Life Cycle Assessment of Transportation Fuels from Canada's Oil Sands through Development of Theoretical Engineering Models

By

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Abstract

Oil sands in Canada are significant in fulfilling the current and the future energy demands of North America. The development of these resources, besides the increased awareness in global carbon management, has given way to various policy regulations such as the Low Carbon Fuel Standard (LCFS) and Europe's Fuel Quality Directive that demand proper quantification and estimation of life cycle (LC) greenhouse gas (GHG) emissions from transportation fuels. Previous studies show the variability in oil sands projects and the demand for proper quantification of project-specific energy consumption and GHG emissions.

The novelty of this study is its aim at developing theoretical models based on engineering first principles to quantify the energy demand and GHGs emitted in oil sands operations using project-specific parameters. These models are used to quantify the GHG emissions in surface mining, steam assisted gravity drainage (SAGD), upgrading, transportation, and refining operations, through identifying the key sensitive parameters. Further, a comprehensive life cycle assessment (LCA) for transportation fuels (gasoline, diesel, and jet fuel) derived from Canada's oil sands is conducted in which all the possible pathways from bitumen extraction to use in vehicles are explored. The life cycle inventory data for the LCA are obtained from the developed theoretical models. The impact of cogeneration of electricity in oil sands recovery, extraction, and upgrading on the LC GHG emissions of gasoline is explored. Sub process level mass allocation is followed to allocate the refinery emissions among the products.

Emissions in surface mining and SAGD range from 180 to 302 kg of CO_2 eq/m^3 of bitumen and 238 to 1,204 kg of CO_2 eq/m^3 of bitumen, respectively, representing a wide range of variability in oil sands projects. Temperature and warm water consumption in surface mining and the steam-to-oil ratio (SOR) in SAGD are major parameters affecting GHG emissions. Hydroconversion upgrading is more energy- and GHG-intensive than delayed coker upgrading but gives a higher SCO yield. Refining SCO to transportation fuels produces 41% and 49% fewer emissions than do dilbit and bitumen, respectively. LC well-to-wheel (WTW) GHG emissions range from 106.8 to 116 g-CO_2eq/MJ of gasoline; 100.5 to 115.2 g-CO_2eq/MJ of diesel, and 96.4 to 109.2 g-CO_2 eq/MJ of jet fuel, depending on the pathway. Combustion emissions (64.7% to 70.3%) are the largest constituent of WTW emissions for gasoline production; recovery forms 7.2% to 16%. The WTW GHG intensity of pathways depends on the allocation method and transportation fuel chosen for comparison.

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Preface

Section of chapter 2 of this thesis has been submitted as Nimana, B., Canter, C., and Kumar, A., "Energy Consumption and greenhouse gas emissions in the recovery and extraction of crude bitumen from Canada's oil sands" to the "Applied Energy" journal. Section of chapter 3 of this thesis has been submitted as Nimana, B., Canter, C., and Kumar, A., "Energy consumption and greenhouse gas emissions in upgrading and refining of Canada's oil sands products" to the "Energy" journal. I was responsible for the concept formulation, data collection and analysis, and manuscript composition. Canter, C. contributed by reviewing the results and provided useful inputs and Kumar, A. was the supervisory author and was involved with the concept formation, analysis and manuscript composition.

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Chapter 1

Introduction

1.1 Background

With the increase in global energy demand and limited conventional oil resources, focus has shifted towards unconventional oil resources such as those in the oil sands in western Canada. The oil sands are a naturally occurring mixture of sand, clay, water, and bitumen, a heavy and extremely viscous oil. Each grain of sand is surrounded by a layer of water and a film of bitumen. Bitumen is so viscous that at room temperature it acts much like cold molasses. At 10 ˚C, bitumen is as hard as a hockey puck and cannot flow or be pumped without being diluted or heated [1].

Bitumen is a kind of crude oil but is different from regular or conventional oil. Conventional crude oil is mixture of mainly pentanes and heavy hydrocarbons and is liquid at atmospheric pressure and temperature [2]. Conventional crude oil is less viscous and dense and so can be recovered from underground reservoirs without stimulation and can be easily pumped through pipelines. Bitumen can only be recovered from its deposits with external stimulants such as heat. Moreover, bitumen cannot be transported through pipeline without processing or mixing lighter hydrocarbons in it.

The oil sands are found in several locations around the globe, including Venezuela, the United States, and Russia, but Alberta has the largest and most developed deposits [3]. The oil sands in Alberta are the third largest proven oil reserves in world (170.2 billion barrels) after Saudi Arabia and Venezuela [4]. As of 2012, Alberta produced 1.9 million bbl/d of raw bitumen, which is projected to increase to 3.8 million bbl/d by 2022 [5].

Oil sands in Alberta cover 140,800 square kilometers area and are separated into Athabasca, Peace River, and Cold Lake regions [6]. Athabasca River deposits are the largest of the three in terms of volume [7]. There are two different methods of recovering and extracting bitumen from the ore. Bitumen that is close to the surface is mined using the open-pit mining method. The typical depth of the mineable deposits is 30 m or less. Bitumen that lies deep within the ground is recovered by in situ methods. The most common in situ recovery method used in the oil sands is steam assisted gravity drainage (SAGD). Cyclic steam stimulation (CSS) is less common in the oil sands.

As bitumen is difficult to pump through a pipeline, it is difficult to get the heavy oil to refineries. Moreover, not all the refineries in North America have the capability to process and refine bitumen (heavy oil). So to access more markets and easily transport the bitumen to refineries, oil sands producers reduce the density and viscosity of the bitumen. This is done through upgrading; decomposing bitumen at high temperatures and stabilizing the products through hydrogen addition. The lighter components produced are blended together to form a superior quality crude called synthetic crude oil (SCO). SCO is light crude oil that can be easily transported and processed in refineries to produce transportation fuels.

Alternatively, oil sands producers need to get their product to refineries that can refine bitumen. To move bitumen, it is mixed with naphtha or a natural gas condensate called a diluent in approximately 3:1 ratio by volume. The resulting less dense, less viscous mixture is called dilbit and can be transported to refineries through a pipeline. Sometimes bitumen is mixed with SCO (the resulting mixture is called synbit) instead of a diluent to make it transportable by pipeline. The crude feed from the oil sands is refined to produce transportation fuels.

With the technologies available today, bitumen from the oil sands can be produced via surface mining or in situ recovery. About 20% of Alberta's oil sands are recoverable by surface mining while the remaining 80% are too deep for mining and require in situ extraction techniques [7]. In 2012, total in situ production accounted for 52% of total crude bitumen production [8]. In situ bitumen production has been increasing at a higher rate compared to mined bitumen production. In 2012, all crude bitumen produced from mining and a small portion (about 7%) of bitumen produced from in situ was upgraded to SCO, yielding 329 million barrels of upgraded bitumen [5]. Upgraded bitumen formed 52% of the total crude bitumen in 2012 [5].

There is high growth in the oil sands industry. 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 of GHG emissions, accounting for 28% of total GHG emissions in the U.S and 24% of the total GHG emissions in Canada [9, 10]. The high GHG intensity of the transportation sector has resulted in regulations such as the Low Carbon Fuel Standard (LCFS) and the European Fuel Quality Directive that demand a 10% reduction in life cycle greenhouse gas (GHG) emissions from transportation fuels by 2020 [11, 12]. In 2007, the Alberta government passed the Specified Gas Emitters Regulations (SGER) 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 [4]. These regulations use a life cycle assessment approach to calculate the carbon footprint of transportation fuels sold. The policy makers have been cognizant of the growth of the oil sands industry in Alberta and have made it necessary to appropriately assess energy consumption and GHG emissions in the oil sands. All of this calls for appropriate quantification and assessment of the life cycle GHG emissions from these oil resources.

The environmental concerns have initiated a debate – GHG emissions from the oil sands vs. GHG emissions from conventional crudes. As discussed earlier, bitumen is recovered from its reservoir by means of external stimulants such as heat. Providing stimulants means providing more energy to recover and process the bitumen than conventional crude oils, resulting in more GHG emissions. It is not sufficient to say that bitumen requires more energy for extraction and processing than conventional crude oil, rather it is necessary to indicate how much more energy is required. This question makes it necessary to appropriately quantify the energy consumption and GHG emissions in the recovery and processing of bitumen and conventional crudes. A “well-to-wheel” life cycle approach, which takes into account the energy consumption and GHG emissions from recovery, extraction, transportation, refining, and combustion, is necessary for appropriate quantification.

Moreover, technology in the oil sands is still in the development stages. Recently developed technologies are focused on improving profitability and reducing the carbon footprint of oil sands-derived fuels. So it is necessary to benchmark life-cycle GHG emissions from oil sands technologies to see if the desired targets set for new developed technologies have been met.

A variety of feeds produced in oil sands such as SCO, dilbit, and bitumen are refined to transportation fuels. Each feed, depending on its characteristics, consumes different amounts of energy and emits different GHG emissions. The refining of oil sands feeds results in different useful end products. So it is necessary to study upgrading and refining operations together in order to be able to compare the net energy consumption and GHG emissions on a similar platform. The variety of feeds and technology in the oil sands makes each project unique in its energy consumption and GHG emissions. This uniqueness demands the estimation of energy consumption and GHG emissions for each individual project.

A life cycle assessment (LCA) is a powerful tool that can measure and regulate 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 fuel on all affected sectors rather than shifting the impact from one sector to other. The LC (life cycle) approach can help to regulate the emissions from transportation fuels as this approach is helpful to reduce overall GHG emissions. An LCA may not be necessary if all sectors of society are individually regulated for GHG emissions [13], but because not all sectors have these regulations, the use of the LC approach for these policies to reduce overall GHG emissions is important.

The life-cycle of transportation fuels starts with the recovery of crude from the resource, which in the oil sands is bitumen production via surface mining or SAGD. After the initial extraction of bitumen from the ore, bitumen is either upgraded to SCO or transported to refineries as dilbit. The feed to refineries is processed and converted to transportation fuels, which are then moved to market for consumption in vehicles. These steps have been detailed in Figure 1. Figure 1 shows the different pathways taken by bitumen to the point of combustion in vehicles. Well-to-wheel (WTW) emissions refer to those associated with all the operations from initial production of crude to the combustion of transportation fuels in vehicles. Well-to-tank (WTT) emissions refer to emissions upstream of vehicle tank, i.e., WTW without the combustion emissions. Tank-to-wheel (TTW) constitutes only combustion emissions. There have been few life cycle assessments of oil sands-derived fuels.

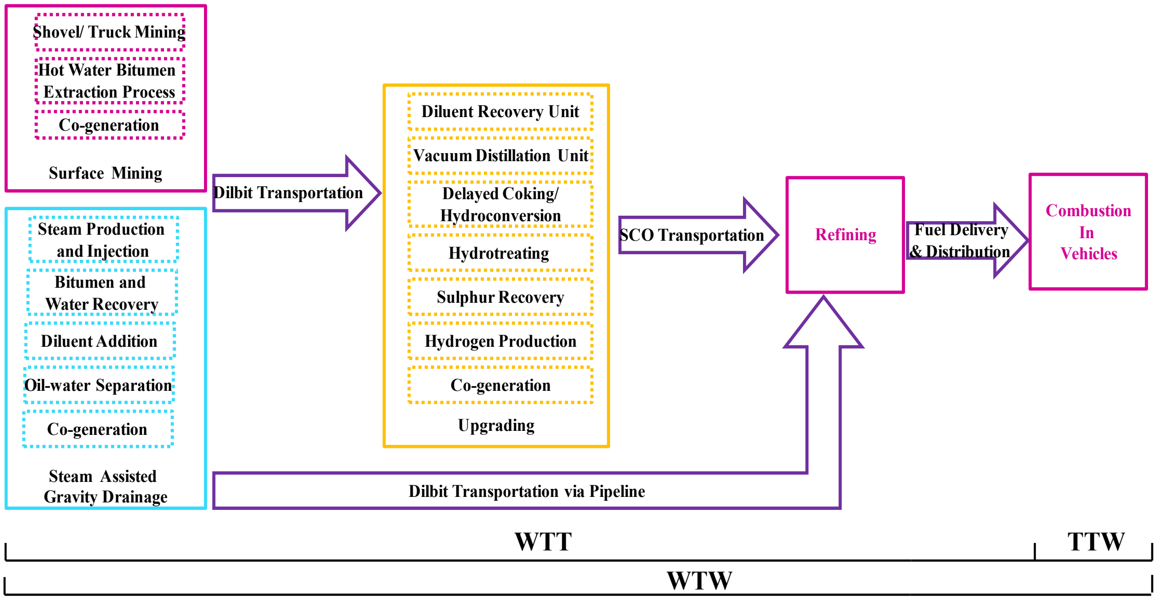

Figure 1: Bitumen life cycle pathways for production, upgrading, transportation, and refining.

Contributions in this field have been from both the academics and consultants. Two studies [14, 15] contracted by the Alberta Government use life cycle GHG emissions to perform a comparative analysis of the production of transportation fuels in the U.S. from local or imported crudes. Jacobs Consultancy [15] used a bottom-up approach to develop a theoretical model to estimate emissions from the oil sands. This study estimated emissions on the assumption that the energy required in surface mining is "one half of the energy needed for SAGD operation operating at a 3 SOR" [15]. This study lacks the transparency of original calculations and provides few details of what has been input to the model. Another study [14], on the other hand, used a top-to-bottom approach to estimate emissions from oil sands activities. The TIAX model focuses on case studies of specific companies and hence does not provide generic numbers for the oil sands industry. The TIAX model used an integrated operation for mining and upgrading and did not separate the emissions of these two unit operations. Jacobs [14] used a proprietary model to estimate energy consumption and emissions for upgrading bitumen, whereas TIAX [13] used numbers from industry. These studies cannot be used to calculate project-specific emissions based on technical parameters such as reservoir and product properties. Other studies [16, 17] conducted in the field answer different questions and do not suffice for the purpose stated above. None of these studies give access to the involved operating parameters, meaning users cannot modify these parameters to evaluate emissions for a different project.

A few existing LCA models incorporate oil sands pathways. The most well-known models, ones that form the basis of policy formulation, are GHGenius [18] and GREET [19], maintained by Natural Resources Canada and Argonne National Laboratory, respectively. The user can construct oil sands pathways within these models by either using the default values or user input data as desired. Both of these models are based on different methodologies and have variations in the default fuel inputs. The differences in the methodologies and variations in the fuel required for each unit operation are outlined in Appendix A. However, these models do not offer a method to estimate the specific energy consumption in any of the unit operations. Both these models present different LCA results due to differences in the default input energy assumptions and methodology followed. Due to these variations and unavailability of specific data for energy consumption, there is a need for the development of a model that would estimate energy consumption based on technical parameters.

Bergerson et al. and Charpentier et al. [20, 21] document the development of GHOST, a LCA model for oil sands-derived pathways. GHOST is based on confidential data for energy consumption from a set of operating projects. It does not offer a method to estimate the energy consumption in oil sands unit operations. GHOST calculates GHG emissions based on these confidential data from a certain set of operating projects in surface mining, SAGD, and upgrading, making it very specific to those operations, and does not offer a method to calculate energy consumption and GHG emissions in these operations for any general project.

There has been separate research on the upgrading and refining of oil sands products. [22] studied the upgrading and refining operation emissions for the oil sands based on certain project data. The results have limitations as these cannot be modified to evaluate emissions for a different project. Some studies [23-25] have looked into the effects of crude quality and refinery configuration for different feeds. These studies are limited to refinery operations and do not analyze upgrading and refinery operations on a common platform to study the effects of obtaining end products from oil sands feeds.

Many oil sands operators – i.e., Syncrude, Suncor, Shell, and Cenovus – report GHG emissions in their annual reports [26-29]. But these results are unaudited and specific to their own operating parameters and projects. They do not project the sensitive parameters on which GHG emissions depend nor do they identify opportunities to reduce GHG emissions. These results represent emissions for certain stages in the life cycle of transportation fuels.

Charpentier et al. [30] reviewed 13 studies including the above-stated models and reports and found inconsistencies in the results due to variations in system boundaries, data quality, methods, and documentation. Charpentier proposed depicting LC emissions as a range rather than point estimates, depending on actual performance data. The author also called for additional research for better characterization of oil sands technologies and pathways. Brandt [31] performed a comparative analysis of GHG emissions in each unit operation in the oil sands as reported by GREET, GHGenius, and industrial consultancy reports. Charpentier et al. [30] and Brandt [31] recommended the use of the GHGenius model for the life cycle assessment of fuel derived from the oil sands. Whereas Charpentier et al. [30] called for additional research for better characterization of oil sands technologies and pathways, Brandt [31] recommended modeling GHG emissions of process-specific configurations.

1.2 Research Motivation

The motivation for this research is drawn from a number of factors. Following statements best summarize these motivating factors and areas that this research addresses to.

- The carbon intensity of transportation fuels such as gasoline, diesel and jet fuel is uniform but the life cycle GHG emissions (including the recovery, transportation and refining) of these transportation differ depending on how they are produced [13].

- It is important to compare GHG emissions from the production of transportation fuels (i.e., gasoline, diesel and jet fuel) from oil sands products with emissions from fuel production from conventional crudes.

- Bitumen in the oil sands goes through many flexible pathways (see Figure 1) that differ in energy and GHG intensity. So it is necessary to quantify the energy consumption and GHG emissions in each pathway in order to answer questions like “Is it environmentally beneficial to upgrade bitumen in Alberta or export it as dilbit?”

- Technology in the oil sands is in the development stages. Therefore, it is necessary to understand the sensitivity of technical parameters on the energy consumption and GHG emissions in each unit operation.

- Regulations require the quantification of emissions from oil sands operations either to impose financial/environmental penalties or to formulate new policies. Hence, it is necessary to benchmark life cycle GHG emissions from oil sands operations to see if desired targets have been met.

There is scarcity of research on the estimation of life cycle GHG emissions from oil sands operations. Most of those studies were performed by consultancies and private stakeholders. So it is necessary to perform an independent assessment in the field. To address the above issues reasonably well, it is necessary to develop a detailed data-intensive model to estimate project-specific energy consumption and GHG emissions in each unit operation (identified in Figure 1) in oils sands activities.

1.3 Project Objectives

The overall objective of this research is to conduct the LCA of production of transportation fuels from oil sands through development of theoretical models based on fundamental science. The specific objectives of the research are:

- Develop a user-friendly data intensive model to estimate energy consumption and GHG emissions in each unit operation (surface mining, SAGD, upgrading, transportation, and refining) in the life cycle of transportation fuels based on fundamental engineering principles.
- Conduct a sensitivity analysis for energy consumption and GHG emissions on various technical parameters and reservoir properties.
- Evaluate and compare the GHG emissions in various oil sands pathways such as upgrading bitumen to SCO followed by refining as compared to transporting dilbit and then refining.
- Estimate the WTW GHG emissions for transportation fuels produced from the oil sands.

1.4 Study Overview

Chapter 2, Energy consumption and greenhouse gas emissions in the recovery and extraction of Canada's oil sands: This chapter describes the development of an Excel model based on first engineering principles used to estimate the recovery and extraction emissions for two major unit operations in the oil sands, surface mining and SAGD. The chapter constitutes the assumptions involved, the methodology of the model, the results obtained, and the sensitivity of the results on various technical parameters. The results obtained have been validated with results from GREET [19], GHGenius [32], the Jacobs Consultancy report [15], and other published literature [20].

Chapter 3, Energy consumption and greenhouse gas emissions in upgrading and refining of Canada's oil sands: This chapter presents the estimation of energy consumption and GHG emissions for upgrading bitumen to SCO based on theoretical engineering models. Two configurations of upgraders – delayed cokers and hydroconversion – are explored. A subsection of this chapter investigates the refining of oil sands products such as SCO, dilbit, and bitumen using a process model, Aspen HYSYS [33]. The results from these two unit operations have been validated with values found in existing literature [15, 19, 20, 32].

Chapter 4, Life cycle assessment of greenhouse gas emissions from Canada's oil sands-derived transportation fuels: This chapter integrates the results of each unit operation detailed in previous chapters into WTW LC emissions of transportation fuels produced via six bitumen pathways. The model for the transportation of feedstock from the extraction/upgrading site to the refinery is also detailed in this chapter. Refinery and upstream emissions are allocated to transportation fuels at the sub process level based on the mass. The GHG emissions from delivery and distribution of fuel along with the vehicle combustion emissions are part of this chapter. A comparative assessment of LC emissions from all six bitumen pathways is performed. The WTW results are compared with other LCA studies for transportation fuels [14, 15, 19, 20, 22, 32, 34].

Chapter 5, Conclusion and Recommendations for Future Work: This chapter concludes the research work in this dissertation and presents notable observations and conclusions. A subsection identifies the areas in which further research is required along with suggestions for improvement of the current model.

Chapter 2

Energy consumption and greenhouse gas emissions in the recovery and extraction of Canada’s oil sands[1]

2.1 Introduction

This chapter introduces the two most widely used recovery operations – surface mining and in situ in the oil sands. A detailed description of the methodology for developing a user-friendly Excel model to estimate project-specific energy consumption and GHG emissions for these recovery operations is provided. The model quantifies the demands of diesel, natural gas, and power in surface mining and electricity and natural gas in SAGD. It further explores the impact of cogeneration in each of the unit operations. Along with the quantification of energy and GHG emissions presented in the results and discussion section, the sensitivity of key parameters on GHG emissions has been explored.

2.1.1 Surface Mining

Surface mining is possible for shallow mines within a 0.4-1.4 stripping ratio (ratio of overburden to oil sands ore thickness), with typical ore thickness of 90 m [35]. A typical mine has an average grade of 9-12%. A high grade contains above 10% bitumen while a low grade ore has 6-8% bitumen. Typical water content in oil sands ore is 5-6% [35].

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[1] The results of this chapter were submitted as Nimana, B., Canter, C., Kumar, A., “Energy consumption and greenhouse gas emissions in the recovery and extraction of crude bitumen from Canada’s oil sands” to *Applied Energy*, 2014; XX:XX (in review).

Surface mining involves three steps – overburden removal, oil sands mining, and bitumen extraction. The topmost layer of soil containing trees, clay, and muskeg, known as overburden, is removed to expose the thick deposit of oil sands. These layers of overburden are stockpiled so that they can be replaced when the mined site is ultimately reclaimed. Oil sands ore is mined using open pit technology, similar to many coal mining operations [7]. Large hydraulic shovels scoop the oil sands into trucks, which transport the ore to crushers to begin the extraction process. Double roll crushers, rotary breakers, and vibrating screens are used to crush the oil sands ore to approximately 5 cm in diameter [35]. A mixer further combines the crushed oil sands ore with warm water (35-50 ˚C) [35, 36] to create slurry that is pumped through a conditioning pipeline to the extraction facilities. This hydrotransport line breaks down the lumps of oil sands ore further and releases the bitumen so that it can attach to air bubbles. The froth in the conditioned slurry is gravity-separated from the sand-rich tailings in the primary separation cell (PSC). A three-layer separation takes place in the PSC. The top layer, consisting of bitumen-rich froth, is skimmed off, deaerated, and further treated using naphtha or paraffin-based solvent to separate the bitumen from water and fine solids. The middle layer, called the middlings, is predominantly fine solids, which is sent to a primary flotation vessel (PFV) for further bitumen extraction. The treated bitumen froth from the PFV is mixed with incoming conditioned slurry. The third layer in the PFV is similar to incoming ore, with a mixture of clay and coarse sand known as tailings. Tailings from PFC and PFV pass from the secondary flotation to a thickner. Additives are used in the thickener to separate clay from water. Recycling this warm water helps to save a significant amount of energy.

2.1.2 In situ recovery

Deeper oil sands ores are recovered using in-situ techniques, which comprise of a single well bore for steam injection and oil production called cyclic steam stimulation (CSS) and two well bore – for continuous steam injection and bitumen production called steam assisted gravity drainage (SAGD). In CSS, steam is inject at a pressure above the fracture pressure of oilsands, opening fractures from the well and allowing steam penetration into surrounding formation. Heat from the condensing steam is allowed to soak which raises the temperature of the oil. Now the oil and condensed water are produced back into the same well and this cycle is repeated.

In the SAGD process, a pair of wellbores, an injector and a producer, 200 to 475 mm in diameter each and 1,000 to 1,600 m long, is drilled into the oil sands, 150 to 700 meters deep, depending on reservoir geology [37]. The injector and the producer sit parallel at a distance of five meters, the injector placed above the producer. Steam from surface well pads is injected at a high temperature and pressure into the injector, forming a steam chamber around it. The heat from the steam is absorbed into the reservoir which raises the temperature of bitumen. Bitumen becomes less viscous at high temperature and flows with gravity into the producer along with water. This mixture of water, oil and gases (present in the reservoir) in lifted to the surface facilities by using a pump or gas lift method. This mixture of bitumen and water is separated using gravity separation. Since the density of bitumen and water is almost the same, a hydrocarbon such as diluent which is a natural gas condensate or naphtha, is added for ease of separation. Diluent mixes with bitumen to form dilbit, which is less dense and less viscous, and thus helps in gravity separation from water. The produced water from the reservoir has to be cleaned and treated to get rid of the oil particles before it can be used to generate steam. The oil particles are removed using oil removal filters, before the water is sent for further treatment. The de-oiled water along with makeup water is treated in ion exchangers or evaporators to remove dissolved solids such as calcium, magnesium and silica, so as to prevent the scaling of pipes and steam generators. This water is then used as boiler feed water to produce steam in steam generators.

2.2 Methodology

2.2.1 Surface mining

The surface mining operation commences with the removal of layers of overburden (rock, sand, and clay) with shovels and trucks. The main energy input in this stage is the diesel fuel used by the shovels and trucks. Step-by-step basic engineering calculations are performed to estimate the diesel consumption per m^3 of bitumen mined.

The first step in model development is to identify the fleet of shovels and trucks used in oil sands projects. The parameters for this fleet can either be user defined or defaults in the model. The fleet considered in this study and its specific fuel consumption per hour were taken from an earlier study [36]. The next step is the calculation of the productivity of the shovels and trucks. The methodology followed in this model (shown in Figure 2) is the standard calculation methodology for general surface mining operations [38]. Oil sands ores are characterized by many parameters. Those most useful here in the calculation of shovel productivity are oil sands ore grade (that is, bitumen saturation, with ranges from 6.8 to 12.2% [39]), oil sands density, and swell factor. The model's oil sands ore grade default is 11.24% , which is an average from various surface mining projects undertaken by six major surface mining companies in 2012 [40].

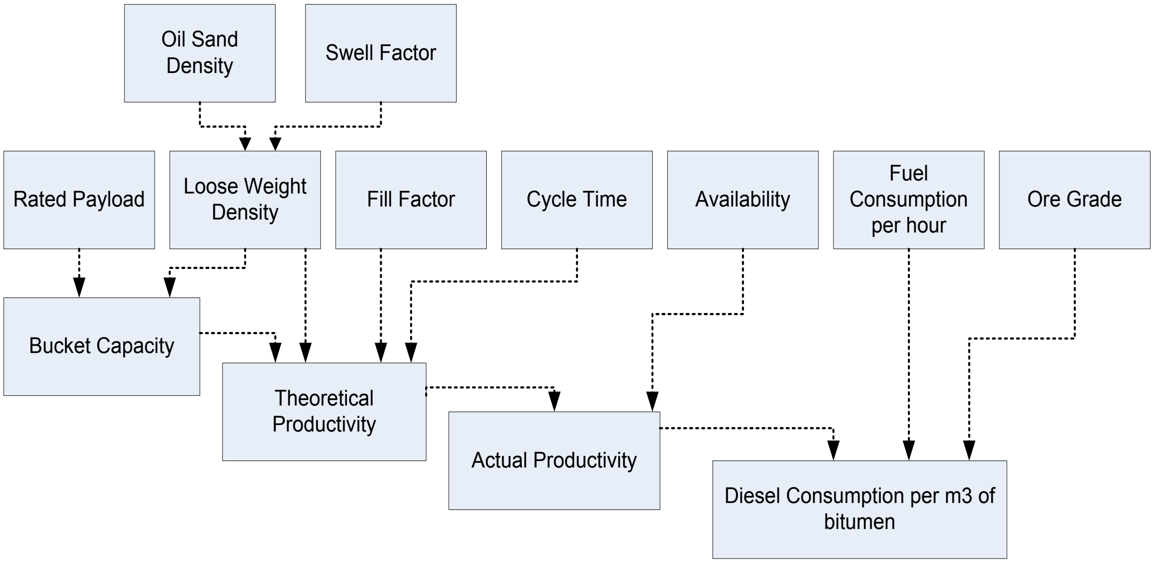

Figure 2: Methodology for calculating diesel consumption in shovels and trucks.

Parameters such as rated payload and cycle time, which are specific to the type and model of the shovel used in the oil sands, are taken from the individual company brochure for that particular type of shovel. The shovel's bucket capacity is based on the material density of the oil sands ore. Further, previously gathered data are used to estimate diesel consumption in shovels per m^3 of bitumen mined.

Truck productivity is based on the calculation of total cycle time. Total cycle time for trucks is the sum of spot and load, haul loaded, turn and dump, haul empty, wait, and delay times. Total cycle time depends on the loading equipment used, the payload capacity of the truck and the number of trucks in the fleet [38]. An average cycle time of 18.2 minutes [38] is selected for a fleet of five trucks. Using the gathered data for fuel consumption, diesel consumption in trucks per m^3 of bitumen mined is calculated.

The mined ore is crushed through double roll crushers and rotary breakers and then sieved through vibrating screens. The material passing through screens is mixed with warm water and transported through a conditioning pipeline to extraction facilities. Operating slurry temperatures range from 35 ˚C to 75 ˚C [41, 42]. Typical operating temperature of slurry mixtures in pipelines is 40-50 ˚C [39]. At extraction facilities, bitumen froth (60% + bitumen; the remainder is water) [43] is separated from sand in separation vessels. The amount of hot water consumed per m^3 of bitumen ranges from 6 to 9 m^3 depending on the grade of the oil sands ore [39].

Table 1: Input parameters to determine natural gas requirements.

Parameter	Value	Comments/References
Warm water consumption (m^3/m^3 of bitumen)	8	Varies by grade (6 - 9 m^3/m^3) [39]
Water temperature (˚C)	50	
Efficiency of heat exchanger (%)	60	Varies depending upon the liquid temperatures and design of exchanger. A generic value is assumed and considered as a sensitivity parameter. See section 2.3.1
Efficiency of steam boiler (%)	85	[42]

The main energy input in extraction is natural gas, which is required to heat water and for electricity used to drive pumps and floatation vessels. The model determines the amount of natural gas required to generate warm water based on heat and mass balance principles. The input parameters for this module are given in Table 1. The amount of natural gas required depends on the process conditions of the steam. The steam used in surface mining is generated at 400 ˚C and 7 MPa [42]. Because of the huge steam requirement and the simultaneous requirement of electricity, all existing oil sands mines have cogeneration facilities [44]. In view of current industry practices, this model incorporates all the options of cogeneration.

The model considers three different cogeneration scenarios in surface mining operations. Case 1: No cogeneration – a stand-alone operation for on-site steam generation using a natural gas-fired industrial boiler and electricity purchased from Alberta’s grid. In this case, the model estimates the natural gas required to generate the steam that in turn heats the process water. The electricity demand for the plant is satisfied by electricity imported from Alberta’s grid, which is mainly coal- and natural gas-based [45].

Case 2: Cogeneration using a steam turbine – a combined operation for on-site steam generation using a natural gas-fired industrial boiler and on-site electricity generation using a steam turbine. The exhaust from the steam turbine undergoes a temperature change in a heat exchanger that heats the process water. The heat exchanger was designed for 1 MPa of saturated steam [42]. The model calculates i) natural gas required and ii) electricity generated in this cogeneration cycle.

Case 3: Cogeneration using a gas turbine – a combined operation for on-site steam generation using a natural gas-fired industrial boiler and on-site electricity generation using a gas turbine. The fuel for the turbine is natural gas. The exhaust from the turbine is at a high temperature of 450-500 ˚C [46]. The mass of exhaust is estimated using a stoichiometric combustion equation [47]. The waste heat energy in the exhaust is recovered in the heat recovery steam generator (HRSG). 55% of the heat in the exhaust is recovered in HRSG [21]. The exhaust energy may or may not be sufficient to heat process water. When there is insufficient exhaust energy, additional natural gas is fired into the HRSG. The model calculates through iterations i) the total natural gas required to heat process water and ii) the electricity generated in this cogeneration cycle.

The electricity consumed in the plant may be either generated on site or purchased from the grid. Apart from this, as electricity is cogenerated, the excess electricity is exported to the grid. Different emissions factors of on-site generated electricity and grid electricity make it mandatory to account for each kind of electricity individually. Due to the special nature of the equipment used in oil sands extraction [42], it is not possible to estimate electricity consumption through basic equations; therefore, the electricity required per m^3 of bitumen was estimated from literature findings and actual data reported by industry to the Energy Resources Conservation Board (ERCB) [40], now the Alberta Energy Regulator, a regulatory body of the Alberta government. Only two oil sands companies have reported data for their stand-alone mining projects [18]. The values used in this model are calculated from the data reported by these companies over three years, 2010-

2012. The model predicts the electricity exported to the grid in each of the cogeneration cases. It has been assumed that the grid infrastructure already exists to take the extra load of electricity export from oil sands.

2.2.2 Steam Assisted Gravity Drainage (SAGD)

In the SAGD process, a pair of horizontal wellbores or pipes (an injector and a producer), is drilled into oil sands, 150-750 meters deep, depending on the reservoir. Steam is injected from above-surface facilities into the injector, then rises, condenses, and washes the hot bitumen along with condensed water into the producer well that is 3-5 m below the injector well. The hot bitumen-water mixture is pumped to the surface where it is separated. Because the density of bitumen and water are not very different, a diluent, usually naphtha or natural gas condensate, is added to facilitate this separation. Diluent mixes with bitumen to increase the American Petroleum Institute (API) gravity of the mixture and thus ease the separation. The water is treated so that it can be used again to produce steam. A detailed schematic of the process is shown in Figure 3.

