APPENDIX W

Life-Cycle Greenhouse Gas Emissions of Petroleum Products from WCSB Oil Sands Crudes Compared with Reference Crudes

-This page intentionally left blank-

TABLE OF CONTENTS

INDEX OF TABLES

INDEX OF FIGURES

ACRONYMS

API American Petroleum Institute

bbl barrel

CCS carbon capture and storage

CO_2 carbon dioxide

CSS cyclic steam stimulation

EIA U.S. Energy Information Administration

EIS Environmental Impact Statement

FCC fluid catalytic cracker

gCO_2/MJ grams carbon dioxide per megajoule

gCO_2e/MJ grams carbon dioxide equivalent per megajoule

GHG greenhouse gas

GOR gas-oil ratio

H2 hydrogen

HHV higher heating value

ISO International Organization for Standardization

kg CO_2e kilograms carbon dioxide equivalent

LCA life-cycle assessment

LCFS California's Low Carbon Fuel Standard

LHV lower heating value

LPG liquefied petroleum gas

m meter

MJ megajoule

MMTCO_2e million metric tons of carbon dioxide equivalent

NA not applicable

NETL National Energy Technology Laboratory

NG natural gas

OECD Organization for Economic Cooperation and Development

PADD Petroleum Administration for Defense Districts

RBOB reformulated blendstock for oxygenate blending

RFS2 USEPA Renewable Fuel Standard

SAGD steam-assisted gravity drainage

SCO synthetic crude oil

SOR steam-oil ratio

TTW tank-to-wheels

WCSB Western Canadian Sedimentary Basin

WTR well-to-refinery gate

WTT well-to-tank

WTW well-to-wheels

1.0 OBJECTIVE

This appendix accompanies the text in Section 4.15, Cumulative Effects Assessment, of the Supplemental EIS, and examines differences between the life-cycle greenhouse gas (GHG) emissions associated with Western Canadian Sedimentary Basin (WCSB) oil sands-derived crudes compared with reference crudes refined in the United States. The ultimate goal of this effort is to provide context for understanding the potential indirect, cumulative GHG impact of the proposed Keystone XL pipeline (the proposed Project). Rather than conducting new modeling or analysis, this study reviews existing life-cycle studies (including several meta-analyses) and models that estimated the GHG implications for WCSB oil sands-derived and reference crudes to (a) identify and evaluate key factors driving the differences and range, and (b) explain the range of life-cycle GHG emission values.

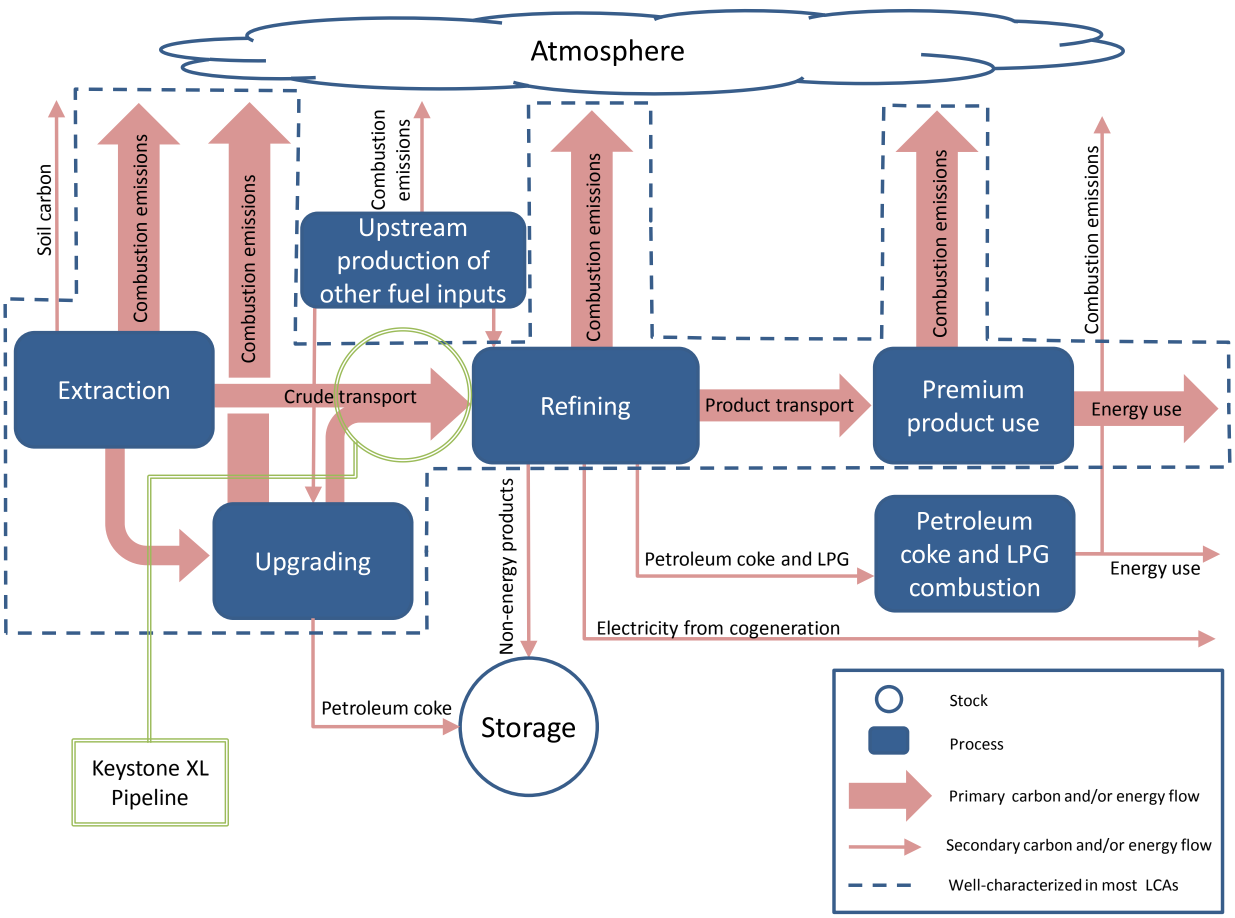
This appendix offers a conceptual framework for understanding the carbon and energy flows within a petroleum system in Section 2.0, Conceptual Framework. Section 3.0, Approach, describes the approach taken, including the scope of the review of the life-cycle studies. Section 4.0, Results and Discussion, then discusses the key factors driving the comparisons between WCSB crudes and reference crudes and examines the differences between the study results across various scenarios. Section 5.0, Petroleum Coke Characteristics, GHG Emissions, and Market Effects, discusses the physical characteristics of petroleum coke, examines studies estimating GHG emissions from coke combustion, and discusses the WCSB oil sands effects on the petroleum coke market. Section 6.0, Incremental GHG Emissions of Displacing Reference Crudes with WCSB Oil Sands, concludes by synthesizing key findings and providing a brief discussion on future trends.

2.0 CONCEPTUAL FRAMEWORK

A comparative life-cycle assessment (LCA) of fuels is driven by two accounting approaches: a carbon mass balance and an energy balance. Within each balance, it is helpful to distinguish between what can be considered primary flows and secondary flows. The primary carbon and energy flows are those associated with the production of three premium fuel products—gasoline, diesel, and kerosene/jet fuel—by refining crude oil. In addition to the premium fuels, other secondary co-products such as petroleum coke, liquefied petroleum gas (LPG), and sulfur are produced as well. Primary flows are generally well-understood and included in LCAs.

In addition to primary flows, there are a range of secondary energy flows and emissions to consider. Because these flows are outside the primary operations associated with fuel production, they are often characterized differently across studies or excluded from LCAs, and estimates of specific process inputs and emission factors vary according to the underlying methods and data sources used in the assessment.

See Figure 2-1 for a simplified petroleum system flow diagram. This framework is helpful for describing differences across life-cycle comparisons of fuel GHG emissions. Classifying the flows as primary and secondary according to the objective of producing premium fuel products from crude helps to understand why certain flows and sources of emissions may be excluded due to a lack of data or methods to estimate secondary flows, where processes are defined relatively consistently, and where different methods are used for treating LCA issues, such as co-products. This helps formulate conclusions about the key drivers that influence fuel life-cycle comparisons.



Source: ICF, Final EIS 2011

Figure 2-1 Simplified petroleum system carbon and energy flow

2.1 CARBON MASS BALANCE

In the case of the carbon mass balance, it is helpful to consider the differences between the primary carbon flows and the secondary carbon flows. Primary carbon flows characterize most of the carbon in the system and start as crude in the ground. The crude is processed into premium fuel products such as gasoline, diesel, and kerosene/jet fuel, which are combusted and converted to CO_2. These carbon flows drive the economics and engineering of the oil business and they are well-understood and well-characterized. Secondary carbon flows exist outside the primary crude–premium-fuel-products–combustion flow. Examples of secondary carbon flows associated with petroleum products include the production and use of petroleum coke; non-energy uses of petroleum, such as lubricating oils, petrochemicals, and asphalt; and changes in biological or soil carbon stocks as a result of land-use change. Among LCA studies, the life-cycle boundaries vary considerably in terms of whether and how they cover secondary carbon flows. Because much of this secondary carbon is peripheral to the transportation fuels business (e.g., petroleum coke is often regarded as an unwanted co-product), studies use different approaches for evaluating these flows, and in some cases, the available information may be less complete compared to the primary crude–premium-fuel-products–combustion part of the system. Note that lube oils and petrochemical feedstocks are considered peripheral to the primary fuel products that are combusted for energy.

2.2 ENERGY BALANCE

The energy balance consists of primary flows of premium fuel product-related energy and secondary flows of imported and exported energy. Most of the energy in the system is involved in extracting, upgrading, refining, transporting, and combusting the crude and premium fuel products, and most of the energy consumed comes from the crude. The vast majority of the energy exits the system when the premium fuel products are combusted. Similar to primary carbon flows, primary energy flows are well-understood and well-characterized. The secondary, imported energy comes from sources other than crude such as purchased electricity or natural gas and includes energy required to build capital equipment and infrastructure. The secondary, exported energy comes from crude but is not retained in the premium fuel product. For example, co-generation used for in situ crude extraction methods generates electricity, which is exported to the grid, or petroleum coke can be burned in lieu of coal to generate steam and/or electricity. The GHG emissions associated with imported and exported energy are highly sensitive to assumptions about the fuels involved.

3.0 APPROACH

The general approach for this study included the following steps, which are described in more detail below:

1. Establish the review scope;
2. Identify the studies for review;
3. Develop a set of critical elements to review in each study;
4. Review the studies and refine the critical elements;
5. Evaluate the elements across studies to identify the key drivers of the differences in GHG intensity; and
6. Summarize the key drivers and place the GHG emission results in context.

3.1 ESTABLISH THE SCOPE FOR THE REVIEW

The scope of the boundaries considered for this analysis include well-to-wheels (WTW) emissions resulting from extraction and processing of the crude from the reservoir, refining of the crude, combustion of the refined products, and transportation between the life stages. This study also examines results for individual stages and portions of the life-cycle for oil sands-derived crudes and reference crudes where values were reported. Not all studies in this review include a full WTW life-cycle assessment; several studies focus on the well-to-tank (WTT) portion of the life-cycle, while others consider only the crude production emissions. WTT analyses include the emissions associated with the processes up to, but not including, combustion of the refined products. This study looks at the GHG implications for the three premium fuel products (i.e., gasoline, diesel, and jet fuel) as well as co-products derived from the different types and sources of crude oil.

In order to understand the differences not only between WCSB oil sands-derived crudes and reference crudes, but also between different types of WCSB oil sands crudes and technologies, this study included the following types of crudes derived from WCSB oil sands:[1]

- Canada oil sands cyclic steam stimulation (CSS) bitumen, synthetic crude oil (SCO),[2] dilbit,[3] and synbit[4]
- Canada oil sands steam-assisted gravity drainage (SAGD) SCO, bitumen, dilbit, and synbit
- Canada oil sands mining SCO, bitumen, dilbit, and synbit

Section 4.2.1.1, Type of Extraction Process, describes the different extraction methods in detail.

Four reference crudes were selected to reflect a range of crude oil sources and GHG intensities:

- The average U.S. barrel consumed in 2005 (National Energy Technology Laboratory [NETL] 2008). This reference was selected because it provides a baseline for fuels produced from the average crude consumed in the United States. It also serves as the baseline in the U.S. Renewable Fuel Standard Program, RFS2 (U.S. Environmental Protection Agency [USEPA] 2010a).
- Venezuela Bachaquero and Mexico Maya, which are representative of heavy crudes currently refined in PADD III refineries.[5] Conceptually, these crudes may be displaced by the arrival of WCSB oil sands at the Gulf Coast refineries, although it is likely that they would find markets elsewhere and would still be produced.
- Saudi Light (i.e., Middle Eastern Sour), which was taken to be the balancing grade for world crude oil supplies in the Keystone XL Assessment. Conceptually, this crude is most likely to be backed out of the world market if additional supplies of WCSB oil-sands crudes are produced.

---

[1] In situ crude extraction methods of steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) are more energy intensive than mining and involve drilling and injecting steam into the wellbore to recover deeper deposits of oil sands than those present on the surface (IHS CERA 2010).
[2] SCO is a product of upgrading bitumen.
[3] Dilbit is diluted bitumen, a mix of bitumen and condensate. Diluting the bitumen reduces the viscosity so that it can flow through a pipeline.
[4] Synbit refers to an SCO and bitumen blend.
[5] Petroleum Administration for Defense Districts (PADDs) are geographic areas of the United States that were delineated in World War II to coordinate the allocation of fuels. PADD III refineries are those located in the Gulf Coast area, namely Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas (EIA 2011).

3.2 IDENTIFY THE STUDIES FOR REVIEW

Several studies provide assessments of the life-cycle GHG implications of WCSB oil sands crude relative to reference crudes. The Department, in conjunction with USEPA, USDOE, and CEQ, selected studies for review on the following basis:

- The reports evaluate WCSB crude oils in comparison to crude oils from other sources.
- The reports focus on GHG impacts throughout the crude oil life-cycle.
- The reports were published within the last 10 years (with one exception), and most were published within the last five years.
- The reports represent the perspectives of various stakeholders, including industry, governmental organizations, and non-governmental organizations.

Table 3-1 provides a list of primary and additional sources identified and reviewed for this analysis, which include eight LCAs, two partial LCAs, six meta-analyses (synthesizing results from other LCAs), two models, one white paper, and two journal articles on land use change.

Table 3-1 Primary and Additional Studies Evaluated

Primary Studies Analyzed	Type	Boundaries
NETL. 2008. Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels.	Individual LCA	WTW
NETL. 2009. An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact of Life Cycle Greenhouse Gas Emissions.	Individual LCA	WTW
IEA. 2010. World Energy Outlook.	Meta-analysis	WTW
IHS CERA. 2010. Oil Sands, Greenhouse Gases, and U.S. Oil Supply: Getting the Numbers Right.	Meta-analysis	WTW
IHS CERA. 2011. Oil Sands, Greenhouse Gases, and European Oil Supply: Getting the Numbers Right.	Meta-analysis	WTW
NRDC. 2010. GHG Emission Factors for High Carbon Intensity Crude Oils, ver. 2.	Meta-analysis	WTW
Energy-Redefined LLC for ICCT. 2010. Carbon Intensity of Crude Oil in Europe Crude.	Individual LCA	WTT[6]
Jacobs Consultancy. 2009. Life Cycle Assessment Comparison of North American and Imported Crudes.	Individual LCA	WTW
Jacobs Consultancy. 2012. EU Pathway Study: Life Cycle Assessment of Crude Oils in a European Context.	Individual LCA	WTW
TIAX LLC. 2009. Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions.	Individual LCA	WTW
Charpentier et al. 2009. Understanding the Canadian Oil Sands Industry's Greenhouse Gas Emissions.	Meta-analysis	WTW
Brandt, A. 2011. Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries.	Meta-analysis	WTW
Additional Studies/Models Analyzed		
RAND Corporation. 2008. Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs.	Individual LCA	WTW
Pembina. 2005. Oil Sands Fever: The Environmental Implications of Canada's	Partial LCA	WTR[7]

[6] Excluding distribution.

Primary Studies Analyzed	Type	Boundaries
Oil Sands Rush.		
Pembina. 2006. Carbon Neutral 2020: A Leadership Opportunity in Canada's Oil Sands. Oil sands issue paper 2.	Partial LCA	WTR[7]
McCann and Associates. 2001. Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles.	Individual LCA	WTW
GHGenius. 2010. GHGenius Model, Version 3.19. Natural Resources Canada.	Model	WTW
GREET. 2010. Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model, Version 1.8d.1. Argonne National Laboratory.	Model	WTW
Pembina. 2011. Life cycle assessments of oil sands greenhouse gas emissions: A checklist for robust analysis.	White Paper	NA
Rooney et al. 2012. Oil Sands Mining and Reclamation Cause Massive Loss of Peatland and Stored Carbon.	Land use change journal article	NA
Yeh et al. 2010. Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands.	Land use change journal article	NA

NA = not applicable, GHG = greenhouse gas, LCA = life-cycle assessment, WTR = well-to-refinery gate, WTW = well-to-wheels.

The list of primary and additional studies reflects recent updates to previous life cycle assessments of oil-sands-derived crudes and information on GHG emissions associated with land use change. Jacobs (2012) developed carbon intensities for Alberta crudes based on first order engineering principles and models and calculation methods used in the GREET model (Jacobs Consultancy [Jacobs] 2012, Argonne National Laboratory 2010). Jacobs also correlated the results with data reported to and audited by the Canadian government. Regulatory authorities in Alberta require extensive bitumen production information ranging from fugitive and flaring data to the energy consumption and GHG emissions from bitumen production both from in-situ mining and from mining upgrading. Jacob's GHG emissions for producing the heavy Alberta crude oils by SAGD are based on engineering estimates using energy consumption that has a close correlation with data reported to the Alberta government (Jacobs 2012, p. 5-41). Jacobs' evaluation of the carbon intensity of mining and upgrading is based on data from audited industry and government reports, and engineering estimates based on estimated parameters governing crude oil production. Engineering models to estimate energy consumption and GHG emissions from bitumen production correlated well with energy use and GHG emissions reported to the Government of Alberta. The IHS CERA study (2011) does not contain any changes in emission estimates from IHS CERA (2010) except for the combustion emissions from the end use of refined products (IHS Cambridge Energy Research Associates [IHS CERA] 2011, 2010).[8]

The Jacobs 2012 report offers new analysis based on first order engineering principles and models. A quantitative analysis of the Jacobs report and its data has not been undertaken.

[7] Up to oil sands facility gate, excluding transportation to refinery and refining.
[8] IHS CERA (2010) provides a value of 384 kg CO_2e per barrel of refined product; IHS CERA (2011) study provides a value of 402 kg CO_2e per barrel of refined product. It is not clear from the 2010 report what refined product blend was used to estimate the combustion emissions value. However, it is clear that the refined product blend used in the 2011 study is different from the one used in the 2010 study. Combustion emissions from end use of refined products are assumed to be the same across all crudes examined in each study.

3.3 DEVELOP A SET OF CRITICAL ELEMENTS TO REVIEW IN EACH STUDY

An initial set of approximately 50 attributes were developed for review, guided by specifications on scope, data quality requirements, and appropriateness of comparisons from the ISO standards (14040:2006, 14044:2006) as well as an engineering understanding of crude oil life-cycle processes. These attributes are listed in Table 3-2. For each study and crude and fuel type specified, these elements included specifics on each stage of the life-cycle (e.g., whether the element was included in the study, and if so, the value, units, and data sources), boundary elements included/excluded, technology assumptions, equivalencies assumptions, information on the allocation approach and treatment of emissions associated with co-products, and elements to assess data quality and the appropriateness of comparisons. General study information was also gathered (e.g., study purpose, reference year, overarching assumptions).

Table 3-2 Attributes Evaluated for Each Study

General	LCA Boundaries	Co-Products
Purpose	Upstream fuels production	Allocation approach
Reference year or years	Flaring/venting	Electricity production from cogeneration
Scope of LCA boundaries	Fugitive leaks	Petroleum coke
Geographic scope	Methane emissions from mine face	Light products (propane, butane)
Functional unit	Methane emissions from tailing ponds	**Data Quality Assessment**
Method	Mining/extraction	Citation of ISO or other LCA standards
Technology Assumptions	Local land use change	Peer review
Extraction method	Indirect land use change	Completeness
Lift methods	Transport to upgrading	Representativeness
Refinery	Upgrading technology	Consistency
Steam/oil ratio	Transport to refinery	Critical data gaps
Other	Refining	Reproducibility
Equivalencies and Conversions	Distribution to retail	Age of data
Global Warming Potential (GWP) coefficients	Storage	Sources of data
HHV or LHV	Combustion	**General Assessment**
API gravity	Inclusion of infrastructure or capital equipment	Appropriateness of comparison
		Overall assessment

ISO = International Organization for Standardization, HHV = higher heating value, LHV = lower heating value, LCA = life-cycle analysis.

3.4 REVIEW THE STUDIES AND REFINE THE CRITICAL ELEMENTS

Each of the primary studies was reviewed in depth, with particular attention to the critical elements. Secondary studies were analyzed in less depth. Data, assumptions, or other information related to the critical elements, were recorded, allowing for easier comparison of criteria across the studies.

After the initial review of the studies against the main criteria, a survey of the data and information collected made it possible to identify those elements that were missing from the initial review or warranted additional attention. For example, the initial review suggested that the treatment of petroleum coke may have a large impact on GHG emissions differences between fuels and studies. Over several iterations, the compiled data and information were analyzed, the criteria were modified to more thoroughly meet the objectives of the analysis, and the studies were reviewed against the enhanced criteria. As preliminary comparisons of the LCA boundaries, study design factors, and input and modeling assumptions were conducted across the studies, key drivers of the results became more apparent, leading to the next step in the analysis.

3.5 Evaluate the Elements Across Studies to Identify the Key Drivers of the Differences in GHG Intensity

Once each study had been reviewed against the refined review criteria, it was possible to compile the relevant emissions estimates, data, and other information to identify the key drivers of the emissions differentials. The key drivers were evaluated across a number of study design factors and assumptions, including, but not limited to, LCA boundaries, time period, allocation methods, crude and fuel types, and functional unit choice. The results were compared across studies where similar design factors and assumptions enabled comparisons to be made between studies. A discussion of the key drivers and the impact they have on the emissions estimates is included in Section 4.4, Analysis of Key Factors and their Impact on WTW GHG Emissions Results.

3.6 Summarize the Key Drivers and Place the GHG Emission Results in Context

The GHG emission results from NETL were used to evaluate and compare the key drivers and GHG results against the other studies included in the assessment (NETL 2008; 2009). NETL's estimates cover a range of the world crude oils consumed in the United States, including the WCSB oil sands as well as the average crude consumed in the United States in 2005.[9] Because the NETL-developed emission factors were selected to be a key input to USEPA's renewable fuel regulations, they serve as an important reference case for evaluating life-cycle emissions for different crude sources.

The key findings from this assessment include a summary of the key drivers and the relative impact that these drivers could have on comparisons of life-cycle GHG emissions between WCSB oil sands crudes and reference crudes. As discussed later, the differences across the studies, and—where data were available within the studies—the relative impact that these differences had on the life-cycle results, were also discussed.

4.0 RESULTS AND DISCUSSION

This section presents an assessment of the studies comparing life-cycle GHG emissions from WCSB oil sands crudes to reference crudes. This section is organized to characterize the key factors across the studies and to evaluate their impact on the final results. By organizing it in this

[9] This 2005 average serves as the baseline in the U.S. Renewable Fuel Standard Program (USEPA 2010a).

way, conclusions are highlighted that are robust across all the studies, and areas where the studies differ are identified.

The discussion starts by introducing the key factors that drive the differences in the life-cycle GHG emission estimates of the studies. The factors belong to two separate groups: (i) study design factors that relate to how the comparison of GHG emissions is structured by each study, and (ii) input and modeling assumptions that are used to calculate the GHG emission results. Study design factors are explained in Section 4.1, Study Design Factors, and input and modeling assumptions are explained in Section 4.2, Input and Modeling Assumptions.

Data quality and transparency issues are then discussed across the studies in Section 4.3, Data Quality and Transparency. This is followed by an analysis of the impact of the key factors on the life-cycle GHG emissions of WCSB oil sands crudes compared to reference crudes. In Section 4.4, Analysis of Key Factors and their Impact on WTW GHG Emissions Results, the NETL studies are used as a basis to evaluate and compare the key study design factors and input and modeling assumptions against the other studies (NETL 2008; 2009). This section provides information on the relative magnitude of impact of each factor, and how each factor contributes to the GHG-intensity of WCSB oil sands crudes relative to reference crudes.

Finally, Section 4.4.3, Summary Comparison of Life-Cycle GHG Emission Results, provides two figures that summarize the relative change in WTW and WTT GHG emissions for gasoline produced from WCSB oil sands crudes relative to each of the four reference crudes in the scope of this assessment.

4.1 STUDY DESIGN FACTORS

Study design factors relate to how the GHG comparison is structured within each study. These factors include the types of crudes and refined products that are compared to each other, the timeframe over which the study results are applicable, the life-cycle boundaries established to make the comparison, and the functional units or the basis used for comparing the life-cycle GHGs for crudes or fuels to each other.

4.1.1 Crude and Fuel Types

The crudes used in LCAs are representative of a crude oil produced from a particular country or region. Most LCAs refer to reference crudes in terms of their country of origin (e.g., Mexico) and the name of the crude (e.g., Maya). The crude’s name is meant to indicate a crude oil with specific properties.

The petroleum properties most commonly used to differentiate between crudes are the fuel’s American Petroleum Institute (API) gravity, sulfur content, and—less frequently—hydrogen-carbon (H-C) ratio. The API gravity indicates how heavy or light a petroleum liquid is compared to water;[10] a lighter liquid has a higher API gravity. Depending on their weight, crudes are often referred to as light (high API gravity), medium (medium API gravity), and heavy (low API

[10] The API gravity of water is 10. Crude oils or products with API gravity less than 10 are heavier than water (sink in water). Oils with gravities greater than 10 float on water. Heavier crude oils have more residuum (i.e., asphaltic) content and less naphtha (i.e., gasoline) and distillate content. Lighter crude oils have more naphtha and distillate content and less residuum content.

gravity). Generally, crudes with a low API gravity require more energy to refine into premium fuel products such as gasoline, diesel, and jet fuel. Crudes with a low sulfur content are referred to as sweet, while those with a high sulfur content are referred to as sour; the more sour the crude, the greater the energy input required to remove the sulfur. Finally, the H-C ratio is an indicator of the cross-linkage of the hydrocarbon chains of which the crude is composed. Crudes with a lower H-C ratio (i.e., more carbon atoms for each hydrogen atom) will require more energy inputs to refine into premium fuel products.

The relative difference in WTW emissions between two crudes varies greatly depending on the properties of the compared crudes. For example, fuels refined from WCSB oil sands crudes will generally have higher life-cycle GHG emissions than fuels from crudes with higher API, low sulfur content, and higher H-C ratio. The relative difference will be much narrower if the same oil sands crude is compared to a crude with a low API, high sulfur content, and low H-C ratio.

As a result, the properties of the reference, or comparison, crudes against which WCSB oil sands are evaluated are very important drivers behind the final result. LCAs that compare WCSB oil sands to heavier reference crudes will yield a narrow range in life-cycle GHG emissions between the two crudes, while analyses that select lighter reference crudes will show a wider range in GHG emissions. Table 4-1 shows the difference in Venezuelan reference crude fuel properties across three studies as an example. TIAX selected a lighter Bachaquero heavy crude than Jacobs; NETL did not provide specific properties, but evaluated two different Venezuelan blends—a conventional blend that excluded heavy oil extraction and upgrading, and a heavy Venezuelan bitumen (TIAX 2009; Jacobs 2009, 2012; NETL 2009).

