SAGD in Reservoirs with Top and Bottom Water Zones

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SAGD in Reservoirs with Top and Bottom Water Zones

by

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A THESIS
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Abstract

Producing bitumen from non-ideal reservoirs is an important challenge for SAGD operators. Thief-zone interactions and with steam chamber coalescence must be considered for optimal process design. Here, a sensitivity analysis is conducted on a thin reservoir with top and bottom aquifers to understand the impact on recovery process performance. Solvent and non-condensable gas addition are considered to determine if they can improve the performance of the recovery process. Particle swarm optimization (PSO) is used to determine alternative operating strategies using both solvent and NCG in recovery processes that achieve reasonable economic and environmental outcomes. The results illustrate that solvent and non-condensable gas co-injection in SAGD can be advantageous. However, processes without solvent gave the best NPV due to the cost of the lost solvent retained in the reservoir.
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Dedication

To my parents who raised me with love and supported me in all my pursuits.
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Chapter One: Introduction

1.1 Overview

Over millions of years, sand, silt, mud and the remains of organic matter accumulated in sedimentary basins forming what is called sedimentary rocks where accumulations of crude oil and natural gas are found (Bott, 2004). In some areas, for example, in Alberta, huge oil volumes migrated and expanded upward and eastward close to the surface into wide sandstone areas roughly about fifty million years ago (Bott, 2004). Under anaerobic conditions, bacterial action resulted in the majority of low molecular weight volatile paraffinic and naphthenic components being degraded. This caused an enrichment of heavy components in the oil phase resulting in the high viscosity of the oil, which is now referred to as heavy oil, extra heavy oil, or bitumen (Richard and Meyer, 2007). In typical oil sands systems, the viscosity of the bitumen is over 100,000 cP and often exceeds 1 million cP (Mehrotra and Svrcek, 1986). This higher viscosity makes bitumen extraction from oil sands reservoirs more difficult to produce and more expensive than conventional reservoirs that did not undergone extensive biodegradation.

Typically, bitumen has an API gravity between 4 and 14°API. This implies that its density can be equal or heavier than that of water. At 10°C (50°F), bitumen is very viscous and does not readily flow from oil sands reservoir under natural or reservoir engineering induced forces (such as from a water-flood). Thus, to extract bitumen from an oil sands reservoir, it must be mobilized. In other words, its viscosity must be reduced to
approximately 10 cP or lower. In most cases, this is done by raising the temperature of the bitumen to greater than 200°C (Su, 2016).

About 20% of bitumen oil sands are found within 70 metres (200 feet) of the surface and can be surface mined (CAPP, 2017). The majority of oil sands resources, however, are deeper underground, at depths up to 500 m. For these reservoirs, the bitumen is extracted from the reservoirs by using in situ reservoir recovery processes such as cyclic steam stimulation (CSS) or steam-assisted gravity drainage (SAGD). Currently, for oil sands reservoirs, such as those found in the Athabasca deposit (mainly in the McMurray Formation), SAGD is the process of choice.

1.2 Western Canada Resource Plays

Bitumen bearing oil sands reservoirs can be found in many locations around the globe, including Canada, China, Venezuela, United States, and Russia. However, Canada has one of the largest deposits and has developed technologically advanced production processes to recovery these resources (CAPP, 2017).

The total petroleum oil in place in the region is as high as 1.8 trillion barrels of which over 176 billion barrels are considered recoverable reserves. Up to 57% of Canada’s estimated hydrocarbon resources are in Western Canada of which the bitumen contained within the unconsolidated sand matrix (typically quartz) in oil sands the third ranks in the world for hydrocarbon reserves. Figure 1.1 shows the reservoir resource area of the Western Canada
Sedimentary Basin. The Geological Survey of Canada indicates the ultimate geological potential of sedimentary region in Western Canada Sedimentary Basin as shown in Figure 1.2.

Figure 1.1: Reservoir resource area of the Western Canada Sedimentary Basin (ST98-2017 Alberta Energy Regulator, 2017).
The Western Canada Sedimentary Basin is the most productive hydrocarbon resource in Canada. The areas cover most parts of Alberta, Saskatchewan, and parts of British Columbia, Manitoba, Yukon and the Northwest Territories (National Energy Board, 2011). In 2003, 87% of Canada’s crude oil and 97% of natural gas production came from the Western Canada Sedimentary Basin (Bott, 2004). There are seven distinct regions of sedimentary rocks in Western Canada and every province has at least a portion of these
regions. The basin covers the majority of the land area of Alberta and Saskatchewan and large areas off the East Coast (National Energy Board, 2011). The Alberta basin has three major oil sands areas, e.g., the Athabasca, Cold Lake, and Peace River deposits as shown in figure 1.3. Each area is covered by overburden consisting of layers of muskeg, glacial tills, sandstone and shale (ST98-2017 Alberta Energy Regulator, 2017).

![Map of Alberta’s oil sands areas and select deposits](image)

**Figure 1.3:** Alberta’s oil sand deposit areas: Athabasca, Cold Lake and Peace River (ST98-2017 Alberta Energy Regulator, 2017).

Different deposits have distinct characteristics and require different techniques to extract bitumen. In Alberta, the largest oil sands deposit is at the Athabasca area especially the McMurray formation. Concerning the petro-physical characteristics of the reservoir, the Athabasca oil sands are dominantly heterogeneous (e.g. mud shales) and this causes reservoir complexity.
The McMurray Formation outcrops along the lower Athabasca River. It was deposited during the Lower Cretaceous period and it consists primarily of unconsolidated sands. The thickness of McMurray formation is up to 150 m, lying over a layer of shale and limestone (resulting in an understrata seal) and beneath the Clearwater formation; a layer of marine shale and sandstone (providing an overburden seal). Whereas the Clearwater formation itself overlain by the Grand Rapids deposits, which is dominated by sandstone (Hein, 2000). Figure 1.4 presents the depositional characteristics, the geology, and gas and bitumen production in McMurray area.

Figure 1.4: Schematic diagram of the depositional characteristics, the geology, and gas and bitumen production in McMurray area (Bachu and Haug, 2002).

In-place volumes and established reserves of crude bitumen extractable using different techniques are shown in Table 1.1. SAGD uses two parallel horizontal wells. Steam is
injected through the upper horizontal well to reduce the viscosity of the bitumen, the steam would condense, and the emulsion of mobilized bitumen and water migrates by gravity to the bottom of the reservoir, where it is being produced to the surface via the lower horizontal well. In-situ average well bitumen productivity by recovery methods is displayed in Figure 1.6. In 2016, about 1,638,000 barrels/day of bitumen was produced by SAGD. Over the last ten years, bitumen production in Alberta is mainly associated with that of new SAGD operations in the Athabasca deposit.

Figure 1.5: Oil sand extraction processed: mining production and in-situ thermal recovery (CAPP, 2017)
Table 1.1: In-place volumes and established reserves of crude bitumen (109m³) extracted from mining production and thermal in-situ recovery (ST98-2017 Alberta Energy Regulator, 2017).

<table>
<thead>
<tr>
<th>Recovery method</th>
<th>Initial volume in-place</th>
<th>Initial established reserves</th>
<th>Cumulative production</th>
<th>Remaining established reserves under active development</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mineable</td>
<td>20.8</td>
<td>6.16</td>
<td>1.06</td>
<td>5.10</td>
</tr>
<tr>
<td>In situ</td>
<td>272.3</td>
<td>21.94</td>
<td>0.75</td>
<td>21.19</td>
</tr>
<tr>
<td>Total</td>
<td>293.1</td>
<td>28.09&lt;sup&gt;a&lt;/sup&gt;</td>
<td>1.81</td>
<td>26.28&lt;sup&gt;a&lt;/sup&gt;</td>
</tr>
</tbody>
</table>

<sup>a</sup> Any discrepancies are due to rounding.

CSS recovers typically about 30 per cent of the bitumen before it becomes uneconomic whereas SAGD can reach as high as approximately 60 per cent (Gates and Wang, 2013). Currently, CSS is used in the Cold Lake and Peace River oil sand deposits for which lower viscosity and higher gas saturations are present (as compared to the Athabasca area). SAGD, on the other hand, is mainly used in the Athabasca region.

Figure 1.6: In-situ bitumen average well productivity by recovery methods (ST98-2017 Alberta Energy Regulator, 2017).
1.3 Steam-Assisted Gravity Drainage (SAGD)

The concept of Steam-Assisted Gravity Drainage (SAGD) was initially proposed by Roger Butler in 1978. The first field trial of SAGD was at Imperial Oil’s cold lake operation, using a vertical injection well and a horizontal production well. Subsequently, the Alberta Oil Sand Technology and Research Authority (AOSTRA) successfully piloted SAGD using two horizontal wells at the Underground Test Facility (UTF).

Figure 1.7 shows the cross-sectional view of the steam chamber that develops in a reservoir operated by SAGD. In the figure, two parallel horizontal wells are drilled inside the reservoir, one above another.

![Cross-sectional view of steam chamber in reservoir operated by SAGD](image)

**Figure 1.7:** Cross-sectional process of chamber profile in the reservoir operated by SAGD (Su, 2016).
The upper well is called the steam injection well, whereas the lower one is the production well. The separation between two wells is typically 4 to 6 meters. The production well is placed roughly 3 to 5 meters above the bottom of the oil-bearing formation. Additionally, injection and production well pairs are typically between 500 and 1,000 m long (Butler et al., 1981; Gates et al., 2007; Peacock, 2009). The steam chamber evolves as injected steam migrates into the oil sands reservoir. At the edge of the depletion chamber, injected steam releases its latent heat through the cold reservoir (Gates et al., 2007; Peacock, 2009; Hubbard et al., 2011; Gates, 2011). After heat is released from the condensing steam at the edge of the steam chamber, the bitumen at the edge is heated and its viscosity is reduced which allows it to flow under the action of gravity. In most SAGD operation, the temperature of steam is between 185 and 230°C, which for most types of bitumen lower the viscosity of the bitumen to below 10 cP. Because of the density difference between steam chamber and bitumen, mobilized bitumen drains along the edge of the chamber under gravity to the bottom production well, which then produces the oil to the surface (Gates et al., 2007). As the process evolves, the steam chamber grows both vertically and laterally within the reservoir.

Efficient steam utilization is critical to successful application of the process. Though SAGD has demonstrated high oil recovery, the process is sensitive to the heterogeneity of the reservoir, e.g., shale and mud layers. In an ideal and homogeneous sand reservoir, the injected steam chamber grows uniformly along the well pairs and thus, the amount of bitumen contacted is relatively high along the well inside the reservoir. In other words, the steam conformance along the well pair is good. On the other hand, a degree of geological
heterogeneity in the reservoir, e.g., presence of shale, mud layers, or brecciated intervals, decreases the uniformity of steam injectivity along the well because shale and mud layers will serve as either barriers or baffles of steam to flow. Presence of water zones also results in an underperformance of the growth of the steam chamber. Regardless of the presence of overlaying or underlying water zones, heat from the injected steam is able to escape into the water zones instead of staying inside the chamber and directly heating bitumen (Xu, 2015). The impacts of geological heterogeneity results in different steam conformance (Wei, 2011).

Figure 1.8 shows an interpretation of steam conformance based on 4D seismic surveys of SAGD project. Interpretations from 4D seismic show that traditional SAGD cannot achieve the uniformity of injected steam along the well pairs (Byerley, 2009). Many hot and cold spots develop along the lateral length, which indicates sub-optimal management of steam within the reservoir. Consequently, the thermal efficiency is not optimal and well utilization is poor. This, in turn, decreases the oil rate and leads to a suboptimal resource recovery with a lower net present value.
The poor conformance as indicated by seismic interpretations of SAGD steam chambers and consequent reduction of performance is an important challenge faced by the in-situ oil sands industry. There is a pressing need to find methods to improve the conformance of SAGD steam chambers along SAGD well pairs as high level of reservoir heterogeneity results in non-uniformity of steam chamber in the reservoir.

To improve SAGD performance, additives, condensable (solvents) or non-condensable (gases) types, have been co-injected with steam. Solvent-additive recovery processes have been explored as means to improve the thermal efficiency of SAGD while reducing the emissions of greenhouse gases. In the Expanding Solvent SAGD (ES-SAGD) process, solvent is added to the steam. The central idea is that the solvent lowers the viscosity of
the oil below that of steam heating alone thus enhancing the oil drainage rate. The key economic measure of ES-SAGD is the amount of solvent lost to the reservoir; if high, the costs of the lost solvent can render the overall recovery process uneconomic. Another process being examined is non-condensable gas (NCG) addition to SAGD. This was referred to as the Steam and Gas Push (SAGP) recovery process by Butler (1999) and is referred to as NCG-SAGD in this thesis. In this process, NCG (often methane or natural gas) replaces some fraction of the steam yielding an improved steam-to-oil ratio. It is widely thought that the addition of NCG to steam helps to build a insulation blanket at the top of the steam chamber which consequently reduces heat losses and improves the thermal efficiency of the process (Pinto et al. 2016). At this point, the commercial potential of ES-SAGD and NCG-SAGD remains unclear.

