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Greenhouse gas emissions from recovery of various North American conventional crudes

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ABSTRACT

Emissions from crude recovery contribute significantly to the life cycle GHG (greenhouse gas) emissions of transportation fuels. Recovery emissions come from drilling and land use change, crude extraction, crude oil processing, venting, flaring, and fugitives. In this study an attempt has been made to provide a transparent quantification of GHG emissions from oil well drilling and land use change, crude recovery and associated gas and water treatment, and venting and flaring for five North American conventional crudes through the development of data-intensive engineering models. Estimates of emissions from crude extraction were made from recovery efficiency, the amount of energy used, and process fuel shares in extraction techniques. Extraction emissions vary from 1.24 g-CO_{2eq}/MJ for Bow River heavy oil to 23 g-CO_{2eq}/MJ for California's Kern County heavy oil. The amount of gas vented and flared per m^3 of crude extracted was determined to quantify venting and flaring emissions. The amount of energy required for crude oil processing was quantified based on the properties of crude oil and different techniques applied in the oil fields. Of the five crudes we studied, California's Kern County heavy oil and Mars crude oil emit the highest and lowest emissions: 23.85 g-CO_{2eq}/MJ and 3.94 g-CO_{2eq}/MJ, respectively.

1. Introduction

Global energy demand is expected to grow by 33% from 2011 to 2035 [1], and this demand will lead to increased production of conventional crude oil and more GHG (greenhouse gas) emissions. California is adopting its LCFS (Low Carbon Fuel Standard) regulation, which requires a decrease of 10% in GHG emissions from all transportation fuels by 2020 [2]. This regulation pushes forward the need to quantify well-to-wheel GHG emissions from various types of conventional crude oil. Different technologies are applied to convert these crudes to their final products, transportation fuels. For policy-making purposes and to fulfill the environmental regulations adopted by different environmental and government agencies, it is important to calculate the GHG emissions from different crude oils in their conversion to final products.

There are few studies of comparative LCA (life cycle assessments) of conventional crude oil. Two earlier studies [3,4] performed an LCA to quantify total well-to-wheel GHG emissions based on reservoir properties, technologies, and published data. These studies are limited as they did not consider all the unit operations required to convert crude oil to transportation fuels. NETL [5] developed a baseline to estimate life cycle GHG emissions from conventional crude oil. Country-specific data have been published with very limited input information. A number of data-intensive LCA models with their own assumptions are available to calculate life cycle GHG emissions from transportation fuels; three well-known models are GREET [6], GHGenius [7], and OPGEE [8]. These models have limitations in differentiating the various crudes, and they use the same average values for all the crudes. To quantify GHG emissions for different pathways and crudes, it is critical that input parameters and characteristics specific to various crudes be used.

Charpentier et al. [9] reviewed thirteen studies in the area of oil sands operations and compared emissions from both oil sands and conventional crude oil production. The authors reported lower emissions for conventional crude oil than for SCO (synthetic crude oil); the emissions were higher for SCO because of the higher energy intensity in bitumen extraction and upgrading to SCO. Brandt [10] reviewed different LCA models and reports for variations in life cycle GHG emissions from the Canadian oil sands. He found inconsistencies between the studies due to different system boundaries, assumptions, and methods. After analyzing several models, Brandt suggested GHGenius as an appropriate LCA model as it has the most extensive boundary. Bergerson et al. [11] quantified life

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cycle oil sands GHG emissions using GHOST (GreenHouse Gas Emissions of Current Oil Sands Technologies). Oil sands project-specific data from several industries were used to analyze life cycle emissions, and Bergerson et al. reported a range of results for the recovery and extraction of bitumen. Garg et al. [12] performed a life cycle assessment of petroleum products from India and found that exploration and production of petroleum uses most of the energy (around 75%), followed by refining and transportation. There are few studies that are based on the development of a bottom-up engineering model that considers all the unit operations in an evaluation of different crude oils. There are also limited input data available in the public domain for conducting LCA studies. This study addresses these gaps.

The overall objective of this research is to estimate the GHG emissions in recovery of five different conventional crudes from North America through the development of data-intensive, bottom-up engineering models and to perform a comparative assessment of the GHG emissions.

2. Scope of research

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

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

2.1. Types of crude

2.1.1. Alaska North Slope crude oil

Alaska produces the second largest amount of oil in the United States, and Alaska North Slope and Cook Inlet Basins are the highest-producing zones. However, 98% (2011 data) [13] of the produced oil comes from the North Slope, which has the 14 largest oil fields in the United States [14]. The crude analyzed in this study is from Alaska North Slope; it is a medium crude oil with an API (American Petroleum Institute) gravity of 29–29.5°API [15].

There are many topping units along the TAPS (Trans-Alaska Pipeline System) that produce light fuel. These topping units send the residues back to the pipeline and the resulting mixture is known as ANS (Alaska North Slope) crude oil. Alaska's largest oil field, Prudhoe Bay, produces most of the oil in the North Slope; the oil goes to West Coast refineries by pipeline and ocean tanker. In 2009, Alaska North Slope's total oil and associated gas production were 37 million m^3 of oil and 90.39 billion m^3 of produced gas [16]. The WAG (water-alternating-gas) enhanced oil recovery method is used extensively in this region to maintain the reservoir pressure and push the oil deposits to the producing wells. The water demand is met by produced water and sea water treatment plants [17]. About 92% (2009 data) [16] of the associated gas that comes out with the crude oil is re-injected through the injection wells to maintain the reservoir pressure.

2.1.2. California's Kern County heavy oil

Kern County crude oil is selected as the analysis crude for California; it has an API gravity of 13°API [18] and so falls in the range of heavy crude oil. Production data used for this study are from the Midway-Sunset Oil Field, which is the largest oil field in the State of California and located in southwestern San Joaquin Valley. As Kern County heavy oil is highly viscous, steam is injected into the reservoirs to reduce the viscosity and enhance flow. An artificial lifting method (i.e., a pump) is required to pull the oil and water mixture out of the reservoir. Steam for oil recovery comes from the Midway-Sunset co-generation plant, which has a maximum capacity of 234 MW [19]. Electricity for operating the pumps and other facilities also comes from the co-generation plant, which uses pipeline natural gas as fuel. In 2009, the total incremental oil production from thermally enhanced oil recovery was approximately 7.8 million m^3 from the Midway-Sunset Oil Field [20].

