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Life cycle assessment of greenhouse gas emissions from Canada's oil sands-derived transportation fuels

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ABSTRACT

A comprehensive LCA (life cycle assessment) for transportation fuels (gasoline, diesel, and jet fuel) derived from Canada's oil sands was conducted, and all the current possible pathways from bitumen extraction to use in vehicles were explored. Authors, in earlier studies, have presented the energy consumption and GHG (greenhouse gas) emission results for individual unit operations-recovery, extraction, upgrading and refining. The LC (life cycle) inventory data for the current LCA study were obtained from theoretical model named FUNNEL-GHG-OS (**FUN**damental E**N**gineering Princip**l**E**s**- based Mode**L** for Estimation of **G**reen**H**ouse **G**ases in the **O**il **S**ands), developed from fundamental engineering principles. The impact of the cogeneration of electricity in oil sands recovery, extraction, and upgrading on the LC GHG emissions of gasoline was explored. LC WTW (well-to-wheel) GHG emissions range from 106.8 to 116 g-CO_2equivalent/MJ of gasoline, 100.5 to 115.2 g-CO_2equivalent/MJ of diesel, and 96.4 to 109.2 g-CO_2equivalent/MJ of jet fuel, depending on the pathway. Combustion emissions (64.7%–70.3%) are the largest constituent of WTW emissions for gasoline production; recovery (through surface mining and steam assisted gravity drainage) forms 7.2%–16% depending on the LC production process of gasoline.

1. Introduction

With the technologies available today, bitumen from the oil sands can be produced via surface mining and in situ recovery. CSS (Cyclic steam stimulation) and SAGD (steam assisted gravity drainage) are most widely used in situ recovery methods in which steam is used as stimulant to reduce viscosity of bitumen and pump it to the surface [1]. About 20% of Alberta's oil sands are recoverable by surface mining; the remaining 80% are too deep for mining and require in situ extraction techniques [2]. In 2012, total in situ production accounted for 52% of the total crude bitumen production and surface mining for the rest [3]. In situ bitumen production has been increasing at a higher rate than has mined bitumen. In 2012, all crude bitumen from mining and a small portion (about 7%) of bitumen produced from in situ was upgraded[1] to SCO (synthetic crude oil), yielding 329 million barrels of upgraded bitumen [4]. Upgraded bitumen formed 52% of the total crude bitumen in 2012 [4].

There is cautioned growth in the oil sands industry due to rising interest in global carbon management. Of all the economic sectors, the transportation fuels sector has attracted the most interest recently. This is due to the fact that the transportation sector is the second largest source (after electricity) of GHG (greenhouse gas) emissions, accounting for 28% of total GHG emissions in the U.S and 26% of the total GHG emissions in Canada [5,6]. The high GHG intensity of the transportation sector has resulted in regulations such as the LCFS (Low Carbon Fuel Standard) and the European Fuel Quality Directive that demand a 10% reduction in life cycle GHG (greenhouse gas) emissions from transportation fuels by 2020 [7,8]. In 2007, the Alberta government passed the SGER (Specified Gas Emitters Regulations) to legislate GHG emissions reduction for large industrial facilities (those emitting over 100,000 tonnes of CO_2e per year) to reduce their carbon emissions by 12% from the 2003–2005 baseline [9]. These regulations use a life cycle assessment approach to calculate the carbon footprint of transportation fuels sold.

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[1] In the process of upgrading, bitumen is fractionated or chemically treated to yield a higher value product. This is achieved either through thermal cracking (coking) or hydrogen based cracking (hydroconversion) [1,19].

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A LCA (life cycle assessment) is a powerful tool that measures and regulates the environmental performance of different fuel systems that may be interrelated. An LCA helps in assessing direct and indirect environmental impacts of a fuel system. The strength of an LCA lies in the fact that it allows policy makers to assess the impacts of a fuel on all affected sectors rather than shifting the impact from one sector to other. The policies mentioned above use the LC (life cycle) approach to regulate the emissions from transportation fuels as this approach is helpful to reduce overall GHG emissions. An LCA may not become part of a particular jurisdiction's regulations if there is a comprehensive policy on GHG emissions across all regions and sectors of society [10], but because not all regions and sectors have these policies, the use of the LC approach to reduce overall GHG emissions is justified.

Significant contributions in the field of LCA of crude oils have been made by Keesom et al. [11] and Rosenfeld et al. [12]. These studies present LC emissions from conventional and non-conventional crudes imported to the U.S. [12] and used data from specific companies to perform the LCA. Though Keesom et al. [11] performed the LCA based on a developed theoretical process model, the authors provide very little information about data sources and inputs to the model. Neither sources [11,12] modeled all the possible bitumen LC pathways in the oil sands. The GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation)[2] model [13], maintained by the Argonne National Laboratory, and GHGenius[3] [14], maintained by Natural Resources Canada, have been widely discussed and used to construct oil sands pathways. Charpentier et al. [15] and Brandt [16] reviewed the results from these models along with other studies and found inconsistencies in the results reported due to variations in system boundaries, data quality, methods, and documentation. Whereas Charpentier et al. [15] called for additional research for better characterization of oil sands technologies and pathways, Brandt [16] recommended modeling emissions of process specific configurations. Bergerson et al. and Charpentier et al. [17,18] document the development of GHOST, a LCA model for oil sands-derived pathways. The database inventory for this model is based on confidential data from industry and mainly focuses on upstream emissions from the oil sands instead of an entire well-to-wheel LCA.

There is little research on estimating LC GHG emissions of transportation fuels from oil sands pathways. FUNNEL-GHG-OS[4] (**FUN**damental E**N**gineering Principl**E**s- based Mode**L** for Estimation of **G**reen**H**ouse **G**ases in the **O**il **S**ands), based on engineering first principles (i.e. using the basic equations of mass and energy balance), is developed to estimate the energy consumption and GHG emissions in surface mining, SAGD (steam assisted gravity drainage), and upgrading operations in the oil sands and is detailed in previous work [1,19]. The main objective of this paper is integration of the energy consumption and GHG emissions results for various oil sands operations, which were mathematically estimated by authors in earlier studies [1,19]. This paper presents the results of a comprehensive WTW (well-to-wheel) LCA of oil sands-derived transportation fuels – gasoline, diesel and jet fuel while exploring all the possible bitumen pathways from extraction to end use in vehicles. Further it adds to the knowledge base for conducting a comprehensive LCA of transportation fuels derived from Canada's oil sands.

