Energy 186 (2019) 115854

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

Evaluation of energy and GHG emissions' footprints of bitumen extraction using Enhanced Solvent Extraction Incorporating Electromagnetic Heating technology

M. Safaei, A.O. Oni, E.D. Gemechu, A. Kumar*

Department of Mechanical Engineering, University of Alberta, 10-203 Donadeo Innovation Centre for Engineering, Edmonton, Alberta T6G 1H9, Canada

ARTICLE INFO

Article history:
Received 8 March 2019
Received in revised form
29 July 2019
Accepted 30 July 2019
Available online 6 August 2019

Keywords:
Bitumen extraction
Enhanced solvent extraction
Electromagnetic heating
Greenhouse gas emissions
Oil sands extraction
Uncertainty analysis

ABSTRACT

Enhanced Solvent Extraction Incorporating Electromagnetic Heating is an emerging technique for in situ oil sands extraction. A bottom-up method based on first engineering principles was conducted to determine the greenhouse gas emissions and energy requirements of the process. Two pathways in which to reduce solvent loss and energy use by the process were investigated. In Pathway I, the produced gases are captured to minimize solvent losses, while Pathway II considers their use as fuel. Energy scenarios were developed to analyze the overall impacts of the electricity sources. A case for Alberta, Canada, was conducted to study the impacts of electricity consumption on emission performance. The current Alberta electricity mix, future Alberta electricity mix (to 2030), 100% renewable electricity (from biomass), and cogeneration were the energy scenarios considered. The results show that energy consumption and greenhouse gas emissions for Pathways I and II are 487.2 and 375.5 MJ/bbl, and 77.7 and 59.77 kg CO_2 eq/bbl of bitumen, respectively. Electricity use by the antenna for heating is the key contributor. The electricity-from-biomass scenario offers the highest emission reduction, 83.0% below Alberta's current electricity mix. Improvement in the antenna performance and cleaner electricity generation would reduce environmental impacts.

1. Introduction

Conventional fossil fuels have a dominant role in global energy supply. Petroleum production, at approximately 100 million barrels per day (mbpd), makes up one-third of the world's energy supply [1]. Most petroleum products are used as transportation fuels and contribute to 20% of global greenhouse gas (GHG) emissions [2]. World energy consumption, driven by population and economic growth, is projected to increase by 28% from 2015 to 2040 [3]. The depletion of fossil fuel reserves is another pressing issue, along with its climate change impact. With current production and consumption trends, there are only 20, 53, and 114 years before the world runs out of crude oil, natural gas, and coal, respectively [4,5]. Hence, making use of the vast resources of unconventional crude reserves around the globe (2129.5 billion barrels) could be a potential solution to satisfy the world's energy demand for decades [5]. Oil sands are one of these unconventional sources. They are composed of sands, water, and bitumen and characterized by their high viscosity and density [6]. Canadian oil sands constitute a larger portion of the total proven global oil reserves [4]. The oil sands reserves in Alberta, a western Canadian province, with 165.4 billion barrels, comprise 13.8% of the world's total proven oil reserves [3,7]. At 2.4 million barrels per day, Alberta's bitumen production represents 2.5% of the world's oil production [7,8]. The production is projected to increase by 54% by 2030 [9].

Bitumen extraction is a challenging process because of the highly viscous nature in which it exists in situ. It must be converted to a flowable form for easy mobility and processing. There are a number of bitumen extraction techniques, but cyclic steam stimulation (CSS) and steam assisted gravity drainage (SAGD) are the most widely used in situ methods [6]. In both the processes, pressurized high temperature steam is injected into a reservoir through injection wells; this transfers heat to the bitumen and reduces its viscosity [10]. The heated bitumen is extracted from in situ through producer wells. Both CSS and SAGD use substantial amounts of natural gas and water to produce steam [10,11]. During this process, a significant portion of the heat is lost inside the reservoir [12].

---

* Corresponding author.
E-mail address: amit.kumar@ualberta.ca (A. Kumar).

https://doi.org/10.1016/j.energy.2019.115854

Abbreviations

cEOR	Cumulative electricity-to-oil ratio of the reservoir
CO_2	Carbon dioxide
CSS	Cyclic steam stimulation
DEA	Diethanolamine
EM	Electromagnetic
ESEIEH	Enhanced Solvent Extraction Incorporating Electromagnetic Heating
FWKO	Free water knockout
gCO_2eq	Grams of carbon-dioxide equivalent
GHG	Greenhouse gas emissions
GOR	Gas-to-oil ratio
GWP	Global warming potential
H_2S	Hydrogen sulfide
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
LCA	Life cycle assessment
Mbpd	Million barrels per day
MSCFD	Thousand standard cubic feet per day
N_2O	Nitrous oxide
P5	5th percentile
P95	95th percentile
SAGD	Steam-assisted gravity drainage
SCO	Synthetic crude oil
TEG	Triethylene glycol

Bitumen recovery is GHG intensive. The sector is responsible for 9.8% of Canada's GHG emissions [13]. A few studies evaluate the energy and emission performances of different bitumen extraction technologies, but they focus mainly on well-established and commercialized extraction technologies such as CSS and SAGD. For example, Bergerson et al. developed a life cycle assessment (LCA) model to estimate the energy use and GHG emissions in surface mining and SAGD processes based on confidential data from industry [14]. Nimana et al. also developed an LCA model to evaluate the energy use and GHG emissions for the same bitumen recovery methods using publicly available data [10]. Their study also examined the effect of cogeneration on bitumen recovery and concluded that GHG emissions in surface mining and SAGD could be reduced by 16–25% and 33–48%, respectively, through cogeneration. Garcia et al. evaluated the impact of capturing CO_2 from power and hydrogen production plants in reducing GHG emissions [15]. The GHG emission reduction opportunities through the use of renewable energies in the SAGD process are analyzed by Betancourt-Torcat et al. and Kramer et al. [16,17]. Some authors investigated alternative energy saving opportunities and changing the current configuration of SAGD plants to reduce GHG emissions [18,19]. Others evaluated the variability in GHG emissions during bitumen extraction in SAGD and CSS through statistical analysis [20,21]. These studies highlight that the discrepancy in output results is mainly due to different reservoir properties. HIS Markit's study considered several improvement options in CSS and SAGD to predict future bitumen extraction emissions [22].

The oil sands industry has been making efforts to develop alternative bitumen extraction and recovering technologies that can help the sector reduce its overall GHG emissions. A number of new technologies are at various stages of development, demonstration, and deployment. These include electromagnetic (EM) heating [23], solvent assisted extraction technique [24], and Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH) [25]. EM heating uses a radio frequency antenna that converts electricity to radio frequency energy. The antenna is placed inside a reservoir to heat the bitumen by vaporizing the formation connate water [26]. The solvent-based extraction technique is based on injecting a light hydrocarbon-solvent as superheated vapor into the reservoir. The solvent later rises and condenses and gives its latent heat to the bitumen [24]. Both EM heating and solvent-based extraction technologies have pros and cons. While both eliminate the water requirement and have high heat transfer efficiency [24,26,27], the low natural gas-to-electricity and then electricity-to-radio frequency conversion efficiencies mean EM's heating energy is not on par with SAGD or CSS [25]. In addition, solvent-based extraction has two major challenges. First, heat transfer from solvent to bitumen is affected by non-condensable gases inside the reservoir, thus special care must be taken to maintain the appropriate operating temperature and pressure to avoid solvent poisoning [28]. Second, solvent consumption and solvent loss are high, which affects the economic feasibility of the technology [29].

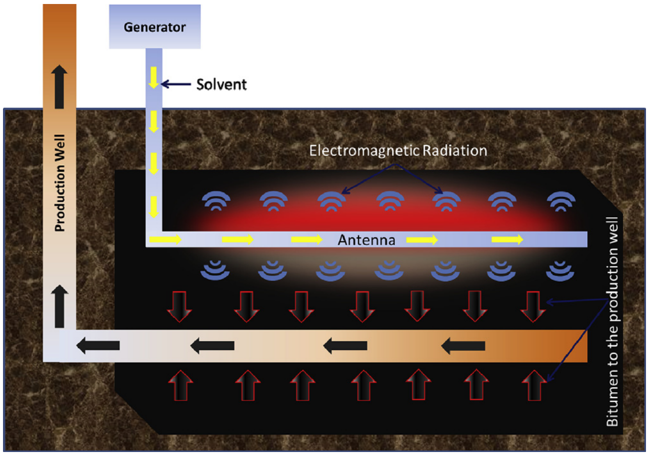

Fig. 1. Schematic diagram of the ESEIEH process.

