Life Cycle Assessment of North American Conventional Crudes for Production of Transportation Fuels

by

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Abstract

Global energy demand is expected to grow substantially and will lead to increased production of crude oil from various sources. The production of crude oil and it's conversion to transportation fuels result in the release of greenhouse gases (GHGs) into the atmosphere. As one of the highest GHG-emitting sectors, the transportation sector requires GHG emissions reductions plans that push forward different policy regulations that require appropriate quantification of life cycle GHG emissions for transportation fuels derived from various crude types. A life cycle assessment (LCA) is an extremely useful tool to assess the greenhouse gas (GHG) emissions for transportation fuels on a well-to-wheel (WTW) basis. In this study, a WTW life cycle assessment was conducted for five North American conventional crude oils. The well-to-wheel life cycle assessment of crude oil includes both the well-to-tank (WTT) and tank-to-wheel (TTW) stages. The WTT stage includes crude recovery, transportation of crude from the feedstock location to the refinery, refining of crude, and transportation and distribution of refined fuels (gasoline, diesel, and jet fuel) to the refueling stations. The combustion of transportation fuels in vehicle engines is known as the TTW stage. All of the life cycle stages consume energy and produce a significant amount of GHG emissions. The purpose of this study was to provide a comprehensive and transparent quantification of greenhouse gas (GHG) emissions for transportation fuels derived from five North American conventional crudes through the development of a data-intensive bottom-up engineering model called FUNNEL-GHG-CCO (**FU**N**N**damental E**N**gineering Princip**l****E**s-based Mode**L** for Estimation of **G**reen**H**ouse **G**ases in **C**onventional **C**rude **O**ils). The model estimates

GHG emissions from all the life cycle stages from the recovery of crude to the combustion of transportation fuels in vehicle engines. GHG emissions from recovery, refining, and transportation were calculated using the amount of energy required for each stage, process energy shares, and emission factors. GHG emissions from crude recovery depend on crude oil and reservoir properties, depth of reservoir, extraction method applied, and gas-to-oil and water-to-oil ratios. The contribution of recovery emissions in the total WTW GHG emissions ranges from 3.12% for Mars crude to 24.25% for California's Kern County heavy oil. The transportation of crude oil and finished fuels contributes only 0.44-1.73% of the total WTW life cycle GHG emissions, depending on the transportation methods and total distance transported. Refining energy use and resulting GHG emissions were allocated to gasoline, diesel, and, jet fuel based on a sub-process level allocation method. Refining emissions vary from 13.66-18.70 g-CO_2eq/MJ-gasoline, 9.71-15.33 g-CO_2eq/MJ-diesel, and 6.38-9.92 g-CO_2eq/MJ-jet fuel derived from Alaska North Slope and California's Kern County heavy oil, respectively. The total WTW life cycle GHG emissions range from 97.55-127.74 g-CO_2eq/MJ-gasoline, 95.01-126.02 g-CO_2eq/MJ-diesel, and 88.17-118.17 g-CO_2eq/MJ-jet fuel derived from Mars and California's Kern County heavy oil, respectively.

Preface

This thesis is an original work by Md Mustafizur Rahman under the supervision of Dr. Amit Kumar. Sections of chapter 2 were published as Rahman, M.M., Canter, C., Kumar, A., "Greenhouse gas emissions from recovery of various North American conventional crudes," *Energy*, 2014. 74(0): p. 607-617. Sections of chapter 3 have been submitted as Rahman, M.M., Canter, C., Kumar, A., "Well-to-wheel life cycle assessment of transportation fuels derived from different North American conventional crudes," to *Applied Energy*. I was responsible for the concept formulation, data collection, model development and validation, and manuscript composition. C. Canter contributed to model validation and manuscript edits. A. Kumar was the supervisory author and was involved with concept formation, evaluation, assessment of results, and manuscript edits.

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Chapter 1: Introduction

1.1. Background

Crude oil is one of the main sources of energy supply in the world. Global energy demand is expected to increase by 33% from 2011 to 2035 [1]. Reflecting the increase in global energy demand, crude oil demand has been growing substantially. This demand is expected to increase the production of crude oil from various sources around the globe. In 2012, the share of conventional crude oil in the total oil production was 80% [1], the remaining 20% came from unconventional sources such as oil sands (bitumen), oil shale, etc.

As of 2012, Canada has the biggest reserves of crude oil in North America with 173.625 billion barrels, followed by the U.S. with 26.544 billion barrels and Mexico with 10.359 billion barrels [2]. In 2012, in North America, the U.S. was the largest oil-producing country with a production of 11,119 thousand barrels per day, followed by Canada with 3,856 thousand barrels per day and Mexico with 2,936 thousand barrels per day [3]. That year 20% of the world's total crude oil was produced in North America [2]. The U.S. was the largest consumer of petroleum in the world at 18,490.2 thousand barrels per day. Canada and Mexico consumed 2350.7 and 2085.6 thousand barrels per day, respectively. Overall, in 2012, approximately 26% of world's total petroleum was consumed in North America [2].

Conventional crude oil is produced from petroleum deposits beneath the earth's surface through the well bore using primary, secondary, or tertiary recovery methods [4]. Conventional crude oil is a mixture of hydrocarbons that exist in a liquid phase at atmospheric temperature and pressure. It is a hydrogen-rich compound with relatively short hydrocarbon chains and lower molecular weight than most unconventional oils [5]. Generally, the extraction of conventional crude is easier and cheaper than the extraction of unconventional crude oil.

The lightness or heaviness of a crude oil is measured by the term API (American Petroleum Institute) gravity. API gravity represents how light or heavy the crude oil is compared to water. If the API gravity of any crude oil is above 10 ºAPI, it is lighter than water. The API gravity can be calculated from the following equation:

$$API\ gravity = \frac{141.5}{Specific\ gravity} - 131.5 \quad (1)$$

If the API gravity is above 31.1 ºAPI, the crude is called light crude. The API gravity of medium oil is in the range of 22.3 ºAPI to 31.1 ºAPI. Heavy crude's API gravity is less than 22.3 ºAPI but above than 10 ºAPI. If the API gravity is less than 10 ºAPI, it is called extra heavy crude oil [6].

At 72%, the transportation sector was the biggest consumer of petroleum (2012 data) [7]. The use of petroleum is associated with environmental impacts. The release of greenhouse gases (GHGs) into the atmosphere is one of the key environmental impacts.

In the U.S. in 2012, the transportation sector was the second highest GHG-emitting sector after the electricity sector and accounted for about 28% of the total GHG emissions [8]. GHG emissions have increased by approximately 18% in this sector between 1990 and 2012 in the U.S. In Canada, the transportation sector contributes 24% of all GHG emissions, nearly as much as the oil and gas sector, which contributes 25% of total GHG emissions [9]. In the European Union (EU), the transportation sector contributes about 25% of the total GHG emissions and is the second highest GHG-emitting sector after the energy sector [10].

Globally, between 1900 and 2009 carbon dioxide (CO_2) emissions increased by 38% [11], an increase that is a big environmental concern. As GHG emissions increase, different environmental regulations come into play to reduce GHG emissions within the transportation sector. California's Low Carbon Fuel Standard (LCFS) and the European Union's Fuel Quality Directive require a decrease of 10% in the carbon intensity of transportation fuels by 2020 [12, 13]. These regulations push forward the need to quantify the GHG emissions for transportation fuels (i.e. gasoline, diesel, and jet fuel) on a life cycle basis, an approach that includes the emissions from crude recovery, transportation of crude and finished fuels, refining, and combustion of transportation fuels in vehicle engines.

A life cycle assessment (LCA) is an extremely useful tool to evaluate the environmental impacts of a product through all the stages associated with its life cycle. This tool helps in making decisions towards sustainability. According to ISO 14040 [14] and ISO 14044 [15], there are four phases of an LCA. These four phases are shown in Figure 1.

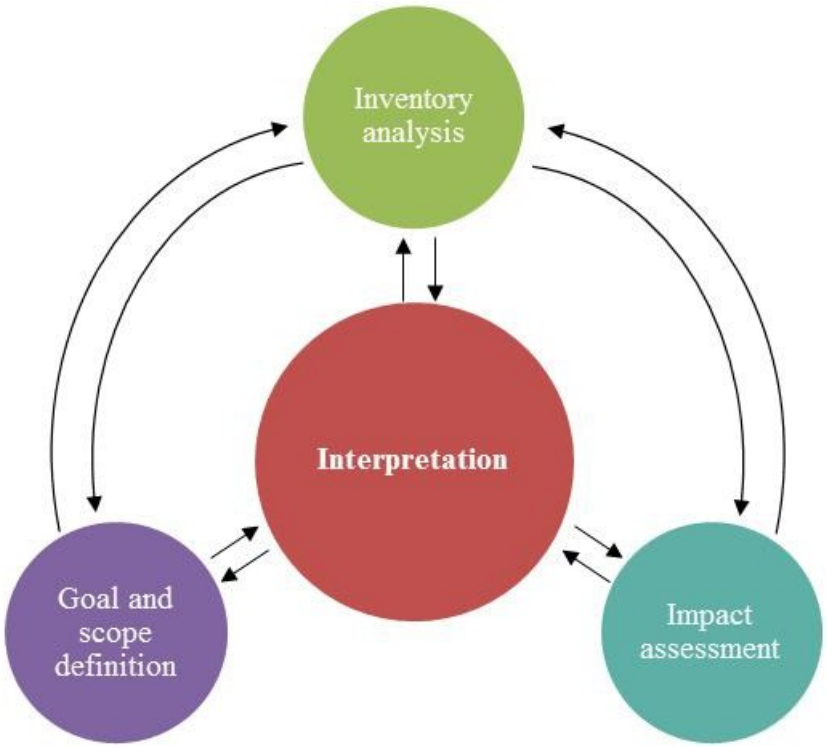

Figure 1: The phases of a life cycle assessment. Adapted from [14]

The definition of goal and scope includes identifying the purposes of the LCA study and defining the LCA system boundary and functional unit. The inventory analysis involves the quantification of inputs (i.e., energy and material use) and outputs (i.e., GHG emissions) of each stage inside the system boundary. The impact assessment includes the classification of impact categories such as human health, environmental, etc., which may then be weighted for importance. The interpretation phase involves reporting the results in the most informative way to be consistent with the defined goal and scope.

A life cycle assessment (LCA) is an approach to quantify GHG emissions (direct emissions and indirect emissions) from all the stages associated with a crude's life from well-to-wheel (WTW). The life cycle of transportation fuels starts with the recovery of crude oil, which involves drilling the oil well, extracting crude from the reservoir, processing the crude oil, and, finally, processing the associated gas and water in order to fulfil the quality requirements. Crude oil is then sent to the refinery to be converted into transportation fuels (gasoline, diesel, and jet fuel), which are sent to refueling stations. GHG emissions associated with these stages are called well-to-tank (WTT) emissions. GHG emissions from the combustion of fuels in engines are called tank-to-wheel (TTW) emissions. Life cycle well-to-wheel (WTW) emissions consist of emissions from both WTT and TTW stages.

There have been a few LCAs on conventional crude oils [16-19]. The Jacobs [16] and TIAX [17] studies did assessments of different North American and imported crude oils. These studies reported well-to-wheel (WTW) life cycle GHG emissions for gasoline and diesel derived from specific crude oils. Some crudes were analyzed by both the Jacobs [16] and TIAX [17] studies, but there were variations in the total WTW life cycle GHG emissions due to different assumptions, system boundaries, methodologies, and data sources. Jacobs Consultancy [16] developed a bottom-up model, which was used to estimate the energy consumption and resulting GHG emissions from the life cycle stages of different conventional crude oils. Unlike Jacobs, TIAX [17] built a model based on a top-down approach in which the authors used industry-reported data to calculate the GHG emissions for different crudes. The TIAX study did not consider GHG emissions from the processing of crude oil and associated gas and water or from oil field fugitives.

Refining emissions contribute largely to WTW GHG emissions, and the Jacobs and TIAX studies have different methods of calculate refining emissions. None of these studies considered GHG emissions from oil well drilling and associated land-use changes. The National Energy Technology Laboratory (NETL) studies [18, 19] analyzed different North American and imported crudes and reported life cycle GHG emissions for gasoline, diesel, and jet fuel. GHG emissions reported by NETL are country-specific and not broken down into specific crudes. The baseline model developed by NETL has limited information about the inputs used in its model.

There are two prominent North American LCA models that quantify WTW life cycle GHG emissions for transportation fuels derived from crude oil. These models are (i) GREET, the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model [20] and (ii) GHGenius, the model developed by $(S\&T)^2$ Consultants [21]. These models consider different stages in the life cycle of crude oil and quantify total life cycle GHG emissions. Another North American LCA tool called OPGEE, the Oil Production Greenhouse gas Emissions Estimator [22], calculates GHG emissions from the extraction, processing, and transportation of crude oil. All of these models are built with their own assumptions, methods, data sources, and system boundaries. To calculate the life cycle GHG emissions for a crude type, the user must change the input parameters because these models use default values that might not be appropriate for all crude types. Also some of these default values are outdated and do not represent the current situation in many jurisdictions.

There are few studies that perform life cycle assessment of crude oil to quantify WTW GHG emissions. Garg et al. [23] conducted an LCA for domestic and imported crudes in India and reported GHG emissions for diesel, petrol, kerosene, and LPG (liquefied petroleum gas). The boundary of the LCA extends from the well to the point of storage of refined products. The authors found that 60-66% of the GHG emissions of the total LCA (without combustion) come from the exploration and production of crude oil. Yan et al. [24] reviewed different LCA studies and reported WTW GHG emissions for transportation fuels in China. This study considered the LCA boundary from crude recovery to fuel consumption in vehicle engines. The authors reported the same life cycle GHG emissions (89 g-CO_2eq/MJ) for conventional gasoline and conventional diesel. Furuholt [25] performed an LCA of gasoline and diesel. The author used a process-level allocation method to allocate the energy consumption and resulting GHG emissions in refining to different products. He found that diesel had lower GHGs than gasoline because less energy is consumed in the production of diesel in the refinery.

There are some LCA studies that evaluate GHG emissions from oil sands products that are different from conventional crudes by their properties. Tarnoczi [26] developed an LCA model to calculate energy use and resulting GHG emissions from the transportation of Canadian oil sands products to different North American markets. The author worked on sixteen projects for pipeline, rail, and the combination of pipeline and rail transportation. Pipeline length and diameter and grid intensity are the reasons for variation in GHG emissions for pipeline transportation. The combustion of diesel is the main reason for the variation in GHG emissions from rail transportation, as mentioned by the author. Thirteen LCA studies were reviewed by Charpentier et al. [27] to compare

GHG intensities of oil sands-derived fuels and conventional crude oil-derived fuels. The authors found lower GHG emissions for conventional crude oil-derived fuels. The production of conventional crude requires less energy than synthetic crude oil (SCO), which is upgraded from bitumen. Bergerson et al. [28] quantified life cycle GHG emissions from the extraction of bitumen using the GHOST (GreenHouse gas emissions of current Oil Sands Technologies) model developed by Charpentier et al. [29]. The authors found overlaps between the well-to-wheel GHG emissions for conventional crude oil and oil sands products. Brandt [30] reviewed different oil sands LCA studies and found inconsistencies in the results. He looked into all the unit operations required to transform oil sands products to finished products. Differences in methods, data quality, and LCA boundaries were found to be the reasons for variation in the results obtained by different LCA studies.

There are a limited number of studies that conduct LCAs of conventional crudes from various sources. This research is focused on development of the new LCA model, FUNNEL-GHG-CCO (**FU**N**N**damental E**n**gineering Princip**l** **E**s-based Mode**L** for Estimation of **G**reen**H**ouse **G**ases in **C**onventional **C**rude **O**ils), based on fundamental engineering principles. The aim is to perform a comprehensive and transparent quantification of GHG emissions for transportation fuels derived from different North American conventional crude oils in greater detail and fill the gaps in the literature. Five conventional crudes – Alaska North Slope, California's Kern County heavy oil and Mars crude (U.S.), Maya crude of Mexico, and Bow River heavy oil of Canada – were studied to calculate GHG emissions from the life cycle stages (crude recovery, transportation of

crude to the refinery, refining of crude, transportation and distribution of finished fuels to the refueling stations, and the combustion of transportation fuels in vehicle engines).

1.2. Research Motivation

The following factors that have encouraged this research:

- There is little research in the area of life cycle assessments (LCA) of conventional crude oils. For the sake of comparison of GHG emissions for conventional crude oil and oil sands products, it is necessary to conduct a comprehensive and independent LCA study on conventional crude oils.

- To fulfill regulations and formulation of appropriate policies, it is important to quantify GHG emissions associated with all the stages in the life of crude oil from recovery to the combustion of transportation fuels in vehicle engines.

- GHG emissions from the combustion (i.e., TTW emissions) of gasoline, diesel, and jet fuel are well established. But GHG emissions from the well-to-tank (WTT) stages are not well quantified. It is important to quantify the GHG emissions associated with the WTT stages (i.e., recovery, transportation, and refining) to understand the contributions of these stages to the total WTW GHG emissions.

- To stress in the areas where GHGs release could be reduced, it is necessary to understand the sensitivity of technical parameters on the energy use and resulting GHG emissions in each unit operation.

1.3. Research Objectives

The overall objective of this thesis is to conduct a comprehensive, transparent, and independent life cycle assessment (LCA) of North American conventional crude slates. The specific objectives are summarized below.

- Develop a data-intensive LCA model named FUNNEL-GHG-CCO (**FU**N**d**amental E**N**gineering Princip**l** **E**s-based Mode**L** for Estimation of **G**reen**H**ouse **G**ases in **C**onventional **C**rude **O**ils) to quantify GHG emissions from various stages of a crude oil's life such as recovery, transportation, refining, and combustion of fuels in engines.

- Estimate the well-to-wheel (WTW) life cycle GHG emissions for three transportation fuels (gasoline, diesel, and jet fuel) derived from five North American conventional crudes, namely Alaska North Slope, California's Kern County heavy oil, Mars, Maya and Bow River heavy oil.

- Perform a sensitivity analysis to check the impact of different technical parameters on the total recovery and WTW GHG emissions.

- Compare the WTW results of this study with results in existing literature and find out the reasons for variation, if any.

1.4. Scope and Limitations of the Thesis

This study focuses on five North American conventional crudes: Alaska North Slope, California's Kern County Heavy oil, Mars crude, Maya crude, and Bow River heavy oil. This study evaluates the GHG emissions (CO_2, CH_4, and N_2O) associated with the different unit operations of the life of a crude oil from recovery to the combustion of transportation fuels in vehicle engines. GHG emissions from infrastructure and equipment production were not included in the analysis, as there is very limited data available for these. There have been some estimation of GHG emissions from infrastructure and equipment production for other pathways and these contribute very small percentage of overall GHG emissions [31]. Scope and limitations of this study are further discussed in chapters 2 and 3.

1.5. Organization of the Thesis

This thesis has four chapters as well as a table of contents, a list of tables, a list of figures, two appendices, and a list of references. The thesis is in paper format. The thesis was written in such a way that each chapter can be read independently. Therefore, there is some repetition of assumptions, data, and results in the chapters.

Chapter 1, Introduction: This chapter includes the background and motivation of the study, research objectives, and scope and limitations of the study.

Chapter 2, Greenhouse Gas Emissions from Recovery of Various North American Conventional Crudes: This chapter describes different sub-unit operations in crude recovery: drilling the oil well, crude extraction, and processing of crudes and associated gas and water. The chapter includes a description of five North American conventional crudes, the functional unit, the methods used to develop the model, results, and discussion. Energy use and resulting GHG emissions for all the stages in crude recovery are presented along with a sensitivity analysis.

Chapter 3, Well-to-Wheel Life Cycle Assessment of Transportation Fuels Derived from Different North American Conventional Crudes: This chapter presents the GHG emissions from refining, crude transportation, delivery and distribution of finished fuels (gasoline, diesel, and jet fuel), and combustion of these finished fuels in vehicle engines. The chapter includes the assumptions, method, results, and discussion. Chapter 3 also presents a comparison of the well-to-wheel (WTW) results with those found in the existing literature [16, 17, 32]. At the end of the chapter, a sensitivity analysis is included to show the impact of different technical parameters on the total WTW GHG emissions.

Chapter 4, Conclusions and Recommendations: This chapter presents some key findings of the study along with some suggestions for further improvement of the LCA model developed in this study.

Chapter 2: Greenhouse Gas Emissions from Recovery of Various North American Conventional Crudes[1]

2.1. Introduction

Recovery of crude is the first stage in the life cycle of transportation fuels. The purpose of this chapter is to quantify the energy use and resulting GHG emissions from the sub-unit operations of crude recovery. Figure 2 shows the sub-unit operations involved in crude recovery. This chapter describes the assumptions and method used to develop the Excel-based model that was used to calculate the energy use and resulting GHG emissions from the recovery of five North American conventional crudes. Recovery emissions come from drilling the oil well and associated land-use change, crude extraction, crude processing, processing associated gas and water, and oil field venting, flaring, and fugitives. GHG emissions from crude recovery are compared with those in the existing literature [16, 17], and reasons of variation in results are discussed. At the end of the chapter, a sensitivity analysis shows the impact of different technical parameters on the total recovery GHG emissions.

[1] A version of this chapter was published as Rahman, M.M., Canter, C., Kumar, A., Greenhouse gas emissions from recovery of various North American conventional crudes. *Energy*, 2014. 74(0): p. 607-617. http://dx.doi.org/10.1016/j.energy.2014.07.026.