The LC of transportation fuels starts with the recovery of crude from the resource, which in the oil sands means bitumen production via surface mining or SAGD. After the initial extraction of bitumen from the ore, bitumen is either upgraded to superior crude oil (known as SCO) or transported to refineries as dilbit, which is made by mixing a diluent in bitumen. The feed to refineries is processed and converted to transportation fuels, which are then moved to market to be consumed in vehicles. These steps are detailed in Fig. 1. The figure shows the different unit operations that bitumen goes through from recovery and extraction to the point of combustion in vehicles. WTW (Well-to-wheel) emissions refer to emissions associated with all the operations from initial production of crude to the combustion of transportation fuel in vehicles. WTT (Well-to-tank) emissions refer to the emissions upstream of the vehicle tank, i.e., WTW without the combustion emissions. TTW (Tank-to-wheel) constitutes only combustion emissions.

2. Methodology

Essential procedures in identifying and assessing the environmental impact of transportation fuels in their LC include defining the system boundaries, functional units, and allocation methods as well as collecting and processing relevant LCI (life cycle inventory) data, followed by an impact assessment [20].

2.1. Goal and scope

The primary goals of this LCA are:

- To use the GHG emissions obtained from the developed theoretical models to quantify the LC emissions of transportation fuels from oil sands products (SCO and bitumen).
- To explore and compare the LC GHG emissions in different bitumen LC pathways.
- To identify the processes with the highest GHG emissions in the production of transportation fuels.
- To add to the knowledge base in the comparison of the GHG intensity of oil sands products to that of conventional crudes.

The scope of this study encompasses all the processes throughout the entire LC from recovery and extraction of bitumen from its resource to the use of transportation fuels in vehicles.

2.1.1. System boundary

Fig. 2(A–F) presents the system boundaries for the LCA of transportation fuels from oil sands products. The boundaries include the burden of all inputs in recovery, extraction, transportation, upgrading, dispensing, and combustion of fuels. Fig. 2(A–F) shows that throughout the LC pathway more than one product are formed. Coke is formed in upgraders, whereas both coke and fuel oil are formed as co-products in refineries along with the major products gasoline, diesel, and jet fuel. Coke and fuel oil are set inside the system boundary implying that the burden required to produce them is borne by major products (diesel, gasoline, and jet fuel). The excess cogenerated electricity in the oil sands that is exported to the Alberta grid is considered outside the system boundary and is appropriately credited.

Along with the direct emissions from the combustion of process fuels, the system boundary encloses the upstream emissions to recover and transport these process fuels. For example, the net

[2] GREET is a spreadsheet based model that contains energy use and GHG emissions to build the different vehicle fuel combinations for full vehicle or fuel life cycle (Wang, M., 2012).

[3] GHGenius is a spreadsheet model that calculates the GHG emissions from extraction of fuel to when it is converted to motive power. It assess a wide variety of fuels and technologies in respect to life cycle energy use, GHG emissions, and cost effectiveness ((S&T)[2], 2012). GHGenius differs from GREET in its methodologies, assumptions and data sources.

[4] FUNNEL-GHG-OS is a spreadsheet model to calculate the energy consumption and GHG emissions in oil sands building different life cycle pathways based on specific project parameters (Nimana et al., 2015a&b).

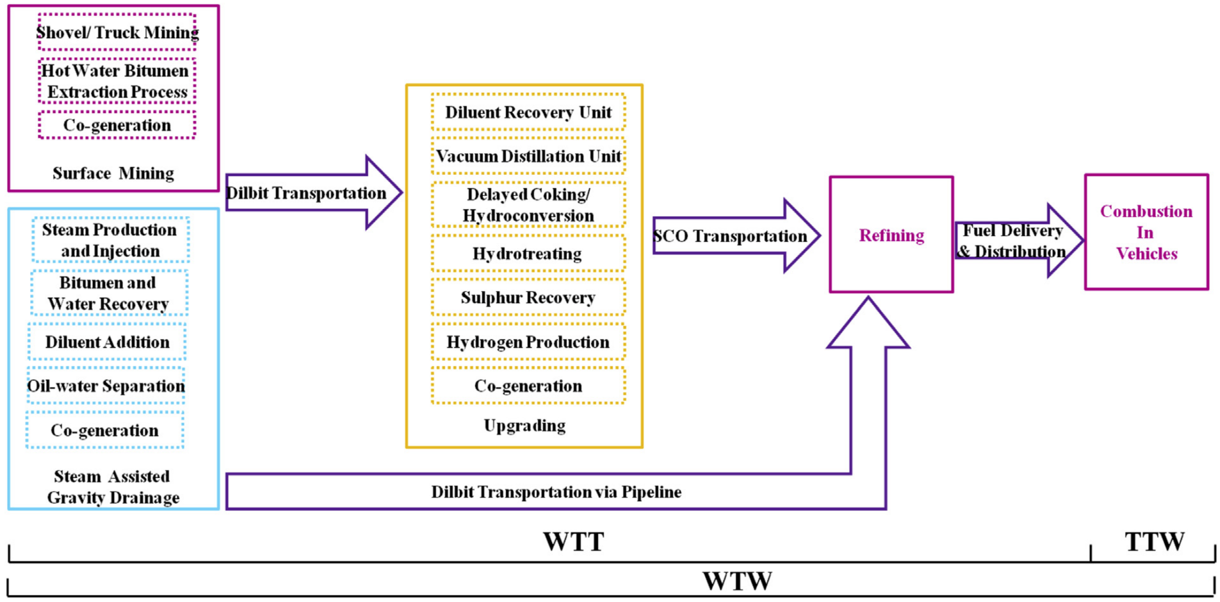

Fig. 1. WTW diagram for the bitumen life cycle showing the different unit operations of recovery, extraction, upgrading, transportation, refining, and combustion along with the involved subunit operation in each unit operation.

emissions include emissions to transport and deliver natural gas. Emissions from flaring, fugitives, land use, equipment, and infrastructure construction are beyond the scope of this research.

2.1.2. Functional unit

The full life cycle is investigated with 1 g of CO_2eq per megajoule of refined product as the functional unit. The functional unit used for life cycle inventory data in upstream stages (recovery and extraction, transportation, upgrading) is one kg-CO_2eq per unit volume of crude feed. The emissions also include the effects of other GHGs such as CH_4 and N_2O on a 100 year time horizon [21]. The LHV (lower heating value) of fuels (to be consistent with the California GREET model) was used to define the energy content. Necessary unit conversions are made to present and compare the results with other studies.

