# Well-to-wheel life cycle assessment of transportation fuels derived from different North American conventional crudes

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## ABSTRACT

A life cycle assessment (LCA) is an extremely useful tool to assess the greenhouse gas (GHG) emissions associated with all the stages of a crude oil's life from well-to-wheel (WTW). All of the WTW lifecycle stages of crude oil consume energy and produce significant amounts of GHG emissions. The present study attempts to quantify the WTW life cycle GHG emissions for transportation fuels derived from five North American conventional crudes through the development of an LCA 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). This model estimates GHG emissions from all the life cycle stages from recovery of crude to the combustion of transportation fuels in vehicle engines. The contribution of recovery emissions in

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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 refined fuel contributes only 0.44-1.73% of the total WTW life cycle GHG emissions, depending on the transportation methods and total distance transported. The GHG emissions for refining were calculated from the amount of energy use in the refining of crude oil to produce transportation fuels. All the upstream GHG emissions were allocated to gasoline, diesel, and jet fuel. Refining GHG emissions vary from 13.66-18.70 g-$CO_2$eq/MJ-gasoline, 9.71-15.33 g-$CO_2$eq/MJ-diesel, and 6.38-9.92 g-$CO_2$eq/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 g-$CO_2$eq/MJ-gasoline derived from Mars crude to 127.74 g-$CO_2$eq/MJ-gasoline derived from California's Kern County heavy oil.

***Keywords***: Life cycle assessment (LCA); greenhouse gas (GHG) emissions; crude transportation; conventional crude; transportation fuels

## 1. Introduction

California's Low Carbon Fuel Standard [1] and the European Union's Fuel Quality Directive [2] require a reduction of carbon intensity in transportation fuels. These regulations have led to increased attention in quantifying the total life cycle greenhouse gas (GHG) emissions for different conventional crudes. In 2012 in the U.S., the petroleum and natural gas systems sector and the petroleum refinery sector were the second and third highest GHG emitting sectors respectively after the power plant sector [3]. During the same year, the share of conventional crude oil in the total oil production was about 70% [4], which made conventional crude oil the

major contributor of GHGs in the petroleum and refining sectors compared to unconventional fossil fuel resources. GHGs are emitted in all life cycle stages of crude oil from recovery to the combustion of transportation fuels in engines. Each crude has different properties, extraction methods, and GHG emissions. It is important to perform a complete life cycle assessment of conventional crude oils from a variety of sources to help in policy making towards sustainability and fulfilling environmental regulations.

There have been a few LCAs analyzing conventional crude oils [5-8]. The Jacobs [5] and TIAX [6] studies did a thorough assessment of different North American and imported crudes. These studies reported WTW life cycle GHG emissions for gasoline and diesel derived from specific crude oils. Some crudes were analyzed by both the Jacobs [5] and TIAX [6] studies, but there were variations in the total WTW GHG emissions due to different assumptions, system boundaries, methodologies, and data sources. The TIAX [6] study did not consider GHG emissions from the processing of crude oil, associated gas and water, and oil field fugitives. Refining emissions contribute largely to the WTW GHG emissions, and the Jacobs and TIAX studies have different methodologies to calculate them. None of these studies considered GHG emissions from oil well drilling and associated land-use change. The National Energy Technology Laboratory (NETL) studies [7, 8] analyzed 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. This study is aimed at addressing the gaps in the literature.

There are two prominent North American LCA models to quantify WTW 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 [9] and (ii) GHGenius, the model developed by$(S\&T)^2$ Consultants[10]. 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[11], calculates GHG emissions from extraction, processing, and transportation of crude. OPGEE does not calculate total life cycle GHG emissions [11]. All these models are built with their own assumptions, methods, data sources, and system boundaries. To calculate the life cycle GHG emissions for an individual crude oil, one must change the input parameters because these models use default values that might not be appropriate for all crudes.

Garg et al. [12] 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. [13] 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-$CO_2$eq/MJ) for conventional gasoline and conventional diesel. Furuholt [14] performed an LCA of gasoline and diesel. 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 academic LCA studies that evaluate GHG emissions from oil sands products that are different from conventional crudes by their properties. Tarnoczi [15] developed an LCA model to calculate energy use and resulting GHG emissions from the transportation of Canadian oil sands products to different 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. The combustion of diesel is the main reason for variation in GHG emissions from rail transportation, as mentioned by the author. Thirteen LCA studies were reviewed by Charpentier et al. [16] 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. [17] 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. [18]. The authors found overlaps between the well-to-wheel GHG emissions for conventional crude oil and oil sands products. Abella et al. [19] developed a model, PRELIM, to calculate energy consumption and resulting GHG emissions from the refining of crude slates. The authors investigated the effect of refinery configuration and crude quality on GHG emissions but did not conduct the whole LCA of different crudes. PRELIM does not calculate total GHG emissions from well-to-wheel. Brandt [20] 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 methodologies, data quality, and LCA boundaries were found to be the reasons for variations in the results obtained by different LCA studies. Recent studies by Nimana et al. [21, 22] quantified GHG emissions in the recovery, and upgrading and refining of Canada's oil sands products but did not consider conventional crudes. In another article [23], the authors developed a model to estimate life cycle WTW GHG emissions from oil sands products but the model does not quantify GHG emissions from conventional crudes. Earlier studies [16-28] mainly worked on different oil sands products

such as synthetic crude oil (SCO), dilbit, and bitumen, which differ from conventional crude oils in their properties and extraction methods. For the sake of comparison of GHG emissions for conventional crude oil and oil sands products (SCO, bitumen), it is necessary to conduct a comprehensive and independent LCA study on conventional crude oils.

There are a limited number of studies [5-8] that conduct LCAs of conventional crude oils from various sources around the globe. Most of the models developed earlier looks at a particular unit operation of the whole life cycle and hence there is a need to look at the whole chain. Some of the studies done earlier integrated different models to get the whole life cycle emissions but there is very limited work on a single dedicated model for a particular crude is missing. This paper develops a data-intensive bottom-up engineering 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) based on fundamental scientific principlest o quantify the GHG emissions of the lifecycle stages of different conventional crudes, in order to fill in the gaps in current 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, the refining of crude, the transportation and distribution of finished fuels to the refueling stations, and the combustion of transportation fuels in vehicle engines. Previously, Rahman et al. [29] quantified the GHG emissions from the recovery of the same crudes considered in this study. The authors included GHG emissions from oil well drilling and associated land-use change, extraction, processing of crude, and venting, flaring, and fugitives in the total recovery emissions. The percentage contribution of recovery emissions is small in the total WTW life cycle GHG emissions. To capture the entire picture, which will help

in decision making towards sustainability, it is important to calculate the total life cycle GHG emissions for transportation fuels derived from different conventional crudes.

## 2. Method

### 2.1. Goal and Scope

The purpose of this study was to quantify the total WTW life cycle GHG emissions for transportation fuels converted from conventional crudes through the development of the FUNNEL-GHG-CCO model. Global warming potential (GWP) was used as the impact category for conducting the LCA. In this study, the functional unit considered was 1 MJ of 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.

### 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 1. 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 1**

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 subunit 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 [30]. 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. Recovery methods used to extract the crudes analyzed in this study are summarized in Table 1.

**Table 1**

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 [29].

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 [29].

Rahman et al. [29] quantified GHG emissions during recovery of the five North American conventional crudes analyzed in this study. The authors included all the subunit 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 Rahman et al. [29] and used in this study in quantifying the total lifecycle GHG emissions for transportation fuels.