Natural gas is required to generate steam in the process, and electricity is required to drive basic equipment, such as the pumps and the evaporator. The model calculates the amount of natural gas and electricity consumption in SAGD unit operations.

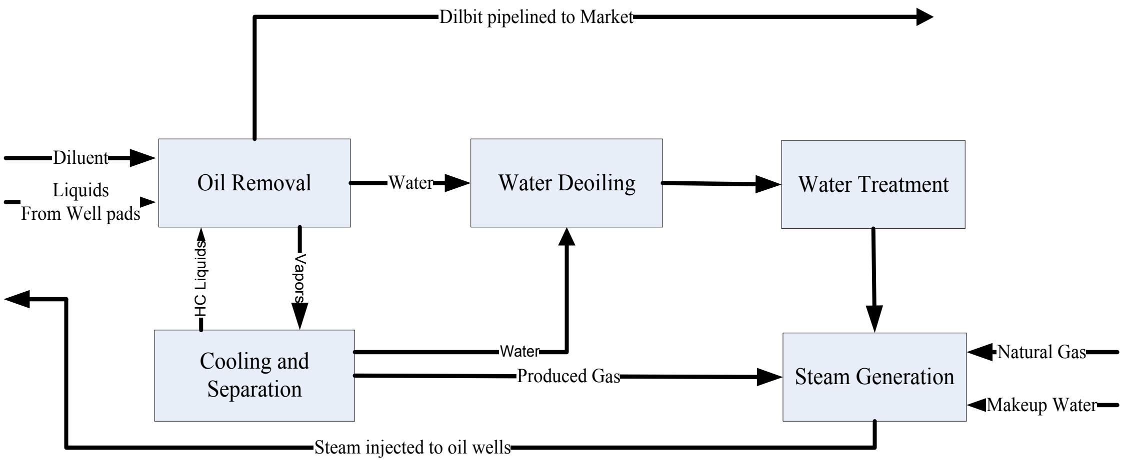

Figure 3: Subunit operations in SAGD.

Natural gas consumption is calculated based on 1) the steam-to-oil ratio (SOR), 2) the process conditions for steam (temperature, pressure, and quality of steam generated), 3) the amount of produced gas, 4) the boiler feed water temperature, and 5) the efficiency of the system equipment. The user can either enter the parameters for specific projects or use the default values in the model. The SOR is a single metric that defines the efficiency of the operation. The SOR can be expressed as a cumulative steam-to oil-ratio (cSOR) or an instantaneous steam-to-oil ratio (iSOR). The cSOR is a measure of the average volume of steam required to produce one unit volume of bitumen over the entire life of project, whereas the iSOR is a measure of the instantaneous or current rate of steam. The SOR may change depending upon the current stage of the project. For an individual well pair, the SOR is high at the start of the project, decreases sharply in the first 18 months, and then declines slightly as the project proceeds towards maturity [48]. The model built is flexible enough to asses both of these options.

The model uses a default iSOR of 2.75, though this figure can vary from 2.1 to 6.54 [49]. The majority of the projects operate at the lower end of the SOR range. The steam used in a SAGD operation is generated at 8 MPa [36] with a dryness factor of 0.8 [21].

The model explores two different cogeneration scenarios in SAGD operations.

Case 4: No cogeneration – a stand-alone operation for on-site steam generation using a natural gas-fired industrial boiler and electricity purchased from Alberta's grid.

Case 5: Cogeneration using a gas turbine – a combined operation for on-site steam generation using a natural gas-fired industrial boiler and on-site electricity generated with a gas turbine.

The methodology for cogeneration is detailed in section 2.2.1. Almost all SAGD operations use gas turbines for cogeneration [46], hence the use of a steam turbine for cogeneration was not explored. The natural gas consumed in the process also depends on the amount of co-produced gas. This can range from 1 to 12 m^3/m^3 of bitumen [21], with a default value of 4 m^3/m^3 of bitumen used in the model. The energy content of co-produced gas is one-third of the energy content of natural gas [50].

The other fuel consumed in SAGD is electricity, which powers pumps, evaporators, and other equipment. The original SAGD operations used gas lift technique to lift fluids, mainly bitumen and condensed water, to the surface. These days, electrical submersible pumps (ESPs) are used. This change has resulted in a lower SAGD operating pressure, thus lowering steam losses and energy use and improving the SOR [48]. The model developed for this study explores both gas lifts and ESPs. The electricity consumption to drive the ESPs is calculated using reservoir characteristics (reservoir temperature, bottomhole pressure), operating parameters (wellhead pressure, horizontal and vertical well depth, diameter of production well), and bitumen properties (viscosity, API). These parameters can be entered by the user, and default values are provided based on data from the literature. The parameters are detailed in Table 2. Pumping power is based on the pressure gradient between the bottomhole pressure and wellhead pressure. This pressure gradient is quantified using head loss due to elevation and friction, which is further based on parameters such as the Reynolds number, relative roughness, diameter of the production well, and velocity. In the gas lift technique, the gas used is either the gas produced along with the bitumen, air, or natural gas. The main source of energy consumption in the gas lift technique is the electricity consumed by the compressor. Compressor power was estimated using basic engineering equations for power calculation. The major consumer of electricity is the evaporator, which is used for water treatment. The recycled water, or make-up water, needs to be treated before it can be used for steam production. Electricity consumption in evaporators was estimated using proved correlations. Evaporator power depends upon the vapor mass flow rate, the rise in temperature in the compressor, and a constant that depends on the size of evaporator [51].

Table 2: Technical parameters used to estimate power consumption in pumps and compressors in SAGD.

Parameter	Value	Comment/Reference
Wellhead pressure (kPa)	1200	1100 kPa is required to maintain flow through surface facilities [52]. A reasonable value to 100 kPa more is assumed to be at the pump outlet.
Bottomhole pressure (kPa)	500	[53]. For a gas lift, higher pressures up to 2100 kPa are used.
Pump efficiency	70%	[54]
Compressor efficiency	75%	[54]
Horizontal well depth (m)	800	[55]. Project specific and in the range of 750–1000m.
Vertical well depth (m)	200	[56]. Project specific and in the range of 100–400m.

2.3 Results and Discussions

2.3.1 Surface Mining

The diesel consumption calculated by the model is in the range of 5-8 L/m^3 of bitumen mined, depending upon the technical parameters and conditions. The fuel used by trucks is a major portion of the total diesel fuel consumed in surface mining unit operations.

The electricity consumed in this unit operation is in the range of 72 kWh to 85 kWh (default value – 80.4 kWh) per m^3 of bitumen mined. In the "no cogeneration" case, all the electricity is purchased from Alberta's grid. For cogeneration projects, electricity is generated on site using natural gas. In some companies' projects, apart from on-site electricity generation, some electricity is purchased from the grid. The grid electricity consumption amounts to 10-20% of the total electricity consumed [40]. The option of using grid electricity along with cogeneration (which is specific to certain projects due to their location) is also explored. The figures in the literature for electricity consumption in surface mining unit operations vary widely. Bergerson et al. reports 50-100 kWh of electricity consumption per m^3 bitumen [20]. A feasibility study of a stand-alone surface mining project estimates 34 kWh of electricity consumption per m^3 of bitumen [42].

In the absence of cogeneration (Case 1), the model calculates that 64 m^3- 90 m^3 (default value – 75 m^3) of natural gas is consumed per cubic meter of bitumen mined. In the case of cogeneration with a steam turbine (Case 2), 75 m^3 to 105 m^3 (default value – 87.4 m^3) is consumed, depending on the process conditions and efficiency of the process. While natural gas consumption increases in the cogeneration case, electricity is cogenerated. The electricity cogenerated is 53 kWh to 74 kWh (default value – 61.8 kWh) per m^3 of bitumen. In Case 3, 78 m^3 to 95 m^3 (default value - 87.3 m^3) of natural gas is consumed, whereas 79 kWh to 140 kWh (default value – 107.3 kWh) of electricity is generated per cubic meter of bitumen mined. Of all the electricity produced on site, a major portion is used to fulfill the electricity demands of the plant and the remaining portion offsets the grid electricity.

Emissions factors for diesel and natural gas equipment used to calculate GHG emissions are imported from the GREET model (version 4.02a) [19]. These factors include both combustion and upstream emissions. Upstream emissions are those associated with recovery, transport, and processing of fuel. 17% of the total diesel emissions come from the upstream emissions of diesel (recovery, transportation, refining etc.). This value drops to 9% in the case of natural gas. An emissions factor of 880 grams of carbon dioxide equivalent per kWh of Alberta's grid electricity used has been used. The surplus electricity that is generated on site using a much cleaner fuel – natural gas – is exported to the coal-based grid. The method used to calculate the associated emissions can greatly affect the emissions for the overall project. In the case of cogeneration, where excess electricity is exported to the grid, an emissions factor of 650 grams of carbon dioxide equivalent per kWh of displaced grid electricity is used. The emissions factor used is as per the memorandum issued by the Climate Change Secretariat, Government of Alberta [57].

The GHG emissions associated with recovery and extraction in surface mining operations are presented in Table 3. The table shows the type and quantity of fuel mix in surface mining. The range of values depicts the variation in surface mining projects, the ore grade, and the technology used.

Table 3: Fuel consumption and GHG emissions in surface mining.

	Fuel Consumption			**Emissions**		
	Unit	Range	Default	Unit	Range	Default
Diesel	L/m^3 of bitumen	5- 8	6.23	kgCO$_2$eq/m^3 of bitumen	16- 25.7	20
Electricity	kWh/m^3 of bitumen	72 - 85	80.4	kgCO$_2$eq/m^3 of bitumen	63.3- 74.8[c]	70.7[c]
Case 1: No cogeneration						
Natural Gas	m^3/m^3 of bitumen	64 - 90	74.4	kgCO$_2$eq/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$_2$eq/m^3 of bitumen	63.3- 74.8[c]	70.7
Case 2: Cogeneration with steam turbine						
Natural Gas	m^3/m^3 of bitumen	75 - 105	87.4	kgCO$_2$eq/m^3 of bitumen	168.6- 236.1	196.5
Electricity Co-produced	kWh/m^3 of bitumen	53 - 74	61.8			
Net electricity	kWh/m^3 of bitumen	11 - 19	18.6[a]	kgCO$_2$eq/m^3 of bitumen	9.68- 16.7[c]	16.4[c]
Case 3: Cogeneration with gas turbine						
Natural Gas	m^3/m^3 of bitumen	78 - 95	87.3	kgCO$_2$eq/m^3 of bitumen	175.4- 213.6	196.3
Electricity Co-produced	kWh/m^3 of bitumen	79 - 140	107.3			
Net electricity	kWh/m^3 of bitumen	7 - 55	26.9[b]	kgCO$_2$eq/m^3 of bitumen	-(4.5 – 35.7)[d]	- 17.5[d]

(a) Imported from the Alberta grid; electricity production with a steam turbine in the default case is lower than the electricity demand of the project; (b) Surplus electricity is exported to the grid and displaces the coal-based grid electricity; (c) Alberta grid emissions; (d) Calculated based on an emissions factor of 650 gm/kWh [57]. Negative sign signifies the credit given for displacing GHG-intensive electricity.

The emissions from surface mining unit operations range from 180 kg to 302 kg CO$_2$ equivalent per cubic meter of bitumen mined (4.4-7.4 gCO$_2$eq/MJ of bitumen), depending upon the process conditions, ore grade, cogeneration scenario, and technology used. Emissions are highest in the “no cogeneration” case (Case 1) – 230 kg- 302 kg/m^3 (5.64-7.4 gCO_2eq/MJ of bitumen) as shown in Table 3. Cogeneration technology with gas turbines can reduce emissions more, as these export more electricity to grid than do steam turbines. Emissions in this case are reduced by 12-30%. Emissions from diesel are a small part (approximately 10%) of total emissions in surface mining. Natural gas emissions (on-site combustion and upstream emissions from natural gas recovery, transportation, processing, etc.) form a major portion of total emissions – 65% in Case 1 to 98% in Case 3. Alberta’s grid electricity use accounts for 24-29% of the total emissions in Case 1 and 4-7% in Case 2. This lower emission is because of cogeneration. Cogeneration satisfies the majority of plant demand. The remaining demand, which is satisfied by the import of grid electricity, accounts for 4-7% of total emissions. In Case 3, the electricity emissions are negative, as shown in the Figure 4. Negative emissions signify the displacement of coal-based grid electricity by the much cleaner natural gas-generated electricity. Net emissions are lowered by 2% to 17%, hence net emissions in Case 3 ranges from 180 kg to 226 kg/m^3 of bitumen mined (4.4 – 5.4 gCO_2eq/MJ of bitumen).

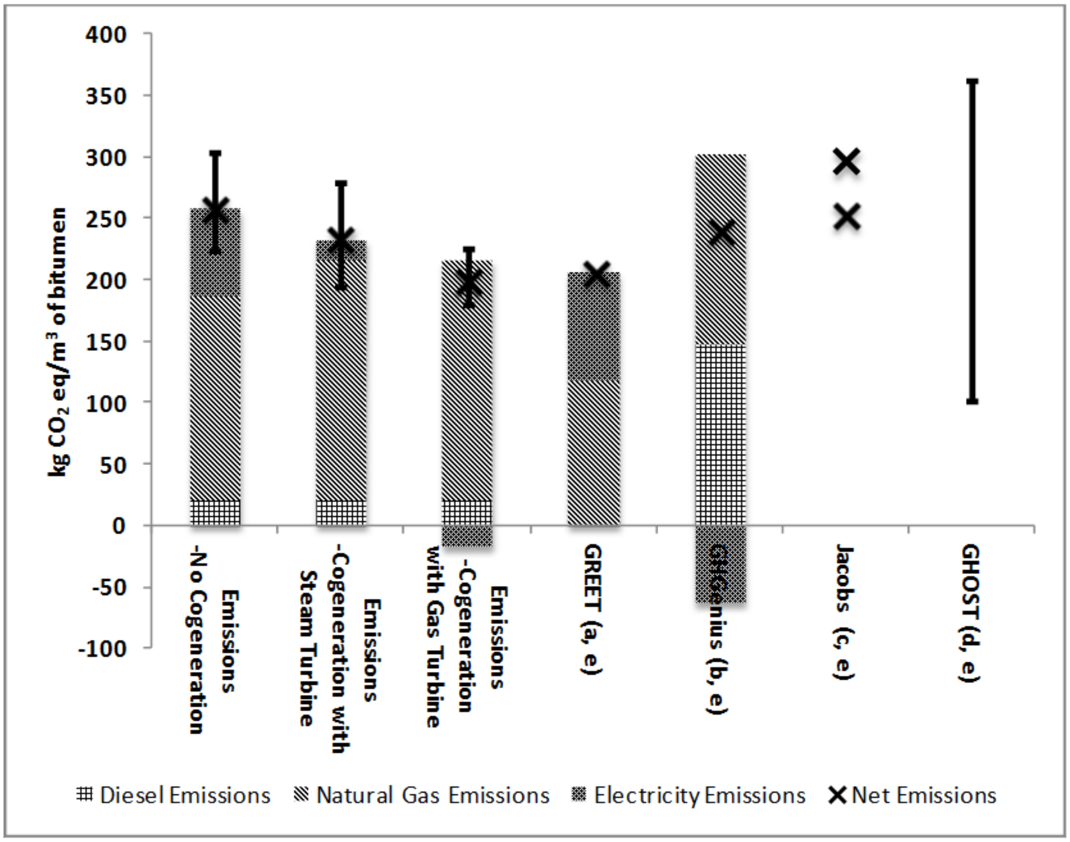

Figure 4: Estimated GHG emissions in surface mining in comparison to existing literature and models.

(a) [19] Emissions are calculated based on default values of fuel consumption specified in the model; (b) [18] Emissions are calculated based on default values of fuel consumption specified in the model; (c) [15] The lower value is with cogeneration and the higher value corresponds to the "no cogeneration" case. The emissions reported are based on the assumption that energy in surface mining is about one half of the energy consumed in SAGD operation with SOR of three; (d) [20] The "no cogeneration" and "with cogeneration" ranges overlap; the range shown is a combined range; (e) Values reported in the literature have been converted using 8 API gravity and LHV of bitumen from the GHGenius, for comparison purposes.

Figure 4 presents emissions results from this research and compares it with those of previous literature and models. The results are in agreement and close in range to values predicted by earlier models and studies. The emissions for the "no cogeneration case" estimated from this research (257.9 kg/m^3 of bitumen) are in between the emissions reported by GREET (206.2 kg/m^3 of bitumen) [19] and Jacobs (297.54 kg/m^3 of bitumen) [15]. The variations in values reported in the existing literature are due to differences in boundary conditions, assumptions, technology evaluated, and fuel input. The GHGenius [18] model considers cogeneration in surface mining operations whereas the GREET model does not. Our research covers and presents results for cases without cogeneration and with cogeneration using steam or gas turbines. The range of emissions presented in this research is obtained using default values and sensitivity analysis, and lies within the broad range represented by GHOST [21].

Sensitivity Analysis

The sensitivity of diesel fuel consumption to key technical parameters is shown in Figure 5. The shovel parameters, such as payload, cycle times, fill factor, availability, and fuel consumption, have little impact on the total diesel consumption because shovels require relatively little fuel.

Of all the truck parameters considered, diesel consumption per hour, availability, and truck payload have significant effects; these parameters require large amounts of diesel and so call for effective truck allocation in order to reduce diesel fuel use [58]. Diesel consumption is sensitive to the ore grade. A good grade of ore, meaning higher concentrations of bitumen, consumes less diesel per unit volume of bitumen mined than low grade ore.

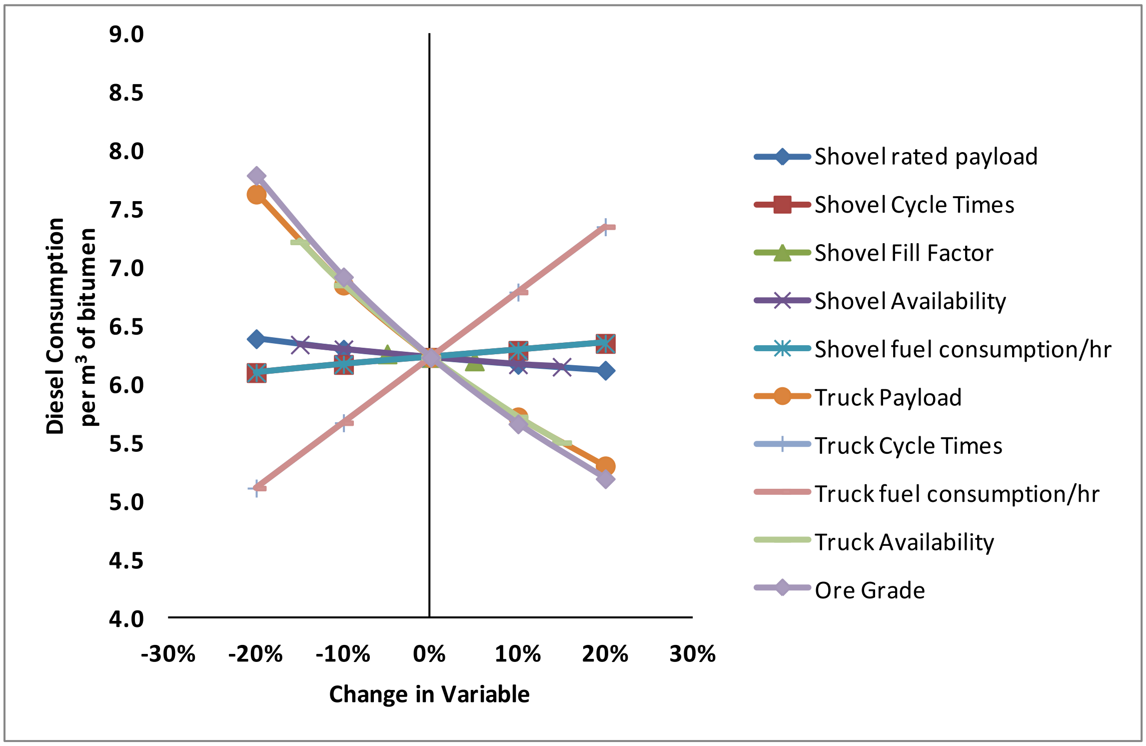

Figure 5: Sensitivity analysis of diesel consumption in shovels and trucks used in surface mining.

An analysis of the sensitivity of various parameters was conducted to determine the effect of each parameter on net GHG emissions from the unit operations. The following key parameters were investigated: water temperature, water consumption, heat exchanger efficiency, boiler efficiency, diesel consumption, electricity consumption, and electricity emissions factors. The sensitivity corresponds to the base case with no cogeneration (Case 1). As illustrated in Figure 6, the emissions in surface mining are highly sensitive to temperature and warm water consumption. Equally influential are the efficiency of the boiler and the heat exchanger. Diesel consumption, the electricity emissions factor, and electricity consumption have a relatively minute effect on net GHG emissions in surface mining because diesel consumption and electricity form a small portion (approximately 10% and 25%, respectively) of total surface mining emissions. Other parameters affect natural consumption, which accounts for around 65% of the total surface mining operations. Lowering water temperature to 35 ˚C from the 50 ˚C used today would result in 25% fewer emissions in surface mining. Approximately 42% more emissions are found in processes that use high temperatures (i.e., around 75 ˚C). Improvements in heat exchanger and boiler efficiency would result in less natural gas use and hence would reduce the total emissions in surface mining. However, because the boiler and heat exchanger technology has already matured, the scope of improvement in this technology is limited. Technology improvements that result in reduced warm water consumption would reduce surface mining emissions. A 10% reduction in the consumption of warm water would result in about a 7% reduction in surface mining emissions.

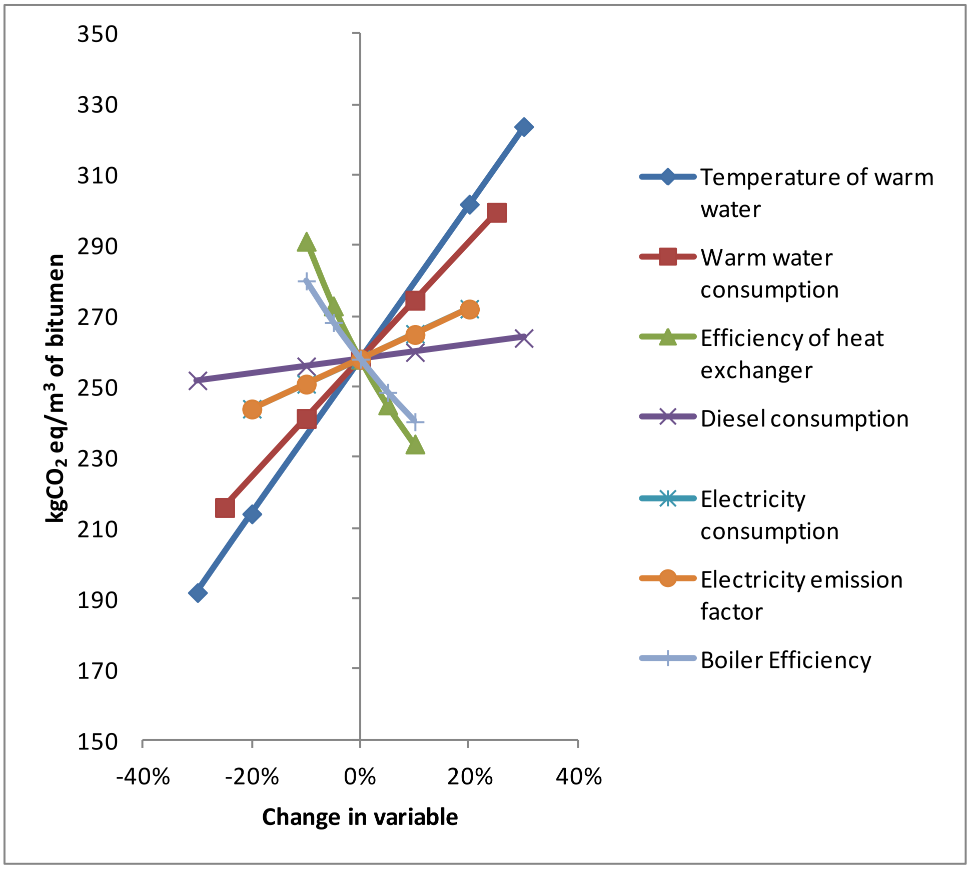

Figure 6: Sensitivity analysis of GHG emissions on key parameters in surface mining (Case 1).

2.3.1 Steam Assisted Gravity Drainage (SAGD)

Specific energy consumption and emissions from each fuel input estimated by the model are shown in Table 4. The natural gas consumption in the "no cogeneration" case (Case 4) varies from 150.3 to 468 (default value – 178.9) m^3/m^3 of bitumen, depending upon the steam-oil ratio and the efficiency of the process. Whereas the SOR varies from project to project and can be user specific, the model uses a default value of 2.5. With improvements in technology and with project maturity, oil sands companies have been able to achieve a SOR as low as 2.1 [49]. Natural gas consumption in the cogeneration case (Case 5) is higher, ranging from 337.9 to 1052 m^3/m^3 of bitumen (default value – 402.2). Electricity consumed in evaporators form a significant portion of the plant's total electricity demand [50]. Industry personnel expect a relationship between instantaneous SOR and electric power consumption [21]. A linear relationship, as shown in Figure 7, is estimated for iSOR and electric power consumption. In [15], a similar kind of relationship was estimated with actual industrial SAGD data and the observation that evaporators are a major consumer of electric energy in SAGD operations. Power consumed by evaporators is correlated linearly to the amount of water treated for steam formation.

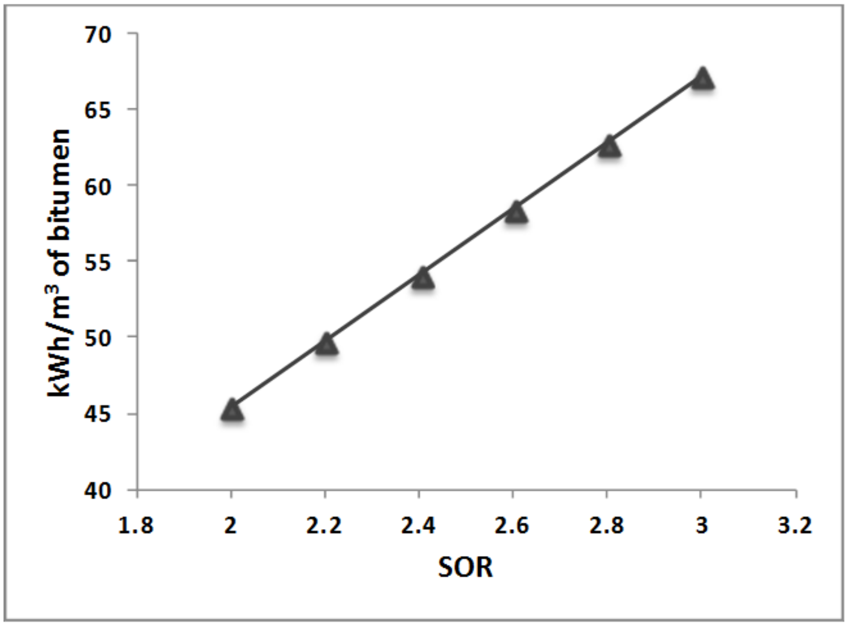

Figure 7: Correlation between electricity consumption and instantaneous SOR in SAGD.

Table 4: Fuel consumption and GHG emissions from SAGD.

	Fuel Consumption			Emissions		
	Unit	Range	Default	Unit	Range	Default
Case 4: 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[c]	49.5
Produced Gas	m^3/m^3 of bitumen	1 – 12[a]	4	$kgCO_2eq/m^3$ of bitumen	2-24.7[e]	8.2
Case 5: With cogeneration						
Natural Gas	m^3/m^3 of bitumen	277.5 - 562	301.8	$kgCO_2eq/m^3$ of bitumen	624- 1263.6	678.6
Electricity Co-produced	kWh/m^3 of bitumen	700 – 886	792.7			
Net electricity	kWh/m^3 of bitumen	653.5-741.3[b]	736.4	$kgCO_2eq/m^3$ of bitumen	-(388- 445.3)[d]	- 478.2[d]
Produced Gas	m^3/m^3 of bitumen	1 - 12	4	$kgCO_2eq/m^3$ of bitumen	2- 24.7[e]	8.2

(a) [21]; (b) Obtained by subtracting the lower values and higher values in the range. But other combinations may be possible; (c) Alberta grid emissions. (d) Calculated based on an emissions factor of 650 gm/kWh [57]. Negative sign signifies the credit given for displacing GHG-intensive electricity. (g) The emissions factor for produced gas is same as natural gas combustion factor.[21] The upstream emissions associated with production, recovery, and transportation are zero as this gas is produced along with the bitumen.

Emissions in SAGD range from 381.7 to 1204 $kgCO_2eq/m^3$ of bitumen (9.3- 29.5 gCO_2eq/MJ of bitumen) in Case 4 to 238 to 843 $kgCO_2eq/m^3$ of bitumen (5.8-20.7 gCO_2eq/MJ of bitumen) in Case 5. As shown in Figure 8, natural gas emissions are the main contributing emissions, 87% in the “no cogeneration” case. Electricity emissions comprise 10-31% (default value – 11%) of the total emissions in SAGD. The produced gas emissions form a very small part of the total emissions in SAGD [21].

Natural gas consumption increases with cogeneration and results in a 69% increase in natural gas emissions. However, the extra natural gas consumption lowers net emissions because electricity in excess to the plant’s demand is produced. This excess electricity displaces the GHG-intensive Alberta grid electricity. Hence the net emissions are reduced by 47%.

The SOR in industry is used to define the efficiency of SAGD operations. Improving the SOR from 2.5 to 2 leads to a 20% reduction in net emissions in Case 4. While this model incorporates the use of evaporators for water treatment, other methods such as warm lime softening may also be employed. GHG emissions from treating the produced water in evaporators are 7% to 8% higher than emissions from treating produced water in warm lime softening [59].

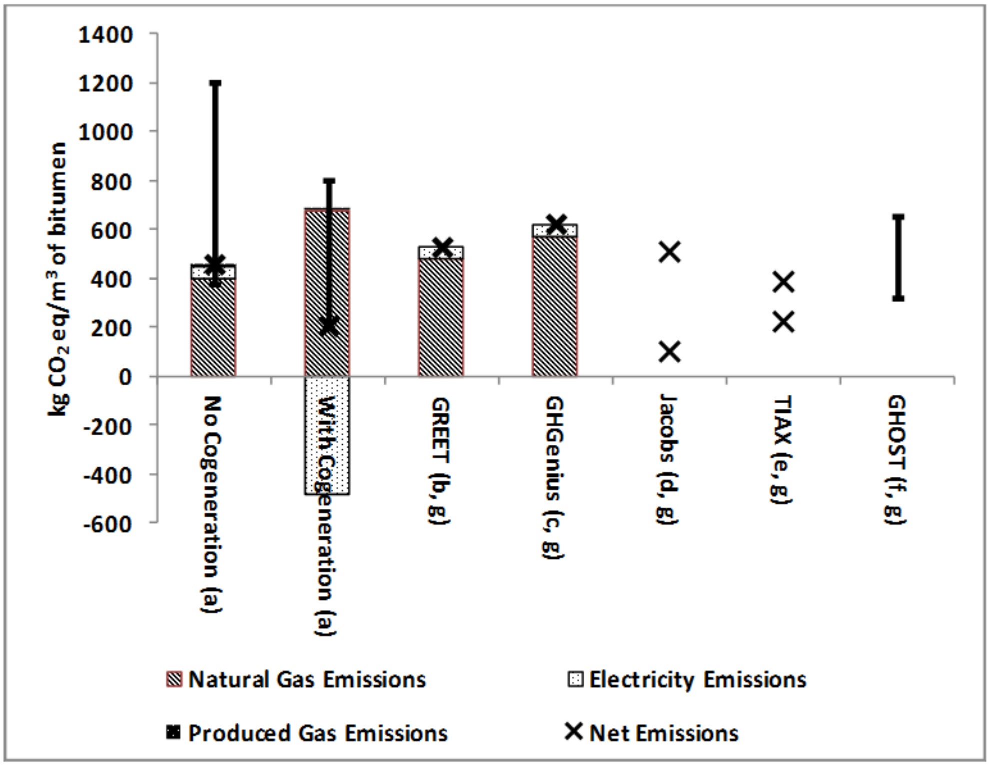

Figure 8: Estimated GHG emissions in SAGD in comparison to existing models and literature.

(a) The wide range of values is due to the exclusive range of SOR considered – 2.1 to 6.54, with a default value of 2.5; (b) [19]. Emissions are calculated based on default values of energy consumption specified in the model; (c) [18]. Emissions are calculated based on default values of energy consumption specified in the model; (d) [15]. The lower value is associated with cogeneration and the higher value corresponds to the "no cogeneration" case. A SOR of 3 is considered. The credits for electricity export are given based on 80% coal based grid electricity; (e) [14]. A SOR of 2.5 is considered. The higher value is for bitumen production in SAGD with electricity export; (f) The SOR considered is in the range of 2.2-3.3; (g) Values reported in the literature were converted for comparison purposes using 8 API gravity and LHV of bitumen from the GHGenius model.

