Scientific Basis. Contribution of Working Group I to the Third Assessment Report of the Intergovernmental Panel on Climate Change* [Houghton, J.T.,Y. Ding, D.J. Griggs, M. Noguer, P.J. van der Linden, X. Dai, K. Maskell, and C.A. Johnson (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 881pp.
IPCC 2007	Forster, P., V. Ramaswamy, P. Artaxo, T. Berntsen, R. Betts, D.W. Fahey, J. Haywood, J. Lean, D.C. Lowe, G. Myhre, J. Nganga, R. Prinn, G. Raga, M. Schulz and R. Van Dorland, 2007: Changes in Atmospheric Constituents and in Radiative Forcing. *In: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M.Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, Table 2.14.
IPIECA 2003	International Petroleum Industry Environmental Conservation Association (IPIECA), American Petroleum Institute (API), International Association of Oil and Gas Producers (OGP), and Battelle. *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions.* December 2003. http://www.ipieca.org/activities/climate_change/downloads/publications/ghg_guidelines.pdf
ISO 2006	International Standards Organization. *ISO 14040:2006 Environmental Management – Life Cycle Assessment – Principals and Framework*. Revises ISO 14040:1997. Developed by TC 207 Environmental Management. Geneva, Switzerland. June 30, 2006.
Jechura 2008	Jechura, John. *Hydrocracking & Hydrotreating*, 2008. http://home.comcast.net/~jjechura/CHEN409/
Lee 2007	Lee, John. Course Notes: Petroleum Engineering 689. Special Topics in Unconventional Resource Reserves Lecture 1A. Texas A&M University - Spring 2007. Accessed 6/4/2008 at:

http://www.pe.tamu.edu/DL_Program/Sample_Courses/689-Lee/PowerPoint/689_Lecture_1A.pdf

Lewis 1997 Lewis, C. A. Fuel and Energy Production Emission Factors. MEET Project: Methodologies for Estimating Air Pollutant Emissions from Transport, 1997.

Maples 1993 Maples, Robert. Petroleum Refinery Process Economics. PennWell Books, 1993.

McCann 1999 McCann, T., and Magee, P. 1999. Crude Oil Greenhouse Gas Life Cycle Analysis Helps Assign Values for CO_2 Emissions Trading. Oil & Gas Journal. February 1999. Vol. 97. Iss. 8. pp. 38-43.

Meyers 2004 Meyers, Robert A. Handbook of Petroleum Refining Processes; Third Edition Copyright © 2004, The McGraw-Hill Companies, Inc. ISBN 0-07-139109-6

NEB 1999 Canadian National Energy Board (NEB), *Canadian Energy - Supply and Demand to 2025*, Appendix 10, 1999. http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/spplydmnd/spplynddmndt20251999/spplydmndppndc1999-eng.pdf

NEB 2006 Canadian National Energy Board (NEB), Canada's Oil Sands Opportunities and Challenges to 2015: An Update, An Energy Market Assessment, June 2006. http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/lsnd/pprtntsndchllngs20152006/pprtntsndchllngs20152006-eng.pdf

Nguyen 1999 Nguyen, M. *Source Inventory Category #67-74 Filling Stations – Storage Tanks*. California Air Resources Board. Sacramento, California. 1999. www.arb.ca.gov/ei/areasrc/districtmeth/BayArea/C67.pdf (accessed August 1, 2007)

NREL 2001 Spath, Pamela and Mann, Margaret. *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming.* NREL/TP-570-27637, 2001.

O&GJ 2005 Stell, Jeannie (ed.) Oil & Gas Journal. 2005 Worldwide Refining Survey, Vol. 103, No. 47. December 19, 2005.

Oregon DEQ 2004 Oregon DEQ. U.S. EPA. *"Life Cycle Inventory of Packaging Options for Shipment of Retail Mail-Order Soft Goods: Appendix A - Energy Requirements and Environmental Emissions for Fuel Consumption"* report prepared by Franklin Associates, Inc. 2004.

ORNL 2007 Oak Ridge National Laboratory (ORNL). Transportation Energy Data Book: Edition 26. ORNL-6978, 2007. http://cta.ornl.gov/data/download26.shtml (accessed June 10, 2008).

Parkash 2003 Parkash, Surinder. Refining Processes Handbook. Elsevier, 2003.

SCAQMD 2008 South Coast Air Quality Management District. "Flares: Emission Data and Minimization Plans." South Coast Air Quality Management District. http://www.aqmd.gov/comply/1118/emissiondata.htm (accessed June 1, 2008)

Sheehan 1998	Sheehan, J., et. al. *Life Cycle Inventory of Biodiesel and Petroleum Diesel for Use in an Urban Bus: Final Report*. NREL/SR-580-24089 UC Category 1503. U.S. Department of Energy, National Renewable Energy Laboratory. Golden, CO. May 1998. www.nrel.gov/docs/legosti/fy98/24089.pdf
StatCan 2008	Statistics Canada. The Supply and Disposition of Refined Petroleum Products in Canada. Catalogue no. 45-004-X. 2008. http://www.statcan.ca/bsolc/english/bsolc?catno=45-004-X
Syncrude 2006	Syncrude Canada Ltd. 2005 Sustainability Report. http://sustainability.syncrude.ca/sustainability2005/environment_health_safety/air_quality.shtml
Tedesco 2004	Tedesco, Steven. Coalbed Methane Potential and Activity of the Western Interior Basin. API Search and Discovery Article #10059 (2004). Published by: AAPG/Datapages, Inc., 1444 South Boulder, Tulsa, OK, 74119, USA. Accessed 6/4/2008 at: http://www.searchanddiscovery.net/documents/2004/tedesco02/images/tedesco2.pdf
UOP 2003	UOP, *Platforming Technology Advances: CycleX System for Increased Hydrogen Production from a Fixed-Bed Reforming Unit*, http://www.uop.com/objects/UOP%20CycleX%20AM-03-93.pdf (accessed March 7, 2008)
USDOC 2004	U.S. Department of Commerce (DOC). *Bituminous Coal Underground Mining: 2002*. EC02-211-212112(RV), December 2004.
VesselTrax 2007	VesselTrax web-site. http://vesseltrax.com/crude_oil_imports.html (accessed January 28, 2008)
Wang 2004	Wang, Michael, Lee, Hanjie, and Molburg, John. Allocation of Energy Use in Petroleum Refineries to Petroleum Products: Implication for Life-Cycle Energy Use and Emission Inventory of Petroleum Transportation Fuels. International Journal of LCA, 9 (1) 34-44. 2004.
Wang 2008	Wang, M. *Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. DOE, Argonne National Laboratory. Ann Arbor, Michigan. 2008. www.transportation.anl.gov/software/GREET
Wild, et.al. 2001	Wild, O., M.J. Prather, and H. Akimoto. Indirect long-term global radiative cooling from NOx emissions. *Geophys. Res. Lett.*, **28**(9), 1719–1722. 2001.

This page intentionally left blank.

Appendix A

Overview of Domestically-Produced and Imported Finished Transportation Fuels

Table A-1 shows the U.S. production, exports and imports of finished motor gasoline and motor gasoline blending components, finished conventional diesel (<500 ppm sulfur), and finished kerosene-type jet fuel for the year 2005. The resulting weighting factors in Table A-2 are used in combination with the modeling of domestically-produced and imported finished fuels described in Sections 2.0 to 5.0 to develop a composite profile for the transportation fuels being consumed in the U.S. in 2005.

Table A-1. U.S. Production, Exports and Imports of Transportation Fuels for 2005 (EIA 2008)

Petroleum Product	Production in U.S. Refineries	Imported to U.S.	Exported from U.S.	Estimated Consumption
	Barrels per Day			
Conventional Gasoline*	7,794,233	1,106,712	199,449	8,701,496
Conventional Diesel**	2,932,578	157,164	39,299	3,050,444
Kerosene-Type Jet Fuel	1,545,825	190,049	52,611	1,683,263

* Gasoline includes: motor gas, conventional, other; motor gas, conventional—blended with alcohol; motor gas, reformulated—blended with ether; and motor gas blending components (RBOB, CBOB, GTAB, and all other)

** Includes distillate with 500 ppm or less sulfur

Table A-2. Weighting Factors for U.S. Refined and Imported Transportation Fuels

Petroleum Product	U.S. Refined Weighting Factor	Imports Weighting Factor
Conventional Gasoline	87.3%	12.7%
Conventional Diesel	94.8%	5.2%
Kerosene-Type Jet Fuel	88.7%	11.3%

The exporting countries and volumes of transportation fuels imported by the U.S. as reported by EIA for the year 2005 are shown in Table A-3 thru Table A-5. Imports reported by EIA destined for Puerto Rico and the Virgin Islands are excluded.

Table A-3. Imports of Finished Motor Gasoline and Motor Gasoline Blending Components to the U.S. in 2005 (EIA 2008)

Exporting Country	Volume Imported (Mbbl)
Algeria	899
Angola	147
Argentina	8,796
Aruba	326
Australia	40
Bahamas, The	529
Belgium	10,790
Brazil	1,668
Bulgaria	541
Canada	63,669
Chile	2,877
China, Peoples Rep	831
Colombia	538
Congo (Brazzaville)	127
Denmark	854
Ecuador	985
Egypt	2,410
Estonia	9,363
Finland	5,242
France	14,316
Gabon	24
Georgia	100
Germany	10,279
Ghana	540
India	3,875
Indonesia	108
Ireland	1,031
Italy	12,514
Japan	906
Korea, South	1,788
Kuwait	50
Latvia	6,863
Lithuania	6,952
Malaysia	618
Martinique	255
Mexico	588
Netherlands	42,316
Netherlands Antilles	2,060

Exporting Country	Volume Imported (Mbbl)
Nigeria	5,609
Norway	5,372
Peru	1,171
Poland	32
Portugal	3,392
Qatar	40
Romania	1,057
Russia	24,913
Saudi Arabia	6,738
Singapore	863
Spain	8,893
Sweden	5,162
Taiwan	1,402
Thailand	69
Trinidad & Tobago	3,283
Turkey	4,228
Turkmenistan	198
United Kingdom	41,653
Uruguay	1,165
Venezuela	30,567
Virgin Islands, U.S.	42,328
Total Imports	**403,950**

Table A-4. Imports of Finished Conventional Diesel Fuel (<500 ppm Sulfur) to the U.S. in 2005 (EIA 2008)

Exporting Country	Volume Imported (Mbbl)
Algeria	299
Aruba	4,646
Belgium	473
Canada	21,429
Denmark	757
Estonia	433
France	142
Germany	279
Indonesia	682
Japan	631
Kazakhstan	206
Korea, South	1,658
Kuwait	231
Latvia	639
Lithuania	135
Netherlands	3,022
Netherlands Antilles	116
Norway	260
Philippines	40
Russia	36
Singapore	746
Sweden	437
Taiwan	529
United Kingdom	297
Venezuela	1,363
Virgin Islands, U.S.	17,879
Total Imports	**56,581**

Table A-5. Imports of Kerosene-Type Jet Fuel to the U.S. in 2005 (EIA 2008)

Exporting Country	Volume Imported (Mbbl)
Algeria	532
Argentina	179
Aruba	2,971
Belgium	287
Canada	4,164
China, Peoples Rep	103
Colombia	431
France	850
India	1,546
Iraq	716
Japan	1,221
Korea, South	15,199
Kuwait	2,618
Malaysia	200
Mexico	1,890
Netherlands	573
Netherlands Antilles	164
Qatar	25
Russia	325
Saudi Arabia	2,947
Singapore	4,652
Taiwan	4,271
Trinidad & Tobago	920
United Kingdom	105
Venezuela	10,894
Virgin Islands, U.S.	11,585
Total Imports	**69,368**

This page intentionally left blank.

Appendix B

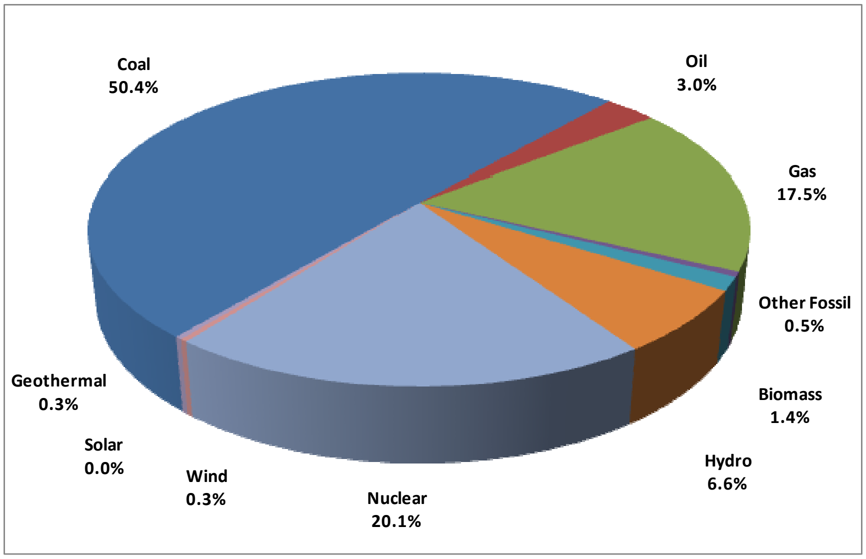
Cradle-to-Gate GHG Emissions Inventory for Electric Power from the U.S. (Average) Grid Mix

Certain emissions from electricity generating facilities are tracked by EPA (EPA 2007a) and are publically available in the Emissions & Generation Resource Integrated Database (eGRID). While this database includes comprehensive coverage of CO_2 emissions from these generating facilities, it does not address other GHG constituents such as N_2O and CH_4 in its inventory.[8]

The emissions data within e-GRID only includes that attributable to operations and does not represent construction or upstream emissions. Therefore, GaBi 4 modeling data were modified to generate a profile more inclusive of upstream and construction emissions not represented within eGRID.

A U.S. electric grid mix was generated where the individual electricity source profiles (solar, wind, hydro, etc.) were aggregated into a mix consistent with the 2004 U.S. electricity source mix. Figure B-1 shows the source mix as a percentage of total U.S. electricity generation.

Figure B-1. Year 2004 Electricity Sources for the Average U.S. Grid Mix



A representation of the GaBi 4 process plan for the U.S. electricity mix is shown in Figure B-2. The process plan incorporates power inputs derived from the electricity generation mix discussed previously and includes 98.2 percent of the total U.S. energy mix. Inputs are expressed in Mega-Joules (MJ) and are net calorific values. The process plan assumes: 1) U.S. "coal generation" is

---

[8] U.S. EPA released eGRID2007 Version 1.0 in September 2008 following the completion of this analysis. eGRID2007 Version 1.0 contains CO_2, CH_4, and N_2O emissions for 2005. The impact was analyzed and determined to have negligible effect on the total life cycle GWP results of this study.

allocated 100 percent to hard coal. 2) U.S. “other fossil generation” (tires, chemicals, batteries, etc.) and “unknown/purchased generation” are allocated 100 percent to lignite (surrogate profile) and 3) No cradle to gate profile is currently available for “biomass/wood generation”, “solar generation”, and “geothermal generation.” The resulting GHG profile generated for the U.S. grid mix is shown in Table B-1.

Figure B-2. 2004 U.S. Electric Grid Power Mix

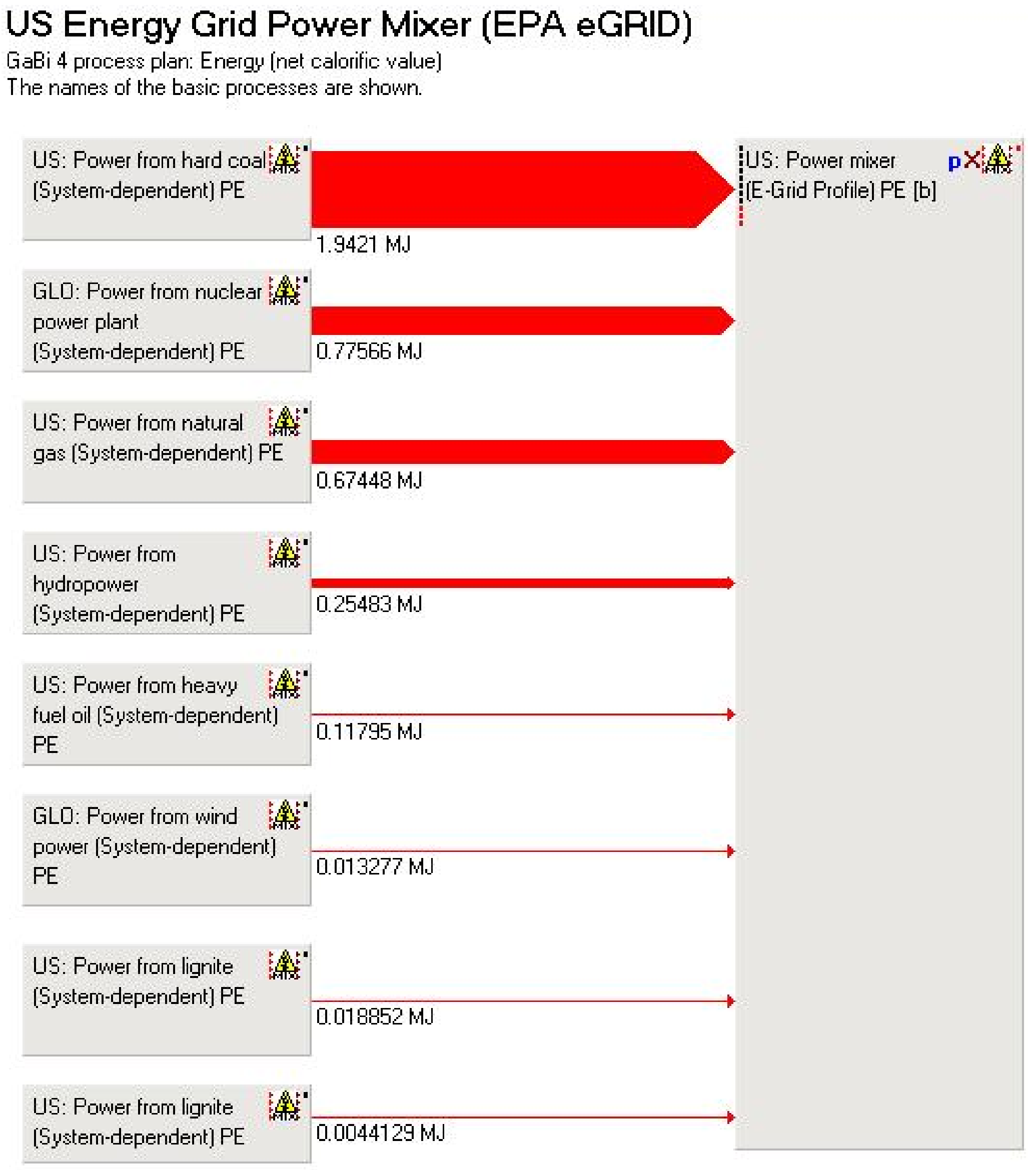


Table B-1. Greenhouse Gas Emissions from 2004 U.S. Electricity Grid Mix

Source	CO_2 Emissions (kg/kWh)	CH_4 Emissions (kg/kWh)	N_2O Emissions (kg/kWh)
2004 U.S. Average Electricity Grid Mix	0.739	8.58E-04	9.59E-06

Appendix C

Cradle-to-Gate GHG Emissions Profile for Fuels Produced in Domestic Refineries

The cradle-to-gate environmental profile (LC Stages #1-3) for production of refinery products is also the upstream emissions profile for the petroleum products that are input to the refinery as a fuel. However, the upstream emissions profile for fuels produced and consumed in the refinery are also part of the LC Stage #3 profile requiring an iterative solution to determine this profile.

Table C-1 shows the volume consumed and the product category for each refinery-produced fuel.

Table C-1. Product Categories Corresponding to Refinery Produced Fuels

Refinery Fuel	2005 Fuel Consumption by U.S. Refineries (bpd)	Product Category for Refinery Fuel
LPG	11,438	Light Ends
Distillate	2,068	Diesel
Residual Fuel Oil	6,047	Residual Fuel Oil
Still Gas	652,701	Light Ends
Petroleum Coke	245,622	Coke
Other Products	14,600	Average of All

Table C-2 shows the preliminary cradle-to-gate profile (LC Stage #1-3) excluding the upstream profile for refinery-produced fuels. This profile is on a per-barrel-refined basis does not include loss factors associated with product transport, but does include losses associated with feedstock transport.

Table C-2. “Cradle-to-Gate” GHG Emissions Profile for Domestic Refineries Excluding Upstream Profile for Refinery-Produced Fuels

Emissions	Units	Gasoline	Diesel	Kerosene & Kerosene-type Jet Fuel	Residual Fuel Oil	Coke	Light Ends	Heavy Ends
CO_2	kg CO_2/day	581,279,653	312,441,600	96,975,964	40,730,261	59,063,564	98,471,258	70,376,749
	kg CO_2/bbl refined	74.4	79.0	60.2	64.9	70.7	58.5	93.4
CH_4	kg CH_4/day	3,958,551	2,023,864	803,809	314,617	418,700	834,008	388,544
	kg CH_4/bbl refined	0.51	0.51	0.50	0.50	0.50	0.50	0.52
N_2O	kg N_2O/day	11,612	6,020	2,001	831	1,227	2,107	1,381
	kg N_2O/bbl refined	0.00149	0.00152	0.00124	0.00132	0.00147	0.00125	0.00183

For example, as a starting point, the upstream profile for still gas is 58.5 kg CO_2 per barrel (corresponding to light ends). The result of multiplying this factor by the consumption of still gas at the refinery is 38 million kg CO_2 per day and the cradle-to-gate emissions profile should be increased by this amount. An iterative solution to calculate the total cradle-to-gate refinery profile follows. The resulting profile for each of the fuels is shown in Table C-3. The emissions associated with production of these species are divvied up to the product slate according to each product category’s energy consumption.

Table C-3. GHG Emissions Profile Consistent with Acquisition of Refinery-Produced Fuels

Fuel	CO_2 (kg/day)	CH_4 (kg/day)	N_2O (kg/day)
LPG	696,439	5,886	15
Distillate	171,312	1,122	3
Residual Fuel Oil	409,065	3,165	8
Still Gas	39,740,582	335,879	850
Petroleum Coke	18,267,585	130,326	380
Other Products	1,095,456	7,768	22
Total	**60,380,439**	**484,146**	**1,278**

Appendix D

Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions

The Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions (IPIECA et al. 2003) outlines various tiers for GHG emissions estimation using data with different levels of detailed information—and hence different levels of precision in the final GHG estimate. Table D-1 shows the different estimation tiers and summarizes the associated emission estimation methodologies. Methodologies outlined in the table refer to detailed calculation procedures presented in the American Petroleum Institute's (API) 2004 Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry (API 2004).

Table D-1. GHG Estimation Tiers and Associated Estimate of Uncertainty (IPIECA et al. 2003)

		Estimation Tiers		
		Tier C	Tier B	Tier A
		+/- 15-30% Uncertainty	< 15% Uncertainty	+/- 5-10% Uncertainty
Source	GHG	Estimation Approach		
Combustion Sources	CO_2	Thermal input (fuel burnt) estimated based on design rating of plant and hours operated, default fuel factors Thermal input (fuel input) based on metering or energy balances on heaters/boilers, fuel composition obtained from occasional spot sampling		Thermal input (fuel input) based on metering or energy balances on heaters/boilers, fuel composition obtained from frequent spot sampling
	CH_4	Not considered	Not considered	Not considered
FCC Coke Burn	CO_2	Thermal input (fuel burnt) estimated based on design rating of plant and hours operated, default coke factor	Coke burn rate calculated based on process mass/energy balance and average coke composition based on spot samples -OR- estimated directly from measured CO and CO_2 concentrations in exhaust (spot samples) and air/oxygen flow rate to regenerator	Coke burn rate calculated based on process mass/energy balance and average coke composition based on spot samples -OR- estimated directly from measured CO and CO_2 concentrations in exhaust (spot samples) and air/oxygen flow rate to regenerator
	CH_4	Not considered	Not considered	Not considered
Flaring	CO_2	Engineering estimates of gas flared i.e., using API flame length correlation and default factor for refinery gas	Process engineering estimates of flared volume based on known purge rates, process unit flows to flare and estimates of non-routine flaring based on plant logs. Weighted average flare gas composition based on estimated composition.	Flared volume estimated from flare gas meters where available, known purge rates and best process engineering estimates, average flare gas composition based on spot samples throughout the year adjusted if significant non-routine flaring.
	CH_4	Not considered	Not considered	Not considered
Hydrogen Plant (process)	CO_2	Process mass balance based on estimated hydrogen production	API Compendium "simple" method based on estimated hydrogen make	API Compendium "complex" method i.e. process mass balance based on known reformer feed rate and composition
	CH_4	Not considered	Not considered	Not considered (spot check on methane content of CO_2 vent stream)
Other Process Sources	CO_2	Not considered	Process mass balance as in API Compendium using activity data based on best engineering estimates	Process mass balance as in API Compendium using activity data based on best engineering estimates
	CH_4	Not considered	Not considered	Not considered
Process Fugitives	CO_2	Not considered	Not considered	Not considered
	CH_4	Not considered	Not considered	Not considered

Appendix E

Nitrous Oxide Emission Factors

Table E-1 lists N_2O emission factors for the various combustion operations encountered in refinery operations. The emission factors were compiled from various sources and reported in the American Petroleum Institute (API) *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry* (API 2004). These factors are both a function of the petroleum species being combusted and the equipment utilized for combustion.

Table E-1. N_2O Emission Factors for Various Combustion Operations Encountered in Refinery Operations (API 2004)

Emission Source	N_2O Emission Factor	
	Original Units	Converted Units
Residual Oil-fired Boilers and Heaters	0.53 lb/1000 gal	2.4×10^{-7} tonne/gal
Distillate Oil-fired Boilers and Heaters	0.26 lb/1000 gal	1.2×10^{-7} tonne/gal
Natural Gas-fired Boilers and Heaters		
Controlled	0.64 lb/10^6 scf	2.8×10^{-7} tonne/10^6 Btu (HHV)
Uncontrolled	2.2 lb/10^6 scf	9.8×10^{-7} tonne/10^6 Btu (HHV)
Natural Gas Combustion Turbines		
Controlled (SCR)	0.03 lb/10^6 Btu	1.4×10^{-5} tonne/10^6 Btu (HHV)
Uncontrolled	0.003 lb/10^6 Btu	1.4×10^{-6} tonne/10^6 Btu (HHV)
Stationary Gas-fired IC Engines (without catalyst controls)		
4-stroke rich burn	0.001 lb/10^6 Btu (HHV)	4.5×10^{-7} tonne/10^6 Btu (HHV)
4-stroke lean burn	0.003 lb/10^6 Btu (HHV)	1.4×10^{-6} tonne/10^6 Btu (HHV)
2-stroke	0.005 lb/10^6 Btu (HHV)	2.3×10^{-6} tonne/10^6 Btu (HHV)
Gasoline IC Engines	0.031 g/L (distillate)	1.17×10^{-7} tonne/gal
Diesel IC Engines	0.4 g/L	1.51×10^{-6} tonne/gal 1.1×10^{-5} tonne/10^6 Btu (HHV)
Large Bore Diesel Engine (> 600 hp)	0.08 g/L	3.03×10^{-7} tonne/gal 2.2×10^{-6} tonne/10^6 Btu (HHV)

This page intentionally left blank.

Appendix F

Overview of Allocation Procedures for Petroleum Refining Operations

Allocation of refinery emissions to the various species in the refinery product slate is a controversial part of the petroleum refining LCA process. It is commonly accepted that gasoline production is a more energy-intensive process than diesel production due to the additional processing steps required to develop optimal gasoline and boutique blends. For example, while all refinery products pass through the atmospheric distillation column, the catalytic reformer, alkylation unit and isomerization unit predominantly process gasoline precursors.

Several allocation methodologies have evolved over time with different allocation mechanisms of varying complexity. These allocation methodologies are most broadly broken into economic-based and process-based allocations.

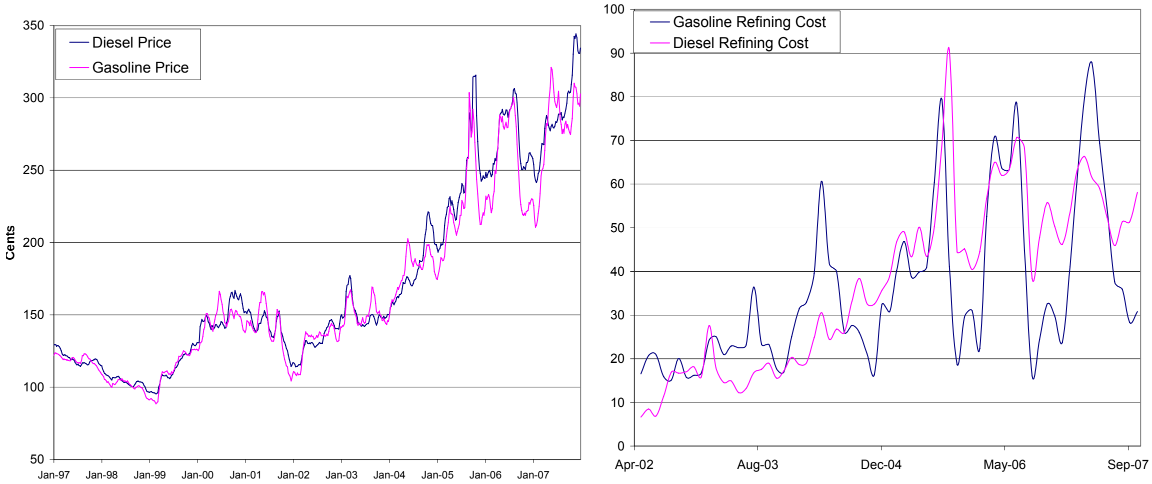
Economic-based Allocations

Economic-based allocation techniques assert that emissions from production are allocated to individual products based on product cost (market value). This mechanism assumes capital cost of related process equipment and operating cost (including utilities) are represented in the product selling price for the various cuts of the product slate and thus emissions should be ratioed accordingly. Complex linear programming techniques have been developed to allocate CO_2 emissions to the various products at an oil refinery using economic factors (Babusiaux 2007).