ESEIEH is considered a game changer oil sands extraction technology because of its high potential to reduce capital intensity, GHG emissions, and water use. ESEIEH combines the best features of both EM heating and solvent extraction techniques [30]. The antenna is placed horizontally in the reservoir to preheat the reservoir, and light solvent is then injected to further reduce the viscosity [25,30]. ESEIEH is considered to require a relatively lower solvent-to-oil[1] ratio than solvent-based extraction and operates at a lower temperature than EM heating and SAGD [25]. Furthermore, it could have a higher oil recovery factor[2] than CSS and SAGD [31]. An overview of the ESEIEH process is presented in Fig. 1.

A handful of studies on ESEIEH technology exist in the literature, mainly focusing on cost and process characterization. Wise and Patterson performed a cash flow analysis to forecast the supply cost of an ESEIEH demonstration project in Alberta's oil sands [32]. Sadeghi et al. used numerical modelling to study the electromagnetic heating phenomena important to fluid flow in oil sand reservoirs [33]. Irani and Saeedfar estimated the minimum amount of

---

[1] Solvent-to-oil ratio is an expression of the amount of solvent required at standard conditions and liquid state to extract one barrel of bitumen.

[2] The oil recovery factor is the amount of reservoir crude that can be recovered economically.

power required to develop the desiccated zone around the antenna in the reservoir [34] and Sadeghi et al. presented an analytical model that predicts oil rate and desiccated zone growth [35]. Wilson et al. use numerical modelling to predict liquid solvent penetration depth [36]. To the best of the authors' knowledge, there is no single study that evaluates the energy and environmental performances of the ESEIEH process. However, identifying the energy and environmental hot spots of new extraction technologies such as ESEIEH at the early stage of development can help industry make required adjustments at a relatively lower cost than when the technologies are already in the market and could also help policymakers make more informed decisions and further facilitate policy formulation. Hence, it is critical to understand the energy and environmental footprint of ESEIEH. This will help in its comparison with in situ methods. This paper, therefore, aims to address these gaps by performing a data-intensive and process-specific LCA based on first engineering principles. The specific objectives of this research are to:

- Develop a process model for the ESEIEH process,
- Develop a spreadsheet-based model to characterize the energy and GHG emissions of the ESEIEH process,
- Identify the parameters that significantly impact the GHG emissions of the ESEIEH process, and
- Evaluate different energy scenarios to improve the ESEIEH process.

2. Method

Fig. 2 illustrates the stages in the production of transportation fuel through the ESEIEH process. The crude extracted from the reservoir is processed on the surface to separate the solvent and the formation water. The bitumen is then blended with lighter hydrocarbons such as natural gas distillates (diluent) to reduce the viscosity so that it can be transported via pipeline. The blended bitumen, known as dilbit, is either sent to the upgrader to be transformed into a higher quality crude (synthetic crude oil [SCO]) or sent directly to a refinery to produce transportation fuels [37].

2.1. Process description

A detailed view of the extraction and separation of the ESEIEH process is provided in Fig. 3. The unit operations considered in each stage of extraction in the reservoir and separation at the surface are discussed below.

2.1.1. Extraction process

The reservoir configuration of the extraction process is similar to SAGD [25] and uses standard oilfield handling equipment. It has a horizontal or vertical well pair with an injector and a production well that produces a mixture of bitumen, gas, solvent, and water as emulsion from the reservoir. A dipole antenna is installed in the injection well to transmit radio frequency waves into the reservoir [25]. The radio frequency wave heats the reservoir, making the bitumen less viscous. Solvent is injected into the reservoir to increase the mobility of the heated bitumen. The reservoir heating temperature and pressure are assumed to be 80 °C and 1.4 MPa, respectively, to produce emulsion in the production well [31,38]. The reservoir pressure and temperature for effective operation of the ESEIEH process are lower than in the steam-based extraction process [10,39]. Depending on the hydrocarbon solvent used, the well temperature ranges from 40°C to 80 °C and the well pressure is operated such that it favors solvent condensation [25]. It is important that the conditions of the well are favorable to ensure that the solvent condenses. In this study, butane is used as solvent and reservoir operating conditions suitable for condensation are assumed [40].

2.1.2. Separation process

The separation process can be divided into four main processes: oil treatment, amine gas treating, glycol dehydration, and demethanizer. The use of steam reboiler and water coolers are more economical than other sources such as glycol mixtures and cooling fans. Therefore, in this study, it is assumed that regenerators use a steam reboiler and water cooler to boil and cool the top product. The pumps and compressors are used to recirculate liquid and gases to where they are required.

2.1.3. Oil treatment unit

Emulsion from the production well is pumped into the surface facility through a cooler that reduces its temperature. The cooler's outlet temperature and pressure are regulated to control the amount of produced gases at the pre-flash tank where components in the gaseous phase are separated from the liquid phase (a mixture of bitumen, solvent, and water). The components in the liquid phase enter the free water knockout (FWKO) drum and mechanical treaters for water separation and further recovery of gases. In order to recover the liquid solvent remaining in the bitumen, the bitumen leaving the FKWO for the stabilizer unit is preheated to about 195 °C [41], thus vaporizing the solvent. The bitumen from the stabilizer unit is then sent to the storage tank where it is mixed with diluent to further improve its viscosity. The separated water is sent to the water treatment unit for treatment. Produced gases, along with separated solvent vapor from the flash tank, mechanical treaters, and stabilizer unit, are compressed and sent to the amine gas treatment unit as shown in Fig. 3.

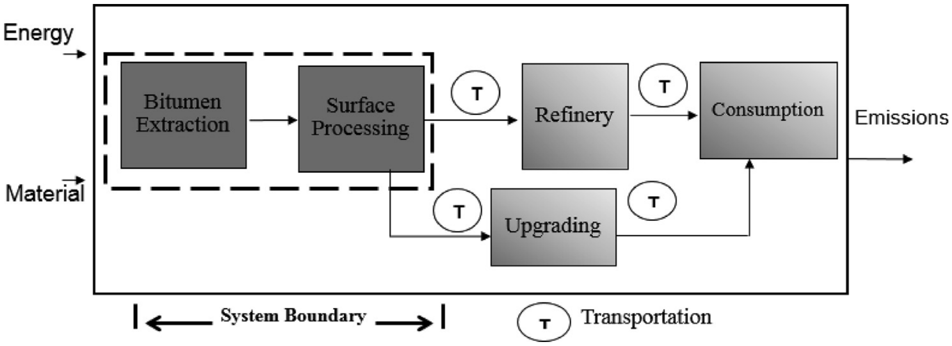

Fig. 2. Schematic of transportation fuel production using the bitumen extraction through the ESEIEH process.

