Techno-Economic Analysis and GHG Emissions' Footprints of Solvent-steam-based Bitumen Extraction

by

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Abstract

The oil sands are a critical source of unconventional fossil fuel. The Canadian oil sands are among the world's largest crude oil deposits. Several oil sands extraction techniques have been developed in recent decades, including solvent-steam based bitumen extraction technology, an emerging process that has the potential to replace new greenfield projects. The solvent-steam process is based on the gravity drainage method, in which a mixture of steam and solvent is used to extract bitumen from a reservoir. The oil sands extraction process is an energy intensive process and results in large amount of greenhouse gas (GHG) emissions. There is a need to develop technologies which can help in the reduction of GHG emissions from oil sands extraction.

In this study, a process simulation model was developed to assess the economics and GHG footprint of the solvent-steam extraction method for a plant established in Alberta, Canada using natural gas and Alberta's grid mix electricity as the sources of energy. A capacity of 25,000 barrels per day of bitumen was considered, with hexane as the solvent. Sensitivity and uncertainty analyses were conducted to observe how the supply cost, energy consumption, and GHG emissions of the solvent-steam process change with changes in input parameters. The supply cost in the base case scenario is CAD 55.5/bbl at a 10% internal rate of return. Capital cost, solvent price, and transportation and blending cost affect the supply cost. The supply cost ranges from CAD 53 to 65.4 per bbl.

The results also showed that energy consumption and associated GHG emissions are 0.92 GJ/bbl and 61.75 kgCO_2eq/bbl, respectively. When uncertainty is considered, the energy consumption and GHG emissions range from 0.7 to 1.2 GJ/bbl and 49.7 to 82.6 kgCO_2eq/bbl at a 90% confidence level, respectively. The overall GHG emissions are more sensitive to the steam-to-oil ratio (SOR) and heater efficiency compared to the solvent-to-oil ratio (SvOR) and emission factors. The use of natural gas combined cycle (NGCC) and biomass for producing heat and electrical energy was also assessed in order to explore their potential to reduce the GHG emissions of the process. Natural gas used to produce steam and solvent vapor is the prime contributor (97%) to overall GHG emissions. A less emission-intensive source of energy such as biomass to generate heat could reduce emissions by up to 91%. The findings of this study will assist oil sands industries and government in evaluating the economic and environmental feasibility of the solvent-steam bitumen extraction process.

Preface

This thesis is an original work by Mustakimul Hoque under the supervision of Dr. Amit Kumar. The results from Chapter 2 were presented as: M. Hoque, A.O. Oni, and A. Kumar, "Development of a techno-economic model for the assessment of cost of bitumen using solvent-steam extraction technology," at the Canadian Chemical Engineering Conference, Energy Symposium – The Fuels Scenario (Biogas, biodiesel, biorefineries, CCS, strategy for energy transition, algae, fungi, and bacteria) in Vancouver, BC, on October 24, 2022. Chapter 2 and Chapter 3 are expected to be submitted as two separate papers to *Applied Energy* as: M. Hoque, A.O. Oni, and A. Kumar, "The development of techno-economic models for the assessment of solvent-steam bitumen extraction method" and M. Hoque, A.O. Oni, and A. Kumar, "Evaluating energy consumption and GHG emissions' footprints of the solvent-steam bitumen extraction method." The author was responsible for the concept formulation, model development, data collection and analysis, and manuscript composition. Dr. A.O. Oni assisted with process modeling and data validation and contributed to manuscript edits. Dr. Amit Kumar was the supervisory author and was involved in the concept formulation, assessment of results, and manuscript edits.

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Abbreviations

Acronyms

API	American Petroleum Institute
BFW	Boiler feed water
cEOR	Cumulative energy-oil ratio
cSOR	Cumulative steam/oil ratio
CSS	Cyclic steam simulation
DOU	De-oiling unit
dilbit	Diluted bitumen
DCF	Discounted cash flow
EM	Electromagnetic
EOR	Enhanced oil recovery
ESP	Electrical submersible pump
ESEIEH	Enhanced solvent extraction incorporating electromagnetic heating
ES-SAGD	Expanding solvent-steam

FCI	Fixed capital investment
FWKO	Free-water knockout
FGU	Fuel gas unit
GHG	Greenhouse gas
GHOST	Greenhouse gas emissions of current oil sands technologies
HTX	Heat exchanger
HU	Heating unit
HPS	High pressure separator
HCR	Hydrocarbon recovery
IC	Indirect cost
IGF	Induced gas flotation
IRR	Internal rate of return
LF	Location factor
LHV	Lower heating value
NPV	Net present value

NCG	Non-condensable gas
OT	Oil treater
OTU	Oil treatment unit
OTSG	Once-through steam generator
RUST	Regression, uncertainty, and sensitivity tool
SvOR	Solvent-to-oil ratio
SAS	Steam-alternating solvent
SAGD	Steam-assisted gravity drainage
SOR	Steam-to-oil ratio
TPS	Three-phase separator
TDIC	Total direct and indirect cost
TIC	Total indirect cost
TPI	Total project investment
TPEC	Total purchased equipment cost
VAPEX	Vapor extraction

VRU	Vapor recovery unit
WLS	Warm lime softening
WTU	Water treatment unit
WTI	West Texas Intermediate
WCS	Western Canadian Select

Symbols and units

bbl	barrel
bpd	barrel per day
CAD	Canadian dollar
gCO_2eq	gram CO_2 equivalent
GJ	gigajoule
kg	kilogram
$kgCO_2eq$	kilogram CO_2 equivalent
km	kilometer
kPa	kilopascal

kWh	kilowatt-hour
MJ	megajoule
mbpd	million barrels per day
Mt	megatonne
MWh	megawatt-hour
scfd	standard cubic feet per day
m	meter
°C	degree Celsius
%	percentage

Chapter 1: Introduction

1.1 Background

One of the primary sources of global energy production is crude oil. Approximately 100 mbpd of crude oil is produced worldwide, making up one-third of the world's total energy demand [1]. The world may run out of oil from its known supplies in 47 years [2]. Global energy use, moreover, will increase by nearly 50% by 2030 from 2020, mostly as a result of economic growth and population [3]. Excessive energy demand is one of the reasons for the oil industry to focus on unconventional oil resources. A potential solution to satisfy the world's energy demand for decades to come is to make use of the proven unconventional crude reserves of 2130 billion bbl around the globe [4]. Canada has the world's third-largest oil sands reserve. It is forecasted that the production is expected to increase approximately 2.5 mbpd in the next 25 years [5]. In an area of more than 142,000 km^2 combined, Canada's oil sands are mainly found in three regions in Alberta and Saskatchewan: Athabasca, Cold Lake, and Peace River [6]. The oil sands reserve in Alberta is about 160.1 billion bbl, which is the fourth largest in the world after Venezuela, Saudi Arabia, and Iran [7].

Oil sands are a mixture of 80-85% clay, 5-10% water, and 10-18% bitumen [8]. Bitumen is a useful resource containing a mixture of highly viscous complex hydrocarbons [9]. The primary challenge of extracting it is its low mobility in the reservoir condition [10]; its viscosity must be reduced in order to flow it out of the reservoir for processing. Steam and hydrocarbon additives are used to reduce the viscosity of bitumen [10]. Steam assisted gravity drainage (SAGD) is the most established and widely used technology for extracting bitumen [11]. In

SAGD, steam is injected into the reservoir at an elevated pressure to reduce bitumen viscosity [12]. The SAGD process has been commercially applied for heavy oil/bitumen production in Canada over several decades [13].

However, SAGD is limited because of its strong dependence on the bitumen production rate, recovery factor, high energy demand, and associated greenhouse gas (GHG) emissions [13]. The production of steam, used as a source of heat to extract bitumen in the SAGD process [14], involves the consumption of natural gas, which makes the extraction process energy and GHG emission intensive [15]. Earlier work by Nimana et al. showed that the natural gas and electrical energy consumption in SAGD release GHG emissions in the range of 8.0-34.0 gCO_2eq/MJ (approx. 52-220 $kgCO_2eq/bbl$) of bitumen, and that steam production and electricity generation are the largest contributors to GHG emissions [16]. Moreover, the extracted bitumen needs to be separated and upgraded, which also generates GHG emissions [17]. Increased bitumen production significantly contributes to Alberta's GHG emissions [18]. Oil and gas sector GHG emissions from the extraction and processing of Canadian oil sands are responsible for 174 $kgCO_2eq/bbl$ of oil, which is higher than the average North American emissions [19]. Canada's oil sands sector emits 27% of the country's total GHG emissions [20], while Alberta accounts for roughly 39% GHG emissions per year [21].

In order to reduce global warming, reducing GHG emissions is critical. Some regulations have been put in place in oil sands industries to reduce GHG emissions. For example, starting in 2030, the Alberta government will apply a \$30/tonne carbon price to its oil sands facilities to make them carbon competitive and reduce GHG emissions [21]. Canada has initiated a plan to achieve net-zero emissions by 2050 through the implementation of carbon mitigation and other technologies [22]. As a result, renewable or less GHG emission-intensive sources of energy have gained a lot of interest in the last few years.

As mentioned, steam-based oil sands extraction processes use natural gas to produce steam, which is highly GHG emission-intensive [23]. Because of the high energy consumption and GHG emissions, extensive research is underway to reduce the energy use and intensity of GHG emissions from the heavy oil extraction processes [24]. However, there are several limitations to reducing energy use without switching to a less or non-thermal-based process [25].

Several extraction methods have been proposed and are in various stages of development that can potentially offer similar or higher oil production rates at lower GHG emissions than steam-based processes. These new methods use solvent, a mixture of steam and solvent, or electromagnetic heating to extract bitumen [10]. For example, vapor extraction (VAPEX) is a thermal solvent process that dilutes the bitumen by injecting vaporized solvents inside the reservoir instead of steam [9]. Experiments by Rezaei et al. showed that superheating the solvent during injection can improve the oil recovery rate in solvent-based extraction processes [26]. The use of CO_2 with steam as an alternative to hydrocarbon solvents in solvent-based processes has also been proven to be cost-effective because solvents cost more [27]. Effective solvent extraction incorporating electromagnetic heating (ESEIEH) technology uses electromagnetic radiation to preheat the reservoir before injecting solvent to facilitate bitumen extraction [28]. Steam and propane are co-injected alternately in the steam-alternating solvent (SAS) process to reduce energy intensity and GHG emissions [29]. Solvents having close thermal properties with water in the reservoir condition are co-injected with steam in the expanding solvent-SAGD (ES-SAGD) process [30].

1.2 Literature review and research gap

The solvent-steam process is an emerging technology based on the method used in SAGD [10]. In the solvent-steam process, a mixture of steam and a suitable hydrocarbon solvent is co-injected into the reservoir to reduce the viscosity of bitumen [30]. The choice of hydrocarbon solvent is crucial because both steam and solvent vapor should have similar thermal properties in the reservoir condition [10]. Steam and solvent vapor should condense simultaneously in the reservoir in order to minimize heat loss and improve bitumen recovery rates [31]. Farouq Ali and Abad used synthetic crude, Mobil solvent, and naphtha to show that the production rate of bitumen depends on the type and concentration of solvent [32]. Experimental studies by Nasr et al. showed that using n-hexane as a solvent increased the oil drainage rate by 50% compared to SAGD [33]. They also proved that almost 95-99% of the injected solvent mixture can be recovered and reinjected, which can promote the economy of the solvent-steam process [33]. Another study showed that mixing steam and solvent to extract bitumen can reduce energy requirements by 11.5% compared to SAGD [34]. Using a mixture of steam and butane (C_4) in EnCana's Christina Lake SAGD Project showed a 30% decrease in the overall energy intensity compared to the SAGD process [35]. Steam-alternating solvent (SAS) process reduced energy consumption by almost 47% compared to SAGD [29]. An economic analysis of a 30 meters Athabasca formation indicated that the solvent-steam process is more economical (by 5%) than SAGD [36]. Suranto et al. reduced CO_2 emissions by 9.1% in hybrid steam-solvent injection compared to pure steam-based processes [37].

Most of the available studies on the solvent-steam process focus on the optimum solvent selection, solvent/steam-to-oil ratio, and recovery rate of oil. Moreover, results from experimental studies on small-scale plants do not represent the accurate performance of a process. None of the available studies performed a bottom-up analysis to evaluate the economic feasibility and environmental footprint of the solvent-steam process. Nor have the parameters which impact the bitumen production cost, energy intensity, and GHG emission intensity of the process been determined. Another concern is that the available results are based on deterministic point estimates. A range of results accounting for the uncertainty associated with the key parameters will enable a more accurate evaluation of the solvent-steam process. Different sources of energy can also be analyzed to optimize the process further. Addressing these research gaps can help the oil sands industry identify potential areas to improve costs and reduce the GHG emissions of the solvent-steam process.

1.3 Research motivations

The following statements best outline the factors that motivated this research:

- SAGD is one of the most popular processes for bitumen extraction. However, it requires a huge amount of steam to dilute bitumen in the reservoir, which makes it very energy and GHG emission intensive. A more environmentally sustainable alternative process is required. The solvent-steam process is an emerging oil sands extraction technology with a similar oil production rate and lower energy consumption and GHG emissions than SAGD.
- Most of the available studies on solvent-steam technology focus on process optimization. There is little to no information on the economic and environmental footrpints of the process. No single established model is available in the public domain.

- A bottom-up economic and GHG emission analysis of the process is mandatory to determine the viability of the process in the current oil market.
- Identifying the key parameters that impact the bitument production cost, energy consumption, and GHG emissions is critical to optimize the process.
- An evaluation of supply cost and GHG emissions is necessary for oil industries and policymakers to understand the economic and environmental footprints of the process.

1.4 Research objective

This research aims to assess the solvent-steam bitumen extraction technology in terms of its economic feasibility, energy intensity, and GHG emissions' footprint. The specific objectives are to:

- Develop a process simulation model of the solvent-steam bitumen extraction technology.
- Evaluate the economic feasibility of the produced dilbit by performing techno-economic analysis based on the assumptions and simulation model output.
- Develop a scale factor to understand the variation in the capital cost of the production plant with capacity and to determine the optimum oil production rate for the process.
- Estimate the total energy consumption and associated GHG emissions of the process.
- Assess different energy sources to reduce the energy intensity and related emissions of the process.
- Identify the key parameters that significantly impact dilbit cost, energy consumption, and GHG emissions.

1.5 Scope and limitation of the thesis

This study focuses on the asessment of the economic and environmental footprints of the solvent-steam bitumen extraction process. The economic feasibility was evaluated by comparing the estimated dilbit price with current benchmark oil prices. This research does not include a comparative analysis of the calculated costs with established bitumen extraction technologies such as SAGD. Having a model with similar assumptions will enable more accurate comparative results. In the sensitivity and uncertainty analysis, only the most important parameters were considered. The scope and limitations of this study are discussed further in Chapter 2 and Chapter 3.

1.6 Organization of thesis

This is a paper-based thesis written in research paper format so that each chapter can be read independently. This results in repetition of some assumptions, data, and results between chapters. The thesis has four chapters as described below.

Chapter 1, Introduction: This chapter describes the background, motivations of the study, research objectives, and scope and limitations of the thesis.

Chapter 2, The development of techno-economic models for the assessment of the solvent-steam bitumen extraction method: This chapter focuses on the economic analysis of the solvent-steam process by developing a discounted cash flow (DCF) model based on the process simulation. The chapter also includes solvent selection, assumptions, process description, results, and discussion. Sensitivity and uncertainty analysis were performed to determine the key cost parameters. The economic feasibility of the steam-solvent process was also evaluated in relation to the current oil market.

Chapter 3, Evaluating energy consumption and GHG emissions' footprints of the solvent-steam bitumen extraction method: This chapter expands the work done in Chapter 2 by estimating the energy cosumption and corresponding GHG emissions of the solvent-steam process using the developed process simulation model. The chapter includes assumptions, results, and discussion. The parameters with the most impact on GHG emissions were also identified from sensitivity analysis. GHG emissions for different scenarions based on utilization of different sources of energy were compared.

Chapter 4, Conclusions and recommendations: This chapter summarizes the key findings and observations of Chapter 2 and Chapter 3. The chapter also discusses recommendations for future work.

Chapter 2: The development of techno-economic models for the assessment of the solvent-steam bitumen extraction method

2.1 Introduction

Oil sands production is an essential part of Canada's economy. Oil sands accounted for 83.6% of all oil production in Alberta in the year 2022 and has supported over 400,000 jobs across the country in 2020 [38]. In addition, oil sands projects provide up to $10 billion in average annual revenue that has helped to pay for roads, schools, and hospitals across Canada [38]. Despite these benefits, the industry has been criticized because it is a large emitter of GHGs. The GHG emission intensities of oil sands extraction range from 99 to 176 kgCO_2eq/bbl, depending on the extraction technology [39]. Several design models have been proposed to reduce the GHG emissions associated with oil sands production. Most of the methods investigated in this study could have a high prospect for GHG emissions reduction. However, very little has been done to assess their economic footprint. The economic impact of these proposed methods is an important factor as it can help ascertain their economic feasibility.

Steam or condensable hydrocarbon solvents are used to reduce bitumen viscosity in a reservoir [40]. When these solvents are heated and injected into the reservoir, they transfer heat to the reservoir walls, thus increasing the mobility of bitumen for extraction. Steam is widely used by oil sands practitioners because it efficiently increases yield [41]. Cyclic steam simulation (CSS) and steam-assisted gravity drainage (SAGD) are popular technologies that use steam to extract bitumen from deep reservoirs. CSS uses a single horizontal wellbore through which high-pressure steam injection and oil extraction are done alternately. In SAGD, two horizontal wells are used for steam injection and oil extraction. Both methods have pitfalls. A large amount of steam is required, leading to high energy consumption, increased operating cost, heat loss to the overburden, and environmental impacts [13, 42]. The energy consumed by SAGD is from 6-14 GJ/m^3 (0.95-2.23 GJ/bbl) of bitumen [43]. Earlier studies also show that the supply cost of bitumen is higher than other equivalents such as West Texas Intermediate (WTI) [44].