2.1.3. Mars crude oil

The Mars Blend is a sour crude oil with an API gravity of 31.5°API [21]. The producing region for the Mars Blend is about 130 miles southeast of New Orleans in the U.S. Gulf Coast. The Mars platform, at deep water in the Gulf of Mexico, is the feedstock location. Water flooding is the dominant recovery method to maintain reservoir pressure and improve the flow of oil. Injection of sea water to maintain reservoir pressure has been practiced since 2004. Sea water is injected into three reservoir zones (Yellow, Green, and Pink sands) using three injectors. In June 2000, production at Mars field was at its peak of 33,069 m^3 of oil per day and 6.14 million m^3 of associated gas per day [22]. The average daily production of Mars is about 3338.73 m^3 of oil and 707,921 m^3 of associated gas that comes with the crude oil.

2.1.4. Maya crude oil

The origin of the Maya crude oil is Mexico, which produces heavy, light, and extra light crude oil. Maya is a heavy grade crude oil with an API gravity of 22°API [23]. Maya crude is produced from the Cantarell field; it is the largest oil field in Mexico and is situated about 100 km off the coast of the Yucatan Peninsula. The productivity of the well decreases with decreasing reservoir pressure. To maintain reservoir pressure and good productivity, nitrogen gas is injected into the Cantarell field's reservoirs. At the same time, a gas lift (an artificial lifting method) is used to lift the crude oil, water, and associated gas mixture to the surface. 34 million m^3 of nitrogen supply comes from the world's biggest nitrogen generation plant at the Cantarell oil field [24]. Oil production reached its peak in 2004 at 333,873.32 m^3 a day and decreased to approximately 88,715 m^3 per day in 2010. Most of the Mexican refineries are not equipped to refine this heavy oil, so it is exported to Canada and the U.S. for refining.

2.1.5. Bow River heavy oil

Alberta's Bow River heavy oil represents the Canadian conventional heavy oil; its API gravity is about 23°API [25]. Alberta is well known for its oil sands production, and about 99% [26] of Alberta's oil is from oil sands; the remaining 1% is from conventional crude oil. Unlike bitumen, conventional crude oil flows easily and can be extracted using a secondary oil recovery method. In Alberta, water flooding, which is the injection of water to maintain reservoir pressure, is used extensively. Sources of water are saline and non-saline, along with produced water, which contributes about 83% [27]. In 2012 the total conventional crude oil production in Alberta was approximately 32.27 million m^3 [28]. Conventional crude oil supplies from Alberta go to North American markets by pipeline [29].

3. Methodology

3.1. Functional unit

For this study, the functional unit is 1 MJ of fuel. This allows comparison between the different crude types because not every

m^3 of crude has the same energy content. Energy calculations are based on the lower heating value of each fuel.

3.2. Drilling

The first unit operation in crude recovery is the drilling of the oil well, the purpose of which is to make a hole in the oil reservoir to allow oil to flow to the surface. There are two types of oil wells, injection and production. Injection wells are used to inject water, gas, steam, or any other fluid to push the oil deposit to the production well and to maintain pressure inside the reservoir. Production wells lift the crude oil to the surface with water and gas. Drilling an oil well requires energy to provide rotational and translatory motion to the drill bit to make the drill hole through the reservoir. In this study, it is assumed that the power required for the drilling operation will be provided by diesel engine rigs, as is common in oil fields. There is an exponential increase in diesel consumption with the true vertical depth of the well, as shown by Equations (1) and (2) [30]. Brandt [30] developed these equations using a range of drilling data. The units of diesel consumption, E, and true vertical depth of well, d, are measured in MJ/m and m respectively.

$$E_{\text{low}} = 128.6 * \exp(0.0005d) \quad (1)$$

$$E_{\text{high}} = 336.3 * \exp(0.0004d) \quad (2)$$

E_{low} and E_{high} represent minimum and maximum diesel consumption during drilling. For all five crudes, average diesel consumption is used as field-specific diesel consumption data are unavailable. The energy required to make a well bore is amortized over the producing life of the well. Emissions are calculated from the ratio of energy required to drill a well to the lifetime productivity of the well in terms of energy, i.e., MJ of crude, and emission factors for diesel combustion. Emission factors for diesel combustion are taken from GREET 1 [6]. The drilling parameters used in this data analysis are summarized in Table 1.

In addition to the GHG emissions from the combustion of diesel to power the drilling rigs, this study includes the emissions associated with land use changes during drilling. Land use changes, such as biomass, land, and peat disturbance, can release CH_4 and N_2O [10]. Land use emissions for the 150-year analysis period are taken from OPGEE (1.1) [31], a life cycle software modeled by the Department of Energy Resources Engineering at Stanford University. To capture the crude oil production period and due to availability of data, a 150-year analysis period is considered in this study. Emissions are based on the low carbon richness for California crude and high carbon richness for both Alberta [37] and Alaska North Slope crude oils. Land use emissions depend upon the intensity of drilling. Moderate intensity drilling is assumed for all the selected crude oils. Moderate intensity drilling corresponds to a medium fractional disturbance of land, which means that the drilling holes are moderately spaced in the oil field.

Table 1
Drilling parameters for all five crudes.

Crude name	Depth of well considered (m)	Lifetime productivity (m^3/well)	Recovery method
Alaska North Slope	2250	10,936.70[a]	Water-alternating-gas
California's Kern County heavy oil	518	21,169.32[b]	Stem injection
Mars	4553	84,876.32[c]	Water flooding
Maya	2794	7,440,605.40[d]	Nitrogen injection assisted by gas lift
Bow River heavy oil	5000	50,903.96[e]	Water flooding

[a] Calculated from the total number of wells and total oil production in the state at the end of 2004 [16].
[b] Calculated from the total number of wells and total oil production in the state at the end of 2005 [31].
[c] Calculated from the total number of wells and total oil production in the U.S. Gulf Coast at the end of 1998 [32,33].
[d] Calculated from the average well production based on an assumed 20-year well life [34].
[e] Calculated from the total number of wells and total oil production in the province at the end of 2008 [35,36].