There are many inherent problems that arise when considering product pricing to allocate process emissions. First, product pricing is often more a factor of market conditions than actual production cost. The most obvious example of this phenomenon is demonstrated quite remarkably in the petroleum refining business. While gasoline production is more capital and energy intensive than diesel production (excluding hydrogen considerations), domestic diesel selling price has been steadily climbing in the past 10 years and is often higher than gasoline, as shown in Figure F-1a. When detailed gasoline and diesel pricing data presented by the EIA are analyzed (EIA 2008), it can be concluded that refining “costs” for diesel have increased to surpass that of gasoline. Figure F-1b shows EIA’s determination of the “refining” contribution to gasoline and diesel prices. Each of these analyses show that while it is generally acknowledged that refining diesel requires less process equipment and utilities, the impact of market-driven aspects on the “cost” of producing diesel and gasoline result in it is being sold at a higher price than gasoline (thus a higher profit margin).

As a result, emissions allocations based on refinery selling prices (without adequate adjustment to account for varying profit margins) will result in higher emissions being allocated to diesel fuels than to gasoline during certain economic cycles.

Figure F-1. Gasoline and Diesel Price (a) and Associated Refining Costs (b) (EIA 2008)



Process-based Allocations:

There are many different methodologies for performing process-based allocations. The simplest method is to ratio emissions with product output on a mass, energy, or volumetric basis. This technique, however, does not take into account the fact that many product streams do not pass through certain process units. Thus products that require extensive processing are allocated the same level of emissions as streams which require very little processing. Attempts to divide refinery level emissions into process unit and associated emissions are extremely difficult to do and detailed process information is not readily available.

It has been suggested by Argonne National Laboratory (ANL) researchers that a simplified approach be used where each individual unit process energy use (energy from incoming streams and energy provided directly to the process) be divided among the products of the unit operation on the basis of mass, energy content, or market value (Wang 2004). However, such approaches consider only unit operation energy consumption and there is no accounting for hydrogen utilization.

The GREET model developed by ANL divides the total refinery energy consumption among constituents of the product slate according to industry "rule-of-thumb" suggesting that 60% of total refining fuel use is allocated to gasoline, 25% to diesel, and the remaining 15% to other petroleum products (Wang 2008).

Many researchers allocate emissions to products based on unit process operations and the associated utilities and emissions of that particular unit, without proper accounting of co-products. One example is the catalytic reforming of naphtha. All utility use has traditionally been allocated to gasoline and adequate accounting of hydrogen by-product disposition is not undertaken. Approximately one half of the total quantity of hydrogen utilized at a refinery is produced as a by-product of reformer operation (Aitani 1996). Discounting this contribution to diesel production (for hydrotreating) biases the results and burdens gasoline with a larger emissions profile and artificially lowers the diesel emissions profile. This phenomenon is more easily seen in Europe where increased demand for diesel (at the expense of gasoline) has resulted in catalytic reforming units operating at capacity, not to produce gasoline, but to produce needed hydrogen. Therefore, the additional energy use and associated emissions should no longer be assigned to gasoline (as would usually be the case) and must be allocated to the benefitting distillate fractions (Alireza 2007).

Hydrogen is used in refineries primarily for desulfurization and hydrocracking processes, with waste (impure) hydrogen being burned as a fuel. To meet current sulfur-level requirements for fuels, practically all finished diesel and gasoline products must be desulfurized during processing. Thus, the utilization of hydrogen must be appropriately allocated to the various product species and their precursors. For example, ten times more hydrogen may be needed to desulfurize diesel than is necessary to desulfurize naphtha fed to a catalytic reformer to produce gasoline (Parkash 2003).

The integrated and complex nature of modern refineries precludes simplistic determinations of energy/utility requirements for any particular unit operation. All allocation mechanisms will be controversial and no mechanism is correct. Thermal inefficiencies are not the same for all unit operations and thus some units will have lower efficiencies than others.

Study Allocation Technique

Allocation of energy (utilities) and hydrogen usage are estimated for the major unit operations undertaken for liquid fuels production at U.S. refineries using system expansion to the extent possible before allocating unit operation throughput to final liquid fuel fractions.

Petroleum products output from refineries have been broadly divided into seven different product categories: gasoline, diesel, kerosene and kerosene-type jet fuel, residual fuel oil, coke, “light ends,” and “heavy ends.” The light ends category is composed of still gas, liquefied refinery gases (LRG), special naphtha, and petrochemical feedstocks. The heavy ends category is composed of asphalt and road oil, lubricants, waxes, and miscellaneous.

The volumetric capacity of the individual unit operations has been assigned to the seven product fractions described above. The capacity is assigned to the final product fractions based upon the relative contribution of the throughput of that operation to the final product category. Rationale for each individual unit operation’s capacity assignments to product categories has been discussed.

Fuels-consumed emissions are assigned to the product fractions based upon the fractional energy usage required to produce these products. The GHG emissions consistent with fuels consumption (minus the quantity attributed to secondary, unrelated production activities) is then multiplied by the appropriate energy consumption fraction for each product category. Since it is not possible to accurately ascribe fuel types, combustion equipment and the resulting emissions to the various refinery operations, a composite energy usage/emissions profile was determined for all refining operations. The GHG emissions associated with the fuels consumed are allocated equivalently for each unit of energy consumed.

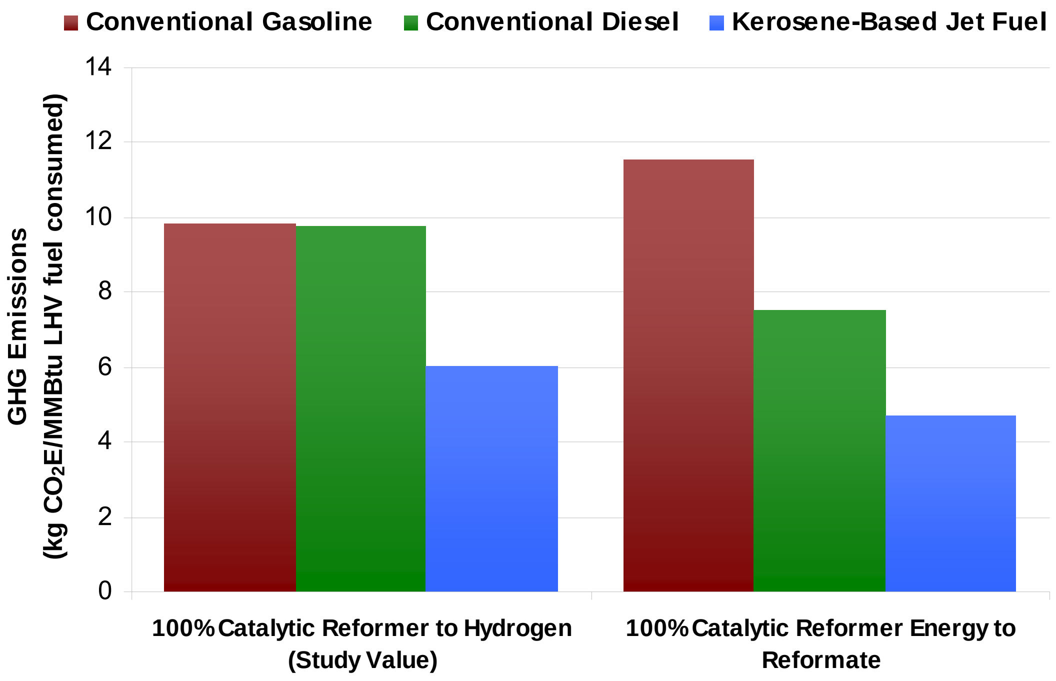
Refinery flaring and methane venting/fugitive emissions have been allocated to product fractions based upon the fraction of the total refinery energy usage required for production of each product category.

Hydrogen production emissions have been assigned to the product fractions according to each categories’ hydrogen consumption/production quantities. There is no differentiation between the sources of hydrogen with regard to pressure or purity.

Catalytic Reformer Allocation

Distribution of the energy associated with the catalytic reformer was discussed in detail in Section 4.2.5.2. System expansion was used to allocate the energy/resource usage to the hydrogen produced in the catalytic reformer using hydrogen production via SMR as the next best alternative. This results in all energy for operation of the catalytic reformer being allocated to the produced hydrogen (as opposed to the reformate). Figure F-2 shows the change in the LC Stage #3 profile for each fuel and emphasizes that this decision has a significant impact on the allocation of energy and the associated emissions between gasoline, diesel, and jet fuel. If all energy for reformer operation is allocated to the reformate (gasoline fraction), then the hydrogen is “free.” As a result, the gasoline GHG emissions are significantly higher while diesel and jet fuel GHG emissions are lower.

Figure F-2. Impact of Modeling Approach for Catalytic Reformer Allocation on LC Stage #3 GHG Emissions Profile



Appendix G

Cradle-to-Gate GHG Emissions Inventory for Hydrogen Production Via SMR with PSA Purification

Hydrogen plant energy requirements and natural gas consumption were derived from Boyce (2004) on the basis of 1 scf of H_2. It is assumed that hydrogen compression to elevated pressures is performed at the refinery and thus associated energy/emissions are included in the refinery energy/fuels consumed total. The hydrogen plant is modeled as a "modern" facility operating by steam methane reforming of natural gas with subsequent hydrogen purification by pressure swing absorption. Natural gas is assumed to have a higher heating value of 1020 Btu/ft^3 (API 2004). Average natural gas density is assumed to be 23.8 ft^3 per pound (API 2004). Hydrogen plant input and utilities are summarized below in Table G-1 (Boyce 2004) for 1 scf of produced hydrogen.

Table G-1. Hydrogen Plant Input/Utilities on the Basis of 1 scf H_2 Produced

NG Feed (kg)	NG Feed (Btu HHV)	NG Fuel (kg)	NG Fuel (Btu HHV)	Electricity (kWh)	HP Steam (lb) [Credit]	HP Steam (Btu) [Credit]
0.00658	352	0.00262	140	0.00052	0.09	106

For hydrogen plant operations occurring on site with U.S. petroleum refineries, it is necessary to calculate the refinery energy usage that is attributable to hydrogen production. When the natural gas feed requirements are excluded from the above data, the result is a net energy requirement of 35.6 Btu HHV per scf of hydrogen. For U.S. petroleum refineries it was estimated, as discussed in Section 4.2.9.2, that for the portion of electricity assumed to be produced at the petroleum refinery, electricity losses must be incorporated. This raises the refinery energy associated with on-site hydrogen plants to 36.5 Btu HHV per scf of hydrogen.

For both merchant and captive hydrogen production, process emissions of CO_2 from the separation/purification process must be determined. CO_2 is produced during the hydrogen production process, as shown in the following equation, and subsequently vented to the atmosphere during hydrogen purification. Thus, for every four moles of hydrogen produced, one mole of CO_2 is emitted.

$$C_xH_{(2x+2)} + 2_xH_2O \rightarrow (3x+1)H_2 + xCO_2$$

Combustion emissions associated with reformer furnace operation were estimated using API emission factors for a natural gas boiler/furnace/heater (API 2004). API emission factors are summarized in Table G-2 for natural gas combustion in a boiler/furnace/heater. The N_2O emissions from the boiler are modeled as uncontrolled since the energy requirements listed in Table G-1 do not include selective catalytic reduction (SCR).

Table G-2. API Emission Factors for Natural Gas Boiler/Furnace/Heater Operation (API 2004)

GHG Gas	API Emission Factor (tonne/MMBtu HHV)
CO_2	0.0531
CH_4	1.0E-06
N_2O	9.8E-07 (uncontrolled) 2.8E-07 (controlled)

Using the above information and upstream life cycle emissions presented in Section 3.0, the following emissions profile was generated for hydrogen production:

Table G-3. Hydrogen Production Emissions and Sources on the Basis of 1 scf H_2 Produced

(kg)	NG Upstream Profile	H_2 Process Emissions (CO_2)	H_2 Plant Fuel Combustion Emissions	Electricity Emissions	Steam Credit	Total
CO_2	3.64E-03	1.88E-02	7.43E-03	3.84E-04	-9.85E-03	**2.04E-02**
CH_4	4.33E-05	0	1.40E-07	4.46E-07	-1.41E-05	**2.98E-05**
N_2O	7.14E-08	0	1.37E-07	4.99E-09	-1.10E-07	**1.03E-07**

Appendix H

Crude Oil and Finished Product Loss Factors

While the volatilization of the liquid fuels does not contribute directly to life cycle GHG emissions, it contributes indirectly by necessitating that a larger overall quantity of fuel be produced to meet a specified need. Loss factors utilized throughout the LC stages are shown in Table H-1 and Table H-2. Loss factors are applied at the end of each activity and for all activities occurring prior to the loss. For example, losses for all product activities shown in Table H-2 are applied to determine the emissions associated with waterborne transport of imports per barrel of fuel consumed in a vehicle.

Table H-1. Feedstock Loss Factors

Feedstock	Transport
Crude Oil	0.285%

Table H-2. Finished Product Loss Factors

Petroleum Product	Waterborne Transport of Imports	Marine Vessel Loading of Imports	Domestic Transport	Bulk Storage	Filling Station	Refueling
Gasoline	0.0293%	0.0726%	0.0851%	0.116%	0.135%	0.0293%
Diesel	0.000071%	0.000071%	0.00019%	0.00025%	0.00025%	0.00041%
Kerosene-Type Jet Fuel	0.000076%	0.000128%	0.00094%	0.00129%	0.00129%	0.00210%

Loss Factor Development

Crude Oil Transport

Losses associated with crude oil transport include more than volatilization losses and, in the absence of better data, a total transport loss was assumed for crude oil transport. Crude oil transport is assumed to incur a 0.285% total loss consistent with a report value by an Eni (2006) for 2005. This loss factor is greater than the losses incurred from crude oil tanker transport, as discussed below.

Losses associated with crude oil transport via tanker to the U.S. can be estimated using EPA AP-42 emissions factors (Section 5.2 Transportation and Marketing of Petroleum Liquids) for tanker operations (EPA 1995). Table H-3 lists the emissions factors for crude oil tanker transport using this alternate method.

Table H-3. Total Organic Emission Factors for Petroleum Marine Vessel Sources*

Source	Units	Crude Oil	Reference
Loading Operations	lb/1000 gallon transferred	0.61	EPA AP-42, Table 5.2-6
Transit	lb/week-1000 gallon transported	1.3	EPA AP-42, Table 5.2-6

* Factors are for dispensed product

These loss factors translate into the percent loss factors shown in Table H-4. Since they are significantly less than the loss factor reported above, the larger value was used.

Table H-4. Crude Oil Tanker Transport Losses

Source	Units	Crude Oil
Loading Operations	% Loss	0.0084%
Transit	% Loss/week	0.0178%

Imported Products Waterborne Transport

Losses associated with imported product transport to the U.S. are estimated using EPA AP-42 emissions factors (Section 5.2 Transportation and Marketing of Petroleum Liquids) for tanker operations (EPA 1995). Table H-5 lists the emissions factors applied to petroleum product tanker transport.

Table H-5. Total Organic Emission Factors for Petroleum Marine Vessel Sources*

Source	Units	Gasoline	Diesel	Kerosene-based Jet Fuel	Reference
Loading Operations (Typical Overall Situation)	lb/1000 gallon transferred	1.8	0.005	0.005	EPA AP-42, Tables 5.2-2 and 5.2-6
Transit	lb/week-1000 gallon transported	2.7	0.005	0.005	EPA AP-42, Table 5.2-6

* Factors are for dispensed product

Domestic Transport and Bulk Storage

Development of evaporative emissions losses associated with domestic transport and during bulk storage is detailed in Table H-6.

Table H-6. Evaporative Emissions During Fuel Distribution (Lewis 1997)

Petroleum Product	Energy Content (MMBtu/ bbl)*	Mean Density (g/bbl)*	Transport Loss (g/GJ)	Transport Loss (bbl/bbl)	Transport (% Loss)	Bulk Terminal (g/GJ)	Bulk Terminal (bbl/bbl)	Bulk Terminal (% Loss)
Gasoline	5.253	117,233	18.0	8.51E-04	0.0851%	24.6	1.16E-03	0.116%
Diesel	5.825	134,048	0.0405	1.86E-06	0.0002%	0.0551	2.53E-06	0.0003%
Kerosene	5.670	126,103	0.199	9.44E-06	0.0009%	0.271	1.29E-05	0.0013%

* EPA 2007c

Vehicle/Aircraft Refueling

Gasoline

Fuel losses during transfer operations at service stations were estimated using EPA AP-42 emissions factors (Section 5.2 Transportation and Marketing of Petroleum Liquids). Table 5.2-7 of the EPA document outlines evaporative emissions from gasoline service station operations (see Table H-7). It is assumed that the underground tank is filled using submerged filling and that vehicle refueling displacement losses are controlled.

Table H-7. Evaporative Emissions from Gasoline Service Station Operations (EPA 1995)

Source	Emission Factor (lb/1000 gallons throughput)
Filling underground tank (Stage I)	
Submerged filling	7.3
Splash filling	11.5
Balanced submerged filling	0.3
Underground tank breathing and emptying	1.0
Vehicle refueling operation (Stage II)	
Displacement losses (uncontrolled)	11.0
Displacement losses (controlled)	1.1
Spillage	0.7

From the above data, there are 10.1 lbs of gasoline lost for every 1,000 gallons of gasoline dispensed to consumers (0.00164 bbl/bbl, or 0.164%).

Conventional Diesel Fuel

EPA AP-42 emission factors are not specified for diesel service station operations. Estimates for diesel losses during refueling operations were derived from a report entitled Methodologies for Estimating Air Pollutant Emissions from Transport (Lewis 1997). For diesel, the filling station emissions are 0.0551 g/GJ (2.53×10^{-6} bbl/bbl, or 0.0003%) and the vehicle refueling emissions are 0.0903 g/GJ (4.14×10^{-6} bbl/bbl, or 0.0004%). The total evaporative losses for this stage are 0.1454 g/GJ (0.0007%).

Kerosene-Based Jet Fuel

According to the U.S. Federal Aviation Administration (FAA) Air Quality Handbook, Appendix D: Aircraft Emission Methodology, there is currently no information available on calculating evaporative-related emissions (e.g., refueling emissions) from commercial aircraft (FAA 1997). The FAA Air Quality Handbook notes that these evaporative related emissions are small due to the low vapor pressure of the fuel and the quick-connect refueling nozzles.

In the absence of use-specific emissions factors for aircraft refueling, product losses associated with kerosene refueling operations (filling station operation and vehicle refueling operations) are used to approximate aircraft refueling losses. According to Lewis (1997), losses associated with refueling with kerosene results in 0.714 g/GJ in evaporative losses (3.39×10^{-5} bbl/bbl, or 0.0034%).

This page intentionally left blank.

Appendix I

Conversion Factors

Life Cycle Stage #5 and final WTW and WTT results are presented on the basis of lower heating values for conventional gasoline, conventional diesel and kerosene-based jet fuel. The energy content and densities used for these final results conversions for the three fuels is shown in Table I-1.

Intermediate calculations in Life Cycle Stages #1 through #4 calculate emissions associated with combustion of various transportation fuels and refinery fuel on a higher heating value basis (see Table I-2).

Densities of various petroleum refining products are shown in Table I-3.

Table I-1. Approximate Heat Content (LHV) and Density of Petroleum Products

Petroleum Product	Heat Content (MMBtu LHV/bbl)	Density (kg/bbl)	Reference
Conventional Gasoline	4.89	117	EPA 2008
Conventional Diesel	5.51	135	EPA 2008
Kerosene-based Jet Fuel	5.23	128	DESC 2008

Table I-2. Approximate Heat Content (HHV) of Petroleum Products (EIA 2008)

Petroleum Product	Heat Content
Asphalt	6.636
Aviation Gasoline	5.048
Butane	4.326
Butane-Propane Mixture (60 percent-40 percent)	4.130
Distillate Fuel Oil	5.825
Ethane	3.082
Ethane-Propane Mixture (70 percent-30 percent)	3.308
Isobutane	3.974
Jet Fuel, Kerosene-Type	5.670
Jet Fuel, Naphtha-Type	5.355
Kerosene	5.670
Lubricants	6.065
Motor Gasoline	
Conventional	5.253
Oxygenated	5.150
Reformulated	5.150
Fuel Ethanol	3.539
Natural Gasoline	4.620
Pentanes Plus	4.620
Petrochemical Feedstocks	
Naphtha less than 401° F	5.248
Other Oils equal to or greater than 401° F	5.825

Petroleum Product	Heat Content
Still Gas	6.000
Petroleum Coke	6.024
Plant Condensate	5.418
Propane	3.836
Residual Fuel Oil	6.287
Road Oil	6.636
Special Naphthas	5.248
Still Gas	6.000
Unfinished Oils	5.825
Unfractionated Stream	5.418
Waxes	5.537
Miscellaneous	5.796

Table I-3. Density Conversions (EPA 2007c)

Hydrocarbon	Density (bbl/tonne)	Density (liters/tonne)
Natural gas liquids	11.6	1,844.2
Unfinished oils	7.46	1,186.04
Liquefied petroleum gas	11.6	1,844.2
Aviation gasoline	8.9	1,415.0
Naphtha jet fuel	8.27	1,314.82
Kerosene jet fuel	7.93	1,260.72
Motor gasoline	8.53	1,356.16
Kerosene	7.73	1,228.97
Naphtha	8.22	1,306.87
Distillate	7.46	1,186.04
Residual oil	6.66	1,058.85
Lubricants	7.06	1,122.45
Bitumen	6.06	963.46
Waxes	7.87	1,251.23
Petroleum coke	5.51	876.02
Petrochemical feedstocks	7.46	1,186.04
Special naphtha	8.53	1,356.16
Miscellaneous products	8.00	1,271.90
Crude oil (2005)*	7.188*	1,142.8*

*API Gravity for 2005 was 30.20 degrees (EIA 2008)

Methane Density = 0.67606 kg/m^3 (EPA 2007c)

Appendix J

Emissions Factors for Various Vehicle Types

The following emissions are for different vehicle types and are representative of the 2005 average fleet. The total fuel use and emissions per mile were provided by the EPA and were extracted from the MOVES model (EPA 2008).

Table J-1. 2005 Fleet Vehicle Emissions for Conventional Gasoline

MOVES Vehicle Class	Total Fuel Use	Vehicle Efficiency	CO_2 Emissions (per mile)	CH_4 Emissions (per mile)	N_2O Emissions (per mile)	GHG Emissions (per mile)	CO_2 Emissions	CH_4 Emissions	N_2O Emissions	GHG Emissions
	Btu LHV/ mile	mpg	kg CO_2/ mile	kg CH_4/ mile	kg N_2O/ mile	kg CO_2E/ mile	kg CO_2/ MMBtu LHV	kg CH_4/ MMBtu LHV	kg N_2O/ MMBtu LHV	kg CO_2E/ MMBtu LHV
11. Motorcycle	4,905	23.7	0.368	4.88E-05	5.44E-06	0.371	75.0	9.95E-03	1.11E-03	75.6
21. Passenger Car	4,866	23.9	0.365	2.37E-05	2.43E-05	0.373	75.0	4.88E-03	4.99E-03	76.6
31. Passenger Truck	6,785	17.2	0.509	3.95E-05	5.50E-05	0.526	75.0	5.83E-03	8.11E-03	77.6
32. Light Commercial Truck	7,436	15.7	0.558	4.56E-05	5.82E-05	0.576	75.0	6.13E-03	7.82E-03	77.5
42. Transit Bus	15,543	7.5	1.166	2.31E-05	3.03E-05	1.176	75.0	1.49E-03	1.95E-03	75.7
43. School Bus	12,663	9.2	0.950	1.94E-04	9.05E-05	0.982	75.0	1.53E-02	7.15E-03	77.6
51. Refuse Truck	13,509	8.6	1.014	1.80E-05	1.89E-05	1.020	75.0	1.33E-03	1.40E-03	75.5
52. Single-Unit Short-Haul Truck	58,321	2.0	4.376	6.04E-05	4.18E-05	4.390	75.0	1.03E-03	7.16E-04	75.3
53. Single-Unit Long-Haul Truck	38,958	3.0	2.923	2.53E-05	3.08E-05	2.933	75.0	6.50E-04	7.91E-04	75.3
54. Motor Home	16,014	7.3	1.202	1.02E-04	3.75E-05	1.215	75.0	6.34E-03	2.34E-03	75.9
61. Combination Short-Haul Truck	15,501	7.5	1.163	1.21E-05	1.44E-05	1.168	75.0	7.79E-04	9.32E-04	75.3
62. Combination Long-Haul Truck	15,374	7.6	1.154	9.76E-06	1.38E-05	1.158	75.0	6.35E-04	8.95E-04	75.3

Table J-2. 2005 Fleet Vehicle Emissions for Conventional Diesel

MOVES Vehicle Class	Total Fuel Use	Vehicle Efficiency	CO_2 Emissions (per mile)	CH_4 Emissions (per mile)	N_2O Emissions (per mile)	GHG Emissions (per mile)	CO_2 Emissions	CH_4 Emissions	N_2O Emissions	GHG Emissions
	Btu LHV/ mile	mpg	kg CO_2/ mile	kg CH_4/ mile	kg N_2O/ mile	kg CO_2E/ mile	kg CO_2/ MMBtu LHV	kg CH_4/ MMBtu LHV	kg N_2O/ MMBtu LHV	kg CO_2E/ MMBtu LHV
21. Passenger Car	3,737	35.1	0.286	2.99E-07	6.53E-07	0.286	76.6	8.00E-05	1.75E-04	76.7
31. Passenger Truck	5,884	22.3	0.451	7.61E-07	1.27E-06	0.451	76.6	1.29E-04	2.16E-04	76.7
32. Light Commercial Truck	6,385	20.6	0.489	9.67E-07	1.57E-06	0.490	76.6	1.51E-04	2.46E-04	76.7
41. IntercityBus	15,383	8.5	1.178	2.37E-06	2.40E-06	1.179	76.6	1.54E-04	1.56E-04	76.6
42. Transit Bus	13,108	10.0	1.004	2.34E-06	2.81E-06	1.005	76.6	1.78E-04	2.14E-04	76.7
43. School Bus	10,062	13.0	0.771	2.33E-06	4.13E-06	0.772	76.6	2.31E-04	4.10E-04	76.7
51. Refuse Truck	10,890	12.1	0.834	2.32E-06	2.54E-06	0.835	76.6	2.13E-04	2.34E-04	76.7
52. Single-Unit Short-Haul Truck	42,541	3.1	3.259	1.97E-06	2.51E-06	3.259	76.6	4.63E-05	5.91E-05	76.6
53. Single-Unit Long-Haul Truck	28,933	4.5	2.216	2.04E-06	2.48E-06	2.217	76.6	7.07E-05	8.57E-05	76.6
54. Motor Home	13,851	9.5	1.061	2.27E-06	2.60E-06	1.062	76.6	1.64E-04	1.88E-04	76.7
61. Combination Short-Haul Truck	23,211	5.7	1.778	1.90E-06	2.08E-06	1.779	76.6	8.19E-05	8.96E-05	76.6
62. Combination Long-Haul Truck	23,947	5.5	1.834	1.86E-06	2.02E-06	1.835	76.6	7.77E-05	8.45E-05	76.6

Appendix K

LTO Emission Factors and Emissions for Various Aircraft

Emissions for aircraft operation are examined for various aircraft for landing and take-off (LTO) operations and emissions are presented in Table K-1 for LTO in kg per MMBtu LHV of jet fuel consumed. IPCC reports the fuel consumption in terms of kg of jet fuel. These values were converted to MMBtu LHV using 0.04099 MMBtu LHV/kg jet fuel (DESC 2005).

