Effect of Solvent Co-Injection on Residual Oil Saturation in SAGD Steam Chamber

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Effect of Solvent Co-injection on Residual Oil Saturation in SAGD Steam Chamber

by

Fernando Javier Rengifo Barbosa

A THESIS
SUBMITTED TO THE FACULTY OF GRADUATE STUDIES IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE DEGREE OF MASTER OF SCIENCE

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies for acceptance, a thesis entitled "Effect of Solvent Co-Injection on Residual Oil Saturation in SAGD Steam Chamber" submitted by Fernando Javier Rengifo Barbosa in partial fulfilment of the requirements for the degree of Master of Science in Petroleum Engineering.

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Abstract

Steam Assisted Gravity Drainage (SAGD) process has been applied over wide area of the Province of Alberta, boosting the Canadian oil reserves to the position of third highest in the world. A key performance indicator of SAGD thermal efficiency is the steam-oil-ratio (SOR) that is the volume of water converted to steam and injected into the formation for each unit volume of produced oil. Even though several cost-saving advances have been made in this technology, SAGD remains expensive in terms of both the oil production cost and the environmental cost associated with greenhouse gases (GHG) emissions. Several kinds of additives have been proposed for improving the thermal efficiency of the process and decreasing the SOR while increasing the cumulative oil recovery.

Solvent addition in SAGD is one alternative that improves the performance by decreasing the oil viscosity by dilution and thereby by decreasing the required amount of heat per produced oil barrel. In solvent enhanced SAGD, a part of steam volume is replaced by hydrocarbon solvent, in order to take advantage of not just heat but also of dilution for viscosity reduction. At the same time, solvent injection reduces heat losses by reducing the operating temperature. The combination of reservoir characteristics and operational constraints influence the choice of solvent as well as its concentration and timing.

No systematic study of residual oil saturation ($S_{or}$) in solvent enhanced SAGD has been reported in the literature. This project tested four solvents (Pentane -C$_5$H$_{12}$, Hexane - C$_6$H$_{14}$, Cracked Naphtha and Natural Gas Condensate) at different concentrations using linear sand-packs that simulated SAGD gravity drainage to quantify their impact on the recovery performance during the injection process and on the residual oil saturation. The addition of all tested solvents to steam increased the rate of oil drainage and reduced the residual oil saturation. Amongst the single component solvents, 15 vol% hexane gave the fastest recovery and lowest residual oil saturation. However, the multicomponent solvents performed even better. Addition of 15 vol% cracked naphtha gave the lowest residual saturation and fastest oil recovery. The performance of gas condensate was also impressive. At 5 vol% concentration it was able to outperform 10 vol% cracked naphtha and 15 vol% hexane in terms of the rate of oil recovery and residual oil saturation.
Dedication

For YOU;
Because YOU give me the best and never leave me alone...
Because YOU grant me everything I dare to ask...
Because YOU take care of my steps and I can walk without fear...
With YOUR support I know I am going to achieve other dreams.
...I hope you keep taking me by YOUR hand...

For someone very special;
I may see myself in your eyes
and I know you understand me
even though you do not speak to me.

For those who accompany me even when I cannot see them...
Thank you for inspiring me...
...this is also for you all.

For those who have always believed in me...
your voices are my breath
and your sights my strength...
...I hope never disappoint you.
Acknowledgements

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Special thanks to the Department of Chemical and Petroleum Engineering at the University of Calgary for accepting me as a graduate student and for providing the required academic and technical resources to develop my studies.

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# List of Symbols, Abbreviations and Nomenclature

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<th>Symbol</th>
<th>Description</th>
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<tbody>
<tr>
<td>API</td>
<td>American Petroleum Institute</td>
</tr>
<tr>
<td>ARC</td>
<td>Alberta Research Council</td>
</tr>
<tr>
<td>BPR</td>
<td>Back Pressure Regulator</td>
</tr>
<tr>
<td>CAPP</td>
<td>Canadian Association of Petroleum Producers</td>
</tr>
<tr>
<td>CERI</td>
<td>Canadian Energy Research Institute</td>
</tr>
<tr>
<td>CMG</td>
<td>Computer Modelling Group Ltd</td>
</tr>
<tr>
<td>cSOR</td>
<td>Cumulative Steam Oil Ratio</td>
</tr>
<tr>
<td>CSS</td>
<td>Cyclic Steam Stimulation</td>
</tr>
<tr>
<td>CWE</td>
<td>Cold Water Equivalent</td>
</tr>
<tr>
<td>D</td>
<td>Darcy</td>
</tr>
<tr>
<td>EI</td>
<td>Energy Intensity</td>
</tr>
<tr>
<td>EOR</td>
<td>Enhanced Oil Recovery</td>
</tr>
<tr>
<td>ES-SAGD</td>
<td>Expanding Solvent SAGD</td>
</tr>
<tr>
<td>g</td>
<td>Acceleration (due to gravity)</td>
</tr>
<tr>
<td>GHG</td>
<td>Green House Gases</td>
</tr>
<tr>
<td>KPI</td>
<td>Key Performance Indicator</td>
</tr>
<tr>
<td>LASER</td>
<td>Liquid Addition to Steam for Enhanced Recovery</td>
</tr>
<tr>
<td>LP-SAGD</td>
<td>Low Pressure SAGD</td>
</tr>
<tr>
<td>mD</td>
<td>Millidarcy</td>
</tr>
<tr>
<td>ml</td>
<td>Millilitre</td>
</tr>
<tr>
<td>NCG</td>
<td>Non-Condensable Gas</td>
</tr>
<tr>
<td>$P_{sat}$</td>
<td>Saturation Pressure</td>
</tr>
<tr>
<td>$S_w$</td>
<td>Water Saturation</td>
</tr>
<tr>
<td>$S_{wi}$</td>
<td>Irreducible Water Saturation</td>
</tr>
<tr>
<td>SAGD</td>
<td>Steam Assisted Gravity Drainage</td>
</tr>
<tr>
<td>SA-SAGD</td>
<td>Solvent-Assisted Steam Assisted Gravity Drainage</td>
</tr>
<tr>
<td>SAGP</td>
<td>Steam and Gas Push</td>
</tr>
<tr>
<td>SAP</td>
<td>Solvent Aided Process</td>
</tr>
<tr>
<td>SAS</td>
<td>Steam Alternating Solvent Process</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
</tr>
<tr>
<td>--------------</td>
<td>-------------</td>
</tr>
<tr>
<td>SimDis</td>
<td>Simulated Distillation</td>
</tr>
<tr>
<td>SOR</td>
<td>Steam Oil Ratio</td>
</tr>
<tr>
<td>VAPEX</td>
<td>Vapour Extraction Process</td>
</tr>
<tr>
<td>$x_b$</td>
<td>Mass fraction of bitumen</td>
</tr>
<tr>
<td>$x_t$</td>
<td>Mass fraction of toluene</td>
</tr>
<tr>
<td>2D</td>
<td>Two Dimensional</td>
</tr>
<tr>
<td>3D</td>
<td>Three Dimensional</td>
</tr>
<tr>
<td>$\rho_b$</td>
<td>Density of bitumen</td>
</tr>
<tr>
<td>$\rho_m$</td>
<td>Density of the bitumen-toluene mixture</td>
</tr>
<tr>
<td>$\rho_t$</td>
<td>Density of toluene</td>
</tr>
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</table>
Chapter One: Introduction

1.1 Overview

SAGD is a process developed in the late 1970s and early 1980s with the initial goal of reducing oil viscosity sufficiently to make the bitumen drain down under gravitational forces into the production well. Heat is transferred from injected steam to the reservoir by conduction and convection using the sensible and latent heat of steam, increasing the oil mobility. Based on particular reservoir characteristics, several enhancements to the SAGD process have been proposed to make it more efficient in terms of economics and ultimate oil recovery [Chung and Butler, 1988].

Under increasing sociopolitical pressure to reduce water consumption, GHG emissions and the exploitation costs [Chhina and Edmunds, 2001], several alternatives to make SAGD a more efficient process are under research, with the main goal of achieving a less-energy intensive and more environmentally friendly process [Yang and Butler, 1992]. Several alternatives, including the use of solvents and additives like surfactants and gases (mostly non-condensable gases), are being evaluated to reduce interfacial tension and oil viscosity, increase the steam chamber size, and reduce heat transfer to thief zones [Chung and Butler, 1988].

Solvent injection into the reservoir (by itself and alternated or co-injected with steam) for highly viscous oil recovery has been studied from some time ago. VAPEX process, which uses vapourized solvent instead of steam, is an analogous process to SAGD [Butler and Mokry, 1990]. VAPEX principally relies on molecular diffusion of solvent into the oil and gravity drainage while SAGD is based on thermal diffusion and gravity drainage. Laboratory tests show VAPEX is technically applicable but not proven commercially successful in the field yet.

“Solvent Added SAGD” (SA-SAGD) is an application that benefits from thermal (steam) and molecular (solvent) diffusion, making it a complex process that is still under research
to optimize the solvent selection, concentration, timing and operational conditions. Depending on the reservoir pressure and temperature, some solvents work by condensation at the steam chamber boundary, where they reduce the bitumen viscosity [Gupta and Gittins, 2009].Others, like carbon dioxide (CO₂), nitrogen (N₂) and methane (CH₄), maintain their properties (as gas in the injection stream) in the reservoir and are called non-condensable gases (NCG´s) [Gittins et al., 2011].

SAGD becomes a more complex process when NCG´s, such as methane (CH₄), carbon dioxide (CO₂), nitrogen (N₂), or air, are added. According to fluid densities difference as well as interaction under heat effects, oil drainage and heat transfer can be significantly affected. NCG´s can be present in SAGD steam chamber but do not dissolve into the liquid phase to any large degree at steam temperatures [Akin et al., 2002]. NCG co-injection with steam in SAGD makes the process less energy consuming, which reduces GHG emissions.

1.2 Motivation and Problem Statement

Improving SAGD performance by solvent co-injection is not a new concept but it is still neither a well-developed nor well-understood technique. SAGD remains the most implemented yet expensive technique for Canadian heavy oil production, as it demands high-energy consumption to generate steam for each barrel of produced oil. This technique entails consuming large quantities of water and fuel (oil/natural gas) [Deng, 2005; National Energy Board, 2000], thereby resulting in a high environmental footprint (GHG and post-production water treatment).

There are ongoing efforts to make Canadian oil production under SAGD process more competitive by making it less energy-intensive, more environment-friendly, more profitable, reducing steam consumption and GHG emissions [Ray and Engelhardt, 1992; McColl et al., 2008], while maintaining a favourable level of oil production rates and total oil recovery. The most promising method of improving the thermal efficiency of
SAGD appears to be co-injection of a suitable hydrocarbon solvent with steam. The solvent, not only enhances the rate of oil production by reducing the oil viscosity, it also improves the oil recovery factor by reducing the residual oil saturation in the drained zone (steam chamber).