Table 4-1 Differences in Reference Crudes Addressed in LCA Studies, as Illustrated by Variations in Properties of Venezuelan Crudes

Study	Crude	Properties	Notes
TIAX (2009)	Venezuela Lake Maracaibo heavy crude	API 17, 2.4% wt sulfur	TIAX selected Bachaquero 17 produced from Venezuela's Lake Maracaibo field as the representative crude oil from Venezuela. The predominant recovery method is thermal recovery with cyclic steam stimulation (CSS) and sucker rod pumping. (TIAX 2009, p. 12)
Jacobs (2009)	Bachaquero - conventional	10.7 API, 2.8% wt sulfur refined into reformulated gasoline (RBOB)	Jacobs selected the heaviest [Bachaquero] blends (p. 6) as the Venezuela reference crude, although several Bachaquero blends are sold, with APIs at 14 and 17 (Jacobs 2009, p. 30).
NETL (2009)	Venezuelan bitumen	API of 7 to 10	While Canada and Venezuela bitumen have similar API gravity (7 to 10 degrees), Venezuela's bitumen has a lower viscosity and a greater reservoir temperature than Canada's. (NETL 2009, p. 6)
	Venezuelan conventional	Not specified	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. (NETL 2008, p. 125)

API = American Petroleum Institute, RBOB = reformulated blendstock for oxygenate blending.

Although the comparisons within each study are internally consistent, the variation in the properties of the reference crudes results in an apples-to-oranges comparison across the different studies. It must be noted that API gravity is not a good measure in comparing synthetic crude oil (SCO) and diluted bitumen (dilbit) because the former is a heart cut product with very little light hydrocarbons and no residuum, while the latter is a dumbbell blend of light hydrocarbons (gas condensate) and bitumen (heavier hydrocarbons). SCO, dilbit, and a full range conventional crude oil may have nearly the same API gravity, but very different energy or GHG intensities to produce a barrel of premium fuel products.

4.1.2 Time Period

The time period over which GHG estimates of WCSB oil sands and reference crudes are valid is a critical design factor. Most studies focused on present conditions or years for which data were available, as shown in Table 4-2. Since the life-cycle emissions of both WCSB oil sands crudes and reference crudes will change over the design lifetime of the proposed Project, comparisons based on current data will not account for future changes that could alter the differential between oil sands and reference crudes.

Table 4-2 Reference Years for LCA Studies

Study	Reference Year(s)
NETL, 2008	2005
NETL, 2009	2005
IEA, 2010	2005-2009[1]
IHS CERA, 2010, 2011	~2005-2030[2]
NRDC, 2010	2006-2010[3]
ICCT, 2010	2009
Jacobs Consultancy, 2009	2000s
Jacobs Consultancy, 2012	2000s
TIAX, 2009	2007-2009[4]
Charpentier et al., 2009	1999-2008[3]
Brandt, 2011	Varies[5]
GHGenius, 2010	Current[6]
GREET, 2010	Current[7]
RAND, 2008	2000s
Pembina Institute, 2005	2000, 2004
Pembina Institute, 2006	2002-2005[8]
McCann and Associates, 2001	2007
Rooney et al., 2012	1990s, 2000s
Yeh et al., 2010	2000s

[1] Reference year reflects the publication dates of the report's main data sources.
[2] Over the past five years the GHG intensity of U.S. oil sands imports has been steady, and is expected to remain steady or decrease somewhat over the next 20 years (IHS CERA 2010, p. 8-9).
[3] Based on the dates of the reports NRDC (2010a and b) compiled, the results from each report are likely based on data several years older than the publication date of the reports.
[4] Oil sands data are chosen to be as close to current as possible. (TIAX 2009, p. 24).
[5] Varies by study addressed in the meta-study.
[6] GHGenius contains data representative of current operations, but the model can run projections out to 2050. (Natural Resources Canada 2010)
[7] GREET contains data representative of current operations and was last updated in 2010 (Argonne National Laboratory 2010).
[8] Data from studies published from 2002 to 2005 (Pembina 2006, p. 11).

LCA = life-cycle assessment.

Most studies contained data from the mid-to-late 2000s, with one study with a reference year in the 1990s and two sources with reference years as current as 2010. Although IHS CERA (2010) noted that the GHG intensity of U.S. oil sands imports […] is expected to remain steady or decrease somewhat over the next 20 years, the study did not model future emissions in detail, nor did it comment on changes in the GHG intensity of other reference crudes (IHS CERA 2010, p. 8-9). GHGenius (2010) uses data representative of current WCSB oil sands operations although the model can run projections out to 2050 (Natural Resources Canada 2010).

Many factors will affect the life-cycle GHG emissions of both WCSB oil sands and reference crudes over time. First, GHG emissions from extraction will increase in the future for most reference crudes as it will take more energy to extract crude from increasingly depleted oil fields and to explore for further resources. In comparison, all WCSB oil sands are near the surface. This means that, for surface-mined bitumen, energy requirements are likely to stay relatively constant. At the same time, in situ extraction—which is generally more energy- and GHG-intensive than mining—will represent a larger share of oil sands production in the future. Some analysts also predict that technical innovation will likely continue to reduce the GHG-intensity of SAGD operations (IHS CERA 2010).

For example, Jacobs (2012) investigated several technologies and process improvements that are reducing the carbon intensity of WCSB oil sands crude production. For SAGD production, these include lower steam-oil ratios (SOR) (see Section 4.2.1.2 Steam-Oil Ratio for In-Situ Extraction) and using mechanical lift methods instead of gas lift (Jacobs 2012, p. ES-14). For mining, efficiencies can be realized from using waste heat from the upgrader or on-site electricity generation to heat water used for bitumen extraction, and from paraffin froth treatment that enables bitumen to be refined directly without upgrading (Jacobs 2012, pp. ES-14, 5-48 to 5-51). These efficiencies could reduce the WTW carbon intensity of refined products from oil sands crudes by 7 to 5 percent for in situ and mining extraction methods, respectively (Jacobs 2012, p. ES-14).

Technologies for combusting or gasifying petroleum coke may also become more prevalent in WCSB oil sands operations, which could increase GHG emissions. For example, OPTI/Nexen's Long Lake Phase 1 integrated oil sands project began operation in January 2009 and gasifies heavy ends produced at the upgrader (Nexen 2011).

Over the longer term, carbon capture and storage (CCS) technologies could reduce the GHG footprint of WCSB oil sands crudes. The timeframe for widespread adoption and commercialization of CCS at oil sands facilities is estimated at 15 to 20 years, but the exact timeframe for the transition from demonstration projects to technological maturation remains highly uncertain (Alberta Carbon Capture and Storage Development Council 2009, p. 12). Shell has already begun planning the construction of an oil sands upgrading facility in the Athabasca oil sands which will capture and store 1 million metric tons of CO_2 annually in a deep saline formation; the facility is scheduled to be fully operational in 2015 (D'Iorio 2011). Additionally, the Alberta Government has pledged \$1.5 billion for three large-scale Alberta-based CCS demonstration projects (McQueen 2012).

The Alberta oil sands pose unique considerations for wide-scale implementation. Because WCSB oil sands are located in an area generally not suitable for underground storage, underground storage of CO_2 captured at oil sands facilities would require pipeline infrastructure to transport the CO_2 to suitable underground storage locations (Bachu et al. 2000, pp. 74-76).

Finally, CCS could also be applicable to concentrated streams of CO_2 released from reference crude production facilities, which would also lower the GHG emissions profile of reference crudes to the extent that CCS is applied at these facilities on a commercial scale.

The gap is more likely to narrow than widen between the GHG emissions for WCSB oil sands production relative to other reference crudes. The gap in WTT GHG emissions between WCSB oil sands and reference crudes will narrow as reference crude production becomes more energy intensive, and as the energy intensity of oil sands in situ production becomes more efficient. On the other hand, there is considerable uncertainty regarding the extent to which coke combustion could increase, and the rate of adoption of CCS and development of CO_2 pipeline infrastructure.

4.1.3 LCA Boundaries

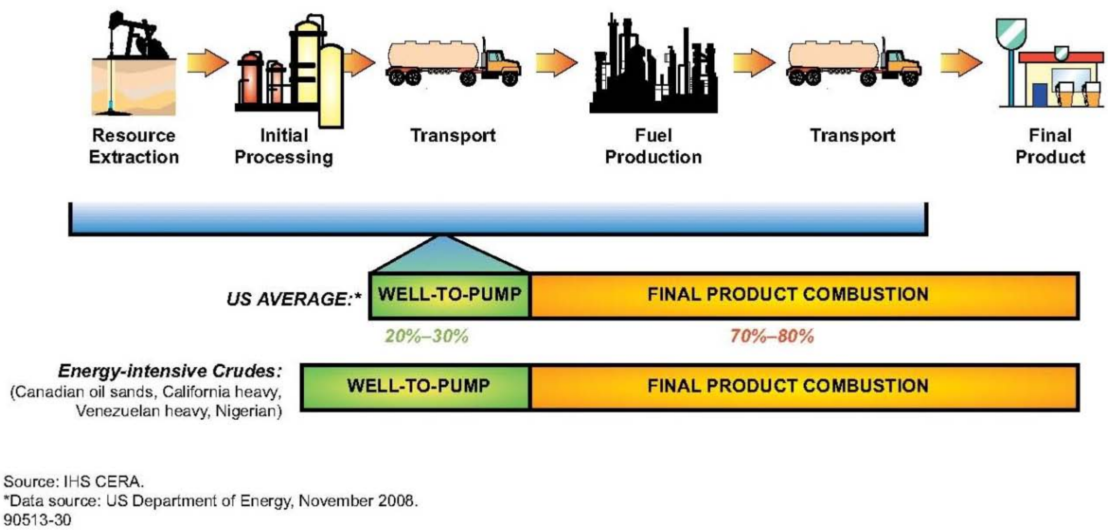
The boundaries of a given LCA describe which sources of GHG emissions are included in the study scope and which are excluded. The following are three common LCA boundaries used in the reviewed studies:

- Well-to-refinery gate (WTR)
- Well-to-tank (WTT) = WTR + refinery-to-tank (RTT)
- Well-to-wheels (WTW) = WTR + RTT + TTW

WTR studies generally include emissions from upstream production of fuels, mining/extraction, upgrading, and transport to refinery. WTT studies generally include emissions of the stages contained in WTR studies, plus refining and distribution. WTW include all stages typically addressed in WTT studies plus emissions from fuels combustion.

Figure 4-1, drawn from the IHS CERA (2010) report, shows the emissions sources typically included in both WTT and WTW boundaries and the relative differences between the WTT emissions from U.S. average crudes and energy-intensive crudes. Regardless of the WTT emissions, final product combustion generally makes up approximately 70 to 80 percent of the WTW emissions and is the same regardless of the crude source.

Table 3-2, located in Section 3.0, Approach, provides the LCA boundaries for each study included in the scope of this assessment. While most studies fall into one of the three categories (i.e., WTR, WTT, or WTW), some studies exclude certain stages. For example, ICCT (2010) included WTT emissions but excluded emissions from the distribution of finished products to the market. These important LCA stage differences across the studies were noted to ensure that comparisons were made across results with the same boundaries (ICCT 2010).



Source: IHS CERA 2010

Figure 4-1 Relative magnitude of WTT (i.e., well-to-pump), TTW (i.e., final product combustion), and WTW emissions for U.S. average crudes and energy-intensive crudes

Within each of the life-cycle stages discussed above, specific flows of carbon and GHG emissions are excluded or handled differently across the studies. These flows include the following:

- Upstream energy use and GHG emissions from producing imported fuels and electricity that are purchased from off-site and brought on-site for process heat and power;
- Fugitive methane emissions, emissions from flaring and venting, and—for oil sands operations—methane emissions from the mine face and tailing ponds;
- Releases and storage of carbon associated with land-use change;
- Energy use and GHG emissions from the production of capital equipment and infrastructure; and
- Inclusion of co-products (see Section 4.1.4, Allocation, Co-Products, and Offsets, for details).

These flows tend to be secondary energy and carbon flows that are not directly associated with the primary flows of energy and carbon associated with premium refined fuel products, as defined in the conceptual framework described in Section 2.0, Conceptual Framework, of this appendix. While primary flows are generally consistently included within the LCA boundaries of the studies, the treatment of secondary carbon flows is handled differently across the studies.

An assessment of these flows across each of the studies—and the impact of these differences across studies on the comparability of results—is discussed in detail in Section 4.4, Analysis of Key Factors and their Impact on WTW GHG Emissions Results.

4.1.4 Allocation, Co-Products, and Offsets

Allocation is a method used by LCA practitioners to attribute a portion of the emissions burden to co-products. Co-products are two or more products that are outputs from a process or product system. For example, in a refinery, gasoline, diesel, and jet fuel are all co-products. Other co-products produced from upgrading and refining crude oil can include petroleum coke, liquefied petroleum gas (LPG), sulfur, and surplus cogenerated electricity.

There are three different approaches for handling co-products in LCAs:

1. All co-products can be included within the LCA boundary (also known as system expansion).
2. It may be possible to split or separate a process into two or more sub-processes that each describes an individual product.
3. When the goal of a study is to evaluate a specific co-product (for instance, gasoline independent of diesel, jet fuel, or other co-products), and it is not possible to expand or split the system, it is necessary to allocate a portion of GHG emissions to each co-product, exclude these other co-products from the LCA system boundary, and only consider the GHG emissions associated with making and consuming the co-product of interest.

ISO standards suggest avoiding allocation, when possible, through methods like system expansion and process division. When allocation cannot be avoided, ISO recommends allocating according to the underlying physical relationships between different products.

Allocation of GHG emissions is not necessary in studies that evaluate WTW emissions per barrel of refined products because the LCA boundary includes all the refined products (i.e., gasoline, diesel, jet fuel, as well as coke, LPG, and sulfur). In contrast, studies that evaluate WTW emissions for specific premium fuels such as gasoline, diesel, or jet fuel allocate a portion of the upstream GHGs to each fuel, typically on a fuel energy-content basis. Additionally, these studies may include the GHG burdens from producing co-products such as LPG and coke, to the premium fuel products (i.e., gasoline, diesel, or jet fuel), or they may allocate GHG emissions to these other co-products as well and exclude them from the system boundary.

Comparisons made between the various studies must take into account how co-products are treated in each study. Although individual studies may be internally consistent in how they treat allocation and co-products, the different approaches to accounting for co-products can have a significant impact on life-cycle emissions, and can result in apples-to-oranges comparisons across the studies.

Petroleum coke, LPG, sulfur, and excess electricity from cogeneration (if applicable) are co-products that are produced as a result of producing the premium fuel products of gasoline, diesel, and jet fuel. These co-products are necessary outputs in order to produce premium fuels and would not be produced in the same quantities on their own. As a result, several studies assign a credit for using these lower-value, or secondary, co-products to offset the production and use of other products or fuels. For example, TIAX (2009) included a credit for exported electricity in certain WCSB oil sands production scenarios, assuming that cogenerated electricity is sold to the grid, offsetting natural gas combustion in turbines (TIAX 2009).

Applying offset, or substitution, credits for petroleum coke and exported electricity can have a large impact on WTW GHG emissions. These credits are discussed in more detail in Sections 0 and 4.2.3.1, Cogeneration and Export of Electricity, and Petroleum Coke Treatment. Charpentier noted that emissions intensities can be significantly impacted by the allocation and crediting methods applied to co-products (e.g., coke, sulfur, cogenerated electricity surplus). There has been little attention to these issues in the literature; hence the lack of prior discussion in this paper. However, thorough treatment of these issues will be required in future studies. (Charpentier et al. 2009)

4.1.5 Metrics

Comparing results from different studies is further complicated by each study's choice of functional unit. The functional unit is the basis for comparing GHG emissions across the different crudes and fuels in each study. While GHG emissions are consistently reported in units of carbon dioxide-equivalent,[11] emissions are expressed over a wide range of different functional units across the studies.

The studies that evaluated WTT and WTW GHG emissions can be classified into two groups: (i) those that evaluated GHG emissions on the basis of a specific premium fuel product (e.g., gasoline independent of diesel or jet fuel), and (ii) those that evaluated GHG emissions per barrel of all refined products.[12] The choice of functional unit affects how the final results are presented, and makes it challenging to compare across different functional units. For example, NETL used three separate functional units: GHG emissions per megajoule (MJ) of gasoline, per megajoule of diesel, and per megajoule of jet fuel. IHS CERA, in contrast, used GHG emissions per barrel of refined products. These functional units cannot be directly compared to one another, and converting the NETL results to a barrel of all refined products requires a careful review of the underlying allocation methods used to separate the gasoline, diesel, jet fuel, and other co-products.

In addition to using different final product functional units, studies also express results in various units of measurement. For WTR studies, results were given in terms of volume (e.g., per barrel of bitumen, dilbit, or SCO) or energy (e.g., megajoule). For WTT and WTW studies, emissions were given in terms of volume, energy, or distance. Studies using a functional unit of volume provided emissions estimates either per barrel of refined products, or per barrel of a specific refined fuel (e.g., gasoline, diesel, or distillates). Studies using a functional unit of energy

[11] As explained in the 2011 Draft U.S. GHG Inventory Report, the IPCC developed the Global Warming Potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas (USEPA 2011). In the U.S. GHG Inventory Report, CO_2 has a GWP of 1, while CH_4 and N_2O have GWPs of 21 and 310, respectively. In this report and many others dealing with GHG emissions, the reference gas used is CO_2, and therefore GWP-weighted emissions are measured in units of CO_2 equivalent (CO_2e). In the studies discussed in this appendix, CO_2 is the predominant GHG emitted, so emissions in units of CO_2e are often nearly equal to the quantity of CO_2 emitted.

[12] IHS CERA (2010) expressed GHG emissions in units of kilograms of carbon dioxide equivalent per barrel of refined product produced, ($kgCO_2e$ per barrel of refined products). Refined products are defined by IHS CERA as the yield of gasoline, diesel, distillate, and gas liquids from each crude. The authors noted that petroleum coke is a co-product of creating the refined products, but did not consider the GHG emissions associated with its combustion. Similar to IHS CERA, IEA (2010) expressed GHG emissions per barrel of crude, assuming the emission from end-use are the same for each crude and equal to those of the combustion of an average crude.

provided emissions estimates per megajoule or Btu and both in terms of higher heating value (HHV) or lower heating value (LHV). Studies using a functional unit of distance provided emissions estimates per km burned in vehicle engine. This wide range of metrics has made comparisons across studies difficult in some instances, necessitating several unit conversions.

4.2 INPUT AND MODELING ASSUMPTIONS

The second set of factors driving the comparisons is input and modeling assumptions that are made at each life-cycle stage. Due to limited data availability and the complexity of and variation in the practices used to extract, process, refine, and transport crude oil, studies often use simplified assumptions to model GHG emissions.

This sub-section summarizes the key input and modeling assumptions in three groups:

1. Factors that affect WCSB oil sands-derived crudes,
2. Factors that affect reference crudes, and
3. Factors that affect both types of crudes.

4.2.1 Factors that Affect Oil Sands-Derived Crudes

Key input assumptions for WCSB oil sands-derived crudes include the type of extraction process (i.e., mining or in situ production); the steam-oil ratio assumed for in situ operations; the efficiency of steam generation, and thus its energy consumption; and—for SCO—the upgrading processes (i.e., pre-refining) modeled and whether estimated downstream refinery GHG emissions account for upgrading.

4.2.1.1 Type of Extraction Process

Two methods of extracting bitumen are currently used in the WCSB oil sands: mining and in situ. Oil sands deposits that are less than 75 meters below the surface can be removed using conventional strip-mining methods and sent for processing. The bitumen is separated from the rock and fine tailings and either blended with diluents for efficient pipeline transport or sent to an upgrader where the bitumen is partially refined into SCO, a lower-viscosity crude oil with lower sulfur content (International Energy Agency [IEA] 2010, p. 149-150; Charpentier et al. 2009, p. 2). Mining accounts for roughly 48 percent of total bitumen capacity in the WCSB oil sands as of mid-2010 (IEA 2010, p. 152).

Oil sands deposits that are deeper than 75 meters below the surface are recovered using in situ methods. Most in situ recovery methods currently in operation involve injecting steam into an oil sands reservoir to heat, and thus decreasing the bitumen’s viscosity, enabling it to flow out of the reservoir sand matrix to collection wells. Steam is injected using cyclic steam stimulation (CSS), where the same well cycles between periods of steam injection and bitumen production, or by steam-assisted gravity drainage (SAGD), where a pair of horizontal wells is drilled; the top well is used for steam injection and the bottom well for bitumen production. Bitumen produced from in situ operations is either upgraded into SCO or blended with condensates (to produce dilbit) or blended with SCO (to produce synbit) and sent directly to refineries that can accept raw bitumen (IEA 2010, p. 149-150; Charpentier et al. 2009, p. 2).

GHG emissions vary by the type of extraction process used to produce bitumen. Due to the high energy demands for steam production, steam injection in situ methods are generally more GHG-intensive than mining operations. Table 4-3 shows that across four meta-analyses of WTW GHG assessments, in situ methods of extraction emit between 3 and 9 percent more GHGs than mining.

Table 4-3 Increase in WTW GHG Emissions from In Situ Extraction of Oil Sands Compared to Mining

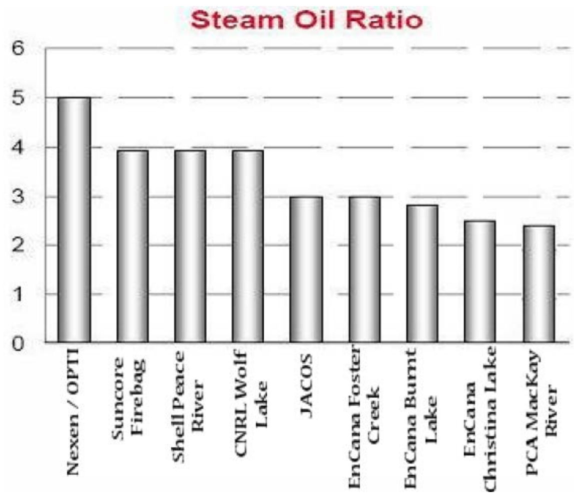
Source	WTW GHG emissions		Units	Percent increase[1]	Notes
	Mining	In situ			
IHS CERA 2010, Table A-8	518.6	554.6	$kgCO_2$/bbl refined products	7%	SCO from in situ compared to mining
NRDC 2010a, p. 2	106	116	gCO_2/MJ gasoline	9%	Average estimate for SCO from in situ compared to mining based on a range of literature values
Charpentier et al. 2009, Figure 2	260 to 310	310 to 350	gCO_2e/km	3 to 9%	SCO from in situ compared to mining, based on comparison of values from the GHGenius and GREET models
Brandt 2011	109	118	gCO_2/MJ of refined fuel delivered	9%	SCO from in situ compared to mining based on GHGenius values

[1] Percent increase in WTW GHG emissions from in situ compared to mining extraction of WCSB oil sands.

gCO_2/MJ = grams carbon dioxide per megajoule, $kgCO_2$/bbl = kilograms carbon dioxide per barrel, gCO_2e/km = grams carbon dioxide equivalent per kilometer, SCO = synthetic crude oil.

4.2.1.2 Steam-Oil Ratio for In-Situ Extraction

The steam-oil ratio (SOR) is the ratio of steam injected to recover oil in SAGD and CSS operations. It is a measure of the steam volume needed to produce a unit volume of oil. The SOR varies across individual in situ projects, as shown in Figure 4-2 and Table 4-4. The values in Figure 4-2 range from 2.5 to 5.0 across SAGD operations in the WCSB oil sands, while Table 4-4 shows a range of 1.94 to 7.26. In addition, SOR is a function of the price of crude oil and natural gas in the world: the higher the price, the more energy can be justified to produce an increment of crude from each well. In any case, less than 100 percent of the bitumen is recovered and more recovery runs up against diminishing returns for increased cost of energy for steam production.



Source: (S&T)2 Consultants 2008a, p. 18.

Figure 4-2 Reported SORs for SAGD WCSB Oil Sands Projects

Table 4-4 Reported SORs for CSS and SAGD WCSB Oil Sands Projects

Operator	Project	Recovery Method	Annual Bitumen Production (106 x m^3)	SOR (weighted average)
Imperial Oil Resources	Cold Lake	Commercial-CSS	8.20	3.49
EnCana Corporation	Foster Creek	Commercial-SAGD	4.40	2.49
Canadian Natural Resources Limited	Primrose and Wolf Lake	Commercial-CSS	3.58	6.00
Suncor Energy Inc.	Firebag	Commercial-SAGD	2.83	3.13
Suncor Energy Inc.	Mackay River	Commercial-SAGD	1.70	2.52
Devon Canada Corporation	Jackfish 1	Commercial-SAGD	1.30	2.42
ConocoPhillips Canada Resources Corp.	Surmont	Commercial-SAGD	0.85	2.81
Cenovus FCCL Ltd.	Christina Lake	Commercial-SAGD	0.77	2.11
Nexen Inc.	Long Lake	Commercial-SAGD	0.72	5.34
Japan Canada Oil Sands Limited	Hangingstone	Commercial-SAGD	0.43	4.04
Great Divide Oil Corporation	Great Divide	Commercial-SAGD	0.37	3.71
Shell Canada Limited	Peace River	Commercial-CSS	0.36	4.25
Husky Oil Operations Limited	Tucker Lake	Commercial-SAGD	0.22	7.26
Shell Canada Energy	Orion	Commercial-SAGD	0.16	6.43
Meg Energy Corp.	Christina Lake	Commercial-SAGD	0.05	6.54
ConocoPhillips Canada Limited	Surmont Pilot	Commercial-SAGD	0.03	3.41
Total E&P Joslyn Ltd.	Joslyn Creek	Commercial-SAGD	0.03	1.94
Total Industry			**26.01**	**3.58**

Source: NRDC 2010b.

CSS = carbon capture and storage, m^3 = square meters, SAGD = steam-assisted gravity drainage, SOR = steam-oil ratio, WCSB = Western Canadian Sedimentary Basin.

The SOR is an important parameter because steam production at SAGD and CSS operations dominates energy consumption in the extraction stage. Charpentier (2009) demonstrates that the GHG emissions from SAGD and CSS operations are very sensitive to the SOR. Every 0.5 increase in the SOR corresponds to a six cubic meter increase in natural gas consumption, or an additional 10 $kgCO_2e$ per barrel of bitumen produced (Charpentier et al. 2009, p. 7, citing NEB 2006). In addition to SOR, the steam generation efficiency and fuel source are also important factors in overall GHG emissions. Information on steam generation efficiency was not located in all the studies reviewed, however.

Table 4-5 summarizes the SOR assumptions in each study. A number of sources did not provide an estimate for the SOR assumed for in situ operations described in the study, but for those that did, the assumed SOR for SAGD ranges from 2.5 to 3, and the SOR for CSS ranges from 3.35 to 4.8, depending on the project assumptions and the source. These findings suggest that, in general, studies assume that the SOR is higher for CSS operations than SAGD operations.

Table 4-5 SOR Assumptions for In Situ WCSB Oil Sands Operations in Each of the studies reviewed

Study	SOR		Notes
	SAGD	CSS	
NETL, 2008	--	--	
NETL, 2009	--	--	
IEA, 2010	NE	NE	States that the industry norm for in situ operations is approaching 3.
IHS CERA, 2010	3	3.35	
IHS CERA, 2011	3	3.35	
NRDC, 2010	NE	NE	Study notes that it varies by crude, but does not explicitly discuss the values.
ICCT, 2010	NE	NE	
Jacobs, 2009	3	NA	
Jacobs, 2012	2 to 3	NE	Assumed an SOR of 3 is representative of current conditions; SOR of 2 is achievable with new production methods. Also investigated a high-end SOR of 4.
TIAX, 2009	2.5	4.8; 3.4	CSS values are for specific operations using onsite electricity and grid electricity, respectively.
Charpentier, et al., 2009	NE	NE	Depends on the study but this meta-analysis indicated that many studies do not report their assumed SORs.
Brandt, 2011	NE	NE	Depends on the study. SORs from each study included in the meta-analysis are compared to SORs reported in Canada's Energy Resources Conservation Board (ERCB) databases, including (1) from several in situ bitumen production projects in 2009 ranging from 2.49 to 5.99, and (2) the SOR from total thermal in situ bitumen production of 3.18 in 2009.
RAND, 2008	2.5	NA	Study indicates that a high-quality SAGD reservoir has an SOR of ~2.5 but this can vary widely by site or operation. Footnote on page 19 indicates that an SOR of 2.5 is also used in the MIT model used in the analysis.