## 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 [31] was built to determine the amount of energy required in each process unit in the refinery to produce gasoline, diesel, and jet fuel. Nimana et al. [22] developed a refinery model with the same parameters and conditions used in Aspen HYSYS's refinery-wide sample model to quantify energy consumption in refining Canada's oil sands products in different U.S. markets. Jacobs consultancy [5] developed a model using Petro Plan software to calculate energy consumption in refining all the crudes studied by them. Refining is one of the most GHG-emitting stages in the life cycle of a crude oil. To conduct an LCA of a crude oil, it is important to calculate how much GHGs are emitted to refine the crude for producing transportation fuels. No data were found on the energy consumed to refine the crudes analyzed in this study. Due to the lack of available data for the parameters and conditions used in different processing units in the refinery, a refinery model was developed using the same parameters and conditions used in Aspen HYSYS's refinery-wide sample model [31]. The diagram of the refinery model can be found in Figure S1 of the supporting information (SI) document. This model can handle both light and heavy crudes. Aspen HYSYS quantifies the energy consumption in each unit operation and the quantity of the final products produced in the refinery which were then used as inputs to the spreadsheet-based model, FUNNEL-GHG-CCO, which traces the energy consumption and resulting GHG emissions from the first unit operation (atmospheric distillation) to the final products to quantify GHG emissions associated with each final product. As FUNNEL-GHG-CCO cannot handle crude quality, the HYSYS model was run individually for five crudes of different quality to get the energy consumption for each crude.

The model was validated against published data for energy consumption in each piece of equipment in the refinery. The results of energy consumption to refine each crude were compared with the values reported in the earlier studies [5, 6, 19]. The model results are in very

good agreement with those values reported in literature. The results obtained in this study were also shared with industry experts.

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 [5, 6].

The refinery 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 [31]. 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 can be found in Tables S1-S5 of the supporting information document. 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% [11] and 75% [32], 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 554.64g-$CO_2$eq/kWh, respectively [33]. All of the energy use and resulting GHG emissions were allocated to gasoline, diesel, and jet fuel.

## 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 2 shows the transportation modes and distances from the field to the refinery.

**Table 2**

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) [35] and 1.16 m/s [36], 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 1 [37] 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.

Equation 1: $h_f=fLv^2/2gD$

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% [11]. 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 [38].

In addition to pipeline transportation, Alaska North Slope and Maya crude involve transportation by ocean tanker. Shipping distances were estimated using Port World's shipping route distance calculator [34]. A 100,000 DWT (deadweight tonnage) ocean tanker with a velocity of 31 km/h [38] was considered for crude transportation. The power required to propel the ocean tanker was calculated using Equation 2 [9] where power, P, is in kW and payload, $f_t$, is in kg.

Equation 2: $P=6766.22+8.305*10^{-5}*f_t$

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% [38] 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 [39]. For the crudes that are refined in PADD 2 and PADD 3, GREET 1 [39] 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 [39] 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 3.

**Table 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 [38]. Fuel economy and emission factors are summarized in Table 4. Emissions of $CH_4$ and $N_2O$ were converted to $CO_2$ equivalents using global warming potential factors for a lifetime of 100years.

**Table 4**

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 [40-43] 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. [44] quantified fugitive methane ($CH_4$) emissions from crude oil production activities using the fugitive emission factors developed in another article by the same authors [45]. 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. [44] were used in this study. Fugitive methane emissions were converted to g-$CO_2$eq/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$m^3$[46]. Using the global warming potential of $CH_4$ for a 100-year time horizon and lower heating value (LHV) of crude oils, fugitive methane emissions were converted to g-$CO_2$eq/MJ-crude.

## 3. Results and Discussion

### 3.1. Refining

Refining of crude oil produces fuel oil, sulfur, coke, etc. along with gasoline, diesel, and jet fuel. Figure 2 shows the yields of these products per barrel (bbl) 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 0.46-0.51bbl/bbl-crude and 0.07-0.13 bbl/bbl-crude, respectively, from these sources. Diesel production varies from 0.19bbl/bbl-crude for Alaska North Slope to 0.28bbl/bbl-crude for California's Kern County heavy oil. Heavier crudes produce more fuel oil than lighter crudes. California's Kern County heavy oil produces 57% more fuel oil per bbl-crude than Alaska North Slope. Production of LPG varies from 0.012-0.015bbl/bbl-crude.

Figure 2 provides a comparison of the product yields obtained in this study with those reported in literature [5]. For Alaska North Slope and Bow River heavy oil, no numbers were found for comparison. The yields from Alaska North Slope were compared with the yields from Arab Medium crude as their API gravities are similar. Bow River heavy oil was compared with Maya crude. Existing studies did not report any numbers for jet fuel. Jacobs [5] reports yields of 10-12% more for gasoline compared to this study. There is a good agreement in total product yield between this study and Jacobs' report.

**Figure 2**

A large amount of energy is required to produce gasoline, diesel, and jet fuel from a raw crude. 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 5.

**Table 5**

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 5).

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 (see Table 6). The numbers obtained for hydrogen consumption are in good agreement with the numbers reported by Jacobs Consultancy [5]. Hydrogen is produced from natural gas through steam methane reforming(SMR), which is an energy-intensive process. Refining energy use in the SMR process varies from 5-8% of the total energy consumption in refining. (According to Nimana et al. [22], of the total energy consumption in refining, 5-7% is used to produce hydrogen.) Some natural gas comes from the saturated gas plant (SGP) that produces methane from the gases coming from hydrotreaters and the reformer in the refinery. The rest of the natural gas is purchased from outside. The amount of natural gas that must be purchased is low, given that a portion of the total feed to the SMR comes from the SGP, and hence the process is less energy intensive than it might be.

**Table 6**

Natural gas is the main source of energy supply in the refinery. About 94-96% of the total energy comes from the combustion of natural gas. 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.

To demonstrate the model's validity, the results obtained in this study were compared with those reported in literature [5, 6, 19] (see Figure 3). Jacobs' study reports 3-10% less energy consumption in crude refining. The energy consumption to refine Mars crude is in very good

agreement with the value reported by Jacobs' study [5]. PRELIM [19] reports 50 MJ/bbl-crude more energy consumption for Bow River heavy oil. Heavier crudes can be blended with the lighter ones to reduce the GHG emissions per bbl compared to the case if the heavier crude is refined separately. As the aim of this study was to compare the environmental footprints of different North American conventional crudes, each crude was studied separately to quantify GHG emissions in all the life cycle stages.

**Figure 3**

Table5 represents GHG emissions on a per day basis. The emissions are to be allocated between 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 share of refined products [47]. This study used two methods to allocate energy use and GHG emissions: the refinery level allocation and the sub-process level allocation. ISO 14041 [48] 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 7 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 7**

Figures 4 and 5 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-$CO_2$eq/MJ-refined fuel (see Figure 4). 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 4.

**Figure 4**

Figure5 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 7.

GHG emissions for gasoline production range from 13.66 g-$CO_2$eq/MJ-gasoline derived from Alaska North Slope to 18.70 g-$CO_2$eq/MJ-gasoline derived from California's Kern County heavy oil. GHG emissions for diesel range from 9.71 g-$CO_2$eq/MJ-diesel derived from Alaska North Slope to 15.33 g-$CO_2$eq/MJ-diesel derived from California's Kern County heavy oil. Emissions from jet fuel production are the lowest and range from 6.38 g-$CO_2$eq/MJ-jet fuel derived from Alaska North Slope to 9.92g-$CO_2$eq/MJ-jet fuel derived from California's Kern County heavy oil.

**Figure 5**

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 2).