3.3. Crude extraction

Crude extraction, the second step in crude recovery, uses a large quantity of energy that will ultimately result in GHG emissions. Initially when any reservoir starts producing oil, the pressure in the reservoir is enough to push the oil to the production well and even to force the oil to flow out to the surface. Sometimes artificial methods are applied to assist the flow of oil. This recovery technique is called primary recovery. As the reservoir ages, the pressure inside the reservoir starts to fall, and less oil is produced. To overcome this problem, secondary recovery methods are used to supply additional energy to the reservoir. In one of these secondary recovery methods, water and/or gas is injected into the injection well. When water is injected, the process is called water flooding, and the injection of gas is known as gas flooding. Sometimes water and gas are injected alternately. Tertiary (or enhanced) recovery, includes thermal recovery (steam injection), gas injection (i.e., natural gas, nitrogen, carbon dioxide), and chemical injection (i.e., polymers and detergent). With enhanced oil recovery, 30–60% [38] more oil can be recovered compared to 25–35% using primary and secondary recovery methods [39].

The recovery methods mentioned in Table 1 are suitable for specific locations based on reservoir properties and availability of injection fluids. Fuel required to extract crude oil depends on the recovery methods applied and characteristics of the crudes. Fuel consumed to extract crude is calculated based on basic energy consumption equations for pumps and compressors. GHG emissions from each recovery method are calculated based on process fuel consumption. After that, the process efficiency of the recovery method is estimated using the following formula [40]:

$$\eta = \frac{\text{Energy Output}}{\text{Process Fuel} + \text{Energy Output}} \quad (3)$$

The energy output in Equation (3) is the sum of the energy from the extracted oil and the associated gas. Using the process efficiency, the energy required per MJ of crude recovered for each pathway of crude extraction is calculated by:

$$\text{Energy Required} = \frac{1}{\eta}\text{-}1 \quad (4)$$

A gas balance shows that produced gas is sufficient to meet onsite demand for all the crudes. So, produced gas is assumed to be combusted in simple gas turbines with an assumed efficiency of 32.6% [41] to produce electricity to run the pumps, compressors, and other electric equipment for each pathway except in the case of California's crude, which uses only pipeline natural gas in a cogeneration plant [20] to produce steam and electricity. Emission factors for natural gas and produced gas used to calculate GHG emissions from recovery of each crude are taken from GREET 1 (2012) [41] and Keesom et al. [4]. The energy required to recover

Table 2
Parameters used for energy calculations.

Crude name	Reservoir pressure (MPa)	Water-to-oil (m^3/m^3)	Gas-to-oil (m^3/m^3)	Steam-to-oil (m^3/m^3)	Injected water-to-oil (m^3/m^3)	Injected gas-to-oil (m^3/m^3)
Alaska North Slope	23.77 [42]	3 [43]	2129 [16]	–	3.6 [43]	1955[a] [16]
California's Kern County heavy oil	0.45 [44]	5.17[b] [20]	168 [20]	4.53 [20]	–	–
Mars	37.92 [45]	5.5 [4]	210[c] [46]	–	4.29[d] [22,46]	–
Maya	10.48 [24]	3 [4]	65 [47]	–	–	174[e] [24,48]
Bow River heavy oil	7.83 [49]	14.90 [50]	321 [3]	–	3.47[f] [51]	–

[a] Produced gas is injected again.
[b] Calculated from the amount of crude produced per well and water cut.
[c] Calculated from the amount of oil and gas produced.
[d] Calculated from the amount of oil produced and water injected.
[e] Calculated from the amount of oil produced and nitrogen injected into the field.
[f] Calculated from the crude oil produced in Alberta and water injected in 2002.

each crude depends on reservoir pressure and depth, water-to-oil ratio, injected water-to-oil ratio, injected gas-to-oil ratio, and steam-to-oil ratio. Table 2 shows the parameters used to calculate energy requirements and to quantify GHG emissions.

It is assumed that injecting water and gas for Alaska North Slope and water for Mars will maintain enough reservoir pressure to allow the oil to flow naturally. But for California's crude oil and Bow River's heavy crude (Alberta), pumps are required to extract the oil from the reservoir. Pressure loss due to friction in the pipeline to lift crude is calculated with the Darcy–Weisbach equation using the Reynolds number, pipe roughness, depth of well, diameter of the pipe, etc. The average roughness of the lift pipe (commercial steel) is assumed to be 0.067 mm [52]. The diameter of the lift pipe ranges from 0.026 to 0.114 m [53], and the average of these values (0.07 m) is used in the pressure loss calculation. The energy required to lift crude oil is calculated from the pressure loss and assumed pump efficiency of 65% [31]. A gas lift is used extensively in the Cantarell oil field for Maya crude. For a gas lift, basic compression equations with an assumed compressor efficiency of 75% [31] are applied to determine the energy consumption. In the Cantarell field, 34 million m^3 of nitrogen gas are injected per day, which requires a total of 373.38 MW power [24].

3.4. Flaring, venting, and fugitive emissions

Flaring, venting, and fugitives are sources of GHG emissions during crude recovery. The combustion of the natural gas that comes out with crude oil from the reservoir is known as flaring. Flaring is done when there is no economic use for this associated gas. The flared gas produces carbon dioxide and possibly carbon monoxide, which are released to the atmosphere. Venting, the release of non-combusted associated gas, is also a significant source of GHG emissions in crude production. Venting occurs through the well head and gas treatment equipment such as the acid gas removal unit, gas dehydrator, etc. The non-intentional release of associated gases through the valves, flanges, pump seals, and gas processing units is known as fugitive emissions. These emissions commonly are the result of leakages in oil field equipment. There were no data available on venting and flaring for the oil fields analyzed in this study, so state- and country-wide data were used to calculate these emissions. There were likewise no data for fugitive emissions, so fugitive volumes for each crude oil were assumed to be 0.1% of the produced gas. Normally, venting and fugitive volumes are less than 1% of the produced gas [4].