Because of the high energy consumed and GHGs emitted by steam-based processes, extensive research has been conducted to improve them. For example, Ashrafi et al. demonstrated that improving heat recovery in SAGD could reduce natural gas consumption and GHG emissions [45]. They found that the overall GHG emissions by SAGD only decreased by 8%. Mojarab et al. worked on improving oil production performance and the thermal efficiency of SAGD in the Athabasca and Cold Lake reservoirs by implementing advanced well configurations [46]. Das investigated oil production under subcooling conditions and low-pressure operation to reduce energy consumption [47]. The co-generation electricity in the SAGD plant is also a common practice to make the extraction process more economical [41]. However, none of these measures will improve SAGD significantly. Thus, alternative oil sands extraction methods that can increase yield and improve environmental friendliness have been proposed. For example, solvent-based bitumen extraction can replace steam with hydrocarbon solvents. Considerably less energy is required to heat solvents than to heat steam [48]. However, the potential for high solvent loss is a major economic concern in solvent-based methods [49]. Electromagnetic heating technology (ESEIEH), another alternative oil sands extraction method, uses a large amount of electricity for heating, and its electromagnetic heating devices are capital-intensive [50].

The solvent-steam extraction process is also an emerging oil sands extraction technology. In this method, steam and solvent are co-injected into the bitumen reservoir to reduce viscosity and enhance production. This process can be seen as a combination of SAGD and a solvent-based process; it was developed to reduce the use of steam, improve bitumen production, and lower GHG emissions. An experimental study conducted by Ayodelle et al. showed that the oil production rate of the steam-solvent process is comparable to SAGD [34]. They also found that the solvent-steam process can reduce energy requirements by 30-40% compared to SAGD. In another study, Li and Mamora showed that the solvent-steam method can deliver a higher oil production rate and oil recovery factor with a lower cumulative steam/oil ratio (cSOR) and cumulative produced oil volume (cEOR) than pure steam injection thermal-based processes [51]. Frauenfeld et al. also showed that the solvent-steam process could recover bitumen at much lower steam-to-oil ratios (SORs) with a reasonable oil recovery rate compared to SAGD [52].

There is no doubt that the increasing carbon tax and environmental regulations are making it imperative for the steam-based processes to reduce the GHG emissions. However, the bitumen produced from this emerging technology must be economically attractive to be competitive in the global market. Most of the information on the solvent-steam is related to the evaluation of process performance using different solvents, optimizing the process, and improving thermal efficiency. There is little information on the economic feasibility of the solvent-steam process. Nasr and Ayodele argued that 95-99% of the injected solvent mixture can be recovered and reinjected, thereby promoting the economics of the solvent-steam process, but they did not include an analysis to justify these numbers [33]. Frauenfeld et al. established that the solvent-steam technology has a comparable cost to conventional SAGD at a lower energy consumption and higher oil rates based on some common economic assumptions that might not hold in an actual plant scenario [52, 53]. Their studies also discussed the impact of operating parameters such as the SOR and solvent selection on the cumulative bitumen cost from the solvent-steam process through a series of experiments based on a laboratory-scale model of the Athabasca reservoirs. However, experimental results on a small-scale plant do not reflect the economic performance of the process at a commercial scale. To the best of authors' knowledge, none of the studies performed a bottom-up economic analysis to determine the supply cost of bitumen from the solvent-steam process and compared it with the current market price, partly because there is no single established model available. Nor has there been any analysis of the economics based on the plant capacity, operating conditions, and other economic parameters on the supply cost of bitumen from solvent-steam technology.

The solvent-steam extraction method is still in the research and development phase, and a complete economic assessment will help better understand its feasibility in the current oil sands market scenario. This study developed a process simulation model for the steam-solvent extraction method and performed a thorough economic analysis to evaluate its applicability. The supply cost of dilbit from solvent-steam technology was estimated through discounted cash flow (DCF) analysis. Sensitivity and uncertainty analyses were performed to determine the key parameters that affect the cost and production of bitumen. Variations in supply cost from changing the plant capacity were used to identify the optimum production rate of bitumen for a solvent-steam process. This research has the following specific objectives:

- To develop a process simulation model for the solvent-steam bitumen extraction technology.

- To perform quantitative techno-economic analysis and to evaluate the cost of the dilbit produced.
- To identify the key parameters that impact the supply cost of the produced dilbit.
- To develop a scale factor for the solvent-steam extraction process to understand the changes in capital cost with the capacity of production.

2.2 Method

2.2.1 Process description

A schematic process diagram of the solvent-steam process is presented in Figure 1. Detailed flowsheets of different process units are provided in Figure A1-A6 of appendix. The solvent-steam extraction process was developed following the gravity drainage technology used in SAGD. Two horizontal wellbores are included to facilitate continuous circulation of the steam-solvent mixture and bitumen, an injection well and a production well. The wells are arranged so that the production well is placed below the injection well. The pressurized steam and solvent vapor mixture at an elevated temperature is injected into the reservoir through the injection well and in contact with the heavily viscous bitumen at the reservoir wall. Vaporized steam and solvent condense after transferring heat and reducing the viscosity of the bitumen as it absorbs the heat. The reservoir starts to expand, and the emulsion (the mixture of bitumen, water, condensed solvent, and other impurities) moves toward the production well by gravity. For a relatively high thermal efficiency, a low liquid level and shorter production time are important as the steam-to-oil ratio (SOR) increases with the heat consumption of the increasing liquid pool in the reservoir [54]. The liquid level inside the chamber can be characterized by the temperature difference between the injector and the producer end [55]. So, to maintain the liquid level in the reservoir, the emulsion is continuously pumped out of the reservoir through the production well using electric submersible pumps (ESPs). Then the emulsion is sent to the surface facility where it is processed.

At the surface facility, the emulsion enters the oil treatment unit (OTU), where a high-pressure separator (HPS) removes gaseous components from it. After that, it passes through the free-water knockout (FWKO) and the oil treater (OT) to separate the oil from the emulsion. The separated bitumen is mixed with a stream of diluent. Ethylene glycol is used in the heat exchanger to transfer heat from the produced water to the diluent. The blend of bitumen and diluent is called diluted bitumen, or dilbit. The dilbit is transported to the upgrading facilities through pipelines. The liquid solvent-rich mixture from the OT is sent to a hydrocarbon recovery (HCR) heater and then a solvent recovery column to separate the liquid solvent from the residue bitumen in the stream. Make-up solvent is added to the separated solvent and sent to the solvent heater. Non-condensable gases (NCGs) are produced from the top of the OT. The produced water in the OTU is sent to the de-oiling unit (DOU) for further purification.

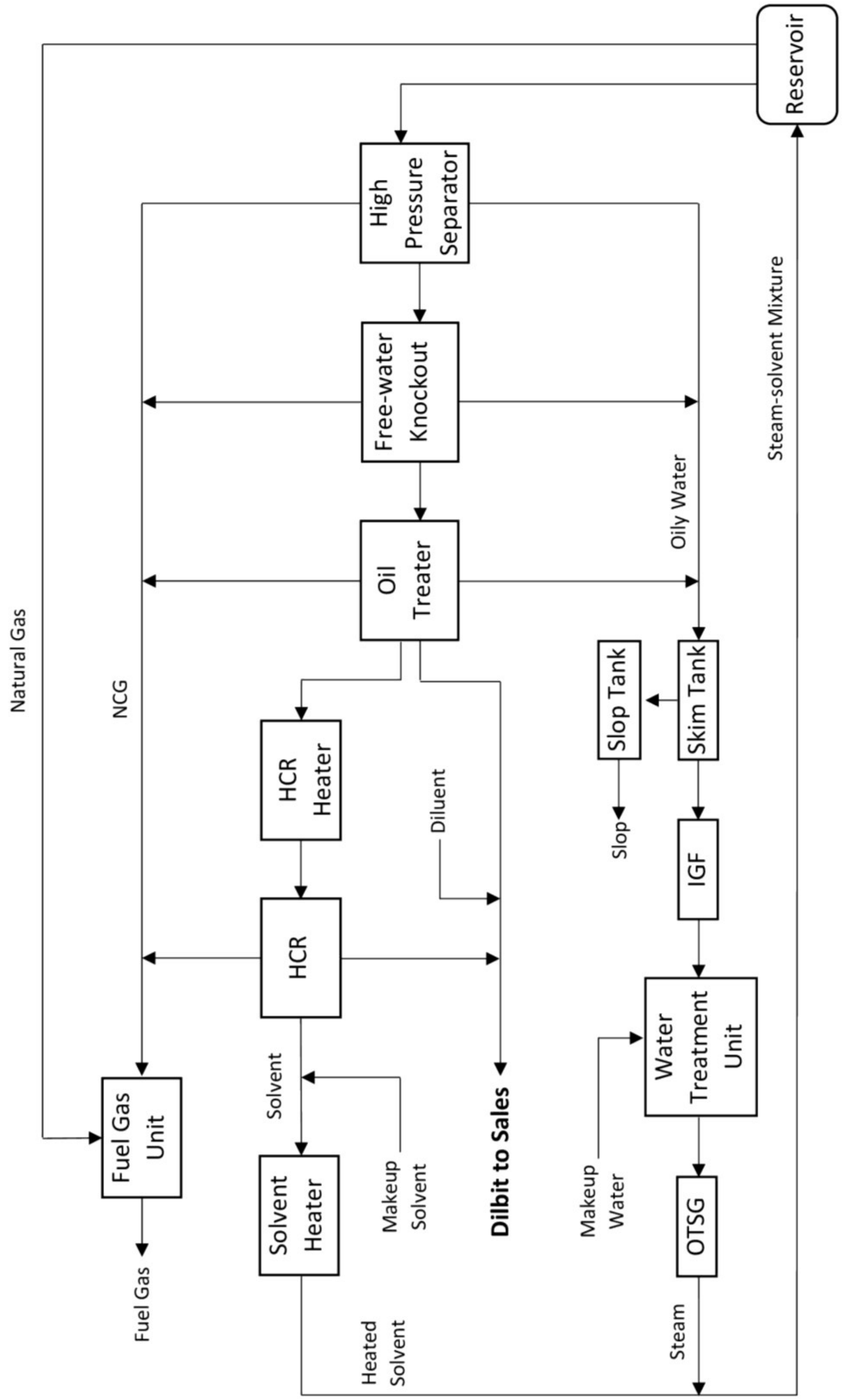

Figure 1: Schematic diagram of the solvent-steam extraction process.

Produced water entering the DOU is circulated through a series of three phase separators (skim tank, slop tank, and induced gas flotation [IGF]) where the remaining NCGs and suspended solid materials are removed. The de-oiled water from the DOU is sent to the water treatment unit (WTU) where the off gases are separated through further processing. Make-up water is added to the de-oiled water, and the combined stream, known as boiler feed water (BFW), is directed to the heating unit (HU). There is also a vapor recovery unit where vapor is separated from the NCGs and sent back to the WTU. The produced NCGs are sent to the fuel gas unit (FGU). The separated fuel gas can be used as a source of energy for the facility.

Liquid solvent from the OTU and BFW from the DOU enter the solvent heater and the once-through heat recovery steam generator (OTSG), respectively. Once the solvent and steam reach a certain temperature and pressure, the steam-solvent mixture is sent to the well-head for further bitumen extraction.

2.2.2 Solvent selection

Choosing a solvent for oil extraction depends on many factors such as reservoir condition, oil production rate, heat loss to the overburden, etc. The solvent-steam process is most effective when the solvent and the steam condense simultaneously when they reach the reservoir wall at the same saturation temperature [30]. The thermal condition of the reservoir is a crucial factor in this case. The solvent does not condense until the mole ratio of the steam and solvent vapor reaches a point where they condense simultaneously [56]. Li et al. showed that the condensation point of the steam and solvent mixture plays an important role in the dilution effects and heat transfer rate to the reservoir [57]. Moreover, they categorized solvents into three groups: light (CO_2, propane to octane), medium (naphtha), and heavy (C_{16}-C_{20}) solvents. Lighter solvents have earlier recovery and less solvent loss, whereas medium and heavier solvents have more solvent loss, which may not be economical. Solvents with condensation points close to water at the reservoir condition should be a better fit for the solvent-steam process. Hexane (C_6) has a condensation temperature closest to steam in the reservoir condition [33]. Experimental studies conducted by Nasr and Ayodele showed that the highest oil drainage rate is achieved when n-hexane is used as a solvent in the extraction process; the oil drainage rate is almost 50% higher than SAGD's [33]. Manfre Jaimes et al. performed a simulation that shows that using hexane as a solvent in the solvent-steam process significantly improves the cumulative oil production and energy-oil ratio (by 45% and 23%, respectively) [58]. Considering these advantages, hexane was selected in this study as the most suitable solvent for the solvent-steam bitumen extraction process.

2.2.3 Process modeling and simulation

The solvent-steam bitumen extraction method was modeled using Aspen HYSYS (Version 12) and used the Peng-Robinson fluid package to predict the thermophysical properties of the fluid components. For the base case scenario, a simulation model was developed for the solvent-steam process at an oil production rate of 25,000 barrels per day (bpd). Petroleum naphtha with a density of API 65 (45.4 lb/ft^3) was used as the diluent. Suitable values for the SOR and SvOR were selected based on the experimental studies of Gupta et al. [59] for optimal oil production rates. The extracted emulsion was produced at 176°C and 1600 kPa. The density of the extracted bitumen from the reservoir was assumed to have an API of 8 (63.63 lb/ft^3) [60]. No loss of ethylene glycol was considered as glycol only transfers heat from the produced water to diluent in a closed loop. All the input values and assumptions considered for the modeling the process are summarized in Table 1. Make-up solvent and water requirements were taken from material balance data.

Table 1: Model inputs for the simulation of the solvent-steam bitumen extraction process

Parameter	**Value**	**Remarks/Comments**
Steam-to-oil ratio (SOR), m^3/m^3	1.8	[59]
Solvent-to oil-ratio (SvOR), m^3/m^3	0.9	[59]
Solvent type	Hexane	[33]
Oil production rate, bpd	25,000	[49]
Solvent retention, %	5	[49, 61]
No. of well-pads	4	[62]
Reservoir temperature, °C	10	[63]
Reservoir pressure, kPa	1400	[64]
Heat losses in the reservoir	90%	[65]
Diluent to oil ratio, m^3/m^3	0.27	[10, 66]
API	8	[60]

2.2.4 Techno-economic assessment

The techno-economic assessment was performed using the developed process simulation model results and literature data. A plant established in Alberta with a 30-year lifetime is considered. All the currencies are in Canadian dollars (CAD) unless mentioned otherwise. A discounted cash flow (DCF) model was developed from the estimated capital and operating costs to determine the dilbit supply cost and evaluate the economic performance of the solvent-steam process. The supply cost is the selling price of oil required to compensate for all the expenses at a specific rate of return. In this analysis, the supply cost of bitumen was determined for a 10% internal rate of return (IRR) [44]. A flat 2% inflation rate for different cost components was assumed based on the year-over-year increase in the consumer price index throughout the plant operating life [67]. The assumptions used in the techno-economic analysis of the solvent-steam process are listed in Table 2.

Table 2: Factors considered in the techno-economic analysis

Parameter	**Value**	**Remarks/Comments**
Base year	2021	-
Currency	CAD	-
Discount rate	10%	[44]
Inflation rate	2%	[67]
Plant characteristics:		
Lifetime	30 years	[49]
Location	Alberta	-
Plant capacity	25,000 bpd of oil	[49]
Plant operating factor	95%	[68]

2.2.4.1 Capital and operating cost

The total capital cost was determined by adding the fixed capital investment (FCI) and the working capital cost. The well-pad and drilling costs for the extraction of bitumen were estimated from industry reports on SAGD projects [43, 69]. These are listed in Table 3. Since the extraction of bitumen from the solvent-steam process follows a similar principle as that used in SAGD, similar unit costs as a function of plant capacity were assumed. However, it was considered the upper bound of the available pricing for well-pair drilling, which makes the capital cost analysis more conservative. The rest of the processing equipment costs were determined using Aspen Process Economic Analyzer (APEA) by equipment sizing and adjusting material selection based on operating conditions. The total project investment (TPI) or total capital cost was estimated based on the assumptions from Peters et al. [70]. These are shown in Table 4. The operating cost refers to the expenses required to keep the plant up and running and comprises direct and indirect costs. The direct costs are listed in Table 5. These costs include utilities, labor, maintenance, transportation, and blending, and are extracted from different sources and available data based on the current market price in Alberta.

Utilities are essential in that they make up for material losses and keep the process going. Utilities refer to the make-up solvent, make-up water, natural gas, and electricity. Based on the assumptions in this study, 5% of the injected solvent is retained in the reservoir during extraction [49, 61]. Energy requirements for the operation of the plant were based on the developed simulation model. This study considered that the produced dilbit will be transported from Edmonton, Alberta to Cushing, Oklahoma. The transportation cost was calculated from the data developed in earlier studies by Sapkota et al. [71] and Verma et al. [72] for the scenario with no diluent return. Bitumen in its natural state is not suitable to flow through pipelines because of its viscous nature. Diluent (petroleum naphtha) is mixed with the recovered bitumen to facilitate transportation. Indirect costs such as general and administrative costs, plant overhead, depreciation, etc., are based on the assumptions given in Table 6.