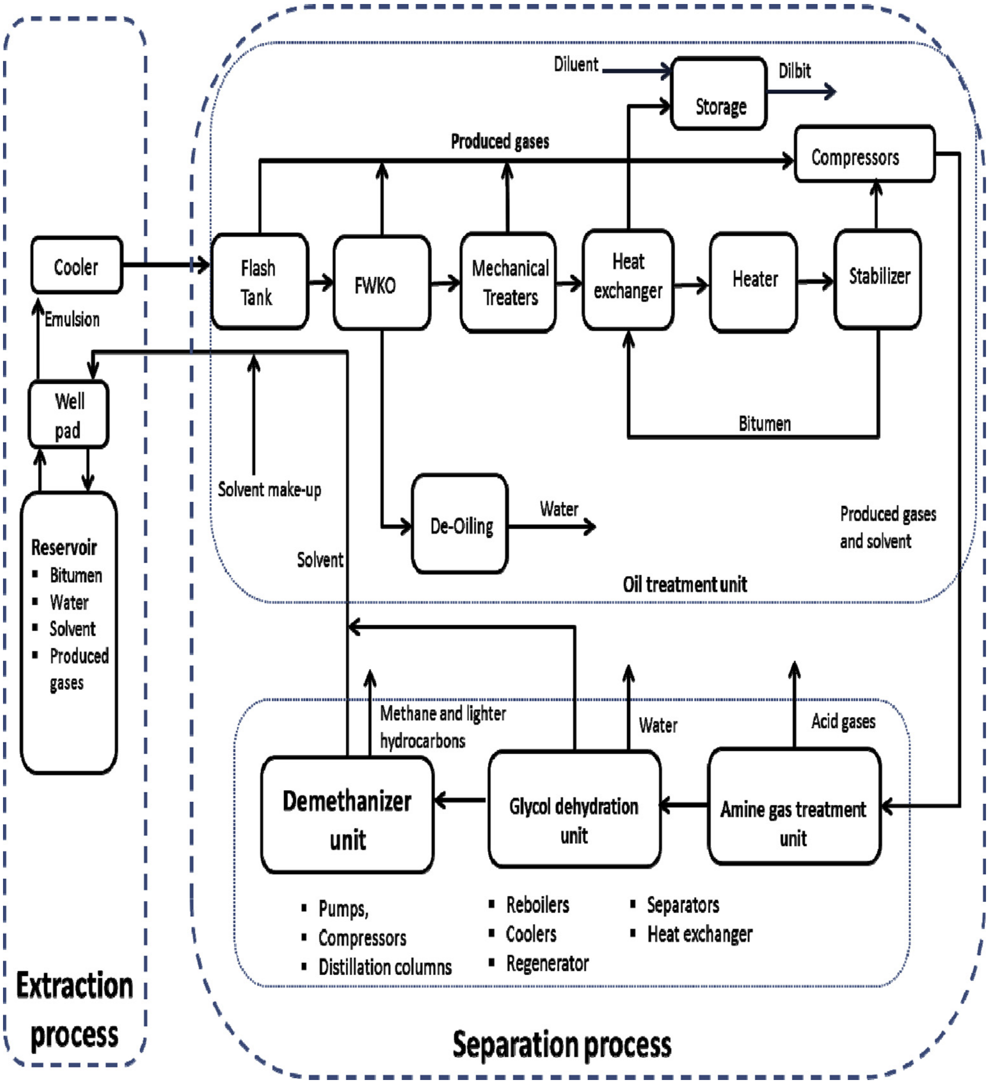

Fig. 3. Schematic diagram of the ESEIEH extraction and separation process.

2.1.4. *Amine gas treatment unit*

The amine gas treatment unit is considered for the removal of acid gases such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S) from the produced gases using diethanolamine (DEA) solution. The amine gas treating process consists of an absorber tower, regenerator unit, pumps, and compressors. In the absorber tower, DEA solution flowing down the tower absorbs CO_2, H_2S, and other contaminants from the produced gases entering at the bottom [42]. Sweet gas (gas free of acid gases and contaminants) is produced as distillate and sent to the dehydration process for water removal. DEAs rich in absorbed acid gases and contaminants are removed as a bottom product in the absorber tower. The rich DEA is sent to the regenerator to produce lean DEA for reuse and CO_2, H_2S, and other contaminants are removed as the distillate in the regenerator [42].

2.1.5. *Glycol dehydration unit*

The glycol dehydration unit consists of an absorber, regenerator, pumps, and compressors. In the absorber unit, triethylene glycol (TEG) flows down from the top of the tower and absorbs wet gas entering at the bottom as they contact each other. Dry gases are produced as distillate while the bottom product, the TEG/water mixture, is sent to the regenerator unit to produce lean TEG for reuse [42]. Depending on the purity of solvent, the recovered solvent is either recycled through the injection well or sent to the demethanizer unit.

2.1.6. *Demethanizer unit*

The main purpose of the demethanizer unit is to purify the solvent and separate methane from other lighter hydrocarbon components. The unit has a distillation tower and a refrigeration unit. The distillation tower, with a top cooler and bottom reboiler, is used to separate solvent (butane) from other lighter hydrocarbons. The refrigeration unit is required to condense the dry gases from the dehydration process, after which the dry gases enter the distillation tower. The solvent leaves the tower at the bottom while the lighter gases leave as distillate [43]. Finally, the recovered and make-up solvent is re-injected into the reservoir.

2.2. *Simulation of the ESEIEH process*

2.2.1. *Estimation of energy consumption*

Table 1 lists all the values and assumptions used to estimate energy use and associated GHG emissions for bitumen extraction in the ESEIEH process.

Table 1
Model input data for the evaluation of energy consumption and GHG emissions in bitumen extraction via ESEIEH.

Parameter	Value
Solvent-to-oil ratio, m^3/m^3 [38]	1.33
Solvent hold-up in the reservoir, % [38,44]	25
Solvent loss inside the reservoir, % [29,38]	5.00
Make-up solvent temperature, °C [45]	10.00
Make-up solvent pressure, kPa [45]	200.00
Reservoir gas-to-oil ratio, (GOR)[a][3], m^3/m^3 [14]	4.00
Reservoir depth, m [44]	153.00
Reservoir pressure, kPa [44]	1400.00
Wellhead pressure, kPa [10]	1800.00
Reservoir cumulative electricity-to oil-ratio (cEOR)[c], GJ/bbl [31,38]	0.18
Antenna efficiency, %	72.00[a]
Furnace efficiency, % [46,47]	80.00
Compressor efficiency, % [48]	80.00
Boiler efficiency, % [14]	85.00
Pump efficiency, % [49]	80.00
Pressure difference for pumping cooling water, kPa [50]	266.00
Energy intensity for water treatment, kwh/bbl of water [51]	0.16
Diluent-to-oil ratio, m^3/m^3 [39]	0.33
Dilbit storage tank temperature, °C [39]	50
Diluent storage tank temperature, °C [39]	5.8
Upstream emissions of solvent, kg CO_2eq/bbl of butane [52]	17.95
Emission factor of natural gas, kg CO_2eq/GJ [52]	68.00
Emission factor of combusted gas in Pathway I[d], kg CO_2eq/GJ	80.24
Emission factor of combusted gas in Pathway II[5], kg CO_2eq/GJ	61.88
Emission factor of Alberta grid electricity (2016 mix)[5], kg CO_2eq/MWh	701.00
Emission factor of Alberta grid electricity (2030 mix)[5], kg CO_2eq/MWh	372.00
Emission factor of electricity from cogeneration, kg CO_2eq/MWh [52–54]	484.00
Emission factor of electricity from biomass power plants, kg CO_2eq/MWh [55]	20.26[b]

[a] Proprietary data from industry. This value also includes the efficiency during transmission of the electricity into the reservoir.
[b] This value corresponds to the emissions during chopping, cropping, and transportation of feedstock to the power plant.
[c] Amount of electrical energy that needs to be delivered to the reservoir for bitumen recovery.
[d] Calculated by authors.

The following equations were used to estimate energy consumption in different unit operations.

Energy consumption of antenna, A_E:

$$A_E = cEOR/\eta_a \quad (1)$$

where cEOR is the cumulative delivered energy to the reservoir-to-oil ratio (GJ/bbl) and η_a is the overall efficiency of the antenna including transmission losses of electricity and conversion of electricity to radio frequency energy.

Energy consumption of pumps, P_E:

$$PE = V*P\Big/\eta_p \quad (2)$$

where V is the emulsion volume (m^3/bbl), P is pressure difference, and η_p is the efficiency of the pump.

Energy consumption in pumps for emulsion extraction, P_{EE}:

$$P_{EE} = M_m^* g^* h + (Mv)*(P_{wellhead} - P_{reservoir}) \quad (3)$$

where M_m is mass of water, solvent, and bitumen mixture (kg/bbl), h is the vertical depth of the producer well (m), g is the gravity (m/s^2), M_V is the mixture volume (m^3), $P_{wellhead}$ is the wellhead pressure (kPa), and $P_{reservoir}$ is the reservoir pressure (kPa).

Energy consumption in the water treatment unit, W_E:

$$W_E = E_i^* W_c \quad (4)$$

where E_i is the energy intensity for water treatment (kWh/bbl of water) and W_c is the amount of water that is extracted along with bitumen, known as water cut (%).

Solvent upstream emissions for bitumen production, $S_{up\text{-}emission\text{-}bitumen}$:

$$S_{up-emission-bitumen} = S_{up-emission}*SOR*S_L \quad (5)$$

where $S_{up\text{-}emission}$ is the upstream emissions of solvent (kg CO_2 eq/bbl solvent), SOR is solvent-to-oil ratio (m^3/m^3), and S_L is solvent loss (%).

2.2.2. Process simulation

The process simulation of the separation processes was carried out using Aspen HYSYS Version 9.0 [56]. The unit operations involved in the process simulation models are distillation columns, reboilers, valves, mixers, splitters, pumps, compressors, heat exchangers, coolers, heaters, and separators. In this study, two simulation models were developed for the analysis of the ESEIEH process. The first investigates the effects on energy consumption and GHG emissions when solvent, together with produced gases, is considered for purification in the demethanizer unit. The second model assumes the produced gases, particularly from the pre-flash and mechanical treaters, are used for combustion in a steam boiler. In this case, the demethanizer unit was not considered. This is because the purity of solvent in the stabilizer unit, where most of the butane is recovered, is relatively high. In this study, for the sake of clarity, the model with the demethanizer is referred to as

---

[3] Amount of gas that is produced along with the bitumen at standard conditions.

Pathway I and the other as Pathway II.

