ATTACHMENT 2

APPENDIX U

Lifecycle Greenhouse Gas Emissions of Petroleum Products from WCSB Oil Sands Crudes Compared with Reference Crudes

LIFECYCLE GREENHOUSE GAS EMISSIONS OF PETROLEUM PRODUCTS FROM WCSB OIL SANDS CRUDES COMPARED WITH REFERENCE CRUDES

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ACRONYMS

°F	degrees Fahrenheit
AERI	Alberta Energy Research Institute
API	American Petroleum Institute
bbl	barrel
bpd	barrels per day
Btu	British thermal unit
C/ha/yr	carbon per hectare per year
CAFE	Corporate Average Fuel Economy
CARB OPGEE	California Air Resources Board, Oil Production Greenhouse Gas Emissions Estimator
CBOB	conventional blendstock for gasoline blending
CCS	carbon capture and storage
CEQ	Council on Environmental Quality
CI	carbon intensity
CNRL	Canadian Natural Resources Limited
CO_2	carbon dioxide
cSOR	cumulative steam-oil ratio
CSS	cyclic steam stimulation
EIA	U.S. Energy Information Administration
EIS	Environmental Impact Statement
ERCB	Alberta Energy Resources Conservation Board
FCC	fluid catalytic cracker
g	gram
G+D	gasoline and diesel
gCO_2/MJ	grams carbon dioxide per megajoule
gCO_2e/MJ	grams carbon dioxide equivalent per megajoule
GDP	gross domestic product
GHG	greenhouse gas
GJ	gigajoule
GOR	gas-oil ratio
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
GWP	global warming potential
H-C	hydrogen-carbon ratio
H2	hydrogen
HHV	higher heating value
ICCT	International Council on Clean Transportation
IE	included elsewhere
IEA	International Energy Agency
IHS CERA	IHS Cambridge Energy Research Associates, Inc.
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
iSOR	instantaneous steam-oil ratio
kg	kilogram
$kgCO_2e$	kilograms carbon dioxide equivalent
kWh	kilowatt–hour
lb	pound
LCA	lifecycle assessment
LCFS	California's Low Carbon Fuel Standard
LHV	lower heating value
LPG	liquefied petroleum gas
m	meter

MJ	megajoule
MMBtu	million British thermal units
$MMTCO_2e$	million metric tons of carbon dioxide equivalent
N/A	Estimates not available from study
NA	not applicable
NEB	National Energy Board
NETL	National Energy Technology Laboratory
NG	natural gas
NGL	natural gas liquids
NHTSA	National Highway Traffic and Safety Administration
NRDC	Natural Resources Defense Council
OECD	Organization for Economic Cooperation and Development
OPTI/Nexen	names of two companies: OPTI Canada and Nexen Inc.
PADD	Petroleum Administration for Defense Districts
PSU	Pennsylvania State University
RBOB	reformulated blendstock for oxygenate blending
RFS2	USEPA Renewable Fuel Standard
RTT	refinery-to-tank
$(S\&T)^2$ Consultants	consultant name
SAGD	steam-assisted gravity drainage
SAR	Second Assessment Report
SCO	synthetic crude oil
SOR	steam-oil ratio
SOx	sulfur oxides
TIAX	company name: TIAX LLC
tpy	tons per year
TTW	tank-to-wheels
UNFCCC	United Nations Framework Convention on Climate Change
WCSB	Western Canadian Sedimentary Basin
WTR	well-to-refinery gate
WTT	well-to-tank
WTW	well-to-wheels
USEPA	U.S. Environmental Protection Agency
USDOE	U.S. Department of Energy
USGS	U.S. Geological Survey

1.0 OBJECTIVE

This appendix accompanies the text in Section 4.14, Greenhouse Gases and Climate Change, of the Final Supplemental EIS, and examines differences between the lifecycle 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 TransCanada Keystone Pipeline, LP (Keystone, or the proposed Project). Rather than conducting new modeling or analysis, this study reviews existing lifecycle 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 lifecycle 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 lifecycle 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, and Section 7.0, Key Findings, conclude by synthesizing key findings and providing a brief discussion on future trends.

2.0 CONCEPTUAL FRAMEWORK

A comparative lifecycle 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 lifecycle 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 lifecycle comparisons.

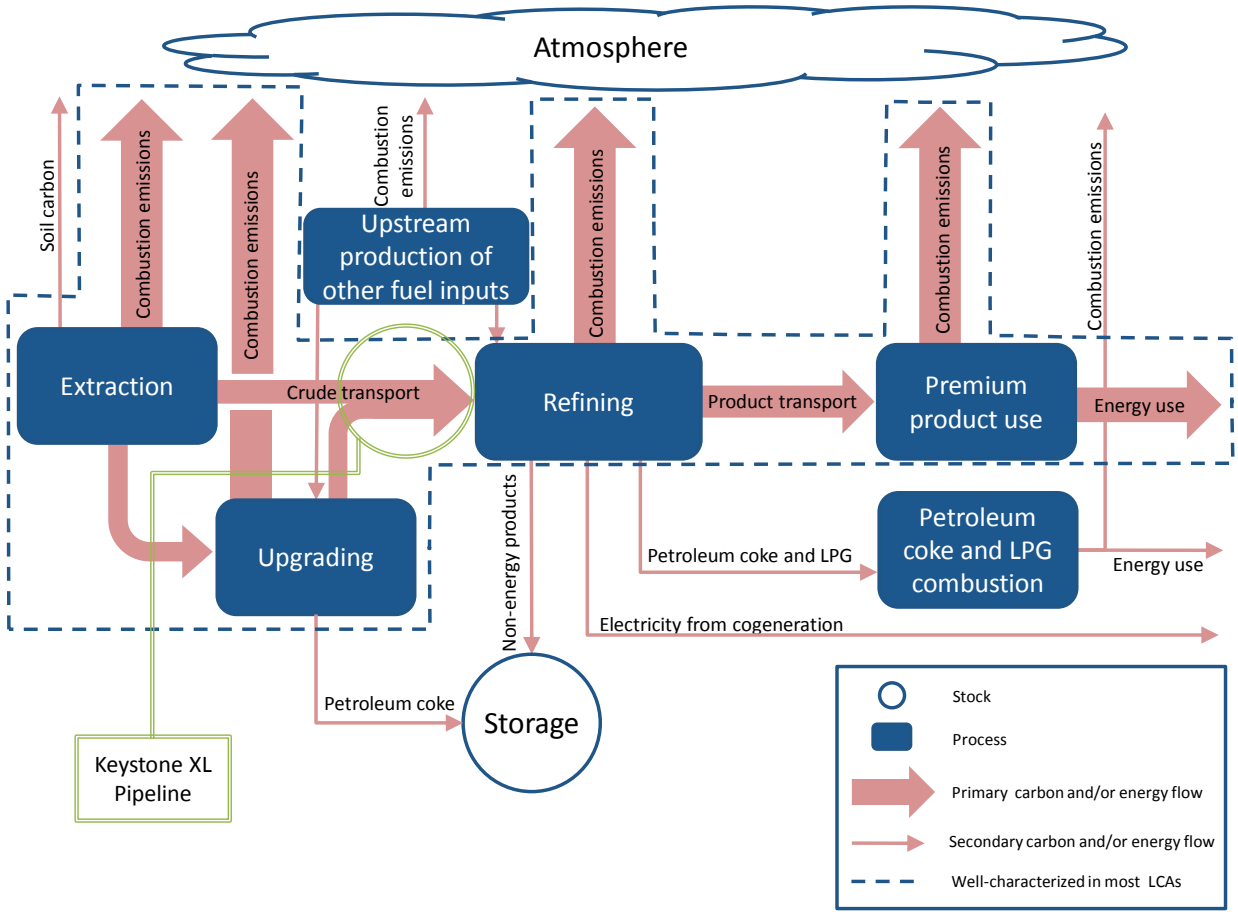


Figure 2-1 Simplified Petroleum System Carbon and Energy Flow

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 carbon dioxide (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 lifecycle 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 lifecycle for oil sands-derived crudes and reference crudes where values were reported. Not all studies in this review include a full WTW lifecycle assessment; several studies focus on the well-to-tank (WTT) portion of the lifecycle, 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

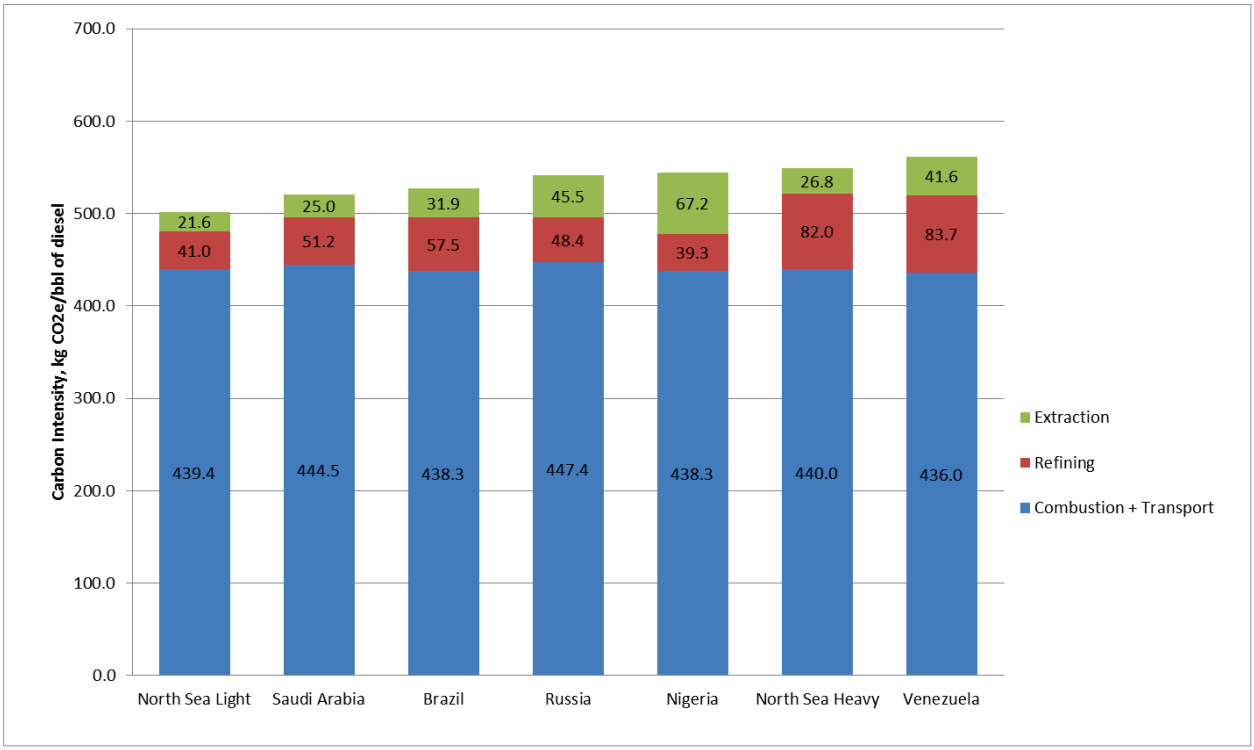
Section 4.2.1.1, Type of Extraction Process, describes the different extraction methods in detail.

There are numerous crude oil sources in the global energy markets, and these crude oils have differing GHG intensities based on their properties (such as API gravity), the extraction method, and the refinery process used. Figure 3-1 illustrates a range of crude oil GHG intensities.

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 3 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. As shown in Figure 3-1, Venezuela Bachaquero lies at the upper end of the WTW GHG emission estimates.
- 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. As shown in Figure 3-1, Middle Eastern Sour lies at the lower end of the WTW GHG emissions estimates.

[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 3 refineries are those located in the Gulf Coast area, namely Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas (EIA 2011). The results in TIAX 2009 and NETL 2008 and 2009 reflect refining at PADD 3 Gulf Coast refineries; the results in Jacobs 2009 reflect refining at PADD 2 Midwest refineries.



Source: Jacobs 2012.

Notes: This figure illustrates the range of GHG intensities for different crudes based on origin, properties, and refining processes. Jacobs 2012 evaluated WTW emissions for crude oils sent to European markets. The results shown are for refineries in the U.S. Gulf Coast, but include transportation and delivery to Europe. $kgCO_2e$/bbl = kilograms carbon dioxide equivalent per barrel.

Figure 3-1 GHG Intensities for Different Crude Oils

3.2 IDENTIFY THE STUDIES FOR REVIEW

Several studies provide assessments of the lifecycle GHG implications of WCSB oil sands crude relative to reference crudes. The Department, in conjunction with USEPA, U.S. Department of Energy (USDOE), and the Council on Environmental Quality, 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 lifecycle.
- 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, five 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
Brandt, A. 2011. Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries.	Meta-analysis	WTW
Charpentier et al. 2009. Understanding the Canadian Oil Sands Industry's Greenhouse Gas Emissions.	Meta-analysis	WTW
Energy-Redefined LLC for ICCT. 2010. Carbon Intensity of Crude Oil in Europe Crude.	Individual LCA	WTT[6]
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
IHS CERA. 2012. Oil Sands, Greenhouse Gases, and U.S. Oil Supply: Getting the Numbers Right – 2012 Update.	Meta-analysis	WTW
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
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
NRDC. 2010. GHG Emission Factors for High Carbon Intensity Crude Oils, v. 2.	Meta-analysis	WTW
TIAX LLC. 2009. Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions.	Individual LCA	WTW
Additional Studies/Models Analyzed		
Bergerson et al. 2012a. Life Cycle Greenhouse Gas Emissions of Current Oil Sands Technologies: Surface Mining and *In Situ* Applications.	Partial LCA	WTR[7]
CARB OPGEE v1.1, 2013. Oil Production Greenhouse Gas Emissions Estimator (OPGEE) Version1.1 Draft A; February 23, 2013.	Partial LCA	WTR[7]
Charpentier et al. 2011a. Life Cycle Greenhouse Gas Emissions of Current Oil Sands Technologies: GHOST Model Development and Illustrative Application.	Partial LCA	WTR[7]
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
Lee and Cheng. 2009. Bitumen and Biocarbon: Land Use Conversions and Loss of Biological Carbon Due to Bitumen Operations in the Boreal Forests of Alberta, Canada.	Land use change white paper	NA
McCann and Associates. 2001. Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles.	Individual LCA	WTW
Pembina. 2005. Oil Sands Fever: The Environmental Implications of Canada's Oil Sands Rush.	Partial LCA	WTR[8]
Pembina. 2006. Carbon Neutral 2020: A Leadership Opportunity in Canada's Oil Sands. Oil sands issue paper 2.	Partial LCA	WTR[8]
Pembina. 2011. Life cycle assessments of oil sands greenhouse gas emissions: A checklist for robust analysis.	White Paper	NA
RAND Corporation. 2008. Unconventional Fossil-Based Fuels: Economic and	Individual LCA	WTW

[6] Excluding distribution.
[7] Including transportation to refinery, excluding refining.
[8] Up to oil sands facility gate, excluding transportation to refinery and refining.

Primary Studies Analyzed	Type	Boundaries
Environmental Trade-Offs.		
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

CARB OPGEE = California Air Resources Board, Oil Production Greenhouse Gas Emissions Estimator, NA = not applicable, GHG = greenhouse gas, LCA = lifecycle assessment, WTR = well-to-refinery gate, WTW = well-to-wheels.

The list of primary and additional studies reflects recent updates to previous lifecycle assessments of oil-sands-derived crudes and information on GHG emissions associated with land use change. The IHS CERA (2011) study contains slight changes in WTT emission estimates from IHS CERA (2010) to account for the hypothetical case in which oil sands are transported into Europe.[9] Furthermore, refining emissions and fuel combustion emissions differ slightly to account for the refinery production and combustion of a different slate of petroleum products than in a North American context (IHS Cambridge Energy Research Associates [IHS CERA] 2011, 2010). The most recent IHS CERA (2012) study incorporates several methodological changes as well as a widened scope estimate, which results in a higher WTW emission estimate for average oil sands crude compared to the two previous studies.[10] IHS CERA (2012) also includes a more recent set of studies in its meta-analysis.

The Jacobs (2012) study provides 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.

While Jacobs (2012) offers new analysis, it focuses on crudes run in European refineries. A quantitative analysis of the Jacobs (2012) report and its data has not been undertaken. Key differences between Jacobs (2009) and Jacobs (2012) oil sands GHG emissions estimates are discussed in Section 4.1.3, Time Period Data in the Studies, of this Appendix.

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

An initial set of approximately 50 attributes was developed for review, guided by specifications on scope, data quality requirements, and appropriateness of comparisons from the International Organization for Standardization (ISO) standards (14040:2006, 14044:2006) as well as an engineering understanding of crude oil lifecycle processes. These attributes are listed in

[9] This necessitates either blending the bitumen with diluent or upgrading it into SCO, in addition to transporting it a greater distance.

[10] The oil sands crude WTW GHG emissions estimates from the study are higher because they incorporate greater GHG emissions for bitumen extraction and diluent production, and they account for production of bitumen only, primary, and SCO from SAGD. For extraction and upgrading, the underlying changes that drive the differences in emissions estimates between the two studies result from the 2012 study incorporating land disturbance (e.g., mine face emissions and tailings pond emissions) data from more recent sources, including Yeh et al. (2010) and Jacobs (2012); the study also incorporated upgrading-related emissions from Jacobs (2012) applied across all studies considered in the meta-analysis. The upper-bound 547 $kgCO_2e$ per barrel of refined product estimate also includes GHG emissions from production of upstream fuel inputs used in crude oil production and processing, such as natural gas and electricity produced off-site.

Table 3-2. For each study and crude and fuel type specified, these elements included specifics on each stage of the lifecycle (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 = lifecycle 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.[11] 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 lifecycle 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 lifecycle 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 lifecycle results, were also discussed.

4.0 RESULTS AND DISCUSSION

This section presents an assessment of the studies comparing lifecycle 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 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 lifecycle 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.

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

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. 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 Lifecycle 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 lifecycle boundaries established to make the comparison, and the functional units or the basis used for comparing the lifecycle 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;[12] 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 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) would require more energy inputs to refine into premium fuel products.

[12] 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.

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 would generally have higher lifecycle GHG emissions than fuels from crudes with higher API, low sulfur content, and higher H-C ratio. The relative difference would 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 would yield a narrow range in lifecycle GHG emissions between the two crudes, while analyses that select lighter reference crudes would 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 LCA Boundaries

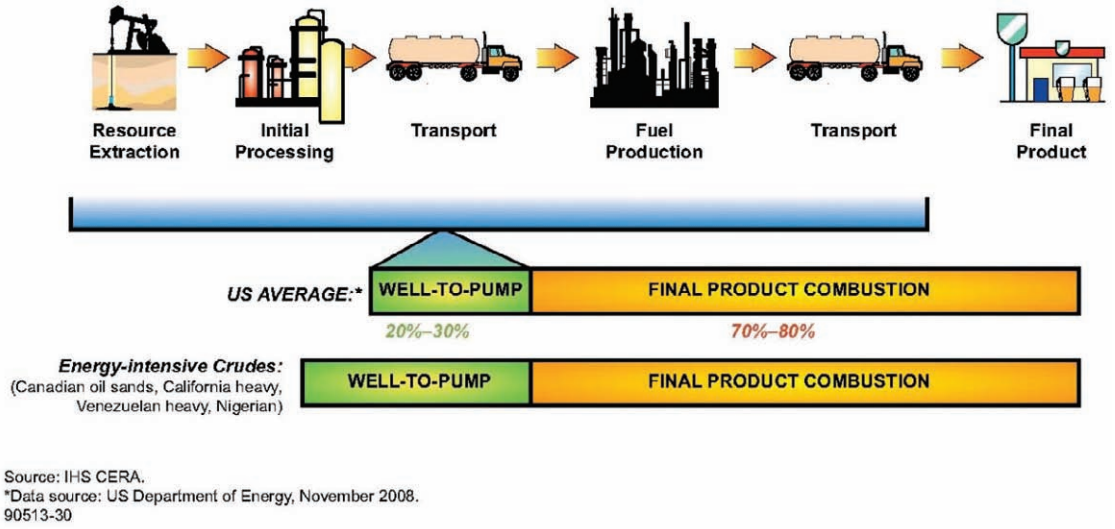
The boundaries of a given LCA describe which sources of GHG emissions are included in the study scope and which are excluded. The following are three common LCA boundaries used in the reviewed studies:

- Well-to-refinery gate (WTR)
- Well-to-tank (WTT) = WTR + refinery-to-tank (RTT)
- Well-to-wheels (WTW) = WTR + RTT + tank-to-wheels (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 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 lifecycle 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 4.1.5, 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.

4.1.3 Time Period of Data in the Studies

As shown in Table 4-2, many of the studies investigated are representative of recent conditions (i.e., within the last 5 to 10 years). Trends that may influence the results of these studies in the near term and over the long term are further discussed in Section 4.1.5, Allocation, Co-Products, and Offsets. Most studies contained data from the mid-to-late 2000s, with four studies' reference years in the 1990s, and two sources' 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," and IHS CERA (2012) suggests similar trends (IHS CERA 2010, pp. 8-9; IHS CERA 2012, pp. 19-20). The IHS CERA studies did not model future emissions in detail, nor did it comment on changes in the GHG intensity of other reference crudes. GHGenius (2010) uses data representative of current WCSB oil sands operations although the model can run projections out to 2050 (Natural Resources Canada 2010).

Table 4-2 Reference Years for LCA Studies

Study	Reference Year(s)
NETL, 2008	2005[a]
NETL, 2009	2005[a]
IEA, 2010	2005-2009[b]
IHS CERA, 2010, 2011, 2012	~2005-2030[c]
NRDC, 2010	2006-2010[d]
ICCT, 2010	2009
Jacobs Consultancy, 2009	2000s[e]
Jacobs Consultancy, 2012	2000s

Study	Reference Year(s)
TIAX, 2009	1998-2009[f]
Charpentier et al., 2009	1999-2008[d]
Brandt, 2011	Varies[g]
GHGenius, 2010	Current[h]
GREET, 2010	Current[i]
RAND, 2008	2000s
Charpentier et al., 2011a	2009[j]
Bergerson et al., 2012a	2009[j]
CARB OPGEE, 2013a	1990s, 2000s
Pembina Institute, 2005	2000, 2004
Pembina Institute, 2006	2002-2005[j,k]
McCann and Associates, 2001	2007
Rooney et al., 2012	1990s, 2000s
Yeh et al., 2010	2000s

[a] The age of data used in NETL (2008, 2009) ranges from 1996 to 2004, but the study is meant to be representative of 2005 conditions; to account for this, the study's authors note where older data are unlikely to significantly differ from 2005 conditions or make adjustments to the older activity data to more accurately reflect 2005 conditions.
[b] Reference year reflects the publication dates of the report's main data sources.
[c] The GHG intensity of U.S. oil sands imports has declined since 1990; however, overall emissions have increased due to the extraction of increased volumes (IHS CERA 2012, p. 19).
[d] 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.
[e] The age of data in Jacobs (2009, 2012) is generally from the 2000s, and the study is meant to be representative of recent conditions. Several data sources from before 2005 were used for reference crudes where updated information was not available. In general, data are less available for reference crudes than for WCSB oil sands crudes (Jacobs 2012).
[f] Oil sands data are chosen as close to current as possible. Oil sands data are derived from permit applications from the early- to mid-2000s. Permit data were updated with more recent data from operating projects, where available (TIAX 2009, p. 24).
[g] Varies by study addressed in the meta-study.
[h] GHGenius contains data representative of current operations, but the model can run projections out to 2050 (Natural Resources Canada 2010).
[i] GREET contains data representative of current operations and was last updated in 2010 (Argonne National Laboratory 2010).
[j] Based on literature and confidential company data published up to 2009.
[k] Data from studies published from 2002 to 2005 (Pembina 2006, p. 11).

CARB OPGEE = California Air Resources Board, Oil Production Greenhouse Gas Emissions Estimator, LCA = lifecycle assessment.