To the best of author’s knowledge, there is no systematic laboratory study of residual oil saturation in solvent enhanced SAGD reported in the literature, even though several studies have touched on this topic [Ayodele and Nasr, 2006; Ayodele et al., 2010; Li et al., 2011; Mohebati et al., 2012; Ibatullin and Zolotukhin, 2009; Mohebati et al., 2009; Li and Mamora, 2010].

The aim of this project is to experimentally examine the impact of solvent addition on residual oil saturation in SAGD using several different solvents at varying concentrations. A secondary objective is to evaluate the effect of solvents on the oil drainage rate under SAGD conditions.

1.3  **Research Methodology**

This study evaluates the performance of different solvents in reducing the residual saturation and improving the oil drainage in solvent enhanced SAGD through laboratory experiments. Tests are conducted in linear sand-packs with Long Lake bitumen. The oil drainage performance is measured for pure steam injection (the base case) and solvent added steam co-injection at different concentrations of four different solvents.

A one-dimensional sand-pack model was developed to conduct gravity drainage experiments under SAGD conditions. The experimental rig allowed varying the solvent type, solvent concentration and operating temperature. The sand-pack was instrumented to accurately measure the operating pressure, temperature, injection rate and produced fluid volumes in each test. Rigorous fluid and porous media analyses were conducted after each test to evaluate the solvent performance. The base case experiments were
conducted with steam alone to quantify the SAGD performance without any solvent. Subsequently, different solvents were added to the injected steam to determine the drainage rate and the final residual oil saturation left in the sand-pack.

1.4 Research Objectives

The objectives of this research were:

1. Develop a linear sand-pack rig capable of operating at temperatures and pressures typical of SAGD operations in the field for evaluating the performance of different solvents in improving the gravity drainage of oil.

2. Use the rig to evaluate the oil drainage performance of steam only injection and test the reproducibility of such measurements.

3. Evaluate the oil drainage performance of solvent added SAGD at different volume fractions of solvents by comparing with the base case of steam only injection.

4. Measure the residual oil saturation remaining in the sand-pack after each test by soxhlet extraction to close the material balance for the oil and determine the material balance error.

1.5 Thesis Structure

This thesis is a compilation of five chapters encompassing the following topics:

- *Chapter One* presents an Introduction, Overview, Motivation and Problem Statement, Research Methodology and Objectives for this research.

- *Chapter Two* presents a literature review on oil recovery by steam injection processes and the use of solvent co-injection with steam to improve the recovery performance.

- *Chapter Three* describes the experimental model for conducting the SAGD and solvent enhanced SAGD experiments. It also describes the materials used and
experimental procedures for sand-pack preparation, oil recovery by steam assisted gravity drainage tests as well as the produced fluid and the post-test sand analysis.

- **Chapter Four** presents the results of SAGD and solvent enhanced SAGD experiments to quantify the potential benefits of solvent-steam co-injection.

- **Chapter Five** presents the conclusions of this research and some recommendations for future work.
Chapter Two: Literature Review

In 2018, Canada accounted for 170 billion barrels of Proved Oil Reserves (10% of total worldwide) [CAPP, 2019]. Much of this oil (roughly 95%) is in oil sands deposits and is located almost entirely in Alberta over a 142,000 square kilometres area (Figure 2-1). Oil sands production from Western Canada (4.36 million b/d in 2018), can be recovered either by mining or by in situ recovery processes. Currently, oil mining area corresponds to 953 square kilometres and additional 3,847 square kilometres can be exploited by surface mining [CAPP, 2018].

![Figure 2-1 Oil sands area in Western Canada [After CAPP, 2018]](image)

The Athabasca, Cold Lake and Peace River oil sands deposits (Figure 2-2) currently account for roughly 95% of the total Canadian production and it is forecast to grow by 1.50 million b/d to reach 4.2 million b/d by 2035 from 2.65 million b/d in 2017 (Figure 2-3).

Mining projects are large-scale in nature and require more upfront capital than smaller scale in situ projects where production can be brought on in phases [CAPP, 2018]. Oil sands reserves and production stem from multiple undergoing and future projects (Figure 2-4).
Figure 2-2 Pay thickness in oil sands deposits in Western Canada [After Alberta Geological Survey, 2013]
Figure 2-3 Canadian oil sands and conventional production [After CAPP, 2018]

Figure 2-4 Oil sands projects Western Canada (Source: http://osip.alberta.ca/map/ as of January 2019)
Different techniques have evolved through the years to establish the best approach for heavy oil recovery around the world. All of these techniques attempt to take advantage of geological aspects, reservoir conditions, operational parameters, technical capabilities, available resources and reduce GHG emissions. However, all these techniques concur about the necessity of increasing the oil mobility. Application of heat and diluent additives can reach this objective. The Canadian industry is greatly dependent on applications of new technologies due to more challenging reservoir characteristics (Figure 2-5).

Surface mining and cold production are low-risk primary recovery approaches for heavy oils, but these are limited to the shallow depth of reservoirs and relatively light oil grades respectively [CAPP, 2018]. Water flooding, as a popular secondary recovery method, is not viable due to the huge viscosity difference between water and oils, leading to low sweep efficiency [Nasr et al., 1998].

To achieve a high recovery factor, EOR methods are essential. The in situ heavy oil viscosity is dependent on reservoir temperature and decreases rapidly with the increase of temperature [Miller and Erno, 1995]. Accordingly, external thermal sources can be used to heat the oil and reduce its viscosity, and such techniques are called thermal recovery methods. The oil viscosity can also be decreased by dilution with solvents and recovery techniques using solvents and other mobility enhancing additives have also been successfully implemented. The estimated supply cost and associated GHG emissions of several recovery techniques are presented in Figure 2-6.

![Figure 2-6 Cost and Carbon emissions for different Oil Sands Extraction Technologies [After CERI, 2017]](image-url)
Figure 2-5 Technology Innovation Chronology of Oil Sands In Situ Extraction [After CERI, 2015]
2.1 Steam Flooding (SF)

This recovery method has been particularly successful in California and Venezuela heavy oil reservoirs [Farouq-Ali, 1970]. In this method, steam is injected from a vertical injection well to drive the oil towards vertical or horizontal producers like water flooding in pattern designs [Shah et al., 2010]. This recovery technique has serious challenges in reservoirs with bottom water and or gas cap as these zones induce heat losses [Baker, 1973]; therefore, reservoir thickness and oil density become key parameters. This process has shown better results with moderately heavy oils compared to extra-heavy or medium gravity oils [Nian, and Cheng, 2017].

Being a continuous process, its effectiveness relies mostly on heat transfer by conduction from steam to heavy oil as latent and sensible heat is delivered into the reservoir at the condensation front [Mandl and Volek, 1969]. At the same time, the drive mechanism is due to over pressure caused by the injected fluid. It was used in few Canadian heavy oil reservoirs without major success due to very low mobility at initial reservoir conditions [Spillette, 1965].

2.2 Cyclic Steam Stimulation (CSS)

This method involves injection of steam at high temperature and pressure (often above the formation fracture pressure) into heavy oil reservoirs using the same well that will be used later as the producer [Butler, 1997]. Once injected, steam delivers its sensible and latent heat to the heavy oil principally by conduction into the reservoir, similar to SF [Aziz et al., 1987]. After enough soaking time, heated bitumen is pumped to surface using the same well that was used for steam injection. The process is thereafter repeated for several cycles [Polikar et al., 2000; Li et al., 2011]. The CSS is quite successful in Canadian heavy oil reservoirs and it has the ability to produce faster oil compared to other methods [Farouq-Ali, 1994]. This process uses either horizontal wells or vertical wells, depending on reservoir thickness and can be followed by other recovery methods [Coskuner, 2009].
2.3 In-Situ Combustion (ISC) / High Pressure Air Injection (HPAI)

In this method, air is injected into reservoir to form a combustion (oxidation) front that pushes the heavy oil ahead of the combustion zone. This process is applicable for both heavy and light oil reservoirs [Sarathi, 1998]. In this technique, heat is generated in the reservoir and it involves complex processes of mass and heat transfer as well as multiple physicochemical reactions that transform the rock and in-situ fluids [Nissen, et al., 2015].

The original concept of ISC method requires the same well configuration as water flooding, using vertical wells with combustion front moving from injector to producer over time. There are not too many active projects of ISC around the world due to difficulties encountered in adequately controlling the process, once started, because of the high temperature, corrosive fluids and gravity override of injected air. Prior to implementing into a field, ISC requires careful evaluations in laboratory with both physical and simulation models [Moore et al., 1999].

ISC method is less successful in Canadian heavy oil reservoirs due to the low oil mobility at the initial reservoir conditions. When air is injected into a reservoir, a combustion front is created in which a part of the reservoir oil is burnt to generate heat [Mahinpey et al., 2007; Cinar et al., 2011], which is used to reduce the oil viscosity and mobilize it towards the producers. A major issue with this process is that the heated oil has to travel through the cold reservoir lying between the combustion front and the production wells, which can cool it down and severely reduce its mobility. Modified well configurations, such as toe-to-heel air injection have been tried to overcome this problem, but none has achieved commercial success.

Sometime, the air is injected with water and the process is sub categorized as wet or super wet combustion. Tremendous amount of research is still taking place to improve the effectiveness of this method.
2.4 Vapour Assisted Petroleum Extraction (VAPEX)

It is analogous to the SAGD process in terms of well configuration, however it is different in terms of the injected fluid, as a solvent vapour is injected instead of steam [Butler and Mokrys, 1990] to reduce the viscosity of heavy oil and bitumen [Ahmadloo et al., 2011]. The energy requirement for VAPEX is lower than for thermal methods and heat transfer is not the main action for oil viscosity reduction [Rezaei and Chatzis, 2007]. The process relies on mass transfer via diffusion and dispersion of the injected solvent for dilution of the oil [Das, 1998].

The mass transfer process is much slower than the heat transfer process and hence it results in low production rate compared to SAGD [Vargas-Vasquez and Romero-Zeron, 2007]. However, it is applicable in thin reservoirs and reservoirs with overlying gas cap or underlying aquifers, as well as carbonate reservoirs with low permeability, vertical fractures [Alkindi et al., 2008], low porosity and low thermal conductivity [Cunha et al., 2007].

2.5 Steam Alternating Solvent (SAS) Injection

This process also has similar well configuration as of SAGD but with different injection pattern and operational strategy. It starts with injection of pure steam at the start up, followed by solvent injection once the steam chamber has been established [Zhao, 2004]. The solvent injection is stopped at the point where the oil production rate becomes too slow and pure steam is again injected. This cycle of alternating between steam and solvent injection is repeated several times until the project reached its economic limit.