As illustrated in Figure 8, the model predicts emissions well within the ranges given in existing models, industry consultancy reports, and peer-evaluated studies. This model covers a large range of iSORs (2.1 to 6.54) and presents a wide range of emissions. GREET and GHGenius models do not consider cogeneration in their default fuel input, hence compare with the “no cogeneration case” in our research. The emissions estimated by GREET and GHGenius are higher (10% and 21%, respectively) than the default emissions in our research, but are covered in the broad range of emissions presented in our research. Jacobs [15] reports lower emissions in the cogeneration case than estimated by our research because of the use of 80% coal-based grid electricity for giving the credits for electricity export. The model predicts values well in the range of the GHOST model values.

Sensitivity Analysis

The sensitivity analysis of GHG emissions in SAGD unit operations was investigated in terms of quantity of steam, steam conditions, reservoir properties, and other technical parameters. The quantity of steam used is represented by the iSOR, whereas saturated pressure and the quality of the steam represent steam conditions. Reservoir considerations include produced gas, horizontal well depth, vertical well depth, bottomhole pressure, and wellhead pressure. Other important technical parameters are the efficiency of the boiler and the heat exchanger.

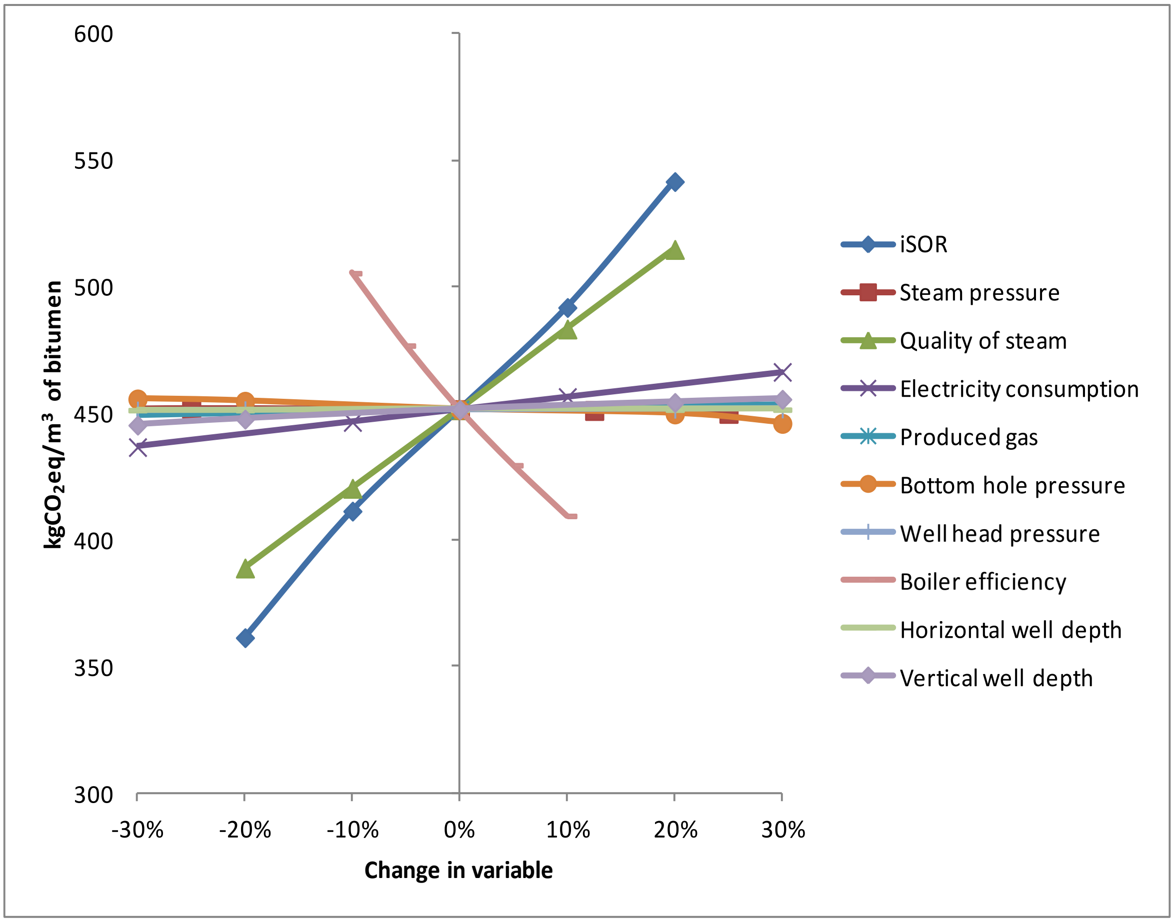

Figure 9: Sensitivity analysis of GHG emissions on key parameters in SAGD (Case 4).

The iSOR and quality of steam used are the parameters to which GHG emissions are most sensitive. As shown in Figure 9, improving the iSOR from 2.5 to 2 would result in a reduction in net emissions by 20%. A 10% increase in the quality of steam at required conditions leads to 7% increase in consumption of natural gas, which leads to higher emissions. The amount of electricity consumed in the pumps or the compressor used in the case of the gas lift depends on parameters such as bottomhole pressure, wellhead pressure, vertical well depth, and horizontal well depth. These parameters have a small effect on the net emissions because electricity emissions are a small portion (about 13% in Case 1) of total emissions in SAGD.

Produced gas in SAGD ranges from 1 to 12 m^3/m^3 of bitumen [21]. This wide range effects the emissions minutely because the LHV of produced gas is one third that of natural gas. Therefore the amount of natural gas displaced by the produced gas does not change by much.

2.4 Conclusions

Our research presents a data intensive theoretical model to estimate energy consumption, fuel mix, and emissions for each individual extraction and recovery project in the oil sands. The model predicts GHG emissions (180 kg to 302 kgCO2eq/m3 of bitumen in surface mining and 381.7 to 1204 kgCO2eq/m3 of bitumen in SAGD) well in the range of existing models and literature. The model would help industry to make decisions to further reduce GHG emissions in each stage in the unit operations. Emissions in surface mining (excluding the fugitive emissions from tailings and land-use emissions) are lower than emissions from SAGD. Emissions in surface mining are sensitive to temperature and warm water consumption. Natural gas is the single largest energy source in both surface mining and SAGD unit operations. In SAGD, where the SOR is the single important factor affecting net emissions, reducing the SOR would mean greater efficiency and fewer GHG emissions. Cogeneration has the potential to lower the net environmental impact of oil sands activities.

Chapter 3

Energy consumption and greenhouse gas emissions in upgrading and refining of Canada's oil sands[2]

3.1 Introduction

This chapter details the upgrading unit operations in oil the sands that are used to convert bitumen to a premium fuel known as synthetic crude oil (SCO). This chapter describes the assumptions and methodology used to develop the Excel model to estimate energy consumption and GHG emissions in each sub unit operation of the upgrader. The main fuels used in upgrading are natural gas and electricity. Natural gas is used as fuel, and feedstock for hydrogen production, as well as for steam production. Fuel gas produced in the upgrader augments the use of natural gas as fuel. This chapter estimates the volume of SCO produced from upgrading a unit of bitumen based on mass balance. The sensitivity of GHG emissions in upgrading operations on key parameters has been analyzed. Further sections of this chapter introduce a typical North American heavy conversion refinery that is capable of refining heavy feeds such as dilbit. A process model built in Aspen HYSYS [33] was used to estimate energy consumption and GHG emissions for refining different feeds. Results obtained from the upgrading and refining operations were compared to those in published literature and reports.

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[2] The results of this chapter were submitted as "Energy consumption and greenhouse gas emissions in upgrading and refining of Canada's oil sands products, Nimana, B., Canter, C., Kumar, A., to *Energy*, 2014; XX:XX (in review).

3.1.1 Upgrading

The bitumen recovered and extracted in both surface mining and steam assisted gravity drainage (SAGD) is highly dense, viscous, and high in sulfur content. Not all the refineries in North America have capability to refine heavy feeds, so to make crude more available and to ease transportation, Canadian crude is upgraded to what is known as synthetic crude oil (SCO). Bitumen is fractionated or chemically treated to yield a higher value product through a process known as upgrading. The aim of upgrading is to obtain the high quality substitute, SCO, or simply to reduce the viscosity of the crude to allow its shipment by pipeline without the need to add a solvent [60]. Upgraders are large, expensive plants that resemble refineries. Generally speaking, upgrading involves two steps – a vacuum residue conversion step to increase the hydrogen-to-carbon ratio called primary upgrading, and a secondary upgrading, which consists of treating the products obtained in primary upgrading to achieve below 0.5% sulfur content in the products [60, 61]. There are two major commercial primary bitumen upgrading processes: coking and hydroconversion. These processes convert raw bitumen to SCO by using heat and hydrogen as cracking agents. In the past, coking has been the predominant choice for primary upgrading as it produces bottomless SCO and can handle higher solids and water content in the feed. However hydroconversion produces a much higher volume yield of SCO because of the addition of hydrogen. The addition of hydrogen decreases the density of the product, thus producing higher volume for a fixed mass of feed.

Process Description:

Atmospheric Distillation Unit (ADU): The upgrading process begins with the separation of diluent from bitumen in the diluent recovery unit (DRU) or the atmospheric distillation unit (ADU). The diluent is reclaimed and sent back to the bitumen production where it is used again. Bitumen is fractionated into lighter fractions such as naphtha and diesel. The atmospheric residue (AR) is sent to the vacuum distillation unit (VDU) for further cracking.

Vacuum Distillation Unit (VDU): Cracking of higher boiling point fractions of bitumen takes place in the VDU. The light (LVGO) and vacuum gas oils (HVGO) produced in the VDU are sent to the gas oil hydrotreating unit (GOHT). The vacuum residue (VR) is sent to a delayed coker unit (DCU) in the case of coking or a hydrocracker in the case of hydroconversion.

Delayed Coking Unit (DCU): The coking unit converts VR into lighter components – fuel gas, naphtha, diesel, and gas oil. Fuel gas is used in the upgrading plant as support fuel to natural gas. Delayed coking produces coke as a byproduct; the coke is either stockpiled on site or transported to some Asian countries for use in power plants where the regulations are not as strict as in North America.

Ebullated Bed Hydrocracker: The hydrocracker unit uses hydrogen to crack the heavier fractions of bitumen to lighter components of naphtha, diesel, and gas oil. The residue from the hydrocracker is again mixed with the inlet feed for further conversion. In some commercial operations bitumen is not fully converted in the hydroconversion unit, thereby generating a small portion of residue that is further processed with a coking unit.

Naphtha, Diesel and Gas Oil Hydrotreating (NHT, DHT, and GOHT): Naphtha and diesel from the ADU, DCU, or hydrocracker are hydrotreated to stabilize hydrocarbons by the addition of hydrogen to unsaturated molecules. This hydrotreatment also removes impurities like sulfur and nitrogen. Similarly, the LVGO and HVGO from the VDU, DCU, or hydrocracker are hydrotreated in the GOHT to produce stabilized compounds.

Hydrogen Production: Hydrogen required in the upgrading process is produced from natural gas via steam methane reforming. Part of this natural gas is used as a feedstock that reacts with steam to form hydrogen, whereas the remaining natural gas is used as a fuel and supplies process heat to the operation.

Sulfur Plant: H_2S from different upgrading steps such as coking or hydrocracking is sent to a sulfur plant where sulfur is recovered using a Claus unit and a tail gas treatment plant.

The Hydrocarbons: The naphtha, diesel, and gas oil obtained after hydrotreating in secondary upgrading are blended to form a mixture called SCO.

3.1.2 Refining

The processing steps in a refinery are designed to obtain transportation fuels such as diesel and gasoline from crude feeds. The refineries are designed based on the feeds to be processed. Heavier feeds are refined in deep conversion refineries which consist of coking and catalytic cracking units. Lighter feeds such as light synthetic crudes are refined in medium conversion or hydroskimming refineries. Medium conversion refineries only consist of catalytic cracking unit and no cokers whereas hydroskimming does not have any residue conversion unit [23, 62]. Although refineries produce a number of profitable products, refineries desire to maximize the volume of transportation fuels gasoline, diesel and jet fuels. A typical refinery in North America is a deep conversion refinery which has coker and catalytic cracking unit.

Process Description:

Heated crude oil is charged to atmospheric distillation column where it breaks into fractions based on their boiling points- gases, kerosene, naphtha, diesel, gas oil and residue. The dense heavy crude called the atmospheric residue is sent to the vacuum distillation tower where it further breaks down to vacuum gas oils. The remaining heavy residue called the vacuum residue is sent to coker for its cracking at higher temperatures. The vacuum residue is thermally cracked in a delayed coker to produce light ends (the gases), naphtha, diesel, gas oil and a solid residue called coke. These processing steps are similar to the upgraders where heavy feeds are processed to convert to a superior refinery feed. The remaining processing steps are as follows:

Catalytic Cracking (FCC): Catalytic cracking converts the heavy gas oils from atmospheric and vacuum distillation unit into lighter hydrocarbons such as naphtha and light cycle oil with the use of heat in presence of catalysts. The light naphtha from cracking blends to form gasoline whereas heavy naphtha blends to form diesel. The slurry mixes to form the fuel oil. Another major product from the catalytic cracking unit is the carbon. This carbon is burnt off the catalyst to regenerate the catalyst.

Hydrocracking (HCD): Depending upon the refinery configuration, the gas oils from atmospheric and vacuum crude units could be sent to FCC or hydrocracking unit or split between the two. Hydrocracking helps to remove feed contaminants (nitrogen, sulfur, metals) and convert low value gas oil to valuable products such as naptha and distillates. This occurs mainly through addition of hydrogen to carbon chains. Hydrocracking in a refinery consumes significant quantities of hydrogen.

Naphtha, Kerosene and Diesel hydrotreating (NHT, KHT, DHT): Hydrotreating of Naptha, kerosene and diesel, which are formed in upstream processing steps of refinery are treated with hydrogen to remove contaminants such as sulfur, nitrogen, metals and to form a stabilize product by saturating olefins and aromatics. The hydrotreating kerosene blends with other hydrocarbons to form end product jet fuel. The diesel after hydrotreating splits to be a part of conventional diesel and fuel oil, heavier components being part of fuel oil. The hydrotreated naphtha is further processed in a reformer.

Alkylation: Olefins from coker, FCC are mixed with isobutane to form a high octane gasoline (alkylate) in presence of hydrofluoric or sulfuric acid. This alkylate mixes with other components to form gasoline.

Reforming: The hydrotreated naphtha is converted to high octane reformate for gasoline blending in a catalytic reforming process. Reforming also produces hydrogen which is used for hydrotreating processes.

Other supporting processes that take place in refinery are amine treatement plant, sulfur removal, hydrogen production. Gas processing units in the refinery separate the C_3 and $C_{4,}$ components of gases that are generated in various processing units such as distillation columns, cokers, catalytic crackers, reformers, and hydrocrackers. The gas which is mainly methane and ethane is treated in amine treatment and sulfur recovery plants before it can be used as fuel gas in refinery. A part of the hydrogen demand of refinery is fulfilled by reformer and the remaining comes from steam methane reforming. A part of the natural gas is used as a feedstock in steam methane reforming which reacts with steam to form hydrogen whereas the remaining natural gas is used as a fuel and supplies process heat to the operation.

3.2 Methodology

3.2.1 Upgrading

SCO is obtained from bitumen in large expensive plants resembling refineries. The steps in bitumen upgrading are different for each upgrader depending upon the technology, crude type, required products, and other techno-economic factors. Generally speaking, upgrading involves two steps – primary upgrading, a vacuum residue conversion step to increase the hydrogen-to-carbon ratio, and secondary upgrading, which consists of treating the products obtained in primary upgrading to achieve sulfur content below 0.5% in the products [60, 61].

The hydrogen-to-carbon ratio may be increased either through carbon rejection (coking) or hydrogen addition (hydroconversion) processes. This study evaluates the energy consumption and GHG emissions of both (coking and hydroconversion) in upgrading. The coking process produces a solid residue called coke, which is rich in carbon, sulfur, and other contaminants. In the hydroconversion process, the heavy feed is cracked in the presence of hydrogen into desirable products, leaving no solid residue. Figures 10 and 11 show the subunit operations involved in the two upgrading configurations analyzed in this study. Distillation columns (atmospheric and vacuum), hydrotreaters (naphtha, diesel, gas oil), steam methane reforming (SMR), and sulfur plants are common to both configurations. Hydrotreating (the addition of hydrogen) of gas oil, distillate and naphtha is mainly employed in secondary upgrading for the removal of sulfur and nitrogen [61]. These processes are common to both upgrading configurations analyzed in this research. In addition to the above subunit operations, the upgrader has a sulfur plant that converts the hydrogen sulfide obtained in the primary coking and hydroconversion process into elemental sulfur. The light ends produced in cokers and hydroconverters form the main constituent of the fuel gas.

The subunit operations involved in upgrading are as identified in Figures 10 and 11. The specific energy consumption in subunit operations is estimated based on basic heat and mass transfer fundamentals. The energy consumed depends on the distillation properties, sulfur content, and API (American Petroleum Institute) gravity of the feed and products. The flow of feed in the upgrading operations is traced based on mass balance and volume percentage of products distilled at each stage. The volume percentage of products distilled depends on the distillation curve of the crude.

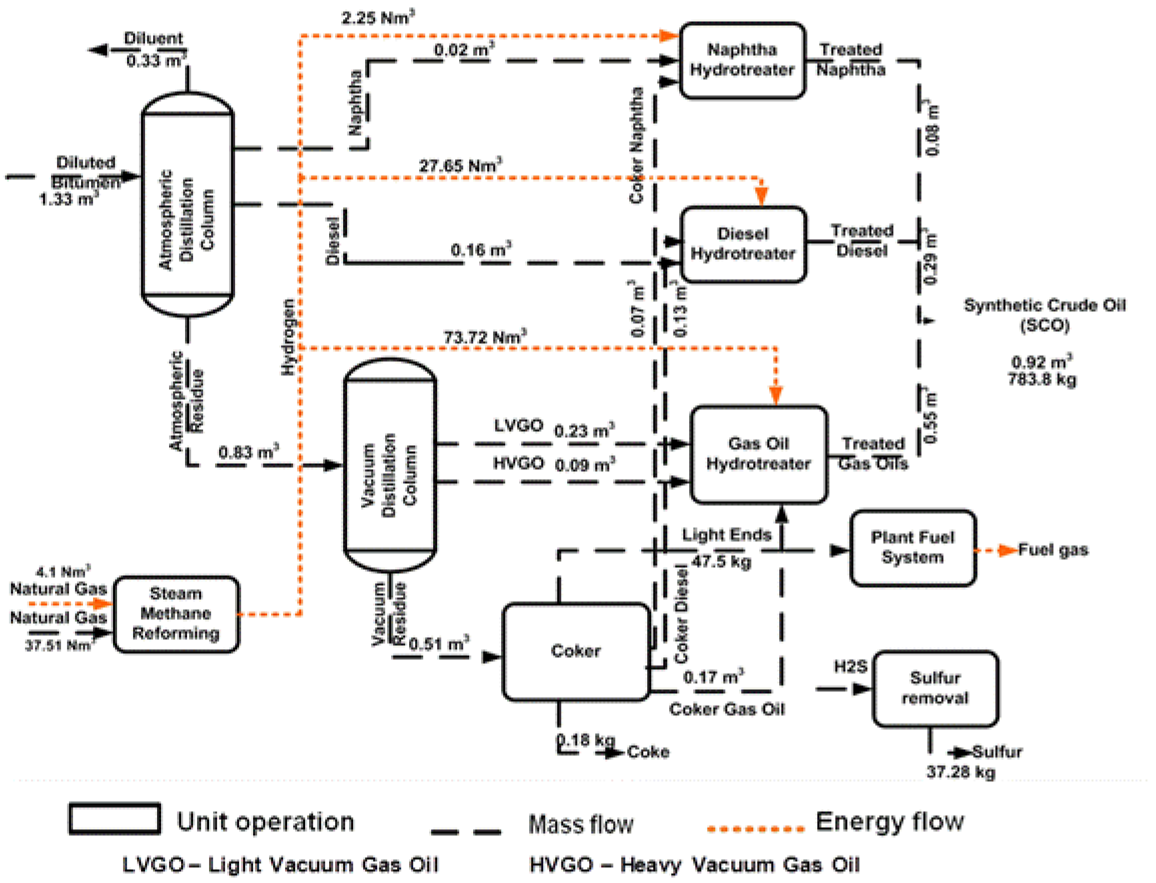

Figure 10: Subunit operations in a coking-based upgrading operation.

The energy consumed in subunit operations is in the form of steam, natural gas, fuel gas, and electricity. The default process conditions and sources of energy shown in Table 5, which were used in the development of the model, were identified based on the upgrader design proposed in [62]. Fuel energy in the atmospheric distillation and vacuum distillation columns is required to heat the crude to its vaporization temperature, and steam is required to strip the distillation products from the fractionating columns [23]. The energy required in subunit operations was calculated based on the design conditions and enthalpy of petroleum fractions. The enthalpy of petroleum fractions such as naphtha, diesel, coker diesel, dilbit, atmospheric gas oil, atmospheric residue, vacuum residue, vacuum gas oils, and coke varies from 1.38 to 2.94 KJ/Kg K [33, 61, 63]. As identified in Table 5, some of the energy required is obtained by using heat exchangers between feed and products. Steam energy and electricity used in each subunit operation is linearly related to the process unit volume feed flow [23] and was obtained from earlier studies [23, 62]. This data used for the development of the model has been detailed in Table 6. The calculations in the model are based on a unit volume of feed input and are assumed to be independent of scale of the plant.

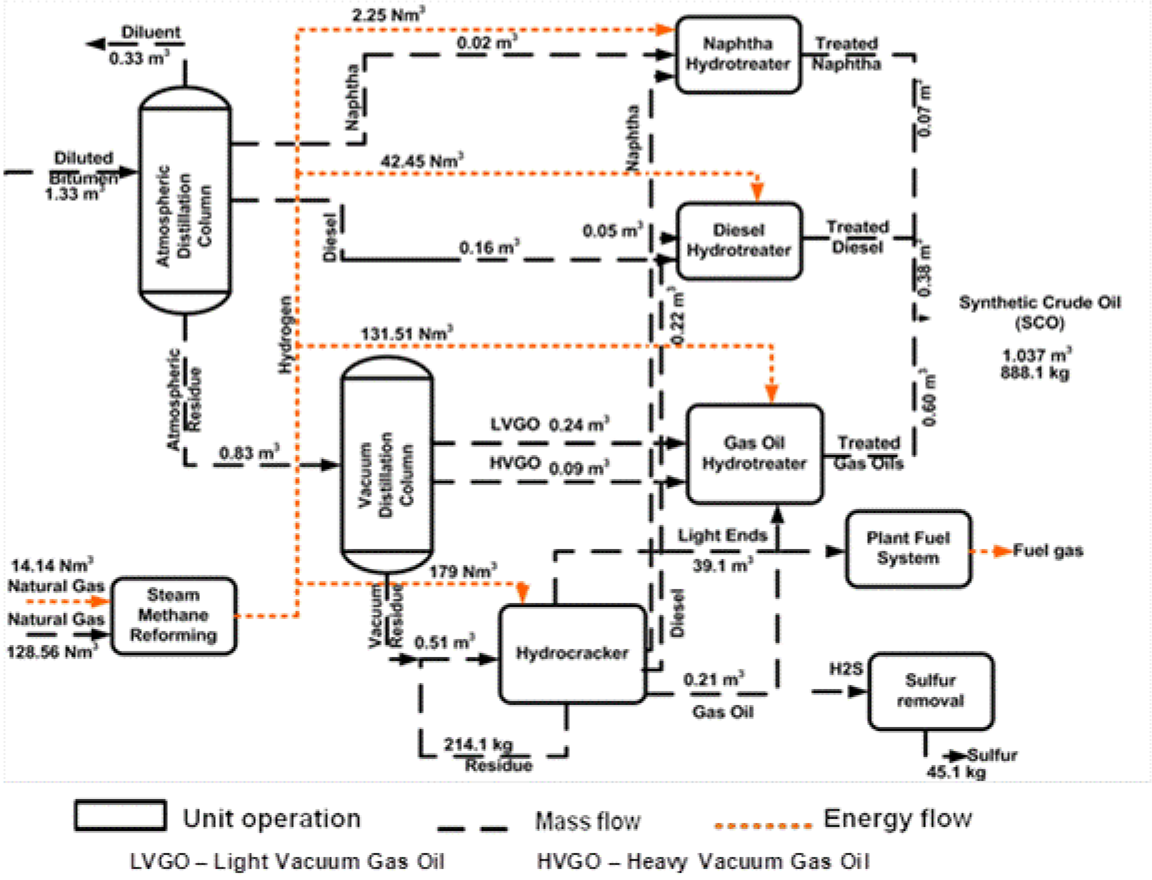

Figure 11: Subunit operations in a hydroconversion-based upgrading operation.

Another important area of energy consumption is hydrogen production. While no hydrogen is consumed in delayed cokers, a huge amount of hydrogen is required in ebullated bed hydrocrackers[3][61]. The delayed coker and hydroconversion upgrading processes yield naphtha, diesel, and gas oil with different properties. The products obtained are hydrotreated in secondary upgrading and consume different amounts of hydrogen. Hydrogen consumption in secondary upgrading leads to desulphurization, denitrification, cracking, and saturation of aromatic rings in the feed [61, 62]. Hydrogen consumption in subunit operations was estimated based on [64]. Hydrogen consumption depends on the type of feed and type of product required, hence it is considered a sensitivity parameter (see section 3.1.1). Changes in mass and volume of the products occur in secondary upgrading due to the removal of sulfur, nitrogen, and saturation of aromatic rings. These mass and volume changes are captured in the calculations based on data specified in [64].

Upgraders employ Steam Methane Reforming (SMR) that use natural gas both as feedstock and as fuel to meet their hydrogen requirements [65]. Natural gas requirements (both feedstock and fuel) are estimated per unit of hydrogen produced based on [66]. Findings from the same study were used to estimate a hydrogen plant's steam and electricity requirements. Steam is produced through heat recovery in SMR processes. This steam production is estimated per unit of hydrogen produced and fulfills some of the steam requirement in other upgrader subunit operations.

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[3] Ebullated bed reactor uses an ebullated or expanded bed of catalyst for hydrocracking (hydrogenation and acidic cracking) of residue feed (Gray, 2010). The ebullated bed reactors are favorable for Athabasca or Cold Lake feeds which have high metal content and high Conradson carbon residue (CCR) values. H-Oil and LC-Finning processes use ebullated bed reactor for upgrading of residue feeds.

Another subunit operation modeled in this research is the sulfur recovery operation. The feed for a sulfur recovery operation is calculated based on the mass balance of sulfur in the whole plant. The sulfur input to the plant is the sulfur contained in the feed. Some sulfur remains in the product (the SCO) or is removed in the coke formed in delayed cokers. The remaining sulfur is treated in the sulfur recovery operation in the form of hydrogen sulfide gas to form liquid sulfur. Hydrogen sulfide formed during hydrotreating is removed by alkanolamine absorption [61] and is then treated in the sulfur recovery operation [62]. Electricity consumed and steam produced in this operation are based on the unit mass of liquid sulfur produced and were estimated based on data from [23].

The energy needed in upgrading operations to heat the feed and produce steam comes from natural gas and fuel gas. Light ends from each subunit operation are combined and treated in the plant fuel system to form the fuel gas. The light ends from the delayed coker and the hydroconverter are the major constituent of the fuel gas [62]. Light ends satisfy a portion of the energy demand in the upgrader. Energy demand fulfilled by the fuel gas is calculated based on the mass of fuel gas produced and energy content of its constituents. The remaining energy demand is met by natural gas combustion.

This research explores cogeneration in oil sands upgrading operations. Cogeneration is a simultaneous operation for on-site generation of steam and electricity using a natural gas-fired boiler and a natural gas turbine. Heat energy is recovered from the high temperature turbine exhaust at 450-500 ˚C [67]. The mass of turbine exhaust is estimated using a stoichiometric combustion equation of the fuel in the turbine [68]. 55% of the heat in the exhaust is recovered using a heat recovery steam generator (HRSG) [21]. The exhaust energy may or may not be able to satisfy the upgrader’s steam demand. When there is insufficient exhaust energy, additional natural gas is fired into the HRSG. The total natural gas required and electricity cogenerated in this cycle is calculated through iterations. If the electricity produced in cogeneration is greater than the plant's electricity demand, the excess is exported to the grid. In the case of no cogeneration, steam is generated on site in a stand-alone operation using a natural gas-fired industrial boiler. The electricity demand of the plant is met by importing the electricity from grid.

Table 5: Process conditions considered for modeling energy consumption in upgrading subunit operations.

	Sub unit Operation	Feed	Process conditions	Energy source	Comments/ References
Atmospheric Distillation	Naphtha Recovery Fractionator	Dilbit (diluted bitumen)	160˚F to 275˚F	Condensing diluent stream	Initial 160˚F temperature is maintained with tempered water from process units. [62]
			275˚F to 450˚F	Steam	
	Diesel Recovery Fractionator	Light Atmospheric Gas Oil	450˚F to 520˚F	Steam	[62]
			520˚F to 575˚F	Vacuum residue stream	
			575˚F to 720˚F	Natural gas/Fuel gas	
	Vacuum Distillation	Atmospheric Residue	690˚F to 780˚F	Natural gas/Fuel gas	[62]
	Delayed Coker	Vacuum Residue	550˚F to 925˚F	Natural gas/Fuel gas	[61, 62]
	Hydroconversion	Vacuum Residue	550˚F to 788˚F	Natural gas/Fuel gas	[61]. Initial temperature of feed same as in case of delayed Coker.
	Naphtha Hydrotreater	Naphtha from ADU & Coker Naphtha	200˚F to 560˚F	Feed effluent	[61]. Hydrotreating occurs at temp below 752˚F [61]. Initial temperature of feed varies 180˚F - 360˚F [62]. Initial temperature of feed for naphtha and gas oil considered similar to diesel.
			560˚F to 608˚F	Natural gas/Fuel gas	
	Diesel Hydrotreater	Diesel from ADU & Coker diesel	200˚F to 560˚F	Feed effluent	
			560˚F to 650˚F	Natural gas/Fuel gas	
	Gas oil Hydrotreater	LVGO + HVGO from VDU & Coker gas oil	200˚F to 560˚F	Feed effluent	
			560˚F to 680˚F	Natural gas/Fuel gas	

Table 6: Input data used in model development for upgrading operations in oil sands.

	Electricity consumption		Steam consumption	Source
	Value	Units	Value	
Atmospheric distillation	0.9	kWh/bbl	5 lb/bbl Naphtha; 6 lb/bbl kerosene; 4 lb/bbl diesel; 2 lb/bbl AGO; 10 lb/bbl AR; 12 lb//bbl VGO; 15 lb/bbl VR;	[23, 62]
Vacuum distillation	0.3	kWh/bbl		
Delayed coker	30	Kwh/t Coke	5 lb/bbl coker naphtha; 5 lb/bbl coker diesel; 5 lb/bbl gas oil;	[23]
Ebullated bed hydroconversion	8	kWh/bbl	50 lb/bbl	[23]
Naphtha hydrotreating	2	kWh/bbl	8 lb/bbl	[23]
Diesel hydrotreating	6	kWh/bbl	10 lb/bbl	[23]
Gas oil hydrotreating	6	kWh/bbl	10 lb/bbl	[23]
Claus sulfur recovery	98	Kwh/t Sulfur	1215 lb/t Sulfur	[23]
Tail gas treatment	463	Kwh/t Sulfur		
Hydrogen production	0.028	Kwh/Nm^3	- 0.86 lb/NM3 of H2	[23]
Hydrogen requirement				
	Unit	Value Delayed coking	Value Hydroconversion	
Naphtha hydrotreating	scf/bbl	170	170	[64]
Diesel hydrotreating	scf/bbl	581.3	892.4	[62, 64]
Gas oil hydrotreating	scf/bbl	912.6	1628	[64]
Hydroconverter	scf/bbl	-	1512	[64]
Hydrogen production				
	Unit	Value		
NG fuel required	m^3/Nm^3 of H$_2$	0.0398		[66]
NG feedstock required	m^3/Nm^3 of H$_2$	0.362		[66]
Efficiency of NG furnance	87%			[69]
NG fired boiler efficiency	85%			[21]
Efficiency of heat exchanger	60%			[70]
Efficiency of gas turbine	32%			[21]
HRSG exhaust recovery	55%			[21]
HRSG direct firing duct burner	95%			[21]

Emission factors for natural gas equipment used to calculate GHG emissions are imported from GREET [19]. These factors include both combustion and upstream emissions. Upstream emissions are those associated with recovery, transport, and processing of fuel. 9% of the total emissions come from the upstream emissions (recovery, transportation, refining etc.) of natural gas. The natural gas is used as a fuel and as a feedstock in hydrogen production. The natural gas used as feedstock does not undergo combustion, hence only the upstream emissions are applicable to feedstock natural gas. Moreover carbon dioxide is produced as a result of SMR reaction to produce hydrogen. This has been captured based on stoichiometry of the reaction that one mole of carbon dioxide is produced for every four moles of hydrogen. An emissions factor of 880 grams of carbon dioxide equivalent per kWh of Alberta's grid electricity used has been used [57]. The surplus electricity that is generated on site using a much cleaner fuel – natural gas – is exported to the coal-based grid. The method used to calculate the associated emissions can greatly affect the emissions figure for the overall project. In the case of cogeneration, where excess electricity is exported to the grid, an emissions factor of 650 grams of carbon dioxide equivalent per kWh of displaced grid electricity is used [57]. The emissions factor used is as per the memorandum issued by the Climate Change Secretariat, Government of Alberta [57]. An emissions factor of 2419.4 gCO_2eq/kg of fuel gas has been estimated based on the composition of gas provided in [62].