An extensive assessment of the secondary data's age was conducted for the four studies that were used to develop WTW GHG emission estimates for WCSB oil sands crudes in Section 6.0, Incremental GHG Emissions (Jacobs 2009, NETL 2008, NETL 2009, and TIAX 2009). The assessment showed that the studies sought to use the latest data available but, where data were limited, resorted to older studies for certain parameters. The older sources of secondary data are primarily for modeling reference crudes, with studies generally using more recent data for modeling WCSB oil sands crudes. In some cases, the studies have updated data from WCSB oil sands project application documents with recent operational data, such as for WCSB oil sands projects modeled in TIAX.

4.1.3.1 Jacobs (2009)

Jacobs (2009) does not explicitly provide a reference year, but the study intended to be representative of production of oil sands crude and a variety of reference crudes in the 2000s. In some cases, however, the study draws on a variety of data sources from 2005 and earlier to create inputs for the oil production model used to calculate the relative GHG intensities of the

various crude oils. Bitumen extraction and production data are predominantly informed by data sources from the mid- and late 2000s. Several parameters for bitumen are drawn from earlier sources, including water-to-oil ratios, which are informed by sources from 2000-2004; gas-to-oil ratios, which are dated to 2004; and gas composition, which is drawn from sources dating from 1997 to 2008. Furthermore, data for energy requirements and efficiency for steam generation and electricity consumption for oil production are from 1985 to 2006 and 1999 to 2009, respectively.

Likewise, Jacobs (2009) also uses several data sources for reference crudes from before 2005 as parameters for its crude production model. For Mexican Maya crude oil, data sources range from the early to late 2000s. The earliest data sources for this source of crude oil range from 1999 to 2005, and are used to describe reservoir pressure, gas production and air separation in the Mexican Cantarell oil field. For Venezuelan Bachaquero crude oil, a variety of data sources predating the 2000s are used to inform assumptions about reservoir pressure, gas production, water production, and steam-to-oil ratios in the field. These draw primarily from the late 1990s to early 2000s, with the sole exception being one of the three sources for reservoir pressure, which dates to 1976. The data sources for Saudi Medium crude are more recent, dating to the mid-2000s. The oldest are for reservoir pressure and gas production, which both date to 2004.

Jacobs (2012) reports the same lifecycle as Jacobs (2009); however, the Jacobs (2012) study used crudes from various production fields that were run in European refineries and produced products to a European specification. For estimated GHG emissions from oil sands, the key difference between the two reports is that one considered more efficient mining operations for developing the Canadian oil sands. In the 2012 report, the bitumen and upgrading industry reported lower GHG emissions based on increased energy efficiency during mining operations. More efficient mining systems involved using low-level waste heat from the upgrader or from onsite electricity generation to produce hot water for extraction. Less energy efficient mining systems use hot water from natural gas heaters. Canadian oil sands in Alberta are predominately developed from more energy efficient mining operations. The Jacobs 2012 report accounts for these lower carbon intensity improvements, whereas the Jacobs 2009 report is based on less energy efficient operations. Additionally, new SAGD operations which use mechanical lift rather than gas lift paired with reduced SOR decreases the carbon intensity of bitumen mining operations. This practice is also taken into account in the Jacobs 2012 study. Comparing Jacobs 2009 to Jacobs 2012, GHG emissions are reduced as much as 6 percent for SAGD produced bitumen, 4 percent for mining and SCO upgrading operations, and 3 percent for bitumen produced via dilbit operations.

4.1.3.2 TIAX (2009)

TIAX (2009) does not explicitly assume a reference year for its estimates of WTW GHG emissions from oil sands crudes. Rather, the lifecycle data for oil sands crudes is informed by a variety of reference cases. The oil sands crude projects used to inform the study were selected based on three criteria: availability of public material balance data, recent production, and high production capacity relative to other projects of its type (TIAX 2009, p. 24). Some larger and more established producers were unable to provide public data, which necessitated selecting several smaller or less established projects. Furthermore, some material and energy balance data were derived from permit applications that predated the study by several years. The data sources include applications and supplemental data submitted to the Canadian Environment and Utilities Board and Alberta Environment, ranging from 1998 to 2006. Project operators with older

application dates were given the opportunity to review the data for accuracy; two operators provided updated data in 2008 and 2009. Older application data was further supplemented by progress reports submitted to the Alberta Energy Resources Conservation Board (ERCB) from 2006 to 2008.

The venting and flaring assumptions for fuel extraction in TIAX (2009) were estimated in some cases by using volumes of methane released from 2004 and 2005 data. TIAX normalized the methane volumes to the mass of total fossil fuel produced in those reference years, and then applied the resulting ratios of methane vented per unit of fossil fuel produced to more recent data. This assumes that the amount of methane vented or flared per unit of fossil fuel produced remained constant. The refinery modeling methodology for the study comprises four models: a national model and regional models for PADD 2, PADD 3, and California. These models are calibrated using 2006 refinery data and then further modified to include a series of fuel standards which had been mostly implemented at the time of the study (2009) and which are expected to be fully implemented in 2015 (TIAX 2009, p. 33). Both the national and regional refinery models assume that the incoming crude oil slates would not change significantly between the calibration year of 2006 and 2015 (TIAX 2009, p. D-37).

TIAX (2009) also incorporates some general supplemental data from industry sources and other scientific studies, including the water content of crudes in a specific geographic region, regional grid electricity mixes, and specific produced gas-to-oil ratios, in order to calculate the recovery energy for the conventional crude oils characterized in the study. The data used to inform recovery energy assumptions for Alaskan North Slope, California Kern County Heavy Oil, Saudi Medium, Iraqi Basrah Medium, and Nigerian Escravos crude oils are informed by mid-to-late 2000s data which is contemporaneous with the study's 2006 calibration year. However, for West Texas Intermediate, Mexican Maya, and Venezuelan Bachaquero 17 crude oils, TIAX incorporates several data sources that date to the early 2000s or earlier. The gas production data for West Texas Intermediate crude oil is dated from 2000. For Mexican Maya crude oil, TIAX uses gas-to-oil ratios (in excess of the gas used for gas lift) for the Mexican Cantarell oil field from 1999. Lastly, Bachaquero 17 crude oil recovery energy calculations are informed by a steam-oil ratio dating to 1969; produced gas-to-oil ratio from 2002; and data for steam oil field boilers (including heat input, heat output, steam production, and electricity demand) from a 1992 handbook.

4.1.3.3 NETL (2008, 2009)

NETL (2008, 2009) assumes 2005 as a reference year and, in most cases, uses activity data specific to the reference year in estimating WTW GHG emissions from oil sands crudes. However, in cases where reference year-specific data are not available, several older data sources are used, ranging from 1996 to 2004. In all cases where older data are used, the authors acknowledge that the activity data predate the reference year and either note where older data are unlikely to significantly differ from 2005 conditions or make adjustments to the older activity data to more accurately reflect 2005 conditions.[13] As part of the lifecycle analysis, NETL estimated GHG emissions from the raw material acquisition stage using purchased crude oil GHG extraction profiles for the corresponding top ten countries importing crude oil, as well as

[13] These adjustments include a higher utilization rate (i.e., 80%) for hydrotreating operations in 2005 compared to the original data source the study used from 1996, adjustments for changes in feedstock quality, environmental emission requirements, changes in product slate, and modified refinery operations (NETL 2008).

for the United States, for the year 2002. The study reports the 2002 crude extraction profiles as a data limitation, but states there are no significant changes in 2005 for crude oil extraction practices for the United States or foreign countries, with the exception of Canada.

In modeling GHG emissions associated with extraction and processing natural gas liquids (NGL), NETL uses data from 2000 based on natural gas production and processing in Canada; however, the authors note that "no significant technology differences/advances occurred in the field of oil and gas extraction in the years between 2000 and 2005 and therefore the data meets the quality objectives" for the study (NETL 2008, p. 13). It is also important to note that the amount of NGL produced in the United States as the result of shale gas well hydraulic fracturing has increased over this time period, but currently-available studies have not estimated what impact, if any, this increase in NGL production may have on NGL extraction and processing GHG emissions. With increased shale gas production, new processing and expansion facilities could come online to keep up with increased gas production. An increase in facilities would certainly increase emissions. However, processing plants are well-regulated and have the lowest GHG emissions of any sector in the natural gas industry.

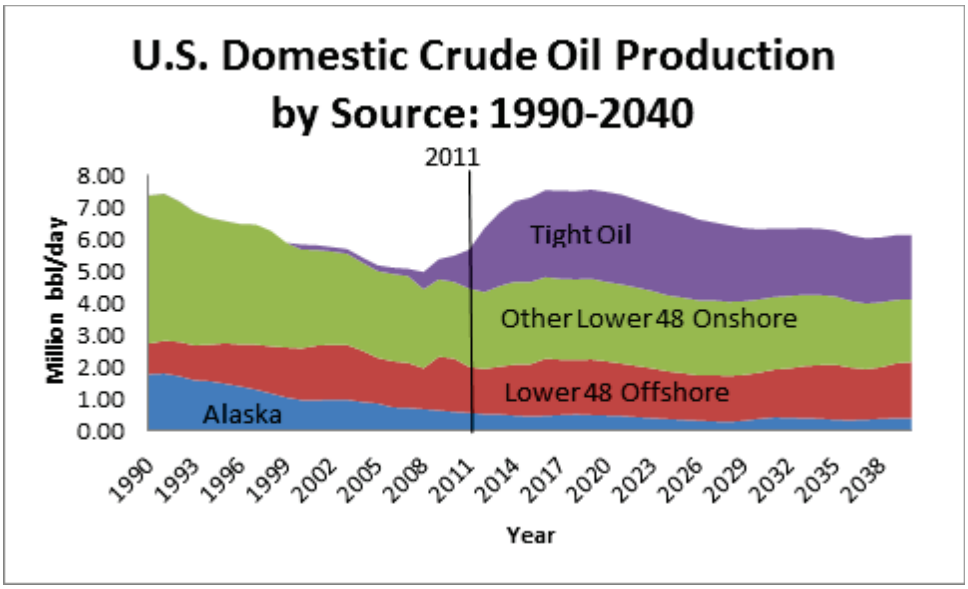
NETL also established a baseline U.S. petroleum feedstock mix for 2005, using the top ten imported country crudes by volume as well as the domestic crude oil volume, all from the U.S. Energy Information Administration (EIA). Given the emergence of tight oil production within the United States since 2005, as well as decreased crude oil imports to the United States since 2005, the crude slate mix in the United States may have changed, and would affect GHG emissions from raw material acquisition and refining. The following section discusses the factors that affect these changes, and the potential implications for the carbon intensities of the LCA in the short and long term.

4.1.4 Near- and Longer-Term Trends that Could Affect WTW GHG Emissions

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 recent conditions or years for which data were available. Since the lifecycle emissions of both WCSB oil sands crudes and reference crudes would change over the design lifetime of the proposed Project, comparisons based on current data would not account for future changes that could alter the differential between oil sands and reference crudes. How the differential would change in the future is not known, but evaluating if currently available studies have determined the impact is important. This section discusses several factors that could play a role in influencing GHG emission estimates in the near or long term.

4.1.4.1 Emergence of Tight Oil Production and Decrease in U.S. Imports

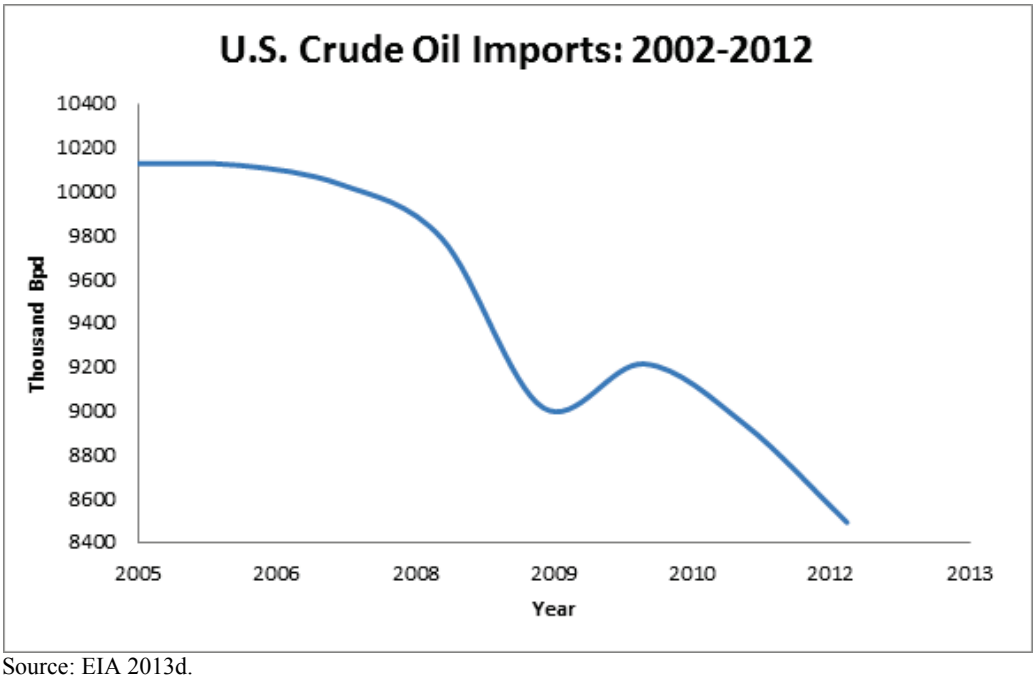
According to the U.S. Energy Information Administration (EIA), U.S. crude oil production is at its highest since 1992 at an average of 7 million barrels per day (bpd) in November and December of 2012 (EIA 2013b). While many factors contribute to supply growth, a large factor is the emergence of tight oil. According to the EIA Annual Energy Outlook 2013, domestic tight oil production has increased from 0.19 million bpd in 2005, to 1.22 million bpd in 2011 (EIA 2013c). Figure 4-2 below illustrates these trends.



Source: EIA 2013c.

Figure 4-2 U.S. Domestic Crude Production by Source from 1990 to 2040

In addition to the emergence of tight oil, a decrease in crude oil imports is changing the U.S. crude oil slate mix. Crude oil imports have fallen nearly 16 percent from 2005 to 2012 (EIA 2013d). The January through April 2013 time period saw 9 percent less imports as compared to the same time period in 2012. Figure 4-3 depicts U.S. crude oil imports from 2005 to 2012.



Source: EIA 2013d.

Figure 4-3 U.S. Crude Oil Imports from 2002 to 2012

Change in Average U.S. Crude Slate Mix

A comparison of the NETL (2009) and the current U.S. crude slate mix is presented in Table 4-3. The NETL (2009) crude slate mix is based on 2005 volumes from EIA, while the current crude slate mix for 2012 is from EIA.

Table 4-3 A Comparison of U.S. Crude Slate Mixes for 2005 and 2012

U.S. Crude Oil Sources	2005[a]		2012[b]	
	Input to U.S. Refineries (1,000s bpd)	Percentage of Refinery Crude Input	Input to U.S. Refineries (1,000s bpd)	Percentage of Refinery Crude Input[d]
U.S. Crude Oil	5,140	33.8%	6,496[c]	42.3%
Canada Crude Oil Canada Oil Sands	1,629	10.7%	2,408	15.7%
Mexico Crude Oil	1,551	10.2%	972	6.3%
Saudi Arabia Crude Oil	1,436	9.4%	1,356	8.8%
Venezuela Crude Oil	1,235	8.1%	906	5.9%
Nigeria Crude Oil	1,075	7.1%	405	2.6%
Iraq Crude Oil	522	3.4%	474	3.1%
Angola Crude Oil	455	3.0%	221	1.4%
Ecuador Crude Oil	276	1.8%	174	1.1%
Algeria Crude Oil	228	1.5%	120	0.8%
Kuwait Crude Oil	222	1.5%	306	2.0%
Other Foreign Crudes	1,452	9.5%	1,524	10.0%
Total	15,221	100%	15,362	100%

[a] Volumes from NETL (2009 Table 2-6); percentages from NETL 2008 Table 2-2.
[b] EIA 2013d.
[c] EIA 2013e.
[d] Percentage calculated by dividing each crude by the total crude oil sent to U.S. refineries in 2012 provided by EIA 2013f.
1,000s bpd = thousands of barrels per day.

The U.S. crude oil share of total refinery crude slate has grown significantly over the last 7 years primarily resulting from increased tight oil production and decreased imports. From Table 4-3, many of the importing countries' crude volumes have decreased significantly, which affects the LCA of GHG emissions for transportation fuels in the United States. However, in preliminary results from a recent assessment, IHS CERA found that the GHG intensity of the U.S. average crude baseline has "not changed materially" between 2005 and 2012 despite significant changes to the crude mix (IHS CERA 2013).[14] Applying GHG intensities developed by NETL (2009) to the 2012 crude mix in Table 4-3, the reduction in WTW GHG intensity is estimated be on the order of 1 percent for gasoline produced from the average crude mix in the United States between 2005 and 2012. These estimates indicate that the overall change in the GHG intensity of the U.S. average crude is minor, as increases in higher-GHG-intensity crudes have been offset by greater volumes of lower-GHG-intensity crudes.

[14] IHS CERA (2013) estimated that the differential between the WTW GHGs for oil sands crudes and their derived 2012 U.S. average crude mix is 9 percent higher, which is 3 percent lower than the IHS CERA (2012) report of a 12 percent differential with the NETL 2005 U.S. average crude mix. IHS CERA attributes the difference to the uncertainty in calculating carbon intensities. IHS CERA (2013) also used a different methodology from NETL to estimate the average crude mix and the GHG emissions for each crude stream.

Impact on Crude Oil Extraction and Refining GHG Emissions

The GHG emissions associated with the raw material acquisition and refining stages of the NETL 2009 LCA study are likely to change due to increased tight oil production, decreased crude oil imports, and a shifting crude slate mix. Little information is available on tight oil production lifecycle effects in the recent U.S. crude oil market; however, analysis of the available studies indicates the emissions from production may increase while emissions from refining may decrease, as discussed below.

In terms of production, tight oil is a light crude (40 to 60 API gravity) (MathPro 2013) that is extracted through horizontal drilling and multi-stage hydraulic fracturing. Hydraulic fracturing is required because of the low permeability of the reservoirs in which tight oil resides. Tight oil development started in the Bakken formation in North Dakota and Montana and is now being developed in the Eagle Ford shale of Texas, the Granite Wash of Texas, the Bone Spring formation in Texas and New Mexico, and the Sprawberry formation in Texas (NEB 2011). The majority of tight oil development is coming from Bakken and Eagle Ford.

In Table 4-4, NETL 2009's 2005 U.S. average feedstock extraction GHG profile is compared to the CARB OPGEE's[15] estimated GHG profile for North Dakota Bakken crude oil. From the comparison, it should be noted that the North Dakota Bakken is nearly 19 percent higher in the crude oil extraction stage emissions. The OPGEE model also indicates that it does not account for hydraulic fracturing emissions and therefore the carbon intensity (CI) value may be low. The CI for crude oil extraction of North Dakota Bakken from OPGEE is 8.19 gCO_2e/MJ (excluding hydraulic fracturing emissions), which is higher than NETL's 2005 U.S. average of 6.9 gCO_2e/MJ. With the addition of hydraulic fracturing emissions, OPGEE's North Dakota Bakken CI value may be even higher than the 2005 U.S. average.

Table 4-4 Comparison of Crude Oil Extraction GHG Profiles for 2005 U.S. Average Crude Oil and North Dakota Bakken Crude Oil

Feedstock Source	Feedstock Extraction GHG Profile (gCO_2e/MJ)	API Gravity
2005 U.S. average[a]	6.90	32.8[b]
North Dakota Bakken[c]	8.19	40.0

[a] Taken from NETL 2009 Table 4-12.
[b] Taken from NETL 2009 Table 2-6.
[c] Values for North Dakota Bakken estimated with CARB OPGEE by subtracting the transportation emissions from the production emissions.

In the refinery stage of the fuel lifecycle, the large share of tight oil feedstock may result in fewer emissions, compared to the NETL (2009) U.S. 2005 average. Refinery emissions and energy inputs decrease as the API gravity of the crude oil increases (i.e., lighter crude oil) and refinery conversion decreases. A study conducted by MathPro for the International Council on Clean Transportation (ICCT) analyzed the refinery emissions of several crudes including tight oil (MathPro 2013). Results from the study show that as refinery feedstock becomes lighter, energy use and the CO_2 emissions from the refinery decrease. The study's analysis of additional tight oil feedstock indicates refinery emissions may be reduced by 7 to 9 percent as compared to the study's 2011 baseline.

[15] California Air Resources Board's Oil Production Greenhouse Gas Emissions Estimator.

No study did a complete WTW LCA of tight oil, and due to the variation in the properties of the reference crudes across the different studies, combining results from different studies would result in an inconsistent comparison. Thus, while information on the lifecycle GHG emission implications of tight oil is not complete, analysis of available studies (CARB OPGEE 2013a and MathPro 2013) indicates the emissions from production may increase while emissions from refining may decrease.

4.1.4.2 Other Factors that may Influence the Longer-Term GHG Emissions of WCSB Oil Sands and Reference Crudes

Many factors would affect the lifecycle GHG emissions of both WCSB oil sands and reference crudes over time. First, GHG emissions from extraction would increase in the future for most reference crudes as it would 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—would represent a larger share of oil sands production in the future – up to 55 percent of total production by 2030 from 37 percent in 2011 (IHS CERA 2012). As with reference crudes, reservoir quality is expected to decline over time and could necessitate increased energy for higher steam-oil ratios (SORs) needed to extract bitumen using *in situ* methods (IHS CERA 2012, p. 20), though this "depletion effect" has not yet been observed and may be relatively minor (Brandt et al. 2013, p. 6). While these factors could increase oil sands lifecycle emissions, some analysts also predict that technical innovations will likely continue to reduce the GHG-intensity of *in situ* SAGD operations. For example, decreased steam use and new hybrid steam-solvent techniques could reduce WTT GHG emissions by as much as 5 to 20 percent for *in situ* production (IHS CERA 2012, p. 19). IHS CERA 2012 also describes a new mining method that will eliminate the upgrading step and reduce WTW GHG emissions by 6 percent (IHS CERA 2012, p. 6).

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 SORs (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 would 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.

On the other hand, traditional oil wells would require more energy intensive techniques to continue exacting oil. 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. This is because traditional oil extraction techniques can only extract between 45 and 55 percent of the oil in the reservoir. To extract more oil, enhanced oil recovery techniques (formerly called Tertiary Recovery Techniques) must be used (Tzimas et al. 2005). These techniques are not only more expensive, but are usually more energy intensive, especially in terms of increased electricity consumption (NETL 2009, Electricity), and potentially more harmful to the environment (USEPA 2013a). Also, these enhanced oil recovery techniques can only currently extract an additional 5 to 15 percent of the oil in the reservoir, which means that additional techniques would need to be developed to continue extracting oil from these reservoirs (Tzimas et al. 2005).

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 would 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 CCS adoption and CO_2 pipeline infrastructure development.

4.1.5 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, 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.

International Organization for Standardization (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 lifecycle 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 4.2.1.4 and 4.2.3.1, Electricity Cogeneration and Export, 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 would be required in future studies. (Charpentier et al. 2009)

4.1.6 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,[16] 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.[17] 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 (2010), 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. IHS CERA (2012) provides GHG emission results both in terms of GHG emissions per barrel of refined products as well as in GHGs per megajoule of gasoline and diesel.

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 provided emissions estimates per megajoule or British thermal unit 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 kilometer burned in vehicle engine. This wide range of metrics has made comparisons across studies difficult in some instances, necessitating several unit conversions.

In expressing GHG emissions in carbon dioxide-equivalent terms, the primary studies reviewed for this analysis (e.g., NETL 2009, Jacobs 2009, and TIAX 2009—which relies on the GREET model) used the latest 100-year global warming potential values from the IPCC's Fourth Assessment Report (IPCC 2007) for methane and nitrous oxide in their estimation of lifecycle GHG emissions. Using 100-year global warming potential values is consistent with the approach

[16] As explained in the U.S. GHG Inventory Report 1990-2011, 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 over a certain period of time (USEPA 2013a). GWPs are typically assessed over a time period of 100 years, although shorter or longer timeframes can also be used. 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, based on the IPCC's Second Assessment Report (IPCC 1996). The 2007 IPCC Fourth Assessment Report, which is referenced by several studies cited within this report, provides updated 100-year GWP values of 25 and 298 for CH_4 and N_2O, respectively. For comparison, the Fourth Assessment Report's 20-year GWP values are 72 for CH4 and 289 for N2O (IPCC 2007). 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.