SAS is developed to utilize both heat and mass transfer but these effects are alternated as the injected fluid shifts from steam (heat transfer) to vapour solvent (mass transfer) [Gupta and Gittins, 2005]. The oil viscosity reduction is achieved at the vapour front, where latent and sensible heat is delivered when steam is injected, or solvent diffuses and disperses in the oil when the solvent is the injected fluid.
2.6 Steam Assisted Gravity Drainage (SAGD) and its Enhancements

As a more advanced form of steam injection, Dr Butler in 1970s invented SAGD in an attempt to recover Alberta bitumen [Butler et al., 1981]. Since then, SAGD has been further developed and commercially applied as the most effective thermal injection method for heavy and extra-heavy oil recovery. High recovery factors up to 70% of OOIP have been achieved with high production rates. Despite several reported pilot tests in United States, China and Venezuela, commercially successful cases exist mostly in Canada.

This method is widely used for bitumen and heavy oil recovery in western Canada. In this process, two parallel horizontal wells 5 m apart from each other in the same vertical plane are placed near the bottom of formation. Steam is injected from the top horizontal well and bitumen is produced from lower horizontal well. The injected steam forms a steam chamber while continued injection promotes the growth of this chamber [Butler, 1991].

Heavy oil viscosity reduction is achieved by heat transfer (mainly conduction but also by convection as per several studies), as the latent and sensible heat of steam is delivered at the edge of steam chamber (see section 2.6.3 for details). This continuous process involves a growing of steam chamber between the under and overlying layers. The process loses substantial amount of heat to the overburden rock and the existence of significant gas and/or water zones in the formation leads to additional heat loss [Gates, 2010].

It is important to have clear understanding of heat transfer to cold oil sand and the energy distribution throughout the steam chamber in the SAGD recovery process. The conformance of the steam chamber is monitored by temperature profiles by having thermocouples throughout the lateral section of horizontal wells [Aherne and Birrel, 2002]. Many studies have analysed the process of heat transfer near the vapour-liquid interface of the steam chamber.
2.6.1 Bitumen Viscosity and Its Relationship to Temperature

The high viscosity of bitumen is due to the high-boiling components in the bitumen, which include a big percentage of asphaltenes. The strong physical interactions of large molecules increase its viscosity, which is extremely sensitive to temperature changes. The temperature increase reduces the strength of the molecular interactions and diminishes the viscosity [Seyer and Gyte, 1989].

Oil viscosity change with temperature has great importance in thermal oil recovery processes since viscosity determines oil phase mobility. Several studies have characterized the oil viscosity change as a function of temperature with laboratory measurements and developed correlations for predicting this change [Andrade, 1930; Walther, 1933; Wright, 1965; Khan et al., 1984].

2.6.1.1 In situ Oil Viscosity Variation

Oil viscosity often shows variation with depth in heavy oil reservoirs, as it tends to increase at higher deposition depths. In Clearwater B formation in east central Alberta viscosity measurements show changes with depth [Erno et al, 1991]. Other analyses confirmed that oil viscosity at the top of reservoir was lower than the viscosity at the bottom [Li et al., 2008]. Numerical reservoir simulations also noted the effect of viscosity variation in SAGD performance predictions [Gates et al., 2008].

2.6.2 SAGD Enhancements

SAGD implementation has become highly developed and commercially applied as the most important thermal recovery method for heavy and extra-heavy oils. However, search has continued to find ways of improving its performance and an attractive strategy is to use a combination of heating and dilution with a solvent [Farouq-Ali and Abad, 1976; Alikhan and Farouq-Ali, 1974]. These new applications are based on combining the benefits of SAGD (heat transfer steam-based) and VAPEX (mass transfer solvent-based).
Tested from late 1960s in a California field [Jeffries-Harris and Coppel, 1969] and in the laboratory [Gates and Caraway, 1971], injection of a steam-solvent mixture into a reservoir is a more complex process. The effect of solvent addition on pressure-volume behaviour of steam-solvent-bitumen systems is significant; dissolved solvent in oil reduces oil viscosity and improves its flow in the reservoir.

2.6.2.1 Expanding Solvent Steam Assisted Gravity Drainage (ES-SAGD)

ES-SAGD involves co-injection of a low molecular weight hydrocarbon with steam, maintaining the dominance of gravity forces on the process. This additive condenses at nearly the same conditions as steam in order to act at the location where steam delivers its latent energy (steam chamber edge). On this basis, both latent heat and dilution lower the bitumen viscosity. As the solvent behaves in a similar manner as the steam, it guaranties the propagation of the solvent to the edge of the chamber [Nasr and Isaacs, 2001]. The steam chamber being an isobaric and isothermal (high temperature) environment, it is ideal for the solvent to remain in vapour phase until it reaches the steam chamber boundary to act where the highest remaining in-situ bitumen saturation is present. [Nasr and Isaacs, 2001].

In an experimental study, it was found that the maximum oil drainage rate under ES-SAGD occurred when the steam temperature matched the solvent vaporization temperature [Nasr et al., 2003]. Figure 2-7 shows the variation of oil drainage rate with different steam/solvent pairs in a laboratory study. The tests were conducted at 215 °C temperature and 2.1 MPa operating pressure.

The drainage rate improved with: (1) the increasing carbon number of the injected hydrocarbon and (2) as the vaporization temperature of the hydrocarbon additive became closer to the injected steam temperature. The drainage rates peaked with hexane, which has the closest vaporization temperature to steam temperature in the test, and then started to decline with octane, which has a higher vaporization temperature as compared to injected steam temperature.
Figure 2-7. Comparison of oil drainage rates [After Nasr et al., 2003]

Figure 2-8 shows the diagram of solvent – steam spectrum that indicates the operation windows of different solvents. The selection of a solvent or a solvent mixture is done in such a way that the solvent can vaporize and condense at the same temperature/pressure conditions as the water phase, and the phase change of solvent is expected to be the same as steam near the vapour/bitumen interface.

2.6.2.2 Solvent Aided Process (SAP)

SAP is described as an improved version of SAGD by addition of small quantity of lighter hydrocarbon solvent (propane, butane, pentane, etc.) to obtain benefits of dilution and
steam heat transfer [Gupta et al., 2003]. This study remarks that steam and solvent are injected at a high temperature (elevated thermal energy) for the solvent to remain vaporized until it reaches the condensation front where it dissolves in the oil at the same time that steam delivers its latent heat.

Solvent co-injection for ES-SAGD is applied immediately after the preheating period, while in the SAP process, the solvent addition is developed after some period under SAGD, so that steam chamber is already formed to certain extent [Gupta et al., 2002]. While in ES-SAGD the vaporization temperature of the solvent needs to be close to the steam temperature [Nasr and Isaacs, 2001; Nasr et al., 2003], in SAP much lighter solvents are used and matching of the condensation/vaporization characteristics of the solvent with steam is not required [Gupta et al., 2002].

Some features that make SAP a preferred process over conventional SAGD were summarized as [Gupta et al., 2002]: (1) Accelerated production as per combination of dilution and heat transfer effects, SAP support to higher production rates while reaching the estimated ultimate recovery in a shorter period compared to conventional SAGD. (2) Cheaper solvents: it uses much lighter hydrocarbons (mainly butane) and these are normally cheaper than heavier components. (3) Facilities configuration: SAP uses an operational configuration quite similar to that for SAGD application. (4) Lower steam oil ratio: steam oil ratio for SAP is significantly lower than for SAGD as per dual effect (heat and mass transfer), making it more efficient in terms of fuel consumption thereby reducing the environmental impact of oil sands production. (5) Down-hole upgrading of bitumen: low molecular weight alkanes used in SAP may precipitate some of the asphaltenes that tend to be dispersed in the bitumen. It can potentially result in improving the quality of the produced oil.

2.6.2.3 Steam Alternating Solvent Process (SAS)

This process uses the SAGD well configuration to inject steam alternated with solvent [Zhao, 2004]. SAS process initialization is similar to SAGD but after sometime, solvent
vapor is injected in place of steam. Some features [Zhao, 2004] of the SAS process are described below.

- Pure steam is injected as in the SAGD process to start-up the operation.
- The steam injection is stopped and solvent injection started when heat loss to the overburden becomes significant as the steam chamber grows to the top of the pay zone.
- The solvent injection is stopped and steam injection restarted when the chamber temperature is reduced, making the production rate low.
- Repeating the steam injection and solvent injection cycle until it is not economic to continue.
- Recovering the solvent still in place through a blow-down phase at the end of the operation.

As steam and solvent injections are alternated, the temperature in chamber fluctuates, therefore making bitumen viscosity also a fluctuating factor. Nonetheless, the increase in viscosity by reduced temperature is partially compensated by solvent dissolution. Preferred solvent should have a dew point temperature somewhere between initial reservoir temperature and steam temperature at the operating pressure [Zhao, 2004].

2.6.2.4 Liquid Addition to Steam for Enhanced Recovery (LASER)

LASER technique integrates hydrocarbon injection solvent in a Cyclic Steam Stimulation (CSS) process at some intermediate stage of reservoir depletion [Leaute and Carey, 2005]. Late-cycle CSS tends to be similar to SAGD because, in mature CSS operations (i.e. in late CSS cycles), gravity becomes increasingly the dominant recovery mechanism due to the substantial decrease in the contribution of the early CSS recovery mechanisms such as formation recompaction, solution gas drive and steam flashing [Leaute and Carey, 2005; Leaute, 2002; Chakrabarty and Gates, 2008].
In LASER, a small fraction of a liquid hydrocarbon solvent (~6% by volume) is added to the steam at the wellhead and upon being vaporized, the solvent is then transported with steam into the reservoir until significant steam condensation occurs at interface of the previously steam stimulated formation and the colder undepleted areas [Al-Murayri, 2012].

Co-injection of the solvent with steam should take place at less than formation fracturing or parting pressure, when a relatively steady build-up of pressure develops throughout each injection cycle [Leaute and Carey, 2005]. They also pointed out that the quantity of the solvent injected into the steam should be preferably chosen to be as large as possible to maximize its effect; however, the quantity should remain well within the maximum solubility of diluent expected at typical bottom hole thermodynamic conditions that are encountered during CSS production cycles. If this was not maintained, foaming of inflowing fluids from the reservoir into the well bore would take place and this could significantly impair the smoothness of downhole pumping operations. The injected solvent or diluent that is recovered should remain for the most part soluble within the produced bitumen phase at the bottom hole conditions of typical CSS operations.

It was also pointed out that the optimum loading of hydrocarbons injected with steam should be chosen to maximize pressure drawdown and fluid removal of the reservoir using conventional CSS artificial lift equipment that are already available, to avoid additional expenses [Leaute and Carey, 2005].