Study	SOR		Notes
	SAGD	CSS	
Pembina Institute, 2005	NE	NE	
Pembina Institute, 2006	NE	NE	
McCann, 2001	NE	NE	
GHGenius, 2010	3.2	--	
GREET, 2010	--	--	

Note: -- = Not located; CSS = carbon capture and storage, NA = Not Applicable; NE = Not Estimated or Not Stated; SAGD = steam-assisted gravity drainage, SOR = steam-oil ratio.

4.2.1.3 Type of Upgrading Processes Modeled

Upgrading lowers the viscosity of, and removes sulfur from, bitumen before it is transported by pipeline for refining. The resulting product from refining is SCO, essentially a pre-refined crude oil with no vacuum residuum and lower sulfur content. The viscosity of bitumen can be lowered either by removing the heaviest fraction of the oil (residuum) by vacuum distillation or precipitation of asphaltenes, or by adding hydrogen in a hydrocracking process. The vacuum residuum can be further refined in a coking process to produce gasoline and distillate (i.e., premium fuel products) range fractions (blended back into the SCO) and petroleum coke. When vacuum residuum is removed in the upgrader, the SCO produces no vacuum residuum in the receiving refineries, requires no energy intensive vacuum residuum upgrading, vacuum gas oil cracking, or residuum coking. Hence, SCO has a higher gasoline, kerosene, and distillate fuel yield per barrel of crude oil, and thereby requires a relatively lower energy intensity to refine, and does not produce petroleum coke as do all other reference crude oils.

Upgraders that use a portion of the heavy ends (i.e., residuum) or petroleum coke for generating heat, electricity, or hydrogen have a higher GHG emissions intensity than those that combust natural gas for heat and power. Table 4-6 includes data for two upgraders (i.e., Northern Lights and Opti/Nexen) that gasify petroleum coke to produce a synthesis gas (or syngas) that can be burned for process heat or electricity, or used as a hydrogen supply for hydrocracking for sulfur removal. The GHG emissions from these upgraders range from 50 to 500 percent higher than the range of emissions from other upgraders in the table, not including the integrated operations in the last two rows, which includes emissions associated with bitumen extraction, processing, and upgrading. Much of this energy and GHG emissions offset downstream refining emissions for processing SCO.

Gasification is not currently widely employed in the oil sands. Of the two gasification upgraders in Table 4-6, only one is currently operating, representing less than 3 percent of total WCSB oil sands bitumen capacity.[13] OPTI/Nexen's Long Lake Phase 1 integrated oil sands project gasifies asphaltenes (i.e., heavy ends from upgrading the bitumen into SCO) from the upgrader to produce steam for SAGD, generate electricity, and produce hydrogen for the hydrocracking unit. Initial production of SCO from the upgrader began in January 2009 (Nexen 2011, AERI 2006).

[13] Production capacity of the first phase of Long Lake is 60,000 barrels of bitumen per day, or 3 percent of the total current WCSB oil sands raw bitumen capacity of 1,923 thousand barrels per day (IEA 2010, p. 152; including both mining and *in situ* operations). As of mid-2010, production was approximately about half of this, or 30,000 barrels of bitumen per day (Nexen 2011).

Table 4-6 Upgrader GHG Emissions per Barrel of SCO[14]

Project	Comments	Direct Emissions Intensity kg/bbl	Indirect Emission Intensity kg/bbl	Total Emission Intensity kb/bbl
Scotford Upgrader	Hydrocracking	33.6	5.8	39.4
Scotford Upgrader after Expansion	Hydrocracking	32.9	10.5	43.4
Scotford Upgrader 2	Hydrocracking	60.9	19.1	80.3
Northwest Upgrader	Delayed coking	92.8	Not available	
Northern Lights Upgrader	Delayed coking/gasification	141.4	Not available	
PC Sturgeon Phase 1	Delayed coking	40.7	Not available	
PC Sturgeon Phase 2	Delayed coking	62.6	Not available	
Opti/Nexen	Integrated/gasification	180-200	Not available	
BA Energy	New technology	14.0	Not available	
Husky Lloydminster	Delayed coking	65.6	Not available	
Suncor	Integrated	108.7	Not available	
Syncrude	Integrated	106.0	Not available	

Source: ((S&T)2 Consultants 2008a)[14]

GHG = greenhouse gases, kg/bbl = kilograms per barrel, SCO = synthetic crude oil.

The second gasification project, the Northern Lights Upgrader, has been placed on hold since 2007. Synenco/SinoCanada had plans to gasify asphaltenes to produce process heat and hydrogen for the hydrocracker unit at a planned upgrading facility outside of Edmonton, Alberta. The upgrader would have received bitumen via pipeline from Synenco/Total's Northern Lights Oil Sands Project near Fort McMurray, Alberta (Edmonton Journal 2007, Sturgeon County 2011).

Coking or hydrocracking upgrading technologies have a small effect on WTW GHG emissions estimates, and reported emissions vary by each project. Jacobs (2009) estimated that hydrocracking using an ebulating bed hydrocracking unit increases WTW GHG emissions by 2 percent compared to coking for gasoline produced from SAGD-extracted SCO. (S&T)2 Consultants (2008a) provided estimates of direct (i.e., on-site) and indirect (i.e., upstream fuel and electricity production) GHG emissions from various operating, planned, and on-hold upgraders in Alberta ((S&T)2 Consultants 2008a, p. 25). The data in Table 4-6 show that direct emissions from delayed coking range from 40.7 to 92.8 $kgCO_2e$ per barrel of SCO, while GHG emissions from hydrocracking range from 33.6 to 60.9 $kgCO_2e$ per barrel. This has to be put into perspective with SCO yielding up to 60 percent gasoline in the downstream refinery as compared to conventional full-range crudes which may yield up to 40 percent gasoline with higher GHG intensity.

[14] Suncor and Syncrude's integrated operations include GHG emissions from bitumen extraction, processing, and upgrading ((S&T)^2 Consultants 2008a, p. 26).

4.2.1.4 Electricity Cogeneration and Export

Cogeneration facilities generate both steam and electricity simultaneously to achieve higher efficiencies than if each were generated separately. Facilities are sized to meet the steam requirements for oil sand extraction, processing, and upgrading requirements. For facilities where steam requirements are greater than for electricity, this leaves an excess capacity for electricity generation that can be exported for use elsewhere on the electricity grid (IHS CERA 2010, pp. 16-18; Jacobs 2009, p. 12).

The treatment of exported electricity in LCAs is a study design factor that is discussed separately in Section 4.1.4, Allocation, Co-Products, and Offsets. The specific input assumptions related to electricity exports have a substantial impact on the WTW GHG emissions of oil sands-derived crudes relative to reference crudes.

Cogeneration assumptions vary across the studies in two ways: whether cogeneration is included, and if so, the assumed source of electricity generation that is offset by electricity cogenerated at oil sands facilities. Jacobs (2009) illustratively[15] demonstrated that applying a credit for offsetting grid electricity with electricity cogenerated at oil sand facilities could reduce the WTW GHG emissions for oil sands crudes to the range of reference crudes (Jacobs 2009, p. 8-17).[16]

Jacobs (2012) did not apply a credit for exporting excess electricity generated at SAGD or upgrading facilities (Jacobs 2012 p. 4-18). In calculating the carbon intensity of production from SAGD processes using reports to the Alberta Energy Conservation Board for facilities that export electricity, the study calculated the natural gas amount that would be used to produce the excess electricity and subtracted this from total natural gas consumption (Jacobs 2012 p. 5-36).

IHS CERA (2010) estimated that electricity exports could reduce the WTW GHG emissions by 1 to 2 percent per barrel of refined products from SAGD bitumen (IHS CERA 2010, pp. 16-17). The authors calculated this range by evaluating a case where oil sands electricity exports offset coal-fired generation on the grid and a case where the offset is equal to the Government of Alberta’s offset credit for renewable power generation.

TIAX (2009) included project-specific data on electricity exports from Suncor Energy’s MacKay River and Canadian Natural Resources Limited’s (CNRL) Primrose in situ oil sands projects in Alberta (TIAX 2009, pp. 27-28). Combined, these projects account for roughly 8 percent of total bitumen capacity in the WCSB oil sands.[17] TIAX assumed that electricity exported to the grid offset electricity that would have been generated by natural gas combined-cycle turbines. Contrary to Jacobs (2009) and IHS CERA, TIAX concluded that exporting cogenerated electricity increased WTW emissions per megajoule of reformulated gasoline by 2 to 6 percent for synbit and dilbit from SAGD and CSS (TIAX 2009, pp. 66, 76).

Finally, in a 2008 update to the GHGenius model, (S&T)2 Consultants removed a cogeneration credit that was previously applied to integrated oil sands extraction and upgrading facilities.

---

[15] Jacobs (2009) did not comprehensively evaluate cogeneration opportunities at oil sands facilities, but included a preliminary, illustrative analysis and recommended further investigation of cogeneration.

[16] Jacobs (2009) evaluated a series of scenarios that varied the level of electricity export and whether natural gas-fired electricity or 80 percent coal-fired electricity was displaced by the exported electricity for SAGD operations.

[17] Based on 1,923 thousand barrels per day of total raw bitumen capacity in the WCSB oil sands (IEA 2010, p. 152). CNRL’s Primrose project has a raw bitumen capacity of 120 thousand barrels per day (IEA 2010, p. 152), while MacKay River has a capacity of 33 thousand barrels per day (Oil Sands Developers Group 2009).

(S&T)2 removed the credit because they were unable to locate evidence that Suncor and Syncrude's integrated oil sands projects were selling power to the local grid ((S&T)2 Consultants 2008a, p. 26). It was unclear whether other studies in the scope of this evaluation considered electricity exports in their results.

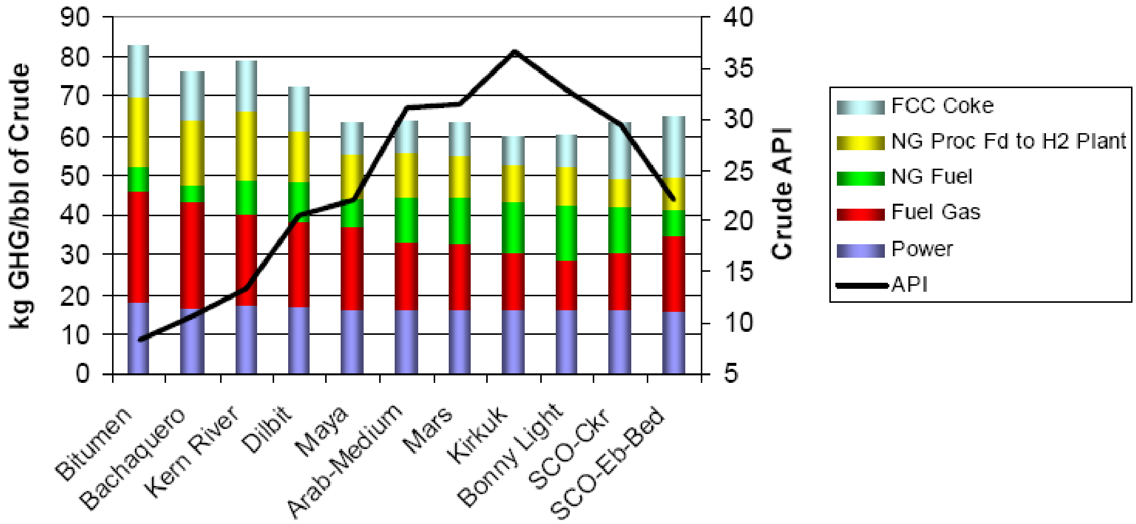
4.2.1.5 Accounting for Upgrading in Refining Emissions Estimates

A barrel of SCO delivered to a refinery has already been processed at the upgrader, and will produce greater quantities of premium fuel products (i.e., gasoline, diesel, and jet fuel), no heavy residuum, and less light ends than a barrel of full-range reference crudes that have not already undergone upgrading. As a result, the energy consumption, and therefore GHG emissions, from refining SCO into a barrel of premium fuel products is lower than that for producing the same amount of premium fuels from virtually all other crudes.

Accounting for the reduced GHG emissions from refining SCO relative to other crudes has a modest effect on WTW GHG emissions, as refinery emissions are roughly 5 to 15 percent of WTW GHG emissions (based on Figure 5.3 in IEA 2010 and Table A-8 from IHS CERA 2010). However, the effect is more significant on a WTT basis. Studies that do not account for the reduction in refinery energy use for SCO will overestimate the GHG emissions from SCO relative to other crude sources.

TIAX (2009) and Jacobs (2009) used refinery models to estimate the GHG emissions at the refinery. TIAX found that refinery energy consumption for SCO was significantly lower than for other crude oils (TIAX 2009 p. 34). The Jacobs (2009) results, shown in Figure 4-3 below, estimated that the GHG emissions to refine a barrel of SCO were on the order of GHG emissions to refine Mexican Maya or Arab Medium crude oil. Note, however, that the Jacobs results are given in terms of refining one barrel of input crude, not in terms of the GHG emissions from producing an equivalent amount of premium fuel products from different crudes and SCO; since SCO produces more premium fuel products per barrel of input than other crudes, GHG emissions from refining SCO are even lower when compared on a per-barrel of premium fuel products basis.

Other studies did not account for this effect in their estimates, or it was unclear whether refinery emissions were adjusted to account for upstream upgrading. NETL (2009) and ICCT (2010) correlated refinery emissions with API gravity, and although NETL noted this limitation, the authors did not evaluate the effect that upgrading would have on SCO GHG emissions at the refinery (NETL 2009, p. 11; ICCT 2010, p. 8, 26). As stated earlier, correlating GHG emissions with API gravity does not account for the intensity of refining SCO or dilbit on a per barrel of premium fuel products basis because these crudes have a different composition of light and heavy ends than other full-range crudes. The IHS CERA (2010) meta-analysis estimated that refining SCO would emit 11 percent more GHGs than refining West Texas Intermediate crude per barrel of refined products; since emissions from refining SCO should be lower than refining other full-range crudes, the study may not have accounted for the reduced GHG emissions per barrel of premium fuel product when refining SCO compared to a conventional crude (IHS CERA 2010, Table A-8; 2011, Table A-7). The report prepared for the oil sands pathways within the GHGenius model did not provide the assumptions for refining SCO into premium fuel products ((S&T)2 Consultants 2008a).



Source: Jacobs 2009, p. 5-41.

Note: Results only include GHG emissions from refining and do not include emissions from upgrading SCO. API = American Petroleum Institute, FCC = fluid catalytic cracker, GHG = greenhouse gases, H2 = hydrogen, NG = natural gas SCO = synthetic crude oil.

Figure 4-3 GHG emissions for refining one barrel of different crudes, SCO, dilbit, and bitumen, by fuel source

4.2.1.6 Dilbit and Accounting for Diluents

Because raw bitumen viscosity is too high to be transported via pipeline, a portion of the bitumen produced from in situ extraction in the WCSB oil sands is diluted with light hydrocarbons (typically natural gas liquids, or condensates, from natural gas and SCO production). This allows sending the bitumen via pipeline to refineries for refining into products such as gasoline, diesel, and jet fuel without needing upgrading into SCO (IEA 2010, NRDC 2010b).

Accounting for the effect of diluting bitumen with condensate has a moderate effect on emissions estimates for two reasons. First, producing and refining condensate from natural gas or SCO into finished products emits fewer GHG emissions per barrel of crude transported in the pipeline than bitumen, so blending the two together results in lower WTW GHG emissions than the same volume of raw bitumen. NRDC (2010b) estimates that this results in roughly a 6 percent decrease in the WTW GHG emissions of dilbit relative to raw bitumen (NRDC 2010b, p. 3). However, if the metric used to compare the GHG emissions from WCSB oil sands crudes is GHG emissions per barrel of premium fuel product, dilbit would have a higher GHG intensity than either SCO or bitumen (not counting bitumen transportation) since the diluents represent 30 percent of the transported dilbit and do not refine into premium fuel products. On an equivalent basis of a barrel of gasoline plus distillate, the transportation GHG intensity would be approximately two times higher for dilbit compared to SCO if the condensate is considered, because the condensate and residuum each represent 30 percent.

Table 4-7 compares the WTW emissions from dilbit to bitumen and SCO from various studies. When the diluent condensate is refined with the bitumen at the refinery, WTW GHG emissions for dilbit are approximately 4 to 7 percent less than for bitumen, based on results from TIAX (2009). Jacobs (2009, 2012) examined scenarios where the diluent is separated from bitumen at the refinery and recirculated back to oil sands facilities in Alberta. The results were similar in both studies; WTW GHG emissions were 6 to 7 percent higher when diluent is recirculated back to Alberta than if the diluent is refined with the bitumen. The estimates where diluent is refined with the raw bitumen at the refinery are representative of the proposed Project, since diluent will not be recirculated by the pipeline. These studies do not appear to give adequate credit for lower refining GHG emissions of SCO as compared to bitumen or dilbit, which each have about 30 percent vacuum residuum, while SCO has the vacuum residuum removed in the upgrader.

Table 4-7 Comparison of WTW GHGs per MJ of Premium Fuel Products Refined from Dilbit, Bitumen, and SCO

Study	Extraction method	Feedstock	WTW GHG emissions (gCO_2e/MJ[1])	Percent change[2]	Notes
TIAX (2009)	SAGD	Bitumen	109	--	
		SCO	111	2%	SCO from SAGD assuming coke is buried
		Dilbit, no recirculation	101 to 105	-4 to -7%	Low end includes a credit for electricity cogeneration
	CSS	Dilbit, no recirculation	105 to 111	--	Low end includes a credit for electricity cogeneration
Jacobs (2009)	SAGD	SCO	116 to 119	--	Low end assumes delayed coking; high end assumes hydrocracking
		Dilbit, no recirculation	113	-3 to -5%	Diluent is separated at refinery and recirculated to Alberta
		Dilbit, recirculation	106	-9 to -11%	Diluent is processed with bitumen at the refinery
Jacobs (2012)	SAGD	Dilbit, no recirculation	111	--	Diluent is refined in a high conversion U.S. Gulf Coast refinery and is not returned to Alberta
		Dilbit, recirculation	105	-6%	Diluent used to ship bitumen to a high conversion U.S. Gulf Coast refinery is returned to Alberta
GHGenius, (S&T)[2] Consultants (2008a)	SAGD	Bitumen	114	--	
		SCO	118	4%	
	CSS	Bitumen	112	--	
		SCO	116	4%	

[1] WTW GHG emissions are in terms of grams CO_2 equivalent per megajoule of reformulated gasoline.
[2] Percent change in WTW GHG emissions relative to bitumen, except for Jacobs (2009), which is the percent change in WTW GHG emissions relative to SCO.

gCO_2e/MJ = grams carbon dioxide equivalent per megajoule, GHG = greenhouse gas, SAGD = steam-assisted gravity drainage, SCO = synthetic crude oil, WTW = well-to-wheels.

Second, diluting raw bitumen with light hydrocarbons creates a dumbbell blend that contains a high fraction of heavy residuum and light ends, with relatively low fractions of hydrocarbons in the middle that can be easily refined into premium fuel products. As a result, producing one barrel of premium fuel products (i.e., gasoline, diesel, and jet fuel) requires more dilbit input and produces more light ends and petroleum coke than refining one barrel of premium fuel products from other crudes and SCO. This results in additional energy use and GHG emissions from refining the dilbit, and producing, distributing, and combusting the light- and heavy-end co-products.

The extent to which this difference in yield of premium fuel products is accounted for in these studies is unclear. IHS CERA's (2010, 2011) estimate for crude production of SAGD dilbit does not appear to adjust GHG emissions per barrel of refined products output for the difference in yield.[18] TIAX (2009) and Jacobs (2009) both show higher refinery emissions for dilbit and synbit on a barrel-of-input-crude basis, but it is not clear to what extent the effect of dumbbell blend yields on refining GHG emissions is accounted for in the refinery models that these studies used.

4.2.2 Factors that Affect Reference Crudes

For the reference crudes, key input assumptions include the oil-water and gas-oil ratios that are used to estimate reinjection and venting or flaring assumptions (e.g., stranded gas versus recovered gas, control levels on venting sources, the allocation of venting/flaring emissions to crude versus produced natural gas), and whether—and what type of—artificial lift (e.g., gas lift, water, steam, CO_2 flood) is considered for extracting crude oil.

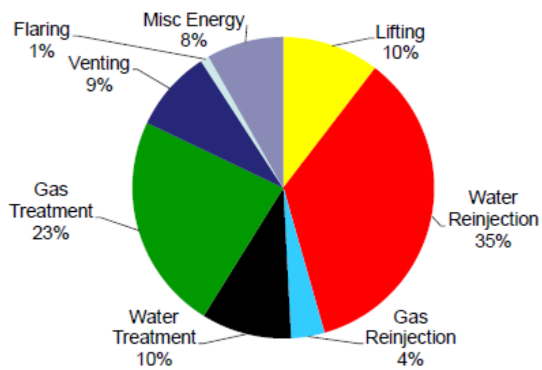
4.2.2.1 Artificial Lift Assumptions

The methods of producing oil from wells drilled into an oil reservoir evolve over the reservoir's lifetime. There are generally three phases of production from a reservoir: primary, secondary, and tertiary. Primary recovery relies on the initial pressure of the oil reservoir itself to lift the oil through evolution of dissolved gas, much like a carbonated beverage foams liquid up the neck of a bottle. Thus primary recovery requires no energy input for extraction. Secondary recovery involves pumping or injecting gas or water into the reservoir to sweep or push out additional oil. In tertiary recovery, steam or CO_2 is injected to loosen the remaining oil adhering to the reservoir solids by lowering its viscosity and swelling its volume to enable it to flow or be pushed out of the reservoir with a water flood. For a given field, GHG emissions intensity increases dramatically through this evolution of recovery techniques. Even the best tertiary recovery techniques known today leave more than 50 percent of the original oil in the ground whereas mining oil sands captures virtually 100 percent of the oil contained in the sand matrix.

The GHG emissions from crude oil production are driven by the methods used to lift the oil out of the ground and produce the oil, and there is significant sensitivity to assumptions about artificial lift, oil, gas, and water separation, and water and gas reinjection practices. IHS CERA documented a wide range in GHG estimates for production of several reference crudes; estimates for Saudi Medium crude ranged from 1 to 25 $kgCO_2e$ per barrel of refined products (IHS CERA 2010, Table A-1). Studies that do not account for lift and associated treatment and reinjection energy requirements will underestimate the GHG emissions from reference crude production relative to oil sands-derived crudes.

[18] GHG emissions for crude production from SAGD dilbit are roughly 70 percent of emissions from SAGD SCO, suggesting that the value is a simple 70/30 ratio of bitumen to dilbit per barrel of refined products. If so, this would not reflect the fact that more bitumen is required to produce the same barrel of refined products than SCO.

Jacobs (2009, 2012) used a crude production model to estimate GHG emissions associated with producing different types of reference crudes. A representative breakdown of the major sources of GHG emissions is shown in Figure 4-4. Similarly, TIAX (2009) considered different lift methods to determine oil production energy use and GHG emissions, as shown in Table 4-8 (TIAX 2009, p. 4). The study used data from different sources to quantify emissions for each crude, and relied on NETL (2008) to estimate grid electricity consumption for several of the crudes modeled. These studies do not appear to evaluate the delivery of water from the Arabian Gulf to the principal Saudi oil field (Ghawar), nor do they appear to evaluate transporting the produced Arab Light crude to the stabilization plant, from the stabilization plant to the shipping terminal, or loading the crude onto the oil tankers. Hence these studies appear to underestimate the Saudi crude production energy in the initial phase of the life cycle from reservoir to freight onboard a tanker.



Source: Jacobs 2012, p. 5-17.

Figure 4-4 Illustrative break-down of major sources of GHG emissions from production of a generic crude oil[19]

Table 4-8 Crude Oil Recovery Methods

Label	Crude Name	Recovery Methods
Alaska	Alaska North Slope	Water Alternating Gas (WAG) and Natural Drive
California Heavy	Kern County Heavy Oil	Steam Injection, Sucker Rod Pumps
Texas	West Texas Intermediate	Water Flooding, Natural Drive
Canada Heavy	Bow River Heavy Oil	Water Flooding, Progressive Cavity Pumps
Iraq	Basrah Medium	Water Flooding, Natural Drive
Mexico	Maya (Canterell)	Nitrogen Flooding, Gas Lift
Nigeria	Escravos	Water Flooding, Gas Lift
Saudi	Saudi Medium	Water Flooding, Natural Drive
Venezuela	Bachaquero (Maracaibo)	Cyclic Steam Stimulation, Sucker Rod Pumps

Source: TIAX 2009, p. 64

[19] The crude oil modeled in this scenario is at 30 API in a reservoir at 5,000 feet. The gas-oil ratio is 1000 standard cubic feet of gas per barrel of oil, and 10 barrels of water are produced to one barrel of oil (Jacobs 2012, p. 5-17).

Crude oil production estimates in NETL (2008) accounted for artificial lift methods (NETL 2008, Attachment 1). The production value of 13.6 $kgCO_2$ per barrel of crude for Saudi Arabia, however, is roughly half that of Jacobs (Jacobs 2012, Figure 5-7).[20] It is not clear if this difference is a result of different assumptions in baseline crudes, or whether the NETL (2008) estimate accurately accounted for shipment and treatment of off-site water used for injection into the reservoir, crude stabilization, or transport to the terminal and loading onto tankers.

4.2.2.2 Sensitivity to Water-Oil and Gas-Oil Ratios

Water-oil and gas-oil (GOR) ratios describe the fraction of the flow from a well that is oil, water, or gas. Several studies use these ratios to develop simplifying relationships between energy use and GHG emissions and oil reservoir characteristics. This simplifying assumption is often necessary due to the complex nature of oil production systems and reservoir characteristics; however, it also causes the studies to become sensitive to variations in these factors, or circumstances where the relationships may not fully apply.

For example, ICCT (2010) derived the volume of gas flared from GOR, energy use in the field, and the quantity of gas exported as well as other data sources from NOAA and the World Bank's Global Gas Flaring Reduction program (ICCT 2010, p. 14). This may overstate the flaring amount depending on the extent to which gas is reinjected to maintain reservoir pressure. It is important to ensure that the disposition of gas is accurately reflected in calculated emissions from flaring since not all the gas produced from the well may be flared. To the extent that natural gas (primarily methane) is vented rather than flared, this can have a significant effect on GHG results, as the GWP of methane is more than 20 times higher (estimates vary from 21 to 23 depending on which IPCC assessment report is cited) than that of CO_2.

4.2.3 Factors that Affect Both Reference and Oil Sands-Derived Crudes

Across both WCSB oil sands and reference crudes, assumptions about how much petroleum coke is produced, stored, and combusted at the upgrader or refinery, and how much is sold to other users, is a key driver of GHG emissions; transportation assumptions have a more limited effect, but vary across the studies.

