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Evaluation of Propane-Butane Mixtures as Solvent in ES-SAGD

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by

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ABSTRACT

SAGD (Steam Assisted Gravity Drainage) is a thermal recovery process for production of nearly immobile bitumen from the deeper oil-sand formation. In this method, two parallel horizontal wells are drilled near the reservoir bottom, one about 5 m higher than the other. Steam injected through the upper well provides heat to the heavy oil to reduce its viscosity. The heated oil flows down into the production well and the space vacated by the oil gets filled with steam, forming a steam saturated zone called a steam chamber. With continued steam injection and oil production, the steam chamber expands vertically and laterally. The SAGD process involves high capital and operating costs, and it suffers from environmental issues.

One option being evaluated for improving the energy efficiency of SAGD is the co-injection of a hydrocarbon solvent with steam. In Solvent Added SAGD (SA-SAGD), a small volume fraction of steam is replaced with a hydrocarbon solvent. The latent heat of steam heats the oil while the solvent dissolves in the oil to make it more mobile. The combined impact of mass transfer and heat transfer makes the production rate higher than what can be achieved with only heating. Currently, the least expensive available solvent is propane, but it is not as effective as heavier solvents. So, mixtures of propane and butane are evaluated in the study to see if we can find a solvent mixture for SA-SAGD that can nearly match the performance of pure butane, but at a lower cost.

SA-SAGD experiments using different mixtures of propane and butane were conducted in a linear sand-pack to determine the extent of improvement over the base case of steam only (SAGD). The results are used to determine the most effective composition of the propane-butane mixture for SA-SAGD application.

ACKNOWLEDGMENT AND DEDICATION

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ABBREVIATIONS, SYMBOLS, AND NOMENCLATURE

BPR	Back Pressure Regulator
CSS	Cyclic Steam Stimulation
cSOR	Cumulative steam oil ratio
EOR	Enhanced Oil Recovery
ESEIEH	Effective Solvent Extraction Incorporating Electromagnetic Heating
ES-SAGD	Expanding Solvent-Steam Assisted Gravity Drainage
GHG	Green House Gas
h	Height
HPAI	High-Pressure Air Injection
IOR	Improved Oil Recovery
ISC	In Situ Combustion
K	Permeability
Kro	Relative permeability of oil
L	Length of horizontal well
MMBPD	Million Barrels Per Day
NCG	Non-Condensable Gases
P	Pressure
PIR	Production Injection Ratio
RF	Radio Frequency
SAGD	Steam Assisted Gravity Drainage
SAGP	Steam and Gas Push
SA-SAGD	Solvent Added- Steam Assisted Gravity Drainage
SAP	Solvent-Aided Process
SAS	Steam Alternating Solvent
SCO	Standard Cost Obligation

Sor	Residual Oil Saturation
$\overline{Sor}$	Average residual oil saturation after time t
SSP	Steam Surfactant Process
T	Temperature
VAPEX	Vapor Extraction
Vc	Convection Velocity
C_3	Propane
C_4	Butane
Z	Drainage height
b	Exponent in cardwell and parson's equation for relative permeability, $[k_r = s^b]$
v_s	Kinematic viscosity of the oil at the temperature of the steam
U	Velocity of temperature advancement in the interface
α	Thermal Diffusivity

CHAPTER- 1: INTRODUCTION AND OVERVIEW

1.1 Introduction

Alberta oil sand deposits are very extensive and a valuable source of hydrocarbons for the future. The Athabasca oil deposits are one of the largest oil accumulations in the world, while the Cold Lake and Lloydminster are also large oil sand deposits [Hosseininejad-Mohebati, 2010]. In 2019 Alberta contributed around 81.8% of Canadian oil production and Canada's proven reserves were estimated to be 168.5 billion barrels [NRCAN, 2019]. The total production of Canada in December 2019 was 23.7 million cubic meters (148.9 million barrels) of crude oil [STATCAN, 2019].

81.8% ● Alberta
10.8% ● Saskatchewan
5.1% ● Newfoundland and Labrador
1.4% ● British Columbia
0.9% ● Manitoba
0.1% ● Other*
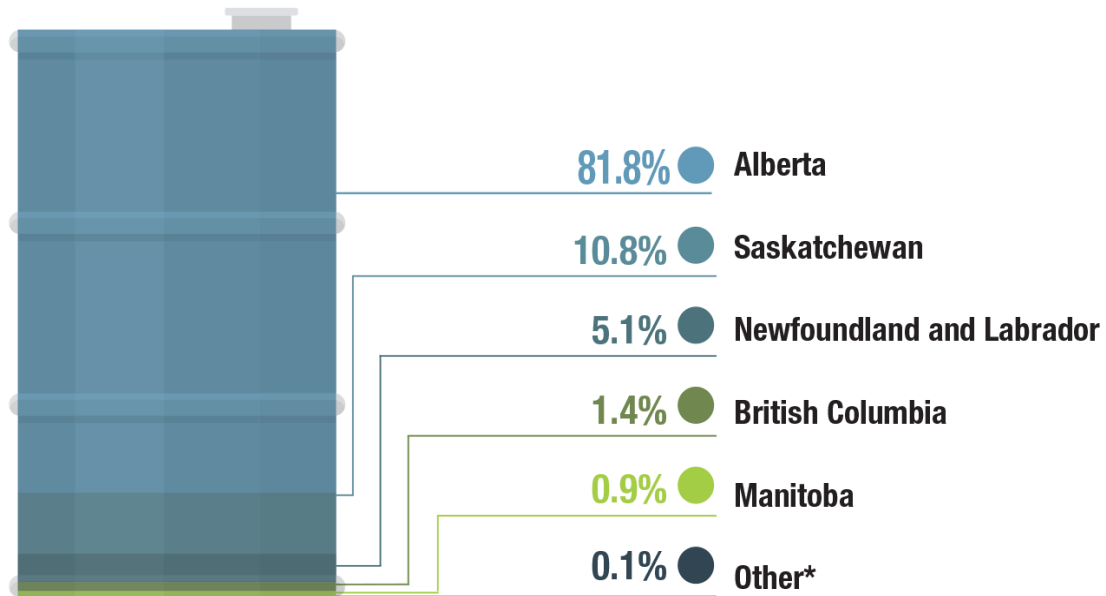
*Other: Nova Scotia, Ontario and the Northwest Territories include crude oil, condensates and pentanes plus.

Figure 1.1: Production forecast by province 2019 [NRCAN 2019].

SAGD is a thermal recovery process, which was initially introduced and developed by Roger Butler and his team [Butler, 1998] with the main objective to make the production of nearly immobile bitumen economically viable. Steam is injected into the reservoir to heat the oil and reduce the viscosity of the oil. Conduction and convection processes are involved in the transfer of heat from the injected steam to the oil. Once the oil mobility is increased and viscosity is decreased the gravitational forces can drain the oil into the lower production well. SAGD is energy-intensive and releases large volumes of greenhouse gases into the atmosphere, so the oil industry is evaluating several new enhancements to reduce the energy consumption in the SAGD process. Solvent Added SAGD is a new technology, which is still under study for increasing the economic viability of the oil recovery process. The main idea is that the solvent added steam is better than only steam for mobilizing the bitumen in the reservoir. [Gates, 2006].

Solvent added SAGD is a hybrid system used to extract oil from bitumen reservoirs and heavy oil reservoirs. [Al-Murayri, 2016]. This method includes a small portion of hydrocarbon solvent injected with steam. The hydrocarbon solvent is miscible with the oil and dilutes the oil, thereby decreasing the viscosity of the oil. The combined effect of dilution with the solvent and heating by the steam makes the oil mobile at a lower temperature, thereby reducing the heat requirement.

In both SAGD and SA-SAGD, a pair of horizontal wells are drilled parallel to each other, which are five meters apart in a vertical direction from one another. The top well serves as the injection well for steam and the bottom well for production. The heated steam at around 200°C is injected with or without a portion of added hydrocarbon solvent, and a chamber of steam is created in the reservoir. The heated steam transfers heat from the boundaries of

this chamber to the oil-sand lying beyond and a major part of solvent (if present) gets dissolved into the oil. The chamber created by the steam solvent mixture gets larger with continued steam injection. It grows vertically and laterally in the reservoir. The solvent remains in the vapor phase inside the steam chamber and the steam condenses along the walls of the steam chamber. As the steam condenses, the vapor becomes gradually richer in the fraction of solvent up to the level at which both condense together as a eutectic mixture. Solvent mass transfer estimation is difficult to analyze to predict how much of it remains in the steam chamber and how becomes dissolved in the oil phase [Yazdani and Maini, 2009]. The key performance goal in this recovery technology is the reduction of the viscosity of bitumen and heavy oil, which occurs at the edges of the steam condensation front. One of the main advantages of SA-SAGD is that amount of the flue gases that are emitted in a steam generation is lowered compared to injection of steam only [Gates, 2007].

As solvent added technology has gained popularity in recent times for the extraction of heavy oil and bitumen, one of the important aspects is the selection criteria of solvent. The selection of solvent is still somewhat arbitrary, and this study is focused on a more specific task of experimentally evaluating different concentrations of Propane and Butane in a binary mixture of the two. A mixture of propane and butane is less expensive than pure butane. Hence, if we can find a composition of this mixture that will be nearly as effective as the pure butane, the overall cost would be reduced without hurting the solvent effectiveness.

1.2 Research Aim and Method

This study aims to experimentally examine the effect of solvent composition on the performance of SA-SAGD using propane-butane mixtures as the solvent. SA-SAGD experiments will be conducted in linear sand-pack models using clean silica sand and Athabasca bitumen. The composition of the propane-butane mixtures will be varied from 0 % butane in the mixture to 100 % butane. The effectiveness of different solvent mixtures will be compared on basis of the total recovery factor and the steam/oil ratio.

1.3 Thesis Structure

The thesis is divided into five different chapters which include,

Chapter-1:

Introduction and overview of the SAGD and SA-SAGD processes. It also includes the main objectives of the research.

Chapter-2:

This chapter includes a literature review of the thermal oil recovery methods used in the petroleum industry. More specifically, it includes the thermal recovery methods used in oil sands.

Chapter-3:

This chapter of thesis describes the components of the experimental setup used in this research along with the procedures used for sand packing and running the SA-SAGD tests with mixtures of two solvents and the procedures for the subsequent analysis of the tests.

Chapter-4:

This chapter presents the experimental results and a discussion of the results.