Transportation GHG emissions for the five conventional crudes analyzed in this study are shown in Figure 6. 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-$CO_2$eq/MJ-crude. On the other hand, transportation emissions from California's Kern County heavy oil are the lowest at 0.10 g-$CO_2$eq/MJ-crude. Mars crude transportation produces GHG emissions of 0.18 g-$CO_2$eq/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-$CO_2$eq/MJ-crude and 0.16 g-$CO_2$eq/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 6**

Transportation and distribution of finished fuels (gasoline, diesel, and jet fuel) involve different modes of transportation, such as ocean tanker, barge, pipeline, rail, and truck. GHG emissions

calculations are based on the distances travelled to carry the fuels to local refueling stations (see Table 3 for the distances assumed). Figure 7 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 ocean tanker and 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-$CO_2$eq/MJ and 0.443 g-CO2eq/MJ. The transportation of gasoline and diesel emits 0.53 g-CO2eq /MJ and 0.46 g-$CO_2$eq/MJ, respectively, in the case of Mars, Maya, and Bow River heavy oil (see Table 3 for transportation modes and distances). GHG emissions from jet fuel transportation were calculated to be 0.45 g-$CO_2$eq/MJ for all the crudes studied.

**Figure 7**

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 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-$CO_2$eq/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 8. 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 8-10).

**Table 8**

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. [44]. 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.

## 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. From the well to the refinery gate there are two stages, crude recovery and crude transportation. The GHG emissions from these stages were calculated on a per MJ-crude basis. But GHG emissions from refining, transportation, and distribution of finished fuels, and vehicle operation were calculated on a per MJ-finished fuel (gasoline, diesel, and jet fuel) basis. So the upstream emissions from crude recovery and crude transportation need to be allocated among gasoline, diesel, and jet fuel. Upstream GHG emissions were distributed based on the net thermal energy

content of each finished fuel. Recovery emissions reported by Rahman et al. [29]were per MJ-crude. Recovery emissions were allocated to finished fuels in order to get the emissions per MJ-finished fuel and are summarized in Table 9. Equations used to allocate the upstream GHG emissions can be found in detail in the supporting information (EquationsS1 and S2). 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 [48] in mind.

**Table 9**

Figures 8-10 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-$CO_2$eq/MJ-gasoline for Mars crude and 127.74 g-$CO_2$eq/MJ-gasoline for California's Kern County heavy oil. Alaska North Slope produces the second lowest emissions at 98.51 g-$CO_2$eq/MJ-gasoline. GHG emissions for Maya and Bow River heavy oil are 100.49 g-$CO_2$eq/MJ-gasoline and 100.78 g-$CO_2$eq/MJ-gasoline, respectively. The wide range in Figures 8-10 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-$CO_2$eq/MJ-diesel and 126.02 g-$CO_2$eq/MJ-diesel, respectively. GHG emissions for Alaska North Slope, Maya, and Bow River heavy oil are 96.19

g-$CO_2$eq/MJ-diesel, 98.10 g-$CO_2$eq/MJ-diesel, and 98.22 g-$CO_2$eq/MJ-diesel, respectively. For jet fuel, GHG emissions range from 88.17 g-$CO_2$eq/MJ-jet fuel for Mars crude to 118.17 g-$CO_2$eq/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-$CO_2$eq/MJ-jet fuel and 2.30-2.34 g-$CO_2$eq/MJ-jet fuel, respectively when high and low values for fugitive emissions are used.

**Figure 8**

**Figure 9**

**Figure 10**

The highest percentages of emissions come from the combustion of transportation fuels in engines (see Figures 8-10). 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 11**

Figure 11 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.

**Figure 12**

A comparison of results obtained in this study with earlier studies [5, 6, 49] was carried out to see the variation of results. Figure 12 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. [29] that include drilling of oil well and associated and land-use emissions, emissions from crude extraction, crude processing, and flaring (complete combustion). The TIAX [6] study did not consider emissions from drilling and land-use change, crude oil processing, and fugitive emissions. Jacobs' study [5] did not consider 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 [6] is about 13 g-$CO_2$eq/MJ-gasoline and 28 g-$CO_2$eq/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. [29] and TIAX [6] is about 5 g-$CO_2$eq/MJ-crude. The difference in recovery emissions for California's Kern County heavy oil reported by Rahman et al. [29] and TIAX [6] is about 12 g-$CO_2$eq/MJ-crude, and Rahman et al. [29] and the Jacobs' [5] study is about 4 g-$CO_2$eq/MJ-crude. Brandt et al. [49] reports 5 g-$CO_2$eq/MJ-crude more emissions than Rahman et al. [29]. For all cases, the TIAX [6] study assumes lower energy consumption and resulting GHG emissions. GHG emissions reported by this study, Jacobs' [5]study, and the study by Brandt et al. [49] for gasoline derived from California's Kern County heavy oil showed less variation than the TIAX study's result [6]. Little variations were seen for the other crudes, too, which are in the range of 7-10 g-$CO_2$eq/MJ-gasoline in this study and the TIAX study [6] and 2-6 g-$CO_2$eq/MJ-gasoline in this study and the study by Jacobs' Consultancy [5].

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. Six 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%. The distance between the refinery and the refueling station was varied by ±20%. Figure 13shows 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-$CO_2$eq/kWh and 571.37 g-$CO_2$eq/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. Base case values for gasoline transportation via pipeline and rail were taken as 241 km and 402 km, respectively (see Table 3). 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-$CO_2$eq/MJ-gasoline lower emissions when the efficiency is increased by 10%. Only 0.05 g-$CO_2$eq/MJ-

gasoline more GHGs are emitted if the transportation distance of gasoline is increased by 20%. The effect of changing the distance from the refinery to the refueling station is insignificant because the transportation of finished fuelscontributesonly0.35-0.54% to the total WTW GHG emissions. As shown in Table 3, gasoline obtained from Alaska North Slope is transported by pipeline (95%) and rail (5%) to the refueling station. If gasoline is transported by rail only, total GHG emissions will decrease by 0.12 g-$CO_2$eq/MJ-gasoline.

**Figure 13**

## 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-$CO_2$eq/MJ-gasoline to 127.74 g-$CO_2$eq/MJ-gasoline, 95.01 g-$CO_2$eq/MJ-diesel to 126.02 g-$CO_2$eq/MJ-diesel, and 88.17 g-$CO_2$eq/MJ-jet fuel to 118.17 g-$CO_2$eq/MJ-jet fuel for Mars crude and California's Kern County heavy oil, respectively. As grid intensity depends on the regional fuel mix that might change from time to time, a sensitivity analysis was conducted to see the impact of grid intensity on the total WTW life cycle GHG emissions. This study could play a vital role in meeting environmental regulations and for policy-making purposes. 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 from different conventional crude oils and oil sands products. 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.

**Acknowledgments**

We thank NSERC/Cenovus/Alberta Innovates Associate Industrial Research Chair in Energy and Environmental Systems Engineering, and Cenovus Energy Endowed Chair in Environmental Engineering for providing financial support for this project. We also thank representatives from Alberta Innovates – Energy and Environment Solutions (AI-EES), Alberta Innovates – Bio Solutions (AI-BIO), Cenovus Energy and Suncor Energy for their inputs in various forms. The authors thank Astrid Blodgett for editorial assistance.

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**Table 1: Recovery methods used to extract five North American conventional crudes. Adapted from [29]**

| Crude Name | Recovery Method |
|---|---|
| Alaska North Slope | Water-alternating-gas |
| California's Kern County heavy oil | Steam injection |
| Mars | Water flooding |
| Maya | Nitrogen injection assisted by gas lift |
| Bow River heavy oil | Water flooding |

**Table 2: 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 Port World's shipping route distance calculator [34].

[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 Port World's shipping route distance calculator [34].