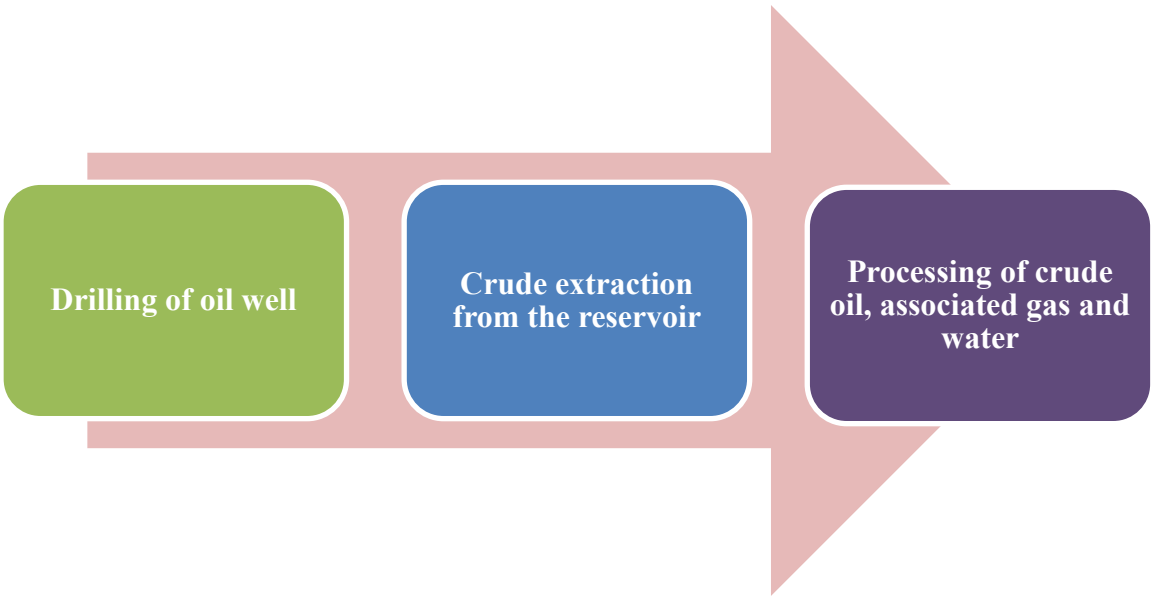

Figure 2: Crude recovery sub-unit operations

2.2. Scope of Research

This study focuses on all the crude recovery sub-unit operations and quantifies GHG emissions from drilling oil wells, crude extraction, venting, flaring, and fugitives, and crude oil processing for five well-known North American crudes. The five crudes evaluated in this study are Alaska North Slope, California's Kern County heavy oil, Mars, Maya, and Bow River heavy oil.

A spreadsheet-based model, FUNNEL-GHG-CCO was developed based on fundamental scientific equations to calculate the energy used and the GHGs emitted in each stage of crude recovery. This model can calculate life cycle recovery GHG emissions from different crudes.

2.2.1. Types of Crude

2.2.1.1. Alaska North Slope Crude Oil

Alaska produces the second largest amount of oil in the United States, and Alaska North Slope and Cook Inlet Basins are the highest-producing zones. However, 98% (2011 data) [33] of the produced oil comes from the North Slope, which has the 14 largest oil fields in the United States [34]. The crude analyzed in this study is from Alaska North Slope; it is a medium crude oil with an API (American Petroleum Institute) gravity of 29-29.5 ºAPI [35].

There are many topping units along the TAPS (Trans-Alaska Pipeline System) that produce light fuel. These topping units send the residues back to the pipeline and the resulting mixture is known as ANS (Alaska North Slope) crude oil. Alaska's largest oil field, Prudhoe Bay, produces most of the oil in the North Slope; the oil goes to West Coast refineries by pipeline and ocean tanker. In 2009, Alaska North Slope's total oil and associated gas production were 37 million m^3 of oil and 90.39 billion m^3 of produced gas [36]. The WAG (water-alternating-gas) enhanced oil recovery method is used extensively in this region to maintain the reservoir pressure and push the oil deposits to the producing wells. The water demand is met by produced water and sea water treatment plants [37]. About 92% (2009 data) [36] of the associated gas that comes out with the crude oil is re-injected through the injection wells to maintain the reservoir pressure.

2.2.1.2. California's Kern County Heavy Oil

Kern County crude oil is selected as the analysis crude for California; it has an API gravity of 13 ºAPI [38] and so falls in the range of heavy crude oil. Production data used for this study are from the Midway-Sunset Oil Field, which is the largest oil field in the State of California and located in southwestern San Joaquin Valley. As Kern County heavy oil is highly viscous, steam is injected into the reservoirs to reduce the viscosity and enhance flow. An artificial lifting method (i.e., a pump) is required to pull the oil and water mixture out of the reservoir. Steam for oil recovery comes from the Midway-Sunset co-generation plant, which has a maximum capacity of 234 MW [39]. Electricity for operating the pumps and other facilities also comes from the co-generation plant, which uses pipeline natural gas as fuel. In 2009, the total incremental oil production from thermally enhanced oil recovery was approximately 7.8 million m^3 from the Midway-Sunset Oil Field [40].

2.2.1.3. Mars Crude Oil

The Mars Blend is a sour crude oil with an API gravity of 31.5 ºAPI [41]. The producing region for the Mars Blend is about 130 miles southeast of New Orleans in the U.S. Gulf Coast. The Mars platform, at deep water in the Gulf of Mexico, is the feedstock location. Water flooding is the dominant recovery method to maintain reservoir pressure and improve the flow of oil. Injection of sea water to maintain reservoir pressure has been practiced since 2004. Sea water is injected into three reservoir zones (Yellow, Green, and Pink sands) using three injectors. In June 2000, production at Mars field was at its peak

of 33,069 m^3 of oil per day and 6.14 million m^3 of associated gas per day [42]. The average daily production of Mars is about 3338.73 m^3 of oil and 707,921 m^3 of associated gas that comes with the crude oil.

2.2.1.4. Maya Crude Oil

The origin of the Maya crude oil is Mexico, which produces heavy, light, and extra light crude oil. Maya is a heavy grade crude oil with an API gravity of 22 ºAPI [43]. Maya crude is produced from the Cantarell field; it is the largest oil field in Mexico and is situated about 100 km off the coast of the Yucatan Peninsula. The productivity of the well decreases with decreasing reservoir pressure. To maintain reservoir pressure and good productivity, nitrogen gas is injected into the Cantarell field's reservoirs. At the same time, a gas lift (an artificial lifting method) is used to lift the crude oil, water, and associated gas mixture to the surface. 34 million m^3 of nitrogen supply comes from the world's biggest nitrogen generation plant at the Cantarell oil field [44]. Oil production reached its peak in 2004 at 333,873.32 m^3 a day and decreased to approximately 88,715 m^3 per day in 2010. Most of the Mexican refineries are not equipped to refine this heavy oil, so it is exported to Canada and the U.S. for refining.

2.2.1.5. Bow River Heavy Oil

Alberta's Bow River heavy oil represents the Canadian conventional heavy oil; its API gravity is about 23 ºAPI [45]. Alberta is well known for its oil sands production, and

about 97% [46] of Alberta's oil reserves is from oil sands; the remaining 3% is from conventional crude oils. Unlike bitumen, conventional crude oil flows easily and can be extracted using a secondary oil recovery method. In Alberta, water flooding, which is the injection of water to maintain reservoir pressure, is used extensively. Sources of water are saline and non-saline, along with produced water, which contributes about 83% [47]. In 2012, the total conventional crude oil production in Alberta was approximately 32.27 million m^3 [48]. Conventional crude oil supplies from Alberta go to North American markets by pipeline [49].

2.3. Methodology

2.3.1. Functional Unit

For this chapter, the functional unit is taken as 1 MJ-fuel. Energy calculations are based on the lower heating value of fuels.

2.3.2. Drilling

The first unit operation in crude recovery is the drilling of the oil well, the purpose of which is to make a hole in the oil reservoir to allow oil to flow to the surface. There are two types of oil wells, injection and production. Injection wells are used to inject water, gas, steam, or any other fluid to push the oil deposit to the production well and to maintain pressure inside the reservoir. Production wells lift the crude oil to the surface

with water and gas. Drilling an oil well requires energy to provide rotational and translatory motion to the drill bit to make the drill hole through the reservoir. In this study, it is assumed that the power required for the drilling operation will be provided by diesel engine rigs, as is common in oil fields. There is an exponential increase in diesel consumption with the true vertical depth of the well, as shown by Equations 2 and 3 [50]. Brandt [50] developed these equations using a range of drilling data. The units of diesel consumption, E, and true vertical depth of well, d, are measured in MJ/m and m respectively.

$$E_{low} = 128.6*\exp(0.0005d) \quad (2)$$

$$E_{high} = 336.3*\exp(0.0004d) \quad (3)$$

E_{low} and E_{high} represent minimum and maximum diesel consumption during drilling. For all five crudes, average diesel consumption is used as field-specific diesel consumption data are unavailable. The energy required to make a well bore is amortized over the producing life of the well. Emissions are calculated from the ratio of energy required to drill a well to the lifetime productivity of the well in terms of energy, i.e., MJ-crude, and emission factors for diesel combustion. Emission factors for diesel combustion are taken from GREET 1 [51]. The drilling parameters used in this data analysis are summarized in Table 1.

Table 1: Drilling parameters along with recovery methods for all five crudes

Crude name	Depth of well considered (m)	Lifetime productivity (m^3/well)	Recovery method
Alaska North Slope	2250	10,936.70[a]	Water-alternating-gas
California's Kern County heavy oil	518	21,169.32[b]	Stem injection
Mars	4553	84,876.32[c]	Water flooding
Maya	2794	7,440,605.40[d]	Nitrogen injection assisted by gas lift
Bow River heavy oil	1524	50,903.96[e]	Water flooding

[a]Calculated from the total number of wells and total oil production in the state at the end of 2004 [36, 52].

[b]Calculated from the total number of wells and total oil production in the state at the end of 2005 [22].

[c]Calculated from the total number of wells and total oil production in the U.S. Gulf Coast at the end of 1998 [53, 54].

[d]Calculated from the average well production based on an assumed 20-year well life [55].

[e]Calculated from the total number of wells and total oil production in the province at the end of 2008 [56, 57].

In addition to the GHG emissions from the combustion of diesel to power the drilling rigs, this study includes the emissions associated with land-use changes during drilling. Land-use changes, such as biomass, land, and peat disturbance, can release methane (CH_4) and nitrous oxide (N_2O) [30]. Land-use emissions for the 150-year analysis period are taken from OPGEE (1.1) [22], a life cycle software modeled by the Department of Energy Resources Engineering at the Stanford University. To capture the crude oil production period, reclamation, and due to availability of data, a 150-year analysis period is considered in this study. Emissions are based on the low carbon richness for California crude and high carbon richness for both Alberta [58] and Alaska North Slope crude oils. Land-use emissions depend upon the intensity of drilling. Moderate intensity drilling is assumed for all the selected crude oils. Moderate intensity drilling corresponds to a medium fractional disturbance of land, which means that the drilling holes are moderately spaced in the oil field.

2.3.3. Crude Extraction

Crude extraction, the second step in crude recovery, uses a large quantity of energy that will ultimately result in GHG emissions. Initially when any reservoir starts producing oil, the pressure in the reservoir is enough to push the oil to the production well and even to force the oil to flow out to the surface. Sometimes artificial methods are applied to assist the flow of oil. This recovery technique is called primary recovery. As the reservoir ages, the pressure inside the reservoir starts to fall, and less oil is produced. To overcome this problem, secondary recovery methods are used to supply additional energy to the

reservoir. In one of these secondary recovery methods, water and/or gas is injected into the injection well. When water is injected, the process is called water flooding, and the injection of gas is known as gas flooding. Tertiary (or enhanced) recovery, includes thermal recovery (steam injection), gas injection (i.e., nitrogen, carbon dioxide), and chemical injection (i.e., polymers and detergent). With enhanced oil recovery, 30-60% [59] more oil can be recovered compared to 25-35% using primary and secondary recovery methods [60].

The recovery methods mentioned in Table 1 are suitable for specific locations based on reservoir properties and availability of injection fluids. Fuel required to extract crude oil depends on the recovery methods applied and characteristics of the crudes. Fuel consumed to extract crude is calculated based on basic energy consumption equations for pumps and compressors. GHG emissions from each recovery method are calculated based on process fuel consumption. The process efficiency of the recovery method is estimated using the following formula [20]:

$$\eta = \frac{Energy\ Output}{Process\ Fuel + Energy\ Output} \tag{4}$$

The energy output in Equation 4 is the sum of the energy from the extracted oil and the associated gas. Using the process efficiency, the energy required per MJ-fuel recovered for each pathway of crude extraction is calculated by:

$$Energy\ Required = \frac{1}{\eta} - 1 \tag{5}$$

A gas balance was done that shows produced gas is sufficient to meet onsite demand for all the crude oils. So, produced gas is assumed to be combusted in simple gas turbines with an assumed efficiency of 32.6% [61] to produce electricity to run the pumps, compressors, and other electric equipment for each pathway except in the case of California's crude, which uses only pipeline natural gas in a co-generation plant [40] to produce steam and electricity. Emission factors for natural gas and produced gas used to calculate GHG emissions from recovery of each crude are taken from GREET 1 (2012) [61] and Keesom et al. [16], respectively. The energy required to recover each crude oil depends on reservoir pressure and depth, water-to-oil ratio, injected water-to-oil ratio, injected gas-to-oil ratio, and steam-to-oil ratio. Table 2 shows the parameters used to calculate energy requirements and to quantify GHG emissions.

Pressure loss due to friction in the pipeline to lift crude is calculated with the Darcy-Weisbach equation using the Reynolds number, pipe roughness, depth of well, diameter of the pipe, etc. The average roughness of the lift pipe (commercial steel) is assumed to be 0.067 mm [62]. The diameter of the lift pipe ranges from 0.026 to 0.114 m [63], and the average of these values (0.07 m) is used in the pressure loss calculation. The energy required to lift crude oil is calculated from the pressure loss and assumed pump efficiency of 65% [22]. A gas lift is used extensively in the Cantarell oil field for Maya crude. For a gas lift, basic compression equations with an assumed compressor efficiency of 75 % [22] are applied to determine the energy consumption. In the Cantarell field, 34 million m^3 of nitrogen gas are injected per day, which requires a total of 373.38 MW power [44].

Table 2: Parameters used for energy calculations

Crude name	Reservoir pressure (MPa)	Water to oil (m^3/m^3)	Gas to oil (m^3/m^3)	Steam to oil (m^3/m^3)	Injected water to oil (m^3/m^3)	Injected gas to oil (m^3/m^3)
Alaska North Slope	23.77 [64]	3 [65]	2129 [36]	-------	3.6 [65]	1955[a] [36]
California's Kern County heavy oil	0.45 [66]	5.17[b] [40]	168 [40]	4.53 [40]	--------	--------
Mars	37.92 [67]	5.5 [16]	210[c] [68]	--------	4.29[d] [42, 68]	--------
Maya	10.48 [44]	3 [16]	65 [69]	--------	---------	174[e] [44, 70]
Bow River heavy oil	7.83 [71]	14.90 [72]	321[17]	--------	3.47[f] [73]	--------

[a]About 92% of produced gas is injected again.

[b]Calculated from the amount of crude produced per well and water cut.

[c]Calculated from the amount of oil and gas produced.

[d]Calculated from the amount of oil produced and water injected.

[e]Calculated from the amount of oil produced and nitrogen injected into the field.

[f]Calculated from the crude oil produced in Alberta and water injected in 2002.

2.3.4. Flaring, Venting, and Fugitive Emissions

Flaring, venting, and fugitives are sources of GHG emissions during crude recovery. The combustion of the natural gas that comes out with crude oil from the reservoir is known as flaring. Flaring is done when there is no economic use for this associated gas. The flared gas produces carbon dioxide and possibly carbon monoxide, which are released to the atmosphere. Venting, the release of non-combusted associated gas, is also a significant source of GHG emissions in crude production. Venting occurs through the well head and gas treatment equipment such as the acid gas removal unit, gas dehydrator, etc. The non-intentional release of associated gases through the valves, flanges, pump seals, and gas processing units is known as fugitive emissions. These emissions commonly are the result of leakages in oil field equipment. There were no data available on venting and flaring for the oil fields analyzed in this study, so state- and country-wide data were used to calculate these emissions. There were likewise no data for fugitive emissions, so fugitive volumes for each crude oil were assumed to be 0.1% of the produced gas. Normally, venting and fugitive volumes are less than 1% of the produced gas [16].

The first step in calculating venting, flaring, and fugitive emissions is to find the volume of vented, flared, and fugitive gases per m^3 of crude oil. This is done by dividing the amount of flared, vented, and fugitive volumes by the total crude oil production in the state or country. The values were then multiplied by the amount of crude oil produced (m^3 per day) for selected individual crudes to obtain vented, flared, and fugitive volumes per day. GHG emissions were calculated from flaring volumes based on the flaring

efficiency, which is assumed to be 95% [74]. GHG emissions vary with the composition of the produced gas. Due to the unavailability of data for any particular oil field, we have assumed a common gas composition for all five crude production pathways in which the main constituents are CH_4-84%, CO_2-6%, and C_2H_6-4% [22]. Flaring emissions were calculated using the flared volume, flaring efficiency, density of each component, stoichiometric relationship between each constituent of associated gas and CO_2, and global warming-potential factors that are taken for 100 years. For venting and fugitive emissions, efficiency and stoichiometric factors are not required. There is considerable uncertainty in fugitive emissions figures due to the lack of published data for individual oil fields. Sensitivity analyses were done to see the impact of fugitive volumes in overall recovery emissions. The flared, vented, and fugitive volumes per m^3 of oil are presented in Table 3 for each of the five crudes.

Table 3: Flared, vented, and fugitive volumes per m^3 of oil to calculate the GHG emissions

Crude name	Flaring (m^3/m^3)	Venting (m^3/m^3)	Fugitive (m^3/m^3)
Alaska North Slope[a]	3.82	0.68	2.13
California's Kern County heavy oil[b]	0.74	0.74	0.11
Mars[c]	1.33	0.78	0.21
Maya[d]	13.46	0.95	0.06
Bow River heavy oil[e]	9.63	1.99	0.32

[a]There is only one reported value, total vented and flared volume [75]. We have split it as 85% flaring and 15% venting according to the U.S. average value [76]. The state's total crude oil production was taken from the U.S. Energy Information Administration [33].

[b]There is only one reported value, total vented and flared volume [77], in which 36.4 million m^3 associated gas is vented [17]. The state's total crude oil production was taken from the U.S. Energy Information Administration [78].

[c]The total value of venting and flaring is taken from the EIA [79] and split to 26% flared and 74% vented [80]. Federal Offshore Gulf of Mexico crude oil production in is taken from the EIA [81].

[d]The flared volume is based on Mexico's total flared data taken from the NOAA [82] and the vented volume taken from the TIAX [17] report. Crude production in Mexico is taken from Ref. [83].

[e]Vented and flared volumes are based on Alberta numbers for venting and flaring taken from the ERCB [84], and crude oil production in Alberta is taken from CAPP [57].

2.3.5. Processing Crude Oil and Associated Gas and Water

When crude oil is lifted to the surface from the reservoir, it is a mixture of oil, water, and gas. Separation of the phases is the first step in crude oil processing and is done to maintain quality requirements before crude transportation. To separate these phases and treat water and associated gas, a significant amount of energy is required, which contributes to GHG emissions. For this study it is assumed that water and oil are separated in a gravity separator. The separator uses chemicals with small environmental concerns, but as no fuel is used in the separator it is not a significant source of GHG emissions. A series of flush drums is used to stabilize the crude oil. The heat duty of the stabilizer column can be calculated as:

$$H = Q*C_p*\Delta T \quad (6)$$

where H is the heat duty in MJ/day, Q is the crude flow rate in m^3/day, C_p is the specific heat of crude oil in MJ/m^3-K, and ΔT is the difference between the reboiler and feed temperatures in K. The specific heat of crude oil and temperatures of the reboiler and feed are taken as 1.79 MJ/m^3-K, 322.04 K, and 446.48 K, respectively, to calculate the heat duty with an assumed heat loss of 2% [85]. Gas-fired heaters are assumed to be the heat sources for the crude oil stabilizer. From the heat duty required, the amount of natural gas is calculated.

The second step in crude oil processing is the treatment of associated gas using an amine treater and a glycol dehydrator. The amine treater removes H_2S and CO_2 in the associated gas. DEA (Diethanolamine), the most widely used gas sweetening solvent, is used in the acid gas removal unit. The gas balance is done to quantify the amount of associated gas that enters the treater. An amine reboiler and several pumps are used in the acid gas removal unit. It is assumed that the reboiler is heated by natural gas and that the pumps are run with onsite electricity. The DEA flow rate is calculated from the amount of H_2S and CO_2 present in the associated gas. The heat duty of the reboiler is calculated from the following equation [86], where the heat duty, H, is in MJ/h and the flow rate of DEA, Q, is in m^3/min:

$$H = 20{,}068.69*Q \tag{7}$$

The power calculations for the circulation pump, booster pump, reflux pump, and aerial cooler are represented by Equations 8, 9, 10, and 11 respectively [86], where power, P, is in kW, flow rate of DEA, Q, is in m^3/min, and the pressure of the system, p, is in kPa.

$$P_{CP} = 0.018*Q*p \quad (8)$$

$$P_{BP} = 11.826*Q \quad (9)$$

$$P_{RP} = 11.826*Q \quad (10)$$

$$P_{AC} = 70.95*Q \quad (11)$$

Dehydrators are used to remove water from the associated gas. This study assumes that glycol dehydrators are used to remove water. Reboiler heaters and pumps are the consumers of energy in glycol dehydrators. The reboiler heat duty can be calculated from the regenerator duty and the amount of water removed and is found by the equation below, where H is the regenerator duty in MJ/kg of H_2O and q is the glycol-to-water ratio in m^3/kg, which is assumed to be 0.0167 [86]. The regenerator duty is calculated using the following rule of thumb [86]:

$$H = 2.1+269.59*q \quad (12)$$

The heat required for the glycol dehydrators is assumed to be supplied by natural gas with a heater efficiency of 80% [22]. During crude recovery a large amount of water comes to the surface with the crude oil and is injected into the reservoir to maintain pressure or is discharged to the environment. To meet environmental regulations this discharged water has to be treated. There are various produced water treatment methods, and they vary from field to field. For simplicity we assumed the same treatment methods for all the selected crudes. Vlasopoulos et al. [87] considered four different water treatment stages with energy consumption per m^3 of water. These stages include various types of water treatment technologies such as hydrocyclones, microfiltration,

ultrafiltration, reverse osmosis, etc. In stages 1–3 the oil and grease are reduced, while in stage 4 is sodium and TDS (total dissolved solids) in water are reduced. The average energy consumption for these stages is taken for water treatment except for stage 4, in which energy consumption for reverse osmosis is assumed. The energy required is assumed to be supplied by onsite electricity production. The energy required at each stage is 0.25 kWh/m^3 of water for stage 1, 0.38 kWh/m^3 for stages 2 and 3, and 1.27 kWh/m^3 for stage 4.