Chapter-5:

This chapter includes a summary of the overall results and the conclusion of the thesis. It also includes some recommendations for future work.

CHAPTER- 2 LITERATURE REVIEW

2.1 Overview

Oil sands development drives a strong national economy, supports public services, and creates jobs. Canadian oil sands create prosperity across the whole of the country, not only in Alberta [CAPP 2020].

The capital investment in oil sands is expected to be weak in the near term and forecasts show a downward trend. Most of the companies of oil sand are deferring the short-term new projects. Most companies, in upcoming times the near term, are focusing on existing facilities to lower the cost and sustain the production. Starting from 2019 until 2039, the projected investment in mining projects is estimated to be C$ 126 billion in both initial and sustaining projects, while estimated C$ 200 billion is expected to be invested in situ thermal, solvent, and cold bitumen production projects [CERI 2019]. The capital investment from 2007 to 2039 is illustrated in Figure 2.1.
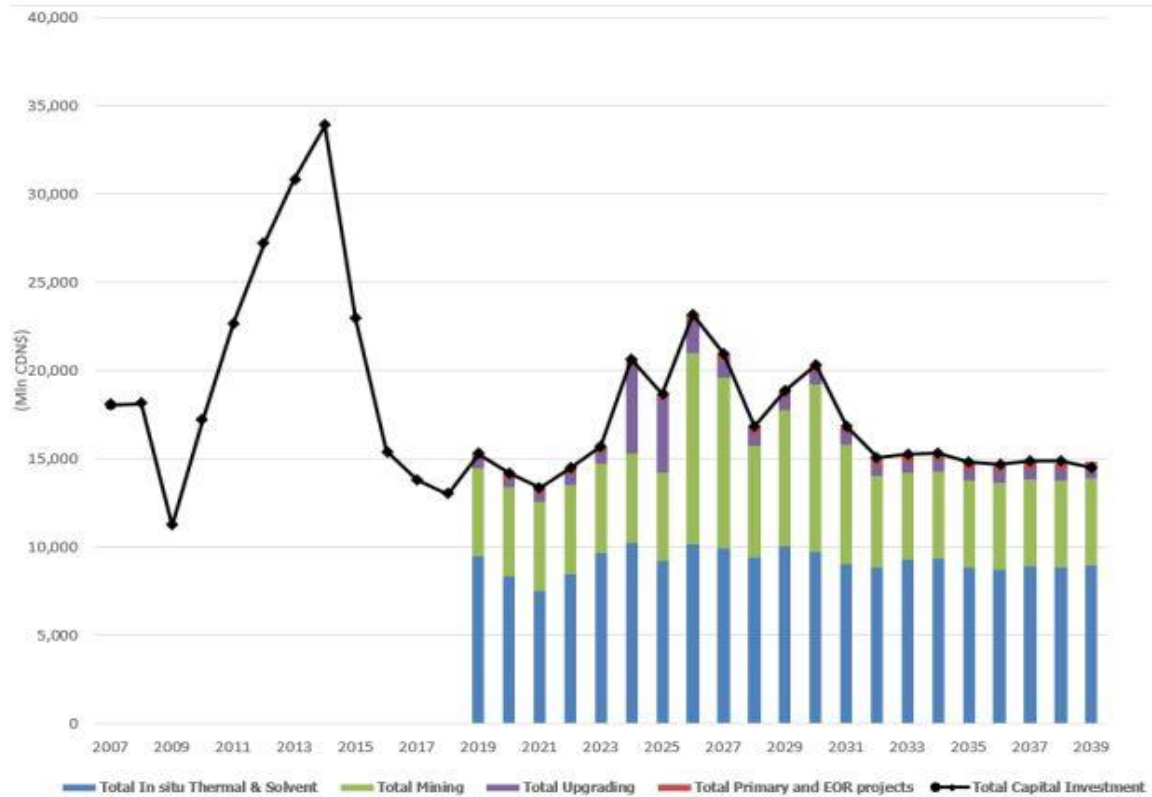
Figure 2.1: Capital investment forecast from 2007 to 2039 [CERI 2019].

The peak yearly expenditures were approximately C$ 34 billion in 2014 but for the next 5 years, the total investment was less than C$ 15 billion per year. In the future, the expenditures are predicted to average C$ 16.5 billion for each year from 2019 to 2039 and it will see a decline of 1/10 of a percent each year on average.

Further, there are some other risks that may impact the capital investment in a way that some projects may be deferred, cost reduction strategies may be successfully deployed, and the uncertainty of pipeline development projects may affect the timing of projects. It is expected that expenditures will be invested in new thermal development projects, or primarily at sustaining the capital and the expanding of existing projects [CERI 2019].

2.1.1 Production Forecast

Figure 2.2 illustrates three different paths for three different scenarios. For the producer of oil sands, the viability of the project relies on many factors in which some important factors are operating cost, transportation cost, production cost, and the demand and supply relationship between them. And one of which is the market price for the blended bitumen.
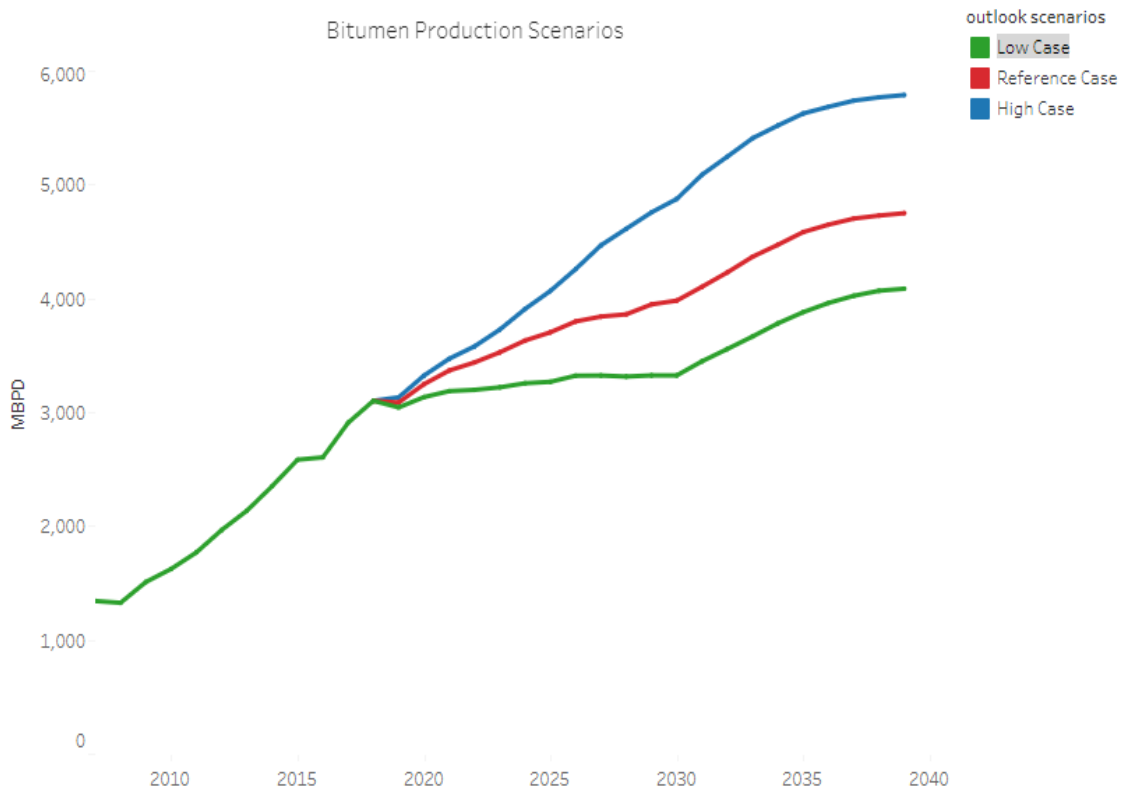
Figure 2.2: Three scenarios of bitumen production [CERI 2019].

The milestone of 3 MMBPD production from oil sands was reached in 2018. Within the boundaries of oil sand areas, the production of bitumen was mainly comprised of in situ "thermal & cold bitumen" which was 1.6 MMBPD, while mining contributed the total production of 1.5 MMBPD.

In 2017 the total production of bitumen was 2.84 MMBPD, which means that the production from oil sands was increased by 7 % year over year. The oil sand production includes the increasing share of Canada's and Alberta's crude oil production. The non-upgraded bitumen including synthetic crude oil "SCO" made the total of two-thirds of overall Canadian crude production in 2018 in which Alberta's total production was 87 percent.

According to the high case scenario in the future, the total production from both mining and in situ (thermal & cold bitumen) is expected to grow to 3.3 MMBPD. By the end of that decade, it will reach 4.9 MMBPD in the year 2030, and it will reach 5.8 MMBPD by the end of the year 2039.

While according to the low case scenario in the future, the total production will rise to 3.1 MMBPD in 2020, to 3.3 MMBPD by the end of the year 2030, and 4.1 MMBPD at the end of the forecasted period. The base case of oil sands production is provided by the CERI's given reference case. According to this scenario, the production will increase to 3.2 MMBPD by the end of the year 2020, 4 MMBPD by the end of the year 2030, and it will peak at 4.7 MMBPD by the end of the forecasted period in 2039 [CERI 2019].

2.2 Improved Oil Recovery (IOR) and Enhanced Oil Recovery (EOR)

Oil recovery processes can be classified into three phases, i.e., Primary, Secondary, and Tertiary, based on what provides the energy to drive the oil into a production well. Primary recovery uses the natural drive energy which is initially available in the reservoir. It does

not need any external source of energy to move the oil into a production well. The main sources of primary energy are fluid and rock expansion, water influx, solution gas, gravity drainage, and gas cap.

Secondary recovery can be defined as recovery through injection of a relatively inexpensive external fluid, for example, natural gas or water, to displace the oil and/or maintain the reservoir pressure.

Tertiary recovery is the recovery occurring after exhausting the secondary recovery and it involves the injection of some special fluid in from of miscible gases, chemical inject,ion, or injection of thermal energy [JJ Sheng, 2010].

Enhanced oil recovery is essentially tertiary recovery. It can be defined as the injection of some chemicals, gases, or sources of thermal energy in the reservoir to improve the volumetric sweep efficiency, improve the microscopic displacement efficiency and maintain the overall pressure of the reservoir. The term "improved oil recovery" is also used in the literature, which covers a broader view for improving oil recovery. Both terms are loosely used, and many authors have considered them synonyms of each other, but others consider IOR to cover anything that improves oil recovery, including reservoir characterization and infill drilling.