1.4 Steam-Assisted Gravity Drainage (SAGD) in Reservoirs with Thief Zones

Generally, SAGD is preferably operated in a thick and high permeability oil-rich reservoir without top gas/water or bottom water to maintain an effective recovery process with no losses of steam to non-productive domains of the oil sand deposit (Elliot and Kovscek, 2007). The thickness of an oil-rich reservoir is a measure of the volume of oil stored, whereas the permeability is a measure of how fast the mobilized oil can be produced from the reservoir. Though many operators have attempted to operate SAGD in ideal reservoirs, the industry must also address the challenges with producing bitumen from structurally complex reservoirs (Aisha, 2014). Examples include thin oil sands reservoirs, reservoirs
with a high degree of shale layers, intraformational water zones, top gas/water zones, bottom water zones, and reservoirs with both top and bottom water zones.

More studies have been published on how to operate SAGD in top gas/water zones compared to how to operate SAGD in bottom water zones. The key conclusion from these studies has been that in reservoirs with top thief zones, the best operating strategy is to inject steam at a pressure similar to that of the top thief zone. Figure 1.9 shows example of the potential steam breakthrough to thief zone observed on 4D seismic picture of two different SAGD wells.

![Figure 1.9: Example schematics of thief zones for SAGD wells (Byerley et al, 2009).](image)

In reservoirs with thief zones, the objective is to limit the amount of steam that is lost to the thief zone, while maximizing the amount of steam that delivers heat to the bitumen-
bearing reservoir rock. The case is similar for bottom water systems in which the steam pressure should be maintained at a value that prevents loss of steam to the bottom water. Currently, there are no papers in the literature on SAGD operations in reservoirs with both top and bottom water zones. This is the subject of the research documented in this thesis. Here, SAGD, ES-SAGD, and NCG-SAGD will be explored in an oil sands reservoir with top and bottom water zones.

1.5 Research Questions

The research questions addressed in this thesis are as follows:

1. How does SAGD perform in a reservoir with underlying and overlying water zones? What is the impact of injection pressure on the performance of the process?

2. Does solvent or NCG addition improve the performance of SAGD in reservoirs with top and bottom water zones? Is there an optimal process, with respect to economic and environmental objectives, for which solvent and NCG addition can be used to yield a feasible recovery process?

1.6 Thesis Organization

This thesis is organized in five chapters. Chapter 2 presents a detailed literature review describing SAGD, completion design and challenges with conventional SAGD operation, thief zones in oil sand reservoirs, and what has been found as presented in the public literature. Chapter 3 provides an analysis of SAGD in a reservoir with top and bottom
water. In addition, ES-SAGD and NCG-SAGD are explored to determine if these enhancements help the recovery process. Chapter 4 describes a study in which robust optimization is used to determine if there is a solvent plus NCG-SAGD process that yields optimal economic and environmental outcomes. Chapter 5 summarizes the key conclusions and recommendations that arise from the research documented in this thesis.
Chapter Two: Review of Literature

2.1 Introduction

Oil sands deposits are generally divided into two categories. The first one is shallow resources less than approximately 70 m deep, which can be extracted by open pit mining. These represent about 20% of oil sands reservoirs in Alberta. The second category is deeper resources generally greater than 70 m deep, which are extracted by in-situ methods, about 80% of oil sands reservoirs in Alberta (Alberta Government, 2013). Examples of in-situ processes include Steam-Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS), both of which are thermal recovery processes where steam is injected into the reservoir to mobilize bitumen.

The concept of conventional SAGD, displayed in Figure 2.1, is simple but efficient. There are three stages of SAGD. First, the circulation stage during which steam is circulated in the injection and production wells (they act effectively as line heat sources) to heat the oil sands region between the wells. It is designed to establish inter-well communication and create an initial steam chamber. This stage takes three to six months. Second, after the inter-well region is heated, SAGD mode occurs where the steam is injected into the top well and production occurs through the lower well. In this stage, the steam chamber evolves first within the reservoir and, at some point of time, reaches the top of the reservoir then spreads laterally. After sufficient recovery or when the instantaneous SOR becomes high the operation either moves to blowdown (production with no injection) or wind down...
(production under gas injection) stages, which constitutes the 3rd stage of the SAGD lifecycle.

Ideally, the steam chamber should evolve uniformly along the entire length of the well pair. Unfortunately, an irregular steam chamber shape is developed in the most cases as is seen in interpretation of seismic data of SAGD field operations (Lerat and Adjemian, 2010). There are many reasons for poor steam conformance along SAGD well pairs including variations of the geology (porosity, permeability, and phase saturations), wellbore trajectory (non-horizontal wellbores), well completion (e.g. slotted liners or interval flow control), and wellbore hydraulics. Many SAGD operators have been trying to improve the conformance of steam along their well pairs to obtain lower steam-to-oil ratios and oil production rate.

Figure 2.1: The SAGD process (Taken from Vista Projects, 2016).
2.1.1 SAGD Performance

A measure of SAGD performance is the steam-to-oil ratio (SOR), which indicates the volume of steam, expressed as cold-water equivalent (CWE), required to produce one volume of bitumen. The SOR is also a measure of the thermal efficiency of the recovery process as well as an indicator of the economics of the process as steam is a direct cost whereas oil is the main revenue. Two forms of SOR are commonly used in the SAGD industry – the cumulative SOR (cSOR) is defined as the ratio of the cumulative steam volume (as CWE) to the cumulative bitumen whereas the instantaneous SOR (iSOR) is the ratio of the daily steam volume (as CWE) to the daily bitumen produced. The lower the SOR, the better the energy efficiency. The effective use of steam is a critical criterion for SAGD design because its operational expenditure is directly linked to steam generation.

Figure 2.2 shows a cross plot between iSOR and the cumulative bitumen production rate per well pair as of Q3 in 2016 for major SAGD projects in Alberta, Canada (McDaniel, 2016). Comparing the iSOR values, the Christina Lake project operated by Cenovus Energy shows the lowest steam usage per barrel of bitumen produced. The Jackfish project, operated by Devon Canada Corporation, has the second best thermal efficiency of SAGD production in Q3, 2016. The average iSOR of the projects dropped from an average of 3.4 m$^3$/m$^3$ in the early years of operations (IHS CERA Report, 2010). A significant factor dictating the SOR performance is the advancement of well completion technology. Not only has this reduction benefited projects in terms of economics, but also the decline of
greenhouse gas (GHG) emission intensity (the amount of GHG released per unit volume of bitumen produced).

Figure 2.2: ISOR Cross-plot by SAGD Projects in Alberta, Canada as of Q3, 2016.

2.1.2 The Challenge of Steam Conformance in SAGD

An effective way to optimize SAGD performance is by ensuring uniform steam distribution (Stastny, 2017); steam conformance, however, is strongly influenced by reservoir heterogeneities (Vander and Yang, 2007; Su and Gates, 2015). High heterogeneity of the reservoir implies that there is significant variations of the porosity, permeability and phase saturations which in turn implies that steam injectivity and bitumen drainage within the reservoir will not be uniform thus leading to non-uniform flow and sweep efficiency.
leading to non-optimal SOR and economics of the oil sand project (Baker et al, 2010; Barillas, 2006). Not only does the reservoir heterogeneity cause a non-uniform steam conformance, but also the well trajectory and design may lead to non-uniform steam injection along the well length. Some operators have attempted to make steam flow more uniform in wells by placing multiple tubing strings in the well where some fraction is injected into the toe of the well and the remainder is injected into the heel of the well. The use of long and short tubing strings in the horizontal injector wells is referred to as a dual tubing completion design. Figure 2.3 illustrates an example of dual tubing well configuration operated by Husky Oil at Tucker Lake and ConocoPhillips Canada and Total E&P Canada at Surmont (Stone and Brown, 2014); a long string connects to the toe and a short string connects to the heel of the well. Installation of dual-tubing strings in the injector and producer wells provides some control of the distribution of heat and production zones.

Figure 2.3: Example of dual tubing string well configurations (Taken from Stone and Brown, 2014).
One method operators use to handle an uneven pressure profile within a well pair to discourage steam breakthrough yielding more uniform steam conformance is subcool control. The subcool temperature difference refers to the temperature difference between the injected steam and the produced fluids. It provides an indication of the liquid level above the producing well, which is desired because this prevents live production of steam (steam breakthrough) from the reservoir. Field subcool control data is shown in Figure 2.4.

A greater subcool temperature difference implies higher liquid level above the producer, which can impair oil production if it is too high. A low subcool temperature difference corresponds to a low liquid level, which may result in steam bypassing directly to the production well (Das, 2005a; Edmunds, 1998). As a rule of thumb, every vertical meter of fluid increases the subcool temperature difference by about 10°C. Figure 2.4 shows that a high subcool leads a lower oil rate and higher SOR.

Figure 2.4: Rate and SOR versus subcooled (Vander and Yang, 2007).
Preferably, an intermediate subcool provides effective productivity and SOR. Nonetheless, this approach has some limitations. As the subcooled level affects the entire production, there is a limited ability to control mobilized fluid across the liner. In addition, it cannot handle a specifically problematic zone along the well pair. The schematic of the subcooled concept in a SAGD operation is illustrated in Figure 2.5.

![Schematic of subcooled concept in a SAGD operation](image)

**Figure 2.5**: Schematic show the subcooled concept in a SAGD operation (Clark, Ascanio, Kruijsdijk, 2010).

### 2.2 SAGD Completion Design and Challenges

The revolution of drilling and completion techniques in SAGD has helped improve its performance. Well completion design is crucial to energy efficiency because it is the first physical element connected to the reservoir. Therefore, well design should be able to perform at a wide range of operating conditions.
In conventional SAGD practice, there are two parallel horizontal wells—Injection and production wells—that are drilled in depth between 90 and 600 meters, with 5 meters of vertical offset and up to 1000 meters of horizontal displacement. An open-hole completion with slotted liner installation is the standard SAGD well design used in the oil and gas industry. Typically 800 to 1000 m slotted liners are installed with tubing strings landed close to the heel and the toe in both the injector and the producer to provide flow distribution control over each well (Stalder, 2013). Currently, SAGD configuration consists of 8 to 12 well pairs per pad. Investments in well design to improve the thermal efficiency of SAGD operations have been shown to contribute to the commercial success of oil sand recovery (Gao, 2014). An illustration of typical SAGD well placement is shown in Figure 2.6. In field practice, the production well is drilled first. It is located as close as possible to the bottom of the reservoir to contact and gain as much oil drainage as possible. Thereafter, the injection well is drilled.

Figure 2.6: An illustration of SAGD well placement (Statoil, 2011).
SAGD operations typically install more than one tubing string for either the injection or production well to improve the uniformity of the injected steam profile along the lateral length. However, the optimal locations and number of tubing strings are still questionable. In a certain case, extra tubing strings may be required to support well monitoring apparatus (Stalder, 2013).

For reliable placement of steam, three areas are needed to be under control: open hole-liner annulus, casing-tubing annulus, and tubing or liner exits. No matter what form of liner or tubing control is in place, steam can migrate along the wellbore if the open hole-liner annulus area is not controlled (Fram and Sims, 2010). Slotted liners with tubing strings deployed are used in the majority of SAGD operations in Western Canada. Generally, these liners are designed to provide production sand control, resist modest collapse loads, and maximize an inflow area. While a variety of configurations has been designed, a success of slotted liner design ensures that the liner can prevent solids infill of the horizontal section of the well, which may result in plugging issues in wellbore. Furthermore, it is essential that slotted liners are designed with sufficient structural capacities to withstand thermal localization in the reservoir, while allowing the maximum production of bitumen with a minimum pressure differential. The specification of slot liners are manufactured by cutting a series of longitudinal slots, typically 0.30-0.4 mm(0.012-0.018 in.) wide by about 50-70 mm(2-2.75 in.) long. Basic slotted liner design requires the capability to balance sand retention, while it allows fluid to flow in the area. Three slot patterns have been used nowadays for both thermal and non-thermal recoverable process, which are demonstrated in Figure 2.7.
2.3 Thief Zones in Oil Sands Reservoirs

The heterogeneity of the reservoir is a ubiquitous challenge in reservoir engineering where the non-uniformity and uncertainty of reservoir properties makes it difficult to obtain high recovery factors from the reservoir. Heterogeneity can take the form of variations of geological properties such as porosity, permeability, and phase saturations as well as variability of the lithology e.g. point bar deposits (Su et al. 2014, 2015), and the existence of thief zones. This zones can exist either above the reservoir (Gates et al. 2007, Al-Turki et al. 2011, Law et al. 2003), below the reservoir (Wei and Gates, 2015), or within the reservoir (Fairbridge et al., 2012). These thief zones can be filled with gas (more likely at the top of the reservoir) and water (can occur as top water or bottom water zones). Doan investigated the effect of the presence of water sand on SAGD performance (Doan, 1999). As the water sand could lie over or under bitumen zones, his numerical simulation were set up to investigate the SAGD case by separating the case with the presence of top water overlying and also the case of bottom water underlying bitumen pay. The result revealed that the presence of top water alone showed higher impact on SAGD operation than the
case of the only existence of bottom water. Moreover, the study concluded that there is a relationship between bitumen recoverable rate and the heat accumulated in the reservoir (Doan, 1999). Unfortunately, Doan’s study did not consider the reservoir having both top and bottom water sands. The SAGD performance on reservoir containing water underlying and overlying thief zones is limited.

Most research in the literature has focused on top water zones with limited research on bottom water zones. To the best of the author’s knowledge, no papers have been published with a focus on reservoirs that have both top and bottom water zones. Thief zones have a tremendous effects on steam chamber growth since steam is lost into these zones instead of transferring heat to the bitumen. In addition, thief zones may be a source of cold water to the steam chamber that robs its energy leading to less energy being delivered to the bitumen. Nexen’s Long Lake and Suncor’s Firebag SAGD projects reported the presence of lean zones intersection. Lean zones are the zone with higher gas or water saturations which act as thief zones in those reservoirs (Xu, 2014). Steam energy losses to a top water zone dramatically effects the energy efficiency of the recovery process and can have a major economic impact on the process.