A detailed data intensive model was developed to estimate the energy consumption and GHG emissions from upgrading operations in oil sands. This involved researching and compilation of data for sub unit operations involved. This data in Table 5 and Table 6 is default input into the model. Data specific to other projects may be entered for the estimation of energy consumption and GHG emissions specific to those projects.

3.2.2 Refining

Feed in the form of crude oil, SCO, and dilbit is processed in a refinery to obtain gasoline, diesel, jet fuel, and other end products. Refining is a complex process that leads to a number of correlated products; detailed and expertise knowledge is required to estimate its energy consumption and GHG emissions. Due to a lack of data available in the public domain, a process model [33] built in Aspen HYSYS was used to estimate energy consumption and GHG emissions.

A refinery of typical configurations, as shown in Figure 12, was modeled. The modeling uses the same default configuration, parameters, and conditions as were used in the sample case in build in Aspen HYSYS [33]. The refinery processing units – the hydrotreater, catalytic cracker, hydrocracker, coker, reformer, and alkylation unit – were simulated using petroleum shift reactors based on the delta base-shift concept [33]. As explained in [33], each unit is represented by a set of key independent variables (usually feed flow rates and feed qualities) and key dependent variables (usually product flow rates, product qualities, utilities, etc.) with their base condition values specified. If the conditions are different from the base point, the dependent variables are calculated from the independent variables using a set of linear equations whose coefficients are the derivatives of the independents with respect to the dependents at the base point. The derivatives are calculated using rigorous first principles models. The utility base values that were used in simulating the refinery in this research were modified and calculated based on the unit volume of feed flow rate. This was done to capture the effect of a change in utilities due to a change in the feed input.

The distillation curve based on the boiling point of fractions, sulfur content, density and carbon residue of crude feed along with the accompanying light ends are inputs to the refinery model simulated in this research. Based on the input, the model predicts the utilities and products for each subunit operation in the refinery. The utilities are in the form of fuel, steam, and power (electricity energy). The individual utilities in each subunit operation are added together to obtain the total energy consumption in the refinery operation. The refinery products as given by the model are liquefied petroleum gas (LPG), diesel fuel, jet/kerosene fuel, gasoline, and fuel oil. Coke is also obtained as a byproduct from the coker.

The energy consumed in the refinery is obtained from fuel gas, natural gas, fuel oil, electricity, and coke [14, 19]. Natural gas is also required as a feedstock to hydrogen production. Some of the feedstock requirement in hydrogen production is fulfilled by methane produced in the saturated gas plant in the refinery. Hydrogen is also produced from the reformer in the refinery. The hydrogen from the reformer is low purity and hence after treatment is used in hydrotreating naphtha, diesel, and kerosene. The remaining low purity hydrogen goes to the plant fuel system and so forms a component of the fuel gas. The hydrogen required in hydrocracking is of high purity; hence it is produced from natural gas in the steam methane reforming process. Different refineries may have different kinds of hydrogen balances.

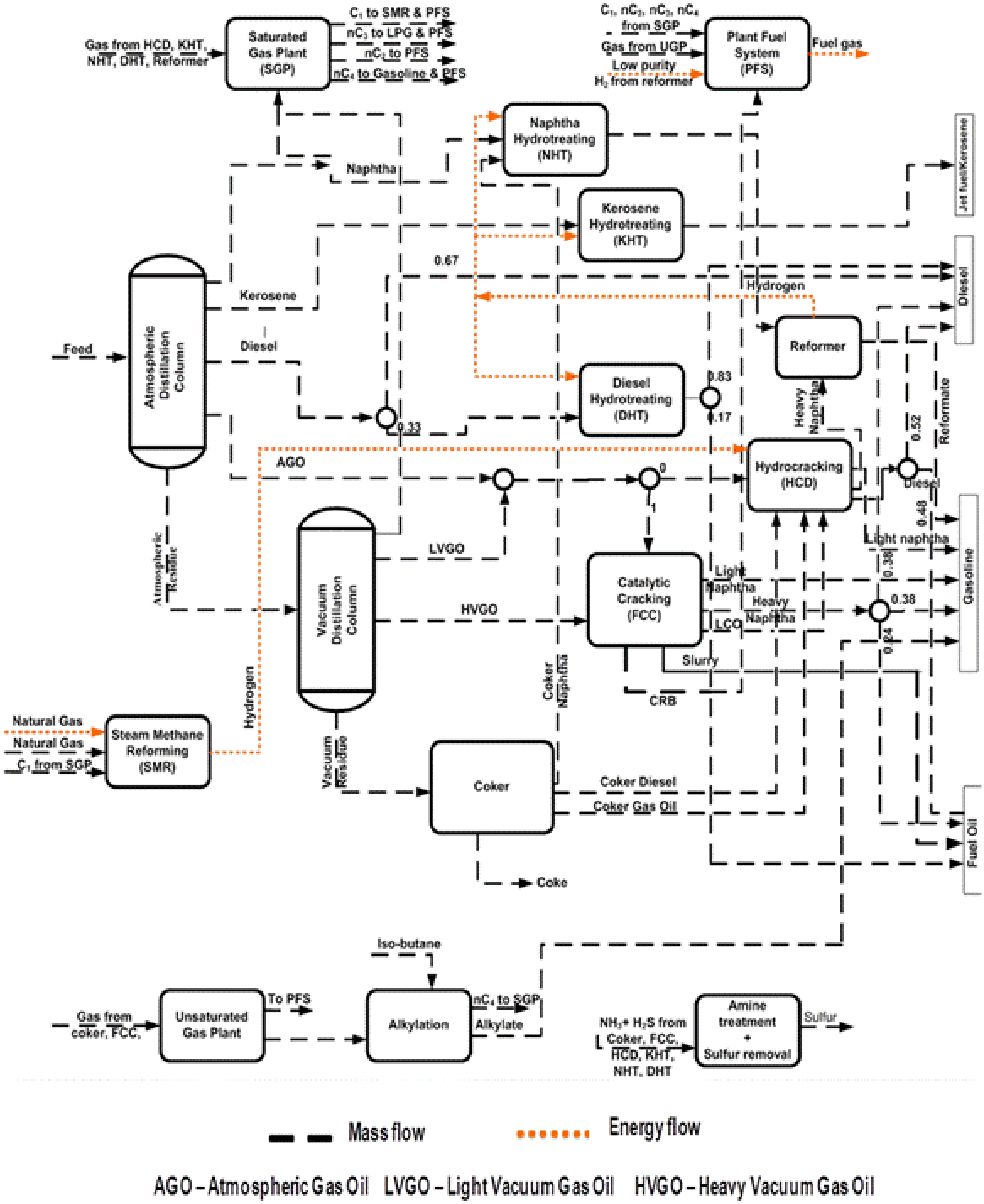


Figure 12: Process flow in a typical North American refinery configuration capable of refining heavy feeds.

3.3 Results and Discussion

3.3.1 Upgrading

The developed model described in section 2.2 has been used to estimate the energy consumption and GHG emissions for upgrading operations. The model has been run using the default data and characteristics of bitumen described in Appendix C (see Figure C-4). The volume/mass flowrates of the intermediate products in the upgrader are shown in Figures 10 and 11.

The total energy required to process a bitumen feed in an upgrader varies depending upon the process. The calculations, based on the above methodology, estimated 3.34 GJ of energy consumption to upgrade one m^3 of bitumen using delayed cokers and 6.87 GJ through hydroconversion. The higher energy consumption in hydroconversion corresponds to the higher hydrogen requirement. Hydrogen production is an energy-intensive process [24]. About 70% of the total energy (see Figure 13) in hydroconversion is required for hydrogen production compared to 42% (see Figure 14) required in upgrading using delayed cokers. Next to hydrogen production, intensive energy consumption occurs in crude distillation (atmospheric + vacuum) columns. Naphtha, diesel, and gas oil hydrotreating contribute in total energy to a smaller scale. These hydrotreating operations consume a lot of energy in the form of hydrogen, which was accounted for in the hydrogen production unit operation. Hence only the remaining fuel energy required to heat the feed to the appropriate temperature is counted in these operations. As shown in Table 5, the majority of heating energy supplied in these operations is from the heat exchange between the feed and the feed effluent. Hence these hydrotreating operations form a small portion of the energy requirement of the plant.

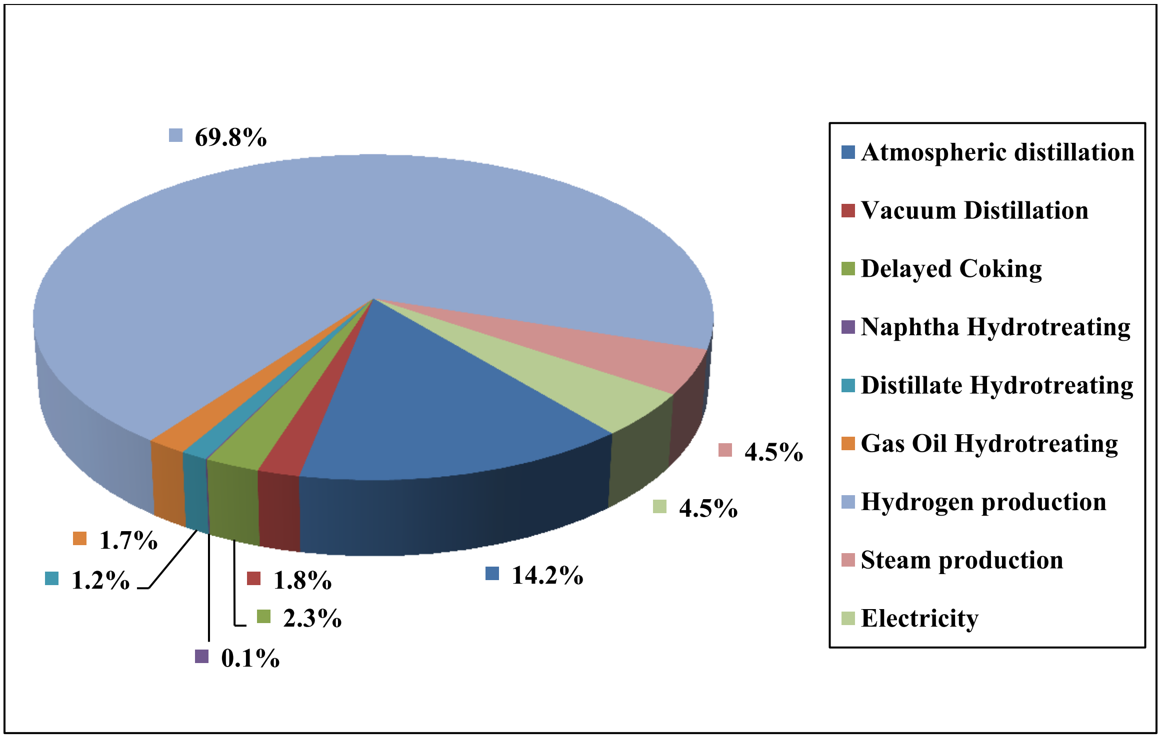


Figure 13: Distribution of energy consumed (6.86 GJ/m3 of bitumen) in hydroconversion upgrading subunit operations.

Table 7 presents the energy consumption of delayed coker and hydroconversion upgraders. The energy requirement of the upgrading plant is fulfilled by natural gas and fuel gas produced in the plant. This model calculates the amount of fuel gas produced in the plant based on the mass balance in subunit operations.

The energy content and emission factor for the produced fuel gas is calculated based on the fuel gas' composition. The composition of fuel gas is plant feed-and time-specific. A similar composition of fuel gas is assumed in both upgrading configurations. 54% and 22% of the energy requirement in delayed coking and hydroconversion, respectively, are fulfilled by the fuel gas produced in the plant. The remaining energy requirement to upgrade one unit volume of bitumen in delayed coking and hydroconversion processes is met by 47 m^3 and 157 m^3 of natural gas, respectively. The electricity demand ranges from 51.9 kWh/m^3 of bitumen in delayed coker upgraders to 84.9 kWh/m^3 of bitumen in hydroconversion upgraders.

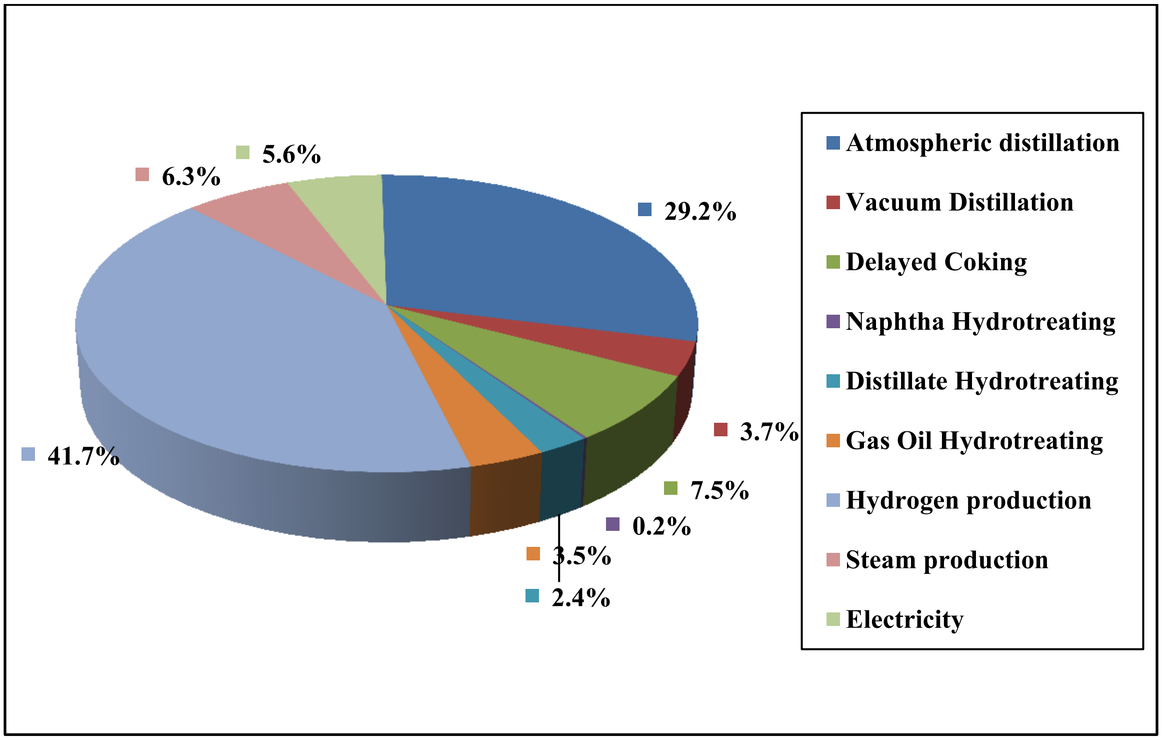


Figure 14: Distribution of energy consumed (3.34 GJ/m^3 of bitumen) in delayed coker upgrading subunit operations.

The SCO obtained from delayed coker upgrading differs from that obtained in hydroconversion in mass, volume, and quality. The mass and volume of SCO is traced based on the mass balance in each subunit operation; estimating the quality of SCO is beyond the scope of this research. As estimated by our model, the volume yield of SCO in hydroconversion is 103.7% compared to 91.1% in delayed coking. As specified in the existing literature, this range can vary from 78%-94% in delayed coking to 95% to 106% in hydroconversion [20, 21, 64, 71]. The higher volume yield corresponds to higher hydrogen consumption in the hydroconversion process [61].

The GHG emissions from upgrading operations are presented in Table 7. Total GHG emissions calculated by the model are 240.3 kgCO_2eq/m^3 of bitumen (5.9 gCO_2eq/MJ of bitumen) in delayed coker upgrading and 433.4 kgCO_2eq/m^3 of bitumen (10.6 gCO_2eq/MJ of bitumen) in hydroconversion upgrading. Combustion gas, along with natural gas feedstock for hydrogen production, accounts for 81% and 82.7% of total emissions in delayed coker upgrading and hydroconversion, respectively, with the remaining coming from grid electricity use. 28.5% of total emissions in delayed coker upgrading and 54.2% in hydroconversion upgrading are from hydrogen production.

Table 7: Energy consumption and emissions in upgrading operations.

		Units		Delayed Coking	Hydroconversion	
SCO produced		m^3/m^3 of bitumen		0.911	1.037	
H_2 requirement		Nm^3/m^3 of bitumen		103.6	355.2	
	Units	**Fuel Consumption**		**Units**	**Emissions**	
		Delayed Coking	**Hydroconversion**		**Delayed Coking**	**Hydro-conversion**
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	264.2
Steam	lb/m^3 of bitumen	120.7	175.2	$kgCO_2eq/m^3$ of bitumen	[α]	[α]
Electricity	kWh/m^3 of bitumen	51.9[β]	84.9[β]	$kgCO_2eq/m^3$ of bitumen	45.6	74.7
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[γ]	-83.0[γ]	$kgCO_2eq/m^3$ of bitumen	-26.9	-53.9

[α] Emissions from steam production are included in natural gas/fuel gas combustion emissions.

[β] This electricity is imported from the grid.

[γ] Negative sign denotes the export of excess electricity to Alberta grid.

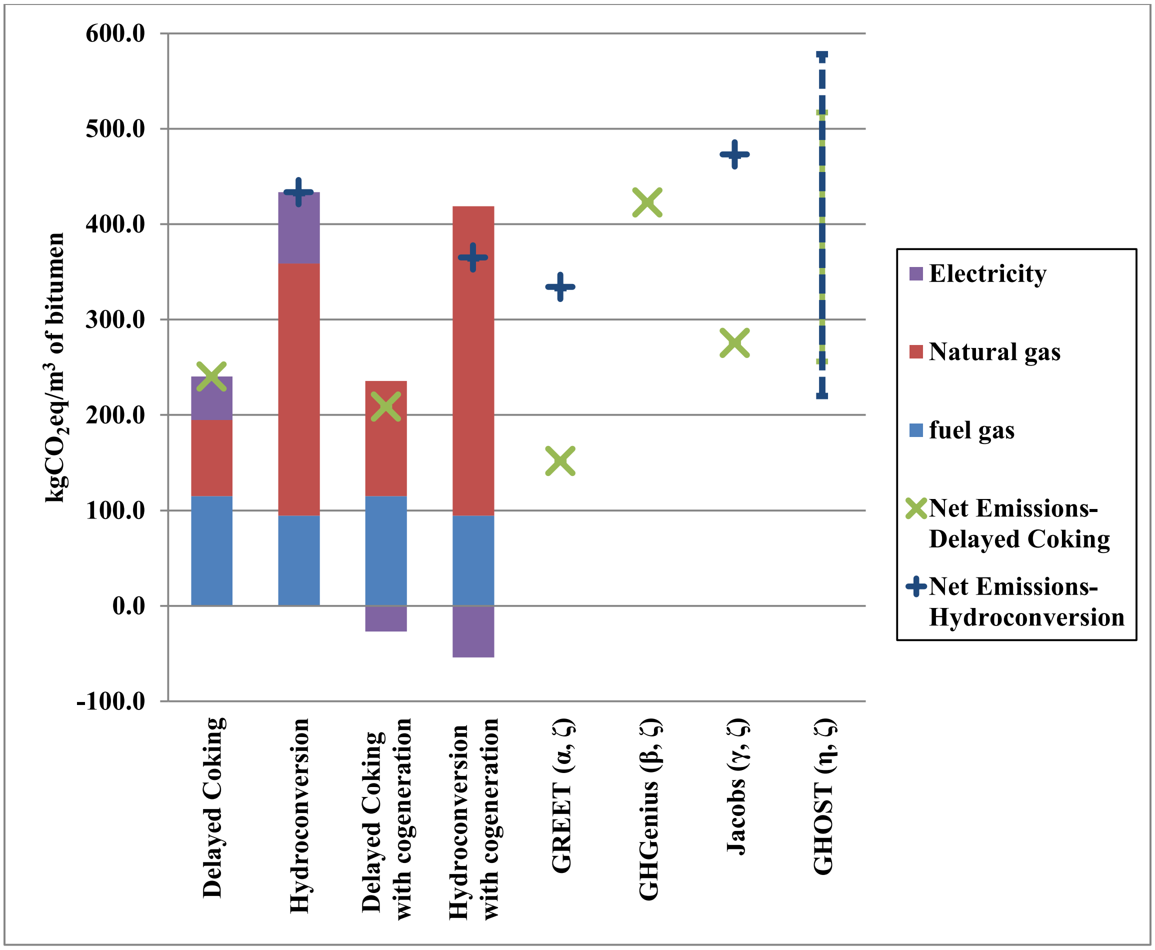


Figure 15: Emissions in upgrading unit operations compared to those in existing literature and models.

(α) Cogeneration has not been considered in the GREET model.

(β) GHGenius does not give separate values for delayed coking and hydroconversion. No cogeneration considered in the model.

(γ) These values correspond to the no cogeneration case in Jacobs' report [15].

(η) The range represented includes the values both with and without cogeneration. The range for emissions in delayed coker upgrading (257-517 kgCO2eq/m3 of bitumen) overlaps with emissions in hydroconversion (221-578 kgCO2eq/m3 of bitumen).

(ζ) The values from the literature and models have been converted using the LHV of bitumen 40.76 GJ/m3 [32].

With the use of cogeneration in the plant, the natural gas consumption increases in both upgrading configurations. The natural gas consumed fulfills the steam demand and produces power in excess of the plant's electricity demand. Delayed coker upgraders export 41.4 kWh and hydroconversion upgraders export 83 kWh electricity to the grid for each m^3 of bitumen feed upgraded. As shown in Figure 15, the net emissions are lowered by 13% in delayed coker upgrading and by 16% in hydroconversion upgrading, in lieu of displacing the carbon-intensive grid power.

Results described in Table 7 and Figure 15 are based on a unit of bitumen fed to the upgrading operation. The energy use and GHG emissions can be converted based on SCO's mass, volume, and energy. The conversion is made based on mass and volume relationships between bitumen and SCO, and estimated by the model. Total GHG emissions for SCO are 263.9 $kgCO_2eq/m^3$ of SCO (7.2 gCO_2eq/MJ of SCO) in delayed coker upgrading and 417.8 $kgCO_2eq/m^3$ of SCO (11.5 gCO_2eq/MJ of SCO).

The model developed in this research for upgrading operation in oil sands is validated with results of existing literature. To demonstrate the validity of the model, the GHG emissions for upgrading a particular feed (characteristics shown in Figure C-4) are estimated using the developed model and are compared in Figure 15 with values reported by existing literature. The values estimated are within 10% of those reported by Jacobs [15]. The emissions estimated in hydroconversion upgrading are 2.5% higher than the GHGenius values [32]. GHGenius [32] does not report separate values for different configurations of upgrading. The values calculated in this research using fundamental engineering principles fall within the wide range predicted by the GHOST model [21], which is based on a set of confidential data.

Sensitivity Analysis

A sensitivity analysis of various parameters was conducted to determine their effect on net GHG emissions from the delayed coker and hydroconversion upgrading operations. The following parameters were investigated: sulfur content, hydrogen consumption, steam energy, electric energy and its emission factor, and the efficiency of the natural gas (NG) heater, steam boiler, and heat exchanger. Hydrogen consumption in naphtha, distillate, and gas oil hydrotreating (and the hydroconverter in the case of hydroconversion upgrading) was varied. The effects of the steam requirement and steam conditions were captured in the steam energy parameter. The sensitivity parameters correspond to the base case with no cogeneration. As shown in Figures 16 and 17, when the parameters are varied by ±30%, the net GHG emissions vary by ±8% in delayed coker and hydroconversion upgrading operations.

Hydrogen consumption in hydroconverters (in the case of hydroconversion upgrading) and gas oil hydrotreating has a prominent effect on net emissions. Hydrogen consumption in naphtha and distillate hydrotreating has a comparatively smaller effect because of the small volume yield of the feed and low hydrogen consumption per barrel of feed. When the total hydrogen consumption of the plant (simultaneously in all hydrogen-consuming subunit operations) increases by 30%, the net emissions vary by 8.3% in delayed coker and 15.8% in hydroconversion upgrading, making hydrogen consumption the most sensitive parameter.

Increasing sulfur content in the feed requires more hydrogen for its removal. It has been assumed that 3 moles of H_2 are consumed for every mole of sulfur removed [72]. When the sulfur content is varied by ±30%, the emissions vary by 19.4 kgCO_2eq. This corresponds to an 8.1% variation in delayed coker and a 4.5% variation in hydroconversion upgrading.

Electric energy is another influential parameter. The electricity requirement and its emission factor have the same effect on net emissions, as shown by overlapping lines in Figures 16 and 17. The efficiency of the natural gas (NG) heater and steam boiler have a comparatively lesser effect on net emissions because of their low variation. When the efficiency of the heat exchanger is varied by ±20%, the change in net emissions ranges from -3.5% to 5.3% in delayed coker upgrading and -1.9% to 2.9% in hydroconversion upgrading.

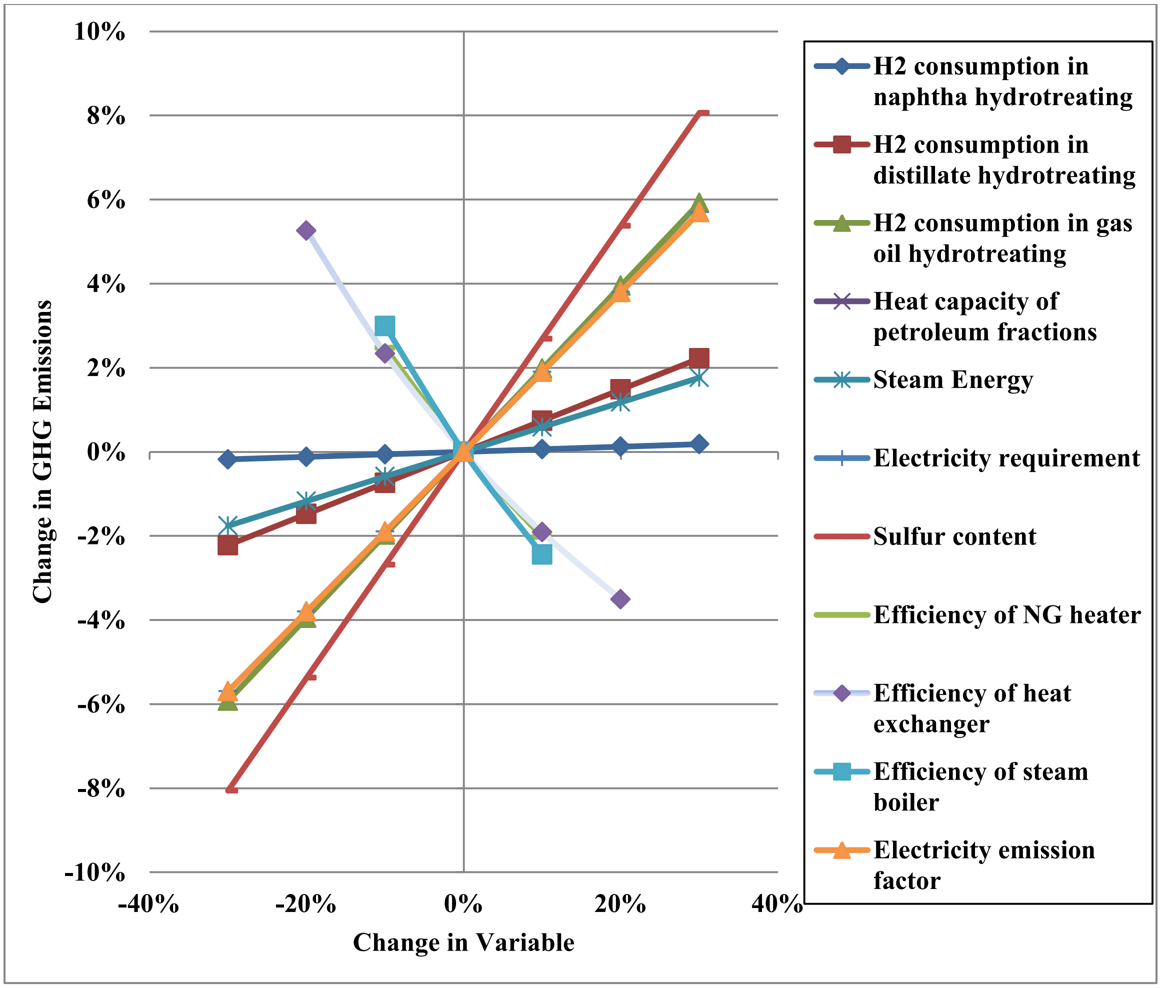


Figure 16: Sensitivity of GHG emissions in delayed coker upgrading on key parameters.

Equipment such as the NG heater, heat exchanger, and steam boiler has been used for a long time in industry, and their technology is established; hence huge variations in their efficiencies are not possible. So, to make the upgrading operations less GHG intensive, reducing the hydrogen and electricity consumption would be a good start. Equally important would be having a low emission factor for the electricity used. Hence a shift of electricity generation from carbon-intensive, coal-based electricity to cleaner fuels such as renewables would reduce the carbon footprint of upgrading operations.

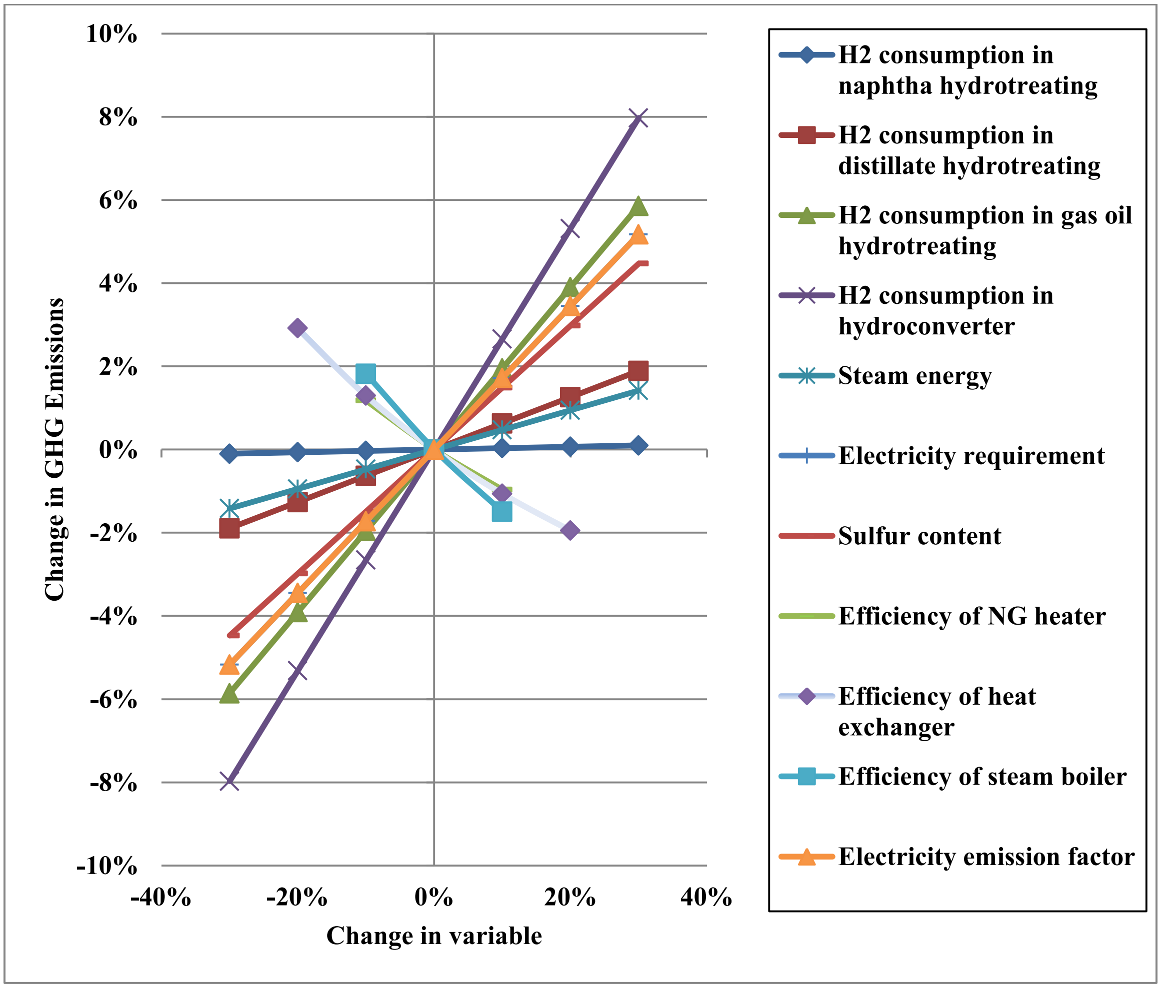


Figure 17: Sensitivity of GHG emissions in hydroconversion upgrading on key parameters.

3.3.2 Refining

The process model described in section 3.2.2 has been used to explore the products obtained, energy consumed, and GHG emitted from processing coker SCO, hydroconversion SCO, dilbit, and bitumen. The input distillation curves, sulfur content, density, and carbon residue of feeds, SCO, and dilbit are shown in Appendix C (Figure C-1, Figure C-2, Figure C-3, Figure C-4, respectively [73]).

On a refining scale of 150 kbpd, the yield of products obtained per barrel of feed from atmospheric and vacuum distillation is shown in Figure 18, and the end products are shown in Table 8. As can be seen on Figure 18, bitumen and dilbit are rich in heavy fractions such as gas oils and residue. SCO from coker and hydroconversion are light feeds rich in naphtha, kerosene, and diesel. Dilbit contains a high fraction of naphtha as it is a blend of naphtha and bitumen.