Currently, among petroleum industries and research groups, it has been agreed that improved oil recovery IOR is the general terminology that implies improving the oil recovery by any means, while the term "enhanced oil recovery" (EOR) is more specific and can be considered a subset of IOR. EOR simply means that something other than

natural gas, brine, or plain water is injected into the oil reservoir [Taber 1997]. EOR can also be defined as a process that reduces the oil saturation below residual oil saturation S_{or}.

The EOR and IOR terminologies are referred to as reservoir processes, and any independent practice cannot be referred to these terminologies. To improve oil recovery in reservoir processes the term IOR can be used. Figure 2.3 explains the difference between IOR and EOR.
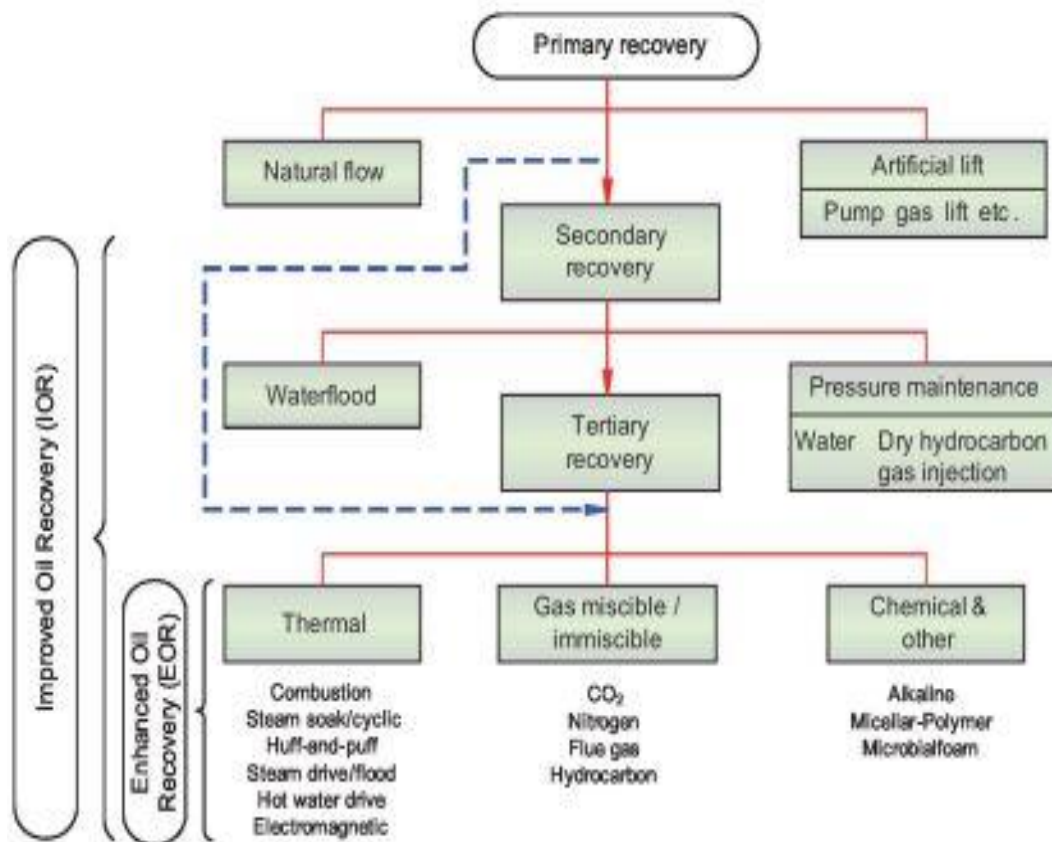
Figure 2.3: The EOR and IOR terminologies and their proposed definitions [Josip, 2005].

Whereas the Improved oil recovery IOR can be summarized as the processes which are mainly applied in the depletion stages in secondary and tertiary processes in order to enhance the overall sweep efficiency coefficient of the reservoir through the displacing fluids. For improving the fluid or oil mobility, it may be useful to use a different well pattern or use a denser spacing of wells, or use horizontal wells, or use fracturing techniques to improve the performance.

This study is mostly focused on thermal recovery techniques, which are used to extract the bitumen or heavy oil from the reservoirs. So, this review will cover only the thermal recovery methods. And in thermal recovery methods, this study is further focused on the steam-assisted gravity drainage (SAGD) methods, which are extensively used in Alberta, Canada.

2.3 Thermal recovery methods and techniques

There are several techniques and methods, which are used for recovering the heavy oil from the reservoir via thermal recovery methods. Heavy oils are produced by injecting sources of heat into the reservoir to reduce the viscosity of the oil and increase its mobility. Thermal recovery methods are the economic and more efficient recovery method, which are extensively used in Canada, Venezuela, and other parts of the world to recover the bitumen and heavy oil from the reservoir [Butler, 1991].

There are various techniques for different ranges of oil viscosity under the umbrella of thermal EOR methods. As an example, for extraction of heavy oil, an effective technique

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is steam flooding, and in order to extract extra heavy oil, cyclic steam stimulation is a more effective technique, while for bitumen recovery, steam-assisted gravity drainage is more suitable [Butler, R. M., and D. J. Stephens 1981]. In all of the above-mentioned processes, one of the drawbacks is the emission of greenhouse gases, which results from fuel burning to generate steam, causing an environmental issue. Therefore, solvent injection in combination with steam has been introduced, in order to mitigate the environmental issue by reducing the amount of steam needed for oil production [Ali, 1976 and O.E. Hernandez 1972]. Adding a light hydrocarbon solvent decreases the viscosity of the oil, as the solvent is miscible in the oil, however, the asphaltenes are immiscible in such solvents and may precipitate out and cause formation damage [Hascakir, 2016].

Another important thermal process, which does not involve steam injection, is the in-situ combustion (ISC), which is applied to very viscous oil reservoirs. This technique can theoretically lead up to a 95% recovery of the oil. However, in this method, the heat front control is difficult, which in turn limits successful field applications of this process [Turta, 2007].

It is not necessary that using thermal EOR will give economically viable recovery of oil in a specific reservoir, which is due to fluid channeling or excessive losses of heat to overburden and under burden in heterogeneous reservoirs and thin reservoirs, respectively.

In tight heavy oil reservoirs, using electromagnetic methods is incumbent for increasing the recovery, while using other thermal EOR techniques would not lead to good recovery due to well injectivity problems [Chhetri, 2008].

The heat transfer mechanisms i.e., convection, conduction, and radiation are necessary parts to understand thermal EOR mechanisms. Interfacial tension variation and changes of the phase lead to mass transfer applications. In order to achieve good production from thermal recovery processes, three main requirements include 1. Bitumen mobilization, 2. Transportation of the mobilized oil towards the production well, 3. Treatment of the produced fluid for useful products [Ali, 2015; Butler, 1997].

Some of the important thermal recovery processes include Steam flooding, Cyclic Steam stimulation "CSS", in situ combustions, High-pressure air injection "HPAI", Vapor assisted petroleum extraction "VAPEX", Steam alternating solvent, "SAS", Steam assisted gravity drainage, "SAGD", and Solvent added steam-assisted gravity drainage, "SA-SAGD" etc. These thermal recovery processes are briefly described in the following.

2.3.1 Steam Flooding

Steam flooding is also referred to as steam displacement or steam drive. It is an important recovery process for less viscous heavy oil reservoirs. Steam flooding is a complex process, which involves simultaneous fluid flow, heat transfer, and mass transfer [Wu, 1977]. This process has been successful in parts of California and Venezuela [Ali, 1970], where the potential of this recovery process was fully realized in the early 1960s. Steam is injected in a flooding pattern using vertical wells, while the oil is driven towards horizontal or vertical wells [shah 2010]. The steam is continuously injected from the injection wells and the oil is pumped out along with the condensed water from production wells.

Although the objective of injecting steam is to heat up the heavy oil in the reservoir, the energy provided also encounters the cold formation water and rock of the reservoir

environment. The losses of heat to overburden and under burden are also encountered during this process. The reservoir oil is produced via producing well once the temperature increase reduces the oil viscosity and increases the mobility. Steam contacts the cold regions of the reservoir, i.e., water, rock, and oil, and this interaction condenses the steam and forms a hot water bank. Once the hot water bank is formed it plays the role of waterflood and pushes the oil towards the producing well [Ronald, 2003].

In steam flooding, the oil recovery is dependent on the rock properties, fluid properties, flow geometry, pattern spacing, shape and thickness of the sand, conditions of the reservoir and injection conditions of the steam [Gomma, 1980]. For 10 to 20 degrees API gravity heavy oils, steam flooding is the preferred method. This steam injection process applied to heavy oil reservoirs sometimes suffers due to unfavorable mobility ratios, gravity override, and steam channeling, which can cause early breakthroughs of the steam. This, in turn, leaves a large volume of oil in the reservoir. The proper balance between heat transfer and the displacement rate can lead to a successful process of steam flooding because a less unfavorable mobility ratio can be attained by lowering the viscosity of oil [Chew, 1987]. For oil sands in Alberta which are currently produced by the CSS process, steam flooding can play a role as a follow-up method for oil recovery [Ali, 1979]. Many of the reservoirs exploited by CSS are reaching a mature phase, which should be considered as suitable candidates for steam flooding [Thomas, 2008].

Steam flooding was essentially developed using vertical wells, but now horizontal wells are also employed to recover the oil. Horizontal wells may prove to be more successful for very viscous oil formations [Shum, 1988].

One of the important factors which affect the performance of steam flooding is the production to injection ratio "PIR" [Xia, 2013]. The process is more viable when less amount of steam is injected to produce more oil from the oil stratum [Smith, 1968].

Most of the reservoir in Alberta requires thermal recovery processes as these reservoirs cannot be produced with conventional recovery processes and steam flooding is one of the possible methods. Steam injection is usually used in thicker reservoirs (>15 m) while their use in thin pay zones, which are less than (6 m), is uneconomical [Zhao, 2013]. The main factor that makes it uneconomical is the high steam oil ratio "SOR," which is caused by higher overburden heat losses in relation to the transfer of heat to heavy oil.

2.3.2 Hot Water Flooding

Hot water flooding is considered as an alternate method of the thermal recovery process for injection of steam [Alajmi, 2009]. The initial purpose of hot water injection was to increase the good injectivity, instead of EOR. However, the injection of hot water into the formation causes heat transfer to the layer of oil and increases the temperature of the reservoir. Moreover, the energy of the reservoir is supplemented to displace the heavy oil to the production well.