[17] 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 emissions from end-use are the same for each crude and equal to those of the combustion of an average crude.

currently taken by various government and international authorities, including the parties to the United Nations Framework Convention on Climate Change (UNFCCC), the 1997 Kyoto Protocol, and the USEPA in various analyses including the national GHG Inventory. On its website, the USEPA explicitly describes its use in agency analyses of 100-year global warming potential values from IPCC's Second Assessment Report (IPCC 1996) rather than more recent IPCC values, as an effort to maintain consistency with international standards under the UNFCCC (USEPA 2010d).[18] However, in 2015 the UNFCCC will require GHG reporting parties to use IPCC 2007 global warming potential values, and certain USEPA programs already use the more recent 100-year global warming potential values from IPCC 2007. One hundred-year global warming potential values were also consistently implemented across the Jacobs (2009), NETL (2009) and TIAX (2009) GHG studies. Other environmental impact statements, such as the National Highway Traffic and Safety Administration's Corporate Average Fuel Economy (NHTSA's CAFE) EIS, have also used the 100-year global warming potential values (NHTSA 2012).

Compared to other fuel sources, such as shale gas, and certain oil producing regions, such as Nigeria, methane emissions from WCSB oil sands crudes are a small portion of lifecycle GHG emissions. According to NETL (2009), methane emissions represent only 4 percent of WTT GHG emissions and 1 percent of WTW GHG emissions, using 100-year global warming potential values. According to estimates from NETL (2008, 2009), using 20-year global warming potential values for methane and nitrous oxide would increase WTW emission estimates by approximately 2 percent for WCSB oil sands crudes compared to estimates using 100-year global warming potential values. Using 20-year global warming potential values would reduce the GHG differential between WCSB oil sands crudes and most of the reference crudes that could be displaced in U.S. refineries. This difference results from the smaller share of methane emissions along the WCSB oil sands crude lifecycle relative to several other reference crudes, while nitrous oxide emissions are comparable. NETL (2009) reports that the WTT methane emissions represent 4 percent of oil sands emissions as compared to 3, 8, and 14 percent for Saudi Light, Venezuela Bachaquero, and Mexican Maya, respectively. Using a higher global warming potential value for methane would thus increase the carbon intensity of Venezuela Bachaquero and Mexican Maya fuels relative to oil sands crude.

4.2 INPUT AND MODELING ASSUMPTIONS

The second set of factors driving the comparisons is input and modeling assumptions that are made at each lifecycle 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
3. Factors that affect both types of crudes

[18] United Nations Framework Convention on Climate Change.

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 main 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; ERCB 2013).

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 4-5 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.

Not included in Table 4-5 is CARB OPGEE (2013a) because it only calculates GHG emissions for the first two lifecycle stages of crude oil extraction and crude oil transport (WTR). However, the model does calculate GHG emissions and energy consumption from bitumen mining and *in situ* extraction. In OPGEE, the Default[19] (not specific to a crude reservoir or country) WTR emissions for mining extraction range from 15.51 to 21.78 gCO_2e/MJ bitumen while default WTR emissions for *in situ* extraction range from 25.96 to 31.63 gCO_2e/MJ bitumen. Emission ranges depend on the mining type (integrated mining and upgrading, or non-integrated mining) or *in situ* extraction (non-thermal, SAGD, or CSS) (CARB OPGEE 2013a, p. 87). For the

[19] Default values are prepopulated values in the model and are not for a specific crude reservoir or country; values are from publically available data and literature sources, which can be modified by the model user.

Default scenario in OPGEE, bitumen mining contributes 70 to 78 percent of total WTR emissions while *in situ* extraction contributes 80 to 83 percent of total WTR emissions.[20]

Table 4-5 Increase in WTW GHG Emissions from *In Situ* Extraction of Oil Sands Compared to Mining

Source	Percent Increase[a]	Notes
IHS CERA 2010, Table A-8	7%	SAGD SCO from *in situ* compared to SCO mining
IHS CERA 2012, Table 2	7 to 9%[b]	SAGD SCO from *in situ* compared to SCO mining
NRDC 2010a, p. 2	9%	Average estimate for SCO from *in situ* compared to mining based on a range of literature values
Charpentier et al. 2009, Figure 2	3 to 9%	SCO from *in situ* compared to mining, based on comparison of values from the GHGenius and GREET models
Brandt 2011	9%	SCO from *in situ* compared to mining based on GHGenius values
Bergerson et al, 2012a, Figure 1	8 to 9%	SCO from *in situ* compared to surface mining. WTR emissions were developed by the authors; refining emissions are taken from TIAX 2009; fuel delivery, refueling, and use stage emissions are taken from GHGenius.

[a] Percent increase in WTW GHG emissions from *in situ* compared to mining extraction of WCSB oil sands.
[b] Range includes tight scope (only direct emissions from oil production site and facilities) on the low end and wide boundary (including emissions from upstream fuels) on the upper end.

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 Table 4-6. Table 4-6 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; with higher prices, 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.

Table 4-6 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	Surmont	Commercial-SAGD	0.85	2.81

[20] WTR emission percentages are calculated from CARB OPGEE (2013a) Default values, for all five bitumen extraction methodologies.

Operator	Project	Recovery Method	Annual Bitumen Production (106 x m^3)	SOR (weighted average)
Corp.				
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 = cyclic steam stimulation, SAGD = steam-assisted gravity drainage, SOR = steam-oil ratio, m^3 = cubic meters.

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). Jacobs (2012) also shows how decreasing the SOR from 4 to 2 can decrease the resulting emissions by more than 50 percent (Jacobs 2012, p. 5-40). 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.

Charpentier et al. (2011a) develop two different estimates of SORs for SAGD and CSS operations, which they define as the instantaneous SOR (iSOR) and cumulative SOR (cSOR) (Charpentier et al. 2011a, p. 9397). The iSOR is typically reported daily while cSOR is reported over a longer time frame. Therefore, the cSOR is more reflective of average project conditions because iSOR varies greatly during the lifetime for any project. In their model of GHG emissions from WCSB oil sands extraction, Charpentier et al. (2011a) apply iSOR for SAGD because "SAGD projects have not been operating long enough to gather sufficient historical data and perspective on cSOR" (p. 9398).

The report by Jacobs (2012) also shows that the top three SAGD production sites in Alberta have been steadily decreasing their SOR while simultaneously increasing their total output. The instantaneous SOR when the projects were first started in 2002 ranged from 4.0 to 5.3. By 2010, the instantaneous SOR had fallen to between 2.3 and 3.2. In the same period, the production from those three sites rose from well below 40,000 bpd to nearly 187,000 bpd in 2010 (Jacobs 2012, pp. 5-32 to 5-35). Brandt et al. (2013) concluded that qualitative work to-date in this area of energy efficiency linked to production has suffered from poor data availability, uncertain methods, new datasets, and a new methodology (to compute energy return ratios). In its analysis of data from oil sands regulatory statistics, the study nevertheless showed long-term trends of oil

sands operations becoming significantly more efficient over time (Brandt et al. 2013).[21] CARB OPGEE (2013a) uses two default estimates of SORs for SAGD and CSS operations taken from GHGenius 4.0c by $(S\&T)^2$ Consultants in the March 2011 update of oil production and refining. As shown in Table 4-7, these values fall within the range of other studies.[22]

Table 4-7 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 4-7 SOR Assumptions for *In Situ* WCSB Oil Sands Operations in Each of the Studies Reviewed

Study	SOR		Notes
	SAGD	CSS	
Charpentier, et al., 2009	NE	NE	Depends on the study but this meta-analysis indicated that many studies do not report their assumed SORs.
CARB OPGEE, 2013a	3.0	3.9	Default SORs in the model derived from the March 2011 update of oil production and refining of GHGenius 4.0c by $(S\&T)^2$ Consultants. The user can define different SORs in the model.
Charpentier et al., 2011a	2.2-3.3	NA	Instantaneous SOR, dry. The authors use this narrower range because 85% of bitumen from oil sands projects operating in January 2009 was produced within this range. The full range is 2.1-5.4. Dry SOR corrects for a liquid water fraction that is produced with the "dry" stream and removed before injection in a separator. Dry iSOR = 0.8*wet cSOR.
Bergerson et al., 2012b	NA	2.6-5.9	Cumulative SOR, wet. The authors use this figure because 82% of total bitumen produced in Alberta up to December 2008 was produced within this range. The full range is 2.6-10.2. Wet SOR is used because CSS projects typically inject wet steam instead of dry steam, which is used in SAGD. Dry cSOR = 0.8*wet cSOR.
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.
GHGenius, 2010	3.2	--	
GREET, 2010	--	--	
ICCT, 2010	NE	NE	
IEA, 2010	NE	NE	States that the industry norm for *in situ* operations is approaching 3.

[21] From 1970 to 2010, point-of-use net energy return on investment (EROI) for oil sands increased from 1 to 3 GJ output per GJ of energy consumed (Brandt et al. 2013). In contrast, the EROI for conventional crudes has decreased over the course of the 20th century and continues to fall due to the increased difficulty of accessing remaining reserves. Where EROI rates in the early 20th century may have been as high as 100 GJ per GJ at the point of extraction, they have declined to 18 GJ/GJ by 2010 (Brandt et al. 2013).

[22] SOR values found in the *Bitumen Extraction & Upgrading* tab under Section 2, *Input assumptions and data* in CARB OPGEE 2013a.

Study	SOR		Notes
	SAGD	CSS	
IHS CERA, 2010	3	3.35	
IHS CERA, 2011	3	3.35	
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.
McCann, 2001	NE	NE	
NETL, 2008	--	--	
NETL, 2009	--	--	
NRDC, 2010	NE	NE	Study notes that it varies by crude, but does not explicitly discuss the values.
Pembina Institute, 2005	NE	NE	
Pembina Institute, 2006	NE	NE	
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.
TIAX, 2009	2.5	4.8; 3.4	CSS values are for specific operations using onsite electricity and grid electricity, respectively.

Note: SOR is not specified in IHS CERA (2012).

-- = Not located; CSS = cyclic steam stimulation, 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 4-8 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 4-8, only one is currently operating, representing less than 3 percent of total WCSB oil sands bitumen capacity.[23] 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).

Table 4-8 Upgrader GHG Emissions per Barrel of SCO[24]

Project	Comments	Direct Emissions Intensity kg/bbl	Indirect Emission Intensity kg/bbl	Total Emission Intensity kg/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)[24].

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 4-8 show that direct emissions from delayed coking range from 40.7 to 92.8 kgCO_2e per barrel of SCO, while GHG

[23] Production capacity of the first phase of OPTI/Nexen's 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).

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

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.

Charpentier et al. (2011a) and Bergerson et al. (2012a) estimate that the upgrading stage results in emissions in the range of 7.4 to 15.0 gCO_2e/MJ SCO for delayed coking and 6.4 to 16.7 gCO_2e/MJ SCO for hydrocracking. WTR emissions estimates are in the range of 18.6 to 44.7 gCO_2e/MJ SCO for delayed coking and 17.6 to 46.3 gCO_2e/MJ SCO for hydrocracking. There is a wider range of variation in GHG emission estimates from the hydrocracking process compared to delayed coking. The upgrading technology can have a significant impact in the total WTR emission estimate as upgrading emissions comprise 34 to 40 percent of total WTR emissions.

CARB OPGEE (2013a) estimates Default upgrading emissions within the model, under the bitumen extraction and upgrading stage. With the bulk of upgrading emissions coming from combustion, the model calculates each fuel type's emissions based on energy demand values provided by GHGenius v4.0c. Upgrading emissions are calculated for a standalone upgrader or for integrated mining and upgrading. As a percentage of total WTR emissions, upgrading emissions from the model range from 39 to 53 percent.[25]

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 4.1.5, 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[26] 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).[27]

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

[25] CARB OPGEE (2013a) range calculated from the five different Default bitumen extraction scenarios.
[26] Jacobs (2009) did not comprehensively evaluate cogeneration opportunities at oil sands facilities, but included a preliminary, illustrative analysis and recommended further investigation of cogeneration.
[27] 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.

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 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; IHS CERA 2012, p. 13). In the IHS CERA (2010) study, 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. In the IHS CERA (2012) study, cogeneration of electricity is included in its wide-boundary results.

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.[28] 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).

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. $(S\&T)^2$ 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.

Charpentier et al. (2011b) and Bergerson et al. (2012b) assume that surplus electricity generated is sold to the grid. In order to allocate the greenhouse gas savings, the authors cite the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry* who use a substitution approach for allocating savings to electricity production (API 2009). To apply this approach, the authors took the difference between actual natural gas consumption in cogeneration systems at oil sands facilities and what would be used in an equivalent industrial boiler to produce the same amount and quality of steam. They calculate a GHG intensity factor for natural gas-fired electricity generation at the cogeneration facility, include the GHG emissions from electricity consumed in the oil sands process in the WTR emission estimates, and exclude GHG emissions attributable to surplus electricity. This approach is used for simplicity and conservatism (Charpentier et al. 2011b, p. 14). The data from the authors show that in the cogeneration case, there is always a decrease of WTR emissions. The emissions per megajoule of dilbit, synbit, or SCO decrease by 2 to 11 percent in surface mining, SAGD, or CSS (Charpentier et al. 2011a, Bergerson 2012a, and Bergerson 2012b).

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 would produce greater quantities of premium fuel products (i.e., gasoline, diesel, and jet fuel), no heavy

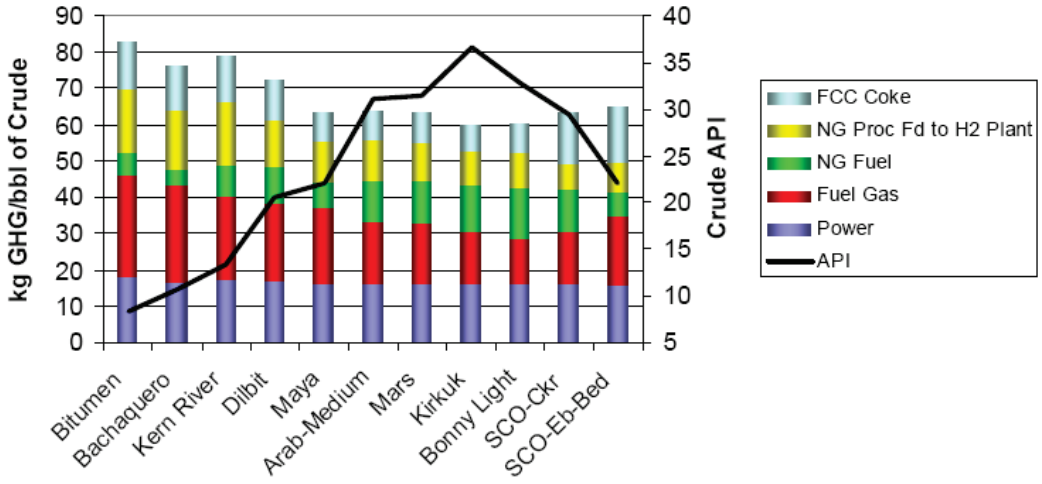
[28] Based on 1,923 thousand barrels per day of total raw bitumen capacity in the WCSB oil sands (IEA 2010, p. 152). CNRL's Primrose project has a raw bitumen capacity of 120 thousand barrels per day (IEA 2010, p. 152), while MacKay River has a capacity of 33 thousand barrels per day (Oil Sands Developers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

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, Table A-8 from IHS CERA 2010, and Table 2 from IHS CERA 2012). However, the effect is more significant on a WTT basis. Studies that do not account for the reduction in refinery energy use for SCO would 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 4-4 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.

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 4-4 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. 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 4-9 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.[29] The estimates where diluent is refined with the raw bitumen at the refinery are representative of the proposed Project, since diluent would 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 4-9 Comparison of WTW GHGs per Megajoule of Premium Fuel Products Refined from Dilbit, Bitumen, and SCO

Study	Extraction Method	Feedstock	WTW GHG Emissions (gCO_2e/MJ^a)	Percent Change[b]	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%	

[a] WTW GHG emissions are in terms of grams CO_2 equivalent per megajoule of reformulated gasoline.
[b] 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

[29] Diluent is brought to oil sands facilities from offsite. Jacobs (2009) accounts for diluent as an input in dilbit production, but does not explicitly state upstream assumptions. TIAX included emissions associated with diluent production (Jacobs 2009, p. H-1).

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, 2012) 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.[30] 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 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

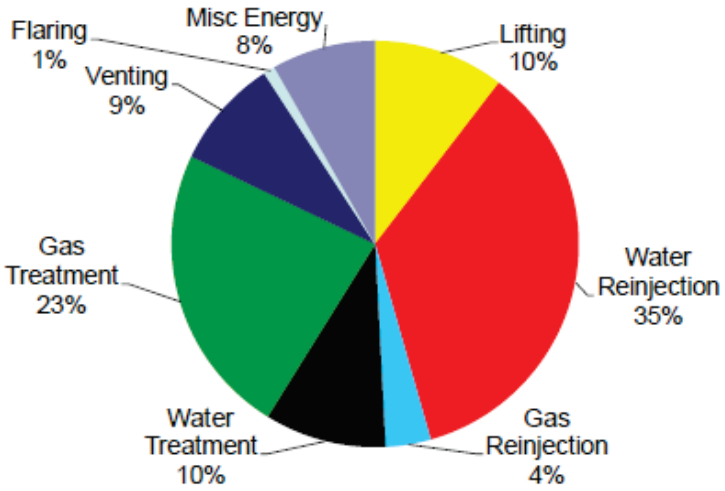
The methods of producing oil from wells drilled into an oil reservoir evolve over the reservoir's lifetime. There are generally three phases of production from a reservoir: primary, secondary, and tertiary. Primary recovery relies on the initial pressure of the oil reservoir itself to lift the oil through 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 22 $kgCO_2e$ per barrel of refined products (IHS CERA 2012, Table 2). Studies that do not account for lift and associated treatment and reinjection energy requirements would underestimate the GHG emissions from reference crude production relative to oil sands-derived crudes.

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 4-5. Similarly, TIAX (2009) considered different lift

[30] 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.

methods to determine oil production energy use and GHG emissions, as shown in Table 4-10 (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 lifecycle from reservoir to freight onboard a tanker.



Source: Jacobs 2012, p. 5-17.

Figure 4-5 Major Sources of GHG Emissions from Production of a Generic Crude Oil[31]

Table 4-10 Crude Oil Recovery Methods

Label	Crude Name	Recovery Methods
Alaska	Alaska North Slope	Water Alternating Gas 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.

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

[31] 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).

Arabia, however, is roughly half that of Jacobs (Jacobs 2012, Figure 5-7).[32] 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.

Crude oil production estimates in the model from CARB OPGEE (2013a) also account for artificial lift methods including downhole pump, gas lift, water flooding, gas flooding, and steam injection. Under the crude oil production and extraction stage, the model allows users to select the artificial lift assumptions, which would vary among different oil fields. From the selected assumptions, the model then computes emissions based on parameters the user enters, which are field-specific.[33] Emerging techniques not included in the model are CO_2 flooding and hydraulic fracturing (CARB OPGEE 2013b, p. 41).

4.2.2.2 Sensitivity to Water-Oil and Gas-Oil Ratios

Water-oil (WOR) 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 CH_4) is vented rather than flared, this can have a significant effect on GHG results, as the GWP of CH_4 is more than 20 times higher (estimates vary from 21 to 25 depending on which IPCC assessment report is cited) than that of CO_2 over a 100-year time horizon. On a shorter time horizon, the relative GWP of methane would be even higher, ranging from 56 to 72 on a 20-year timescale.

The *User Guide & Technical Documentation* for the CARB OPGEE model indicates that the WOR tends to increase with the age of the oil field, and that increasing WOR results in increased upstream energy use (CARB OPGEE 2013b). Further study with OPGEE indicates that upstream GHG emissions for heavy oil (API <20) extraction using steam injection for thermal enhanced oil recovery (TEOR) with both high and moderate WOR are in similar ranges with light oil (API >20) conventional extraction with high WOR (El-Houjeiri and Brandt 2012).

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

[32] Jacobs (2012) estimates approximately 4 gCO_2/MJ of crude for Saudi Arabian Medium, or 24 $kgCO_2$/bbl assuming 6.119 gigajoule per barrel (GJ/bbl) crude oil (Jacobs 2012, Figure 5-7).
[33] CARB OPGEE (2013a) Production and Extraction stage.

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, Incremental GHG Emissions of Displacing Reference Crudes with WCSB Oil Sands, 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 would 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 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,[34] 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). The IHS CERA (2012) analysis assumed that the GHG impact of coke combustion is negligible as it assumes that it is "simply displacing coal that would otherwise have been burned in power generation" (p. 8). As shown in Table 4-8 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.[35] Table 4-11 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. Charpentier et al. (2011a) and Bergerson et al. (2012a) acknowledge that the combustion of coke is a byproduct in the upgrading stages. Emissions from coke production in the delayed coking process are included

[34] Based on a comparison of WTW GHG emissions from SAGD SCO where all the coke is gasified for process energy to SAGD SCO where the coke is buried (i.e., stored) and not combusted.

[35] The allocation rules that studies apply to petroleum coke are a study design factor that is addressed in Section 4.1.5, 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.

in their emission estimates, but the authors consider emissions from the disposal or use of petroleum coke as outside the scope of the studies (Charpentier et al. 2011b, p. 6).

Table 4-11 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. 48, G-6	Does not include combustion emissions 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.	GHG emissions from producing coke are allocated to the other premium fuel products. Coke combustion is not included.
IHS CERA 2010, p. 36; IHS CERA 2011, p. 17-18	Unclear to what extent emissions from use of coke are included.	Excludes coke from combustion emissions.
IHS CERA 2012, p. 8	Not stated	Emissions from use of petroleum coke are not included as they are assumed to be negligible.
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
Charpentier et al. (2011b, p. 6) and Bergerson et al. (2012b)	Emissions from cokers are accounted for in the model but the emissions from disposal or the use of co-produced coke are not.	Not included; lifecycle boundaries only include oil sands extraction and upgrading stages.
Pembina 2006	Gasification of coke was included in high-emission scenarios for hydrogen production for upgrading.	Not stated

Study	Petroleum coke from upgrading bitumen at the upgrading facility	Petroleum coke from reference crudes or bitumen at the refinery
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 = lifecycle 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. refineries. Based on Table 4-11, 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 lifecycle system boundary. Excess petroleum coke produced from PADD 3 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 lifecycle 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 (2012) found that transportation emissions make up less than 2 percent of total WTW emissions (IHS CERA 2012 Appendices, p. 12). IHS CERA (2010) also documented considerable variation in transportation estimates, ranging from 1 to 14 $kgCO_2e$/bbl for crude transportation from Mexico.

Bergerson et al. (2012a) found that the transportation emissions make up around 4 percent of WTW emissions for all the scenarios studied (surface mining, SAGD, and CSS extraction of dilbit, synbit, and SCO, respectively). While the transportation emissions estimated by the authors comprise a larger share of total WTW emissions than in IHS CERA, the transportation emissions in Bergerson et al. (2012a) are still low compared to emissions from other lifecycle stages estimated by the authors.

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 lifecycle 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 lifecycle GHG emissions from land use change associated with oil sands extraction (NETL 2009, IHS CERA 2010, 2011, 2012, Jacobs 2009, TIAX 2009, Charpentier et al. 2011a, Bergerson et al. 2012a), although Jacobs (2012), CARB OPGEE (2013a), 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 lifecycle literature on oil sands-derived crudes. Recent studies (Rooney et al. 2012, Yeh et al. 2010, Lee and Cheng 2009) 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 that would have been sequestered had a land-based carbon sink, such as a peatland, not been cleared for development.