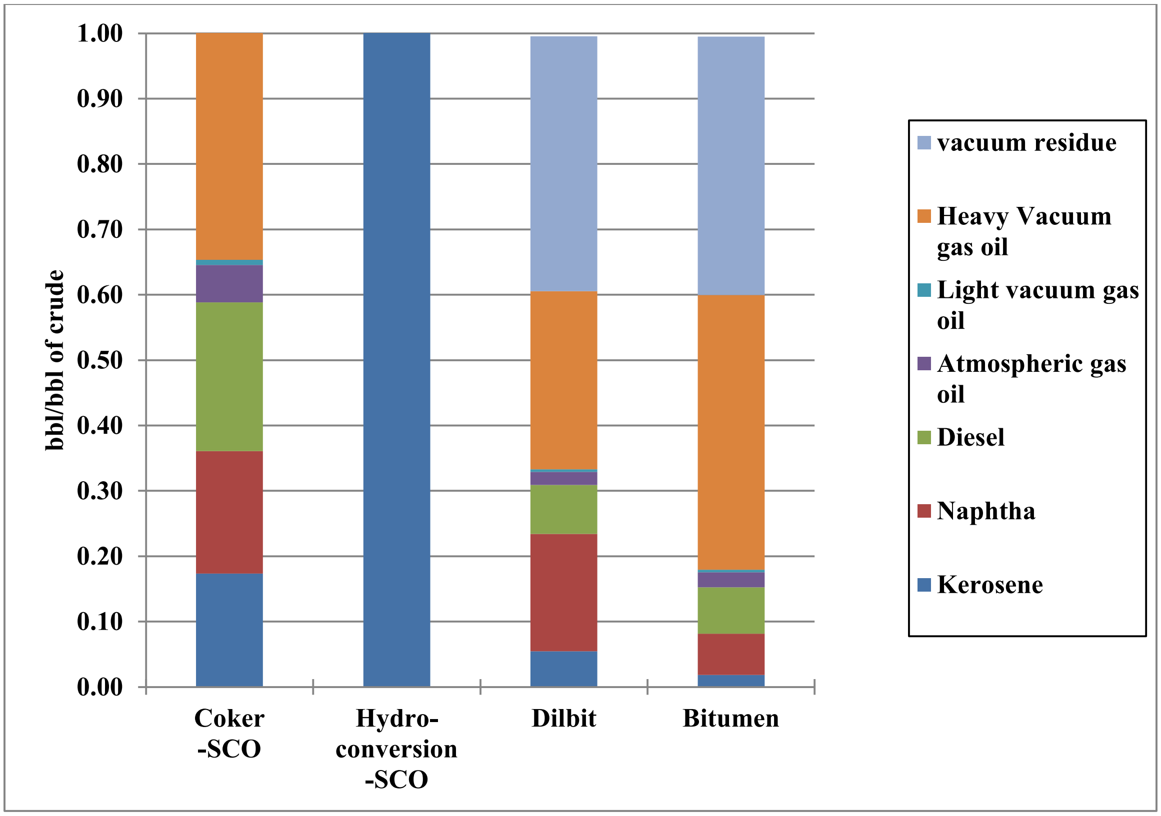


Figure 18: Products obtained from atmospheric and vacuum distillation of feeds.

Table 8: Ends products obtained from the refining of different feeds.

Products		**Feed**			
	Units	Coker -SCO	Hydroconversion -SCO	Dilbit	Bitumen
Fuel gas	bbl/bbl of feed	0.14	0.15	0.22	0.21
LPG	bbl/bbl of feed	0.01	0.01	0.01	0.01
Diesel	bbl/bbl of feed	0.28	0.28	0.18	0.19
Kerosene/Jet fuel	bbl/bbl of feed	0.17	0.13	0.05	0.02
Gasoline	bbl/bbl of feed	0.48	0.53	0.51	0.54
Fuel oil	bbl/bbl of feed	0.10	0.11	0.12	0.14
Coke	kg/bbl of feed	0.00	0.00	3.63	4.15

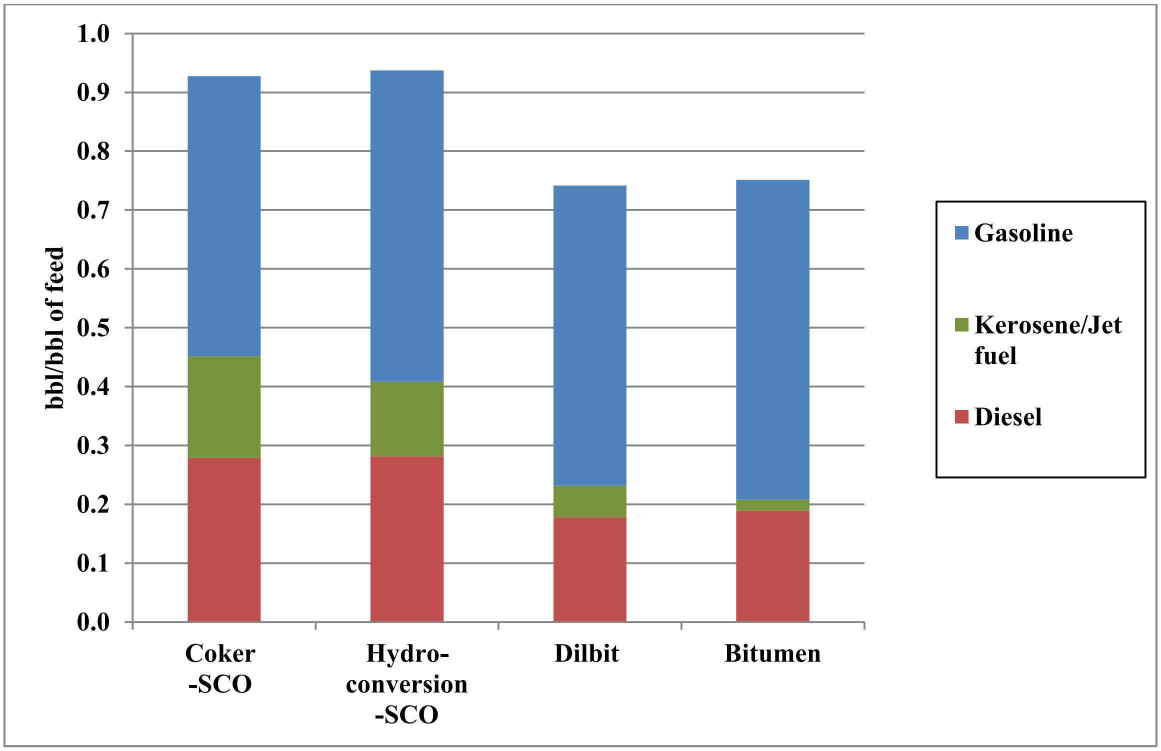


Figure 19: Yield of useful products obtained from the refining of feeds.

As shown in Figure 19, SCO from cokers and hydroconversion produces a higher volume of products than do the heavier feeds dilbit and bitumen. Dilbit and bitumen produce a higher volume of fuel oil than does SCO. The heavier the feed, the higher the production of fuel oil. Gasoline, jet fuel, and diesel are the useful and desired products. Most refineries minimize the production of fuel oil [15]. Coke is formed as a byproduct when refining bitumen and dilbit. Due to the higher carbon residue content (13% in bitumen as compared to 10.5% in dilbit), more coke is formed from bitumen. The refining of hydroconversion SCO produces a higher volume of gasoline and diesel as compared to coker SCO. This is because the hydroconversion SCO is more severely hydrotreated and hydrocracked during its upgrading.

In general, lighter crudes tend to have a larger naphtha fraction than heavier crude, as is obvious from Figure 19. Naphtha is the easiest fraction to convert to gasoline [23], and so the volume of gasoline from dilbit should be more than that from bitumen. But Figure 19 shows the opposite. This is in agreement with the findings of an earlier study [23]. The higher volume of useful products from bitumen than dilbit may be attributed to high mass of input feed in the case of bitumen. For the same volume of feeds, the mass of bitumen is 8% more than that of dilbit. The volume of diesel and gasoline obtained on a per mass basis of dilbit is higher than bitumen, which is in agreement with the general thought that a higher volume of gasoline and diesel is obtained from lighter crudes with a larger naphtha fraction.

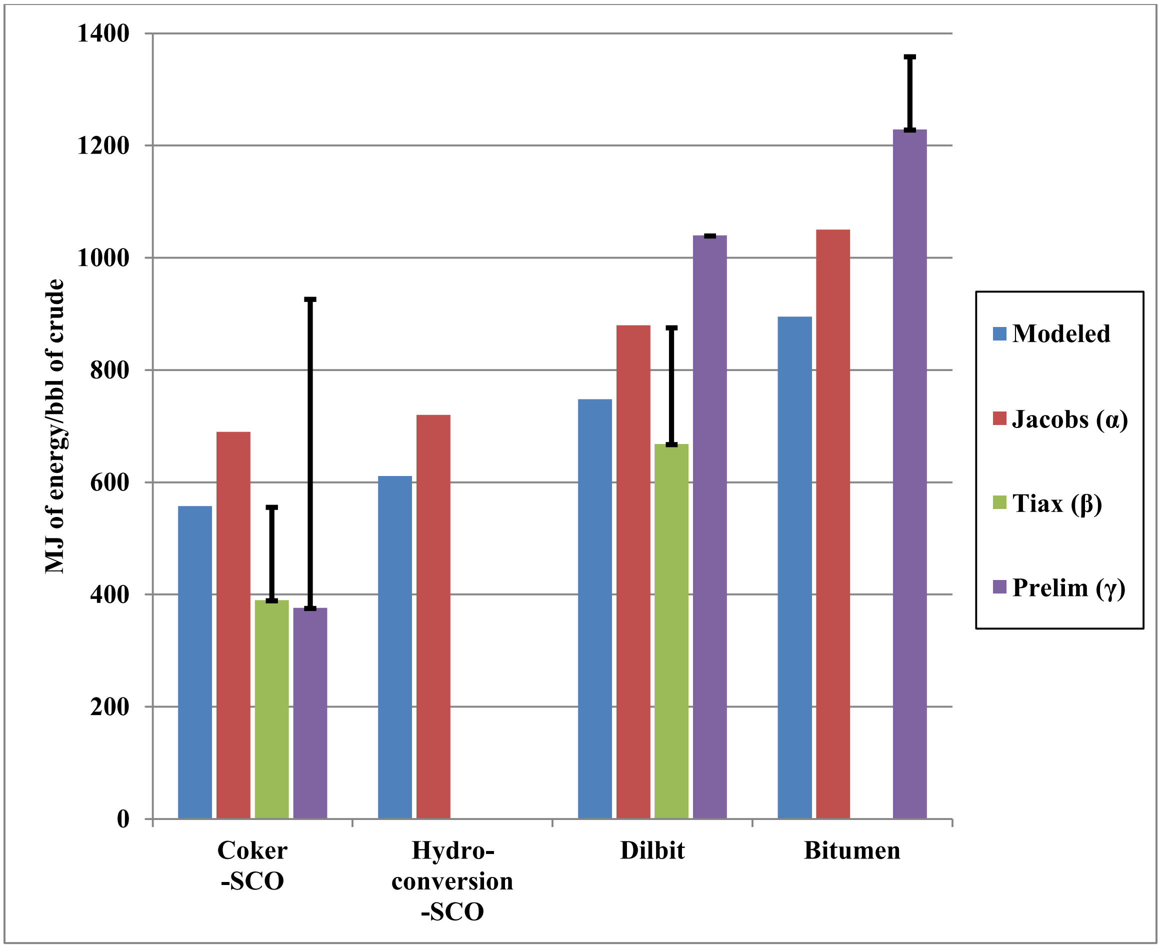


Figure 20: Energy consumption per barrel of crude modeled compared to existing studies.

(α) [15]. (β) [14]. TIAX has not separately mentioned the energy consumption for SCO from coker and hydroconversion. The range includes SCOs processed in PADD 2, PADD 3 and California.(γ) [23]. PRELIM does not differentiate between the energy consumption for SCO from coker and hydroconversion. The range includes the energy consumption for varying quality of SCOs processed in different configurations of refinery.

The energy consumption in refining feeds is shown in Figure 20. Energy consumed in refining ranges from 557.8 MJ/bbl to 895.1 MJ/bbl of crude, depending on the crude refined. The energy consumption varies depending upon the quality of crude, the end products desired, and the configuration of the refinery [14, 15, 23]. Bitumen and dilbit are rich in heavier fractions of gas oils and vacuum residue and therefore need more energy than SCO to convert the heavy fractions to useful products. The energy consumed in refining coker SCO is less than in hydroconversion SCO as the former is bottomless (no vacuum residue) [15]. Bitumen is the heaviest of all crudes and consumes approximately 60% more than coker SCO.

To demonstrate the validity of the results obtained in this research, the energy consumed for refining feeds with characteristics shown in Figures C-1, C-2, C-3 and C-4 are compared with the values reported in existing literature. Energy consumption modeled for the refining of SCO and dilbit fall in the range of those reported by Tiax [14]. The modeled values are 14% to 20% lower than those reported by Jacobs [15]. Prelim [23] reports higher values for dilbit and bitumen than the modeled values. The energy consumption modeled for refining SCO is in good agreement with the range reported by Prelim.

The breakdown of energy consumption for SCO and dilbit is shown in Figures 21 and 22, respectively. 22%-30% of the total energy in refining is consumed in the atmospheric and vacuum distillation columns. Reformer, hydrocracking (HCD), and catalytic cracking (FCC) are other areas of high energy consumption. 9%-18% of the total energy is consumed in catalytic cracking. The higher ratio of energy consumption in FCC in the refining of SCO than in dilbit or bitumen is attributed to lower total energy consumption in SCO. The energy consumption in the reformer varies from 13% to 16% for SCO and 7% to 9% for dilbit and bitumen. The energy consumed in the reformer is highest in absolute numbers in the case of dilbit because of the high naphtha feed input to the reformer. A significant portion of energy (11% to 17%) is consumed in an unsaturated gas plant (UGP) and increases as the feed to it increases. But because of higher total energy consumption for heavy feeds, the percentage of energy consumed is higher for light feeds.

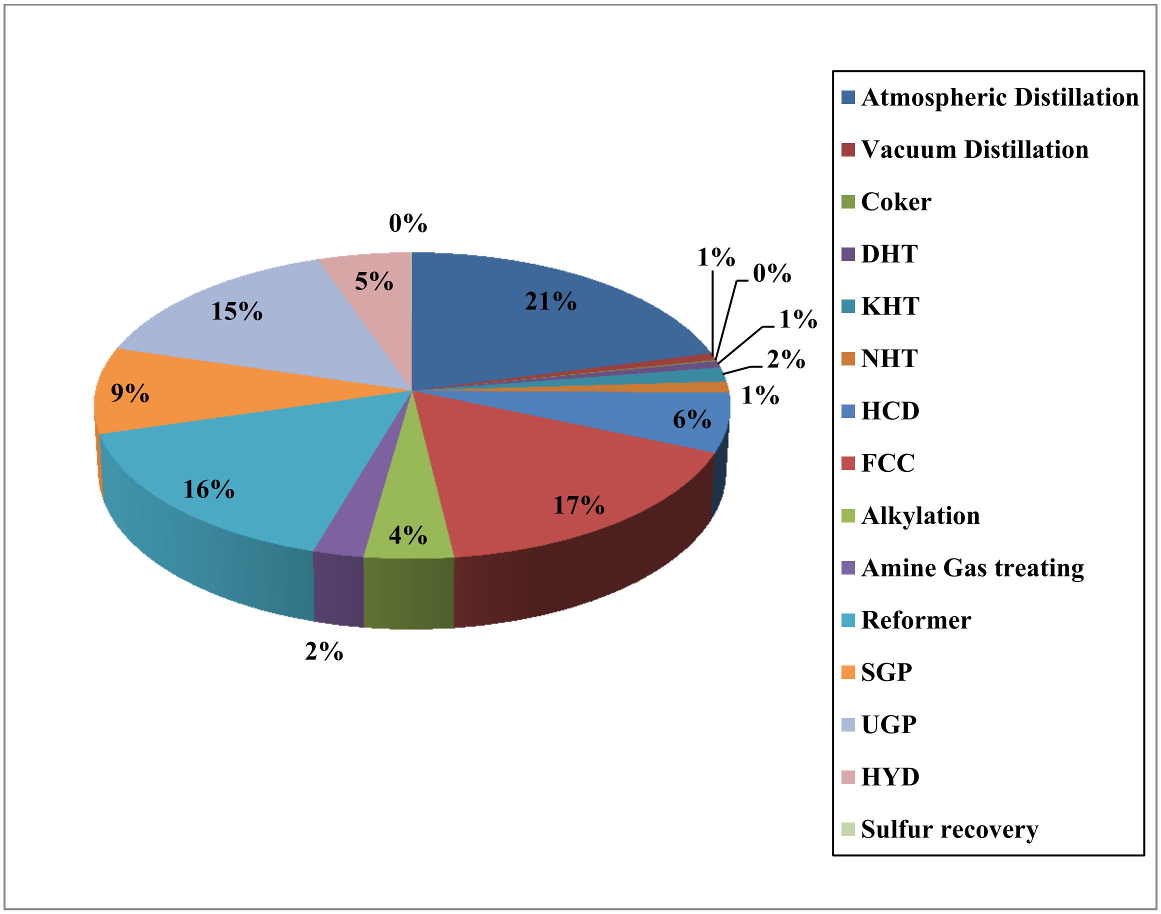


Figure 21: Breakdown of energy consumption in each subunit operation for refining coker SCO.

Hydrogen production (HYD) is an energy-intensive process [24]. Energy consumed in hydrogen production is 5% to 7% of a refinery's total energy consumption. The feedstock to this unit operation is methane from a saturated gas plant (SGP) and natural gas imported from outside. The gases from hydrotreaters and the reformer are treated and separated in the SGP to produce methane, which reduces the external intake of natural gas, making hydrogen production less energy intensive. Steam is produced in the sulfur recovery process, making sulfur recovery less energy intensive. In fact, net energy in the form of steam is produced in Claus sulfur recovery and tail gas treatment [23].

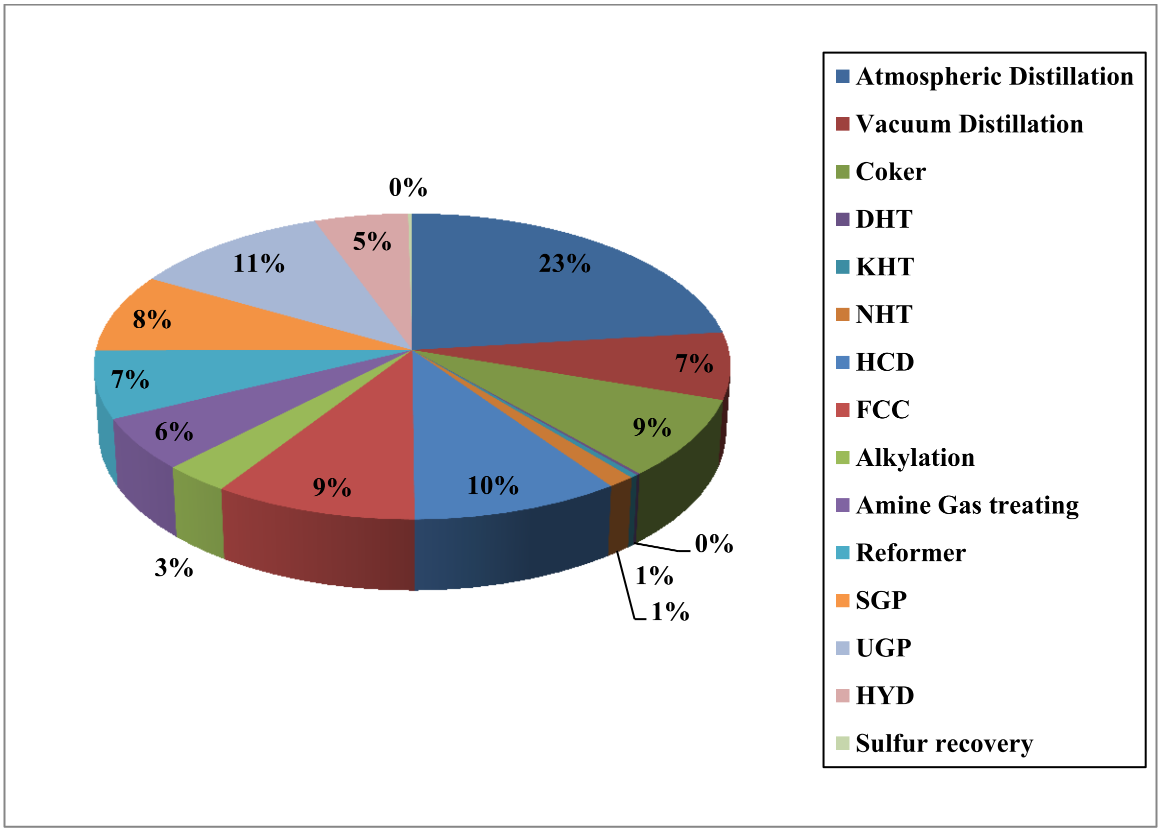


Figure 22: Breakdown of energy consumption in each subunit operation for refining dilbit.

Steam, electricity, coke, fuel gas, and natural gas provide the energy required in refining operations. 6% to 8% of the total energy required is from electricity. This electricity may be generated on site or imported from the grid. Steam is another major form of energy required; about 14% to 17% of the total energy required is in the form of steam, and it is assumed that all steam energy is required in the form of high pressure steam [23]. Coke deposited on the fluid catalytic cracking (FCC) catalyst is burned off to restore catalyst activity and also satisfies some of the energy requirement [23]. 10% to 19% of the total energy is from coke burn-off, depending upon the feed. The remaining energy is from fuel gas and natural gas. The type of fuel used for the energy required affects the GHG emissions. This research explores the use of 100% fuel gas, 100% natural gas, and 100% fuel oil to obtain the required energy.

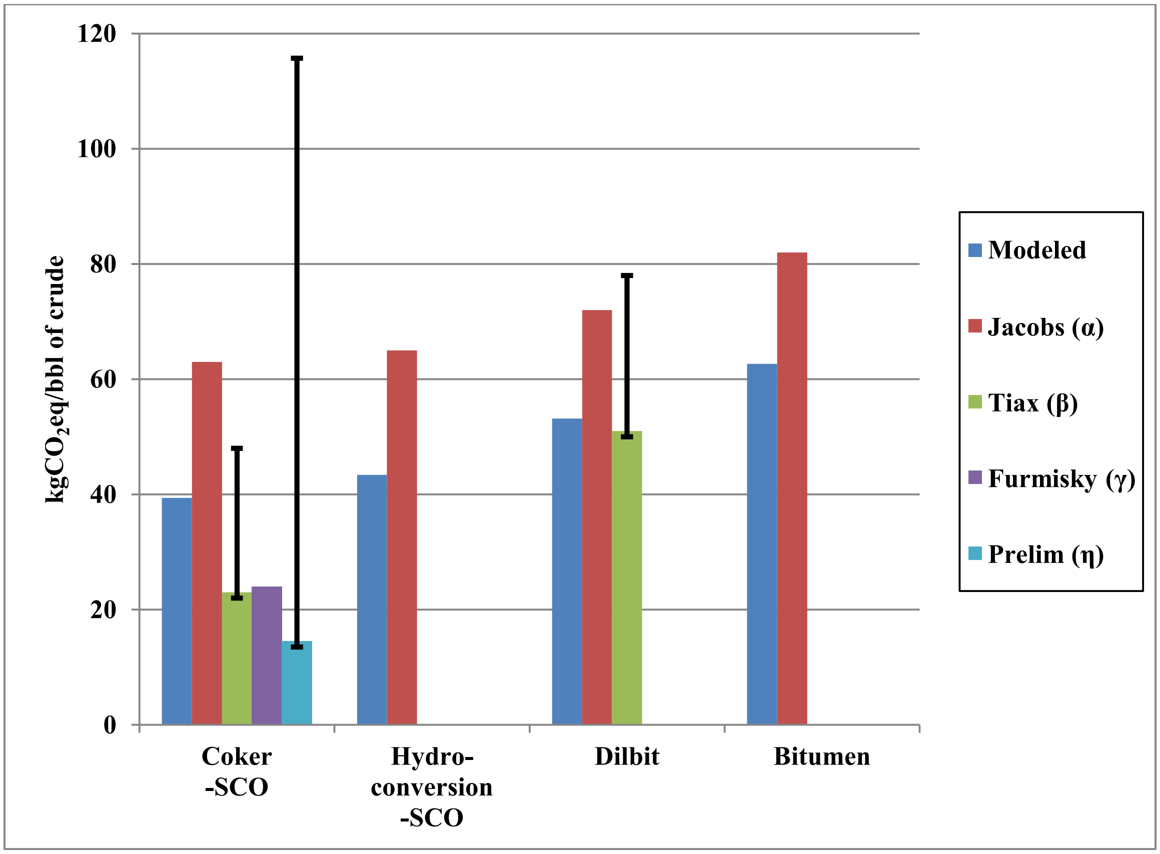


Figure 23: The results of this study's modeled GHG emissions per barrel of crude compared to existing studies.

(α) [15]. (β) [14]. TIAX has not differentiated between the GHG emissions for SCO from coker and hydroconversion. The range includes SCOs processed in PADD 2, PADD 3, and California. (γ) [22]. Did not analyze other crudes. (η) [23].

GHG emissions from crude feed processing vary from 39 kg/bbl of coker SCO to 63 kg/bbl of bitumen (see Figure 23). GHG emissions are proportional to the net energy input shown in Figure 20. The higher energy consumption of heavier feeds such as dilbit and bitumen leads to more emissions. The use of natural gas instead of refinery gas does not affect the net emissions by much, whereas the use of fuel oil instead of refinery gas increases the emissions by 18% when refining bitumen. The GHG emissions modeled per barrel of crude are well in agreement with figures from existing literature. The modeled results fall in the range reported by Tiax [14]. The values reported by Jacobs [15] are 24% to 38% higher than the modeled results but also higher than values reported in other literature. This variation is possible due to considerations of different crude qualities and different refinery configurations [23, 74]. Prelim [23] reports a wide range of GHG emissions for SCO based on the crude type.

Refineries produce a number of correlated products whose yields depend on the quality of crude and severity of refining. Increased production of one refined product affects the yield of other products and also affects the overall energy consumption and net GHG emissions in a refinery. The International Standard Organization (ISO) guideline for life-cycle assessments recommends avoiding allocation wherever possible [24]. Because the purpose of this research is to compare GHG emissions from the refining of different oil sands products, it is necessary to have a common base for comparison. As shown in Figure 24, the common base chosen is the total energy content of refined products so that allocation to refined products is avoided. The total energy content in a substance is defined as the product of its volume yield and thermal energy per unit volume. GHG emissions range from 7.9 gCO_2eq/MJ of refined product from coker SCO to 15.72

gCO_2eq/MJ of refined product from bitumen. Refining SCO to fuels produces 41% and 49% fewer emissions than does refining dilbit and bitumen, respectively.

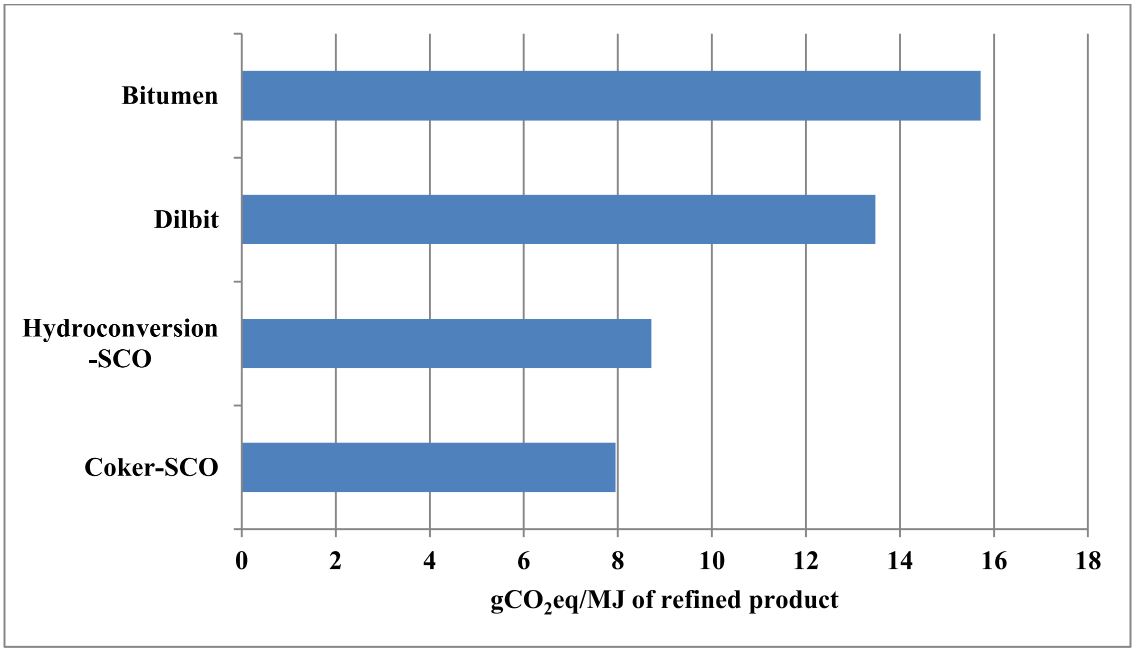


Figure 24: GHG emissions from the refining of oil sands crudes.

While SCO produces lower emissions during refining, the upstream emissions from the upgrading of bitumen to SCO needs to be accounted for. Figure 25 shows the effect of including upgrading emissions with refining emissions. Bitumen goes to the refinery as a blend of bitumen and naphtha or diluent. The diluent is separated from the blend in an atmospheric distillation column [62]. The burden of these corresponding emissions is attributed to the bitumen feed. Bitumen transportation includes the transportation of the bitumen-naphtha blend and the return transportation of the diluent from the refinery to the upgrader over a distance of 3000 km. In this case, transportation emissions are 5% to 21% of total emissions, the latter corresponding to the transportation of bitumen. Of all the pathways to obtain end-product energy from bitumen upgrading, emissions are highest from hydroconversion processes, as seen in Figure 25 [15]. Emissions from producing end products from the direct refining of bitumen are 19% higher than those from the delayed coker.

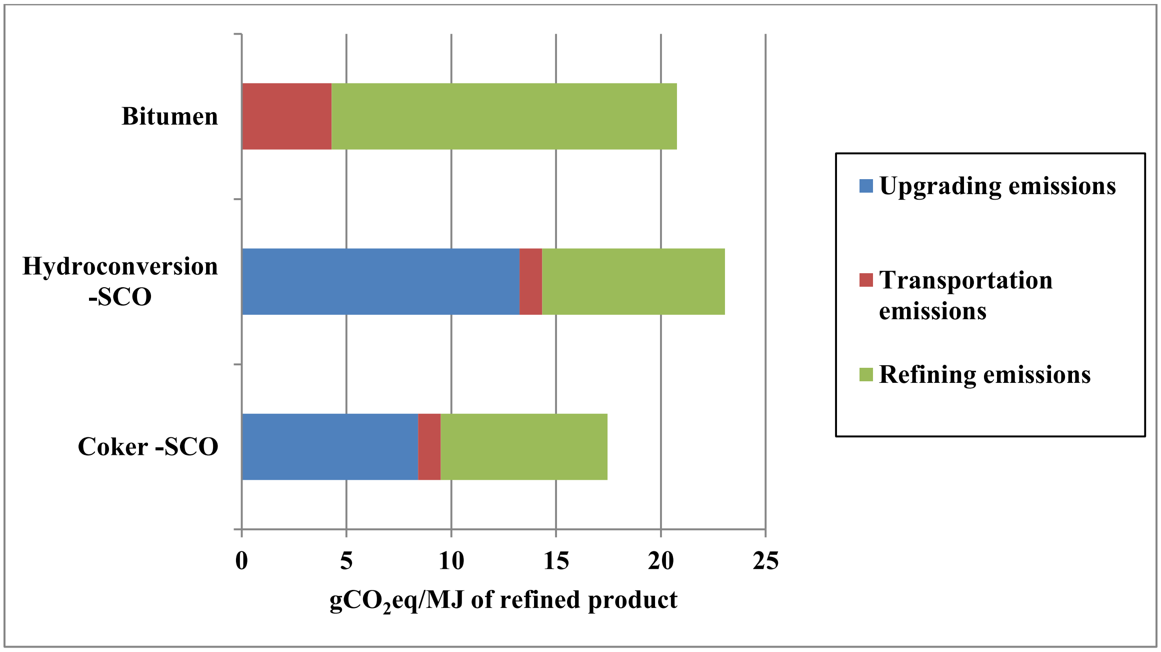


Figure 25: GHG emissions from upgrading, transportation, and refining oil sand crudes.

3.4 Conclusions

A detailed, data-intensive model based on first principles was developed to estimate project-specific emissions in bitumen upgrading. GHG emissions from bitumen upgrading in hydroconversion (433.4 kgCO_2eq/m^3 of bitumen) are 80% higher than in delayed cokers (240.3 kgCO_2eq/m^3 of bitumen). But the volume yield of SCO in the former case is 14% higher, resulting in 263.9 kgCO_2eq and 417.8 kgCO_2eq emissions per m^3 of SCO respectively. Emissions in upgrading are most sensitive to hydrogen consumption and the feed's sulfur content. The refining of oil sands crudes consumes 557.8 MJ to 895.1 MJ per bbl of crude. The yield of refined products from heavier feeds such as bitumen is lower than that from SCO. The refining of SCO to fuels produces 41% and 49% lower emissions than dilbit and bitumen, respectively. GHG emissions for obtained refined products through direct refining of bitumen are higher than emissions from refining after delayed coker upgrading and lower than refining after hydroconversion upgrading.