2.6.2.5 Non-Condensable Gas (NCG) Co-injection

NCG application involves co-injection of a gas that does not dissolve into the oil phase to any large degree at reservoir pressure and temperature [Aherne and Birrell, 2002]. As this process adds a gas, SAGD becomes more complex in the presence of NCG (such as methane -CH₄, carbon dioxide -CO₂, nitrogen -N₂, air, etc.), since these gases can significantly affect the displacement of oil. NCG steam co-injection for SAGD is less energy consuming (per unit volume of oil production), thereby reducing greenhouse gas emissions.
NCG-SAGD shows several interaction in the reservoir including:

1. Separation (NCG tends to go to the upper part of the reservoir),
2. Gas fingering (in its way to the upper part of the reservoir),
3. Heat loss reduction (isolation effect to thief zones and reduced thermal conductivity),
4. Asphaltene precipitation (mainly at the limits of steam chamber),
5. Pressure increase/maintenance (in the steam chamber), and
6. Steam chamber expansion (increase in cross section area).

2.6.2.6 N-Solv

N-Solv (thermal solvent oil recovery process) uses a heated solvent to reduce viscosity of the heavy oil in-place as per developments to 2007. In a previous work, Nenniger proposed cold solvent injection instead of steam. However, chamber growth was slow, resulting in low oil production rates [Nenniger, 1976].

N-Solv is implemented under some specific operational features that make it different from SAGD as:

- Placing a downhole heater in the formation adjacent to the oil producing zone to heat the “heat transfer fluid” which is preferred to be a solvent.
- Energizing the downhole heater and passing the heat transfer fluid through it.
- Injecting the heated heat transfer fluid into the oil bearing formation to reduce the effective viscosity of the oil in-place.
- Recovering the mobilized oil to form an oil extraction chamber in the oil bearing formation.

2.6.3 Mechanisms Involved in SAGD and SA-SAGD Processes

Solvent co-injection differs from just steam injection in several interactions between fluids and rock, and needs to be analysed carefully to better approach their specific performance.
2.6.3.1 Steam-Bitumen/Rock Heat Transfer

Earlier in its development, the heat transfer in SAGD was considered to be primarily by conduction [Butler and Stephens, 1981; Reis, 1992; Akin, 2005; Liang, 2005; Nukhaev et al., 2006; Azad and Chalaturnyk, 2010] at the edge of steam chamber [Irani and Ghannadi, 2013] and the classic SAGD heat transfer models did not consider the contribution of convection to be significant. However, some researchers [Farouq-Ali, 1997; Edmunds, 1999a, b; Ito and Suzuki, 1996, 1999; Ito et al., 1998; Sharma and Gates, 2011; Irani and Ghannadi, 2013] questioned the assumption that thermal conduction dominates heat transfer at the edge of SAGD chamber. An obvious effect of solvent addition on the heat transfer is the lowering of the temperature at the edge of the steam chamber due to reduced partial pressure of steam, which would directly reduce the conductive heat transfer.

Thermal conduction beyond the edge of a SAGD chamber to cold bitumen considers no heat loss as a result of bitumen drainage [Irani and Gates, 2013]. When the bitumen drains from chamber sides, there is a considerable amount of heat taken out from the system, which has to be considered. Their research shows that there are two forms of convective flow that should be considered in thermal heat transfer at the edge of the SAGD steam chamber: (1) the convective flux from condensate flow normal to the edge of the steam chamber; and (2) the convective flux from flowing bitumen and condensate parallel to the edge of the steam chamber (Figure 2-9).

![Figure 2-9 Convection mechanism in SAGD [After Irani and Gates, 2013]](image)
2.6.3.2 *Solvent-Bitumen Mass Transfer*

Mass transfer in solvent co-injection occurs between steam and solvent vapour as well as between the solvent and heavy oil, however the exact mechanisms of these processes are still under research [Das, 1995].

Several studies state that the transition zone (interchange or mixing zone) is mainly the condensation front [Dunn et al., 1981]. However, when high connate water saturation exists, the solvent can penetrate the cold bitumen zone by displacing the mobile water, making convective transport of solvent a significant factor. Moreover, earlier estimates suggested that diffusion was not the only mass transfer process [Das, 1995; Dunn et al., 1981; Das and Butler, 1998] and dispersion needed to be included [Dunn et al., 1981].

The diffusive mixing occurs when two or more fluids encounter each other at the interface [Nguyen and Farouq-Ali, 1998], where molecular diffusion occurs due to the concentration gradient of various components in a system [Wen et al., 2005]. The molecular diffusion coefficient or diffusivity controls the rate at which solvent dissolves in oil [Riazi, 1996], thus directly affecting recovery.

When the fluids are flowing through the porous medium, then there may be some additional mechanical mixing taking place [Dunn et al., 1989]. This increased mixing caused by uneven fluid flow or velocity gradients is designated dispersion [Perkins, 1963]. There are two types of dispersions. One is dispersion in the longitudinal direction or direction of gross fluid movement. The second is dispersion transverse to the direction of gross fluid movement. The dispersions will not be equal in these two directions; hence, we must consider each separately [Robbins, 1989].

2.6.3.3 *Viscosity Reduction*

As the solvent (lighter material) blends with bitumen components (mainly heavy), the bitumen viscosity decreases. The lower the solvent boiling point, the more pronounced is the bitumen viscosity reduction [Seyer and Gyte, 1989].
Figure 2-10 shows viscosity reduction when different concentrations of solvents are mixed with bitumen at different temperatures [Zargar and Farouq-Ali, 2018]. It is apparent that the viscosity reduction is more pronounced at lower temperatures.

![Viscosity model](image)

**Figure 2-10 Viscosity model for several bitumen-solvent mixtures [After Zargar and Farouq-Ali, 2018]**

### 2.6.3.4 Changes in Wettability

Residual oil saturation is one of the parameters that correlates with wettability [Baker, 1988]. As steam injection continues, the residual oil saturation decreases [Poston et al., 1970]. This suggests a shift in wettability towards more water-wet conditions. However, some studies claim that there is an increase in oil-wetness as the steam propagates [Bennion et al., 1992; Unal et al., 2015] as per the interaction of heavy oil components and rock that alter wettability from water-wet to oil-wet [Mukhametshina et al., 2015]. In ES-SAGD, the presence of solvent can induce asphaltene deposition, which can make the rock more oil-wet.

### 2.6.3.5 Asphaltene Deposition

The asphaltene fraction of crude oil is defined as insoluble in n-alkanes, but soluble in aromatics [Yen et al., 1961; Huc, 2011]. Asphaltenes are known to precipitate out of solution under several conditions including variation in temperature, pressure or a change in composition resulting from the addition of diluents. Paraffins, aromatics, and resins are
soluble oil fractions when maintaining a specific ratio of each fraction [Haghighat and Maini, 2008]. The precipitation mechanism of asphaltenes is of a complex nature due to the tendency of asphaltenes to self-associate and the cross-molecular association between asphaltene-resin and resin-resin species in crude oil [Duda and Lira-Galeana, 2006; Haghighat and Maini, 2012].

This precipitation may have several consequences, such as heavy oil upgrading (lighter produced oil), reduction in permeability and plugging of flowlines [Mukhametshina and Hascakir, 2014].

2.7 Solvent Injection Tests in Laboratory and Numerical Simulation

Co-injection of methane, ethane, propane, butane, pentane, natural gasoline, naphtha, and synthetic Great Canadian Oil Sands crude with steam in steam-stimulation was studied in 1980 [Redford and McKay, 1980]. In another study, CO₂, ethane and naphtha were used with steam. This test concluded that naphtha could improve recovery while NCG provides solution-gas drive in the pressure-drawdown phase [Redford, 1982]. Nasr et al. [1991] experimentally evaluated steam-solvent co-injection in the laboratory.

Another study examined the injection of CO₂, ethane or propane, at a pressure below the dew point at reservoir temperature, in a gravity drainage process [Nenniger, 1976]. Jurinak and Soni [1987] used numerical simulation to evaluate solvent co-injection with small quantities of a volatile solvent in a fracture-assisted steam flood. Butler and Mokrys [1989] reported that the solvent can be deployed in an analogous behaviour to steam in SAGD, to recover bitumen in a gravity drainage process.

Many reported studies of solvent injection have used experiments in rectangular sand-packs [Mokrys et al., 1995; Butler and Jiang, 2000; Karmaker and Maini, 2003; Yazdani and Maini, 2005; Moghadam et al., 2007; Rahnema et al., 2008; Ayub and Tuhinuzzaman, 2007; Ahmadloo et al., 2011] or cylindrical sand-packs [Haghighat and Maini, 2010; Jia et
al., 2013] or Hele-Shaw Cells. Different compositions of C$_1$, C$_3$, C$_4$ and CO$_2$ where used in rectangular sand-packs or cylindrical sand-pack, and Hele-Shaw Cell. Numerical simulation was used in several other studies to examine the solvent injection process [Das, 2008; Gul and Tarivedi, 2010; Xu et al., 2012; Yazdani et al., 2012].

2.8 Field Applications of Solvent Injection

Several field applications of solvent co-injection have been reported in SAGD projects like Surmont - ConocoPhillips [ConocoPhillips 2013, 2014], Long Lake - CNOOC Intl Ltd [Orr, 2009], Firebag - Suncor [Orr, 2009], Christina Lake – Cenovus [Cenovus, 2016], Leismer - Equinor [Statoil, 2015], Selmac – Cenovus [Cenovus, 2017], Algar - Connacher [Connacher, 2012; Lau et al., 2012] and Cold Lake - ExxonMobil [Dickson et al., 2011]. Their results included pros and cons as per operational parameters.

These field applications considered solvent recovery (because of the cost of solvent and reinjection possibility), SOR (Steam Oil Ratio) reduction and RF increment as key performance indicators (KPI). As per published information, results are varied, positive and promising, even though the micro-scale performance (mineralogical reactions) was not evaluated and topics like asphaltene segregation remain unknown.

2.9 Other Considerations for Solvents Applications

As per previously discussed effects of solvent injection, the earlier research focused primarily on the applicability of solvents for field operations. In order to guide any future development, solvent interaction with mineralogy should also be considered.

Alberta oil sand deposits consist of bitumen (4-18 wt%), inorganic materials (55-80 wt%) and water (2-15 wt%) [Bichard, 1987]. It is generally recognized that the coarse sands do not cause any problem throughout extraction process [Osacky et al., 2013] however, microsize minerals (mainly clays) are detrimental [Sandford and Seyer, 1979].
Previous studies about Alberta oil sands composition have reported kaolinite, illite, smectite, chlorite and mixed layer clay minerals as the main clay constituents of oil sands [Bayliss and Levinson, 1976; Ignasiak et al., 1983]. These clays can interact with solvent, bitumen and connate water as per their reduced particle size, high specific surface area, swelling capacity, cation exchange capacity, layer charge and specific physicochemical properties.