Table 3: Capital cost assumptions

Parameter	**Value**	**Remarks/Comments**
No. of well-pairs per well-pad	8	[9]
Cost of well-pad, CAD/bbl	4527	[43]
Cost of drilling, mil CAD/well-pair	4.34	[69]
Cost of pipelines, CAD/bbl	2263	[43]

Table 4: Assumptions for estimating the total project investment (TPI) [70]

Parameter	**Assumption**
Total purchase equipment cost (TPEC)	100% of TPEC
Total installed cost (TIC)	302% of TPEC
Indirect cost (IC)	89% of TPEC
Total direct and indirect cost (TDIC)	TIC + IC
Contingency	20% of TDIC
Fixed capital investment (FCI)	TDIC + contingency
Location factor (LF)	10% of FCI
Total project investment (TPI)	FCI + LF

Table 5: Operating cost input values

Parameter	Value	Remarks/Comments
Water, CAD/bbl	1.25	[73]
Hexane, CAD/kg	1.08	[74]
Glycol, CAD/kg	2.32	[75]
Diluent, CAD/bbl	61.9	[76]
Electricity, CAD/MWh	68.50	[77]
Natural gas, CAD/MWh	12.53	[77]
Average labor wage, CAD/hr	39.89	[78]
Number of operating labors	15	Assumed

Table 6: Operating cost assumptions [49]

Parameter	Assumption
Plant overhead	70.8% of operating labor + 3.6% of FCI
Maintenance and repairs	6% of FCI
Depreciation	10% of FCI
Laboratory charges	15% of operating labor
Operating charges	0.9% of FCI
Direct supervisory or clerical labor charges	18% of operating labor

2.2.4.2 Scale factor

The relationship between investment cost and plant capacity can be determined by evaluating the scale factor of a plant. The cost-to-capacity method from Tribe and Alpine was used to estimate the scale factor for the solvent-steam extraction process [49, 79]. Costs for a wide range of plant capacities were analyzed. According to the cost-to-capacity method, a scale factor less than unity implies increasing returns to scale whereas a scale factor equal to or greater than unity means constant or decreasing returns to scale. The equipment ratings change as the production capacity changes; thus, the capital cost and the bitumen production cost also change.

2.2.4.3 Sensitivity and uncertainty analysis

Sensitivity analysis is important in that it helps determine how changes in input parameters affect the output(s). In the developed DCF model for the base case, the supply cost was determined based on some fixed input data and assumptions that are variable in real life. The costs of equipment, utilities, transportation, etc., are volatile and depend on the economy, plant location, and many other factors. This variation results in uncertainty in the calculated supply cost. The Morris method is used to identify the most sensitive inputs by taking a range of data for the input variables and determining their impact on the output. The sensitivity is realized by showing the relationship between the Morris standard deviation and the mean value to observe changes in different input parameters. For each input parameter, a higher standard deviation refers to non-linearity, and a larger Morris mean represents more impact on the output. The output is highly sensitive to the input parameters that have a high mean on the Morris plot. The Morris plot shows us a qualitative analysis of the key parameters. After identifying the most sensitive parameters that affect the supply cost, an uncertainty analysis was performed using Monte Carlo simulation for 10,000 iterations. Uniform distributions are assumed for the input parameters. The uncertainty analysis determines the probable range at which the supply cost may vary for a range of input parameters. Table 7 presents the lower and upper bound for each of the input parameters considered. Considering that the solvent-steam technology is still in development phase, values of the input parameters available in the literature vary widely. A ±30% of the base input values were considered to reflect the most probable ranges found in the literature and market data. Similar ranges can also be found in techno-economic analyses of solvent-based and ESEIEH process by Isabel et al. [49, 50]. The sensitivity and uncertainty analyses were performed using the RUST model developed by Di Lullo et al. [80].

Table 7: Input ranges for sensitivity analysis

Parameter	**Range**	**Remarks/ Comments**
Capital cost, mil CAD	3.97-7.37	-
IRR, %	7-13	[44, 50]
Hexane, CAD/kg	0.75-1.40	[74]
Transportation, CAD/bbl	6.3-11.7	[72]
Make-up water, CAD/m^3	0.88-1.63	[73]
Electricity, CAD/GJ	13.32-24.74	[77]
Natural gas, CAD/GJ	2.44-4.52	[77]
Labor, CAD/hr	27.92-51.86	[78]
Diluent, CAD/bbl	43.44-80.47	[76]

2.3 Results

2.3.1 Material balance

Conducting the material balance of a process is important for equipment sizing, identifying and quantifying material losses, monitoring improvements and yield of products, and evaluating economic benefits. The material balance of the solvent-steam process was determined by exploring material flows in and out of every stage. Table 8 provides the overall material balance of the extraction process. The table shows each material input into and out of the process. The process's overall material losses or material used can be determined in this manner. The materials supplied to the process or produced by the process include solvent, boiler feed water (BFW), diluent, natural gas, produced gases, bitumen, and glycol. Increasing these materials' production or use could have a significant economic impact on the process.

Regarding consumption or losses, the need to replace solvent losses is critical to the process. The primary aim of introducing solvents is to reduce GHG emissions; however, losing solvents can be detrimental to the economic sustainability of the process. From the material balance calculations, the total make-up solvent required is 0.1 bbl/bbl, which is 11.5% percent of the input solvent. As mentioned earlier, it was assumed that 5% (0.05 bbl/bbl) solvent is retained in the reservoir. This subject (solvent losses in the reservoir) is not well understood even for solvent extraction processes. Different publications show a wide range of solvent loss in the bitumen reservoir. Toro Monsalve et al. [50] and Safaei et al. [61] reported a 5% solvent loss for a solvent-based bitumen extraction process. A value of 20% solvent retained in the reservoir has been reported in another study for a solvent-based extraction process [81]. Jurinak and Soni studied the co-injection of solvent with steam in a fractured steam flood through a numerical analysis and found out that although co-injection is feasible, it reduces steam use by half; however, an increase in the oil produced results in 0.3 barrels of solvent to the reservoir [48]. Over 50% of the solvent loss is a result of solvent trapped in the bitumen that cannot be recovered from the oil treatment unit. An attempt to recover these solvents will jeopardize the purity of the solvent, which is maintained at 99.7%.

The BFW needed for extraction is an integral part of the extraction process. It was estimated that the total water to make up for the losses to the reservoir and in the central processing facility is 0.04 m^3/bbl. The water (steam) losses are primarily through the OTSG blowdown. Although the water blowdown accounts for 8% of the BFW, it represents 67.4% of the overall water losses in the process. Water blowdown is necessary to reduce the amount of recycled total dissolved solids in the BFW and to prolong the life of the boiler (OTSG). The remaining losses are in the reservoir and steam pipes and are negligible. These values are typical for conventional steam-based extraction processes.

The diluent added to the produced bitumen accounts for 27% (by volume) of the dilbit transported through the pipelines. The addition of diluent is necessary to lower the viscosity (to 26.42 cP) of the extracted bitumen to meet pipeline specifications. A SAGD process producing the same quality and amount of bitumen will require 30% diluent to meet pipeline specifications. The required diluent decreases by 3% because of the solvent trapped in the bitumen during separation. Asphaltene precipitation due to solvent extraction in the reservoir could also be an important factor reducing the amount of diluent used. However, this study did not account for the precipitation of asphaltene in the analysis as it will not significantly impact the outcome.

The produced gas and natural gas are used for heating purposes. Mixing these gases for heating is common practice in the conventional steam-based extraction process. The contribution of the produced gas is less than 1%. It is also important to mention that the mixture contains some parts of the solvent that were separated in the vapor recovery unit.

Table 8: Material balance of the solvent-steam extraction process based on developed process simulation model

Material	**Input**	**Output**
Solvent, bbl/bbl	0.14	0.13
Boiler feed water, m^3/bbl	0.35	0.28
Produced gases, scfd/bbl	-	128.4
Natural gas, scfd/bbl	24.1	-
Glycol, bbl/bbl	1.2	1.2
Diluent, bbl/bbl	0.27	-

*No loss was considered for glycol

2.3.2 Techno-economic assessment

In this section, the focus is on understanding the effect of capital and operating costs on bitumen production costs and how integrating solvent into steam-based bitumen extraction influences the production cost. Table 9 presents the solvent-steam extraction technology's cost breakdown (CAPEX and OPEX). The bitumen supply cost was estimated to be CAD 55.5/bbl at a 10% IRR. The capital cost and operating cost were estimated to be CAD 567 million and CAD 257 million per year, respectively.

Table 9: Breakdown of supply cost of bitumen

Parameter	**Cost per bbl (CAD/bbl)**
Capital costs:	
Oil treatment unit	0.33
Heating unit	1.18
Well-pads and drilling	2.55
Others	0.62
Operating costs:	
Labor cost	0.13
Maintenance cost	3.10
Transportation and blending	23.36
Plant overhead, laboratory, and operating charges	2.42
Depreciation	5.16
Utility cost	12.89
General and administrative cost	3.76
Total supply cost	**55.50**

2.3.2.1 Capital cost

The main capital cost components are the well-pads and drilling, which make up over 50% of the total capital cost. Well-pads comprise the well-pairs and are the central area for injecting solvents/steam and producing emulsions (bitumen). Each well-pair is connected to a main header line that leads to a central processing unit, where bitumen is separated. The well-pads are designed to handle high temperatures and high pressures, usually over 180°C and 10,000 psi at their deepest point. The high-quality material needed for the construction of well-pads makes them expensive. Furthermore, the areas needed for a well-pad are usually large, about 5-10 acres; this size requirement also contributes to the high cost of the well-pads. The heating unit is the second most capital-intensive unit and comprises an OTSG and a solvent heater. This unit accounts for 25% of the capital cost. The OTSG is different than a typical boiler; it handles a large volume of water at high pressure and high temperature. Thus, a large surface area to heat and high-quality construction materials, making the OTSG expensive. The OTSG's tubes can be exposed to salt deposition from the produced water in the bitumen reservoir that contains soluble and non-soluble oil/organics and suspended and dissolved solids, as well as the chemicals used in the process. Although the produced water is treated in the water treatment unit, the OTSG is still susceptible to a high amount of salt (generally referred to as the total dissolved solids). Because of this risk, its tubes are designed with good quality material to withstand corrosion. The oil treatment unit accounts for 7% of the capital cost. The major cost components of this unit are the solvent recovery heater and solvent recovery column; they account for 33% and 17.8% of the oil treatment unit capital cost, respectively. This equipment is added for the separation of bitumen or the recovery of solvent. Both pieces of equipment are additional costs to the extraction process that are not part of steam-based extraction processes. However, their contributions are not significant; they account for 6% of the overall capital cost. That said, an increase in the SvOR would increase the size and capital costs of this equipment because of the increase in the solvent flow rate. It is important to note that as the SvOR increases, the SOR must be lowered to achieve the same volume of bitumen. Thus, the cost of the OTSG will decrease as the SvOR increases.

Lastly, the water treatment unit, de-oiling unit, and VR unit have less impact on the supply cost; they account for 7% of the overall capital cost. As reported in an earlier study, Toro Monsalve et al., the costs of these units are generally low [50].

2.3.2.2 Operating cost

Operating costs include utilities, labor, and transportation, which are a significant part of the solvent-steam extraction process. They account for 91.6% of the total supply cost. Transportation and blending costs account for 50% of the total operating cost. This cost is from the addition of diluent to bitumen to meet pipeline specifications and transporting dilbit (from Edmonton, Alberta to Cushing, Oklahoma). The high cost of diluent significantly impacts the transportation of bitumen. Diluent accounts for about 60% of the transportation and blending cost. Adding diluent to the produced bitumen increases the volume of transported dilbit, thus increasing the overall transportation cost. As mentioned earlier, diluent accounts for 27% of the transported dilbit. The volume of diluent needed for blending could range from 20% to 50% depending on the bitumen API value and the type of diluent used. For example, an earlier case study shows that about 46% diluent is needed to meet the pipeline specification for a bitumen API value of 7.1 [65]. Literature shows that bitumen with an API of 8.5 requires dilbit with 33% naphtha (by volume) to meet pipeline specifications [60]. The use of natural gas condensate as diluent could make up about 35-40% dilbit by volume [82]. However, it is fair to say that the most common ratio of bitumen to diluent is roughly 28% diluent to 72% bitumen, or one barrel of bitumen requires about 0.39 barrels of diluent [83]. The bitumen API value in this study is 8.2. This value is lower than the value reported in the literature because in earlier work, some solvents were trapped in the bitumen, which increased the API value from 8.2 to

10.2 [60]. The unit cost of diluent is generally high because of many factors such as availability. Currently, aside from conventional diluents such as naphtha, natural gas condensate, etc., affordable products are sourced. Furthermore, in this study, it was pipeline transportation was considered because it is cheaper than railway transportation (Verma et al. [72]). The current analysis shows that if railway transportation of dilbit (with no diluent return) is considered, the new supply cost of dilbit will increase by 18.5%.

Utilities comprise the cost of make-up solvent (hexane), make-up water, natural gas, and electricity. They make up 27% of the operating cost. The make-up solvent accounts for a significant part (21%). Natural gas, electricity, and make-up water account for 5.5%, 1%, and 0.1%, respectively. As mentioned earlier, make-up solvent is a result of losses in the reservoir and the processing facilities. The solvent, hexane, is widely used in many industries such as food processing and pharmaceutical. So, hexane demand is high, which also increases its market price. In addition, the unit cost of hexane is high because pure hexane is expensive to produce as it requires careful distillation to separate it from hydrocarbons with a similar boiling point. Unfortunately, it is the most suitable solvent for solvent-steam bitumen extraction.

The natural gas consumption in the OTSG and HCR heater is another important utility that accounts for 5.5% of the operating cost. This consumption was compared to a steam-based process (SAGD) producing the same amount of bitumen. The solvent-steam process lowers fuel consumption by 25.5% compared to a steam-based process operating with an SOR of 3.0. When the SvOR was lowered from 0.9 to 0.7, natural gas was reduced by 27.5% compared to the SAGD process (with a SOR of 3.0). These results are valuable for decision-making when considering the environmental impact of the solvent-steam extraction process. Depreciation, maintenance, and overhead charges have little or no impact on the operating cost.

2.3.2.3 Sensitivity and uncertainty analysis

Figure 2 shows the sensitivity results using the Morris method. In the Morris plot, parameters with a large Morris mean are sensitive to the output (supply) while those with high standard deviation indicate the interaction effect with one or more parameters. The diluent and capital cost are the most sensitive parameters; they have the highest Morris mean. IRR, transportation cost, hexane, and natural gas are moderately sensitive. Natural gas, make-up water, labor costs, and electricity price have very low means and standard deviations, hence they are less significant to the supply cost and are not considered in the uncertainty analysis.

Figure 3 shows the uncertainty plot of the supply cost. From the analysis, the supply cost of the solvent-steam bitumen extraction process ranges from CAD 53.0 to CAD 65.4 per barrel at a 90% confidence level. The range in the uncertainty value is mostly influenced by the diluent cost, capital cost, IRR, and transportation cost.

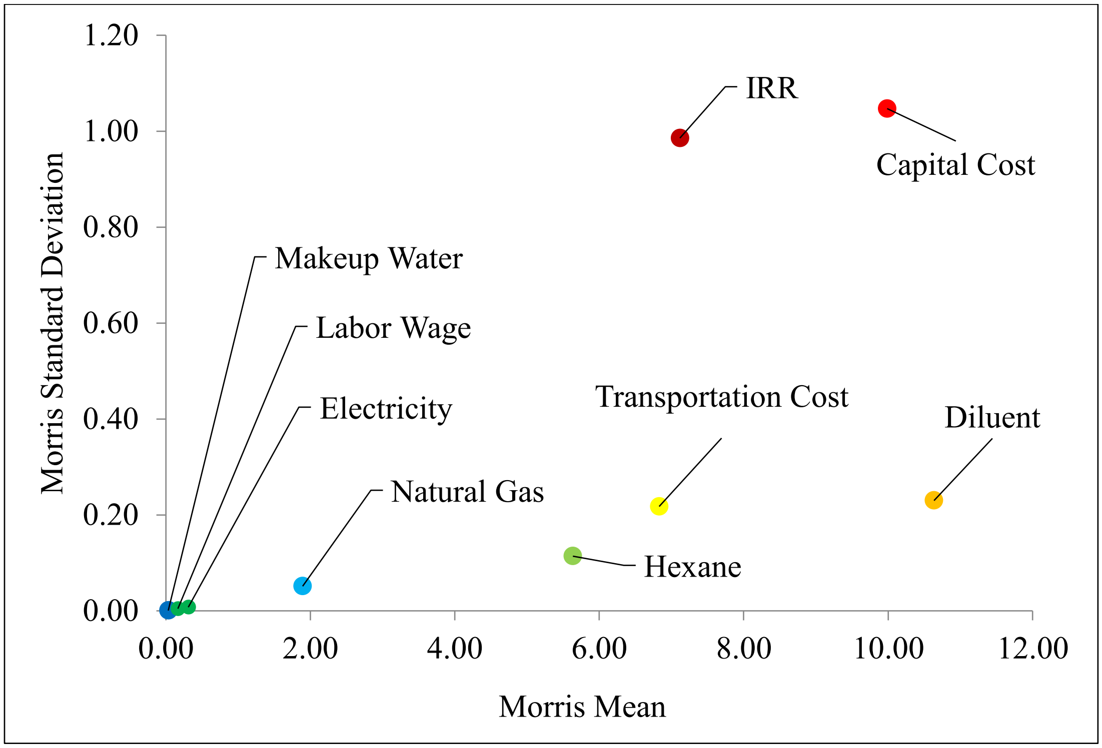

Figure 2: Morris sensitivity analysis of supply cost.