Chapter 4

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

This chapter describes the well-to-wheel life cycle assessment of the transportation fuels gasoline, diesel, and jet fuel, which are obtained from the refining of oil sands products. The life cycle inventories of the transportation fuels are investigated from well to wheel. This includes all stages of the life cycle of a transportation fuel (recovery & extraction, transportation, upgrading, refining, fuel dispensing, and combustion in vehicles).

4.1 Introduction

An LCA is a technique used to better comprehend the environmental impact of a product throughout its life from raw material acquisition through production, to its use and disposal. ISO 14040 [75] and ISO 14044 [76] define the four elements for an LCA framework (shown in Figure 26). The "goal and scope definition" aims to clearly define the goal and scope of the study. The goal of the study requires describing the intentions for carrying out the LCA and also the intended audience. The scope of the study covers the description of the functional unit used in the analysis, the operations to be studied, and the system boundary. The life cycle inventory analysis involves data collection and calculation procedures to identify the inputs and outputs of the system under consideration. The third step, "life cycle impact assessment," refers to the identification of the impact categories (global warming potential, human impact, social impact, etc.) and to assigning the data collected to the relevant impact categories. Finally, in the "life cycle interpretation" section the results from steps 2 and 3 are combined to study the impact as per the goal of the study, and accordingly conclusions and recommendations are made.

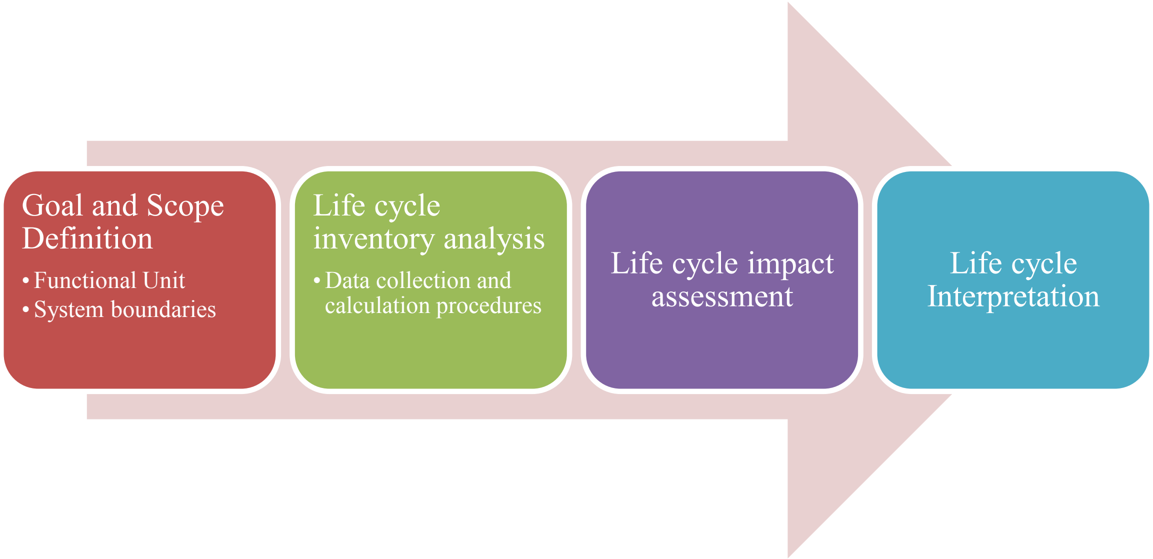


Figure 26: Framework as per international standards to carry LCA of a product.

4.2 Methodology

Essential procedures in identifying and assessing the environmental impact of transportation fuels in their LC include defining the system boundaries, functional unit, and allocation methods as well as the collection and processing of relevant life cycle inventory (LCI) data, followed by an impact assessment [75].

4.2.1 Goal and Scope

The primary goals of this LCA are:

- To utilize the GHG emissions obtained from the developed theoretical models to quantify the LC emissions of transportation fuels from oil sands products namely SCO and bitumen.
- To explore and compare the LC GHG emissions among different bitumen LC pathways those exist in oil sands.
- To identify the processes those are associated with the highest greenhouse gas emissions in production of transportation fuels.
- To add to the knowledge base for comparing the GHG intensity of oil sands products to the 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.

4.2.1.1 System boundary

Figure 27(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. Figure 27(A-F) shows that throughout the LC pathway more than one product are formed. Coke is formed in upgraders where as both coke and fuel oil are formed as co products in refineries along with gasoline, diesel and jet fuel as major products. Coke and fuel oil are placed inside the system boundary implying that the burden required to produce these shall be borne by major products- diesel, gasoline and jet fuel. The excess cogenerated electricity in oil sands that is exported to the Alberta grid is considered outside the system boundary and hence is appropriately credited for.

Along with the direct emissions from combustion of process fuels, the system boundary encloses the upstream emissions to recover and transport these process fuels. For example, the net emissions include emission to transport and deliver natural gas. Emission due to flaring, fugitives, land use, equipment and infrastructure construction are beyond the scope of this research.

4.2.1.2 Functional Unit

The full life cycle is investigated with gram of CO_2eq per megajoule of refined product as the functional unit. The functional unit used for lifecycle inventory data in upstream stages (recovery & extraction, transportation, upgrading) is 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. The lower heating value (LHV) of fuels (to be consistent with the California GREET model) has been used to define the energy content. Necessary unit conversions are made to present and compare the results with other studies.

4.2.2 Life cycle inventory (LCI)

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

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

A total number of six pathways (as shown in Figure 27(A-F)) involving the above unit operations have been formed and investigated in this LCA. These pathways represent the variability of oil sands. The bitumen in oil sands can be recovered through shovel truck mining operations or through thermal recovery methods such as SAGD. The bitumen is extracted from the recovered oil sand ore through surface extraction facilities (see chapter 2 for details of these operations). The main energy inputs in surface mining operations are identified as diesel, natural gas and electricity. The bitumen recovered from surface mining and SAGD is a highly viscous and hydrogen deficient heavy feed. Due to these properties of bitumen, it can neither be pipelined nor refined in all refineries. The developing oil sands industry has chosen different ways as a solution to this problem. One such way is to process bitumen in mini refinery like plants called upgraders, where bitumen is processed to form a superior refinery feed called SCO. SCO is light oil (API ~ 30), 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 is mixed with lighter hydrocarbons such as natural gas condensate or naphtha called as diluent. The diluent is mixed in bitumen in an approximate ratio of 25:75 so as to achieve the appropriate API and viscosity to use in a pipeline. Pathways 1, 2, 3 and 4 (shown in

Figure 27(A-F)) are based on an average transport distance of 500 km between the extraction site and upgrader. The diluent is separated and recycled (assuming no loss of diluent) back to extraction site for the same distance. Two most common configurations of upgraders in oil sands are explored using these pathways - upgrading in delayed cokers or through 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 where the bitumen is not upgraded but transported as dilbit for a distance of 3000 km to refineries. At the refineries, dilbit is separated and 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 of configuration detailed in [77]. The transportation fuels- gasoline, diesel and jet fuel produced from refining of oil sands feeds are delivered and distributed to retail locations, which are later combusted in vehicles.

The quality of LCI data is a key factor in the validity of this analysis. The quality of data aggregated can also vary depending on the methodology used to obtain the data. Data collected may be a direct reporting by a specific company or may be aggregated for entire sector. The lack of industrial data available in public domain for the oil sands sector made it very difficult to collect the data. Hence to obtain good quality data that would be representative of the oil sands industry, technical models based on engineering first principles were developed for each unit operation in oil sands. These models are used to obtain LCI data for energy consumption in each upstream unit operation – recovery & extraction, upgrading as detailed in [70, 77].

Energy in surface mining is consumed in form of diesel, natural gas and electricity. The consumption and GHG emissions of diesel for mining of bitumen in shovel trucks is estimated by performing engineering calculations for productivity of shovel and trucks for a certain assumed fleet (detailed in [70]). Natural gas consumption is calculated from the warm water requirement utilizing heat and mass transfer principles. Due to special nature of the floatation cells and equipment required for extraction in surface mining, electricity requirement is estimated from literature findings and actual data reported by industry to the Energy Resources Conservation Board (ERCB) [40], now the Alberta Energy Regulator, a regulatory body of the Alberta government.

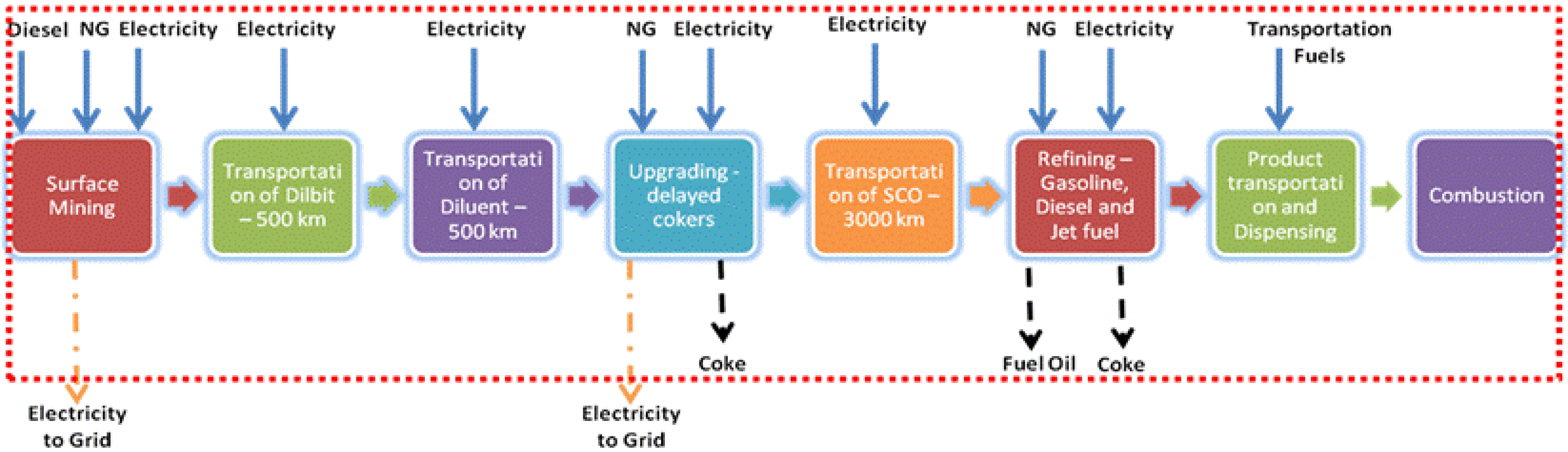


Figure 27 (A): Pathway 1- Surface mined bitumen is upgraded in delayed cokers and the produced SCO refined to gasoline and diesel.

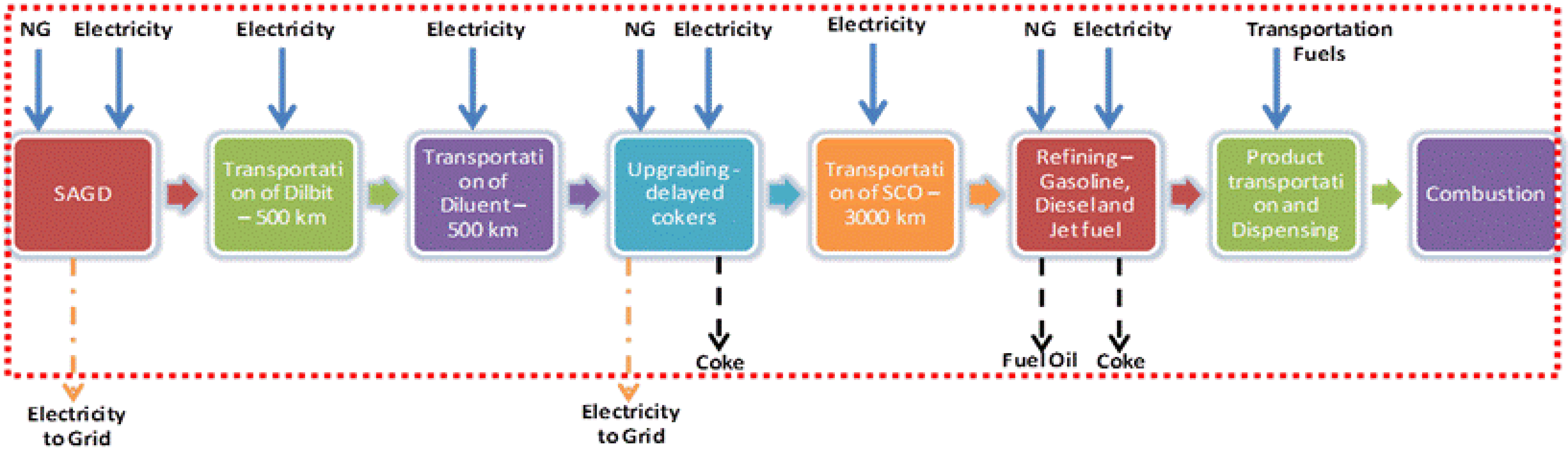
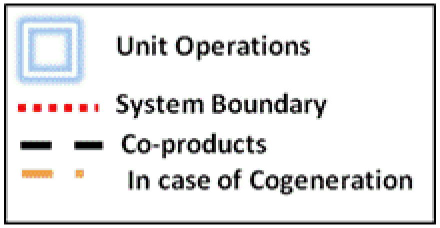


Figure 27 (B): Pathway 2- Bitumen recovered in SAGD is upgraded in delayed cokers and the produced SCO refined to gasoline and diesel.



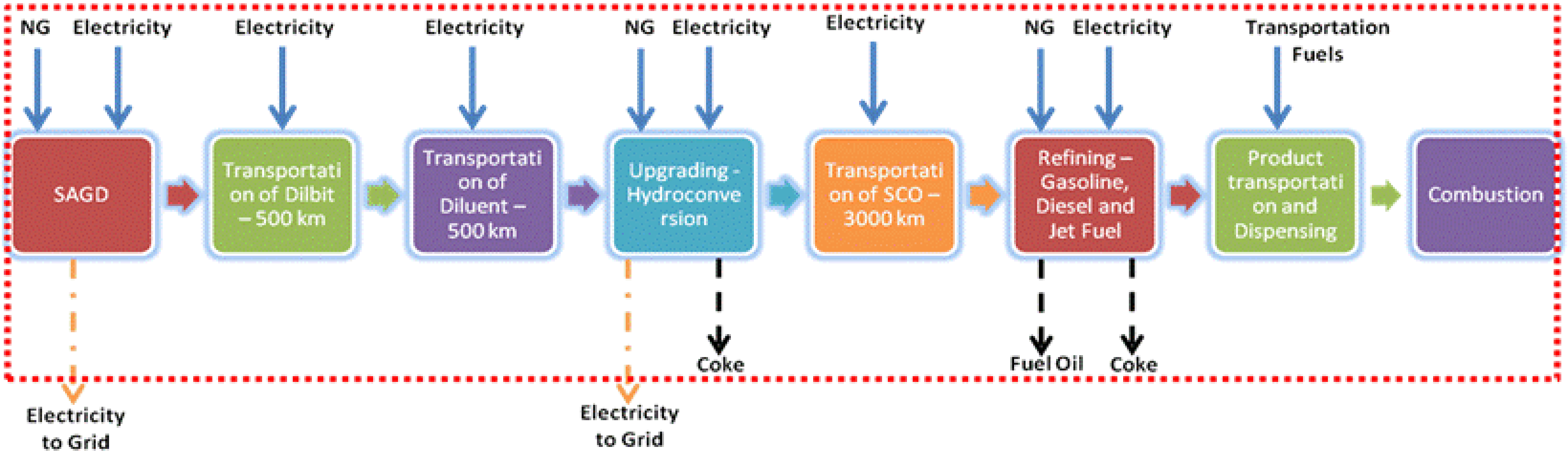


Figure 27 (C): Pathway 3- Bitumen recovered in SAGD is upgraded through hydroconversion and the produced SCO refined to diesel and gasoline.

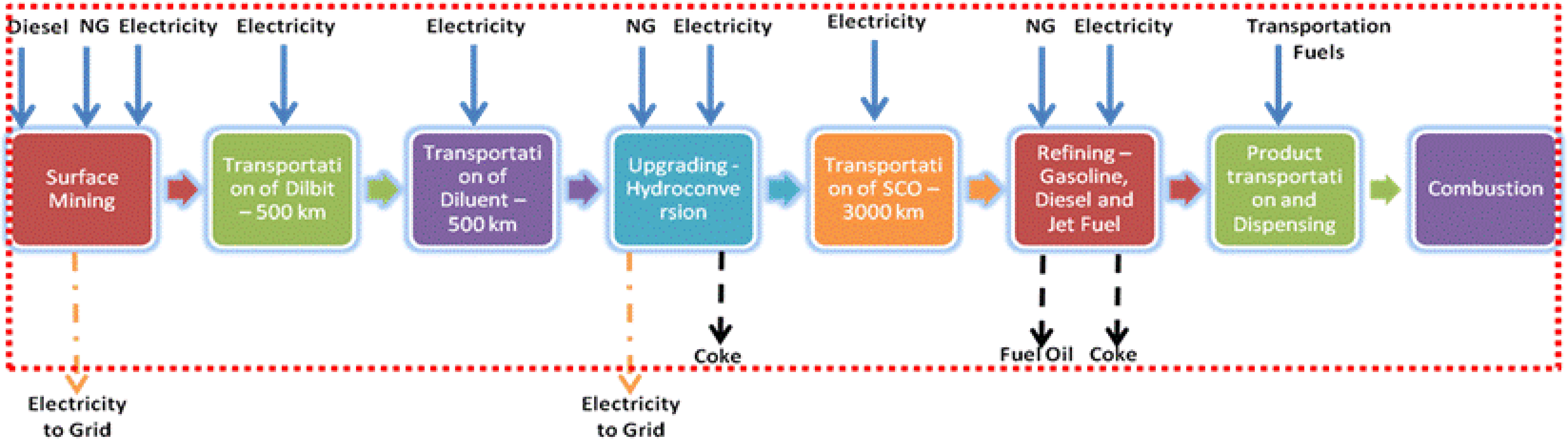
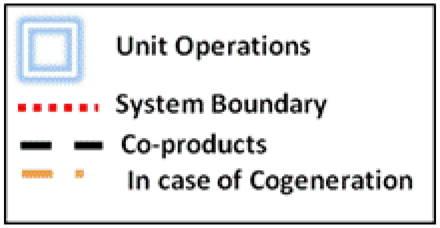


Figure 27 (D): Pathway 4- Surface mined bitumen is upgraded through hydroconversion and the produced SCO refined to gasoline and diesel.



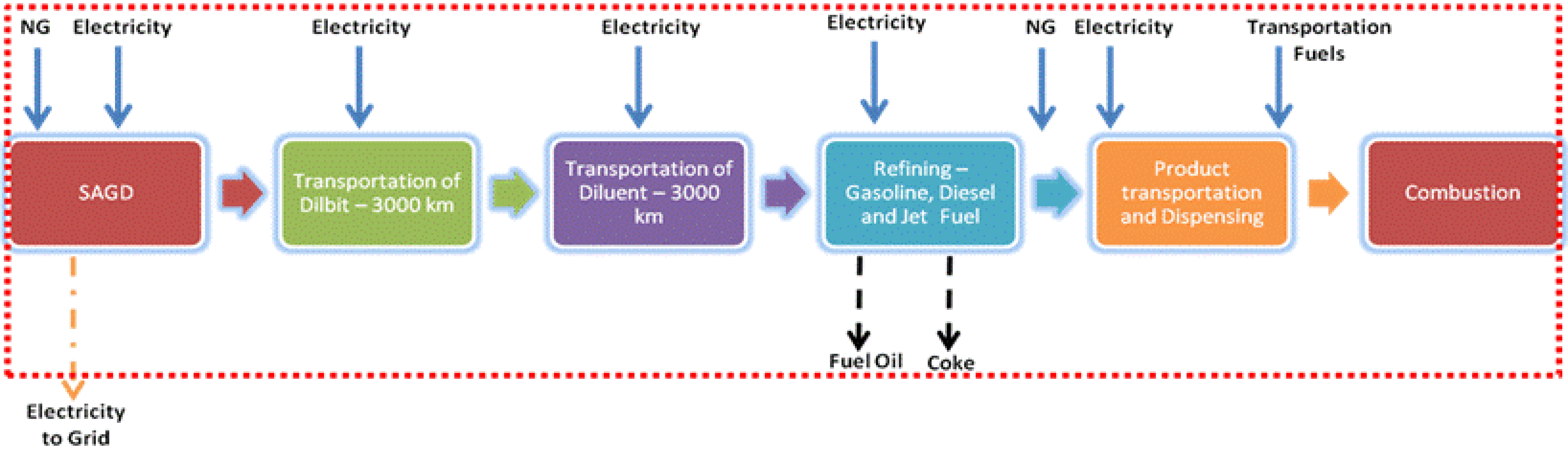


Figure 27 (E): Pathway 5- Bitumen recovered in SAGD is transported as dilbit to refineries and refined to produce gasoline and diesel.

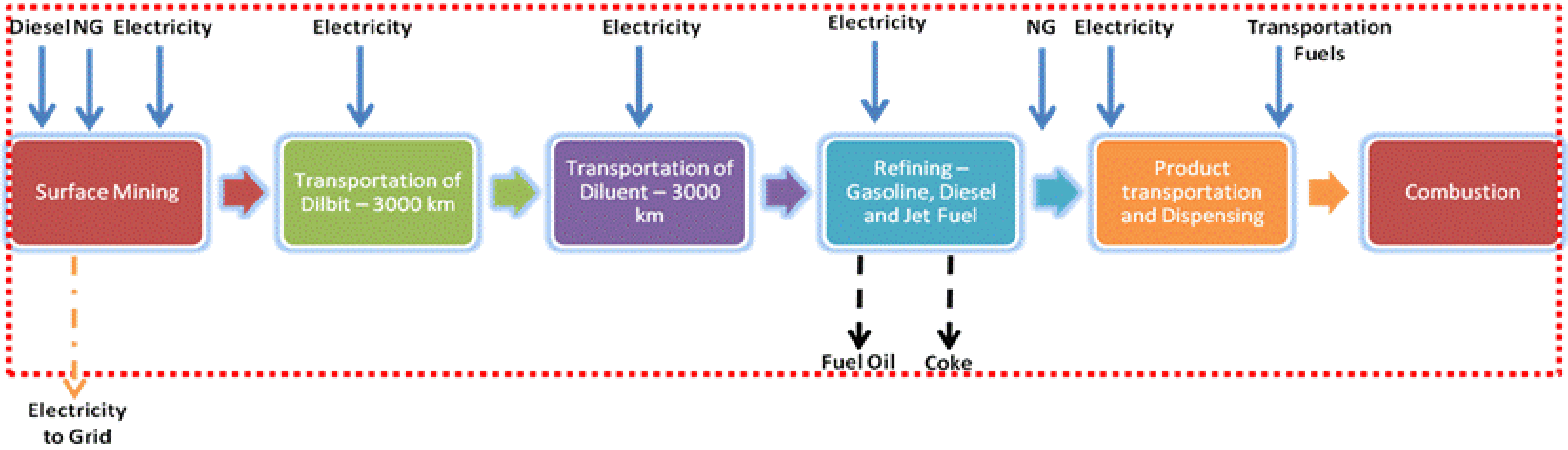
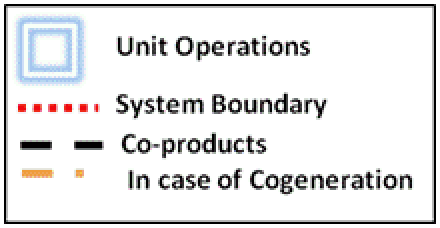


Figure 27 (F): Pathway 6- Surface mined bitumen is transported as dilbit to refineries and refined to produce gasoline and diesel.



Natural gas and electricity are energy providers and hence 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 [70]) on the instantaneous steam to oil ratio (iSOR) of a project. The main consumers of electric energy are the evaporators for water treatment and pumps 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 evaporator.

The widely used upgrading configurations- delayed coker and hydroconversion are divided into sub unit operations described in [77]. The flow of feed in upgrading sub unit operations is traced based on mass balance and volume percentage of products distilled at each stage. Hydrogen requirement in each subunit operations is calculated based on the mass of feed to be treated. Detailed engineering calculations (see Appendix B for equations) are performed to estimate the energy- steam, natural gas, fuel gas and electricity, required in each sub unit operation. The GHG emissions are figured out from energy requirement using appropriate emissions factors.

Feedstock Transportation

Transportation is inseparable stage in the life cycle of transportation fuels as the feedstock (crude) and the fuel (refined products) need to be delivered from the site of their production to the site of use. The feedstock in oil sands that needs to be transported is bitumen. Bitumen is delivered to the upgrader where it transformed to SCO, subsequent transportation of SCO to refinery or it can be directly delivered to refineries. The refined products are further delivered to the bulk terminal, from where they are distributed to refueling stations. These all modes of transportation require different amounts of energy and hence emit variable GHG emissions. The below section describes the estimation of GHG emissions in various transportation modes.

As noted in section chapter 1, bitumen is highly viscous crude that does not flow at room temperature. In order to pipeline bitumen, it is mixed with lighter hydrocarbons – naphtha or natural gas condensate known as diluent. The mixture known as dilbit is pipelined to the required destination. A distance of 500 km has been assumed between the extraction facility and upgraders [21]. This assumption is representative of the distance between extraction facilities located in Fort McMurray and upgraders in Fort Saskatchewan. The refineries are assumed to be located at an approximate distance of 3000 km from the extraction facilities and upgraders in Alberta. The distance assumed here represents the distance between extraction, upgrading facilities in Fort McMurray and refineries in PADD III region in the U.S.

A theoretical engineering model based on first principles is built 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, which is indicative of refinery capacity in North America [78]. The pipeline diameter is calculated based on continuity equation and an assumed velocity of 1.5 m/s

[79, 80]. The calculated Reynolds number and absolute roughness of new commercial steel pipeline [81] 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 [21]. 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 weighted average of the Canadian and U.S. provincial electricity grid emission factors along the pipe, is used to convert the electric energy consumed to GHG emissions. The properties of crude feed and pipeline specifications that have been used in development of transportation model are detailed in Table 9.

Table 9: Parameters and specifications for pipeline transport of Dilbit/SCO/Diluent.

Crude feed	Dilbit	SCO	Diluent	Comments/Sources
Capacity (bpd)	200000	150000	50000	[α]
API	22	32	55	[61]
Kinematic Viscosity (cST)	200	10	1.3	[61]
Distance (km)	3000;500	3000	3000;500	[β]
Pipeline velocity (m/s)	1.5	1.5	1.5	
Pipe inner diameter (inch)	22	19	11	[γ]
Pump efficiency	70%	70%	70%	
Absolute roughness (m)	0.000046	0.000046	0.000046	[81]

[α] Dilbit is a 75:25 mixture of bitumen and diluent.

[β] 3000 km- length of dilbit pipe from extraction facility to refinery; 500 km- length of dilbit pipe from extraction facility to upgrader.

[γ] Calculated based on continuity equation.

The GHG emissions from pipeline transportation of feed for 500 and 3000 kms are shown in Figure 27. Dilbit is the most viscous and heavy feed, hence is most energy and GHG intensive. Diluent is less viscous and lighter feed as compared to SCO, but the emissions for diluent transportation over the same distance are higher because the scale of transportation of diluent. Diluent is transported in pipelines in smaller capacities hence the emissions per unit of feed transported are higher. Capacity/scale of transportation has a significant effect on LC GHG emissions of pipeline transportation.

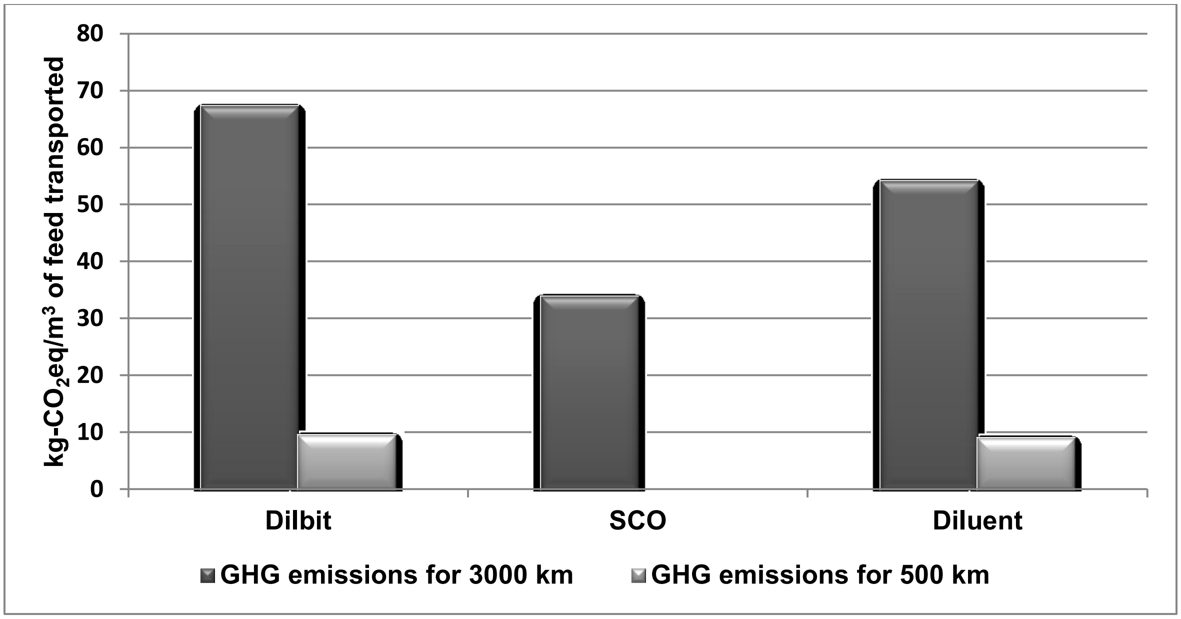


Figure 27: GHG emissions from pipeline transportation of feed for a distance of 500 and 3000 kms.

The data inventory for refining oil sand feeds is obtained by simulating a typical deep conversion refinery using a process model in Aspen HYSYS [33]. Apart from the energy consumption in refining of 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 has been used to obtain the energy consumption and the yield of transportation fuel- gasoline and diesel from refining of SCO and bitumen. It is difficult to trace the journey of transportation fuels from refinery to retail outlets. This is assumed to be more of a local transportation and would have much smaller impact on net results as crude feeds, which are transported over long distances. Considering this assumption, the LCI data for transportation and distribution of gasoline and diesel is obtained from GREET [19]. The value for GHG emissions from the combustion of gasoline and diesel in vehicles depends on the carbon content of the fuel [15, 19]. The GHG emission factor of gasoline and diesel combustion engines in vehicles as well as the efficiency of vehicles are pretty much established and have been obtained from GREET [19]. Table 10 summarizes the GHG emission factors used in this research.

Table 10: Emissions factors used in life cycle assessment of transportation fuels.

Fuel	Unit	Emission factor	Comments/Source
Diesel	g-CO2eq/MMBTU	94385	[19]
Natural gas	g-CO2eq/MMBTU	64769	[19]
Natural gas as feedstock to Hydrogen production	g-CO2eq/MMBTU	5390	[19]
Reaction emissions from hydrogen production	g-CO2eq/gm of natural gas	2.75	Calculated based on stoichometery
Upgrader fuel gas	g-CO2eq/kg	2419.4	Calculated based on composition of fuel gas
Refinery fuel gas	g-CO2eq/MMBTU	64200	[19]
Alberta grid Electricity	g-CO2eq/kWh	880	[57]
Grid electricity for refinery	g-CO2eq/kWh	581	α
Electricity for pipeline transport	g-CO2eq/kWh	725	β
For crediting electricity export to Alberta grid	g-CO2eq/kWh	650	[57]
FCC coke	g-CO2eq/MMBTU	10200	[19]

α) Average of Emissions & Generation Resource Integrated Database regions (eGRID) – ERCT, SPSO, SRMV [82, 83] in U.S. where PADD (Petroleum Administration for Defense Districts) 3 refineries are located.

β) Distance weighted average of electricity grid emission factor for eGRID regions - MROW, SPNO, SPSO in U.S. and Alberta, Saskatchewan and Manitoba in Canada from which the pipeline passes from Alberta to PADD 3 [57, 83].

Fuel Transportation and distribution

The petroleum products produced in the refinery are distributed to end user through refueling stations. The products from the refinery are first transported to bulk terminals and then to refueling stations. It is a very challenging task to trace the flow of refined products from refinery gate to refueling stations. The basic assumptions and values from GREET [19] have been used to estimate the emissions from transportation and distribution of refined products. As per GREET, ocean tanker, barge, pipeline and rail are used for transportation of refined products from refinery to the bulk terminal. About 75% of refined products are transported in pipelines. Truck is used for local distribution of refined products from bulk terminal to refueling stations. Table 11 details the assumptions and results of fuel transportation and distribution. The GHG emissions per unit of diesel, gasoline and jet fuel energy are about the same and approximate to 0.5 g-CO_2eq/MJ.

Table 11: Data for transportation and distribution of fuel.

	Conventional Diesel					Conventional Gasoline					Jet fuel				
Mode	**Ocean Tanker**	**Barge**	**Pipeline**	**Rail**	**Truck**	**Ocean Tanker**	**Barge**	**Pipeline**	**Rail**	**Truck**	**Ocean Tanker**	**Barge**	**Pipeline**	**Rail**	**Truck**
Distance traveled (miles)	1,933	520	400	800		1,959	520	410	800		1,933	520	400	800	
Distance traveled (miles)					30					30					30
% share in transportation	12%	6%	75%	7%		17%	4%	72%	7%		12%	6%	75%	7%	
% share in distribution					100%					100%					100%
	GHG emissions														
Fuel transportation (gCO2eq/mmbtu)	365.4					360.0					362.2				
Fuel distribution (gCO2eq/mmbtu)	165.1					163.0					164.1				

Table 12: LCI data inventory for surface mining, SAGD, upgrading, transportation of feed, refining, transportation, distribution and combustion emissions for gasoline and diesel.