Table 4-12 provides estimates of carbon stocks, carbon sequestration rates, and land reclamation rates for Canadian boreal forests and peatlands from Rooney et al. (2012) and Yeh et al. (2010). The studies conclude that oil sands developments would 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 4-12 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[a]	See p. 4, from Beilman et al. 2008	1,213	Table S5, Table S6, Vitt et al. 2000
		High	1,650[a]		--	--
	Average oil sands biomass		--	--	78	Table S7[b]
	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	--	--	--[c]	--
		High	--	--	--[c]	
Post-mining above-ground biomass stocks (metric tons C/ha)	Reclaimed lands	Low	--	--	76	See assumptions on p. S13[d]
		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[e]
		High	146		101	

Carbon pool	Land type		Rooney et al. 2012 Value	Rooney et al. 2012 Source	Yeh et al. 2010 Value	Yeh et al. 2010 Source
Carbon stock loss (metric tons C/ha)	Average carbon loss from reclamation of oil sands	Low	--	--	271[f]	Calculated from information in Table S7
		High	--	--	411[g]	
	Carbon loss from reclamation of peatland to upland forest	Low	384	See p. 5[h]	778 [j]	
		High	1,600	See p. 5[i]	1,067[k]	
Forgone carbon sequestration (metric tons C/ha/yr)	Forest		--	--	0[l]	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.

[a] Carbon stock depends on peat depth, composition, and bulk density.
[b] Assumes distribution is 23% peatland and 77% upland forest (see Table 2, note c in Yeh et al. 2010)
[c] Yeh et al. (2010) assume that peatland is reclaimed to boreal forest at the rate of boreal forest carbon uptake.
[d] 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.
[e] Assumes 30% of carbon is sequestered in soil at a constant rate throughout 150 year modeling period (Yeh et al. 2010, p. S13).
[f] 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).
[g] 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).
[h] 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).
[i] 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).
[j] 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).
[k] 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).
[l] 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.

-- = Not estimated, C/ha/yr = carbon per hectare per year.

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 would 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 would occur at an annual rate of 1.35 to 2.25 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 percent 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). Similarly, Lee and Cheng (2009) noted that natural peatlands of continental western Canada have historically increased their total carbon storage by 0.19 metric tons of carbon per hectare per year (Lee and Cheng 2009, p. 29). 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.[36] Yeh et al. (2010) looks at average per-hectare emissions from lands mined for oil sands, which they estimate to be 23 percent peatland and 77 percent boreal forest. A third study, Lee and Cheng (2009) examines land area already changed and that may potentially change by surface mining and *in situ* extraction, and the associated total above- and below-ground organic carbon content in each land area. For each land area—including areas developed as of June 2009, areas for projects approved and proposed as of June 2009, and the total minable area—Lee and Cheng also estimate the peatland area potentially changed and the subsequent lost CO_2 sequestration potential per year. However, they did not estimate annual peatland soil carbon loss values from surface mining or *in situ* extraction. Thus, only peatland results from Rooney et al. (2012) and Yeh et al. (2010) are comparable. Peatland soil carbon loss values were within a similar range: 384 to 1,600 metric tons of carbon/year in Rooney et al. (2012) and 778 to 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 lifecycle 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 lifecycle GHG emissions from oil sands production (considering both surface mining and *in situ* production) over a 150-year modeling period.[37,38] In comparison, the authors estimate that land use change accounts for less than 0.4 percent of emissions from

[36] 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.
[37] Yeh et al. compare GHG emissions per megajoule of crude refinery feedstock to full lifecycle 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.
[38] 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 lifecycle emissions.

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 lifecycle GHG emissions associated with extraction, upgrading, transportation, refining, and combustion of refined products from oil sands-derived crudes. By comparison, Lee and Cheng (2009) estimated that potential loss of annual sequestration potential from land use change of peatlands resulting from approved and proposed new bitumen surface mining projects as of June 2009 would range from 3,627 to 7,009 metric tons of carbon per year (or 194 kg of carbon per hectare). 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).

The primary driver for the release of stored carbon from land use change in Alberta is the replacement of carbon-rich peatland (containing 530 to 1,650 metric tons of carbon per hectare) with relatively low carbon post-mining soils (containing 50 to 146 metric tons of carbon per hectare). In three of the mines examined in Rooney et al. (2012), 67 percent of the peatlands were reclaimed; this land conversion proportion was then scaled by the total area permitted for oil sands mining to estimate the peatland loss for the entire region studied. The uncertainty in the carbon release estimate is derived from the wide range of carbon storage values for both the peatland and the post-mining soil.

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. 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 (Jacobs 2012, pp. 1-62 to 1-64).

Representativeness was a key area of concern in some of the studies in that they lacked data on actual facility operations. NRDC (2010b) 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). The GHOST model uses

publicly available data on currently operating oil sands projects; GHOST model development is described in Charpentier et al. (2011 a) and applied to estimate lifecycle GHG emissions from oil sands technologies in Charpentier et al. (2011 a and b) and Bergerson et al. (2012a and b). In addition, the model also uses confidential operating data from five companies. The authors state that the data were verified with mass and energy balance calculations and with other sources. The data compilation method for input parameters and ranges of parameter values are detailed in Charpentier et al. (2011b, p. 8).[39]

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 lifecycle 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. Charpentier et al. (2011a and b) and Bergerson et al. (2012a and 2012b) provide certain input data as a range of values. These ranges are developed through confidential operating data provided by oil sands facilities, data from literature, and industry experts. The confidential data are augmented with publicly available data to make the range more robust (Charpentier et al. 2011a, p. 9398). The industry operating data and literature data receive a higher weight when developing the ranges, while the data provided through expert elicitation receive a lower weight (Charpentier et al. 2011b, p. 8).

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 lifecycle GHG emissions of WCSB oil sands crudes compared to reference crudes. To analyze the effects, the key factors and lifecycle 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 lifecycle GHG emissions.

[39] Charpentier et al. (2011 a) estimated WTR GHG emissions for oil sands SAGD of 8.7-18.5 gCO2e/MJ dilbit, 12.6-23.8 g CO2e/MJ synbit, and 18.1-40.9 g CO2e/MJ SCO. Bergerson et al. (2012a) estimated WTR GHG emissions for oil sands surface mining of 3.5-12.7 gCO2e/MJ dilbit, 9.2-19.9 g CO2e/MJ synbit, and 10.6-32.4 g CO2e/MJ SCO.

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) (USEPA 2010a).

4.4.1 Analysis of Study Design Factors

Table 4-13 summarizes key design factors across the studies identified through this assessment. The first row of Table 4-13 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. High, medium, or low categories were assigned based on analysis and judgment.

In general, the studies reviewed are consistent with one another in how they treat some factors. For example, the studies' lifecycle 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 4-13 (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. However, in its 2012 update study, IHS CERA assumed that petroleum coke combustion emissions are negligible as the petroleum coke displaces coal that would have been burned. 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).

Table 4-13 Summary of Key Study Design Features that Influence GHG Results

Estimated Relative WTW Impact:[a]		High					Medium				Low
Source	Data Reference Year(s)	Petroleum coke combustion[b]	Cogeneration credit[c]	Upstream production of fuels included[d]	Flaring/ venting GHG emissions included	Capital equipment included[e]	Refinery emissions account for upgrading[f]	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, 2012	~2005-2030	V	V	No	NS	NS	NA	No	V	NS	V
NRDC, 2010	2006-2010	NS[g]	NS[g]	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[h]	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[g]	NS[g]	V	NS	V	NA	No	NS	NS	NS
Brandt, 2011	V	V	V	NS[g]	V	NS[g]	V	V	V	V	V
RAND, 2008	2000s	NS	NS	NS	Yes	No	No	No	Yes	Yes	Yes
Charpentier et al. 2011a	2009	No	Yes[i]	Yes	Yes	No	NA	No	No	Yes	NS
Bergerson et al. 2012a	2009	No	Yes[i]	Yes	Yes	No	NA	No	No	Yes	NS
CARB OPGEE, 2013a	1990s, 2000s	No	NS	Yes	Yes	No	NA	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

Estimated Relative WTW Impact:[a]		High					Medium				Low
Source	**Data Reference Year(s)**	**Petroleum coke combustion[b]**	**Cogeneration credit[c]**	**Upstream production of fuels included[d]**	**Flaring/ venting GHG emissions included**	**Capital equipment included[e]**	**Refinery emissions account for upgrading[f]**	**Local and indirect land use change included**	**Methane emissions from tailing ponds included**	**Fugitive leaks included**	**Methane emissions from mine face**
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

[a] 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.
[b] 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.
[c] 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 would reduce the GHG emissions from oil sands crudes relative to reference crudes.
[d] 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).
[e] Indicates whether the study included GHG emissions from the construction and decommissioning of capital equipment such as buildings, equipment, pipelines, rolling stock.
[f] 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.
g Not discussed in the meta-study; may vary by individual studies analyzed.
[h] 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).
[i] The authors do not assign a cogeneration credit, but instead calculate the portion of surplus electricity that is exported to the grid and exclude GHG emissions from the generation of this electricity from the lifecycle boundary (Charpentier et al. 2011b, p. 14).

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

- 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).[40]

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 emissions for average WCSB oil sands. IHS CERA (2012) includes upstream GHG emissions for fuel production in its wide scope estimate, resulting in a 6 percent increase in WTW emissions compared to its tighter scope estimate which only includes direct emissions from the oil production site and facilities.
- 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 would 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.[41]

[40] 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).

[41] 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 would 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).

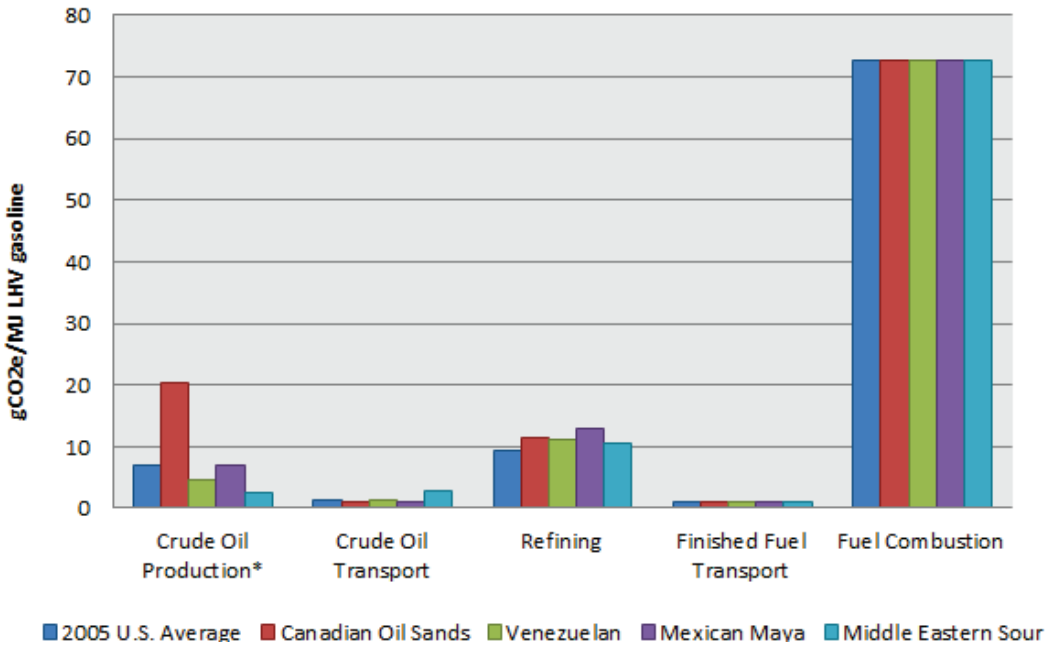
- None of the studies included the GHG impacts associated with capital equipment and construction of facilities, machinery, and infrastructure needed to produce oil sands. According to Bergerson and Keith, the relative percentage increase to WTW GHG emissions from incorporating capital equipment is between 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 lifecycle studies (Charpentier et al. 2009, p. 10). Charpentier et al. (2011a) and Bergerson et al. (2012a) do not account for lifecycle GHG emissions associated with capital equipment.
- 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 lifecycle studies reviewed included land use change GHG emissions in the WTW lifecycle 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 would 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).
- 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 lifecycle GHG results provided by NETL (2008, 2009). Figure 4-6 summarizes GHG emissions for each of the reference crudes and average WCSB oil sands crude across the different lifecycle 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 4-6 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 lifecycle 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 4-6 WTW GHG Emissions across the Fuel Lifecycle for WCSB Oil Sands Average Crude (i.e., Canadian Oil Sands) and Reference Crudes

Table 4-14 summarizes the lifecycle GHG emissions for gasoline produced from oil sands-derived crude relative to other reference crudes consumed in the United States (NETL 2009).

Table 4-14 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

Lifecycle 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 57% SCO from mining, based on data from 2005 and 2006	NA
Upgrading	NA	IE	NA	NA	NA		
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%		

[a] NETL 2009 values converted from $kgCO_2e$/MMBtu (million British thermal units) 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.

MMBtu = million British thermal units, CSS = cyclic steam stimulation, gCO_2e/MJ = grams carbon dioxide equivalent per megajoule, GHG = greenhouse gas, IE = included elsewhere; MJ = megajoule, NA = Not applicable; LHV = Lower heating value; SCO = synthetic crude oil, WTT = Well-to-tank; WTW = Well-to-wheels.

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 4-14.

- First, NETL (2009) developed its weighted-average GHG emission estimate for oil sands extraction (including upgrading) from data on mining and CSS *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, CARB OPGEE c1.1.2013). 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 lifecycle 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 would 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 would produce different fractions of residuum and light ends than full-range crudes. Accounting for this effect in the refinery would change the differences between WTW GHG emissions from WCSB oil sands-derived premium fuels.
- Fourth, as noted in Table 4-14 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 lifecycle (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.[42] Note also in the NETL comparisons in Figure 4-6 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.

To reflect recent data published since the NETL (2008, 2009) study, the results from comparative crudes in the CARB OPGEE (2013a) model were evaluated against the NETL (2008, 2009) results:

- The CARB OPGEE report also analyzed several crudes from the countries listed in Table 4-14 for the first two lifecycle stages of crude oil extraction and crude oil transport. It analyzed fourteen crudes from Canada, six from Venezuela, one from Mexico, and three from Saudi Arabia. The first two lifecycle stages in NETL (2009) for Saudi Arabia, Venezuela, and Mexico are based on country average profiles. The Venezuelan crudes analyzed in CARB OPGEE that are comparative to NETL have carbon intensities between 5.92 and 9.70 gCO_2e/MJ, the range of which is slightly above 5.7 gCO_2e/MJ in NETL, shown in Table 4-14. The Mexican crude analyzed in the CARB OPGEE that is comparative to NETL has a carbon intensity of 8.61 gCO_2e/MJ, which is slightly above 8.2 gCO_2e/MJ in NETL, shown in Table 4-14. The two Saudi Arabia crudes analyzed in the CARB OPGEE that are comparative to NETL have carbon intensities of 6.84 and 7.32 gCO_2e/MJ, the range of which is above 5.3 gCO_2e/MJ in NETL, shown in Table 4-14.
- Canadian oil sands were also analyzed by the CARB OPGEE report for crude oil extraction and transport. The raw bitumen API gravity values are similar in both reports (8 to 11° API in CARB OPGEE and 7 to 10° API in NETL [2009]). The CARB OPGEE report has dilbit and SCO gravities at 32° API, while NETL lists blended or upgraded oil sands at 20º to 33º API. The comparison between CIs listed in CARB OPGEE for these Canadian oil sands are between 17.14 and 20.74 gCO_2e/MJ, which is slightly below 21.3 gCO_2e/MJ in NETL, shown in Table 4-14.
- From CARB OPGEE, the difference in upstream emissions (i.e., crude oil extraction and crude oil transportation) is less between the displaced crudes and the Canadian oil sands, compared to the equivalent difference in emissions from NETL 2009. This results in

[42] 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. The effect of including petroleum coke transport to Asia was evaluated, assuming that the voyage is roughly equivalent to ocean transport of crude oil from Saudi Arabia to the Gulf of Mexico, and transport GHG emissions were adjusted by the fraction of crude converted to petroleum coke.

upstream emissions from the displaced crudes and the Canadian oil sands to be closer than originally inferred from NETL 2009.

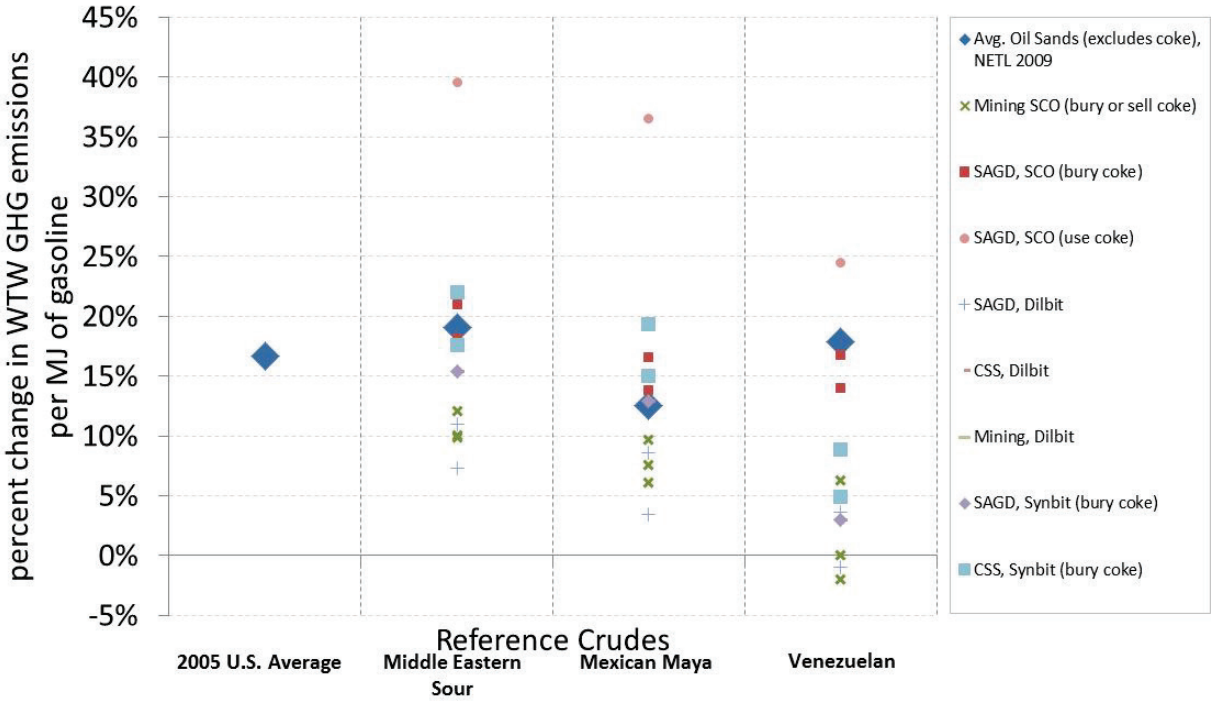
4.4.3 Summary Comparison of Lifecycle GHG Emission Results

Figure 4-7 and Figure 4-8 compare, respectively, the WTW and WTT GHG emissions of gasoline produced from WCSB oil sands crudes relative to the four reference crudes based on data from the studies included in this assessment. To develop these figures, estimates of WTW and WTT emissions were taken directly from the NETL (2008, 2009), Jacobs (2009), and TIAX (2009) studies. Estimates were plotted according to the WCSB oil sands production method (e.g., surface mining, *in situ*) and by different scenarios examined in the studies (e.g., end-use of petroleum coke: either used as a process fuel, buried/stockpiled, or sold to other markets). Where necessary, the WTW and WTT emissions estimates were converted to units of grams of carbon dioxide equivalent per megajoule of gasoline (lower heating value [LHV]).[43] Finally, the percentage changes in WTW and WTT emissions from WCSB oil sands crudes compared to each reference crude were calculated. To ensure they were internally consistent with each study's LCA boundaries and assumptions, WCSB oil sands crudes and reference crudes were compared within each study: for example, since NETL (2008, 2009) was the only study that included an estimate for the 2005 U.S. average mix, only NETL's estimate of emissions from WCSB oil sands crudes was compared to the 2005 U.S. average mix reference.

The results in Figure 4-7 and Figure 4-8 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 4-7 and Figure 4-8 (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: (i) used (i.e., combusted or gasified) for process energy or hydrogen, (ii) stockpiled or buried, or (iii) sold as a co-product. For dilbit, the symbols identify whether the estimate includes the production and combustion of petroleum coke and applies a substitution credit on the basis that petroleum coke is used to offset coal-fired electricity generation, or (ii) excludes petroleum coke from the system boundary. Across the three studies included in Figure 4-7 and Figure 4-8, while some studies modeled different scenarios for handling coke produced *at the upgrader* for oil sands crudes, each study applied internally consistent assumptions for handling petroleum coke produced *at the refinery* for oil sands crudes and reference crudes. For example, for all crudes modeled in TIAX, any GHG emissions associated with petroleum coke produced at the refinery were excluded, but the study did model scenarios where petroleum coke combustion is included at the upgrader for oil sands crudes where it is used as a process fuel (i.e., the "use coke" scenario).

[43] NETL (2008, 2009) estimates were converted from $kgCO_2e$/MMBtu gasoline to gCO_2e/MJ; Jacobs (2009) and TIAX (2009) emissions were presented in gCO_2e/MJ, so no conversion was required.

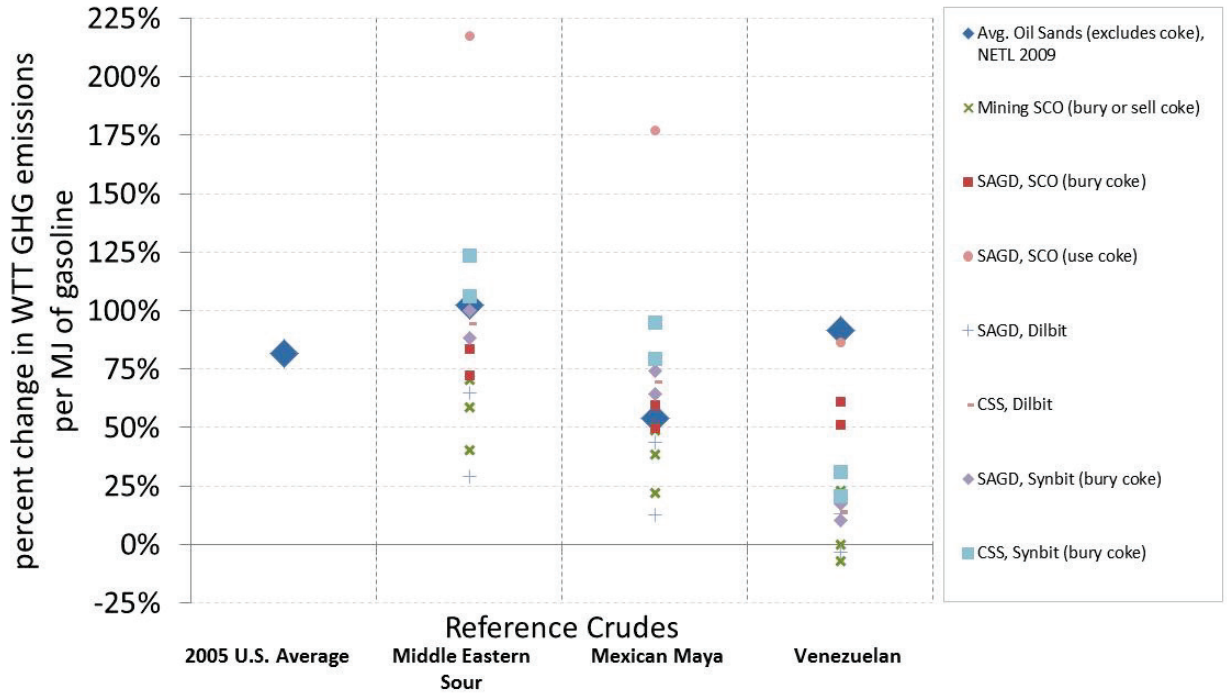


Sources: Data from NETL 2009, Jacobs 2009, TIAX 2009.