In SAGD operation, given that the major drive mechanism for flow is gravity drainage, there is a major concern related to the presence of thief zones in an oil sand reservoir, which has a detrimental effect on oil sand recovery including lower reservoir pressure during SAGD operation. Especially, the case is found when the pressure in the thief zones are below the SAGD operating pressure due to the natural gas production (Law, Nar and Good,
2003; Bao and Chen, 2010). The Alberta Department of Energy (ADOE) and Alberta Energy and Utilities Board (AEUB, now referred to as the Alberta Energy Regulator, AER) launched a series of numerical studies of field scale operations to evaluate the impact of top water and gas zones (Good and Felty, 1997) on SAGD under a variety of reservoir conditions, e.g., reservoir thickness and oil saturation. The results demonstrate that gas caps and the top water zones act as thief zones on the SAGD process during which the directional movement of steam has a tendency flowing toward the gas cap and top water zones. Moreover, the amount of steam loss is proportional to the thicknesses of top water and gas cap zones and a differential pressure between steam chamber and such thief zones. These circumstances were for the case in which the injection pressure is higher than that of the top thief zone pressure.

Therefore, various operating strategies are needed to deal with thief zones. Good (1997) conducted a numerical study to observe the SAGD performance in the presence of a top gas zone laying over the bitumen reservoir. Two-dimensional simulation model is analysed with a number of sensitivity cases. The result revealed that the higher thickness of the gas cap, the lower the bitumen recovery rate. In addition, a significant variation of the fluid rate and well bottom-hole pressure are evident in the simulation result depending on the nature of the thief zone. Figure 2.8 shows the potential challenges faced by SAGD operations when thief zones are present.
Figure 2.8: Challenges in SAGD operation due to thief zones (Statoil, 2014).

An example of steam chamber interaction with top thief zones and associated effect is presented in Figure 2.9. After the steam chamber was developed, it would reach to the top part of bitumen deposit and subsequently would migrate laterally within the thief zones. The mobile top water would migrate by gravity downward into the steam chamber, cooling down the reservoir, quenching the chamber. This results in less heat delivered to the steam-bitumen interface; hence, increasing the instantaneous SOR and finally affecting the economics of the operation.

Figure 2.9: Steam chamber interaction with thief zones (Thebault, 2011).
2.3.1 Top Gas Zones

A gas cap overlaying bitumen can behave as a thief zone. If the steam injection pressure is higher than that of the top gas zone, the steam chamber, when it reaches the top gas zone will penetrate and invade the thief zone. This means that steam is delivered to the gas zone rather than to the bitumen; thus, the efficiency of the recovery process is lowered and the SOR is raised. On the other hand, if the steam injection pressure is lower than that of the gas zone, then the gas will invade the chamber lowering the partial pressure of steam. This will lead to a lower steam pressure and temperature, which will potentially lower oil drainage rates and raise the SOR. If the steam pressure is equal to that of the gas zone, then the system is balanced and although conductive heat losses from the steam chamber may occur, there will be little or no convective flow between the chamber and the top gas zone.

2.3.2 Top Water Zones

Similar to top gas zones, the interaction of the steam chamber and top water zone is controlled by the pressure difference between the two. However, water from the top water zone drains even if the steam pressure is higher or equal to that of the top water zone, although the rate of water drainage is lower in the case where the steam pressure is lower than that of the top water zone (Gates et al. 2007). If the steam pressure is higher than that of the top water zone, the steam invaded the top water zone and water drains into the steam chamber. This raises the SOR of the process. If the steam pressure is lower than that of
the top water zone, the water in the top water zone drains into the chamber and, to some extent, quenches it and stops the leak. Gates et al. (2007) showed that the rate of water flow and steam losses could be controlled by operating the process during which the steam injection pressure is roughly equal to that of the top water zone.

Top water is usually considered as a heat sink for steam and the thickness and extent of the top water zone is a key control variable on the process. Doan (1999) demonstrated that oil sand recovery was reduced dramatically due to the influence of top water zone, which effects SAGD performance. Another investigation by Nars (2003) on the impact of top water zone used field scale numerical simulation. The results supported the assumption that the higher differential pressure between top water and steam chamber results in the lower SAGD performance regardless to confined or unconfined top water zone. Onwughalu studied the impact of top water on SAGD by setup a numerical simulation case studies of limited and unlimited top water. The results demonstrated that unlimited top water reservoir has more influence on the performance of SAGD operation than that of limited top water reservoir. These simulation results were observed as unlimited top water case showed the higher cSOR and lower cumulative oil. At very high steam injection pressures, e.g. 2000 kPa, unlike in the limited top water case, a high temperature profile for an unlimited top water case may not essentially correspond to large steam chamber volume (Onwughalu, 2015).
2.3.3 Bottom Water Zones

Similar to top water, a bottom water zone is potentially a heat sink for injected steam and is also able to cool the mobilized bitumen (Wei and Gates, 2015). The effect of bottom water thief zones was studied by Doan, who summarized that there was a correlation between oil recoverable rates, accumulation of heat in the reservoir, and water sand thickness. The results also showed that oil sand recovery rate was lower in the presence of a bottom water zone (Doan, 1999). Wei (2015) showed that pulsing the injection pressure around the pressure of the bottom water zone was one of the optimal operating strategies to control the growth of steam profile.

Husky (2008) operated the Tucker Lake SAGD operation in the presence of a bottom water zone. The key challenge that Husky faced was that when the SAGD well pairs were started, water flow channels were established between the injector and the bottom water zone. The water zone acted as a thief zone for steam and the well pairs were not successful. However, as suggested by Wei (2015), the well pairs, if raised above the oil-water contact can be operated successfully. Husky (2008) installed new well pairs that were raised above the oil-water contact and the performance of the operation improved significantly.

2.3.4 Top and Bottom Water Zones

At this point, several operations are challenged by the presence of both top and bottom water zones. One such operator is the Korean National Oil Corporation’s BlackGold
project which in the southeast of Fort McMurray area within the Athabasca Oil Sands region of northern Alberta. This bitumen reservoir is the Lower Cretaceous McMurray Formation. The reservoir has top and bottom water zones, whose temperatures and pressures are monitored continuously by observation wells. Their operating strategy is to prevent steam breakthrough to the top zones by lowering the steam injection pressure to the pressure of the top zone. However, none of the previous reports have studied how to handle the bottom water thief zone (Harvest Operation Corp., 2011). Thief zones for SAGD are critical because of the tremendous potential of energy losses into water zones, and sometimes gas zones, instead of directly heating bitumen. Figure 2.10 presents how SAGD well pairs operate at the Surmount Oil Sand lease. These wells lack a good steam conformance due to the existence of top and bottom water zones, therefore, proper risk identification of thief zones and close monitoring of steam chamber profile is required (ConocoPhillips, 2017).

Currently, no research have been published describing the impact and methods to improve the performance of SAGD in the presence of both top and bottom water zones. This is the subject of the research documented in this thesis.
Figure 2.10 presents how do SAGD well pairs operate at Surmount Oil Sand lease lacking a good steam conformance due to the existence of top bottom water zones (ConocoPhillips, 2017).

2.4 Review of SAGD Studies with Thief Zones

A good operating strategy has to take into account the presence of thief zones. Several studies have considered the optimization of SAGD in oil sand reservoir with thief zones (Good, 1997; Doan, 1999; Law, 2003a, 2003b; Nasr, 2003; Gates, 2007). Since 1990, Saskoil and Butler performed a physical experiment model in two dimensions of vertical steamflood and SAGD, in which the bottom aquifer acted as a thief zone in the reservoir (Saskoil and Butler, 1990). Whereas the injection well was placed close to the top of the reservoir formation, the production wells were tested at different elevations from the bottom water zone to above in the bitumen pay zone. This experiment was set up to demonstrate the SAGD performance due to the variation of steam injection pressure, the
thickness of water pay and elevation of the production well. The experiment started from the circulation stage during which a vertical steamflood initiated thermal communication path between SAGD producer and injector, as well as oil was displaced by steam to the production well. At the time of steam breakthrough, the circulation stage was switched to SAGD operation mode by decreasing the pressure of the injected steam. Then, gravity drainage dominated the process. The result showed that the production pressure had to be close to that of the aquifer to minimize the amount of produced water from the aquifer. In addition, when the production well was placed slightly above the water-oil contact, the higher initial oil rate at an early SAGD operational stage was achieved. Later, the highest recovery factor was realized in the case where the production well was located at the water-oil contact level. They also pointed out that the onset of oil production for the well located at the lowest in the water zone was delayed.

Law (2003a, 2003b) studied the effect of thief zone in the bitumen reservoir with top water section on bitumen drainage rate and heat loss of an injected steam. Laboratory studies were set up with a physical model of the reservoir with top water and SAGD operation in a 60 cm x 30 cm diameter high-pressure vessel. The results of the experiments showed that the larger the differential pressures between the steam chamber and top water zone, the lower the oil production rate and the higher the SOR.

Law (2003a) also investigated the case with a top water zone experimentally. In addition, top gas zone was conducted to observe the impact on SAGD performance of a top thief zone. The experimental study concluded that the greater the pressure difference between
oil zone and top thief zone, the larger the amount of oil and injected steam flow into the top thief zone which in turn causes lower oil production rate and higher SOR. This proved that the pressure control between two zones is critical for SAGD operation. Therefore, thief zones can cause detrimental heat losses during SAGD operation (Wang and Leung, 2015).

Since 2008, Husky has operated their SAGD operation in the Clearwater Formation (Husky, 2008). The bottom water thief-zone had greater than 80% water saturation with the water-to-oil contact transitioned from 0.5 to 0.8. While the average porosity and oil saturation values are 0.31 and 0.57, respectively, in this zone. The Tucker Lake SAGD operation data, sourced from public disclosures, is shown in Figure 2.11.

From the data, the cumulative SOR of this SAGD operation is very high and declines to about 10 m$^3$/m$^3$. Additionally, the produced water rate exceeded the steam injection rate (steam is expressed as cold-water equivalent); the extra water came from the bottom water zone. Husky also showed that the viscosity gradient from the top to the base of the bitumen formation ranged from 300,000 cP (top) to more than 2 million cP (bottom). With the decline of a vertical oil saturation profile, it clearly showed that water phase mobility is significantly greater than that of the oil phase and that this is especially the case at the lower section of the oil pay section.
Chung investigated the influence of SAGD process with co-injection of non-condensable gas (NCG) with the steam. The result revealed that NCG co-injection was able to prevent additional water influx in the reservoir by maintaining the pressure in the steam chamber. Furthermore, the study found that there existed a correlation between the amount of an injected NCG and steam injection pressure, which jointly impact the efficiency of the process (Chung, 2013).

Fairbridge et al. (2012) conducted a study to determine how intraformational water zones impacts SAGD performance (Fairbridge, 2012). Based on these results, SAGD performance was found to be affected by the water zones, whereas the intraformational water zones behave as thief zones.
Peterson and Edmunds (Peterson and Edmunds, 2010) evaluated Saskoil and Butler’s start-up procedure. Steam circulation was conducted in the injection well, whereas a large volume of steam was injected through the production well. Peterson, by using numerical modelling, analysed a series cases each with different placements of the production and the injection well (from 1.5, 2.5, 3.5, 4.5 to 5.5 m above the oil-water contact). The target was to enlarge the injected steam volume during SAGD start-up but still trying to keep the production well within the bottom water zone. The results showed that the best performance was achieved in the case where the production well is positioned at the base of the bottom water zone. This is inconsistent to the results obtained by Wei and Gates (2015). Peterson and Edmunds’ results also showed that when the production well was placed at the base of the water zone, the oil production rate was delayed (Peterson and Edmunds, 2010). The field results from Laracina (2013) where the production wells were placed in the water zone demonstrated that Peterson and Edmunds results led to an erroneous conclusion.

Zhou investigated another case of an improvement of SAGD performance where fishbone well configuration concept and polymer injections were tested in the reservoir overlaying top water zone (Zhou, 2016). Zhou’s study proved that polymer injection was capable to establish a stability of viscous layer and that can prevent top water invasion into steam chamber profile. Additionally, steam injected through the fishbone configuration supplemented the improvement of steam distribution into the reservoir and improved SAGD performance.
2.5 SAGD Optimization

Kisman and Yeung (1995) assessed SAGD performance in the Burnt Lake oil sand lease in the Cold Lake deposit by numerical modelling (this reservoir does not have associated gas cap or bottom water present in the neighborhood of the well pairs). Various operating strategies were tested in a sensitivity analysis by varying of various operating parameters (Kisman and Yeung, 1995). Compared to the reservoir condition above, the bottom zone of the reservoir showed poorer quality. The simulation results from locating well in the bottom zone in lower permeability had a significant effect in the overall performance and showed a decrease in the oil rate as the depletion of an operating pressure.

Shin and Polikar investigated three major Canadian oil sand reservoirs. Reservoir models were analysed to optimize the operating parameters related to SAGD process to and optimal operating conditions to maximize the net present value of the project. The study addressed the time period during SAGD circulation (pre-heating), spacing between the injection and the production wells, operating pressure, steam injection rate (at maximum) and also finding the effect to reservoir thickness. The results indicated that the major key in controlling SAGD performance in the reservoir is the reservoir thickness and permeability (Shin and Polikar, 2005).