4.2.3.1 Petroleum Coke Treatment

Petroleum coke, discussed further in Section 6.0, is a co-product produced by thermal decomposition of vacuum residuum into lighter hydrocarbons during bitumen upgrading and crude oil refining (see Figure 2-1). Petroleum coke is approximately 95 percent carbon by weight. In contrast with the premium products the refinery produces, coke is an undesirable co-product that has very low demand in the U.S. marketplace and is therefore shipped to overseas markets, primarily China. Roughly 5 to 10 percent by volume of a barrel of crude ends up as coke. Heavier crudes will produce a larger fraction of coke than lighter fuels. Venezuela Bachaquero, Mexican Maya, and dilbit produce about 50 percent more coke than average U.S. 2005 crude or Saudi Light crude. Since SCO has had all the vacuum residuum removed in the upgrader before it reaches the refinery (TIAX 2009, Appendix D, p. 17), it has no petroleum

[20] Jacobs (2012) estimates approximately 4 gCO_2/MJ of crude for Saudi Arabian Medium, or 24 $kgCO_2$/bbl assuming 6.119 GJ/bbl crude oil (Jacobs 2012, Figure 5-7).

coke manufactured in downstream refineries, or petroleum coke transportation and combustion emissions as do all other reference crudes processed in refineries, i.e., U.S., Mexican, Venezuelan, or Saudi crudes.

The treatment of coke is a primary driver behind the comparisons of WTW GHG assessments of oil sand-derived crudes relative to reference crudes. For example, TIAX found that coke combustion could increase WTW emissions by 14 percent, and Pembina estimated that coke gasification at the upgrader could account for a 50 percent increase in GHG emissions from extraction and upgrading bitumen (TIAX 2009, p. 66, 76; Pembina 2006, p. 11). IHS CERA (2010) found that if petroleum coke combustion is included, TTW combustion emissions of refined crude increase about 13 percent (from 384 to 432 $kgCO_2e$/barrel). As shown in Table 4-6 above, data from planned and operational upgraders in Alberta show that gasification of petroleum coke and other heavy ends substantially increases GHG emissions. These examples demonstrate the significance of coke assumptions in WTW emission estimates.

The main concern in modeling GHG emissions from petroleum coke is ensuring that coke produced at the upgrader is treated consistently with coke produced at the refinery.[21] Table 4-9 summarizes the assumptions applied by several studies within the scope of this assessment to petroleum coke generated at both upgrading (from bitumen into SCO) and in refineries (from refining crude oil and bitumen into refined products). The NETL (2008), IHS CERA (2010 and 2011), and GHGenius ((S&T)2 Consultants 2008a) studies do not specifically state how petroleum coke is treated at upgraders and refineries, respectively, making it difficult to determine what assumptions about petroleum coke combustion were applied.

Table 4-9 Assumptions Regarding Petroleum Coke Produced at Upgraders and Refineries in Different LCA Studies

Study	Petroleum coke from upgrading bitumen at the upgrading facility	Petroleum coke from reference crudes or bitumen at the refinery
NETL 2008	Not stated	GHG emissions from producing coke are allocated to the coke product itself. Combustion of marketable coke leaving the refinery is not included. Refinery emissions do include petroleum coke burned as catalyst in the refinery.
Jacobs 2009, pp. 10, 16, 8-3	Coke is stored, not used as fuel. Report recommended further study into upgrading technologies that use coke for energy supply.	GHG emissions from producing coke are allocated to the other premium fuel products. Coke is sold as a substitute for coal in electricity generation.
Jacobs 2012, pp. 6-3, 9-4 to 9-23	Coke produced at the upgrader is stored and not subject to further conversion.	GHG emissions from producing, refining, and transporting coke are allocated to the premium fuel products. A credit is applied for coke combustion, assuming it displaces coal for an incremental increase of 2 gCO_2/MJ of refined fuel.
TIAX 2009, pp.	Does not include combustion emissions	GHG emissions from producing coke are

[21] The allocation rules that studies apply to petroleum coke are a study design factor that is addressed in Section 4.1.4, Allocation, Co-Products, and Offsets. In addition to allocation rules, however, the assumptions about how coke is managed by upgraders and refineries are important factors governing the results of WTW GHG emissions assessments.

Study	Petroleum coke from upgrading bitumen at the upgrading facility	Petroleum coke from reference crudes or bitumen at the refinery
48, G-6	from coke. Only considers how to allocate upstream emissions associated with producing the coke. Evaluates three scenarios: use (SAGD-only), bury, and sell coke. If sold, TIAX allocates GHG emissions to the production of coke; no credit is included for offsetting coal combustion.	allocated to the other premium fuel products. Coke combustion is not included.
IHS CERA 2010, p. 36; IHS CERA 2012, p. 17-18	Unclear to what extent emissions from use of coke are included.	Excludes coke from combustion emissions.
IEA 2010	Not stated	Not stated
McCann 2001, pp. 4, 5	Not clearly stated. Appears that coke is combusted at the upgrader in at least one of the data sources used.	Coke was assumed to offset natural gas at the refinery.
RAND 2008	Not stated	Not stated
Pembina 2006	Gasification of coke was included in high-emission scenarios for hydrogen production for upgrading.	Not stated
GHGenius - (S&T)[2] 2008a, Table 6.6, p. 25	Coke is used at the upgrader, contributing to 15% of energy requirement or 1,100 MJ per metric ton of upgrading SCO. Remaining coke and LPG not combusted at upgrader is assumed to offset emissions from coal combustion at electric generating units.	Not stated

gCO_2/MJ = grams carbon dioxide per megajoule, GHG = greenhouse gas, LCA = life-cycle assessment, LPG = liquefied petroleum gas, MJ = megajoule, SAGD = steam-assisted gravity drainage, SCO = synthetic crude oil.

The fates of petroleum coke are influenced by market effects and access to markets, and differ depending on whether petroleum coke is produced at WCSB oil sands facilities in Alberta or at U.S. Gulf Coast refineries. Based on Table 4-9, the basis of the studies is that petroleum coke produced by upgrading bitumen into SCO is either: (i) combusted (for process heat, electricity, or hydrogen production); (ii) stored; or (iii) sold as a fuel for combustion. In contrast, the studies assume that petroleum coke produced at refineries that is not combusted by the refineries themselves (it is the rare case in the United States that petroleum coke is combusted by a refinery) is either (i) used to supplement coal combustion for electricity generation or (ii) that the emissions associated with producing and combusting the coal are allocated outside the assumed life-cycle system boundary. Excess petroleum coke produced from PADD III refineries is typically shipped to Asia where it is combusted for electricity generation.

These factors are influenced by market interactions involving petroleum coke supply relative to the availability of other competing fuel substitutes. These dynamic market effects are difficult to characterize and are generally not explicitly modeled in existing life-cycle assessments (Brandt 2011, Jacobs 2012). The consumption of petroleum coke at WCSB oil sands facilities may be influenced by the availability of low-cost natural gas to these facilities, while transporting raw or diluted bitumen to refineries in the Gulf Coast that sell coke to other markets may therefore cause a greater share of the coke to be combusted rather than stockpiled (Brandt 2011).

None of the studies included in this assessment's scope provide information on industry-averaged petroleum coke management practices at oil sands operations. Jacobs (2009, 2012) assumed that all coke is stockpiled, noting that the practice of storing coke is typical and that the transport costs of marketing the material from Alberta exceed its value (Jacobs 2009, p. 4-10). In contrast, TIAX examines three scenarios where petroleum coke at upgraders is either used as a fuel, sold as a product, or buried. In comments to TIAX's report, Suncor Energy noted that 34 percent of the coke generated by upgrading bitumen is combusted in SCO production and that the rest is sold or stockpiled (TIAX 2009, p. G-3). As noted in Section 4.2.1.3, Type of Upgrading Processes Modeled, OPTI/Nexen's Long Lake Phase 1 integrated oil sands project currently gasifies asphaltenes from the upgrader for process heat, electricity, and hydrogen.

4.2.3.2 Transportation Emissions

Transportation GHG emissions arise from the transport of bitumen, SCO, and crude to U.S. refineries, the distribution of refined premium fuel products (e.g., gasoline, diesel, and jet fuel) to end use in the United States, and from the transport of light- and heavy-end co-products such as LPG and petroleum coke to markets for these fuels.

Transportation emissions have a small to moderate effect on WTW GHG emissions. IHS CERA (2010) found that transportation emissions make up less than 1 percent of total WTW emissions (IHS CERA 2010, p. 34). The study also documented considerable variation in transportation estimates, ranging from 1 to 14 $kgCO_2e$/bbl for crude transportation from Mexico.

Although the contribution of transportation GHG emissions to WTW GHG emission is minor, transportation emission calculations should account for the distance and modes of transportation—including domestic transportation from the oil field to an export terminal in the case of international crudes—and include transportation emissions for all products produced from bitumen, crude, or SCO for a given amount of premium fuel products produced from the refinery. The variation in transportation estimates across different studies may result from different approaches to modeling transportation emissions, or an incomplete consideration of the full supply chain from field to refinery.

4.2.3.3 Land Use Change Emissions

Land use change emissions refer to the life-cycle GHGs emitted via human activities, such as development, deforestation, and other physical impacts to the land. These can include immediate GHG releases from land disturbance as well as long-term changes to GHG sequestration patterns from changes in ecosystems. The land use changes resulting from WCSB oil sands development include the development of infrastructure, deforestation, and disturbance of peat-forming marshland to facilitate petroleum extraction. Many studies, however, exclude the life-cycle GHG emissions from land use change associated with oil sands extraction (NETL 2009, IHS CERA 2010 and 2011, Jacobs 2009, TIAX 2009), although Jacobs (2012) and GHGenius (2010) have used recent assessments to estimate emissions from local land use changes related to WCSB oil sands development. Consequently, the carbon flux from land use changes is currently poorly characterized in the body of life cycle literature on oil sands-derived crudes. Recent studies (Rooney et al. 2012, Yeh et al. 2010) have sought to characterize these carbon flows to examine the implications for GHG emissions and carbon sequestration.

Carbon is sequestered and stored in several land-based stocks, including above- and below-ground biomass (i.e., biomass carbon stocks), and soil organic carbon (i.e., soil carbon stocks). Extraction of both conventional crudes and bitumen and the subsequent reclamation of extraction sites affect the levels of carbon in these stocks through several key carbon flows. These include immediate carbon release from land clearance and soil disturbance, foregone carbon sequestration, and carbon uptake during land reclamation. Foregone sequestration refers to the carbon which would have been sequestered had a land-based carbon sink, such as a peatland, not been cleared for development.

Table 4-10 provides estimates of carbon stocks, carbon sequestration rates, and land reclamation rates for Canadian boreal forests and peatlands from Rooney and Yeh. The studies conclude that oil sands developments will result in net releases of carbon from land-based stocks through the following mechanisms:

- Release of carbon stored in forest and peatland biomass and soil carbon stocks, which is only partially replaced by the uptake of carbon during reclamation of the disturbed land post-development; and
- Forgone carbon sequestration in peatlands, which would otherwise sequester carbon at annual rates between 0.17 to 0.24 metric tons of carbon per hectare.

Table 4-10 Carbon Stock Estimates, Long-Term Carbon Sequestration Rates, and Land Reclamation Rates for Canadian Boreal Forests and Peatlands

			Rooney et al. 2012		Yeh et al. 2010	
Carbon pool	**Land type**		**Value**	**Source**	**Value**	**Source**
Original carbon stocks (metric tons C/ha)	Biomass		--	--	90	Table S5, see footnote; Searchinger et al. 2008
	Forest soil		--	--	206	
	Peatland biomass		Included	See p. 4; included in peatland soil estimate	36	Table S5, see footnote; Wieder et al. 2009
	Peatland soil	Low	530[1]	See p. 4, from Beilman et al. 2008	1,213	Table S5, Table S6, Vitt et al. 2000
		High	1,650[1]		--	--
	Average oil sands biomass		--	--	78	Table S7[2]
	Average oil sands soil		--	--	438	
Rate of carbon uptake during reclamation (metric tons C/ha/yr)	Forest	Low	--	--	1.35	Table S7; Carrasco et al. 2006; Amiro et al. 2003
		High	--	--	2.25	
	Peatland	Low	--	--	--[3]	--
		High	--	--	--[3]	
Post-mining above-ground biomass stocks (metric tons C/ha)	Reclaimed lands	Low	--	--	76	See assumptions on p. S13[4]
		High	--		90	
Post-mining soil carbon stocks (metric tons C/ha)	Reclaimed soils	Low	50	See p. 5, Cumulative Effects Management Association (2010)	61	See assumptions on p. S13[5]
		High	146		101	

			Rooney et al. 2012		Yeh et al. 2010	
Carbon pool	**Land type**		**Value**	**Source**	**Value**	**Source**
Carbon stock loss (metric tons C/ha)	Average carbon loss from reclamation of oil sands	Low	--	--	271[6]	Calculated from information in Table S7
		High	--	--	411[7]	
	Carbon loss from reclamation of peatland to upland forest	Low	384	See p. 5[8]	778[10]	
		High	1,600	See p. 5[9]	1,067[11]	
Forgone carbon sequestration (metric tons C/ha/yr)	Forest		--	--	0[4]	See Table S7
	Peatland	Low	0.19	Vitt et al. 2000, Turetsky et. al 2002	0.17	See Table S7, Turetsky et. al 2002
		High	0.24		0.24	

Source: Rooney et al. 2012 and Yeh et al. 2010.

Notes:
-- = Not estimated, C/ha/yr = carbon per hectare per year.
[1] Carbon stock depends on peat depth, composition, and bulk density.
[2] Assumes distribution is 23% peatland and 77% upland forest (see Table 2, note c in Yeh et al. 2010)
[3] Yeh et al. (2010) assume that peatland is reclaimed to boreal forest at the rate of boreal forest carbon uptake.
[4] Yeh et al. (2010, p. S13) assume that reclaimed forest sequesters carbon in aboveground biomass for 80 years at 1.35 to 2.25 metric tons of carbon/ha/yr (30% of this is sequestered in soils), or until aboveground biomass reaches the pre-disturbance level.
[5] Assumes 30% of carbon is sequestered in soil at a constant rate throughout 150 year modeling period (Yeh et al., 2010, p. S13).
[6] Calculated from original above and below ground carbon stock for average of oil sands lands, minus post-mining carbon stocks. Based on Table S7, assumes 70% of soil carbon loss, and 84% of biomass carbon loss (Yeh et al. 2010, p. S15).
[7] Calculated from original above and below ground carbon stock for average of oil sands lands, minus post-mining carbon stocks. Based on Table S7, assumes 90% of soil carbon loss and 100% of biomass carbon loss (Yeh et al. 2010, p. S15).
[8] Calculated from the original carbon stock, minus the post-mining carbon stock: 4.8 million metric tons carbon loss, divided by 12,414 hectares = 384 metric tons carbon/hectare (Rooney et al. 2012, p. 5).
[9] Calculated from the original carbon stock, minus the post-mining carbon stock: 19.9 million metric tons carbon loss, divided by 12,414 hectares = 1,600 metric tons carbon/hectare (Rooney et al. 2012, p. 5).
[10] Calculated from original above and below-ground carbon stocks for peatlands, minus post-mining carbon stocks. Based on Table S7, assumes 70% of soil carbon loss, and 84% of biomass carbon loss (Yeh et al. 2010, p. S15).
[11] Calculated from original above and below-ground carbon stocks for peatlands, minus post-mining carbon stocks. Based on Table S7, assumes 90% of soil C loss and 100% of biomass C loss (Yeh et al. 2010, p. S15).
[12] Yeh et al. (2010) assume the long-term net carbon accumulation rates (including natural and human disturbances) are zero for all eco-regions except peatlands.

The studies found that the net carbon release is particularly influenced by the disturbance of peatlands for two reasons. First, carbon-rich peatlands disturbed by oil sands mining operations will likely be largely reclaimed to upland forests or marshes and riparian shrublands (Rooney et al. 2012, p. 1; Yeh et al. 2010, p. 8768). The two studies estimate that the carbon stock in peatland is between 1.8 to 5.6 times larger than in boreal forest, although estimates of carbon stock in peatland vary widely, depending on peat depth, composition, and bulk density (Rooney et al. 2012, p. 4). Yeh et al. assume that carbon sequestration in reclaimed forests will occur at an annual rate of 1.35 to 2.2.5 metric tons of carbon per hectare until the aboveground biomass equals the pre-disturbance level, or for 80 years, whichever condition is met first, and that 30% of the sequestered carbon is stored in the soil at a constant rate for 150 years. Rooney et al. found that soil carbon stocks post-mining are between 50 to 146 metric tons of carbon per hectare—one-third to one-thirtieth of the pre-mining peatland carbon stock (Rooney et al. 2012, p. 5). The estimates of carbon stocks in soils reclaimed from peatland are reasonably consistent in the two studies: 50 to 146 metric tons carbon per hectare in Rooney et al. (2012), and 61 to 101 metric tons carbon per hectare in Yeh et al. (2010).

Second, unlike mature forests, which Yeh et al. assume have achieved a steady-state of carbon flux, peatlands continue to sequester carbon underground for much longer periods of time. Rooney et al. and Yeh et al. estimate that peatland continues to sequester carbon over the long-term at an annual rate of 0.17 to 0.24 metric tons of carbon per hectare (Rooney et al. 2012, p. 5; Yeh et al. 2010, p. 8768). As peatlands are reclaimed into boreal forests, this impacts the long-term sequestration potential of the land as well as increases short-term emissions from the aboveground storage of peat, which can decay and release both CO_2 and CH_4 (Yeh et al. 2010, pp. 8766-8767).

A full comparison between the studies is not possible, since Rooney et al. (2012) and Yeh et al. (2010) examine different aspects of the carbon impacts of oil sands mining. Rooney et al (2012) looks at per-hectare and total emissions loss associated with mining peatland only, and does not explicitly separate out aboveground biomass.[22] Yeh et al. (2010) looks at average per-hectare emissions from lands mined for oil sands, which they estimate to be 23% peatland and 77% boreal forest. Thus, only peatland results for the two studies are comparable. Peatland soil carbon loss values were within a similar range: 384 – 1,600 metric tons of carbon/year in Rooney et al. (2012) and 778 – 1,067 metric tons of carbon/year in Yeh et al. (2010); the range in Rooney et al. (2012) is larger because they estimated a wide range for the value of peatland soil carbon storage, depending on peat depth, composition, and bulk density. Given this and the difference in accounting for above and below ground carbon stocks in the two approaches, the results are reasonably consistent with each other.

Yeh et al. found that the net contribution of land use change to life-cycle emissions from WCSB oil sands development is relatively small, with the land use GHG emissions amounting to less than 0.4 to 2.5 percent of WTW life-cycle GHG emissions from oil sands production (considering both surface mining and in-situ production) over a 150-year modeling period.[23,24] In comparison, the authors estimate that land use change accounts for less than 0.4 percent of emissions from conventional crude extraction in California (i.e., less than 0.4 gCO_2e/MJ), and 0.1 to 4 percent of emissions from conventional oil extraction in Alberta (i.e., 0.1 to 3.4 gCO_2e/MJ).

In absolute terms, Rooney et al. found that land use changes for approved oil sands development could release 11.4 to 47.3 million metric tons of carbon (or 68 to 283 metric tons of carbon per hectare) and reduce sequestration by 5,734 to 7,241 metric tons of carbon per year (or 34 to 43 kg of carbon per hectare), though the authors did not compare these releases and losses to life-cycle GHG emissions associated with extraction, upgrading, transportation, refining, and

[22] Rooney et al. (2010, p. 4) estimates total initial peatland carbon storage and compares this to carbon storage in post-mining soils; the extent to which aboveground biomass contributes to these estimates is not explicitly provided.
[23] Yeh et al. compare GHG emissions per megajoule of crude refinery feedstock to full life cycle GHGs per megajoule of refined gasoline. The authors acknowledge that these two terms are not exactly equivalent, but they are evaluated as an approximate comparison. Further adjustments for efficiency losses at the refinery and allocation of GHG emissions to other refined products would be necessary for a fully consistent comparison.
[24] Yeh et al. also estimate that methane emission from tailings ponds could contribute an additional 0 to 7.91 gCO_2e/MJ of crude refinery feedstock. Together, land use change and tailings pond emissions could contribute up to 11% of overall life cycle emissions.

combustion of refined products from oil sands-derived crudes. According to Jacobs (2012), the GHG emissions from land disturbance estimated in Rooney et al. correspond to 0.5 to 3 gCO_2/MJ of bitumen, and 0.003 gCO_2e/MJ from loss of CO_2 sequestration (Jacobs 2012, p. 5-55).

4.3 DATA QUALITY AND TRANSPARENCY

As discussed in the previous sections, study design factors and assumptions drive the WTW GHG comparisons between oil sand-derived crudes relative to reference crudes. However, the results ultimately hinge on a third key factor: data quality. The quality of the data in the LCAs relates to a number of elements including precision, completeness, representativeness (i.e., time-related, geographical, and technology coverage), consistency, reproducibility, data sources, uncertainty, and documentation of missing data (ISO 14044:2006). The ability to assess data quality is contingent on the level of transparency provided by the study authors.

The quality of the data and transparency in the presentation of the data elements, assumptions, and data gaps varies considerably by study. Representativeness was a key area of concern in some of the studies in that they lacked data on actual facility operations. NRDC (2010) notes that studies used pre-project startup data (e.g., from applications for facilities that are not yet built or operating). According to Pembina (2011), both Jacobs (2009) and TIAX (2009) did not incorporate data from the two largest mining projects. TIAX uses data from six oil sands projects that represent 34 percent of the 2009 total oil sands production capacity in Alberta; two of these projects were not yet producing at the time of the report. Additionally, some studies base individual life-stage emissions on few parameters (e.g., API gravity for refining) (NETL 2008, 2009; ICCT 2010).

Most studies do not provide complete transparency in their methodologies, assumptions, or data sources. This is partially a function of the difficulty in accessing necessary data elements on or from non-transparent international crude production operations. Data on oil sands fields are typically less robust (and include a smaller data set) than those for reference crudes. This impedes the ability to make meaningful results comparisons for oil sands-derived crudes and reference crudes. ICCT (2010) acknowledges the lack of data/transparency for oil sands and in general notes, Where data were missing, Energy-Redefined LLC made estimates based on expert judgment and calculations and calibrated them with known data and available studies for verification, (ICCT 2010, p. 12). Some studies used proprietary models (e.g., a crude production model in Jacobs [2009] and an oil field model in ICCT [2010]), which keep various assumptions and calculations hidden.

Few studies considered uncertainty, and none of them rigorously treat underlying uncertainties in data inputs and models. Pembina (2006) selected point estimates for GHG emissions from different industry sources to present life-cycle stages together—an approach that could risk inconsistent characterization of the processes within the study. Other studies (e.g., IHS CERA 2010, 2011) calculated averages from a wide range of values and developed point estimates without providing bounds on uncertainty. Such bounds are important because a high bound on a reference crude can overlap with a low bound on an oil sands crude.

4.4 Analysis of Key Factors and their Impact on WTW GHG Emissions Results

This section analyses the effect that the various key factors described in Sections 4.1, Study Design Factors, and 4.2, Input and Modeling Assumptions, have on the life-cycle GHG emissions of WCSB oil sands crudes compared to reference crudes. To analyze the effects, the key factors and life-cycle results from NETL (2008, 2009) are compared against the other studies. Comparing the factors and results of one study against all other studies identifies the key factors that differ the most, and the magnitude of the impact that they have on life-cycle GHG emissions.

The NETL studies were selected as a basis for comparison against the other studies for several reasons. They cover a range of the world crude oils consumed in the United States, including the WCSB oil sands as well as the average crude consumed in the United States in 2005. The NETL factors have informed other fuel-related policy issues, as they have been used for the baseline in the USEPA Renewable Fuel Standard (RFS2).

4.4.1 Analysis of Study Design Factors

Table 4-11 summarizes key design factors across the studies identified through this assessment. The first row of Table 4-11 qualitatively assesses the impact of including each factor in a WTW analysis into an approximate high/medium/low arrangement based on results from across the studies evaluated. The high impact factors were those found to result in greater than about 3 percent change in WTW emissions across the studies; medium impact indicates an approximate 1 to 3 percent change in WTW emissions, and low impact indicates less than about 1 percent change in WTW emissions. The assignment to high, medium, or low categories is based on ICF analysis and judgment.

Estimated Relative WTW Impact:[1]		**High**					**Medium**				**Low**
Source	**Data Reference Year(s)**	**Petroleum coke combustion**[2]	**Cogeneration credit**[3]	**Upstream production of fuels incldued**[4]	**Flaring/ venting GHG emissions included**	**Capital equipment included**[6]	**Refinery emissions account for upgrading**[5]	**Local and indirect land use change included**	**Methane emissions from tailing ponds included**	**Fugitive leaks included**	**Methane emissions from mine face**
NETL, 2008	2005	No	NS	Yes	Yes	No	No	No	NS	Yes	NS
NETL, 2009	2005	No	NS	Yes	Yes	No	No	No	NS	NS	NS
IEA, 2010	2005-2009	NS	NS	Yes	NS	NS	NA	No	Yes	NS	NS
IHS CERA, 2010, 2011	~2005-2030	V	V	No	NS	NS	NA	No	V	NS	V
NRDC, 2010	2006-2010	NS[7]	NS[7]	P	NS	NS	NA	No	NS	NS	NS
ICCT, 2010	2009	NS	No	P	Yes	No	No	No	NS	Yes	NS
Jacobs, 2009	2000s	Yes	Yes	Yes	Yes	No	Yes	No	No	Yes	No
Jacobs, 2012	2000s	Yes	No[8]	Yes	Yes	No	Yes	Local	Yes	Yes	Yes
TIAX, 2009	2007-2009	P	P	Yes	Yes	No	Yes	No	Yes	Yes	Yes
Charpentier, et al., 2009	1999-2008	NS[7]	NS[7]	V	NS	V	NA	No	NS	NS	NS
Brandt, 2011	V	V	V	NS[7]	V	NS[7]	V	V	V	V	V
RAND, 2008	2000s	NS	NS	NS	Yes	No	No	No	Yes	Yes	Yes
Pembina Institute, 2005	2000, 2004	NS	NS	NS	P	No	No	No	NS	P	NS
Pembina Institute, 2006	2002-2005	NS	NS	No	P	No	No	No	Yes	Yes	Yes
McCann, 2001	2007	P	NS	Yes	NS	No	NS	No	NS	NS	NS
GHGenius, 2010	Current	Yes	No	Yes	Yes	No	NS	Local	Yes	Yes	Yes
GREET, 2010	Current	NS	NS	Yes	Yes	No	NS	No	NS	Yes	NS
Rooney, et al., 2012	1990s, 2000s	NA	NA	NA	NA	NA	NA	Local	No	NA	NA
Yeh, et al., 2010	2000s	NA	NA	NA	NA	NA	NA	Local	Yes	NA	NA

Notes: Yes = included in life-cycle boundary; No = not included; P = partially included; NS = not stated; NA = not applicable; V = varies by study addressed in meta-study.

[1] High impact = greater than about 3 percent change in WTW emissions. Medium impact = approximately 1 to 3 percent change in WTW emissions. Low impact = less than about 1 percent change in WTW emissions.
[2]Yes indicates that GHG results for products such as gasoline, diesel, and jet fuel do include petroleum coke production and combustion. No indicates that GHG emissions from petroleum coke production and combustion were not included in the system boundary for gasoline, diesel, or jet fuel. The effect of including petroleum coke depends on how much is assumed to be stored at oil sands facilities versus sold or combusted, and whether a credit is included for coke that offsets coal combustion.
[3] Yes indicates that the study applied a credit for electricity exported from cogeneration facilities at oil sands operations that offsets electricity produced by other power generation facilities. No" indicates a credit was not applied. Including a credit for oil sands will reduce the GHG emissions from oil sands crudes relative to reference crudes.
[4] Indicates whether studies included GHG emissions from the production of fuels that are purchased and combusted on-site for process heat and electricity (e.g., natural gas).
[5] Indicates whether refinery emissions account for the fuel properties of SCO relative to reference crudes. Since SCO is upgraded before refining, it requires less energy and GHG emissions to refine into gasoline, diesel, and jet fuel products.
[6] Indicates whether the study included GHG emissions from the construction and decommissioning of capital equipment such as buildings, equipment, pipelines, rolling stock.
[7] Not discussed in the meta-study; may vary by individual studies analyzed.
[8] Jacobs (2012) did not apply a credit for export of excess electricity generated at SAGD or upgrading facilities. In calculating the carbon intensity of production from SAGD processes using reports to the Alberta Energy Conservation Board for facilities that export electricity, the study calculated the natural gas amount that would be used to produce the excess electricity and subtracted this from total natural gas consumption (Jacobs 2012, p. 5-36).