The Peng-Robinson, acid gas-chemical solvent, and glycol fluid packages were the equations of state used to develop the simulation models to predict the thermodynamic conditions of the oil treatment process and demethanizer, amine gas treating process, and dehydration unit, respectively. These fluid packages were adequate to predict the process conditions. The operating conditions of unit operations were found by optimizing the operation parameters in Aspen HYSYS. Those values are presented in Table S4 in the SI.

Natural gas and the Alberta electricity grid mix are the two sources of energy for process units. The energy required by each process unit to extract 25,000 bbl of bitumen is evaluated to give a reasonable account of the impact on the environment. The emulsion from the production well is 2.16 bbl per bbl of bitumen. The emulsion is a mixture consisting of 25,000 bbl of bitumen, 23,294 bbl of solvent, 5500 bbl of water, and 560 thousand standard cubic feet per day (MSCFD) produced gas (containing acid gases, hydrogen, and light hydrocarbons. The compositions are shown in Table S1). In typical steam assisted gravity drainage (SAGD) operations, produced gases from the well are directly used with natural gas to fire steam boilers [39]. However, in a solvent extraction process such as ESEIEH, options are available to either directly use the produced gases (which are in this case mixed with solvent) with natural gas to fire steam boilers or treat them to recover more solvent. The concern in the former approach is continuous solvent loss through combustion in the steam boiler. On the other hand, treating the produced gases to recover solvent may require additional investment and energy consumption. In this study, the two options are examined in terms of energy consumption and associated GHG emissions.

2.3. Scenarios for GHG emissions assessment

In this study, the initial ESEIEH (base case) assessment was carried out using Alberta's current electricity grid mix to examine its GHG emissions. To explore the impact of electricity sources on the overall GHG emissions of the ESEIEH process, the electricity grid mix in 2030, cogeneration, and using a 100% renewable energy source were evaluated.

2.3.1. Current Alberta grid mix scenario

Since 2016, Alberta's electricity grid mix has been dominated by GHG-intensive coal power plants, which make up 39% of the total share.

2.3.2. 2030 Alberta grid mix scenario

Currently, renewable energy makes up only 14.0% of the mix [57]. The province plans to phase out coal-fired electricity generation power plants and replace this energy with renewables and natural gas by 2030 [58], which will raise the renewables' share to 30% [57]. This shift in grid energy will lower the grid carbon intensity and therefore has been adopted as a scenario in our study.

2.3.3. Cogeneration

A common practice for electricity generation in existing oil sands extraction processes is cogeneration [53,59]. Part of the steam produced for bitumen extraction is used to generate electricity, thus reducing natural gas consumption and GHG emissions. As steam-based extraction processes are likely to operate alongside the ESEIEH process, it is important to consider the benefits of cogeneration.

2.3.4. Renewable electricity (biomass)

In addition, the benefits of renewable resources such as biomass, which is plentiful in northern Alberta [6] are examined here. The concept is to use biomass-based electricity for the ESEIEH process.

2.4. Sensitivity and uncertainty analyses

Since process simulation-based models are deterministic in nature, the uncertainty in their outcomes needs to be quantified before they are used for decision-making. The uncertainty in model output is due to the variability and uncertainty in model inputs. Performing sensitivity and uncertainty analyses provides a means to evaluate the variability in the output of the process simulation-based estimates. In this study, sensitivity analysis was used to identify input parameters that are sensitive to the model output. Monte Carlo simulation runs were performed to evaluate the uncertainties in the output.

Triangular and uniform distributions were considered for the input parameters since limited data is available on input variables [61]. Uniform distribution needs minimum and maximum values to be generated and maintains constant probability over this range of values. Triangular distribution requires a minimum, mode, and a maximum to be generated [62]. The GOR and cEOR depend on the reservoir properties. Moreover, there are few simulations and little field-scale data on the cEOR in different reservoirs. Therefore, uniform distributions were used for these variables. Triangular distribution was considered for the other parameters because of the scarcity of the data. The input variables and their distributions are listed in Table 2.

3. Results

The energy and GHG emissions associated with each process unit in the two pathways of bitumen extraction through ESEIEH were examined. In Pathway I, the simulation model was designed such that the produced gases from the flash tank and mechanical treaters were treated alongside the gases from the stabilizer unit in the amine unit, glycol dehydration, and demethanizer unit (Fig. 3). In Pathway II, however, these gases were used for combustion in steam boilers, thus eliminating the need for a demethanizer unit. Relevant information on how these pathways interact with reservoir operations and surface facilities in terms of energy consumed and associated emissions are discussed.

The energy consumption and corresponding GHG emissions for Pathway I (with a demethanizer) and Pathway II (without a demethanizer) are 487.2 and 375.5 MJ/bbl, and 77.7 and 59.77 kg CO_2 eq/bbl, respectively. The extraction and separation processes were 51.5% and 48.5% of Pathway I and 66.8% and 33.2% of Pathway II. Of the total energy consumed in both pathways, electrical energy has the largest share (Pathway I: 73.3%, Pathway II: 72.4), and the

Table 2
Input parameters and their distributions for uncertainty analysis for bitumen recovery using ESEIEH method.

Input	Monte Carlo distribution
Antenna efficiency, %	Triangular (54, 72, 86)[a]
cEOR, (GJ/bbl) [31,38]	Uniform (0.16,0.20)
SOR, m^3/m^3 [38]	Triangle (1.04,1.33,1.6)[b]
Solvent loss,% [29,38]	Triangle (2, 5, 10)
Compressor efficiency, % [63]	Triangle (75, 80, 85)
Furnace efficiency, % [46,47]	Triangle (70, 80, 92)
Boiler efficiency, % [14,64–66]	Triangle (70%, 85%, 90%)
Pump efficiency, % [67]	Triangle (70%, 80%, 92%)
GOR, m^3/m^3 [14]	Uniform (1,12)

[a] Proprietary data from industry.

[b] The literature only reports an SOR of 1.33. The authors considered a range of ±20%.

Table 3
Energy and GHG emissions of the ESEIEH process.

Process	Pathway I		Pathway II	
	Energy consumption (MJ/bbl)	GHG emissions ($kgCO_2eq/bbl$)	Energy consumption (MJ/bbl)	GHG emissions ($kgCO_2eq/bbl$)
Extraction process				
Emulsion lifting	0.6	0.1	0.6	0.1
Solvent injection	0.3	0.1	0.3	0.1
Antenna	250.0	48.7	250.0	48.7
Separation process				
Oil treatment	95.4	8.9	95.0	8.0
Amine gas treating	20.9	1.5	20.7	1.5
Glycol dehydration	10.8	1.7	9.0	1.4
Demethanizer	109.3	16.7	–	–
Total	487.2	77.7	375.5	59.8

rest of the energy is in the form of heat generated by natural gas and/or produced gas combustion. Table 3 presents the energy consumption and GHG emissions associated with each process. The energy required and the associated GHG emissions in the extraction process are crucial to the overall production processes for the pathways considered. In Pathway I, the inclusion of the demethanizer unit contributed an additional 102.2 MJ/bbl and 16.1 $kgCO_2eq/bbl$ to energy consumption and GHG emissions, respectively.

Earlier studies on existing steam-based extraction processes give emissions values of 45–190 $kgCO_2eq./bbl$ of produced bitumen in SAGD [10,14]. The emissions values from the ESEIEH process (Pathways I and II) are within the range of values reported for steam-based processes. It should be noted that direct comparison cannot be made at this level of operation because the bitumen produced by these processes may differ in composition and properties, suggesting that their volume flow and/or energy content are not equivalent. Direct comparison is suitable after bitumen upgrading and/or refining, when final products have similar properties.

3.1. Extraction process

The total energy consumed in the extraction process for Pathways I and II is ~251.0 MJ per barrel of bitumen. The energy required for solvent injection and emulsion pumping is less than 0.1% of the total energy consumed in the extraction process for both pathways. The energy required for heating the reservoir through the antenna is intensive; for both pathways, about 250 MJ of electrical energy needs to be converted to radio frequency energy to produce 1 barrel of emulsion. The GHG emissions associated with the extraction process were estimated to be ~49.0 $kgCO_2eq./bbl$ for both pathways.