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

**Table 3: 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 4: Fuel economy and emission factors used to calculate 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 |

**Table 5: 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-$CO_2$eq/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 |

**Table 6: Hydrogen ($H_2$) requirements and percentage of total refining energy to produce $H_2$ in the steam methane reforming (SMR) unit**

| Crude Name | $H_2$ Requirement (kg-$H_2$/bbl) | Portion of Total Refining Energy Use in SMR Process (%) |
|---|---|---|
| Alaska North Slope | 1.66 | 4.89 |
| California's Kern County heavy oil | 2.63 | 8.33 |
| Mars | 1.84 | 5.94 |
| Maya | 2.15 | 5.88 |
| Bow River heavy oil | 1.91 | 6.35 |

**Table 7: 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 |

**Table 8: 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 |

**Table 9: Recovery emissions [29] 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 ($g\text{-}CO_2eq/MJ$) |
|---|---|---|---|
| Alaska North Slope | 6.06 | 6.06 | 6.06 |
| California's Kern County heavy oil | 30.98 | 30.98 | 30.78 |
| 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).

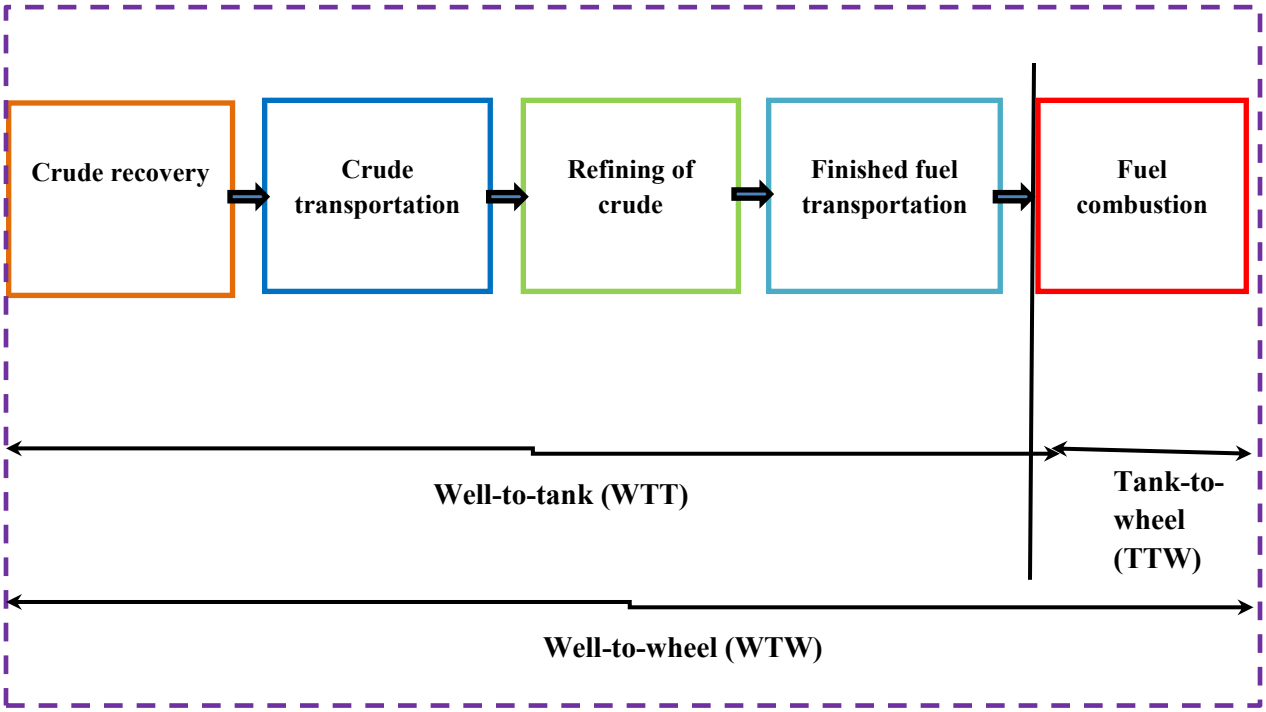
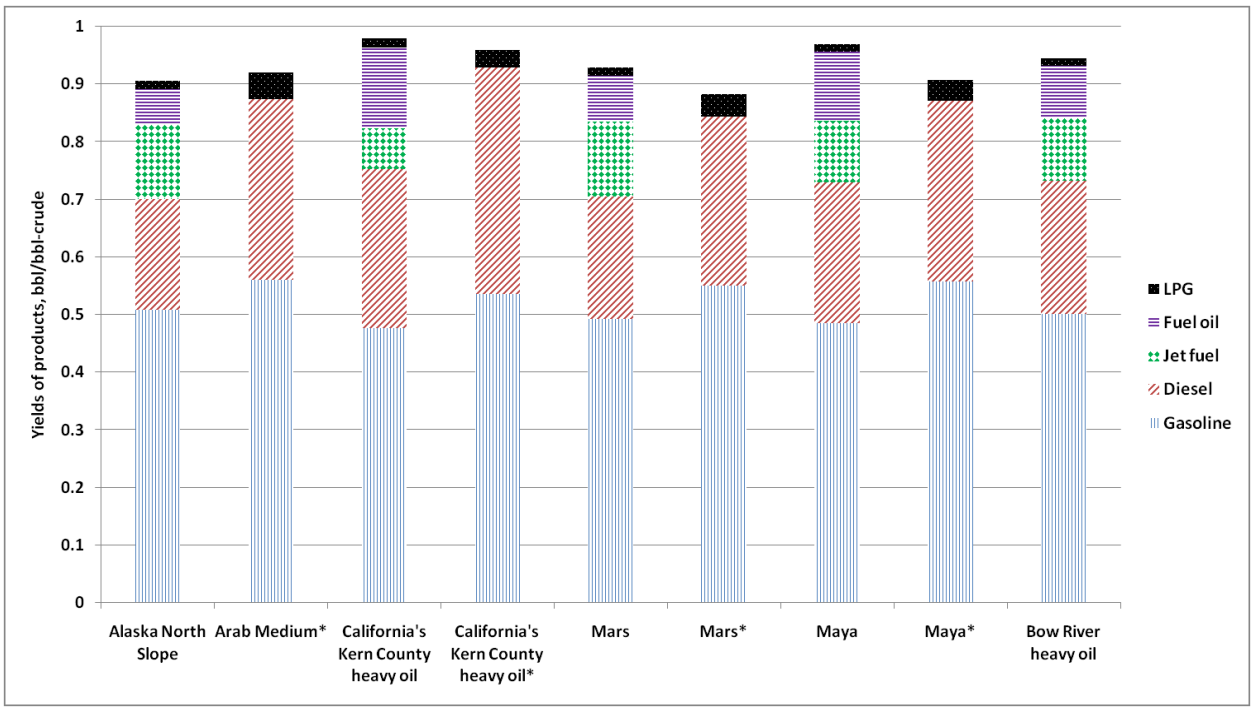



**Figure 1: Life cycle assessment (LCA) boundary**




*The crudes for which the numbers were taken from literature [5].