Bao studied the case of the Surmont lease, which was recorded as a pilot project to study the problems with gas caps and top water zones connected and laid over the bitumen interval (Bao, 2012). In the study, geostatistical modelling workflow and thermal SAGD
simulation was constructed. Through sensitivity analysis, solvent mixture co-injected with steam (ES-SAGD) was tested to improve bitumen recovery underlying a top thief zone. Four thief zone cases were evaluated using numerical simulation with reservoir variation in the top gas and top water zones: Case A - no top water, Case B - no top gas, Case C - no thief zone, and Case D - thicker gas cap. Example results are displayed in Figure 2.12. Based on the results, the two-dimensional (2D) models revealed that SAGD performance is more sensitive to the injection pressure when a thief zone is present. Earlier steam breakthroughs into the top water zone occur at higher injection rate and water drains down to the steam chamber in the top water cases. The cSOR is lower as shown in Case C for which no thief zone was specified. Therefore, Bao suggested that to optimize cumulative oil production, the steam-trap control strategy must be managed carefully by setting a higher rate of injected steam at the start and lower value thereafter. However, Bao does not disclose the proper values of the steam rate or pressure.

Gates and Chakrabarty (2006) conducted a SAGD optimization study in the McMurray oil sands reservoir. By altering the evolution of the steam injection pressure through time, the cSOR was dramatically improved. The strategy for the steam injection pressure was that it should be high at the early stage of SAGD operation since the chamber profile is not yet connected with the cap rock and all heat energy transferred directly into the reservoir (Gates and Chakrabarty, 2006). High pressure implies high saturation temperature, which means lower oil viscosity and higher thermal efficiency as there is no heat loss through the cap rock. Later on in an operation, after the steam chamber has reached the cap rock, the pressure should be lowered to minimize heat losses. At the later stage, the differential
temperature between the chamber and the cap rock was kept lower which then causes lower heat losses.

![Figure 2.12: The growth of steam chamber for different thief zone configurations (Taken from Bao, 2012).](image)

Egerman optimized Mobil’s Celtic SAGD pilot by matching history from the field and improving the process by simulation-aided optimization. Sensitivity analysis was run by controlling production rate and varying an injected steam rate. From the study, Egerman’s strategy was to improve the expansion of steam chamber growth within the reservoir as much as possible and to maintain steam away from the production well to avoid steam breakthrough. The optimized process concluded that a decline of subcool temperature
difference from 60 to 30°C results in enhanced growth of the steam chamber (Egerman, 2001).

Queipo proposed a solution an optimization method of model-based global optimization. This optimized concept based on the technique of neural networks, design and analysis of computer experiments (DACE) modelling and adaptive sampling. The subcooled temperature difference was a constraint in the study, while the targeted reservoir was optimized. The results revealed the algorithm improved of SAGD optimization where an adjustment of injection pressure, vertical space between two wells and an injected steam rate were adapted by weighting a summation of cumulative oil production and cumulative steam injection (Queipo, 2001).

2.6 What is missing in the literature?

The literature review reveals that no publication studies related to the performance of SAGD, ES-SAGD and NCG-SAGD in oil sand reservoir in the presence of top and bottom water zones and how the steam injection pressure impact the process. Many publications either focus only on an existence of top water or bottom water. Moreover, in this research we further explore how solvent or NCG addition aids SAGD performance and improves bitumen production under reservoir with top and bottom water zones. An optimal process on solvent and NCG co-injection with steam were explored to figure out a feasible recovery process with respect to economic and environmental objectives.
Chapter Three: An analysis of SAGD, ES-SAGD and NCG-SAGD in a thin reservoir with top and bottom aquifer

3.1 Introduction

The presence of overlying and underlying water zones in bitumen formations makes these reservoirs challenging for application of SAGD. In Athabasca oil sands deposits, if the initial pressure of water or gas zones is lower than that of the SAGD operating pressure, then these zones can act as thief zones (Rourke and Anderson, 1999). High-pressure steam injection into a lower pressure reservoir heats and mobilizes bitumen but after the steam chamber has connected to the top and bottom water zones, it flows into these zones bypassing the oil (Bachu and Haug, 2002). If the overall pressure of the steam drops due to the contact with the low pressure zone, the saturation temperature of the steam falls and consequently, the bitumen viscosity is adversely affected leading to less than ideal efficiency. SAGD operated at reduced pressure, lower than that of the thief zones, may reduce excessive heat losses to thief zone but then fluids from the thief zones may invade the steam chamber. In addition, lower operating pressure means lower saturation temperature, which leads to the higher bitumen viscosity. This in turn implies less oil drainage and reduced bitumen productivity and higher steam-to-oil ratio. On the other hand, increasing the steam injection pressure results in rapid vertical rise of steam chamber and hastens steam encroachment to the thief zone since the higher pressure of an injected steam is capable to create a path of steam breakthrough to the surface (Nkiru, 2015). Thus,
a balance between overpressured and underpressured injection into the steam chamber in the presence of thief zones is essential.

Several variants of recovery processes for oil sands reservoirs in which a hydrocarbon additive is co-injected with steam have been developed. One popular method is ES-SAGD where diluent (gas condensate typically consisting of 5% aromatics and 95% C6 to C8 alkanes) is injected together with steam; an alternative is called the Solvent Aided Process, SAP, where butane is co-injected with steam (Cenovus, 2013; Orr, 2009; Gupta et al, 2002; Gupta and Gittins, 2005). A field trial of SAP was operated by Encana in the Senlac area and described by Gupta et al. (2002). The field trial results proved that on addition of the solvent, the oil production rate increased from 300 to 470 t/d over a two-month period without any alteration for the steam injection rate (Gupta et al, 2002). Generally, the solvent volume fraction used in the steam is less than 5% (Nasr and Isaacs, 2001; Leaute and Carey, 2005; Ayodele et al. 2010). In an alternative process, non-condensable gas (NCG) is added to steam; Butler (1999) called this process the Steam and Gas Push (SAGP) process. Here, this process is referred to as the NCG-SAGD process. In typical practice, the volume fraction of NCG, e.g. methane or natural gas, is in the steam is equal to about 5%. Cenovus conducted a field pilot of NCG-SAGD (with methane) in their Foster Creek operation (Cenovus Energy, 2012b) using a ramp-down strategy. The result of the field trial was that the oil recovery was enhanced and the steam-to-oil ratio was reduced while maintaining the pressure of the operation.
A clear potential for adverse performance of SAGD in reservoirs with top and bottom water thief-zones, and a great opportunity for solvent and NCG addition to steam to improve recovery performance are recognized. Consequently, the research documented here focuses on how solvent and NCG additive processes can improve the performance of SAGD recovery processes in relatively thin oil sands reservoirs with top and bottom water zones. Though hybrid thermal-solvent-NCG processes yield improved bitumen recovery, it remains unclear how these additives might improve the performance of SAGD in the presence of top and bottom water zones. Top and bottom water thief-zone interactions and steam chamber coalescence effects within the same bitumen reservoir are important to consider for optimal process design. To understand process dynamics, in this thesis, a sensitivity analysis is conducted to understand the role of solvent and NCG individually on the dynamics and performance of the recovery process.

### 3.2 Reservoir Simulation Model

A two-dimensional (2D) reservoir simulation model was created from a full geological model of an oil sands reservoir in the Athabasca area. This reservoir has both top water and bottom water zones. The reservoir model is displayed in Figure 3.1. The thicknesses of the oil column, top water zone, and bottom water zone are 12 m, 5 m, and 3 m, respectively. The geological properties of the reservoir were populated by using geostatistics (sequential Gaussian simulation for porosity, permeability, and phase saturations) using data sourced from log and core data (core data was used to construct porosity-permeability transforms and the vertical-to-horizontal permeability ratio).
Figure 3.1: Cross-sectional views of the reservoir model.
The average porosity of the reservoir is equal to about 0.26. The vertical permeability, the horizontal permeability and the $k_v/k_h$ distribution have the value in average about 4,322 mD, 3,202 mD, and 0.74, respectively. As shown in Figure 3.1, the oil column is relatively clean with few shale layers. The initial water saturation is equal to about 0.33 with minimum and maximum values equal to 0.006 and 1, respectively. The distribution of oil saturation is in the range between 0.72 and 0.98. The initial reservoir temperature and pressure are equal to 11°C and 1,600 kPa, respectively. The top of the top water zone is at 253 m depth, whereas the top of the bottom water is at 265 m depth. The SAGD production well is positioned 2 m above the base of the oil column and the injection well is positioned 5 m above the production well. The initial pressures of the top and bottom water zones are 1496 and 1690 kPa, respectively. At the sides of the top and bottom water zones, the edge grid blocks are artificially enlarged (to 0.0003225 km$^3$) to model the water zones extended capacity and continuously provide or take water from the system. In other words, the top and bottom water zones extend beyond the edges of the model and the cut-off for water saturation to be considered water zone is when the value exceeds 60%.

Reservoir simulation models are helpful to understand the dynamic of SAGD process and to provide guidance for field development plan, as well sensitivity analysis of multiple parameters affecting on recovery performance. The CMG STARS$^\text{TM}$ thermal reservoir simulator (CMG, 2016) is used to solve the mass, flow, and energy balances. The STARS$^\text{TM}$ reservoir simulator solves the mass and energy balances in the context of multiphase (oil, water, and gas) Darcy flow in porous media by using the finite volume method; details can be found in CMG (2016). Phase equilibrium is imposed using a K-
value based flash algorithm. A full description of the simulator, discretization strategy, governing equations, and time stepping are documented in the CMG User’s Manual (CMG 2016). The properties of the reservoir materials are listed in Table 3.1. Figures 3.2 displays the oil-water and oil-gas relative permeability curves.

**Table 3.1: Input parameters for the reservoir model.**

<table>
<thead>
<tr>
<th>Properties</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net pay, m</td>
<td>12</td>
</tr>
<tr>
<td>Initial pressure at 240 m, kPa</td>
<td>1,600</td>
</tr>
<tr>
<td>Reservoir temperature, °C</td>
<td>11</td>
</tr>
<tr>
<td>Dead oil viscosity @ 11°C, cP</td>
<td>550,580</td>
</tr>
<tr>
<td>Dead oil viscosity @ 200°C, cP</td>
<td>6,315</td>
</tr>
<tr>
<td>Oil density @ 1,600 kPa, kg/ m³</td>
<td>995,907</td>
</tr>
<tr>
<td>Oil thermal conductivity, kJ/m day °C</td>
<td>11.5</td>
</tr>
<tr>
<td>Solution gas density, kg/m³</td>
<td>11.2191</td>
</tr>
<tr>
<td>Water density, kg/m³</td>
<td>1000.3</td>
</tr>
<tr>
<td>Water thermal conductivity, kJ/m day °C</td>
<td>53.5</td>
</tr>
<tr>
<td>Gas thermal conductivity, kJ/m day °C</td>
<td>5</td>
</tr>
<tr>
<td>Horizontal to vertical permeability k_v/k_h</td>
<td>0.74</td>
</tr>
<tr>
<td>Effective rock compressibility, 1/kPa</td>
<td>1.40E-05</td>
</tr>
<tr>
<td>Rock heat capacity, kJ/m³ °C</td>
<td>2600</td>
</tr>
<tr>
<td>Rock thermal conductivity, kJ/m day °C</td>
<td>660</td>
</tr>
<tr>
<td>Overburden thermal conductivity, kJ/m day °C</td>
<td>151</td>
</tr>
<tr>
<td>Underburden thermal conductivity, kJ/m day °C</td>
<td>151</td>
</tr>
</tbody>
</table>

From the reservoir simulation model, the grid block dimensions are 1 m in the cross-well direction, 750 m in the down-well direction, and 0.3 m in the vertical direction. In other words, the grid block dimensions are 1 m × 1 m × 0.3 m in i, j, and k direction. The model consists of 9,250 grid blocks. A grid sensitivity was conducted where the grid blocks were halved in the cross-well and vertical directions for the SAGD, ES-SAGD, and NCG-SAGD.
cases. The produced oil volume and steam-to-oil ratios were changed by less than 0.1%.
Thus, the grid was considered sufficiently resolved to model the three recovery processes.
The operations were simulated for a total of ten years.

Figure 3.2: Relative permeability curves governing multiphase flow in the reservoir.

3.2.1 Well Constraints

Prior to SAGD operation, the inter-well region was heated by using steam circulation for
three months. This was done by placing temporary heaters in the locations of the wells.
To deal with thermally expanded fluids, the production was open and set with a bottom-
hole pressure constraint equal to the initial reservoir pressure at its elevation (Gates et al.
2007). Similarly, for the injection well location, a temporary production well was placed
in the location of the injection well and operated at the initial pressure of the reservoir at
that elevation. After three months of heating, the heaters were switched off, the temporary
production well was removed, and steam injection was started into the upper well (SAGD
mode). During SAGD, to mimic steam trap control, the production well was constrained to 10 m$^3$/day (expressed at surface conditions by cold-water equivalent, CWE). For the injection well, the total injection pressure were set to 1100, 1600, and 2100 kPa which are below, balanced, and over the reservoir pressure, respectively; with steam quality equal to 0.9 for all cases.