2.4. Results and Discussion

2.4.1. Drilling and Land-Use

For drilling, the source of emissions is the combustion of diesel to power the drilling rig. Diesel consumption varies from 0.13 MJ/well to 6.44 MJ/well depending upon the depth of the wells. The lifetime productivity of the well, shown in Table 1, has a large impact on GHG emissions. For the same well depth, higher productivity lowers the amount of GHGs as emissions are calculated from the ratio of energy consumption in drilling to the amount of crude coming from the well in its whole lifetime. Table 1 shows that of all the crudes looked at for this study, Maya produces the most (7,440,605.40 m^3/well) and Alaska North Slope the least (10,936.70 m^3/well). Land-use impact also contributes GHG emissions in crude recovery and is summarized in Table 4 for each of the crudes.

Emissions through land-use change in crude recovery contribute less than 0.4% (less than 0.35 g-CO_2eq/MJ) of the total life cycle emissions for conventional crudes in California

and 0.1-4% (0.12-3.39 g-CO_2eq/MJ) for conventional crudes in Alberta for a modeling period of 150 years [58]. Land-use emissions for California's Kern County heavy oil and Bow River heavy oil lie in the range reported by Yeh et al. [58].

Table 4: Land-use GHG emissions for 150-year analysis period

Crude name	GHG emissions (g-CO_2eq/MJ)
Alaska North Slope	0.79
California's Kern County heavy oil	0.13
Mars	0
Maya	0
Bow River heavy oil	0.79

For Mars and Maya, because this analysis considers offshore fields, it is assumed there would not be any GHGs released to the atmosphere due to the sea acting as a sink. For Alaska North Slope and Bow River heavy oil, land-use emissions make up a significant portion of total drilling and land-use emissions. Total drilling and land-use emissions for Alaska North Slope and Bow River heavy crude oil are around 0.8 g-CO_2eq/MJ. No land-use emissions were reported for the offshore Maya and Mars crudes. 0.15 g-CO_2eq/MJ and 0.21 g-CO_2eq/MJ drilling and land-use emissions have been calculated for California's Kern County and Mars crude oil, respectively, while Maya has negligible drilling emissions.

2.4.2. Crude Extraction

The energy and emissions calculations in crude extraction are based on the extraction efficiency. Table 5 represents the extraction efficiencies for the five crudes considered in this study. Energy required in the form of electricity or heat at each stage of crude recovery is supplied by produced gas or pipeline natural gas except for drilling, which uses diesel. Table 6 shows the energy requirement at each stage of crude recovery.

Table 5: Efficiencies for crude oil extraction as calculated using Equation 4

Crude name	Extraction efficiency
Alaska North Slope	95.9%
California's Kern County heavy oil	65%[a]
Mars	98.2%
Maya	98.6%
Bow River heavy oil	98.2%

[a]1805 kWh/m^3 electricity is exported to the local (California) grid after fulfilling the field demand. So this pathway receives an emission credit for selling the electricity. The grid emission factor is taken from the Air Resources Board, California [88].

Among all the crude extraction methods, the tertiary method, used by California's Kern County heavy oil, is the most energy intensive and has an extraction efficiency of 65% (see Table 5), the lowest among the crudes. To produce electricity and steam at the same time, a large quantity of natural gas is used in the co-generation plant. In addition, as this crude is much more viscous than other crudes, artificial lifting consumes a large amount

of electricity, resulting in more GHG emissions. The total extraction emissions for this crude are 41 g-CO_2eq/MJ. However, this pathway receives an emission credit of 18 g-CO_2eq/MJ for selling the surplus electricity to the California grid. When the credit is subtracted from the total emissions, the net emissions are 23 g-CO_2eq/MJ. The grid emission factor for California is taken as 360 g-CO_2eq/kWh [89].

Alaska North Slope has an extraction efficiency of 95.9% (see Table 5), and the extraction emissions (2.88 g-CO_2eq/MJ) are from the pumps and compressors. Mars and Bow River heavy oil extraction requires less energy and therefore has a higher extraction efficiency (98.2%) than Alaska North Slope and California's Kern County heavy crude oil. These crudes have emissions of 1.26 and 1.24 g-CO_2eq/MJ, respectively. Maya uses the gas lift extraction method along with nitrogen injection with an extraction efficiency of 98.6%. Emissions for the production and compression of nitrogen were taken from the literature [16] and are 1.3 g-CO_2eq/MJ. Maya has emissions of 2.3 g-CO_2eq/MJ with 1 g-CO_2eq/MJ coming from the gas lift and injecting compressors.

Venting, flaring, and fugitive emissions lie in the range of 0.34-2.33 g-CO_2eq/MJ depending upon the gas-to-oil ratio, volume of flared and vented gas in each state or province, and amount of crude production for each pathway. GHG emissions from venting, flaring, and fugitives are presented in Table 7.

Table 6: Energy requirement per MJ-fuel at different sub-processes as calculated in this study

Crude name	Drilling (kJ of diesel)	Extraction (kJ of gas)	Processing oil, water, and gas (kJ of gas)
Alaska North Slope	0.12	42.79	11.18
California's Kern County heavy oil	0.20	545.91[a]	7.91
Mars	2.34	18.66	11.77
Maya	0.01	13.68	9.90
Bow River heavy oil	0.36	18.47	18.33

[a]Amount of natural gas used to produce steam and electricity. About 38 kWh/m^3 of electricity is used in operations and surplus electricity is sold to grid.

Table 7: GHG emissions from venting, flaring, and fugitive for five crudes

Crude name	Venting (g-CO_2eq/MJ)	Flaring[a] (g-CO_2eq/MJ)	Flaring[b] (g-CO_2eq/MJ)	Fugitive (g-CO_2eq/MJ)
Alaska North Slope	0.27	0.18	0.08	0.85
California's Kern County heavy oil	0.25	0.04	0.01	0.04
Mars	1.51	0.07	0.03	0.08
Maya	0.33	0.72	0.27	0.03
Bow River heavy oil	1.49	0.52	0.19	0.13

[a]Flaring emissions from complete combustion of associated gas.

[b]Flaring emissions from non-combusted associated gas.

2.4.3. Processing of Oil and Associated Gas and Water

The final sub-unit operation in crude recovery is the processing of crude oil along with the associated gas and water. Processing is done with fluid pumps and heaters that use electricity and natural gas, respectively. Electricity is generated from the gas produced by onsite gas turbines that emit GHGs. Table 8 shows the total processing emissions for the five different crudes considered in this study.

Table 8: GHG emissions from processing oil, water, and gas as calculated in this study

Crude name	**GHG emissions ($g\text{-}CO_2eq/MJ$)**
Alaska North Slope	0.75
California's Kern County heavy oil	0.53
Mars	0.79
Maya	0.69
Bow River heavy oil	1.23

Dissolved gases need to be driven out from crude oil; this is done with direct-fired natural gas heaters that contribute significantly to the total processing emissions. Natural gas heaters emit the same amount of emissions per m^3 of crude oil (0.53 $g\text{-}CO_2eq/MJ$) at the same temperature difference, and the specific heat of crude is taken for all crude oil pathways to calculate the heat duty. Total processing emissions are highest in Bow River

heavy oil crude (see Table 8) due to the processing of large quantity of produced water. More associated water is processed in this pathway than any other pathway and in any other crude recovery method, and so more GHGs are emitted in this crude than any other considered in this study.

For Alberta, the water-to-oil ratio is taken to be about 15, resulting in an emission of 0.7 g-CO_2eq/MJ. For California's Kern County heavy oil, only produced gas combustion emissions are reported here. Electricity emissions were subtracted in crude extraction to find the net electricity sold to California grid.

2.4.4. Total Emissions Associated with Crude Recovery

Figure 3 shows all of the GHG emissions in crude recovery: emissions from drilling and land-use, crude extraction, crude oil processing, and venting, flaring, and fugitives. The highest and lowest emissions come from California's Kern County heavy oil at 23.88 g-CO_2eq/MJ and Mars at 3.95 g-CO_2eq/MJ, respectively. Alaska North Slope has the second highest emissions at 5.81 g-CO_2eq/MJ. For Maya and Bow River heavy oil, emissions from total crude recovery are 4.32 g-CO_2eq/MJ and 5.63 g-CO_2eq/MJ, respectively.

For Alaska North Slope, extraction makes up 49% of the GHG emissions through the operations of various pumps and compressors. The contributions from drilling and land-use, crude processing, and venting, flaring, and fugitives are 14%, 13%, and 24%, respectively. For California's Kern County heavy oil, 96% of the total emissions come

from crude extraction. Drilling and land-use change, crude processing, and venting, flaring, and fugitive emissions are relatively small. For Mars, crude is recovered by water flooding with pumps; water flooding contributes to 32% of total recovery emissions. Venting, flaring, and fugitives contribute 43%, and 5% of emissions come from drilling.

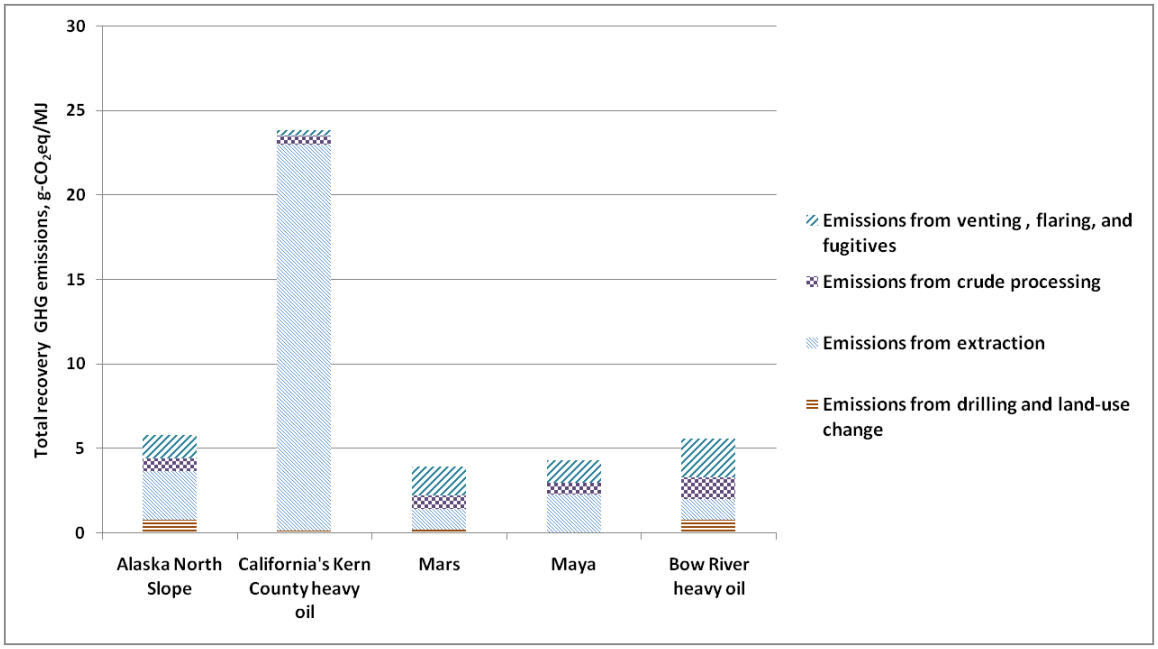

Figure 3: Total GHG emissions from crude recovery

For Maya, however, drilling emissions are negligible; most of the emissions are due to crude extraction, and venting, flaring, and fugitive emissions are the second highest contributor. For Bow River heavy oil, venting, flaring, and fugitives emissions contribute 41% of total recovery emissions, and extraction and crude processing each contribute 22%.

Variations are found between the recovery emissions found in this study and those in recent studies conducted by TIAX [17] and Jacobs Consultancy [16] (see Figure 4). These variations are due to different assumptions and boundaries used in the studies.

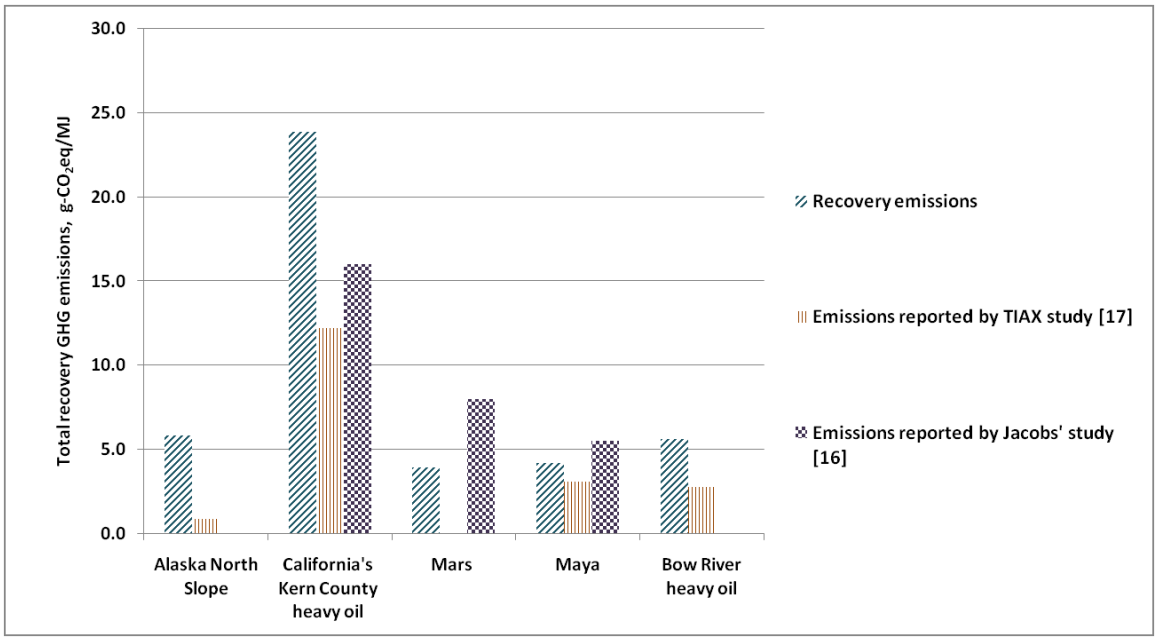

Figure 4: Comparison of total recovery GHG emissions with reported literature

Only the analysis done by the authors of this study considered the emissions from drilling and land-use change. TIAX [17] considers the emissions from crude extraction and venting and flaring but does not consider emissions from drilling, land-use change, and the processing of different phases. For individual crudes, Jacobs' study presents a range of crude recovery emissions, and the average of that range is presented in Figure 4. According to Jacobs' study, extraction recovery emissions from Mars, Maya, and California's heavy crude are 6-10 g-CO_2eq/MJ, 4-7 g-CO_2eq/MJ, and 12-21 g-CO_2eq/MJ, respectively. Figure 4 shows a wide variation in emissions for Kern County heavy oil. The steam-to-oil ratio and grid emission factor are the most sensitive parameters for this

crude. For the same steam-to-oil ratio, variations in emissions between this study and Jacobs' study range from 2 to 3 g-CO_2eq/MJ. For California crude, TIAX does not indicate anything about the variation of the steam-to-oil ratio or the grid emission factor. There were no other analyses found in the literature on recovery emissions for specific crudes.

2.4.5. Sensitivity Analysis

A sensitivity analysis was performed to determine which parameter has the largest effect on the GHG emissions. Different independent parameters were selected that were expected to have some effect on the total GHG emissions for each crude. The sensitivity factors were varied by ±20%, except for the pump efficiency, which was varied by ±10%. Figures 5 to 9 show the sensitivity analysis for all five different crude oils.

For Alaska North Slope (Figure 5), four parameters were varied, among which the discharge pressure of compressor and fugitive volume have the maximum impact on recovery emissions. Increased discharge pressure results in a greater energy requirement that in turn increases emissions. The discharge pressure of the water injection pump and injected water-to-oil ratio have similar impacts on total GHG emissions.

Five parameters were selected for California's Kern County heavy oil to check their impacts on total recovery emissions. Pump efficiency, fugitive volume, and well depth have negligible impacts on GHG emissions, while grid emission factor and the steam-to-oil ratio have the maximum impact and are illustrated in Figure 6. Increasing the steam-

to-oil ratio increases the GHG emissions as more natural gas is burned to produce the extra steam. GHG emissions decrease with increased grid emission factor as onsite electricity is sold to a more GHG-intensive grid, and so this pathway receives credit for that.

In the case of Mars crude, a 20% increase in the injected water-to-oil ratio and discharge pressure of pump increases emissions by 6%. The water-to-oil ratio increases the emissions by 1% when the ratio is increased by 20%. For Maya crude, four parameters were selected to see their impacts on results. The amount of nitrogen injected has the highest sensitivity; increasing the nitrogen by 20% increases the emissions by 0.16 g-CO_2eq/MJ. For the other three parameters, there is an increasing trend with increased percentage variations.

Decreasing the pump efficiency increases the GHG emissions in the case of Bow River heavy oil. The injected water-to-oil ratio increases the energy consumption and results in 3% more emissions when the ratio is increased by 20%. The discharge pressure of pump and the fugitive volume have little impact on total GHG emissions.

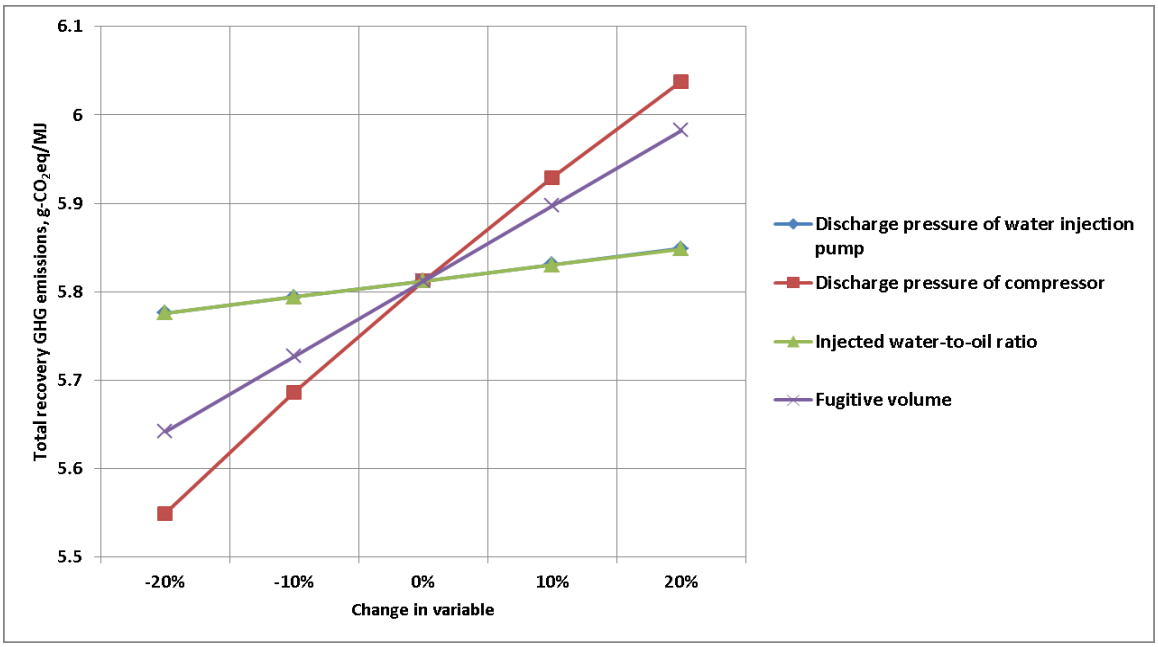

Figure 5: Sensitivity analysis of total recovery GHG emissions for Alaska North Slope crude

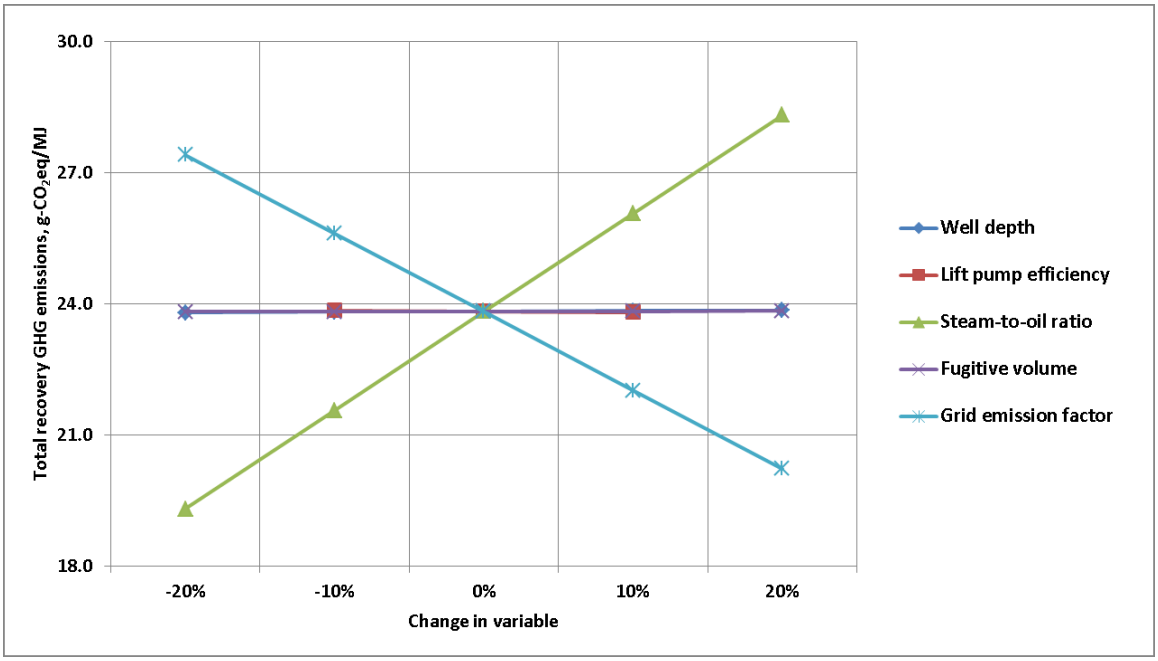

Figure 6: Sensitivity analysis of total recovery GHG emissions for California's Kern County heavy crude