The immiscible displacement process occurs during the injection of hot water into the formation, in which hot water displaces the crude oil [Dong, 2011]. In the hot water injection process, no latent heat is involved, which causes the efficiency of the thermal method to be lower than that of the injection of the steam process [Zhao, 2015]. The key mechanism in hot water flooding, when compared to conventional water flooding, is the

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reduction of the mobility ratio by decreasing the viscosity of oil [Abass, 2013]. Oil viscosity is reduced by sensible heat and sweep efficiency is improved by improvement in mobility ratio, which delays the water breakthrough.

One of the significant problems in hot water flooding is that due to the lower enthalpy (compared to steam), not enough heat energy is carried by hot water. The second problem is the channeling of water, which is caused by heterogeneities in the reservoir, and the different mobilities of oil and hot water. Due to the lower resistance of the flow of hot water, it tends to move towards a more permeable formation. As a result of viscous fingering, the channeling of water is formed easily in the formation. These two disadvantages of hot water flood result in water breakthrough in earlier phases, which negatively affects the process. An enhanced oil recovery method, just after a hot water flood, is adding a surfactant to recover heavy oil by allowing the formation of an emulsion in the reservoir [Bagheri and Clark, 2015]. Thus, the thermal technique of hot water floods can also be combined with chemical floods to enhance recovery. In hot water floods, the temperature increase reduces the oil viscosity but inefficient sweep results due to an unfavorable mobility ratio. The sweep efficiency can be increased by introducing polymers. A combination of the hot water flood and polymer flood can improve the production in a way that the injectivity of polymer is improved by hot water. In this scenario, the high viscosity polymers result in an improved mobility ratio [Rego, 2017].

Another enhancement of hot water flood is the co-injection of carbon dioxide with hot water. In this method, the mechanism involves the dissolution of carbon dioxide into heavy oil, which further reduces the viscosity of oil beyond what is achieved with the temperature increase due to hot water [Shi, 2019].

In the hot water flood technique, the viscosity is readily decreased, but in high permeability zones, one of the main constraints is water channeling in the reservoir. The method can leave large amounts of oil unrecovered. The use of high-temperature carbon dioxide foam, generated with some surfactants, can reduce the risk of water channeling and the efficiency of oil displacement can be significantly increased [Liu, 2020].

2.3.3 In-Situ Combustion (ISC)

The process of in situ combustions is under extensive study since the 1950s. In this process oxidizing gases i.e., enriched oxygen air or simple air is injected into the formation, to generate enough heat. Fire flooding is another term for it, which refers to the burning front movement in the reservoir.

Heat is generated by burning a part of the oil in the reservoir. In this process, the gas drive, formed by combustion gases and water drive along with steam drive are responsible for driving enough amount of oil towards the production well [Castanier, 2003]. In situ combustion is further divided into the following categories, which is based on the propagation direction of the front and the operating conditions.

2.3.3.1 Forward Combustion

It is the combustion process in which the front and the airflow have the same direction. All moves towards the production well. In this process, the ignition occurs in the vicinity of the injection well. This method is used most often in infield practice.

Forward combustion is further divided into "Dry Combustion" in which enriched air or only dry air is injected, and "Wet Combustion" in which water is co-injected with the air.

2.3.3.2 Backward combustion or reversed combustion.

This process is the opposite of the forward combustion process. In this method the front moves in opposite direction to that of airflow. In this method, the ignition occurs in the vicinity of the production well.

2.3.3.3 High-Pressure Air Injection (HPAI)

HPAI or High-Pressure Air Injection is the process that is mainly used for light oil formations having low permeability which are deep enough [Moore, 2002]. This process involves the oxidation of oil at a lower temperature.

In the process of in situ combustions where only forward combustion is in common practice, just after the ignition, the fronts start to propagate. This occurs by continuous air flow. Between the injector and producer well, several portions or zones can be seen as the front starts to progress. These zones form due to continuous chemical reactions occurring along with mass and heat transport. Figure 2.5 shows the typical location of various zones and the temperature profile of various zones.
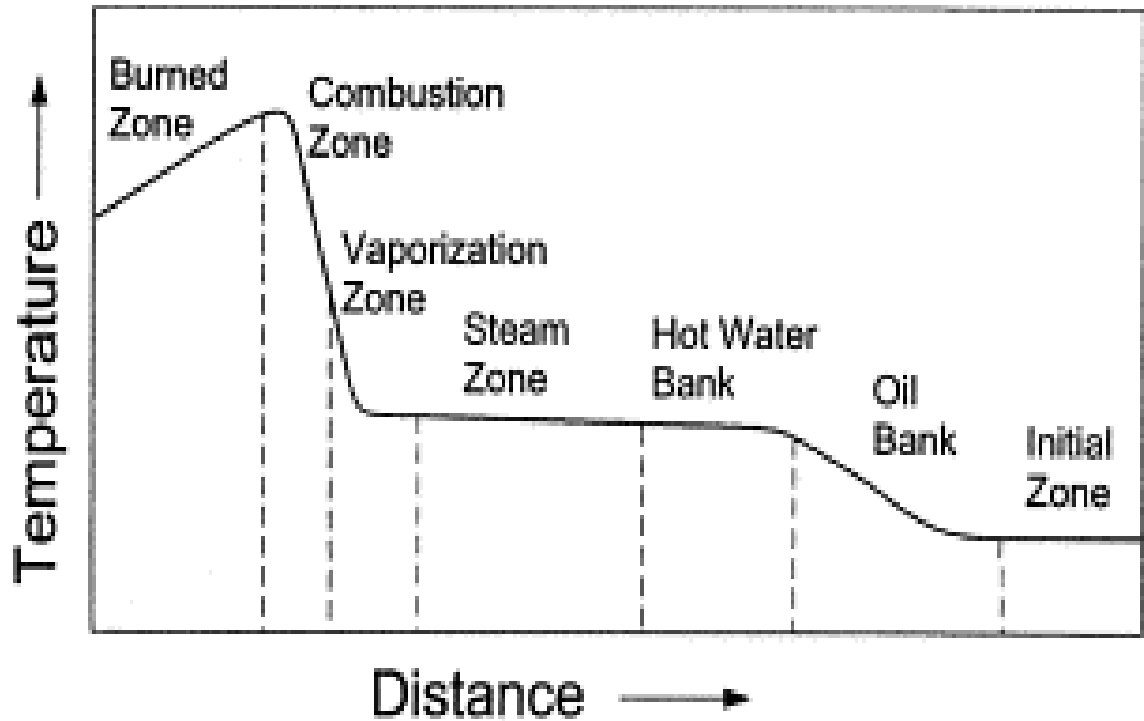
Figure 2.4: Various zones during process of in situ combustion [Prats, 1982].

The nature of various zones formed during the process starting from injector well to producer well is described below.

1) **Burned Zone:**

    This zone contains the already burned volume, but it may have a small portion of unburnt residual organic solids. Alteration of minerals is possible due to high temperatures. This zone contains no oil.

2) **Combustion zone:**

    In this zone oxidation at high temperature occurs, as the fuel combines with oxygen. It is a thin zone no more than a few inches. It contains the highest temperature. Carbon dioxide and water form due to burning reactions. Fuel burnt amount is an

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essential parameter as it determines the amount of air to be injected for burning a certain proportion of reservoir volume.

3) **Vaporization or Cracking zone:**

This zone is downstream of the combustion zone, where the oil is in the form of residual oil just behind the plateau of steam. Due to the high combustion temperature, the crude modifies. Light oil vaporizes and transfers ahead, where it mixes with the original oil. Solid organics deposit in the rock and some hydrocarbon gases evolve by thermal cracking of the heavy oil.

4) **Steam zone or Steam Plateau:**

A large amount of oil displaced is in front of steam. This plateau is just downstream of the vaporization zone. A small amount of thermal cracking may occur which depends on the temperature. Further ahead some vapors of hydrocarbon condense.

5) **Hot Water Bank:**

A hot water bank forms just after the steam plateau. It is because the temperature is now lower than the saturated steam temperature.

6) **Oil Bank:**

After the hot water bank comes the oil bank. Most of the displaced oil is in this zone coming from upstream. Due to upstream thermal cracking, this zone also includes a good portion of light oil.

7) Initial Zone:

This zone lies after the oil bank, and it includes the original undisturbed reservoir. From products of combustion, the mechanism of production is gas drive. The combusted gases due to increased mobility may result in small gas saturation in this region.

2.3.4 Cyclic Steam Stimulation (CSS)

Cyclic steam stimulation is also called huff-n-puff, steam huff n puff, and steam soak. For a specific period, steam is initially injected through production well in the process of cyclic steam stimulation. After injection of steam, the well is shut down and a specific time is given to soak the formation by steam. The steam and oil are then produced from the same well.

The soak time allows the injected steam to transfer its latent heat to the reservoir, which causes oil viscosity to decrease, and the pressure of the reservoir to increase. Initially, high saturation of oil heated to the steam temperature leads to high-rate production of oil. The rate of oil production decreases with time due to heat losses occurring in the fluid and rocks, leading to lower reservoir pressure, and higher viscosity of the oil [Sheng, 2013]. At this point, a new cycle may be initiated of steam injection. The cycle has the possibility to be repeated several times.

The process was first discovered by a shell in the field Mene Grande Tar sands of Venezuela in 1969 when the eruption of steam was observed at the surface due to

overburden breakdown. In this incident, the backflow of injection wells was implemented to relieve the pressure of the reservoir and an increased amount of oil was noted in the back-produced wells [Haan, 1969].

For the application of such operations to the fields in the future needed sound planning, so an evaluation of coring and drilling started in 1973 [Buckles, 1979]. The cyclic steam stimulation in Canadian heavy oil reservoirs proved to be quite successful as it gives faster recovery than other methods [Farouq Ali, 1994].

Due to some of the limitations in cyclic steam stimulation, further advancement was introduced. Mostly after the fifth cycle, the upcoming cycles did not give good results in terms of the cumulative steam oil ratio (cSOR). To counter the problem, improved completion designs were suggested, and the cycles and the variables involved in these cycles were studied to improve the number of cycles and produce more oil by increasing the number of cycles [Suranto, Permadi, and W. Bae, 2016].