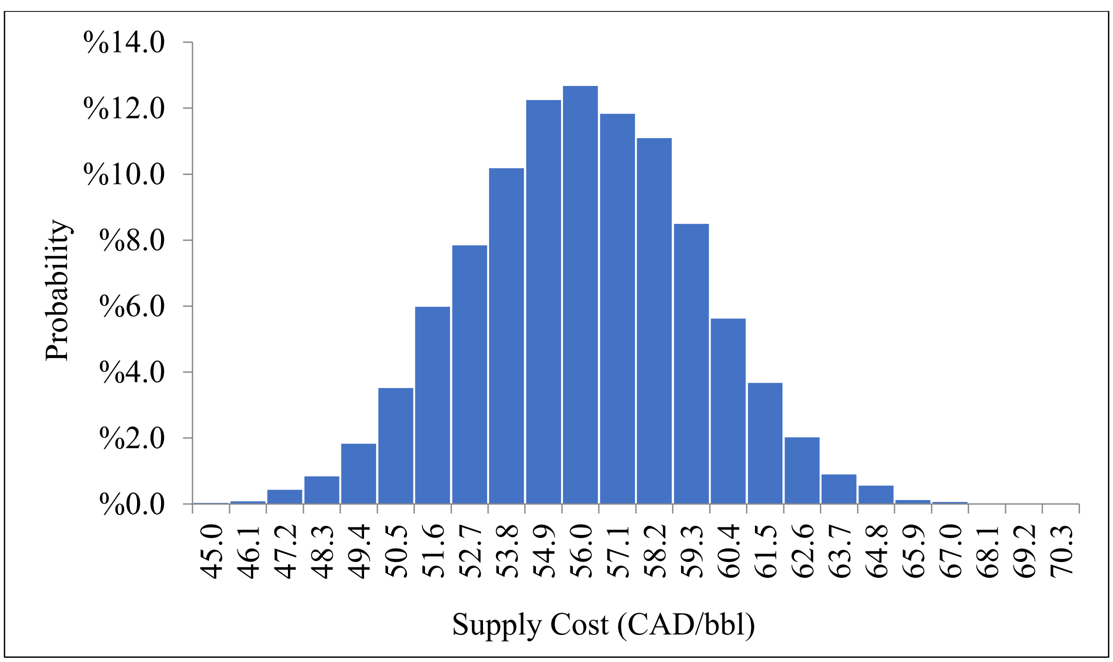

Figure 3: Uncertainty analysis of supply cost.

2.3.3 Plant capacity

The economics of a production plant may vary significantly depending on its capacity. To find the optimal production rate, variations in the cost components (e.g., capital, operating, and supply costs) of the solvent-steam process was investigated over a wide range of plant capacities (from 5,000 to 85,000 bpd). Figure 4 shows changes in capital and operating cost with changes in plant capacity. As the plant capacity goes up, both the total capital and total operating cost increase. However, the increase in the total operating cost is steeper than in the total capital cost. The total capital cost is higher than the total operating cost for lower capacity plants. For a 55,000 bpd production rate, almost the same values are found for capital and operating costs. As the plant capacity increases, the total operating cost exceeds the total capital cost. This is because the total capital cost constitutes fixed costs (i.e., for well-heads and pipeline drilling) that are distributed across the dilbit costs, resulting in a higher cost per barrel of oil for a lower production rate. The total operating cost, on the other hand, comprises variable parameters that become dominant as the dilbit production rate increases.

Variations in supply cost with changes in oil production rates from the solvent-steam process are presented in Figure 5. The lowest supply cost was CAD 51.01/bbl at 85,000 bpd and the highest was CAD 75.35/bbl at 5,000 bpd plant capacity. The calculated scale factor for the developed solvent-steam extraction process is 0.80. The supply cost decreases with an increase in plant capacity because the scale factor is less than unity. The drop in supply cost is steeper for plants with lower capacity, and the curve gradually flattens as the plant capacity increases. The considered fixed costs in the economic model are responsible for this trend. From this analysis, it is clear that larger solvent-steam bitumen extraction plants with 25,000 bpd of oil production or more are economically more viable than smaller capacity plants. A similar trend can be seen for SAGD plants. Depending on the SAGD plant capacity and design, the supply cost can be around US$10 per barrel [8]. The Hangingstone SAGD Project operators in Alberta propose increasing their plant capacity from 12,000 bpd to 80,000 bpd of oil [84].

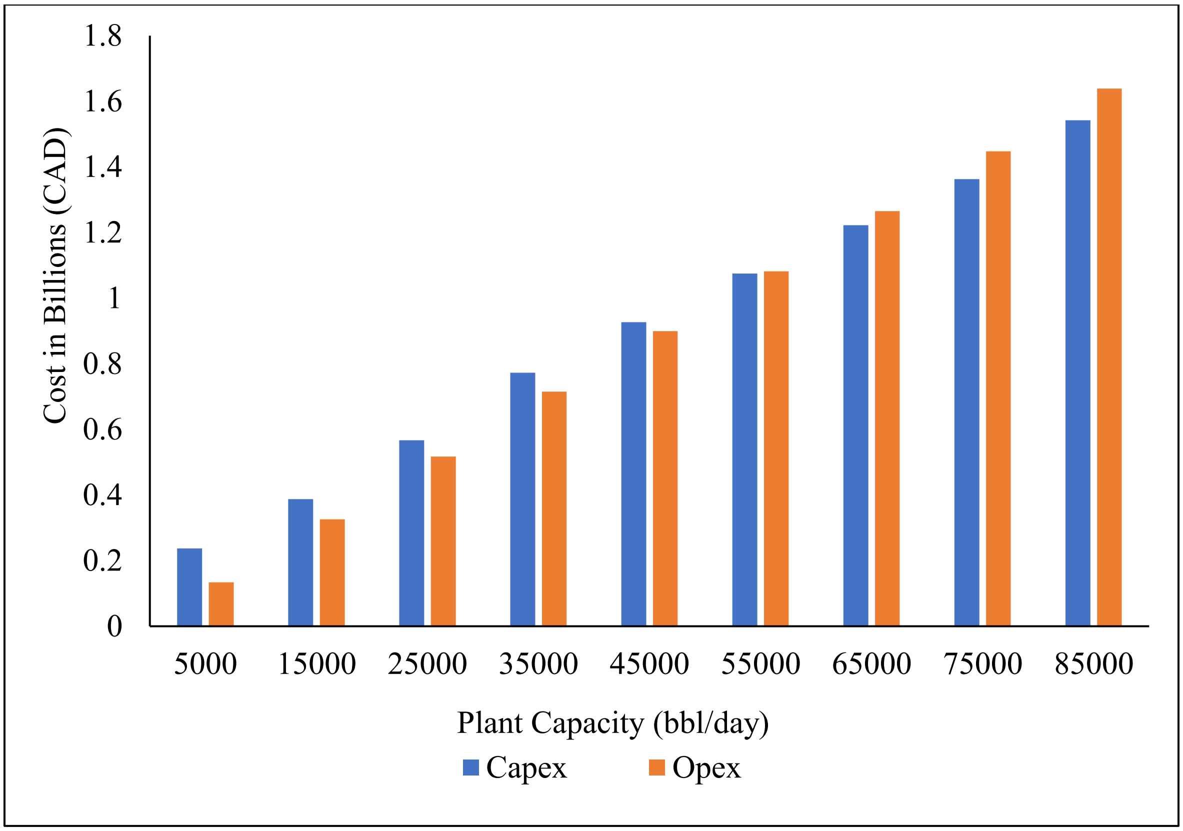

Figure 4: Capital and operating cost vs plant capacity.

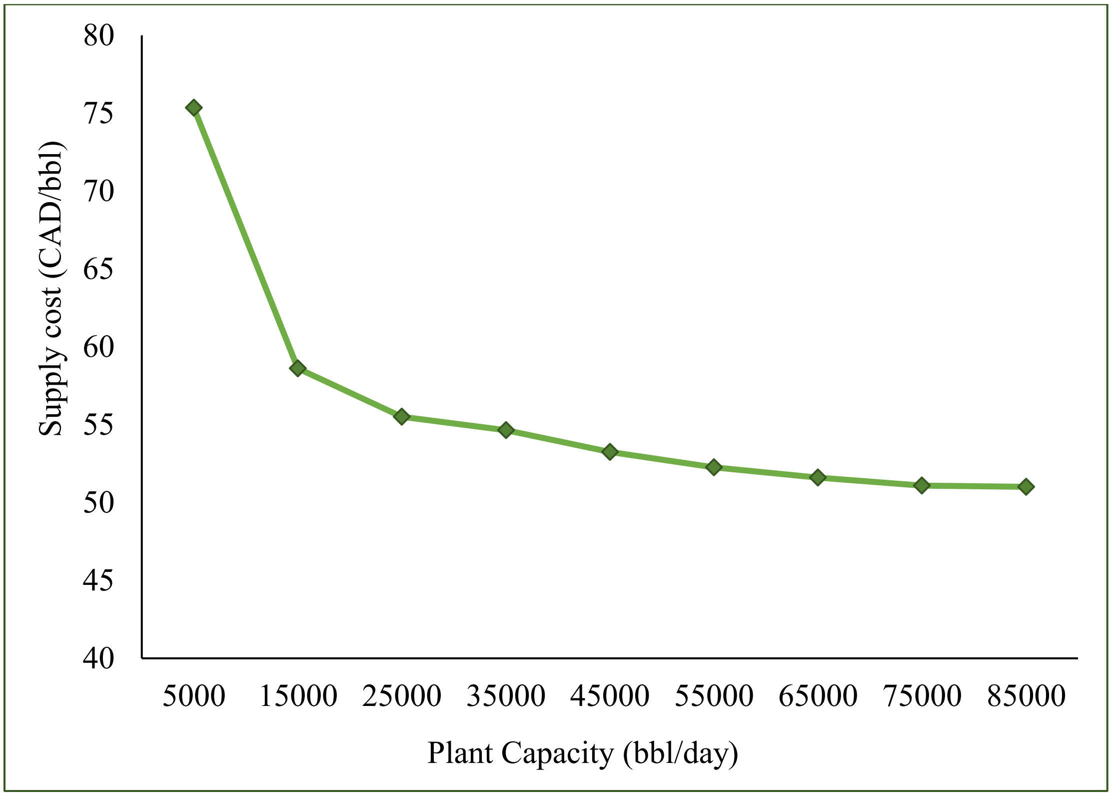

Figure 5: Supply cost vs plant capacity.

2.4 Discussion

In the previous section, the overall cost and the key parameters that affect the supply cost of the solvent-steam bitumen extraction method were discussed. It is also important to discuss the economic performance of the process by comparing the estimated supply cost with that of other established bitumen extraction technologies. Changes in economic performance should be evaluated and compared to steam and solvent-based methods since the solvent-steam process is a combination of both. This will help us understand the feasibility of the solvent-steam process in the current oil market. A report on a greenfield SAGD project showed that the supply cost of bitumen is around CAD 64.62/bbl at a 10% discount rate, including transportation and blending costs [44]. The cost breakdown of the SAGD supply cost from the report shows that the capital investment is the most significant supply cost component of SAGD. As mentioned before, the OTSG is a cost-intensive part of the steam-based bitumen extraction process. Conventional OTSGs produce steam at 75-80%, which contributes to the high cost of producing steam [85]. SAGD plants use only steam to extract bitumen, so an OTSG with a larger capacity is required, thus increasing capital costs. However, the amount of steam required in the solvent-steam process is reduced by using a mixture of steam and solvent, which also lowers the cost of the OTSG and the overall capital cost. To produce 25,000 bpd of oil, the SAGD process requires 110% more steam than the solvent-steam process [43]. Additionally, as the solvent-steam method uses less steam during the extraction process, the cost of natural gas required for producing steam is also lower than for SAGD.

The supply cost of dilbit from the solvent-based bitumen extraction process ranges from CAD 48.2 to 63.7 per bbl; the make-up solvent cost makes up the bulk of this (36%) [49]. Solvent loss is a major concern in solvent-based processes. Solvent is expensive and since only solvent is used to extract bitumen, the cost of make-up solvent is high in solvent-based technologies. However, in the solvent-steam process, using a blend of steam and solvent reduces the cost of make-up solvent by nearly 50% compared to the solvent-based process.

The supply cost of the solvent-steam method is competitive with the steam- and solvent-based bitumen extraction technologies discussed above. However, straight-forward comparisons might not be entirely accurate since oil prices vary with oil quality and the oil produced from each process has different compositions. Direct comparison will be more accurate when the costs are evaluated based on identical assumptions and the final products have similar properties after the produced bitumen is upgraded.

It is more appropriate to compare the supply cost with current benchmark oil prices in order to evaluate the profitability of solvent-steam technology in today's oil market. The most commonly used benchmark for oil in Canada is Western Canadian Select (WCS). According to the Canada Energy Regulator, the WCS price in 2021 was USD 52/bbl [77]. At this supply cost, the solvent-steam process seems viable if the produced dilbit is sold at Hardisty (Alberta, Canada). However, in this analysis, pipeline transportation of the produced dilbit to Cushing, Oklahoma was considered. West Texas Intermediate (WTI) is the primary benchmark for buying and selling oil in North America, oil sourced mainly from inland Texas. The WTI oil price in 2021 was USD 64.5/bbl [77]. The oil market uses specific oil compositions to benchmark crude oil prices at different locations. WTI is one of the highest quality oils in the world, with a sulphur content of 0.34% [86]. WCS is the Canada's largest crude oil stream, often regarded as a dilbit stream that primarily consists of non-upgraded bitumen. WCS has a much higher blended sulphur content (3.0-3.5%) [87]. The lower the sulphur content, the easier and less energy intensive the oil is to refine. Hence, the oil price from WCS is sold at a lower price than WTI's. Based on the available historical data, it is safe to assume an approximately 25% discount on the WCS price over WTI [88]. Assuming that the produced oil can be sold at the same discounted price, the dilbit price will be approximately CAD 60/bbl. The estimated supply cost from our analysis seems economically feasible compared to this price. Also, because of the in situ partial upgrading of the recovered oil from solvent-steam technology, the selling price may improve further.

2.5 Conclusion

In this study, a process simulation model was developed for the solvent-steam bitumen extraction technology. A production capacity of 25,000 bpd of bitumen was considered for a plant established in Alberta. Hexane was chosen as the ideal solvent for the process. A techno-economic model was developed to calculate the supply cost of dilbit and evaluate its economic performance. The estimated supply cost is CAD 55.5/bbl at a 10% IRR. When uncertainty is considered, the supply cost ranges from CAD 53.0 to 65.4 per bbl at a 90% confidence level. The sensitivity analysis shows that the supply cost is most sensitive to the capital investment, diluent cost, transportation and blending cost, and IRR. These parameters were found to be the most important when the economic performance of the process was done. The calculated scale factor is 0.80, which suggests that the project will be more profitable for a larger-scale plant. Compared to current market prices, the estimated supply cost of the solvent-steam extraction process is economically attractive. The solvent-steam process is also cost competitive with currently established technologies and can be considered a replacement for new greenfield projects. This study will help the oil industry and policymakers understand the feasibility of the solvent-steam bitumen extraction process in the current oil market.

Chapter 3: Evaluating energy consumption and GHG emissions' footprints of the solvent-steam bitumen extraction method

3.1 Introduction

Oil sands bitumen has very low mobility in the reservoir condition, which makes it challenging to extract [89]. Bitumen extraction processes require considerable energy, mostly from the combustion of natural gas and electricity, resulting in high GHG emissions. The oil sands industry, therefore, is seeking alternative bitumen extraction technologies to lower GHG emissions.

Steam assisted gravity drainage (SAGD) is one of the most popular bitumen extraction technologies [11]. In SAGD, two horizontal wellbores are drilled, one above the other, to facilitate simultaneous steam injection and bitumen extraction. The injected steam comes in contact with the reservoir wall and dilutes the bitumen. The primary source of GHG emissions in the steam-based oil sands extraction process is from the combustion of fossil fuel for steam generation [90]. SAGD has high energy demand and emissions from high water consumption [48]. With the increasing carbon tax and rigid environmental regulations, steam-based bitumen extraction processes such as SAGD are focusing on implementing technologies which can help in reduction of GHG emissions. Orellana et al. estimated that the emissions from the SAGD process in Alberta are in the range of 49 to 102 kgCO_2eq/bbl with a median of 68 kgCO_2eq/bbl [91]. Reducing GHG emissions to mitigate climate change while meeting the world's energy demand is a significant challenge. In Canada, GHG emissions from the oil and gas industry are projected to reach 233 Mt of CO_2 annually by 2030 [92]. Canada initiated a climate plan to reduce its GHG emissions to 40-50% by 2030 to achieve a net-zero emissions future by 2050 [92]. So, interest in less energy-intensive oil extraction technologies to reduce the associated environmental impact has been growing steadily. Ashrafi et al. found approximately 8% energy savings and 61,700 tonnes fewer CO_2 equivalent GHG emissions per year could be achieved by reducing the amount of natural gas used in a typical SAGD plant [45]. Nimana et al. showed that the steam-to-oil ratio (SOR) had the most influence on SAGD GHG emissions and that these emissions can be reduced by 33-48% through cogeneration [16]. Some studies have considered the use of renewable energy sources such as solar or nuclear power in oil sands extraction to reduce the environmental impact [93, 94].

Canada's oil sands companies are exploring new extraction technologies that use less energy and cause less GHG emissions [6]. Currently, expanding solvent addition and electromagnetic SAGD are the two leading methods for enhancing bitumen production [95]. The vapor extraction (VAPEX) process uses gravity drainage to recover oil by injecting vaporized hydrocarbon solvent (propane or butane) into the reservoir; this method consumes less energy than SAGD [96]. As a result, the overall environmental impact is significantly reduced since the production of steam is not required for VAPEX [25]. CO_2 injection into the reservoir has also been implemented to improve oil recovery in conventional technologies such as VAPEX or SAGD [97]. In the electromagnetic heating (EM) method, a radio frequency antenna is inserted inside the reservoir to mobilize the bitumen by vaporizing connate water [98]. The Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH) method extracts oil using electromagnetic devices and solvents [61]. ESEIEH operates at a lower temperature than SAGD, which is beneficial because it reduces the energy intensity [99].

However, ESEIEH is cost intensive and highly dependent on antenna efficiency and electrical energy [49].