3.2. Separation process

The energy consumed in the separation process and the corresponding GHG emissions are 236.4 and 124.7 MJ/bbl, and 28.8 and 10.9 $kgCO_2eq./bbl$ for Pathways I and II, respectively. The oil treating process and the demethanizer process are the most emission-intensive units for Pathway I; they contributed about 31.0% and 57.9%, respectively, to the overall emissions of the separation process. In Pathway II, the oil treating process is also the most emission-intensive unit; it contributed 74.0%, while the amine process and glycol dehydration process contributed 13.5% and 12.5%, respectively. The overall solvent losses in the separation unit are 2.4% and 3.8% of the total solvent input for Pathway I and II, respectively. For both pathways, most of the solvent losses are from the stabilizer unit, amounting to 2.4%. In Pathway II, the use of produced gases from the flash tank and mechanical treaters for combustion were about 1.0% and 0.3%, respectively. There are no significant solvent losses in the free water knock out vessel and other units of the process.

The oil treating process for both pathways is similar in configuration, operating conditions, and the amount of produced gas required. However, the differences are that compression of the produced gases from the flash tank and mechanical treaters in the amine gas treatment unit are not required in Pathway II. In Pathway II, the produced gases are assumed to be used for heating purposes, while higher compression power and cooling are required to meet the operating conditions of the amine treating unit for Pathway I. The combusted produced gases (from the flash tank and mechanical treaters in Pathway II) contain some solvent, which is lost through its use in the boiler. The produced gases that are sent to the amine unit are predominantly butane (96.9% for Pathway I and 97.7 for Pathway II), and their overall volume flow (standard cubic feet) per barrel of bitumen is 1252.6. When the produced gases from the flash tank and mechanical treaters are not considered for treatment, the value is 1214.0 SCF/bbl of bitumen (Pathway II). The reduced volume flow of the produced gases lowers the energy consumption and GHG emissions by 0.41 MJ/bbl and 0.89 $kgCO_2eq./bbl$, respectively, in the oil treatment unit. In the stabilizer unit, where most of the solvent in the emulsion is recovered, about 40% of the energy supplied by the fired heater is recovered through heat integration. However, the overall energy consumed by the stabilizer unit is over 80% of the total energy consumed in the oil treatment unit for both pathways. In the amine treatment unit, the steam reboiler, cooling water pump, and booster pump for the circulation of DEA are the main energy consumers. The steam reboiler is the most energy-intensive unit; it is responsible for over 97.0% of the energy consumed by the amine treatment unit in both pathways. Although there are more acid gases in Pathway I than in Pathway II, the relative difference, 9.34×10^{-3} kg/bbl of bitumen for CO_2 and 1.29×10^{-5} kg/bbl of bitumen for H_2S, does not significantly contribute to the emissions or the energy consumed. The reason is that the additional DEA required to sufficiently remove the increased acid gases has little impact on the energy consumed in the regenerator and booster pumps. The increase in energy consumed and emissions is 0.21 MJ/bbl of bitumen and 0.04 $kgCO_2eq./bbl$ of bitumen, respectively, in the amine treatment unit. Similarly, the additional water removed from the glycol dehydration unit for Pathway I does not significantly influence energy consumption and emissions. The increase in energy consumed and emissions in Pathway I is 1.79 MJ/bbl and 0.35 $kgCO_2eq./bbl$ of bitumen, respectively.

The drying of solvent (water removal) in the glycol dehydration unit is essential. Solvent purities are 98.6% and 99.3% for Pathways I and II, respectively, after drying. However, in Pathway I, because it is important to improve the purity of solvent beyond its present level and recover the light hydrocarbons (which are predominantly methane), the dehydrated product is sent to the demethanizer. The purity of solvent increases to 99.8% after the light hydrocarbons, which contain 95.5% methane, are removed. In this study, it is assumed that light hydrocarbons removed from the demethanizer are used for combustion in the steam boilers. The energy required to increase the purity of solvent by 1.0% in the demethanizer is ~109.3 MJ/bbl of solvent. In Pathway I, about 46.2% of the overall energy consumed in the separation process is by the demethanizer unit. Furthermore, the most energy-intensive units in the demethanizer are the compressors, which are responsible for 68.0% of the energy consumption, followed by the steam boiler (29.4%) and pumps (2.6%). The compressors provide external refrigeration in order to condense the feed composition to the demethanizer distillation column. Since the feed is predominately butane, more energy is required than in a typical demethanizer, in which the feed is composed of lighter hydrocarbons such as methane [43].

4. Discussion

4.1. Extraction and separation process

The antenna and demethanizer contribute significant amounts of energy use and GHG emissions to the overall extraction and separation processes. The GHG emissions for each pathway are comparable except for the relatively high amount of electrical energy required for refrigeration in the demethanizer unit in Pathway I.

In the reservoir, the GHG emissions in Pathway II are slightly higher because more make-up solvent and additional power for the injection of solvent into the reservoir are required. It is also important to mention that, depending on the nature of the reservoir, solvent-to-oil ratio, type of solvent used, electromagnetic generator and antenna efficiency, GHG emissions and energy consumption estimates vary. Reservoirs with more water are more likely to show lower energy consumption because the radio frequency (low frequency) tends to generate more heat energy when it penetrates or travels through water [26]. This, on the other hand, is an opportunity to reduce the amount of solvent used. Reservoirs with high heavy metal content are more likely to increase energy demand because a strong low frequency is required [68]. Reducing the solvent-to-oil ratio can lower energy consumption; however, this may involve a trade-off between bitumen recovery yield and energy consumption. Energy consumption can also be reduced by improving the efficiency of the antenna and using highly conductive electrical transmission lines that produce and transfer electromagnetic energy, respectively, to the antenna. Improved antenna design can also reduce energy use and GHG emissions [26].

During the separation process, capturing the produced gases from the production well increases unit operations and energy consumption because the composition of the produced gases from the well reduces the purity of solvent in the process before solvent re-injection into the well. Although reducing the solvent purity percentage does not significantly consume energy in the amine and dehydration units, an additional unit (the demethanizer) is required to avoid solvent poisoning, which can lead to poor heat transfer in the reservoir. That said, lighter hydrocarbons such as methane and ethane are more likely to pose a serious threat to bitumen extraction because the operating conditions (temperature and pressure) of the reservoir do not favour methane and ethane condensation. Methane, which makes up about 63.6 mol% of the produced gases in the well, is the component most likely to impede heat and mass transfer. Its accumulation and increased concentration in the reservoir will increase the gas-to-oil ratio, thus lowering the length of time bitumen is exposed directly to radio frequency energy from the antenna. These conditions can also result in the convective flow of light hydrocarbon gases in the production and injection well, thus raising their pressure and preventing the inflow of solvent through the injection well. Heavier hydrocarbons, however, are a low threat to bitumen extraction. They are more likely to condense at the operating conditions of the reservoir. That said, the increased concentration of heavier hydrocarbons in the solvent might lead to the expense of additional separation columns and increased energy consumption and emissions. The increase in energy is more likely to be from the refrigeration of the demethanizer feed streams and the column reboilers. For these reasons, it is important to keep solvent purity as high as possible before the solvent is injected into the production well. In Pathway II, solvent loss to combustion through produced gases helps avoid both the energy consumption and emissions of additional units but at the expense of increased make-up solvent. It is important to mention that solvent loss depends on gas composition and flow rates in the reservoir. In situations where the flow rates of produced gases or methane in the reservoir are high, the overall required make-up solvent increases. In pathways where make-up solvent may have a significant impact on cost, an economic and environmental assessment is useful to identify the key trade-offs for a sustainable operation.

4.2. The impact of electricity sources on the ESEIEH process

The analysis of the ESEIESH process showed that electrical energy takes the largest share of overall energy consumption and GHG emissions. Energy-related emissions can be significantly reduced by lowering the electrical emissions footprints. This can be done by lowering the electricity emissions factor by improving the electrical energy mix or using a cleaner electrical source.

In this study, the effects on ESEIESH of Alberta's future grid mix, the current electricity grid mix, and cogeneration were explored. Pathway II (without a demethanizer) was analyzed. Because the results in both pathways are similar, for brevity, Pathway I (with a demethanizer) is not shown or discussed.