Table K-1. LTO Emission Factors for Typical Aircraft (IPCC 2006)

		LTO emissions factors (kg/LTO/) (12)				LTO emissions (kg/MMBtu LHV)		
	AIRCRAFT	$CO_2^{(11)}$	$CH_4^{(7)}$	$N_2O^{(9)}$	**LTO Fuel Consumption (kg/LTO)**	$CO_2^{(11)}$	$CH_4^{(7)}$	$N_2O^{(9)}$
Large Commercial Aircraft (1) (2)	A300	5,450	0.12	0.2	1,720	77.3	0.0017	0.00284
	A310	4,760	0.63	0.2	1,510	76.9	0.0102	0.00323
	A319	2,310	0.06	0.1	730	77.2	0.0020	0.00334
	A320	2,440	0.06	0.1	770	77.3	0.0019	0.00317
	A321	3,020	0.14	0.1	960	76.7	0.0036	0.00254
	A330-200/300	7,050	0.13	0.2	2,230	77.1	0.0014	0.00219
	A340-200	5,890	0.42	0.2	1,860	77.3	0.0055	0.00262
	A340-300	6,380	0.39	0.2	2,020	77.1	0.0047	0.00242
	A340-500/600	10,660	0.01	0.3	3,370	77.2	0.0001	0.00217
	707	5,890	9.75	0.2	1,860	77.3	0.1279	0.00262
	717	2,140	0.01	0.1	680	76.8	0.0004	0.00359
	727-100	3,970	0.69	0.1	1,260	76.9	0.0134	0.00194
	727-200	4,610	0.81	0.1	1,460	77.0	0.0135	0.00167
	737-100/200	2,740	0.45	0.1	870	76.8	0.0126	0.00280
	737-300/400/500	2,480	0.08	0.1	780	77.6	0.0025	0.00313
	737-600	2,280	0.1	0.1	720	77.3	0.0034	0.00339
	737-700	2,460	0.09	0.1	780	76.9	0.0028	0.00313
	737-800/900	2,780	0.07	0.1	880	77.1	0.0019	0.00277
	747-100	10,140	4.84	0.3	3,210	77.1	0.0368	0.00228
	747-200	11,370	1.82	0.4	3,600	77.1	0.0123	0.00271
	747-300	11,080	0.27	0.4	3,510	77.0	0.0019	0.00278
	747-400	10,240	0.22	0.3	3,240	77.1	0.0017	0.00226
	757-200	4,320	0.02	0.1	1,370	76.9	0.0004	0.00178
	757-300	4,630	0.01	0.1	1,460	77.4	0.0002	0.00167
	767-200	4,620	0.33	0.1	1,460	77.2	0.0055	0.00167
	767-300	5,610	0.12	0.2	1,780	76.9	0.0016	0.00274
	767-400	5,520	0.1	0.2	1,750	77.0	0.0014	0.00279

		LTO emissions factors (kg/LTO/) (12)				LTO emissions (kg/MMBtu LHV)		
	AIRCRAFT	CO_2(11)	CH_4(7)	N_2O(9)	LTO Fuel Consumption (kg/LTO)	CO_2(11)	CH_4(7)	N_2O(9)
	777-200/300	8,100	0.07	0.3	2,560	77.2	0.0007	0.00286
	DC-10	7,290	0.24	0.2	2,310	77.0	0.0025	0.00211
	DC-8-50/60/70	5,360	0.15	0.2	1,700	76.9	0.0022	0.00287
	DC-9	2,650	0.46	0.1	840	77.0	0.0134	0.00290
	L-1011	7,300	7.4	0.2	2,310	77.1	0.0782	0.00211
	MD-11	7,290	0.24	0.2	2,310	77.0	0.0025	0.00211
	MD-80	3,180	0.19	0.1	1,010	76.8	0.0046	0.00242
	MD-90	2,760	0.01	0.1	870	77.4	0.0003	0.00280
	TU-134	2,930	1.8	0.1	930	76.9	0.0472	0.00262
	TU-154-M	5,960	1.32	0.2	1,890	76.9	0.0170	0.00258
	TU-154-B	7,030	11.9	0.2	2,230	76.9	0.1302	0.00219
Regional Jets	RJ-RJ85	1,910	0.13	0.1	600	77.7	0.0053	0.00407
	BAE 146	1,800	0.14	0.1	570	77.0	0.0060	0.00428
	CRJ-100ER	1,060	0.06	0.03	330	78.4	0.0044	0.00222
	ERJ-145	990	0.06	0.03	310	77.9	0.0047	0.00236
	Fokker 100/70/28	2,390	0.14	0.1	760	76.7	0.0045	0.00321
	BAC111	2,520	0.15	0.1	800	76.9	0.0046	0.00305
	Dornier 328 Jet	870	0.06	0.03	280	75.8	0.0052	0.00261
	Gulfstream IV	2,160	0.14	0.1	680	77.5	0.0050	0.00359
	Gulfstream V	1,890	0.03	0.1	600	76.9	0.0012	0.00407
	Yak-42M	2,880	0.25	0.1	910	77.2	0.0067	0.00268
Jets (3)	Cessna 525/560	1,070	0.33	0.03	340	76.8	0.0237	0.00215

Notes:
(1) ICAO Engine Exhaust Emissions Data Bank (ICAO, 2004) based on average measured data. Emissions factors apply to LTO (Landing and Take off) only.
(2) Engine types for each aircraft were selected on a consistent basis of the engine with the most LTOs. This approach, for some engine types, may underestimate (or overestimate) fleet emissions which are not directly related to fuel consumption (eg NOx, CO, HC).
(2) Emissions and Dispersion Modeling System (EDMS) (FAA 2004b)
(8) Assuming 10% of total VOC emissions in LTO cycles are methane emissions (Olivier, 1991) (as in the 1996 IPCC Guidelines).
(9) Estimates based on Tier I default values (EF ID 11053) (as in the 1996 IPCC Guidelines).
(10) The sulfur content of the fuel is assumed to be 0.05% (as in the 1996 IPCC Guidelines).
(11) CO_2 for each aircraft based on 3.16 kg CO_2 produced for each kg fuel used, then rounded to the nearest 10 kg.
(12) Information regarding the uncertainties associated with this data can be found in: Lister and Norman, 2003; ICAO, 1993.

Appendix L

Study GHG Results Presented in Alternate Units

The following tables and figures present GHG emissions on a kg-per-barrel-consumed basis and kg-per-GJ-fuel-consumed basis and in alternate IPCC global warming potential values based on the 1996 and 2001 technical reports (Table 1.1).

Table L-1. GHG Emissions for Liquid Fuels Production (kg CO_2E/barrel consumed)

	LC Stage #1: Raw Material Acquisition	LC Stage #2: Raw Material Transport	LC Stage #3: Liquid Fuels Production	LC Stage #4: Product Transport and Refueling	LC Stage #5: Vehicle / Aircraft Operation	Total Well-to-Wheels
Conventional Gasoline (kg CO_2E/barrel consumed)						
Total	**35.8**	**7.0**	**47.9**	**5.3**	**375**	**471**
CO_2	23.9	6.9	46.2	5.2	367	449
CH_4 (CO_2E)	11.7	0.1	1.4	0.1	0.6	13.9
N_2O (CO_2E)	0.2	0.0	0.2	0.0	7.3	7.8
Conventional Diesel (kg CO_2E/barrel consumed)						
Total	**36.6**	**7.3**	**52.6**	**4.8**	**422**	**524**
CO_2	24.6	7.1	50.8	4.7	422	509
CH_4 (CO_2E)	11.8	0.1	1.6	0.1	0.0	13.6
N_2O (CO_2E)	0.2	0.0	0.2	0.0	0.3	0.8
Kerosene-Based Jet Fuel (kg CO_2E/barrel consumed)						
Total	**35.3**	**7.0**	**31.6**	**5.2**	**407**	**486**
CO_2	23.8	6.9	30.5	5.1	403	470
CH_4 (CO_2E)	11.4	0.1	0.9	0.1	0.1	12.6
N_2O (CO_2E)	0.2	0.0	0.1	0.0	3.3	3.7

Table L-2. GHG Emissions for Liquid Fuels Production (kg CO_2E/GJ LHV fuel consumed)

	LC Stage #1: Raw Material Acquisition	LC Stage #2: Raw Material Transport	LC Stage #3: Liquid Fuels Production	LC Stage #4: Product Transport and Refueling	LC Stage #5: Vehicle / Aircraft Operation	Total Well-to-Wheels
Conventional Gasoline (kg CO_2E/GJ LHV fuel consumed)						
Total	**6.94**	**1.36**	**9.27**	**1.03**	**72.6**	**91.21**
CO_2	4.63	1.34	8.96	1.01	71.1	87.0
CH_4 (CO_2E)	2.27	0.02	0.27	0.01	0.11	2.68
N_2O (CO_2E)	0.04	0.008	0.04	0.006	1.41	1.51
Conventional Diesel (kg CO_2E/GJ LHV fuel consumed)						
Total	**6.29**	**1.25**	**9.05**	**0.83**	**72.7**	**90.13**
CO_2	4.23	1.23	8.74	0.82	72.6	87.6
CH_4 (CO_2E)	2.03	0.02	0.27	0.01	0.00	2.33
N_2O (CO_2E)	0.03	0.007	0.04	0.005	0.05	0.14
Kerosene-Based Jet Fuel (kg CO_2E/GJ LHV fuel consumed)						
Total	**6.41**	**1.28**	**5.72**	**0.95**	**73.6**	**88.00**
CO_2	4.30	1.25	5.53	0.93	73.1	85.1
CH_4 (CO_2E)	2.07	0.02	0.17	0.01	0.01	2.28
N_2O (CO_2E)	0.04	0.007	0.025	0.006	0.60	0.67

Table L-3. GHG Emissions for Liquid Fuels Production Based on 1996 IPCC GWP (kg CO_2E/MMBtu LHV of Fuel Consumed)

	LC Stage #1: Raw Material Acquisition	LC Stage #2: Raw Material Transport	LC Stage #3: Liquid Fuels Production	LC Stage #4: Product Transport and Refueling	LC Stage #5: Vehicle / Aircraft Operation	Total Well-to-Wheels
Conventional Gasoline (kg CO_2E/MMBtu LHV fuel consumed)						
Total	**6.94**	**1.44**	**9.74**	**1.09**	**76.7**	**95.9**
CO_2	4.89	1.41	9.45	1.07	75.0	91.9
CH_4 (CO_2E)	2.01	0.0162	0.242	0.0125	0.10	2.38
N_2O (CO_2E)	0.0410	0.0087	0.0474	0.0067	1.55	1.65
Conventional Diesel (kg CO_2E/MMBtu LHV fuel consumed)						
Total	**6.30**	**1.32**	**9.51**	**0.88**	**76.7**	**94.6**
CO_2	4.46	1.30	9.22	0.86	76.6	92.4
CH_4 (CO_2E)	1.80	0.0147	0.239	0.0109	0.0017	2.07
N_2O (CO_2E)	0.0376	0.0081	0.0442	0.0053	0.0541	0.149
Kerosene-Based Jet Fuel (kg CO_2E/MMBtu LHV fuel consumed)						
Total	**6.41**	**1.35**	**6.01**	**1.00**	**77.8**	**92.5**
CO_2	4.54	1.32	5.83	0.978	77.1	89.8
CH_4 (CO_2E)	1.83	0.0147	0.151	0.0115	0.011	2.02
N_2O (CO_2E)	0.0381	0.0082	0.0280	0.0062	0.654	0.735

Table L-4. GHG Emissions for Liquid Fuels Production Based on 2001 IPCC GWP (kg CO_2E/MMBtu LHV of Fuel Consumed)

	LC Stage #1: Raw Material Acquisition	LC Stage #2: Raw Material Transport	LC Stage #3: Liquid Fuels Production	LC Stage #4: Product Transport and Refueling	LC Stage #5: Vehicle / Aircraft Operation	Total Well-to-Wheels
Conventional Gasoline (kg CO_2E/MMBtu LHV fuel consumed)						
Total	**7.13**	**1.44**	**9.76**	**1.09**	**76.6**	**96.0**
CO_2	4.89	1.41	9.45	1.07	75.0	91.9
CH_4 (CO_2E)	2.20	0.0177	0.265	0.0137	0.11	2.61
N_2O (CO_2E)	0.0391	0.0083	0.0453	0.0064	1.47	1.58
Conventional Diesel (kg CO_2E/MMBtu LHV fuel consumed)						
Total	**6.47**	**1.32**	**9.53**	**0.88**	**76.7**	**94.8**
CO_2	4.46	1.30	9.22	0.86	76.6	92.4
CH_4 (CO_2E)	1.97	0.0161	0.262	0.0120	0.0018	2.26
N_2O (CO_2E)	0.0359	0.0077	0.0422	0.0050	0.0517	0.143
Kerosene-Based Jet Fuel (kg CO_2E/MMBtu LHV fuel consumed)						
Total	**6.58**	**1.35**	**6.02**	**1.00**	**77.7**	**92.7**
CO_2	4.54	1.32	5.83	0.978	77.1	89.8
CH_4 (CO_2E)	2.00	0.0163	0.165	0.0126	0.012	2.21
N_2O (CO_2E)	0.0363	0.0079	0.0267	0.0059	0.625	0.701

Figure L-1. GHG Emissions for Liquid Fuels Production (kg CO_2E/barrel consumed)

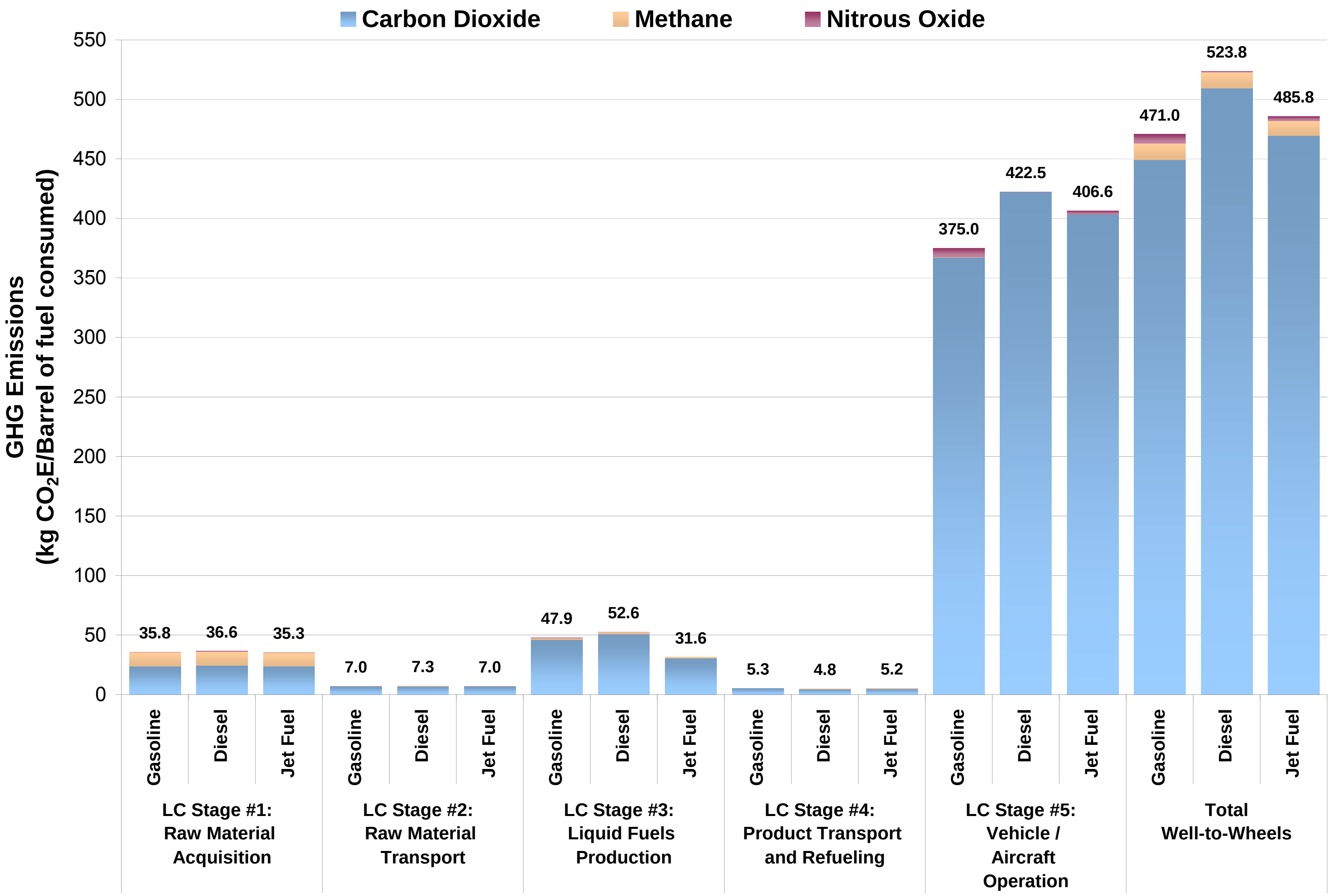


Figure L-2. GHG Emissions for Liquid Fuels Production (kg CO_2E/GJ LHV fuel consumed)

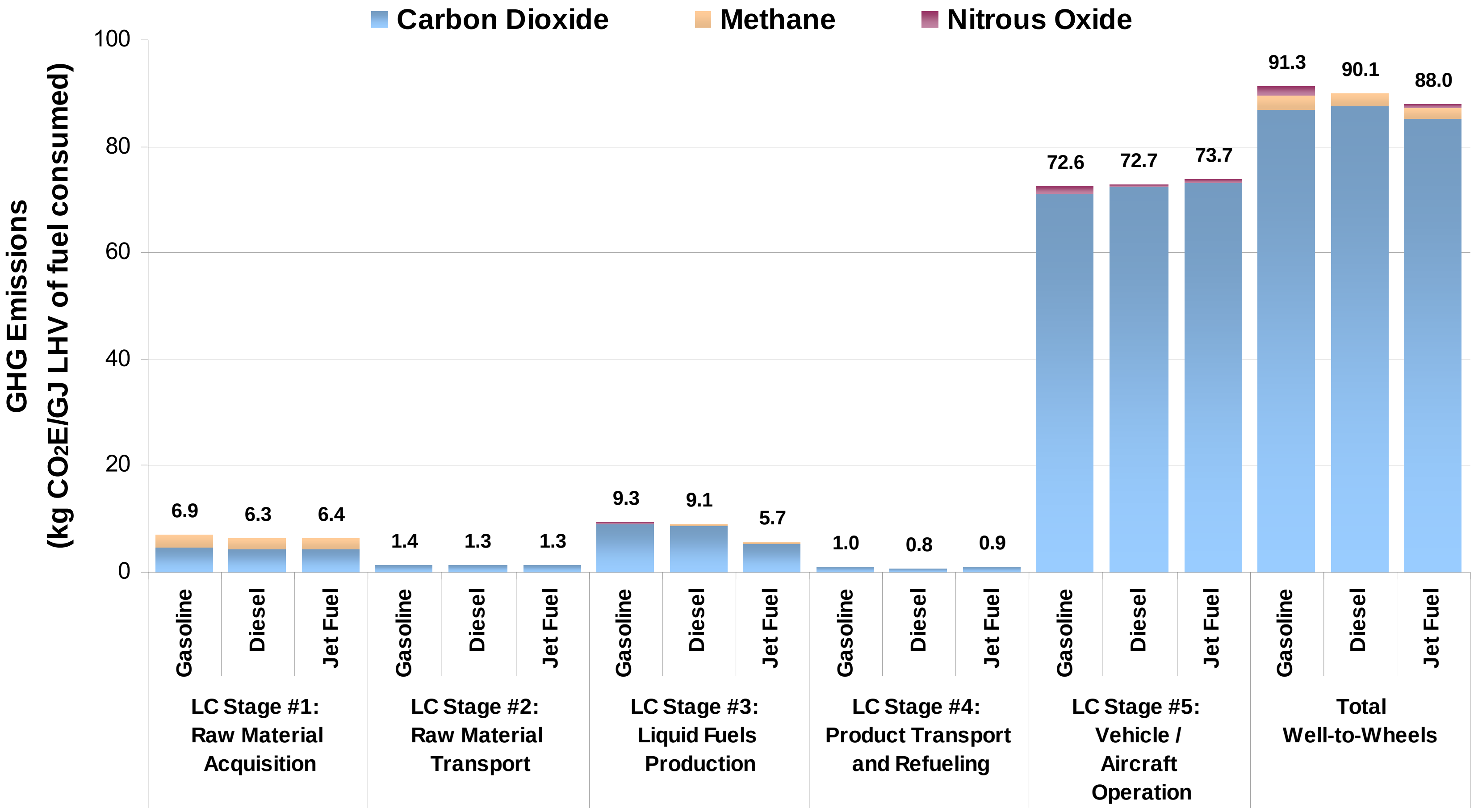


Figure L-3. GHG Emissions for Liquid Fuels Production Based on 1996 IPCC GWP (kg CO_2E/MMBtu LHV of Fuel Consumed)

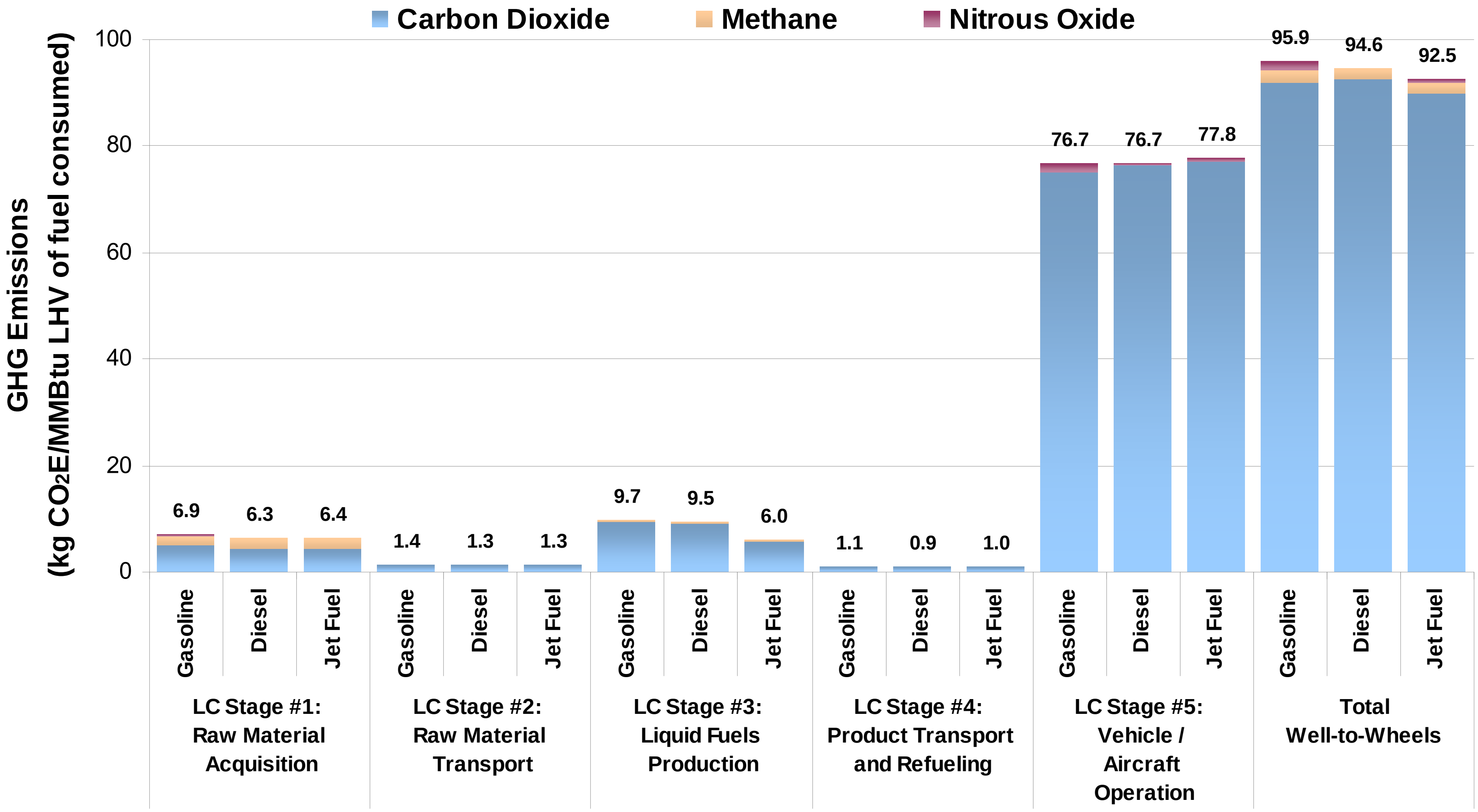
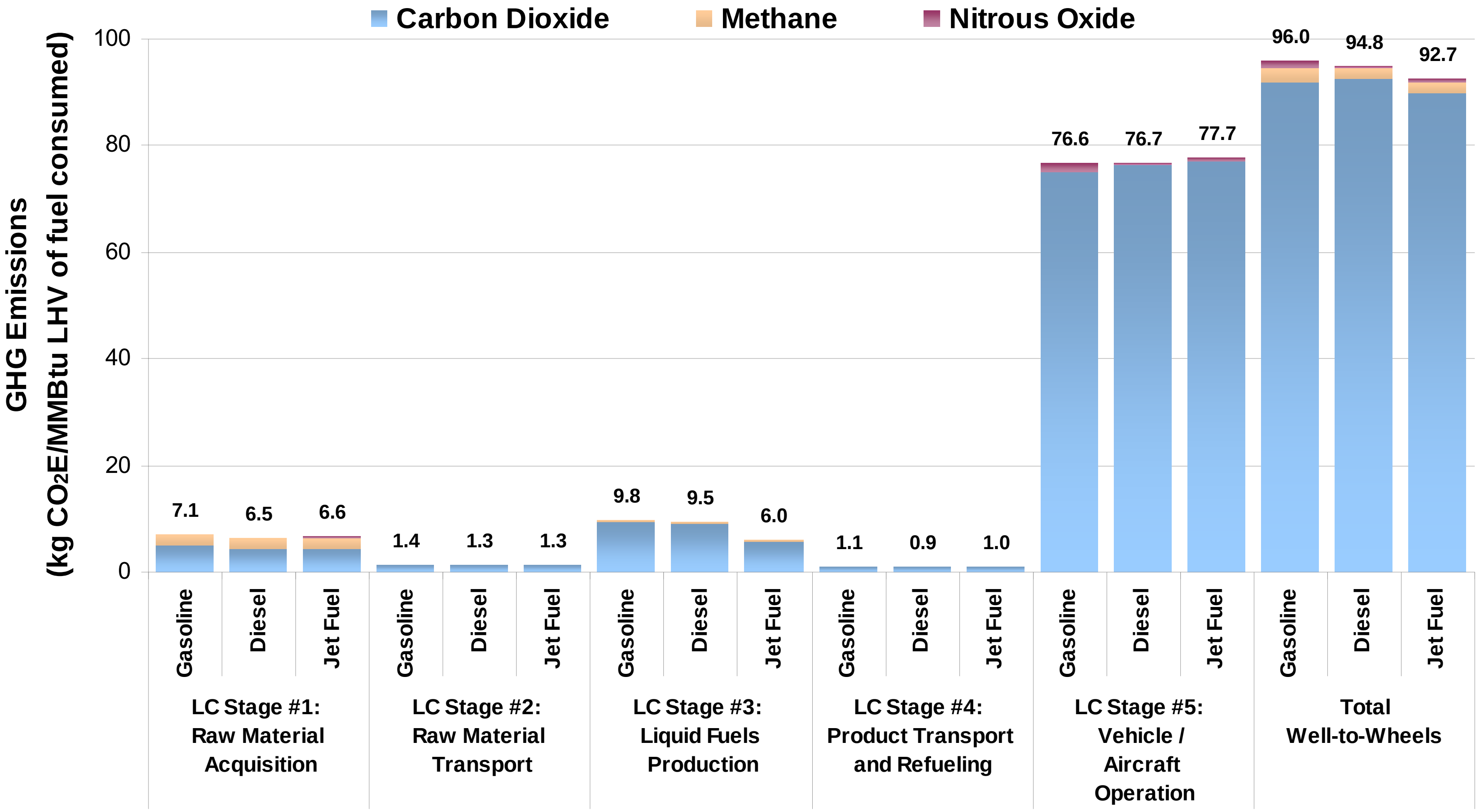


Figure L-4. GHG Emissions for Liquid Fuels Production Based on 2001 IPCC GWP (kg CO_2E/MMBtu LHV of Fuel Consumed)



This page intentionally left blank.

Attachment 1

Documentation Associated with Profiles Extracted from GaBi 4

Production of crude oil in Algeria

1. Technology description of the Crude oil production

1.1 Introduction

The production of crude oil was modelled as a combined natural gas and crude oil production. In most cases beside crude oil, different parts of natural gas and NGL (natural gas liquids) are produced as by-products. For the different by-products allocation by lower calorific value was applied. The combined production comprises the exploration and production of crude oil and natural gas as well as all the desulphurization of natural gas. The data set includes all relevant parts of the upstream industry. Production may take place onshore and offshore. Both are taken into account proportionate to their ratio of the total production of a country.

1.2 Exploration

Exploration comprises the search of hydrocarbon (HC) deposits and the drilling of wells. The search for new deposits is conducted at first by seismic survey, which is not included in the data set. In a second step testing wells are drilled which can be characterized as wildcat wells for areas with low information about the subsurface, exploration wells for information gathering and appraisal wells to assess characteristics such as flow rate, amount of hydrocarbon, pressure and others. After a successful testing the production well is drilled to produce hydrocarbons.

Vertical wells are drilled by the rotary mode. The base of a drilling facility is a rig. For offshore drilling jack-up rigs, based on a buoyant steel hull with 3 or more legs, semi-submersible rigs, which float at all times on pontoons, or drill ships are used. The oil rig contains machinery and fulfils the role of superstructure bearing the load of a drill string. Driven by a diesel unit the drill string transmits his rotation on a drill bit, which brakes up the stone and extends the hole (up to 0,8 m wide). The drill string is gradually lengthened as the well gets deeper. The drill cuttings are removed by a drilling fluid (drilling mud), which is pumped inside the drill string, leaves the drill string at the drill bit and is then floated together with the drill cuttings back to the surface between drill string and the inner surface of the well due to the high pressure generated by piston pumps. At the rig the drilling fluid is separated from drill cuttings and circulated. The drilling fluid also serves to cool the drill bit, to seal the drill hole against seepage and to prevent wall cave-ins. Depending on geology and technology water-based, oil-based and synthetic-based fluids are used. They are mixed with barium sulphate and bentonite to increase the density of the fluid as well as further additives. After finishing the drilling or at least after 1000m, the well is cased with concrete and smoothly steel pipes (0.08-0.2 m diameter) and prepared for production. In general due to the lack of infrastructure for preparing and transportation, produced oil and gas is flared. Small amounts of gas are also vented into the atmosphere. During the drilling high amounts of drill cuttings and waste water arise. At offshore exploration the cuttings are discharged to water or brought ashore depending on drilling fluid and legislation.