The solvent-steam method is another emerging bitumen extraction technology. A mixture of steam and solvent vapor is used in the solvent-steam process, which reduces the amount of steam required compared to SAGD. Nasr et al. developed the expanding solvent-SAGD (ES-SAGD) method in which solvent with properties close to water is co-injected with steam [100]. The solvent-steam process has the potential to overcome the drawbacks of SAGD by reducing SOR and start-up capital expenses [101]. An experimental study by Frauenfeld et al. showed that the solvent-steam process can achieve a similar bitumen recovery rate at a 40% lower SOR compared to SAGD [36]. Li et al. worked on the optimal solvent selection for the solvent-steam process and showed that the oil recovery factor increases with higher hydrocarbon solvents [31]. Most studies on the solvent-steam process are focused on the oil recovery rate [51], optimum solvent type [102], and associated costs [53]. Ayodelle et al. reduced energy consumption by 11.5% in the solvent-steam process compared to SAGD but did not provide a detailed energy or emission analysis [34].

To the best of the authors' knowledge, there are no studies on the energy consumption and GHG emissions of the solvent-steam bitumen extraction method. A comprehensive analysis of this bitumen extraction method is necessary to understand the energy intensity along with GHG emissions on a commercial scale model. In this study, a process model simulation for the solvent-steam method was developed and the model was used to evaluate the energy consumption and GHG emissions of the process. A sensitivity analysis was also carried out to determine the key parameters that affect the emissions. Alternative sources of energy were also evaluated to improve environmental performance. This study will help policymakers and the oil sands community to understand the feasibility of solvent-steam bitumen extraction technology from an environmental perspective. The specific objectives of this study are as follows:

- To develop a process model for the solvent-steam bitumen extraction process.
- To evaluate energy consumption and GHG emissions of the process.
- To identify the parameters that significantly impact the energy intensity and GHG emissions.
- To analyze scenarios for reducing the GHG emissions of the solvent-steam bitumen extraction technology.

3.2 Method

3.2.1 Solvent selection

The recovery of bitumen from the solvent-steam method is greatly influenced by the type and volume of solvent used and the solvent placement [32]. Selecting a suitable hydrocarbon solvent is critical to the production of oil. Redford and McKay showed that oil recovery can be improved by using higher molecular-weight hydrocarbon blends [103], and Liu et al. found that lighter solvents increase heat loss in the reservoir [104]. Ghasemi and Whitson [102] worked on a range of hydrocarbon additives (C_5 to C_{12}) in order to identify the optimum solvents for the solvent-steam method. According to their study, C_6, C_7, and C_8 led to higher solvent recovery compared to C_5, C_{12}, and C_{15}. To reduce heat loss in the reservoir and to enhance the recovery rate of bitumen, the steam and solvent vapor should condense at the same time in the reservoir [31]. In other words, a solvent with a condensation temperature close to steam should be selected. The thermal condition in the reservoir also plays a vital role here. Experimental studies have shown that using n-hexane (C_6) in solvent-steam bitumen extraction can result in a 50% higher oil drainage rate than SAGD [33]. The vaporization temperature of n-hexane is closest to steam in the reservoir condition. In the developed solvent-steam process model, therefore, the n-hexane (C_6) was selected as the ideal solvent.

3.2.2 Process description

The solvent-steam bitumen extraction method is based on the same gravity drainage principle used in SAGD. Figure 6 shows a detailed schematic of the process. Detailed flowsheets of different process units are presented in Figure A1-A6 of appendix.

3.2.2.1 Heating unit

A steam and solvent vapor mixture is produced in the heating unit before being injected into the reservoir. Two separate heaters are used to heat the solvent and boiler feed water (BFW). The high-pressure solvent (3500 kPa) is sent to the solvent heater where it is vaporized at 226°C. Steam, on the other hand, is produced in a boiler at 5,088 kPa and 265°C using BFW from the water treatment unit (WTU). A conventional drum boiler or once-through steam generator (OTSG) is generally used for generating steam in bitumen extraction processes [17]. In the developed process model, an OTSG for steam production was considered. A series of vapor-liquid separators are used to achieve the desired quality of steam before sending it to the reservoir. Finally, the steam and vapor solvent are mixed at the wellhead and injected into the reservoir for bitumen extraction.

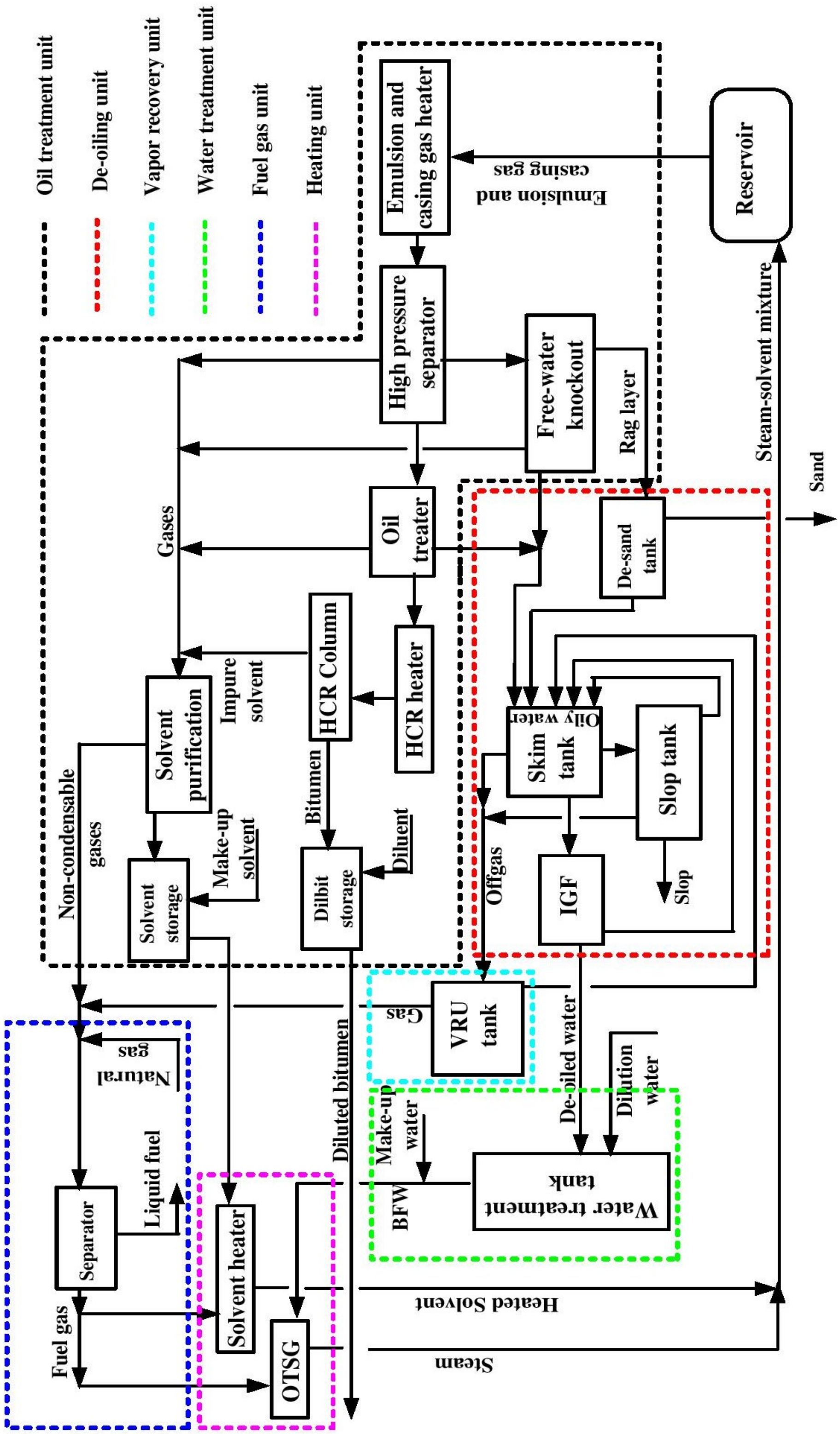

Figure 6: Schematic of the steam-solvent process

3.2.2.2 Emulsion lifting

Two separate horizontal wellbores are drilled, one above the other, and extend to the bottom of the reservoir. The upper well is called the injection well and the bottom well is known as the producer or production well. The steam and solvent vapor mixture produced in the heating unit at 223°C and 2600 kPa is injected into the reservoir base through the injection well. The mixture expands in the reservoir and comes in contact with the reservoir wall; it then releases heat and condenses while the highly viscous bitumen on the reservoir wall is heated. When the viscosity of the bitumen is low enough, it becomes mobile and drains through the bottom of the reservoir by gravity. During this operation, the reservoir expands with the drainage of bitumen and the liquid pool level near the production well rises. The steam-to-oil ratio (SOR) increases with the heat consumed by the liquid pool, so it is important to maintain the liquid level in the reservoir [54]. Moreover, if the liquid pool level goes above the injection well, it may affect the steam-solvent injection and reduce overall productivity. So it is recommended that the liquid level be kept between the injection and the production well inside the reservoir; this can be monitored by the temperature gap between the two wells [55]. Bitumen, condensed solvent and water, and casing gases (mostly methane) are lifted to the surface through the producer well using electronic submersible pumps (ESPs) installed on each wellhead. The extracted emulsion is then sent to the processing facility to separate the bitumen.

3.2.2.3 Oil treatment unit

In the processing facility, emulsion and casing gases from the producer well first enter the oil treatment unit (OTU) where they are heated to 134°C and passed through a series of three-phase separators (TPSs). A high-pressure separator (HPS) operating at 1000 kPa is used to separate the liquid and gaseous substances (methane, water, and hexane vapor) from the emulsion. The lighter liquid flows into the free-water knockout (FWKO), where the rag layer is separated from water. The heavier liquid mixture goes to another TPS, the oil treater, where water and off-gases are removed. The solvent and bitumen mixture from the oil treater is heated to 230°C in the hydrocarbon recovery (HCR) heater and sent to the HCR column. Here, bitumen is separated from the solvent through several stages of condensation ranging from 132-142 kPa and 76-163°C. Bitumen produced this way is highly viscous and not suitable to flow through pipelines. A diluent is mixed with the separated bitumen in a tank (dilbit storage) that reduces its viscosity to meet pipeline specifications. The blend of diluent and bitumen is referred to as dilbit and is sold or sent to an upgrading facility. The separated impure solvent from the HCR column goes through another TPS known as the solvent treater, where the non-condensable gases (NCGs) are removed. Hexane loss during the overall separation process is around 7%. Finally, make-up solvent is added to the separated solvent to compensate for any solvent loss and sent to the solvent heater in the heating unit. The lighter liquid (mostly water) extracted from the separators in the OTU is directed towards the de-oiling unit for purification.

3.2.2.4 De-oiling unit

The separated rag layer from the FWKO is sent to the de-sand tank for the removal of sand particles. The produced water from the OTU, vapor recovery unit (VRU), and de-sand tank is pumped through a series of TPSs – a skim tank, slop tank, and induced gas floatation (IGF) unit – where oil droplets, suspended solids, and off-gases are removed. Water collected at the bottom of the slop tank and IGF is cycled back to the skim tank for further processing. The de-oiled water produced in this unit is sent to the water treatment unit (WTU) for further treatment. The removed off-gases are sent to the VRU.

3.2.2.5 Water treatment unit

De-oiled water from the de-oiling unit enters the water treatment tank, where dissolved minerals (calcium, magnesium, and silica) and any remaining oil droplets are removed by the warm lime softening (WLS) process. BFW is produced by combining recycled BFW, make-up water, and water produced from the WTU and sent to the heating unit.

3.2.2.6 Vapor recovery unit

Off-gases collected from the skim and slop tank are compressed from to 495 kPa. In order to liquefy the water vapor in the off-gas stream, it is cooled to 45°C. The condensed water is separated from the cooled off-gas stream in a TPS, which is further de-oiled by sending it back to the skim tank in the de-oiling unit. The recovered gases are sent to the fuel gas unit.

3.2.2.7 Fuel gas unit

The non-condensable gases (NCGs) separated from the OTU and VRU are sent to the fuel gas unit. These produced gases are mixed with natural gas and used as an energy source to power the boilers and other heating equipment.

3.2.3 Process modeling and simulation

The solvent-steam bitumen extraction process model was simulated using Aspen HYSYS V12®. The Peng-Robinson equation of state was used for the fluid package. According to the simulation data, the volume of extracted emulsion from the reservoir is 3.7 bbl per bbl of bitumen. In order to meet pipeline specifications for transporting bitumen, diluent (petroleum naphtha) is used to elevate the bitumen density to API 19 (56.88 lb/ft^3) [105]. The lower heating value (LHV) of natural gas was considered in our calculations. Important assumptions and input data considered for the base case model are listed in Table 10.

Table 10: Model inputs for the simulation of energy consumption and GHG emissions from the solvent-steam extraction process

Parameter	**Value**	**Remarks/Comments**
Oil production rate, bpd	25,000	[49]
Steam-to-oil ratio (SOR)	1.8	[59]
Solvent-to-oil ratio (SvOR)	0.9	[59]
Solvent type	Hexane (C_6)	[33]
Reservoir temperature, °C	100	[63]
Reservoir pressure, kPa	1400	[64]
Heat losses in the reservoir, %	90	[106]
Diluent-to-oil ratio, m^3/m^3	0.27	[10, 66]
Heater efficiency, %	80	[107]
Biomass boiler efficiency, %	92	[106]
Lower heating value (LHV) of natural gas, MJ/kg	46.22	[108]
LHV of biomass, MJ/kg	17.6	[109]
Emission factors:		
Natural gas (NG), kgCO_2eq/GJ	55.78	[23]

Parameter	Value	Remarks/Comments
NG upstream, $kgCO_2eq/GJ$	8.88	[110]
Electricity (Alberta grid), gCO_2eq/kWh	544	[23]
Natural gas combined cycle, $kgCO_2eq/MWh$	367	[111]
Biomass[a], $kgCO_2eq/GJ$	5.63	[23]

[a] This value corresponds to the emissions during chopping, cropping, and transportation of feedstock to the power plant

3.2.3.1 Estimation of electricity and natural gas requirements

The amount of electrical energy consumed to operate pumps, compressors, air blowers, and other equipment was calculated from the simulation model results. The total natural gas consumption was calculated based on Equation 1 from Farzaneh-Gord et al.'s study [112].

$$Natural\ gas\ flow\ rate\ (kg/hr) = \frac{Total\ duty\ (MJ/h)}{Heater\ efficiency \times LHV\ of\ natural\ gas\ (MJ/kg)} \quad (1)$$

3.2.3.2 Estimation of emissions

The GHG emissions of the process due to the energy consumption were calculated using Equations 3 (from Cóndor et al. and Akagi et al. [113, 114]) and 4 (from Spork et al.) [115].

$$Emissions\ from\ heat\ consumption\ (kgCO2eq/bbl) = \frac{Emission\ factor\ of\ heat\ source\ (kgCO2eq/GJ) \times Heat\ energy\ consumption\ (GJ/hr)}{Bitumen\ flow\ rate\ (bbl/hr)} \quad (3)$$

$$Emissions\ from\ electrical\ equipment\ (kgCO2eq/bbl) = \frac{Emission\ factor\ of\ electricity\ source\ (kgCO2eq/kWh) \times Electricity\ consumption (kW)}{Bitumen\ flow\ rate\ (bbl/hr)} \quad (4)$$

All the GHG emission factors considered in this study are listed in Table 10. The total GHG emissions were calculated by adding the total GHG emissions from heat and electrical energy consumption.

3.2.4 GHG emission scenarios

In this study, a base case and 2 other scenarios were considered and the GHG emissions of the solvent-steam bitumen extraction process was analyzed. The GHG emissions in each scenario were evaluated and compared.

For the base case, the electrical energy required to operate the process equipment was met by using current Alberta grid mix electricity. Natural gas and coal-fired plants are used to generate 89% of Alberta's electricity and are responsible for its high emission factor [116]. Natural gas was considered as the source of fuel for the heaters. Energy consumption in different unit operations was investigated to determine the key contributor to the overall GHG emissions.

In scenario 1, a natural gas combined cycle (NGCC) power plant was considered for meeting the electricity and heat requirements of the solvent-steam process. NGCC plants have higher efficiency (up to 63%) than a typical coal or simple gas turbine power plant, which can potentially reduce the overall GHG emissions of the process [117].

In scenario 2, biomass-generated heat was used as the source of heat and electrical energy. About 67% of the produced biomass energy in Canada is used by different process industries (such as the pulp and paper industry) [118]. Energy generated from biomass plants is cleaner and has low carbon emissions overall life cycle, which may be a possible solution for reducing the GHG emissions of the overall bitumen extraction process [118]. Biomass is considered nearly carbon neutral as the amount of carbon emitted during its combustion is nearly the same as the amount of carbon taken up by the plants or trees during its growth.

3.2.5 Sensitivity and uncertainty analysis

Sensitivity analysis helps to evaluate the uncertainty in the output due to variations in inputs. In order to investigate the parameters that are most sensitive to the total GHG emissions in the solvent-steam model, sensitivity analysis based on the input ranges listed in Table 11 was performed. The Morris method was used to determine the mean and standard deviation, from the most sensitive input parameters were identified. A higher standard deviation indicates a non-linear relationship between input and output, and a higher Morris mean value signifies greater impact on the output. For uncertainty analysis, an Aspen HYSYS case study was used to generate the output values based on the most sensitive inputs. The sensitivity analysis was carried out using the RUST tool developed by our research group colleagues [80].

Table 11: Input ranges for sensitivity and uncertainty analysis

Parameters	**Ranges**	**Remarks/Comments**
Steam-to-oil ratio (SOR)	1.5-2.2	[59]
Solvent-to-oil ratio (SvOR)	0.6-1.2	[59]
Boiler efficiency, %	70-90	[119]
NG upstream emission factor, $kgCO_2eq/GJ$	7.9-17.8	[120]
Electricity emission factor, $kgCO_2eq/kWh$	372-701	[61]

3.3 Results and discussion

Energy analysis provides the energy requirement in each component and estimates the GHG emissions in different sections of a process. The electrical and heat energy consumed in the different units of the solvent-steam bitumen extraction process and the associated GHG emissions per bbl of oil production for the base case are shown in Table 12. The total energy consumption and corresponding GHG emissions of the solvent-steam bitumen extraction process are 0.92 GJ/bbl and 61.74 $kgCO_2eq/bbl$, respectively. Heat energy plays an important role; it is responsible for 97% and 93% of the overall energy consumption and GHG emissions, respectively.