The first step in calculating venting and flaring emissions is to find the volume of vented, flared, and fugitive gases per m^3 of crude oil. This is done by dividing the amount of flared, vented, and fugitive volumes by the total crude oil production in the state or country. The values were then multiplied by the amount of crude oil produced (m^3 per day) for selected individual crudes to obtain vented, flared, and fugitive volumes per day. GHG emissions were calculated from flaring volumes based on the flaring efficiency, which is assumed to be 95% [55]. GHG emissions vary with the composition of the produced gas. Due to the unavailability of data for any particular oil field, we have assumed a common gas composition for all five crude production pathways in which the main constituents are CH_4-84%, CO_2-6%, and C_2H_6-4% [31]. Flaring emissions were calculated using the flared volume, flaring efficiency, density of each component, stoichiometric relationship between each constituent of associated gas and CO_2, and global warming-potential factors that are taken for 100 years. For venting and fugitive emissions, efficiency and stoichiometric factors are not required. There is considerable uncertainty in venting, flaring, and fugitive emissions figures due to the lack of published data for individual oil fields. Sensitivity analyses were done to see the impact of fugitive volumes in overall recovery emissions. The flared, vented, and fugitive volumes per m^3 of oil are presented in Table 3 for each of the five crudes.

3.5. Processing crude oil and associated gas and water

When crude oil is lifted to the surface from the reservoir, it is a mixture of oil, water, and gas. Separation of the phases is the first

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

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

[a] There is only one reported value, total vented and flared volume [56]. We have split it as 85% venting and 15% flaring according to the U.S. average value [57]. The state's total crude oil production was taken from the U.S. Energy Information Administration [13].
[b] There is only one reported value, total vented and flared volume [58], in which 36.4 million m^3 associated gas is vented [3]. The state's total crude oil production was taken from the U.S. Energy Information Administration [59].
[c] The total value of venting and flaring is taken from the EIA [60] and split to 26% flared and 74% vented [61]. Federal Offshore Gulf of Mexico crude oil production in is taken from the EIA [62].
[d] The flared volume is based on Mexico's total flared data taken from the NOAA [63] and the vented volume taken from the TIAX [3] report. Crude production in Mexico is taken from Ref. [64].
[e] Vented and flared volumes are based on Alberta numbers for venting and flaring taken from the ERCB [65], and crude oil production in Alberta is taken from CAPP [66].

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

$$H = Q \cdot C_p \cdot \Delta T \tag{5}$$

where H is the heat duty in MJ/day, Q is the crude flow rate in m^3/day, C_p is the specific heat of crude oil in MJ/m^3-K, and ΔT is the difference between the reboiler and feed temperatures in K. The specific heat of crude oil and temperatures of the reboiler and feed are taken as 1.79 MJ/m^3-K, 322.04 K, and 446.48 K, respectively, to calculate the heat duty with an assumed heat loss of 2% [67]. Natural gas-fired heaters are assumed to be the heat sources for the crude oil stabilizer. From the heat duty required, the amount of natural gas is calculated.

The second step in crude oil processing is the treatment of associated gas using an amine treater and a glycol dehydrator. The amine treater removes H_2S and CO_2 in the associated gas. DEA (diethanolamine), the most widely used gas sweetening solvent, is used in the acid gas removal unit. The gas balance is done to quantify the amount of associated gas that enters the treater. An amine reboiler and several pumps are used in the acid gas removal unit. It is assumed that the reboiler is heated by natural gas and that the pumps are run with onsite electricity. The DEA flow rate is calculated from the amount of H_2S and CO_2 present in the associated gas. The heat duty MJ/h of the reboiler is calculated from the following equation [68], where the heat duty, H, is in MJ/h and the flow rate of DEA, Q, is in m^3/min:

$$H = 20{,}068.69 \cdot Q \tag{6}$$

The power calculations for the circulation pump, booster pump, reflux pump, and aerial cooler are represented by Equations (7)–(10) respectively [68], where power, P, is in kW, flow rate of DEA, Q, is in m^3/min, and the pressure of the system, p, is in kPa.

$$P_{CP} = 0.018Q * p \tag{7}$$

$$P_{BP} = 11.826Q \tag{8}$$

$$P_{RP} = 11.826Q \tag{9}$$

$$P_{AC} = 70.95Q \tag{10}$$

Dehydrators are used to remove water from the associated gas. This study assumes that glycol dehydrators are used to remove water. Reboiler heaters and pumps are the consumers of energy in glycol dehydrators. The reboiler heat duty can be calculated from the regenerator duty and the amount of water removed and is found by the equation below, where H is the regenerator duty in MJ/kg of H_2O and q is the glycol-to-water ratio in m^3/kg, which is assumed to be 0.0167 [68]. The regenerator duty is calculated using the following rule of thumb [68]:

$$H = 2.1 + 269.59 \cdot q \tag{11}$$

The heat required for the glycol dehydrators is assumed to be supplied by natural gas with a heater efficiency of 80% [31]. During crude recovery a large amount of water comes to the surface with the crude oil and is injected into the reservoir to maintain pressure or is discharged to the environment. To meet environmental regulations this discharged water has to be treated. There are various produced water treatment methods, and they vary from field to field. For simplicity we assumed the same treatment methods for all the selected crudes. Vlasopoulos et al. [69] considered four different water treatment stages with energy consumption per m^3 of water. These stages include various types of water treatment technologies such as hydrocyclones, microfiltration, ultrafiltration, reverse osmosis, etc. In stages 1–3 the oil and grease are reduced, while in stage 4 is sodium and TDS (total dissolved solids) in water are reduced. The average energy consumption for these stages is taken for water treatment except for stage 4, in which energy consumption for reverse osmosis is assumed. The required energy is assumed to be supplied by onsite electricity production. The energy required at each stage is 0.25 kWh/m^3 of water for stage 1, 0.38 kWh/m^3 for stages 2 and 3, and 1.26 kWh/m^3 for stage 4.

4. Results and discussion

4.1. Drilling and land use

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

Emissions through land use change in crude recovery contribute less than 0.4% (less than 0.35 g-CO_{2eq}/MJ) of the total life cycle emissions for conventional crudes in California and 0.1–4% (0.12–3.39 g-CO_{2eq}/MJ) for conventional crudes in Alberta for a modeling period of 150 years [37]. Land use emissions for California's Kern County heavy oil and Bow River heavy oil lie in the range reported by Yeh et al. [37]. For Mars and Maya, because this analysis considers offshore fields, it is assumed there would not be any GHGs released to the atmosphere due to the sea acting as a sink. For Alaska North Slope and Bow River heavy oil, land use emissions make up a significant portion of total drilling and land use emissions. Total drilling and land use emissions for Alaska North Slope and Bow River heavy crude oil are around 0.8 g-CO_{2eq}/MJ. No land use emissions were reported for the offshore Maya and Mars crudes. 0.15 g-CO_{2eq}/MJ and 0.21 g-CO_{2eq}/MJ drilling and land use emissions have been calculated for California's Kern County and

Table 4
Land use GHG emissions for 150-year analysis period [31].