**Figure 2: Yields of products from the refining of crudes**

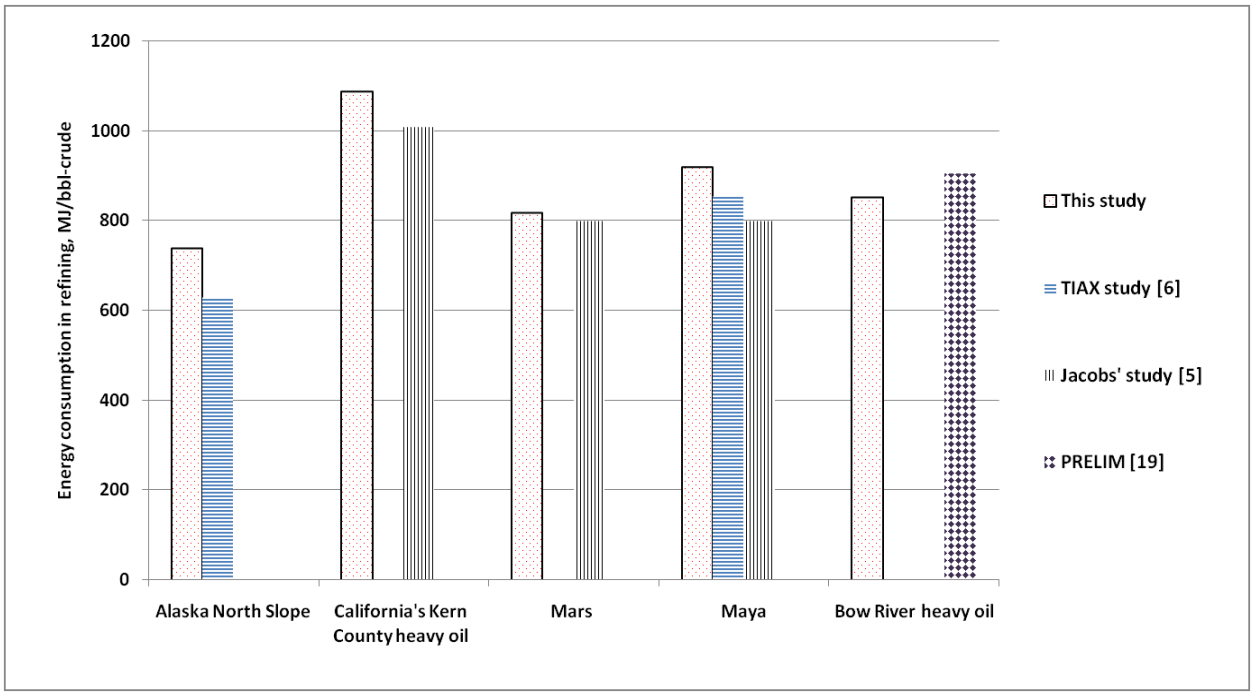



**Figure 3: Comparison of this study's energy consumption results with existing data**

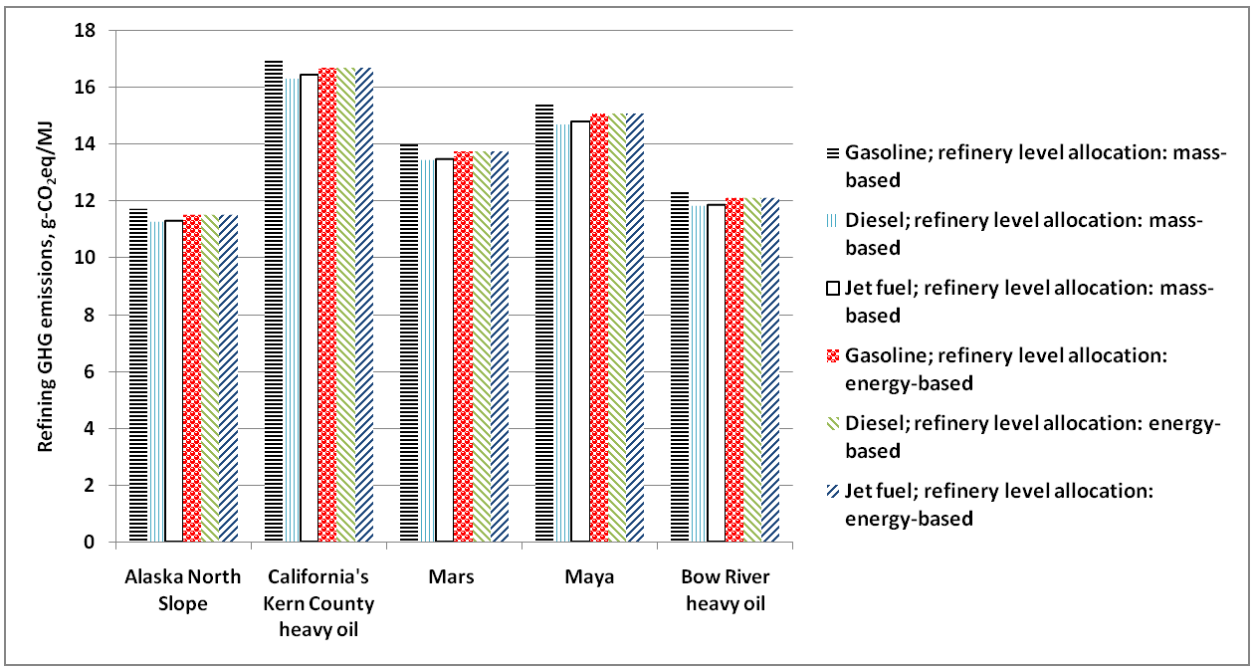



**Figure 4: GHG emissions for transportation fuels based on refinery level allocation**

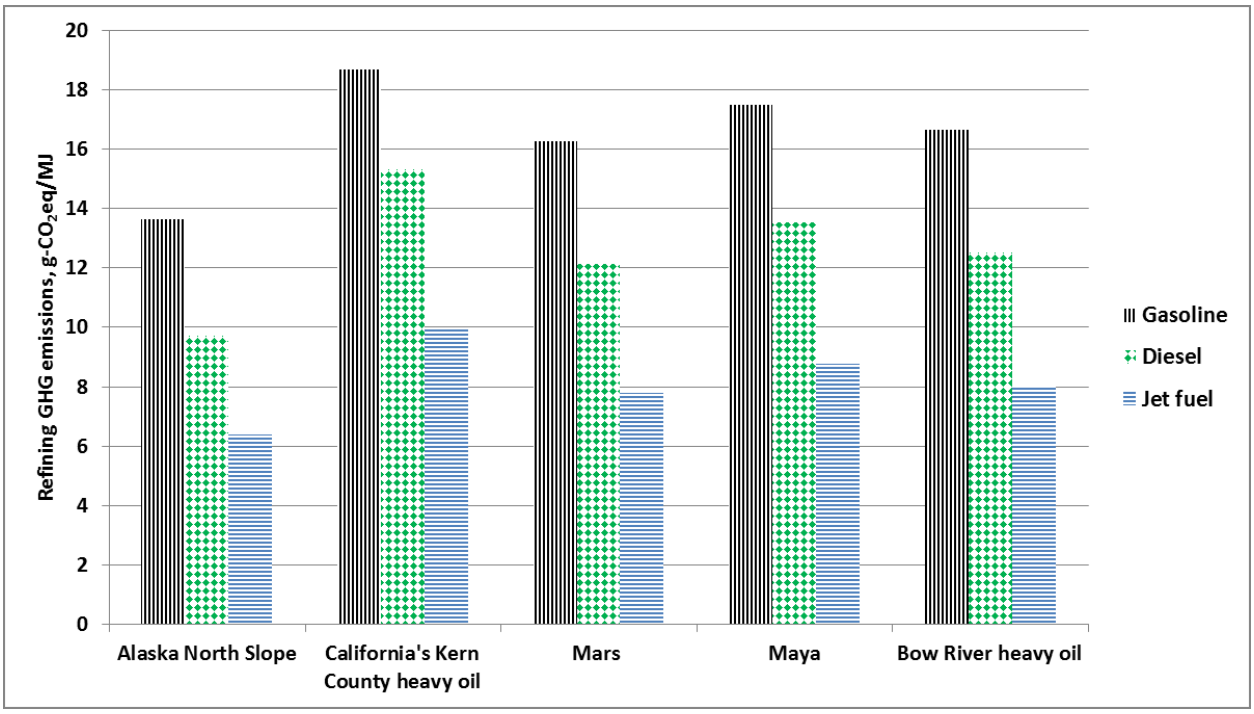