2.2. LCI (life cycle inventory)

The LC bitumen pathways in the oil sands involves following unit operations:

- Recovery and Extraction – surface mining or SAGD
- Transportation of dilbit, diluent, and SCO.
- Upgrading in delayed cokers or through hydroconversion
- Refining of oil sand products
- Fuel delivery and dispensing
- Combustion of gasoline, diesel and jet fuel in vehicles

Six pathways (shown in Fig. 2(A–F)) involving the above unit operations were formed and investigated in this LCA. These pathways represent the variability of projects in the oil sands. The bitumen in the oil sands can be recovered through shovel truck mining operations or through thermal recovery methods such as SAGD [19,22,23]. The bitumen is extracted from the recovered oil sands ore through surface extraction facilities. The main energy inputs in surface mining operations are diesel, natural gas, and electricity. The bitumen recovered from surface mining and SAGD is a highly viscous and hydrogen-deficient heavy feed and so can neither be pipelined nor refined in all refineries. The developing oil sands industry has sought different solutions to bitumen's transport and refining challenges. One solution is to process bitumen in a mini-refinery such as an upgrader, where bitumen is processed to form the superior refinery feed, SCO. SCO is a light oil (API ~ 30), is low in sulfur, and has low viscosity. SCO can be easily transported and refined. In order to transport bitumen to an upgrader or refinery via pipeline, the bitumen needs to be mixed with lighter hydrocarbons such as natural gas condensate or naphtha, known as a diluent. The diluent is mixed with bitumen in an approximate ratio of 1:3 to achieve the appropriate API and viscosity to use in a pipeline. Pathways 1, 2, 3, and 4 (shown in Fig. 2(A–D)) are based on an average transport distance of 500 km between the extraction site and the upgrader. The diluent is separated and recycled (assuming no loss of diluent) back to the extraction site for the same distance. Details on GHG emissions from oil sands' recovery, upgrading and refining are given by the authors in earlier studies [19,22].

Pathways are constructed using the two most common upgrader configurations – delayed cokers and hydroconversion. It is assumed that the refinery is situated at a distance of 3000 km from the upgrader, hence the SCO obtained after upgrading is transported to refineries via pipeline for a distance of 3000 km. Pathways 5 and 6 explore the cases in which the bitumen is not upgraded but transported as dilbit for a distance of 3000 km to refineries. At the refineries, dilbit is separated and the diluent is recycled (assuming no loss of diluent) back to the extraction site via pipeline for the same distance of 3000 km. The crude feed to refineries – SCO in pathways 1, 2, 3 and 4 and bitumen in pathways 5 and 6 – is processed in a typical deep conversion refinery[5] of a configuration detailed by authors in an earlier study [19]. The transportation fuels – gasoline, diesel, and jet fuel – produced from the refining of oil sands feeds are delivered and distributed to retail locations and are later combusted in vehicles.

[5] Deep conversion refinery employs cokers and cracking units to convert heavy residue fraction into marketable products such as diesel, gasoline and jet fuel (Nimana et al., 2015b).

The quality of LCI data is a key factor in the validation of this analysis. The quality of data aggregated can vary depending on the methodology used to obtain the data. Data collected may be specific to a company or may the aggregate for an entire sector. The lack of industrial data available in the public domain for the oil sands sector made it very difficult to assemble data for the LCA. Hence to obtain good quality data that would be representative of the oil sands industry, FUNNEL-GHG-OS, an engineering model based on engineering first principles was developed for each unit operation in the oil sands. FUNNEL-GHG-OS, detailed by authors in earlier studies [19,22] is used to obtain LCI data for energy consumption in each upstream unit operation (recovery and extraction and upgrading).

The energy consumed in surface mining is in the form of diesel, natural gas, and electricity. The consumption and GHG emissions of diesel for the mining of bitumen in shovel trucks is estimated by performing engineering calculations for shovel and truck productivity for a certain assumed fleet (detailed in Ref. [1]). Natural gas consumption is calculated from the warm water requirement using heat and mass transfer principles. Due to the special nature of the floatation cells and equipment required for extraction in surface mining, the electricity requirement was estimated from literature findings and actual data reported by industry to the ERCB (Energy Resources Conservation Board) [24], now the Alberta Energy Regulator, a regulatory body of the Alberta government.

Natural gas and electricity provide energy and hence are the main sources of GHG emissions for SAGD operations. The natural gas requirement and corresponding GHG emissions are calculated by performing heat and mass transfer calculations (detailed in Ref. [1]) on the iSOR (instantaneous steam-to-oil ratio) of a project. The main consumers of electric energy are the evaporators for water treatment and pumps used to extract bitumen from ground. The electric energy consumption in evaporators is estimated from correlations between vapor mass flow rate, the rise in temperature in the compressor, and a constant that depends on the size of the evaporator [1,19].

The widely used upgrading configurations – delayed coker and hydroconversion – are divided into the subunit operations described by authors in an earlier study [19]. The flow of feed in upgrading subunit operations is traced based on mass balance and volume percentage of products distilled at each stage. The hydrogen requirement in each subunit operation is calculated based on the mass of feed to be treated. Detailed engineering calculations are performed to estimate the energy – steam, natural gas, fuel gas, and electricity – required in each subunit operation. The GHG emissions are determined from the energy requirement using appropriate emissions factors.

A theoretical engineering model based on first principles is built in FUNNEL-GHG-OS to estimate the energy consumption and GHG emissions for pipeline transportation of dilbit (bitumen to diluent ratio: 75:25) and SCO. The pipeline is designed to transport 150,000 bpd of feed to a refinery, a figure appropriate for refinery capacity in North America [25]. The pipeline diameter is calculated based on a continuity equation and an assumed velocity of 1.5 m/s [26,27]. The calculated Reynolds number and absolute roughness of new commercial steel pipeline [28] is used to determine friction factor from the Moody chart. The Darcy–Weisbach equation is used to determine the head loss due to friction. The power required to overcome the head loss due to friction is provided by the pumps through the length of the pipeline. Based on the length of the pipeline, booster stations are required to provide the energy to overcome friction losses. Electricity is considered to be the main energy source that drives the inlet and the booster station pumps [18]. As electric energy is the only energy consumed, it is the main source of GHG emissions in pipeline transport. An emission factor of 725 g-CO_2eq/kWh, calculated based on the weighted average of the Canadian and U.S. provincial electricity grid emission factors [29,30] along the pipe, is used to convert the electric energy consumed to GHG emissions. The properties of crude feed and pipeline specifications that were used to develop this transportation model are detailed in Table 1.

The data inventory for refining oil sand feeds is obtained by simulating a typical deep conversion refinery using a process model in Aspen HYSYS [32]. Apart from the energy consumption in refining SCO and bitumen (that is transported to the refinery as dilbit), other important data information required for a LCA is the yield of transportation fuel from refineries. Different oil sand feeds give different yields of gasoline and diesel. The process model in Aspen HYSYS was used to obtain the energy consumption and the yield of transportation fuel – gasoline and diesel – from the refining of SCO and bitumen. It is difficult to trace the journey of transportation fuels from the refinery to retail outlets. This journey is considered local transportation and would therefore have a much smaller impact on net results than crude feeds, which are transported over long distances. With this assumption, the LCI data for the transportation and distribution of gasoline and diesel are obtained from GREET [13]. The value for GHG emissions from the combustion of gasoline and diesel in vehicles depends on the carbon content of the fuel [11,13]. The GHG emissions factor of gasoline and diesel combustion engines in vehicles as well as vehicle efficiency are established and were obtained from GREET [13]. Table 2 details the LCI data used for each unit operation in the LC of transportation fuels. Table 3 summarizes the GHG emission factors used in this research.