With respect to the base case simulation model presented in Fig. 3 (Pathway I), Fig. 4 shows the current Alberta electricity grid mix, the proposed Alberta electricity grid mix by 2030, cogeneration, and 100% renewable energy, along with the corresponding contributions from the unit operations. The figure shows that the ESEIEH process can be significantly improved by adopting the future grid mix, cogeneration, or 100% biomass. A 100% electricity supply from biomass, the Alberta electricity grid mix in 2030, and cogeneration show 83.4%, 39.3%, and 25.2% reductions in GHG emissions, respectively. Furthermore, unlike the Alberta electricity grid mix in 2030 and cogeneration, where associated GHG emissions from the antenna contributed over 66% of the overall GHG emissions, the use of 100% biomass lowers the antenna emissions' share to 16.2%. A similar result is found in the uncertainty analyses of the four sources of electricity through a Monte Carlo simulation (see Fig. 5). The resulting life cycle emissions distributions show that biomass electricity sources have the lowest emissions intensity and the current Alberta grid mix has the highest. However, the error bars of the cogeneration and Alberta electricity grid mix by 2030 overlap, so it is not possible to confidently conclude which scenario has lower emissions. The results of uncertainty analyses show probability ranges of emissions from 9.96 to 87.7 $kgCO_2eq.$/bbl, depending on the source of electrical energy. GHG emissions fall to their lowest values (9.96–13.1 $kgCO_2eq$/bbl) when the source of electrical energy is biomass. The tornado plots in Fig. 6 show the input parameters with the highest impact on the output uncertainty for each electricity source considered. In the biomass power

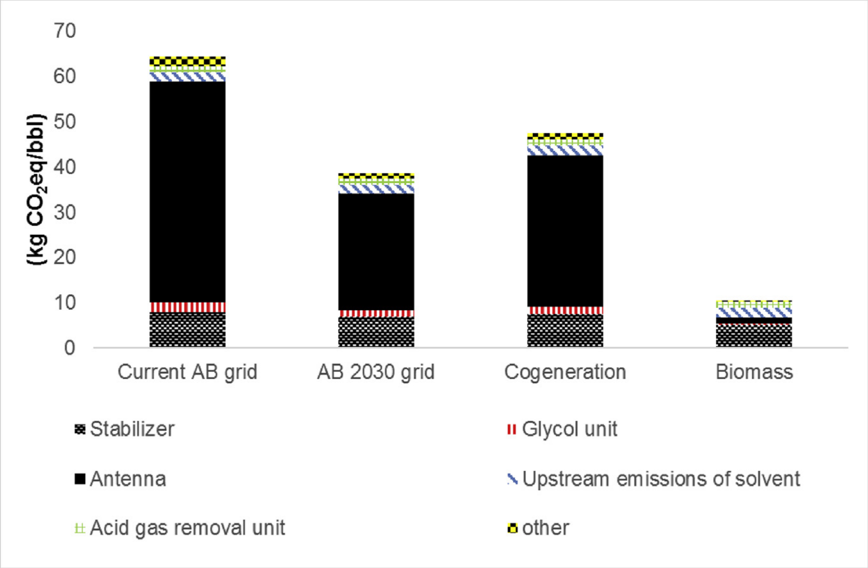

Fig. 4. The effect of electricity sources on the ESEIEH process (Pathway II).

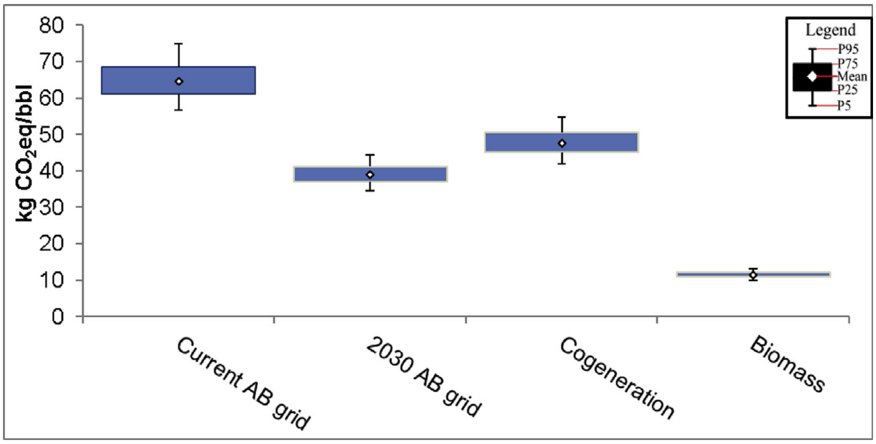

Fig. 5. Uncertainty analysis of the different sources of electricity on the ESEIEH process (Pathway II).

plant scenario, solvent loss is the main source of uncertainty mainly due to its relatively wide range (2–10%), emission-intensive process for producing solvent, and insignificant contribution of electricity-consuming units to the overall GHG emissions because of the low emission factor assumed for the biomass. Antenna efficiency and reservoir cEOR are the main sources of uncertainty in the other scenarios because they have a significant impact on electricity consumption.

As discussed in section 3, electricity comprises up to 73% of overall energy use in ESEIEH process and hence the source of the electricity drastically impacts the GHG emissions of this technology. However, in steam based technologies more than 95% of overall energy use is due to the consumption of the natural gas [10,14]. Therefore, the main reason behind different GHG emissions of these methods is due to the different type of energy inputs. Furthermore, ESEIEH operates at lower tempreture compared to steam based methods and hence consumes less energy [25].

5. Conclusion

In this study, a process simulation model was developed to evaluate the energy and GHG emissions associated with the ESEIEH process. The recovery process was divided into two sections, extraction in the reservoir and separation at the surface, in order to identify the main areas of energy consumption and emissions. For surface separation, two pathways were developed. In the first, the produced gases from the well are captured to minimize solvent losses and the second considers their use as fuel in steam boilers. The first pathway requires an additional unit to ensure the purification of solvent. Energy consumptions in Pathways I and II are 487.2 and 375.5 MJ/bbl, respectively, with corresponding GHG emissions of 77.7 and 59.8 kg CO_2 eq/bbl, respectively. The first pathway is more emissions and energy intensive. In both pathways, electrical energy consumed by the antenna is responsible for the largest share of overall energy consumption and GHG emissions. Any performance improvement in the antenna would considerably reduce the overall environmental impacts. Other sources of electricity (the proposed Alberta electricity grid mix by 2030, cogeneration, and 100% renewable energy) showed significantly reduced energy consumption and GHG emissions. Since process simulation-based models are deterministic in nature, the uncertainty in their outcomes needs to be quantified for reliable decision-making. An

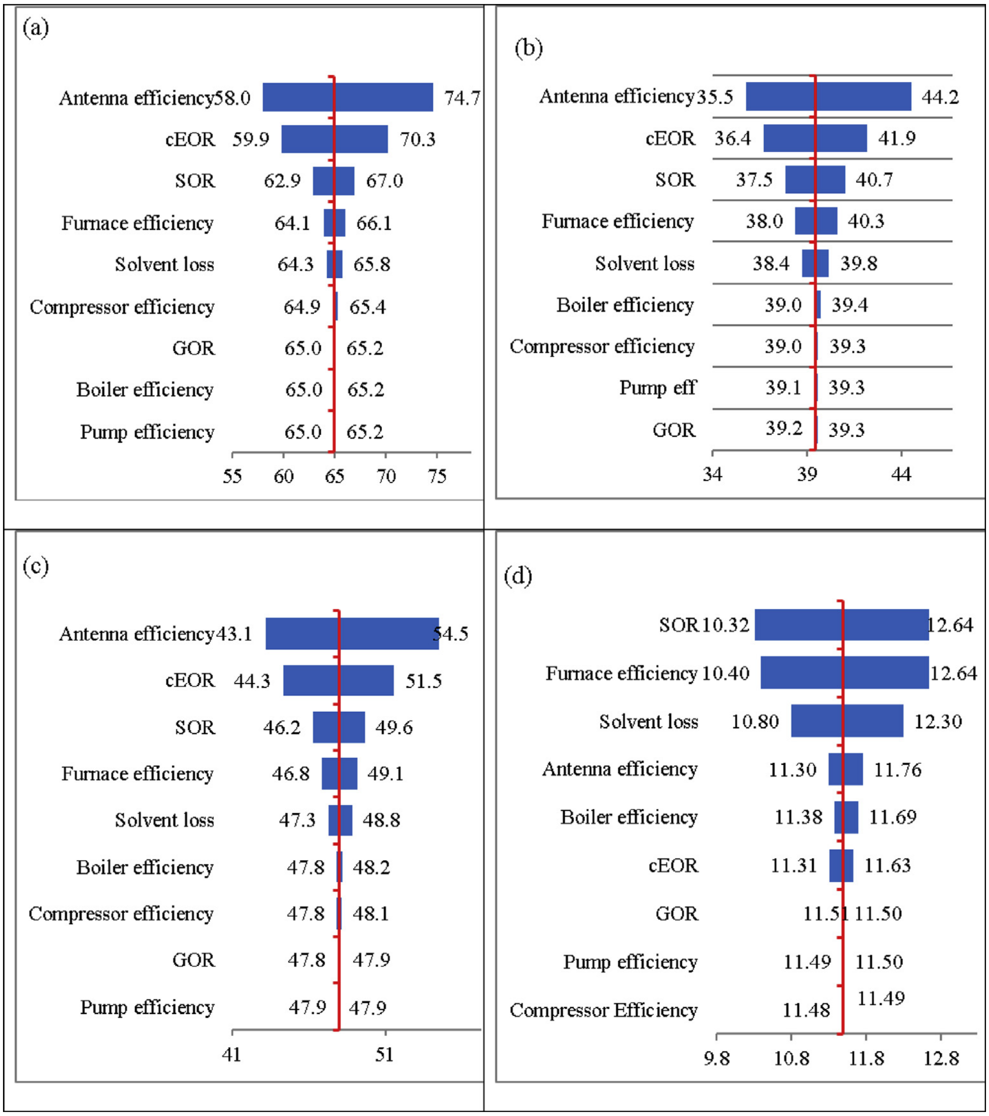

Fig. 6. Tornado plots. (a) Current Alberta electricity mix, (b) 2030 Alberta electricity mix, (c) Cogeneration, (d) Biomass.