1.3 Production & Preparation

Ideally the oil is transported as an oil-gas mixture to the surface without any effort by the high pressure of the hydrocarbon deposit. The flow of oil runs dry, when the pressure of the deposit will get lower as the flow resistance or when the pressure was already lower at the beginning. For further exploitation it is necessary to use pumps or to reinject a part of the separated natural gas to maintain a high pressure in the deposit. Advanced measures raise the production are the reinjection of produced water or sea water and the reinjection of steam to increase the viscosity or surface tension of the oil-gas mixture.

The produced oil-gas mixture is a composite of crude oil, natural gas, brine and other impurities. In a preparation process the natural gas and the NGL is separated from the oil. In a second preparation step most of the water is separated from the oil due to the different densities. The remaining emulsified water and salt is removed in a dewatering and desalting plant. Small amounts of produced natural gas are often still flared, sometimes also vented, due to missing preparation and transportation opportunities. Hydrogen sulphide contained in the natural gas in different concentrations, has to be removed before transportation via pipelines due to the high corrosive impact. The hydrogen sulphide is recovered from the natural gas by the Claus process producing elementary sulphur and, depending on technology standards, a certain amount of sulphur dioxide. The arising water with concentrations of approximately 15 or more mg hydrocarbons per litre is reinjected into the gas field, discharged into the sea (onshore and in shore) or evaporated in pits. During preparation different kinds of waste and used chemicals arise which have to be disposed. A certain amount of gas and oil is flared or vented into the atmosphere because of leakage or security reasons. The mechanical energy and electricity for pumping and all other machinery is provided by gas turbines and diesel units. At onshore facilities a certain amount is provided by the grid.

2 General comments of the LCA assessment method

This chapter gives background information on the principal modelling approach.

2.1 System boundaries and functional unit

Functional unit: The functional unit is 1 bbl of crude oil.

This process includes all relevant Mass and energy flows for the exploration and extraction of crude oil. Figure 2-1 gives an overview on the considered processes along with their key in- and outputs

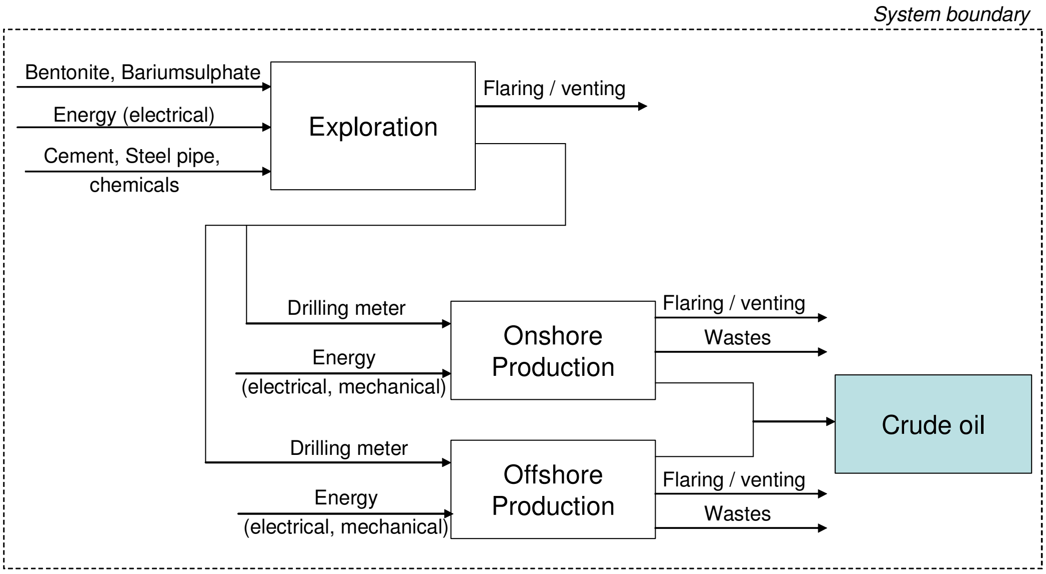


Figure 2-1 System boundary for crude oil production

The exploration is modelled per drilling meters and is considered in the model via drilling meters per mass of produced hydrocarbon. Quantities of borehole volume, removed rock are based on multiple sources such as [6]-[8]. Amount of Bentonite and Bariumsulphate and water for drilling mud is taken from [6]. The material used for reinforcing the well is calculated based on [9]-[12]. The power demand for drilling is taken from [13]. For venting of natural gas the averaged national natural gas composition is considered [14], [23]. The energy demand for production is given in section 3.2. The associated emissions are calculated using emission factors sourced from [16] and industry data. Venting of solution gas from oil producing well is also considered. For flaring region specific flare amounts and emissions are included, see section 3.3 and [15], [21], [22]. Solid wastes and waste water are considered. The referring data is sourced from [15], [17]-[20] and as stated in section 3.4.

2.2 Allocation or system expansion

For the combined crude oil, natural gas and natural gas liquids production allocation by lower calorific value is applied. The lower heating values of the products are given in section 3.5.

2.3 Data completeness

The coverage for the exploration data (crude oil, natural gas, natural gas liquids) is 90% of mass and energy and 95% of the environmental relevance (expert judgement).

2.4 Data selection and combination principles

The data sources for the complete product system are sufficiently consistent: The data on the energy carrier supply chain is based on statistics with country/region specific transport distances and energy carrier composition as well as industry and literature data on the inventory of exploration, extraction and processing. LCI modelling is fully consistent.

2.5 Reference year

Reference year for the data set is 2002. Although some of the emission data and product properties are sourced from different years representativeness for the reference year is considered good.

2.6 Data treatment and extrapolations principles

In terms of the country/region specific crude oil production, missing data of certain parameters has been used from countries with a comparable technology[1]. Data measured at a group of representative production facilities have been used to represent the national production.

---

[1] If this ist he case it is indicated in the tables in section 3.

3 Country specific data

3.1 Production

Table 1 shows the production ratio of natural gas, NGL and crude oil on a weight basis as well as the drilling feet per pound hydrocarbon produced.

Table 1 Production parameters

Parameter	Value	Source
Portion of natural gas production	49.83%	[4]
Portion of NGL production	17.4%	[4]
Portion of crude oil production	32.77%	[1]
Drilling meters for onshore production	0.57×10^{-06} ft/lb HC produced	[2]

3.2 Energy use

The specific energy use distinguished between electricity and mechanical energy is shown in Table 2.

Table 2 Energy consumption parameters

Parameter	Value	Source
Electricity demand	34.39 Btu/lb HC	Region value for Africa [15] and own calculations
Mechanical energy demand	309.54 Btu/lb HC	Region value for Africa [15] and own calculations
Total energy demand	343.93 Btu/lb HC	Region value for Africa [15]

3.3 Flaring and venting

The flaring and venting of hydrocarbons during the production process is shown in Table 3. The flared Hydrocarbons are the sum of flared natural gas and solution gas compounds.

Table 3 Flaring and venting parameters

Parameter	Value	Source
Flared Hydrocarbons	0.030 lb/lb HC	[5], [24]
Vented Hydrocarbons	0.0041 lb/lb HC	[5]

3.4 Waste and waste water

The amount of solid waste and waste water emitted during the production process is summarised in Table 4.

Table 4 Waste and waste water parameters

Parameter	Value	Source
Solid waste	0.0017 lb/lb HC	Value for Nigeria [3]
Waste water onshore	0.044 lb/lb HC	[15]

3.5 Product properties

The lower heating value as a country specific product property is given in Table 5.

Table 5 Product properties

Parameter	Value	Source
Net calorific value natural gas	19148.19 Btu/lb	[23]
Net calorific value crude oil	18709.68 Btu/lb	[1]

4 References

[1] IEA: Oil information 2002, International Energy Agency, 2004

[2] Pennwell: The international petroleum Encyclopaedia 1997

[3] Shell Nigeria 2004 People and the environment Annual Report, 2005

[4] IEA: Natural Gas Information 2002, International Energy Agency, 2004

[5] EIA: International Energy Annual 2003; Energy Information Administration, 2004

[6] OGP: Environmental aspects of the use and disposal of non aqueous drilling fluids associated with offshore oil& gas operations, 2003

[7] Da Prat, G.: Well Testing management , SPE Foundation, presentation 2002

[8] Vickery et al.: Successful high rate gas completion through combination of extreme overbalance perforating and one trip perforate and gravel pack techniques, Baker oil tools, 2001

[9] N. Lapeyrouse: Formulas and calculations for Drilling, Production and work over, 2nd Edition, Golf Professional Publishing, 2002

[10] Gordon, D. et al. Underbalanced Drilling with casing SPE, SPE Drilling & completion 2005

[11] Ohio Department of Health: Materials used in drilling and construction of wells, 1999

[12] Culver, G.: Drilling and well construction, Chapter 6, OIST, Department of Energy 1998

[13] Vektor AS – Environmental developments in Well testing, 2000

[14] BP: Das Buch zum Erdöl (The book on Crude oil), 1989

[15] OGP, International Association of Oil and Gas Producers: Environmental performance in the E&P industry 2003, 2004

[16] US EPA: Compilation of Air pollutant emission factors, AP 42, Volume I: Stationary point and area sources, Fifth edition, United States Protection Agency, Office of air quality planning and standards, 1995-2000.

[17] US EPA: Profile of the Oil and Gas Extraction Industry, 2nd Section, 2000

[18] PSI: Management of produced water on offshore oil installations, Policy Studies Institute, 2005

[19] OGP: Aromatics in produced water occurrence, fate & effects and treatment, International Association of Oil and Gas Producers, 2002

[20] OGP: Fate and effects of naturally occurring substances in produced water on the marine environment, International Association of Oil and Gas Producers, 2005

[21] Leahey, G et at.: Theoretical and observational assessments of flare efficiencies, Journal of Air & Waste Management Association, Volume 51, December 2001

[22] Johnson, M.R. et al.: Efficiency measurements of flares in a cross flow, Dep. Of Mechanical Engineering, University of Alberta, Combustion Canada conference, 1999

[23] EIA: C.5 Gross Heat Content of Dry Natural Gas Production, 1980-2004, Energy Information Administration, 2005

[24] World Bank: Global gas Flaring reduction initiative, 2004

Production of crude oil in Angola

1. Technology description of the Crude oil production

1.1 Introduction

The production of crude oil was modelled as a combined natural gas and crude oil production. In most cases beside crude oil, different parts of natural gas and NGL (natural gas liquids) are produced as by-products. For the different by-products allocation by lower calorific value was applied. The combined production comprises the exploration and production of crude oil and natural gas as well as all the desulphurization of natural gas. The data set includes all relevant parts of the upstream industry. Production may take place onshore and offshore. Both are taken into account proportionate to their ratio of the total production of a country.

1.2 Exploration

Exploration comprises the search of hydrocarbon (HC) deposits and the drilling of wells. The search for new deposits is conducted at first by seismic survey, which is not included in the data set. In a second step testing wells are drilled which can be characterized as wildcat wells for areas with low information about the subsurface, exploration wells for information gathering and appraisal wells to assess characteristics such as flow rate, amount of hydrocarbon, pressure and others. After a successful testing the production well is drilled to produce hydrocarbons.

Vertical wells are drilled by the rotary mode. The base of a drilling facility is a rig. For offshore drilling jack-up rigs, based on a buoyant steel hull with 3 or more legs, semi-submersible rigs, which float at all times on pontoons, or drill ships are used. The oil rig contains machinery and fulfils the role of superstructure bearing the load of a drill string. Driven by a diesel unit the drill string transmits his rotation on a drill bit, which brakes up the stone and extends the hole (up to 0,8 m wide). The drill string is gradually lengthened as the well gets deeper. The drill cuttings are removed by a drilling fluid (drilling mud), which is pumped inside the drill string, leaves the drill string at the drill bit and is then floated together with the drill cuttings back to the surface between drill string and the inner surface of the well due to the high pressure generated by piston pumps. At the rig the drilling fluid is separated from drill cuttings and circulated. The drilling fluid also serves to cool the drill bit, to seal the drill hole against seepage and to prevent wall cave-ins. Depending on geology and technology water-based, oil-based and synthetic-based fluids are used. They are mixed with barium sulphate and bentonite to increase the density of the fluid as well as further additives. After finishing the drilling or at least after 1000m, the well is cased with concrete and smoothly steel pipes (0.08-0.2 m diameter) and prepared for production. In general due to the lack of infrastructure for preparing and transportation, produced oil and gas is flared. Small amounts of gas are also vented into the atmosphere. During the drilling high amounts of drill cuttings and waste water arise. At offshore exploration the cuttings are discharged to water or brought ashore depending on drilling fluid and legislation.

1.3 Production & Preparation

Ideally the oil is transported as an oil-gas mixture to the surface without any effort by the high pressure of the hydrocarbon deposit. The flow of oil runs dry, when the pressure of the deposit will get lower as the flow resistance or when the pressure was already lower at the beginning. For further exploitation it is necessary to use pumps or to reinject a part of the separated natural gas to maintain a high pressure in the deposit. Advanced measures raise the production are the reinjection of produced water or sea water and the reinjection of steam to increase the viscosity or surface tension of the oil-gas mixture.

The produced oil-gas mixture is a composite of crude oil, natural gas, brine and other impurities. In a preparation process the natural gas and the NGL is separated from the oil. In a second preparation step most of the water is separated from the oil due to the different densities. The remaining emulsified water and salt is removed in a dewatering and desalting plant. Small amounts of produced natural gas are often still flared, sometimes also vented, due to missing preparation and transportation opportunities. Hydrogen sulphide contained in the natural gas in different concentrations, has to be removed before transportation via pipelines due to the high corrosive impact. The hydrogen sulphide is recovered from the natural gas by the Claus process producing elementary sulphur and, depending on technology standards, a certain amount of sulphur dioxide. The arising water with concentrations of approximately 15 or more mg hydrocarbons per litre is reinjected into the gas field, discharged into the sea (onshore and in shore) or evaporated in pits. During preparation different kinds of waste and used chemicals arise which have to be disposed. A certain amount of gas and oil is flared or vented into the atmosphere because of leakage or security reasons. The mechanical energy and electricity for pumping and all other machinery is provided by gas turbines and diesel units. At onshore facilities a certain amount is provided by the grid.

2 General comments of the LCA assessment method

This chapter gives background information on the principal modelling approach.

2.1 System boundaries and functional unit

Functional unit: The functional unit is 1 bbl of crude oil.

This process includes all relevant Mass and energy flows for the exploration and extraction of crude oil. Figure 2-1 gives an overview on the considered processes along with their key in- and outputs

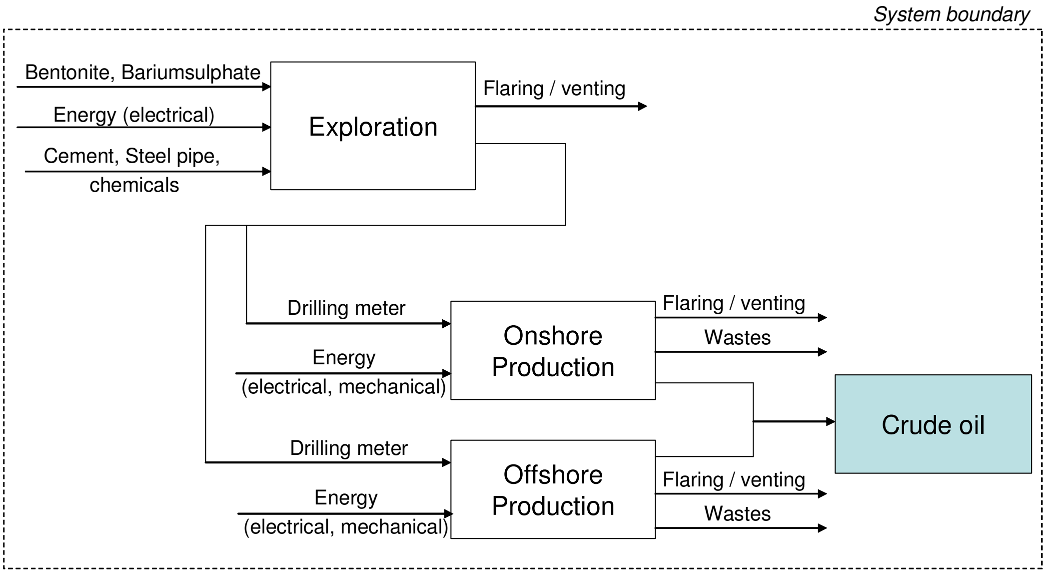


Figure 2-1 **System boundary for crude oil production**

The exploration is modelled per drilling meters and is considered in the model via drilling meters per mass of produced hydrocarbon. Quantities of borehole volume, removed rock are based on multiple sources such as [12]-[14]. Amount of Bentonite and Bariumsulphate and water for drilling mud is taken from [12]. The material used for reinforcing the well is calculated based on [15]-[18]. The power demand for drilling is taken from [19]. For venting of natural gas the averaged national natural gas composition is considered [5], [20] and [1]. The energy demand for production is given in section 3.2. The associated emissions are calculated using emission factors sourced from [22] and industry data. Venting of solution gas from oil producing well is also considered. For flaring region specific flare amounts and emissions are included, see section 3.3 and [21], [27], [28]. Solid wastes and waste water are considered. The referring data is sourced from [21], [23]-[26] and as stated in section 3.4.

2.2 Allocation or system expansion

For the combined crude oil, natural gas and natural gas liquids production allocation by lower calorific value is applied. The lower heating values of the products are given in section 3.5.

2.3 Data completeness

The coverage for the exploration data (crude oil, natural gas, natural gas liquids) is 90% of mass and energy and 95% of the environmental relevance (expert judgement).

2.4 Data selection and combination principles

The data sources for the complete product system are sufficiently consistent: The data on the energy carrier supply chain is based on statistics with country/region specific transport distances and energy carrier composition as well as industry and literature data on the inventory of exploration, extraction and processing. LCI modelling is fully consistent.

2.5 Reference year

Reference year for the data set is 2002. Although some of the emission data and product properties are sourced from different years representativeness for the reference year is considered good.

2.6 Data treatment and extrapolations principles

In terms of the country/region specific crude oil production, missing data of certain parameters has been used from countries with a comparable technology[1]. Data measured at a group of representative production facilities have been used to represent the national production.

---

[1] If this ist he case it is indicated in the tables in section 3.

3 Country specific data

3.1 Production

Table 1 shows the production ratio of natural gas, NGL and crude oil on a weight basis as well as the drilling feet per pound hydrocarbon produced.

Table 1 Production parameters

Parameter	Value	Source
Portion of natural gas production	1.11%	[1]
Portion of NGL production	0%	[1]
Portion of crude oil production	98.89%	[2]
Drilling meters for offshore production	1.12×10^{-07} ft/lb HC produced	[3]

3.2 Energy use

The specific energy use distinguished between electricity and mechanical energy is shown in Table 2.

Table 2 Energy consumption parameters

Parameter	Value	Source
Electricity demand	34.39 Btu/lb HC	Value for region Africa [21] and own calculations
Mechanical energy demand	309.54 Btu/lb HC	Value for region Africa [21] and own calculations
Total energy demand	343.93 Btu/lb HC	Value for region Africa [21]

3.3 Flaring and venting

The flaring and venting of hydrocarbons during the production process is shown in Table 3. The flared Hydrocarbons are the sum of flared natural gas and solution gas compounds.

Table 3 Flaring and venting parameters

Parameter	Value	Source
Flared Hydrocarbons	0.061 lb/lb HC	[11]
Vented Hydrocarbons	0.017 lb/lb HC	[11]

3.4 Waste and waste water

The amount of solid waste and waste water emitted during the production process is summarised in Table 4.

Table 4 Waste and waste water parameters

Parameter	Value	Source
Solid waste	0.0017 lb/lb HC	Value for Nigeria [4]
Waste water offshore	0.49 lb/lb HC	[21]

3.5 Product properties

The lower heating value as a country specific product property is given in Table 5.

Table 5 Product properties

Parameter	Value	Source
Net calorific value natural gas	18851.55 Btu/lb	[5]
Net calorific value crude oil	18309.87 Btu/lb	[6];[7];[8];[9];[10]

4 References

[1] IEA: Natural Gas Information 2002, International Energy Agency, 2004

[2] IEA: Oil information 2002, International Energy Agency, 2004

[3] Pennwell: The international petroleum Encyclopaedia 1997

[4] Shell Nigeria 2004 People and the environment Annual Report, 2005

[5] EIA: C.5 Gross Heat Content of Dry Natural Gas Production, 1980-2004, 2005

[6] EIA: C.3 Gross Heat Content of Crude Oil, 1980-2003, 2004

[7] Haverly: Crude assay libraries, 2005

[8] Statoil: Statoil crudes, 2005

[9] ChevronTexaco: http://www.chevrontexaco.com/crudemarketing/, 2005

[10] Energy Intelligence Group: The Crude Oils and Their Key Characteristics, 2003

[11] EIA: International Energy Annual 2003; Energy Information Administration, 2004

[12] OGP: Environmental aspects of the use and disposal of non aqueous drilling fluids associated with offshore oil& gas operations, 2003

[13] Da Prat, G.: Well Testing management , SPE Foundation, presentation 2002

[14] Vickery et al.: Successful high rate gas completion through combination of extreme overbalance perforating and one trip perforate and gravel pack techniques, Baker oil tools, 2001

[15] N. Lapeyrouse: Formulas and calculations for Drilling, Production and work over, 2nd Edition, Golf Professional Publishing, 2002

[16] Gordon, D. et al. Underbalanced Drilling with casing SPE, SPE Drilling & completion 2005

[17] Ohio Department of Health: Materials used in drilling and construction of wells, 1999

[18] Culver, G.: Drilling and well construction, Chapter 6, OIST, Department of Energy 1998

[19] Vektor AS – Environmental developments in Well testing, 2000

[20] BP: Das Buch zum Erdöl (The book on Crude oil), 1989

[21] OGP, International Association of Oil and Gas Producers: Environmental performance in the E&P industry 2003

[22] US EPA: Compilation of Air pollutant emission factors, AP 42, Volume I: Stationary point and area sources, Fifth edition, United States Protection Agency, Office of air quality planning and standards, 1995-2000.

[23] US EPA: Profile of the Oil and Gas Extraction Industry, 2nd Section, 2000

[24] PSI: Management of produced water on offshore oil installations, Policy Studies Institute, 2005

[25] OGP: Aromatics in produced water occurrence, fate & effects and treatment, International Association of Oil and Gas Producers, 2002

[26] OGP: Fate and effects of naturally occurring substances in produced water on the marine environment, International Association of Oil and Gas Producers, 2005

[27] Leahey, G et at.: Theoretical and observational assessments of flare efficiencies, Journal of Air & Waste Management Association, Volume 51, December 2001

[28] Johnson, M.R. et al.: Efficiency measurements of flares in a cross flow, Dep. Of Mechanical Engineering, University of Alberta, Combustion Canada conference, 1999

Production of crude oil in Canada

1. Technology description of the Crude oil production

1.1 Introduction

The production of crude oil was modelled as a combined natural gas and crude oil production. In most cases beside crude oil, different parts of natural gas and NGL (natural gas liquids) are produced as by-products. For the different by-products allocation by lower calorific value was applied. The combined production comprises the exploration and production of crude oil and natural gas as well as all the desulphurization of natural gas. The data set includes all relevant parts of the upstream industry. Production may take place onshore and offshore. Both are taken into account proportionate to their ratio of the total production of a country.

1.2 Exploration

Exploration comprises the search of hydrocarbon (HC) deposits and the drilling of wells. The search for new deposits is conducted at first by seismic survey, which is not included in the data set. In a second step testing wells are drilled which can be characterized as wildcat wells for areas with low information about the subsurface, exploration wells for information gathering and appraisal wells to assess characteristics such as flow rate, amount of hydrocarbon, pressure and others. After a successful testing the production well is drilled to produce hydrocarbons.

Vertical wells are drilled by the rotary mode. The base of a drilling facility is a rig. For offshore drilling jack-up rigs, based on a buoyant steel hull with 3 or more legs, semi-submersible rigs, which float at all times on pontoons, or drill ships are used. The oil rig contains machinery and fulfils the role of superstructure bearing the load of a drill string. Driven by a diesel unit the drill string transmits his rotation on a drill bit, which brakes up the stone and extends the hole (up to 0,8 m wide). The drill string is gradually lengthened as the well gets deeper. The drill cuttings are removed by a drilling fluid (drilling mud), which is pumped inside the drill string, leaves the drill string at the drill bit and is then floated together with the drill cuttings back to the surface between drill string and the inner surface of the well due to the high pressure generated by piston pumps. At the rig the drilling fluid is separated from drill cuttings and circulated. The drilling fluid also serves to cool the drill bit, to seal the drill hole against seepage and to prevent wall cave-ins. Depending on geology and technology water-based, oil-based and synthetic-based fluids are used. They are mixed with barium sulphate and bentonite to increase the density of the fluid as well as further additives. After finishing the drilling or at least after 1000m, the well is cased with concrete and smoothly steel pipes (0.08-0.2 m diameter) and prepared for production. In general due to the lack of infrastructure for preparing and transportation, produced oil and gas is flared. Small amounts of gas are also vented into the atmosphere. During the drilling high amounts of drill cuttings and waste water arise. At offshore exploration the cuttings are discharged to water or brought ashore depending on drilling fluid and legislation.

1.3 Production & Preparation

Ideally the oil is transported as an oil-gas mixture to the surface without any effort by the high pressure of the hydrocarbon deposit. The flow of oil runs dry, when the pressure of the deposit will get lower as the flow resistance or when the pressure was already lower at the beginning. For further exploitation it is necessary to use pumps or to reinject a part of the separated natural gas to maintain a high pressure in the deposit. Advanced measures raise the production are the reinjection of produced water or sea water and the reinjection of steam to increase the viscosity or surface tension of the oil-gas mixture.

The produced oil-gas mixture is a composite of crude oil, natural gas, brine and other impurities. In a preparation process the natural gas and the NGL is separated from the oil. In a second preparation step most of the water is separated from the oil due to the different densities. The remaining emulsified water and salt is removed in a dewatering and desalting plant. Small amounts of produced natural gas are often still flared, sometimes also vented, due to missing preparation and transportation opportunities. Hydrogen sulphide contained in the natural gas in different concentrations, has to be removed before transportation via pipelines due to the high corrosive impact. The hydrogen sulphide is recovered from the natural gas by the Claus process producing elementary sulphur and, depending on technology standards, a certain amount of sulphur dioxide. The arising water with concentrations of approximately 15 or more mg hydrocarbons per litre is reinjected into the gas field, discharged into the sea (onshore and in shore) or evaporated in pits. During preparation different kinds of waste and used chemicals arise which have to be disposed. A certain amount of gas and oil is flared or vented into the atmosphere because of leakage or security reasons. The mechanical energy and electricity for pumping and all other machinery is provided by gas turbines and diesel units. At onshore facilities a certain amount is provided by the grid.

2 General comments of the LCA assessment method

This chapter gives background information on the principal modelling approach.

2.1 System boundaries and functional unit

Functional unit: The functional unit is 1 bbl of crude oil.

This process includes all relevant Mass and energy flows for the exploration and extraction of crude oil. Figure 2-1 gives an overview on the considered processes along with their key in- and outputs

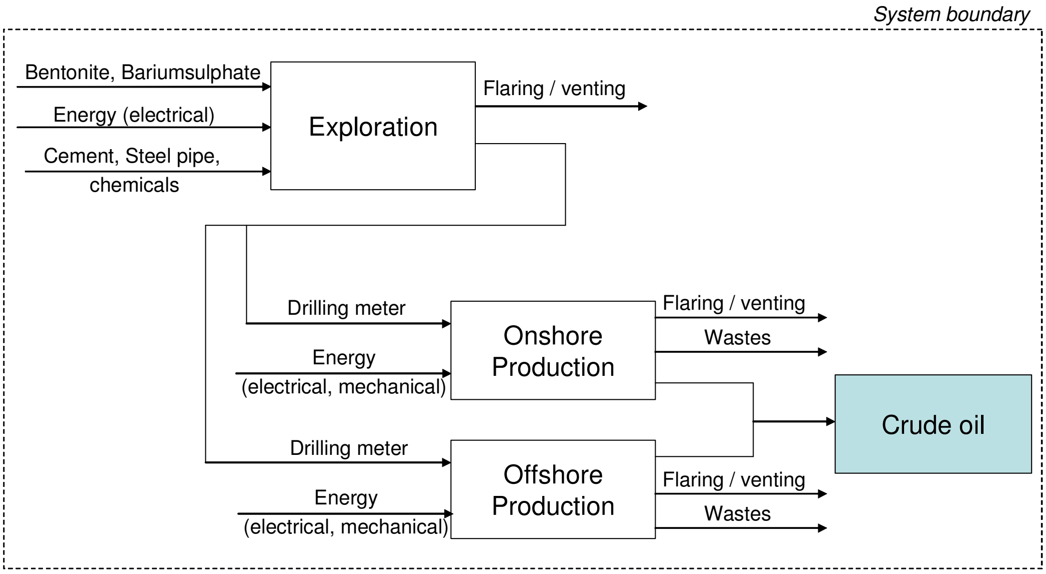


Figure 2-1 System boundary for crude oil production

The exploration is modelled per drilling meters and is considered in the model via drilling meters per mass of produced hydrocarbon. Quantities of borehole volume, removed rock are based on multiple sources such as [21]-[23]. Amount of Bentonite and Bariumsulphate and water for drilling mud is taken from [21]. The material used for reinforcing the well is calculated based on [24]-[27]. The power demand for drilling is taken from [28]. For venting of natural gas the averaged national natural gas composition is considered [29]. The energy demand for production is given in section 3.2. The associated emissions are calculated using emission factors sourced from [31] and industry data. Venting of solution gas from oil producing well is also considered. For flaring region specific flare emissions are included see section 3.3 and [30],[36],[37]. Solid wastes and waste water are considered. The referring data is sourced from [30], [32]-[35] and as stated in section 3.4. .