Table 12: Energy consumption and GHG emission of the solvent-steam process (base case)

Process unit	**Heat energy (MJ/bbl)**	**Electrical energy (MJ/bbl)**	**Total emissions ($kgCO_2eq/bbl$)**
Heating unit	795	6.12	52.33
Emulsion lifting	-	12.66	1.91
Oil treatment unit	97.2	6.76	7.30
De-oiling unit	-	0.64	0.1
Vapor recovery unit	-	0.08	0.01
Water treatment unit	-	0.59	0.09
Total	**892.2**	**26.85**	**61.74**

The heating unit, where steam and solvent vapor are produced at high pressure before being injected into the reservoir, is the most energy-intensive section of the solvent-steam process; 87% of the total energy is consumed there. Around 23% of the total electricity is used by centrifugal pumps that increase the pressure of the water and solvent in the heating unit. The OTSG and the solvent heater, the two main components of the heating unit, require heat energy. Natural gas is used to generate heat energy in our base case model. Around 89% of the total natural gas is consumed in the heating unit. The OTSG used to produce steam is the most energy-intensive equipment; it has an estimated power rating of 215 MW and is responsible for 80% and 93.5% of the overall energy consumption and GHG emissions, respectively. The OTSG accounts for 93.4% of the total energy consumed in the heating unit. The efficiency of the OTSG is also an important factor. A typical OTSG can produce steam at a quality of 75-

80%, which also contributes to its higher energy requirement [85]. The OTSG is operated a bit differently than conventional boilers. It is designed to operate with low quality feed water because of the WLS process, which makes its application ideal for oil sands projects [121]. Improving the efficiency of the OTSG will reduce energy consumption. On the other hand, the power rating of the solvent heater for producing solvent vapor is 15 MW; it shares only 6% and 6.6% of the total energy consumption and GHG emissions, respectively.

The solvent-to-oil ratio (SvOR), type of solvent used, reservoir properties, etc., may impact the energy consumed in the solvent heater. Selecting appropriate values for the SvOR and SOR is important to achieve better energy efficiency and, with that, an improved oil production rate. Lowering these ratios, however, will lower the energy consumption at the expense of reduced oil recovery. For the same bitumen production rate, increasing the SvOR will lower the SOR and vice versa. As mentioned, steam and solvent should be injected at a specific temperature and pressure so that they condense in the reservoir at the same time. Otherwise, the heat transfer to the reservoir wall will not be uniform, thus increasing energy consumption and reducing bitumen yield [100]. It is also important to maintain the liquid level between the injector and the producer well [122]. A higher liquid level might increase heat loss and decrease productivity, which would lead to higher energy consumption. Gas content in the reservoir can also affect solvent retention and heat transfer rate. Heat and mass transfer in the reservoir should be carefully optimized since they have a significant impact on the energy efficiency and oil production rate [54].

The emulsion is lifted with the ESPs installed on each wellhead. 32 ESPs were considered, each with a power rating of 114.5 kW. They are the most electrical energy-intensive units, accounting for 47% of the overall electricity consumption. Electrical energy consumption during lifting will vary depending on the viscosity of the emulsion. A higher emulsion density will increase the power ratings of the pumps.

The oil treatment unit is responsible for 98.8% and 97.3% of the overall energy use and GHG emissions, respectively. This unit is where bitumen, solvent, water, and NCGs are separated from the emulsion. Solvent separation is the most energy-intensive process in the oil treatment unit. The most important components in the solvent separation process are the HCR heater and the solvent distillation column. The HCR heater is operated using natural gas and consumes the majority (92.3%) of energy used in the oil treatment unit. It is responsible for 11% of the overall natural gas consumption. Because of this consumption, the HCR heater is emission-intensive; about 84% of the GHG emissions in the oil treatment unit are from the HCR heater. The obtained hexane purity after the extraction of solvent in the distillation column is 99.7%. Another round of solvent separation is required to increase the purity of the hexane. This is not feasible, however, given the energy and emission intensity of the HCR heater. Thus, dissolved hexane in the separated bitumen is an economic loss; however, this might be beneficial because of its partial upgrading effect on the produced bitumen. The oil treatment unit is responsible for 25.2% of the total electrical energy consumption. This electricity is mostly shared by centrifugal pumps and air blowers at different stages of the oil treatment process. Only 14% of GHG emissions in the oil treatment unit are from electricity consumption.

The fuel gas is separated from the produced gases in the fuel gas unit. Fuel gas is mainly composed of methane (96.2 mol%). Mixing fuel gas with natural gas as a source of energy to operate the heaters/boilers is a common practice in oil extraction plants and also reduces the overall natural gas requirement of the process. Of course, the amount of produced fuel gas largely depends on the type of reservoir and its gas content. The other units such as the de-oiling unit, vapor recovery unit, and water treatment unit are not energy intensive and together share only around 5% of the total electrical energy consumption.

3.3.1 Comparison of GHG emissions from the solvent-steam process using different sources of energy

Figure 7 shows how the overall GHG emissions of the base case compares with the other considered solvent-steam bitumen extraction process scenarios. The base case results show that heat produced with natural gas contributes 93% to the total GHG emissions. In scenario 1, electrical and heat energy from an NGCC power plant is considered. It lowers GHG emissions by only 2% compared to the base case. In scenario 2, biomass is considered for heat and power production. Biomass is a widely available renewable source of energy with a low emission factor compared to fossil fuels [23]. Biomass could be a suitable alternative to natural gas; biomass-generated heat reduces GHG emissions by 85%. When biomass is used to generate both heat and power, GHG emissions are reduced by 91%. The amount of biomass required to meet the heat and electricity demand is 55.3 kg/bbl.

An alternative source of electrical energy with low environmental impact might not significantly improve the solvent-steam process, given that it is partly a steam-based technology in which fossil fuel meets most of the energy requirements. Instead, selecting a cleaner source of energy such as biomass to generate heat for steam production will be more beneficial for GHG emissions reduction. That said, biomass is relatively expensive, has a low conversion efficiency (up to 45%), and also has adverse impacts on the environment (deforestation) [123].

These factors must be taken into consideration. Biomass plants also require considerable space, which might not be an issue since oil sands plants are usually established in locations with large open areas [124]. However, the availability of the raw material may be a concern for biomass-based plants.

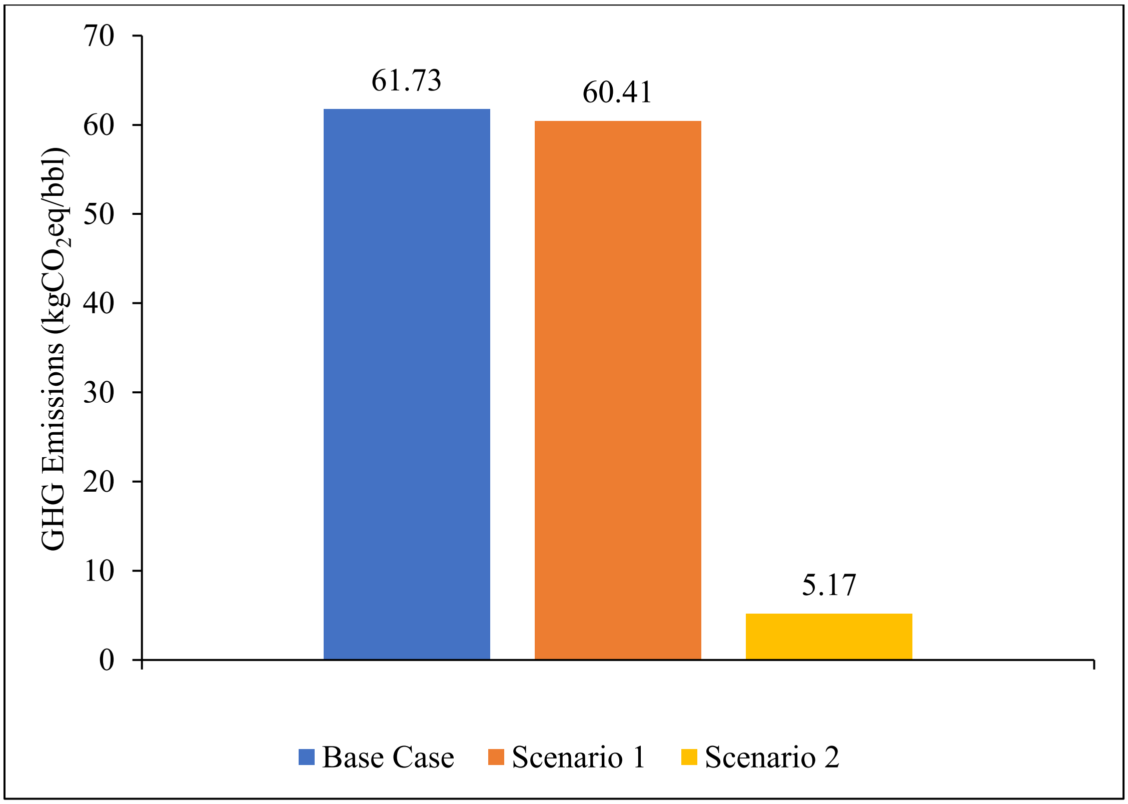

Figure 7: The effect of using different sources of energy in the solvent-steam process

3.3.2 Sensitivity and uncertainty analyses

The sensitivity analysis of the GHG emissions is presented through the Morris plot in Figure 8. The GHG emissions of the solvent-steam process are sensitive to the steam-to-oil ratio (SOR) and heater efficiency. The plot shows that these parameters have largest mean and standard deviation, which makes them the most sensitive. The natural gas upstream emission factor, solvent-to-oil ratio (SvOR), and electricity emission factor are moderately sensitive to GHG emissions.

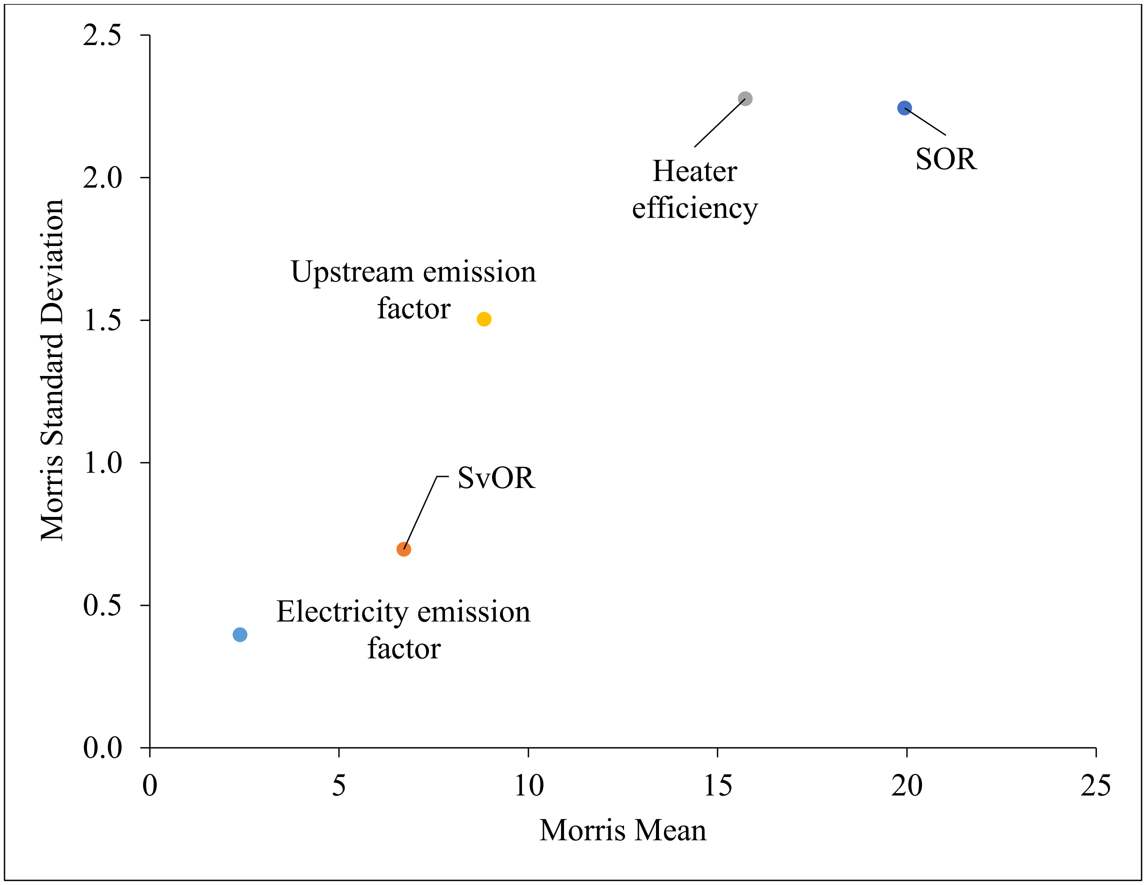

Figure 8: Sensitivity analysis of the GHG emissions (base case)

Figure 9 shows the uncertainty analysis of the base case and the considered scenarios by plotting the distribution frequency of the GHG emission values. The bottom and the top error bars show the 5th and 95th percentiles, whereas the bottom and the top of the boxes show the 25th and 75th percentiles of the GHG emissions. For the base case, the probability ranges in the GHG emissions are from 49.68 to 82.61 kgCO_2eq/bbl. In scenarios 1 and 2, the GHG emissions range from 45.65 to 77.12 $kgCO_2eq/bbl$ and 3.94 to 6.64 $kgCO_2eq/bbl$, respectively. The GHG emissions distributions show that base case and scenario 1 have the highest and scenario 2 has the lowest GHG emissions intensity. However, between the base case and scenario 1, it is difficult to decide which offers lower GHG emissions since their error bars overlap. The evaluated range of GHG emissions values from the uncertainty analysis provides more realistic insight into the overall environmental performance and feasibility of the solvent-steam process compared to other technologies.

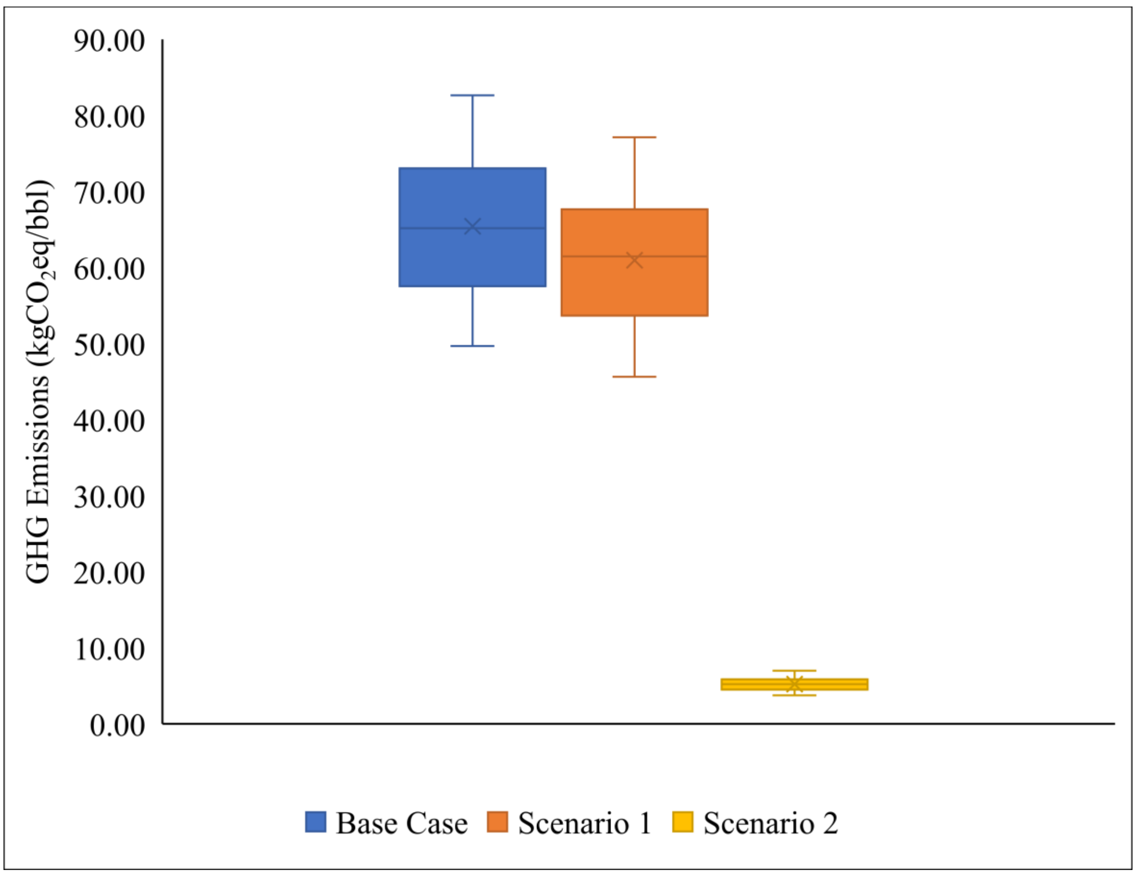

Figure 9: Uncertainty analysis of the GHG emissions of the solvent-steam process

3.3.3 Comparison of the environmental impact of the solvent-steam process with other technologies

It is important to understand how the overall environmental impact of the solvent-steam bitumen extraction process compares with the other currently established oil extraction technologies. Table 13 shows the range of GHG emissions of some popular bitumen extraction processes using different sources of energy. While using natural gas and Alberta grid electricity, the solvent-steam process in this study has significantly lower emissions than SAGD and CSS, respectively. However, VAPEX generates lower GHG emissions than the solvent-steam process since it requires no steam and consumes less energy. Similarly, ESEIEH does not require steam and thus has lower GHG emissions than the solvent-steam process. On the other hand, using biomass-generated electricity and heat in the solvent-steam process results in considerably lower GHG emissions than ESEIEH. The GHG emissions from the different energy sources listed in Table 13 show that the GHG emissions' range from the solvent-steam process is comparable that of with other bitumen extraction technologies. However, straightforward comparison at this level of analysis might not be entirely feasible. Energy consumption and GHG emissions of the bitumen extraction process are greatly impacted by the reservoir condition, API gravity, asphaltene content, considered assumptions, and other factors. A more accurate comparative analysis might be achieved when the final products have similar properties after upgrading or refining.