Surface Mining						
	Units	**Energy consumption**		**Units**	**GHG emissions**	
		Range	Default		Range	Default
Diesel	L/m^3 of bitumen	5-8	6.23	kgCO$_2$eq/m^3 of bitumen	16-25.7	20
Electricity	kWh/m^3 of bitumen	72-85	80.4	kgCO$_2$eq/m^3 of bitumen	63.3-74.8$^{\alpha}$	70.7 $^{\alpha}$
No cogeneration						
Natural Gas	m^3/m^3 of bitumen	64-90	74.4	kgCO$_2$eq/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$_2$eq/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$_2$eq/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)$^{\beta}$	-17.5 $^{\beta}$
SAGD						
Produced gas	m^3/m^3 of bitumen	1-12	4	$kgCO_2eq/m^3$ of bitumen	2-24.7	8.2
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	301.8	$kgCO_2eq/m^3$ of bitumen	624-1263.6	678.6
Electricity co-produced	kWh/m^3 of bitumen	700-886	792.7			
Net electricity	kWh/m^3 of bitumen	653.5-741.3$^{\gamma}$	736.4	$kgCO_2eq/m^3$ of bitumen	-(388-445.3) $^{\beta}$	-478.2 $^{\beta}$

Upgrading						
		Delyed Coking	**Hydroconver-sion**		**Delyed Coking**	**Hydroconver-sion**
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$_2$eq/m^3 of bitumen	114.8	94.5
No cogeneration						
Natural gas	m^3/m^3 of bitumen	40.4	147.1	kgCO$_2$eq/m^3 of bitumen	79.9[ν]	264.2[ν]
Steam	lb/m^3 of bitumen	120.7	175.2		[η]	[η]
Electricity	kWh/m^3 of bitumen	51.9	84.9	kgCO$_2$eq/m^3 of bitumen	45.6[α]	74.7[α]
With Cogeneration						
Natural gas	m^3/m^3 of bitumen	68.9	197.1	kgCO$_2$eq/m^3 of bitumen	120.7	324.4
Electricity exported	kWh/m^3 of bitumen	-41.4	-83	kgCO$_2$eq/m^3 of bitumen	-26.9[β]	-53.9[β]
Transportation of SCO – 3000 km[†]	kWh/m^3 of		46.7	kgCO$_2$eq/m^3 of		33.8

	SCO			SCO	
Transportation of Dilbit – 3000 km[†]	kWh/m^3 of bitumen		123.6	kgCO_2eq/m^3 of bitumen	89.6
Transportation of Diluent – 3000 km[†]	kWh/m^3 of diluent		74.6	kgCO_2eq/m^3 of diluent	54.1
Transportation of Dilbit – 500 km[†]	kWh/m^3 of bitumen		17.5	kgCO_2eq/m^3 of bitumen	12.7
Transportation of Diluent – 500 km[†]	kWh/m^3 of diluent		37.2	kgCO_2eq/m^3 of diluent	27
Refining[ζ]					
		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	
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	10.8	12.5	15.2	

	feed			
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		
Combustion emissions for conventional diesel	gm/MJ	75.14		
Combustion emissions for conventional gasoline	gm/MJ	75.78		

[α] Alberta grid emissions.

[β] Negative sign signifies the credit given for displacing GHG-intensive grid electricity. Includes both scenarios - cogeneration using a steam turbine and gas turbine.

[γ] Obtained by subtracting the lower values and higher values in the range. But other combinations may be possible.

[η] Emissions from steam production are included in natural gas/fuel gas combustion emissions.

[†] Based on a transportation scale of 150,000 bpd of SCO, 200,000 bpd of dilbit, 50,000 bpd of diluent.

[ζ] 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.

[ν] includes the emissions for separation of diluent from dilbit.

Combustion

The last stage in the well to wheel analysis of transportation fuels is the combustion in vehicles. Apart from CO_2, vehicle emissions include CH_4, N_2O, SO_x, NO_x, particulates and volatile organic compounds (VOCs). This life cycle analysis includes the effect of greenhouse gases, hence only CH_4, N_2O, and CO_2 counted. The vehicles emissions from combustion of transportation fuels are based on carbon content of the fuel. As the emissions factors for combustion of gasoline, diesel and jet fuel are established, these values are obtained from GREET [19]. GREET model was run to obtain the emission factors for passenger cars and passenger aircraft (single aisle). Following emission factors for combustion of transportation fuels in vehicles are obtained from GREET.

	Conventional Gasoline	Conventional Diesel	Jet Fuel
g-CO_2eq/MJ	75.14	75.78	73.2

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

Allocation: The system boundaries depicted in Figure 27(A-F) for production of transportation fuels involve more than one co-product. This leads to typical allocation problem in LCA which refers to criteria for determining how to split or partition the environmental burden associated with the processes among the co-products produced. International Standard Organization (ISO) provides a guide for LCA where allocation is required [75]. The guideline for LCA recommends avoiding allocation where possible and allocating GHG emissions on sub process level, if required. Because the purpose of this research is to compare the LC GHG emissions for producing transportation fuels, which produces multiple products, allocation becomes necessary. Earlier studies have used allocation schemes based on mass, energy content, market value or hydrogen content [23, 24, 84, 85]. This research allocates the refinery emissions on sub process level instead of aggregate approach, based on mass of the products. The rationale behind choosing mass as weighting factor is that the energy use is proportional to the mass of products processed [84]. The GHG emissions for each sub unit operation are distributed among the products, as per Eq. (1). These GHG emissions are added into the emissions of next sub unit operations where the products go. The GHG emissions from supporting processes such as amine gas treatment, sulfur recovery, and saturated gas plant are distribute among diesel, gasoline and jet fuel based on the mass fraction of each product. All the GHG emissions from SMR for hydrogen production are added to hydrocracking GHG emissions as all the hydrogen produced in SMR is consumed in hydrocracking operation.

$$\begin{aligned} &Emissions\ allocated\ to\ product\ (i)(g - CO_2eq/day) \\ &\quad = Emissions\ in\ sub\ unit\ operation\ \left(\frac{g - CO_2eq}{day}\right) \times \frac{M_i}{\sum_{i=j.k.l\ldots} M_i} \end{aligned} \tag{1}$$

Where M_i= mass of the product (i) produced

$j.k.l$ ... are the products of each sub unit operation.

Table 12 shows the disaggregated LCI for energy consumption and emissions for each life cycle stage in the LCA. Data collected has to be integrated to calculate the LC GHG emissions for each pathway. As observed in the table, the data collected has been 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 form of gasoline, diesel and jet fuel (see Eq. (2))

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

Where E_i= total energy content of the product (i) produced per day

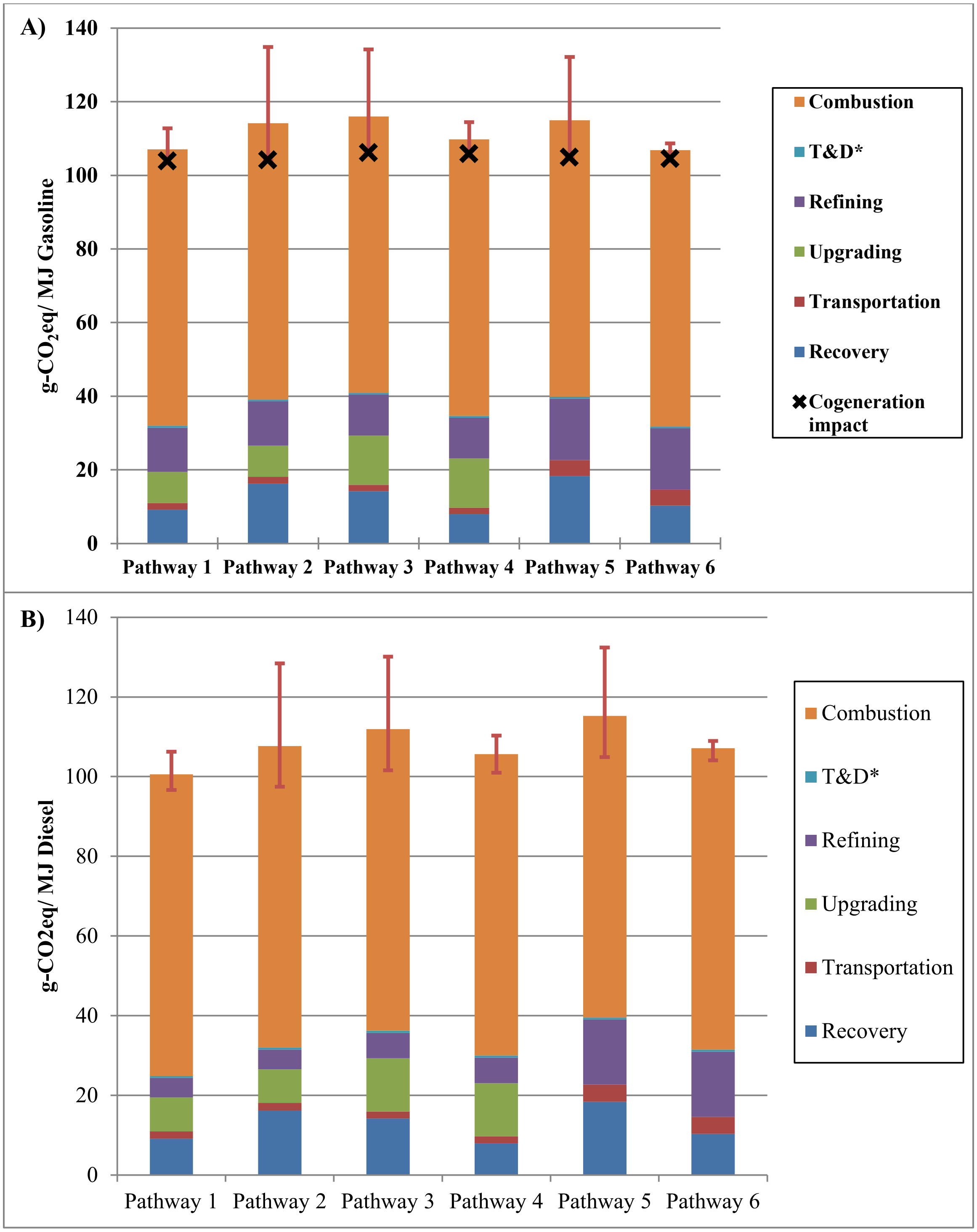
$j.k.l$ are the diesel, gasoline and jet fuel.

The environmental impact of LC can be studied using various environmental indicators. Global warming potential (GWP) 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_2equivalent on a 100 year time horizon based IPCC (Intergovernmental Panel on Climate Change)2007 [86].

4.3 Results and Discussions

4.3.1 Life cycle impact assessment (LCIA)

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 Figure 28). The wide range shows the variability in oil sands projects and is obtained from range of emissions (detailed in Table 12) in oil sands unit operations. In the default case analyzed with data specified in Table 12, 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 upon the pathway. The variations in the LC emissions of gasoline, diesel and jet fuel from different pathways is basically due to difference in upstream and refining emissions, the distribution and combustion emissions being the same. Pathways in the descending order of the GHG intensity for gasoline production are 3, 5, 2, 4, 1, and 6. Refining of SCO is less energy and GHG intensive as compared to bitumen. This is because the SCO is a light fuel obtained by upgrading bitumen.


A)
140
120
100
80
60
40
20
0
g-CO_2eq/ MJ Gasoline
Pathway 1
Pathway 2
Pathway 3
Pathway 4
Pathway 5
Pathway 6
Combustion
T&D*
Refining
Upgrading
Transportation
Recovery
✖ Cogeneration impact
B)
140
120
100
80
60
40
20
0
g-CO2eq/ MJ Diesel
Pathway 1
Pathway 2
Pathway 3
Pathway 4
Pathway 5
Pathway 6
Combustion
T&D*
Refining
Upgrading
Transportation
Recovery

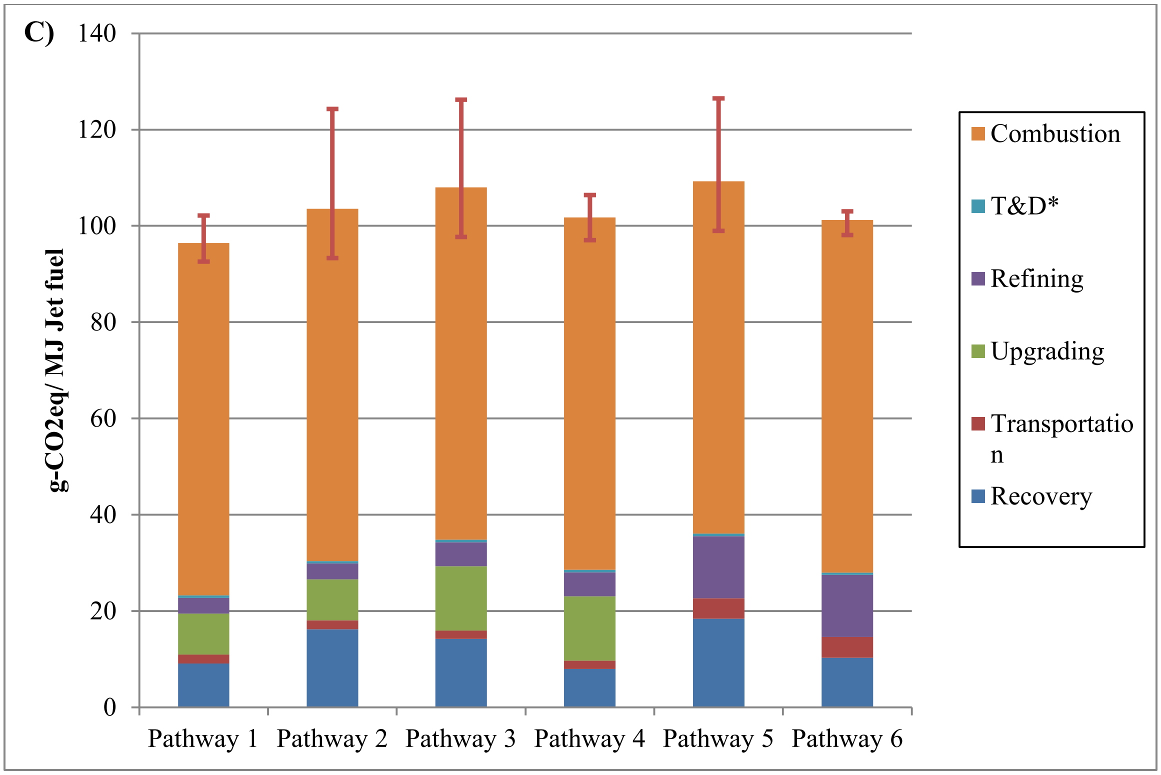


Figure 28: LC WTW GHG emissions for A) gasoline, B) Diesel and C) Jet fuel.

* 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 [21].

The strategy for allocation of refinery emissions has been detailed in above section. Based on the above strategy, it has been observed that production of gasoline in a refinery is most GHG intensive, followed by diesel and jet fuel [84, 85]. The GHG allocation factors in a refinery (shown in Table 13) vary with the feeds to the refinery. Feeds vary in energy consumption and the production of gasoline, diesel and jet fuel which affects the allocation factors. The GHG emission allocation factors are different if allocated based on refinery level or at next sub process level. These allocation factors are detailed in Table 13. GHG Emissions allocated to gasoline at sub process level are higher than those allocated at refinery level. Refinery level allocation makes diesel and jet fuel less GHG intensive than sub process level. The allocation factors for bitumen at sub process level do not differ by much than at refinery level, but are significantly different for SCO. The allocation method significantly affects the refinery GHG emissions allocation to transportation fuels, resulting in different values of WTW emissions. The GHG intensity order of pathways may change based on allocation method. Pathway 5 replaces pathway 3 for the least GHG intensive option for the production of gasoline when refinery GHG emissions are allocated on an energy basis at the refinery level compared to the mass basis as in the former case.

Table 13: Refinery level and sub process level GHG emission allocation factors for gasoline, diesel and jet fuel.

	Sub process level allocation- Mass basis			Refinery level allocation- Mass basis			Refinery level allocation - energy basis		
	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
Hydro-conversion	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

Different LC stages contribute differently to the net GHG emissions depending upon the pathway. Combustion GHG emissions form a highest portion of WTW emissions ranging from 64.7% to 70.3% in gasoline; 65.7% to 75.3% in diesel and 67% to 75.9% in jet fuel. The remaining are well to refinery (WTR) GHG emissions; transportation and distribution of end products being a very small percentage of WTW emission (~0.5%). Recovery and extraction comprise 7.2% to 16% portion of WTW emissions for gasoline production. In pathways 1, 2, 3 & 4 upgrading and refining add up to 17.9% to 22.3% of total GHG emissions. This is because of 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 total GHG emissions in pathway 5 and 6 respectively.

Gasoline production from upgrading SAGD bitumen is most GHG intensive. GHG intensity wise, production of one transportation fuel may be better from one pathway while other transportation fuel may be better from other pathway. Explicitly, the 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 as compared to other pathways if a different transportation fuel is chosen for comparison.

4.3.1.1 Impact of cogeneration

Oil sands projects use large amount of energy in form of steam and electricity. This provides an opportunity for cogeneration in oil sands. Cogeneration is a significant part of many oil sands projects, where 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 LC perspective. A detailed cogeneration model ([70, 77]) was developed to study effect of cogeneration in recovery, extraction and upgrading. Power exported to the grid is based on co-generating 100% of the steam required in surface mining, SAGD and upgrading operations. This is the design basis for most of oil sands facilities [15]. The impact of cogeneration on WTW emissions of gasoline is shown in Figure 28 (A). The ‘X’ marks in the figure labeled as ‘cogeneration impact’ show the net emission values when cogeneration is employed in recovery and upgrading operations. Employing cogeneration in oil sands offsets the WTW emissions of gasoline by 2% to 9%. Highest impact of cogeneration is observed in pathways 2, 3 and 5. This is because of large requirement of steam in SAGD process. The 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 as compared to pathway 6, which was least GHG intensive without cogeneration.

4.3.2 Comparison to other LCA studies for transportation fuels

A comprehensive comparison of the modeled LCA results with other studies was carried out (see Figure 30). Studies for comparison were from earlier studies [14, 15, 19, 20, 32]. All the studies for comparison have not reported results for all the pathways, which have been 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 [32] are higher than the modeled default values but within the range specified. The modeled results very closely match with results from [15], distancing by only 1 to 3 g-CO_2eq/MJ of gasoline. Range of values reported in [20] overlaps the range of modeled values for pathways 1 and 2 and on the lower side for pathway 5& 6. Apart from the above mentioned studies, the modeled results for pathway 1 are compared to results of [34, 87] as mentioned in [30], 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.

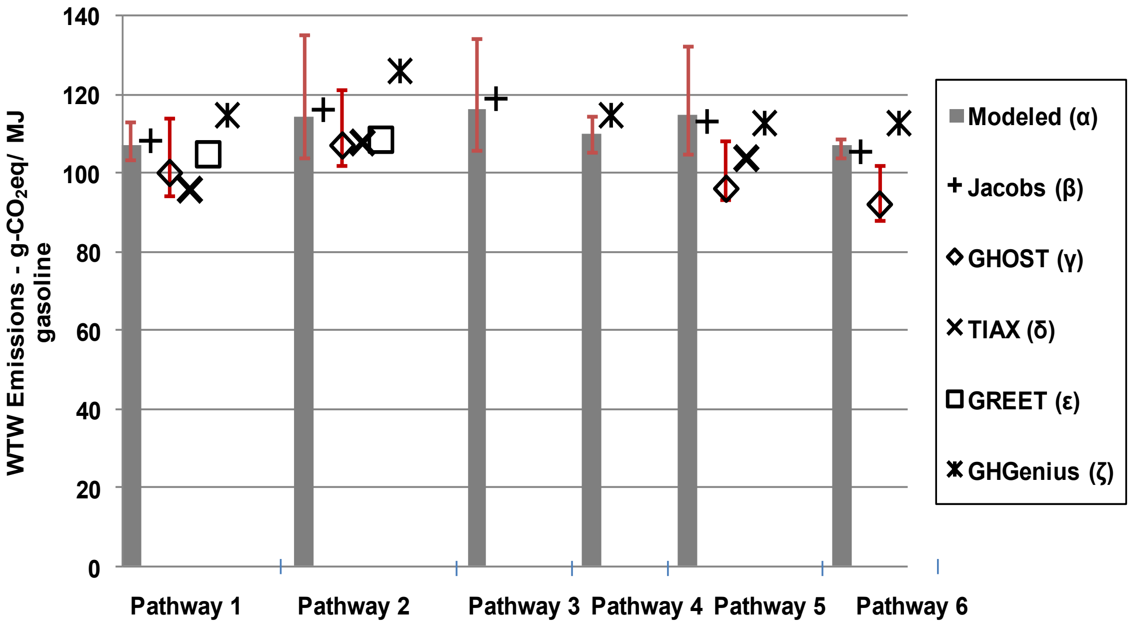


Figure 29: Comparison of modeled WTW GHG emissions for gasoline with literature values.

(α) The modeled results are for low sulfur gasoline. (β) [15]. Values taken are for reformulated gasoline blendstock for oxygen blending (RBOB). Pathway 4 is not modeled. (γ) [20]. The range shown for pathway 1 is applicable for pathway 1 & 4. Range shown for pathway 2 is applicable for pathway 2 & 3. (δ) [14]. The results are for PADD 3 and sell coke case. This case is chosen for comparison as it is similar to the modeled case. (ε) [19]. GREET does not separate the upgrading using delayed coker and hydroconversion. The value shown in pathway 1 is applicable for pathway 1 & 4; pathway 2 is applicable for pathway 2 & 3. (ζ) [32]. Pathway 3 is not modeled. Note: Unit conversions, wherever necessary are made using LHV values from GREET.

4.4 Conclusion

A comprehensive WTW life cycle assessment for transportation fuels- gasoline, diesel and jet fuel is performed considered six different bitumen pathways in oil sands. The data utilized in WTW analysis is obtained from developed theoretical models 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 pathway. The main contributors to the LC emissions are from combustion of fuels in vehicles followed up refining of crude. Strategy of allocating of total emissions to the co-products affects the order of pathways based on the LC GHG intensity. 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.

Chapter 5

Conclusion and Recommendations for Future Work

5.1 Conclusion

Detailed insights into the LCA models GREET and GHGenius show inconsistencies and variability in the methodologies, assumptions, and default values for energy consumption and GHG emissions in the oil sands. These widely discussed models do not clearly offer a method to estimate project-specific energy consumption in oil sands operations. In-depth understanding and expertise are required to use these models to run scenarios for oil sands activities.

In this study, detailed data-intensive models based on engineering first principles were developed for surface mining, SAGD, upgrading, and pipeline transportation of feedstock in the oil sands. These models were developed in a user-friendly interface. A process model in HYSYS was developed to study refining operations. The engineering models developed estimate energy consumption and GHG emissions based on technical parameters like reservoir properties, feed properties, equipment efficiencies, etc. These models identify the areas of high energy consumption and GHG emissions in each of unit operation in the oil sands. The model for upgrading explores the two most widely used upgrader configurations – delayed coker and hydroconversion. The model calculates the amount of SCO produced when a unit volume of bitumen is upgraded in both delayed coker and hydroconversion upgrading. The refinery process model developed can be used to estimate the mass yield of transportation fuels for a particular feed. The user has the flexibility to either use the default process conditions or enter their own parameters for any other project. The developed models can be used to investigate the sensitivity of key parameters on energy consumed and GHGs emitted in each unit operation in the oil sands. This would further help industry to make environmentally responsible decisions.

Energy use in oil sands conversion is mainly consumed in the form of natural gas and electricity, along with diesel consumed in surface mining. The main source of energy consumed in the oil sands is natural gas, which is used for the production of steam and hydrogen. The huge steam requirement makes recovery through SAGD more energy and GHG intensive than surface mining (excluding the emissions from tailings). Hydroconversion upgrading consumes more hydrogen than delayed coker upgrading but produces a higher volume of SCO. The refining of SCO to diesel, gasoline, and jet fuel consumes less energy than does the refining of bitumen. The energy use and GHG intensity of transportation of heavy feedstocks such as dilbit are higher than the transportation of SCO over the same distance.

This study features an extensive set of sensitivity analyses for all the unit operations in the oil sands. GHG emissions in surface mining are most sensitive to the temperature and consumption of water while GHG emissions in SAGD are most sensitive to iSOR of the project. Emissions in upgrading are sensitive to hydrogen consumption and sulfur content in the feed. Reducing the warm water consumption and lowering the temperature of water used in surface mining; lowering the iSOR in SAGD; and producing hydrogen for upgrading through renewable sources are all attractive options for reducing the GHG intensity of oil sands activities.

Another key observation in this research is that cogeneration in the oil sands can reduce the GHG intensity of oil sands activities. The use of cogeneration in the oil sands reduces GHG emissions by 2% to 9% per energy unit of gasoline produced.

A comprehensive WTW life cycle assessment for transportation fuels – gasoline, diesel, and jet fuel – was performed, and all six bitumen pathways in oil sands activities were considered. The LC WTW GHG emissions lie in a small range: 106.5 to 116 g-CO_2equivalent/MJ of gasoline, 100.5 to 114.9MJ of diesel, and 96.4 to 108.9 MJ of jet fuel, depending on the pathway. It may be difficult to choose one pathway over the other based on its GHG intensity as the GHGs in these pathways lie in a narrow range. The GHG pathway intensity order is affected by the allocation method of refinery and upstream emissions among transportation fuels and also by which transportation fuels are chosen for comparison. One pathway is not always less GHG intensive for production of all the transportation fuels (gasoline, diesel, and jet fuel).

5.2 Recommendations for Future work

1. Improvement of existing model:

- Electricity consumption in surface mining: The electricity consumption in surface mining is currently based on literature findings and data reported by industry to the ERCB (Energy Resources Conservation Board now known as Alberta Energy Regulator). The special nature and variety of equipment (i.e., floatation vessels) used in surface mining and the lack of data made it difficult to model electricity consumption in surface mining equipment. A detailed study is required to model the electricity consumption in the special equipment used in surface mining.
- Integrated surface mining and upgrading operations: Models have been developed to estimate energy consumption and GHG emissions for stand-alone surface mining and upgrading operations. Some companies have upgraders close to the surface mining site. The upgrader location has implications on the total energy use as the upgrader would have a combined cogeneration plant; fuel gas from the upgrader may be used for extraction in surface mining operations. Hence further insights into such modifications are required, and another unit operation with integrated surface mining and upgrading operations should be developed.
- Fluid bed coking: Current research explores the two most widely used upgrading technologies, delayed coker and hydroconversion upgrading. Some companies like Syncrude technology called fluid bed coking in which coke generated in the reactor is burned to provide heat for thermal cracking reactions. Fluid bed coking and delayed coking give a different SCO yield. Further study is required to incorporate the energy consumption and GHG emissions in this upgrading configuration.

2. Effect of allocation strategies: The method of allocating refinery and upstream emissions to transportation fuels has a major impact on the well–to-wheel results. An attempt was made to understand differences in allocation on refinery levels and sub process levels. Further research is required on other allocation strategies such as the allocation of emissions based on fuel hydrogen content to study their impact on WTW emissions. Most existing studies used different allocation techniques and report variable results. A need is felt to reach a consensus on the allocation strategy to be used for policy formulation and decision making.

3. Land use emissions and equipment emissions: The emissions from the use of energy providers such as diesel, natural gas, and electricity were counted for this research, but emissions from the use of land and infrastructure were not. Though land use and infrastructure emissions are thought to be minor, the boundary should be expanded to include them in the WTW emissions.

4. Venting, flaring, and fugitives: The system boundary of WTW analysis should be expanded and emissions from venting, flaring, and fugitives should be accounted for. An attempt should be made to estimate the VFF (Venting, flaring and fugitives) emissions based on engineering first principles and to incorporate them in the current model. VFF emissions should include those from tailing ponds in the case of recovery of bitumen through surface mining. Fugitive emissions depend upon the production of gas along with crude and also on the equipment used for extraction and processing of crude oil. Hence looking at the oil-to-gas ratio and equipment used would be a good starting point for the estimation of fugitives. Accounting for fugitives in the oil sands would also help in comparing the fugitives from oil sands and conventional crudes.

5. Effect of refinery configurations: A typical deep conversion refinery is used in this research to estimate the refinery emissions for processing different feeds. A number of refinery configurations such as deep conversion, medium conversion, and hydroskimming refineries exist to process SCO and bitumen separately. These refinery configurations would obtain different mass yield of transportation fuels and hence affect the WTW emissions of transportation fuels. A detailed study of the impact of refinery configuration on the WTW emissions is required.

6. Effect of coke: Coke is a major co-product from oil sand upgrading operations. In current upgrading operations, most coke is stockpiled. There have been ideas for the export of coke to other countries where the environmental regulations for power plants are not very strict. Coke can also be buried into the land mine sites. Hence further research is required to explore these ideas and their GHG impact on the oil sands. Coke is also produced in refineries. In the current research, it was assumed that coke from upgrading and refinery were stockpiled. Attempts should be made to study the difference in the quality of upgrader and refinery coke and accordingly investigate the effect of their use on WTW emissions.

7. Technological advancements in oil sands operations: As mentioned in an earlier chapter, oils sands technologies are still in developmental phases. The oil sands industry is exploring new ideas such as the addition of solvents such as butane or hexane to reduce the steam requirement for bitumen extraction in SAGD and CSS technology. In situ upgrading schemes (such as the Shell in situ upgrading process, Toe-to-Heel Air Injection (THAI), etc.) have been proposed to combine upgrading with bitumen

production. While these technologies are still in pilot stages, the energy consumption and GHG impact of these technologies should be studied to help in decision making.

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Appendix A

Variations in GREET and GHGenius

LCA is a highly informative but labor, time and research intensive method. There are a variety of LCA models available [18, 19, 88, 89] which help to reduce the workload to perform an LCA for any pathway by providing the basic framework and database. These models provide varying results based on different assumptions, different database inventory and varying data sources. This research investigates the methodologies and assumptions for oil sands pathways in two North American models GREET [19] maintained by Argonne National Laboratory, and GHGenius [18] maintained by Natural Resources Canada that have formed the basis of policy formulations. GREET has been used by two studies [14, 15] contracted by Alberta Government as the base model to evaluate the life cycle GHG emissions of transportation fuels from conventional and non-conventional crudes. Charpentier et al. [30] and Brandt [31] reviewed these models as a part of their studies to review literature. Both the authors recommended the use of GHGenius model for life cycle assessment of transportation fuels from oil sands. Whereas Charpentier reviewed the boundaries and stages modeled in these LCA models, Brandt provided overview of the results of GHG emissions in oil sand operations. None of these studies carried out in depth analysis of default data assumptions and methodologies for each unit operations in the life cycle of bitumen pathways in oil sands. This chapter aims at providing a detailed investigation of the methodologies and assumption for each unit operation in the life cycle of bitumen pathway.

Both the models, GREET and GHGenius employ different methodologies to estimate emission in each unit operation in oil sands which have been highlighted in Figure A-1. GREET uses efficiency of the process to obtain the energy input per unit of energy output using the formula: [90]

$$Energy_{in} = {}^{1}/_{efficiency}$$

Where: $efficiency$ for any stage is defined as energy output divided by energy input.

Equation 1 is used to calculate the total energy input to a process. The energy input to a process can be either as a feedstock or as fuel. GREET identifies these separately as different emission factors. Whereas combustion of energy as fuel generates a lot of GHG emissions, using energy as feedstock would have different emissions depending on the process. GREET further calculates the process fuels input using Equation 2.

$$Process\ fuels = {}^{1}/_{efficiency} - 1$$

Where $Process\ fuels$ = amount of energy fuel required to produce on unit of energy as output.