One of the other methods proposed to increase the efficiency of oil recovery in reservoirs with some limitations is the gas-assisted cyclic steam stimulation [Jianqiang, Wang, Tang, 2012]. Here, a non-condensable gas is injected with steam, which provides additional drive energy in the production cycle.

2.3.5 Vapour Extraction (VAPEX)

The method of vapor extraction (VAPEX) is a recovery process in which a vaporized solvent is used in place of steam. In this process, the solvent creates a vapor-filled chamber

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in the reservoir and the vaporized solvent dissolves in the bitumen to reduce its viscosity. The solution formed in the method drains by gravity to a production well. In the vicinity of the production well, hot water injected with the solvent causes the solvent to re-distill towards the upper part. This re-distilled solvent again dissolves into the bitumen for further production [Butler, Mokrys, 1991].

The process of VAPEX is analogous to SAGD. The process mainly comes into consideration when there are some limitations in the reservoir to use SAGD for production, e.g., in carbonate reservoirs with low porosity and thin reservoirs. A gas cap (thin) or bottom water/aquifer can be advantageous for the VAPEX process but can be problematic in SAGD [Yazdani and Maini, 2005]. Some other reported advantages of VAPEX show it to be environmentally friendly and less capital intensive. The process is also very efficient regarding the energy requirement for production [Das, 1998]. However, it has not proven to be economically viable in the field, primarily due to a much slower rate of oil production.

2.3.6 Steam Assisted Gravity Drainage (SAGD)

The process of Steam Assisted Gravity Drainage commonly called SAGD was initially introduced and modified by Roger Butler [Butler,1998]. This process involves gravity drainage as the key mechanism so that the heated bitumen with reduced viscosity drains downward to the production well.

In the SAGD process, there are two very simple mechanisms involved. The first one is the viscosity reduction due to the exchange of heat between the injected steam and the reservoir materials and the other one is the gravity drainage. One of the main requirements of SAGD

is that the reservoir should have sufficient vertical permeability, otherwise the rate of production under gravity drainage would be restricted. Moreover, when the net pay zone thickness is less than 15 meters, the SAGD process may not be economically viable.

The process of SAGD involves the injection of the steam which is continuously injected through the injection well. In the SAGD process, the injection and production wells are vertically separated from each other with a vertical distance of around 5 meters.

The pre-heating process is an essential part of the SAGD operation. In this phase, the oil is heated up between the injection and production well so that the oil becomes mobile enough to drain under gravity. Pre-heating is achieved by the circulation of the steam injected through the tubing and the condensate comes in the annular space upward.
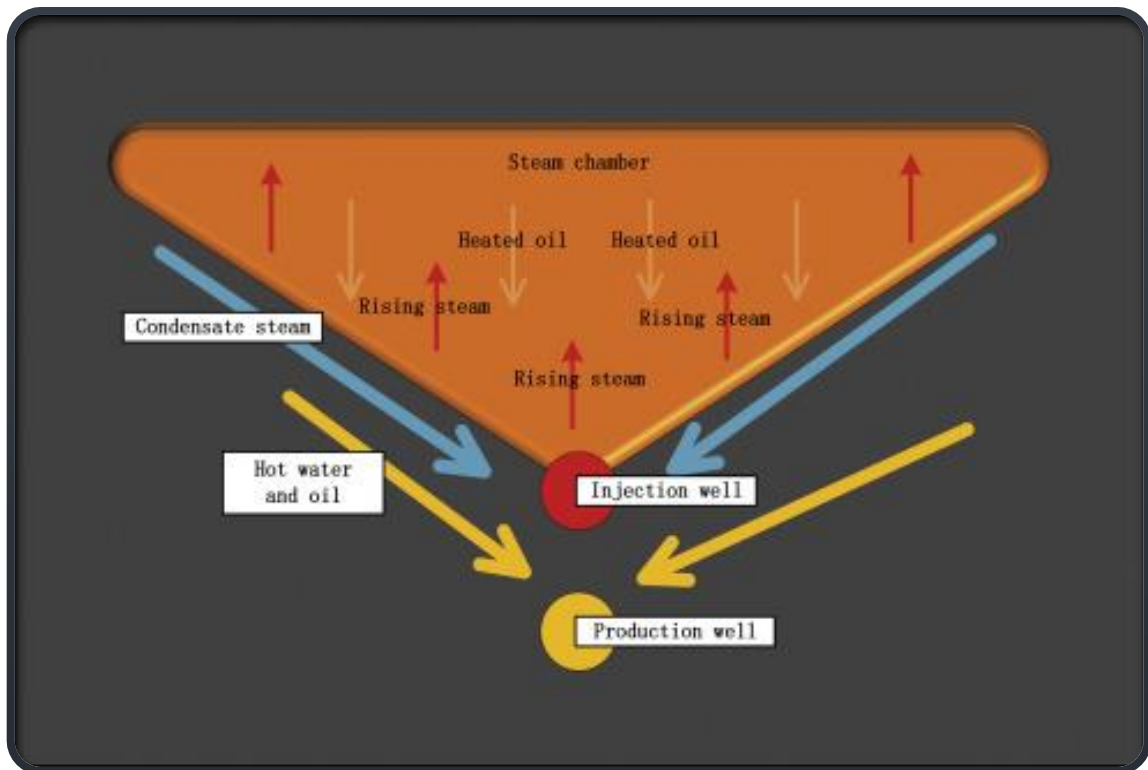
Figure 2.5: Steam Assisted Gravity Drainage (SAGD) [Zhang, 2018].

The steam injected through the injection well starts to create a steam chamber within the reservoir. Due to heat exchange at the boundary of the steam chamber and the undrained zone, the oil gets heated up and the steam condenses as it transfers the heat to the oil. Both the heated oil and the condensate move downward due to the gravity effect.

SAGD process is more efficient in the sense that it results in quicker depletion of the reservoir and recovers a higher percentage of the oil in place [Nasr, Tawfik, 2003]. The SAGD process is affected by reservoir heterogeneities, for example, the presence of shale layers can interfere in the development of the steam chamber, and thief zones can waste a part of the injected steam.

Under appropriate reservoir conditions, SAGD can be successful. Favorable reservoir characteristics include high permeability, both horizontal and vertical, and nearly immobile oil [Farouq-Ali, 1997].

2.3.7 Analytical Model of SAGD

The main objective of SAGD process is to improve the oil recovery by displacing the oil with steam in a gravity stable direction. Gravity the main driving force already exists, and steam injected close and above the production well will tend to rise. The condensate along with oil which is warmed up by steam will flow down to production well. [Butler, 1991].

Residual Oil Saturation

The oil saturation that remains in the steam chamber can calculated by equation (1) [Cardwell, 1949].

$$\bar{S}or = \frac{(b-1)}{b}\left[\frac{v_s\,\phi Z}{bkgt}\right]^{1/(b-1)} \quad\text{...} (1)$$

In equation 1, if "Z" is set to its maximum possible value h and "b" is assumed to be the typical value of 3.5, then the resulting equation becomes the equation for residual oil saturation in SAGD, [Butler, 1991].

$$\bar{S}or = 0.43\left[\frac{v_s\,\phi h}{kgt}\right]^{0.4} \quad\text{...} (2)$$

Where:

$\bar{S}or$ = Average residual oil saturation after time t

k = Permeability

Z = Drainage height

b = Exponent in Cardwell and Parson's equation for relative permeability, $\left[k_r = s^b\right]$

v_s = Kinematic viscosity of the oil at the temperature of the steam

h = Height

Darcy's Law

Darcy law relates the flow rate of a liquid to its viscosity, the permeability of the porous medium through which it is flowing and the pressure gradient driving the flow and for oil flowing at the edge of the steam chamber, it becomes.

$$q = \frac{kA}{\mu}\frac{\Delta P}{L}$$ .... (3)

Butler [1991] used Equation (3) to derive the following relationship for oil drainage rate in SAGD.

$$q = \frac{kg\alpha L sin\theta}{mv_s U}$$ .... (4)

Where:

k = Permeability

v_s = Kinematic viscosity of the oil at the temperature of the steam

h = Height

U = Velocity of temperature advancement in the interface

α = Thermal Diffusivity

L = Length of horizontal well

Material Balance equation

Material Balance at interface can be considered to define another relation between "q" and velocity at the front [Butler, 1991].

The material balance equation can be written as follows for a thin vertical element,

$$\left[\frac{\partial q}{\partial x}\right]_t = \phi \Delta S_o \left[\frac{\partial y}{\partial t}\right]_x$$ .... (5)

From equation 5 the velocity of interface is related to [∂y/∂t] and angle θ, by equation 6,

$$U = -cos\theta \left[\frac{\partial y}{\partial t}\right]_x$$ .... (6)

The value of U from the above equation can be substituted into equation 4 and further

simplification and rearrangements lead to Equation 7 [Butler, 1991].

$$q = -\frac{kg\alpha L\phi\Delta S_o}{mv_s}\left[\frac{\partial y}{\partial t}\right]_t \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (7)$$

Drainage rate

By rearranging equation 7 to separate the variables and then integrating, Butler obtained

the following equation for rate of oil drainage from one side of the horizontal well in

SAGD.

$$q = L\sqrt{\frac{2\phi\Delta S_o kg\alpha h}{mv_s}} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (8)$$

Above resultant equation indicates the drainage rate is function of height of drainage and

doesn't depend on horizontal extension or shape of interface [Butler, 1991].

Interface position

The horizontal velocity is independent of time but is a function of the height (vertical).

Assuming the steam chamber is a vertical plane above production well initially, then the

displacement in horizontal is given as function of height "y" and time "t" by Equation 9

[Butler, 1991].

$$x = t\sqrt{\frac{kg\alpha}{2\phi\Delta S_o mv_s(h-y)}} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (9)$$

The property "m" was introduced to allow and depict the temperature effect on viscosity. In the following equation the exponent "m" is defined as function of the viscosity-temperature relationship of oil from the reservoir temperature to the steam temperature [Butler, 1991].

$$m = \left[v_s \int_{T_r}^{T_s} \left[\frac{1}{v} - \frac{1}{v_r} \right] \frac{dT}{T - T_r} \right]^{-1} \quad \text{... (10)}$$

Butler and Stephens [1981] modified Equation 8 to account for the fixed position of the horizontal production well that does not allow the bottom of the steam chamber interface to move horizontally and derived the following equation for the oil production in SAGD.

$$q = \sqrt{\frac{1.5\phi \Delta S_o \alpha k g h}{m v_o}} \quad \text{.. (11)}$$

2.3.6.1 Solvent Added-Steam Assisted Gravity Drainage (SA-SAGD) as an enhancement of Steam Assisted Gravity Drainage (SAGD)

The process of Solvent Added- Steam Assisted Gravity Drainage "SA-SAGD" is an enhancement of the classical SAGD process. This enhancement results in lowering the Steam-Oil ratio (SOR) and accelerating the rate of oil production.