In general, bitumen recovery decreases with increasing fines content (particles smaller than <44 μm) in the oil sands [Sandford, 1983]. Laboratory experiments have shown that the addition of montmorillonite and calcium ions into oil sands decreased bitumen recovery, whereas the addition of kaolinite or illite did not have a significant effect on bitumen recovery [Kasongo et al., 2000].

Even though solvents like toluene, xylenes and acetone can outperform many others when injected, they represent a health risk (highly toxic) if they reach fresh water aquifers during the injection process. Because of it, environmental regulations reject their use in field applications.
Chapter Three: Experimental Apparatus and Methods

This research involved the building of a one-dimensional physical sand-pack model capable of operating at temperatures and pressures typically implemented in SAGD operations in the field. The sand-pack model was used to evaluate the effect of different solvents on the residual oil saturation left behind in the sand-pack after completion of the steam assisted gravity drainage test. In addition, the recovery performance in terms of the volume of oil produced versus volume of steam injected was also monitored and analyzed.

3.1 Experimental Model Design

The main design objective was to develop an apparatus that can provide quick answer to the question of which solvent would have greater beneficial impact on the performance of SAGD. Several considerations regarding the test parameters, including the ease of assembling-disassembling and running the tests, and ensuring the reproducibility of sand-pack characteristics, were taken into account in designing the equipment.

The major components in the experimental set-up were: a steam generator; a sand-pack model; a continuous-flow ISCO pump to inject de-ionized water into the steam generator; another ISCO pump to inject solvents; a solvent transfer cylinder; a back pressure regulator; thermocouples and temperature monitoring panel and control devices. A sketch diagram showing the interconnections between these components for the initially designed experimental apparatus is presented in Figure 3-1. Figure 3-2 shows a picture of the assembled rig.

3.1.1 Sand-Pack Model

A one-dimensional cylindrical physical model for vertical use was fabricated using stainless steel pipe with 2.54 cm internal diameter and 30 cm effective sand-pack length. It provided a steam injection port near the base (2.5 centimetres above the sand-pack bottom) to simulate SAGD operating conditions (Figure 3-3).
Figure 3-1. Schematic of experimental rig set-up

Figure 3-2. Experimental set-up
The sand-pack was equipped with axially movable end-caps, which permitted application of axial stress on the sand by tightening the end-cap bolts. Each end-cap had a flow port and a fluid distribution pattern milled into the circular surface that was in contact with the sand. The flow pattern was covered with 200-mesh stainless steel screen. Four thermocouple ports were included to monitor the temperature in the sand at different locations, numbered Thermocouples 1, 2, 3 and 4. (Figure 3-4).

Figure 3-3. One-dimensional cylindrical physical model

Figure 3-4. Inner thermocouples placement
3.1.2 Steam Generator

A flow through steam generator was used for producing the steam. It was essentially a three meters long stainless steel tube of 3/8 inch diameter, which contained a full-length rod heater of 3/16 inch diameter placed along its axis. The steam was generated by injecting deionized water into the annulus between the heater and the tube from one end and allowing it to pass through the annulus in contact with the electrical heater. The tube and heater assembly was coiled into a six-inch diameter coil and this coil was placed inside an aluminum box, which was then filled with an insulating material. The power supplied to the heater was adjustable with a Variac, which allowed production of superheated steam at the selected flow rate. The output from the steam generator went directly into the injection port of the sand-pack (Figure 3-5).

![Figure 3-5. Steam generation and steam-solvent co-injection arrangement](image)

3.1.3 Continuous-flow ISCO Pump for Water Injection

A continuous flow ISCO pump was used to inject de-ionized water to the steam generator at constant rate. The pump contained two high-pressure stainless steel syringes connected with a switching valve assembly, which allowed one syringe to be filled while the other was injecting water into the steam generator (Figure 3-6).
3.1.4  ISCO Pump for solvent injection

For experiments with solvent, another pump was used to inject the solvent from a transfer cylinder into the flow line connecting the steam generator to the sand-pack inlet (Figure 3-6). The transfer cylinder was equipped with a floating piston to isolate the pump fluid from the solvent.

![Figure 3-6. Paired water injection and solvent injection system](image)

3.1.5  Solvent Transfer Cylinder

A 400 ml stainless steel transfer cylinder, was used for injecting the solvents. The solvent was placed on the bottom of its floating piston, which was pushed down hydraulically by the solvent injection pump to inject the solvent at constant flow rate (Figure 3-7).

3.1.6  Back Pressure Regulator

The production line passed through a Back Pressure Regulator (BPR) that kept the pressure constant at the production end of the sand-pack. It was set at 230 psi (1.585 MPa) in all tests. The production line connecting the sand-pack to the BPR was heat traced to avoid plugging it, since, without such heat tracing, the bitumen could have cooled down during its passage through it (Figure 3-8).
3.1.7 Thermocouples and Temperature Monitoring Panel

A thermocouple was located in the steam generator to monitor the temperature and ensure that the steam generator was operating at a temperature well above the saturation temperature of steam at the operating pressure. Four thermocouples were placed on the outside of the sand-pack wall insulation (see Figure 3-4 for details), which was then wrapped with heat-tapes to reduce the temperature difference between the inside sand and the outer surface of insulation. At the sand-pack steam inlet port, a thermocouple was
installed to monitor the incoming steam temperature. Another thermocouple was installed at the sand-pack outlet to record the produced fluids temperature (Figure 3-9).

![Figure 3-9. Sand-pack thermocouples at fluids inlet and outlet](image)

A by-pass line was installed to allow direct flow from the steam generator to BPR, until steam injection conditions were achieved before letting the stream to go through the sand-pack (Figure 3-10).

![Figure 3-10. Production arrangement](image)
The sand-pack model was mounted directly on the steam generator box to minimize the length of the flow line from steam generator to the sand-pack. Six dual channel thermocouples read-outs were used to monitor the temperatures in different parts of the system (Figure 3-11).

![Figure 3-11. Temperature Monitoring System](image)

### 3.1.8 Heat Tapes and Variacs

Several Variacs were used to control the power going into each heating tape. Thus, each heating tape was able to operate independently to maintain a slightly lower temperature on the outside of insulation to avoid heat addition to the system and operate the rig in a near adiabatic mode (Figure 3-12).

![Figure 3-12. Zoned heating system](image)
The sand-pack was insulated with glass-fibre tape and four electrical heating tapes were installed on the outside of the insulation, over four axial zones of the sand-pack. A second insulation layer was installed on top of the heating tapes. External thermocouples were placed in the inner insulation in each axial segment to monitor the temperature of the insulation. (Figure 3-13).

![Figure 3-13. Insulated sand-pack](image)

### 3.2 Materials

The materials used in the experiments included sand, de-ionized water, bitumen and solvents. These are briefly described below.

#### 3.2.1 Bitumen

Cleaned and dehydrated Long Lake bitumen was used for each SAGD and steam-solvent co-injection test for oil flooding the sand-pack porous medium after initially saturating it with de-ionized water. It was provided by CNOOC International Ltd. According to previous works [Jonasson and Kerr, 2013], Long Lake bitumen has an API gravity of 6.16 which under temperature-density correlation [Gates, 2014] equates a density of 1.0085 grm/ml at 24 °C. Other reported properties of the bitumen are listed in Table 3-1.
Table 3-1. Long Lake Bitumen properties

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Molar Mass (grm / mol)</th>
<th>Density (@ 24°C) (grm / ml)</th>
<th>Critical Pressure (MPa)</th>
<th>Critical Temperature (°K)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long Lake Bitumen</td>
<td>600</td>
<td>1.0085</td>
<td>0.939</td>
<td>1067.06</td>
</tr>
</tbody>
</table>

3.2.2 Sand

Several sizes of pure silica sand (silicon dioxide) were used in this study. Sand mesh sizes of 12-20, 16-30 and 100-140 were tested for SAGD performance and the size 16-30 was used for SA-SAGD tests.

3.2.3 Solvents

Pentane (99% purity) and hexane (99% purity) used in these tests were supplied by Sigma Aldrich. The cracked naphtha (Table 3-2) and natural gas condensate (Table 3-3) used in these tests were provided by CNOOC International Ltd.

Table 3-2. Cracked Naphtha composition

<table>
<thead>
<tr>
<th>Component</th>
<th>Composition (Mole Fraction)</th>
</tr>
</thead>
<tbody>
<tr>
<td>nC₄</td>
<td>0.0063</td>
</tr>
<tr>
<td>iC₅</td>
<td>0.0565</td>
</tr>
<tr>
<td>nC₅</td>
<td>0.0816</td>
</tr>
<tr>
<td>C₆</td>
<td>0.1391</td>
</tr>
<tr>
<td>C₇+</td>
<td>0.7165</td>
</tr>
<tr>
<td>Total</td>
<td>1.0000</td>
</tr>
</tbody>
</table>

3.3 Experimental Procedures

The experiment involved several steps of preparation before running the SAGD or SA-SAGD tests. These are briefly described below.
Table 3-3. Natural Gas Condensate composition

<table>
<thead>
<tr>
<th>Component</th>
<th>Composition (Mole Fraction)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>0.0002</td>
</tr>
<tr>
<td>C₁</td>
<td>0.0012</td>
</tr>
<tr>
<td>C₂</td>
<td>0.0020</td>
</tr>
<tr>
<td>C₃</td>
<td>0.0038</td>
</tr>
<tr>
<td>iC₄</td>
<td>0.0024</td>
</tr>
<tr>
<td>nC₄</td>
<td>0.0731</td>
</tr>
<tr>
<td>iC₅</td>
<td>0.2349</td>
</tr>
<tr>
<td>nC₅</td>
<td>0.2149</td>
</tr>
<tr>
<td>C₆</td>
<td>0.1819</td>
</tr>
<tr>
<td>C₇+</td>
<td>0.2856</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1.0000</strong></td>
</tr>
</tbody>
</table>

3.3.1 Sand Packing into the Holder

For each experiment, after installing the four internal thermocouples, the sand-pack holder was slowly filled with Ottawa sand. The wall of the holder was tapped with a brass hammer during this procedure to facilitate good settling of the sand. After inserting the end-caps and installing the bolts, the sand-pack was again tapped with the hammer and the bolts were gradually tightened to apply axial stress on the sand. The tapping of the holder and tightening of the bolts were alternated several times until the bolts were tightened to a preset torque. The sand-pack was then flooded with CO₂ for air removal, evacuated with a vacuum pump and saturated with de-ionized water under pressure to dissolve any remaining CO₂. Water was then flowed through the sand-pack at 200 psi back pressure to remove any dissolved CO₂. The permeability of the sand-pack was measured by monitoring the flow rate of water under fixed gravity head. Finally, it was flooded with Long Lake bitumen to remove displaceable water and establish the initial oil saturation.
3.3.2 Porosity and Permeability Measurements

The sand matrix bulk volume was determined after installing all fittings and thermocouples by measuring the weight of water needed to completely fill it with water. The bulk volume was of the sand-pack was 155 ml. The weight of the sand used for filling the holder was measured for each test.