3.2.2 Cases

The input parameters evaluated here are the total injection pressure, solvent addition to steam, and NCG addition to steam. The solvent used here is hexane as a surrogate for diluent and the NCG is methane. The nine cases evaluated here are listed in Table 3.2. For the solvent cases, the volume fraction of solvent in the injected fluids is 5% whereas for the NCG-SAGD cases, the volume fraction of methane is 5%.

Table 3.2: Simulation cases.

<table>
<thead>
<tr>
<th>Case Number</th>
<th>Total Injection Pressure, kPa</th>
<th>Recovery Process</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1100</td>
<td>SAGD</td>
</tr>
<tr>
<td>2</td>
<td>1600</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>2100</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>1100</td>
<td>ES-SAGD</td>
</tr>
<tr>
<td>5</td>
<td>1600</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>2100</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>1100</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>1600</td>
<td>NCG-SAGD</td>
</tr>
<tr>
<td>9</td>
<td>2100</td>
<td></td>
</tr>
</tbody>
</table>
3.3 Results and Discussion

The results from the SAGD, ES-SAGD, and NCG-SAGD cases are presented in the following subsections.

3.3.1 SAGD

Figure 3.3 displays the cumulative oil production from the reservoir with SAGD operated at injection pressures of 1,100, 1,600, and 2,100 kPa. The cumulative oil produced peaks in Case 2, reaching to 192,000 m$^3$ after 5 years of operation. The lowest cumulative oil recovered occurs in the low-pressure case (Case 1). However, the oil rate of Case 1 is relatively stable during the 10 years of operation. The spike in an early of operation occurred because large amount of steam rate flowed inside reservoir in the early. Later, it dropped down when the chamber reached the top water zones. As a consequent, water from top water zone started flowing into the chamber, causing the production dropped before climbing up again. Figure 3.4 shows plots of the cumulative steam-to-oil ratio (cSOR) for Cases 1, 2, and 3. Even though Case 2 contributes the highest cumulative oil produced, it exhibits a moderate cSOR profile. As shown in Figure 3.4, the lowest injection pressure has the smallest cSOR because less heat loss was allowed to the top and bottom water thief zones, but lower injected steam may the reduce oil drainage rate. The steam-to-oil ratio (cSOR) which is a measure of process economics has its lowest value in Case 1 of around 3.26 m$^3$/m$^3$ in year 5 and 5.25 m$^3$/m$^3$ after 10 years of operation. Case 1 consumed the lowest amount of steam injected (expressed as cold water equivalent, CWE) as well
produced the lowest volume of water as shown in Figure 3.5 where the water injected and produced rate are close to each other at just over 118.42 and 214.29 m³/day, respectively.

Figure 3.3: Cumulative oil production and oil rate of SAGD compared between Cases 1, 2, and 3 when steam is injected continuously at 1,100 kPa, 1600 kPa and 2,100 kPa.
Figure 3.4: Cumulative Steam oil ratio (cSOR) of SAGD compared between Cases 1, 2, and 3 when steam is injected continuously at 1,100 kPa, 1,600 kPa and 2,100 kPa.

Figure 3.5: Water injected (CWE of steam) and produced rate of SAGD compared between Cases 1, 2, and 3 when steam is injected continuously at 1, kPa and 2,100 kPa.
The onset of water rate is made clearer when the ternary plot, shown in Figure 3.6, is examined. Figure 3.6 illustrates the cross-sectional view of oil saturation, temperature, and ternary distribution after Years 1, 2, 5, and 10. The results demonstrate that steam chamber grew the fastest and largest when the process was operated at the higher injection pressure (Cases 2 and 3).
Figure 3.6: Visualization of the oil saturation distribution, temperature distribution, and ternary phase distribution for Years 1, 2, 5, and 10 of SAGD compared between Cases 1, 2, and 3 when steam is injected continuously at 1,100 kPa, 1600 kPa and 2,100 kPa
3.3.2 ES-SAGD

Figure 3.7 displays the cumulative produced oil volume and oil rate when 5% by volume solvent was added to the injected steam. The highest cumulative volume of oil occurs in Case 5, which is equal to about $170,250 \, \text{m}^3$ after 5 years of ES-SAGD production. After 10 years of operation, however, the highest cumulative oil production is that of the low-pressure case, Case 4, with $217,500 \, \text{m}^3$ produced after 8 years.

![Figure 3.7: Cumulative oil production and oil rate of ES-SAGD compared between Cases 4, 5, and 6 when steam is injected continuously at 1,100 kPa, 1600 kPa and 2,100 kPa.](image-url)
A comparison of the SAGD and ES-SAGD cases reveals that the ES-SAGD cases, plotted in Figure 3.8, achieve lower cSOR than that in the SAGD cases. In Case 4, the cSOR reaches as low as 2.3 m$^3$/m$^3$ in Year 5. Figures 3.9 and 3.10 display the water injection (CWE of steam) and production rates and cumulative injection and production volumes of solvent versus time for each of the ES-SAGD cases. In Case 4, over the first 8 years of operation, the injected water (steam) and produced water rates are roughly equal. Similarly, the injected and produced solvent rates are similar. For solvent losses to the reservoir, in Case 4 the net lost solvent to the reservoir is equal to about 69,750 m$^3$ after 5 years of operation whereas in Cases 5 and 6, the losses are over 314,250 and 618,000 m$^3$, respectively.

![Figure 3.8: Cumulative Steam oil ratio (cSOR) of ES-SAGD compared between Cases 4, 5, and 6 when steam is injected continuously at 1,100 kPa, 1600 kPa and 2,100 kPa.](image)
Figure 3.9: Water injected (CWE of steam) and produced rate of ES-SAGD compared between Cases 4, 5, and 6 when steam is injected continuously at 1,100 kPa, 1600 kPa and 2,100 kPa.

Figure 3.10: Cumulative solvent injection and production of ES-SAGD compared between Cases 4, 5, and 6 when steam is injected continuously at 1,100 kPa, 1600 kPa and 2,100 kPa.
In general, the results demonstrate that ES-SAGD is more thermally efficient recovery process than SAGD. Solvent co-injection can improve the thermal efficiency of SAGD process because it lowers the cSOR and solvent losses are reasonably low, especially when the recovery process is operated at lower pressure than the original reservoir pressure.

Figure 3.11 show the evolution of oil saturation, temperature distribution, and ternary distribution of ES-SAGD during Years 1, 2, 5, and 10. The size of the steam chamber is slightly larger than that of traditional SAGD due to the larger volume of oil production. The combination of heat from steam and dilution of the oil phase with solvent promoted both lateral and vertical growth of depletion chamber. However, the characteristic of thin reservoir (12 m oil pay thickness in this study) resulted in the steam chamber reaching the top and bottom water zones relatively fast except for Case 4 where the injection pressure is lower than the original reservoir pressure. However, the growth of the size of the depletion chamber at the lower pressure is hindered due to water from the top water zone flowing into the chamber. With continuous steam injection into the reservoir, after the chamber reaches the top water zone, the chamber encroached the water zones in most cases and expanded rapidly due to the higher mobility of the water in the top zone. The lower the steam injection pressure, the longer it took the steam chamber to reach the top and bottom water thief zones as observed from Figure 3.11. This is due to the slightly higher bitumen viscosity (due to lower saturation temperature at lower pressure) and the lower pressure difference between the chamber and top water zone.
The performance of ES-SAGD relies on the synergy between solvent solubility and steam heating. Even though solvent co-injection improves the bitumen recovery rate of SAGD, the economics of solvent injection needs to be addressed since the value of the lost solvent can overwhelm the additional revenues gained from the enlarged bitumen production rate. Figure 3.12 depicts solvent mole fraction in the oil phase after Years 1, 2, 5, and 10 of operation. The illustration shows that a thin layer of solvent is concentrated in the bitumen sand at the edge of depletion chamber. Therefore, the solvent there was able to reduce oil viscosity. The mixture of the condensed solvent and mobilized steam and bitumen were produced back to the surface, hence, the oil drainage rate was improved for low steam injection case. In the higher-pressure cases, due to steeper and stronger pressure gradients from the chamber to the top water zone, solvent did not accumulate within the reservoir but was pushed rapidly upward into the top water zone where it was lost. In contrast, in the low injection pressure case, a solvent-rich zone accumulated and expanded largely at the bottom of reservoir where the chamber was limited.
Figure 3.11: Visualization of the oil saturation distribution, temperature distribution, and ternary phase distribution for Years 1, 2, 5, and 10 of ES-SAGD compared between Cases 4, 5, and 6 when steam is injected continuously at 1,100 kPa, 1600 kPa and 2,100 kPa.
Figure 3.12: Visualization of Solvent mole fraction distribution during Years 1, 2, 5, and 10 of ES-SAGD compared between Cases 4, 5, and 6 when steam is injected continuously at 1,100 kPa, 1600 kPa and 2,100 kPa.
3.3.3 NCG-SAGD

Figure 3.13 presents a plot of the cumulative oil production and oil rate versus time when methane was co-injected with steam. After 5 years of operation, Case 9 (high steam injection pressure) reveals the largest cumulative oil production at 122,250 m³. In the meantime, the cumulative oil volumes of Cases 7 and 8 are only 42,750 and 61,500 m³, respectively. NCG-SAGD appears to harm the rate of produced oil compared to SAGD and ES-SAGD cases at the same total steam injection rate, but it helps to reduce the required volume of steam injection where the reduction of cSOR is observed in Figure 3.14. NCG-SAGD is effective in the early years of operation since a relatively high oil rate is observed. Later, a changing operating strategy might be the better choice to improve production. Similar to the SAGD and ES-SAGD cases, as shown in Figure 3.14, the lowest injection pressure NCG-SAGD case achieved the lowest cSOR equal to about 2.8 m³/m³.

Figure 3.13: Cumulative oil production and oil rate of NCG-SAGD compared between Cases 7, 8, and 9 when steam is injected continuously at 1,100 kPa, 1600 kPa and 2,100 kPa.
Figure 3.14: Cumulative Steam oil ratio (cSOR) of NCG-SAGD compared between Cases 7, 8, and 9 when steam is injected continuously at 1,100 kPa, 1600 kPa and 2,100 kPa.

Figure 3.15 displays the water consumption and production of the NCG-SAGD cases. The water rate produced is slightly higher than that injected (CWE of steam) into the reservoir. However, the steam consumption rate is relatively low which the volume of produced water also drops corresponding to these phenomena. The steam rate is reduced to maintain the constant total injection pressure. Figure 3.16 displays the amount of cumulative methane injected and produced in the NCG-SAGD cases. The higher the injection pressure, the greater is the amount of methane retained in the reservoir. In contrast with the low injection pressure (Case 7), the cumulative injected volume of methane is about 7,899,000 Sm³ whereas the cumulative methane produced is 7,269,750 Sm³.
Figure 3.15: Water injected (CWE of steam) and produced rate of NCG-SAGD compared between Cases 7, 8, and 9 when steam is injected continuously at 1,100 kPa, 1,600 kPa and 2,100 kPa.

Figure 3.16: Cumulative methane injection and production of NCG-SAGD compared between Cases 7, 8, and 9 when steam is injected continuously at 1,100 kPa, 1,600 kPa and 2,100 kPa.
Figure 3.17 displays the cross-sectional views of oil saturation, temperature, and ternary distributions. Ternary distribution revealed that there is higher residual oil in the process compared to SAGD and ES-SAGD cases because of lower temperature gradients caused by methane injection. Case 7 has the lowest cSOR and water and methane consumption rates are relatively low. However, this case has low oil production rate. The visualizations show that methane co-injected with steam is able to decelerate the growth of the steam chamber and the top water thief had more influence on steam distribution than that of the bottom water thief-zone. Thus, low concentration of NCG should be injected to avoid steam chamber growth deceleration according to methane accumulation around the steam chamber thickens after the depleted top water is replaced by methane. Methane accumulation at the top of the chamber changes the shape of steam chamber because vertical growth is slow down and lateral growth is promoted. Moreover, top gas over-rides the top water zone especially in low steam injection pressure case (Case 7) and water invades the chamber. The addition of NCG to the reservoir lowers the partial pressure of steam in the chamber which results in lower steam pressure and temperature. Therefore, Case 7 realizes lower oil drainage rate due to smaller steam chamber that is surrounded by lower temperature profiles caused by methane envelope and higher SOR.

Compared with the SAGD cases, NCG co-injection is more likely to show better performance when it operates in the reservoir with substantial heat loss potential. The NCG which has molecular weight less than that of steam moved to the top of the steam chamber, accumulated and acted as an insulator leading to more heat directed to the side edges of the depletion chamber where the oil is located. Figure 3.18 displayed the methane mole
fraction distribution during Years 1, 2, 5, and 10. Methane develops horizontal thin strips that penetrate into the formation before it rises to the top water due to high pressure. The concentration of methane is highest at the top of steam chamber. The greatest methane saturated distribution occurs at the edge of the steam chamber.
Figure 3.17: Visualization of the oil saturation distribution, temperature distribution, and ternary phase distribution for Years 1, 2, 5, and 10 of NCG-SAGD compared between Cases 7, 8, and 9 when steam is injected continuously at 1,100 kPa, 1600 kPa and 2,100 kPa.
Figure 3.18: Visualization of methane mole fraction distribution during Years 1, 2, 5, and 10 of NCG-SAGD compared between Cases 7, 8, and 9 when steam is injected continuously at 1,100 kPa, 1600 kPa and 2,100 kPa.
3.3.4 Oil Mobility

Figure 3.19 and 3.20 shows the oil viscosity and oil effective permeability distribution developed during SAGD, ES-SAGD, and NCG-SAGD operations at the different total injection pressure. The visualization reveals that ES-SAGD help support mobility of oil in the reservoir because solvent is reduce effectively the oil viscosity due to the partial pressure and diffusion effect. The oil rate for the other cases, on the other hand, decline gradually because of higher oil mobility extract more bitumen production at an early year of operation as shown in Figures 3.21.