In general, the studies reviewed are consistent with one another in how they treat some factors. For example, the studies' life-cycle boundaries generally exclude emissions associated with land use changes and capital equipment. As discussed at length in Sections 4.1 and 4.2, Study Design Factors and Input and Modeling Assumptions, the studies vary widely, however, in their treatment of other factors such as their treatment of petroleum coke and exports of cogenerated electricity.

The first two categories in Table 4-11 (i.e., petroleum coke combustion and cogeneration credit) relate to how the studies treat allocation and co-product design factors. The remaining categories compare the completeness of the LCA boundaries of the studies. The data reference years column indicates the time period over which the results of each study are representative. With respect to the first two categories dealing with allocation and co-product design factors:

- The petroleum coke combustion column indicates whether GHG emissions for premium fuel refined products include the emissions from producing and combusting petroleum coke. Treatment of petroleum coke can have a large impact on WTW GHG emissions. For example, IHS CERA (2010) estimated that the inclusion of petroleum coke combustion would increase the combustion emissions from a barrel of refined fuel products by 48 $kgCO_2e$, or roughly an 8 to 10 percent increase in WTW GHG emissions, depending on the crude type. NETL allocated the emissions from the production and combustion of co-product petroleum coke outside the LCA system boundary (NETL 2008). Across the other studies, a wide variation of approaches account for petroleum coke (see Section 4.2.3.1, Petroleum Coke Treatment, for details).
- The cogeneration credit column shows whether the studies include an electricity cogeneration GHG credit for excess capacity of electricity generation that can be exported for use elsewhere on the electricity grid. As described in Section 4.2.1.4, Electricity Cogeneration and Export, applying a GHG credit for avoided grid-based electricity reduces the WTW GHG emissions for oil sands crudes relative to the range of reference crudes. It is unclear whether NETL assigned electricity cogeneration GHG credit in its study. Jacobs (2009) indicated that including an electricity cogeneration GHG credit for displaced grid-based electricity has the potential to reduce the WTW GHG emissions for oil sands crudes to within the range of reference crudes (Jacobs 2009, p. 1-13). This translates into roughly a 5 to 10 percent reduction in WTW GHG emissions assuming displacement of the local Alberta electricity grid mix, which is mostly coal-based electricity (Jacobs 2009).[25]

The remaining categories indicate whether several secondary carbon flows are included within the LCA boundaries of the studies (see Figure 2-1 for reference):

- NETL and most other studies include the GHG emissions associated with upstream production of purchased fuels and electricity that is imported to provide process heat and to power machinery throughout crude production. The upstream GHG emissions for natural gas fuel and electricity production used in the production of oil sands are significant. Jacobs (2009, 2012) includes GHG emissions associated with the natural gas and electricity upstream fuel cycle which accounts for roughly 4 to 5 percent of the total WTW GHG

[25] The latest Jacobs study (2012) does not apply a cogeneration credit for electricity exports from SAGD and oil sands upgrading facilities (Jacobs 2012, p. 4-18).

emissions for average WCSB oil sands. IHS CERA (2010) indicates that although their study excludes upstream fuel and electricity GHG emissions, the inclusion of the upstream GHG emissions would add 3 percent to WTW emissions on a per-barrel-of-refined-products basis.

- Emissions associated with flaring and venting are a high impact source of GHG emissions included in the NETL study. The TIAX 2009 study indicates that including venting and flaring emissions associated with oil sands production (particularly for mining extraction techniques) contributes up to 4 percent of total WTW GHG emissions. Flaring and venting emissions are included in several other studies; however, a few studies reviewed did not explicitly state whether they were included.
- Only a few studies modeled the effect that upgrading SCO has on downstream GHG emissions at the refinery. Jacobs (2009) and TIAX (2009) include this effect and determine that the GHG impact of upgrading bitumen into SCO will reduce the emissions at the refinery. Compared to refining bitumen directly, refining SCO (which already has been upgraded) would reduce WTW GHG emissions by between 1 and 2 percent.[26]
- None of the studies included the GHG impacts associated with capital equipment and construction of facilities, machinery, and infrastructure needed to produce oil sands. According to Bergerson and Keith, the relative percentage increase to WTW GHG emissions from incorporating capital equipment is between 9 and 11 percent (Bergerson and Keith 2006). Charpentier et al. discuss the need to more fully investigate and include these potentially significant supply chain infrastructure GHG emissions in future oil sands life-cycle studies (Charpentier et al. 2009, p. 10).
- During oil sands production, local and indirect land use change emissions associated with changes in biological carbon stocks from the removal of vegetation, trees, and soil during oil sands mining operations may be significant. Except Jacobs (2012) and GHGenius, none of the other life-cycle studies reviewed included land use change GHG emissions in the WTW life-cycle assessment. Studies describing the potential GHG emissions impacts of including land use change emissions estimate potential increases in WTW GHG emissions for oil sands range from less than 1 to 3 percent (Yeh et al. 2010). To the extent that land is reclaimed after oil sands operations are completed, this lost carbon would be returned over a long time period and may stabilize at lower levels than pre-mining conditions. Rooney et al. found that, under current mining reclamation plans, carbon-rich peatlands disturbed by oil sands mining operations will be largely reclaimed to upland forests or marshes and riparian shrublands. Soil carbon stocks post-mining are between 50 to 146 metric tons of carbon per hectare—one-third to one-thirtieth of the pre-mining peatland carbon stock, depending on the original peat depth, composition, and bulk density (Rooney et al. 2012, p. 5).

[26] Due to the complexity of refining processes, it is difficult to estimate the magnitude of this effect. Comparing refining emissions from TIAX (2009) and Jacobs (2009)—which accounted for the fact that upgraded SCO will require less energy to refine into premium products—to refining emissions from GHGenius and NETL—which did not account for this affect—showed a 1 to 2 percent reduction in WTW GHG emissions, on average, across the studies. Comparing individual studies, the minimum change was 0.4 percent and the maximum was 4.1 percent. These changes may not be entirely attributable to accounting for upgraded SCO at the refinery, but they represent a rough, upper-bound estimate. Refining values for TIAX, Jacobs, GHGenius, and GREET were taken from Brandt (Brandt 2011, Table 8, p. 45).

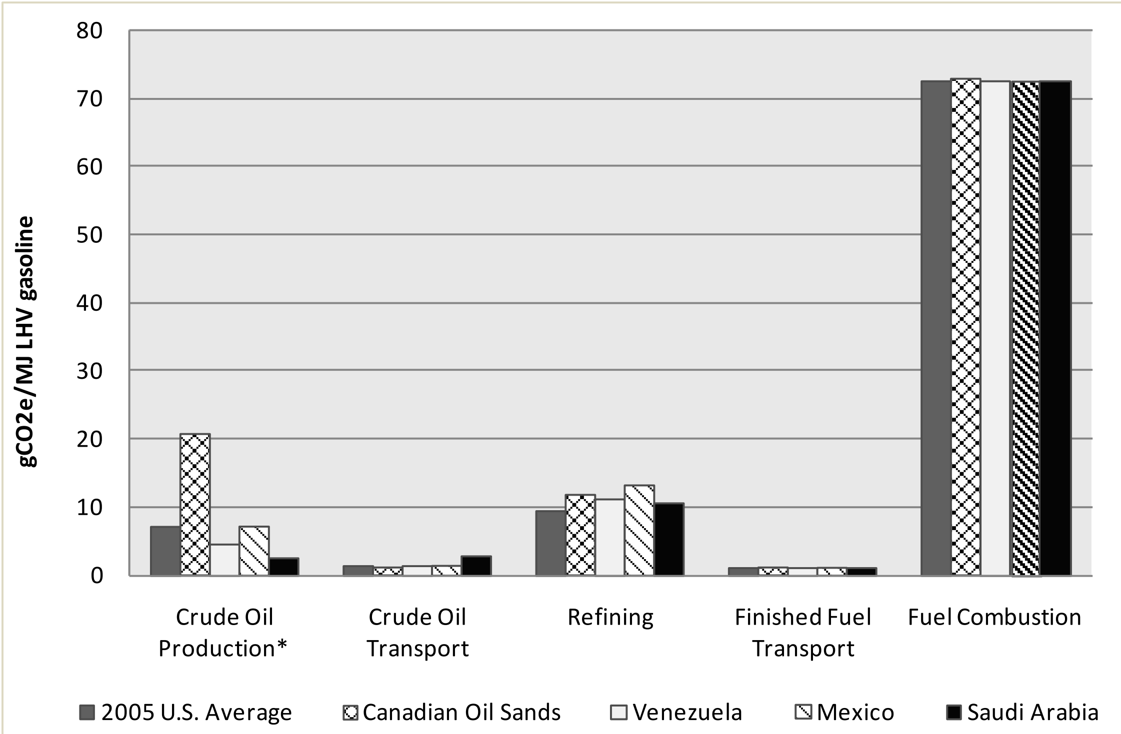
- Methane emissions from fugitive leaks, oil sands mining operations, and tailings ponds are not included across all studies. Jacobs (2012), TIAX (2009), Pembina (2006), and GHGenius include the impacts of both sources. Fugitive emissions from leaks throughout the oil sands production process can potentially contribute up to 1 percent of WTW GHG emissions according to emissions estimates from Environment Canada's National Inventory Report (Environment Canada 2010). Emissions from oil sands mining and tailings ponds potentially have a larger impact on WTW GHG emissions, contributing 0 to 9 percent of total WTW GHG emissions (Yeh et al. 2010). IHS CERA excludes emissions from methane released from tailings ponds but recognizes there is considerable uncertainty and variance in quantifying these emissions (IHS CERA 2010, p. 15).
- Methane emissions from the mine face of oil sands mining operations are in the low-impact category. Only the Jacobs (2012), Pembina (2006), RAND (2008), and GHGenius sources recognize and include this emissions source, although many studies did not explicitly state whether these emissions were included or not considered. Methane emissions from the mine face are estimated to contribute less than 1 percent of total WTW GHG emissions (Pembina 2006, p. 11).

4.4.2 Analysis of Input and Modeling Assumptions

This section assesses several key input assumptions that influence the life-cycle GHG results provided by NETL (2008, 2009). Figure 4-5 summarizes GHG emissions for each of the reference crudes and average WCSB oil sands crude across the different life-cycle stages as quantified in the NETL studies.

NETL provides a single WCSB oil sands (i.e., Canadian Oil Sands) estimate that represents a weighted average of 43 percent crude bitumen from in situ production and 57 percent SCO from mining (NETL 2009). The NETL study did not account for the fact that condensate is blended with crude bitumen to form dilbit, which is transported via pipeline to U.S. refineries. Since condensate has a lower GHG intensity than crude bitumen, per-barrel GHG emissions from dilbit are less than per-barrel emissions from crude bitumen. Note that in the NETL studies the upgrading stage for WCSB oil sands is included in the crude oil production stage. The GHG emissions from the crude oil production stage for WCSB oil sands are more than double the GHG emissions compared to the range of crude oil production for the reference crudes.

Figure 4-5 also shows that the transport stages (both the crude oil transport upstream and the finished fuel transport downstream) collectively account for a small minority (2 to 4 percent) of the total WTW GHG emissions across all reference crudes and WCSB oil sands. Finally, the fuel combustion stage (i.e., TTW) component of the WTW fuel life-cycle GHG emissions for all reference crudes and oil sands are identical and account for the majority (70 to 80 percent) of the total WTW GHG emissions.



Source: All values from NETL 2009.

Note: GHG emissions are presented in grams CO_2 equivalent per megajoule of gasoline on a lower heating value (LHV) basis.

* Includes upgrading for WCSB oil sands.

Figure 4-5 WTW GHG emissions across the fuel life-cycle for WCSB oil sands average crude (i.e., Canadian Oil Sands) and reference crudes

Table 4-12 summarizes the life-cycle GHG emissions for gasoline produced from oil sands-derived crude relative to other reference crudes consumed in the United States (NETL 2009).

Table 4-12 GHG Emissions for Producing Gasoline from Different Crude Sources from NETL 2009 and Estimates of the Impact of Key Assumptions on the Differential between Oil Sands and U.S. Average Crude

Life-Cycle Stage	GHG Emissions (gCO_2e/MJ LHV gasoline)[a]					Findings on Key Assumptions Influencing Results	
	2005 U.S. Average	Canadian Oil Sands	Venezuela	Mexico	Saudi Arabia	Description	Estimated Ref Crude WTW Impact[b]
Crude Oil Extraction	6.9	20.4[c]	4.5	7.0	2.5	Oil sands estimate assumes a weighted average of 43% crude bitumen not accounting for blending with diluent to form dilbit) from CSS in situ production and	NA
Upgrading	NA	IE	NA	NA	NA		

Life-Cycle Stage	GHG Emissions (gCO_2e/MJ LHV gasoline)[a]					Findings on Key Assumptions Influencing Results	
	2005 U.S. Average	Canadian Oil Sands	Venezuela	Mexico	Saudi Arabia	Description	Estimated Ref Crude WTW Impact[b]
						57% SCO from mining, based on data from 2005 and 2006	
Crude Oil Transport	1.4	0.9	1.2	1.1	2.8	Relative distances vary by study	Low increase or decrease
Refining	9.3	11.5[d]	11.0	12.9	10.4	Did not evaluate impact of upgrading SCO prior to refinery; only affects oil sands crudes.	Medium decrease
Finished Fuel Transport	1.0	0.9	0.9	0.9	0.9	Transportation excluded co-product distribution	Low increase
Total WTT	18.6	33.7	17.6	22.0	16.7		
Fuel Combustion	72.6	72.6	72.6	72.6	72.6		
Total WTW	91.2	106.3	90.2	94.6	89.3	All crudes other than Canadian oil sands when petroleum coke is accounted in U.S. Gulf Coast refineries	High increase
Difference from 2005 U.S. Average	0%	17%	-1%	4%	-2%		

Notes: CSS = carbon capture and storage, gCO_2e/MJ = grams carbon dioxide equivalent per megajoule, GHG = greenhouse gas, IE = Included elsewhere; NA = Not applicable; LHV = Lower heating value; SCO = synthetic crude oil, WTT = Well-to-tank; WTW = Well-to-wheels.

[a]NETL 2009 values converted from $kgCO_2e$/MMBtu using conversion factors of 1,055 MJ/MMBtu and 1000 g/kg.
[b]Estimated impact on the WTW GHG emissions for reference crudes, except where noted (i.e., refining assumption affects oil sands crudes), as result of addressing the key assumptions/ missing emission sources. High = greater than approximately 3 percentage points change, Medium = approximately 1 to 3 percentage points change, and Low = less than approximately 1 percentage point change in WTW emissions.
[c] Included within extraction and processing emissions.
[d] Calculated by subtracting other process numbers from WTT total; report missing this data point.
[e] The effect that including petroleum coke manufacture, transportation, and combustion has on WTW results depends on assumptions about the replacement of petroleum coke supply from Gulf Coast refineries in its market by coal or fuel oil.

The results from the NETL study are subject to several input assumptions that influence the analysis results. These assumptions, and their estimated scale of impact on the WTW results, are presented below and are summarized in the last two columns of Table 4-12.

- First, NETL (2009) developed its weighted-average GHG emission estimate for oil sands extraction (including upgrading) from data on mining and CCS in situ operations in 2005 and 2006. The estimate that the NETL study used for mining oil sands was based on a 2005 industry report that estimates higher values than more recent estimates of surface mining GHG emissions (TIAX 2009; Jacobs 2009, 2012). The in situ GHG estimate is based on a CSS operation which, while CSS operations tend to be more GHG intensive than SAGD processes, is generally in the range of in situ estimates in other studies (e.g., TIAX 2009, Jacobs 2009). The NETL study, however, did not account for the fact that natural gas condensate is blended with crude bitumen to form dilbit, which is transported via pipeline to the United States. Since condensate has a lower GHG intensity than crude bitumen, per-barrel GHG emissions from dilbit are less than per-barrel emissions from crude bitumen.

- Second, NETL allocated refinery emissions from co-products other than gasoline, diesel, and jet fuel to the co-products themselves, including petroleum coke and only considered combustion emissions from gasoline, diesel, and kerosene-type jet fuel (NETL 2009, p. 72). This approach removes the GHG emissions associated with producing and combusting co-products from the study's life-cycle boundary. This was consistent with NETL's goal of estimating the contribution of crude oil sources to the 2005 baseline GHG emissions profile for three transportation fuels (gasoline, diesel, and kerosene-type jet fuel). As discussed in Section 4.2.3.1, Petroleum Coke Treatment, including the GHG emissions from the production and combustion of petroleum coke significantly increases WTW GHG emissions for crudes where the petroleum coke is combusted. If petroleum coke produced from refineries is assumed to supplement coal combustion, however, the net emissions from coke combustion will be much smaller. As a result, the effect of including petroleum coke combustion depends on study assumptions about the end use of petroleum coke at both the refinery and upgrader, and whether the elimination of petroleum coke manufacture when SCO is refined is offset by the crude oil displaced by WCSB crude or by additional coal production. The energy demand in the market supplied by petroleum coke does not change.
- Third, the NETL study used linear relationships to relate GHG emissions from refining operations to specific crudes based on API gravity and sulfur content. The study notes that these relationships do not account for the fact that bitumen blends and SCO in particular will produce different fractions of residuum and light ends than full-range crudes. Accounting for this effect in the refinery will change the differences between WTW GHG emissions from WCSB oil sands-derived premium fuels.
- Fourth, as noted in Table 4-12 and described in Section 4.4.1, Analysis of Study Design Factors, the NETL study did not fully evaluate the impact of pre-refining SCO at the upgrader prior to the refining stage and is potentially overstating the emissions associated with refining oil sands. Upgraded bitumen in the form of SCO would require less refining and GHG emissions would decrease by roughly 1 to 2 percentage points relative to other reference crudes.
- Finally, since the transport stages of the fuel life cycle (both upstream crude oil transport and downstream finished fuel transport) account for minor portions (1 to 3 percent and 1 percent, respectively) of the overall WTW GHG emissions across the reference crudes and oil sands, the impact of transportation distance assumptions on total WTW GHG emissions are small. For example, in the finished fuel transport stage, emissions associated with crude co-product distribution are excluded and would increase relative transport GHG emissions by approximately 0.2 to 0.3 percentage points if included.[27] Note also in the NETL comparisons

[27] All crude oils with exception of SCO have a vacuum residuum content, which is processed in the Gulf Coast refineries to G+D (gasoline plus diesel) and petroleum coke. Nearly all U.S. petroleum coke manufactured in southeast Texas is exported to China, India, and other foreign locations. ICF evaluated the effect of including petroleum coke transport to Asia, assuming that the voyage is roughly equivalent to ocean transport of crude oil from Saudi Arabia to the Gulf of Mexico, and adjusting transport GHG emissions by the fraction of crude that is converted to petroleum coke.

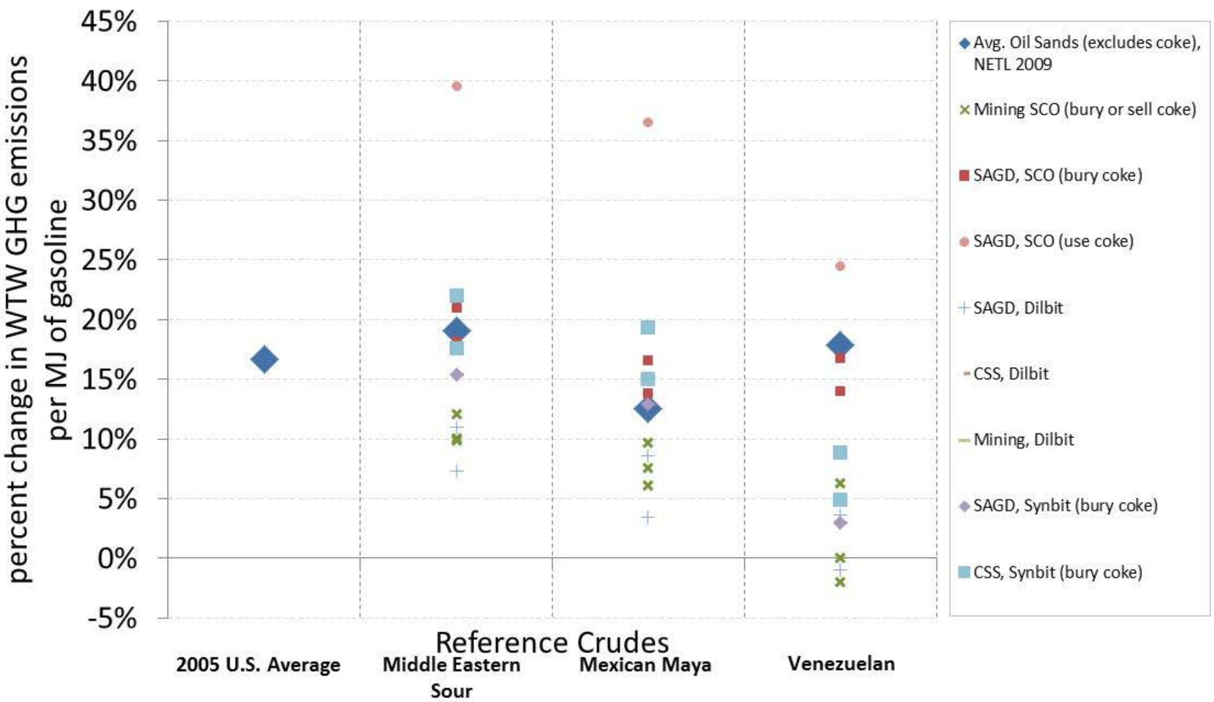
in Figure 4-5 that Mexican Maya and Venezuelan crude transport are shown to be equal, at about half the value of Saudi Arabia crudes. However, the transport distance of Mexican crude to Southeast Texas is less than half that of Venezuelan crude, and 7 percent of the distance of Saudi crudes. This differential would be compounded on a GHG emissions per barrel of premium fuel product basis as Mexican and Venezuelan heavy crudes produce less premium fuel per barrel transported than Saudi crudes.

4.4.3 Summary Comparison of Life-Cycle GHG Emission Results

Figure 4-6 and Figure 4-7 compare, respectively, the WTW and WTT GHG emissions of gasoline produced from WCSB oil sands crudes relative to four reference crudes based on data from the studies included in this assessment. These figures were developed from an extensive review of the design and input assumptions of the life-cycle studies in the scope of this assessment.

The results in Figure 4-6 and Figure 4-7 are plotted as the percentage change in WTW and WTT GHG emissions from gasoline derived from WCSB oil sands relative to gasoline from the four reference crudes. The large diamonds indicate the NETL results for gasoline produced from the average mix of WCSB oil sands imported to the United States in 2005. The other symbols illustrate the range of GHG emissions estimates across the studies for different oil sands production methods and scenarios.

Apart from the NETL results in Figure 4-6 and Figure 4-7 (which are indicated by large diamonds), each symbol corresponds to a specific method of producing WCSB oil sands crude (e.g., producing SCO from mining, dilbit from SAGD). For SCO and synbit, the symbols also indicate the treatment of petroleum coke produced at the upgrader. For example, the studies assumed that petroleum coke is either: (i) used (i.e., combusted or gasified) for process energy or hydrogen, (ii) stockpiled or buried, or (iii) sold as a co-product.



Sources: Data from NETL 2009, Jacobs 2009, TIAX 2009.

Notes: The percent differentials are calculated using the oil sands results relative to the corresponding study's reference crude. Only NETL (2008, 2009) provided a value for the 2005 U.S. average reference crude. A positive percentage indicates the oil sands' WTW is greater than the X-axis reference chart.

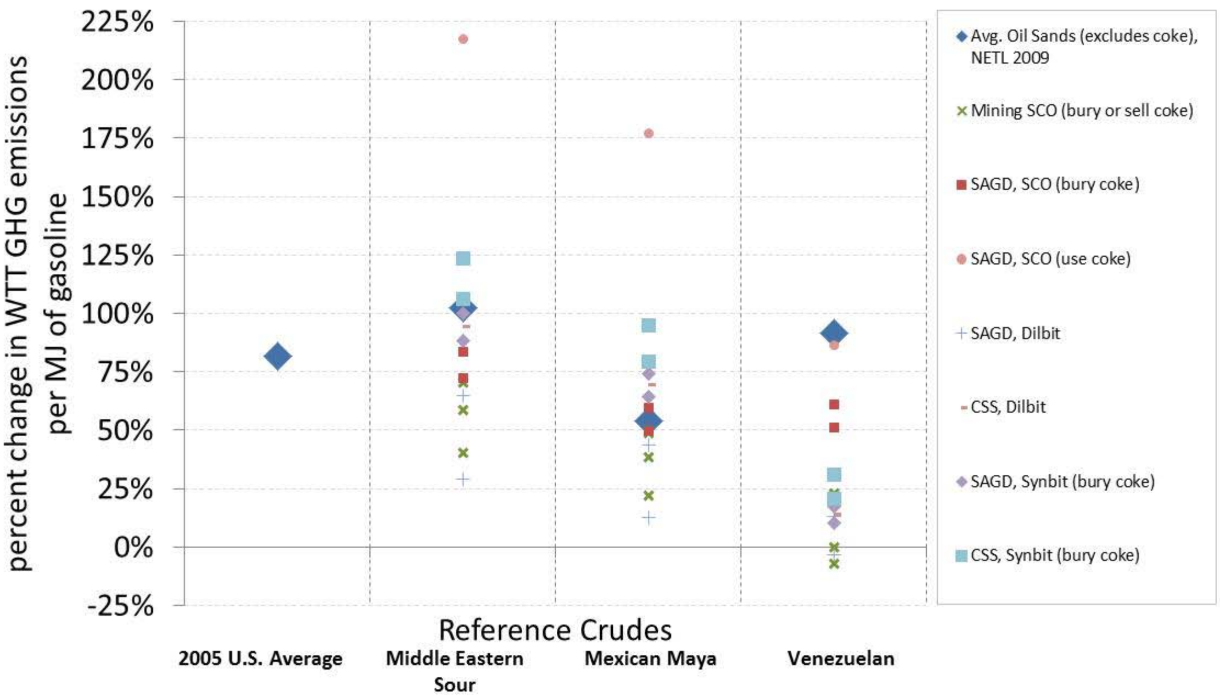
In this chart, all emissions are given per megajoule of reformulated gasoline with the exception of NETL 2009, which is given per megajoule of conventional gasoline.

Venezuela Conventional is used as the NETL reference crude for Venezuela Bachaquero in this analysis. This is a medium crude, not a heavy crude; thus, the NETL values are compared against a lighter Venezuelan reference crude than other studies.

*Dilbit fuels do not include emissions associated with recirculating diluents back to Alberta. TIAX (2009) did not consider recirculation of diluent back to Alberta. Jacobs (2009) evaluated a scenario where diluent is recirculated to Alberta, which increased WTW emissions by 7 gCO_2/MJ (LHV), or 7 percent, for reformulated gasoline relative to the case where diluent is not recirculated. This scenario has not been included in this figure because diluent will not be recirculated by the proposed Project.

CSS = cyclic steam stimulation, GHG greenhouse gas, MJ = megajoule, SAGD = steam-assisted gravity drainage, SCO = synthetic crude oil, WTW = well-to-wheels.

Figure 4-6 Comparison of the percent differential for various WTW GHGs from gasoline produced from WCSB oil sands relative to reference crudes



Sources: Data from NETL 2009, Jacobs 2009, TIAX 2009.