Variability in LCI data is inevitable due to different technologies employed in the oil sands. The efficiency of oil sands technologies is improving over time and has resulted in changes in energy consumption and GHG emissions. Considering the variability of oil sands projects, a range of results has been considered for each unit operation. The range of results was obtained by performing a sensitivity analysis of key parameters in oil sands technologies.

Allocation: The system boundaries depicted in Fig. 2(A–F) for the production of transportation fuels involve more than one coproduct. This leads to typical allocation problems in an LCA, that is, determining criteria for how to split or partition the environmental burden associated with the processes among the coproducts produced. The ISO (International Standard Organization) provides a guideline for an LCA where allocation is required [20]. The guideline recommends avoiding allocation where possible and allocating GHG emissions on a subprocess level, if required. Because the purpose of this research is to compare the LC GHG emissions from producing transportation fuels, a process that produces multiple products, allocation becomes necessary. Earlier studies have used allocation schemes based on mass, energy content, market value, or hydrogen content [34–37]. This research allocates the refinery emissions on a subprocess level instead of an aggregate approach, that is, one based on the mass of the products. The rationale behind choosing mass as a weighting factor is that the energy use is proportional to the mass of the products processed [36]. The GHG emissions for each subunit operation are distributed among the products, as per Eq. (1). These GHG emissions are added into the emissions of next subunit operations where the products go. The GHG emissions from supporting processes such as amine gas treatment and sulfur recovery as well as saturated gas plants are distributed among diesel, gasoline, and jet fuel based on the mass fraction of each product. All the emissions from SMR (Steam Methane Reforming) process for hydrogen production [38,39] are added to hydrocracking emissions as all the

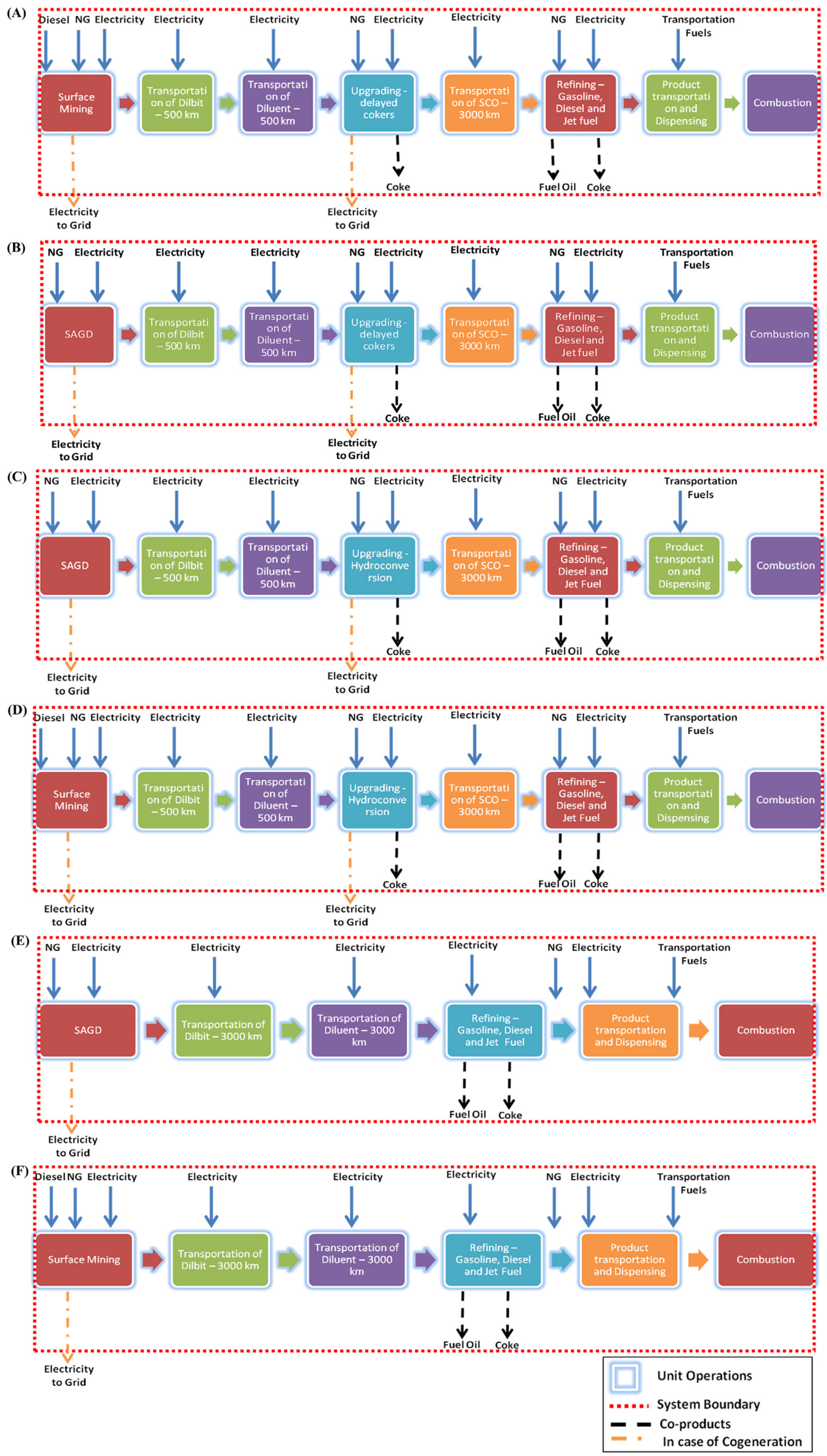
(A)
Diesel NG Electricity
Electricity
Electricity
NG Electricity
Electricity
NG Electricity
Transportation Fuels
Surface Mining
Transportation of Dilbit – 500 km
Transportation of Diluent – 500 km
Upgrading - delayed cokers
Transportation of SCO – 3000 km
Refining – Gasoline, Diesel and Jet fuel
Product transportation and Dispensing
Combustion
Coke
Fuel Oil
Coke
Electricity to Grid
Electricity to Grid
(B)
NG Electricity
Electricity
Electricity
NG Electricity
Electricity
NG Electricity
Transportation Fuels
SAGD
Transportation of Dilbit – 500 km
Transportation of Diluent – 500 km
Upgrading - delayed cokers
Transportation of SCO – 3000 km
Refining – Gasoline, Diesel and Jet fuel
Product transportation and Dispensing
Combustion
Coke
Fuel Oil
Coke
Electricity to Grid
Electricity to Grid
(C)
NG Electricity
Electricity
Electricity
NG Electricity
Electricity
NG Electricity
Transportation Fuels
SAGD
Transportation of Dilbit – 500 km
Transportation of Diluent – 500 km
Upgrading - Hydroconversion
Transportation of SCO – 3000 km
Refining – Gasoline, Diesel and Jet Fuel
Product transportation and Dispensing
Combustion
Coke
Fuel Oil
Coke
Electricity to Grid
Electricity to Grid
(D)
Diesel NG Electricity
Electricity
Electricity
NG Electricity
Electricity
NG Electricity
Transportation Fuels
Surface Mining
Transportation of Dilbit – 500 km
Transportation of Diluent – 500 km
Upgrading - Hydroconversion
Transportation of SCO – 3000 km
Refining – Gasoline, Diesel and Jet Fuel
Product transportation and Dispensing
Combustion
Coke
Fuel Oil
Coke
Electricity to Grid
Electricity to Grid
(E)
NG Electricity
Electricity
Electricity
Electricity
NG Electricity
Transportation Fuels
SAGD
Transportation of Dilbit – 3000 km
Transportation of Diluent – 3000 km
Refining – Gasoline, Diesel and Jet Fuel
Product transportation and Dispensing
Combustion
Fuel Oil
Coke
Electricity to Grid
(F)
Diesel NG Electricity
Electricity
Electricity
Electricity
NG Electricity
Transportation Fuels
Surface Mining
Transportation of Dilbit – 3000 km
Transportation of Diluent – 3000 km
Refining – Gasoline, Diesel and Jet Fuel
Product transportation and Dispensing
Combustion
Fuel Oil
Coke
Electricity to Grid
Unit Operations
System Boundary
Co-products
In case of Cogeneration