Figure 3.21 plotted the oil mobility distribution at Years 1, 2, 5, and 10 comparison between SAGD, ES-SAGD, and NCG-SAGD operation. The visualization shows that the higher total injection pressure leads to the higher bitumen mobility and the lower bitumen viscosity. The mobility of bitumen improved gradually in the ES-SAGD cases, that is, steam/solvent injection is capable to enhance oil extraction in horizontal direction of the steam chamber, which the operation is beneficial for thin oil sand reservoir. In contrast, the presence of NCG at the edges of steam chamber decreased oil mobility because of early condensation before contacting the bitumen zone. Heat transfer is impaired and NCG-SAGD is unable to create enhanced oil mobility.
Figure 3.19: Visualization of Oil viscosity distribution during Years 1, 2, 5, and 10 of SAGD, ES-SAGD and NCG-SAGD compared at 1,100 kPa, 1600 kPa and 2,100 kPa total injection pressure.
Figure 3.20: Visualization of Oil effective permeability distribution during Years 1, 2, 5, and 10 of SAGD, ES-SAGD and NCG-SAGD compared at 1,100 kPa, 1600 kPa and 2,100 kPa total injection pressure.
Figure 3.21: Visualization of oil phase mobility distribution during Years 1, 2, 5, and 10 of SAGD, ES-SAGD and NCG-SAGD compared at 1,100 kPa, 1600 kPa and 2,100 kPa total injection pressure.
3.4 Conclusions

The results suggest that the injection pressure of steam can affect the performance of SAGD, ES-SAGD, and NCG-SAGD. Simulations run for 10 years, but the effect can be seen since year 5. Higher pressure can yield higher cumulative oil production, however, the faster steam chamber invades top and bottom water zones which adversely impact the performance of the recovery process. Consequently, this leads to a less efficient operation after a few years of operation because of high heat losses into thief zones.

In addition, the solvent and non-condensable gas co-injection in SAGD can be more advantageous at lower injection pressures. The top water thief zone has more influence on oil drainage performance than that of the bottom water thief-zone. The results of the simulation revealed that additives aid steam injection in SAGD, e.g. ES-SAGD and NCG-SAGD improve operational performance where the lower cSOR can be found. Solvent co-injection can yield a more efficient thermal process by using low concentration of solvent in the injected stream. Meanwhile, lighter non-condensable gases, such as methane, accumulate at the top water zones of steam chamber in the gaseous form. Although NCG-SAGD can reduce cSOR and improve the reservoir performance in top water thief zones, very low concentration of non-condensable gas should be injected to avoid steam chamber growth deceleration.
Chapter Four: A robust optimization of a solvent plus NCG-SAGD process

4.1 Introduction

In-situ recovery techniques such as SAGD are widely used to recover bitumen from oil sand reserves but face major challenges associated with greenhouse gas (GHG) emissions arising from steam generation (Acosta, 2010; Hein et al. 2013; Gates and Larter, 2014). Achieving sustainable bitumen production from oil sand recovery processes requires a balance between production economics and the corresponding environmental issues such as GHG emissions, water consumption. The most common proxy measure for the assessment of the performance of SAGD’s cost-to-revenue ratio and GHG-to-oil ratio is the SOR. Steam, through natural gas combustion and water treatment and handling, is the main cost in SAGD. Natural gas combustion accounts for the largest contributor to GHG emissions. The balance between economics and environment poses an interesting and important optimization problem for SAGD recovery process design.

Most SAGD operations target the reduction of the cumulative steam-to-oil ratio (cSOR): steam is the operating cost of the process whereas oil production represents process revenues. Commercial SAGD operations aim to deliver as much of an injected steam directly to the bitumen without losses of any energy to non-productive zones. Thief zones, e.g. top and bottom water, however, lower the thermal efficient of the SAGD process because injected steam escapes to these zones and heats non-productive rock.
Previous studies focused on optimization of the SAGD and SAGD variants have typically only taken the SOR or net energy invested to oil ratio into account (Gates and Chakrabarty, 2006, 2008; Edmunds and Chhina, 2001). Several have examined solvent and non-condensable gas (NCG) co-injection but none, in the public literature, have examined the case linking both environment and economics together. Moreover, none of the published research has optimized the recovery process in a relatively thin oil sands reservoir with top and bottom water thief-zones especially in thin reservoir. Several operators are facing these types of reservoirs with thief zones in the Athabasca deposit (ConocoPhillips, 2017; Husky, 2016; Nexen, 2017). Although SAGD has demonstrated technical and economic success for recovery of bitumen, it has not been firmly established as a successful process in reservoirs with adjacent thief zones.

One potential method to enhance oil mobility in thin oil sands reservoirs with top and bottom water zones are steam and solvent injection process such as ES-SAGD or the Solvent Aided Process (SAP) (Nars, 2003; Gupta and Gittins, 2006; Ivory et al., 2008; Ayodele et al., 2010 Gates, 2010; Zhu, 2012; Yu and Chen, 2017). These recovery processes have been designed to increase heat and mass transfer of the interfacial area at the chamber boundary where both steam condensation and solvent dissolution in bitumen help to mobilize bitumen (Zhao and Nasr, 2005). Results from simulation studies and field trials have shown that solvent co-injection with steam results in a reduction of injected steam and thus the combustion of natural gas needed to generate the injected steam (Deng et al., 2008; Orr, 2009; Bao, 2012; Cenovus, 2013, Nkiru, 2015). However, a pressing issue for these operations is the loss of solvent, which represents a significant cost to the process.
Cenovus (2010) has indicated that SAP with 0.05 volume fraction solvent (butane) in the injected steam improved the production rate by 30% and provided an incremental total oil recovery of 15% with reduced fuel gas usage of 3%. However, the incremental costs associated with SAP were increased by 10 to 20% with respect to facility capital expenditures (CAPEX) and solvent operational expenditures (OPEX). The economics of ES-SAGD and SAP are largely dependent on the instantaneous solvent recycle ratio where in excess of about 80% is required for a diluent-based solvent for the process to be economic (McDaniel, 2011). Subsequently, some operators e.g. (Nexen, 2014; Cenovus, 2011; Jacos, 2014) implemented non-condensable gas (NCG) co-injection with steam instead of solvents due to its lower cost than that of solvent, based on Butler’s Steam and Gas Push (SAGP) process (Butler, 1997). Here, when NCG is co-injected with steam in a SAGD process, it is referred to as NCG-SAGD. Nexen (2014) reported that NCG, i.e. methane and natural gas, addition benefited the recovery process because it acts as an insulation layer, inhibiting leakage of steam into thief zones and reducing the effective permeability to water (Nexen, 2014). Jacos (2014) reported that NCG-assisted SAGD at Hangingstone reduced the amount of injected steam used in the recovery process and noted that NCG co-injection is cost neutral from a steam cost point of view (Jacos, 2014).

The evidence, from both simulation studies and field operations, suggest that either ES-SAGD or NCG-SAGD benefit the oil production rate to some extent over that of SAGD. What remains unclear is what is the best operating strategy for ES-SAGD or NCG-SAGD or both to achieve both economic (maximum net present value, NPV) and environmental (minimum possible GHG emissions) objectives. In the research documented here, a
A rigorous optimization study is conducted to determine alternative operating strategies using both solvent and NCG in recovery processes in oil sands reservoirs that have both top and bottom water zones that achieve economic and environmental objectives.

### 4.2 Reservoir Simulation Model

A two-dimensional (2D) reservoir simulation model was created from a full detailed geological model of an oil sands reservoir with both top and bottom water zones in the Athabasca area. The reservoir model is displayed in Figure 4.1.

This reservoir is the same reservoir model used in Chapter Three; the key parameters of the reservoir model is listed in Table 4.1. The thicknesses of the oil interval, top water, and bottom water zones are 12 m, 5 m. and 3 m, respectively. Figures 4.2 displays the oil-water and oil-gas relative permeability curves. To recall, views of the reservoir properties are displayed in Table 4.2.

To conduct the thermal reservoir simulations, the CMG STAR™ thermal reservoir simulator is used. This simulator solves the mass and energy balance, in the context of multiphase Darcy flow, by using the finite volume method in which the reservoir domain is discretized into gridblocks (CMG, 2016). Phase equilibrium is evaluated in each gridblock by using a K-value-based flash calculation.
For the reservoir simulation model, the grid block dimensions are 1 m in the cross-well direction, 750 m in the down-well direction, and 0.3 m in the vertical direction. The model consists of 9,250 grid blocks. A grid sensitivity analysis was conducted where the grid blocks were halved in the cross-well and vertical directions for the individual solvent plus NCG-SAGD cases. The produced oil volume and steam-to-oil ratios were changed by less than 0.1%. Thus, the grid was considered sufficiently resolved to model the three recovery processes. The operations were simulated for a total of five years.

Table 4.1: Input parameters for the reservoir model.

<table>
<thead>
<tr>
<th>Properties</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net pay, m</td>
<td>12</td>
</tr>
<tr>
<td>Initial pressure at 240 m, kPa</td>
<td>1,600</td>
</tr>
<tr>
<td>Reservoir temperature, °C</td>
<td>11</td>
</tr>
<tr>
<td>Dead oil viscosity @ 11°C, cP</td>
<td>550,580</td>
</tr>
<tr>
<td>Dead oil viscosity @ 200°C, cP</td>
<td>6.315</td>
</tr>
<tr>
<td>Oil density @ 1,600 kPa, kg/ m³</td>
<td>995.907</td>
</tr>
<tr>
<td>Oil thermal conductivity, kJ/m day °C</td>
<td>11.5</td>
</tr>
<tr>
<td>Solution gas density, kg/m³</td>
<td>11.2191</td>
</tr>
<tr>
<td>Water density, kg/m³</td>
<td>1000.3</td>
</tr>
<tr>
<td>Water thermal conductivity, kJ/m day °C</td>
<td>53.5</td>
</tr>
<tr>
<td>Gas thermal conductivity, kJ/m day °C</td>
<td>5</td>
</tr>
<tr>
<td>Horizontal to vertical permeability k_v/k_h</td>
<td>0.74</td>
</tr>
<tr>
<td>Effective rock compressibility, 1/kPa</td>
<td>1.40E-05</td>
</tr>
<tr>
<td>Rock heat capacity, kJ/m³ °C</td>
<td>2600</td>
</tr>
<tr>
<td>Rock thermal conductivity, kJ/m day °C</td>
<td>660</td>
</tr>
<tr>
<td>Overburden thermal conductivity, kJ/m day °C</td>
<td>151</td>
</tr>
<tr>
<td>Underburden thermal conductivity, kJ/m day °C</td>
<td>151</td>
</tr>
</tbody>
</table>
Table 4.2: Summary of basis reservoir properties.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Min.</th>
<th>Avg.</th>
<th>Max.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>0.26</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vertical permeability, mD</td>
<td>4,322</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizontal permeability, mD</td>
<td>3,202</td>
<td></td>
<td></td>
</tr>
<tr>
<td>kv/kh distribution</td>
<td>0.74</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial water saturation</td>
<td>0.006</td>
<td>0.33</td>
<td>1</td>
</tr>
<tr>
<td>Oil saturation distribution</td>
<td>0.72</td>
<td>0.85</td>
<td>0.98</td>
</tr>
<tr>
<td>Initial reservoir temperature, °C</td>
<td>11</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial reservoir pressure, kPa</td>
<td>1,600</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial pressure of top water zone, kPa</td>
<td>1,496</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial pressure of bottom water zone, kPa</td>
<td>1690</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

4.2.1 Well Constraints

Prior to a solvent plus NCG SAGD operation, the inter-well region was heated by using steam circulation for three months. This was done by placing temporary heaters and production wells in the locations of the injection and production wells to deal with thermally expanded fluids. The temporary production wells were opened and set with a bottom-hole pressure constraint equal to the initial reservoir pressure at their elevations (Gates et al. 2007). After three months of heating, the heaters were switched off, the temporary production wells were removed, and steam injection was started into the upper well (SAGD mode). During SAGD, to mimic steam trap control, the production well was constrained to 10 m³/day (expressed at surface conditions by cold-water equivalent, CWE). For the injection well, the total injection pressure were set to 1100 kPa for the base case with steam quality equal to 0.9 for all realizations.
4.2.2 Optimization Strategy

The input parameters evaluated here are the total injection pressure, volume fraction of the solvent and NCG in the injectant stream. The remainder of the injectant stream is steam at 90% quality. The solvent used here is hexane as a surrogate component for diluent whereas the NCG is methane. The objective function for the optimization is the Net Present Value (NPV), defined as the difference between the present value of cash inflows and the present value of cash outflows, evaluated over a production period spanning 5 years. The cash flow is calculated over yearly periods. A discount rate is used to incorporate the time value of money, which equals to the yearly interest rate. The NPV equation used for calculation is given by:
Figure 4.1: Cross-sectional views of the reservoir model.
Figure 4.2: Relative permeability curves governing multiphase flow in the reservoir.

\[
NPV = \sum_{j=1}^{N_J} \left( \sum_{t=N_1}^{N_2} \frac{Q \cdot U \cdot C}{(1+Y)^t} \right)
\]

where:

- \( t \) is the time of the cash flow in days,
- \( N_1 \) is the number of days from the NPV Present Date to the Start Date Time,
- \( N_2 \) is the number of days from the NPV Present Date to the end date time unit value,
- \( j \) represents each objective function term,
- \( N_J \) is the number of objective function terms for the NPV objective function,
- \( Q \) is quantity,
- \( U \) is unit value,
C is a conversion factor equals to 750 in this study (converts injection and production values to a 750 m long well), and

Y is the yearly discount rate (yearly interest rate) which is set at 4%.