Notes: The percent differentials are calculated using the oil sands results relative to the corresponding study's reference crude. Only NETL (2008, 2009) provided a value for the 2005 U.S. average reference crude. A positive percentage indicates the oil sands' WTW is greater than the X-axis reference chart.
In this chart, all emissions are given per megajoule of reformulated gasoline with the exception of NETL 2009, which is given per megajoule of conventional gasoline.
Venezuela Conventional is used as the NETL reference crude for Venezuela Bachaquero in this analysis. This is a medium crude, not a heavy crude; thus, the NETL values are compared against a lighter Venezuelan reference crude than other studies.
*Dilbit fuels do not include emissions associated with recirculating diluents back to Alberta. TIAX (2009) did not consider recirculation of diluent back to Alberta. Jacobs (2009) evaluated a scenario where diluent is recirculated to Alberta, which increased WTW emissions by 7 gCO_2/MJ (LHV), or 7 percent, for reformulated gasoline relative to the case where diluent is not recirculated. This scenario has not been included in this figure because diluent will not be recirculated by the proposed Project.

CSS = cyclic steam stimulation, GHG greenhouse gas, MJ = megajoule, SAGD = steam-assisted gravity drainage, SCO = synthetic crude oil, WTT = well-to-tank.

Figure 4-7 Comparison of the percent differential for various WTT GHGs from gasoline produced from WCSB oil sands relative to reference crudes

Symbols that repeat in the comparison to each reference crude indicate that there are varying differentials even for the same scenario based on different studies (e.g., SAGD, SCO (bury coke)). The percentage differences across the oil sands are a result of (i) differences in technologies and practices utilized to produce the oil sands-derived gasoline including in situ SAGD, in situ CSS, or mining; (ii) differences in the pathway for refining the extracted bitumen (i.e., whether the bitumen was upgraded to SCO, refined as dilbit, refined as synbit, or refined as bitumen directly); and (iii) differences in individual life-cycle studies' design factors and input assumptions. These three factors drive a wide range in results for the overall WTW and WTT comparisons shown in Figure 4-6 and Figure 4-7.

Figure 4-6 and Figure 4-7 show that WCSB oil sands-derived gasoline WTW and WTT GHG emissions differentials are larger than gasoline produced from the four reference crudes. Two data points—SCO from mining where the coke is buried, and dilbit from SAGD—estimate that life-cycle GHG emissions from WCSB oil sands are lower than the Venezuelan Bachaquero reference crude assumed in the studies from which the data were drawn.

More specifically, as shown in Figure 4-6, the NETL results show that the WTW GHG emissions from gasoline produced from WCSB oil sands crude are as much as 17 percent higher than gasoline from the average mix of crudes consumed in the United States in 2005. Gasoline from certain WCSB oil sands crude production schemes emits a maximum of 19, 13, and 16 percent more life-cycle GHG emissions than Middle Eastern Sour, Mexican Heavy (i.e., Mexican Maya), and Venezuelan Bachaquero crudes, respectively.

Figure 4-6 also illustrates that on a WTW basis, gasoline produced from SCO via in situ methods of oil sands extraction (i.e., SAGD and CSS) in general has higher life-cycle GHG emissions than mining extraction methods. This difference is primarily attributable to the energy requirements of producing steam as part of the in situ extraction process.

Gasoline produced from dilbit generally has lower GHG emissions per barrel of crude delivered to the refinery than mining and in situ methods. This is a result of blending raw bitumen with a diluent condensate for transport via pipeline. This analysis evaluates the refining of both bitumen and diluent at the refinery, since diluent will not be recirculated by the proposed Project. GHG emissions per barrel of crude from synbit are similar to mining and in situ SCO.

In Figure 4-7, the same trends are illustrated from the WTT perspective. The percentage increase in WTT GHG emissions shown in Figure 4-7 compared to gasoline produced from reference crudes is much larger than the percentages found in the WTW perspective used in Figure 4-6. This is because the majority of WTW emissions occurs during the combustion stage (i.e., between 70 to 80 percent) and is generally identical irrespective of the feedstock (i.e., reference crude or oil sands) as shown in Figure 4-5 above. Therefore, the WTT perspective dramatically increases the GHG emissions differential between different crudes because the percentage differences are calculated using the same numerator as in the WTW calculations, but with a much smaller denominator.

The GHG emissions across different oil sands extraction, processing, and transportation methods vary by roughly 25 percent on a WTW basis. Life-cycle GHG emissions of fuels produced from oil sands crudes are higher than fuels produced from lighter crude oils, such as Middle Eastern Sour crudes and the 2005 U.S. average mix. Compared to heavier crudes from Mexico and Venezuela crudes, WTW emissions from oil sands crudes range from a maximum 37 percent increase for SAGD SCO involving burning the coke at the upgrader to a 2 percent decrease for mining SCO and burying or selling the coke.

Estimates from recent life-cycle studies are within these ranges: a recent study by IHS CERA, found that transportation fuels produced from oil sands result in average WTW GHG emissions that are 14 percent higher than the average crude refined in the United States (results range from 5 to 23 percent higher) (IHS CERA 2012). In addition, Jacobs found that WTW GHG intensities of transportation fuels produced from oil sands are within 7% to 12% of the upper range of the WTW intensity of conventional crudes (Jacobs 2012).

5.0 PETROLEUM COKE CHARACTERISTICS, GHG EMISSIONS, AND MARKET EFFECTS

The Final EIS, released in August 2011, found that the treatment of petroleum coke in life-cycle studies was an important factor that influences the life-cycle GHG emission results. It is important when comparing oil sands and the reference crudes that the full life cycle be evaluated, not just the upstream or refining stage. The issue of petroleum coke is not a standalone issue for oil sands crudes, it is also a life-cycle consideration for the heavy conventional crudes. If the GHG emissions from producing and combusting petroleum coke and other co-products are included within life-cycle boundaries for one type of crude, it must be done for the other crudes for an even comparison.

Producing a barrel of premium fuels (i.e., gasoline, diesel, and kerosene/jet fuel) from bitumen produces roughly the same amount of petroleum coke as a barrel of premium fuels refined from heavy crudes, such as Venezuelan Bachaquero or Mexican Maya. The actual net GHG emissions from petroleum coke, however, depend on the final end use of the petroleum coke (i.e., whether it is stockpiled or combusted) and how its end use affects demand for other fuels such as coal. Since a portion of the petroleum coke produced from upgrading WCSB oil sands bitumen is currently stockpiled and not combusted, whereas the petroleum coke produced from refining reference crudes at Gulf Coast refineries is combusted, GHG emissions from petroleum coke produced from WCSB oil sands crudes are slightly lower than petroleum coke GHG emissions from other heavy reference crudes.

Recent reports published since the Final EIS (Oil Change International 2013; Gordon 2012) have also recognized petroleum coke as an important source of GHG emissions in the crude oil life cycle. To better understand the importance of petroleum coke in the life cycle of both oil sands-derived and reference crudes, this section describes:

- The characteristics of petroleum coke relative to coal, for which it serves as a substitute in the electric power sector;
- The effect of including petroleum coke production and combustion in life-cycle GHG emission estimates of oil sands and other reference crudes; and,
- A discussion of market effects related to changes in of petroleum coke production, how these effects have been captured in existing LCA studies, likely markets for petroleum coke, and potential effects on the demand for other fuels.

Physical characteristics of petroleum coke are provided in Table 5-1, including heating value (on a higher heating value basis), carbon content, and CO_2 emissions per unit energy. For comparison, these characteristics are also provided for bituminous, sub-bituminous, lignite and anthracite types of coal. The change in CO_2-intensity for these coals is provided relative to petroleum coke on an energy basis. Table 5-1 shows that bituminous, sub-bituminous, and lignite coal are between about 4 and 9 percent less CO_2-intensive than petroleum coke on an energy basis, while anthracite coal is approximately 2 percent more CO_2-intensive.

Table 5-1 Petroleum coke and coal heating values, carbon contents, and CO_2 emissions per unit energy from EPA (2012)

Characteristic	Units	Petroleum coke	Bituminous coal	Sub-bituminous coal	Lignite coal	Anthracite coal
Heating value[a]	e.g., million Btu / short ton	30.12[b]	23.89[c]	17.14[c]	12.87[c]	22.57[c]
Carbon content[d]	e.g., % carbon, by weight	92%	67%	50%	38%	70%
CO_2 emissions per unit energy	$kgCO_2$ / million Btu	102.10[e]	93.27[f]	97.17[f]	97.67[f]	103.67[f]
	e.g., grams CO_2 / MJ	96.77	88.40	92.10	92.57	98.26
Change in emissions-intensity relative to petroleum coke	% change	--	-9%	-5%	-4%	2%

Notes: Data in table reflects national characteristics provided by EPA (2012) U.S. Inventory of Greenhouse Gas Emissions: 1990-2010. Original sources cited in EPA (2012) are provided below.
a On a higher heating value basis.
b EIA (2010). Annual Energy Review 2009. U.S. Energy Information Administration.
c EIA (1993). State Energy Report 1992. U.S. Energy Information Administration.
c Calculated from heating value and CO_2 emissions per unit energy.
e Based on data sourced from EIA (1994), EIA(2009), EPA (2009) and EPA (2010b).
f Calculated from USGS (1998) and PSU (2010); data presented in EPA (2010c).

CO_2 = carbon dioxide, kg = kilogram, MJ = megajoule.

Recent reports (Oil Change International 2013; Gordon 2012) have critiqued existing LCA studies for allocating GHG emissions from producing and combusting petroleum coke outside the study boundaries, or for assuming that petroleum coke combustion substitutes or offsets the combustion of coal. Defined pathways for individual products are the cornerstone of LCA, and must be appropriate to the goal and scope of the study. For example, NETL excluded GHG emissions from petroleum coke production and combustion because they are outside the boundary of premium fuel products (i.e., gasoline, diesel, and kerosene/jet fuel) (NETL 2008, 2009). This approach is consistent with the study's goal of estimating the contribution of crude oil sources to the 2005 baseline emissions profile for premium fuels.

Other life-cycle studies do not exclude the GHG emissions from the production and combustion of petroleum coke and other co-products that leave the system boundary. Instead, these studies typically apply a substitution credit for the fuels that are offset in other markets by the use of petroleum coke and other co-products. To calculate the credit, studies generally assume one-to-one substitution on an energy basis (i.e., one Btu of coal is offset by one Btu of petroleum coke). Although some studies have assumed that the net GHG emissions from offsetting coal for coke are negligible, other studies have accounted for the fact that petroleum coke has a higher CO_2 intensity on an energy basis when compared to bituminous and sub-bituminous coal. For example, Jacobs (2009) found this net difference to be approximately 8 gCO_2/MJ (plus a small, unspecified adjustment to account for transportation of coke versus coal) (p. 8-3); the most recent Jacobs report (Jacobs 2012, p. 9-12) assumed that offsetting coal combustion with petroleum coke results in a small incremental net increase of approximately 2 gCO_2/MJ.

Since the treatment of petroleum coke and other co-products has a large effect on WTW GHG emissions, it is important to ensure that consistent system boundaries are applied when comparing GHG emissions from WCSB oil sands crudes to other reference crudes. For example, the GHG emissions from oil sands extraction and upgrading have been estimated as 3.2 to 4.5 times higher than conventional oil production (Oil Change International 2013; Huot 2011), but this comparison does not describe entirely equivalent crude oil types. The upstream LCA stage for oil sands includes the process of upgrading, which removes the heavy coke bottom of the crude barrel. For conventional crudes, the extraction stage does not contain the equivalent process of upgrading or coking; instead, for conventional crudes the coking process occurs within the refining stage.

Since the boundaries across different LCA studies differ depending on the goal and scope of a particular study, the change in WTW emissions from oil sands crudes relative to other reference crudes are compared on an internally-consistent basis (i.e., by comparing the relative change within studies, not across different studies) in Figures 4-6, 4-7, and 6-1, and in Section 6.

Virtually all crude oils, light, medium, and heavy, including bitumen, contain a fraction of the raw oil out of the ground that does not boil even under full vacuum conditions. This fraction, called vacuum residuum will thermally destruct into lower molecular weight hydrocarbon compounds and elemental carbon when heated above about 800°F. This fraction is commonly used for three products: asphalt, residual fuel oil (called No. 6 fuel oil or bunker fuel) and petroleum coke production. The coking process takes advantage of the thermal destruction nature of vacuum residuum by heating the oil above the thermal destruction temperature and quickly discharging the hot oil into a drum where the hydrocarbons exit the top as vapors and the elemental carbon settles to the bottom as petroleum coke.

Canadian oil sands bitumen contains about 40 percent vacuum residuum fraction. When this bitumen is blended with 30 percent diluent, creating what is referred to as dilbit, the dilbit contains about 30 percent vacuum residuum fraction. Venezuelan Bachaquero crude contains about 40 percent vacuum residuum, and Arab Light crude contains about 20 percent vacuum residuum. So the vacuum residuum of Canadian oil sands bitumen is within the range of crude oils commonly refined in the Gulf Coast which is the proposed destination of Canadian oil sands crudes.

Domestic petroleum coke consumption in the United States is unlikely to significantly increase, so petroleum coke exports are likely to continue, with China remaining a large importer of U.S. petroleum coke to meet its domestic energy demands. Since the U.S. EPA specified sulfur limits on No. 6 fuel oil (which are very hard and expensive to achieve in anything but low sulfur crude oils), the U.S. electrical power industry largely abandoned use of No. 6 fuel oil for electricity generation. This limitation of sulfur in fuel oil did not solve the acid rain air pollution problem in the Northeastern United States, so the U.S. EPA specified SOx emissions controls on coal-fired power plants. Flue gas stack scrubbers remove the SOx, and hence, the acid rain problem is largely resolved today. Nevertheless, No. 6 fuel oil has not re-entered the power generation market because refineries have installed coking units to convert No. 6 fuel oil into petroleum coke.

While coke can be used as a supplement to coal in electrical power plants, with declining reliance on coal and long term contracts with coal suppliers, petroleum coke has not significantly penetrated the U.S. power plant industry. For example, in 2011, petroleum coke consumption was equivalent to 0.5 percent of coal consumption for electricity generation across all sectors (EIA 2012a). Most of the Gulf Coast coke is exported to markets in China, Japan, and Mexico, which accounted for 35 percent of all exports in 2011 (EIA 2012b). China was the single largest importer of U.S. petroleum coke, accounting for approximately 14 percent of U.S. exports (EIA 2012b).

The sulfur content of petroleum coke in the United States is a consideration for coal-fired power plants as they must control SOx emissions with flue gas scrubbers. Consideration is also given to the sulfur content of No. 6 fuel oil, but the power industry is converting to plentiful and inexpensive natural gas, and the coking assets are in place to process virtually all vacuum residuum that is not destined to the asphalt market.

The proposed Project will transport an approximate 50/50 mix of SCO and dilbit. Petroleum coke from the bitumen upgraded into SCO is produced at Canadian upgraders. A significant portion of this petroleum coke—approximately 50 to 75 percent (ERCB 2010; Oil Change International 2013, citing Alberta ERCB)—is currently stockpiled because it faces the same barriers to penetrate the Canadian coal-fired power plant market as does petroleum coke in the United States; it cannot be economically transported by rail for export to overseas markets.

The dilbit half of the proposed Project's throughput would be transported to Gulf Coast refineries where it would produce approximately the same quantities of petroleum coke as other heavy reference crudes such as Venezuelan Bachaquero and Mexican Maya. So of the proposed Project's total WCSB oil sands throughput, slightly more than half the petroleum coke is produced in Canada, where approximately 50 to 75 percent of it is currently stockpiled and the rest substituted for other fuels in the production and upgrader process. The rest of the petroleum coke (all that is produced from the dilbit fraction and none in the SCO) is produced at Gulf Coast refineries where it is used as a fuel in domestic or overseas markets.

Petroleum refineries attempt to maximize the use of all assets. So Gulf Coast refineries will choose blends of Canadian oil sands crudes (dilbit, SCO, synbit) with other domestic and imported crudes to fill out the refinery assets including the coker units. Hence, approximately the same quantity of petroleum coke would be produced from a mix of crudes that backs out imported crude oils such as Mexican Maya, Venezuelan Bachequero, and Saudi Arabian Light crudes. The coke produced from Canadian oil sands crudes would be marketed the same as current coke: most of it would be exported, with China being a large importer of U.S. petroleum coke.

The petroleum coke-associated GHG emissions from oil sands should fundamentally be similar to some heavy reference crudes given the following:

- Accounting for the non-combustion for perhaps half the upgrader petroleum coke manufacture;
- The combustion of coke manufactured from reference crude oils (including transportation to the China market);
- The lower refining emissions of SCO (because all the residuum processing was done at the upgrader); and
- The likely transportation of displaced reference crudes to alternative markets (e.g. Mexican Maya transported 10,000 miles to China rather than 700 miles to the Gulf Coast).

The oil sands petroleum coke-associated GHG emissions will likely be higher than the U.S. average barrel especially with rapidly expanding shale oil production in North America.

While certain LCA studies developed detailed data models of oil sands production, processing, transport and refining processes, including petroleum coke, they do not have access to the detailed data of the processes used to produce other reference crudes. For example, all conventional crudes, such as Saudi Arab Light and most of U.S. production prior to the shale oil boom are in various stages of declining production, requiring enhanced production techniques with larger energy intensities per barrel of oil produced. As a result, the conventional crude production carbon intensity can be expected to trend upward, whereas the WCSB oil sands carbon intensity can be expected to be relatively flat since the deposits are shallow, they can be extracted using mining or near-surface in situ methods, and new production methods could potentially reduce the energy intensity. Even Saudi Arab Light crude from the giant Ghawar field in Saudi Arabia, which is produced with a 10-million barrel per day water flood pumped from the Arabian Gulf, is rapidly increasing in water cut, such that in 10 years it is possible that oil sands will be less energy intensive, well to wheels, than Saudi Arab Light delivered to the same Gulf Coast destination. A large share of Gulf Coast petroleum coke is shipped to China because:

- It is less expensive, including the shipping, than China’s coal; and
- China is struggling to keep pace with its rapidly growing economy with equally rapid coal production growth.

Coal accounted for nearly half the increase in global energy use over the past decade, and China was responsible for nearly half of global coal use in 2009 (IEA 2011). China, as well as India, are expected to lead in energy consumption growth in non-OECD[28] Asian regions, which is projected to rise by 91 percent from 2010 to 2035 (EIA 2012c).

At the same time, Mexico, Venezuela, and other large petroleum producers depend heavily on their crude oil exports to support their national economies. Just as Section 1.4, Market Analysis, found it unlikely that the proposed Project construction would have a substantial impact on the rate of oil sands development, these other petroleum producers are unlikely to forego crude oil sales if the U.S. substitutes Canadian oil sands crudes for Mexican and Venezuelan crudes. They can be expected to sell their crudes for whatever price the market will bear, and that would likely be to China. Similarly, all the production and transportation assets are in place for Saudi Arabia to supply the crude oil displaced from the U.S. market to any country in the world who will buy it.

Expanding electrical power generation in China is easier and more cost-effective with No. 6 fuel oil than coal. Both No. 6 fuel oil and coal have high sulfur contents, and China has significant air pollution problems primarily from coal power plants. So when China chooses to invest in a solution to air pollution, installing power plant flue gas scrubbers is a leading option. That will make No. 6 fuel oil equally suitable for power generation, but more economical in new power plants than coal. Therefore, it is more likely that worldwide crude oils displaced from the Gulf Coast refineries with Canadian oil sands crudes, will find their way to China, along with roughly the same amount of petroleum coke from the Gulf Coast, both displacing coal production in China.

[28] Organization for Economic Cooperation and Development.

Supplementing the worldwide crude oil market, Canadian oil sands crude would more likely substitute for expanded coal production in China rather than expand the use of solid carbon fuels (coal and coke) used in power generation in North America or China. With the discovery of economic production of light, sweet crude oils from hydraulic fracturing shale, the combination of expanded light U.S. crude and heavy Canadian oil sands production will likely not alter petroleum refining assets in the Gulf Coast with regard to coking capacity. Refineries designed to run primarily heavy crudes may have to add facilities to pre-distill light ends from light shale oil crudes, but the remaining secondary units of the refineries (vacuum distillation unit, gas oil cracking, coking, and hydrotreating distillate products) can be protected like any asset in place. In fact, the U.S. petroleum refining industry is gradually shrinking with competition from renewable energy (ethanol, wind, biodiesel) and natural gas entry into traditional crude oil transportation fuel markets. Refineries are projected to close down, and only selective capacity additions for processing expanded shale oil crude oils in conjunction with Canadian oil sands can be expected in the most profitable, large refineries.

6.0 INCREMENTAL GHG EMISSIONS OF DISPLACING REFERENCE CRUDES WITH WCSB OIL SANDS

As noted in Section 1.4 of the Supplemental EIS, the proposed Project would not substantially influence the rate or magnitude of oil extraction activities in Canada, or the overall volume of crude oil transported to the United States or refined in the United States. Thus, from a global perspective, the decision whether or not to build the Project will not affect the extraction and combustion of WCSB oil sands crude on the global market. However, on a life-cycle basis and compared with reference crudes refined in the United States, oil sands crudes could result in an increase in incremental GHG emissions.[29] Although a life-cycle analysis is not strictly necessary for purposes of evaluating the potential environmental impacts attributable to the proposed Project under NEPA, it is relevant and informative for policy-makers to consider in a variety of contexts.

For illustrative purposes, this Appendix provides information on the incremental life-cycle GHG emissions (in terms of the U.S. carbon footprint) from WCSB oil sands crudes likely to be transported by the proposed Project (or any transboundary pipeline). The incremental emissions are a function of:

- The throughput of the pipeline;
- The mix of oil sands crudes transported by the pipeline; and
- The GHG-intensity of the crudes in the pipeline compared to the crudes they displace.

[29] Note that a substantial share of these emissions would occur outside the United States. Also note that the U.S. National Inventory Report, like other national inventories, only characterizes emissions within the national border, rather than using a life-cycle approach. If the United States used a life-cycle approach, upstream emissions from other imported crudes would be attributed to the United States.

Acknowledging the methodological differences in GHG-intensity estimates between the studies, this section estimates weighted-average GHG emissions from WCSB oil sands crudes for a subset of the studies reviewed. The weighted-average results are used to estimate incremental GHG emissions from WCSB oil sands relative to displacing an equivalent volume of reference crudes in U.S. refineries.

6.1 WEIGHTED-AVERAGE GHG EMISSIONS FROM WCSB OIL SANDS CRUDES TRANSPORTED IN THE PROPOSED PROJECT

While Figure 4-5 and Figure 4-7 indicate the full range of life-cycle GHG emissions estimates associated with individual methods of oil sands production, the actual life-cycle GHG emissions of WCSB oil sands crude that would be imported by the proposed Project or a similar transboundary pipeline to the United States would be a weighted-average mix of crudes produced using different methods of extraction, upgrading or diluting, and petroleum coke management practices. For example, IHS CERA (2010) assumed an average 55 percent dilbit and 45 percent SCO for WCSB oil sands imported to United States, and NETL (2008) assumed 57 percent SCO and 43 percent crude bitumen.[30] In the Supplemental EIS, the Department assumes that the average crude oil flowing through the pipeline would consist of about 50 percent Western Canadian Select (dilbit) and 50 percent Suncor Synthetic A (SCO).

Estimating an average oil sands value allows for direct comparison with other average reference crude estimates, but it is difficult to characterize the average mix for WCSB oil sands due to the various: (i) methods of producing bitumen from oil sands deposits (i.e., mining versus in situ), (ii) fuel sources used (e.g., petroleum coke combustion versus natural gas import and electricity export), and (iii) products produced from these operations (i.e., dilbit, synbit, and SCO). The average mix of WCSB oil sands production will also change over time depending on factors such as the share of in situ extraction relative to mining, the use of coke as a fuel source, and upgrading capacity.

ICF applied the following method to develop a weighted-average estimate for WCSB oil sands crudes likely to be transported in the proposed Project. First, a subset of studies was established that provided sufficient information to develop a weighted-average GHG estimate for WCSB oil sands. Next, an estimated mix of WCSB oil sands crudes likely transported by the proposed Project in the near-term was developed. Finally, the studies' WTW GHG emission estimates for different WCSB oil sands crudes were applied to the mix of crudes likely to be transported by the proposed Project to calculate a weighted-average for WCSB oil sands crude for each study.

[30] There is a synergy between the two methods for producing and transporting bitumen down the pipeline in that the SCO upgrader produces steam and electricity that can be used in the SAGD process while mining is more energy-efficient in extracting bitumen from the field.

Only a subset of the studies included in this assessment provides sufficient information to develop a weighted-average GHG estimate for WCSB oil sands crude. To define sufficient information, the following criteria were applied:

- Study includes the WCSB oil sands crude types that are likely to be transported in the proposed Project. A 50/50 split between SCO and dilbit was assumed for consistency with the Final EIS.
- Study evaluates the full WTW life-cycle. Studies that evaluated only a portion of the life cycle (e.g., only WTR or up to the refinery gate) cannot be accurately compared with other studies on a full life-cycle basis.
- Study is a unique, original analyses, independent of other studies included in the review (i.e., not a meta-analysis of the same studies included in the review); several of the studies were meta-analyses that summarized or averaged the results from other studies already included in this review (e.g., IHS CERA [2010, 2011], Brandt [2011]).

The analysis also ensured that the studies used consistent functional units to evaluate WTW GHG emissions so that accurate comparisons could be made. Table 6-1 evaluates each of the studies included in this assessment against the criteria. Of the studies, Jacobs (2009), TIAX (2009), and NETL (2008, 2009) provided sufficient independent information to develop internally-consistent averages for the mix of WCSB oil sands crudes likely to be transported by the proposed Project.

Table 6-1 Evaluation of Studies that Provided Sufficient Independent, Comprehensive Information to Develop Weighted-Average GHG Emissions Estimates for WCSB Oil Sands Crudes

Study	Type	Includes crudes likely transported by proposed Project	Evaluates full WTW GHG emissions	Does not average across same studies already included in review	Meets criteria
NETL 2008; 2009	Individual LCA	Y[1]	Y	Y	Y
IEA 2010[3]	Meta-analysis	N[2]	Y	N	N
IHS CERA, 2010	Meta-analysis	Y	Y	N	N
IHS CERA, 2011	Metal-analysis	Y	Y	N	N
NRDC, 2010	Meta-analysis	Y	Y	N	N
ICCT, 2010	Individual LCA	N[4]	N[5]	Y	N
Jacobs, 2009	Individual LCA	Y	Y	Y	Y
Jacobs, 2012	Individual LCA	Y	Y	Y	Y[7]
TIAX, 2009	Individual LCA	Y	Y	Y	Y
Charpentier et al., 2009	Meta-analysis	N[6]	Y	N	N
Brandt, 2011	Meta-analysis	Y	Y	N	N
RAND, 2008	Individual LCA	N[7]	N[8]	N	N
Pembina Institute, 2005	Partial LCA	N[9]	N[10]	Y	N
Pembina Institute, 2006	Partial LCA	N[11]	N[10]	Y	N
McCann, 2001	Individual LCA	N[12]	Y	Y	N
GHGenius, 2010	Model	N[13]	Y	Y	N
GREET, 2010	Model	N[14]	Y	Y	N

Study	Type	Includes crudes likely transported by proposed Project	Evaluates full WTW GHG emissions	Does not average across same studies already included in review	Meets criteria
Rooney et al., 2012	Land use change journal article	N[16]	N[16]	Y	N
Yeh et al., 2010	Land use change journal article	N[17]	N[17]	Y	N

[1] NETL assumed a mix of 43 percent blended bitumen and 57 percent SCO, and used crude bitumen as a proxy for the blended bitumen component.
[2] IEA includes estimates for high/low in situ and mining. Does not specify SCO or dilbit crude types.
[3] IEA results are compared on a per-barrel-of-crude basis.
[4] ICCT evaluates average mix of oil sands imported to Europe.
[5] ICCT GHG emissions include refining, but exclude final distribution of premium fuel products.
[6] Charpentier et al. did not evaluate dilbit as a crude pathway.
[7] RAND only evaluated SCO from WCSB oil sands.
[8] RAND only evaluated WTR GHG emissions.
[9] Pembina (2005) only evaluated oil sands average, but did not specify the composition.
[10] Pembina (2005, 2006) only evaluated WTR GHG emissions.
[11] Pembina (2006) only evaluated GHG emissions from SCO.
[12] McCann only evaluated GHG emissions from SCO.
[13] McCann results are compared on a per-1,000-liters-of-transportation fuel basis.
[14] GHGenius does not include a pathway for dilbit production; the model only includes bitumen ((S&T)[2] Consultants 2008b).
[15] Published estimates for SCO and dilbit from WCSB oil sands crudes were not located for GREET, and development of these factors was beyond the scope of this assessment.
[16] Rooney et al. (2012) only evaluated GHG emissions from local land-use change.
[17] Yeh et al. (2010) only evaluated GHG emissions from local land-use change and tailing ponds.