Crude name	GHG emissions (g-CO_{2eq}/MJ)
Alaska North Slope	0.79
California's Kern County heavy oil	0.13
Mars	0
Maya	0
Bow River heavy oil	0.79

Table 5
Efficiencies for crude oil extraction as calculated using Equation 3.

Crude name	Extraction efficiency
Alaska North Slope	96.8%
California's Kern County heavy oil	65%[a]
Mars	98.2%
Maya	98.6%
Bow River heavy oil	98.2%

[a] 1805 kWh/m^3 electricity is exported to the local (California) grid after fulfilling the field demand. So this pathway receives an emission credit for selling the electricity. The grid emission factor is taken from the Air Resources Board, California [54].

Mars crude oil, respectively, while Maya has negligible drilling emissions.

4.2. Crude extraction

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

Among all the crude extraction methods, the tertiary method, used by California's Kern County heavy oil, is the most energy intensive and has an extraction efficiency of 63% (see Table 5), the lowest among the crudes. To produce electricity and steam at the same time, a large quantity of natural gas is used in the co-generation plants. In addition, as this crude is much more viscous than other crudes, artificial lifting is necessary, and artificial lifting consumes a large amount of electricity, resulting in more GHG emissions. The total extraction emissions for this crude are 41 g-CO_{2eq}/MJ. However, this pathway receives an emission credit of 18 g-CO_{2eq}/MJ for selling the surplus electricity to the California grid. When the credit is subtracted from the total emissions, the net emissions are 23 g-CO_{2eq}/MJ. The grid emission factor for California is taken as 360 g-CO_{2eq}/kWh [70].

Alaska North Slope has an extraction efficiency of 96.8% (see Table 5), and the extraction emissions (2.21 g-CO_{2eq}/MJ) are from the injection pumps and compressors. Mars and Bow River heavy oil extraction requires less energy and therefore has a higher extraction efficiency (98.2%) than Alaska North Slope and California's Kern County heavy crude oil. These crudes have emissions of 1.26 and 1.24 g-CO_{2eq}/MJ, respectively. Maya uses the gas lift extraction method along with nitrogen injection with an extraction efficiency of 98.6%. Emissions for the production and compression of nitrogen were taken from the literature [4] and are around 1.3 g-CO_{2eq}/MJ. Maya has emissions of 2.3 g-CO_{2eq}/MJ with 1 g-CO_{2eq}/MJ coming from the gas lift and injecting compressors.

Venting, flaring, and fugitive emissions lie in the range of 0.33–2.24 g-CO_{2eq}/MJ depending upon the gas-to-oil ratio, volume of flared and vented gas in each state or province, and amount of crude production for each pathway.

Table 6
Energy requirement per MJ of crude at different sub-processes as calculated in this study.

Crude name	Drilling (kJ of diesel)	Extraction (kJ of gas)	Processing oil, water, and gas (kJ of gas)
Alaska North Slope	0.12	32.79	19.82
California's Kern County heavy oil	0.20	545.91[a]	7.91
Mars	2.34	18.66	11.77
Maya	0.01	13.68	9.90
Bow River heavy oil	0.36	18.47	18.33

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

4.3. Processing of oil and associated gas and water

The final subunit operation in crude recovery is the processing of crude oil along with the associated gas and water. Processing is done with fluid pumps and heaters that use electricity and natural gas, respectively. Electricity is generated from the gas produced by onsite gas turbines that emit GHGs. Table 7 shows the total processing emissions for the five different crudes considered in this study.

Water needs to be driven out from crude oil; this is done with direct-fired natural gas heaters that contribute significantly to the total processing emissions. Natural gas heaters emit the same amount of emissions per m^3 of crude oil (0.53 g-CO_{2eq}/MJ) at the same temperature difference, and the specific heat of crude is taken for all crude oil pathways to calculate the heat duty. Emissions are highest in Alaska North Slope crude due to the processing of produced water and sea water and associated gas. More associated gas is processed in this pathway than any other pathway and in any other crude recovery method, and so more GHGs are emitted in this crude than any other considered in this study.

For Alberta, the water-to-oil ratio is taken to be about 15, resulting in an emission of 0.7 g-CO_{2eq}/MJ. The processing of gas contributes negligibly to the total processing emissions. For California's Kern County heavy oil, only natural gas combustion emissions are reported here. Electricity emissions were subtracted in crude extraction to find the net electricity sold to California grid.

4.4. Total emissions associated with crude recovery

Fig. 1 shows all of the GHG emissions in crude recovery: emissions from drilling and land use, crude extraction, crude oil processing, and venting, flaring, and fugitives. The highest and lowest emissions come from California's Kern County heavy oil at 23.85 g-CO_{2eq}/MJ and Mars at 3.94 g-CO_{2eq}/MJ, respectively. Alaska North Slope has the second highest emissions at 5.73 g-CO_{2eq}/MJ. For Maya and Bow River heavy oil, emissions from total crude recovery are 4.20 g-CO_{2eq}/MJ and 5.54 g-CO_{2eq}/MJ, respectively.

For Alaska North Slope, extraction makes up 39% of the GHG emissions through the operation of various pumps and compressors. The contributions from drilling and land use, crude processing, and venting, flaring, and fugitives are 14%, 23%, and 24%, respectively. For California's Kern County heavy oil, 96% of the total emissions come from crude extraction. Drilling and land use change, crude processing, and venting, flaring, and fugitive emissions are relatively small. For Mars, crude is recovered by water flooding with pumps; water flooding contributes to 32% of total recovery emissions. Venting, flaring, and fugitives contribute 43%, and 5% of emissions come from drilling. For Maya, however, drilling

Table 7
GHG emissions from processing oil, water, and gas as calculated in this study.