Table 4.3 lists the economic data used in the optimization study. The oil price used in this study originates from the Western Canadian Select (WCS) price trend over the past couple years (2015-2017) which consists of Canadian heavy conventional and bitumen crude oils originated from Western Canada. The discount rate takes into account the time value of money. The rate reflects the cost of capital plus safety margin for project evaluation. However, the same rate was used for all factors to simplify the NPV calculation.

Table 4.3: Input parameters for NPV calculation.

<table>
<thead>
<tr>
<th>Factors</th>
<th>Unit</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Price (WCS)*</td>
<td>$/stb</td>
<td>50.00</td>
</tr>
<tr>
<td>Produced gas (Methane)**</td>
<td>$/stb</td>
<td>2.40</td>
</tr>
<tr>
<td>Produced solvent**</td>
<td>cents/gal</td>
<td>191.70</td>
</tr>
<tr>
<td>Methane price</td>
<td>$/MM Btu</td>
<td>2.40</td>
</tr>
<tr>
<td>Solvent price (Hexane)</td>
<td>cents/gal</td>
<td>191.70</td>
</tr>
<tr>
<td>Steam generation</td>
<td>$/m³</td>
<td>13.78</td>
</tr>
<tr>
<td>Water treatment</td>
<td>$/stb</td>
<td>0.25</td>
</tr>
<tr>
<td>Discount rate***</td>
<td>%</td>
<td>0.04</td>
</tr>
</tbody>
</table>

*Western Canadian Select  
**Assume 100% returned quality  
***Assume same yearly discount for all  

In this research, the particle swarm optimization (PSO) technique is used (Kennedy and Russell, 1995). The PSO algorithm, implemented in the CMG CMOST™ computer-assisted optimization tool (CMOST, 2016), is a co-operative, gradient-free, population-
based stochastic global search swarm intelligence method. Stochastic optimization technique is basically letting the particles move about freely after each iteration. In PSO, the potential solutions, called particles, fly through the problem space by following the current optimum particles. PSO have been used in various petroleum recovery processes due to its high efficient and capability to step out from local optima (Mohamed et. al., 2010; Onwunalu and Durlofsky, 2011; Wang et. al., 2012; Zhang, et. al. 2011; Kennedy and Mendes 2004). The PSO algorithm mimics the social behavior of swarms of fish and birds flocks in nature. In PSO, a swarm of particles is used as agents, each characterized by its parameter set values, to demonstrate different scenarios. The movement of each particle is influenced by three terms: 1) the inertia force or velocity at the last time step, 2) customized history or the particles’s local best-known position, and 3) social influence or the swarm’s best recognized position (the global best value of the swarm of particles). In other words, the position of the particle is encoded by the values of the search parameters and the movement of each particle in the parameter space is affected by all its neighbors as well as local optimal values and the current global best value. The particles move towards the position in the search space that exhibit better values of the objective function, remembering each local (particle’s) best known position and global (swarm’s) best known position.

The algorithm is displayed in Figure 4.3. In the PSO run conducted here, the maximum number of iterations (updates of the positions in the parameter space) is equal to 1,500.
Particle swarm optimization algorithm (CMG, 2015); xlocal is the local best position whereas xglobal is the position of swarm’s global best position found so far.

The update velocity vector for each particle is calculated by:

\[ \mathbf{v}_{t+1} = \alpha \mathbf{v}_t + \beta_1 \eta_1 (\mathbf{x}_{local} - \mathbf{x}_t) + \beta_2 \eta_2 (\mathbf{x}_{global} - \mathbf{x}_t) \]  

where \( \alpha \) and \( \beta \) are user-set parameters that control the speed of the evolutionary optimization process and the relative contributions of the velocity and local and global (so far) parameters values, \( \mathbf{v} \) is the velocity vector (in the parameter space) of the update, \( \mathbf{x} \) is the position vector (the parameter values), and \( \eta_1 \) and \( \eta_2 \) are random numbers between 0 and 1 (uniformly distributed). The updates of the parameter vector are given by:

\[ \mathbf{x}_{t+1} = \mathbf{x}_t + \mathbf{v}_{t+1} \]  

Each particle in the initialization stage are random with respect to locations (distributed uniformly) and the initial velocities are set to equal to 0. At time \( t+1 \), the updated location of each particle is obtained in two steps. First, updating the velocity of a particle; \( \alpha \) is
inertia weight (set equal to 0.7298), $\beta_1$ is cognitive weight (set equal to 1.49618) and $\beta_2$ is the social weight (set equal to 1.49618). These values have been found to balance local and global influences for the algorithm as reported in Heng and Chaodong (2014). Second, updating the location of a particle. After the locations of all particles (parameter values in the parameter space), all of the particle’s local history and swarm’s global best position are updated. The objective function at the new set of particles locations (parameters values) is then calculated. Then, the algorithm repeats until the maximum number of iterations is reached in which stop condition depends on the problem to be optimized (Heng and Chaodong, 2014).

### 4.2.3 Objective Functions

In the optimization study conducted here, the objective function is as follows:

\[
NPV = \sum_{t=N_1}^{N_2} \frac{(P_{Oil} - P_{Water} - P_{Steam} + P_{Solvent} + P_{Methane})}{(1+Y)^t}
\]

(4)

where

\[
P_{Oil} = Q_{Oil} U_{Oil} C
\]
\[
P_{Water} = Q_{Water} U_{Water} C
\]
\[
P_{Steam} = Q_{Steam} U_{Steam} C
\]
\[
P_{Solvent} = (Q_{SP} - Q_{SI}) U_{S} C
\]
\[
P_{Methane} = (Q_{MP} - Q_{MI}) U_{M} C
\]

where:
$t$ is the time of the cash flow in days (1826),

$N_1$ is the number of days from the NPV Present Date to the Start Date Time,

$N_2$ is the number of days from the NPV Present Date to the end date time unit value,

$C$ is a conversion factor (750),

$Y$ is the yearly discount rate or yearly interest rate (0.04),

$Q_{Oil}$ is the cumulative oil production,

$U_{Oil}$ is the oil price,

$Q_{Water}$ is the cumulative produced water,

$U_{Water}$ is the water treatment price,

$Q_{Steam}$ is the cumulative steam injection,

$U_{Steam}$ is the steam price,

$Q_{SP}$ is the cumulative solvent production,

$Q_{SI}$ is the cumulative solvent injection,

$U_{S}$ is the solvent price,

$Q_{MI}$ is the cumulative methane injection, and

$U_{M}$ is the methane price.
The objective functions of the NPV provides a better measure of the performance of the process than that of the steam-to-oil ratio because the net solvent stored in the reservoir is also considered. The best way to reflect the impact of the net solvent stored during the process is through its economic value. The adjustable parameters and their ranges are listed in Table 4.4.

Table 4.4: Adjustable parameters and their ranges for optimization run.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Range</th>
<th>Base case value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total injection pressure*</td>
<td>1,000 to 2,500 kPa</td>
<td>1,100 kPa</td>
</tr>
<tr>
<td>Volume fraction of solvent</td>
<td>0 to 0.9</td>
<td>0.25</td>
</tr>
<tr>
<td>Volume fraction of methane</td>
<td>0 to 0.9</td>
<td>0</td>
</tr>
<tr>
<td>Volume fraction of steam</td>
<td>0 to 1</td>
<td>0.75</td>
</tr>
</tbody>
</table>

*Injection temperature is a function of the injection pressure (saturated steam)

4.3 Results and Discussion

Figure 4.4 displays the value of the NPV versus iteration number. The value of the NPV at the base case values of the adjustable parameters is equal to about $20.5M. The parameter space explored yields NPV values as low as -$912M. After 1,500 iterations, the best NPV was found to be $40.8M. The data in Figure 4.4 shows that the PSO method achieves values close to the best value found within about 50 iterations demonstrating the robustness of the optimization method. The cases determined by the PSO provide a data set that can be explored for the best values of other operating measures such as the cumulative steam-to-oil ratio (cSOR) and the cumulative oil produced from the reservoir. In the following analysis, the information string gives the input parameters as follows:
Table 4.5 lists the cases amongst the 1,500 cases that yielded the best NPV, cSOR, and cumulative oil produced ($Q_{oil}$) which can be compared to the base case to determine how the strategies improved the performance with respect to the NPV, cSOR, and $Q_{oil}$. Referring to Table 4.5, the highest NPV case has a reasonable amount of oil production. In this case, zero solvent was injected in the process due to the high cost of solvent which lower the NPV value due to losses. Also, in this case, about 0.59 of the volume fraction of injectant was methane and due to its relatively low price, most remained in the reservoir during and after the process evaluation time (5 years). In addition, the highest NPV case required high steam injection for bitumen extraction which had the outcome of high total injection pressure and higher cSOR than other cases. However, due to the low price of natural gas, the higher steam injection volume does not adversely affect the NPV significantly. Despite this, the greater use of natural gas implies greater GHG emissions. Table 4.5 lists the amount of CO2 arising from combusting the natural gas for steam generation for each of the cases. The results show that the amounts are substantial and that the worst emissions intensities occur for the best NPV and cumulative oil produced cases.
Figure 4.4: Evolution of NPV versus iteration.

Table 4.5: Values of the adjustable parameter that yielded the best NPV, cSOR, and $Q_{oil}$. The volumes and mass are per 1 m of well; to obtain values for 750 m well, multiply by 750. The economics are based on a 750 m well length.

<table>
<thead>
<tr>
<th>Injection pressure:Solvent Fraction:Methane Fraction:Steam Fraction</th>
<th>Base Case</th>
<th>Best NPV</th>
<th>Best cSOR</th>
<th>Best $Q_{oil}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection pressure:Solvent Fraction:Methane Fraction:Steam Fraction</td>
<td>1,100:0.25:0.75</td>
<td>1,682:0.59:0.41</td>
<td>1,000:0.68:0.13</td>
<td>1,710:0.36:0.52</td>
</tr>
<tr>
<td>NPV</td>
<td>$$20,477,564</td>
<td>$40,769,993</td>
<td>$17,412,046</td>
<td>$-912,000,000$</td>
</tr>
<tr>
<td>cSOR</td>
<td>m$^3$/m$^3$</td>
<td>2.3</td>
<td>5.7</td>
<td>2.1</td>
</tr>
<tr>
<td>$Q_{oil}$</td>
<td>m$^3$</td>
<td>120.11</td>
<td>260.20</td>
<td>98.17</td>
</tr>
<tr>
<td>Cum. Solvent Inj.</td>
<td>m$^3$</td>
<td>93.09</td>
<td>0</td>
<td>131.82</td>
</tr>
<tr>
<td>Cum. Solvent Prd.</td>
<td>m$^3$</td>
<td>86.99</td>
<td>0</td>
<td>127.56</td>
</tr>
<tr>
<td>Cum. NCG Inj.</td>
<td>m$^3$</td>
<td>0</td>
<td>2,125.10</td>
<td>706.86</td>
</tr>
<tr>
<td>Cum. NCG Prd.</td>
<td>m$^3$</td>
<td>34.55</td>
<td>173.87</td>
<td>522.20</td>
</tr>
<tr>
<td>Cum. Steam Inj.*</td>
<td>m$^3$</td>
<td>279.27</td>
<td>1,487.95</td>
<td>204.86</td>
</tr>
<tr>
<td>Cum. Water Prd.</td>
<td>m$^3$</td>
<td>377.51</td>
<td>1,058.14</td>
<td>310.31</td>
</tr>
<tr>
<td>Cum. CO$$_{2}$ Emitted</td>
<td>kg</td>
<td>39.110</td>
<td>275.340</td>
<td>36.890</td>
</tr>
</tbody>
</table>

*Steam expressed as cold-water equivalent
A comparison between the highest NPV and greatest cumulative oil production cases shows that the greater cumulative oil production case is a result of a solvent plus NCG-SAGD process operated at a total injection pressure that is similar but above to the original reservoir pressure. However, the elevated pressure caused steam reaches the top water thief zones faster. However, in terms of water injection and water production, less produced water is observed for the case with the highest NPV where only methane is co-injected into the reservoir. In contrast, more produced water is shown for the greatest cumulative oil production case because solvent remains in the reservoir replacing water within the system.

Traditionally, cSOR is a reasonable indicator of SAGD economics. Based the lowest cSOR case, the optimum value of cSOR showed a similar value to that of the base case where total injection pressure is below the original reservoir pressure. In this case, less steam is required for the process, and as a consequence, the chamber develops slowly even with co-injection of both solvent and methane. Due to a lower cSOR, reduced emissions occur because of lower steam consumption which is a key benefit of this process. Yet, the NPV is relatively high because of high solvent and NCG content in the injectant stream. In the lowest cSOR case, less cumulative oil production is realized compared to the base case due to higher volume fraction of methane where too much methane co-injection impedes the growth of steam chamber (Pinto et al. 2017) and lowers the oil drainage rate.