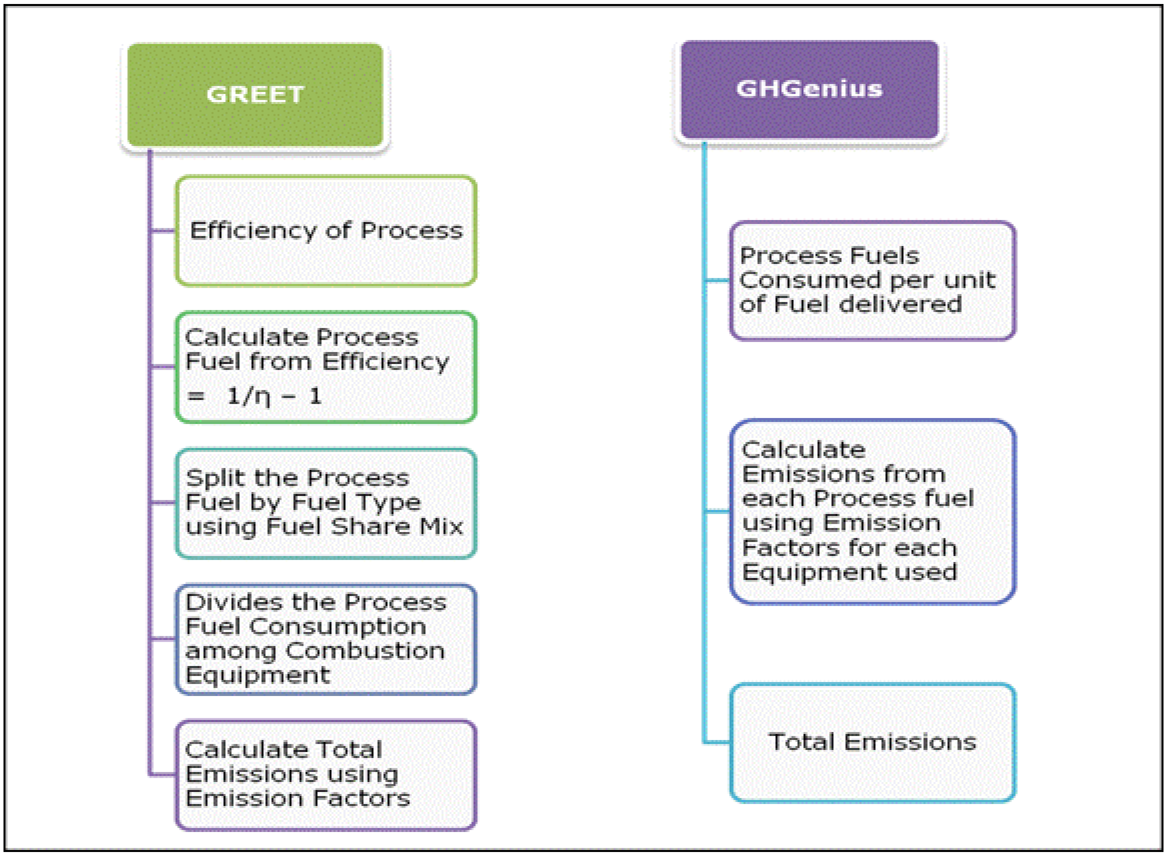


Figure A-1: Difference in methodologies of GREET and GHGenius for estimation of emissions.

Further the process fuel energy is allocated to different process fuels such as diesel, residual oil, natural gas, coal, electricity etc. used in the operation. This allocation of total energy to different process fuels for every process is then converted to total emissions using appropriate emissions factors for the type of combustion equipment utilized.

In contrast to the GREET methodology of starting with the efficiency of a process, GHGenius begins its estimation of GHG emissions with direct input of process fuel consumed per unit of fuel delivered. The direct relationship between mass and volume is used to proceed from one unit operation to the other. For example, one mass unit of SCO is assumed to be same as mass unit of bitumen. This may not be the case always as the mass of SCO is always less than bitumen and depends on upgrading operation as shown in Chapter 3. GHGenius considers the API (American Petroleum Institute) gravity relations between feeds to be mass additive, which is incorrect (density of crude is additive in volume). Further the process fuels are allocated to the combustion equipment utilized. Based on the emission factors of the combustion equipment, total emissions are calculated.

Surface Mining

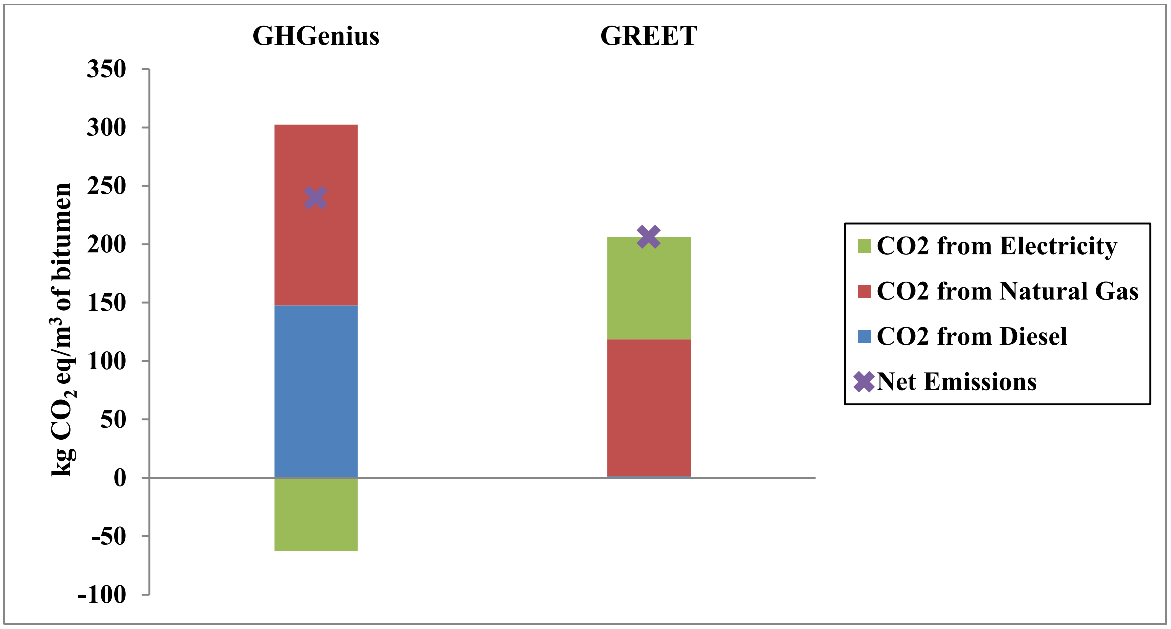


Figure A-2: Different GHG emissions in surface mining operation reported by GREET and GHGenius models.

As shown in Figure A-2, there is variation in the results reported by GHGenius and GREET. GHGenius reports higher emissions of 239.3 kgCO$_2$eq/ m^3 of bitumen as compared to 206.2 kgCO_2eq/ m^3 of bitumen reported by GREET. The basic reasons behind these differences are:

- Different share of fuel mix
- Difference in assumptions related to cogeneration of electricity
- Different efficiency of electricity generation from NG

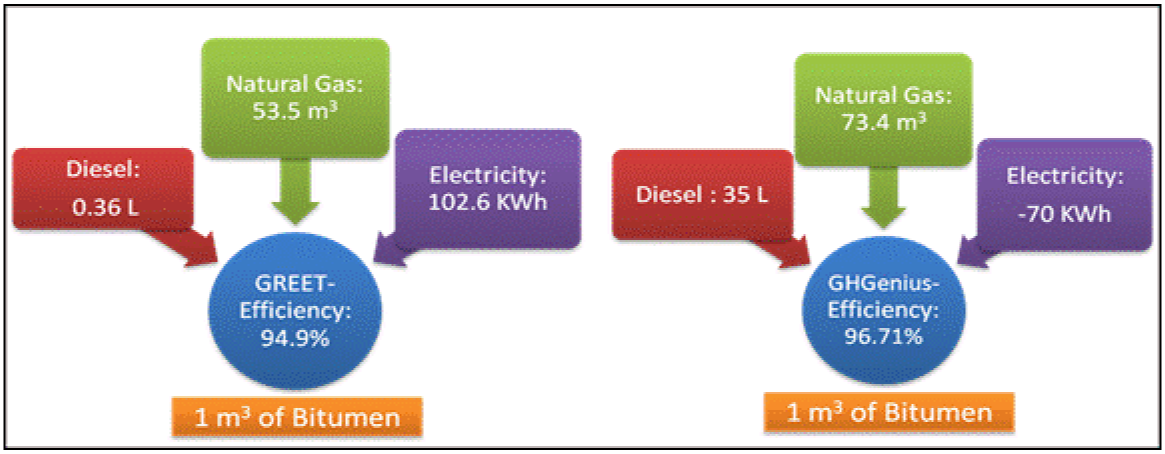


Figure A-3: Different fuel mix inputs in GREET and GHGenius

The energy inputs for the surface mining operation are in the form of diesel, natural gas and electricity. As shown in Figure A-3 GHGenius assumes 35 L of diesel consumption per unit of bitumen produced, which is 100 times more than the GREET assumption of 0.36 L. GREET has a lower input of natural gas but a higher input of electricity than GHGenius model. GREET does not account for any cogeneration in surface mining and hence has a positive input of 102.6 kWh/m^3 of bitumen as compared to GHGenius which accounts for cogeneration and has net export of electricity (70 kWh/m^3 of bitumen). Both these models use different efficiency of natural gas power plant, with GHGenius using a higher efficiency of 45% as compared to 35% used by GREET. These factors account for the difference in the efficiency of surface mining process in oil sands, as estimated by these models. GREET assumes an efficiency of 94.9% for this operation, whereas GHGensius estimates a higher efficiency of 96.71%. The difference in efficiency, fuel mix and cogeneration assumptions account for the differences in the emissions reported by these models.

These models are inconsistent with assumption of electricity production and export from oil sands. Both these models have used Alberta grid electricity ratio for electricity production and electricity export from oil sands. This assumption is not valid as the most of the electricity production in oil sands is on-site and from natural gas. And the extra electricity exported displaces the Alberta grid electricity, 53.1% of which comes from coal, 37.4% from natural gas and remaining from other resources such as hydro, wind and biomass [91].

These inconsistencies have been removed and properly accounted for in this research initiative. The diesel and natural gas consumption has been estimated from engineering first principles, which are detailed in chapter 1. Cases of with and without cogeneration have been explored. Different emission factors for on-site electricity production and electricity export to Alberta grid have been used for proper estimation of emissions in surface mining operation.

SAGD:

An exercise similar to surface mining has been performed for SAGD operation. A detailed investigation into the emissions reported by these models was done. As shown in Figure A-4, GHGenius reports higher emissions than GREET by 18%. This is because of the difference in the assumptions of energy consumption in these models. The default input of natural gas energy and electric energy in GREET are lower than GHGenius (218.9 vs. 255 m^3/m^3 of bitumen of natural gas, 58.78 vs. 65 kWh/ m^3 of bitumen of power consumption). None of these models have accounted for cogeneration in SAGD operation which is not the actual scenario in oil sands SAGD operations.

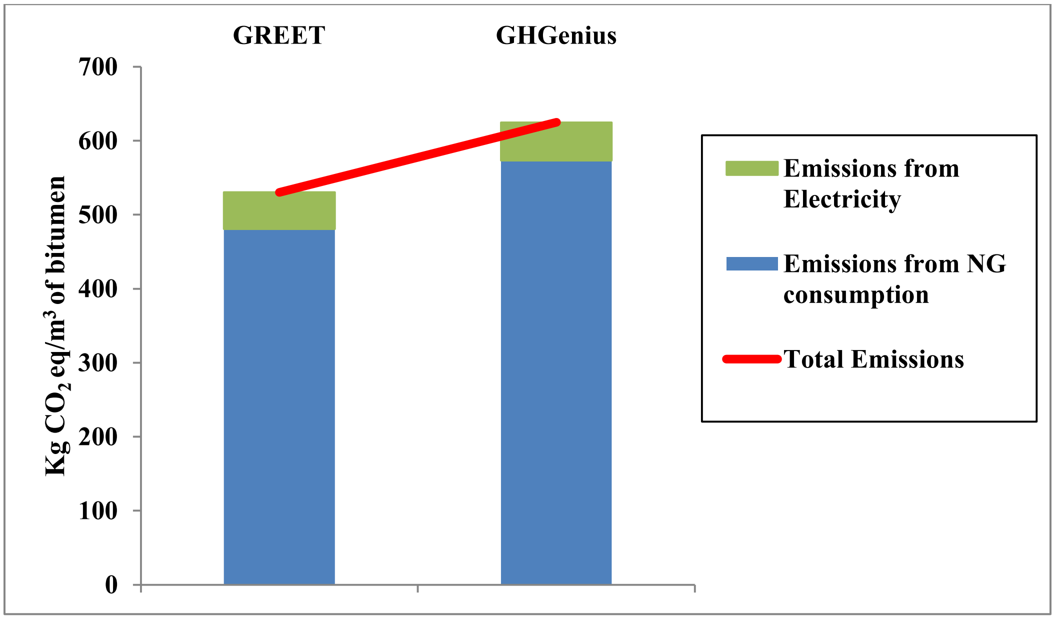


Figure A-4: Comparison of GHG emissions in SAGD as reported by GREET and GHGenius models.

In our current research initiative, an effort has been made to estimate the natural gas and electricity consumption based on technical parameters. This has been detailed in chapter 2. Attempt has been made to estimate the electricity export to grid in SAGD operation, based on theoretical engineering models. Different emission factors have been used for on-site electricity production and export of electricity to grid, for appropriate quantification of emission in SAGD.

Upgrading:

GREET and GHGenius models report different results for emissions in upgrading operation. Continuing on our investigation into the reasons for these differences, these models were run to analyze the GHG emissions and energy consumption in upgrading operation.

As observed in Figure A-5, GHGenius reports (413.1 – 422.7 kg/ m^3 of bitumen) higher emissions for upgrading operation as compared to GREET (151.8 – 333.4 kg/ m^3 of bitumen). The emissions reported by GHGenius are approximately 23.7% more for upgrading bitumen from surface mining and 178% more for upgrading bitumen from SAGD. These variations in emissions arise because of following differences in the models.

The bitumen to be upgraded can either be recovered through surface mining or SAGD operations (see chapter 2 for details of these operations). GREET reports different emissions for upgrading bitumen recovered from surface mining and SAGD, the latter being 120% more. This is based on the assumption that bitumen obtained in different recovery processes is upgraded through different techniques. On the contrary GHGenius reports approximate same emissions for both kinds of upgrading techniques. Both these models have assumed a different fuel mix for energy required in the upgrading operation. GREET has default input energy of natural gas (97.1%) and electricity (2.80%), whereas GHGenius assumes the energy required in upgrading operation to be obtained from natural gas (46%), electricity (2%), coke (11%) and still gas (40%). GREET assume no coke or still gas to be burned in upgrader.

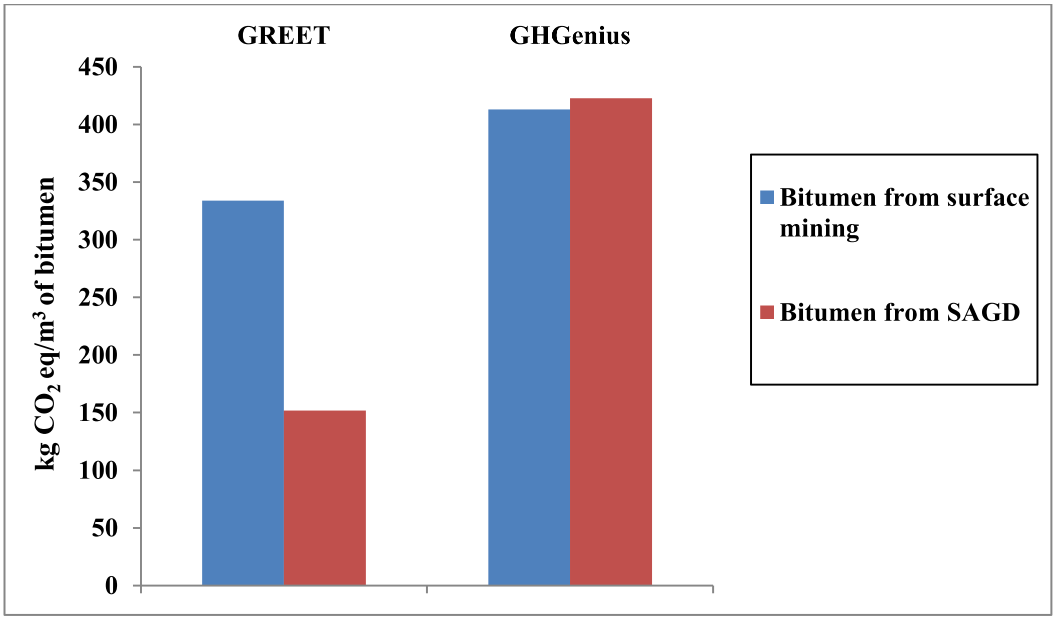


Figure A-5: Comparison of GHG emissions in upgrading operation as reported by GREET and GHGenius

Upgrading operations consume significant quantities of hydrogen to convert bitumen to SCO (see Chapter 3 for details). While GREET explicitly mentions the amount of hydrogen consumed (11.6 scf/mmbtu of bitumen for upgrading bitumen from in situ recovery and 290.3 scf/mmbtu of bitumen for upgrading bitumen from surface mining) in upgrading operations, no such information is found in GHGenius. Further these models have not considered electricity and steam to be cogenerated in upgrading operations.

Keeping all these inconsistencies in mind, the current research initiative aims at estimating the energy consumption and GHG emissions in upgrading operations from the very basic fundamental engineering principles. The two most used configuration- delayed coking and hydroconversion employed in upgrading operations in oil sands have been modeled (see Chapter 3). Appropriate quantification of hydrogen requirement has been done based on the feed to be upgraded using data from published literature. The model has the ability to estimate the volume of the product (SCO) produced in upgrading operation.

Appendix B

Basic equations used for energy estimation in surface mining and SAGD operations

Equations for calculating the fuel consumption in shovels

$$d = \frac{D_i}{S_f} \tag{1}$$

$$Bc = \frac{Rp}{d} \tag{2}$$

$$P = \frac{Bc * fi * d * 3600}{Ct * Ai} \tag{3}$$

$$F_s = \frac{\sum_{i=n} \frac{P_i}{F_{hi}} * N_i}{\sum_{i=n} N_i} \tag{4}$$

Where

Bc = Bucket Capacity of shovel in m^3; Rp = Rated payload for the shovel in tonnes; d = loose weight density in tonnes/m^3 ; D_i = density of oil sands in tonnes/m^3; S_f = swell factor; Ct = Cycle time for each shovel in seconds; fi = Fill factor; P = Practical productivity of shovels in tonnes/hr; F_{hi} = hourly consumption of diesel in litres for each shovel model; n = number of shovels of each model in the fleet; Ai = Availability of shovels; F_s = Fuel consumption in shovels in litres per tonne of oil sands

Equations for calculating the fuel consumption in trucks

$$P = \frac{T_p * 60}{Ct * Ai} \tag{5}$$

$$F_t = \frac{\sum_{i=n} \frac{P_i}{F_{hi}} * N_i}{\sum_{i=n} N_i} \tag{6}$$

P = practical productivity of trucks in tonnes/hr; T_p = payload for trucks in tonnes; Ct = cycle time for each shovel in minutes; F_{hi} = hourly consumption of diesel in litres for each truck model; n = number of trucks of each model in the fleet; F_t = fuel consumption in trucks in liters per tonne of oil sands

Equation for calculating natural gas energy in surface mining

$$E_n = \frac{m * (t_o - t_i) * C}{\eta_h * \eta_b} \tag{7}$$

E_n = natural gas energy required to produced warm water; t_o , t_i = outlet and inlet water temperatures; C = specific heat of water ; η_h, η_b= efficiency of heat exchanger and boiler

Equations for cogeneration using steam turbine

$$Amount\ of\ steam\ required\ \left(m_s\ in\ \frac{kg}{m^3} of\ bitumen\right) = \frac{m * (t_o - t_i) * C}{\eta_h * (H_{s1} - H_w)} \tag{8}$$

$$Amount\ of\ electricity\ generated\ (\frac{kWh}{m^3} of\ bitumen) = \eta_t * (H_{s2} - H_{s1}) * m_s * 0.000278 \tag{9}$$

$$Natural\ gas\ required\ (\frac{m^3}{m^3} of\ bitumen)$$

$$= \frac{m_s * (H_{s2} - H_w)}{\eta_b * LHV} \quad (10)$$

H_{s2}, H_{s1}, H_w : Enthalpy of steam at 7 Mpa and 400 ˚C; enthalpy of steam at 1 Mpa and saturated temp; enthalpy of water at 145 ˚C respectively; LHV: lower heating value of natural gas; $t_o\,, t_i$ = outlet and inlet water temperatures; C = specific heat of water ; η_h, η_b= efficiency of heat exchanger and boiler

Equations for cogeneration using gas turbine

$$Steam\ energy\ required\ (E_s) = \frac{m * (t_o - t_i) * C}{\eta_h} \quad (11)$$

$$Useful\ energy\ recovered\ from\ exhaust\ gases\ \left(\frac{kj}{kg} of\ NG - 1\right)$$

$$= \eta_x * m_r * C_e * T_e \quad (12)$$

$$Electricity\ produced\ \left(\frac{kWh}{m^3}\text{ of bitumen}\right)$$

$$= mass\ of\ NG - 1 * LHV * \eta_g * 0.000278 \quad (13)$$

$$Mass\ of\ NG - 2 (kg)$$

$$= \frac{E_s - (mass\ of\ NG - 1 * useful\ energy\ recovered\ from\ exhaust\ gases)}{\eta_{hrsg} * LHV} \quad (14)$$

η_x: heat recovery steam generator exhaust recovery; m_r: mass of exhaust gases per unit mass of natural gas feed to gas turbine (NG-1); C_e : heat capacity of exhaust gases; T_e: temperature of exhaust gases; η_g : efficiency of gas turbine; η_{hrsg}: efficiency of HRSG direct firing duct burners; (NG-1): natural gas feed to turbine; (NG-1): natural gas feed to HRSG

Equation for estimation of natural gas in SAGD

$$Natural\ gas\ required\ \left(\frac{m^3}{m^3}\ of\ bitumen\right) = \frac{iSOR * (H_s - H_w)}{q * \eta_b * LHV} \quad (15)$$

$iSOR$: instantaneous steam to oil ratio (dry); H_s, H_w : enthalpy of steam (80% quality) at 8 Mpa and 500 ˚C; enthalpy of boiler feed water at 150 ˚C ; q: quality of steam; η_b: steam boiler efficiency; LHV: lower heating value of natural gas

Equation for estimation of electricity consumption in evaporators

$$Power\ consumed\ in\ Evaporators\ (kW) = C * M * \Delta\ t \quad (16)$$

M = vapour mass flow (t/h); C= constant (2.5 – 3.0)

Appendix C

Building Refinery Model in Aspen HYSYS

The distillation curve is characteristic of the components making the feed. The distillation curve represents how much hydrocarbon can be distilled, leaving behind heavy components. Upgrading is the conversion of heavier to lighter components by breaking long-chain hydrocarbons. This is achieved with heat and subsequently hydrogen to stabilize the broken chains. The amount of hydrogen and energy required to convert heavy components to lighter components is very specific to the distillation curve of the feed. The volume of synthetic crude oil (SCO) obtained from the upgrading of bitumen depends on the boiling points of the components forming the bitumen. The higher the percentage of heavier fractions, the more energy and hydrogen are required to upgrade bitumen. Similarly, the energy required in a refinery to obtain the transportation fuels gasoline and diesel is specific to the input feeds. Models developed in this research were run for the following distillation curves:

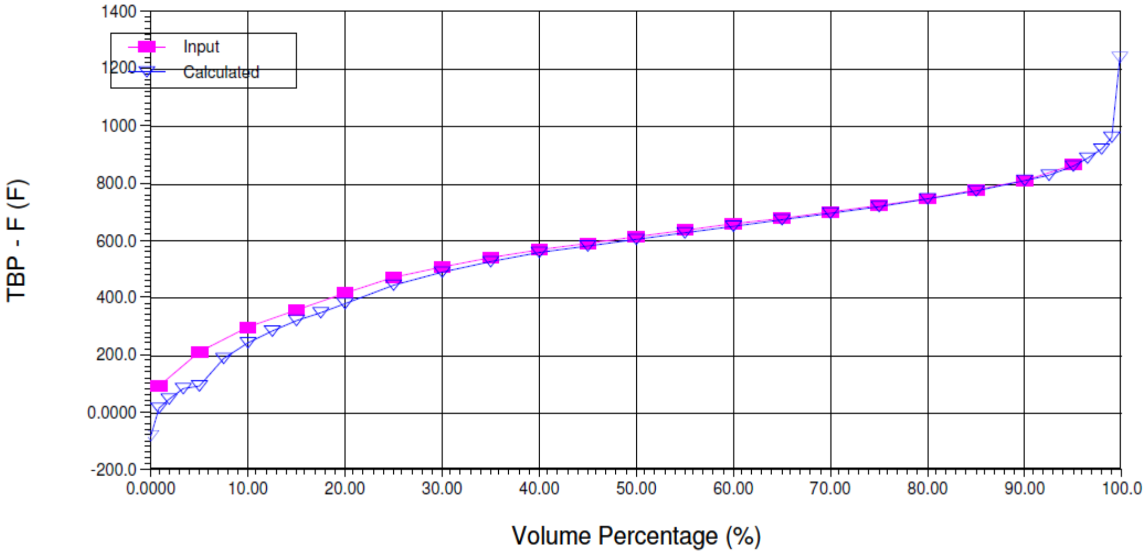
C-1 represents SCO obtained from upgrading bitumen in a delayed coker operation.

C-2 represents SCO obtained from upgrading bitumen in a hydroconversion unit.

C-3 represents dilbit obtained from mixing of diluent and bitumen.

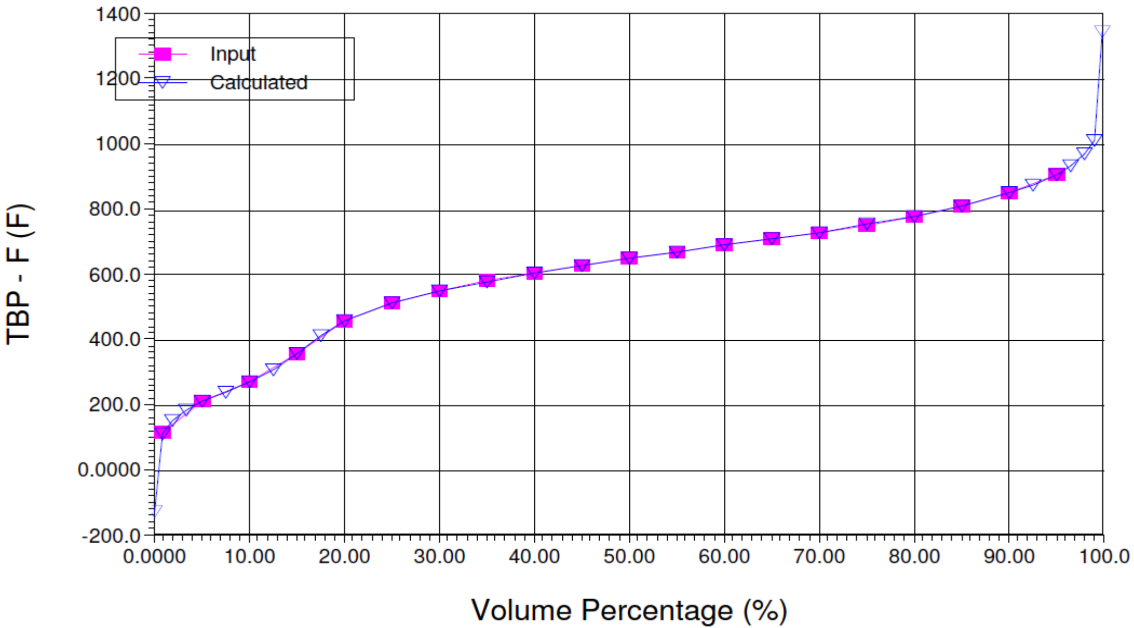
C-4 represents bitumen used as input to both upgrading and refining operations.

These distillation curves were obtained from Aspen HYSYS after entering the volume percentage of fractions distilled as a function of boiling point. The model was run using feeds represented by these curves, but it has the ability to estimate the energy consumption and GHG emissions for other feeds. Other characteristic properties of the feeds such as sulfur content and carbon residue (which is representative of the amount of coke formed) are also mentioned in the Figures C-1 to C-4.



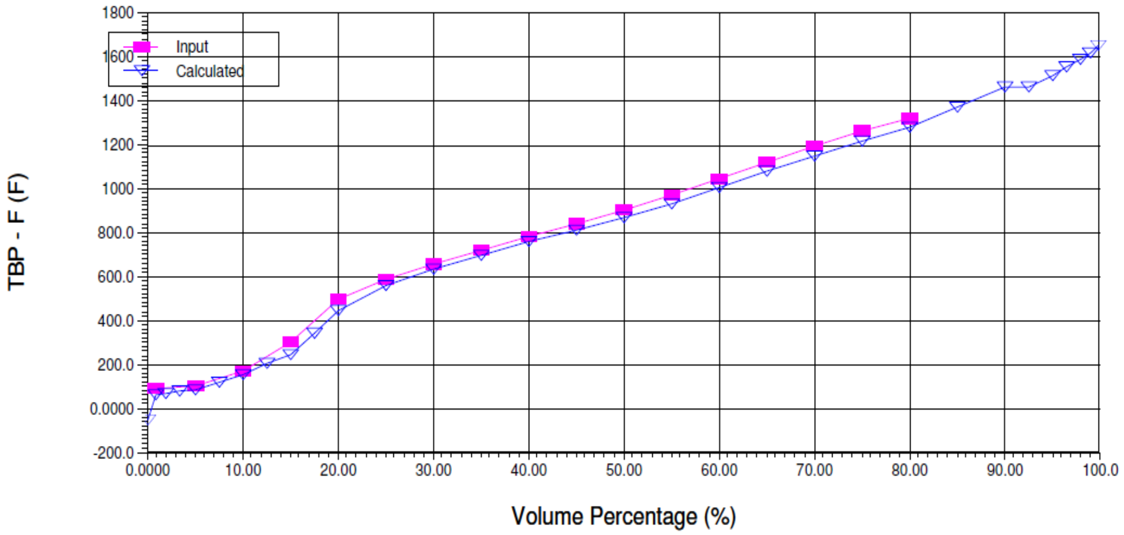
Sulfur Content	Density	Carbon Residue
0.18 wt%	862.9kg/m3	0.001 mass%

Figure C-1: Distillation curve, sulfur content, density, and carbon residue of coker SCO as input to the model.



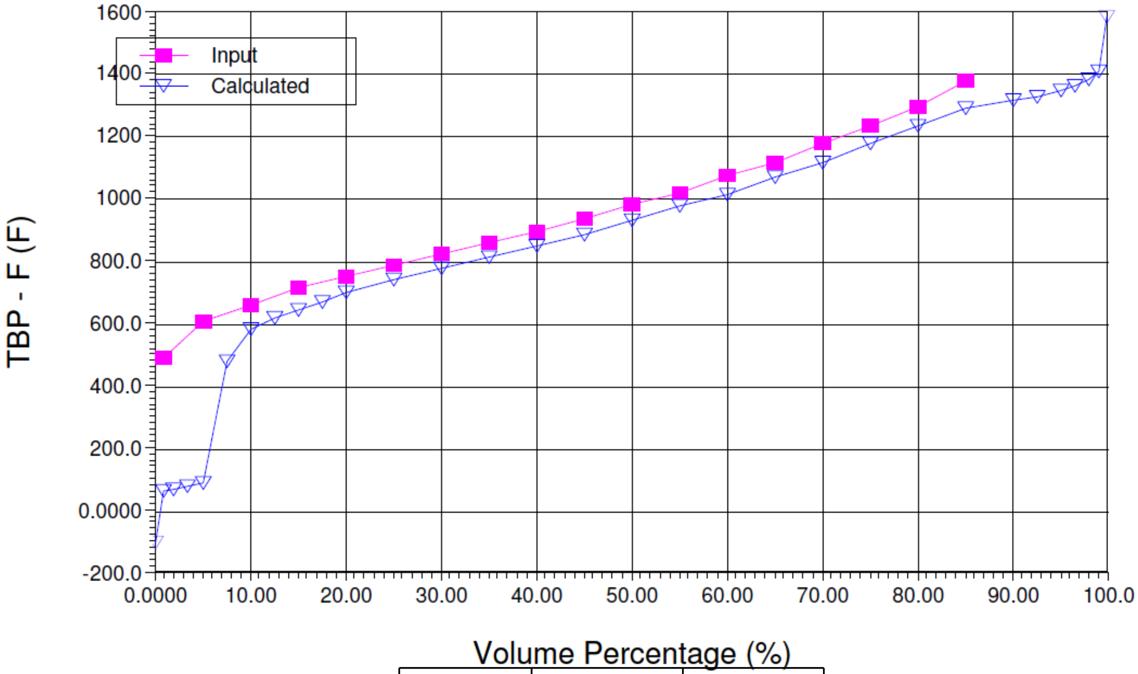
Sulfur Content	Density	Carbon Residue
0.08 wt%	856kg/m3	0.1 mass%

Figure C-2: Distillation curve, sulfur content, density, and carbon residue of hydroconversion SCO as input to the model.



Sulfur Content	Density	Carbon Residue
3.73 wt%	933.2 kg/m3	10.5 mass%

Figure C-3: Distillation curve, sulfur content, density, and carbon residue of dilbit as input to the model.



Sulfur Content	Density	Carbon Residue
4.94 wt%	1014 kg/m3	13 mass%

Figure C-4: Distillation curve, sulfur content, density, and carbon residue of bitumen as input to the model.

Modification made to the existing Aspen refinery wide model

The existing Aspen HYSYS refinery wide model available in built in case in version 7.3 is for a mixture of certain sweet and sour crudes. The existing model could not be used for our purpose as we need to assess individual crudes separately. Moreover changing the capacity of the refinery did not change the utilities required in each sub unit operation in the refinery. So it was decided that we create our own refinery model in Aspen HYSYS with similar configuration and use default process conditions and parameters.

To create the model to assess particular crude the streams throughout the refinery are traced and drawn for that crude. These intermediate streams are characterized with properties of the products for the crude being analyzed. The properties considered are the density, sulfur content and carbon residue. The columns that simulate the atmospheric distillation and vacuum distillation columns are specified with the temperatures, pressures and draw stages mentioned in the original model.

The shift reactor is used to simulate the naphtha hydrotreater, diesel hydrotreater, kerosene hydrotreater, coker, fluid catalytic cracker, hydrocracker, reformer, and alkylation. The base values of the utility shift parameters in all shift reactors is specified on per volume of feed basis as compared to net values (independent of feed volume) in the original model. The input utility shift parameters are obtained by dividing the utilities specified in the original model with the input feed. Additionally on the same page for utility shift specifications the option for ‘per feed flowrate’ is checked in and volume basis selected from the dropdown list.