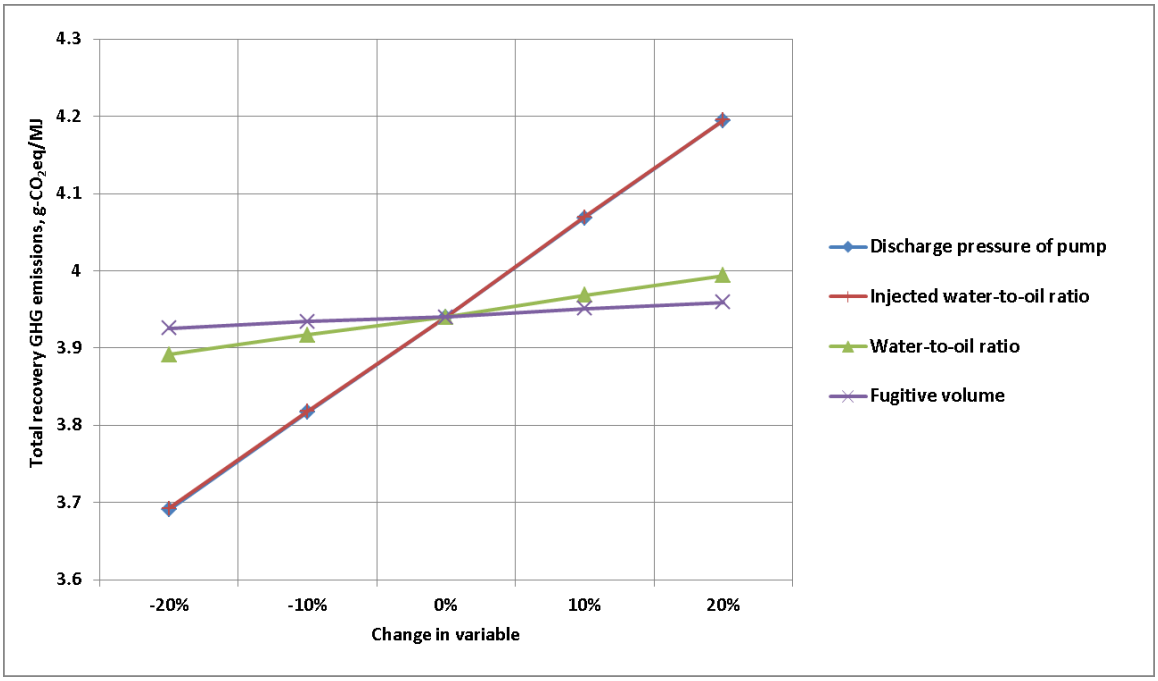

Figure 7: Sensitivity analysis of total recovery GHG emissions for Mars crude

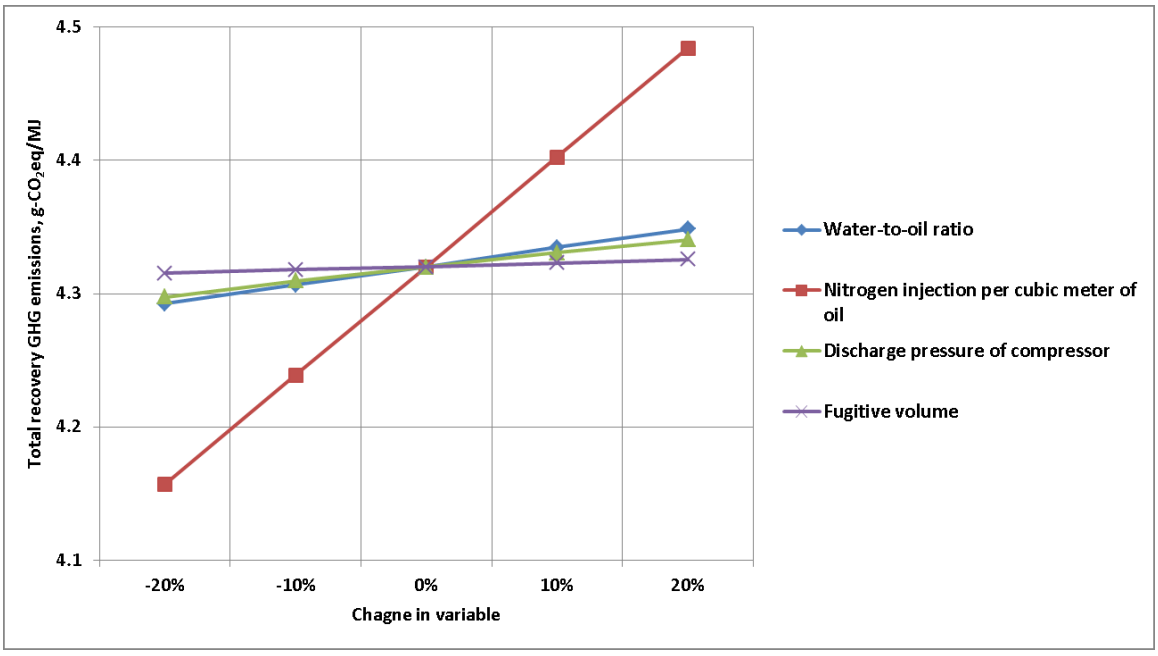

Figure 8: Sensitivity analysis of total recovery GHG emissions for Maya crude

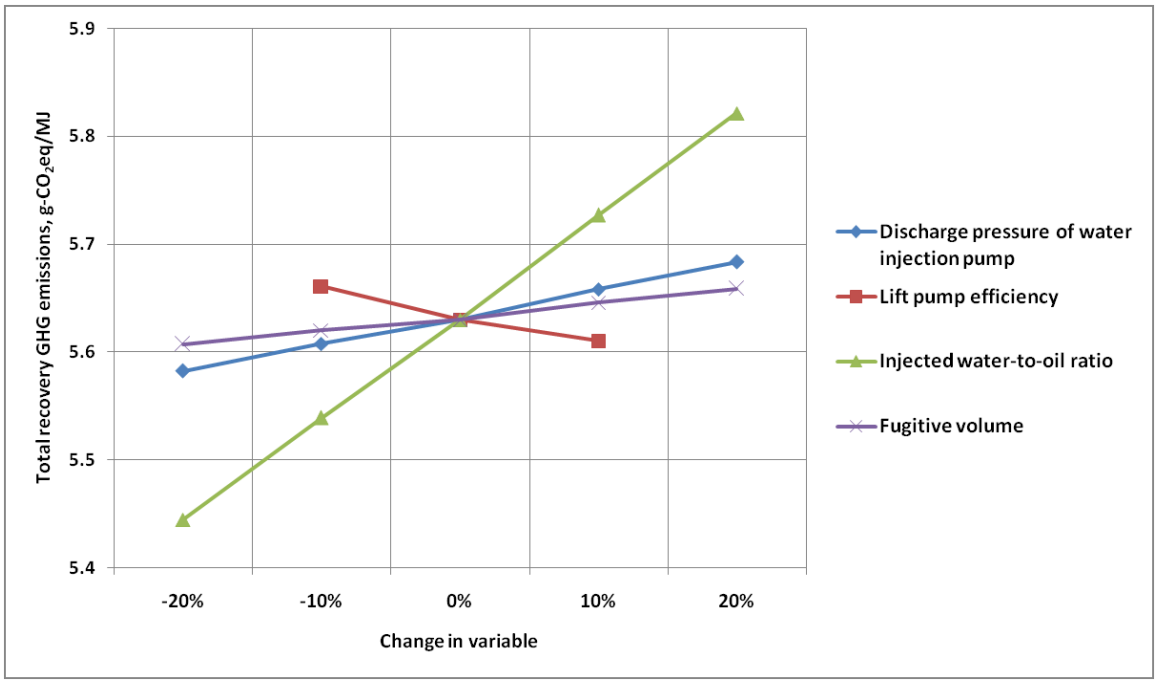

Figure 9: Sensitivity analysis of total recovery GHG emissions for Bow River heavy crude

2.5. Conclusions

A transparent quantification of recovery GHG emissions was made using fundamental equations and through the development of a data-intensive engineering model. The highest and lowest emissions come from California's Kern County heavy oil at 23.88 g-CO_2eq/MJ and Mars at 3.95 g-CO_2eq/MJ, respectively. Alaska North Slope has the second highest emissions at 5.81 g-CO_2eq/MJ. For Maya and Bow River heavy oil, emissions from total crude recovery are 4.32 g-CO_2eq/MJ and 5.63 g-CO_2eq/MJ, respectively. As different data sources were used for this study, a sensitivity analysis was used to show the impact of different technical parameters on total recovery GHG

emissions. The results of this study will help the oil industry consider different areas to reduce emissions to meet environmental regulations. This study also facilitates the comparison between emissions from oil sands and from conventional crude oil extraction by providing extraction emissions from different conventional crude oils.

Chapter 3: Well-to-Wheel Life Cycle Assessment of Transportation Fuels Derived from Different North American Conventional Crudes[2]

3.1. Introduction

This chapter is aimed at estimating the total life cycle GHG emissions for transportation fuels derived from five North American conventional crudes. This chapter describes the assumptions and methods used to develop the life cycle assessment model that is used to calculate GHG emissions associated with all the stages of a crude oil's life from well-to-wheel (WTW). Recovery emissions (i.e., GHG emissions from drilling an oil well, land-use change, crude extraction, processing of crude oil, associated gas and water, and flaring due to complete combustion) were taken from chapter 2 and allocated to gasoline, diesel, and jet fuel. Energy consumption in refining was calculated using the Aspen HYSYS's [90] refinery model. This model gives the yields of different products and amount of energy consumed in each unit operation in the refinery. Transportation model gives the amount of GHGs emitted from the transportation of crude oil and finished fuels. All the GHG emissions numbers, including emissions from fuel combustion in vehicles, were aggregated to present the total life cycle GHG emissions. Life cycle GHG emissions obtained were compared with figures from the existing literature. At the end of the

[2] A version of this chapter was submitted as Rahman, M.M., Canter, C., Kumar, A., Well-to-wheel life cycle assessment of transportation fuels derived from different North American conventional crudes, to *Applied Energy* in 2014.

chapter a sensitivity analysis shows the impact of different technical parameters on total WTW GHG emissions.

3.2. Method

3.2.1. Goal and Scope

The purpose of this study was to compare the total WTW life cycle GHG emissions for transportation fuels converted from conventional crudes through the development of the FUNNEL-GHG-CCO model. This paper analyzes five North American conventional crudes: Alaska North Slope, California's Kern County heavy oil, Mars crude, Maya crude, and Bow River heavy oil. In this chapter, the functional unit considered was 1 MJ-fuel. Energy calculations are based on the lower heating value (LHV) of the fuels.

The scope of this study encloses all the stages of a crude oil's life cycle from recovery of crude to the combustion of transportation fuels in vehicle engines. Infrastructure and equipment production emissions were not included in the analysis.

3.2.2. Life Cycle Assessment (LCA) Boundary

Crude oil life cycle GHG emissions consist of well-to-tank (WTT) emissions and tank-to-wheel (TTW) emissions. In order to compare different crudes, a consistent LCA boundary was chosen and is presented in Figure 10. The WTT stage includes crude recovery, transportation of crude to the refinery, refining of crude, and transportation and

distribution of refined fuels to the local refueling stations. The combustion of transportation fuels in vehicle engines is considered the TTW stage.

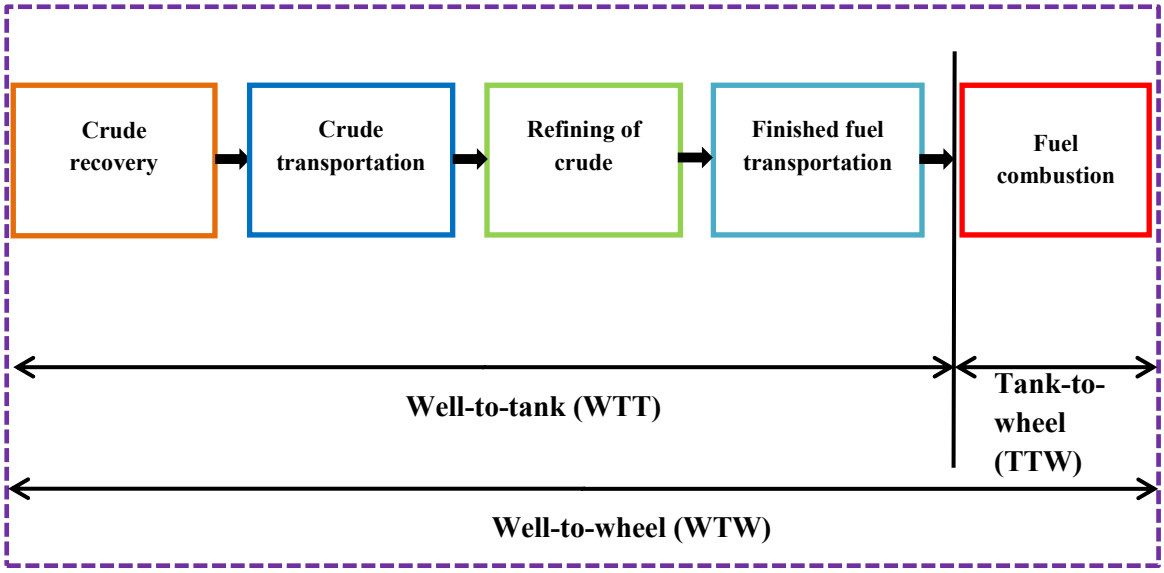

Figure 10: Life cycle assessment (LCA) boundary

3.2.3. Crude Recovery

Crude recovery is the first unit operation in the LCA of crude oil. Crude recovery can be divided into the following sub-unit operations: the drilling of the oil well, crude extraction, and the processing of crude oil, associated gas and water. Crude recovery starts with drilling a hole into the reservoir in order to inject fluid to maintain reservoir pressure and extract the crude. Drilling the oil well consumes energy, which increases exponentially with the depth of the reservoir [50]. Usually drilling rigs are powered by

diesel engines that produce GHG emissions. During drilling, land and vegetation are disturbed, leading to a release of GHGs to the atmosphere for onshore oil fields.

When the crude recovery is in its early stages it is possible to extract oil naturally as there is enough pressure in the reservoir. This extraction method is called primary recovery. Sometimes extraction pumps are required when the pressure falls within the reservoir. Pressure depletes as the reservoir ages. Many methods have been developed to maintain reservoir pressure to extract more crude from the reservoir. Secondary methods include the injection of water and/or gas into the reservoir to push the oil to the production well. Some crudes are highly viscous and do not flow to the production wells. Steam is required to reduce the oil's viscosity; when steam is used, this method is called thermal enhanced oil recovery. When the crude is extracted from the reservoir, it's a mixture of crude oil and associated gas and water. The amount of energy required to extract crude from the reservoir depends on the extraction method, reservoir properties, and crude properties (i.e., density, viscosity, etc.), as well as the gas-to-oil, water-to-oil, and steam-to-oil ratios. The operation of the equipment used in crude extraction (pumps, compressors, etc.) is the source of GHG emissions. Release of combusted associated gas that comes with the crude oil is known as flaring. Flaring is a significant source of GHG emissions in crude recovery. Flaring is done in fields where there is no economic use for the associated gas [4].

To maintain quality requirements for crude transportation, crude oil must be processed to separate different phases, and gas and water must be removed. The produced gas and water are either reused to maintain reservoir pressure or disposed to the environment. But

before being reused and/or disposed of, this gas and water must be treated. A large amount of energy is used to separate phases and treat associated gas and water, resulting in GHG emissions [4]. GHG emissions from recovery of five North American conventional crudes were quantified in chapter 2 which includes all the sub-unit operations in crude recovery. GHG emissions from drilling of oil well and associated land-use change, crude extraction, flaring (complete combustion), and the processing of crude oil, associated gas and water were taken from chapter 2 and used in this chapter in quantifying the total life cycle GHG emissions for transportation fuels.

3.2.4. Refining

After crude oil is transported from the feedstock location to the refinery, it is refined to produce transportation fuels (i.e., gasoline, diesel, and jet fuel). The energy required to refine each crude oil depends on the refinery configuration and crude properties, such as density, sulfur content, etc. In this study, a refinery model in Aspen HYSYS [90] was built to determine the amount of energy required in each process unit in the refinery to produce gasoline, diesel, and jet fuel. The refinery model was developed using the same parameters and conditions used in Aspen HYSYS's refinery-wide sample model [90], which can handle several crudes at a time. Unlike the refinery-wide sample model, the model developed in this study can handle only one crude oil at a time. It was assumed that the refinery is located in: Los Angeles, California to refine Alaska North Slope and California's Kern County heavy oil; Cushing, Oklahoma to refine Mars and Bow River heavy oil; and, Houston, Texas to refine Maya crude. The refinery location is important,

as the electricity needed for the refinery was assumed to be purchased from the local grids and emission factors vary with grid electricity mixes [16, 17].

The refinery model can handle both sweet and sour crudes. The model consists of various refinery processing units: diesel hydrotreater, kerosene hydrotreater, naphtha hydrotreater, catalytic cracker, hydrocracker, reformer, and isomerization and alkylation units. These units are all built using petroleum shift reactors [90]. The model was run individually for the five crudes to process 150,000 barrels or 23,848 m^3 per day. Crude distillation data, density, and sulfur content for each crude oil were given as inputs to the refinery model. The sources of crude distillation data, density, and sulfur content of five conventional crudes are summarized in Table 9. The model calculates energy consumed in each processing unit and amount of each refined fuel produced. The major refined products are gasoline, diesel, and jet fuel.

Three types of process energy – electricity, heat, and steam – are required for the refinery processing units. It was assumed that natural gas was used to produce heat and steam for the refinery use. To calculate the amount of natural gas required for heating and steam production, the heater and steam boiler efficiencies were taken as 80% [22] and 75% [91], respectively. The total GHG emissions were determined from the amount of natural gas and electricity required and emission factors for the combustion of natural gas and grid electricity. Grid emission factors for Los Angeles, Cushing, and Houston were taken as 278.20, 720.03, and 554.64 g-CO_2eq/kWh, respectively [92]. All of the energy use and resulting GHG emissions were allocated to gasoline, diesel, and jet fuel.

Table 9: Sources of crude distillation data, density, and sulfur content for five crudes

Crude name	Crude distillation data	Density	Sulfur content
Alaska North Slope	[93]	[93]	[93]
California's Kern County heavy oil	[94]	[17]	[17]
Mars	[95]	[95]	[95]
Maya	[96]	[98]	[98]
Bow River heavy oil	[97]	[99]	[99]

3.2.5. Crude Oil and Finished Fuel Transportation

Energy use and the resulting GHG emissions in transportation depend on the transportation mode and distance. Refinery locations were selected for five crudes, and the distances from the field to the refinery were estimated based on the shipping routes and pipeline maps in North America. Table 10 shows the transportation modes and distances from the field to the refinery.

Mars and Maya crudes are produced in offshore fields, namely the Mars platform and the Cantarell oil field, respectively. These crudes are transported to refineries using both onshore and offshore pipelines. A pipeline transportation model was developed to transport 150,000 barrels or 23,848 m^3 per day of crude oil. The pipeline operating

pressure and velocity of flow were assumed to be 50 bar (5000 kPa) [100] and 1.16 m/s [101], respectively. Based on the volumetric flow rate and flow velocity, the inside diameter of the pipeline was calculated to be 22 inches (0.56 m). Using the Reynolds number and the relative roughness of commercial steel pipe, the friction factor was found from the Moody diagram. Equation 13 [102] gives the head loss due to friction where the head loss, h_f, is in m, friction factor, f, distance of pipeline, L, is in m, velocity of flow, v, is in m/s, acceleration due to gravity, g, is in m/s^2, and inside diameter of the pipe, D, is in m.

$$h_f = fLv^2/2gD \quad (13)$$

The total energy required for pumping to overcome friction was determined from the volumetric flow rate, density of crude, head loss due to friction, and assumed pump efficiency of 65% [22]. To calculate GHG emissions, the total energy required for pumping was multiplied by the electricity emission factor. For onshore pipelines, grid electricity emission factors were used for the different regions through which the pipelines go. Offshore pipelines were assumed to be run by onsite electricity produced by natural gas turbines. For those, the emission factor for producing electricity using a natural gas turbine was taken from GREET 1 [61].

In addition to pipeline transportation, Alaska North Slope and Maya crude involve transportation by ocean tanker. Shipping distances were estimated using PortWorld's shipping route distance calculator [103].

Table 10: Transportation distances and modes considered for five North American crudes

Crude name	Refinery location	Pipeline transport (km)	Marine transport (km)
Alaska North Slope	Los Angeles, California	1288[a]+80[b]	2339[c]
California's Kern County heavy oil	Los Angeles, California	370[d]	0
Mars	Cushing, PADD 2	209[e]+1101[f]	0
Maya	Houston, PADD 3	80[g]+80[h]	1117[i]
Bow river heavy oil	Cushing, PADD 2	2600[j]	0

[a]Distance of Trans-Alaska Pipeline System (TAPS) that runs from Prudhoe Bay to the Valdez sea port.

[b]Distance assumed from the sea port to the refinery in Los Angeles, California.

[c]Distance from the Valdez sea port to the Los Angeles sea port, estimated using PortWorld's shipping route distance calculator [103].