Figure 4.5 showed the visualization of temperature, oil saturation, and ternary distribution after end of operation of the base, best NPV, best cSOR, and best \( Q_{oil} \) cases. The best NPV case gave the highest and most extensive temperature distribution because the low amount
of NCG (<1% methane in the chamber) does not dilute the steam (which would lower its saturation temperature). In the other cases where solvent plus methane addition occurs, the drainage efficiency of the process suffers due to temperature effects on solvent dissolution. In terms of oil saturation, the best Q_{oil} case revealed the lowest oil saturation especially at the edge of the chamber because of the combination of solvent and methane co-injection. In these cases, the solvent helped to drain more oil, whereas methane impeded steam escape to the top water thief zones. However, this case does not achieve the highest NPV because of the high cost of solvent losses. The oil saturation of the base and best cSOR cases showed similar distributions with a small amount of solvent within the depletion chamber. However, the best NPV case (with only NCG co-injection into the thin reservoir) benefits the process since the NCG accumulated at the top and acts as a thin insulation layer to hinder steam escape from the bitumen zone. In the best Q_{oil} case, the ternary distribution reveals that the bottom water and solvent accumulates at the base of the chamber.
Figure 4.5: The visualization of temperature, oil saturation and ternary distribution after end of operation of the base, best NPV, best cSOR, and best Qoil cases.

In case of the highest cumulative oil production, the result showed that high amount of solvent volume fraction is capable to extract more oil from the thin reservoir with top and bottom water zones because solvent co-injection with steam promoted both lateral and vertical growth of the depletion chamber. However, the result showed negative NPV because solvent price is high and most of it was retained in the reservoir. Each case is discussed in detail in the following
4.3.1 The Highest NPV Case (InjP: Solvent: CH4: Steam = 1,682:0.00:0.59:0.41)

The highest NPV value was realized with an injection pressure of 1,682 kPa, zero solvent, and a combination of steam and NCG co-injection. The key reason that the optimizer did not eliminate solvent was due to its cost. The objective function for this case has better results than that of the base case; about $40.8M is the highest NPV value from the 1,232th run which is twice the original NPV of the base case (1100:0.25:0:0.75) of about $20.5M. Moreover, the cumulative oil production is double compared to that achieved with the base case.

Figure 4.6 presents the cSOR profiles for all cases including the optimal solution where the highest NPV is obtained (the optimal case is the case with the highest NPV) versus time. The results show a wide variability of the operation profiles due to the changes of the operating strategies associated with the three adjustable parameters. In the worst cases, the cSOR reaches over 20 m$^3$/m$^3$ for a period; at these values, the processes are not considered practically feasible. This is associated with cases where steam is injected at high pressure, reaches the top water zone rapidly, and is lost to the thief zone; but these results in relatively low oil production volumes since steam bypasses the oil interval to the top water zone. For those processes where the cSOR profile is low, this is typically found for processes where the injection pressure is lower than that of the reservoir (with corresponding low steam saturation temperature). However, this also results in relatively low oil volume produced.
Figure 4.6: cSOR profiles of cases obtained from PSO.

Figure 4.7 displays performance profiles for the cases including cumulative injected and produced volumes of fluids. Also shown are the base case results and the optimal profiles associated with the best NPV achieved from the PSO run. The results show that the cumulative oil and oil rates from the optimal NPV solution are significantly greater than that of the base case. An examination of the cumulative solvent injection and production profiles reveals that in most cases that use solvent, the amount of solvent retained in the reservoir is large, often exceeding 30%. A similar result is obtained for NCG, however, from an economic point of view, since the NCG cost is relatively low, NCG losses are not as critical to the process’ economics as is the case with solvent.
Figure 4.7: Performance profiles of cases obtained from PSO. The volumes are per 1 m of well. To obtain values for 750 m well, multiply by 750.

From Figure 4.7, an examination of the water profiles reveals that in the optimum NPV case, the amount of water (steam, expressed as cold-water equivalent) produced is greater than the volume injected.

Figure 4.8 showed the temperature, pressure, and oil mobility distributions in the reservoir at year 2015 of the case, which have the best NPV case. The oil saturation, water saturation, gas mole fraction of methane, and ternary distribution at year 2015 of best NPV case are presented in Figure 4.9. The results show that after five years, steam conformance is good with the steam chamber reaching up to the top water zone. The most mobile oil is found at the base of the chamber. There is a large buildup of water (liquid) in the reservoir with little interaction from the bottom water, however, nothing goes beyond the production well. The visualization also shows that the depleted oil region exceeds the size of the high temperature zone. The flow of gas is above the water layer towards the far edges of the domain.
Figure 4.8: Temperature, pressure, and oil mobility distributions after five years of operation of the best NPV case.

Figure 4.9: Temperature, pressure, and oil mobility distributions after five years of operation of the best NPV case.
4.3.2 Oil Price Sensitivity

PSO runs can be used to examine the sensitivity of the results with respect to oil price. Here, four scenarios are examined where the economics are evaluated at $30/bbl, $40/bbl, $50/bbl, and $80/bbl. The results of the analysis are displayed in Figure 4.10. The results show, as expected, that the higher the oil price, the greater is the NPV. The red diamond symbols demonstrate the optimal solution obtained. It can be seen that PSO converge to an area with relative high NPV, which indicate that the optimization algorithm is effective of finding optimum values within a small amount of simulation runs.

Figure 4.10: The plot between NPV and all iterations for each oil price. The economics is based on a 750 m well pair length.
The results in Figure 4.10 reveal that the optimum cases are split into two groups: one operating strategy for oil price at $30/bbl and $40/bbl and another operating strategy for oil price at $50/bbl and $80/bbl. These two operating strategies are similar in that both use no solvent, the injection pressures are similar, and the NCG and steam fractions in the injectant streams are similar. The results for these two operating strategies are listed in Table 4.6.

**Table 4.6:** Comparison of oil price sensitivity. The volumes are per 1 m of well. To obtain values for 750 m well, multiply by 750. The economics are based on a 750 m well length.

<table>
<thead>
<tr>
<th>Oil Price</th>
<th>$/bbl</th>
<th>30</th>
<th>40</th>
<th>50</th>
<th>80</th>
</tr>
</thead>
<tbody>
<tr>
<td>Optimal Input</td>
<td></td>
<td>1,617:0:0.56:0.44</td>
<td>1,682:0:0.59:0.41</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NPV</td>
<td>$</td>
<td>18,813,189</td>
<td>29,628,435</td>
<td>40,769,993</td>
<td>74,376,239</td>
</tr>
<tr>
<td>cSOR</td>
<td>m³/m³</td>
<td>5.2</td>
<td>5.7</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Qoil</td>
<td>m³</td>
<td>251.31</td>
<td>260.20</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cum. Solvent Inj.</td>
<td>m³</td>
<td>0</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cum. Solvent Prd.</td>
<td>m³</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cum. NCG Inj.</td>
<td>m³</td>
<td>1,657.81</td>
<td>2,125.09</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cum. NCG Prd.</td>
<td>m³</td>
<td>160.72</td>
<td>173.87</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cum. Steam Inj.*</td>
<td>m³</td>
<td>1302.70</td>
<td>1487.95</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cum. Water Prd.</td>
<td>m³</td>
<td>1,102.42</td>
<td>1,058.14</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Steam expressed as cold water equivalent

The results in Table 4.6 show that solvent is not a preferred injectant into the reservoir; this is due to its cost and amount retained in the reservoir. The results reveal that solvent losses overwhelm the economics of the processes at all of the oil prices examined. The optimal cases also demonstrate that to operate SAGD in a relatively thin oil sand reservoir with top and bottom water zones, the results suggest that a total injection pressure at the value close to the original reservoir pressure (in this case, about 1,600 kPa) is best because this pressure will not encourage injectant losses to the thief zones. This result is consistent with Gates et al. (2007). The results also show that a combination of steam and NCG is preferred to
obtain the best economics from the process. This is due to the relatively low price of the NCG and thus losses of NCG to the reservoir are more tolerant than that of the solvent. An increasing methane accumulation enables methane in gas phase to escape to the top water zone; however, with low injection pressure, the amount of convective transport of NCG to the top water zone is small. The accumulation of NCG at the top of the depletion chamber helps to reduce heat loss above the chamber thus improving the thermal efficiency of the process.

In addition, the total steam injection value nearly reservoir pressure supplements with methane injection pressure which also in gas phase is capable to maintain reservoir pressure in late life, that is, this phenomenon decelerated the mobilized potential of top and bottom water invades bitumen zones and increases bitumen mobility at a certain extent. Methane co-injection assists with bitumen drainage from the above the steam chamber. SOR is improved without negative effect on recovery because methane is more direct and simply injected into the reservoir. Therefore, less operating cost is found. Regarding the sensitivity of an optimization, the plotted between NPV and iteration numbers as shown in Fire 4.10 revealed that it might be enough to run only 100 iteration numbers because the optimal value is reached. However, over 1500 iteration numbers is run for the sake of exhausting all possible solutions and ensure global convergence.
4.4 Conclusions

Optimization of oil sands recovery processes is challenging when dealing with the combination between solvent, NCG and steam especially with different objective functions of NPV, maximum oil, or minimum steam-to-oil ratio. Here, particle swarm optimization was used to examine improvements that could be made to solvent-NCG-SAGD. Despite the challenges of optimizing the total steam injection and the volume fraction of solvent, non-condensable gas and steam, the results demonstrate that the preferred options are ones without solvent due to the cost of the lost solvent to the reservoir. NCG, on the other hand, due to its relatively low cost, is a good additive to support increased recovery and economics from the process with top and bottom water zones. The optimal NPV case was achieved with a portion of NCG co-injection at the steam injection pressure slightly higher than that of the original reservoir pressure, since steam escape to the top and bottom water zones is avoided. Higher steam injection pressure can decrease the amount of oil produced since steam does not have enough time to grow in bitumen zone; instead it moves upward directly to the top water zone. NCG is necessary because it can decelerate the growth of depletion chamber thus limiting its contact with the top water zones. Controlling the optimal injection pressure is important because it too limits the growth of the chamber thus slowing the losses of injectant to the top water zone.
Chapter Five: Conclusions and recommendations

5.1 Conclusions

Production of oil sands reservoirs using recovery processes such as Steam-Assisted Gravity Drainage (SAGD) is a challenge in reservoirs that are thin and have top and bottom water zones. The research here is the first to explore how to operate combinations of solvent and non-condensable gas (NCG) co-injection with steam in a SAGD well configuration. The research examined solvent-aided and NCG-aided SAGD processes and used an automated optimization algorithm to explore improvements that can be made to the SAGD operating strategy both from economic and environmental perspectives.

The conclusions from the research documented in the thesis are as follows:

1. The results suggest that the injection pressure of steam affects the performance of SAGD, ES-SAGD, and NCG-SAGD. Higher pressure can yield higher cumulative oil production; however, this implies a more rapid invasion of the depletion chamber to the top and bottom water zones, which adversely affects the performance of the recovery process. Consequently, it leads to unhealthy operating conditions after a few years of operation because of high heat losses into thief zones. The solvent and non-condensable gas co-injection in SAGD offers benefits at lower injection pressures.
2. The top water thief zone has more influence on oil drainage performance than that of the bottom water thief zone.
3. The results revealed that solvent and NCG additives aid steam injection in SAGD, e.g. ES-SAGD and NCG-SAGD improve operational performance where reduced cSOR is achieved.

4. Solvent co-injection can yield a more efficient thermal process when using relatively low concentration of solvent in the injected stream. Injected NCG accumulates at the top water zones of depletion chamber.

5. Though NCG-SAGD can reduce cSOR and improve the reservoir performance in top and bottom water thief zones, low amounts of NCG should be injected to avoid steam chamber growth deceleration.

6. Optimization of oil sands recovery processes is challenging when dealing with the combination between solvent, NCG and steam especially with the different objective functions of NPV, maximum oil, or minimum steam-to-oil ratio. Here, particle swarm optimization was used to examine improvements that could be made to solvent-NCG-SAGD. The results reveal that the preferred options are ones without solvent due to the cost of the lost solvent retained in the reservoir. NCG, due to its relatively low cost, is a good additive to support increased recovery and economics from the process with top and bottom water zones.

7. The optimal NPV case was achieved with NCG co-injection at the steam injection pressure slightly higher than that of the original reservoir pressure. Higher steam injection pressure can decrease the amount of oil produced since steam does not have enough time to grow in bitumen zone; instead it moves upward directly to the top water zone. NCG has benefits since it can slow the growth of depletion chamber thus limiting its contact with the top water zones.
8. Controlling the injection pressure is key since it too slows the growth of the chamber thus reducing the losses of injectant to the top water zone.

5.2 Recommendations

Future work should focus in the following aspects:

1. Examine how different types of solvent plus NCG mixing could be utilized to enhance the performance SAGD recovery in thin reservoir with the presence of top and water thief zones.

2. More research on a solvent or NCG additive performances with various operating strategies e.g. wind down or blow down strategy is needed to determine enhancements to process performance.

3. Explore rigorous optimization on how various concentration of the different type of solvent plus NCG mixing could improve bitumen recovery process and give the high NPV, which implies the project profits with respect to economic and environment.

4. Sensitivity analysis should be conducted with different algorithm to see which technique is the best optimization.

5. Recommend to run 3D reservoir model to see if the behaviour of steam chamber in thief zones is effected by steam conformance.
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