Table 1
Parameters and specifications for pipeline transport of dilbit/SCO/diluent.

Crude feed	Dilbit	SCO	Diluent	Comments/Sources
Capacity (bpd)	200000	150000	50000	[a]
API	22	32	55	[31]
Kinematic viscosity (cST)	200	10	1.3	[31]
Distance (km)	3000; 500	3000	3000; 500	[b]
Pipeline velocity (m/s)	1.5	1.5	1.5	
Pipe inner diameter (inch)	22	19	11	[c]
Pump efficiency	70%	70%	70%	
Absolute roughness (m)	0.000046	0.000046	0.000046	[28]

[a] Dilbit is a 75:25 mixture of bitumen and diluent.
[b] 3000 km = length of dilbit pipe from extraction facility to refinery; 500 km = length of dilbit pipe from extraction facility to upgrader.
[c] Calculated based on the continuity equation.

hydrogen produced in SMR is consumed in hydrocracking operations.

$$\text{Emissions allocated to product } (i)(g-CO_2eq/day) = \text{Emissions in sub unit operation} \left(\frac{g-CO_2eq}{day}\right) \times \frac{M_i}{\sum\limits_{i=j.k.l\ldots} M_i} \tag{1}$$

where M_i = mass of the product (i) produced$j.\ k.\ l\ \ldots$ are the products of each subunit operation.

Table 2 shows the disaggregated LCI for energy consumption and emissions for each life cycle stage in the LCA. Data collected have to be integrated to calculate the LC GHG emissions for each pathway. As observed in the table, the data collected are presented in different units. A common unit needs to be identified to integrate the data and analyze all the pathways simultaneously. In this analysis, the unit considered is g-CO_2eq/MJ of gasoline, diesel, and jet fuel. All the upstream emissions from recovery, extraction, upgrading, and transportation are allocated to total thermal energy produced in the form of gasoline, diesel, and jet fuel (see Eq. (2))

$$\text{Upstream emissions allocated to product } (i)(g-CO_2eq/day) = \frac{\text{Emissions in each unit operation} \left(\frac{g-CO_2eq}{day}\right)}{\sum\limits_{i=j.k.l} E_i} \tag{2}$$

where E_i = total energy content of the product (i) produced per day. j, k, l are the diesel, gasoline, and jet fuel.

The environmental impact of an LC can be studied using various environmental indicators. GWP (Global warming potential) represented by g-CO_2equivalent/MJ of gasoline, diesel, and jet fuel is selected to study the environmental impact of transportation fuels. Other global warming gases, methane and nitrous oxide, have been accounted for and converted to the CO_2equivalents (25 for CH_4 and 298 for N_2O) on a 100-year time horizon based on the IPCC (Intergovernmental Panel on Climate Change) recommendation 2007 [21].

3. Results and discussions

3.1. LCIA (life cycle impact assessment)

The LC WTW GHG emissions range from 103.2 to 134.9 g-CO_2equivalent/MJ of gasoline; 96.7 to 132.4 g-CO_2equivalent/MJ of diesel, and 92.5 to 126.5 g-CO_2equivalent/MJ of jet fuel, depending on the pathway (see Fig. 3). The wide range shows the variability in oil sands projects and is obtained from the range of emissions (detailed in Table 2) in oil sands unit operations. In the default case analyzed with data specified in Table 2, the LC WTW GHG emissions range from 106.5 to 116 g-CO_2equivalent/MJ of gasoline, 100.5–114.9 MJ of diesel, and 96.4–108.9 MJ of jet fuel, depending upon the pathway. The variations in the LC emissions of gasoline, diesel, and jet fuel from different pathways are due to differences in upstream and refining emissions; distribution and combustion emissions are the same. Pathways in the descending order of the GHG intensity for gasoline production are 3, 5, 2, 4, 1, and 6. The refining of SCO is less energy- and GHG-intensive than the refining of bitumen. This is because SCO is a light fuel obtained by upgrading bitumen [40]. Based on these pathways, 54.6%–77.6% of raw bitumen by mass is converted to transportation fuels-diesel, gasoline and jet fuel.

The strategy for the allocation of refinery emissions is detailed above. Based on the strategy, it has been observed that the production of gasoline in a refinery is the most GHG intensive, followed by diesel and jet fuel [36,37]. The GHG allocation factors in a refinery (shown in Table 4) vary with the feeds to the refinery. Feeds vary in energy consumption and the production of gasoline, diesel, and jet fuel, which affect the allocation factors. The GHG emission allocation factors are different if allocated based on refinery level or at the next subprocess level. These allocation factors are detailed in Table 4. GHG emissions allocated to gasoline at a subprocess level are higher than those allocated at the refinery level. Refinery level allocation makes diesel and jet fuel less GHG intensive than at the subprocess level. The allocation factors for bitumen at the subprocess level do not differ by much compared to the refinery level but are significantly different for SCO. The allocation method significantly affects the refinery GHG emissions allocated to transportation fuels, resulting in different values of WTW emissions. The GHG intensity order of pathways changes based on allocation method. Pathway 5 replaces pathway 3 for the least GHG intensive option for the production of gasoline when refinery GHG

Fig. 2. (A): Pathway 1- Surface-mined bitumen is upgraded in delayed cokers and the produced SCO refined to gasoline and diesel. (B): Pathway 2- Bitumen recovered in SAGD is upgraded in delayed cokers and the produced SCO refined to gasoline and diesel. (C): Pathway 3- Bitumen recovered in SAGD is upgraded through hydroconversion and the produced SCO refined to diesel and gasoline. (D): Pathway 4- Surface mined bitumen is upgraded through hydroconversion and the produced SCO refined to gasoline and diesel. (E): Pathway 5- Bitumen recovered in SAGD is transported as dilbit to refineries and refined to produce gasoline and diesel. (F): Pathway 6- Surface-mined bitumen is transported as dilbit to refineries and refined to produce gasoline and diesel.