1. 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.
2. 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.
3. 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.
4. 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 would not be recirculated by the proposed Project.
5. Each data point represents the percent change in estimated WTW GHG emissions for gasoline derived from the different oil sands crudes compared to the reference crudes. Where a symbol appears more than once for a given reference crude, it represents data from different studies.

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

Figure 4-7 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.

1. 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' WTT is greater than the X-axis reference chart.
2. 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.
3. 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.
4. 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 would not be recirculated by the proposed Project.
5. Each data point represents the percent change in estimated WTW GHG emissions for gasoline derived from the different oil sands crudes compared to the reference crudes. Where a symbol appears more than once for a given reference crude, it represents data from different studies.

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

Figure 4-8 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 lifecycle 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 4-7 and Figure 4-8.

Figure 4-7 and Figure 4-8 show WCSB oil sands-derived gasoline WTW and WTT GHG emissions differentials are larger than gasoline produced from the four reference crudes, although a few WCSB crudes are slightly less-intensive than the heaviest reference crude, Venezuelan Bachaquero. The differential ranges from 0 to 25 percent (on a WTW basis) for most scenarios, increasing to 40 percent in a case where the petroleum coke produced from WCSB oil sands crude is used at the upgrader compared to reference crudes where petroleum coke is excluded from the lifecycle boundary (i.e., the SAGD SCO "use coke" case).[44] The differential ranges are much higher on a WTT basis that only considers GHG emissions up to the refinery gate and excludes finished fuel combustion. Two data points—SCO from mining where the coke is buried, and dilbit from SAGD—estimate that lifecycle 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 4-7, the NETL results show that the WTW GHG emissions from gasoline produced from WCSB oil sands crude are up to 17 percent higher than gasoline from the average mix of crudes consumed in the United States in 2005. The NETL results show that gasoline from WCSB oil sands crude production schemes emits , 13, 18, and 19 percent more lifecycle GHG emissions than Mexican Heavy (i.e., Mexican Maya), Venezuelan Bachaquero, and Middle Eastern Sour crudes, respectively.

Figure 4-7 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 lifecycle 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 would 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 4-8, the same trends are illustrated from the WTT perspective. The percentage increase in WTT GHG emissions shown in Figure 4-8 compared to gasoline produced from reference crudes is much larger than the percentages found in the WTW perspective used in Figure 4-7. 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 4-6 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. Lifecycle GHG emissions of fuels produced from oil sands crudes are higher than fuels produced from lighter crude oils, such as Middle Eastern

[44] This estimate is based on TIAX (2009). The SAGD SCO "use coke" case assumes that petroleum coke produced at the upgrader is consumed as a process fuel, and combustion emissions are included in the lifecycle boundary of the SCO. For reference crudes in TIAX, production and combustion emissions from petroleum coke produced at refineries were excluded from the lifecycle boundary. This is the key driver behind the large percent increase shown in Figure 4-8 and Figure 4-9 for the SAGD SCO "use coke" case.

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 lifecycle studies are within these ranges. The 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 percent of the upper range of the WTW intensity of conventional crudes (Jacobs 2012).

5.0 PETROLEUM COKE CHARACTERISTICS, GHG EMISSIONS, AND MARKET EFFECTS

The treatment of petroleum coke in lifecycle studies is an important factor that influences the lifecycle GHG emission results. It is important when comparing oil sands and the reference crudes that the full lifecycle 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 lifecycle consideration for the heavy conventional crudes. If the GHG emissions from producing and combusting petroleum coke and other co-products are included within lifecycle 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 (Oil Change International 2013; Gordon 2012) have also recognized petroleum coke as an important source of GHG emissions in the crude oil lifecycle. To better understand the importance of petroleum coke in the lifecycle 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 lifecycle 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 USEPA (2012a)

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., gCO_2/MJ	96.77	88.40	92.10	92.57	98.26
Change in emissions-intensity relative to petroleum coke[g]	% change	--	-9%	-5%	-4%	2%

Sources: Data reflect national characteristics provided by USEPA (2012a) U.S. Inventory of Greenhouse Gas Emissions: 1990-2010. Original sources cited in USEPA (2012a) 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.
[d] Calculated from heating value and CO_2 emissions per unit energy.
[e] Based on data sourced from EIA (1994), EIA (2009), USEPA (2009) and USEPA (2010c).
[f] Calculated from USGS (1998) and PSU (2010); data presented in USEPA (2010d).
[g] The change in emissions intensity is given in terms of the change in GHG emission to produce a unit of energy from each type of coal compared to petroleum coke. GHG intensity is compared on an energy basis—as opposed to a mass basis—because energy is the final desired output when petroleum coke or coal are used as fuels.

Btu = British thermal unit, 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 lifecycle 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., 1 Btu of coal is offset by 1 Btu of petroleum coke).[45] 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.

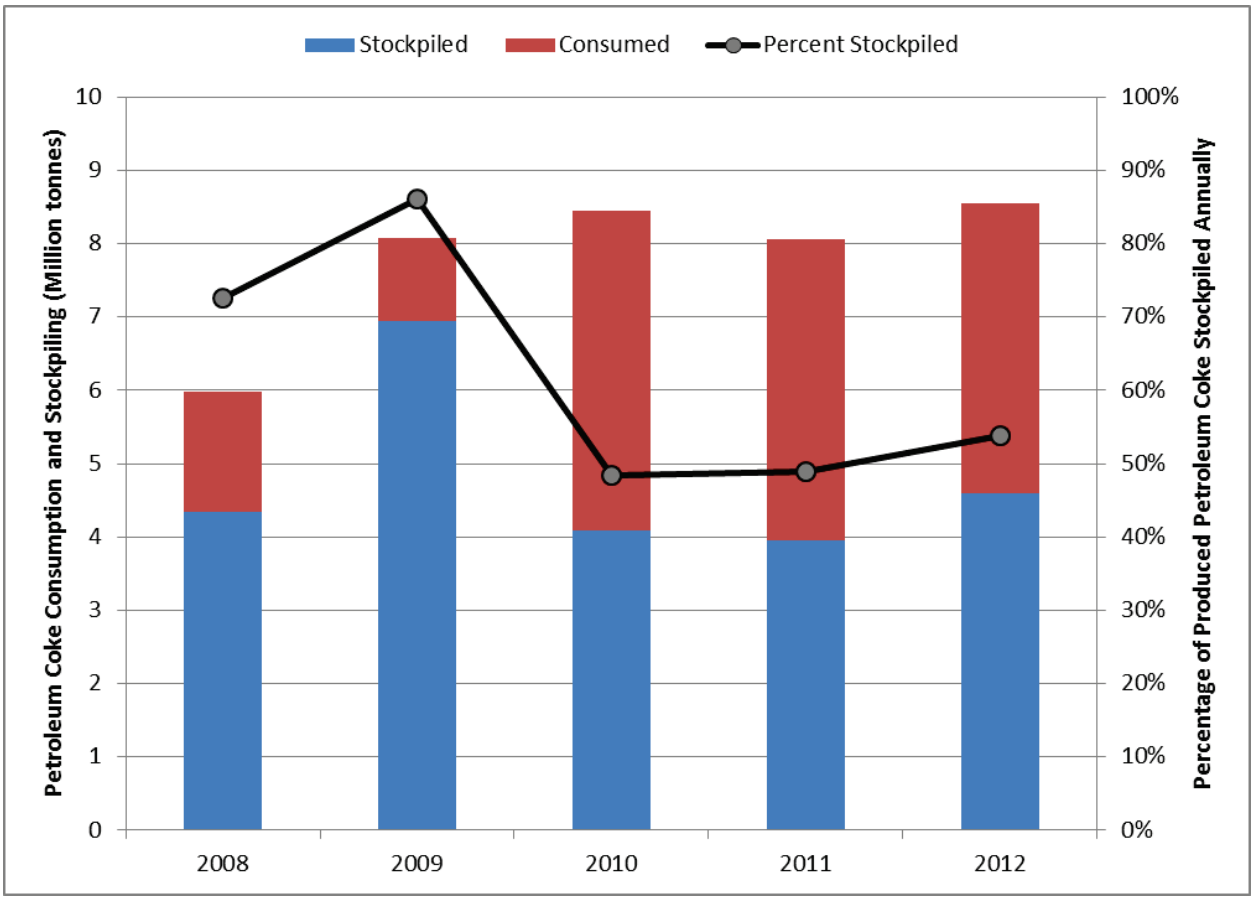
Virtually all crude oils, light, medium, and heavy, including bitumen, contain a fraction of the raw oil out of the ground that does not boil even under full vacuum conditions. This fraction, called vacuum residuum, will thermally destruct into lower molecular weight hydrocarbon compounds and elemental 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 50 percent vacuum residuum fraction (Jacobs 2012, p. 1-22; Netzer 2006, p. 15). 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 also contains about 50 percent vacuum residuum (Jacobs 2012, p. 1-22), and Arab Light crude contains about 20 percent vacuum residuum (Brandt 2011, p. 17). 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 WCSB oil sands crudes.

The proposed Project would transport an approximate 80/20 mix of dilbit and SCO. Petroleum coke from the bitumen upgraded into SCO is produced at Canadian upgraders. A significant portion of this petroleum coke—approximately 50 percent (ERCB 2011, 2012, 2013)—is

[45] The comparison between petroleum coke and coal is made on an energy basis—as opposed to a mass basis—because energy is the final desired output when petroleum coke or coal are used as fuels.

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. Figure 5-1 shows that total petroleum coke production has increased from slightly less than 6 million metric tons in 2008 to over 8.4 million metric tons in 2012. While the total production has increased, the absolute amount stockpiled has remained relatively unchanged, except for the year 2009, which saw a dramatic increase. The percentage stockpiled has slightly increased since 2010, from 48 percent to nearly 54 percent.



Source: ST39 Alberta Mineable Oil Sands Plant Statistics, ERCB 2013.

Figure 5-1 Amount of Petroleum Coke Consumed and Stockpiled at Oil Sands Facilities in Alberta

The dilbit portion 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.[46] Hence, approximately the same petroleum coke quantity would be produced from a mix of crudes in the proposed Project that backs out imported crude oils such as Mexican Maya, Venezuelan

[46] According to Jacobs (2009, p. 5-18), for the same volume of crude input, dilbit produces approximately 55 lb of petroleum coke per barrel, equivalent to Mexican Maya. Raw bitumen produces 64 lb of petroleum coke per barrel, equivalent to Venezuelan Bachaquero.

Bachaquero, 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. So of the proposed Project's total WCSB oil sands throughput, slightly more than 20 percent of the petroleum coke is produced in Canada, where approximately 50 percent of it is currently stockpiled and the rest sold to other markets or substituted for other fuels in the production and upgrader process. The rest of the petroleum coke (all that is produced from the dilbit fraction) is produced at Gulf Coast refineries where it is used as a fuel in predominantly overseas markets.

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 USEPA 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 (also called *residual 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 USEPA specified sulfur oxides (SOx) emission controls on coal-fired power plants.[47] See Figure 5-2, which shows the implementation timeline of USEPA's regulation of SOx emissions from power plants and the downward trend in residual fuel oil supply in the United States between 1984 and 2011 (USEPA 2012b, EIA 2012f). 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. The downward trend has continued since 1990, and by 2011, the amount of residual fuel oil supplied to the electric power sector had fallen by over 90 percent from 1990 levels.

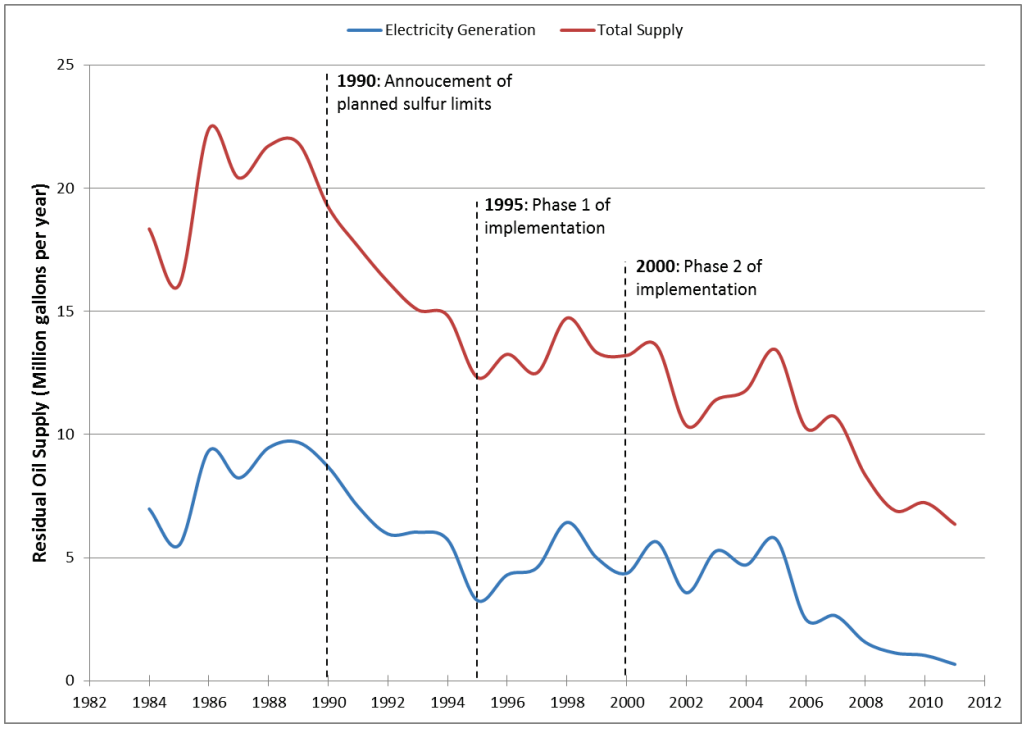
Piles of petroleum coke have recently gained attention in the Midwest. Although Midwest refiners have for a long period of time produced petroleum coke and stored inventory in piles, the production of petroleum coke from Midwest refiners has increased due to the capacity expansion of refinery cookers, some of which are processing Canadian oil sands crude. Although the piles of petroleum coke have at times been higher than some community members recall, most of the petroleum coke is eventually transported out to markets. Community concerns have been around petroleum coke particulate fines in the atmosphere and the unsightly petroleum coke piles. Some communities are advocating regulations like those in California that require that piles of petroleum coke must be enclosed or covered (Corley 2013).

While coke can be used to supplement 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.[48] For example, in 2011, petroleum coke consumption was equivalent to 0.5 percent of coal consumption for electricity generation across all sectors (EIA

[47] The regulation of SOx for coal-fired power plants was first announced in 1990, under Section 110 of the Clean Air Act (40 CFR Part 51, Subparts F and G). The regulation would be carried out in two phases, with Phase I beginning in 1995 and Phase II beginning in 2000. Before the regulation was announced, nearly 10 million gallons of residual fuel oil was supplied to the electric power sector per year (and over 20 million gallons of residual fuel oil was supplied in total). By 1995 at the beginning of Phase I, residual fuel oil use had fallen to less than 4 million gallons per year in the electric power sector.

[48] 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.

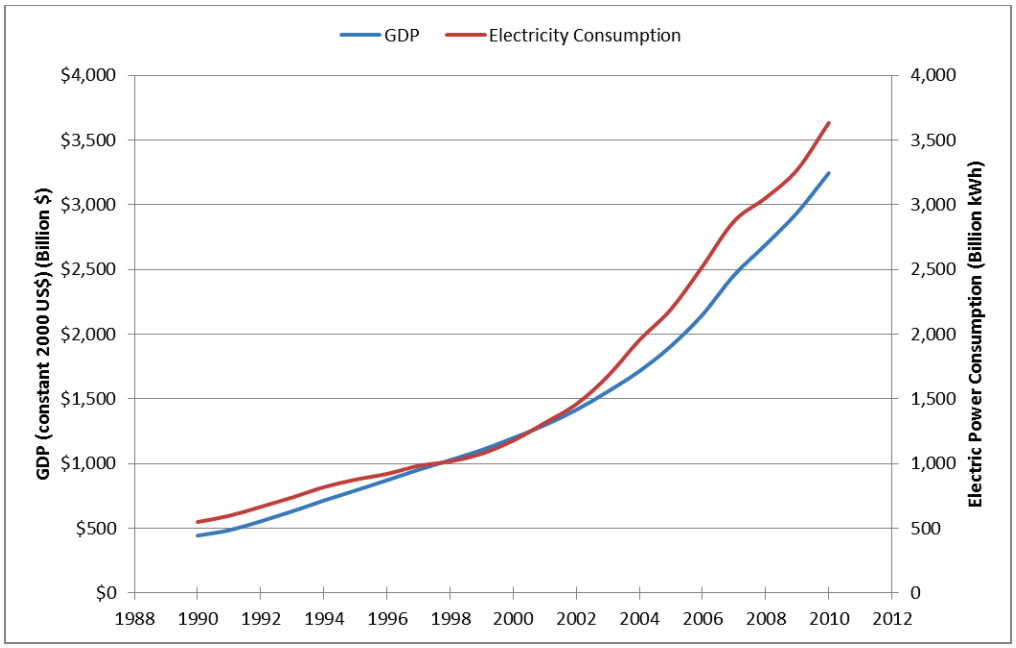
2012a). Most of the Gulf Coast coke is exported to markets in China, Japan, and Mexico, which accounted for 35 percent of all exports in 2011 (EIA 2012b). China was the single largest importer of U.S. petroleum coke, accounting for approximately 14 percent of U.S. exports (EIA 2012b). In addition, the higher sulfur content of petroleum coke may make it an unattractive fuel from a financial perspective due to the capital investment needed for flue gas desulfurization and equipment to scrub the air emissions.



Source: EIA 2012b.

Figure 5-2 The Effect of SOx Regulations on Residual Fuel Oil Consumption for Electricity Generation in the United States

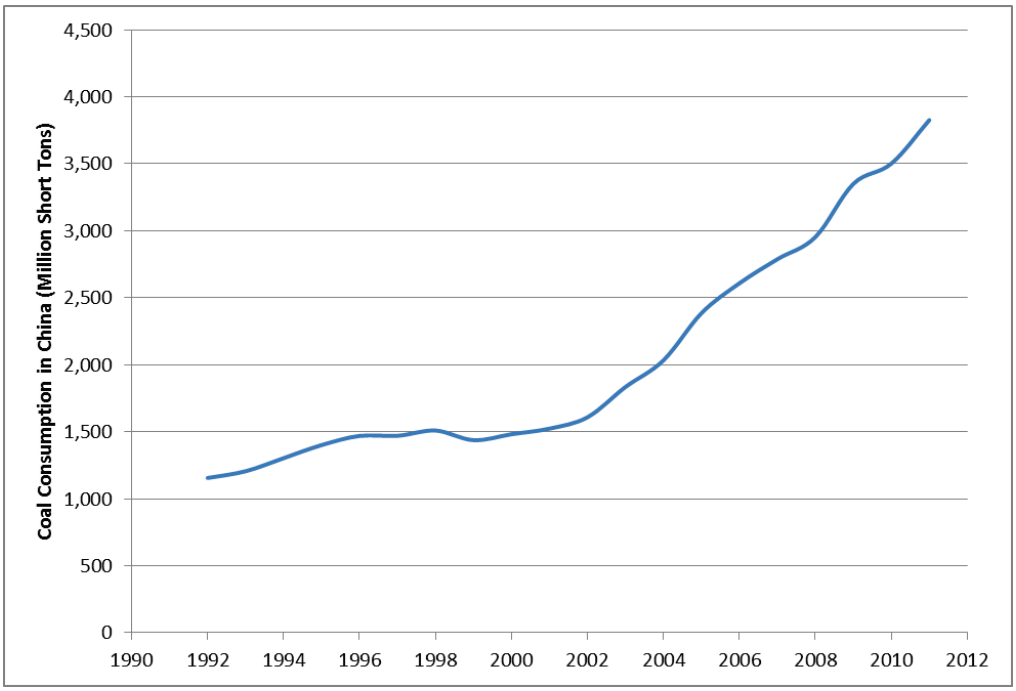
A large share of Gulf Coast petroleum coke is currently shipped to China. As China's economy has rapidly grown in the past 20 years, so has their electricity demand. As seen in Figure 5-3, as China's economy (illustrated by their GDP) has grown, its electricity demand has risen at almost exactly the same rate (EIA IES 2012d, World Bank 2012). Recently, China has begun struggling to keep up with this growth in electricity demand. Since 2002, its coal consumption has risen sharply, as seen in Figure 5-4. Internal production was able to satisfy demand until 2008, when China was still a net exporter of coal; since 2009, however, China has begun importing coal to keep up with rising electricity demand (IEA 2012). Around this time, U.S. exports of both coal and petroleum coke increased significantly from less than 400 thousand short tons of pet coke and 250 thousand short tons of coal per year in 2008 to over 5 million short tons of pet coke and 10 million tons of coal per year in 2012. This trend is shown in Figure 5-5 (EIA 2013a).



Sources: U.S. Energy Information Administration International Energy Statistic (Electricity Consumption) (EIA 2012d); World Bank - World Development Indicators (GDP) (World Bank 2013).

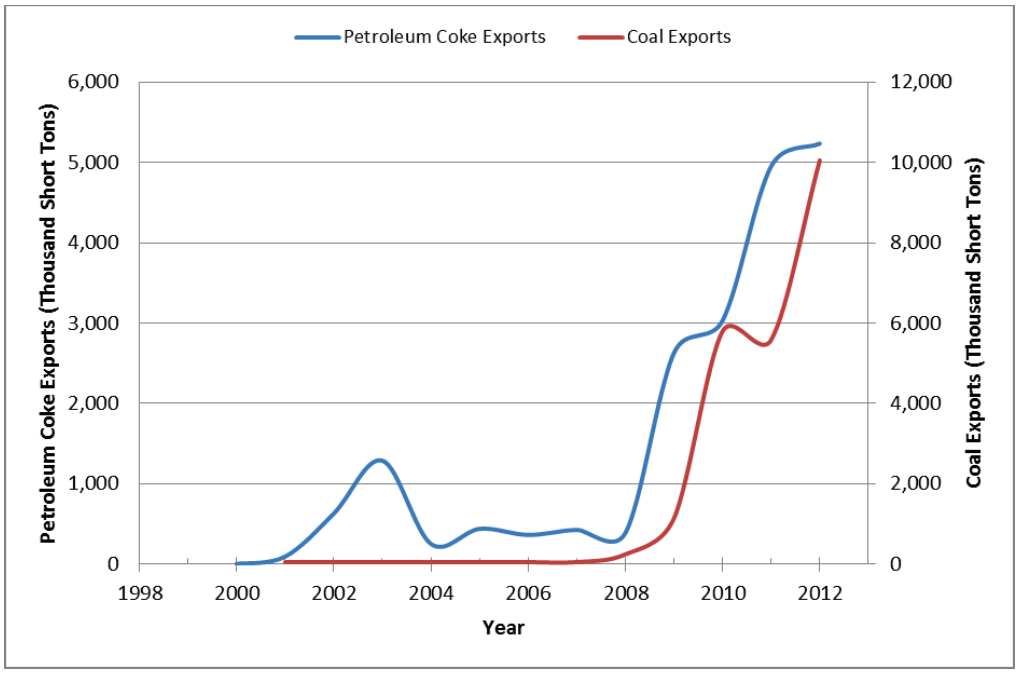
GDP = gross domestic product, kWh = kilowatt-hour.

Figure 5-3 Comparison of China's GDP and Electricity Consumption from 1990 to 2010



Source: U.S. Energy Information Administration International Energy Statistics (EIA 2012e).

Figure 5-4 China's Coal Consumption from 1992 to 2011



Sources: Petroleum Coke Data: U.S. EIA 2013a (converted from barrels to short tons using EIA conversion factor of 5 bbl/short ton of petroleum coke). Coal data: U.S. EIA 2009-2013. Quarterly Coal Report.

Note: Data for coal exports prior to 2008 are for illustrative purposes only; exports totaled less than 50,000 short tons per year, but exact numbers were not provided. Data plotted before 2008 is at 50,000 short tons per year.