GHG = greenhouse gas LCA = life-cycle assessment, N = no, WTW = well-to-wheels, Y = yes.

It is assumed that 50 percent of pipeline throughput will be SCO, and 50 percent will be dilbit (as discussed in the Supplemental EIS). According to the Alberta Energy Resources Conservation Board (ERCB 2010), all WCSB dilbit is currently produced using in situ production. All WCSB bitumen produced from mining is upgraded to SCO and 12 percent of SCO is produced via in situ methods (ERCB 2010, pp. 2-18, 2-24). Applying this production mix to a 50/50 split of SCO and dilbit yields an estimated mix of 50 percent in situ-produced dilbit, 44 percent mining-produced SCO, and 6 percent in situ-produced SCO transported in the proposed Project.

WTW GHG emissions for in situ dilbit, in situ SCO was evaluated, and mining SCO in Jacobs (2009) and TIAX (2009) using the following assumptions:

- For Jacobs (2009):
  - In situ SCO: The average of SAGD SCO from delayed coking and ebulating bed hydrocracking for WTW GHG emissions was used. Jacobs (2009) did not provide estimates for other types of in situ production methods, and assumed that all petroleum coke is stockpiled or buried at WCSB oil sands facilities.
  - In situ dilbit: Jacob's estimate for WTW GHG emissions from SAGD dilbit, assuming diluent is consumed at the refinery, was applied. Recirculation of diluent to Alberta was not included since diluent will not be recirculated by the proposed Project.
  - Mining SCO: Jacob's estimate for mining SCO from delayed coking was used.

- For TIAX (2009):
  - In situ SCO: A weighted average of WTW GHG emissions from SAGD SCO where petroleum coke is buried (i.e., TIAX's bury coke scenario), and where it is used as a fuel (i.e., TIAX's use coke scenario) was taken. It was assumed that 75 percent of petroleum coke is stockpiled, and 25 percent is used as fuel, based on data from ERCB (ERCB 2010, p. 2-30).[31]
  - In situ dilbit: The average of TIAX's WTW GHG emissions estimates for facilities that export electricity and do not export electricity was taken. A weighted average was calculated between dilbit from SAGD and CSS facilities, assuming 53 percent SAGD and 47 percent dilbit, based on ERCB (ERCB 2010, p. 2-22).[32]
  - Mining SCO: TIAX's estimate for mining SCO was used, assuming that all petroleum coke is buried. TIAX did not investigate a scenario where petroleum coke produced from mining SCO is used as a fuel.
- For NETL (2008):
  - Because NETL provided an average Canadian oil sands value assuming a 43 percent mix of blended bitumen and 57 percent SCO, it was not necessary to calculate a weighted average, though as a result the underlying GHG intensities are not on an equal mathematical footing with the values computed from the Jacobs and TIAX studies. Because the NETL study did not decompose the value into its constituent parts, it was not possible to adjust the underlying percentages to represent the same pipeline mix.

Table 6-2 provides the WTW GHG emission estimates in each study for the weighted-average WCSB oil sands crude likely to be transported in the proposed Project and the other reference crudes included in the scope of this assessment. These results are near-term averages for WCSB oil sands crudes likely to be transported in the proposed Project. They are based on current industry-average production mixes and practices, which are likely to change over time.

---

[31] Based on industry-average practices reported by ERCB (ERCB 2010, pp. 2-24, 2-30). Petroleum coke is produced at upgraders operated by Suncor Energy Inc., Syncrude Canada Ltd., Canadian Natural Resources Ltd. (CNRL), and Nexen Inc. Suncor represents 45 percent of SCO production from these facilities and uses roughly 26 percent of its petroleum coke as fuel, with 7 percent sold to other sources. Syncrude represents 46 percent of SCO production and uses 21 percent of petroleum coke as fuel. CNRL represents 8 percent of SCO production and stockpiles all of its coke. Nexen represents 1 percent of SCO production and gasifies all its coke for process heat and hydrogen production. Weighting coke management practices by SCO production for each facility yields a coke stockpiling-to-use ratio of 75 to 25 percent across all facilities.

[32] According to ERCB, of *in situ* bitumen produced from SAGD and CSS, SAGD represented 53 percent of production in 2009, and CSS accounted for 47 percent of production (ERCB 2010, p. 2-22). Primary production of bitumen (i.e., using conventional oil production techniques) accounted for 32.9 thousand m^3 per day, or 14 percent of total oil sands production in 2009, but was not included since GHG emission estimates for this production method were not provided in the studies included in the scope of this assessment.

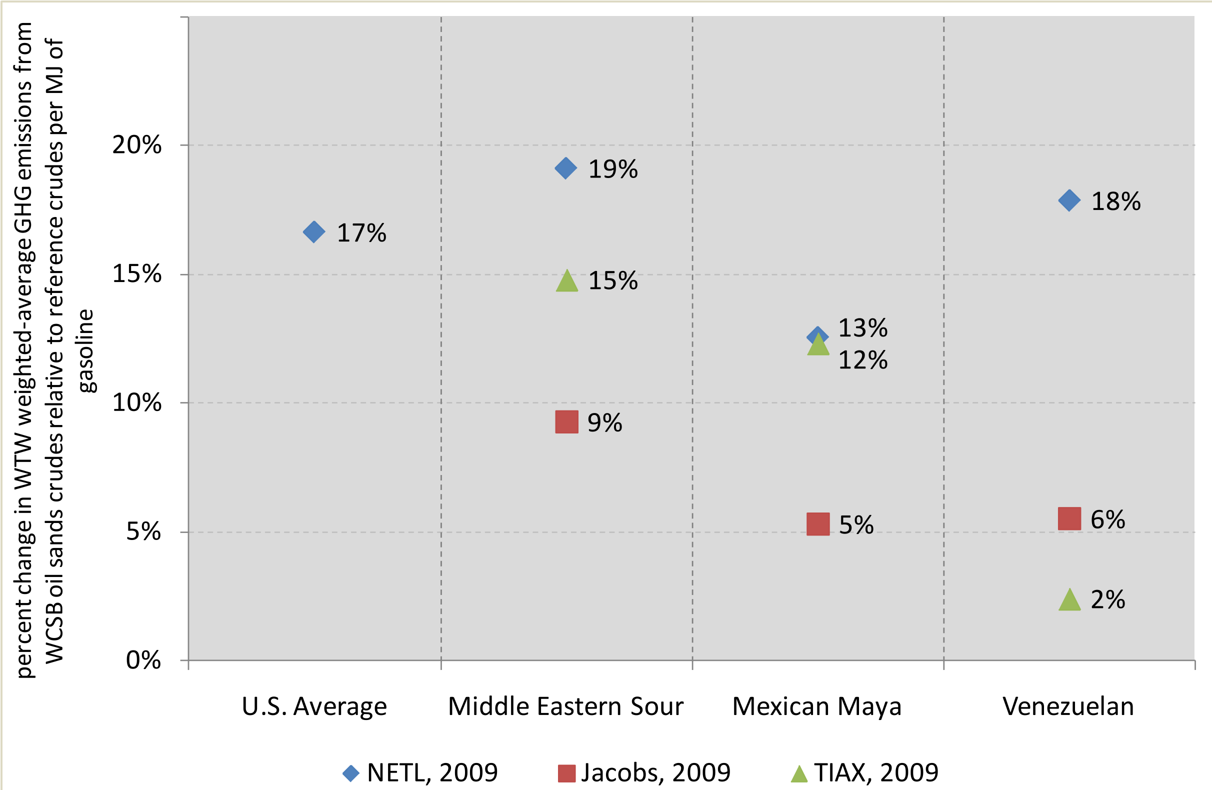
Table 6-2 WTW GHG Emissions Estimates for Weighted-Average WCSB Oil Sands Crude Likely to be Transported in the Proposed Project and Other Reference Crudes, by Study

Study	Crude type	WTW GHG Emissions gCO_2 per MJ (LHV)		
		Gasoline	Diesel	Kerosene/Jet Fuel
Jacobs 2009	WCSB oil sands (average)[2]	107 / 109[3]	105	N/A
	In situ SCO	118 / 117[3]	114	N/A
	In situ dilbit	106 / 108[3]	103	N/A
	Mining SCO	108 / 108[3]	105	N/A
	Middle Eastern Sour	98 / 99[3]	98	N/A
	Mexican Maya	102 / 102[3]	103	N/A
	Venezuelan	102 / 102[3]	100	N/A
TIAX 2009	WCSB oil sands (average)[2]	104	95	N/A
	In situ SCO	115	109	N/A
	In situ dilbit	105	96	N/A
	Mining SCO	102	92	N/A
	Middle Eastern Sour	91	83	N/A
	Mexican Maya	93	86	N/A
	Venezuelan	102	91	N/A
NETL 2008, 2009	WCSB oil sands (average)	106	105	102
	U.S. Average (2005)	91	90	88
	Middle Eastern Sour	89	89	86
	Mexican Maya	94	96	91
	Venezuelan[1]	90	90	87

[1]Venezuela Conventional is used as the NETL reference crude for Venezuela Bachaquero in this analysis; this is a medium crude, not a heavy crude.
[2] Weighted-average of WCSB oil sands crudes, assuming 50 percent in situ-produced dilbit, 44 percent mining-produced SCO, and 6 percent in situ-produced SCO.
[3] Jacobs (2009) provided results in terms of reformulated blendstock for gasoline blending (RBOB) and conventional blendstock for gasoline blending (CBOB); the results for gasoline are given here as RBOB/CBOB.

GHG = greenhouse gas, N/A = Estimates not available from study, gCO_2 per MJ = grams carbon dioxide per megajoule, LHV = lower heating value, SCO = synthetic crude oil, WCSB = Western Canadian Sedimentary Basin, WTW = well-to-wheels.

Figure 6-1 indicates the GHG intensity of crudes likely to be transported in the proposed Project relative to each of the four reference crudes on a gasoline basis. Across all reference crude types, the results show a 2 to 19 percent increase in WTW GHG emissions from the weighted-average mix of oil sands crudes expected to be transported in the proposed Project relative to the reference crudes in the near term. Heavier crudes generally take more energy to produce and emit more GHGs than lighter crudes, and in particular, the weighted-average WCSB oil sands crude is currently more energy- and carbon-intensive than lighter crudes like Middle Eastern Sour. Although the three studies have underlying differences in assumptions, the comparisons illustrated in Figure 5-1 are internally consistent in that they make comparisons between crudes from the same study.



Sources: NETL 2009, Jacobs 2009, TIAX 2009

Notes:

1. In this chart, all emissions are per megajoule of reformulated gasoline with the exception of NETL 2009, which is per megajoule of conventional gasoline.
2. Venezuela Conventional is used as the NETL reference crude for Venezuela Bachaquero in this analysis; this is a medium crude, not a heavy crude; thus, the NETL values are compared against a lighter Venezuelan reference crude than other studies.
3. The percent differentials refer to results for scenarios from the various studies and are calculated using the oil sands results relative to the corresponding study's reference crude.

GHG = greenhouse gas, WCSB = Western Canadian Sedimentary Basin, WTW = well-to-wheels.

Figure 6-1 Percent change in near-term WTW weighted-average GHG emissions from the mix of WCSB oil sands crudes that may be transported in the proposed Project relative to reference crudes

6.2 Incremental GHG Emissions from Displacing Reference Crudes With WCSB Oil Sands Crudes in U.S. Refineries

This section applies weighted-average WTW GHG emissions for WCSB oil sands crude to the expected initial and potential capacities of the proposed Project to calculate the potential total WTW GHG emissions added to the U.S. carbon footprint, on a life-cycle basis, from the crude transported by the proposed Project. This is compared against the WTW GHG emissions from an equivalent volume of each of the four reference crudes (i.e., U.S. average in 2005, Middle Eastern Sour, Mexican Maya, and Venezuelan Bachaquero) to calculate the total incremental GHG emissions from displacing these reference crudes with WCSB oil sands in U.S. refineries.

These results only consider the effect of displacing these reference crudes in U.S. refineries; they do not estimate how global markets for WCSB oil sands crudes would be affected by the proposed Project. This is discussed elsewhere in the Supplemental EIS.

In order to assess the total WTW GHG emissions associated with weighted-average WCSB oil sands crudes likely to be transported in the proposed Project, it is necessary to account for the various refined products produced from the crude. Therefore, the crude pipeline capacity was converted from barrels of crude to an equivalent yield of gasoline and distillate products (i.e., the functional unit of per barrel of premium refined fuel products) using the data provided in Table 6-3 for each respective study. NETL and TIAX provide average U.S. refinery yields of gasoline and distillates, whereas Jacobs provides yields for individual crudes, including WCSB SCO and dilbit.

Table 6-3 Yield of Gasoline and Distillates and Equivalent Barrels of Gasoline and Distillates from 100,000 Barrels of Crude Oil ($MMTCO_2e$)

Study[1]	Yield of gasoline and distillates[2] per barrel of crude oil	Equivalent barrels of gasoline and distillates produced from 100,000 barrels of crude oil	Source
Jacobs	95%	94,738	Jacobs 2009, p. 5-18
TIAX	82%	82,114	TIAX 2009, p. E-1
NETL	77%	77,000	NETL 2008, p. 83

[1] The NETL and TIAX yields are based on average U.S. refinery product yields, whereas the Jacobs yield is based on the product yield from refining SCO and dilbit crudes.
[2] The yield of gasoline and distillates (i.e., premium fuel products) is calculated for each study as the total volume of gasoline, diesel, and kerosene or kerosene-based jet fuel, divided by total refinery output.

$MMTCO_2e$ = million metric tons carbon dioxide equivalent.

The WTW GHG intensity of weighted-average WCSB oil sands crude likely to be transported in the proposed Project and other reference crudes are shown in Table 6-2 in terms of the functional unit of per megajoule of gasoline, diesel, and jet fuel products. The GHG intensities are converted to a weighted-average functional unit of barrels of gasoline and distillates (i.e., the total sum of gasoline, diesel, and jet fuel products) based on the relative yield of gasoline and distillates from each study.[33,34]

With similar functional units (i.e., barrels of gasoline and distillates) of the crude transported via the proposed Project and the weighted average WTW GHG emissions associated with oil sands crudes production, total WTW GHG emissions are calculated based on operational volume capacities of the pipeline. Similarly, the WTW GHG emissions associated with reference crudes is calculated in terms of the functional unit of barrels of gasoline and distillate yield based on operational volume capacities of the pipeline.

[33] For NETL, the relative yield of gasoline, diesel, and kerosene/jet fuel as a percentage of gasoline and distillates is 58%, 30%, and 12% respectively based on the volumetric fraction of total refinery production (NETL 2008, Table 4-54). For Jacobs, the relative yield of RBOB, CBOB, and diesel was calculated for each crude based on the refinery product yields in Table 5-4 (2009, p. 5-18). For TIAX, the relative yield of gasoline, diesel, and jet fuel is 57%, 32%, and 11% respectively, based on the U.S. average modeling results provided in Table E-1 (2009, p. E-1).
[34] Since TIAX did not provide GHG intensity results for jet fuel, ICF calculated the weighted-average assuming that the GHG intensity was similar to diesel on an energy basis, and using the energy content values for diesel and jet fuel in Table E-1.

Using the weighted-average estimate for the mix of WCSB oil sands crudes likely to be transported in the proposed Project, the incremental annual WTW GHG emissions associated with displacement of 100,000 barrels of each reference crude oil per day with WCSB oil sands crude oil are shown in Table 6-4. The incremental GHG emissions were calculated by subtracting from the WTW GHG emissions an equivalent displaced volume of each reference crude..

Table 6-4 Incremental Annual GHG Emissions of Displacing 100,000 Barrels per Day of each Reference Crude with WCSB Oil Sands ($MMTCO_2e$)

Reference Crude	Jacobs, 2009	TIAX, 2009[1]	NETL, 2009[1]
Middle Eastern Sour	1.3	2.0	2.5
Mexican Maya	0.5	1.6	1.7
Venezuelan2	0.4	0.5	2.4
U.S. Average (2005)	NA	NA	2.3

Note: The incremental annual GHG emissions presented here are calculated using internally consistent comparisons for each reference crude and the weighted average WCSB oil sands crude using information from each respective each study. The incremental annual GHG emissions estimates for displacing the U.S. average (2005) reference crude is only provided for NETL (2009) because only NETL included a U.S. average reference.

[1] The NETL and TIAX studies allocate a portion of GHG emission to co-products other than gasoline, diesel, and jet fuel products, which are not accounted for in these estimates. As a result, incremental GHG emissions are underestimated for those studies.

[2] Venezuelan conventional crude values for NETL refer to a medium crude, not the heavy crude Venezuelan Bachaquero.

NA = not applicable, $MMTCO_2e$ = million metric tons carbon dioxide equivalent, WCSB = Western Canadian Sedimentary Basin.

The incremental GHG emissions in Table 6-4 are compared against four different reference crude oils. To the extent that Middle Eastern Sour is the world balancing crude, it may ultimately be the crude that is backed out of the world market by WCSB oil sands crudes. From another perspective, if the proposed Project is built and the PADD III refineries continue using about the same input mix of heavy crudes as they currently use, Venezuelan Bachaquero or Mexican Mayan are likely to be displaced by WCSB oil sand crudes. Finally, NETL (2009) estimated the GHG emissions intensity of the average barrel of crude oil refined in the United States in 2005. The Jacobs and TIAX studies are not compared to this reference crude because they did not include a U.S. average estimate.

The three studies referenced in Table 6-4 used different methods to allocate GHG emissions between premium fuels (e.g., gasoline, diesel, and jet fuel) and other co-products (e.g., light and heavy ends, petroleum coke, sulfur). Jacobs (2009) attributes all GHG emissions associated with extracting, refining, and distributing other co-products to premium fuels,[35] so the incremental GHG emissions for Jacobs (2009) in Table 5-4 do take into account the production and use of these co-products.

As noted elsewhere in the Supplemental EIS, the initial throughput of the proposed Project is projected to be 830,000 barrels of crude per day with 100,000 barrels per day supplied by Bakken crude production and the remaining 730,000 barrels per day supplied by the WCSB oil

[35] Jacobs (2009) also applies a substitution credit for offsetting other products that are replaced by each of the co-products. For example, the production and use of petroleum coke is assumed to offset GHG emissions from coal-fired electricity production.

sands. However, assuming that the full 830,000 bpd capacity of the pipeline is used to transport only WCSB crude, and based on the results in the Jacobs (2009) study, incremental GHG emissions from the proposed Project would be 11.1 million metric tons of CO_2 equivalent ($MMTCO_2e$) if the oil sands crude oil transported by the proposed Project offset an equivalent amount of Middle Eastern Sour crude oil. Incremental emissions would be 4.4 $MMTCO_2e$ annually if oil sands crude oil offset Mexican Maya crude oil and 3.7 $MMTCO_2e$ annually if Venezuela Bachaquero crude oil were offset.

Unlike the Jacobs study, the NETL and TIAX studies allocate a portion of GHG emissions to co-products other than gasoline, diesel, and jet fuel products, and these emissions are not included in the WTW GHG results shown in Table 6-2. As a result, the incremental GHG emissions estimates for TIAX and NETL in Table 5-4 may underestimate total incremental GHG emissions.[36]

TIAX found that the change in refinery energy use associated with an incremental barrel output of co-products other than gasoline, diesel, and jet fuel contributed to less than 1 percent of energy use and GHG emissions per barrel of refined product at the refinery, so any error introduced by the underestimate of GHG emissions attributed to co-products is negligible (TIAX 2009, p. 34; Appendix D, p. 42). According to the results of the TIAX study, incremental GHG emissions from the portion of WCSB oil sands crudes transported by the proposed Project would be 16.7 $MMTCO_2e$ if oil sands crude oil offset an equivalent amount of Middle Eastern Sour crude oil. Incremental emissions would be 13.4 $MMTCO_2e$ and 4.0 $MMTCO_2e$ annually if oil sands crudes offset Mexican Maya and Venezuelan Bachaquero crude oil, respectively.

Based on the results of NETL (2009), incremental emissions from the portion of WCSB oil sands crudes transported by the proposed Project would be 20.7 $MMTCO_2e$ annually if oil sands crude oil offset an equivalent amount of Middle Eastern Sour crude oil. Incremental emissions would be 13.8 $MMTCO_2e$ and 19.5 $MMTCO_2e$ annually if oil sands crudes offset Mexican Maya and Venezuelan Bachaquero crude oil, respectively. Compared to the average barrel of crude oil refined in the United States in 2005, incremental emissions from oil sands crudes would be 18.7 $MMTCO_2e$ annually. The effect of allocating a portion of the life-cycle GHG emissions of refining crude oils to other, non-premium co-products was larger in the NETL study than in either of the studies by Jacobs (which did not allocate any emissions to other co-products) or TIAX (which allocated less than 1 percent of GHG emissions at the refinery to other co-products). To estimate the magnitude of this effect, the NETL results for WCSB oil sands and the 2005 U.S. average crude oils were adjusted to include other product emissions modeled in NETL's analysis. The lead NETL study author was contacted to vet the approach used to make this adjustment in order to ensure that it was made consistently with the NETL study framework (Personal communication, Timothy Skone, 2011). Adjusting the NETL results to include other

[36] Adjusting the TIAX and NETL GHG emission estimates to include co-products other than gasoline, diesel, and kerosene/jet fuel would require two pieces of information: (i) the GHG intensity of the other products, for both WCSB crudes and reference crudes, and (ii) the yield of the other products, for both WCSB crudes and reference crudes. TIAX (2009) and NETL (2008) do not provide explicit emissions intensity factors or product yields in a format that enables separate emissions estimates to be developed for these products. These products largely comprise the remaining fractions of the input crude that cannot be converted into premium products, and take relatively little incremental energy and GHG emissions to produce.

product emissions could increase the differential in incremental emissions from displacing the 2005 U.S. mix of crude oils with WCSB oil sands crude by roughly 30 percent.

The full range of incremental GHG emissions associated with the displacement of the reference crudes by the WCSB oil sands crude estimated from the quoted subset of studies is 3.7 to 20.7 $MMTCO_2e$ annually. This is equivalent to annual GHG emissions from combusting fuels in approximately 770,800 to 4,312,500 passenger vehicles or the CO_2 emissions from combusting fuels used to provide the energy consumed by approximately 190,400 to 1,065,400 homes for one year.[37]

The increments presented here are based on life-cycle emission estimates for current or near-term conditions in the world oil market. Over time, however, the GHG emission estimates for fuels derived from both WCSB oil sands crude oils and the reference crude oils are likely to change. For instance, it will become more energy-intensive to produce reference crudes over time as fields mature and secondary and tertiary recovery techniques, such as CO_2 flooding are required to maintain production levels (see Section 4.2.2.1 Artificial Lift Assumptions).

At the same time, in situ extraction methods are projected to represent a larger share of the overall oil sands production – increasing from about 45 percent of 2009 oil sands production to an estimated 53 percent by 2030 (ERCB 2010). In particular, the share of SAGD in situ extraction methods are projected to rise from roughly 18 percent in 2009 to 40 percent of oil sands production in 2030 (IHS CERA 2011).[38] Although it is unclear how the GHG-intensity of reference crudes relative to WCSB oil sands crudes will change over time, it is likely that GHG intensity for future reference crudes will trend upward at a slightly faster rate than WCSB oil sands-derived crudes. If this is the case, the differential in WTW GHG emissions of WCSB oil sands crudes is likely to decrease relative to reference crudes.

7.0 KEY FINDINGS

Life cycle assessment is a useful analytical tool for evaluating the climate change implications of refining one fuel source in the United States relative to another. It is suitable for this application because it allows for a more complete understanding of the climate change impacts. The GHGs associated with extraction of crude from a reservoir through refined fuel combustion in vehicles can be expressed in a single metric of CO_2-equivalent GHG emissions per unit of transportation fuel; the emissions have the same effect on global climate change regardless of where they are emitted (e.g., whether in Alberta, Saudi Arabia, Venezuela, or Mexico during crude production and widely dispersed during fuel combustion). In addition, LCA has a precedent and regulatory standing in similar fuel-related policy issues, such as USEPA's Renewable Fuel Standard (RFS2) and the State of California's Low Carbon Fuel Standard (LCFS).

Applying LCA to petroleum systems is at the cutting-edge of LCA state of the art. The complex life cycle of fuels requires the consideration of a large number of analytical design issues. As

[37] Equivalencies based on USEPA's GHG Equivalency calculator available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html

[38] Although the balance of mining and *in situ* extraction will change in the future, there are incentives for producers to keep GHG intensity as low as possible. For example, Alberta's climate policy requires that oil sands producers and other large industrial GHG emitters reduce their emissions intensity by 12 percent from an established baseline.

discussed in Section 4.1, Study Design Factors, these include developing rules for how to handle co-products (Section 4.1.4, Allocation, Co-Products, and Offsets) within the study's system boundaries or to allocate the GHG emissions associated with production and use of these outputs outside the boundaries. The choice of functional unit (Section 4.1.5, Metrics), whether in terms of a barrel of crude, a barrel of refined premium fuel products (including or excluding co-products), or a barrel of a specific product such as gasoline or diesel, also influences the presentation of the results. Finally, the design life of the proposed Project and the likelihood of substantial changes in emissions intensity over time make the results sensitive to the study timeframe (Section 4.1.2, Time Period) and any assumptions used to forecast future trends in technology, fuel use, global oil supply, and extraction methods. It is necessary to be aware of each LCA study's treatment of these issues to understand the results and to make meaningful comparisons of the life-cycle GHGs from different crude sources.

In addition, information on a large number of individual inputs and assumptions (Section 4.2, Input and Modeling Assumptions) is necessary to capture the relative life-cycle GHG emissions between fuels in sufficient detail. In many cases, key information and data sources are proprietary or not otherwise publicly available, which reduces the quality or transparency (Section 4.3, Data Quality and Transparency) (and sometimes both) of the final results. This can make it difficult to resolve discrepancies between different studies or to identify the underlying drivers behind variation in the results of WTW LCAs.

Despite the wide variation in design, inputs, and assumptions within the LCA studies reviewed, several key findings emerge. The following findings are clearly supported by the LCA results:

1. WCSB crudes, as likely transported through the proposed Project, are on average more GHG-intensive than the crudes they would displace in the United States. In a comparison of the relative increase in weighted-average GHG emissions between WCSB oil sands-derived crudes that would likely be transported by the proposed Project and other reference crudes, each of the three most comprehensive and comparable WTW studies show that WCSB oil sands have higher life-cycle GHG emissions than the four reference crudes. The difference between WCSB oil sands and heavy Mexican and Venezuelan crudes is narrower than lighter crudes, such as Middle Eastern Sour. Thus, the life-cycle carbon footprint, for transportation fuels produced in U.S. refineries, would increase if the project were approved.
2. The Supplemental EIS examined the potential for growth-induced impacts that could be associated with the proposed Project in Section 1.4, Market Analysis, and it is unlikely that construction of the proposed Project would have a substantial impact on the rate of development of the WCSB oil sands. As described in Section 1.4, even when considering the incremental cost of non-pipeline transport options, should the proposed Project be denied, a 0.4 to 0.6 percent reduction in WCSB production could occur by 2030, and should both the proposed Project and all other proposed pipeline projects not be built, a 2 to 4 percent decrease in WCSB oil sands production could occur by 2030. Based on the market analysis in Section 1.4, the incremental life-cycle emissions associated with the proposed Project are estimated in the range of 0.07 to 0.83 $MMTCO_2e$ annually if the proposed Project were not built, and in the range of 0.35 to 5.3 $MMTCO_2e$ annually if all pipeline projects were denied, based on the following:

a. The full range of incremental GHG emissions associated with the more carbon-intensive WCSB oil sands that would be transported through the proposed Project across the analyzed reference crudes (which could be displaced at the Gulf Coast refineries) is estimated to range from 3.3 to 20.8 $MMTCO_2e$ annually (the methodology used to derive this range is explained further in this section).

b. If the proposed Project was not built, analysis demonstrates that WCSB oil sands would likely be developed, but there is potentially a 0.4 to 0.6 percent reduction in production, and if all other proposed pipeline projects were not built, there would potentially be a 2-4% reduction in WCSB oil sands production.

c. The range of GHG emissions represents the incremental GHG emissions for displacement of the analyzed reference crudes for the stated scenarios.