**Figure 5: GHG emissions for transportation fuels based on sub-process level allocation: mass-based**

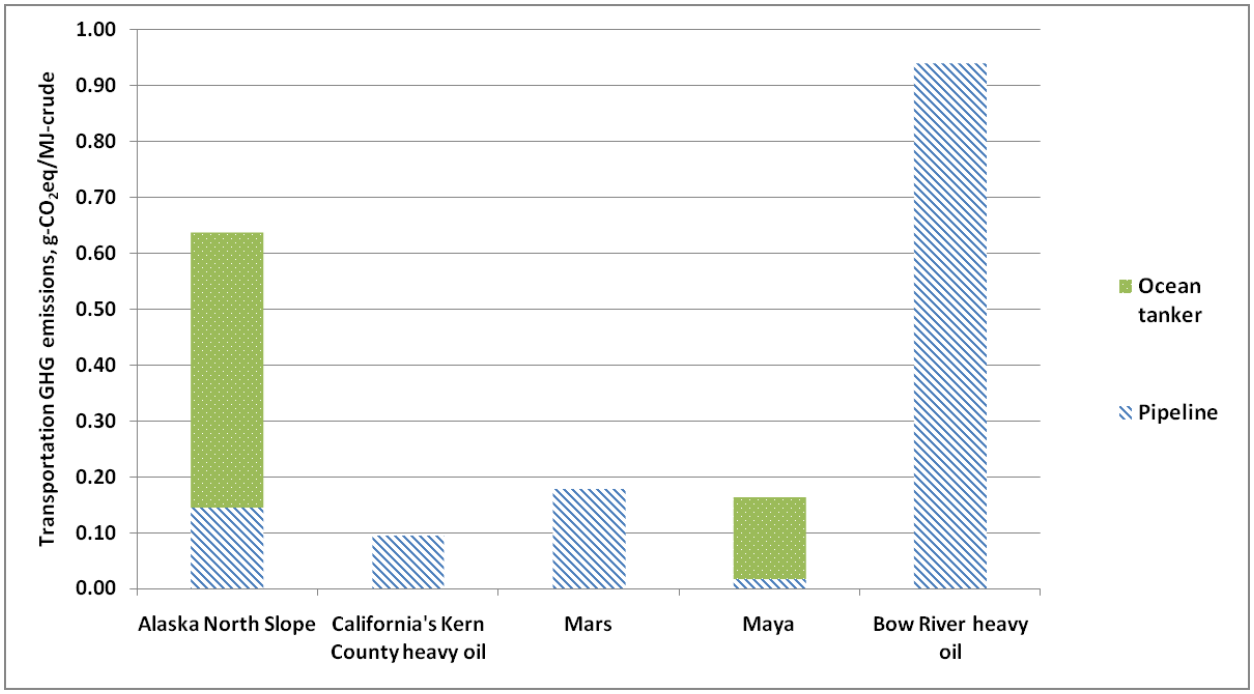



**Figure 6: GHG emissions from pipeline and ocean tanker transportation**

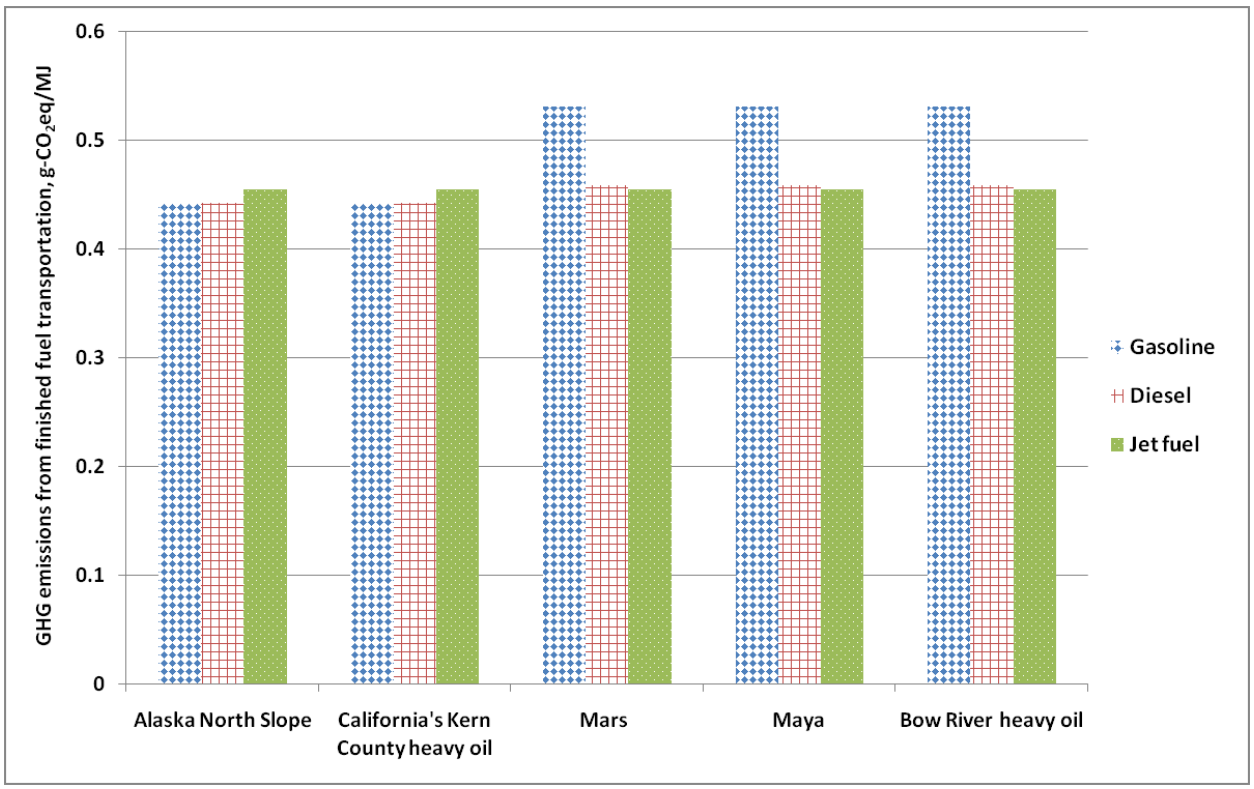



**Figure 7: GHG emissions from the transportation of finished fuels**

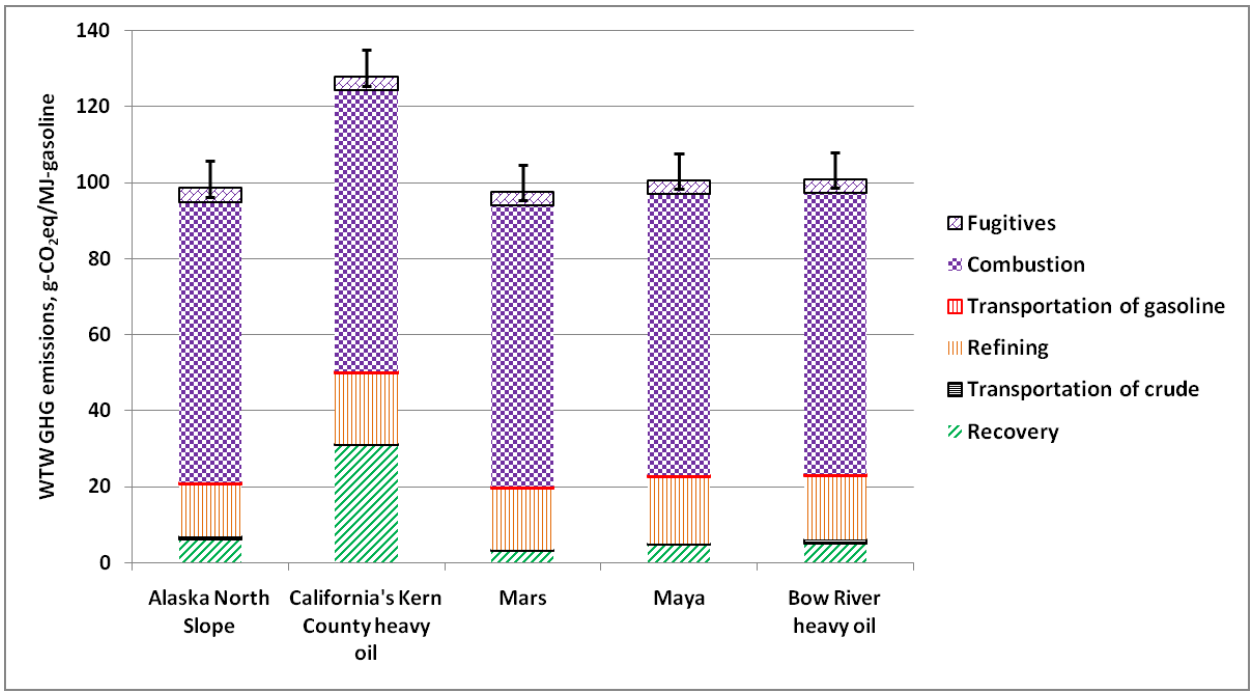



**Figure 8: Life cycle WTW GHG emissions for gasoline**

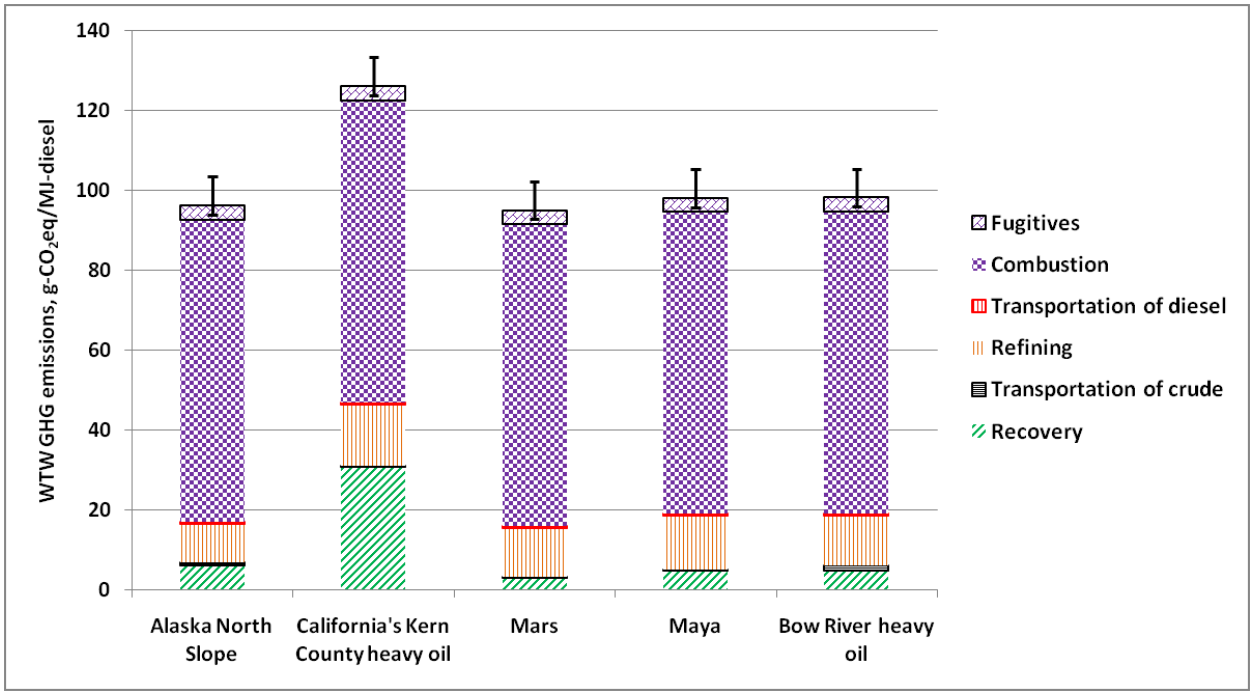