Table 2
LCI data inventory for surface mining, SAGD, upgrading, transportation of feed, refining, transportation, distribution, and combustion emissions for gasoline and diesel.

	Units	Energy consumption		Units	GHG emissions	
		Range	Default		Range	Default
Surface mining						
Diesel	L/m^3 of bitumen	5–8	6.23	$kgCO_2eq/m^3$ of bitumen	16–25.7	20
Electricity	kWh/m^3 of bitumen	72–85	80.4	$kgCO_2eq/m^3$ of bitumen	63.3–74.8[a]	70.7[a]
No cogeneration						
Natural gas	m^3/m^3 of bitumen	64–90	74.4	$kgCO_2eq/m^3$ of bitumen	143.9–202.4	167.2
Electricity co-produced	kWh/m^3 of bitumen	0	0			
Net electricity	kWh/m^3 of bitumen	72–85	80.4	$kgCO_2eq/m^3$ of bitumen	63.3–74.8	70.7
With cogeneration						
Natural gas	m^3/m^3 of bitumen	75–105	87.3	$kgCO_2eq/m^3$ of bitumen	168.5–236.1	196.3
Electricity co-produced	kWh/m^3 of bitumen	53–140	107.3			
Net electricity	kWh/m^3 of bitumen	7–55	26.9	$kgCO_2eq/m^3$ of bitumen	−(4.5–35.7)[b]	−17.5[b]
SAGD						
Produced gas	m^3/m^3 of bitumen	1–89	20.5	$kgCO_2eq/m^3$ of bitumen	2–200	46.1
No cogeneration						
Natural gas	m^3/m^3 of bitumen	150.3–468	18.9	$kgCO_2eq/m^3$ of bitumen	337.9–1052	402.2
Electricity co-produced	kWh/m^3 of bitumen	0	0			
Net electricity	kWh/m^3 of bitumen	47.5–144.7	56.3	$kgCO_2eq/m^3$ of bitumen	41.8–127.3	49.5
With cogeneration						
Natural gas	m^3/m^3 of bitumen	277.5–562	301	$kgCO_2eq/m^3$ of bitumen	624–1263.6	677.4
Electricity co-produced	kWh/m^3 of bitumen	653.5–741.3	792.7			
Net electricity	kWh/m^3 of bitumen	653.5–741.3[c]	736.4	$kgCO_2eq/m^3$ of bitumen	−(388–445.3)[b]	−478.2[b]
Upgrading						
		Delayed Coking	Hydroconversion		Delayed Coking	Hydroconversion
SCO produced	m^3/m^3 of bitumen	0.911	1.037			
Hydrogen requirement	Nm^3/m^3 of bitumen	103.6	355.2			
Fuel gas	kg/m^3 of bitumen	47.5	39.1	$kgCO_2eq/m^3$ of bitumen	114.8	94.5
No cogeneration						
Natural gas	m^3/m^3 of bitumen	40.4	147.1	$kgCO_2eq/m^3$ of bitumen	79.9[g]	264.2[g]
Steam	lb/m^3 of bitumen	120.7	175.2		[d]	[d]
Electricity	kWh/m^3 of bitumen	51.9	84.9	$kgCO_2eq/m^3$ of bitumen	45.6[a]	74.7[a]
With cogeneration						
Natural gas	m^3/m^3 of bitumen	68.9	197.1	$kgCO_2eq/m^3$ of bitumen	120.7	324.4
Electricity exported	kWh/m^3 of bitumen	−41.4	−83	$kgCO_2eq/m^3$ of bitumen	−26.9[b]	−53.9[b]
Transportation of SCO – 3000 km[e]	kWh/m^3 of SCO		46.7	$kgCO_2eq/m^3$ of SCO		33.8
Transportation of dilbit – 3000 km[e]	kWh/m^3 of bitumen		123.6	$kgCO_2eq/m^3$ of bitumen		89.6
Transportation of diluent – 3000 km[e]	kWh/m^3 of diluent		74.6	$kgCO_2eq/m^3$ of diluent		54.1
Transportation of dilbit – 500 km[e]	kWh/m^3 of bitumen		17.5	$kgCO_2eq/m^3$ of bitumen		12.7
Transportation of diluent – 500 km[e]	kWh/m^3 of diluent		37.2	$kgCO_2eq/m^3$ of diluent		27
Refining[f]						
		Coker SCO	Hydroconversion SCO	Bitumen		
Gasoline	MJ/bbl of feed	2397.7	2664.7	2801.3		
Diesel	MJ/bbl of bitumen	1600.2	1616.3	1084.9		
Jet Fuel	MJ/bbl of bitumen	954.4	698.6	101.9		
Fuel energy required	MJ/bbl of feed	502.1	547.4	808.2		
Natural gas as feedstock for hydrogen production	MJ/bbl of feed	16.8	22.4	32.2		
Electricity requirement	kWh/bbl of feed	10.8	12.5	15.2		
GHG emissions						
Process gas emissions	$kgCO_2eq$/ bbl of feed	32.1	35.1	52.7		
Separation of diluent from dilbit	$kgCO_2eq$/ bbl of feed	–	–	3.0		
Electricity	$kgCO_2eq$/ bbl of feed	6.3	7.1	8.8		
FCC coke burn off emissions	$kgCO_2eq$/ bbl of feed	1.0	1.2	1.1		
Transportation and distribution of diesel	gm/MJ	0.50				
Transportation and distribution of gasoline	gm/MJ	0.49				
Transportation and distribution of jet fuel	gm/MJ	0.50				
Combustion emissions for conventional diesel	gm/MJ	75.14				
Combustion emissions for conventional gasoline	gm/MJ	75.78				
Combustion emissions for jet fuel	gm/MJ	73.20				

[a] Alberta grid emissions.
[b] Negative sign signifies the credit given for displacing GHG-intensive grid electricity. Includes both scenarios – cogeneration using a steam turbine and using a gas turbine.
[c] Obtained by subtracting the lower values and higher values in the range. But other combinations may be possible.
[d] Emissions from steam production are included in natural gas/fuel gas combustion emissions.
[e] Based on a transportation scale of 150,000 bpd of SCO, 200,000 bpd of dilbit, 50,000 bpd of diluent.
[f] Based on refining capacity of 150,000 bpd of SCO and bitumen. 50,000 bpd of diluent is separated and recycled back to the recovery site.
[g] includes the emissions for separation.

emissions are allocated on an energy basis at the refinery level compared to the mass basis as in the former case.