Crude name	GHG emissions (g-CO_{2eq}/MJ)
Alaska North Slope	1.35
California's Kern County heavy oil	0.53
Mars	0.79
Maya	0.69
Bow River heavy oil	1.23

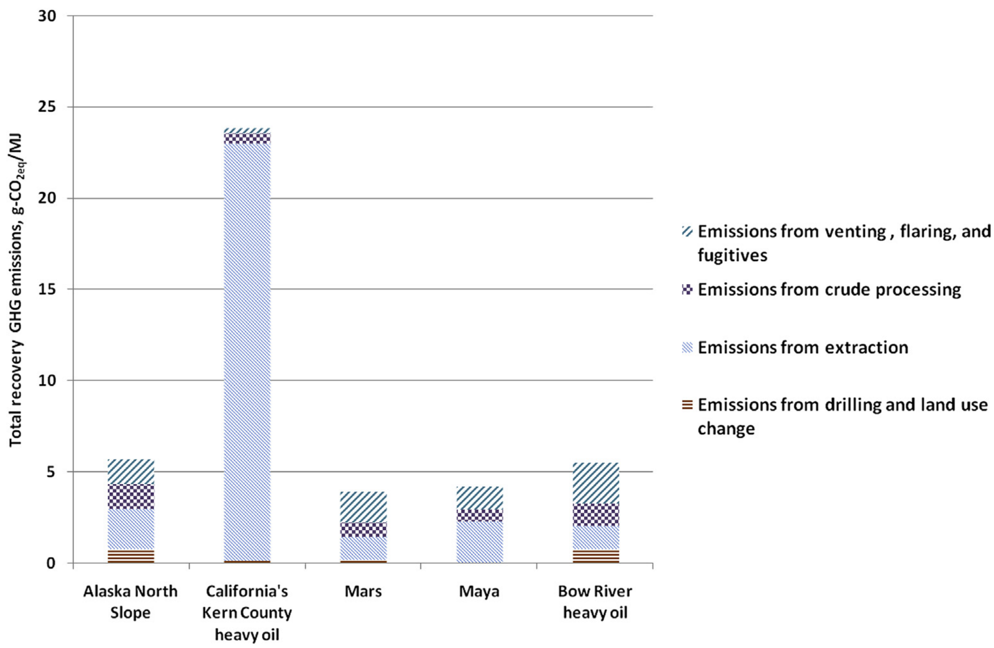

Fig. 1. Total GHG emissions from crude recovery.

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

Variations are found between the recovery emissions found in this study and those in recent studies conducted by TIAX [3] and Jacobs Consultancy [4] (see Fig. 2). These variations are due to different assumptions and boundaries used in the studies. Only the analysis done by the authors of this paper considered the emissions from drilling and land use change. TIAX [3] considers the emissions from crude extraction and venting and flaring but does not consider emissions from drilling, land use change, and the processing of different phases. For individual crudes, Jacobs' study presents a range of crude recovery emissions, and the average of that range is presented in Fig. 2. According to Jacobs' study, extraction recovery emissions from Mars, Maya, and California's heavy crude are 6–10 g-CO_{2eq}/MJ, 4–7 g-CO_{2eq}/MJ, and 12–21 g-CO_{2eq}/MJ, respectively. Fig. 2 shows a wide variation in emissions for Kern County heavy oil. The steam-to-oil ratio and grid emission factor are the most sensitive parameters for this crude. For the same steam-to-oil ratio, variations in emissions between this study and Jacobs' range from 2 to 3 g-CO_{2eq}/MJ. For California

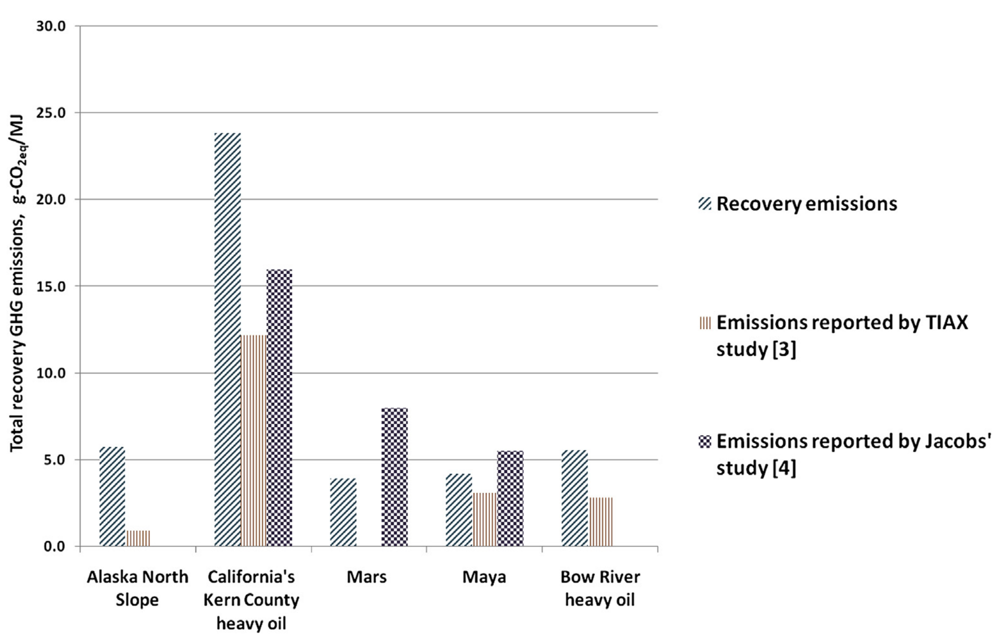

Fig. 2. Comparison of total recovery GHG emissions with reported literature.