**Figure 9: Life cycle WTW GHG emissions for diesel**

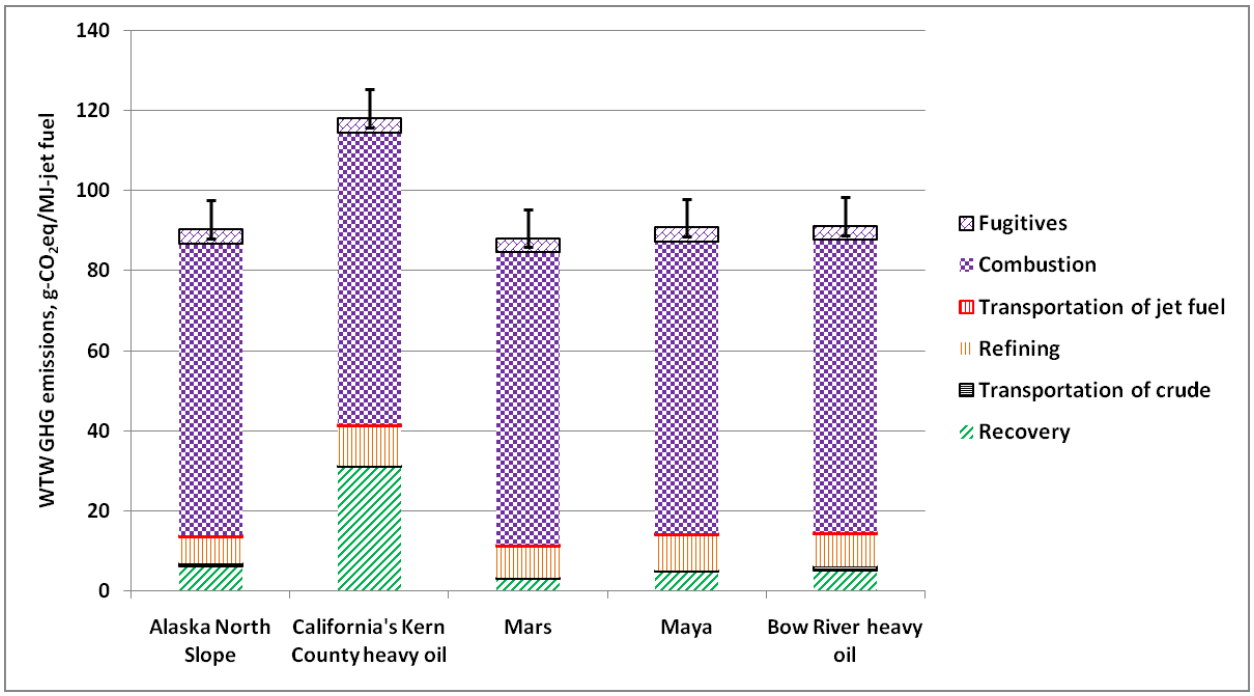



**Figure 10: Life cycle WTW GHG emissions for jet fuel**

Note: The range of values of life cycle GHG emissions for gasoline, diesel, and jet fuel (Figures 8-10) are based on low and high values for fugitive emissions. The base case represents medium fugitive emissions.