2.2 Allocation or system expansion

For the combined crude oil, natural gas and natural gas liquids production allocation by lower calorific value is applied. The lower heating values of the products are given in section 3.5.

2.3 Data completeness

The coverage for the exploration data (crude oil, natural gas, natural gas liquids) is 90% of mass and energy and 95% of the environmental relevance (expert judgement).

2.4 Data selection and combination principles

The data sources for the complete product system are sufficiently consistent: The data on the energy carrier supply chain is based on statistics with country/region specific transport distances and energy carrier composition as well as industry and literature data on the inventory of exploration, extraction and processing. LCI modelling is fully consistent.

2.5 Reference year

Reference year for the data set is 2002. Although some of the emission data and product properties are sourced from different years representativeness for the reference year is considered good.

2.6 Data treatment and extrapolations principles

In terms of the country/region specific crude oil production, missing data of certain parameters has been used from countries with a comparable technology[1]. Data measured at a group of representative production facilities have been used to represent the national production.

---

[1] If this ist he case it is indicated in the tables in section 3.

3 Country specific data

3.1 Production

Table 1 shows the production ratio of natural gas, NGL and crude oil on a weight basis as well as the drilling feet per pound hydrocarbon produced. Note that all values are given for unallocated joint production of Natural gas, NGL and crude oil.

Table 1 Production parameters

Parameter	Value	Source
Portion of natural gas production	56.22%	[1]
Portion of NGL production	7.73%	[1]
Portion of crude oil production	36.05%	[1]
Drilling meters for onshore production	0.42×10^{-05} ft/lb HC produced	[2]
Drilling meters for offshore production	0.67×10^{-05} ft/lb HC produced	[2]

3.2 Energy use

The specific energy use distinguished between electricity and mechanical energy is shown in Table 2.

Table 2 Energy consumption parameters

Parameter	Value	Source
Electricity demand	85.98 Btu/lb HC	[5] and own calculations
Mechanical energy demand	412.71 Btu/lb HC	[5] and own calculations
Total energy demand	498.70 Btu/lb HC	[5] and own calculations

3.3 Flaring and venting

The flaring and venting of hydrocarbons during the production process is shown in Table 3. The flared Hydrocarbons are the sum of flared natural gas and solution gas compounds.

Table 3 Flaring and venting parameters

Parameter	Value	Source
Flared Hydrocarbons	0.0072 lb/lb HC	[5];[6];[7]
Vented Hydrocarbons	0.0043 lb/lb HC	[6];[7]

3.4 Waste and waste water

The amount of solid waste and waste water emitted during the production process is summarised in Table 4.

Table 4 Waste and waste water parameters

Parameter	Value	Source
Solid waste	0.0060 lb/lb HC	Global value Calculated from [8];[9];[10];[11];[12];[13];[14]
Waste water onshore	0.017 lb/lb HC	[30]
Waste water offshore	0.91 lb/lb HC	[30]

3.5 Product properties

The lower heating value as a country specific product property is given in Table 5.

Table 5 Product properties

Parameter	Value	Source
Net calorific value natural gas	19496.42 Btu/lb	[15]
Net calorific value crude oil	18008.93 Btu/lb	[16];[17];[18];[19];[20]

4 References

[1] IEA: Natural Gas Information 2002, International Energy Agency, 2004

[2] IEA: Oil information 2002, International Energy Agency, 2004

[3] Pennwell: The international petroleum Encyclopaedia 1997

[4] British Columbia, CA: Ministry of Energy, Mines and Petroleum Resources: Drilling, Production and Distribution Statistics 1994 – 2004, 2005

[5] Canadian Association of Petroleum Producers (CAPP): A National Inventory of Greenhouse Gas ; 2004

[6] UKOOA: Accidental Oil Spills, 1999

[7] CAPP - Canadian Association of Petroleum Producers: Estimation of Flaring and Venting Volumes from Upstream Oil and Gas facilities, 2002

[8] Yukos: Yukos and the environment, 2003

[9] Shell: Sustainability report 2003, http://www.shell.com/home/Framework?siteId=my-en&FC2=/my-en/html/iwgen/society_environment/environment/sustainable2003/zzz_lhn.html&FC3=/my-en/html/iwgen/society_environment/environment/sustainable2003/sd03_protecttheenvironment_1008.html, 2004

[10] Shell Nigeria 2004 People and the environment Annual Report,2005

[11] Nederlandse Aardolie Maatschappij (NAM): Bron van energie, 2003

[12] BP Pakistan 2003 Environmental Statement, 2004

[13] BP Trinidad & Tobago: 2003 Environmental Statement Trinidad BU, 2004

[14] Shell in the UK report 2001, 2002

[15] Newfoundland Ocean Industries Association: Natural Gas Utilization Study, 1998

[16] EIA: C.2 Barrels of Crude Oil Per Metric Ton, 1980-2003, 2005

[17] EIA: C.3 Gross Heat Content of Crude Oil, 1980-2003, 2005

[18] Haverly: Crude assay libraries, 2005

[19] ChevronTexaco: http://www.chevrontexaco.com/crudemarketing, 2005

[20] Energy Intelligence Group: The Crude Oils and Their Key Characteristics, 2003

[21] OGP: Environmental aspects of the use and disposal of non aqueous drilling fluids associated with offshore oil& gas operations, 2003

[22] Da Prat, G.: Well Testing management , SPE Foundation, presentation 2002

[23] Vickery et al.: Successful high rate gas completion through combination of extreme overbalance perforating and one trip perforate and gravel pack techniques, Baker oil tools, 2001

[24] N. Lapeyrouse: Formulas and calculations for Drilling, Production and work over, 2nd Edition, Golf Professional Publishing, 2002

[25] Gordon, D. et al. Underbalanced Drilling with casing SPE, SPE Drilling & completion 2005

[26] Ohio Department of Health: Materials used in drilling and construction of wells, 1999

[27] Culver, G.: Drilling and well construction, Chapter 6, OIST, Department of Energy 1998

[28] Vektor AS – Environmental developments in Well testing, 2000

[29] Uniongas, http://www.uniongas.com/aboutus/aboutng/composition.asp,2006

[30] OGP, International Association of Oil and Gas Producers: Environmental performance in the E&P industry 2003

[31] US EPA: Compilation of Air pollutant emission factors, AP 42, Volume I: Stationary point and area sources, Fifth edition, United States Protection Agency, Office of air quality planning and standards, 1995-2000.

[32] US EPA: Profile of the Oil and Gas Extraction Industry, 2nd Section, 2000

[33] PSI: Management of produced water on offshore oil installations, Policy Studies Institute, 2005

[34] OGP: Aromatics in produced water occurrence, fate & effects and treatment, International Association of Oil and Gas Producers, 2002

[35] OGP: Fate and effects of naturally occurring substances in produced water on the marine environment, International Association of Oil and Gas Producers, 2005

[36] Leahey, G et at.: Theoretical and observational assessments of flare efficiencies, Journal of Air & Waste Management Association, Volume 51, December 2001

[37] Johnson, M.R. et al.: Efficiency measurements of flares in a cross flow, Dep. Of Mechanical Engineering, University of Alberta, Combustion Canada conference, 1999

Production of crude oil in Ecuador

1. Technology description of the Crude oil production

1.1 Introduction

The production of crude oil was modelled as a combined natural gas and crude oil production. In most cases beside crude oil, different parts of natural gas and NGL (natural gas liquids) are produced as by-products. For the different by-products allocation by lower calorific value was applied. The combined production comprises the exploration and production of crude oil and natural gas as well as all the desulphurization of natural gas. The data set includes all relevant parts of the upstream industry. Production may take place onshore and offshore. Both are taken into account proportionate to their ratio of the total production of a country.

1.2 Exploration

Exploration comprises the search of hydrocarbon (HC) deposits and the drilling of wells. The search for new deposits is conducted at first by seismic survey, which is not included in the data set. In a second step testing wells are drilled which can be characterized as wildcat wells for areas with low information about the subsurface, exploration wells for information gathering and appraisal wells to assess characteristics such as flow rate, amount of hydrocarbon, pressure and others. After a successful testing the production well is drilled to produce hydrocarbons.

Vertical wells are drilled by the rotary mode. The base of a drilling facility is a rig. For offshore drilling jack-up rigs, based on a buoyant steel hull with 3 or more legs, semi-submersible rigs, which float at all times on pontoons, or drill ships are used. The oil rig contains machinery and fulfils the role of superstructure bearing the load of a drill string. Driven by a diesel unit the drill string transmits his rotation on a drill bit, which brakes up the stone and extends the hole (up to 0,8 m wide). The drill string is gradually lengthened as the well gets deeper. The drill cuttings are removed by a drilling fluid (drilling mud), which is pumped inside the drill string, leaves the drill string at the drill bit and is then floated together with the drill cuttings back to the surface between drill string and the inner surface of the well due to the high pressure generated by piston pumps. At the rig the drilling fluid is separated from drill cuttings and circulated. The drilling fluid also serves to cool the drill bit, to seal the drill hole against seepage and to prevent wall cave-ins. Depending on geology and technology water-based, oil-based and synthetic-based fluids are used. They are mixed with barium sulphate and bentonite to increase the density of the fluid as well as further additives. After finishing the drilling or at least after 1000m, the well is cased with concrete and smoothly steel pipes (0.08-0.2 m diameter) and prepared for production. In general due to the lack of infrastructure for preparing and transportation, produced oil and gas is flared. Small amounts of gas are also vented into the atmosphere. During the drilling high amounts of drill cuttings and waste water arise. At offshore exploration the cuttings are discharged to water or brought ashore depending on drilling fluid and legislation.

1.3 Production & Preparation

Ideally the oil is transported as an oil-gas mixture to the surface without any effort by the high pressure of the hydrocarbon deposit. The flow of oil runs dry, when the pressure of the deposit will get lower as the flow resistance or when the pressure was already lower at the beginning. For further exploitation it is necessary to use pumps or to reinject a part of the separated natural gas to maintain a high pressure in the deposit. Advanced measures raise the production are the reinjection of produced water or sea water and the reinjection of steam to increase the viscosity or surface tension of the oil-gas mixture.

The produced oil-gas mixture is a composite of crude oil, natural gas, brine and other impurities. In a preparation process the natural gas and the NGL is separated from the oil. In a second preparation step most of the water is separated from the oil due to the different densities. The remaining emulsified water and salt is removed in a dewatering and desalting plant. Small amounts of produced natural gas are often still flared, sometimes also vented, due to missing preparation and transportation opportunities. Hydrogen sulphide contained in the natural gas in different concentrations, has to be removed before transportation via pipelines due to the high corrosive impact. The hydrogen sulphide is recovered from the natural gas by the Claus process producing elementary sulphur and, depending on technology standards, a certain amount of sulphur dioxide. The arising water with concentrations of approximately 15 or more mg hydrocarbons per litre is reinjected into the gas field, discharged into the sea (onshore and in shore) or evaporated in pits. During preparation different kinds of waste and used chemicals arise which have to be disposed. A certain amount of gas and oil is flared or vented into the atmosphere because of leakage or security reasons. The mechanical energy and electricity for pumping and all other machinery is provided by gas turbines and diesel units. At onshore facilities a certain amount is provided by the grid.

2 General comments of the LCA assessment method

This chapter gives background information on the principal modelling approach.

2.1 System boundaries and functional unit

Functional unit: The functional unit is 1 bbl of crude oil.

This process includes all relevant Mass and energy flows for the exploration and extraction of crude oil. Figure 2-1 gives an overview on the considered processes along with their key in- and outputs

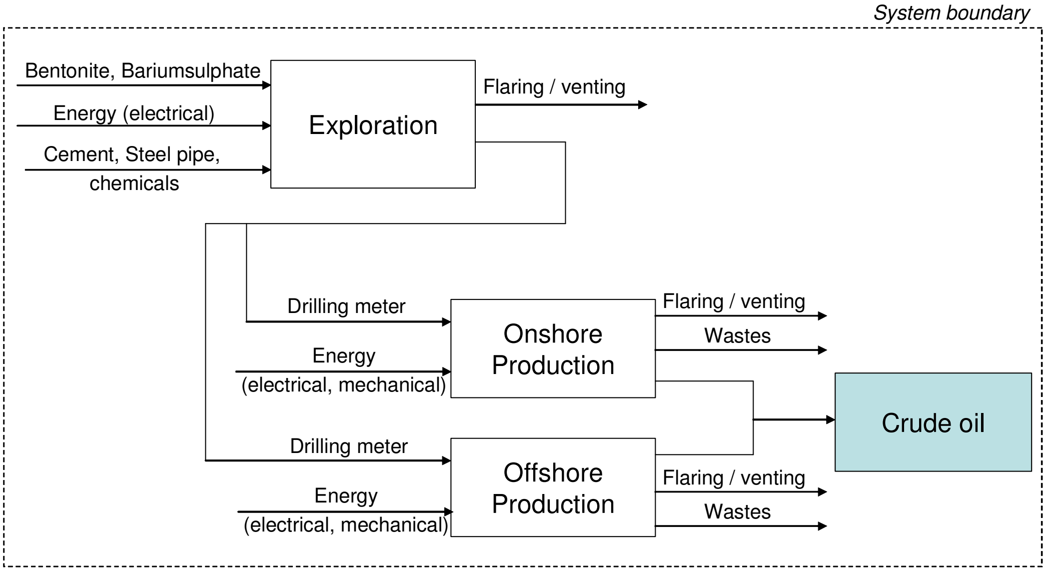


Figure 2-1 **System boundary for crude oil production**

The exploration is modelled per drilling meters and is considered in the model via drilling meters per mass of produced hydrocarbon. Quantities of borehole volume, removed rock are based on multiple sources such as [11]-[13]. Amount of bentonite and bariumsulphate and water for drilling mud is taken from [11]. The material used for reinforcing the well is calculated based on [14]-[17]. The power demand for drilling is taken from [18]. For venting of natural gas the averaged national natural gas composition is [19]. The energy demand for production is given in section 3.2. The associated emissions are calculated using emission factors sourced from [20] and industry data. Venting of solution gas from oil producing well is also considered. For flaring region specific flare emissions are included see section 3.3 and [4],[25],[26]. Solid wastes and waste water are considered. The referring data is sourced from [4], [21]-[24] and as stated in section 3.4.

2.2 Allocation or system expansion

For the combined crude oil, natural gas and natural gas liquids production allocation by lower calorific value is applied. The lower heating values of the products are given in section 3.5.

2.3 Data completeness

The coverage for the exploration data (crude oil, natural gas, natural gas liquids) is 90% of mass and energy and 95% of the environmental relevance (expert judgement).

2.4 Data selection and combination principles

The data sources for the complete product system are sufficiently consistent: The data on the energy carrier supply chain is based on statistics with country/region specific transport distances and energy carrier composition as well as industry and literature data on the inventory of exploration, extraction and processing. LCI modelling is fully consistent.

2.5 Reference year

Reference year for the data set is 2002. Although some of the emission data and product properties are sourced from different years representativeness for the reference year is considered good.

2.6 Data treatment and extrapolations principles

In terms of the country/region specific crude oil production, missing data of certain parameters has been used from countries with a comparable technology[1]. Data measured at a group of representative production facilities have been used to represent the national production.

---

[1] If this ist he case it is indicated in the tables in section 3.

3 Country specific data

3.1 Production

Table 1 shows the production ratio of natural gas, NGL and crude oil on a weight basis as well as the drilling feet per pound hydrocarbon produced.

Table 1 Production parameters

Parameter	Value	Source
Portion of natural gas production	0%	[1]
Portion of NGL production	0.41%	[1]
Portion of crude oil production	99.59%	[2]
Drilling meters for onshore production	0.46 x10^{-06} ft/lb HC produced	[3]

3.2 Energy use

The specific energy use distinguished between electricity and mechanical energy is shown in Table 2.

Table 2 Energy consumption parameters

Parameter	Value	Source
Electricity demand	22.79 Btu/lb HC	Value for Region Latin America [4] and own calulations
Mechanical energy demand	206.36 Btu/lb HC	Value for Region Latin America [4] and own calulations
Total energy demand	227.85 Btu/lb HC	Value for Region Latin America [4]

3.3 Flaring and venting

The flaring and venting of hydrocarbons during the production process is shown in Table 3. The flared Hydrocarbons are the sum of flared natural gas and solution gas compounds.

Table 3 Flaring and venting parameters

Parameter	Value	Source
Flared Hydrocarbons	0.033 lb/lb HC	[10]
Vented Hydrocarbons	0.0011 lb/lb HC	[10]

3.4 Waste and waste water

The amount of solid waste and waste water emitted during the production process is summarised in Table 4.

Table 4 Waste and waste water parameters

Parameter	Value	Source
Solid waste	0.000073 lb/lb HC	Value for Trinidad Tobago [5]
Waste water onshore	0.017 lb/lb HC	Value for Region Latin America [4]

3.5 Product properties

The lower heating value as a country specific product property is given in Table 5.

Table 5 Product properties

Parameter	Value	Source
Net calorific value natural gas	20760.35 Btu/lb	[1]
Net calorific value crude oil	18094.91 Btu/lb	[6];[7];[8];[9]

4 References

[1] IEA: Natural Gas Information 2002, International Energy Agency, 2004

[2] IEA: Oil information 2002, International Energy Agency, 2004

[3] Pennwell: The international petroleum Encyclopedia 1997

[4] OGP, International Association of Oil and Gas Producers: Environmental performance in the E&P industry 2003

[5] BP Trinidad & Tobago: 2003 Environmental Statement Trinidad BU, 2004

[6] EIA: C.2 Barrels of Crude Oil Per Metric Ton, 1980-2003, 2004

[7] EIA: C.3 Gross Heat Content of Crude Oil, 1980-2003, 2004

[8] Haverly: Crude assay libraries, 2005

[9] Energy Intelligence Group: The Crude Oils and Their Key Characteristics, 2003

[10] EIA: International Energy Annual 2003; Energy Information Administration, 2004

[11] OGP: Environmental aspects of the use and disposal of non aqueous drilling fluids associated with offshore oil& gas operations, 2003

[12] Da Prat, G.: Well Testing management , SPE Foundation, presentation 2002

[13] Vickery et al.: Successful high rate gas completion through combination of extreme overbalance perforating and one trip perforate and gravel pack techniques, Baker oil tools, 2001

[14] N. Lapeyrouse: Formulas and calculations for Drilling, Production and work over, 2nd Edition, Golf Professional Publishing, 2002

[15] Gordon, D. et al. Underbalanced Drilling with casing SPE, SPE Drilling & completion 2005

[16] Ohio Department of Health: Materials used in drilling and construction of wells, 1999

[17] Culver, G.: Drilling and well construction, Chapter 6, OIST, Department of Energy 1998

[18] Vektor AS – Environmental developments in Well testing, 2000

[19] EIA: C.5 Gross Heat Content of Dry Natural Gas Production, 1980-2004, 2005

[20] US EPA: Compilation of Air pollutant emission factors, AP 42, Volume I: Stationary point and area sources, Fifth edition, United States Protection Agency, Office of air quality planning and standards, 1995-2000.

[21] US EPA: Profile of the Oil and Gas Extraction Industry, 2nd Section, 2000

[22] PSI: Management of produced water on offshore oil installations, Policy Studies Institute, 2005

[23] OGP: Aromatics in produced water occurrence, fate & effects and treatment, International Association of Oil and Gas Producers, 2002

[24] OGP: Fate and effects of naturally occurring substances in produced water on the marine environment, International Association of Oil and Gas Producers, 2005

[25] Leahey, G et at.: Theoretical and observational assessments of flare efficiencies, Journal of Air & Waste Management Association, Volume 51, December 2001

[26] Johnson, M.R. et al.: Efficiency measurements of flares in a cross flow, Dep. Of Mechanical Engineering, University of Alberta, Combustion Canada conference, 1999

Production of crude oil in Iraq

1. Technology description of the Crude oil production

1.1 Introduction

The production of crude oil was modelled as a combined natural gas and crude oil production. In most cases beside crude oil, different parts of natural gas and NGL (natural gas liquids) are produced as by-products. For the different by-products allocation by lower calorific value was applied. The combined production comprises the exploration and production of crude oil and natural gas as well as all the desulphurization of natural gas. The data set includes all relevant parts of the upstream industry. Production may take place onshore and offshore. Both are taken into account proportionate to their ratio of the total production of a country.

1.2 Exploration

Exploration comprises the search of hydrocarbon (HC) deposits and the drilling of wells. The search for new deposits is conducted at first by seismic survey, which is not included in the data set. In a second step testing wells are drilled which can be characterized as wildcat wells for areas with low information about the subsurface, exploration wells for information gathering and appraisal wells to assess characteristics such as flow rate, amount of hydrocarbon, pressure and others. After a successful testing the production well is drilled to produce hydrocarbons.

Vertical wells are drilled by the rotary mode. The base of a drilling facility is a rig. For offshore drilling jack-up rigs, based on a buoyant steel hull with 3 or more legs, semi-submersible rigs, which float at all times on pontoons, or drill ships are used. The oil rig contains machinery and fulfils the role of superstructure bearing the load of a drill string. Driven by a diesel unit the drill string transmits his rotation on a drill bit, which brakes up the stone and extends the hole (up to 0,8 m wide). The drill string is gradually lengthened as the well gets deeper. The drill cuttings are removed by a drilling fluid (drilling mud), which is pumped inside the drill string, leaves the drill string at the drill bit and is then floated together with the drill cuttings back to the surface between drill string and the inner surface of the well due to the high pressure generated by piston pumps. At the rig the drilling fluid is separated from drill cuttings and circulated. The drilling fluid also serves to cool the drill bit, to seal the drill hole against seepage and to prevent wall cave-ins. Depending on geology and technology water-based, oil-based and synthetic-based fluids are used. They are mixed with barium sulphate and bentonite to increase the density of the fluid as well as further additives. After finishing the drilling or at least after 1000m, the well is cased with concrete and smoothly steel pipes (0.08-0.2 m diameter) and prepared for production. In general due to the lack of infrastructure for preparing and transportation, produced oil and gas is flared. Small amounts of gas are also vented into the atmosphere. During the drilling high amounts of drill cuttings and waste water arise. At offshore exploration the cuttings are discharged to water or brought ashore depending on drilling fluid and legislation.

1.3 Production & Preparation

Ideally the oil is transported as an oil-gas mixture to the surface without any effort by the high pressure of the hydrocarbon deposit. The flow of oil runs dry, when the pressure of the deposit will get lower as the flow resistance or when the pressure was already lower at the beginning. For further exploitation it is necessary to use pumps or to reinject a part of the separated natural gas to maintain a high pressure in the deposit. Advanced measures raise the production are the reinjection of produced water or sea water and the reinjection of steam to increase the viscosity or surface tension of the oil-gas mixture.

The produced oil-gas mixture is a composite of crude oil, natural gas, brine and other impurities. In a preparation process the natural gas and the NGL is separated from the oil. In a second preparation step most of the water is separated from the oil due to the different densities. The remaining emulsified water and salt is removed in a dewatering and desalting plant. Small amounts of produced natural gas are often still flared, sometimes also vented, due to missing preparation and transportation opportunities. Hydrogen sulphide contained in the natural gas in different concentrations, has to be removed before transportation via pipelines due to the high corrosive impact. The hydrogen sulphide is recovered from the natural gas by the Claus process producing elementary sulphur and, depending on technology standards, a certain amount of sulphur dioxide. The arising water with concentrations of approximately 15 or more mg hydrocarbons per litre is reinjected into the gas field, discharged into the sea (onshore and in shore) or evaporated in pits. During preparation different kinds of waste and used chemicals arise which have to be disposed. A certain amount of gas and oil is flared or vented into the atmosphere because of leakage or security reasons. The mechanical energy and electricity for pumping and all other machinery is provided by gas turbines and diesel units. At onshore facilities a certain amount is provided by the grid.

2 General comments of the LCA assessment method

This chapter gives background information on the principal modelling approach.

2.1 System boundaries and functional unit

Functional unit: The functional unit is 1 bbl of crude oil.

This process includes all relevant Mass and energy flows for the exploration and extraction of crude oil. Figure 2-1 gives an overview on the considered processes along with their key in- and outputs

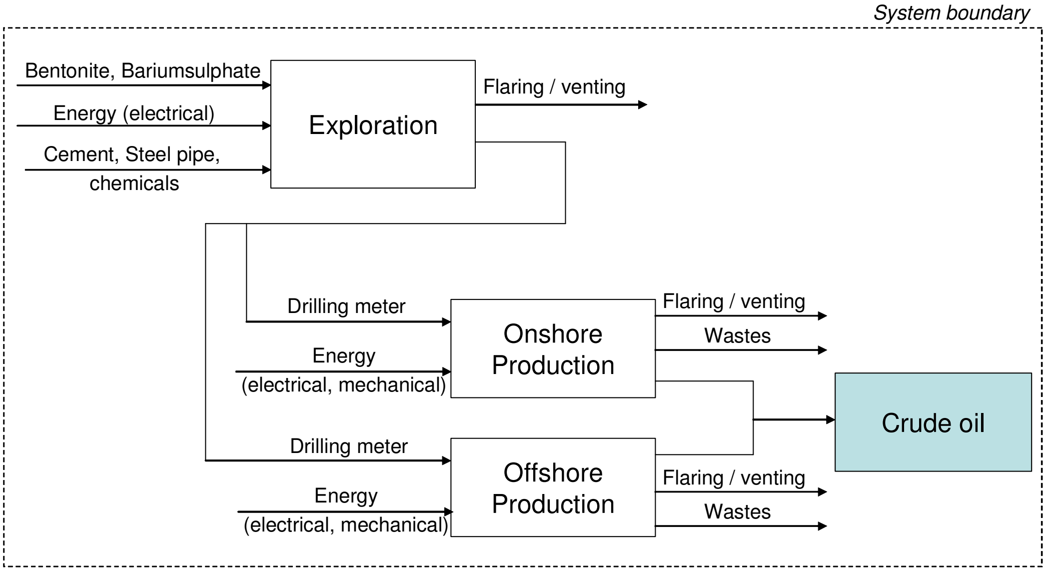


Figure 2-1 System boundary for crude oil production

The exploration is modelled per drilling meters and is considered in the model via drilling meters per mass of produced hydrocarbon. Quantities of borehole volume, removed rock are based on multiple sources such as [15]-[17]. Amount of Bentonite and Bariumsulphate and water for drilling mud is taken from [15]. The material used for reinforcing the well is calculated based on [18]-[21]. The power demand for drilling is taken from [22]. For venting of natural gas the averaged national natural gas composition is considered [30]. The energy demand for production is given in section 3.2. The associated emissions are calculated using emission factors sourced from [23] and industry data. Venting of solution gas from oil producing well is also considered. For flaring region specific flare amounts and emissions are included, see section 3.3 and [4], [28], [29]. Solid wastes and waste water are considered. The referring data is sourced from [4], [24]-[27] and as stated in section 3.4.

2.2 Allocation or system expansion

For the combined crude oil, natural gas and natural gas liquids production allocation by lower calorific value is applied. The lower heating values of the products are given in section 3.5.

2.3 Data completeness

The coverage for the exploration data (crude oil, natural gas, natural gas liquids) is 90% of mass and energy and 95% of the environmental relevance (expert judgement).

2.4 Data selection and combination principles

The data sources for the complete product system are sufficiently consistent: The data on the energy carrier supply chain is based on statistics with country/region specific transport distances and energy carrier composition as well as industry and literature data on the inventory of exploration, extraction and processing. LCI modelling is fully consistent.

2.5 Reference year

Reference year for the data set is 2002. Although some of the emission data and product properties are sourced from different years representativeness for the reference year is considered good.

2.6 Data treatment and extrapolations principles

In terms of the country/region specific crude oil production, missing data of certain parameters has been used from countries with a comparable technology[1]. Data measured at a group of representative production facilities have been used to represent the national production.

---

[1] If this ist he case it is indicated in the tables in section 3.

3 Country specific data

3.1 Production

Table 1 shows the production ratio of natural gas, NGL and crude oil on a weight basis as well as the drilling feet per pound hydrocarbon produced.

Table 1 Production parameters

Parameter	Value	Source
Portion of natural gas production	3.18%	[1]
Portion of NGL production	0.64%	[1]
Portion of crude oil production	96.18%	[2]
Drilling meters for onshore production	0.29x10-07 ft/lb HC produced	[3]

3.2 Energy use

The specific energy use distinguished between electricity and mechanical energy is shown in Table 2.