The volume of water injected after evacuating the sand-pack was measured. The weights of the dry and water filled sand-pack were also measured to determine the volume of water present in the sand-pack. This volume was taken as the pore volume. The water density was measured at laboratory conditions (1.00 g/ml at 24 °C, using a 10 and 25 ml pycnometers) for pore and bulk volume calculations. The porosity of the sand matrix was then calculated by dividing pore volume by bulk volume.

3.3.3 Oil flood

To establish the initial oil saturation, the model was flooded with bitumen until residual water saturation was reached. Due to the high viscosity of the bitumen, the oil flooding was done at elevated temperature by placing a heating tape on the sand-pack model to heat it to 70 °C. Since the density of the oil used was higher than that of water, oil flooding was done in vertically upward direction to improve the sweep efficiency (Figure 3-14).

The water produced during the oil flood was weighed and the corresponding volume was considered to be equal to the volume of oil in the sand-pack. Volume ratio between oil and pore volume was considered to be equal to the oil saturation. Similarly, volume ratio between remaining water and pore volume was considered to be equal to the irreducible water saturation. All SAGD and solvent enhanced SAGD experiments in this study were carried out using dead oil with no initial gas saturation.
3.3.4 SAGD and SA-SAGD Tests

To simulate the preheating stage, the sand-pack’s zone one heating tape was turned on until 70 °C were recorded in the sand. To ensure superheated steam injection into the sand-pack, sand-pack steam inlet and production outlet valves were kept shut to allow the steam from steam generator to flow through the bypass line until 207 °C were read at sand-pack inlet thermocouple at 230 psi (1.585 MPa) pressure.

Once the steam injection conditions were achieved, steam injection was shifted to the main line by opening sand-pack inlet and production line valves, and closing the bypass valve. Maintaining constant flow rate (2 ml/min), operational parameters like temperature and pressure were recorded at each time step (15 - 20 min) until 20 hydrocarbon pore volumes (HCPV) of injected steam volume was reached.

When a solvent was co-injected, the same procedure was performed and when the calculated steam temperature was achieved, steam and solvent co-injection was initiated.
3.3.5  Produced Fluid Analysis

After completion of the experiment, sand and liquids samples were analysed to calculate the residual oil saturation as well as to develop the material balance analysis of oil, taking into account the oil left in the sand-pack and the oil in the produced fluid samples.

3.3.5.1  SAGD Experiments

30 ml of toluene was added to each one of the twenty samples to mix with bitumen and break the bitumen-water emulsion. The bottom water layer was separated from the samples using a separatory funnel and the supernatant hydrocarbon phase plus remaining water was analyzed using the Dean Stark Distillation technique (Figure 3-15), to calculate the amount of oil and water in each sample.

![Figure 3-15. Dean Stark Distillation](image)

Due to the high water volume in each sample, it was found that the Dean Stark process was very time consuming. To reduce the sample analysis time, a technique based on solvent addition and measurement of the density of separated solvent-bitumen mixture was developed. For this, each collected sample was mixed with a fixed amount of toluene (30 ml) and it was agitated in an ultrasonic water-bath set at 60 °C. After mixing in the bath, the supernatant hydrocarbon phase was separated and its density was measured with a
The density of toluene-bitumen mixture can be related to the toluene density and bitumen density by:

\[ \rho_m = v_t \rho_t + v_b \rho_b \]  \hspace{1cm} (1)

where \( \rho_m \) is the density of the bitumen-toluene mixture (grm/ml); \( v_t \) is the volume fraction of toluene (%); \( \rho_t \) is the density of toluene (grm/ml); \( v_b \) is the volume fraction of bitumen (%), which is equal to \((1-v_t)\); and \( \rho_b \) is the density of bitumen (grm/ml). As this equation assumes an ideal solution, several measurements were conducted by varying toluene concentration in prepared samples (Figure 3-16).

![Figure 3-16. Bitumen-Toluene density versus toluene concentration](image)

The linear change in density of bitumen-toluene mixture suggests that the bitumen-toluene mixture is ideal because non-ideal mixtures tend to show considerable deviation from such linear behaviour in relation to concentration. Therefore, the volume fraction of bitumen in the mixture could be determined from the measured density. Knowing that the volume of toluene in the mixture was 30 ml, the volume of bitumen in the mixture could be calculated.

3.3.5.2 SAGD Solvent Co-injection Experiments

During the solvent co-injection tests, the injected solvent was produced with the bitumen and water. The produced fluid came out of the BPR at high temperature (at the boiling point
of water) and due to the highly volatile nature of the solvent, most of the solvent evaporated during the sample collection in open sample vessels. To facilitate near complete removal of the solvent the open collection vessel was left open while the sample cooled down to room temperature. The remaining sample contained only bitumen and water. The analysis of the bitumen-water mixtures was done using the density method describe above, assuming that the volatile solvent had evaporated out of the sample.

3.3.6 Soxhlet Extraction of Sand

Once the sand-pack model was depressurized, the sand matrix was carefully removed and visually examined per each of the four zones. The entire sand matrix was weighed and then analyzed by the Soxhlet extraction method (Figure 3-17) to determine its water content and residual oil content.

The sand matrix was loaded into an extraction thimble and put inside the main chamber of the Soxhlet extractor. Toluene vapour flowed up into the Soxhlet chamber housing the thimble and further up into the condenser after which it cooled and dripped down into the Soxhlet chamber. Co-distilled water and condensed toluene were continuously separated in a trap to recycle toluene through the extraction thimble, thereby dissolving the bitumen in the sand matrix, while retaining the co-distilled water in the trap.
Bitumen in the thimble dissolved in warm toluene as time elapsed and started dripping into the distillation flask. This process was continued until bitumen-free toluene started dripping from the thimble into the distillation flask. Finally, a material balance approach was used to determine the physically-separated amounts of water, bitumen and sand. The weight of oil was determined from measured weights of the original sand matrix, cleaned-dry sand and collected water.
Chapter Four: Experimental Results and Discussion

For fair comparisons between all solvents, it was necessary to maintain the same conditions and experimental protocols throughout the study as per:

- Sand mesh size and packing procedure
- Sand-pack dimensions
- Preheating period, temperature and steam flow rate
- Sampling procedures
- Post experiment analyses

4.1 Preliminary Experiments to Validate the Rig

These experiments were run to test the set-up integrity, calibrate its components and define optimum operational parameters to be maintained during the whole study in order to make a fair and straight comparison between the results. Therefore, steam injection rate, Variac’s power settings to minimize the heat loss and sample analyses to be used on solid and fluid samples were developed.

4.1.1 Permeability Tests

After preparing sand-packs with three different silica sand sizes [(1) 100-140, (2) 12-20 and (3) 16-30 mesh], the permeability measurement tests were conducted. Sand-pack matrix properties for the three experiments are presented in Table 4-1. These sand-packs were subsequently used for conducting base-case SAGD experiments to select the optimum mesh size in terms of the length of the test and recovery performance. The objective of these tests was to ensure that the rig operates in a satisfactory manner and to select the sand size that will give a manageable run time along with a recovery factor that is representative of the field applications.
Table 4-1. Sand mesh selection, sand-pack properties

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>Sand Mesh</th>
<th>PV (ml)</th>
<th>Bitumen Vol (ml)</th>
<th>Connate Water (ml)</th>
<th>Porosity (%)</th>
<th>Perm (D)</th>
<th>Swi (%)</th>
<th>So (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>100 - 140</td>
<td>58.5</td>
<td>46.8</td>
<td>11.8</td>
<td>38.0</td>
<td>25.5</td>
<td>20.1</td>
<td>79.9</td>
</tr>
<tr>
<td>2</td>
<td>12 - 20</td>
<td>55.1</td>
<td>44.5</td>
<td>10.6</td>
<td>36.3</td>
<td>215</td>
<td>19.3</td>
<td>80.7</td>
</tr>
<tr>
<td>3</td>
<td>16 - 30</td>
<td>57.8</td>
<td>47.7</td>
<td>10.1</td>
<td>37.5</td>
<td>105</td>
<td>17.5</td>
<td>82.5</td>
</tr>
</tbody>
</table>

4.1.2 Steam Generator Test

During the preliminary experiments, the temperature data were collected and plotted to examine the steam generator performance and stability. The steam generator was able to provide steam at a stable temperature that was at or slightly higher than the steam saturation temperature at the operating pressure. The steam temperature decreased only by 2-4 °C in going from steam generator to the sand-pack inlet (Figure 4-1). For subsequent experiments, this temperature decrease was further reduced to as low as 1-2 °C by improving the insulation.

![Figure 4-1. Heat loss control](image-url)
Fluctuations in sand-pack outlet temperature were occurring because of heat flow between zones and pressure changes due to opening and closing of the back pressure regulator (Figure 4-2). This problem was reduced in subsequent tests by a more careful control of the power delivered by each Variac.

Sand-pack thermocouples readings allowed monitoring the steam chamber growth with time (Figure 4-3). Sand-pack zones two and three gradually reached a temperature of 207 °C, indicating that steam was delivering its heat up to this thermocouple’s location after approximately 3.8 and 4.25 hours of injection respectively. When power from heating tapes Variacs was increased, heat addition from heating tapes was apparent as per the peak in all of the temperature readings (interval 3.8 - 5.5 hours). Once heating tapes’ Variacs for zones two, three and four were turned down, readings at zones three and four declined drastically (5.5 hours onwards). Zone two, due to its proximity to steam injection inlet, kept temperatures similar to zone one.

These tests also allowed calibrating the Variac power delivery settings for each sand-pack zone. The temperature difference between the inside sand temperature and the temperature outside the inner layer of insulation was kept low to reduce the heat loss from the walls of
the sand-pack. This required frequent monitoring of sand-pack inside and outside temperatures and adjustments of the amount of energy delivered by each heating tape.

![Sand Pack Temperature](image)

Figure 4-3. Steam chamber growing profile

4.1.2.1 Sand Mesh Selection

These three sand-packs provided permeabilities of 25.5, 215 and 105 Darcy respectively. The sand-pack with 25.5 Darcy permeability was tested for 16 hours, but it failed to propagate the steam chamber beyond a few inches above the injection point. The highest permeability sand-pack showed rapid propagation of the steam chamber, which reached the top in less than 6 hours. The intermediate permeability sand showed a slower vertical propagation of steam but the chamber was able to propagate into the top segment in 8 hours. The rate of propagation was fast enough to finish the test in a reasonable time yet slow enough to allow good control of external temperatures to minimize the heat loss. As a result, the silica sand mesh 16-30 was selected for the subsequent experiments.