Different LC stages contribute differently to the net GHG emissions depending upon the pathway. Integrating the results detailed in Tables 2 and 3, it can be observed that combustion GHG emissions form the highest portion of WTW emissions, ranging from 64.7% to 70.3% in gasoline, 65.7%–75.3% in diesel, and 67%–75.9% in jet fuel. The remaining are WTR (well-to-refinery) GHG emissions. Transportation and distribution of end products form a small percentage of WTW emissions (~0.5%). Recovery and extraction comprise 7.2%–16% of WTW emissions for gasoline production. In pathways 1, 2, 3, and 4 upgrading and refining add up to 17.9%–22.3% of total GHG emissions. This is because a large amount of natural (NG) and process gas is required for steam and hydrogen production. Refining GHG emissions are 14.5% and 15.6% of the total GHG emissions in pathways 5 and 6, respectively.

Gasoline production from upgrading SAGD bitumen is the most GHG intensive. In terms of GHG intensity, the production of one transportation fuel may be better through one pathway while another transportation fuel may be better from another pathway. Specifically, gasoline production is least GHG intensive in pathway 6, whereas diesel and jet fuel production are least GHG intensive in pathway 1. This implies that certain pathways may look better compared to other pathways if a different transportation fuel is chosen for comparison.

3.1.1. The impact of cogeneration

Oil sands projects use large amounts of energy in the form of steam and electricity. This use of energy provides an opportunity for cogeneration in the oil sands [42]. Cogeneration is a significant part of many oil sands projects; any excess electric power is exported to the grid. Co-product GHG emission credits are applied as the export power displaces high GHG-intensive grid electricity. These credits are important from a LC perspective. A detailed cogeneration model [19,22] built in FUNNEL-GHG-OS to study the effects of cogeneration in recovery, extraction, and upgrading. Power exported to the grid is based on cogenerating 100% of the steam required in surface mining, SAGD, and upgrading operations. This is the design basis for most oil sands facilities [11]. The impact of cogeneration on WTW emissions of gasoline is shown in Fig. 3(A). The “X” in the figure (labeled as “cogeneration impact”) shows the net emission values when cogeneration is employed in recovery and upgrading operations. Employing cogeneration in the oil sands offsets the WTW emissions of gasoline by 2–9%. The largest impact of cogeneration is observed in pathways 2, 3, and 5. This is because of the large steam requirement in SAGD processes. Cogeneration also affects the order of GHG intensity of pathways for gasoline production. Now pathway 1, employing surface mining and delayed coker upgrading, is the least GHG intensive compared to pathway 6, which was least GHG intensive without cogeneration.

3.2. Comparison to other LCA studies for transportation fuels

A comprehensive comparison of the modeled LCA results with earlier studies [11–14,17] was carried out (see Fig. 4). These studies do not all report results for all the pathways modeled in this research. Hence the comparison is made with the corresponding results. The modeled range of values is found to be in good agreement with other studies. The default values reported by GHGenius [14] are higher than the modeled default values but within the range specified. The modeled results very closely match results from Ref. [11], varying by only 1 to 3 g-CO_2eq/MJ of gasoline. The range of values reported in Ref. [17] overlaps the range of modeled values for pathways 1 and 2 and on the lower side for pathways 5and 6. Apart from the above-mentioned studies, the modeled results for pathway 1 were compared to the results of [43,44] as mentioned in Ref. [15] and found to be within 3–9% of the modeled default results. Small offsets among the results are because of different system boundaries, data sources, allocation methods, and end products.

4. Conclusion

A comprehensive WTW life cycle assessment for transportation fuels – gasoline, diesel and jet fuel – was performed, and six different bitumen pathways in oil sands activities were considered. The data used in the WTW analysis were obtained FUNNEL-GHG-OS (**FUN**damental E**N**gineering Principl**E**s- based Mode**L** for Estimation of **G**reen**H**ouse **G**ases in the **O**il **S**ands), a theoretical model based on engineering first principles. The LC WTW GHG emissions range from 106.5 to 116 g-CO_2equivalent/MJ of gasoline, 100.5 to 114.9 g-CO_2equivalent/MJ of diesel, and 96.4 to 108.9 g-CO_2equivalent/MJ of jet fuel, depending on the oil sand pathway for transportation fuel production. The method of allocating total emissions to the co-products affects the total WTW emissions of transportation fuels. The LC GHG intensity order of pathways may be different for different transportation fuels. The WTW LC emissions results presented in this research are found in good agreement with earlier studies.

Table 3
GHG Emissions factors used in the life cycle assessment of transportation fuels.

Fuel	Unit	Emissions factor	Comments/Source
Diesel	g-CO_2eq/MMBTU	94385	[13]
Natural gas	g-CO_2eq/MMBTU	64769	[13]
Natural gas as feedstock to hydrogen production	g-CO_2eq/MMBTU	5390	[13]
Reaction emissions from hydrogen production	g-CO_2eq/gm of natural gas	2.75	Calculated based on stoichiometry
Upgrader fuel gas	g-CO_2eq/kg	2419.4	Calculated based on composition of fuel gas
Refinery fuel gas	g-CO_2eq/MMBTU	64200	[13]
Alberta grid electricity	g-CO_2eq/kWh	880	[29]
Grid electricity for refinery	g-CO_2eq/kWh	581	[a]
Electricity for pipeline transport	g-CO_2eq/kWh	725	[b]
For crediting electricity export to Alberta grid	g-CO_2eq/kWh	650	[29]
FCC coke	g-CO_2eq/MMBTU	10200	[13]

[a] Average of Emissions & Generation Resource Integrated Database regions (eGRID) – ERCT, SPSO, SRMV [30,33] in U.S. where PADD (Petroleum Administration for Defense Districts) 3 refineries are located.

[b] Distance weighted average of electricity grid emission factor for eGRID regions – MROW, SPNO, SPSO in the U.S. and Alberta, Saskatchewan, and Manitoba in Canada – from which the pipeline passes from Alberta to PADD 3 [29,30].