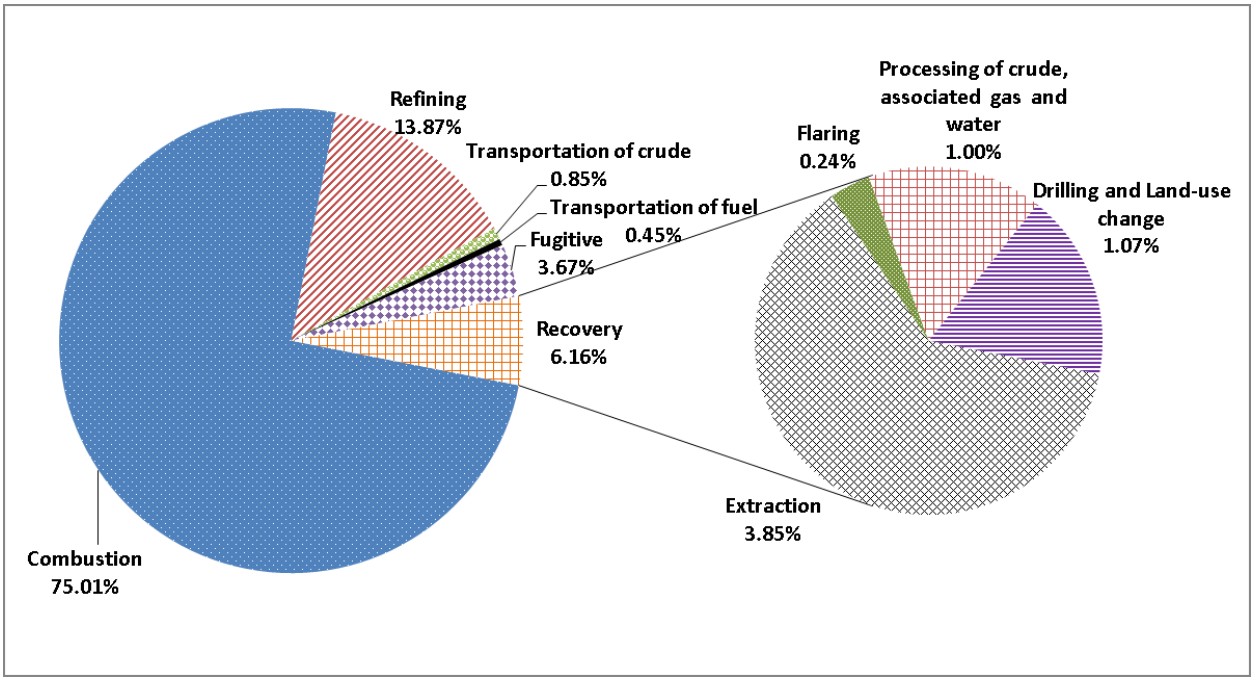



**Figure 11: Percentage contribution of GHG emissions for gasoline obtained from Alaska North Slope**

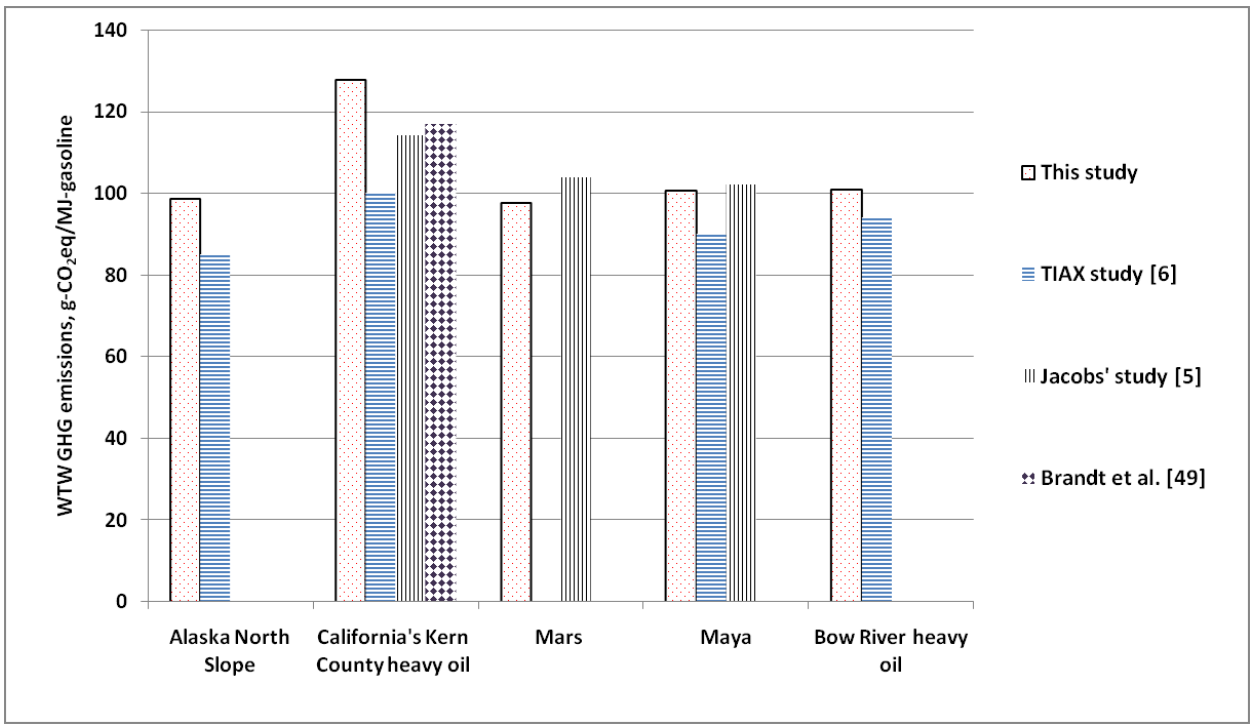



**Figure 12: Comparison of WTW GHG emissions for gasoline with existing literature**

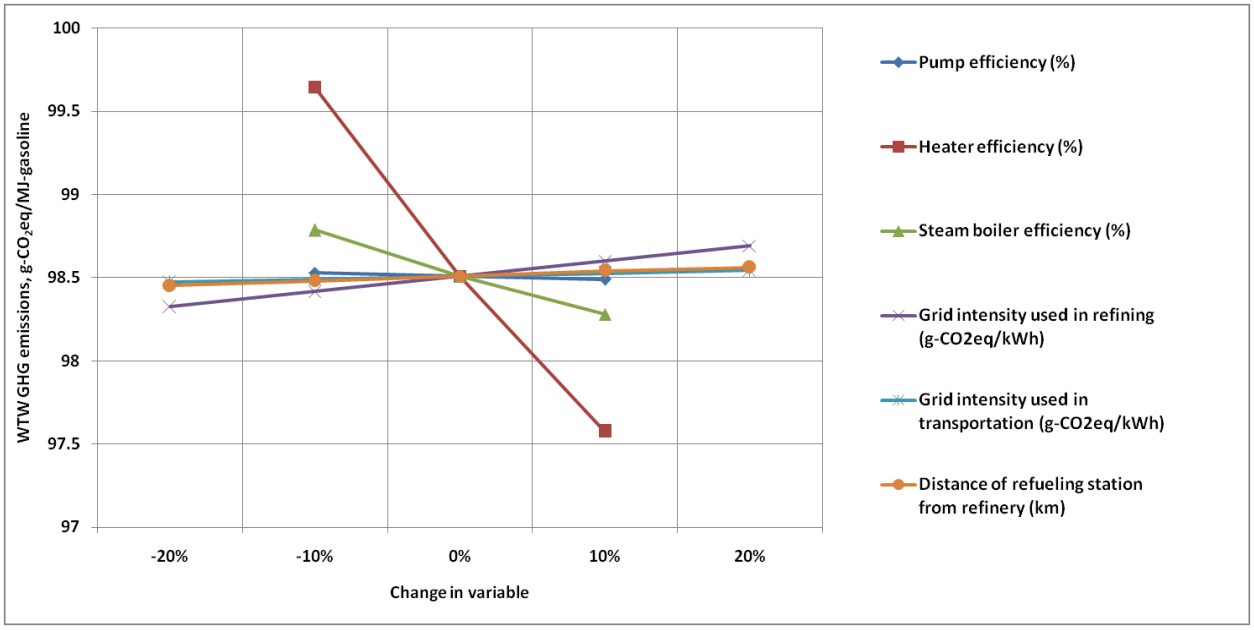



**Figure 13: Sensitivity analysis of total WTW GHG emissions for gasoline derived from Alaska North Slope**