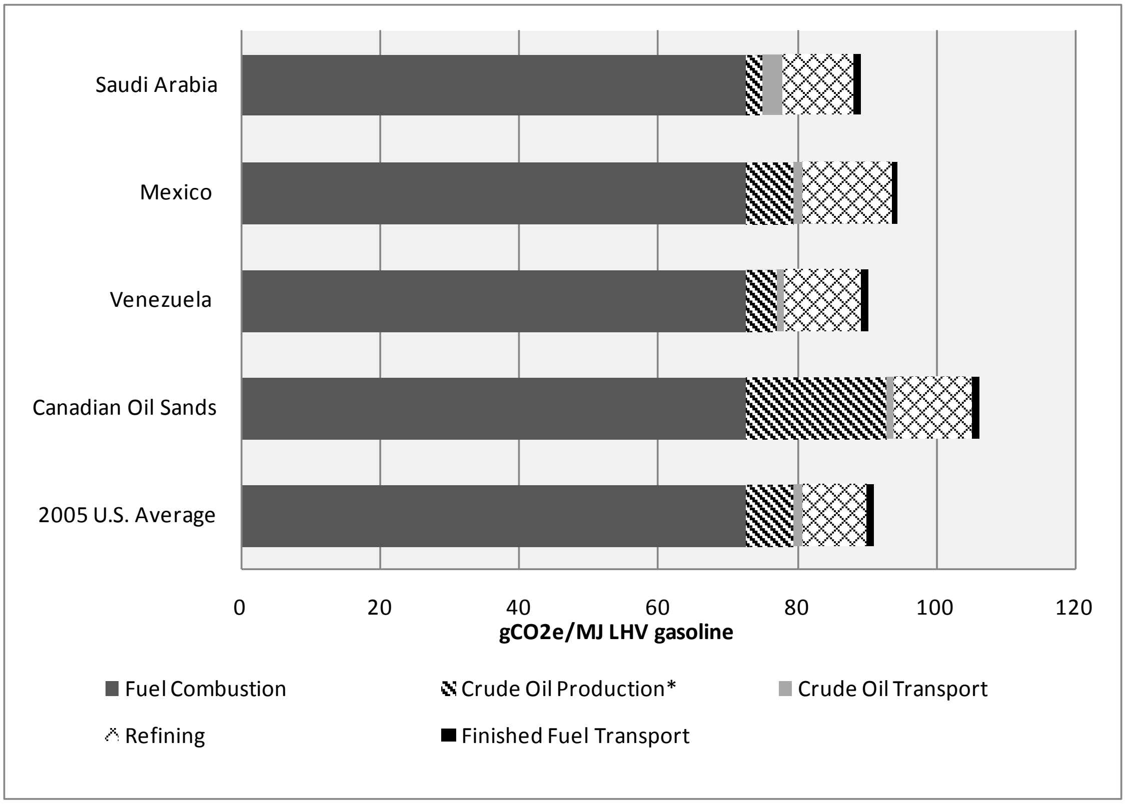
3. A large source of variance for a given crude across the studies is the treatment of lower-value products such as petroleum coke, electricity exports from cogeneration, and secondary carbon effects such as land-use change and capital equipment. The primary flows of energy and carbon from the premium fuel products produced at the refinery are generally well-understood and characterized across the various studies. In contrast, the treatment of lower-value products, electricity imports and exports, and secondary carbon flows varies widely across the various studies, as shown in Table 4-11. Many of these factors have a medium to large effect on WTW emissions. The different treatments of secondary flows contribute to a large portion of the variation in the results across the studies.

4. Upgrading bitumen to allow its flow through a pipeline shifts a portion of the GHG emissions from refining to further upstream in the life cycle, i.e., just prior to crude transport. Upgrading bitumen into SCO removes the light ends and heavy residuum ahead of transport to the refinery. As a result, a barrel of SCO will produce a greater quantity of premium products than a barrel of full-range reference crudes that have not been upgraded. Furthermore, a barrel of dilbit contains 30 percent diluents (that do not make significant contribution to gasoline) and 70 percent bitumen (with a high fraction of residuum, requiring a higher amount of energy-intensive coking to make gasoline and distillate fuels along with a higher fraction of petroleum coke than light crudes). Although a number of studies did not account for this effect, refinery models used by Jacobs (2009, 2012) and TIAX (2009) validated this result. Studies that do not account for the reduction in refinery energy use for SCO will overestimate the GHG emissions from SCO relative to other crude sources.

5. The relative GHG-intensity of both reference crudes and oil sands-derived crudes will change differently over time. The studies reviewed in this assessment represent a current snapshot of life-cycle emissions within the studies for given reference years, shown in Table 4-11. The life-cycle GHG emissions of both WCSB oil sands and reference crudes, however, will change differently over time. Conventional (deep) crude reservoirs require higher energy intensive secondary and tertiary production techniques as the reservoirs deplete and as water cut of the produced reservoir fluids increases, and even the best recovery techniques capture less than 50 percent of the original oil in place. Oil sands surface mining, given the vast aerial extent of the WCSB and that mining recovers 100 percent of the crude oil in place, is expected to have a relatively constant energy intensity long into the future.

6. The largest share of GHG emissions from the fuel life-cycle occurs from combustion of the fuel itself, regardless of the study design and input assumptions. The study design and input

assumption factors discussed above concern only 20 to 30 percent of the WTW GHG emissions for most fuels. The remaining 70 to 80 percent result from refined fuel products combustion. Figure 7-1 shows the contribution from fuel combustion (i.e., tank-to-wheel [TTW] emissions) relative to extraction, refining, transportation and distribution (i.e., WTT emissions) for gasoline produced from reference and oil sands-derived crudes (NETL 2008). When WTT emissions and combustion emissions are evaluated together, the percentage change in WTW GHG emissions are much smaller than on a WTT basis.



Source: Developed with results data from NETL 2009.
* Includes upgrading for WCSB oil sands.

gCO_2e/MJ = grams carbon dioxide equivalent per megajoule, LHV = lower heating value, WCSB = Western Canadian Sedimentary Basin.

Figure 7-1 WTW GHG emissions by life-cycle stage for WCSB oil sands average crude (i.e., Canadian Oil Sands) and reference crudes

In contrast with the above list of robust findings, the results from the studies included in the scope of this assessment differ on the following points:

- It is not clear whether WCSB oil sands-derived crudes are currently more GHG-intensive than other heavy crudes or crudes with high flaring rates. The life-cycle GHG emissions of WCSB oil sands crudes can fall within the same range as heavier crudes such as heavy Venezuelan crude oil and California heavy oil, and lighter crudes that are produced from operations that flare most of the associated gas (e.g., Nigerian light crude). The overall results vary by study, however, and are driven by study design factors, such as the type of WCSB oil sands extraction method evaluated, the extraction methods and properties of the reference crude that WCSB oil sands crudes are compared against, as well as study-specific inputs and assumptions including treatment of petroleum coke, cogeneration, and secondary carbon flows.

- There is no common set of LCA boundaries or metrics for comparing WTW GHG emissions across different fuels and crudes. For example, key design issues where studies differ include: (i) treatment of petroleum coke and lower-value products; (ii) the functional unit, or metrics used to present WTW GHG emissions; (iii) methods of estimating and including secondary carbon flows, such as direct and indirect land use change, and capital infrastructure. In some cases (e.g., selection of LCA boundaries and functional unit), these issues will be determined by the ultimate study goal or purpose; in other cases, there is no established method or approach for including certain emissions (e.g., land-use change and capital equipment).
- It is not clear how changes in technology will affect the relative GHG-intensity of reference crudes and WCSB oil sands-derived crudes, but it is believed the gap between these crudes is more likely to narrow than widen. The life-cycle GHG emissions of WCSB oil sands and reference crudes will change over time, but it is not clear how these changes will impact the relative GHG emissions of reference crudes relative to WCSB oil sands crudes. On one hand, secondary and tertiary recovery techniques will become necessary to extract larger shares of oil, increasing the GHG emissions of reference crudes. ExxonMobil has made the point in The Outlook for Energy, A View to 2030, 2005 Edition, that the best tertiary recovery techniques can recover approximately 40 to 45 percent of the original oil in place, and while the industry does not know what the next best extraction techniques will be, the industry will not leave 55 percent of the World's proven reserves in the ground. Exploration for new oil reservoirs will also continue, while the location and extent of WCSB oil sands is well understood. On the other hand, in situ extraction, which is generally more energy- and GHG-intensive than mining, will represent a larger share of oil sands production in the future, although technical innovation will likely continue to reduce the GHG intensity. Technologies for combusting or gasifying petroleum coke may also become more prevalent in WCSB oil sands (or reference crude) operations, increasing GHG emissions. Over the longer term, CCS technologies could capture and sequester CO_2 emissions, reducing the GHG footprint of WCSB oil sands crudes; the timeframe for adopting CCS at oil sands facilities is highly uncertain (on the order of two or more decades), and similar technologies would be applicable to concentrated streams of CO_2 released from reference crude production facilities.
- The oil sands' GHG results do not necessarily represent the average or actual oil sands composition (i.e., the types and shares of oil sands-derived crudes) that would flow through the proposed Project pipeline. Some studies provide averages (e.g., NETL provides a WCSB oil sands average that is comprised of 57 percent SCO and 43 percent bitumen; IHS CERA (2010) provides an average for WCSB oil sands imported to the United States assuming 55 percent dilbit and 45 percent SCO) while others include results for several types of oil sands and different scenarios that vary the treatment of petroleum coke and other factors. Elsewhere in this Supplemental EIS, the Department assumes that the average crude oil

flowing through the pipeline would consist of about 50 percent Western Canadian Select (dilbit) and 50 percent Suncor Synthetic A (SCO). Although an average GHG-intensity estimate for WCSB oil sands allows for a direct comparison to other reference crudes imported to the United States, it is difficult to characterize the average mix due to variations and uncertainty in: (i) methods of producing bitumen from oil sands deposits (i.e., mining versus in situ), (ii) fuel sources used (e.g., combustion of petroleum coke versus natural gas, export of electricity), and (iii) products produced from these operations (i.e., dilbit, synbit, and SCO). These mixes are likely to change over time as well.

Table 7-1 provides a summary of the key drivers that influence the WTW GHG emissions from the studies included in this assessment. The vertical columns establish whether each driver results in an increase or decrease in GHG emissions from WCSB oil sands crudes relative to reference crudes, or if the result is uncertain. The horizontal rows group each driver according to its magnitude of impact on WTW GHG emissions (i.e., small, medium, or large), as discussed in Sections 4.1, 4.2, and 0, Study Design Factors, Input and Modeling Assumptions, and Analysis of Key Factors. The magnitude of impact is based on a synthesis of the estimates cited throughout the life-cycle studies reviewed.

Table 7-1 Summary of Key Factors, their Magnitude of Impact on WTW GHG Emissions, and their Effect on GHG Emissions of WCSB Oil Sands Crudes Relative to Reference Crudes

Magnitude of Impact[1]	**Change in GHG emissions of WCSB oil sands crudes relative to reference crudes**		
	Increase	**Decrease**	**Uncertain**
Large	• Including a credit for fuels offset by petroleum coke combustion at the refinery • Using residual products (such as petroleum coke) instead of natural gas at upgrading • Increased combustion of coke at oil sands facilities • Comparing WCSB oil sands crudes against lighter reference crudes • Comparing higher GHG-intensity WCSB oil sands production methods (e.g., in situ) to reference crudes • For dilbit: recirculating diluent from refineries back to Alberta	• Inclusion of production and combustion emissions from petroleum coke and other co-products produced at refinery • Including emissions credit for electricity export from oil sands facilities • Accounting for artificial lift, water, and gas treatment in reference crude production • Future increases in secondary and tertiary production of reference crudes • Comparing WCSB oil sands crudes against heavier reference crudes • Comparing lower GHG-intensity WCSB oil sands production methods (e.g., mining) to reference crudes	• Future changes in GHG intensity of oil sands crudes • Adoption of carbon capture and storage technologies • Including upstream production of purchased electricity and fuels brought on-site • Including emissions associated with capital equipment and infrastructure

Magnitude of Impact[1]	Change in GHG emissions of WCSB oil sands crudes relative to reference crudes		
	Increase	**Decrease**	**Uncertain**
Medium	• Including land use changes • Including methane emissions from mining tailings ponds • Assuming electricity exported from oil sands facilities offsets low GHG-intensity electricity generation (i.e., natural gas instead of coal)	• Comparing oil sands derived crude with a relatively low SOR • For SCO: Including the effect that upgrading SCO has on downstream GHG emissions at the refinery	• Accounting for carbon flows associated with land use change of reclaimed land
Small	• Including methane emissions from mine face	• Including transportation emissions associated with co-products	• Accounting for actual crude distance traveled and mode of transportation, including domestic transportation from oil field to port • Including fugitive emissions from all processing facilities

[1] Large = greater than approximately 3 percentage point change in WTW emissions. Medium = approximately 1to 3 percentage point change in WTW emissions. Small = less than approximately 1 percentage point change in WTW emissions.

GHG = greenhouse gas, SCO = synthetic crude oil, WCSB = Western Canadian Sedimentary Basin, WTW = well-to-wheels.

8.0 REFERENCES

(S&T)[2] Consultants. 2008a. 2008 GHGenius Update. Natural Resources Canada, Office of Energy Efficiency (NRCAN OEE). Website: www.ghgenius.ca/reports.

(S&T)[2] Consultants. 2008b. GHGenius forums: Operation: Bitumen for Refining - energy intensity. Response from Dan O'Connor, (S&T)[2] Consultants to Trevor Stephenson regarding bitumen and dilbit pathways for WCSB oil sands production. December 19, 2009. Website: http://www.ghgenius.ca/forum/index.php?action=vthread&forum=5&topic=229. Accessed March 10, 2011.

AERI. See Alberta Energy Research Institute.

Alberta Carbon Capture and Storage Development Council. 2009. Accelerating Carbon Capture and Storage Implementation in Alberta. Website: http://www.energy.alberta.ca/Initiatives/1690.asp. Accessed January 27, 2011.

Alberta Energy Research Institute (AERI). 2006. Alternatives to the Use of Natural Gas Environmental Issues Associated with Gasification Technology. Website: http://albertainnovates.ca/media/13900/alternatives%20to%20the%20use%20of%20natural%20gas%20environmental%20issues%20associated%20with%20gasification%20technology.pdf. Accessed February 24, 2011.

Amiro, B.D., J.I. MacPherson, R.L. Desjardins, J.M. Chen, and J. Liu. 2003. Post-Fire Carbon Dioxide Fluxes in the Western Canadian Boreal Forest: Evidence from Towers, Aircraft and Remote Sensing. Agricultural and Forest Meteorology, 115 (1-2), 91-107.doi: 10.1016/S0168-1923(02)00170-3.

Argonne National Laboratory. 2010. Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET). Version 1.8d.1.

Bachu, S., M. Brulotte, M. Grobe, and S.A. Stewart. 2000. Suitability of the Alberta Subsurface for Carbon Dioxide Sequestration in Geological Media. Website: http://www.ags.gov.ab.ca/publications/abstracts/ESR_2000_11.html. Accessed January 27, 2011.

Beilman, D.W., D.H. Vitt, J.S. Bhatti, and S. Forest. 2008. Peat Carbon Stocks in the Southern Mackenzie River Basin: Uncertainties Revealed in a High-Resolution Case Study. Glob. Change Biol., 14:1221–1232. doi: 10.1111/j.1365-2486.2008.01565.x.

Bergerson, J., and D. Keith. 2006. Life-Cycle Assessment of Oil Sands Technologies. Paper No. 11 of the Alberta Energy Futures Project. University of Calgary; J. Bergerson's (2007), The Impact of LCFS on Oil Sands Development: Hybrid LCA Methods, Presentation at the InLCA/LCM Conference, October 2, 2007. University of Calgary. Website: http://www.lcacenter.org/InLCA2007/presentations/LCFS-Bergerson.pdf.

Brandt, A. 2011. Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries. Stanford University. Website: https://circabc.europa.eu/d/d/workspace/SpacesStore/db806977-6418-44db-a464-20267139b34d/Brandt_Oil_Sands_GHGs_Final.pdf. Accessed November 5, 2012.

Carrasco, J.J., J.C. Neff, and J.W. Harden. 2006. Modeling Physical and Biogeochemical Controls over Carbon Accumulation in a Boreal Forest Soil. J. Geophys. Res., 111. doi: 10.1029/2005JG000087.

Charpentier, A.D., J.A. Bergerson, and H.L. MacLean. 2009. Understanding the Canadian Oil Sands Industry's Greenhouse Gas Emissions. Environmental research Letters 4 (2009) 014005. Website: http:/stacks.iop.org/ERL/4/14005. Accessed November 6, 2012.

Cumulative Effects Management Association. 2010. Results from Long Term Soil and Vegetation Plots Established in the Oil Sands Region (2009): Soils Component (Paragon Soil and Environmental Consulting, Edmonton, AB).

D'Iorio, M. 2011. Large-Scale CCS Demonstration Projects in Canada. IEA WPFF - MOST CCUS Workshop: Joint Activities and Opportunities. Website: http://www.iea.org/media/workshops/2011/wpffbeijing/20_Deck.pdf. Accessed February 12, 2013.

Edmonton Journal. 2007. Synenco shelves upgrader plans. Edmonton, Alberta. Website: http://www.canada.com/edmontonjournal/news/business/story.html?id=2cdab20c-9e8c-4761-a4e0-a4ff9b2f5aac. Accessed February 4, 2011.

EIA. See U.S. Energy Information Administration.

Environment Canada. 2010. National Inventory Report: 1990-2008 Greenhouse Gas Sources and Sinks in Canada. Website: http://www.ec.gc.ca/ges-ghg.

ERCB. See Energy Resources Conservation Board.

Energy Resources Conservation Board (ERCB). 2010. ST-53 2009 Alberta In-Situ Oil Sands.

GHGenius. See Natural Resources Canada.

GREET. See Argonne National Laboratory.

Gordon, D. 2012. The Carbon Contained in Global Oils. Carnegie Endowment for International Peace. Website: http://www.carnegieendowment.org/2012/12/18/carbon-contained-in-global-oils/euzi. Accessed January 7, 2013.

Huot, M. 2011. Oilsands and climate change: How Canada's oilsands are standing in the way of effective climate action. Briefing note. The Pembina Institute. Website: http://pubs.pembina.org/reports/oilsands-and-climate-fs-201109.pdf. Accessed January 23, 2013.

ICCT. See International Council on Clean Transportation.

IEA. See International Energy Agency.

International Council on Clean Transportation (ICCT). 2010. Carbon Intensity of Crude Oil in Europe Crude.

IHS Cambridge Energy Research Associates, Inc. (IHS CERA). 2010. Oil Sands, Greenhouse Gases, and U.S. Oil Supply: Getting the Numbers Right.

________. 2011. Oil Sands, Greenhouse Gases, and European Oil Supply: Getting the Numbers Right.

________. 2012. Oil Sands, Greenhouse Gases, and U.S. Oil Supply Getting the Numbers Right—2012 Update.

IHS CERA. See IHS Cambridge Energy Research Associates, Inc.

International Energy Agency (IEA). 2010. World Energy Outlook 2010.

________. 2011. World Energy Outlook, 2011. International Energy Agency.

ISO 14040:2006, Environmental management—Life cycle assessment—Principles and framework.

ISO 14044:2006, Environmental management—Life cycle assessment—Requirements and guidelines.

Jacobs Consultancy. 2009. Life Cycle Assessment Comparison of North American and Imported Crudes. Alberta Energy Research Institute and Jacobs Consultancy.

________. 2012. EU Pathway Study: Life Cycle Assessment of Crude Oils in a European Context. Alberta Petroleum Marketing Commission and Jacobs Consultancy.

McCann and Associates. 2001. Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles in 2007. Prepared for Regional Infrastructure Working Group by T.J. McCann and Associates Ltd. November16.

McQueen, D. 2012. Responsible Energy in Alberta. Website: http://www.stakeholderforum.org/sf/outreach/index.php/component/content/article/164-cop18day9private-sector/1275-responsible-energy-in-alberta.

National Energy Board (NEB). 2006. Canada's Oil Sands: Opportunities and Challenges to 2015: an Update. Website: http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/lsnd/lsnd-eng.html.

National Energy Technology Laboratory (NETL). 2008. Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels. November 26, 2008.

_________. 2009. An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact of Life Cycle Greenhouse Gas Emissions. March 27.

Natural Resources Canada. 2010. GHGenius Model, Version 3.19.

Natural Resources Defense Council (NRDC). 2010a. GHG Emission Factors for High Carbon Intensity Crude Oils. Ver. 2. September.

________. 2010b. Setting the Record Straight: Lifecycle Emissions of Tar Sands. Website: http://docs.nrdc.org/energy/ene_10110501.asp.

NEB. See National Energy Board.

NETL. See National Energy Technology Laboratory.

Nexen, Inc. 2011. Operations - Oil Sands - Long Lake. Website: http://www.nexeninc.com/Operations/OilSands/LongLake.aspx. Accessed February 4, 2011.

NRDC. See Natural Resources Defense Council.

Oil Change International. 2013. Petroleum Coke: The Coal Hiding in the Tar Sands. Website: http://priceofoil.org/wp-content/uploads/2013/01/OCI. Petcoke.FINAL SCREEN.pdf. Accessed January 21, 2013.

Oil Sands Developer's Group. 2009. OSDG Athabasca Region Project List. Website: http://www.docstoc.com/docs/43608734/OSDG-Athabasca-Region-Project-List. Accessed February 16, 2011.

Pembina Institute. 2005. Oil Sands Fever: The Environmental Implications of Canada's Oil Sands Rush. November.

________. 2006. Carbon Neutral 2020: A Leadership Opportunity in Canada's Oil Sands. Oil Sands Issue Paper No. 2. October.

________. 2011. Life cycle assessments of oil sands greenhouse gas emissions: A checklist for robust analysis. January.

Pennsylvania State University (PSU). 2010. Coal Sample Bank and Database. Data received by SAIC 18 February 2010 from Gareth Mitchell, The Energy Institute, Pennsylvania State University.

PSU. See Pennsylvania State University.

RAND Corporation. 2008. Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs.

Rooney, R.C., S.E. Bayley, and D.W. Schindler. 2012. Oil sands mining and reclamation cause massive loss of peatland and stored carbon. Proceedings from the National Academy of Sciences of the United States of America. doi: 10.1073/pnas.1117693108. Website: http://www.pnas.org/content/109/13/4933.

Searchinger, T., R. Heimlich, R.A. Houghton, F. Dong, A. Elobeid, J. Fabiosa, S. Tokgoz, D. Hayes, and T.H. Yu. 2008. Use of U.S. Croplands for Biofuels Increases Greenhouse Gases through Emissions from Land Use Change. Science, 319 (5867), 1238–1240. doi: 10.1126/science.1151861.

Skone, T. 2011. Personal communication with Timothy Skone, Office of Strategic Energy Analysis and Planning, National Energy Technology Laboratory (NETL), and Christopher Evans, ICF International. July 6, 2011.

Sturgeon County. 2011. Northern Lights Upgrader. Sturgeon County. Website: http://www.sturgeoncounty.ab.ca/NorthernLights/tabid/299/Default.aspx. Accessed February 4, 2011.

TIAX LLC. 2009. Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions. Alberta Energy Research Institute and TIAX LLC.

Turetsky, M., K. Wieder, L. Halsey, and D. Vitt. 2002. Current Disturbance and the Diminishing Peatland Carbon Sink. Geophys. Res. Lett., 29 (11), 1526, doi:10.1029/2001GL014000.

U.S. Energy Information Administration (EIA). 2011. Oil Market Basics: Appendix A – PADD Map. Website: http://www.eia.doe.gov/pub/oil_gas/petroleum/ analysis_publications/oil_market_basics/default.htm. Accessed February 25, 2011.

________. 1993. State of Energy Report 1992. Washington, DC.

________. 1994. EIA Manufacturing Consumption of Energy (MECS) 1991, U.S. Department of Energy, Energy Information Administration, Washington, DC.

________. 2009. Annual Energy Review, Energy Information Administration, U.S. Department of Energy, Washington, DC. DOE/EIA-0384(2008).

________. 2010. Annual Energy Review 2009. U.S. Energy Information Administration (EIA). Washington, DC.

________. 2012a. Electric Power Monthly. U.S. Energy Information Administration. Website: http://www.eia.gov/electricity/monthly/. Accessed January 28, 2013.

________. 2012b. Exports by Destination, Petroleum Coke. U.S. Energy Information Administration. Retrieved from http://www.eia.gov/dnav/pet/pet_move_expc_a_EPPC_EEX_mbbl_a.htm. Accessed January 28, 2013.

________. 2012c. Annual Energy Outlook 2012. Website: http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

U.S. Environmental Protection Agency (USEPA). 2009. 1970 - 2008 Average annual emissions, all criteria pollutants in MS Excel. National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data. Office of Air Quality Planning and Standards. Retrieved from http://www.epa.gov/ttn/chief/trends/ index.html.

________. 2010a. U.S. Renewable Fuel Standard Program (RFS2): Regulatory Impact Analysis, EPA-420-R-10-006. February 2010.

________. 2010b. 2009 Average annual emissions, all criteria pollutants in MS Excel. National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data. Office of Air Quality Planning and Standards.

________. 2010c. Carbon Content Coefficients Developed for EPA's Mandatory Reporting Rule. Office of Air and Radiation, Office of Atmospheric Programs, U.S. Environmental Protection Agency, Washington, D.C.

________. 2011. Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2009. EPA 430-R-11-005. February 15, 2011.

________. 2012. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010. U.S. Environmental Protection Agency (EPA). Website: http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html. Accessed January 24, 2013.

USEPA. See U.S. Environmental Protection Agency.

U.S. Geological Survey (USGS). 1998. CoalQual Database Version 2.0.

USGS. See U.S. Geological Survey.

Vitt, D.H., L.A. Halsey, I.E. Bauer, and C. Campbell. 2000. Spatial and Temporal Trends in Carbon Storage of Peatlands of Continental Western Canada through the Holocene. Can. J. Earth Sci. 37, 683-693. doi: 10.1139/e99-097.

Wieder, R.K., K.D. Scott, K. Kamminga, M.A.Vile, D.H. Vitt, T. Bone, B. Xu, B.W. Benscoter, and J.S. Bhatti. 2009. Post-Fire Carbon Balance in Boreal Bogs of Alberta, Canada. Global Change Biol., 15, 63–81. doi: 10.1111/j.1365-2486.2008.01756.x.

Yeh, S., S.M. Jordaan, A.R. Brandt, M.R. Turetsky, S. Spatari, and D.W. Keith. 2010. Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands. Environmental Science & Technology: Article ASAP. doi:10.1021/es1013278. Website: SSRN: http://ssrn.com/abstract=1613046.