Table 13: Environmental impact of different bitumen extraction processes

Extraction process	**Type of used energy**	**Emissions ($kgCO_2eq/bbl$)**	**Reference**
Solvent-steam	Natural gas heat and Alberta grid electricity	49.7-82.61	Present work
	NGCC heat and electricity	45.7-77.12	
	Biomass-generated heat and electricity	3.94-6.64	
SAGD	Natural gas heat and Alberta grid electricity	61.0-220.0	[16]
CSS	Natural gas heat and Alberta grid electricity	61.0-109.0	[91]
ESEIEH	Alberta grid electricity	56.0-75.0	[61]
	Biomass-generated electricity	9.96-13.1	[61]
VAPEX	Natural gas heat and Alberta grid electricity	24.8-29.1	[25]

3.4 Conclusion

In this study, a detailed process model of solvent-steam bitumen extraction technology was developed. Natural gas and the current Alberta grid mix electricity were the two major sources of energy considered for the base case model. For a production capacity of 25,000 bpd, the total energy consumption was 0.92 GJ/bbl and the resulting GHG emissions were 61.75 $kgCO_2eq/bbl$. When uncertainty is considered, the energy consumed and GHG emissions range from 0.7 to 1.2 GJ/bbl and 49.7 to 82.6 $kgCO_2eq/bbl$, respectively. The sensitivity analysis showed that GHG emissions overall are highly sensitive to the steam-to-oil ratio (SOR) and heater efficiency. These parameters should be carefully evaluated in order to improve process performance. Heating units accounted for 87% and 85% of the overall energy consumption and

GHG emissions, respectively. Heat energy produced from natural gas was responsible for 93% of the total GHG emissions. The use of a natural gas combined cycle and biomass as energy sources lowered GHG emissions by 2% and 91%, respectively, compared to the base case. The results of this study show that the solvent-steam bitumen extraction process is environmentally viable and has the potential to replace new greenfield projects. This analysis will also help policymakers and design engineers in oil sands industries understand the environmental feasibility of the solvent-steam bitumen extraction process.

Chapter 4: Conclusions and recommendations for future work

4.1 Conclusion

This thesis presented the results of a techno-economic analysis as well as the energy comsumption and GHG emissions' footprint of the solvent-steam bitumen extraction technology. The objective was to evaluate the economic and environmental performance of the solvent-steam process in order to assist policymakers, industry, and government in formulating policies and making informed decisions. First, a process model simulation was developed in Aspen HYSYS V12® for a plant in Alberta producing 25,000 bpd of bitumen over a 30-year lifespan. Hexane was selected as the most suitable hydrocarbon solvent for the process since its condensation temperature is closest to steam. A comprehensive techno-economic model was created to investigate the capital investment and operating costs based on the results from the process simulation and some assumptions. The supply cost of bitumen and economies of scale were evaluated through a discounted cash flow analysis. A Morris plot was used to perform a sensitivity analysis for a range of input values to identify the parameters that most impact the supply cost of bitumen. The most sensitive parameters were used to conduct uncertainty analysis through a Monte Carlo simuation to calculate the range in supply cost. The estimated supply cost of bitumen was then compared with benchnmark prices to understand the economic feasibility of the solvent-steam process.

This study also included an evaluation of energy consumption and the GHG emissions footprint. Natural gas and Alberta-grid electricity were the primary energy sources for operating the boilers and electrical equipment, respectively, in the base case model. In the other scenarios, natural gas combined cycle (NGCC) and biomass-generated heat and electricity were investigated. Associated GHG emissions were calculated to determine the environmental impact of the process. The key parameters that affect the overall GHG emissions were identified through a sensitivity analysis for a range of input parameters. The range of GHG emission values was determined through uncertainty analysis. Finally, the GHG emissions from the solvent-steam process were compared with currently established technologies to determine its environmental feasibility.

4.1.1 Techno-economic assessment

The results from the techno-economic model show that the bitumen supply cost is CAD 55.5/bbl at 10% IRR. Figure 10 shows the breakdown of supply cost. Transportation and blending cost accounted for 50% of the total operating and 42% of the total supply cost. The cost of adding diluent to bitumen to meet pipeline specifications made up a significant portion (60%) of the transportation and blending cost. Transporting dilbit by rail will increase the overall supply cost of bitumen by 18.5%. Well-pads and drilling make up more than half the capital investment. The most cost-intensive equipment is the OTSG, used for producing steam; it makes up 25% of the capital cost. As a mixture of steam and solvent is used to extract bitumen, less steam is required for the solvent-steam process than for SAGD. Almost 99.7% hexane was recovered from the emulsion at the end of the separation process. The sensitivity analysis results show that capital investment, diluent cost, transportation and blending cost, and IRR have the greatest impact on the supply cost. For a 30% change in the capital cost, the supply cost changes by around 7%; capital cost is the most sensitive input parameter according to the Morris plot. Similarly, for a 30% change in the diluent, hexane, and transportation cost, the supply cost changes by nearly 6.5%, 4.9%, and 3.8%, respectively. Uncertainty analysis shows more realistic supply cost values of CAD 53-65.40 per barrel at a 90% confidence level. The calculated scale factor was 0.8, which proves that the project would be economically more profitable with increasing plant capacity due to the benefits of the economy of scale. The supply cost per barrel reduces from CAD 75.35 to 51.01 as the bitumen production rate increases from 5,000 to 85,000 bpd. Compared to benchmark prices such as WTI and WCS, the estimated supply cost of bitumen from the solvent-steam process is economically competitive.

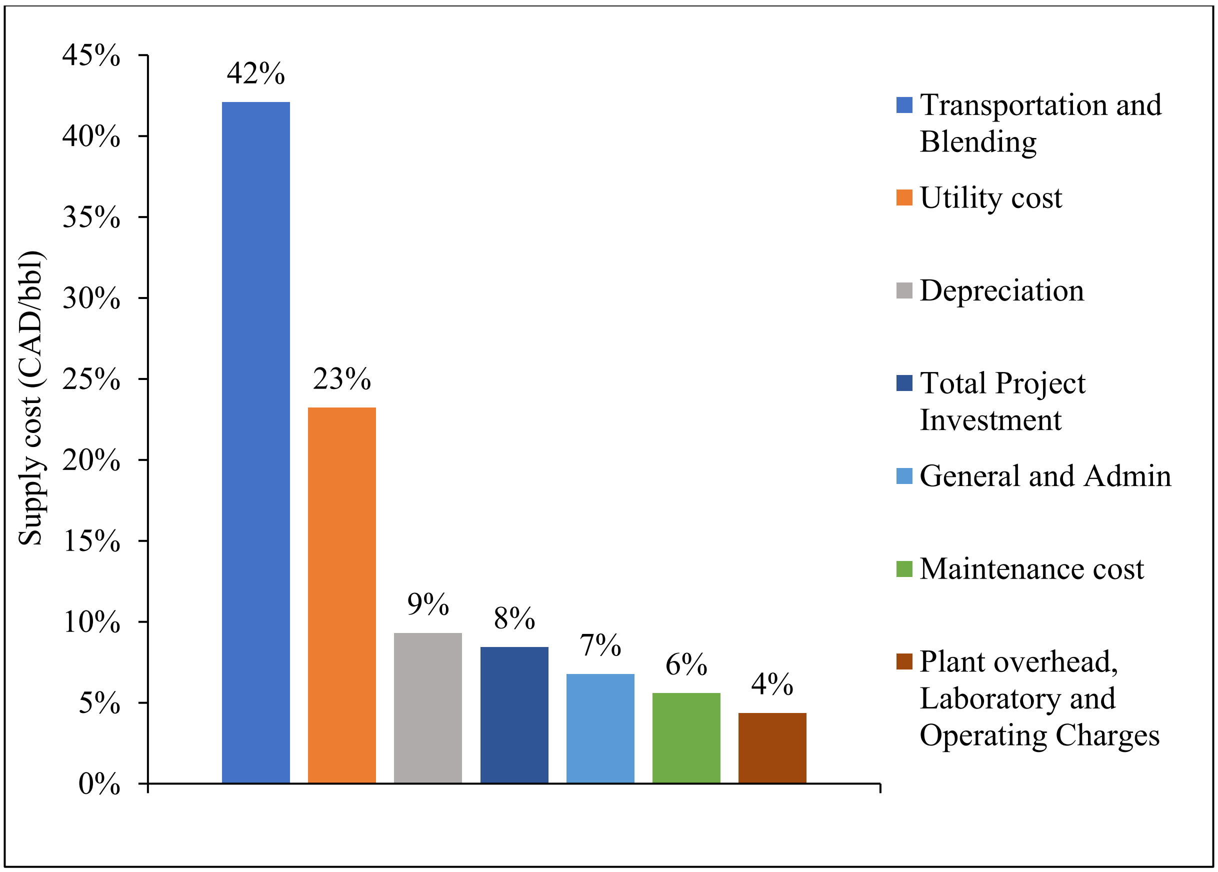

Figure 10: Breakdown of supply cost of bitumen

4.1.2 Energy consumption and GHG emissions

The results from the solvent-steam process model show that the total energy consumption is 0.921 GJ/bbl and associated GHG emissions are 61.75 kgCO_2eq/bbl while using natural gas-generated heat and Alberta grid electricty (base case). The heating unit involved the production of steam and vapor solvent. It is the most energy-intensive section and accounted for 87% and 85% of the overall energy consumption and GHG emissions, respectively. The OTSG, used to produce steam, was the most energy-intensive equipment and accounted for 80% of the total energy consumption. Natural gas is the most important source of energy; it is responsible for 97% of the total energy consumption. The OTSG, solvent heater, and HCR heater are the only three pieces of equipment that consumed natural gas and did so at a rate of 742.92, 52.13, and 97.15 MJ/bbl, respectively. Electrical energy incurs only 7% of the overall GHG emissions. Almost 47% of the total electrical energy is consumed in the ESPs during emulsion lifting. Figure 11 shows the electrical and heat energy consumption in different process units.

According to the sensitivity analysis of the base case model, the solvent-to-oil ratio (SOR) and heater efficiency have the most impact on the overall GHG emissions. For a 12.5% change in the heater efficiency, the GHG emissions vary by up to 9.5%. In the other considered scenarios – natural gas combined cycle (scenario 1) and biomass-generated heat and electricity (scenario 2) – the total GHG emissions are 60.41 and 5.17 kgCO_2eq/bbl, respectively. An almost 92% lower GHG emission value compared to the base case was achieved when heat and electrical energy from biomass was considered. The uncertainty analysis measured a realistic range of emission values between 49.7 and 82.6 kgCO_2eq/bbl at a 90% confidence level for the base case. For scenarios 1 and 2, the GHG emission values ranged from 45.65 to 77.12 and 3.94 to

6.64 $kgCO_2eq$/bbl, respectively. The solvent-steam process has significantly lower emissions than SAGD and CSS, which indicates its environmental viability.

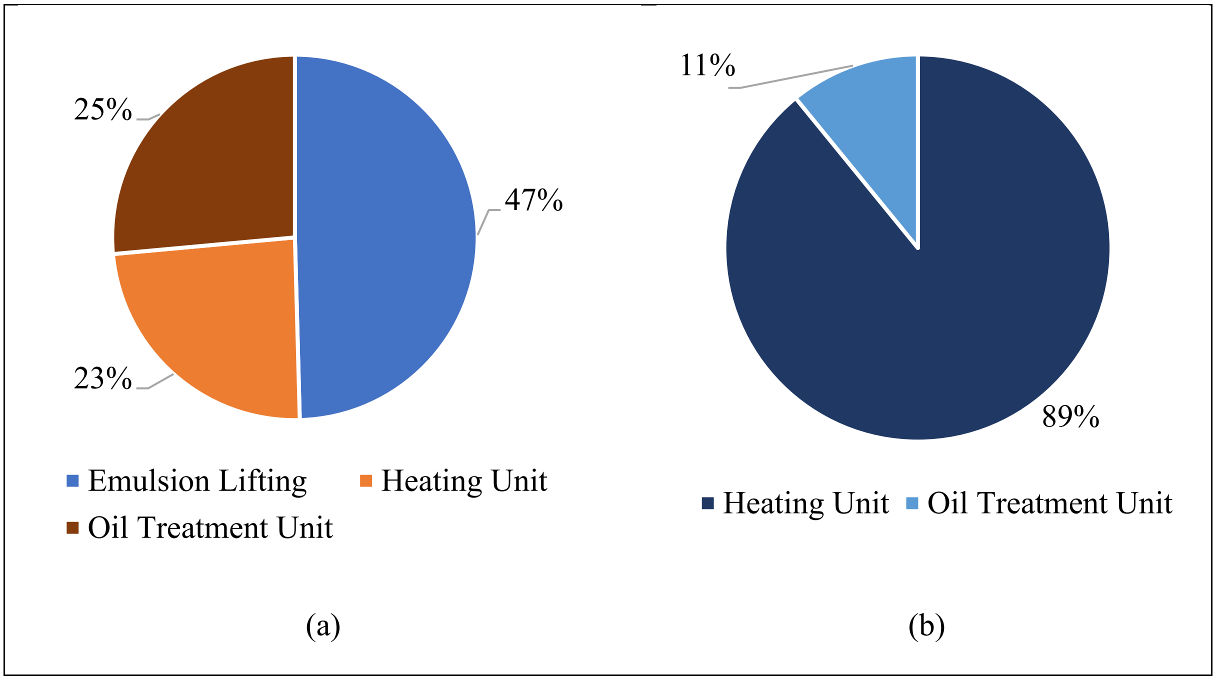

Figure 11: (a) Electrical and (b) heat energy consumption in different process units

The results from this study show that the solvent-steam bitumen extraction process is feasible from both economic and environmental points of view. Based on the current oil market, the supply cost and GHG emissions are also competitive. The solvent-steam process has the potential to replace new greenfield projects.

4.2 Recommendations for future work

This thesis presents a techno-economic analysis and GHG emissions' footprints of the solvent-steam bitumen extraction technology. Some key recommendations for future work are as follows:

- The economics of the solvent-steam process was only compared with benchmark oil prices. A detailed comparison of costs with other currently established bitumen extraction technologies will provide a better understanding of the economic standpoint of the solvent-steam process. A single model based on similar assumptions and compositions of the end product is required for accurate comparative analysis.
- The process equipment costs were calculated from the simulation software and published sources. Real-time cost data can be used from industry and existing projects and compared with the theoretical results.
- For a more accurate comparison with other technologies, the associated costs, and GHG emissions of upgrading and refining the produced dilbit can also be included in the a follow up study.
- A cost evaluation of all the scenarios considering different energy sources can be presented to identify the most suitable scenario based on the economic and environmental impacts of the process.
- The model presented is based on conservative input distributions. Data from industry and existing projects would reduce the uncertainty in input distributions and improve the accuracy of the results.
- Given the lack of data, the current study did not include GHG emissions from infrastructure construction and land use. Although these GHG emissions are meant to be minimal, they should be included in the system boundaries to study their effects.
- Renewable sources of energy such as geothermal, nuclear, wind, hydro, solar, etc., can also be considered to generate electricity and heat for bitumen extraction and processing.