[d]Distance estimated from the Midway-Sunset Oil Field, San Joaquin Valley, California to the refinery in Los Angeles, California.

[e]Distance from the Mars platform to New Orleans, Louisiana (offshore pipeline).

[f]Distance estimated from New Orleans to the refinery in Cushing, Oklahoma, PADD 2.

[g]Distance assumed from the Cantarell oil field to the Cayo Arcas sea port (offshore pipeline).

[h]Distance assumed from the Houston sea port to the refinery located in Houston, Texas, PADD 3.

[i]Distance from the Cayo Arcas sea port to the Houston sea port, estimated using PortWorld's shipping route distance calculator [103].

[j]Distance from Hardisty to the refinery in Cushing, Oklahoma, PADD 2.

A 100,000 DWT (deadweight tonnage) ocean tanker with a velocity of 31 km/h [61] was considered for crude transportation. The power required to propel the ocean tanker was calculated using Equation 14 [51] where power, P, is in kW and payload, f_t, is in kg.

$$P=6766.22+8.305*10^{-5}*f_t \quad (14)$$

Energy intensities for the up-trip and down-trip were determined using the energy consumed by the ocean tanker, DWT, velocity of the tanker, and assumed load factors of 80% and 70% [61] for up-trip and down-trip, respectively. Residual oil is assumed to be burned in the ocean tanker engine to provide propulsion power. Total GHG emissions from crude transportation by an ocean tanker were found using the energy intensities and the emission factor for residual oil.

Finished fuels (gasoline, diesel, and jet fuel) are transported from the refineries to local refueling stations. The fuels are assumed to be transported from the refineries by different modes such as pipeline, rail, ocean tanker, barge, etc. to the bulk terminal and from the bulk terminal to the local refueling stations by heavy duty trucks [104]. For the crudes that are refined in PADD 2 and PADD 3, GREET 1 [104], default values for U.S. gasoline and U.S. diesel were used for transport modes, shares, and distances. As Alaska North Slope and California's Kern County heavy oil are refined in California, we have assumed the GREET 1 [104] default California gasoline and diesel transport values. On the other hand, for jet fuel transportation, U.S. conventional jet fuel values for modes, shares, and distances were used for all the crudes. Finished fuel transportation modes, shares and distances are summarized in Table 11.

3.2.6. Fuel Combustion in Vehicles

The final stage in the life cycle of transportation fuel is the combustion of transportation fuels in engines and is considered as the tank-to-wheel (TTW) stage. Vehicles emit nitrogen oxides (NO_x), volatile organic compounds (VOC_S), carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), sulfur dioxide (SO_2), etc. This study considers only CH_4, CO_2, and N_2O to calculate GHG emissions in CO_2 equivalents. These emissions vary among different vehicle types (passenger cars, light duty trucks, heavy duty trucks, etc.). In this study, GHG emissions from the combustion of gasoline and diesel were calculated for passenger cars, while emissions from jet fuel combustion were determined for passenger aircraft (small twin-aisle). Emissions of CH_4, N_2O, and CO_2 from the combustion of gasoline and diesel in passenger cars were calculated using the fuel economy (energy used per km distance travelled by the vehicle) and emission factors (gm/km). Fuel economy and emission factors for gasoline and diesel, and GHG emissions from jet fuel combustion, were taken from GREET 1 [61]. Fuel economy and emission factors are summarized in Table 12. Emissions of CH_4 and N_2O were converted to CO_2 equivalents using global warming potential factors for a lifetime of 100 years.

Table 11: Modes, shares, and distances for the transportation of gasoline, diesel, and jet fuel

Transportation mode	California	PADD 2	PADD 3
Pipeline			
Distance (km)	241 (177)	208, 177* (177)	208, 177* (177)
Share (%)	95 (46.4)	66.6, 46.4*, (46.4)	66.6, 46.4*, (46.4)
Rail			
Distance (km)	402 (789)	241, 789* (789)	241, 789* (789)
Share (%)	5 (5.1)	2.2, 5.1*, (5.1)	2.2, 5.1*, (5.1)
Ocean Tanker			
Distance (km)	0	0	0
Share (%)	0	0	0
Barge			
Distance (km)	0 (322)	547, 322* (322)	547, 322* (322)
Share (%)	0 (48.5)	31.2, 48.5*, (48.5)	31.2, 48.5*, (48.5)

Heavy Duty Truck			
Distance (km)	48	48	48
Share (%)	100	100	100

*values are for diesel and values in parenthesis are for jet fuel when different from gasoline transportation.

Table 12: Fuel economy and emission factors used to calculate tank-to-wheel (TTW) GHG emissions

Fuel	Gasoline	Diesel
Fuel Economy (MJ/km)	3.17	2.67
Emission Factors (gm/km)		
CH_4	0.0093	0.0019
N_2O	0.0074	0.0074
CO_2	230.43	200.00

3.2.7. Fugitive Methane (CH_4) Emissions

Intentional and unintentional release of methane (CH_4) to the atmosphere is known as fugitive methane emissions. Methane emissions from crude oil production are not well estimated and may vary from field to field. Some studies [105-108] quantified fugitive methane emissions as a percentage (between 1 and 12%) of produced natural gas (mainly methane and ethane). None of these studies estimated fugitive methane emissions from crude oil and natural gas production separately. The range of fugitive emissions estimated by these studies is too high and these emissions are based on specific locations. A recent study by Schwietzky et al. [109] quantified fugitive methane (CH_4) emissions from crude oil production activities using the fugitive emission factors developed in another article by the same authors [110]. The authors reported the world's crude oil fugitive methane emissions (Tg/yr) with a range of values (low-6 Tg/yr, medium-17 Tg/yr, and high-51

Tg/yr). Low and high values are based on a 95% confidence interval. Due to the unavailability of data on fugitive methane emissions for the crude oils analyzed in this study, average fugitive emissions (2006-2011) for crude oil reported by Schwietzky et al. [109] were used in this study. Fugitive methane emissions were converted to g-CO_2eq/MJ-crude to be in line with the functional unit of this study. World's average crude oil production for the years 2006-2011 were used to calculate the emissions in g-CH_4/m^3-crude. During 2006-2011, the average production of crude oil in the world was 4.27E+09 m^3 [111]. Using the global warming potential of CH_4 for a 100-year time horizon and lower heating value (LHV) of crude oil, fugitive methane emissions were converted to g-CO_2eq/MJ-crude.

3.3. Results and Discussion

3.3.1. Refining

Refining of crude oil produces fuel oil, sulfur, coke, etc. along with gasoline, diesel, and jet fuel. Figure 11 shows the yields of these products per kg of crude oil feed. Gasoline and jet fuel production are highest for Alaska North Slope and lowest for California's Kern County heavy oil. The yields of gasoline and jet fuel are 0.42-0.48 kg/kg-crude and 0.07-0.13 kg/kg-crude, respectively, from these sources. Diesel production varies from 0.20 kg/kg-crude for Alaska North Slope to 0.27 kg/kg-crude for California's Kern County heavy oil. Heavier crudes produce more fuel oil than lighter crudes. California's Kern County heavy oil produces 76% more fuel oil per kg-crude than Alaska North

Slope. Production of LPG, sulfur, and coke varies from 0.008-0.01 kg/kg-crude, 0.001-0.003 kg/kg-crude, and 0.003-0.011 kg/kg-crude, respectively.

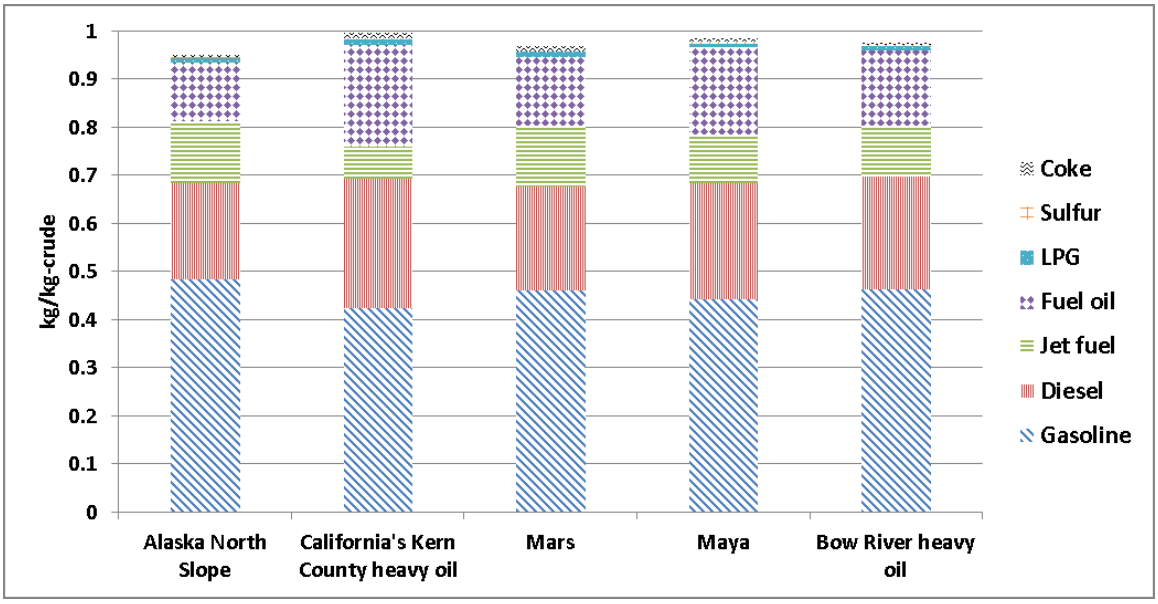

Figure 11: Yields of products from the refining of crudes

The sources of energy use in refining are natural gas and grid electricity. Natural gas provides the heat and steam required in the refining process. The energy requirement and resulting GHG emissions to refine each crude oil are presented in Table 13.

More energy is required to refine heavier crudes (low API gravity or high density) than lighter crudes into finished fuels. California's Kern County heavy oil and Alaska North Slope are the heaviest and lightest among the crudes, which make them the highest and lowest consumers of energy, respectively. As a result California's Kern County heavy oil and Alaska North Slope emit the highest and lowest amounts of GHG emissions (see Table 13).

Table 13: Energy use and resulting GHG emissions from the refining of five North American crudes

Crude name	Natural gas (MJ/day)	Electricity (MJ/day)	GHG emissions (g-CO_2eq/day)
Alaska North Slope	1.06E+08	6.79E+06	6.49E+09
California's Kern County heavy oil	1.54E+08	9.63E+06	9.40E+09
Mars	1.15E+08	7.39E+06	7.97E+09
Maya	1.33E+08	8.04E+06	8.71E+09
Bow River heavy oil	1.20E+08	7.82E+06	8.32E+09

The other reason for variations in energy requirements is the amount of hydrogen required to process each crude oil. The hydrogen requirements for California's Kern County heavy oil and Alaska North Slope are the highest and lowest, respectively. GHG emissions from the combustion of natural gas to produce heat and steam make up the largest contribution to the total refining GHG emissions. Grid intensity has little impact on refining GHG emissions because only 5.71-6.11% of the total refining energy comes from the local grids.

Table 13 represents GHG emissions on a per day basis. The emissions are to be allocated among the finished products on per MJ-product (gasoline, diesel, and jet fuel) basis to compare well-to-wheel GHG emissions. Energy use and the resulting GHG emissions are assumed to be allocated only to transportation fuels (gasoline, diesel, and jet fuel).

Allocation can be based on mass content, energy content, or the market value of refined products [112]. This study used two methods to allocate energy use and GHG emissions: the refinery level allocation and the sub-process level allocation. ISO 14041 [113] suggests allocating energy use at the sub-process level whenever possible. In this study, allocation was done at the refinery level based on mass and energy content of gasoline, diesel, and jet fuel as well as at the sub-process level based on mass content. For refinery level allocations we calculated the total refining energy use and resulting GHG emissions and distributed them to gasoline, diesel, and jet fuel based on mass and energy contents of the products. However, for the sub-process level allocation, energy associated with each refining process was distributed among the product streams based on the mass content of the products. Energy use with types such as heat, steam, and electricity was traced through the refinery from atmospheric distillation process to the refinery's finished products, which directly gives the energy use to produce each finished product. Energy use and resulting GHG emissions associated with fuel oil, LPG, coke, sulfur, etc. were allocated to gasoline, diesel, and jet fuel based on the mass content of transportation fuels.

Table 14 shows the energy allocation for the final products at the refinery level and sub-process level. For the refinery level allocation, the mass-based method results in refining energy shares of 59.43% for gasoline, 24.58% for diesel, and 15.99% for jet fuel in case of Alaska North Slope crude oil. Refinery level allocation, energy-based method results in energy shares of 58.52% for gasoline, 25.15% for diesel, and 16.33% for jet fuel. Refinery level allocations do not reveal the reality that all the products in the refinery do not go through the same processes.

Table 14: Energy allocation for end products at the refinery and sub-process levels

Crude name	Product	Refinery level (%)		Sub-process level (%): mass based
		Mass based	Energy based	
Alaska North Slope	Gasoline	59.43	58.52	69.66
	Diesel	24.58	25.15	21.26
	Jet fuel	15.99	16.33	9.08
California's Kern County heavy oil	Gasoline	55.88	54.91	61.47
	Diesel	35.40	36.24	33.27
	Jet fuel	8.72	8.85	5.26
Mars	Gasoline	57.26	56.29	66.48
	Diesel	27.00	27.65	24.38
	Jet fuel	15.74	16.06	9.14
Maya	Gasoline	56.29	55.22	63.98
	Diesel	30.80	31.61	28.31
	Jet fuel	12.91	13.17	7.71
Bow River heavy oil	Gasoline	57.85	56.81	66.25
	Diesel	29.02	29.77	26.15
	Jet fuel	13.13	13.42	7.60

Figures 12 and 13 show the GHG emissions for three transportation fuels derived from five crudes based on refinery level allocation and sub-process level allocation,

respectively. Refinery level allocation, mass-based and energy-based, showed close results in terms of g-CO_2eq/MJ-refined fuel (see Figure 12). Refining emissions (mass-based and energy-based) are highest and lowest for California's Kern County heavy oil and Alaska North Slope crude oil, respectively, as shown in Figure 12.

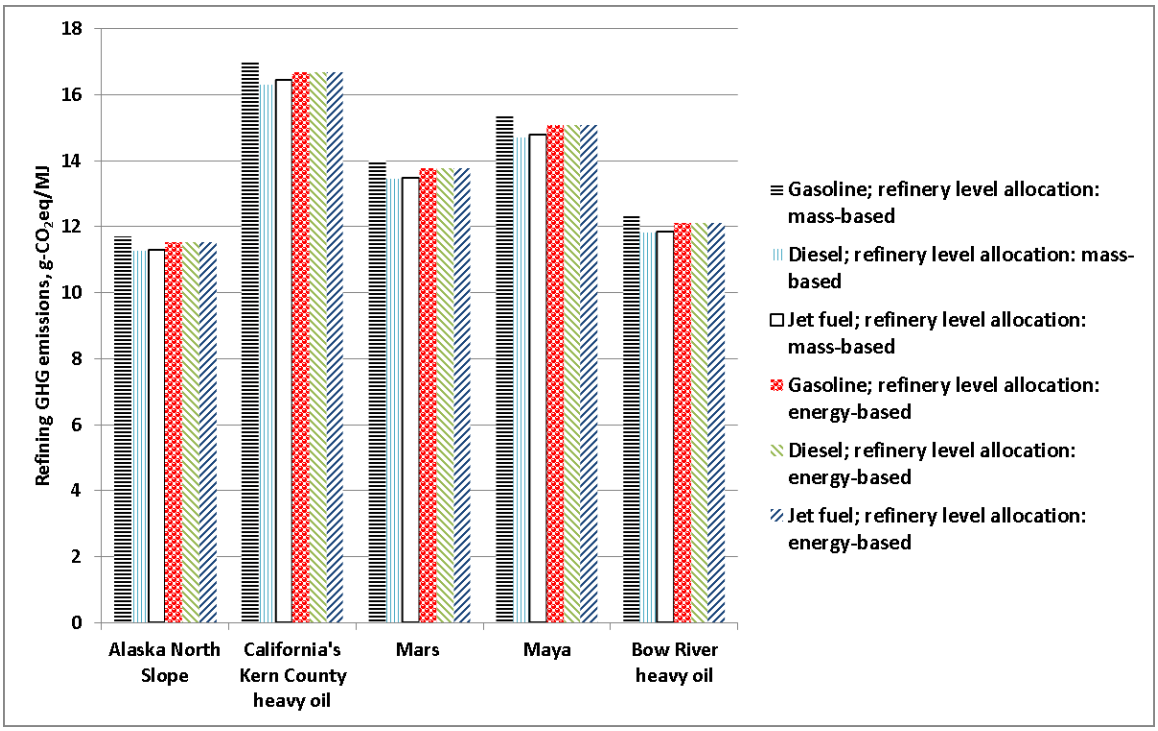

Figure 12: GHG emissions for transportation fuels based on refinery level allocation

Figure 13 shows that gasoline production emits the highest GHG emissions, followed by diesel and jet fuel production, for sub-process level allocation. Gasoline and jet fuel are the most and least energy intensive, respectively, because gasoline is produced through many more processes than jet fuel in the refinery. The energy required to produce diesel falls between gasoline and jet fuel. There are differences in energy shares for gasoline, diesel, and jet fuel compared to refinery level allocations. Sub-process level allocation

results in energy shares of 69.66% for gasoline, 21.26% for diesel, and 9.08% for jet fuel derived from Alaska North Slope. The share of energy used to produce final products from other crudes can be found in Table 14.

GHG emissions for gasoline production range from 13.66 g-CO_2eq/MJ-gasoline derived from Alaska North Slope to 18.70 g-CO_2eq/MJ-gasoline derived from California's Kern County heavy oil. GHG emissions for diesel range from 9.71 g-CO_2eq/MJ-diesel derived from Alaska North Slope to 15.33 g-CO_2eq/MJ-diesel derived from California's Kern County heavy oil. Emissions from jet fuel production are the lowest and range from 6.38 g-CO_2eq/MJ-jet fuel derived from Alaska North Slope to 9.92 g-CO_2eq/MJ-jet fuel derived from California's Kern County heavy oil.

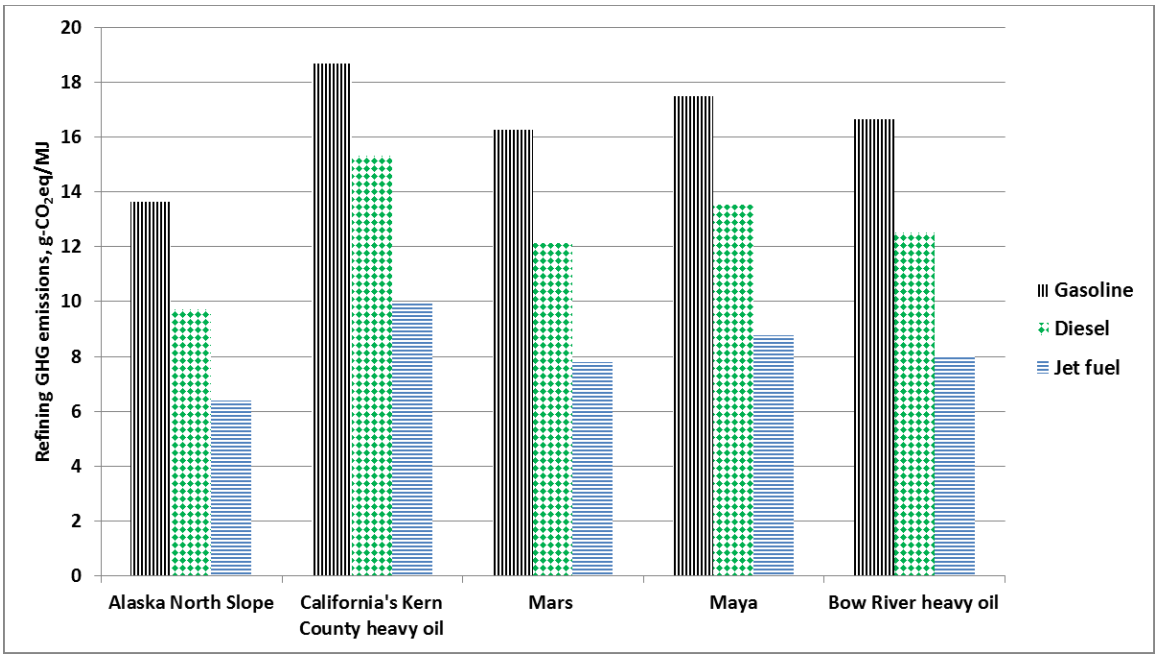

Figure 13: GHG emissions for transportation fuels based on sub-process level allocation: mass-based

3.3.2. Transportation

Grid electricity is the only source of energy for pipeline transportation of Alaska North Slope, California's Kern County heavy oil, and Bow River heavy oil as these three crudes use only onshore pipeline transportation. Mars and Maya crudes use grid electricity for the onshore pipelines and electricity produced by gas turbines for the offshore pipelines. Alaska North Slope and Maya crudes involve ocean tanker transportation for a distance of 2339 km and 1117 km, respectively (see Table 10).

Transportation GHG emissions for the five conventional crudes analyzed in this study are shown in Figure 14. The energy requirement and resulting GHG emissions for pipeline transportation increase with increasing pipeline length. GHG emissions also depend on the grid intensities of the regions through which the pipeline goes. Regional grid emission factors were used for the calculation of pipeline transportation emissions. Among the crudes, Bow River heavy oil travels the farthest and as a result has the highest transportation emissions, 0.94 g-CO_2eq/MJ-crude. On the other hand, transportation emissions from California's Kern County heavy oil are the lowest at 0.10 g-CO_2eq/MJ-crude. Mars crude transportation produces GHG emissions of 0.18 g-CO_2eq/MJ-crude. The contribution of onshore pipeline for Mars crude is 87% because Mars crude involves much more onshore than offshore transportation. Total GHG emissions from the transportation of Alaska North Slope and Maya crude are 0.64 g-CO_2eq/MJ-crude and 0.16 g-CO_2eq/MJ-crude, respectively. The combustion of residual oil in ship propulsion produces GHG emissions in ocean tanker transportation. Both up-trip and down-trip travel were considered in calculating crude transportation emissions by ocean tanker. The

share of GHG emissions from ocean tanker transportation in the total transportation emissions are 77% and 89% for Alaska North Slope and Maya crude, respectively.