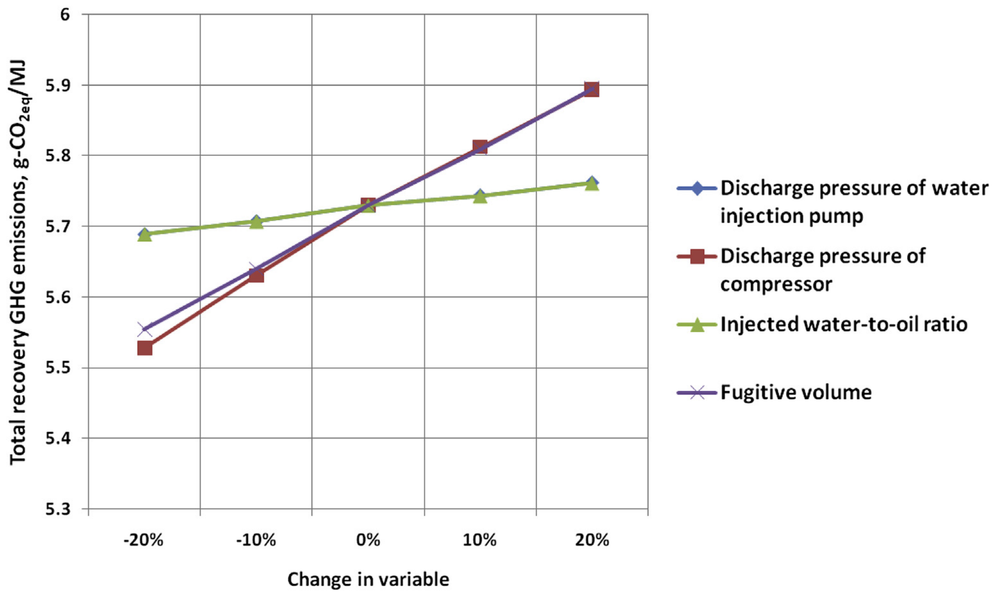

Fig. 3. Total recovery GHG emissions for Alaska North Slope crude.

crude, TIAX does not indicate anything about the variation of the steam-to-oil ratio or the grid emission factor. There were no other analyses found in the literature on recovery emissions for specific crudes.

4.5. Sensitivity analysis

A sensitivity analysis was performed to determine which parameter has the largest effect on the GHG emissions. Different independent parameters were selected that were expected to have some effect on the total GHG emissions for each crude. The sensitivity factors were varied by ±20%, except for the pump efficiency, which was varied by ±10%. Figs. 3–7 show the sensitivity analysis for all five different crude oils.

For Alaska North Slope (Fig. 3), four parameters were varied, among which the discharge pressure of compressor and fugitive volume have the maximum impact on recovery emissions. Increased discharge pressure results in a greater energy requirement that in turn increases emissions. The discharge pressure of the water injection pump and injected water-to-oil ratio have similar impacts on total GHG emissions.

Five parameters were selected for California's Kern County heavy oil to check their impacts on total recovery emissions. Pump efficiency, fugitive volume, and well depth have negligible impacts on GHG emissions, while grid emission factor and the steam-to-oil ratio have the maximum impact and are illustrated in Fig. 4. Increasing the steam-to-oil ratio increases the GHG emissions as more natural gas is burned to produce the extra steam. GHG emissions decrease with increased grid emission factor as onsite electricity is sold to a more GHG-intensive grid, and so this pathway receives credit for that.

In the case of Mars crude, a 20% increase in the injected water-to-oil ratio and discharge pressure of pump increases emissions by 6%. The water-to-oil ratio increases the emissions by 1% when the ratio

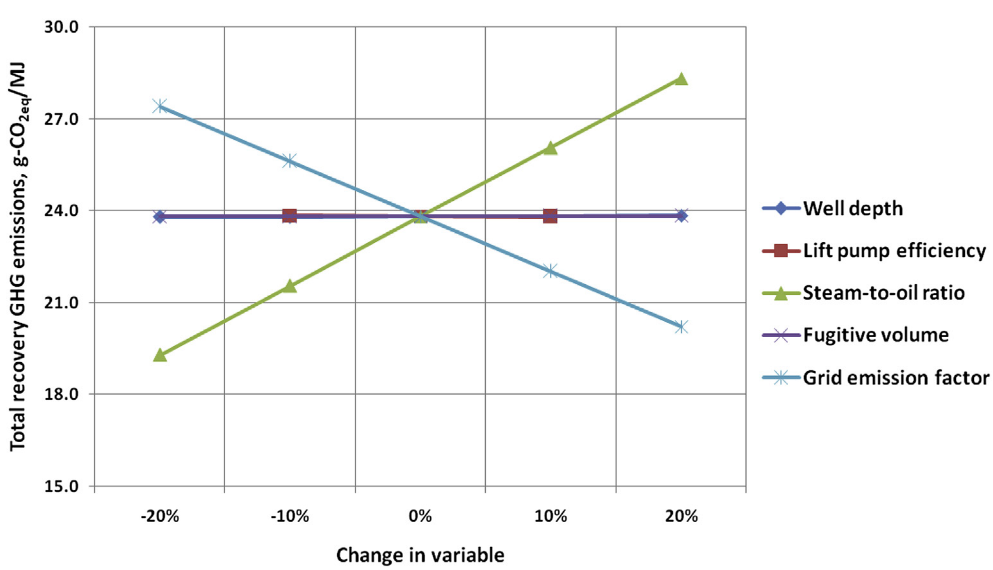

Fig. 4. Total recovery GHG emissions for California's Kern County heavy crude.

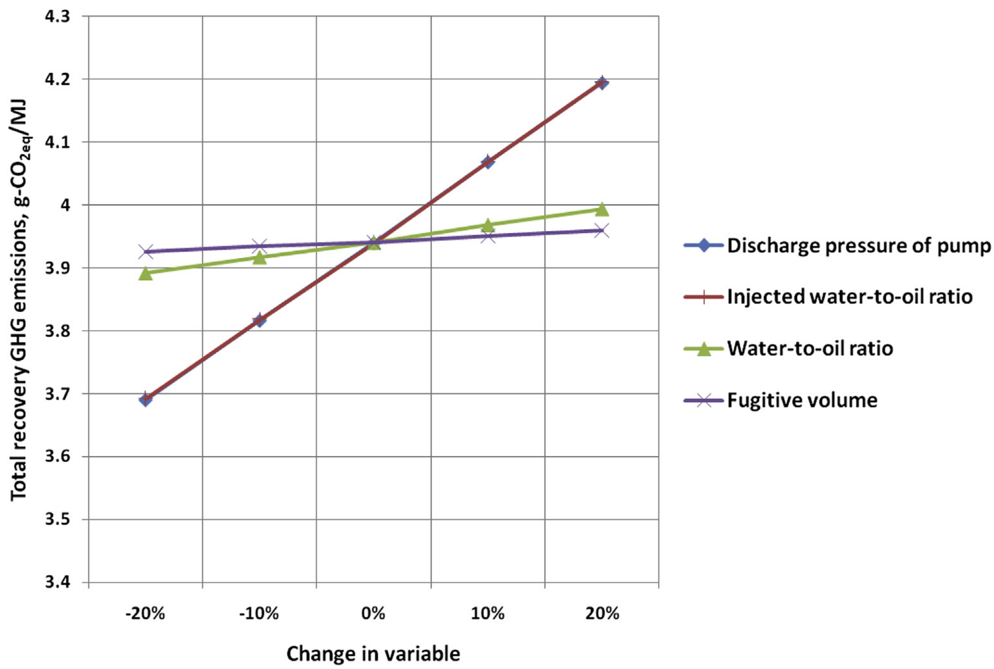

Fig. 5. Total recovery GHG emissions for Mars crude.