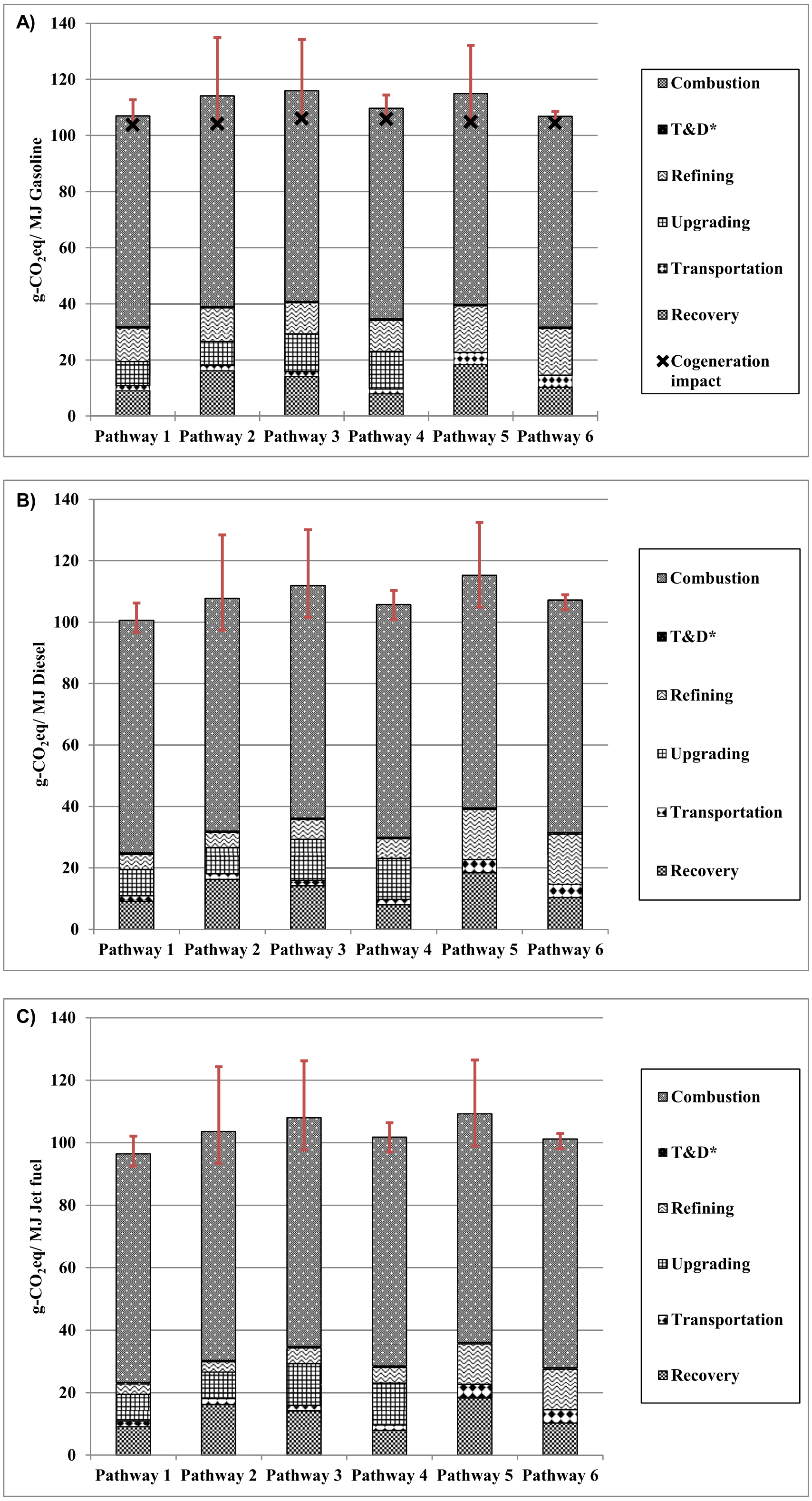

Fig. 3. LC WTW GHG emissions for (A) gasoline, (B) diesel, and (C) jet fuel * T&D refers to transportation and distribution of end product. Note: The range values of WTW emissions of each transportation fuel are obtained by adding the minimum and maximum values respectively for recovery and upgrading operations. Values outside the specified range are possible by other combinations. iSOR considered for SAGD operation ranges from 2.1 to 3.5 as most of the oil sands projects perform in this range [18,41].

Table 4
Refinery level and subprocess level GHG emission allocation factors for gasoline, diesel, and jet fuel.

	Subprocess level allocation – Mass basis[a]			Refinery level allocation – Mass basis[b]			Refinery level allocation – Energy basis[c]		
	Gasoline	Diesel	Jet fuel	Gasoline	Diesel	Jet fuel	Gasoline	Diesel	Jet fuel
Coker SCO	0.74	0.18	0.07	0.69	0.23	0.08	0.48	0.32	0.19
Hydroconver-sion SCO	0.70	0.23	0.08	0.54	0.32	0.14	0.54	0.32	0.14
Bitumen	0.72	0.26	0.02	0.69	0.28	0.03	0.70	0.27	0.03

[a] Defined as: kg of individual product (gasoline, diesel, jet fuel)/kg of end products (gasoline + diesel + jet fuel).
[b] Defined as: kg of individual product (gasoline, diesel, jet fuel)/kg of end products (gasoline + diesel + jet fuel).
[c] Defined as: MJ of individual product (gasoline, diesel, jet fuel)/MJ of end products (gasoline + diesel + jet fuel).

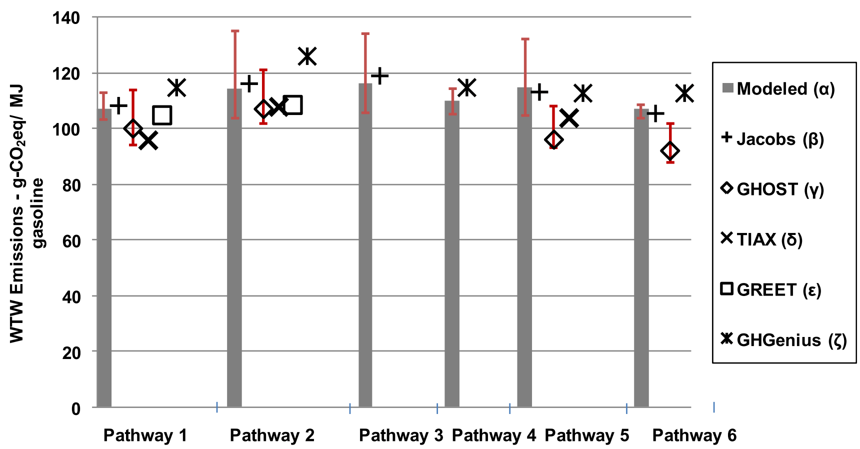

Fig. 4. Comparison of modeled WTW GHG emissions for gasoline with literature values (α) The modeled results are for low sulfur gasoline. (β) [11]. Values taken are for reformulated gasoline blendstock for oxygen blending (RBOB). Pathway 4 is not modeled. (γ) [17]. The range shown for pathway 1 applies to pathways 1 & 4. Range shown for pathway 2 applies to pathways 2 & 3. (δ) [12]. The results are for PADD 3 and the sell coke case. This case is chosen for comparison as it is similar to the modeled case. (ε) [13]. GREET does not separate the upgrading using delayed coker and hydroconversion. The value shown in pathway 1 applies to pathways 1 & 4; the value shown in pathway 2 applies to pathways 2 & 3. (ζ) [14]. Pathway 3 is not modeled. Note: Unit conversions, wherever necessary, are made using LHV values from GREET.

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