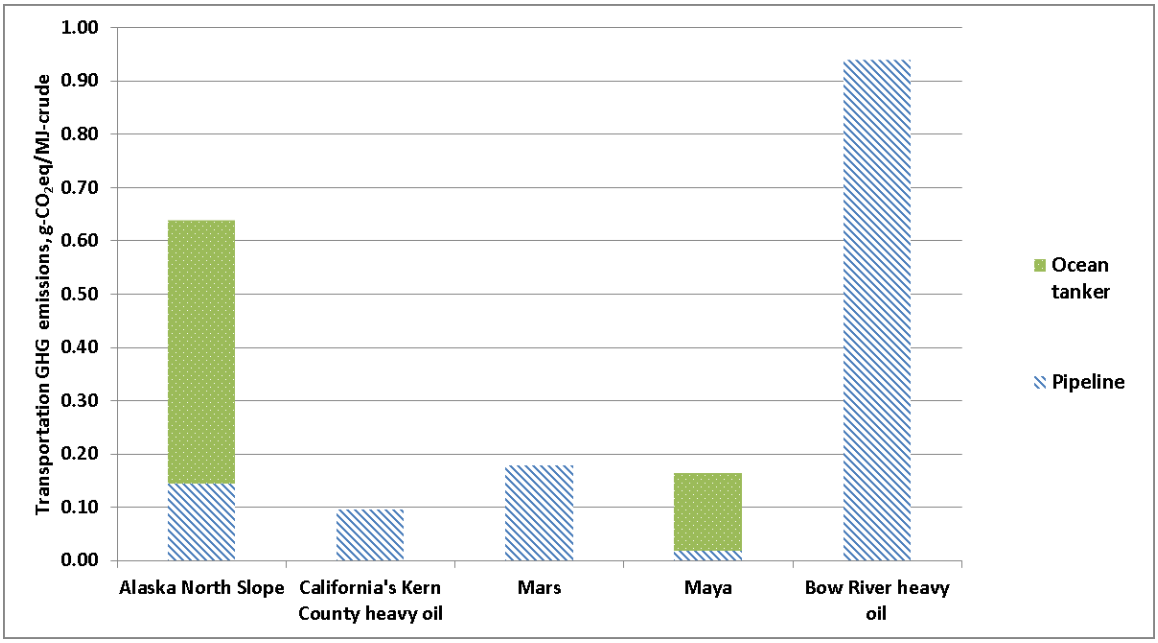

Figure 14: GHG emissions from pipeline and ocean tanker transportation

Transportation and distribution of finished fuels (gasoline, diesel, and jet fuel) involve different modes of transportation, such as barge, pipeline, rail, and truck. GHG emissions calculations are based on the distances travelled to carry the fuels to local refueling stations (see Table 11 for the distances assumed). Figure 15 shows the GHG emissions from the transportation of finished fuels derived from the five crudes studied. The sources of GHG emissions from the transportation of refined fuels are the combustion of residual oil for the barge, use of diesel in rail and truck engines, and use of electricity for pipelines. GHG emissions from the transportation of gasoline and diesel derived from Alaska North Slope and California's Kern County heavy oil are found to be 0.442 g-

CO_2eq/MJ and 0.443 g-CO2eq/MJ. The transportation of gasoline and diesel emits 0.53 g-CO2eq /MJ and 0.46 g-CO_2eq/MJ, respectively, in the case of Mars, Maya, and Bow River heavy oil (see Table 11 for transportation modes, shares, and distances). GHG emissions from jet fuel transportation were calculated to be 0.45 g-CO_2eq/MJ for all the crudes studied.

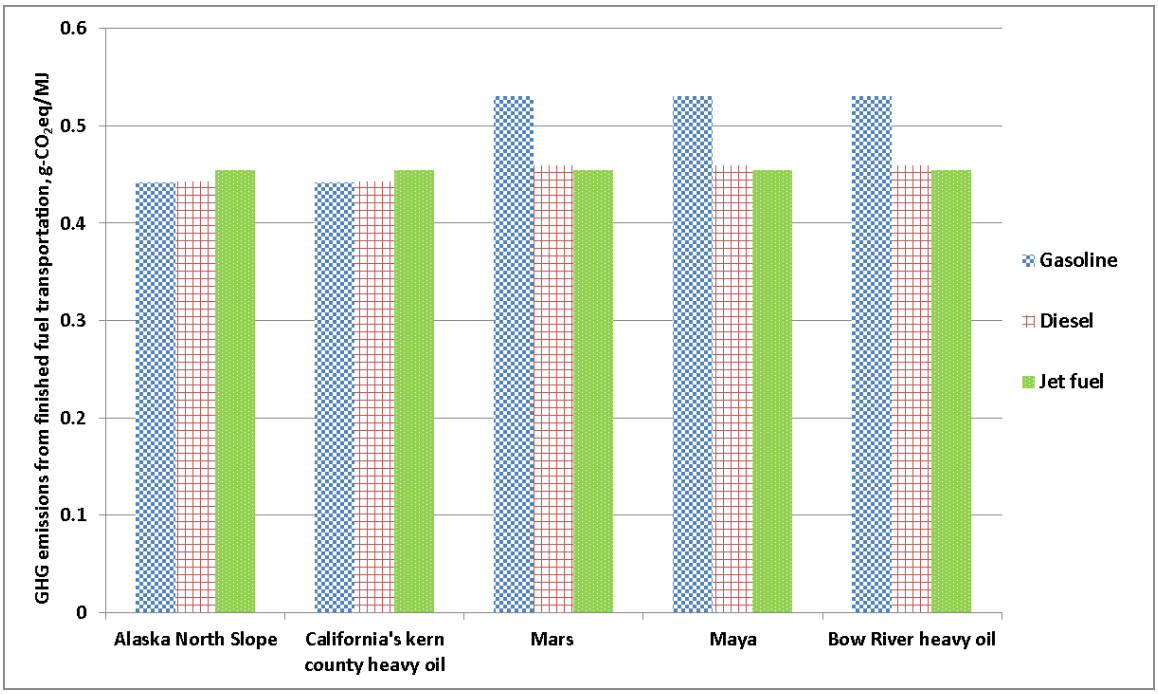

Figure 15: GHG emissions from the transportation of finished fuels

3.3.3. Fugitive Methane (CH_4) Emissions

Crude oil fugitive methane (CH_4) emissions include (i) the intentional release of CH_4 (e.g., venting of produced gas) in crude oil production, (ii) incomplete flaring (incomplete combustion of produced gas), and (iii) the unintentional release of CH_4 (e.g., leaks)

associated with crude production, refining, and transportation. As discussed in section 3.2.7, low, medium, and high fugitive CH_4 emissions (Tg/yr) were converted to emissions in g-CO_2/MJ-crude. Low, medium, and high values for fugitive CH_4 emissions are found to be 0.97, 2.75, and 8.24 g-CO_2eq/MJ-crude. These emissions were allocated to gasoline, diesel, and jet fuel based on the net thermal energy content of these transportation fuels and are summarized in Table 15. Medium fugitive CH_4 emissions were used as the base value for fugitive emissions in this study. Low and high values for fugitive emissions were used to show a range of total WTW GHG emissions for gasoline, diesel, and jet fuel (see Figures 16-18).

Fugitive emissions may vary from location to location and depend on the rate of release (intentional or unintentional) of CH_4 in the oil fields. There are no reports in the literature on the fugitive emissions from the specific oil fields for specific crude oils considered in this study. Due to the scarcity of data on fugitive emissions in the public domain, we used the world's oil fugitive CH_4 emissions reported by Schwietzke et al. [109]. Measurement of CH_4 emissions in the oil fields by the operators is required to estimate fugitive emissions from the production of a particular crude type.

Table 15: Fugitive emissions allocated to gasoline, diesel, and jet fuel as calculated in this study

Crude name	Gasoline ($g\text{-}CO_2eq/MJ$)			Diesel ($g\text{-}CO_2eq/MJ$)			Jet Fuel ($g\text{-}CO_2eq/MJ$)		
	Low	**Medium**	**High**	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
Alaska North Slope	1.27	3.61	10.83	1.27	3.61	10.83	1.27	3.61	10.83
California's Kern County heavy oil	1.27	3.61	10.83	1.27	3.61	10.83	1.27	3.61	10.83
Mars	1.26	3.58	10.75	1.26	3.58	10.75	1.26	3.58	10.75
Maya	1.26	3.56	10.69	1.26	3.56	10.69	1.26	3.56	10.69
Bow River heavy oil	1.25	3.55	10.66	1.25	3.55	10.66	1.25	3.55	10.66

3.3.4. Life Cycle GHG Emissions

A life cycle assessment includes calculating GHG emissions associated with all the stages of a crude oil's life from well-to-wheel. The functional unit needs to be the same for comparison. GHG emissions from refining, transportation of finished fuels, and vehicle operation were calculated on a per MJ-finished fuel (gasoline, diesel, and jet fuel) basis. The upstream emissions from crude recovery and crude transportation need to be allocated among gasoline, diesel, and jet fuel. These upstream GHG emissions were distributed based on the net thermal energy content of each finished fuel. Recovery emissions were allocated to finished fuels in order to get the emissions per MJ-finished fuel and are summarized in Table 16. Though this study presents different methods of allocating refining GHG emissions to gasoline, diesel, and jet fuel, sub-process level allocation results were used in calculating the total life cycle GHG emissions, keeping the recommendation of ISO 14041 [113] in mind.

Figures 16-18 show the life cycle WTW GHG emissions for gasoline, diesel, and jet fuel. The lowest and highest emissions for gasoline are at 97.55 g-CO_2eq/MJ-gasoline for Mars crude and 127.74 g-CO_2eq/MJ-gasoline for California's Kern County heavy oil. Alaska North Slope produces the second lowest emissions at 98.51 g-CO_2eq/MJ-gasoline. GHG emissions for Maya and Bow River heavy oil are 100.49 g-CO_2eq/MJ-gasoline and 100.78 g-CO_2eq/MJ-gasoline, respectively.

Table 16: Recovery emissions allocated to gasoline, diesel, and jet fuel as calculated in this study

Crude name	Gasoline (g-CO_2eq/MJ)	Diesel (g-CO_2eq/MJ)	Jet fuel (g-CO_2eq/MJ)
Alaska North Slope	6.06	6.06	6.06
California's Kern County heavy oil	30.98	30.98	30.98
Mars	3.04	3.04	3.04
Maya	4.80	4.80	4.80
Bow River heavy oil	4.94	4.94	4.94

Recovery emissions include emissions from the drilling of the oil well and associated land-use change, crude extraction, processing of crude oil, associated gas and water, and flaring (complete combustion of produced gas).

The wide range in Figures 16-18 shows the variation in total life cycle GHG emissions due to the variation in fugitive methane (CH_4) emissions. If high fugitive emissions are considered, the total life cycle GHG emissions for gasoline are increased by 6-7%. Use of low fugitive emissions reduces the life cycle GHG emissions by 2-2.5% compared to the base case (medium fugitive emissions).

Mars crude's and California's Kern County heavy oil's diesel GHG emissions estimates are the lowest and highest of the five at 95.01 g-CO_2eq/MJ-diesel and 126.02 g-CO_2eq/MJ-diesel, respectively. GHG emissions for Alaska North Slope, Maya, and Bow River heavy oil are 96.19 g-CO_2eq/MJ-diesel, 98.10 g-CO_2eq/MJ-diesel, and 98.22 g-

CO_2eq/MJ-diesel, respectively. For jet fuel, GHG emissions range from 88.17 g-CO_2eq/MJ-jet fuel for Mars crude to 118.17 g-CO_2eq/MJ-jet fuel for California's Kern County heavy oil. In the case of diesel, the use of low and high values for fugitive emissions decreases and increases the total life cycle GHG emissions by 2-2.5% and 6-8%, respectively. WTW GHG emissions for jet fuel increase and decrease by 7.11-7.22 g-CO_2eq/MJ-jet fuel and 2.30-2.34 g-CO_2eq/MJ-jet fuel, respectively when high and low values for fugitive emissions are used.

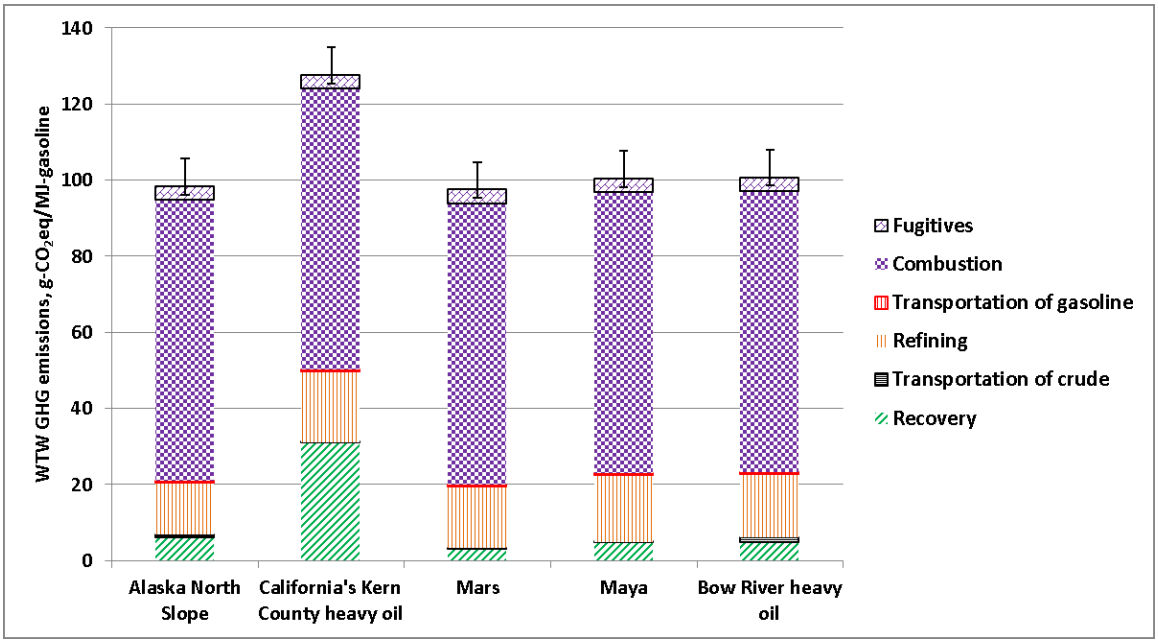

Figure 16: Life cycle WTW GHG emissions for gasoline

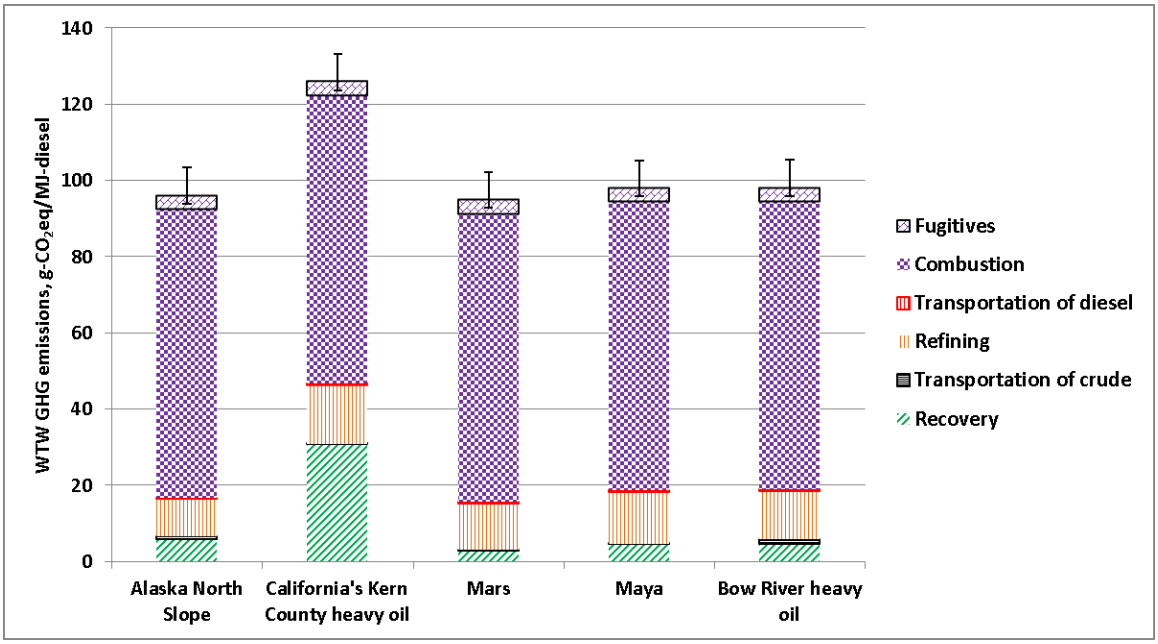

Figure 17: Life cycle WTW GHG emissions for diesel

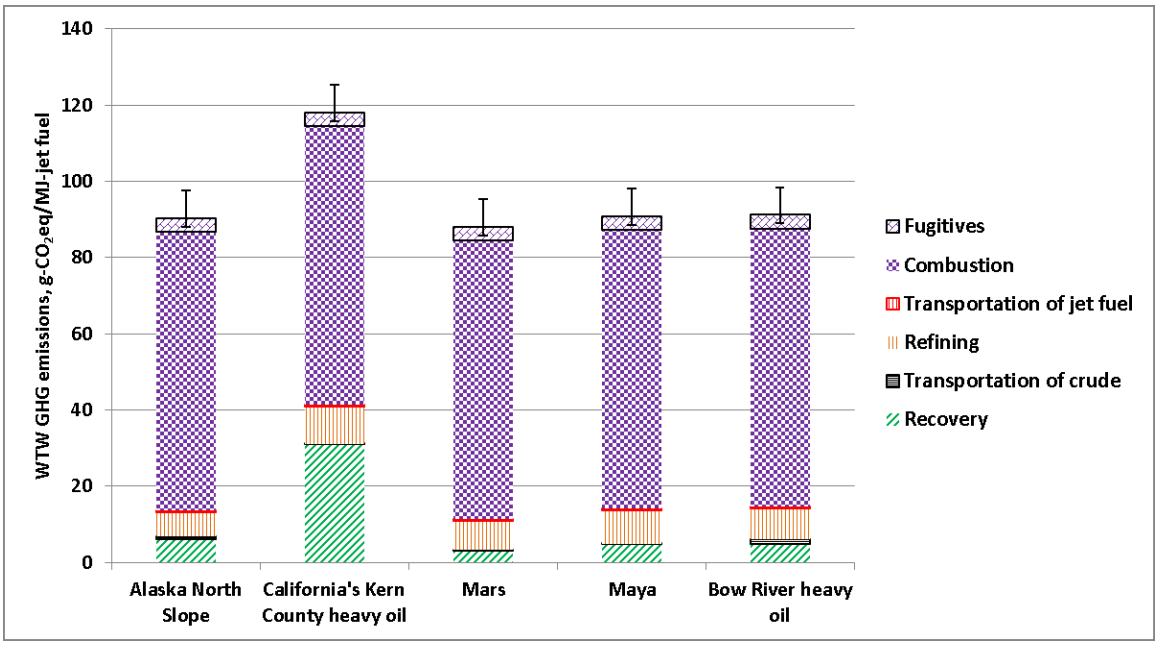

Figure 18: Life cycle WTW GHG emissions for jet fuel

Note: The range of values of life cycle GHG emissions for gasoline, diesel, and jet fuel (Figures 16-18) are based on low and high values for fugitive emissions. The base case represents medium fugitive emissions.

The highest percentages of emissions come from the combustion of transportation fuels in engines (see Figures 16-18). The combustion of gasoline, diesel, and jet fuel produces GHG emissions of 73.89 g-CO_2/MJ-gasoline, 75.53 g-CO_2/MJ-diesel, and 73.08 g-CO_2/MJ-jet fuel, respectively.