Table 2 Energy consumption parameters

Parameter	Value	Source
Electricity demand	24.50 Btu/lb HC	Value for middle east region [4] and own calculations
Mechanical energy demand	219.25 Btu/lb HC	Value for middle east region [4] and own calculations
Total energy demand	245.05 Btu/lb HC	Value for middle east region [4]

3.3 Flaring and venting

The flaring and venting of hydrocarbons during the production process is shown in Table 3. The flared Hydrocarbons are the sum of flared natural gas and solution gas compounds.

Table 3 Flaring and venting parameters

Parameter	Value	Source
Flared Hydrocarbons	0.0059 lb/lb HC	[14]
Vented Hydrocarbons	0.0017 lb/lb HC	[14]

3.4 Waste and waste water

The amount of solid waste and waste water emitted during the production process is summarised in Table 4.

Table 4 Waste and waste water parameters

Parameter	Value	Source
Solid waste	0.0060 lb/lb HC	Global value [5];[6];[7];[8];[9];[10];[11]
Waste water onshore	0.030 lb/lb HC	Value for middle east region [4]

3.5 Product properties

The lower heating value as a country specific product property is given in Table 5.

Table 5 Product properties

Parameter	Value	Source
Net calorific value natural gas	18413.05 Btu/lb	[1]
Net calorific value crude oil	18288.37 Btu/lb	[12];[13]

4 References

[1] IEA: Natural Gas Information 2002, International Energy Agency, 2004

[2] IEA: Oil information 2002, International Energy Agency, 2004

[3] Pennwell: The international petroleum Encyclopaedia 1997

[4] OGP, International Association of Oil and Gas Producers: Environmental performance in the E&P industry 2003, 2004

[5] Yukos: Yukos and the environment, 2003

[6] Shell: http://www.shell.com/home/Framework?siteId=my-en&FC2=/my-en/html/iwgen/society_environment/environment/sustainable2003/zzz_lhn.html&FC3=/my-en/html/iwgen/society_environment/environment/sustainable2003/sd03_protecttheenvironment_1008.html, 2004

[7] Shell Nigeria 2004 People and the environment Annual Report, 2005

[8] Nederlandse Aardolie Maatschappij (NAM): Bron van energie, 2003

[9] BP Pakistan 2003 Environmental Statement, 2004

[10] BP Trinidad & Tobago: 2003 Environmental Statement Trinidad BU, 2004

[11] Shell in the UK report 2001, 2002

[12] Haverly: Crude assay libraries, 2005

[13] Energy Intelligence Group: The Crude Oils and Their Key Characteristics, 2003

[14] EIA: International Energy Annual 2003; Energy Information Administration, 2004

[15] OGP: Environmental aspects of the use and disposal of non aqueous drilling fluids associated with offshore oil& gas operations, 2003

[16] Da Prat, G.: Well Testing management , SPE Foundation, presentation 2002

[17] Vickery et al.: Successful high rate gas completion through combination of extreme overbalance perforating and one trip perforate and gravel pack techniques, Baker oil tools, 2001

[18] N. Lapeyrouse: Formulas and calculations for Drilling, Production and work over, 2nd Edition, Golf Professional Publishing, 2002

[19] Gordon, D. et al. Underbalanced Drilling with casing SPE, SPE Drilling & completion 2005

[20] Ohio Department of Health: Materials used in drilling and construction of wells, 1999

[21] Culver, G.: Drilling and well construction, Chapter 6, OIST, Department of Energy 1998

[22] Vektor AS – Environmental developments in Well testing, 2000

[23] US EPA: Compilation of Air pollutant emission factors, AP 42, Volume I: Stationary point and area sources, Fifth edition, United States Protection Agency, Office of air quality planning and standards, 1995-2000.

[24] US EPA: Profile of the Oil and Gas Extraction Industry, 2nd Section, 2000

[25] PSI: Management of produced water on offshore oil installations, Policy Studies Institute, 2005

[26] OGP: Aromatics in produced water occurrence, fate & effects and treatment, International Association of Oil and Gas Producers, 2002

[27] OGP: Fate and effects of naturally occurring substances in produced water on the marine environment, International Association of Oil and Gas Producers, 2005

[28] Leahey, G et at.: Theoretical and observational assessments of flare efficiencies, Journal of Air & Waste Management Association, Volume 51, December 2001

[29] Johnson, M.R. et al.: Efficiency measurements of flares in a cross flow, Dep. Of Mechanical Engineering, University of Alberta, Combustion Canada conference, 1999

[30] EIA: C.5 Gross Heat Content of Dry Natural Gas Production, 1980-2004, 2005

Production of crude oil in Kuwait

1. Technology description of the Crude oil production

1.1 Introduction

The production of crude oil was modelled as a combined natural gas and crude oil production. In most cases beside crude oil, different parts of natural gas and NGL (natural gas liquids) are produced as by-products. For the different by-products allocation by lower calorific value was applied. The combined production comprises the exploration and production of crude oil and natural gas as well as all the desulphurization of natural gas. The data set includes all relevant parts of the upstream industry. Production may take place onshore and offshore. Both are taken into account proportionate to their ratio of the total production of a country.

1.2 Exploration

Exploration comprises the search of hydrocarbon (HC) deposits and the drilling of wells. The search for new deposits is conducted at first by seismic survey, which is not included in the data set. In a second step testing wells are drilled which can be characterized as wildcat wells for areas with low information about the subsurface, exploration wells for information gathering and appraisal wells to assess characteristics such as flow rate, amount of hydrocarbon, pressure and others. After a successful testing the production well is drilled to produce hydrocarbons.

Vertical wells are drilled by the rotary mode. The base of a drilling facility is a rig. For offshore drilling jack-up rigs, based on a buoyant steel hull with 3 or more legs, semi-submersible rigs, which float at all times on pontoons, or drill ships are used. The oil rig contains machinery and fulfils the role of superstructure bearing the load of a drill string. Driven by a diesel unit the drill string transmits his rotation on a drill bit, which brakes up the stone and extends the hole (up to 0,8 m wide). The drill string is gradually lengthened as the well gets deeper. The drill cuttings are removed by a drilling fluid (drilling mud), which is pumped inside the drill string, leaves the drill string at the drill bit and is then floated together with the drill cuttings back to the surface between drill string and the inner surface of the well due to the high pressure generated by piston pumps. At the rig the drilling fluid is separated from drill cuttings and circulated. The drilling fluid also serves to cool the drill bit, to seal the drill hole against seepage and to prevent wall cave-ins. Depending on geology and technology water-based, oil-based and synthetic-based fluids are used. They are mixed with barium sulphate and bentonite to increase the density of the fluid as well as further additives. After finishing the drilling or at least after 1000m, the well is cased with concrete and smoothly steel pipes (0.08-0.2 m diameter) and prepared for production. In general due to the lack of infrastructure for preparing and transportation, produced oil and gas is flared. Small amounts of gas are also vented into the atmosphere. During the drilling high amounts of drill cuttings and waste water arise. At offshore exploration the cuttings are discharged to water or brought ashore depending on drilling fluid and legislation.

1.3 Production & Preparation

Ideally the oil is transported as an oil-gas mixture to the surface without any effort by the high pressure of the hydrocarbon deposit. The flow of oil runs dry, when the pressure of the deposit will get lower as the flow resistance or when the pressure was already lower at the beginning. For further exploitation it is necessary to use pumps or to reinject a part of the separated natural gas to maintain a high pressure in the deposit. Advanced measures raise the production are the reinjection of produced water or sea water and the reinjection of steam to increase the viscosity or surface tension of the oil-gas mixture.

The produced oil-gas mixture is a composite of crude oil, natural gas, brine and other impurities. In a preparation process the natural gas and the NGL is separated from the oil. In a second preparation step most of the water is separated from the oil due to the different densities. The remaining emulsified water and salt is removed in a dewatering and desalting plant. Small amounts of produced natural gas are often still flared, sometimes also vented, due to missing preparation and transportation opportunities. Hydrogen sulphide contained in the natural gas in different concentrations, has to be removed before transportation via pipelines due to the high corrosive impact. The hydrogen sulphide is recovered from the natural gas by the Claus process producing elementary sulphur and, depending on technology standards, a certain amount of sulphur dioxide. The arising water with concentrations of approximately 15 or more mg hydrocarbons per litre is reinjected into the gas field, discharged into the sea (onshore and in shore) or evaporated in pits. During preparation different kinds of waste and used chemicals arise which have to be disposed. A certain amount of gas and oil is flared or vented into the atmosphere because of leakage or security reasons. The mechanical energy and electricity for pumping and all other machinery is provided by gas turbines and diesel units. At onshore facilities a certain amount is provided by the grid.

2 General comments of the LCA assessment method

This chapter gives background information on the principal modelling approach.

2.1 System boundaries and functional unit

Functional unit: The functional unit is 1 bbl of crude oil.

This process includes all relevant Mass and energy flows for the exploration and extraction of crude oil. Figure 2-1 gives an overview on the considered processes along with their key in- and outputs

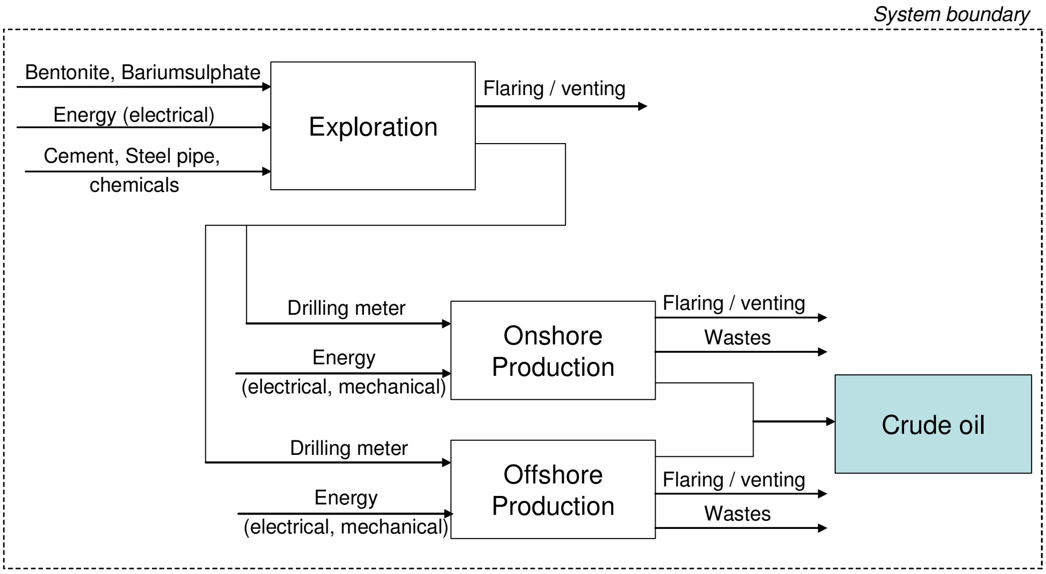


Figure 2-1 System boundary for crude oil production

The exploration is modelled per drilling meters and is considered in the model via drilling meters per mass of produced hydrocarbon. Quantities of borehole volume, removed rock are based on multiple sources such as [3],[16],[17]. Amount of Bentonite and Bariumsulphate and water for drilling mud is taken from [3]. The material used for reinforcing the well is calculated based on [18]-[21]. The power demand for drilling is taken from [22]. For venting of natural gas the averaged national natural gas composition is considered [33], [23] and [32]. The energy demand for production is given in section 3.2. The associated emissions are calculated using emission factors sourced from [25] and industry data. Venting of solution gas from oil producing well is also considered. For flaring region specific flare amounts and emissions are included, see section 3.3 and [24], [30], [31]. Solid wastes and waste water are considered. The referring data is sourced from [24], [26]-[29] and as stated in section 3.4.

2.2 Allocation or system expansion

For the combined crude oil, natural gas and natural gas liquids production allocation by lower calorific value is applied. The lower heating values of the products are given in section 3.5.

2.3 Data completeness

The coverage for the exploration data (crude oil, natural gas, natural gas liquids) is 90% of mass and energy and 95% of the environmental relevance (expert judgement).

2.4 Data selection and combination principles

The data sources for the complete product system are sufficiently consistent: The data on the energy carrier supply chain is based on statistics with country/region specific transport distances and energy carrier composition as well as industry and literature data on the inventory of exploration, extraction and processing. LCI modelling is fully consistent.

2.5 Reference year

Reference year for the data set is 2002. Although some of the emission data and product properties are sourced from different years representativeness for the reference year is considered good.

2.6 Data treatment and extrapolations principles

In terms of the country/region specific crude oil production, missing data of certain parameters has been used from countries with a comparable technology[1]. Data measured at a group of representative production facilities have been used to represent the national production.

---

[1] If this ist he case it is indicated in the tables in section 3.

3 Country specific data

3.1 Production

Table 1 shows the production ratio of natural gas, NGL and crude oil on a weight basis as well as the drilling feet per pound hydrocarbon produced.

Table 1 Production parameters

Parameter	Value	Source
Portion of natural gas production	6.44%	[33]
Portion of NGL production	3.70%	[33]
Portion of crude oil production	89.86%	[1]
Drilling meters for onshore production	1.23×10^{-07} ft/lb HC produced	[2]

3.2 Energy use

The specific energy use distinguished between electricity and mechanical energy is shown in Table 2.

Table 2 Energy consumption parameters

Parameter	Value	Source
Electricity demand	24.5 Btu/lb	Value for Region Middle East [24] and own calculations
Mechanical energy demand	219.25 Btu/lb	Value for Region Middle East [24] and own calculations
Total energy demand	245.05 Btu/lb	Value for Region Middle East [24]

3.3 Flaring and venting

The flaring and venting of hydrocarbons during the production process is shown in Table 3. The flared Hydrocarbons are the sum of flared natural gas and solution gas compounds.

Table 3 Flaring and venting parameters

Parameter	Value	Source
Flared Hydrocarbons	0.0007 lb/lb HC	[15]
Vented Hydrocarbons	0.0025 lb/lb HC	[15]

3.4 Waste and waste water

The amount of solid waste and waste water emitted during the production process is summarised in Table 4.

Table 4 Waste and waste water parameters

Parameter	Value	Source
Solid waste	0.0060 lb/lb HC	Global value [3];[5];[6];[7];[8];[9];[10]
Waste water onshore	0.030 lb/lb HC	Value for Region Middle East [24]

3.5 Product properties

The lower heating value as a country specific product property is given in Table 5.

Table 5 Product properties

Parameter	Value	Source
Net calorific value natural gas	18413.05 Btu/lb	[32]
Net calorific value crude oil	18219.59 Btu/lb	[13];[14];[13];[14]

4 References

[1] IEA: Oil information 2002, International Energy Agency, 2004

[2] Pennwell: The international petroleum Encyclopaedia 1997

[3] OGP: Environmental aspects of the use and disposal of non aqueous drilling fluids associated with offshore oil& gas operations, 2003

[4] Yukos: Yukos and the environment, 2003

[5] Shell: http://www.shell.com/home/Framework?siteId=my-en&FC2=/my-en/html/iwgen/society_environment/environment/sustainable2003/zzz_lhn.html&FC3=/my-en/html/iwgen/society_environment/environment/sustainable2003/sd03_protecttheenvironment_1008.html, 2004

[6] Shell Nigeria 2004 People and the environment Annual Report, 2005

[7] Nederlandse Aardolie Maatschappij (NAM): Bron van energie, 2003

[8] BP Pakistan 2003 Environmental Statement, 2004

[9] BP Trinidad & Tobago: 2003 Environmental Statement Trinidad BU

[10] Shell in the UK report 2001, 2002

[11] EIA: C.2 Barrels of Crude Oil Per Metric Ton, 1980-2003, 2004

[12] EIA: C.3 Gross Heat Content of Crude Oil, 1980-2003, 2004

[13] Haverly: Crude assay libraries, 2005

[14] Energy Intelligence Group: The Crude Oils and Their Key Characteristics, 2004

[15] EIA: International Energy Annual 2003; Energy Information Administration, 2004

[16] Da Prat, G.: Well Testing management , SPE Foundation, presentation 2002

[17] Vickery et al.: Successful high rate gas completion through combination of extreme overbalance perforating and one trip perforate and gravel pack techniques, Baker oil tools, 2001

[18] N. Lapeyrouse: Formulas and calculations for Drilling, Production and work over, 2nd Edition, Golf Professional Publishing, 2002

[19] Gordon, D. et al. Underbalanced Drilling with casing SPE, SPE Drilling & completion 2005

[20] Ohio Department of Health: Materials used in drilling and construction of wells, 1999

[21] Culver, G.: Drilling and well construction, Chapter 6, OIST, Department of Energy 1998

[22] Vektor AS – Environmental developments in Well testing, 2000

[23] BP: Das Buch zum Erdöl (The book on Crude oil), 1989

[24] OGP, International Association of Oil and Gas Producers: Environmental performance in the E&P industry 2003, 2004

[25] US EPA: Compilation of Air pollutant emission factors, AP 42, Volume I: Stationary point and area sources, Fifth edition, United States Protection Agency, Office of air quality planning and standards, 1995-2000.

[26] US EPA: Profile of the Oil and Gas Extraction Industry, 2nd Section, 2000

[27] PSI: Management of produced water on offshore oil installations, Policy Studies Institute, 2005

[28] OGP: Aromatics in produced water occurrence, fate & effects and treatment, International Association of Oil and Gas Producers, 2002

[29] OGP: Fate and effects of naturally occurring substances in produced water on the marine environment, International Association of Oil and Gas Producers, 2005

[30] Leahey, G et at.: Theoretical and observational assessments of flare efficiencies, Journal of Air & Waste Management Association, Volume 51, December 2001

[31] Johnson, M.R. et al.: Efficiency measurements of flares in a cross flow, Dep. Of Mechanical Engineering, University of Alberta, Combustion Canada conference, 1999

[32] EIA: C.2 of Dry Natural Gas Production, 1980-2004, 2005

[33] IEA: Natural Gas Information 2002, International Energy Agency, 2004

Production of crude oil in Mexico

1. Technology description of the Crude oil production

1.1 Introduction

The production of crude oil was modelled as a combined natural gas and crude oil production. In most cases beside crude oil, different parts of natural gas and NGL (natural gas liquids) are produced as by-products. For the different by-products allocation by lower calorific value was applied. The combined production comprises the exploration and production of crude oil and natural gas as well as all the desulphurization of natural gas. The data set includes all relevant parts of the upstream industry. Production may take place onshore and offshore. Both are taken into account proportionate to their ratio of the total production of a country.

1.2 Exploration

Exploration comprises the search of hydrocarbon (HC) deposits and the drilling of wells. The search for new deposits is conducted at first by seismic survey, which is not included in the data set. In a second step testing wells are drilled which can be characterized as wildcat wells for areas with low information about the subsurface, exploration wells for information gathering and appraisal wells to assess characteristics such as flow rate, amount of hydrocarbon, pressure and others. After a successful testing the production well is drilled to produce hydrocarbons.

Vertical wells are drilled by the rotary mode. The base of a drilling facility is a rig. For offshore drilling jack-up rigs, based on a buoyant steel hull with 3 or more legs, semi-submersible rigs, which float at all times on pontoons, or drill ships are used. The oil rig contains machinery and fulfils the role of superstructure bearing the load of a drill string. Driven by a diesel unit the drill string transmits his rotation on a drill bit, which brakes up the stone and extends the hole (up to 0,8 m wide). The drill string is gradually lengthened as the well gets deeper. The drill cuttings are removed by a drilling fluid (drilling mud), which is pumped inside the drill string, leaves the drill string at the drill bit and is then floated together with the drill cuttings back to the surface between drill string and the inner surface of the well due to the high pressure generated by piston pumps. At the rig the drilling fluid is separated from drill cuttings and circulated. The drilling fluid also serves to cool the drill bit, to seal the drill hole against seepage and to prevent wall cave-ins. Depending on geology and technology water-based, oil-based and synthetic-based fluids are used. They are mixed with barium sulphate and bentonite to increase the density of the fluid as well as further additives. After finishing the drilling or at least after 1000m, the well is cased with concrete and smoothly steel pipes (0.08-0.2 m diameter) and prepared for production. In general due to the lack of infrastructure for preparing and transportation, produced oil and gas is flared. Small amounts of gas are also vented into the atmosphere. During the drilling high amounts of drill cuttings and waste water arise. At offshore exploration the cuttings are discharged to water or brought ashore depending on drilling fluid and legislation.

1.3 Production & Preparation

Ideally the oil is transported as an oil-gas mixture to the surface without any effort by the high pressure of the hydrocarbon deposit. The flow of oil runs dry, when the pressure of the deposit will get lower as the flow resistance or when the pressure was already lower at the beginning. For further exploitation it is necessary to use pumps or to reinject a part of the separated natural gas to maintain a high pressure in the deposit. Advanced measures raise the production are the reinjection of produced water or sea water and the reinjection of steam to increase the viscosity or surface tension of the oil-gas mixture.

The produced oil-gas mixture is a composite of crude oil, natural gas, brine and other impurities. In a preparation process the natural gas and the NGL is separated from the oil. In a second preparation step most of the water is separated from the oil due to the different densities. The remaining emulsified water and salt is removed in a dewatering and desalting plant. Small amounts of produced natural gas are often still flared, sometimes also vented, due to missing preparation and transportation opportunities. Hydrogen sulphide contained in the natural gas in different concentrations, has to be removed before transportation via pipelines due to the high corrosive impact. The hydrogen sulphide is recovered from the natural gas by the Claus process producing elementary sulphur and, depending on technology standards, a certain amount of sulphur dioxide. The arising water with concentrations of approximately 15 or more mg hydrocarbons per litre is reinjected into the gas field, discharged into the sea (onshore and in shore) or evaporated in pits. During preparation different kinds of waste and used chemicals arise which have to be disposed. A certain amount of gas and oil is flared or vented into the atmosphere because of leakage or security reasons. The mechanical energy and electricity for pumping and all other machinery is provided by gas turbines and diesel units. At onshore facilities a certain amount is provided by the grid.

2 General comments of the LCA assessment method

This chapter gives background information on the principal modelling approach.

2.1 System boundaries and functional unit

Functional unit: The functional unit is 1 bbl of crude oil.

This process includes all relevant Mass and energy flows for the exploration and extraction of crude oil. Figure 2-1 gives an overview on the considered processes along with their key in- and outputs

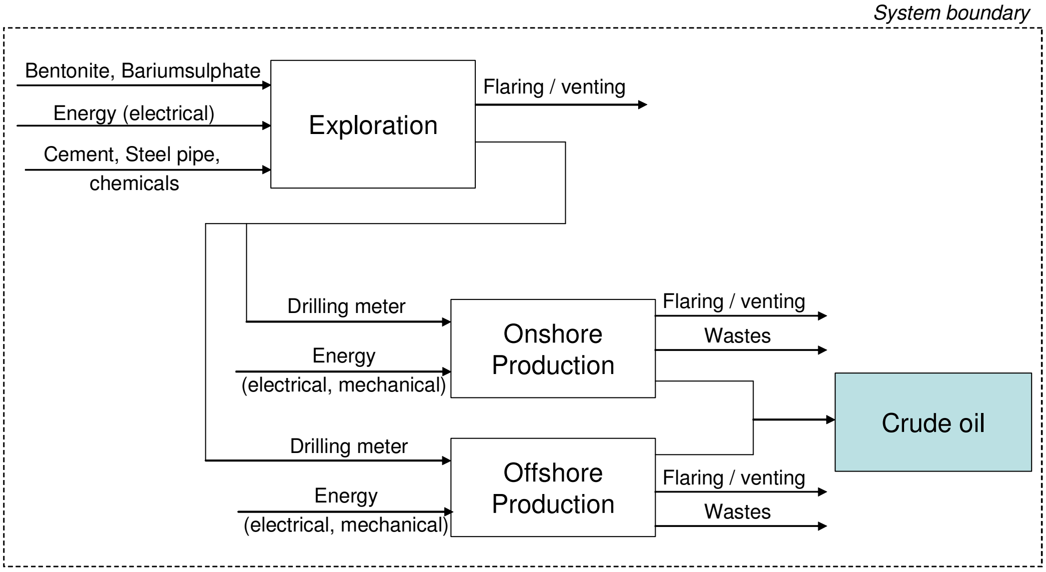


Figure 2-1 **System boundary for crude oil production**

The exploration is modelled per drilling meters and is considered in the model via drilling meters per mass of produced hydrocarbon. Quantities of borehole volume, removed rock are based on multiple sources such as [16]-[18]. Amount of bentonite and bariumsulphate and water for drilling mud is taken from [16]. The material used for reinforcing the well is calculated based on [19]-[22]. The power demand for drilling is taken from [23]. For venting of natural gas the averaged national natural gas composition is considered [24], [32]. The energy demand for production is given in section 3.2. The associated emissions are calculated using emission factors sourced from [25] and industry data. Venting of solution gas from oil producing well is also considered. For flaring region specific flare emissions are included see section 3.3 and [4],[30],[31]. Solid wastes and waste water are considered. The referring data is sourced from [4], [26]-[29] and as stated in section 3.4.

2.2 Allocation or system expansion

For the combined crude oil, natural gas and natural gas liquids production allocation by lower calorific value is applied. The lower heating values of the products are given in section 3.5.

2.3 Data completeness

The coverage for the exploration data (crude oil, natural gas, natural gas liquids) is 90% of mass and energy and 95% of the environmental relevance (expert judgement).

2.4 Data selection and combination principles

The data sources for the complete product system are sufficiently consistent: The data on the energy carrier supply chain is based on statistics with country/region specific transport distances and energy carrier composition as well as industry and literature data on the inventory of exploration, extraction and processing. LCI modelling is fully consistent.

2.5 Reference year

Reference year for the data set is 2002. Although some of the emission data and product properties are sourced from different years representativeness for the reference year is considered good.

2.6 Data treatment and extrapolations principles

In terms of the country/region specific crude oil production, missing data of certain parameters has been used from countries with a comparable technology[1]. Data measured at a group of representative production facilities have been used to represent the national production.

---

[1] If this ist he case it is indicated in the tables in section 3.

3 Country specific data

3.1 Production

Table 1 shows the production ratio of natural gas, NGL and crude oil on a weight basis as well as the drilling feet per pound hydrocarbon produced. Note that all values are given for unallocated joint production of Natural gas, NGL and crude oil.

Table 1 Production parameters

Parameter	Value	Source
Portion of natural gas production	14.02%	[2]
Portion of NGL production	5.85%	[2]
Portion of crude oil production	80.12%	[33]
Drilling meters for onshore production	1.05 x10^{-06} ft/lb HC produced	[3]
Drilling meters for offshore production	1.05 x10^{-06} ft/lb HC produced	[3]

3.2 Energy use

The specific energy use distinguished between electricity and mechanical energy is shown in Table 2.

Table 2 Energy consumption parameters

Parameter	Value	Source
Electricity demand	22.78 Btu/lb HC	Value for region Latin America [4] and own calculations
Mechanical energy demand	202.06 Btu/lb HC	Value for region Latin America [4] and own calculations
Total energy demand	227.85 Btu/lb HC	Value for region Latin America [4]

3.3 Flaring and venting

The flaring and venting of hydrocarbons during the production process is shown in Table 3. The flared Hydrocarbons are the sum of flared natural gas and solution gas compounds.

Table 3 Flaring and venting parameters

Parameter	Value	Source
Flared Hydrocarbons	0.022 lb/lb HC	[33], [34] and own calculations
Vented Hydrocarbons	0.0055 lb/lb HC	[33], [34] and own calulations

3.4 Waste and waste water

The amount of solid waste and waste water emitted during the production process is summarised in Table 4.

Table 4 Waste and waste water parameters

Parameter	Value	Source
Solid waste	0.0060 lb/lb HC	Global value [5];[6];[7];[8];[9];[10];[11]
Waste water onshore	0.017 lb/lb HC	Value for region Latin America [4]
Waste water offshore	0.091 lb/lb HC	Value for region Latin America [4]

3.5 Product properties

The lower heating value as a country specific product property is given in Table 5.

Table 5 Product properties

Parameter	Value	Source
Net calorific value natural gas	17755.28 Btu/lb	[24]
Net calorific value crude oil	18946.13 Btu/lb	[12];[13];[14];[15]

4 References

[1] World Bank: Global gas flaring reduction initiative, 2004

[2] IEA: Natural Gas Information 2002, International Energy Agency, 2004

[3] Pennwell: The international petroleum Encyclopedia 1997

[4] OGP, International Association of Oil and Gas Producers: Environmental performance in the E&P industry 2003, 2004

[5] Yukos: Yukos and the environment, 2003

[6] Shell: http://www.shell.com/home/Framework?siteId=my-en&FC2=/my-en/html/iwgen/society_environment/environment/sustainable2003/zzz_lhn.html&FC3=/my-en/html/iwgen/society_environment/environment/sustainable2003/sd03_protecttheenvironment_1008.html, 2004

[7] Shell Nigeria 2004 People and the environment Annual Report, 2005

[8] Nederlandse Aardolie Maatschappij (NAM): Bron van energie, 2003

[9] BP Pakistan 2003 Environmental Statement, 2004

[10] BP Trinidad & Tobago: 2003 Environmental Statement Trinidad BU, 2004

[11] Shell in the UK report 2001, 2002

[12] EIA: C.2 Barrels of Crude Oil Per Metric Ton, 1980-2003, 2004

[13] EIA: C.3 Gross Heat Content of Crude Oil, 1980-2003, 2004

[14] Haverly: Crude assay libraries, 2005

[15] Energy Intelligence Group: The Crude Oils and Their Key Characteristics, 2004

[16] OGP: Environmental aspects of the use and disposal of non aqueous drilling fluids associated with offshore oil& gas operations, 2003

[17] Da Prat, G.: Well Testing management , SPE Foundation, presentation 2002

[18] Vickery et al.: Successful high rate gas completion through combination of extreme overbalance perforating and one trip perforate and gravel pack techniques, Baker oil tools, 2001

[19] N. Lapeyrouse: Formulas and calculations for Drilling, Production and work over, 2nd Edition, Golf Professional Publishing, 2002

[20] Gordon, D. et al. Underbalanced Drilling with casing SPE, SPE Drilling & completion 2005

[21] Ohio Department of Health: Materials used in drilling and construction of wells, 1999

[22] Culver, G.: Drilling and well construction, Chapter 6, OIST, Department of Energy 1998

[23] Vektor AS – Environmental developments in Well testing, 2000

[24] EIA: C.5 Gross Heat Content of Dry Natural Gas Production, 1980-2004, 2005

[25] US EPA: Compilation of Air pollutant emission factors, AP 42, Volume I: Stationary point and area sources, Fifth edition, United States Protection Agency, Office of air quality planning and standards, 1995-2000.