In this process, instead of using pure steam injection, a portion of the steam is replaced with a hydrocarbon solvent or solvents to improve the overall performance of the process in terms of improved quality of the produced oil and reduced energy requirements. The

solvent is injected into the vapor phase with steam. In this scenario, the injected solvent plays a key role in reducing the oil viscosity, as the solvent transfers its heat to the oil and in conjunction, it also dilutes the heavy oil or bitumen. One of the other key roles it plays is that the solvent acts as a barrier for heat losses as it insulates the region between the overburden and the steam chamber in the reservoir.

The process of SA-SAGD involves many complexities and the working mechanisms and the physics of the process are not yet fully investigated [Khaledi, Rahman, 2015]. To overcome the problems originating due to these complexities, studies are still being done to understand the behavior of the process.

SA-SAGD, as an enhancement and improved technology of SAGD, gave promising results, where it improved dead oil rate and live oil rate by almost 20% and 18 % respectively, for a similar value of permeability, as compared to the classical method of SAGD [Mohammadzadeh, Omidreza, 2012].

Hydrocarbon solvents injected with steam lower the viscosity of heavy oil by solvent dilution [Gupta et al., 2005]. Propane as a co-injection solvent is also used because of its lighter characteristic than butane and other heavier hydrocarbons [Ferguson et al., 2001].

SAGD and SA-SAGD Mechanisms

The mechanisms involved in the classical SAGD process are also involved in SA-SAGD, but SA-SAGD involves additional complications. The solvent mass transfer into the bitumen or oil occurs in this process and the reduction in viscosity is higher than that of the

SAGD process due to the combined impact of heating and dilution. Some of the main mechanisms that are involved in SAGD and SA-SAGD processes are described below.

a) Thermal Expansion:

Due to combined effect of conduction and convection of of heat and the rise in temperature the bitumen volume tends to increase, this effect will create pressure in the pore scale level. The overall expansion results in generating the high pressure in the reservoir and dilates the sand.

Thermal expansion effect on creates a shear and causes the dilation of the oil sand which results in enhancing the permeability in the reservoir [Cokar, M, 2013].

Lower residual oil saturation is remained due to the dilation at the steam chamber edge, so the performance of SAGD can be varied due to thermogeomechanics at the steam chamber [Cokar, M, 2013].

Another main mechanism involves the viscosity reduction of the oil due to thermal expansion.

b) Gravity Drainage:

One of the key mechanisms in the SAGD process is the drainage of the oil down to the production well due to gravity. Gravity becomes more effective and efficient when the vertical permeability is higher in the reservoir. The heavy oil in the reservoir gets heated up by the transfer of heat through convection and conduction, which in turn lowers the viscosity of the oil. The mobile oil then drains into the lower located production well under the influence of gravity.

c) Viscosity Reduction:

An essential mechanism in the SAGD process is the reduction of the viscosity of heavy oil. In SAGD, heat lowers the viscosity of oil to make it mobile and in SA-SAGD the solvent added in steam also plays a role in reducing the viscosity of the oil. So, the transfer of heat and the phase behavior of the co-injected solvents, both play vital roles in viscosity reduction [Gates, 2007; Li, 2018]. The extent of viscosity reduction with increasing temperature for oil and oil-solvent blends is shown in Figure 2.7.
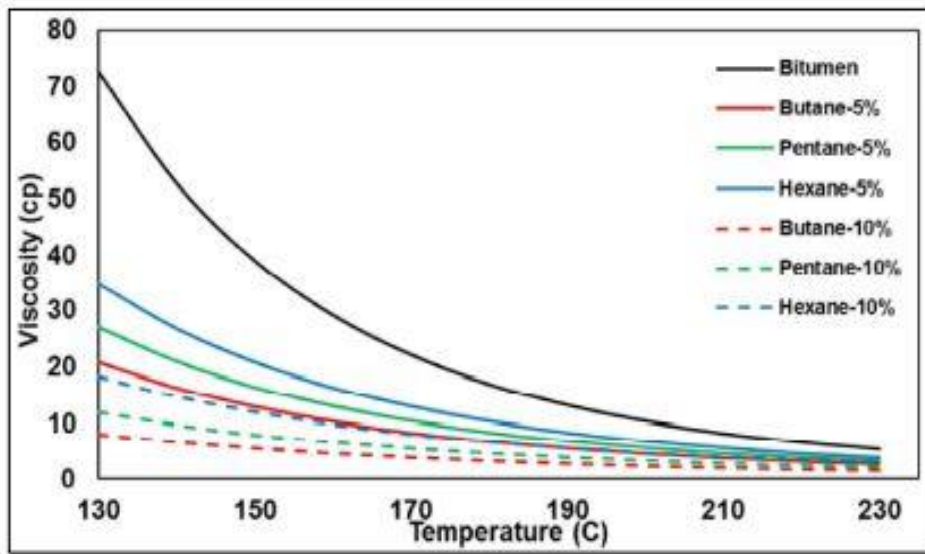
Figure 2.6: Ratio of viscosity for solvents-bitumen with increasing temperature [Zargar, Zeinab, and S. M. Ali, 2018].

d) <u>Heat Transfer to Reservoir Rock and Oil:</u>

The latent heat of steam is released and transferred to the reservoir rock and the fluids saturate the rock. When the steam is injected into the reservoir, the higher pressure of steam allows the steam to propagate outwards in the reservoir (by displacing oil and water) and it starts creating a steam saturated zone (often called steam chamber). In the conventional SAGD process, the heat is transferred to the cold oil when steam encounters the oil. This phenomenon occurs at the depletion edge of the chamber, causing a reduction of oil viscosity, which allows the oil to drain down due to the gravity effect. This heat transfer is a key factor in the process.

Earlier, the transfer of heat was considered to occur only by conduction, and the heat transfer due to convection was not considered important [Butler, R. M., and D. J. Stephens, 1981]. Later, the concept was modified, and it was pointed out that, due to the condensate flow ahead of the steam front, convection also plays a vital role in heat transfer [Ali, 1997]. Both conduction and the convection of heat, are important in transferring the heat energy. However, the conduction generally plays a bigger role, and the contribution of convection depends on the flow velocity of the condensate [Jia, Xinfeng, et al. 2019].
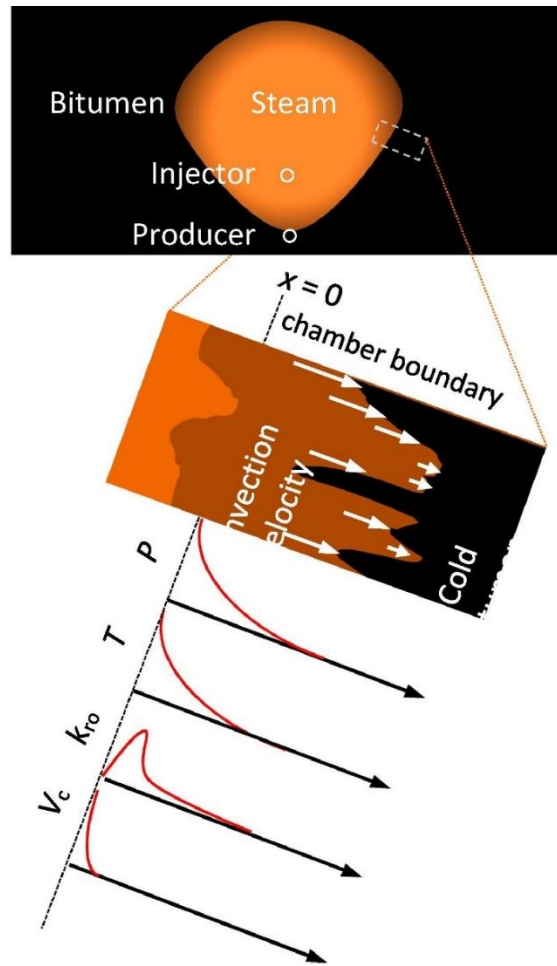
Figure 2.7: Schematics of heat transfer (Transient) beyond steam chamber of SAGD [Jia, Xinfeng, et al. 2019].

e) Mass Transfer between Solvent-Bitumen and Solvent-Steam:

In reservoir conditions, one of the notable properties is the high viscosity of the oil. All in situ production methods aim to lower its viscosity and make it mobile. Available options for reducing the oil viscosity include increasing the temperature and dilution with a less viscous miscible fluid, for example, a light hydrocarbon solvent [Gates, Chakrabarty, 2008]. In SA- SAGD, the transfer of mass between fluids occurs, one is

the mass transfer between the vapor phase and bitumen, which allows the solvent vapors to dissolve and dilute the oil. The other mass transfer process occurs in the vapor phase due to the diffusion of the solvent from a higher concentration zone towards a lower concentration [Das,1997].

In SA-SAGD, the solvent and steam injected into the reservoir encounter bitumen and form a system of multiple fluids. Depending on the composition and location of fluids, these fluids may exhibit multiphase equilibria, thereby affecting the behavior of drainage near the boundary of the steam chamber [Arshad, Mohsin, 2015]. To understand the complex mechanism of mass transfer between the fluids and its effects on the reservoir system, pore-scale studies need to be conducted.

f) Heat Conduction at the edge of steam chamber:

During the injection of steam in injection wells of SAGD process the injected steam is forced in outward direction. This process causes the loss of latent heat at the edge of steam chamber when the steam encounters the cold bitumen.

2.3.6.2 Further Enhancement and Variations in SAGD

Several other modifications of the original SAGD process have been proposed as being capable of enhancing the process in terms of improved energy efficiency, applicability to a wider range of reservoirs, improved rate of oil production, or higher recovery factor. Most of these rely on using a steam additive but differ in terms of what is added to steam and in what manner. In the following, a brief discussion of the more well-known modifications is presented.

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

The concept of ES-SAGD was reported by Nasr and Izra [1999] and Nasr [2003]. It was later patented by Nasr and Ayodele [2006]. This process is similar to the solvent - SAGD hybrid discussed above. Why it is called "Expanding Solvent – SAGD" is not clear.