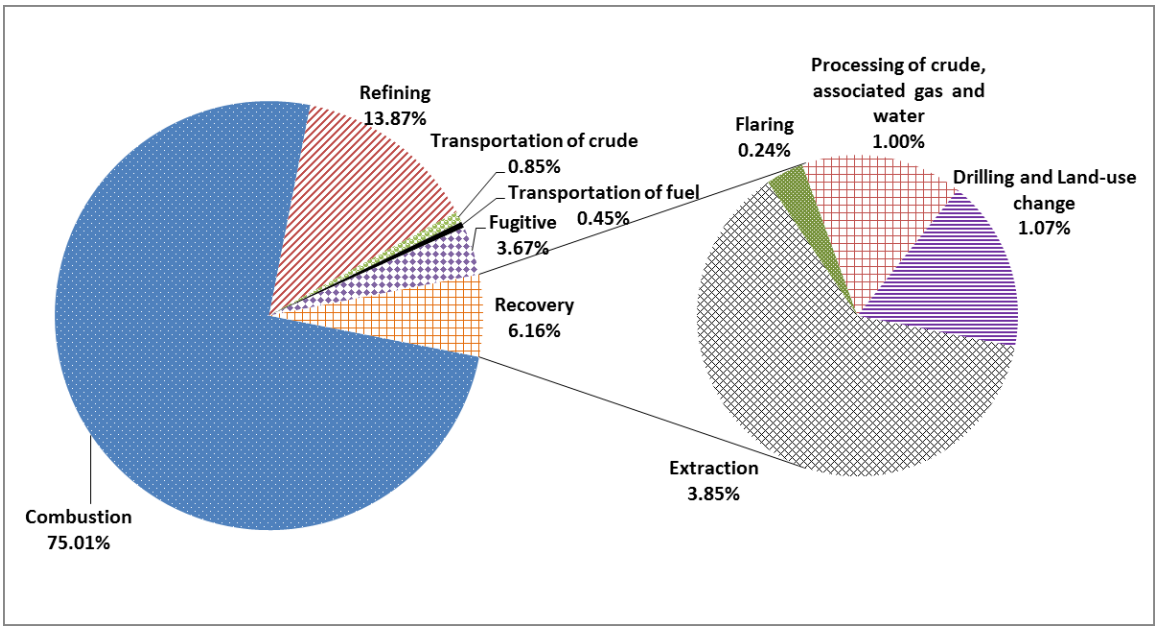

Figure 19: Percentage contribution of GHG emissions for gasoline obtained from Alaska North Slope

Figure 19 shows that the emissions from combustion of gasoline in vehicles has the highest (75.01%) contribution to WTW GHG emissions followed by emissions from refining (13.87%), recovery of crude (6.16%), and fugitive (3.67%). The transportation of crude and refined gasoline has very little contribution to WTW GHG emissions. GHG emissions from the extraction of crude, drilling and land-use change, processing of crude, associated gas and water, and flaring contribute 3.85%, 1.07%, 1.00%, and 0.24%, respectively, to the total life cycle GHG emissions. The contribution of GHG emissions

from diesel combustion, refining, recovery, fugitive and transportation are 78.52%, 10.09%, 6.30%, 3.75%, and 1.33% of the total WTW life cycle GHG emissions. For jet fuel derived from Alaska North Slope, the contribution of GHG emissions from refining, recovery, and fugitive are 7.06%, 6.71%, and 3.99% respectively. 80.81% and 1.43% of WTW GHG emissions come from the combustion of jet fuel and transportation of crude and finished jet fuel. For gasoline derived from California's Kern County heavy oil, the contribution of GHG emissions from recovery, refining, fugitive, transportation of crude and gasoline, and combustion emissions are 24.25%, 14.64%, 2.83%, 0.45%, and 57.84%, respectively. The percentage contribution of GHG emissions for gasoline derived from Mars, Maya, and Bow River heavy oil are highest for combustion followed by refining, and recovery. The life cycle GHG intensity order could be different for diesel and jet fuel derived from different crudes.

A comparison of results obtained in this study with earlier studies [16, 17, 32] was carried out to see the variation of results. Figure 20 shows the variation between total WTW GHG emissions for gasoline produced from different crudes for the analysis in this study, along with other studies. There are variations in crude recovery emissions as these studies do not have the same system boundary. This study used recovery emissions reported by Rahman et al. [4] that include drilling of oil well and associated and land-use emissions, emissions from crude extraction, crude processing, and flaring (complete combustion).

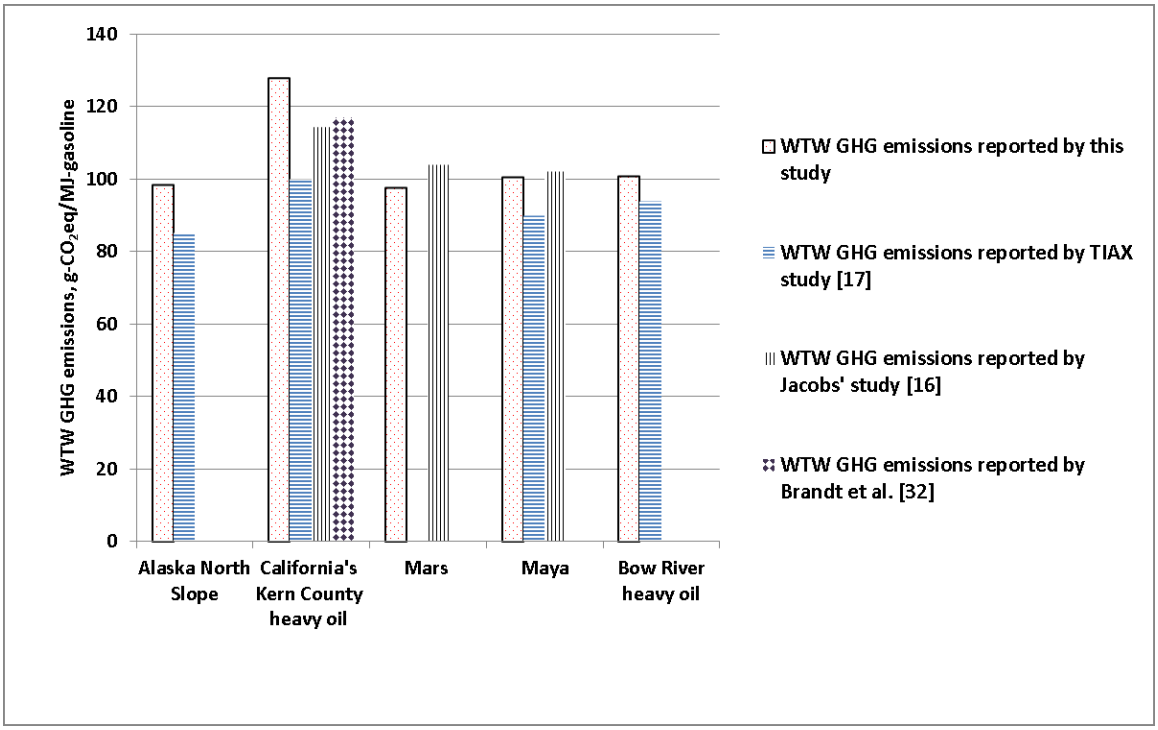

Figure 20: Comparison of WTW GHG emissions for gasoline with existing literature

The TIAX [17] study did not consider emissions from drilling and land-use change, crude oil processing, and fugitive emissions. Jacobs' study [16] did not consider GHG emissions from drilling and associated land-use change. Transportation distances, refinery configuration, refinery location, and allocation method are other reasons for variations in WTW life cycle results. For Alaska North Slope and California's Kern County heavy oil, the variation in GHG emissions between this study and the TIAX study [17] is about 13 g-CO_2eq/MJ-gasoline and 28 g-CO_2eq/MJ-gasoline, respectively, mainly due to variations in recovery, refining, and fugitive emissions.

The difference in recovery emissions for Alaska North Slope reported by Rahman et al. [4] and TIAX [17] study is about 5 g-CO_2eq/MJ-crude. The difference in recovery

emissions for California's Kern County heavy oil reported by Rahman et al. [4] and TIAX [17] is about 12 g-CO_2eq/MJ-crude, and Rahman et al. and the Jacobs' [16] study is about 4 g-CO_2eq/MJ-crude. Brandt et al. [32] reports 5 g-CO_2eq/MJ-crude more emissions than Rahman et al. [4]. For all cases, the TIAX [17] study assumes lower energy consumption and resulting GHG emissions. GHG emissions reported by this study, Jacobs' [16] study, and the study by Brandt et al. [32] for gasoline derived from California's Kern County heavy oil showed less variation than the TIAX study's result [17]. Little variations were seen for the other crudes, too, which are in the range of 7-10 g-CO_2eq/MJ-gasoline in this study and the TIAX study [17] and 2-6 g-CO_2eq/MJ-gasoline in this study and the study by Jacobs' Consultancy [16].

3.3.5. Sensitivity Analysis

A sensitivity analysis was conducted to determine the impacts of different technical parameters used in transportation and refining on the total WTW life cycle GHG emissions for gasoline. Five parameters were identified and varied to see their impacts on WTW results. Grid intensities used in the transportation model and refining were varied by ±20% while the efficiency of the pumps used in pipeline transportation and efficiencies of heaters and steam boilers used in refineries were varied by ±10%. Figure 21 shows the sensitivity analysis for gasoline derived from Alaska North Slope crude. The base case values were taken to be 65%, 80%, and 75% for pump efficiency, heater efficiency, and steam boiler efficiency, respectively. 278.20 g-CO_2eq/kWh and 571.37 g-CO_2eq/kWh were taken as the base case values for grid intensity used for refining and

transportation of crude from oil field to the Valdez sea post, respectively. The natural gas heater's efficiency has the greatest impact on total WTW GHG emissions because refining emissions make up a major portion of the total WTW GHG emissions and about 77% of the total energy use in refining comes from the combustion of natural gas in the heaters. An increase in efficiency results in reduced GHG emissions, as increased efficiency leads to decreased energy use and resulting GHG emissions. On the other hand, an increase in grid intensities increases the WTW GHG emissions. A 20% increase in grid intensity used for refining and transportation increases the emissions by 0.19% and 0.04%, respectively. The steam boiler's efficiency has the second highest impact on WTW GHG results and the pump's efficiency has the lowest impact. The steam boiler efficiency results in 0.23 g-CO2eq/MJ-gasoline lower emissions when the efficiency is increased by 10%. All the other crudes showed a similar ranking of the driving parameters for the total WTW GHG emissions (see Figures 22-25).

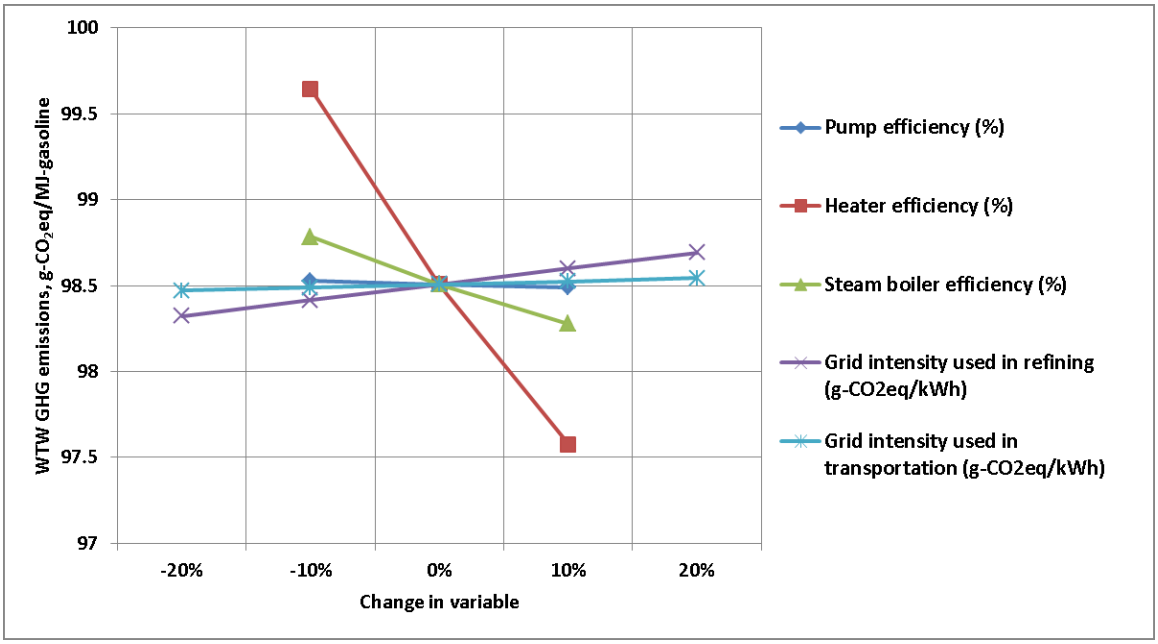

Figure 21: Sensitivity analysis of total WTW GHG emissions for gasoline derived from Alaska North Slope

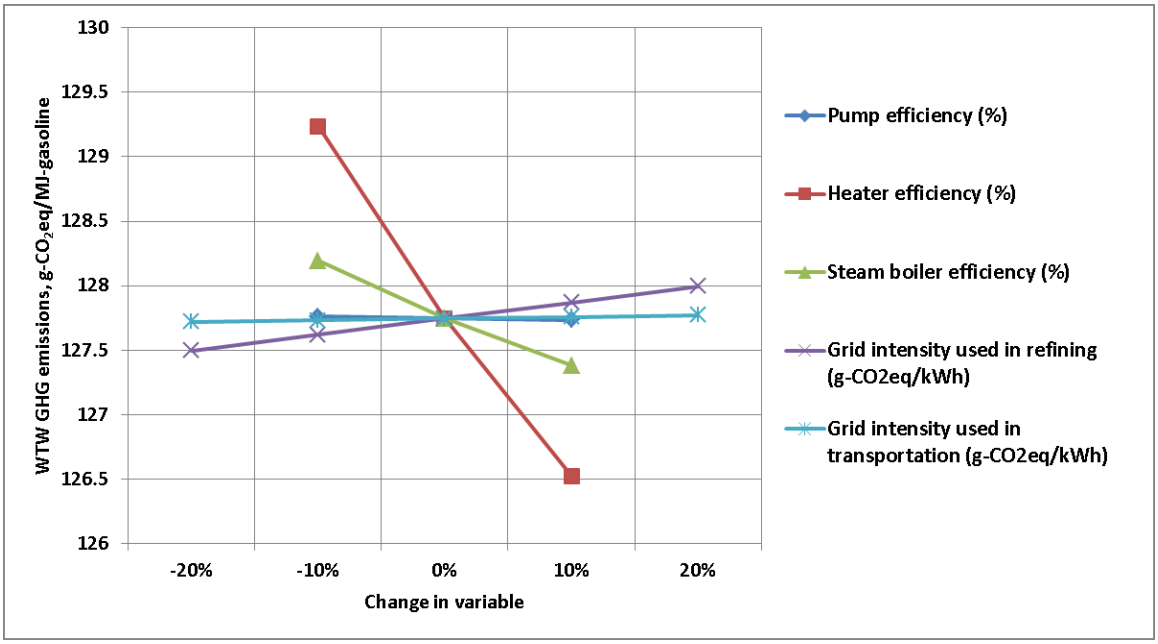

Figure 22: Sensitivity analysis of total WTW GHG emissions for gasoline derived from California's Kern County heavy oil

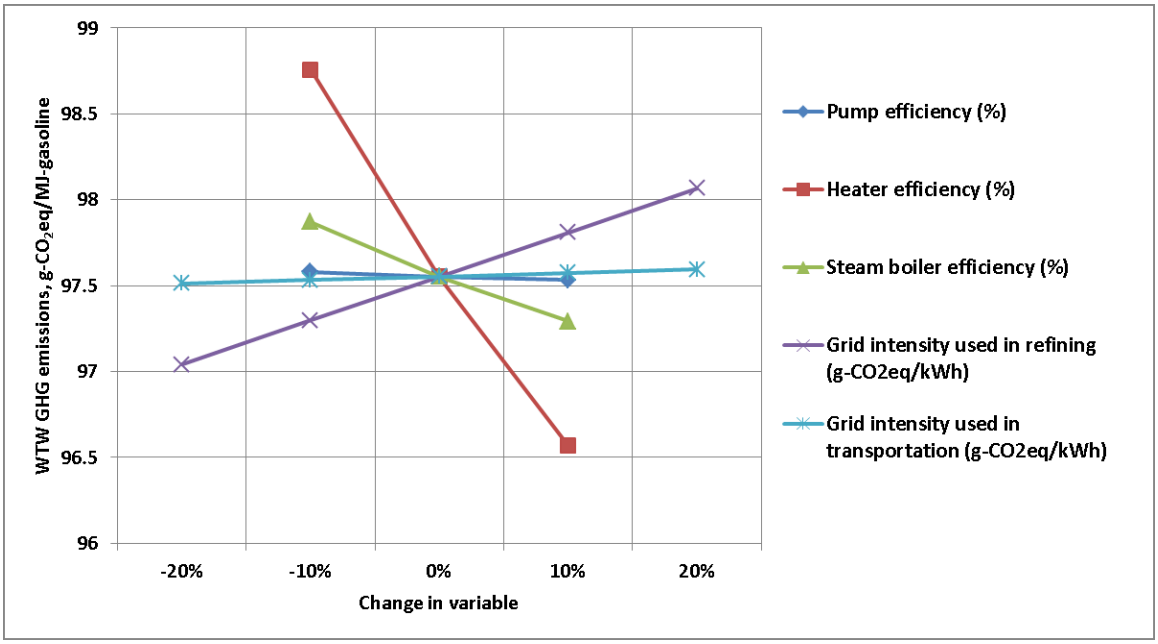

Figure 23: Sensitivity analysis of total WTW GHG emissions for gasoline derived from Mars crude

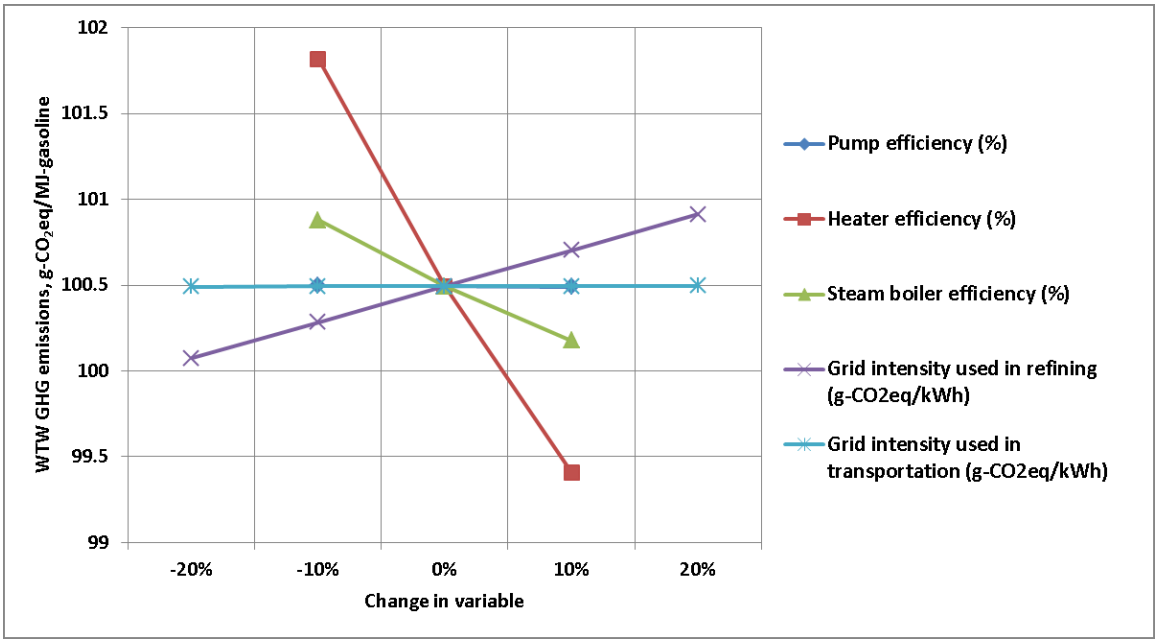

Figure 24: Sensitivity analysis of total WTW GHG emissions for gasoline derived from Maya crude

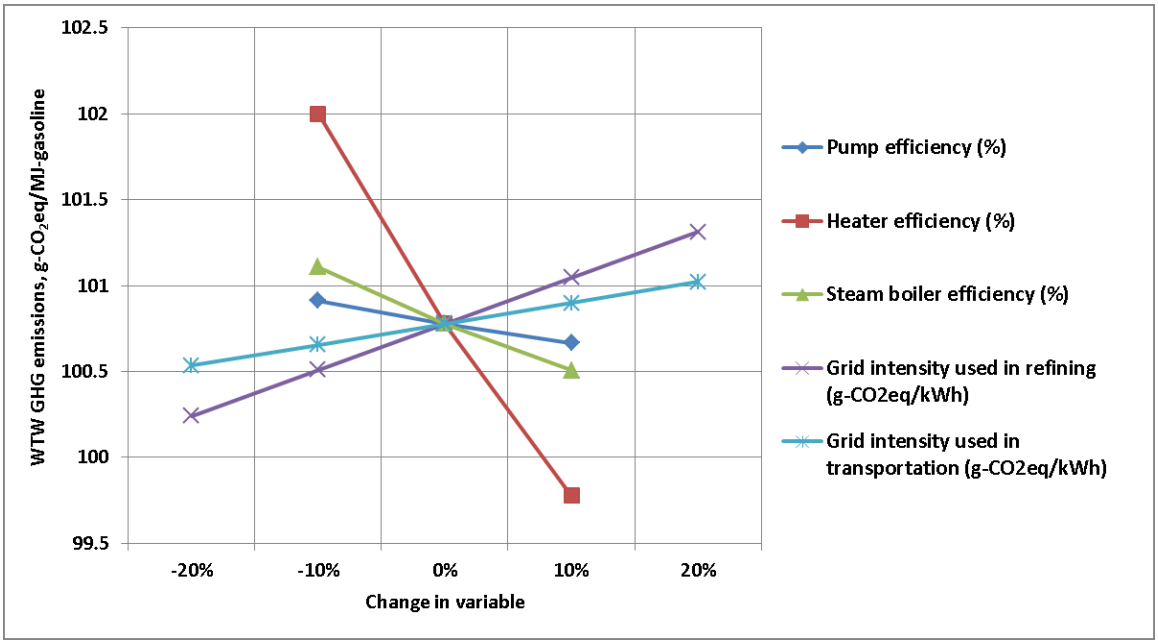

Figure 25: Sensitivity analysis of total WTW GHG emissions for gasoline derived from Bow River heavy oil

3.4. Conclusions

This study provides a comprehensive and transparent quantification of well-to-wheel (WTW) life cycle GHG emissions for transportation fuels (gasoline, diesel, and jet fuel) derived from five North American conventional crude oils through the development of an independent bottom-up data-intensive LCA model (FUNNEL-GHG-CCO). GHG emissions calculated using this model take into account all the stages of the crude oil life cycle from recovery to the combustion of petroleum in vehicle engines. Of all the crudes considered, gasoline has higher GHG emissions than both diesel and jet fuel, mainly due to higher energy consumption and resulting GHG emissions in gasoline production in the refinery. The allocation of energy use and resulting GHG emissions to each

transportation fuel plays an important role in calculating the total WTW GHG emissions. This study used sub-process level allocation to distribute refining emissions to transportation fuels. The well-to-wheel GHG emissions for the three transportation fuels range from 97.55 g-CO_2eq/MJ-gasoline to 127.74 g-CO_2eq/MJ-gasoline, 95.01 g-CO_2eq/MJ-diesel to 126.02 g-CO_2eq/MJ-diesel, and 88.17 g-CO_2eq/MJ-jet fuel to 118.17 g-CO_2eq/MJ-jet fuel for Mars crude and California's Kern County heavy oil, respectively. The results of this study could be used in comparative assessment of different North American crude slates and for decision making by the government and the industry.