[26] US EPA: Profile of the Oil and Gas Extraction Industry, 2nd Section, 2000

[27] PSI: Management of produced water on offshore oil installations, Policy Studies Institute, 2005

[28] OGP: Aromatics in produced water occurrence, fate & effects and treatment, International Association of Oil and Gas Producers, 2002

[29] OGP: Fate and effects of naturally occurring substances in produced water on th marine environment, International Association of Oil and Gas Producers, 2005

[30] Leahey, G et at.: Theoretical and observational assessments of flare efficiencies, Journal of Air & Waste Management Association, Volume 51, December 2001

[31] Johnson, M.R. et al.: Efficiency measurements of flares in a cross flow, Dep. Of Mechanical Engineering, University of Alberta, Combustion Canada conference, 1999

[32] California Energy Commission: Natural gas composition and Quality, 2005

[33] IEA: Oil Information 2002, International Energy Agency, 2004

[34] EIA: International Energy Annual 2003; Energy Information Administration, 2004

Production of crude oil in Nigeria

1. Technology description of the Crude oil production

1.1 Introduction

The production of crude oil was modelled as a combined natural gas and crude oil production. In most cases beside crude oil, different parts of natural gas and NGL (natural gas liquids) are produced as by-products. For the different by-products allocation by lower calorific value was applied. The combined production comprises the exploration and production of crude oil and natural gas as well as all the desulphurization of natural gas. The data set includes all relevant parts of the upstream industry. Production may take place onshore and offshore. Both are taken into account proportionate to their ratio of the total production of a country.

1.2 Exploration

Exploration comprises the search of hydrocarbon (HC) deposits and the drilling of wells. The search for new deposits is conducted at first by seismic survey, which is not included in the data set. In a second step testing wells are drilled which can be characterized as wildcat wells for areas with low information about the subsurface, exploration wells for information gathering and appraisal wells to assess characteristics such as flow rate, amount of hydrocarbon, pressure and others. After a successful testing the production well is drilled to produce hydrocarbons.

Vertical wells are drilled by the rotary mode. The base of a drilling facility is a rig. For offshore drilling jack-up rigs, based on a buoyant steel hull with 3 or more legs, semi-submersible rigs, which float at all times on pontoons, or drill ships are used. The oil rig contains machinery and fulfils the role of superstructure bearing the load of a drill string. Driven by a diesel unit the drill string transmits his rotation on a drill bit, which brakes up the stone and extends the hole (up to 0,8 m wide). The drill string is gradually lengthened as the well gets deeper. The drill cuttings are removed by a drilling fluid (drilling mud), which is pumped inside the drill string, leaves the drill string at the drill bit and is then floated together with the drill cuttings back to the surface between drill string and the inner surface of the well due to the high pressure generated by piston pumps. At the rig the drilling fluid is separated from drill cuttings and circulated. The drilling fluid also serves to cool the drill bit, to seal the drill hole against seepage and to prevent wall cave-ins. Depending on geology and technology water-based, oil-based and synthetic-based fluids are used. They are mixed with barium sulphate and bentonite to increase the density of the fluid as well as further additives. After finishing the drilling or at least after 1000m, the well is cased with concrete and smoothly steel pipes (0.08-0.2 m diameter) and prepared for production. In general due to the lack of infrastructure for preparing and transportation, produced oil and gas is flared. Small amounts of gas are also vented into the atmosphere. During the drilling high amounts of drill cuttings and waste water arise. At offshore exploration the cuttings are discharged to water or brought ashore depending on drilling fluid and legislation.

1.3 Production & Preparation

Ideally the oil is transported as an oil-gas mixture to the surface without any effort by the high pressure of the hydrocarbon deposit. The flow of oil runs dry, when the pressure of the deposit will get lower as the flow resistance or when the pressure was already lower at the beginning. For further exploitation it is necessary to use pumps or to reinject a part of the separated natural gas to maintain a high pressure in the deposit. Advanced measures raise the production are the reinjection of produced water or sea water and the reinjection of steam to increase the viscosity or surface tension of the oil-gas mixture.

The produced oil-gas mixture is a composite of crude oil, natural gas, brine and other impurities. In a preparation process the natural gas and the NGL is separated from the oil. In a second preparation step most of the water is separated from the oil due to the different densities. The remaining emulsified water and salt is removed in a dewatering and desalting plant. Small amounts of produced natural gas are often still flared, sometimes also vented, due to missing preparation and transportation opportunities. Hydrogen sulphide contained in the natural gas in different concentrations, has to be removed before transportation via pipelines due to the high corrosive impact. The hydrogen sulphide is recovered from the natural gas by the Claus process producing elementary sulphur and, depending on technology standards, a certain amount of sulphur dioxide. The arising water with concentrations of approximately 15 or more mg hydrocarbons per litre is reinjected into the gas field, discharged into the sea (onshore and in shore) or evaporated in pits. During preparation different kinds of waste and used chemicals arise which have to be disposed. A certain amount of gas and oil is flared or vented into the atmosphere because of leakage or security reasons. The mechanical energy and electricity for pumping and all other machinery is provided by gas turbines and diesel units. At onshore facilities a certain amount is provided by the grid.

2 General comments of the LCA assessment method

This chapter gives background information on the principal modelling approach.

2.1 System boundaries and functional unit

Functional unit: The functional unit is 1 bbl of crude oil.

This process includes all relevant Mass and energy flows for the exploration and extraction of crude oil. Figure 2-1 gives an overview on the considered processes along with their key in- and outputs

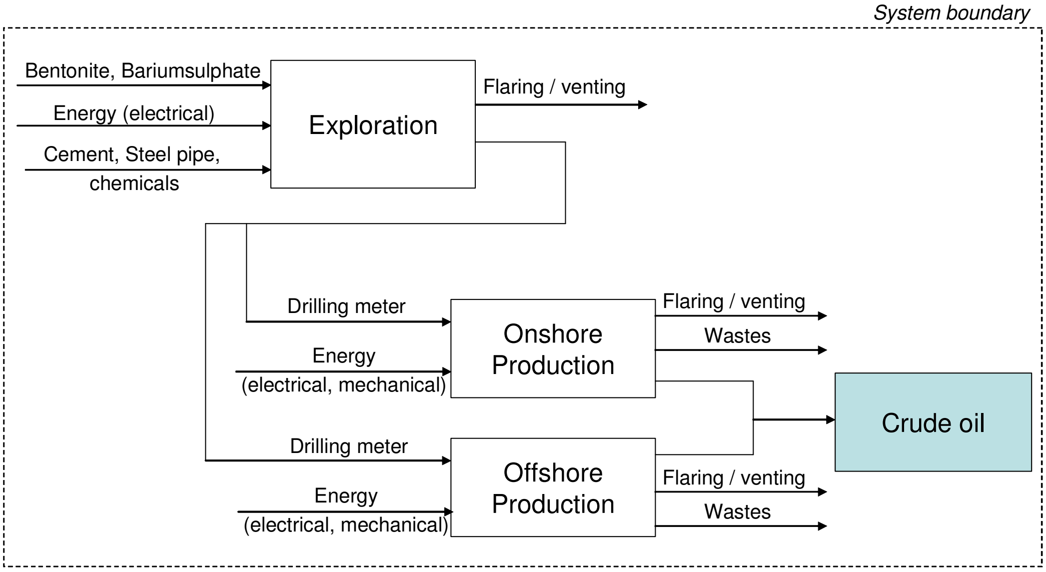


Figure 2-1 **System boundary for crude oil production**

The exploration is modelled per drilling meters and is considered in the model via drilling meters per mass of produced hydrocarbon. Quantities of borehole volume, removed rock are based on multiple sources such as [11]-[13]. Amount of Bentonite and Bariumsulphate and water for drilling mud is taken from [11]. The material used for reinforcing the well is calculated based on [14]-[17]. The power demand for drilling is taken from [18]. For venting of natural gas the averaged national natural gas composition is considered [27], [19]. The energy demand for production is given in section 3.2. The associated emissions are calculated using emission factors sourced from [20] and industry data. Venting of solution gas from oil producing well is also considered. For flaring region specific flare amounts and emissions are included, see section 3.3, [25], [26]. Solid wastes and waste water are considered. The referring data is sourced from [3], [21]-[24] and as stated in section 3.4.

2.2 Allocation or system expansion

For the combined crude oil, natural gas and natural gas liquids production allocation by lower calorific value is applied. The lower heating values of the products are given in section 3.5.

2.3 Data completeness

The coverage for the exploration data (crude oil, natural gas, natural gas liquids) is 90% of mass and energy and 95% of the environmental relevance (expert judgement).

2.4 Data selection and combination principles

The data sources for the complete product system are sufficiently consistent: The data on the energy carrier supply chain is based on statistics with country/region specific transport distances and energy carrier composition as well as industry and literature data on the inventory of exploration, extraction and processing. LCI modelling is fully consistent.

2.5 Reference year

Reference year for the data set is 2002. Although some of the emission data and product properties are sourced from different years representativeness for the reference year is considered good.

2.6 Data treatment and extrapolations principles

In terms of the country/region specific crude oil production, missing data of certain parameters has been used from countries with a comparable technology[1]. Data measured at a group of representative production facilities have been used to represent the national production.

---

[1] If this ist he case it is indicated in the tables in section 3.

3 Country specific data

3.1 Production

Table 1 shows the production ratio of natural gas, NGL and crude oil on a weight basis as well as the drilling feet per pound hydrocarbon produced.

Table 1 Production parameters

Parameter	Value	Source
Portion of natural gas production	10.34%	[1]
Portion of NGL production	3.71%	[1]
Portion of crude oil production	85.95%	[28]
Drilling meters for onshore production	0.43 $x10^{-06}$ ft/lb HC produced	[2]
Drilling meters for offshore production	0.34$x10^{-06}$ ft/lb HC produced	[2]

3.2 Energy use

The specific energy use distinguished between electricity and mechanical energy is shown in Table 2.

Table 2 Energy consumption parameters

Parameter	Value	Source
Electricity demand	34.39 Btu/lb HC	Value for region Africa [3] and own calculations
Mechanical energy demand	309.54 Btu/lb HC	Value for region Africa [3] and own calculations
Total energy demand	343.93 Btu/lb HC	Value for region Africa [3]

3.3 Flaring and venting

The flaring and venting of hydrocarbons during the production process is shown in Table 3. The flared Hydrocarbons are the sum of flared natural gas and solution gas compounds.

Table 3 Flaring and venting parameters

Parameter	Value	Source
Flared Hydrocarbons	0.10 lb/lb HC	[10]
Vented Hydrocarbons	0.029 lb/lb HC	[10]

3.4 Waste and waste water

The amount of solid waste and waste water emitted during the production process is summarised in Table 4.

Table 4 Waste and waste water parameters

Parameter	Value	Source
Solid waste	0.0017 lb/lb HC	[4]
Waste water onshore	0.44 lb/lb HC	Value for region Africa [3]
Waste water offshore	0.53 lb/lb HC	[4]

3.5 Product properties

The lower heating value as a country specific product property is given in Table 5.

Table 5 Product properties

Parameter	Value	Source
Net calorific value natural gas	18851.55 Btu/lb	[27]
Net calorific value crude oil	18391.55 Btu/lb	[5];[6];[7];[8];[9]

4 References

[1] IEA: Natural Gas Information 2002, International Energy Agency, 2004

[2] Pennwell: The international petroleum Encyclopaedia 1997

[3] OGP, International Associations of Oil and Gas Producers: Environmental performance in the E&P industry 2003, 2004

[4] Shell Nigeria 2004 People and the environment Annual Report, 2005

[5] EIA: C.2 Barrels of Crude Oil Per Metric Ton, 1980-2003, 2004

[6] EIA: C.3 Gross Heat Content of Crude Oil, 1980-2003, 2004

[7] Haverly: Crude assay libraries, 2005

[8] ChevronTexaco: http://www.chevrontexaco.com/crudemarketing/, 2005

[9] Energy Intelligence Group: The Crude Oils and Their Key Characteristics, 2004

[10] International Energy Annual 2003; Energy Information Administration, 2004

[11] OGP: Environmental aspects of the use and disposal of non aqueous drilling fluids associated with offshore oil& gas operations, 2003

[12] Da Prat, G.: Well Testing management , SPE Foundation, presentation 2002

[13] Vickery et al.: Successful high rate gas completion through combination of extreme overbalance perforating and one trip perforate and gravel pack techniques, Baker oil tools, 2001

[14] N. Lapeyrouse: Formulas and calculations for Drilling, Production and work over, 2nd Edition, Golf Professional Publishing, 2002

[15] Gordon, D. et al. Underbalanced Drilling with casing SPE, SPE Drilling & completion 2005

[16] Ohio Department of Health: Materials used in drilling and construction of wells, 1999

[17] Culver, G.: Drilling and well construction, Chapter 6, OIST, Department of Energy 1998

[18] Vektor AS – Environmental developments in Well testing, 2000

[19] BP: Das Buch zum Erdöl (The book on Crude oil), 1989

[20] US EPA: Compilation of Air pollutant emission factors, AP 42, Volume I: Stationary point and area sources, Fifth edition, United States Protection Agency, Office of air quality planning and standards, 1995-2000.

[21] US EPA: Profile of the Oil and Gas Extraction Industry, 2nd Section, 2000

[22] PSI: Management of produced water on offshore oil installations, Policy Studies Institute, 2005

[23] OGP: Aromatics in produced water occurrence, fate & effects and treatment, International Association of Oil and Gas Producers, 2002

[24] OGP: Fate and effects of naturally occurring substances in produced water on the marine environment, International Association of Oil and Gas Producers, 2005

[25] Leahey, G et at.: Theoretical and observational assessments of flare efficiencies, Journal of Air & Waste Management Association, Volume 51, December 2001

[26] Johnson, M.R. et al.: Efficiency measurements of flares in a cross flow, Dep. Of Mechanical Engineering, University of Alberta, Combustion Canada conference, 1999

[27] EIA: C.5 Gross Heat Content of Dry Natural Gas Production, 1980-2004, 2005

[28] IEA: Oil Information 2002, International Energy Agency, 2004

Production of crude oil in Saudi Arabia

1. Technology description of the Crude oil production

1.1 Introduction

The production of crude oil was modelled as a combined natural gas and crude oil production. In most cases beside crude oil, different parts of natural gas and NGL (natural gas liquids) are produced as by-products. For the different by-products allocation by lower calorific value was applied. The combined production comprises the exploration and production of crude oil and natural gas as well as all the desulphurization of natural gas. The data set includes all relevant parts of the upstream industry. Production may take place onshore and offshore. Both are taken into account proportionate to their ratio of the total production of a country.

1.2 Exploration

Exploration comprises the search of hydrocarbon (HC) deposits and the drilling of wells. The search for new deposits is conducted at first by seismic survey, which is not included in the data set. In a second step testing wells are drilled which can be characterized as wildcat wells for areas with low information about the subsurface, exploration wells for information gathering and appraisal wells to assess characteristics such as flow rate, amount of hydrocarbon, pressure and others. After a successful testing the production well is drilled to produce hydrocarbons.

Vertical wells are drilled by the rotary mode. The base of a drilling facility is a rig. For offshore drilling jack-up rigs, based on a buoyant steel hull with 3 or more legs, semi-submersible rigs, which float at all times on pontoons, or drill ships are used. The oil rig contains machinery and fulfils the role of superstructure bearing the load of a drill string. Driven by a diesel unit the drill string transmits his rotation on a drill bit, which brakes up the stone and extends the hole (up to 0,8 m wide). The drill string is gradually lengthened as the well gets deeper. The drill cuttings are removed by a drilling fluid (drilling mud), which is pumped inside the drill string, leaves the drill string at the drill bit and is then floated together with the drill cuttings back to the surface between drill string and the inner surface of the well due to the high pressure generated by piston pumps. At the rig the drilling fluid is separated from drill cuttings and circulated. The drilling fluid also serves to cool the drill bit, to seal the drill hole against seepage and to prevent wall cave-ins. Depending on geology and technology water-based, oil-based and synthetic-based fluids are used. They are mixed with barium sulphate and bentonite to increase the density of the fluid as well as further additives. After finishing the drilling or at least after 1000m, the well is cased with concrete and smoothly steel pipes (0.08-0.2 m diameter) and prepared for production. In general due to the lack of infrastructure for preparing and transportation, produced oil and gas is flared. Small amounts of gas are also vented into the atmosphere. During the drilling high amounts of drill cuttings and waste water arise. At offshore exploration the cuttings are discharged to water or brought ashore depending on drilling fluid and legislation.

1.3 Production & Preparation

Ideally the oil is transported as an oil-gas mixture to the surface without any effort by the high pressure of the hydrocarbon deposit. The flow of oil runs dry, when the pressure of the deposit will get lower as the flow resistance or when the pressure was already lower at the beginning. For further exploitation it is necessary to use pumps or to reinject a part of the separated natural gas to maintain a high pressure in the deposit. Advanced measures raise the production are the reinjection of produced water or sea water and the reinjection of steam to increase the viscosity or surface tension of the oil-gas mixture.

The produced oil-gas mixture is a composite of crude oil, natural gas, brine and other impurities. In a preparation process the natural gas and the NGL is separated from the oil. In a second preparation step most of the water is separated from the oil due to the different densities. The remaining emulsified water and salt is removed in a dewatering and desalting plant. Small amounts of produced natural gas are often still flared, sometimes also vented, due to missing preparation and transportation opportunities. Hydrogen sulphide contained in the natural gas in different concentrations, has to be removed before transportation via pipelines due to the high corrosive impact. The hydrogen sulphide is recovered from the natural gas by the Claus process producing elementary sulphur and, depending on technology standards, a certain amount of sulphur dioxide. The arising water with concentrations of approximately 15 or more mg hydrocarbons per litre is reinjected into the gas field, discharged into the sea (onshore and in shore) or evaporated in pits. During preparation different kinds of waste and used chemicals arise which have to be disposed. A certain amount of gas and oil is flared or vented into the atmosphere because of leakage or security reasons. The mechanical energy and electricity for pumping and all other machinery is provided by gas turbines and diesel units. At onshore facilities a certain amount is provided by the grid.

2 General comments of the LCA assessment method

This chapter gives background information on the principal modelling approach.

2.1 System boundaries and functional unit

Functional unit: The functional unit is 1 bbl of crude oil.

This process includes all relevant Mass and energy flows for the exploration and extraction of crude oil. Figure 2-1 gives an overview on the considered processes along with their key in- and outputs

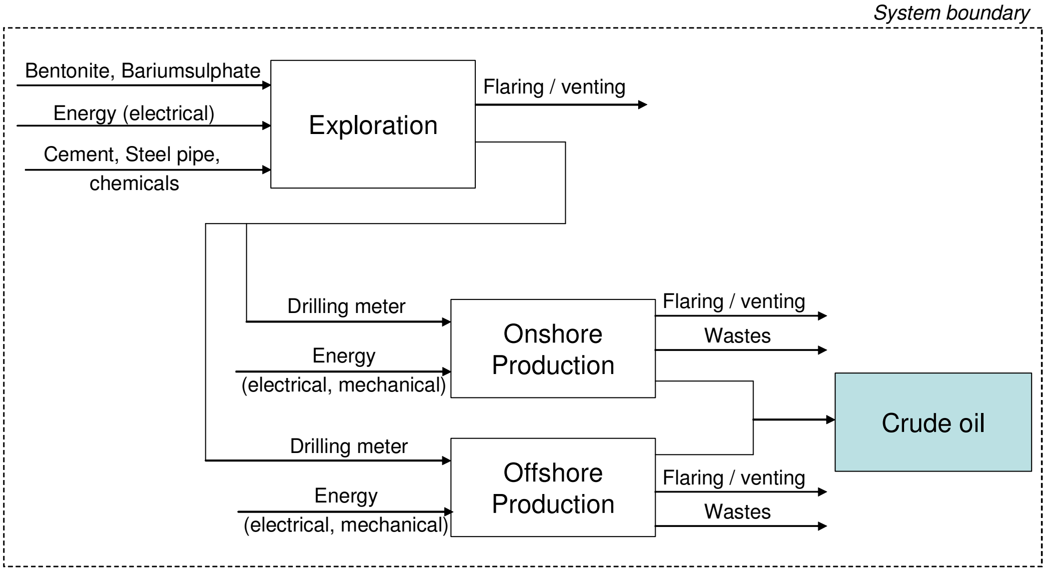


Figure 2-1 System boundary for crude oil production

The exploration is modelled per drilling meters and is considered in the model via drilling meters per mass of produced hydrocarbon. Quantities of borehole volume, removed rock are based on multiple sources such as [16]-[18]. Amount of Bentonite and Bariumsulphate and water for drilling mud is taken from [16]. The material used for reinforcing the well is calculated based on [19]-[22]. The power demand for drilling is taken from [23]. For venting of natural gas the averaged national natural gas composition is considered [32]. The energy demand for production is given in section 3.2. The associated emissions are calculated using emission factors sourced from [25] and industry data. Venting of solution gas from oil producing well is also considered. For flaring region specific flare amounts and emissions are included, see section 3.3 and [24], [30], [31]. Solid wastes and waste water are considered. The referring data is sourced from [24], [26]-[29] and as stated in section 3.4.

2.2 Allocation or system expansion

For the combined crude oil, natural gas and natural gas liquids production allocation by lower calorific value is applied. The lower heating values of the products are given in section 3.5.

2.3 Data completeness

The coverage for the exploration data (crude oil, natural gas, natural gas liquids) is 90% of mass and energy and 95% of the environmental relevance (expert judgement).

2.4 Data selection and combination principles

The data sources for the complete product system are sufficiently consistent: The data on the energy carrier supply chain is based on statistics with country/region specific transport distances and energy carrier composition as well as industry and literature data on the inventory of exploration, extraction and processing. LCI modelling is fully consistent.

2.5 Reference year

Reference year for the data set is 2002. Although some of the emission data and product properties are sourced from different years representativeness for the reference year is considered good.

2.6 Data treatment and extrapolations principles

In terms of the country/region specific crude oil production, missing data of certain parameters has been used from countries with a comparable technology[1]. Data measured at a group of representative production facilities have been used to represent the national production.

---

[1] If this ist he case it is indicated in the tables in section 3.

3 Country specific data

3.1 Production

Table 1 shows the production ratio of natural gas, NGL and crude oil on a weight basis as well as the drilling feet per pound hydrocarbon produced.

Table 1 Production parameters

Parameter	Value	Source
Portion of natural gas production	10.22%	[1]
Portion of NGL production	7.79%	[1]
Portion of crude oil production	81.99%	[33]
Drilling meters for onshore production	$0.51x^{-07}$ ft/lb HC produced	[2]
Drilling meters for offshore production	$0.51x^{-07}$ ft/lb HC produced	[2]

3.2 Energy use

The specific energy use distinguished between electricity and mechanical energy is shown in Table 2.

Table 2 Energy consumption parameters

Parameter	Value	Source
Electricity demand	24.51 Btu/lb	Value for region Middle East [24] and own calculations
Mechanical energy demand	219.25 Btu/lb	Value for region Middle East [24] and own calculations
Total energy demand	245.05 Btu/lb	[24]

3.3 Flaring and venting

The flaring and venting of hydrocarbons during the production process is shown in Table 3. The flared Hydrocarbons are the sum of flared natural gas and solution gas compounds.

Table 3 Flaring and venting parameters

Parameter	Value	Source
Flared Hydrocarbons	0.00032 lb/lb HC	[15] and own calculations
Vented Hydrocarbons	0.000092 lb/lb HC	[15] and own calculations

3.4 Waste and waste water

The amount of solid waste and waste water emitted during the production process is summarised in Table 4.

Table 4 Waste and waste water parameters

Parameter	Value	Source
Solid waste	0.0060 lb/lb HC	Global value [4];[5];[6];[7];[8];[9];[10]
Waste water onshore	0.030 lb/lb HC	[24]
Waste water offshore	3.11 lb/lb HC	Value for the Middle East Region [24]

3.5 Product properties

The lower heating value as a country specific product property is given in Table 5.

Table 5 Product properties

Parameter	Value	Source
Net calorific value natural gas	18413,05 Btu/lb	[32]
Net calorific value crude oil	18249,68 Btu/lb	[11];[12];[13];[14]

4 References

[1] IEA: Natural Gas Information 2002, International Energy Agency, 2004

[2] Pennwell: The international petroleum Encyclopaedia 1997

[3] OGP, International Association of Oil and Gas Producers: Environmental performance in the E&P industry 2003, 2004

[4] Yukos: Yukos and the environment, 2003

[5] Shell: http://www.shell.com/home/Framework?siteId=my-en&FC2=/my-en/html/iwgen/society_environment/environment/sustainable2003/zzz_lhn.html&FC3=/my-en/html/iwgen/society_environment/environment/sustainable2003/sd03_protecttheenvironment_1008.html, 2004

[6] Shell Nigeria 2004 People and the environment Annual Report, 2005

[7] Nederlandse Aardolie Maatschappij (NAM): Bron van energie, 2003

[8] BP Pakistan 2003 Environmental Statement, 2004

[9] BP Trinidad & Tobago: 2003 Environmental Statement Trinidad BU, 2004

[10] Shell in the UK report 2001, 2002

[11] EIA: C.2 Barrels of Crude Oil Per Metric Ton, 1980-2003, 2004

[12] EIA: C.3 Gross Heat Content of Crude Oil, 1980-2003, 2004

[13] Haverly: Crude assay libraries, 2005

[14] Energy Intelligence Group: The Crude Oils and Their Key Characteristics, 2004

[15] International Energy Annual 2003; Energy Information Administration, 2004

[16] OGP: Environmental aspects of the use and disposal of non aqueous drilling fluids associated with offshore oil& gas operations, 2003

[17] Da Prat, G.: Well Testing management , SPE Foundation, presentation 2002

[18] Vickery et al.: Successful high rate gas completion through combination of extreme overbalance perforating and one trip perforate and gravel pack techniques, Baker oil tools, 2001

[19] N. Lapeyrouse: Formulas and calculations for Drilling, Production and work over, 2nd Edition, Golf Professional Publishing, 2002

[20] Gordon, D. et al. Underbalanced Drilling with casing SPE, SPE Drilling & completion 2005

[21] Ohio Department of Health: Materials used in drilling and construction of wells, 1999

[22] Culver, G.: Drilling and well construction, Chapter 6, OIST, Department of Energy 1998

[23] Vektor AS – Environmental developments in Well testing, 2000

[24] OGP, International Association of Oil and Gas Producers: Environmental performance in the E&P industry 2003

[25] US EPA: Compilation of Air pollutant emission factors, AP 42, Volume I: Stationary point and area sources, Fifth edition, United States Protection Agency, Office of air quality planning and standards, 1995-2000.

[26] US EPA: Profile of the Oil and Gas Extraction Industry, 2nd Section, 2000

[27] PSI: Management of produced water on offshore oil installations, Policy Studies Institute, 2005

[28] OGP: Aromatics in produced water occurrence, fate & effects and treatment, International Association of Oil and Gas Producers, 2002

[29] OGP: Fate and effects of naturally occurring substances in produced water on th marine environment, International Association of Oil and Gas Producers, 2005

[30] Leahey, G et at.: Theoretical and observational assessments of flare efficiencies, Journal of Air & Waste Management Association, Volume 51, December 2001

[31] Johnson, M.R. et al.: Efficiency measurements of flares in a cross flow, Dep. Of Mechanical Engineering, University of Alberta, Combustion Canada conference, 1999

[32] EIA: C.5 Gross Heat Content of Dry Natural Gas Production, 1980-2004, 2005

[33] IEA: Oil Information 2002, International Energy Agency, 2004

Production of crude oil in Venezuela

1. Technology description of the Crude oil production

1.1 Introduction

The production of crude oil was modelled as a combined natural gas and crude oil production. In most cases beside crude oil, different parts of natural gas and NGL (natural gas liquids) are produced as by-products. For the different by-products allocation by lower calorific value was applied. The combined production comprises the exploration and production of crude oil and natural gas as well as all the desulphurization of natural gas. The data set includes all relevant parts of the upstream industry. Production may take place onshore and offshore. Both are taken into account proportionate to their ratio of the total production of a country.