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Appendix

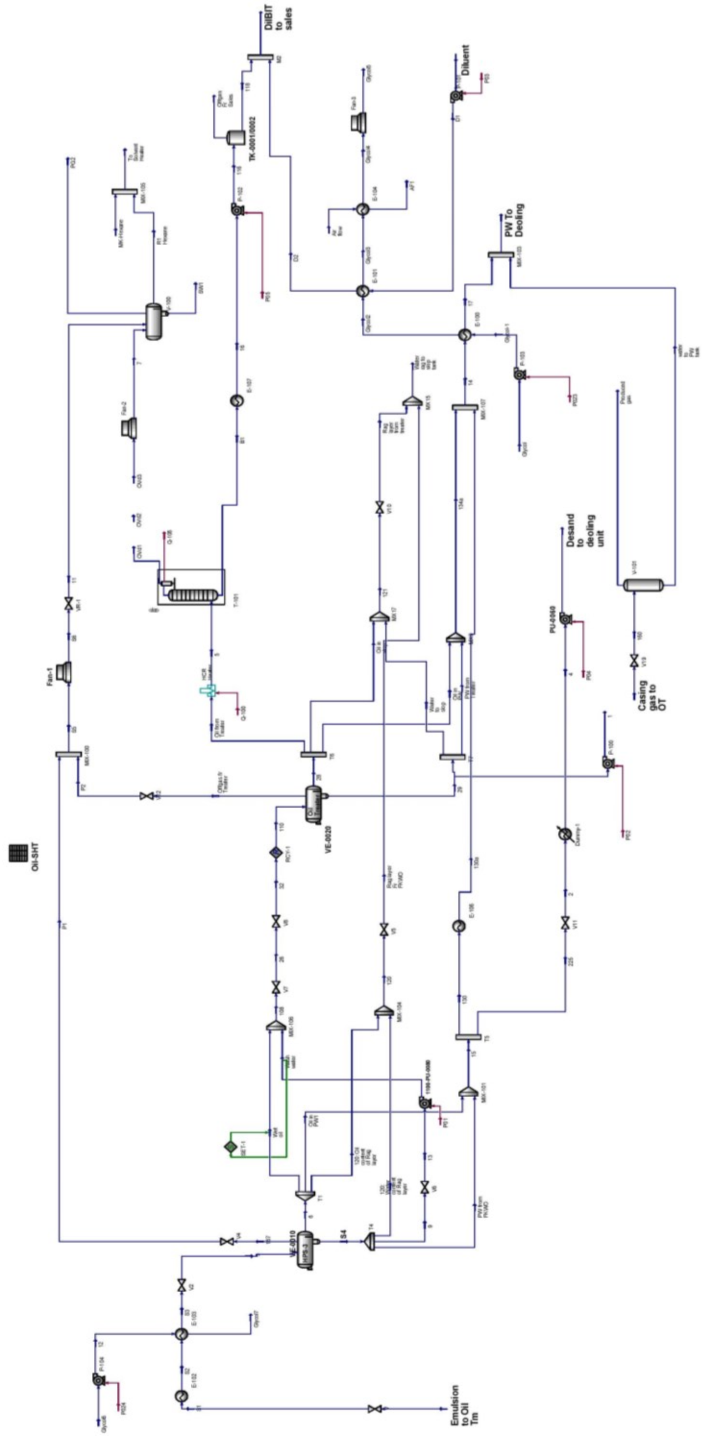

Figure A1: Aspen flowsheet of oil treatment unit

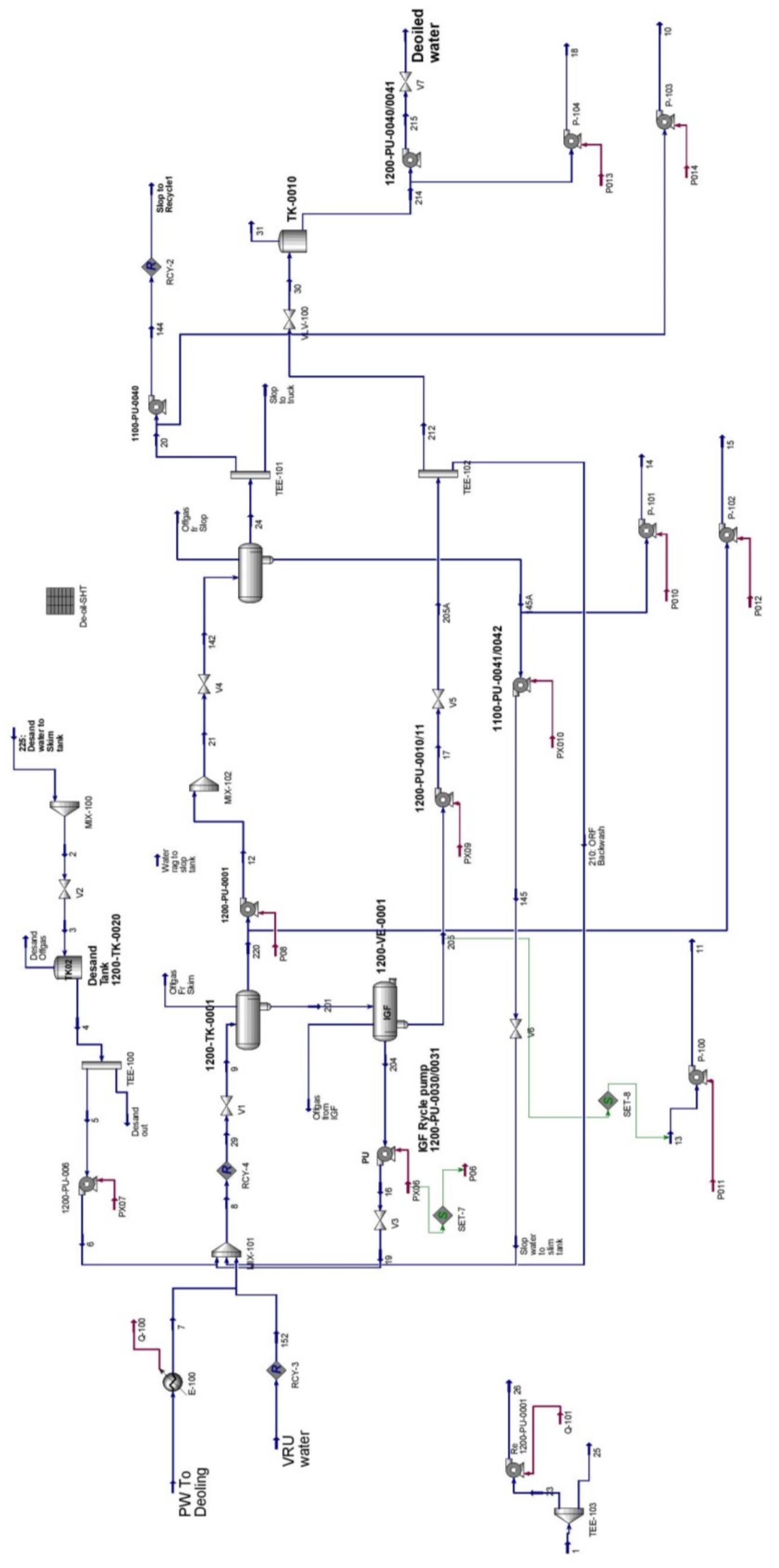

Figure A2: Aspen flowsheet of de-oiling unit

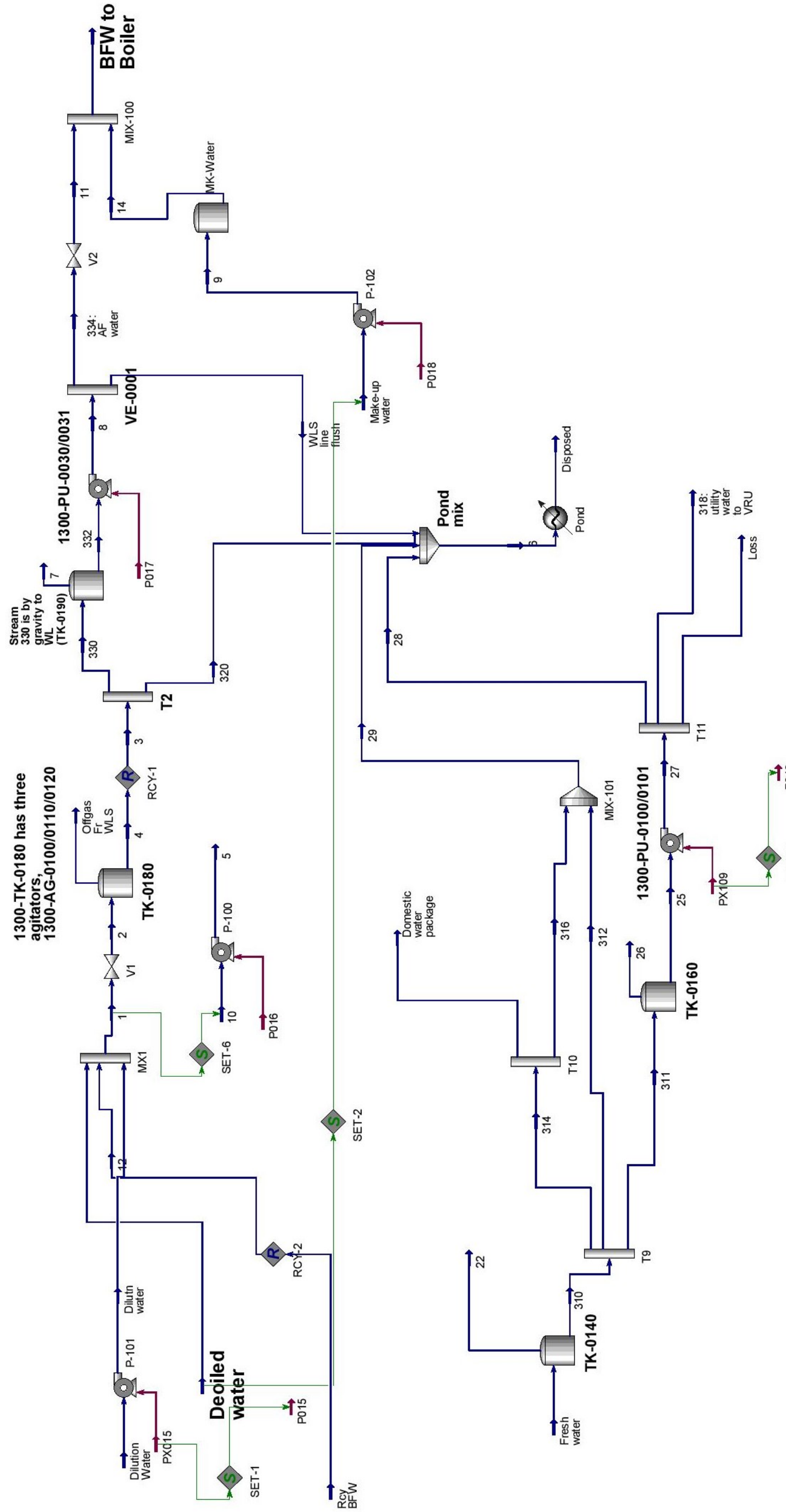

Figure A3: Aspen flowsheet of water treatment unit

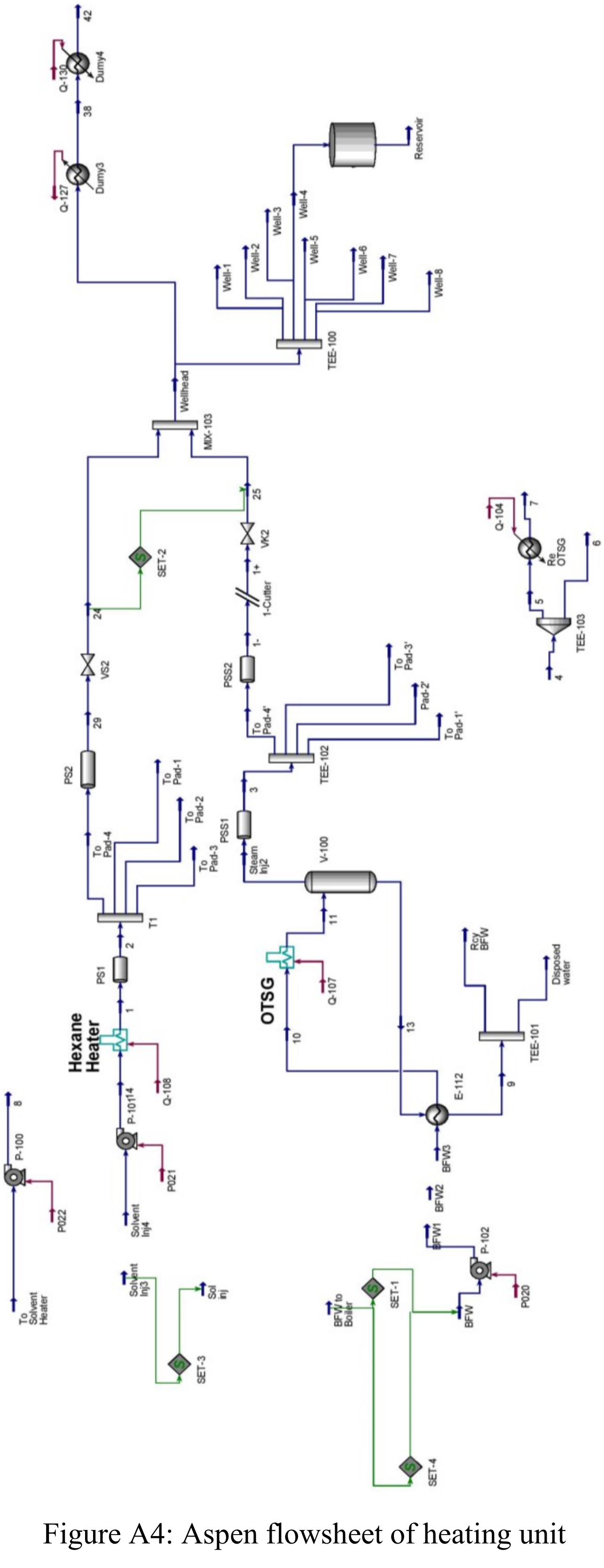

Figure A4: Aspen flowsheet of heating unit

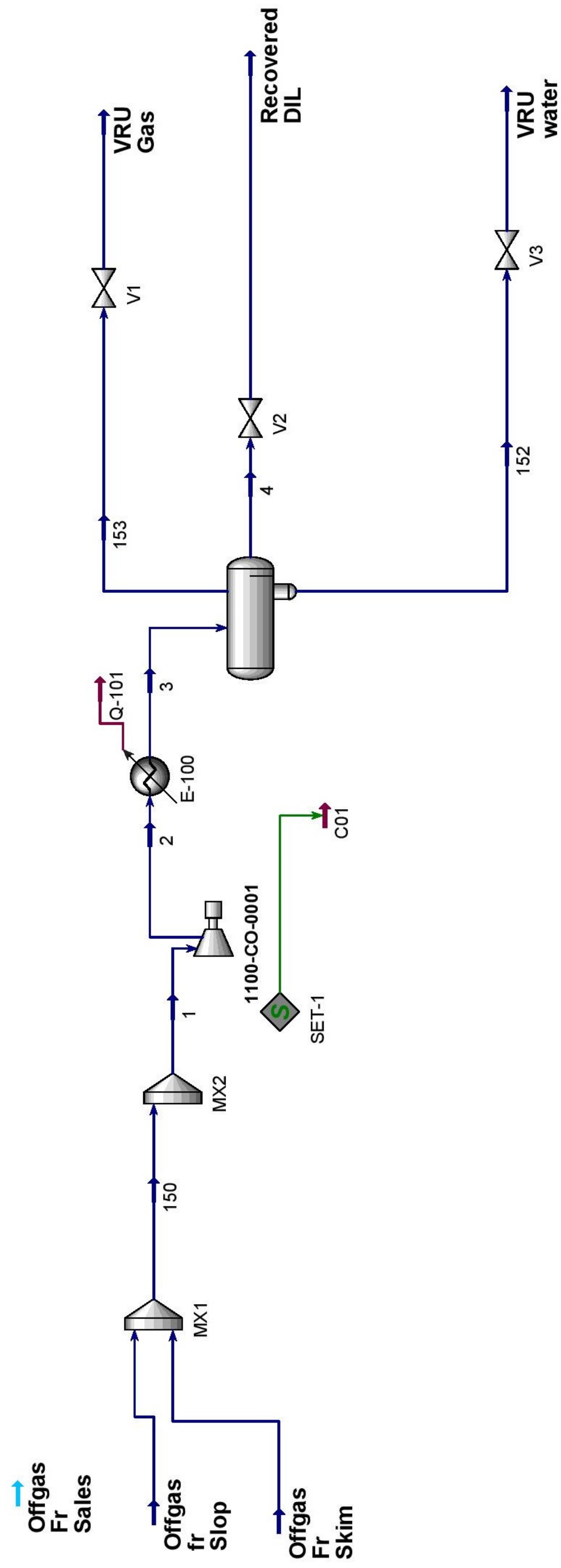

Figure A5: Aspen flowsheet of vapor recovery unit

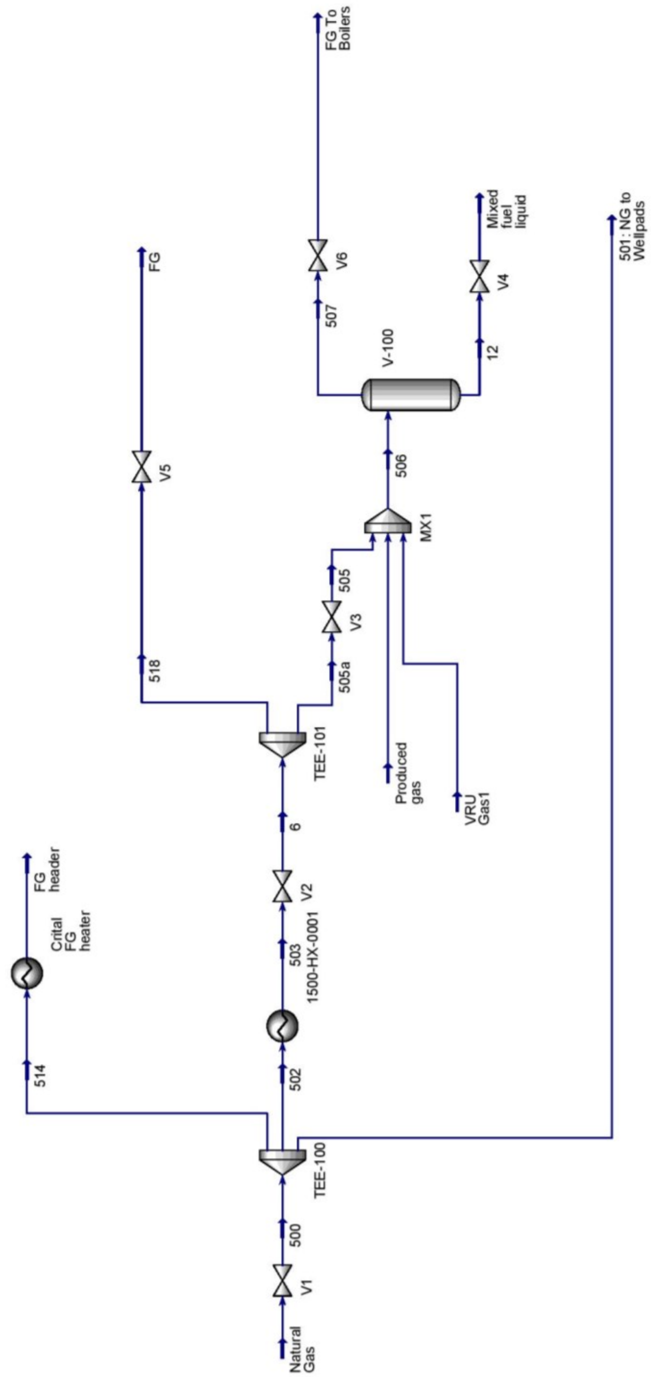

Figure A6: Aspen flowsheet of fuel gas unit