is increased by 20%. For Maya crude, four parameters were selected to see their impacts on results. The amount of nitrogen injected has the highest sensitivity; increasing the nitrogen by 20% increases the emissions by 0.16 g-CO_{2eq}/MJ. For the other three parameters, there is an increasing trend with increased percentage variations.

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

5. Conclusions

A transparent quantification of recovery GHG emissions was made using fundamental equations and through the development of data-intensive engineering models. The highest and lowest emissions come from California's Kern County heavy oil at 23.85 g-CO_{2eq}/MJ and Mars at 3.94 g-CO_{2eq}/MJ, respectively. Alaska North Slope has the second highest emissions at 5.73 g-CO_{2eq}/MJ. For Maya and Bow River heavy oil, emissions from total crude recovery are 4.20 g-CO_{2eq}/MJ and 5.54 g-CO_{2eq}/MJ, respectively. As different data sources were used for this study, a sensitivity analysis was

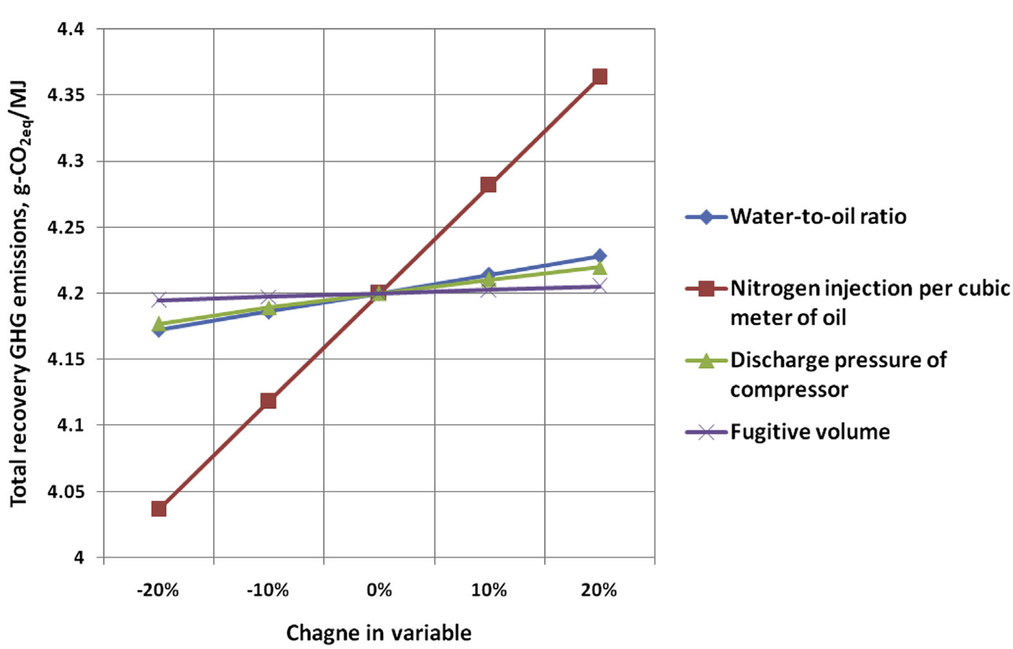

Fig. 6. Total recovery GHG emissions for Maya crude.

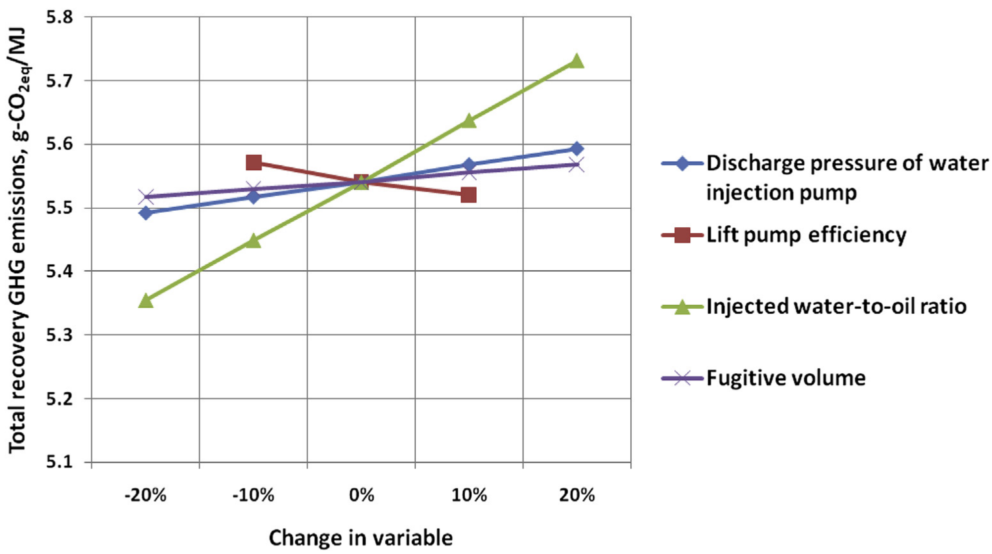

Fig. 7. Total recovery GHG emissions for Bow River heavy crude.

used to show the impact of different parameters on total recovery GHG emissions. The results of this paper will help the oil industry consider different areas to reduce emissions to meet environmental regulations. This study also facilitates the comparison between emissions from oil sands and from conventional crude oil extraction by providing extraction emissions from different conventional crude oils.

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