Figure 5-5 U.S. Exports of Coal and Petroleum Coke to China from 1994 to 2012

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, is expected to lead in energy consumption growth in non-OECD[49] Asian regions, which is projected to rise by 91 percent from 2010 to 2035 (EIA 2012c). Against this demand, the influx of new coke into the market and the impact it might have on the coal and electricity markets is relatively small. Recent reports (Oil Change International 2013) have raised concerns about the influx of new coke into the market and the impact it might have on the coke and electricity markets. According to Jacobs (2012), for every barrel of bitumen processed, 61 pounds of coke are produced (Jacobs 2012, p. 6-7). At full capacity of the pipeline (830,000 bpd), and assuming that the pipeline carries 70 percent bitumen mix, this translates to just over 15,400 metric tons of coke produced per day. China, the largest importer of U.S. coke, consumed over 9.5 million metric tons of coal per day in 2011 (EIA 2012e). If all the produced coke is shipped to China, this would only replace 0.16 percent of the coal currently consumed there. In addition, in June 2013, China announced the launch of a 3-year pilot GHG cap-and-trade emissions trading program, initially focused on the Shenzhen Special Economic Zone with expansion planned for four other major cities and two regions (Sweet 2013). If such a program were to be adopted nation-wide, it would provide an incentive for using fuels with lower GHG emissions intensities, which could in turn sharply decrease demand for petroleum coke in China.

[49] Organization for Economic Cooperation and Development.

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

- Because WCSB oil sands crude contains a similar fraction of vacuum residuum—the fraction of crude oil that is commonly used to produce petroleum coke, among other products—as other heavy crudes, such as Mexican Mayan and Venezuelan Bachaquero, WCSB oil sands crude would produce roughly the same amount of petroleum coke as a barrel of heavy crudes that are commonly refined in the Gulf Coast;
- Accounting for the non-combustion of approximately half the upgrader petroleum coke manufacture is needed;
- Even if the share of petroleum coke stockpiled at upgraders in Canada declines, lifecycle GHG emissions from oil sands will nonetheless continue to be similar to the heavy reference crudes because oil sands contains approximately the same amount of petroleum coke as the heavy reference crudes;
- Accounting for the combustion of coke manufactured from reference crude oils (including transportation to the China market) is needed;
- SCO has lower refining emissions (because all the residuum processing was done at the upgrader);
- Raw bitumen contains a similar fraction of vacuum residuum—the fraction of crude oil that is commonly used to produce petroleum coke, among other products—as other heavy crudes, such as Venezuelan Bachaquero that are commonly refined in the Gulf Coast; and
- Displaced reference crudes would likely be transported 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 would likely be higher than the U.S. average barrel especially with rapidly expanding shale oil production in North America.

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

As set forth in Section 1.4, Market Analysis, a direct change in production of 830,000 bpd of oil sands crudes in Canada is not likely to occur with approval or denial of the proposed Project. Section 1.4 reaffirms the conclusion of the Draft Supplemental EIS that: “Approval or denial of any one crude oil transport project, including the proposed Project, remains unlikely to significantly impact the rate of extraction in the oil sands, or the continued demand for heavy

crude oil at refineries in the U.S." [50] However, on a lifecycle basis and compared with reference crudes refined in the United States, oil sands crudes could result in an increase in incremental GHG emissions.[51] Although a lifecycle analysis is not strictly necessary for purposes of evaluating the potential environmental impacts attributable to the proposed Project consistent with 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 lifecycle GHG emissions (in terms of the proposed Project'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 two components, which are each described in the following sections:

1. The WTW GHG emissions of the weighted-average mix of WCSB oil sands crudes likely to be transported in the proposed Project, (Section 6.1); and
2. The WTW GHG emissions of reference crudes that are likely to be displaced by WCSB oil sands crudes at U.S. refineries (Section 6.3).

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 (and excluding the Market Analysis conclusions). The results are presented in Section 6.5, Incremental GHG Emissions from Displacing Reference Crudes with WCSB Oil Sands Crudes in U.S. Refineries.

The incremental GHG emissions represent those indirect emissions from crude oils that are potentially attributable to the proposed Project excluding the Market Analysis conclusions. These incremental proposed Project-related GHG emissions have been estimated by the following method:

- As presented in this Appendix, a study was undertaken based on a review of existing lifecycle studies and models that estimated GHG emissions and implications for WCSB oil sands-derived crudes compared to reference crudes currently distributed and refined in the United States. The study determined the full lifecycle GHG emissions of the WCSB crude oils and the reference crudes.

[50] The Draft Supplemental EIS estimated how production would be affected by approval or denial of the proposed pipeline. Updated analysis in Section 1.4 suggests that previous estimates likely overstated the production impact of the proposed pipeline, and that the range of prices in which denial of the proposed project could make a meaningful difference to oil sands production over the long-run is most likely a small one. As noted in Section 1.4, under certain conditions, lower-than-expected oil prices could affect the outlook for the oil sands and transportation constraints could exacerbate other adverse global market conditions. At around $70/bbl (WTI-equivalent), the impact on long term production is likely to be less than 170,000 bpd even if one assumes that the proposed project as well as all other new and expanded Canadian and cross-border pipeline capacity are not constructed, if the cost "penalty" for using rail is at the upper end of the assessed range, and if other costs and differentials do not fall along with oil prices. Above that level, most oil sands projects will be economic with or without the proposed project or other cross-border pipelines; below it, many oil sands projects could be uneconomic regardless of transport options.

[51] 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 lifecycle approach. If the United States used a lifecycle approach, upstream emissions from other imported crudes would be attributed to the United States.

- For completeness and for comparison purposes, the GHG emissions associated with land use changes attributable to the WCSB crude oil mining and to a lesser extent *in situ* extraction methods have also been calculated.

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

While Figure 4-5 and Figure 4-8 indicate the full range of lifecycle GHG emissions estimates associated with individual methods of oil sands production, the actual lifecycle 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.[52] In the Final Supplemental EIS, the Department assumes that the average crude oil flowing through the pipeline would consist of about 80 percent Western Canadian Select (dilbit) and 20 percent Suncor Synthetic A (SCO) to reflect the trend away from upgrading in Alberta.

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 would 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.

The following method was applied 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.

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. An 80/20 split between dilbit and SCO was assumed to reflect the trend away from upgrading in Alberta.

[52] 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.

- Study evaluates the full WTW lifecycle. Studies that evaluated only a portion of the lifecycle (e.g., only WTR or up to the refinery gate) cannot be accurately compared with other studies on a full lifecycle basis.
- Study is a unique, original analysis, 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[a]	Y	Y	Y
IEA 2010[b]	Meta-analysis	N[c]	Y	N	N
IHS CERA, 2010	Meta-analysis	Y	Y	N	N
IHS CERA, 2011	Meta-analysis	Y	Y	N	N
IHS CERA, 2012	Meta-analysis	Y	Y	N	N
NRDC, 2010	Meta-analysis	Y	Y	N	N
ICCT, 2010	Individual LCA	N[d]	N[e]	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[f]	Y	N	N
Brandt, 2011	Meta-analysis	Y	Y	N	N
RAND, 2008	Individual LCA	N[g]	N[h]	N	N
Charpentier et al., 2011a	Partial LCA	Y	N[i]	Y	N
Bergerson et al., 2012a	Partial LCA	Y	N[i]	Y	N
CARB OPGEE, 2013a	Model	Y	N	Y	N
Pembina Institute, 2005	Partial LCA	N[j]	N[k]	Y	N
Pembina Institute, 2006	Partial LCA	N[l2]	N[k]	Y	N
McCann, 2001	Individual LCA	N[m]	Y[n]	Y	N
GHGenius, 2010	Model	N[o]	Y	Y	N
GREET, 2010	Model	N[p]	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[q]	N[q]	Y	N
Yeh et al., 2010	Land use change journal article	N[r]	N[r]	Y	N

[a] 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.
[b] IEA results are compared on a per-barrel-of-crude basis.
[c] IEA includes estimates for high/low *in situ* and mining. Does not specify SCO or dilbit crude types.
[d] ICCT evaluates average mix of oil sands imported to Europe.
[e] ICCT GHG emissions include refining, but exclude final distribution of premium fuel products.
[f] Charpentier et al. did not evaluate dilbit as a crude pathway.
[g] RAND only evaluated SCO from WCSB oil sands.
[h] RAND only evaluated WTR GHG emissions.
[i] Charpentier et al. (2011a) and Bergerson et al. (2012a) only evaluated WTR GHG emissions; the authors do include estimates from external studies developed by TIAX and GHGenius to develop rough order of magnitude estimates, but these are not internally-consistent WTW estimates.
[j] Pembina (2005) only evaluated oil sands average, but did not specify the composition.
[k] Pembina (2005, 2006) only evaluated WTR GHG emissions.
[l] Pembina (2006) only evaluated GHG emissions from SCO.
[m] McCann only evaluated GHG emissions from SCO.
[n] McCann results are compared on a per-1,000-liters-of-transportation fuel basis.
[o] GHGenius does not include a pathway for dilbit production; the model only includes bitumen ((S&T)^2 Consultants 2008b).
[p] 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.
[q] Rooney et al. (2012) only evaluated GHG emissions from local land-use change.
[r] Yeh et al. (2010) only evaluated GHG emissions from local land-use change and tailing ponds.

GHG = greenhouse gas, LCA = lifecycle assessment, N = no, WTR = well-to-refinery, WTW = well-to-wheels, Y = yes.

It is assumed that 80 percent of pipeline throughput would be dilbit, and 20 percent would be SCO. According to the Alberta Energy Resources Conservation Board (ERCB 2013), all WCSB dilbit is currently produced using *in situ* production. All WCSB bitumen produced from mining is upgraded to SCO and 7 percent of SCO is produced via *in situ* methods (ERCB 2013, pp. 3-20). Applying this production mix to a 80/20 split of dilbit and SCO yields an estimated mix of 80 percent *in situ*-produced dilbit, 18.6 percent mining-produced SCO, and 1.4 percent *in situ*-produced SCO transported in the proposed Project.

WTW GHG emissions for *in situ* dilbit, *in situ* SCO, and mining SCO in Jacobs (2009), TIAX (2009), and NETL (2008) were evaluated using the following assumptions:

- For Jacobs (2009):
  - *In situ* SCO: An average was calculated for *in situ* SCO based on the study's data for SAGD SCO from delayed coking and ebulating bed hydrocracking for WTW GHG emissions. 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 was used for WTW GHG emissions from SAGD dilbit, assuming diluent is consumed at the refinery. Recirculation of diluent to Alberta was not included since diluent would 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 was calculated from the study's estimates 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). It was assumed that 54 percent of petroleum coke is stockpiled, and 46 percent is used or sold as fuel, based on data from ERCB (ERCB 2011, 2012, 2013).[53]
  - *In situ* dilbit: The average was calculated from TIAX's WTW GHG emissions estimates for facilities that export electricity and do not export electricity. A weighted average was calculated between dilbit from SAGD and CSS facilities, assuming 65 percent SAGD and 35 percent dilbit, based on ERCB (ERCB 2013, p. 3-15).[54]
  - 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, calculating a weighted average was not necessary, 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. Therefore, it is important to note that the 43/57 mix of blended bitumen and SCO assumed in NETL differs from the 80/20 mix of dilbit and SCO assumed when estimating WTW GHG emissions for *in situ* dilbit, *in situ* SCO, and mining SCO in the Jacobs and TIAX studies.

Table 6-2 provides the WTW GHG emission estimates in each study, as well as the calculated 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, based on current industry-average production mixes and practices, which are likely to change over time.

[53] Based on a 3-year average of petroleum coke practices across the oil sands in 2012 reported by ERCB (ERCB 2011, 2012, 2013). 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 59 percent of its petroleum coke as fuel, with 16 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 96 percent 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 50/50 coke stockpiling-to-use ratio across all facilities. To limit year-to-year variability, the ratio was calculated from a 3-year average of petroleum coke management data from ERCB. The stockpiling-to-use ratio was 48/52, 49/51, and 54/46 in 2010, 2011, and 2012 respectively—a slight upward trend in stockpiling over the past 3 years.

[54] According to ERCB, of *in situ* bitumen produced from SAGD and CSS, SAGD represented 65 percent of production in 2012, and CSS accounted for 35 percent of production (ERCB 2013, p. 3-15). Primary production of bitumen (i.e., using conventional oil production techniques) accounted for 39 thousand m^3 per day, or 25 percent of total *in situ* bitumen production in 2012, 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. IHS CERA (2012) projects that primary production will decline from about 13 percent of total oil sands production to about 5 percent in 2030.

Table 6-2 WTW GHG Emissions Estimates and Calculated Weighted-Average WCSB Oil Sands Crude 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)[a]	106 / 108[3b]	104	N/A
	In situ SCO	118 / 117[b]	114	N/A
	In situ dilbit	105 / 108[b]	103	N/A
	Mining SCO	108 / 108[b]	105	N/A
	Middle Eastern Sour	98 / 99[b]	98	N/A
	Mexican Maya	102 / 102[b]	103	N/A
	Venezuelan	102 / 102[b]	100	N/A
TIAX 2009	WCSB oil sands (average)[a]	104	964	N/A
	In situ SCO	118	112	N/A
	In situ dilbit	105	97	N/A
	Mining SCO	102	92	N/A
	Middle Eastern Sour	89	82	N/A
	Mexican Maya	92	85	N/A
	Venezuelan	102	91	N/A
NETL 2008, 2009	WCSB oil sands (average) [c]	106	105	102
	U.S. Average (2005)	91	90	88
	Middle Eastern Sour	89	89	86
	Mexican Maya	94	96	91
	Venezuelan[d]	90	90	87

[a] Weighted-average of WCSB oil sands crudes, assuming 80 percent *in situ*-produced dilbit, 18.6 percent mining-produced SCO, and 1.4 percent *in situ*-produced SCO.

[b] 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.

[c] NETL did not calculate separate GHG emissions estimates for bitumen and SCO; instead, the authors used an average estimate based on a 43/57 mix of blended bitumen and SCO. This composition estimate differs from the 80/20 mix of dilbit and SCO crudes likely to be transported by the proposed Project.

[d] Venezuela Conventional is used as the NETL reference crude for Venezuela Bachaquero in this analysis; this is a medium crude, not a heavy crude.

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.

The WTW carbon 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 gCO_2e per megajoule of gasoline, diesel, and jet fuel products. These GHG intensities were converted to a weighted-average $kgCO_2e$ per of barrel of gasoline and distillates (i.e., the total sum of gasoline, diesel, and jet fuel products) for each of the WTW lifecycle stages, as shown in Table 6-3, based on the relative yield of gasoline and distillates from each study.[55,56]

[55] 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 6-6 (Jacobs 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 (Jacobs 2009, p. E-1).

[56] 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.

Table 6-3 WTW GHG Emissions per Barrel for Weighted-Average WCSB Oil Sands Crude, by Study and Lifecycle Stage

Study[a]	GHG Emissions $kgCO_2e$ per Barrel of Gasoline and Distillates[b]						
	Mining/ extraction	Upgrading	Crude Oil Transport	Refining	Finished Fuel Transport	Fuel Combustion	WTW Total
Jacobs[c]	82	14	1	71	2	387	557
TIAX[c]	74	IE	9	59	IE	390	533
NETL	105	IE	5	61	5	393	568

[a] 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.
[b] 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.
[c] Weighted-average of WCSB oil sands crudes, assuming 80 percent *in situ*-produced dilbit, 18.6 percent mining-produced SCO, and 1.4 percent *in situ*-produced SCO.

GHG = greenhouse gas, IE = emissions from lifecycle stage included in other lifecycle stage, $kgCO_2e$ = kilograms carbon dioxide equivalent, SCO = synthetic crude oil, WCSB = Western Canadian Sedimentary Basin, WTW = well-to-wheels.

6.1.1 Land Use Change Emissions

The GHG emissions from land clearing for WCSB oil sands projects were not included in the NETL, Jacobs, or TIAX studies. Because other studies have developed recent estimates for these land use change emissions (discussed in Section 4.2.3.3, Land Use Change Emissions), this section applies those estimates to calculate the contribution of land use change to WTW GHG emissions from WCSB oil sands crudes.

Jacobs (2012) provided estimates of land use based on Yeh et al. (2010) for oil sands developments (see Table 6-4). These estimates include GHG emissions from losses in soil carbon, biomass, forgone CO_2 sequestration in peat land, and methane emissions from tailings ponds.[57]

Table 6-4 Net Land Use GHG Intensity of WCSB Oil Sands Surface Mining and *In Situ* Extraction Methods per Megajoule of Refinery Feedstock

WCSB Oil Sands Extraction Process	Net Land Use GHG Intensity (gCO_2e/MJ Refinery Feedstock, HHV)		
	Central	Low	High
Surface mining	3.90	0.83	10.24
In situ	0.07	0	0.23

Source: Yeh et al. (2010), Table 3.

GHG = greenhouse gas, HHV = higher heating value, gCO_2e =grams carbon dioxide equivalent, MJ = megajoule, WCSB = Western Canadian Sedimentary Basin.

Yeh et al. (2010) provided these estimates on the basis of grams of CO_2-equivalent GHG emissions per megajoule of refinery feedstock. Jacobs (2012) converted these results to a per-megajoule of bitumen basis using a typical SCO yield from bitumen. They included an estimate

[57] TIAX (2009) separately included methane emissions from tailing ponds in its WTW GHG emission estimates for WCSB oil sands crudes; comparing these results to the estimates from Yeh et al. (2010) double-counts these emissions. Yeh et al. (2010) estimated methane emissions from tailing ponds at between 0 to 7.91 gCO_2e/MJ refinery feedstock, or roughly 0 to 8 percent of WTW GHG emissions on a gasoline basis.

for methane emissions from the mine face of 0.7 gCO_2e/MJ of bitumen. Jacobs' values for Yeh et al.'s central estimate for mining and *in situ* is show in Table 6-5.

Table 6-5 Land Use Change Estimates from Jacobs (2012) Based on Yeh et al. (2010)

	SCO Basis		Bitumen Basis			
	Oil Sands Mining	Oil Sands *In-Situ*	Oil Sands Mining		Oil Sands *In-Situ*	
Yeh et al. 2010	**gCO_2e/MJ of SCO**	**gCO_2e/MJ of SCO**	gCO_2e/ MJ of Bitumen	Percent of total	gCO_2e/ MJ of Bitumen	Percent of total
Soil CO_2	1.2	0.07	0.98	25%	0.06	86%
Biomass CO_2	0.04	0.00	0.03	1%	0.00	0%
Foregone sequestration of CO_2	0.03	0.01	0.02	1%	0.01	14%
Tailing pond CH_4	2.6	0.00	2.12	55%	0.00	0%
Total	3.9	0.08	3.16	--	0.06	--
Jacobs estimate of CH_4 from mine face	--	--	0.70	18%	--	--
Total land use impact for study	3.9	0.08	3.86	100%	0.06	100%

Source: Jacobs (2012), p. 5-54.

CO_2 = carbon dioxide, CH_4 = methane, gCO_2e = grams carbon dioxide equivalent, MJ = megajoule, SCO = synthetic crude oil.

Jacobs calculated values for Yeh et al.'s central estimate only; the high and low estimates from Yeh et al. (2010) were scaled by an equivalent yield of SCO from bitumen to calculate the full range. These values were converted using the energy content of bitumen[58] and the yield of gasoline and distillates per barrel of bitumen from Jacobs (see Table 6-13) to calculate low, central, and high estimates of net land use GHGs for surface mining and *in situ* WCSB oil sands crudes (see Table 6-6).

Table 6-6 Net Land Use GHG Intensity of WCSB Oil Sands Surface Mining and *In Situ* Extraction Methods per Barrel of Gasoline and Distillates

	Net Land Use GHG Intensity ($kgCO_2e$/bbl gasoline and distillates)		
WCSB Oil Sands Extraction Process	**Central**	**Low**	**High**
Surface mining land use intensity (calculated)	24.3	4.3	52.5
In situ mining land intensity (calculated)	0.4	0.0	1.3

bbl = barrel, GHG = greenhouse gas, $kgCO_2e$ = kilograms carbon dioxide equivalent, WCSB = Western Canadian Sedimentary Basin.

Finally, weighted average low, central, and high estimates of annual land use change GHG emissions were calculated based on the assumed composition of WCSB oil sands crude that the proposed Project would transport (i.e., 80 percent *in situ* dilbit, 18.6 percent surface mining SCO, and 1.4 percent *in sit*u SCO). The median weighted-average central estimate of annual land-use change emissions for WCSB oil sands crudes were estimated at 4.9 $kgCO_2e$/barrel of gasoline and distillates, ranging from 0.8 to 10.8 $kgCO_2e$/barrel of gasoline and distillates (see Table 6-7).

[58] The energy content of bitumen is 6,300 MJ barrel in Jacobs (2009, Tables 8-5 and 8-6).

Table 6-7 Weighted-Average Net Land Use GHG Intensity of WCSB Oil Sands Crudes per Barrel of Gasoline and Distillates

Weighted-Average Land Use Intensity (calculated) ($kgCO_2e$/bbl gasoline and distillates)		
Central	Low	High
4.9	0.8	10.8

GHG = greenhouse gas, bbl = barrel, $kgCO_2e$ = kilograms carbon dioxide equivalent, WCSB = Western Canadian Sedimentary Basin.

6.1.2 Effect of Varying the Composition of WCSB Oil Sands Crudes on Weighted-Average GHG Emission

As noted above, the composition of WCSB oil sands crude that would be transported by the proposed Project is assumed to be 80 percent dilbit and 20 percent SCO.[59] However, the composition of WCSB oil sands crudes would possibly vary. To investigate the effect of changes in composition on the WTW weighted-average GHG emissions of WCSB oil sands crudes transported in the proposed Project, two additional composition scenarios were assessed, as summarized in Table 6-8. The "baseline" composition scenario (80 percent dilbit and 20 percent SCO) was compared to two alternate scenarios: one which assumes the WCSB oil sands portion of crudes transported by the proposed Project is 100 percent SCO and one which assumes the WCSB oil sands portion is 100 percent dilbit. WTW weighted-average GHG emissions from the three scenarios are summarized in Table 6-9 and are calculated based on data from Jacobs 2009 and TIAX 2009. NETL (2009) did not develop separate estimates for SCO and dilbit, and therefore does not allow for adjustment in the share of SCO and dilbit; [60] consequently, results for NETL could not be estimated in Table 6-8.

Table 6-8 Baseline and Alternative Scenarios Varying the Production Mix of WCSB Oil Sands Crudes

	Production Mix of WCSB Oil Sands Crude in the Proposed Project		
Crude Type	**All SCO Scenario (100% SCO, 0% Dilbit)**	**Baseline Scenario (50% SCO, 50% Dilbit)**	**All Dilbit Scenario (0% SCO, 0% Dilbit)**
In situ, SCO	7%	1.4%	0%
*In sit*u, dilbit	0%	80%	100%
Mining, SCO	93%	18.6%	0%

SCO = synthetic crude oil, WCSB = Western Canadian Sedimentary Basin.

Table 6-9 shows that varying the production mix results in different emissions estimated with the data from the two studies. The Jacobs result increases by 3.3 percent under the 0 percent dilbit scenario compared to the baseline scenario while the TIAX results decrease by roughly

[59] It is assumed that, of the total share of SCO transported in the proposed Project, 93 percent of the SCO share consists of SCO extracted through surface mining, with the remaining 7 percent of SCO from *in situ* extraction.

[60] NETL provides a single WCSB oil sands estimate that represents a weighted average of 43 percent crude bitumen from *in situ* production and 57 percent SCO from mining (NETL 2008, 2009). See Section 4.4.2, Analysis of Input and Modeling Assumptions, for details. 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 and did not provide the assumed mix of extraction methods for bitumen and SCO. Therefore, it is important to note that the 43/57 mix of blended bitumen and SCO assumed in NETL differs from the 80/20 mix of dilbit and SCO assumed in the baseline scenario for estimating WTW GHG emissions of the WCSB oil sands portion of the crudes carried in the proposed Project.

1 percent. The reverse is true for the 100 percent dilbit scenario, with emissions decreasing by 0.8 percent for Jacobs and increasing by 0.3 percent for TIAX, relative to the baseline scenario.