examination of the uncertainty results shows that probability ranges of GHG emissions from 9.96 to 87.7 $kgCO_2eq./bbl$, depending on the source of electrical energy and the pathway considered. The uncertainty results show that biomass electricity sources have the lowest emissions and the current Alberta grid mix has the highest. In the biomass scenario, solvent loss is the main source of uncertainty, and antenna efficiency and the cumulative energy-to-oil ratio of the reservoir are the main sources of uncertainty in Alberta's current electricity grid mix, Alberta's electricity grid mix by 2030, and cogeneration.

Declarations of interest

None.

Acknowledgements

We thank the NSERC/Cenovus/Alberta Innovates Associate Industrial Research Chair in Energy and Environmental Systems Engineering and the Cenovus Energy Endowed Chair in Environmental Engineering for providing financial support for this project. We also thank representatives from Alberta Innovates, Suncor Energy, Cenovus Energy Inc., Environment and Climate Change Canada (ECCC), Natural Resources Canada (NRCan), Alberta Department of Energy (ADOE) and Mr. Chris Patterson (Devon Canada) for their valuable inputs and comments in various forms. As a part of the University of Alberta's Future Energy Systems (FES) research initiative, this research was made possible in part thanks to funding from the Canada First Research Excellence Fund (CFREF). The authors are thankful to Astrid Blodgett for editing this paper.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.energy.2019.115854.

References

[1] Finley M. The oil market to 2030-implications for investment and policy. Economics of Energy & Environmental Policy 2012;1(1):25–36.

[2] International Energy Agency. CO_2 emissions from fuel combustion 2018: overview. 2018 [cited 2018 November 28]; Available from, https://webstore.iea.org/co2-emissions-from-fuel-combustion-2018-overview.

[3] Energy Information Administration. International energy outlook 2016 [cited

2017 June 2017]; Available from, https://www.eia.gov/outlooks/ieo/pdf/0484(2016).pdf; 2016.

[4] Centre for Energy Economics Research and Policy. BP statistical review ofWorld energy june 2016 [cited 2018 29 November]; Available from, http://oilproduction.net/files/especial-BP/bp-statistical-review-of-world-energy-2016-full-report.pdf; 2016.

[5] Jaffe AM, Medlock III KB, Soligo R. The status of world oil reserves: conventional and unconventional resources in the future supply mix. 2011.

[6] Gosselin P, Hrudey SE, Naeth MA, Plourde A, Therrien R, Van Der Kraak G, Xu Z. Environmental and health impacts of Canada's oil sands industry. Royal Society of Canada Expert Panel Report, Ottawa. 2010. ON 2010 [cited 2017 September 12]; Available from, https://rsc-src.ca/sites/default/files/pdf/RSC%20Oil%20Sands%20Panel%20Main%20Report%20Oct%202012.pdf.

[7] Alberta energy. Facts and statistics [cited 2018 2/5]; Available from: http://www.energy.alberta.ca/OilSands/791.asp; 2016.

[8] [cited 2018 January 20]; Available from, https://www.iea.org/about/faqs/oil/.

[9] Canadian Association of Petroleum Producers. 2017 Crude oil forecast, markets and transportation [cited 2018 January 17]; Available from, https://www.capp.ca/publications-and-statistics/crude-oil-forecast; 2017.

[10] 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. Appl Energy 2015;143:189–99.

[11] Walden Z. Emission abatement potential for the Alberta oil sands industry and carbon capture and storage (CCS) applicability to coal-fired electricity generation and oil sands. 2011 [cited 2015 October 14]; Available from, https://www.ceri.ca/studies/Emission-abatement-potential-for-the-Alberta-oil-sands-industry-and-carbon-capture-and-storage-(CCS)-applicability-to-coal-fired-electricity-generation-and-oil-sands.

[12] Mukhametshina A, Martynova E. Electromagnetic heating of heavy oil and bitumen: a review of experimental studies and field applications. Journal of Petroleum Engineering 2013;2013:1–7.

[13] Natural Resources Canada. Crude oil facts [cited 2018 April 9]; Available from, http://www.nrcan.gc.ca/energy/facts/crude-oil/20064; 2018.

[14] Charpentier AD, Kofoworola O, Bergerson JA, MacLean HL. Life cycle greenhouse gas emissions of current oil sands technologies: GHOST model development and illustrative application. Environ Sci Technol 2011;45(21):9393–404.

[15] Ordorica-Garcia G, Elkamel A, Douglas P, Croiset E, Gupta M. Assessing the potential of power and hydrogen technologies with CO_2 capture to optimize future energy production in the Canadian oil sands industry. Online article. Available from, https://www.researchgate.net/publication/260301656_Assessing_the_Potential_of_Power_and_Hydrogen_Technologies_with_CO_2_Capture_to_Optimize_Future_Energy_Production_in_the_Canadian_Oil_Sands_Industry.

[16] Betancourt-Torcat A, Elkamel A, Ricardez-Sandoval L. Optimal integration of nuclear energy and water management into the oil sands operations. AIChE 2012;58(11):3433–53.

[17] Kraemer D, Bajpayee A, Muto A, Berube V, Chiesa M. Solar assisted method for recovery of bitumen from oil sand. Appl Energy 2009;86(9):1437–41.

[18] Ashrafi O, Navarri P, Hughes R, Lu D. Heat recovery optimization in a steam-assisted gravity drainage (SAGD) plant. Energy 2016;111:981–90.

[19] Carreon CE, Mahmoudkhani M, Alva-Argaez A, Bergerson J. Evaluation of energy efficiency options in steam assisted gravity drainage oil sands surface facilities via process integration. Appl Therm Eng 2015;87:788–802.

[20] Di Lullo G, Zhang H, Kumar A. Uncertainty in well-to-tank with combustion greenhouse gas emissions of transportation fuels derived from North American crudes. Energy 2017;128:475–86.

[21] Orellana A, Laurenzi IJ, MacLean H, Bergerson JA. Statistically enhanced model of in situ oil sands extraction operations: an evaluation of variability in greenhouse gas emissions. Environmental Science & Technology; 2017.

[22] HIS Markit. Greenhouse gas intensity of oil sands production: today and in the future [cited 2018 September 16]; Available from, https://ihsmarkit.com/forms/contactinformation.html?efid=tFSzO+2aeGqpKuUQPMWZ3Q==; 2018.

[23] Jha AK, Joshi N, Singh A. Applicability and assessment of micro-wave assisted gravity drainage (mwagd) applications in mehsana heavy oil field, India. In: SPE heavy oil conference and exhibition. Kuwait: Society of Petroleum Engineers: Kuwait City; 2011. p. 1–9.

[24] Nenniger J, Dunn S. How fast is solvent based gravity drainage?. In: Canadian international petroleum conference. Calgary, Alberta, Canada: Petroleum Society of Canada; 2008. p. 1–7.

[25] Trautman, M., D. Ehresman, N. Edmunds, G. Taylor, and M. Cimolai. Effective solvent extraction system incorporating electromagnetic heating. Google Patents, 2013; Available from: http://www.google.ca/patents/US8776877.

[26] Kasevich, R.S. Method and apparatus for in-situ radiofrequency assisted gravity drainage of oil (RAGD). Google Patents, 2008; Available from: https://www.google.com/patents/US20090050318.

[27] Pedro Vaca DP, Okoniewski M. The application of radio frequency heating technology for heavy oil and oil sands production [cited 2017 November 14]; Available from, http://www.acceleware.com/sites/all/pdf/20140604_RF_HEATING_WHITEPAPER.pdf; 2014.

[28] Nenniger, J. and E. Nenniger. Method and apparatus for stimulating heavy oil production. Google Patents, 2005; Available from: http://google.com/patents/CA2351148C?cl=no.