Chapter 4: Conclusions and Recommendations

4.1. Conclusions

This study investigated five North American conventional crudes: Alaska North slope, California's Kern County heavy oil, Mars crude, Maya crude, and Bow River heavy oil. There are some North American LCA models that estimate well-to-wheel (WTW) life cycle greenhouse gas (GHG) emissions, but they are limited in that they do not calculate GHG emissions for any particular crude type. Moreover, these studies do not have consistent system boundaries. To fill the gap in existing literature, this study conducted a comprehensive life cycle assessment (LCA) of five conventional crude oils with a consistent system boundary through the development of a comprehensive and transparent LCA model called FUNNEL-GHG-CCO (**FUN**damental E**N**gineering Princip**l****E**s-based Mode**L** for Estimation of **G**reen**H**ouse **G**ases in **C**onventional **C**rude **O**ils).

This study's system boundary starts from the oil well drilling and ends at the combustion of transportation fuels (gasoline, diesel, and jet fuel) in vehicle engines. The LCA model developed in this study includes the GHG emissions from the life cycle stages including crude recovery, refining, transportation of crude and finished fuels, and combustion of fuels. GHG emissions from crude recovery include emissions from oil well drilling and associated land-use change, crude extraction, processing of crude oil, associated gas and water, and flaring (complete combustion) of associated gas. Recovery emissions were calculated based on crude oil and reservoir properties, oil well depth, water-to-oil ratio, gas-to-oil ratio, etc. The refinery was modeled in Aspen HYSYS, which gives the energy

use in the process units (i.e., atmospheric distillation, vacuum distillation, hydrotreaters, etc.) and the volume of each final product (gasoline, diesel, jet fuel, LPG, fuel oil, etc.) produced. Energy consumption in refining was traced from the first process (atmospheric distillation) to the final product streams, and GHG emissions associated with these streams were calculated. Refining emissions were calculated for gasoline, diesel, and jet fuel as these are desired transportation fuels.

All of the WTW life cycle stages consume energy and produce a significant amount of GHG emissions. For the drilling of oil wells, only diesel is consumed (to power the drilling rigs), and consumption of energy is negligible compared to the other unit operations. Crude recovery and refining operations consume both electricity and natural gas. The transportation model developed for pipeline transportation of crude assumes grid electricity for onshore pipelines and electricity produced by gas turbines for offshore pipelines. The combustion of transportation fuels in engines is the most GHG-intensive aspect, followed by refining and crude recovery, except in the case of California's Kern County heavy oil, for which the highest GHG emissions are from combustion followed by recovery and refining. As the combustion emissions are fixed for gasoline, diesel, and jet fuel and do not change with type of crudes, well-to-tank (WTT) could be a good basis for comparison. WTT GHG emissions are lowest for Mars crude at 23.67 g-CO_2eq/MJ-gasoline and highest for California's Kern County heavy oil at 53.86 g-CO_2eq/MJ-gasoline.

Variations have been found in collected data from various sources. Sensitivity analyses were conducted for crude recovery, transportation, and refining operations to see the

impact of different technical parameters on the total WTW life cycle GHG emissions. Results of this study show differences with the earlier studies [16, 17, 32]. The reasons for these variations are from differences in system boundaries, data quality, and methods used.

Life cycle GHG emission results show a wide variation among the crudes. This is mainly due to the extraction methods used in the fields, crude oil properties that ultimately affect the energy consumption, and resulting GHG emissions in refining and transportation. The contribution of transportation emissions is not significant to the total life cycle GHG emissions. If we consider gasoline as the reference fuel, Mars crude is the least GHG-intensive and California's Kern County heavy oil is the most GHG-intensive crude. Considering diesel and jet fuel as the reference fuel, the ranking of life cycle GHG emissions for all crudes remains the same. The life cycle GHG emissions for five North American conventional crudes range from 97.55 g-CO_2eq/MJ-gasoline to 127.74 g-CO_2eq/MJ-gasoline, 95.01 g-CO_2eq/MJ-diesel to 126.02 g-CO_2eq/MJ-diesel and 88.17 g-CO_2eq/MJ-jet fuel to 118.17 g-CO_2eq/MJ-jet fuel.

Oil sands are different from conventional crudes by its properties and extraction methods. The aim of this study was to quantify the life cycle GHG emissions for five North American conventional crude oils. Figures 26-28 show the comparison of life cycle GHG emissions for gasoline, diesel, and jet fuel from the five North American conventional crude oils with the oil sands, respectively. This comparison is critical as oil sands are important for the North American energy sector. The WTW GHG emissions range from 106.8-116 g-CO_2eq/MJ-gasoline, 100.50-115.20 g-CO_2eq/MJ-diesel, and 96.40-109.20 g-

CO_2eq/MJ-jet fuel for oil sands, depending on the pathway [114]. Applying co-generation can reduce the life cycle GHG emissions from oil sands by 2-9% [114], which will make oil sands less GHG intensive and the WTW life cycle GHG emissions from oil sands will lie in the range of GHG emissions from conventional crudes. California's Kern County heavy oil emits more GHGs than the oil sands due to the reason that this heavy crude uses a steam-to-oil ratio (SOR) of 4.53 [40] while the average SOR for oil sands is about 2.8 [114].

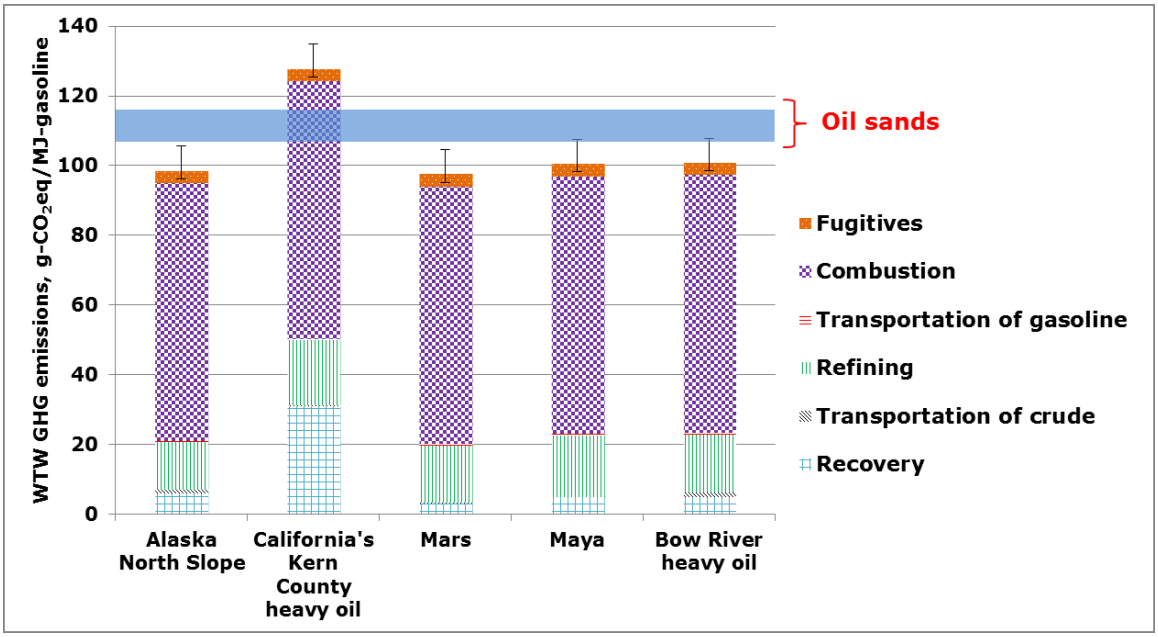

Figure 26: Comparison of WTW GHG emissions for gasoline derived from conventional crudes and oil sands

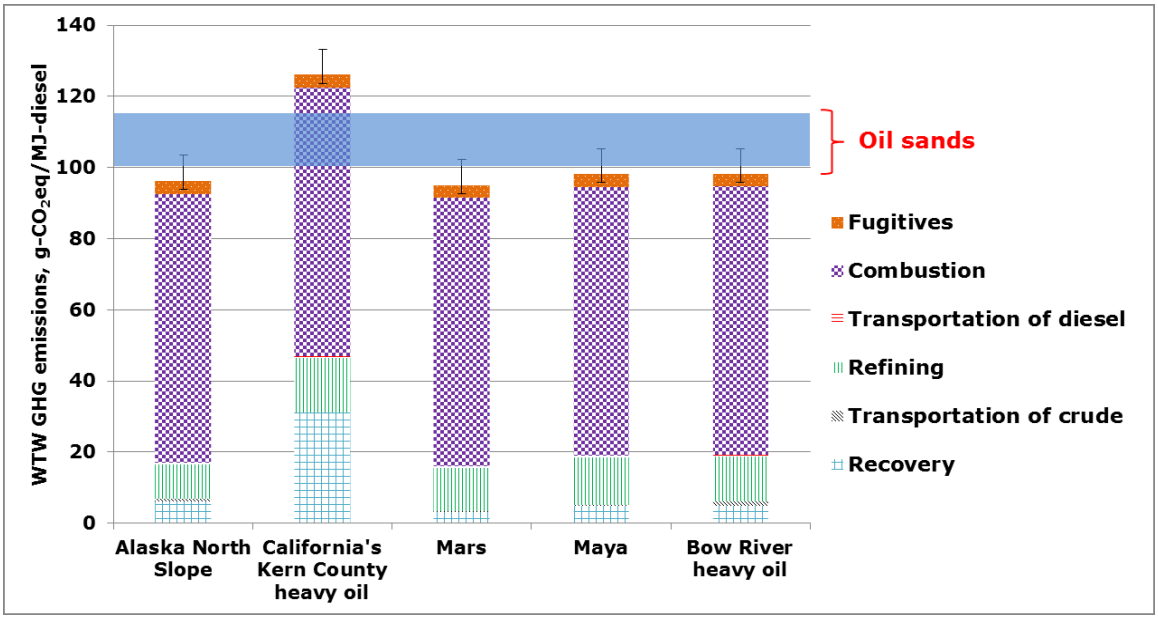

Figure 27: Comparison of WTW GHG emissions for diesel derived from conventional crudes and oil sands

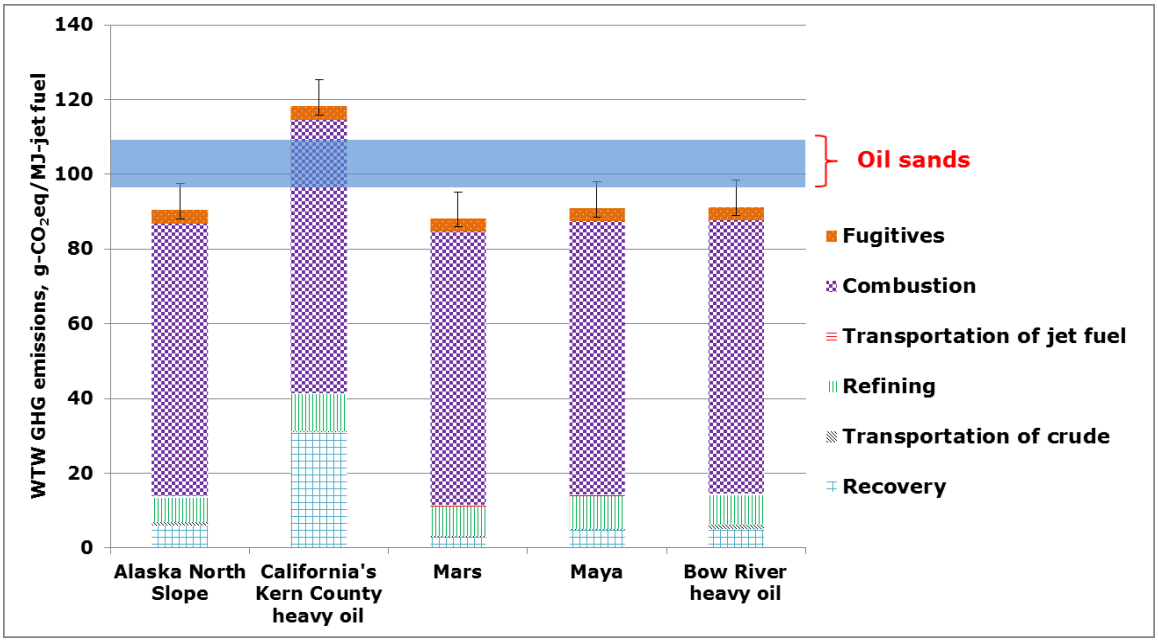

Figure 28: Comparison of WTW GHG emissions for jet fuel derived from conventional crudes and oil sands

This study could play a vital role in policy formulation and investment decision making. As this study considers all the stages of the life cycle of different conventional crudes, it will help the oil industry to stress the areas where GHG intensity could be reduced. This study will also facilitate the comparison of life cycle GHG emissions for different conventional crude oil-derived fuels and oil sands-derived fuels.

4.2. Recommendations for Future Work

This study performed a life cycle assessment of five North American conventional crude oils. The following are some key recommendations for future work:

- Beside North American crudes, other conventional crudes such as Arab Medium (Saudi Arabia), Basrah Medium (Iraq), Escravos (Nigeria), Bachaquero 17 (Venezuela), etc., that are imported to U.S. markets could be studied. This will facilitate decision making and assist in the ongoing debate on which crude oil is cleaner.

- Future work should stress more detailed research on GHG emissions from land-use change for different onshore crudes. Additional research could be conducted to emphasize environmental impacts such as acidification, eutrophication, water use, etc.

- This study investigated water flooding, gas flooding, steam injection, and nitrogen injection extraction methods. Other extraction technologies such as CO_2 flooding, polymer flooding, etc., could be studied to calculate GHG emissions from these techniques and compare the WTW results.

- Including the GHG emissions from infrastructure and equipment production in the system boundary would be useful.

- There have been some studies on fugitive emissions from natural gas wells, but there is very limited information about fugitive emissions associated with the production of specific crude types. A detailed study on fugitive emissions from conventional oil wells should be included in the future study.

- Refinery configuration has an impact on energy use and resulting GHG emissions. Different refinery configurations should be modeled to see the impact on total WTW GHG emissions.

- This study used mass-based sub-process level allocation in refining. Sub-process level allocation of refining energy use and resulting GHG emissions based on energy content and market value could be analyzed to find the impact of different allocation methods on WTW results.

List of Publications

Journal publications

1. Rahman, M.M., Canter, C., Kumar, A., Greenhouse gas emissions from recovery of various North American conventional crudes. *Energy*, 2014. 74(0): p. 607-617.
2. Rahman, M.M., Canter, C., Kumar, A., Well-to-wheel life cycle assessment of transportation fuels derived from different North American conventional crudes. Submitted to *Applied Energy*.

Conference presentations

1. Rahman, M.M., Canter, C.E., Kumar, A., Comparison of fugitive emissions in production and utilization of various North American conventional crude oils, presented at the 63rd Canadian Chemical Engineering Conference, Fredericton, NB, October 20-23, 2013.
2. Rahman, M.M., Canter, C.E., Kumar, A., Comparative analysis of well-to-wheel greenhouse gas emissions for transportation fuels reported by different life cycle assessment studies, presented at the 64th Canadian Chemical Engineering Conference, Niagara Falls, ON, October 19-22, 2014.
3. Rahman, M.M., Kumar, A., A life cycle assessment of greenhouse gas emissions for transportation fuels derived from North American conventional crudes, presented at the AIChE Annual Meeting, Atlanta, GA, November 16-21, 2014.

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Appendix A

A.1. Basic equations used in crude extraction

Power required for water injection pump:

$$P = \frac{\Delta p * Q}{3600 * \eta} \quad \text{(A.1)}$$

where

P=Power, kW

Δp=Pressure of pumping, kPa

Q=Volumetric flow rate of water, m^3/h

η=Efficiency of the pump, %

Power required for compression:

$$P = Z[(\frac{n}{n-1})280.72\frac{p_a}{T_a}T_s\{(\frac{p_d}{p_s})^{(\frac{n-1}{n})} - 1\}]\ Q/\eta \quad \text{(A.2)}$$

where

P=Power, kW

Z=Compressibility factor

n=Polytropic index

Q=Compressor discharge rate, MMm^3/h

p_a=Atmospheric pressure, kPa

T_a=Atmospheric temperature, K

T_s=Suction temperature, K

P_d=Discharge pressure, kPa

P_s=Suction pressure, kPa

η=Efficiency of the compressor, %

The constant 280.72 has a unit of kWh/MMm^3-kPa

Reynolds Number:

$$R_e = \frac{\rho v d}{\mu} \tag{A.3}$$

where

ρ=Density of fluid, kg/m^3

v=Velocity of flow, m/s

d=Diameter of pipe, m

μ=Dynamic viscosity of fluid, Pa.s

A.2. Basic equations used for calculating GHG emissions from flaring and venting

GHG emissions from flaring of combusted associated gas assuming complete combustion:

$$E_{F,c} = Q_F \eta_F \Sigma_i X_i \rho_i \Pi_i \tag{A.4}$$

GHG emissions from non-combusted associated gas:

$$E_{F,n-c} = Q_F(1-\eta_F)\Sigma_i X_i \rho_i GWP_i \quad (A.5)$$

GHG emissions from venting of associated gas:

$$E_V = Q_V \Sigma_i X_i \rho_i GWP_i \quad (A.6)$$

where

$E_{F,c}$=Flaring emissions from combusted gas, g-CO_2eq/day

$E_{F,n-c}$=Flaring emissions from non-combusted gas, g-CO_2eq/day

E_V=Venting emissions, g-CO_2eq/day

Q_F=Flaring volume, m^3/day

Q_V=Venting volume, m^3/day

η_F=Flaring efficiency, %

i=Index of gas species CO_2, CH_4, C_2H_6, C_3H_8, and C_4H_{10}

x_i=Molar fraction of gas component i

ρ_i= Density of gas component i, g/m^3

Π_i=Stoichiometric relationship between component i and product CO_2 for complete combustion

GWP_i=Global warming potential (GWP) of gas component i

A.3. Basic equations used for pipeline model development for transportation

Diameter of pipe:

$$D = \sqrt{\frac{4Q}{v\Pi}} \tag{A.7}$$

Relative roughness of pipe:

$$Relative\ roughness = \frac{\varepsilon}{D} \tag{A.8}$$

Power required overcoming friction:

$$P = Q\rho g h_f \tag{A.9}$$

where

D=Diameter of pipe, m

P=Power required overcoming friction, W

ε=Absolute roughness, m

Q=Volumetric flow rate, m^3/s

v=Velocity of flow, m/s

ρ=Density of fluid, kg/m^3

g= Acceleration of gravity, m/s^2

h_f=Head loss due to friction, m

A.4. Equations used for allocating total refining emissions to the final products (gasoline, diesel, and jet fuel)

GHG emissions allocated to products based on refinery level allocation (mass-based):

$$E_{m,i} = E_{m,T} \frac{m_i}{\Sigma_{i=j,k,l} m_i} \quad \text{(A.10)}$$

GHG emissions allocated to products based on refinery level allocation (energy-based):

$$E_{m,i} = E_{m,T} \frac{E_i}{\Sigma_{i=j,k,l} E_i} \quad \text{(A.11)}$$

where

$E_{m,i}$=GHG emissions allocated to product i, g-CO_2eq/day

$E_{m,T}$=Total refining emissions, g-CO_2eq/day

m_i=Mass of product i produced, kg/day

E_i=Total energy of product i produced, MJ/day

j,k, and l are the gasoline, diesel, and jet fuel, respectively

Energy allocated to product streams based on sub-process level allocation:

$$E_{p,i} = (E_1 + E_2 + \cdots + E_{pe})\left(\frac{m_{p,i}}{m_{p,i} + m_{p,j} + m_{p,k} + \cdots + m_{p,n}}\right) \quad \text{(A.12)}$$

where

$E_{p,i}$=The cumulative energy used for product stream i, coming out of any process, MJ/day

E_1 and E_2=Energy carried in by the input streams to any process represents the cumulative process energy expended from the very first process (e.g., atmospheric distillation) to the current process, MJ/day

E_{pe}=Current process energy which is consumed in the process, MJ/day

m_p=Mass of product streams

i, j, k,…n are the products coming out of the process

Appendix B

B.1. Emission factors (EFs) used for calculating greenhouse gas (GHG) emissions

Table B.1. Emission factors used in this study

Fuel	Equipment	Upstream emissions ($g\text{-}CO_2eq/MJ$)	Combustion emissions ($g\text{-}CO_2eq/MJ$)	Source
Diesel	Stationary reciprocating engine	18.84	74.02	[61]
Diesel	Heavy duty truck	18.84	74.64	[61]
Diesel	Locomotive	18.84	74.25	[61]
Residual oil	Ocean tanker	12.11	80.80	[61]
Produced gas	Gas turbine	0	67.40	[16]
Natural gas	Industrial boiler	18.21	56.60	[61]
Natural gas	Gas turbine	18.21	56.79	[61]

B.2. Global warming potential (GWP) factors used in this study for calculating greenhouse gas (GHG) emissions

Greenhouse gases do not have the same heat-trapping potential. Global warming potential (GWP) is a relative measure of how much heat a greenhouse gas (GHG) can trap over a specified time horizon. The reference gas is carbon dioxide (CO_2). In this study, GHG emissions were calculated for a 100-year time period. GHG emissions were calculated as CO_2 equivalents based on the GWP factors summarized in Table B.2. The GWP of methane (CH_4) is 25, which means that CH_4 will trap 25 times more heat in the atmosphere than CO_2 over the next 100 years if the mass of CH_4 and CO_2 are considered the same.

Table B.2: Global warming potential factors used in this study

Greenhouse gas	GWP factors for a 100-year time horizon
Carbon dioxide (CO_2)	1
Methane (CH_4)	25
Nitrous oxide (N_2O)	298