Table 6-9 Percent Change in WTW Weighted-Average GHG Emissions from Varying the Production Mix of WCSB Oil Sands Crudes

	WTW Weighted-Average GHG Emissions per Barrel of Gasoline and Distillates ($kgCO_2$/bbl G+D)			Percent Change from Baseline Scenario	
Study	All SCO Scenario	Baseline Scenario	All Dilbit Scenario	All SCO Scenario	All Dilbit Scenario
Jacobs, 2009	575	557	552	3.34%	-0.84%
TIAX, 2009	522	533	530	-1.19%	0.30%

GHG = greenhouse gas, $kgCO_2$/bbl G+D = kilograms carbon dioxide per barrel gasoline and diesel, SCO = synthetic crude oil, WCSB = Western Canadian Sedimentary Basin, WTW = well-to-wheels.

That Jacobs shows an increase in emissions under a greater share of SCO, while TIAX shows a decrease is due to the fact that the Jacobs study estimates that WTW GHG emissions from mined SCO are higher than those from *in situ* dilbit, whereas TIAX estimates that emissions from mined SCO are lower than *in situ* dilbit. For example, in comparing the calculated WTW emission factors from Jacobs and TIAX, the results for *in situ* SCO and dilbit are relatively close (i.e., Jacobs's values are 2 to 3 percent higher than TIAX values). However, emissions for surface-mined SCO in Jacobs are 11 percent higher than surface-mined SCO values in TIAX. Values for SCO from *in situ* and mining, and *in situ* dilbit developed from Jacobs and TIAX are shown in Table 6-10.

Table 6-10 WTW Weighted-Average GHG Emissions from WCSB Oil Sands Crudes

	WTW GHG Emissions per Barrel of Gasoline and Distillates ($kgCO_2$/bbl G+D)		
Study	*In situ*, SCO	*In situ*, dilbit	Mining, SCO
Jacobs, 2009	624	552	572
TIAX, 2009	593	533	515

GHG = greenhouse gas, $kgCO_2$/bbl G+D = kilograms carbon dioxide per barrel gasoline and diesel, SCO = synthetic crude oil, WCSB = Western Canadian Sedimentary Basin, WTW = well-to-wheels.

This analysis suggests that the difference in WTW weighted-average GHG emissions would be relatively minor—on the order of -1 to 3 percent—as compared to the baseline scenario; depending on the study, a greater share of *in situ*-produced dilbit could increase or decrease the WTW GHG emissions of the WCSB oil sands crude portion of the proposed Project's throughput.

6.2 TREATMENT OF PETROLEUM COKE IN WTW GHG EMISSION ESTIMATES

The combustion of co-products is a significant source of GHG emissions along the lifecycle of both WCSB oil sands and other crudes. Jacobs (2009), TIAX (2009), and NETL (2009) use 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). The treatment of petroleum coke has been summarized in Section 5.0, Petroleum Coke Characteristics, GHG Emissions, and Market Effects. The purpose of this section is to separately show the contribution

of petroleum coke to WTW GHG emissions estimates for WCSB oil sands crudes and other reference crudes. The results of this section are used to show the contribution of petroleum coke in the incremental GHG emission estimates developed in Section 6.5, Incremental GHG Emissions from Displacing Reference Crudes with WCSB Oil Sands Crudes in U.S. Refineries.

Table 6-11 shows the GHG emissions from production and combustion of petroleum coke and other co-products from Jacobs (2009), TIAX (2009), and NETL (2009). For WCSB oil sands crudes, the table also shows GHG emissions accounting for stockpiling at Canadian upgraders, assuming that an 80/20 ratio of dilbit to SCO would be transported by the proposed Project, that none of the bitumen produced from dilbit is stockpiled, and that 54 percent of the bitumen produced from SCO is stockpiled at Canadian upgraders (ERCB 2013). The GHG emissions provided in Table 6-11 were calculated for each study using the following approach:

- For Jacobs (2009):
  - GHG emissions associated with extracting, refining, distributing, and combusting co-products were allocated to premium fuels (i.e., gasoline, diesel, and jet fuel).
  - The values in Table 6-11 for Jacobs reflect the emissions from production and combustion of petroleum coke only. Emissions for the production and combustion of other co-products—and the fuels offset by these other co-products—are included in the WTW emission estimates in Table 6-3.
  - GHG emissions from the production and combustion of petroleum coke were calculated by taking the amount of petroleum coke produced per barrel of crude (Jacobs 2009, Table 5-4, p. 5-18), multiplying this by the GHG-intensity of petroleum coke (Jacobs 2009, p. 8-3), and normalizing these emissions per barrel of gasoline and distillates based on the yield for each crude type (Jacobs 2009, Table 5-4, p. 5-18).
- For TIAX (2009):
  - TIAX allocated GHG emissions from the production and combustion of co-products to the co-products themselves and excluded them from the study's lifecycle boundary. Using a refinery model, the authors 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 the GHG emissions allocated to co-products at the refinery are negligible (TIAX 2009, p. 34; Appendix D, p. 42).
  - To calculate GHG emissions from the combustion of petroleum coke for WCSB oil sands crudes, the amount of petroleum coke produced per barrel of SCO (1,330 MJ of coke per barrel of SCO) was taken from a mining and upgrading oil sands operation (Figure 3-12 in TIAX 2009, p. 26). This was multiplied by the GHG intensity of petroleum coke (96.77 gCO_2/MJ) (USEPA 2012a) and normalized per barrel of gasoline and distillates based on an 82 percent yield (TIAX 2009, Table E-1, p. E-1).
  - Petroleum coke emissions for the remaining crudes were estimated using the ratio of vacuum residuum of each reference crude relative to the vacuum residuum fraction of bitumen, taken from the distillation curve in TIAX (2009, Appendix D, Exhibit 3.2, p. 17) and assuming a 25/75 ratio of diluent to bitumen (TIAX 2009, p. 23). The petroleum coke yield was not provided directly for the reference crudes in the study; this

estimate is approximate based on the information that was publicly available from the TIAX (2009) study.

- For NETL (2008, 2009):
  - NETL (2008, 2009) allocated GHG emissions from the production and combustion of co-products to the co-products themselves and excluded them from the study's lifecycle boundary. The effect of allocating a portion of the lifecycle 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 and GHG emissions from the combustion of petroleum coke and other co-products, the NETL results for WCSB oil sands crudes and the reference crudes were adjusted to include the production and combustion emissions of the co-products 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 (Timothy Skone, personal communication, July 6, 2011).

Table 6-11 also calculates a substitution credit for petroleum coke that is used to offset coal-fired electricity generation. Jacobs (2009, 2012) applied a substitution credit for offsetting other products that are replaced by each of the co-products. The combustion of petroleum coke is assumed to offset GHG emissions from coal-fired electricity production on a one-to-one basis per unit of energy.[61] Jacobs (2009, p. 8-3) estimated the substitution credit would result in a net emission of 8.2 gCO_2 per MJ of petroleum coke combusted. Jacobs (2012, p. 1-41) assumed the net emissions would be 2 gCO_2 per MJ of petroleum coke based on the refinery configurations investigated in the study.

The credit assumed in Jacobs (2009) is applied to petroleum coke emissions in Table 6-11 to calculate the corresponding substitution credit for both Jacobs and TIAX results. The results show that roughly 90 percent of the GHG emissions are offset by coal displacement on a one-to-one energy basis. A substitution credit was not calculated for NETL (2009) because the results include the production and combustion of other co-products.

Table 6-11 GHG Emissions from the Production and Combustion of Petroleum Coke and Other Co-Products for WCSB Oil Sands Crudes and Other Reference Crudes

		GHG Emissions –from production and combustion of petroleum coke and other co-products	**Substitution Credit** –for combustion of petroleum coke	**Net GHG Emissions** –from production, combustion of petroleum coke and other co-products, and coal substitution
Study	**Crude**	($kgCO_2$-equivalent per barrel of gasoline and distillates)		
Jacobs[a]	WCSB oil sands	110 / 98[b]	100 / 90[b]	9 / 8[b]
	Middle Eastern Sour	36	33	3
	Mexican Maya	99	91	8

[61] The comparison between petroleum coke and coal is made on an energy basis—as opposed to a mass basis—because energy is the final desired output when petroleum coke or coal are used as fuels.

	Venezuelan	113	103	10
TIAX[c]	WCSB oil sands	145 / 129[b]	132 / 118[b]	13 / 11[b]
	Middle Eastern Sour	67	61	6
	Mexican Maya	109	100	9
	Venezuelan	105	96	9
NETL[d]	WCSB oil sands	156 / 151		
	U.S. Average (2005)	131		
	Middle Eastern Sour	124	Not calculated[e]	Not calculated[e]
	Mexican Maya	132		
	Venezuelan	126		

[a] Jacobs (2009) estimates represent the GHG emissions from the production and combustion of petroleum coke only. GHG emissions from other co-products and co-product emissions offsets are included in the weighted average WTW GHG emissions estimates in Table 6-3.

[b] The second value for WCSB oil sands crudes represents petroleum coke emissions from WCSB oil sands emissions, accounting for stockpiling at Canadian upgraders. Petroleum coke stockpiling at Canadian upgraders assumes that the proposed Project has an 80/20 ratio of dilbit to SCO, that none of the bitumen produced from dilbit is stockpiled, and that 54 percent of the bitumen produced from SCO is stockpiled at Canadian upgraders (ERCB 2013).

[c] TIAX (2009) estimates represent the GHG emissions from the production and combustion of petroleum coke only; information on the production of other co-products is not available from the study.

[d] NETL (2009) estimates include GHG emissions from the production and combustion of all co-products including petroleum coke, residual fuel oil, and light and heavy ends.

[e] NETL (2009) includes the production and combustion of co-products other than petroleum coke (i.e., residual fuel oil and light and heavy ends). The study did not calculate an emissions offset for these values, so a substitution credit has not been included for the NETL results.

-- = Not applicable, GHG = greenhouse gas, $kgCO_2e$ = kilograms carbon dioxide equivalent, WCSB = Western Canadian Sedimentary Basin.

The results from Table 6-11 are used in Section 6.5, Incremental GHG Emissions, to separately show the contribution of co-products—particularly the production and combustion of petroleum coke and the effect of the substitution credit for one-to-one displacement of coal for electricity generation.

6.3 WEIGHTED-AVERAGE GHG EMISSIONS FROM REFERENCE CRUDES REPLACED BY WCSB OIL SANDS CRUDES

To estimate incremental GHG emissions from WCSB oil sands transported by the proposed Project, this analysis compares the WTW GHG emissions associated with weighted-average WCSB oil sands crudes to those of reference crudes that may be displaced by WCSB oil sands crudes transported by the proposed Project to U.S. Gulf Coast refineries. As noted above, four reference crudes were selected to reflect a range of crude oil sources and GHG intensities:

- The average U.S. barrel consumed in 2005 (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 Renewable Fuel Standard Program, RFS2 (USEPA 2010a).
- Venezuela Bachaquero and Mexico Maya, which are representative of heavy crudes currently refined in PADD 3 refineries. 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 used as 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.

The estimates of WTW GHG intensity of these reference crudes from each of the three studies included in the incremental analysis are shown in Table 6-2 in terms of gCO_2e per megajoule of gasoline, diesel, and jet fuel products. For a consistent comparison with WCSB oil sands crudes, it is necessary to account for the various refined products produced from each crude. Therefore, the WTW GHG emissions estimates for reference crudes were converted from barrels of crude to a weighted-average $kgCO_2e$ per barrel 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 for each respective study. [62,63] The WTW GHG emissions estimates for the relevant reference crudes are provided in Table 6-12 for each of the WTW lifecycle stages.

Table 6-12 WTW GHG Emissions per Barrel for Reference Crudes, by Study and Lifecycle Stage

		GHG Emissions $kgCO_2e$ per Barrel of Gasoline and Distillates[a]					
Study	Crude Type	Crude Oil Production	Crude Oil Transport	Refining	Finished Fuel Transport	Fuel Combustion	WTW Total
Jacobs	Middle Eastern Sour	43	15	69	2	396	526
	Mexican Maya	68	6	74	2	398	549
	Venezuelan	52	7	86	2	405	553
	WCSB	96	1	71	2	387	557
TIAX	Middle Eastern Sour	1	5	59	IE	390	456
	Mexican Maya	17	1	63	IE	390	470
	Venezuelan	55	1	67	IE	390	513
	WCSB	74	9	59	IE	390	533
NETL	U.S Average (2005)	36	7	47	5	393	488
	Middle Eastern Sour	13	15	55	5	393	480
	Mexican Maya	36	6	70	5	393	510
	Venezuelan	23	6	58	5	393	485
	WCSB	105	5	61	5	393	568

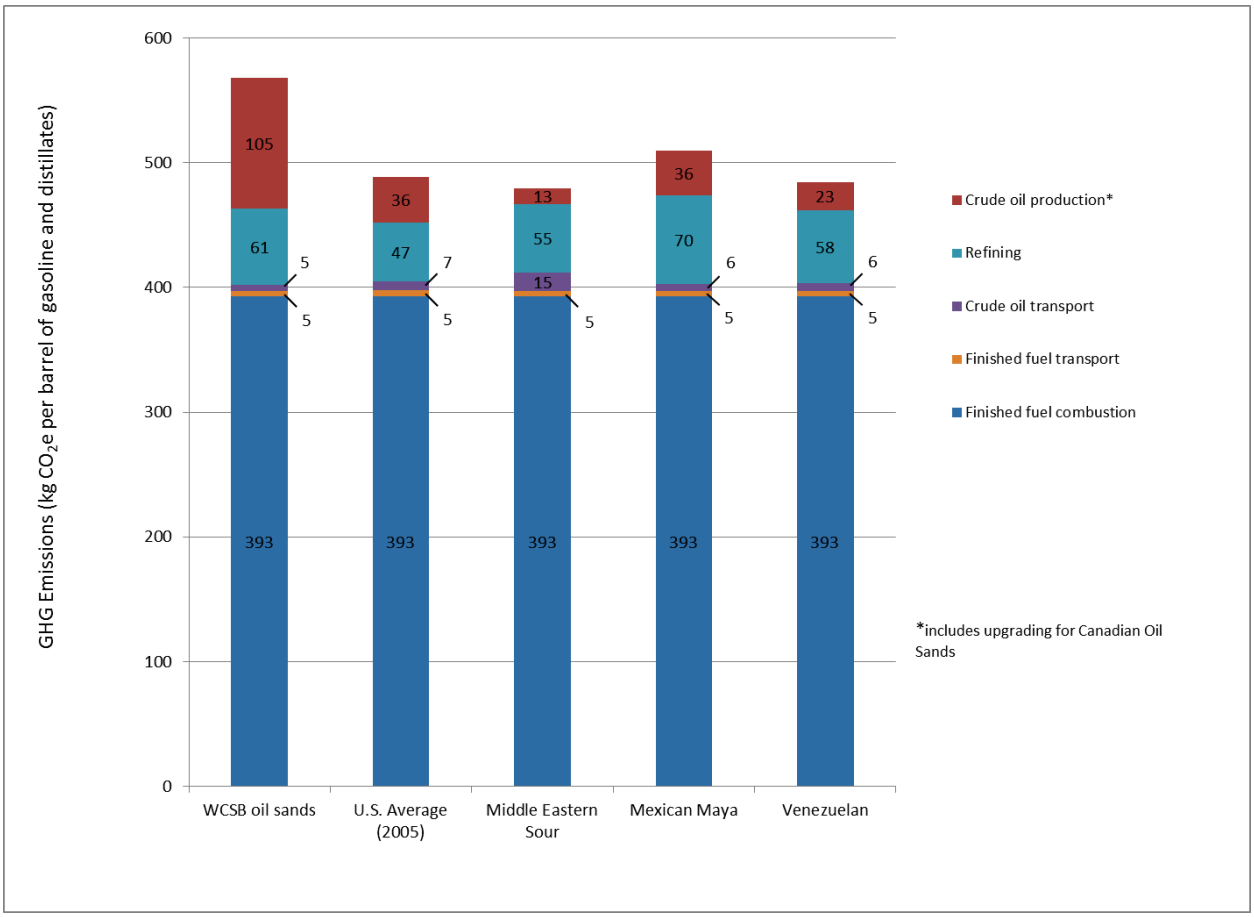
[a] The yield of gasoline and distillates (i.e., premium fuel products) is calculated for each study as the total volume of gasoline, diesel, and kerosene or kerosene-based jet fuel, divided by total refinery output.
Note: The WCSB crude oils are taken from Table 6-3 and the Crude Oil Production column for WCSB combines both extraction and upgrading.

GHG = greenhouse gas, IE = emissions from lifecycle stage included in other lifecycle stage, $kgCO_2e$ = kilograms carbon dioxide equivalent, SCO = synthetic crude oil, WCSB = Western Canadian Sedimentary Basin, WTW = well-to-wheels.

[62] For NETL, the relative yield of gasoline, diesel, and kerosene/jet fuel as a percentage of gasoline and distillates is 58, 30, and 12 percent 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 refinery product yields in Table 6-6 (Jacobs 2009, p. 5-18). For TIAX, the relative yield of gasoline, diesel, and jet fuel is 57, 32, and 11percent respectively, based on the U.S. average modeling results provided in Table E-1 (TIAX 2009, p. E-1).

[63] Since TIAX did not provide GHG intensity results for jet fuel, the weighted-average was calculated assuming that the GHG intensity was similar to diesel on an energy basis, and was calculated using the energy content values for diesel and jet fuel in Table E-1.

When comparing weighted average WTW GHG emissions estimates for WCSB oil sands crudes (Table 6-3) to those of reference crudes (Table 6-12) replaced by WCSB oil sands crudes transported by the proposed Project, finished fuel combustion represents the dominant share—between X and Y percent of WTW emissions[64]—and the differences between WCSB oil sands crudes and reference crudes are largely driven by higher mining/extraction emissions. Figure 6-1 compares weighted-average WCSB oil sands crudes in NETL (2009) to WTW emissions from relevant references crudes across the WTW lifecycle stages.



Source: NETL 2009.

1. In this chart, all emissions are per barrel of gasoline and distillates.
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, and thus, the NETL values are compared to a lighter Venezuelan reference crude than other studies.

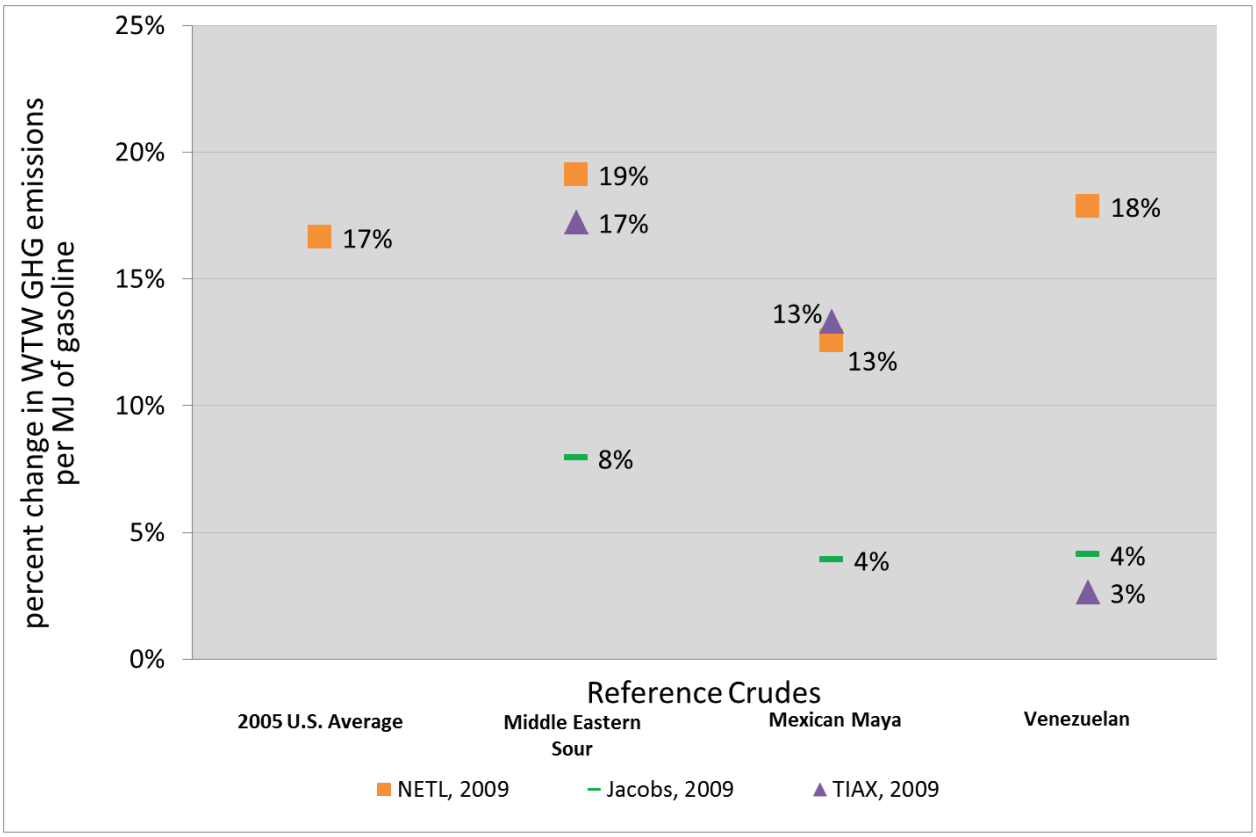
GHG = greenhouse gas, kg CO_2e = kilograms per carbon dioxide equivalent, WCSB = Western Canadian Sedimentary Basin.

Figure 6-1 WTW Weighted-Average GHG Emissions from the Mix of WCSB Oil Sands Crudes Compared to Reference Crudes in NETL (2009)

This trend is further demonstrated in Figure 6-2, which indicates the GHG intensity of crudes likely to be transported in the proposed Project relative to each of the four reference crudes on a

[64] Including co-product emissions and without assuming any substitution credit, based on the calculations developed in Section 6.3, the share of finished fuel combustion is calculated to range from 54 to 69 percent. Total combustion emissions from finished fuel and co-products would range from 75 to 87 percent.

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 6-2 are internally consistent in that they make comparisons between crudes from the same study.



Sources: NETL 2009, Jacobs 2009, TIAX 2009.

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, and thus, the NETL values are compared to 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, MJ = megajoules, WTW = well-to-wheels.

Figure 6-2 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

6.4 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 proposed Project's carbon footprint, on a lifecycle basis, from the crude transported. 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. This section draws together the different contributing factors for GHG emissions to calculate the GHG emissions impact of the proposed Project.

The total lifecycle emissions associated with production, refining, and combustion of 830,000 bpd of oil sands crude oil is approximately 147 to 168 million metric tons of CO_2 equivalent ($MMTCO_2e$) per year. The annual lifecycle GHG emissions from 830,000 bpd of the four reference crudes examined in this section are estimated to be 124 to 159 $MMTCO_2e$. The range of incremental GHG emissions for crude oil that would be transported by the proposed Project is estimated to be 1.3 to 27.4 $MMTCO_2e$ annually.[65, 66]

The estimated range of potential emissions is large because there are many variables, including the reference crude that is displaced, which reference crude is used for the comparison, and which study is used for the comparison. Below is more summary information explaining the range:

- The upper end of this range, the 27.4 MMTCO2e estimate, is based on comparing the average emissions for 830,000 bpd of oil sands crude (the total capacity of the proposed Project), assuming the displaced reference crude is a light, low-GHG crude oil, such as Middle-Eastern Sour, and looking at emissions estimates from the NETL study.
  - Based on these same assumptions, and looking at the Jacobs study, the estimate would be approximately 9.0 $MMTCO_2e$.
  - Based on these same assumptions, and looking at the TIAX study, the estimate would be approximately 22.2 $MMTCO_2e$.

[65] Because the estimates of lifecycle emissions from oil sands (i.e., 147 to 168 $MMTCO_2e$) and the four reference crudes (i.e., 124 to 159 $MMTCO_2e$) both represent ranges across various studies, it is not possible to subtract the high and low bounds from each to arrive at the net emissions result. Instead, the results for oil sands crudes from one study need to be consistently compared against the results for the other reference crudes from the same study to produce the final net emissions result (i.e., 1.3 to 27.4 $MMTCO_2e$).