[29] Boone T, Sampath K. Assessment of GHG emissions associated with in-situ heavy oil recovery processes. In: World heavy oil congress; 2012. p. 1–8. Aberdeen, Scotland.

[30] Bohm M. Effective solvent extraction incorporating electromagnetic heating (ESEIEH™) [cited 2019 April 16]; Available from, https://eralberta.ca/wp-content/uploads/2017/05/ESEIEH-Interim-Report.pdf; 2018.

[31] Patterson C. An overview of oil recovery using radio frequency heating technology: the tools,techniques and processes behind the ESEIEH hydrocarbon extraction process. Presented at the World Heavy Oil Conference. Calagry, Alberta: Canada; 2016.

[32] Wise S, Patterson C. Reducing supply cost with Eseieh™ pronounced easy, SPE Canada heavy oil technical conference abstract. Calgary, Alberta, Canada: Society of Petroleum Engineers; 2016. p. 12.

[33] Sadeghi A, Hassanzadeh H, Harding T, MacFarlane B, Haghighat P. Numerical modelling of electromagnetic-based hybrid eor techniques for bitumen recovery, abstract, ECMOR XVI - 16th european conference on the mathematics of oil recovery. 2018 [Barcelona, Spain].

[34] Irani M, Saeedfar A. Equilibrium analysis of desiccated zone growth during radio-frequency heating, abstract, SPE Canada heavy oil technical conference. Calgary, Alberta, Canada: Society of Petroleum Engineers; 2018. p. 19.

[35] Sadeghi A, Hassanzadeh H, Harding TG. Modeling of desiccated zone development during electromagnetic heating of oil sands. J Pet Sci Eng 2017;154:163–71.

[36] Wilson JA, Wehking JD, Trautman M, Blue ME, Kumar R. Modeling phase change heat transfer of liquid/vapor Systems in free and porous media, abstract. 57502. ASME 2015 International Mechanical Engineering Congress and Exposition; 2015. V08BT10A055.

[37] Nimana B, Canter C, Kumar A. Life cycle assessment of greenhouse gas emissions from Canada's oil sands-derived transportation fuels. Energy 2015;88:544–54.

[38] Wise S, Patterson C. Reducing supply cost with Eseieh™ pronounced easy, abstract, SPE Canada heavy oil technical conference. Calgary, Alberta, Canada: Society of Petroleum Engineers; 2016. p. 1–12.

[39] COSIA. Water and energy recovery from flue gas. 2014 [cited 2017 June 14]; Available from: http://www.cosia.ca/uploads/files/challenges/ghg/COSIA%20Challenge%20GHG%20-%20Water%20and%20Energy%20Recovery%2016-10-14.pdf.

[40] National Insitute of Standards and Technology. Thermophysical properties of fluid systems. Standard Reference Database 2017 [cited 2017 April 17]; Available from, https://webbook.nist.gov/chemistry/fluid/.

[41] Manning FS, Thompson RE. Oilfield processing of petroleum: crude oil, vol. 2. Pennwell Books; 1995.

[42] Manning FS, Thompson RE. Oilfield processing of petroleum: natural gas, vol. 1. Pennwell Books; 1995.

[43] Nawaz M, Jobson M. Synthesis and optimization of demethanizer flowsheets for low temperature separation processes. Distillation Absorption; 2010. p. 79–84.

[44] Bogdanov I, Cambon S, Mujica M, Brisset A. Heavy oil recovery via combination of radio-frequency heating with solvent injection, abstract. SPE Canada Heavy Oil Technical Conference. Society of Petroleum Engineers; 2016.

[45] Soiket MIH, Oni AO, Kumar A. The development of a process simulation model for energy consumption and greenhouse gas emissions of a vapor solvent-based oil sands extraction and recovery process. Energy 2019;173:799–808.

[46] Titan Air. Direct fired vs. indirect fired heaters. 2016 [cited 2017 July 19]; Available from, http://blog.titan-air.com/blog/direct-fired-vs.-indirect-fired-heaters.

[47] Shah RK, Sekulic DP. Fundamentals of heat exchanger design. John Wiley & Sons; 2003.

[48] El-Houjeiri H, Vafi K, Duffy J, McNally S, Brandt A. Oil production greenhouse gas emissions estimator–OPGEE v1. 1 draft D: user guide & technical documentation. Department of Energy Resources Engineering; 2014. Available from, http://pangea.stanford.edu/departments/ere/dropbox/EAO/OPGEE/OPGEE_documentation_v2.0b.pdf.

[49] Nesbitt B. Handbook of pumps and pumping: pumping manual international. Elsevier; 2006.

[50] Turton R, Bailie RC, Whiting WB, Shaeiwitz JA. Analysis, synthesis and design of chemical processes. Pearson Education; 2008.

[51] Vlasopoulos N, Memon F, Butler D, Murphy R. Life cycle assessment of wastewater treatment technologies treating petroleum process waters. Sci Total Environ 2006;367(1):58–70.

[52] Energy Systems. Argonne national laboratory. GREET_1_2017 [cited 2017 March 10]; Available from, https://greet.es.anl.gov; 2017.

[53] Layzell DB, Shewchuk E, Sit SP, Klein M. Cogeneration options for a 33,000 bpd SAGD facility: greenhouse gas and economic implications [cited 2017 November 16]; Available from, http://www.cesarnet.ca/sites/default/files/CESAR-Scenarios-Cogeneration-Options-for-SAGD-Facility.pdf; 2016.

[54] Government of Alberta. Technical guidance for completing specified gas compliance reports [cited 2017 October 12]; Available from, http://aep.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/documents/TechGuidanceCompletingSpecGasComplianceRpts-Feb2014.pdf; 2014.

[55] Thakur A, Canter CE, Kumar A. Life-cycle energy and emission analysis of power generation from forest biomass. Appl Energy 2014;128:246–53.

[56] Aspen HYSYS. Aspen Technology Inc; 2016., Version 9.0.

[57] Alberta Electric System Operator. AESO 2016 long-term outlook [cited 2018 December 1]; Available from, https://www.aeso.ca/download/listedfiles/

AESO-2016-Long-term-Outlook-WEB.pdf; 2016.

[58] Government of Alberta. Capping oil sands emissions: transitioning to an output-based allocation approach and a legislated limit to oil sands emissions under the Climate Leadership Plan [cited 2017 September 7]; Available from, https://www.alberta.ca/climate-oilsands-emissions.aspx; 2017.

[59] Doluweera G, Jordaan S, Moore M, Keith D, Bergerson J. Evaluating the role of cogeneration for carbon management in Alberta. Energy Policy 2011;39(12):7963–74.

[61] Prakash V. 3 point estimate: triangular distribution vs beta distribution (PERT) [cited 2017 June 27]; Available from, http://www.pmchamp.com/3-point-estimate-triangular-distribution-vs-beta-distribution-pert/; 2017.

[62] Law, A.M., W.D. Kelton, and W.D. Kelton. Simulation modeling and analysis. Vol. 2. 1991, New York: McGraw-Hill.

[63] El-Houjeiri H, Vafi K, Duffy J, McNally S, Brandt A. Oil production greenhouse gas emissions estimator—OPGEE version 2 draft D: user guide & technical documentation. Stanford, USA: Department of Energy Resources Engineering. Stanford University; 2017 [cited 2017 March 13]; Available from, http://pangea.stanford.edu/departments/ere/dropbox/EAO/OPGEE/OPGEE_documentation_v2.0b.pdf.

[64] Brooks C. Facts about firetube boilers and boiler efficiency [cited 2017 July 27]; Available from, http://cleaverbrooks.com/reference-center/insights/Boiler%20Efficiency%20Guide.pdf; 2010.

[65] Stark C. Reducing energy cost through boiler efficiency. Raleigh, USA: Department of Poultry Science North Carolina State University; 2015 [cited 2016 March 16]; Available from, https://www.ncsu.edu/project/feedmill/pdf/E_Reducing%20Energy%20Cost%20Through%20Boiler%20Efficiency.pdf.

[66] International Energy Agency - Energy Technology Network. Industrial combustion boilers [cited 2017 June 27]; Available from, https://iea-etsap.org/E-TechDS/PDF/I01-ind_boilers-GS-AD-gct.pdf; 2010.

[67] Nimana B, Verma A, Di Lullo G, Rahman MM, Canter CE, Olateju B, Zhang H, Kumar A. Life cycle analysis of bitumen transportation to refineries by rail and pipeline. Environ Sci Technol 2016;51(1):680–91.

[68] Wheeler, T.J., W.R. Dreher Jr, and D.K. Banerjee. Accelerating the start-up phase for a steam assisted gravity drainage operation using radio frequency or microwave radiation. 2013, Google Patents.