1.2 Exploration

Exploration comprises the search of hydrocarbon (HC) deposits and the drilling of wells. The search for new deposits is conducted at first by seismic survey, which is not included in the data set. In a second step testing wells are drilled which can be characterized as wildcat wells for areas with low information about the subsurface, exploration wells for information gathering and appraisal wells to assess characteristics such as flow rate, amount of hydrocarbon, pressure and others. After a successful testing the production well is drilled to produce hydrocarbons.

Vertical wells are drilled by the rotary mode. The base of a drilling facility is a rig. For offshore drilling jack-up rigs, based on a buoyant steel hull with 3 or more legs, semi-submersible rigs, which float at all times on pontoons, or drill ships are used. The oil rig contains machinery and fulfils the role of superstructure bearing the load of a drill string. Driven by a diesel unit the drill string transmits his rotation on a drill bit, which brakes up the stone and extends the hole (up to 0,8 m wide). The drill string is gradually lengthened as the well gets deeper. The drill cuttings are removed by a drilling fluid (drilling mud), which is pumped inside the drill string, leaves the drill string at the drill bit and is then floated together with the drill cuttings back to the surface between drill string and the inner surface of the well due to the high pressure generated by piston pumps. At the rig the drilling fluid is separated from drill cuttings and circulated. The drilling fluid also serves to cool the drill bit, to seal the drill hole against seepage and to prevent wall cave-ins. Depending on geology and technology water-based, oil-based and synthetic-based fluids are used. They are mixed with barium sulphate and bentonite to increase the density of the fluid as well as further additives. After finishing the drilling or at least after 1000m, the well is cased with concrete and smoothly steel pipes (0.08-0.2 m diameter) and prepared for production. In general due to the lack of infrastructure for preparing and transportation, produced oil and gas is flared. Small amounts of gas are also vented into the atmosphere. During the drilling high amounts of drill cuttings and waste water arise. At offshore exploration the cuttings are discharged to water or brought ashore depending on drilling fluid and legislation.

1.3 Production & Preparation

Ideally the oil is transported as an oil-gas mixture to the surface without any effort by the high pressure of the hydrocarbon deposit. The flow of oil runs dry, when the pressure of the deposit will get lower as the flow resistance or when the pressure was already lower at the beginning. For further exploitation it is necessary to use pumps or to reinject a part of the separated natural gas to maintain a high pressure in the deposit. Advanced measures raise the production are the reinjection of produced water or sea water and the reinjection of steam to increase the viscosity or surface tension of the oil-gas mixture.

The produced oil-gas mixture is a composite of crude oil, natural gas, brine and other impurities. In a preparation process the natural gas and the NGL is separated from the oil. In a second preparation step most of the water is separated from the oil due to the different densities. The remaining emulsified water and salt is removed in a dewatering and desalting plant. Small amounts of produced natural gas are often still flared, sometimes also vented, due to missing preparation and transportation opportunities. Hydrogen sulphide contained in the natural gas in different concentrations, has to be removed before transportation via pipelines due to the high corrosive impact. The hydrogen sulphide is recovered from the natural gas by the Claus process producing elementary sulphur and, depending on technology standards, a certain amount of sulphur dioxide. The arising water with concentrations of approximately 15 or more mg hydrocarbons per litre is reinjected into the gas field, discharged into the sea (onshore and in shore) or evaporated in pits. During preparation different kinds of waste and used chemicals arise which have to be disposed. A certain amount of gas and oil is flared or vented into the atmosphere because of leakage or security reasons. The mechanical energy and electricity for pumping and all other machinery is provided by gas turbines and diesel units. At onshore facilities a certain amount is provided by the grid.

2 General comments of the LCA assessment method

This chapter gives background information on the principal modelling approach.

2.1 System boundaries and functional unit

Functional unit: The functional unit is 1 bbl of crude oil.

This process includes all relevant Mass and energy flows for the exploration and extraction of crude oil. Figure 2-1 gives an overview on the considered processes along with their key in- and outputs

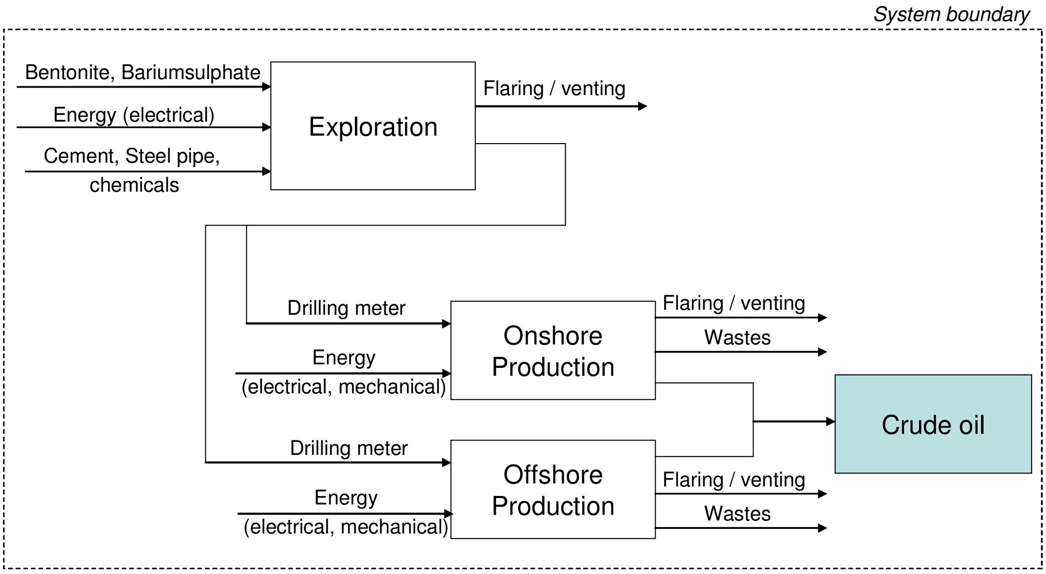


Figure 2-1 System boundary for crude oil production

The exploration is modelled per drilling meters and is considered in the model via drilling meters per mass of produced hydrocarbon. Quantities of borehole volume, removed rock are based on multiple sources such as [11]-[13]. Amount of bentonite and bariumsulphate and water for drilling mud is taken from [11]. The material used for reinforcing the well is calculated based on [14]-[17]. The power demand for drilling is taken from [18]. For venting of natural gas the averaged national natural gas composition is considered [19], [27]. The energy demand for production is given in section 3.2. The associated emissions are calculated using emission factors sourced from [20] and industry data. Venting of solution gas from oil producing well is also considered. For flaring region specific flare emissions are included see section 3.3 and [3],[25],[26]. Solid wastes and waste water are considered. The referring data is sourced from [3], [21]-[24] and as stated in section 3.4.

2.2 Allocation or system expansion

For the combined crude oil, natural gas and natural gas liquids production allocation by lower calorific value is applied. The lower heating values of the products are given in section 3.5.

2.3 Data completeness

The coverage for the exploration data (crude oil, natural gas, natural gas liquids) is 90% of mass and energy and 95% of the environmental relevance (expert judgement).

2.4 Data selection and combination principles

The data sources for the complete product system are sufficiently consistent: The data on the energy carrier supply chain is based on statistics with country/region specific transport distances and energy carrier composition as well as industry and literature data on the inventory of exploration, extraction and processing. LCI modelling is fully consistent.

2.5 Reference year

Reference year for the data set is 2002. Although some of the emission data and product properties are sourced from different years representativeness for the reference year is considered good.

2.6 Data treatment and extrapolations principles

In terms of the country/region specific crude oil production, missing data of certain parameters has been used from countries with a comparable technology[1]. Data measured at a group of representative production facilities have been used to represent the national production.

---

[1] If this ist he case it is indicated in the tables in section 3.

3 Country specific data

3.1 Production

Table 1 shows the production ratio of natural gas, NGL and crude oil on a weight basis as well as the drilling feet per pound hydrocarbon produced.

Table 1 Production parameters

Parameter	Value	Source
Portion of natural gas production	10.56%	[1]
Portion of NGL production	2.89%	[1]
Portion of crude oil production	86.55%	[28]
Drilling meters for onshore production	0.14×10^{-05} ft/lb HC produced	[2]
Drilling meters for offshore production	0.14×10^{-05} ft/lb HC produced	Estimated to be the same as onshore

3.2 Energy use

The specific energy use distinguished between electricity and mechanical energy is shown in Table 2.

Table 2 Energy consumption parameters

Parameter	Value	Source
Electricity demand	22.79 Btu/lb HC	Value for Region Latin America [3] and own calculations
Mechanical energy demand	206.36 Btu/lb HC	Value for Region Latin America [3] and own calculations
Total energy demand	227.85 Btu/lb HC	Value for Region Latin America [3]

3.3 Flaring and venting

The flaring and venting of hydrocarbons during the production process is shown in Table 3. The flared Hydrocarbons are the sum of flared natural gas and solution gas compounds.

Table 3 Flaring and venting parameters

Parameter	Value	Source
Flared Hydrocarbons	0.013 lb/lb HC	[10], [30]
Vented Hydrocarbons	0.0016 lb/lb HC	[10], [30]

3.4 Waste and waste water

The amount of solid waste and waste water emitted during the production process is summarised in Table 4.

Table 4 Waste and waste water parameters

Parameter	Value	Source
Solid waste	0.000073 lb/lb HC	Value for Trinidad Tobago [4]
Waste water onshore	0.017 lb/lb HC	[3]
Waste water offshore	0.091 lb/lb HC	[3]

3.5 Product properties

The lower heating value as a country specific product property is given in Table 5.

Table 5 Product properties

Parameter	Value	Source
Net calorific value natural gas	19982.22 Btu/lb	[19]
Net calorific value crude oil	18228.18 Btu/lb	[5];[6];[7];[8];[9]

4 References

[1] IEA Natural Gas Information 2002, International Energy Agency, 2004

[2] Pennwell: The international petroleum Encyclopedia 1997

[3] OGP, International Association of Oil and Gas Producers: Environmental performance in the E&P industry 2003, 2004

[4] BP Trinidad & Tobago: 2003 Environmental Statement Trinidad BU, 2004

[5] EIA: C.2 Barrels of Crude Oil Per Metric Ton, 1980-2003, 2004

[6] EIA: C.3 Gross Heat Content of Crude Oil, 1980-2003, 2004

[7] Haverly: Crude assay libraries, 2005

[8] Energy Intelligence Group: The Crude Oils and Their Key Characteristics, 2004

[9] ChevronTexaco: http://www.chevrontexaco.com/crudemarketing/, 2005

[10] EIA: International Energy Annual 2003; Energy Information Administration, 2004

[11] OGP: Environmental aspects of the use and disposal of non aqueous drilling fluids associated with offshore oil& gas operations, 2003

[12] Da Prat, G.: Well Testing management , SPE Foundation, presentation 2002

[13] Vickery et al.: Successful high rate gas completion through combination of extreme overbalance perforating and one trip perforate and gravel pack techniques, Baker oil tools, 2001

[14] N. Lapeyrouse: Formulas and calculations for Drilling, Production and work over, 2nd Edition, Golf Professional Publishing, 2002

[15] Gordon, D. et al. Underbalanced Drilling with casing SPE, SPE Drilling & completion 2005

[16] Ohio Department of Health: Materials used in drilling and construction of wells, 1999

[17] Culver, G.: Drilling and well construction, Chapter 6, OIST, Department of Energy 1998

[18] Vektor AS – Environmental developments in Well testing, 2000

[19] EIA: C.5 Gross Heat Content of Dry Natural Gas Production, 1980-2004, 2005

[20] US EPA: Compilation of Air pollutant emission factors, AP 42, Volume I: Stationary point and area sources, Fifth edition, United States Protection Agency, Office of air quality planning and standards, 1995-2000.

[21] US EPA: Profile of the Oil and Gas Extraction Industry, 2nd Section, 2000

[22] PSI: Management of produced water on offshore oil installations, Policy Studies Institute, 2005

[23] OGP: Aromatics in produced water occurrence, fate & effects and treatment, International Association of Oil and Gas Producers, 2002

[24] OGP: Fate and effects of naturally occurring substances in produced water on the marine environment, International Association of Oil and Gas Producers, 2005

[25] Leahey, G et at.: Theoretical and observational assessments of flare efficiencies, Journal of Air & Waste Management Association, Volume 51, December 2001

[26] Johnson, M.R. et al.: Efficiency measurements of flares in a cross flow, Dep. Of Mechanical Engineering, University of Alberta, Combustion Canada conference, 1999

[27] California Energy Commission: Natural gas composition and Quality, 2005

[28] IEA: Oil Information 2002, International Energy Agency, 2004

[29] EIA: International Energy Annual 2003; Energy Information Administration, 2004

[30] World Bank: Global gas flaring reduction initiative, 2004

Production of crude oil and natural gas in the USA

1. Technology description of the Crude oil production

1.1 Introduction

The production of crude oil and natural was modelled as a combined natural gas and crude oil production. In the case of crude oil wells, different parts of natural gas and NGL (natural gas liquids) are produced as co-products and vice versa for natural gas wells. For the different co-products allocation by lower calorific value was applied. The combined production comprises the exploration and production of crude oil and natural gas as well as all the desulphurization of natural gas. The data set includes all relevant parts of the upstream industry. Production may take place onshore and offshore. Both are taken into account proportionate to their ratio of the total production of a country.

1.2 Exploration

Exploration comprises the search of hydrocarbon (HC) deposits and the drilling of wells. The search for new deposits is conducted at first by seismic survey, which is not included in the data set. In a second step testing wells are drilled which can be characterized as wildcat wells for areas with low information about the subsurface, exploration wells for information gathering and appraisal wells to assess characteristics such as flow rate, amount of hydrocarbon, pressure and others. After a successful testing the production well is drilled to produce hydrocarbons.

Vertical wells are drilled by the rotary mode. The base of a drilling facility is a rig. For off-shore drilling jack-up rigs, based on a buoyant steel hull with 3 or more legs, semi-submersible rigs, which float at all times on pontoons, or drill ships are used. The oil rig contains machinery and fulfils the role of superstructure bearing the load of a drill string. Driven by a diesel unit the drill string transmits his rotation on a drill bit, which brakes up the stone and extends the hole (up to 0,8 m wide). The drill string is gradually lengthened as the well gets deeper. The drill cuttings are removed by a drilling fluid (drilling mud), which is pumped inside the drill string, leaves the drill string at the drill bit and is then floated together with the drill cuttings back to the surface between drill string and the inner surface of the well due to the high pressure generated by piston pumps. At the rig the drilling fluid is separated from drill cuttings and circulated. The drilling fluid also serves to cool the drill bit, to seal the drill hole against seepage and to prevent wall cave-ins. Depending on geology and technology water-based, oil-based and synthetic-based fluids are used. They are mixed with barium sulphate and bentonite to increase the density of the fluid as well as further additives. After finishing the drilling or at least after 1000m, the well is cased with concrete and smoothly steel pipes (0.08-0.2 m diameter) and prepared for production. In general due to the lack of infrastructure for preparing and transportation, produced oil and gas is flared. Small amounts of gas are also vented into the atmosphere. During the drilling high amounts of drill cuttings and waste water arise. At offshore exploration the cuttings are discharged to water or brought ashore depending on drilling fluid and legislation.

1.3 Production & Preparation

Crude oil

Ideally the oil is transported as an oil-gas mixture to the surface without any effort by the high pressure of the hydrocarbon deposit. The flow of oil runs dry, when the pressure of the deposit will get lower as the flow resistance or when the pressure was already lower at the beginning. For further exploitation it is necessary to use pumps or to reinject a part of the separated natural gas to maintain a high pressure in the deposit. Advanced measures raise the production are the reinjection of produced water or sea water and the reinjection of steam to increase the viscosity or surface tension of the oil-gas mixture.

The produced oil-gas mixture is a composite of crude oil, natural gas, brine and other impurities. In a preparation process the natural gas and the NGL is separated from the oil. In a second preparation step most of the water is separated from the oil due to the different densities. The remaining emulsified water and salt is removed in a dewatering and desalting plant. Small amounts of produced natural gas are often still flared, sometimes also vented, due to missing preparation and transportation opportunities.

Natural gas

Due to the high pressure in the gas field the production of natural gas is done without the need of pumps. In good gas fields up to 80% of the gas can be produced without any further measures. In deposits with stone of low porosity, the production rate is increased by pumping liquids under high pressure into the deposit to crack open the stone. Hydrogen sulphide contained in the natural gas in different concentrations, has to be removed before transportation via pipelines due to the high corrosive impact. The hydrogen sulphide is recovered from the natural gas by the Claus process producing elementary sulphur and, depending on technology standards, a certain amount of sulphur dioxide. The arising water with concentrations of approximately 15 or more mg hydrocarbons per litre is reinjected into the gas field, discharged into the sea (onshore and in shore) or evaporated in pits. During preparation different kinds of waste and used chemicals arise which have to be disposed. A certain amount of gas and oil is flared or vented into the atmosphere because of leakage or security reasons. The mechanical energy and electricity for pumping and all other machinery is provided by gas turbines and diesel units. At onshore facilities a certain amount is provided by the grid.

2 General comments of the LCA assessment method

This chapter gives background information on the principal modelling approach.

2.1 System boundaries and functional unit

Crude oil:

Functional unit: The functional unit is 1 bbl of crude oil.

This process includes all relevant Mass and energy flows for the exploration and extraction of crude oil. Figure 2-1 gives an overview on the considered processes along with their key in- and outputs

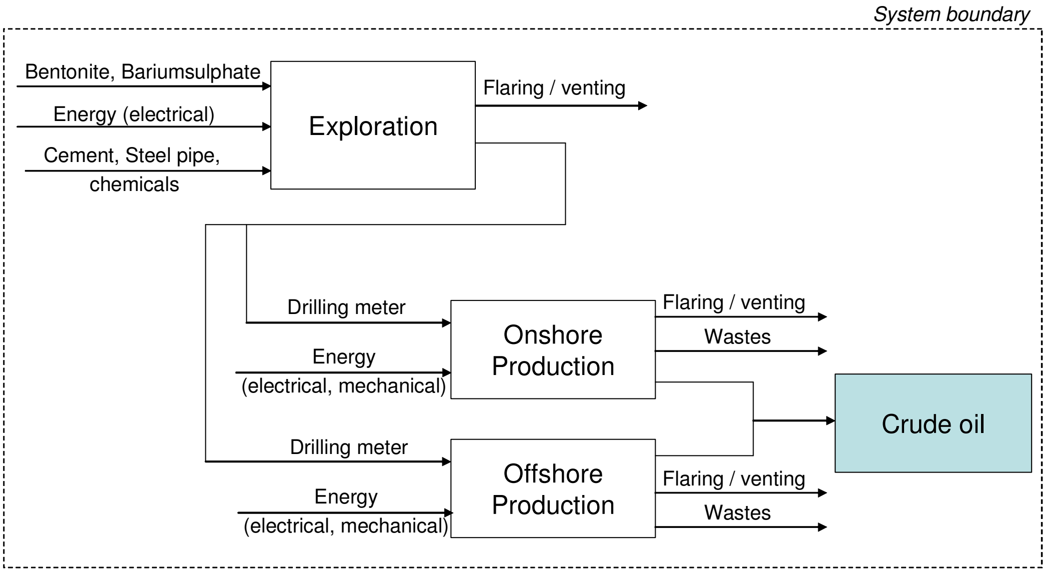


Figure 2-1 **System boundary for crude oil production**

Natural gas

Functional unit: The functional unit is 1 stand cubic feet of natural gas.

This process includes all relevant Mass and energy flows for the exploration and extraction of crude oil. Figure 2-2 gives an overview on the considered processes along with their key in- and outputs

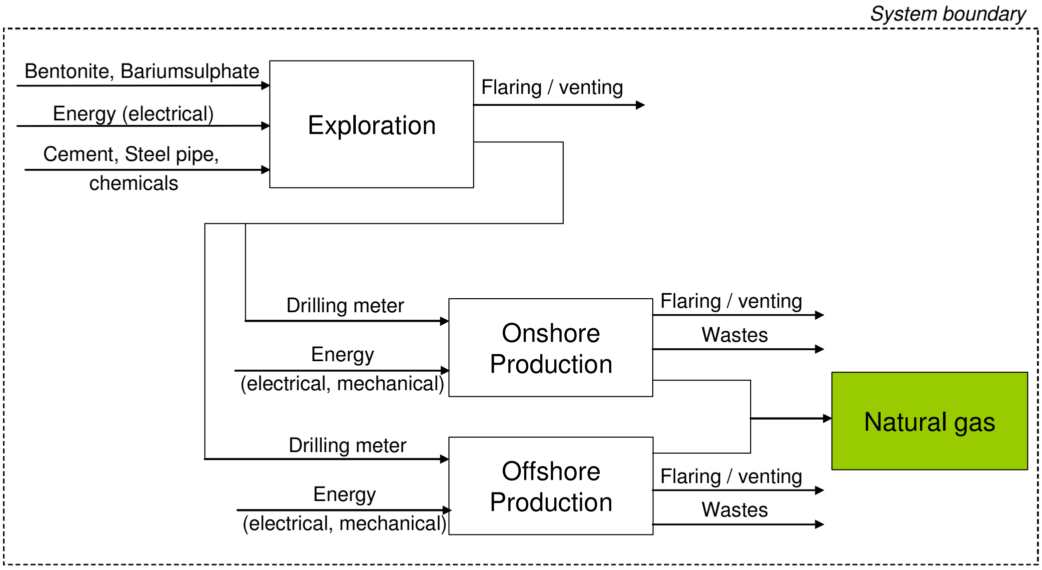


Figure 2-2 System boundary for natural gas production

The exploration is modelled per drilling meters and is considered in the model via drilling meters per mass of produced hydrocarbon. Quantities of borehole volume, removed rock are based on multiple sources such as [17]-[19]. Amount of Bentonite and Bariumsulphate and water for drilling mud is taken from [17]. The material used for reinforcing the well is calculated based on [20]-[23]. The power demand for drilling is taken from [24]. For venting of natural gas the averaged national natural gas composition is considered [33], [35]. The energy demand for production is given in section 3.2. The associated emissions are calculated using emission factors sourced from [26] and industry data. Venting of solution gas from oil producing well is also considered. For flaring region specific flare emissions are included see section 3.3 and [25],[31],[32],[37]. Solid wastes and waste water are considered. The referring data is sourced from [25], [27]-[30], [36] and as stated in section 3.4. .

2.2 Allocation or system expansion

For the combined crude oil, natural gas and natural gas liquids production allocation by lower calorific value is applied. The lower heating values of the products are given in section 3.5.

2.3 Data completeness

The coverage for the exploration data (crude oil, natural gas, natural gas liquids) is 90% of mass and energy and 95% of the environmental relevance (expert judgement).

2.4 Data selection and combination principles

The data sources for the complete product system are sufficiently consistent: The data on the energy carrier supply chain is based on statistics with country/region specific transport distances and energy carrier composition as well as industry and literature data on the inventory of exploration, extraction and processing. LCI modelling is fully consistent.

2.5 Reference year

Reference year for the data set is 2002. Although some of the emission data and product properties are sourced from different years representativeness for the reference year is considered good.

2.6 Data treatment and extrapolations principles

In terms of the country/region specific crude oil production, missing data of certain parameters has been used from countries with a comparable technology[1]. Data measured at a group of representative production facilities have been used to represent the national production.

---

[1] If this ist he case it is indicated in the tables in section 3.

3 Country specific data

3.1 Production

Table 1 shows the production ratio of natural gas, NGL and crude oil on a weight basis as well as the drilling feet per pound hydrocarbon produced. Note that all values are given for unallocated joint production of Natural gas, NGL and crude oil.

Table 1 Production parameters

Parameter	Value	Source
Portion of natural gas production	58.56%	[1]
Portion of NGL production	6.64%	[1]
Portion of crude oil production	34.80%	[34]
Share of offshore production[2]	12,9%	[39]
Drilling meters for onshore production	0.71×10^{-05} ft/lb HC produced	[2]
Drilling meters for offshore production	0.71×10^{-05} ft/lb HC produced	[2]

3.2 Energy use

The specific energy use distinguished between electricity and mechanical energy is shown in Table 2.

Table 2 Energy consumption parameters

Parameter	Value	Source
Electricity demand	26.23 Btu/lb HC	Value for region North America [25] and own calculations
Mechanical energy demand	236.45 Btu/lb HC	Value for region North America [25] and own calculations
Total energy demand	262.25 Btu/lb HC	Value for region North America [25]

---

[2] Based on gross withdrawal

3.3 Flaring and venting

The flaring and venting of hydrocarbons during the production process is shown in Table 3. The flared Hydrocarbons are the sum of flared natural gas and solution gas compounds.

Table 3 Flaring and venting parameters

Parameter	Value	Source
Flared Hydrocarbons	0.0037 lb/lb HC	[16], [37]
Vented Hydrocarbons	0.00094 lb/lb HC	[16] and own calculations

3.4 Waste and waste water

The amount of solid waste and waste water emitted during the production process is summarised in Table 4.

Table 4 Waste and waste water parameters

Parameter	Value	Source
Solid waste	0.0060 lb/lb HC	Global value [3];[4];[5];[6];[7];[8];[9]
Waste water onshore	0.017 lb/lb HC	[25]
Waste water offshore	0.91 lb/lb HC	[25]

3.5 Product properties

The lower heating value as a country specific product property is given in Table 5.

Table 5 Product properties

Parameter	Value	Source
Net calorific value natural gas	16762,1909 Btu/lb	[35]
Net calorific value crude oil	18030,4254 Btu/lb	[10];[11];[12];[13];[14];[15]

4 References

[1] IEA Natural Gas Information 2002, International Energy Agency, 2004

[2] Pennwell: The international petroleum Encyclopaedia 1997

[3] Yukos: Yukos and the environment, 2003

[4] Shell: http://www.shell.com/home/Framework?siteId=my-en&FC2=/my-en/html/iwgen/society_environment/environment/sustainable2003/zzz_lhn.html&FC3=/my-en/html/iwgen/society_environment/environment/sustainable2003/sd03_protecttheenvironment_1008.html, 2004

[5] Shell Nigeria 2004 People and the environment Annual Report, 2005

[6] Nederlandse Aardolie Maatschappij (NAM): Bron van energie, 2003

[7] BP Pakistan 2003 Environmental Statement, 2004

[8] BP Trinidad & Tobago: 2003 Environmental Statement Trinidad BU, 2004

[9] Shell in the UK report 2001, 2002

[10] EIA: C.2 Barrels of Crude Oil Per Metric Ton, 1980-2003, 2004

[11] EIA: C.3 Gross Heat Content of Crude Oil, 1980-2003, 2004

[12] Haverly: Crude assay libraries, 2005

[13] Energy Intelligence Group: The Crude Oils and Their Key Characteristics, 2003

[14] James W. Bunger and Associates, Inc.: Z-BaSIC™ Crude Oil Assay, West Texas sour, 2000

[15] Aaron Dillard: Crude oil Quality Programs, Light Louisiana Sweet,2001

[16] EIA: International Energy Annual 2003; Energy Information Administration, 2004

[17] OGP: Environmental aspects of the use and disposal of non aqueous drilling fluids associated with offshore oil& gas operations, 2003

[18] Da Prat, G.: Well Testing management , SPE Foundation, presentation 2002

[19] Vickery et al.: Successful high rate gas completion through combination of extreme overbalance perforating and one trip perforate and gravel pack techniques, Baker oil tools, 2001

[20] N. Lapeyrouse: Formulas and calculations for Drilling, Production and work over, 2nd Edition, Golf Professional Publishing, 2002

[21] Gordon, D. et al. Underbalanced Drilling with casing SPE, SPE Drilling & completion 2005

[22] Ohio Department of Health: Materials used in drilling and construction of wells, 1999

[23] Culver, G.: Drilling and well construction, Chapter 6, OIST, Department of Energy 1998

[24] Vektor AS – Environmental developments in Well testing, 2000

[25] OGP, International Association of Oil and Gas Producers: Environmental performance in the E&P industry 2003

[26] US EPA: Compilation of Air pollutant emission factors, AP 42, Volume I: Stationary point and area sources, Fifth edition, United States Protection Agency, Office of air quality planning and standards, 1995-2000.

[27] US EPA: Profile of the Oil and Gas Extraction Industry, 2nd Section, 2000

[28] PSI: Management of produced water on offshore oil installations, Policy Studies Institute, 2005

[29] OGP: Aromatics in produced water occurrence, fate & effects and treatment, International Association of Oil and Gas Producers, 2002

[30] OGP: Fate and effects of naturally occurring substances in produced water on the marine environment, International Association of Oil and Gas Producers, 2005

[31] Leahey, G et at.: Theoretical and observational assessments of flare efficiencies, Journal of Air & Waste Management Association, Volume 51, December 2001

[32] Johnson, M.R. et al.: Efficiency measurements of flares in a cross flow, Dep. Of Mechanical Engineering, University of Alberta, Combustion Canada conference, 1999

[33] California Energy Commission: Natural gas composition and Quality, 2005+

[34] IEA: Oil Information 2002, International Energy Agency, 2004

[35] EIA: C.5 Gross Heat Content of Dry Natural Gas Production, 1980-2004, 2005

[36] BP: Environmental Statement Lower 48 U.S. Oil and Gas Operations, 2001

[37] World Bank: Global gas flaring reduction initiative, 2004

[38] EIA: Natural gas navigator, Exploration & reserves, Footage drilled for Crude Oil and Natural gas wells, Department of Energy, 2005

[39] Pennwell: The international petroleum Encyclopedia 2004