[66] These estimates include GHG emissions from co-product combustion and any offsets for displacement of coal from petroleum coke co-products, as calculated in Table 4.14-4.

- The lower end of the range, down to the 1.3 MMTCO2e estimate, is based on assuming the displaced reference crude is a heavy crude such as Mexican Maya or Venezuelan heavy, and looking at the results from the Jacobs study.
  - Based on these same assumptions, and looking at the TIAX study, the estimate would be approximately 5.9 $MMTCO_2e$ for Venezuelan Heavy to 17.4 $MMTCO_2e$ for Mexican Maya.
  - Based on the assumption that the displaced reference crude is Mexican Maya, and looking at the NETL study, the estimate would be approximately 18.4 $MMTCO_2e$.[67]

The above estimates represent the total incremental emissions associated with production and consumption of 830,000 bpd of oil sands crude compared to the reference crudes. These estimates represent the potential increase in emissions attributable to the proposed Project if one assumed that approval or denial of the proposed Project would directly result in a change in production of 830,000 bpd of oil sands crudes in Canada. However, as set forth in the Final Supplemental EIS Section 1.4, Market Analysis, such a change is not likely to occur. Section 1.4 reaffirms the conclusion of the Draft Supplemental EIS that: "Approval or denial of any one crude oil transport project, including the proposed Project, remains unlikely to significantly impact the rate of extraction in the oil sands, or the continued demand for heavy crude oil at refineries in the U.S." [68] The results showing the WTW GHG emissions from the weighted average of WCSB oil sands crudes and reference crudes, and the incremental WTW GHG emissions from displacing reference crudes in U.S. refineries are presented in Figure 6-3.[69] The figure was developed based on (i) the WTW GHG emissions for WCSB oil sands crudes from Table 6-3, (ii) the petroleum coke and co-product GHG emissions and substitution credits (or offsets) calculated in Table 6-11, (iii) the WTW GHG emissions for other reference crudes in Table 6-12, and (iv) the land use change estimates in Table 6-7.

These estimates were converted to annual GHG emissions by multiplying by the maximum throughput of the proposed Project (830,000 barrels per day) and assuming operation over the full 365 days in a year.[70] The throughput of the proposed Project was normalized to a basis of

[67] The Venezuelan crude oil assessed in the NETL study, that was closest to the Venezuelan Bachaquero reference crude, was a conventional medium oil, not a heavy crude oil. Therefore, the NETL comparison uses a lighter Venezuelan reference crude than the Jacobs and TIAX studies.

[68] The Draft Supplemental EIS estimated how production would be affected by approval or denial of the proposed pipeline. Updated analysis in Section 1.4 suggests that previous estimates likely overstated the production impact of the proposed pipeline, and that the range of prices in which denial of the proposed project could make a meaningful difference to oil sands production over the long-run is most likely a small one. As noted in Section 1.4, under certain conditions, lower-than-expected oil prices could affect the outlook for the oil sands and transportation constraints could exacerbate other adverse global market conditions. At around $70/bbl (WTI-equivalent), the impact on long term production is likely to be less than 170,000 bpd even if one assumes that the proposed project as well as all other new and expanded Canadian and cross-border pipeline capacity are not constructed, if the cost "penalty" for using rail is at the upper end of the assessed range, and if other costs and differentials do not fall along with oil prices. Above that level, most oil sands projects will be economic with or without the proposed project or other cross-border pipelines; below it, many oil sands projects could be uneconomic regardless of transport options.

[69] The results in TIAX 2009 and NETL 2008 and 2009 reflect refining at PADD 3 refineries; Jacobs 2009 results reflect refining at PADD 2 refineries.

[70] As noted elsewhere in the Final 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 sands. This analysis conservatively uses the full initial throughput of the proposed Project in developing annual GHG emission estimates.

gasoline and distillates using the yields in each study (Jacobs 2009, TIAX 2009, NETL 2008, 2009) shown in Table 6-13.

Table 6-13 Yield of Gasoline and Distillates and Equivalent Barrels of Gasoline and Distillates from 100,000 Barrels of Crude Oil ($MMTCO_2e$)

Study[a]	Yield of Gasoline and Distillates[b] 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	89%[3]	88,972	TIAX 2009, p. E-1
NETL	77%	77,000	NETL 2008, p. 83

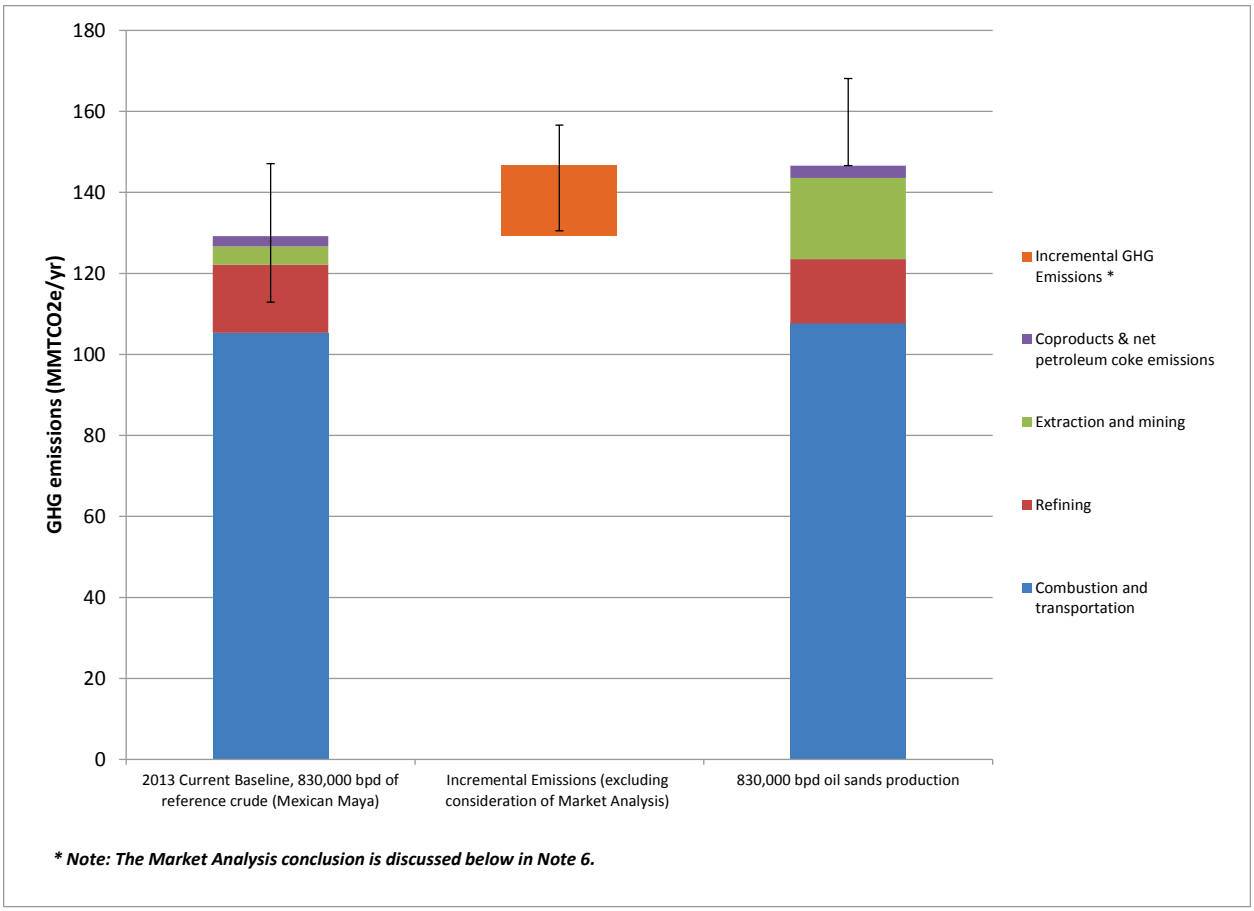
[a] The NETL and TIAX yields are based on average U.S. refinery product yields, whereas the Jacobs yield is based on the product yield from refining SCO and dilbit crudes. The average yields used from NETL and TIAX likely underestimate the gasoline and distillates yield for SCO, and overestimate the gasoline and distillates yield from dilbit.
[b] 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 increments presented here are based on lifecycle 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 oil sands crude oils and the reference crude oils are likely to change. For instance, it would likely become more energy-intensive to produce reference crudes over time as fields mature and secondary and tertiary recovery techniques, such as CO_2 or water flooding, are required to maintain production levels. Many of the reference crude oil reservoirs are 1 to 2 miles (or more) underground or under the ocean floor, and exploration efforts for new deep oil reservoirs would continue as known reservoirs deplete.

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.

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.

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 6-14. The incremental GHG emissions were calculated by subtracting from the WTW GHG emissions an equivalent displaced volume of each reference crude.



Notes:
1) The columns plotted are illustrative to show the order of magnitude of GHG emissions for the different lifecycle stages (TIAX 2009 data was used as a mid-range data set; for the 2013 Current Baseline, Mexican Maya was used at the Reference Crude).
2) The range bars represent the range of GHG emissions estimated across the three studies (NETL 2009, Jacobs 2009, TIAX 2009) and each of the reference crudes.
3) The results are based on the preceding results presented in Section 4.14.3.5, Incremental GHG Emissions, which are from Appendix U, Lifecycle Greenhouse Gas Emissions, and based on NETL 2009, Jacobs 2009, TIAX 2009.
4) 2013 Current Baseline: This represents today's position of the WTW GHG emissions currently being emitted based on 830,000 bpd of each of the selected reference crudes (the column is for TIAX Mexican Maya as per note 1, and the range bar is for all reference crudes).
5) 830,000 bpd Oil Sands Production: This assumes the proposed Project is built and a maximum of 830,000 bpd of WCSB crude oil is transported to the Gulf Coast refineries.
6) Incremental Emissions: This represents the difference between the 2013 Current Baseline and the 830,000 bpd Oil Sands Production, and excludes consideration of the Market Analysis. The orange bar represents incremental emissions. The bar itself is for a single crude (Mexican Maya) from the TIAX study. The range bar is representative of all studies and reflects the 1.3 to 27.4 $MMTCO_2e$ annual incremental emissions presented in the Final Supplemental EIS. These Incremental Emissions represent the potential increase in emissions attributable to the proposed Project if one assumed that approval or denial of the proposed Project would directly result in a change in production of 830,000 bpd of oil sands crudes in Canada. However, as set forth in Section 1.4, Market Analysis, such a change is not likely to occur. Section 1.4 notes as stated in the conclusion of the Draft Supplemental EIS that approval or denial of any one crude oil transport project, including the proposed Project, remains unlikely to significantly impact the rate of extraction in the oil sands, or the continued demand for heavy crude oil at refineries in the United States.

Figure 6-3 WTW GHG Emissions from Weighted Average WCSB Oil Sands Crudes, and Incremental WTW GHG Emissions from Displacing Reference Crudes

Table 6-14 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[a]	NETL, 2009[a]
Middle Eastern Sour	1.03	2.0	2.5
Mexican Maya	0.25	1.6	1.7
Venezuelan[b]	0.24	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.

[a] 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.

[b] 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.

GHG emissions from both mining and *in situ* SAGD oil sands crude production have decreased over the last decade (IHS CERA 2012, p. 19)[71]. Although it is unclear how the GHG intensity of reference crudes relative to oil sands crudes will change over time, if these trends continue (i.e., the GHG intensity for future reference crudes continued upward and the GHG intensity of future oil sands production continue downward), then the differential in WTW GHG emissions of oil sands crudes would decrease relative to reference crudes.

The full summary of results for all studies and scenarios is shown in Table 6-15.

Table 6-15 Incremental WTW GHG Emissions from Weighted-Average WCSB Oil Sands Crudes Relative to Reference Crudes[a]

		NETL (2009)	Jacobs (2009)	TIAX (2009)
		Million metric tons CO_2-equivalent per year[a]		
Annual WTW GHG emissions from WCSB oil sands crudes transported by the proposed Project[b]	A	133	157	144
GHG emissions from the production and combustion of co-products[c]	B	36	28	35
Emissions offset from fuels replaced by co-products[c]	C	0	26	32
Subtotal (equivalent to 2020 with proposed Project Scenario)	=A+B-C	168	160	147

[71] The estimate of oil sands GHG intensity used in this Final Supplemental EIS is based on an approximate 80 percent mix of *in situ* production. This estimated mix of *in situ* production is based on the pipeline design specifications that assume up to an approximate 80 percent mix of diluted bitumen, which is derived primarily from *in situ* projects.

		NETL (2009)	Jacobs (2009)	TIAX (2009)
		Million metric tons CO_2-equivalent per year[a]		
WTW GHG emissions from reference crudes[b] (equivalent to 2013 Current Conditions)	D			
U.S. average		145	NA	NA
Middle Eastern Sour		141	151	124
Mexican Maya		150	158	129
Venezuelan[d]		142	159	141
Incremental GHG emissions from proposed Project in 2020[e] excluding Market Analysis conclusions[f]	= C - D			
U.S. average		23.5	NA	NA
Middle Eastern Sour		27.4	9.0	22.2
Mexican Maya		18.4	2.2	17.4
Venezuelan		25.7	1.3	5.9

[a] Results were converted to million metric tons CO_2e/year from $kgCO_2e$/barrel of gasoline and distillates by multiplying by the throughput of the proposed Project (830,000 barrels of crude oil per day), converted to a basis of gasoline and distillates using the yield values in Table 6-13. Annual GHG emissions were calculated assuming the proposed Project operates at this throughput for 365 days per year.
[b] Based on WTW GHG emissions provided in Table 6-3 and Table 6-10.
[c] Based on petroleum coke and other co-products GHG emissions and substitution credits provided in Table 6-11.
[d] Venezuelan Conventional is used as the NETL reference crude for Venezuelan Bachaquero in this analysis. This is a medium crude, not a heavy crude. Therefore, the NETL comparison uses a lighter Venezuelan reference crude than the Jacobs and TIAX studies.
[e] Does not account for changes in the GHG intensity of WCSB oil sands crudes relative to other reference crudes in the future.
[f] As set forth in Section 1.4, Market Analysis, a direct change in production of 830,000 bpd of oil sands crudes in Canada is not likely to occur with approval or denial of the proposed Project. Section 1.4 reaffirms the conclusion of the Draft Supplemental EIS that: "Approval or denial of any one crude oil transport project, including the proposed Project, remains unlikely to significantly impact the rate of extraction in the oil sands, or the continued demand for heavy crude oil at refineries in the U.S."

CO_2e = carbon dioxide equivalents, GHG = greenhouse gas, SCO = synthetic crude oil, WTW = well-to-wheel, WCSB = Western Canadian Sedimentary Basin.

If these incremental emissions are summed for the entirety of the proposed Project timeframe (construction plus 50 operational years), the total accumulated range of incremental WTW GHG emissions attributable to the proposed Project would be as summarized in Table 6-16.

As discussed in Section 4.1.4, Near- and Longer-Term Trends that Could Affect WTW GHG Emissions, the increments presented here are based on lifecycle 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 would 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). Many of the reference crude oil reservoirs are 1 to 2 miles (or more) underground or under the ocean floor and exploration efforts for new deep oil reservoirs would continue as known reservoirs continue to deplete. In contrast, bitumen reserves in the WCSB are sufficiently extensive that "depletion effects" have not been observed thus far and are not expected in the near-term future (Brandt et al. 2013).

Table 6-16 Accumulated Incremental WTW GHG Emissions over Proposed Project Lifetime

Crude	Construction GHG Emissions[a]	Land Use Change Emissions[b]	50-Year Incremental GHG Emissions[c]	Accumulated Incremental GHG Emissions[d]
	$MMTCO_2e$			
Incremental GHG Emissions for Construction and Operation of the Proposed Project plus Incremental Emissions Associated with Production and Consumption of 830,000 bpd of Oil Sands Crude[d]	0.24	70	65 - 1,370	135 – 1,430

[a] Results from Table 4.14-1.

[b] Results from Table 4.14-6, where the results were converted to annual GHG emissions by multiplying by the maximum throughput of the proposed Project (830,000 bpd), assuming operation over the full 365 days in a year. The throughput of the proposed Project was normalized to a basis of gasoline and distillates using the yields in each study. The result was multiplied by 50 years.

[c] Results from Table 4.14-7 multiplied by 50 years. Does not account for changes in pipeline throughput over time or changes in the GHG intensity of WCSB oil sands crudes relative to other reference crudes in the future. Operational GHG emissions are assumed to be covered in the incremental emissions as part of the lifecycle assessment.

[d] Calculated by summing the Construction GHG Emissions, Land Use Change Emissions and 50-Year Incremental GHG Emissions.

GHG = greenhouse gas, $MMTCO_2e$ = million metric tons carbon dioxide equivalent, WTW = well-to-wheels.

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 58 percent by 2022 (ERCB 2013). In particular, the share of SAGD *in situ* extraction methods are projected to rise from roughly 20 percent in 2011 to 45 percent of oil sands production in 2030 (IHS CERA 2012).[72] Although it is unclear how the GHG intensity of reference crudes relative to WCSB oil sands crudes would change over time, it is likely that GHG intensity for future reference crudes would 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

Lifecycle 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

[72] Although the balance of mining and *in situ* extraction would 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.

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 lifecycle of fuels requires the consideration of a large number of analytical design issues. As discussed in Section 4.1, Study Design Factors, these include developing rules for how to handle co-products (Section 4.1.5, 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 4.1.6, 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 4.1.3, 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 lifecycle GHGs from different crude sources.

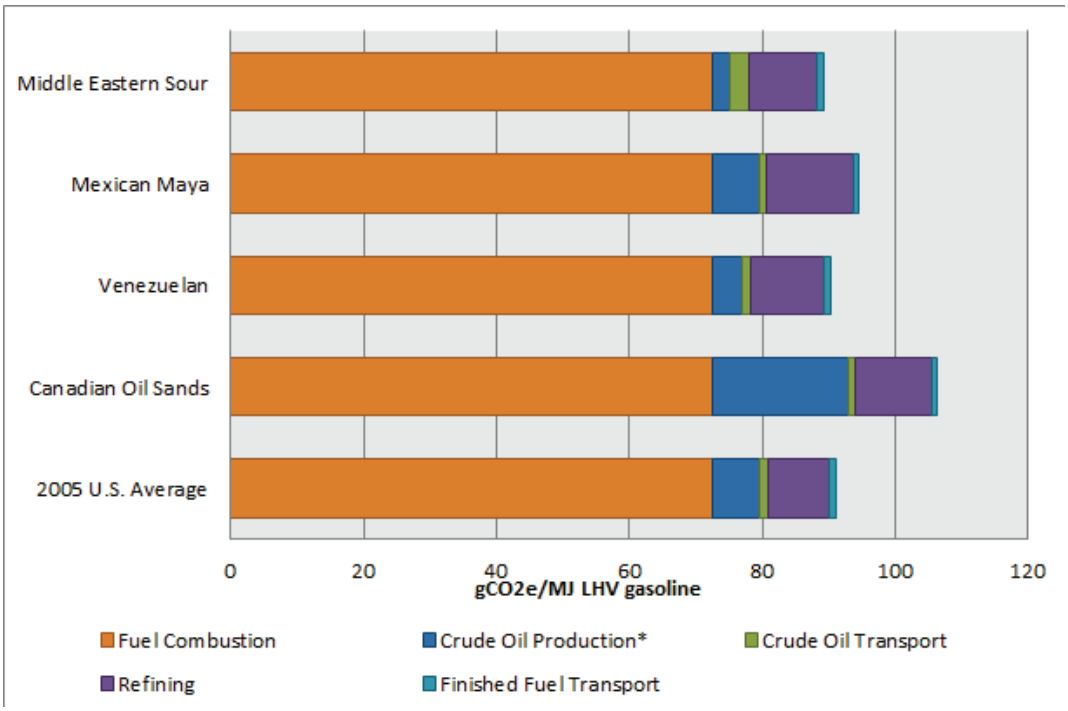
In addition, information on a large number of individual inputs and assumptions (Section 4.2, Input and Modeling Assumptions) is necessary to capture the relative lifecycle GHG emissions between fuels in sufficient detail. In many cases, key information and data sources are proprietary or not otherwise 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. 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 lifecycle 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 lifecycle carbon footprint, for transportation fuels produced in U.S. refineries, would increase if the project were approved.
2. The total lifecycle emissions associated with production, refining, and combustion of 830,000 bpd of oil sands crude oil is approximately 147 to 168 million metric tons of CO_2 equivalent ($MMTCO_2e$) per year. The annual lifecycle GHG emissions from 830,000 bpd of the four reference crudes examined in this section are estimated to be 124 to 159 $MMTCO_2e$. The range of incremental GHG emissions for crude oil that would be transported by the proposed Project is estimated to be 1.3 to 27.4 $MMTCO_2e$ annually. The estimated range of potential emissions is large because there are many variables, including the reference crude that is displaced, which reference crude is used for the comparison, and which study is used for the comparison.

3. The above estimates represent the total incremental emissions associated with production and consumption of 830,000 bpd of oil sands crude compared to the reference crudes. These estimates represent the potential increase in emissions attributable to the proposed Project if one assumed that approval or denial of the proposed Project would directly result in a change in production of 830,000 bpd of oil sands crudes in Canada. However, as set forth in Section 1.4, Market Analysis, such a change is not likely to occur. Section 1.4 reaffirms the conclusion of the Draft Supplemental EIS that: "Approval or denial of any one crude oil transport project, including the proposed Project, remains unlikely to significantly impact the rate of extraction in the oil sands, or the continued demand for heavy crude oil at refineries in the U.S."
4. The incremental GHG emissions associated with production and consumption of 830,000 bpd of oil sands crude oil compared to the reference crude oils is estimated to be 1.3 to 27.4 $MMTCO_2e$ annually. This is equivalent to annual GHG emissions from combusting fuels in approximately 270,833 to 5,708,333 passenger vehicles, the CO2 emissions from combusting fuels used to provide the energy consumed by approximately 64,935 to 1,368,631 homes for 1 year, or the annual CO2 emissions of 0.4 to 7.8 coal fired power plants.
5. The increments presented here are based on lifecycle 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 oil sands crude oils and the reference crude oils are likely to change. For instance, it would likely become more energy-intensive to produce reference crudes over time as fields mature and secondary and tertiary recovery techniques, such as CO_2 or water flooding, are required to maintain production levels. Many of the reference crude oil reservoirs are 1 to 2 miles (or more) underground or under the ocean floor, and exploration efforts for new deep oil reservoirs would continue as known reservoirs deplete.
6. 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 4-13. 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.
7. Upgrading bitumen to allow its flow through a pipeline shifts a portion of the GHG emissions from refining to further upstream in the lifecycle, 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 would 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 would overestimate the GHG emissions from SCO relative to other crude sources.

8. The relative GHG-intensity of both reference crudes and oil sands-derived crudes would change differently over time. The studies reviewed in this assessment represent a current snapshot of lifecycle emissions within the studies for given reference years, shown in Table 4-13. The lifecycle GHG emissions of both WCSB oil sands and reference crudes, however, would 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.
9. The largest share of GHG emissions from the fuel lifecycle 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., 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 Lifecycle 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:

- Although the weighted-average GHG intensity of WCSB oil sands crudes was estimated to be more intensive than the reference crudes, it is not clear whether all WCSB oil sands-derived crudes are currently more GHG intensive than other heavy crudes or crudes with high flaring rates. Depending on several factors including extraction method, process fuel type, and process efficiency, the lifecycle GHG emissions of certain 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 would 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 would 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 lifecycle GHG emissions of WCSB oil sands and reference crudes would change over time, but it is not clear how these changes would impact the relative GHG emissions of reference crudes relative to WCSB oil sands crudes. On one hand, secondary and tertiary recovery techniques would 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 would not leave 55 percent of the World's proven reserves in the ground. Exploration for new oil reservoirs would 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, would represent a larger share of oil sands production in the future, although technical innovation would 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 Final Supplemental EIS, the Department assumes that the average crude oil flowing through the pipeline would consist of about 80 percent Western Canadian Select (dilbit) and 20 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 4.4, 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 lifecycle 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[a]	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
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

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

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