A hydrocarbon solvent, in vapor form, is injected with steam. The steam heats the formation while the solvent, not only transfers heat for viscosity reduction but also gets dissolved into the bitumen to further decrease the viscosity. Here the solvent in the vapor phase also creates a heat-transfer barrier above the steam chamber and insulates the upper region for reducing heat loss to the overburden. In most of the reported examples, 90% or more of the injected solvent gets recovered with the production fluid, and in the blowdown period, approximately 75% of the solvent retained can be collected [ConocoPhillips, 2009].

The optimum selection of hydrocarbon additive is made so that both water and the additive evaporate and condense together, for avoiding the complexities of multiphase behavior [Nasr, Tawfik N., 2003].
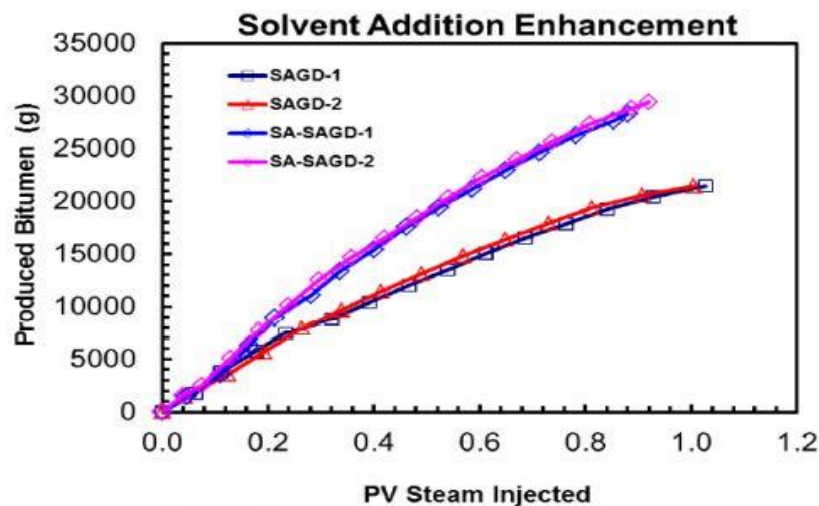
Figure 2.8: Enhancement by solvent addition [Khaledi, 2012].

The benefit of ES-SAGD/SA-SAGD was investigated by ExxonMobil at the reservoir conditions of Athabasca oil sands [Khaledi, 2012]. As a result, the author reported the oil recovery rate to be substantially higher than SAGD. Figure 2.9 shows the results of the increased performance of ES-SAGD/SA-SAGD compared to the SAGD.

2) Steam Surfactant Process (SSP)

The SSP (Steam Surfactant Process), involves the injection of surfactant chemicals with steam. Surfactant's main function is reducing the interfacial tension between immiscible liquids and the surface energy of solid-liquid interfaces [Gupta and Zeidani, 2013]. The mechanisms involved in SSP include interfacial tension reduction, oil relative permeability enhancement, and alteration of the wettability of reservoir rock.

Different surfactants can act differently, as they may act as wetting agents, foaming and emulsifying agents, dispersants, or detergents. Surfactants are mostly organic compounds, and they can have characteristics of both hydrophilic and hydrophobic groups that attract water and repel water, respectively. The process is still under development and no field-scale test has been reported in the open literature. However, some field pilots may have been conducted but their results have not been disclosed.

3) Steam Alternating Solvent (SAS)

Steam Alternating Solvent (SAS) process is an enhancement of SAGD in which steam and solvent are alternately injected using the same well. The injection of solvent is started when

the steam chamber top zone reaches the overburden and starts the heat loss in a significant amount. The solvent injection is continued until it reduces the temperature of the steam chamber by some threshold amount, then pure steam is injected again to increase the temperature. This repetition continues until the production becomes uneconomical. The well configuration for SAS is the same as that of SAGD [Zhao, Litong. 2004].

4) Solvent-Aided Process (SAP)

In Solvent-Aided Process, first introduced by [Gupta, S.Gittins, 2004], lighter hydrocarbon solvents, like, propane and butane, are injected with steam to further reduce the viscosity through dilution [Gupta et al, 2005]. The addition of solvent starts after the steam injection creates a fully developed steam chamber in the reservoir. The steam chamber initially develops in the same way as in the normal SAGD process and reaches the top of the formation, after which the injection of solvent vapor is started. The vaporized solvent injected with steam travels with the steam through the steam chamber and accumulates where the steam condensation is taking place, i.e., ahead of the steam front and near the top of the formation. Near the steam front, the solvent dissolves in the heated oil, reducing its viscosity. Near the top of the formation, the solvent reduces the steam temperature due to reduced partial pressure of water vapor in the vapor phase. Solvent dissolution is beneficial for oil recovery, but its increased amount can obstruct steam front propagation by hindering the heat transfer from condensing steam to cold oil.

5) SAGD with Non-Condensable Gases (NCG)

Butler developed a SAGP (Steam and Gas push) process [Butler and Jiang, 2000], which employs co-injection of methane gas with steam to increase the SAGD efficiency. Unlike SAGD, SAGP is operated at lower temperatures, and this results in the benefit of lower heat losses into the reservoir rock and overburden.

In the presence of non-condensable gases, such as nitrogen air or methane, the mechanism of SAGD can become more complicated. Non-condensable gases (NCG) presence in the steam chamber of SAGD could occur naturally also when the oil contains dissolved gases that are released by heating. However, when such gases are injected with steam they do not get dissolved in the oil in large volumes at the temperature of steam [Aherne and Birrell, 2002]. They tend to accumulate near the top of the formation and near the steam front.

One of the concerns raised is that NCG injection, causes NCG to accumulate at the chamber top, thus cooling down the chamber. Low-temperature reduces the oil viscosity consequently and reduces the production rate of bitumen [Aherne and Maini, 2006].

Some field-scale simulation studies attempted to examine the effect of NCG in the SAGD process [Hossein et al, 2015]. Solubility, dispersion, and diffusion were considered in the liquid phase. Results showed improved bitumen recovery with lowering of the SOR. This study recommended co-injection of methane at less than 3 mol% concentration in the injected fluid.

6) Electric Heating (In Situ Reflux (ISR) and Radio Frequency (RF) Heating)

a) Electric Heating

A recent thermal enhanced oil recovery advancement is a process called Electricity-Assisted thermal EOR, which also uses gravity drainage for oil recovery. Although several variations of electric heating have been considered, the most straightforward method used is called conductive electrical heating. In this method, electric heaters transfer heat energy directly to the fluids in the reservoir. The fluid receives heat by direct contact with electric heaters, which are placed in the wells. The heating process efficiency depends on the thermal conductivity of the formation, which is dependent on the reservoir rock properties, oil, gas, and water saturation, porosity, etc. One of the electric heating processes developed by industry is called In-Situ Reflux (ISR), [Harding, Thomas G, 2016], which is briefly described below.

In Situ Reflux (ISR)

The In Situ Reflux, or In Situ (Steam) Reflux (ISR), is a novel EOR process for delivering effective and efficient energy to the fluid by placing electric heaters in the well and reducing the amount of heat transfer fluids injected into the reservoir. A vapor chamber, similar to the steam chamber in SAGD is formed by vaporizing injected fluids and the connate water. The process forms a vapor chamber that rises, but heat losses to the reservoir fluid and matrix of the reservoir formation cause the vapors to condense into a liquid. The

liquid condensates along with the bitumen drain downward due to gravity (similar as in SAGD).

In this process, as the fluid comes into the lower part and approaches the electric heaters (ISR), the fluid encounters temperature above the saturated steam temperature, and re-vaporization of water occurs, this re-vaporized fluid is "back refluxed" towards the chamber. The flowing path of bitumen is towards the production wells which is uninhibited by steam condensates.
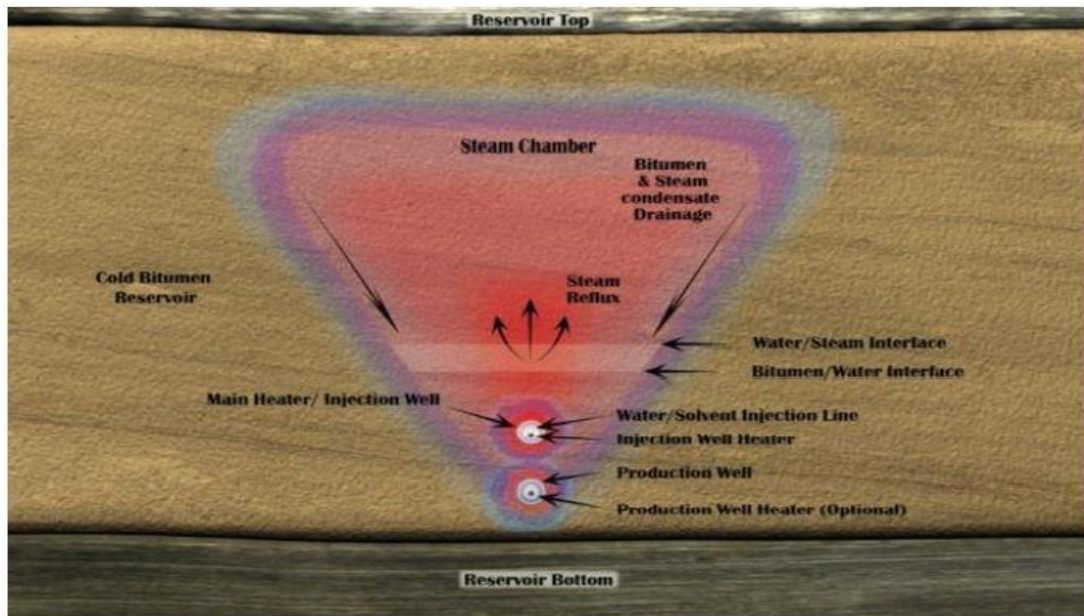
Figure 2.9: ISR process schematic [Harding, Thomas G, 2016].

Radio Frequency (RF) Heating

Heating electromagnetically at radio frequencies is another variation in the process of electric heating. In this method, the antennas placed in the wells generate electromagnetic

waves. The in-situ water in the reservoir affects the impedance of the medium (Heated), while the efficiency of the whole process is dependent on the impedance of the heated medium.

To balance the amount of heat power and the penetration depth, the alteration can be made to employ different frequencies. The configuration of wells also depends on the reservoir type to be developed. Heated bitumen/oil may also require some additional source of energy to produce it. As in this process, it is required to convert the energy of electricity into electromagnetic waves, this process reduces the efficiency of electromagnetic heating, as compared to Ohmic resistive heating which is very high in inefficiency. However, in this process, the heating of the reservoir can penetrate deeper around the wells in less time.