4.1.2.2 Experimental Parameters Selection

During these preliminary experiments, steam injection rate was varied between 1.0 to 4.5 ml/min. A good rate would be one that gives the fastest rise of steam chamber without sending live steam to the sand-pack production port. The best performance in terms of
steam chamber growth in the medium permeability sand-pack (previously selected sand mesh 16-30) was reached when using 2.0 ml/min injection rate. As a result, it was the selected injection rate for the subsequent tests. Effective steam chamber growth after 8 hours test was confirmed by visual inspection of the sand from each zone (Figure 4-4).

![Figure 4-4. Sand matrix final condition after SAGD process](image)

At this stage, it was apparent that process efficiency in terms of SOR and cSOR was not as high as expected in the field. The primary reason was the small cross-sectional area of the sand-pack giving large heat loss from the walls and no room for lateral expansion of the steam chamber. Since the primary objective was to examine the relative performance of different solvents on the residual oil saturation, it was considered not to be a limiting drawback.

### 4.2 Experiment 4 (Base Case - SAGD)

After selecting the sand size and the steam injection rate, a steam only test was conducted to define the base case SAGD performance. The sand packing was done as per established protocols, resulting in sand-pack properties listed below (Table 4-2).
Table 4-2. Base Case – SAGD, sand-pack properties

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>Sand Mesh (ml)</th>
<th>PV (ml)</th>
<th>Bitumen Vol (ml)</th>
<th>Connate Water (ml)</th>
<th>Porosity (%)</th>
<th>Perm (D)</th>
<th>Swi (%)</th>
<th>So (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>16 - 30</td>
<td>58.2</td>
<td>47.3</td>
<td>10.9</td>
<td>36.9</td>
<td>100.4</td>
<td>18.7</td>
<td>81.3</td>
</tr>
</tbody>
</table>

The steam injection temperature for supplying superheated steam was determined from steam table. The steam generator Variac was adjusted accordingly. The operating pressure was 250 psi and the steam generator temperature was adjusted to deliver 207 °C steam at the injection port.

As per fixed run time of 9.5 hours and the number of collected samples, temperature at zone four did not rise up to 207 °C, like in the other zones. This may have restricted the full bitumen drainage from this zone and possibly reduced the final recovery factor (Figure 4-5). However, the steam chamber propagation up to the third zone was clearly visible in the recorded temperature profile.

![Base-Case Sand Pack Temperature](image_url)

**Figure 4-5. Base Case – SAGD, steam chamber growing profile**

After completion of the steam assisted gravity drainage test, during which the produced fluid was collected in discrete samples, the sample analysis was performed as per defined protocol for sample analysis. The residual oil saturation, Sor, was measured directly by
extracting the sand samples from the sand-pack as well as deduced from the material balance (Table 4-3). The value obtained from sand extraction was somewhat lower and is considered more reliable.

Table 4-3. Base Case – SAGD, production data

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>HCPV (ml)</th>
<th>Injection Rate (2 ml/min)</th>
<th>Cum Inj Steam (ml)</th>
<th>Prod Bit (ml)</th>
<th>RF (%)</th>
<th>Sor – Sand (%)</th>
<th>Sor – MB (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>47.3</td>
<td>2.0</td>
<td>946</td>
<td>29.4</td>
<td>62.2</td>
<td>28.4</td>
<td>30.8</td>
</tr>
</tbody>
</table>

The analysis of the collected samples allowed plotting of RF (recovered bitumen divided by HCPV) versus the volume of steam injected for performance evaluation of the process as shown in Figure 4-6. The horizontal dotted red line indicates measured HCPV in ml (Figure 4-6). The oil production continued at more or less steady pace up to the end of the test.

Figure 4-6. Base Case – SAGD, produced fluid data
4.3 Experiments 5, 6 and 7 (Pentane co-injection)

These three experiments involved pentane co-injection. The sand-packing and oil saturation steps were similar to previous experiments and the measured characteristics of the three packs used in these tests are listed in Table 4-4.

Table 4-4. Properties of sand-packs used in pentane co-injection tests

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>Solvent (vol%)</th>
<th>PV (ml)</th>
<th>Bitumen Vol (ml)</th>
<th>Connate Water (ml)</th>
<th>Porosity (%)</th>
<th>Perm (D)</th>
<th>Swi (%)</th>
<th>So (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>Pentane 5%</td>
<td>57.9</td>
<td>50.4</td>
<td>7.5</td>
<td>36.7</td>
<td>93.2</td>
<td>12.9</td>
<td>87.1</td>
</tr>
<tr>
<td>6</td>
<td>Pentane 10%</td>
<td>57.3</td>
<td>50.1</td>
<td>7.2</td>
<td>36.7</td>
<td>96.6</td>
<td>12.5</td>
<td>87.5</td>
</tr>
<tr>
<td>7</td>
<td>Pentane 15%</td>
<td>57.5</td>
<td>50.3</td>
<td>7.2</td>
<td>36.8</td>
<td>100.9</td>
<td>12.4</td>
<td>87.6</td>
</tr>
</tbody>
</table>

Final temperature in sand-pack zones two, three and four were not as high as in the Base-Case, suggesting lower energy requirements compared to the Base-Case SAGD (Figure 4-7, 4-8 and 4-9). As expected, this effect was accentuated with increasing concentration of the solvent. The presence of solvent vapor reduces the partial pressure of steam, resulting in lower saturation temperature.

Figure 4-7. Pentane co-injection 5 vol%, steam chamber growing profile
Collected samples were quite similar in volume to HCPV (red dotted line) while RF were higher during early times (first half of the tests) as shown in Figure 4-10, 4-11 and 4-12. The cSOR also decreased as solvent concentration increased.
Figure 4-10. Pentane co-injection 5 vol%, produced fluid data

Figure 4-11. Pentane co-injection 10 vol%, produced fluid data
S_{or} was again determined two ways: (1) from the extraction of the sand matrix and (2) by the material balance. There was a small difference between the two results for each experiment (Table 4-5). The residual oil saturation decreased with increasing concentration of the solvent in injected steam.

### Table 4-5. Pentane co-injection, production data

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>HCPV (ml)</th>
<th>Injection Rate (2 ml)</th>
<th>Cum Injection (ml)</th>
<th>Prod Bit (ml)</th>
<th>RF (%)</th>
<th>S_{or} – Sand (%)</th>
<th>S_{or} – MB (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>50.4</td>
<td>1.9 ml H_{2}O + 0.1 ml C_{5}H_{12}</td>
<td>1,008</td>
<td>38.2</td>
<td>74.3</td>
<td>19.9</td>
<td>22.4</td>
</tr>
<tr>
<td>6</td>
<td>50.1</td>
<td>1.8 ml H_{2}O + 0.2 ml C_{5}H_{12}</td>
<td>1,002</td>
<td>39.5</td>
<td>79.6</td>
<td>16.1</td>
<td>17.8</td>
</tr>
<tr>
<td>7</td>
<td>50.3</td>
<td>1.7 ml H_{2}O + 0.3 ml C_{5}H_{12}</td>
<td>1,006</td>
<td>41.1</td>
<td>82.2</td>
<td>15.1</td>
<td>15.6</td>
</tr>
</tbody>
</table>
Figure 4-13 compares the oil recovery performance of ES-SAGD against the base case SAGD. It is seen that there is significant improvement in RF performance with pentane co-injection at all three concentrations. The difference in the final recovery factor between 10% and 15% pentane is not that large, suggesting that the optimum concentration may be around 10%. It was noted that the higher concentration of 15% gives more boost to the recovery behavior in early part of the test, but later it loses its effectiveness. This suggests that it may be advantageous to start at higher solvent concentration and then gradually reduce the solvent amount in the later parts of production.

4.4 Experiments 8, 9 and 10 (Hexane Co-injection)

In these experiments, the co-injected solvent was hexane. The characteristics of the three sand-packs used in these tests are listed in Table 4-6.

The liquid solvent was mixed with the steam near the inlet of the sand-pack and was vaporized by the steam. Final temperatures in sand-pack zones two, three and four were again lower than those for the base case - SAGD and even somewhat lower compared with pentane experiments (Figure 4-14, 4-15 and 4-16).
Table 4-6. Hexane co-injection, sand-pack properties

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>Solvent (vol%)</th>
<th>PV (ml)</th>
<th>Bitumen Vol (ml)</th>
<th>Connate Water (ml)</th>
<th>Porosity (%)</th>
<th>Perm (D)</th>
<th>Swi (%)</th>
<th>So (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>Hexane 5%</td>
<td>57.4</td>
<td>50.2</td>
<td>7.2</td>
<td>36.9</td>
<td>101.8</td>
<td>12.6</td>
<td>87.4</td>
</tr>
<tr>
<td>9</td>
<td>Hexane 10%</td>
<td>57.4</td>
<td>50.3</td>
<td>7.1</td>
<td>37.0</td>
<td>100.6</td>
<td>12.3</td>
<td>87.7</td>
</tr>
<tr>
<td>10</td>
<td>Hexane 15%</td>
<td>57.1</td>
<td>50.0</td>
<td>7.1</td>
<td>36.6</td>
<td>96.4</td>
<td>12.4</td>
<td>87.6</td>
</tr>
</tbody>
</table>

Figure 4-14. Hexane co-injection 5 vol%, steam chamber growing profile

Figure 4-15. Hexane co-injection 10 vol%, steam chamber growing profile
Figure 4-16. Hexane co-injection 15 vol%, steam chamber growing profile

Samples contained higher bitumen volume compared to base case-SAGD and also pentane (Figure 4-17, 4-18 and 4-19), at the time cSOR decreased as solvent volume fraction increased.

Figure 4-17. Hexane co-injection 5 vol%, produced fluid data
Figure 4-18. Hexane co-injection 10 vol%, produced fluid data

Figure 4-19. Hexane co-injection 15 vol%, produced fluid data
Cumulative injection volume was in range of 1,000 – 1,006 ml. The residual oil saturations based on sand extraction and material balance are listed in Table 4-7. The residual oil saturations were lower with hexane compared to pentane at all three concentrations, showing that hexane is a better solvent than pentane for SA-SAGD.

Table 4-7. Hexane co-injection, production data

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>HCPV (ml)</th>
<th>Injection Rate (2 ml/min)</th>
<th>Cum Inj Steam (ml)</th>
<th>Prod Bit (ml)</th>
<th>RF (%)</th>
<th>Sor – Sand (%)</th>
<th>Sor – MB (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>50.2</td>
<td>1.9 ml H₂O + 0.1 ml C₆H₁₄</td>
<td>1,004</td>
<td>38.0</td>
<td>75.8</td>
<td>19.4</td>
<td>21.2</td>
</tr>
<tr>
<td>9</td>
<td>50.3</td>
<td>1.8 ml H₂O + 0.2 ml C₆H₁₄</td>
<td>1,006</td>
<td>40.8</td>
<td>81.2</td>
<td>15.3</td>
<td>16.5</td>
</tr>
<tr>
<td>10</td>
<td>50.0</td>
<td>1.7 ml H₂O + 0.3 ml C₆H₁₄</td>
<td>1,000</td>
<td>41.9</td>
<td>83.8</td>
<td>12.9</td>
<td>14.2</td>
</tr>
</tbody>
</table>

The recovery performance of the three ES-SAGD tests is compared against the base case SAGD in Figure 4-20. The recovery improved with increasing solvent concentration but the incremental improvement for each increase in the solvent concentration became smaller at higher concentration. At hexane concentration of 5 vol%, RF increased 13.7%, surpassing the 5 vol% pentane co-injection performance (12.2%). RF enhancement at this concentrations compared to the base case was 8.0%. There was a significant difference between 10 and 15 vol% hexane performance that was not that clear-cut when pentane was co-injected. Moreover, with hexane, the enhancement was more pronounced for higher concentrations in the later part of the test.
4.5 Experiments 11, 12 and 13 (Cracked Naphtha co-injection)

Cracked Naphtha was co-injected in these three experiments. The same protocols were applied in these experiments as in the previous tests in preparation of the sand-pack for steam injection. The characteristics of the sand-packs used in these tests are listed in Table 4-8.

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>Solvent (vol%)</th>
<th>PV (ml)</th>
<th>Bitumen Vol (ml)</th>
<th>Connate Water (ml)</th>
<th>Porosity (%)</th>
<th>Perm (D)</th>
<th>$S_{wi}$ (%)</th>
<th>$S_o$ (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>11</td>
<td>Cracked Naphtha 5%</td>
<td>57.1</td>
<td>50.1</td>
<td>7.0</td>
<td>36.6</td>
<td>97.2</td>
<td>12.3</td>
<td>87.7</td>
</tr>
<tr>
<td>12</td>
<td>Cracked Naphtha 10%</td>
<td>57.5</td>
<td>50.3</td>
<td>7.2</td>
<td>37.0</td>
<td>96.1</td>
<td>12.5</td>
<td>87.5</td>
</tr>
<tr>
<td>13</td>
<td>Cracked Naphtha 15%</td>
<td>57.3</td>
<td>50.2</td>
<td>7.1</td>
<td>38.0</td>
<td>95.8</td>
<td>12.4</td>
<td>87.6</td>
</tr>
</tbody>
</table>

The cracked naphtha was mixed with the steam near the inlet of the sand-pack and was vaporized by the steam too. Final temperatures in sand-pack zones two, three and four were
again lower than those for the base case – SAGD and even somewhat lower compared with pentane and hexane experiments (Figure 4-21, 4-22 and 4-23).

![Cracked Nafta 5 vol% Sand Pack Temperature](image)

*Figure 4-21. Cracked Naphtha co-injection 5 vol%, steam chamber growing profile*

![Cracked Nafta 10 vol% Sand Pack Temperature](image)

*Figure 4-22. Cracked Naphtha co-injection 10 vol%, steam chamber growing profile*

The residual oil saturation decreased with increasing concentration of the solvent reaching below 10% at the 15 vol% concentration (Figure 4-24, 4-25 and 4-26). The cSOR continued decreasing with increase in solvent concentration.
Figure 4-23. Cracked Naphtha co-injection 15 vol%, steam chamber growing profile

Figure 4-24. Cracked Naphtha co-injection 5 vol%, produced fluid data
Figure 4-25. Cracked Naphtha co-injection 10 vol%, produced fluid data

Figure 4-26. Cracked Naphtha co-injection 15 vol%, produced fluid data
The values calculated from sand-extraction and material balance calculations are listed in Table 4-9. The values obtained with cracked naphtha by the two methods were close with material balance giving somewhat higher values.

Table 4-9. Cracked Naphtha co-injection, production data

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>HCPV (ml)</th>
<th>Injection Rate (2 ml/min)</th>
<th>Cum Inj Steam (ml)</th>
<th>Prod Bit (ml)</th>
<th>RF (%)</th>
<th>Sor – Sand (%)</th>
<th>Sor – MB (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>11</td>
<td>50.10</td>
<td>1.9 ml H(_2)O + 0.1 ml CN</td>
<td>1,002</td>
<td>39.36</td>
<td>78.6</td>
<td>18.0</td>
<td>18.8</td>
</tr>
<tr>
<td>12</td>
<td>50.30</td>
<td>1.8 ml H(_2)O + 0.2 ml CN</td>
<td>1,006</td>
<td>41.25</td>
<td>82.0</td>
<td>14.0</td>
<td>15.7</td>
</tr>
<tr>
<td>13</td>
<td>50.20</td>
<td>1.7 ml H(_2)O + 0.3 ml CN</td>
<td>1,004</td>
<td>45.16</td>
<td>90.0</td>
<td>8.6</td>
<td>9.0</td>
</tr>
</tbody>
</table>

The oil recovery profile is shown in Figure 4-27. Cracked naphtha displayed better performance compared to pentane and hexane at all three concentrations. Even at the lowest saturation, the recovery factor increased by 16.5% of OOIP. At the highest concentration the increase was 28% of OOIP.

Figure 4-27. Cracked Naphtha co-injection, recovery factor comparison
4.6 Experiment 14 (Natural Gas Condensate co-injection)

For this experiment, natural gas condensate was used as the solvent. Same protocols as in the previous tests were applied in preparation of the sand-pack for this test. The sand-pack characteristics are listed in Table 4-10.

Table 4-10. Natural Gas Condensate co-injection, sand-pack properties

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>Solvent (vol%)</th>
<th>PV (ml)</th>
<th>Bitumen Vol (ml)</th>
<th>Connate Water (ml)</th>
<th>Poro (%)</th>
<th>Perm (D)</th>
<th>Swi (%)</th>
<th>So (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>14</td>
<td>Natural Gas Condensate 5%</td>
<td>57.6</td>
<td>50.0</td>
<td>7.6</td>
<td>36.6</td>
<td>103.3</td>
<td>13.3</td>
<td>86.7</td>
</tr>
</tbody>
</table>

Final temperature in sand-pack zones two, three and four were much lower than those for the Base Case - SAGD, and also lower compared with other solvents at this concentration (Figure 4-28).

![Natural Gas Cond 5 vol% Sand Pack Temperature](image)

Figure 4-28. Natural Gas Condensate co-injection 5 vol%, steam chamber growing profile

The residual oil saturations based on sand extraction and material balance are listed in Table 4-11. The final recovery factor was 85.3%. Measured sample for this test are plotted in Figure 4-29.
Table 4-11. Natural Gas Condensate co-injection, production data

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>HCPV (ml)</th>
<th>Injection Rate (2 ml/min)</th>
<th>Cum Inj Steam (ml)</th>
<th>Prod Bit (ml)</th>
<th>RF (%)</th>
<th>Sor – Sand (%)</th>
<th>Sor – MB (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>14</td>
<td>50.00</td>
<td>1.9 ml H₂O + 0.1 ml GC</td>
<td>1,000</td>
<td>42.65</td>
<td>85.3</td>
<td>12.2</td>
<td>12.8</td>
</tr>
</tbody>
</table>

Figure 4-29. Natural Gas Condensate co-injection 5 vol%, produced fluid data

The recovery profile of this test is compared with the base case in Figure 4-30. The final recovery factor was 23.3% OOIP higher with co-injection of the natural gas condensate, which is much better than any other solvent at this concentration.
Comparison of all tests

For each of the three sets of experiments, solvent concentration directly affected RF performance, and it increased as experiments moved from pentane to cracked naphtha and natural gas condensate (Figure 4-31). Increasing the solvent concentration made the SOR and cSOR to decrease with all solvents. However, this behaviour is not linear for any of the solvents. The performance enhancement was better with cracked naphtha compared to the two single component solvents. Moreover, natural gas condensate showed even better results as per its performance at 5 vol%, which was better than cracked naphtha at 10 vol% (Figure 4-31). Based on these tests, the natural gas condensate appears to be the best solvent for improving the SAGD performance at a modest cost.
Figure 4-31. Recovery Factor through time comparison
Chapter Five: Summary, Conclusions and Recommendations

5.1 Summary

A linear sand-pack rig was built with capabilities to operate at temperatures and pressures typical of SAGD field operations. The rig was designed to simulate the rising chamber part of SAGD operations, during which the steam vapor flows up while the condensed water and oil flow down. The rig was capable of injecting superheated steam into the sand-pack. Heat loss from the walls of the sand-pack was reduced by covering the outside surface with insulation and heating the outer surface of the insulation with heat tapes to reduce the temperature difference between the metal wall of the sand-pack and the outer surface of the insulation. Tests were conducted to compare the performance of plain SAGD (steam only injection) SA-SAGD, in which a solvent was co-injected with steam at a fixed volume fraction in the injected fluid. The performance of several solvents was evaluated at different concentrations.

5.2 Conclusions

1. Amongst the three sand grain sizes tested, the 16-30 mesh sand, with 105 Darcy permeability, was the best compromise in terms of the run time and recovery factors.

2. It is not practicable to use sand with typical reservoir permeability in this type of work due to extremely low rise-rate of the steam chamber.

3. These tests can be used to evaluate the relative performance of different solvents at different concentrations in terms of the residual oil saturation and recovery factors obtained at a fixed value of the pore volumes injected. However, they do not provide a good estimate of the steam oil ratio due to heat loss and the absence of room for any lateral expansion of the steam chamber.

4. Between the two pure component solvents tested, hexane displayed better performance than pentane at all three concentrations.
5. The performance of cracked naphtha was better than that of hexane at same concentration.

6. Natural gas condensate gave the best performance and it appears to have the best chances of success in the field.

5.3 Recommendations

1. The rig performance can be improved by using a stronger insulation and installing an automatic control system to maintain nearly the same temperature on the outside of the insulation as measured in the sand-pack at the same vertical location.

2. These tests involved countercurrent flow of steam and oil in vertical direction through a small cross-sectional area of sand. This may have hampered the oil drainage. It would be interesting to test the performance in sand-packs oriented at different angles to the vertical.

3. These tests used a constant concentration of solvent in each test. It would be interesting to evaluate the effectiveness of systematically varying the concentration during the tests.

4. In view of the cost and availability of solvents, it would be interesting to evaluate the performance of mixtures of natural gas condensate and propane.

5. These tests used connate saturation of deionized water in the sand-packs. It would be useful to test the performance with simulated field brine to see whether the salinity causes any difference in the performance.

6. It would be also desirable to test the performance of water-soluble solvents, like dimethyl ether in such tests.
References


presented at the Canadian International Petroleum Conference (CIPC), Calgary, 7-9 June.


McColl, D., Mei, M., Millington, D., Kumar, Ch., Gill, G. and Howard, P. 2008. “Green Bitumen: The Role of Nuclear, Gasification, and CCS in Alberta’s Oil Sands. Part II – Oil Sands Costs and Production”. Calgary, Alberta, Canada.