ESEIEH (Effective Solvent Extraction Incorporating Electromagnetic Heating) developed by Harris Corporations is an example of Radio Frequency (RF) heating. In ESEIEH, bitumen/oil is concurrently heated with electrical energy and diluted with an injected solvent to drain it due to gravity. ESEIEH`s advantages include lower emissions and less requirement of energy as compared to the other processes [Energy Solutions Overview].
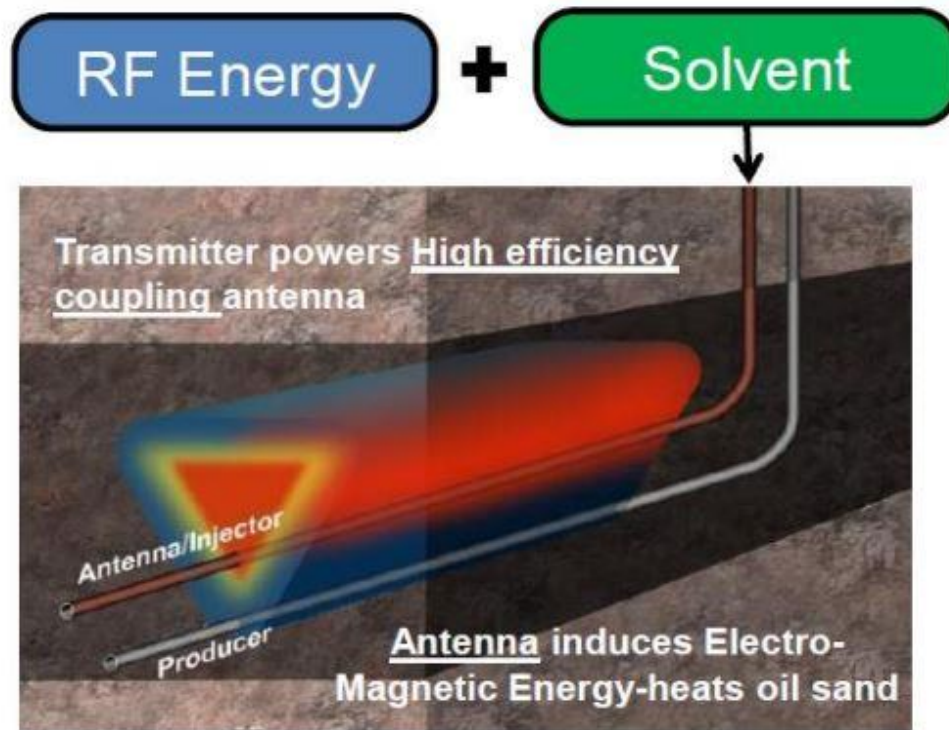
Figure 2.10: Schematic diagram of ESEIEH process [Energy Solutions Overview].

2.3.6.3 Solvent injection - Some Field Examples

There have been several field trials of solvent enhanced SAGD in Canada. Some of the field projects are mentioned here. ConocoPhillips, in its Surmont SAGD project in Alberta, Canada, has been running filed pilots using solvent co-injection [AER presentation, 2015]. Another project using a solvent is Long Lake operated by CNOOC Intl Ltd. [Orr, 2009]. ExxonMobil used solvent in their Cold Lake field project [Dickson, 2011]. Encana Corporation (now Cenovus) used a solvent-aided process in SAGD at Senlac, Saskatchewan [Gupta, Gittins, 2005; Bayestehparvin, 2017] and Christina Lake, in Alberta [Gupta, Gittins, 2006; Chen et al. 2018]. Shell Canada in Peace River, Alberta, used solvents (gas condensate) to enhance the steam flood [Castellanos et al., 2016]. Imperial

Oil in Cold Lake, for their SAGD operations, used gas condensates to enhance the recovery [Zeidani, 2013].

The above-mentioned field trials show that solvent co-injected with steam is of great interest to the industry. However, its economic viability has not been confirmed with any full-scale commercial field application. To further enhance its ability to recover oil and bitumen, further studies are needed.

CHAPTER- 3: EXPERIMENTAL APPARATUS AND EXPERIMENTAL METHODS

A cylindrical sand-pack model was used for conducting SA-SAGD experiments. This model was capable of operating at temperature and pressure typically used in the field scale SAGD operations in Canada. The sand-pack model was used to evaluate the effect of different solvents on the oil recovery performance of steam-assisted gravity drainage. Due to the small diameter of the sand-pack, this model simulates only the early part of the SAGD operation when the steam chamber rises vertically. It does not model the laterally spreading chamber part of the process that occurs when the steam chamber has reached the top of the formation.

A schematic diagram of the experimental rig is shown in Figure 3.1 and Figure 3.2 presents a photograph of the actual setup. It comprises many components, including the sand-pack model, three positive displacement pumps, two piston-equipped transfer vessels, a steam generator, a back pressure regulator, a data acquisition system, heating tapes and thermocouples. These components and their purpose in the rig are described below.

3.1 Components of Experimental Rig

The following figures (3.1 and 3.2) show the schematic and photograph of the experimental

rig used for tests.
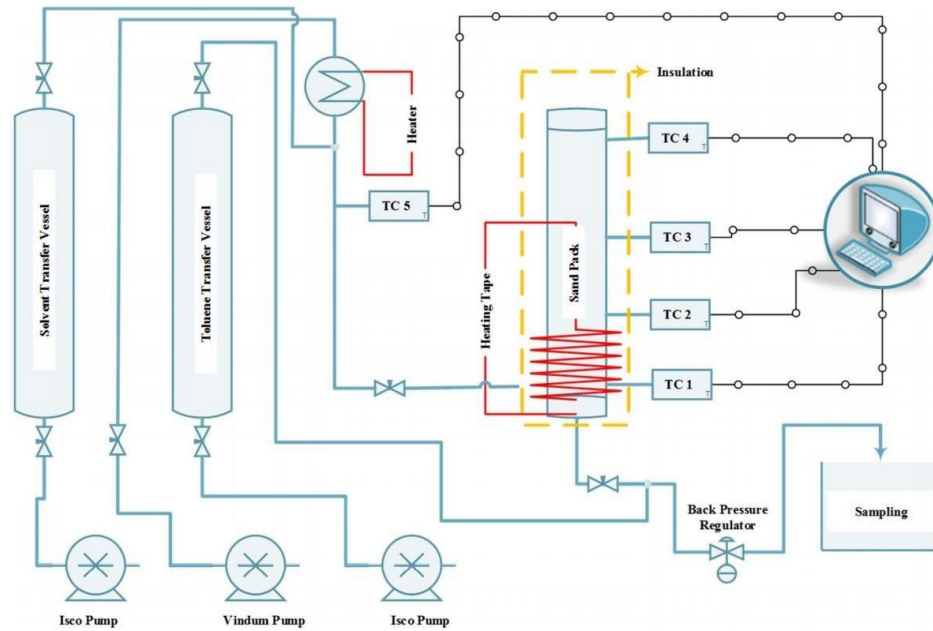
Figure 3.1: Schematic diagram of the experimental rig.

Figure 3.2: Experimental setup for SAGD and SA-SAGD experiments.

3.1.1 Vindum Pump for Water injection

A Vindum positive displacement pump (Model VP- 12K-SS, shown in Figure 3.3) was used for injecting de-ionized water into the steam generator to generate steam for the SAGD experiments. Water is continuously injected with a measured flow rate. It can easily maintain a constant flow rate of up to 30 ml/min at discharge pressure up to 5,000 PSIG.
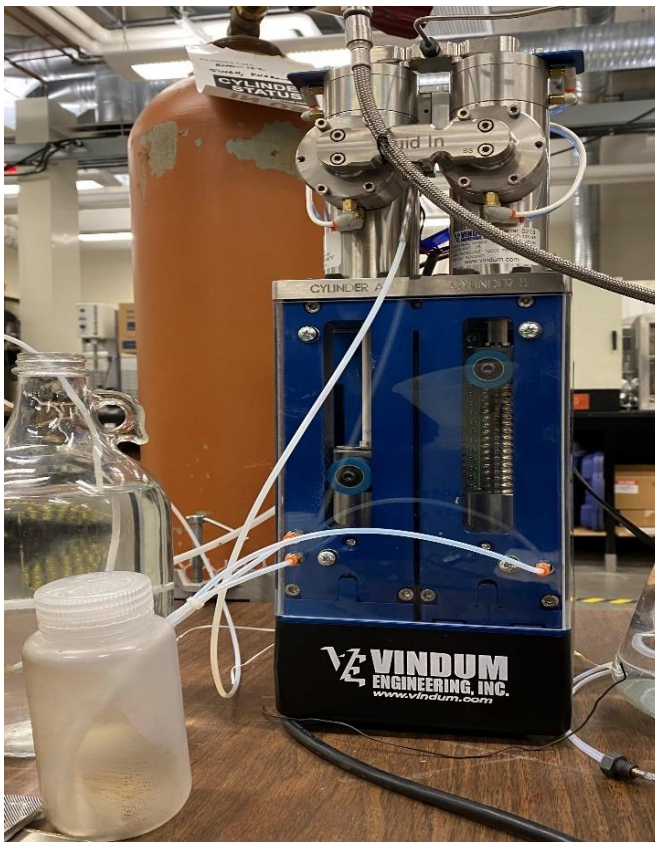
Figure 3.3: Vindum pump for water injection

3.1.2 ISCO Pump for Solvent and Toluene injection

Two single-barrel ISCO syringe pumps were used in the rig. One was for injecting the solvent at a constant rate in SA-SAGD experiments, while the other ISCO pump was used for injecting toluene into the production line going from the sand-pack to the backpressure regulator. Toluene was injected at a low rate to prevent the produced bitumen from gumming up the backpressure regulator. Figure 3.4 shows the type of ISCO pumps used in these experiments.

Figure 3.4: ISCO pump for solvent injection

3.1.3 Solvent Transfer Cylinder

A piston-equipped transfer cylinder (shown in Figure 3.5) was used to inject the solvent. The solvent was placed on top of the piston, which was initially pushed down to the bottom of the cylinder. The bottom of the piston was hydraulically pushed up by injecting water to drive the solvent. The solvent was mixed with steam coming out of the steam generator before it entered the sand-pack.
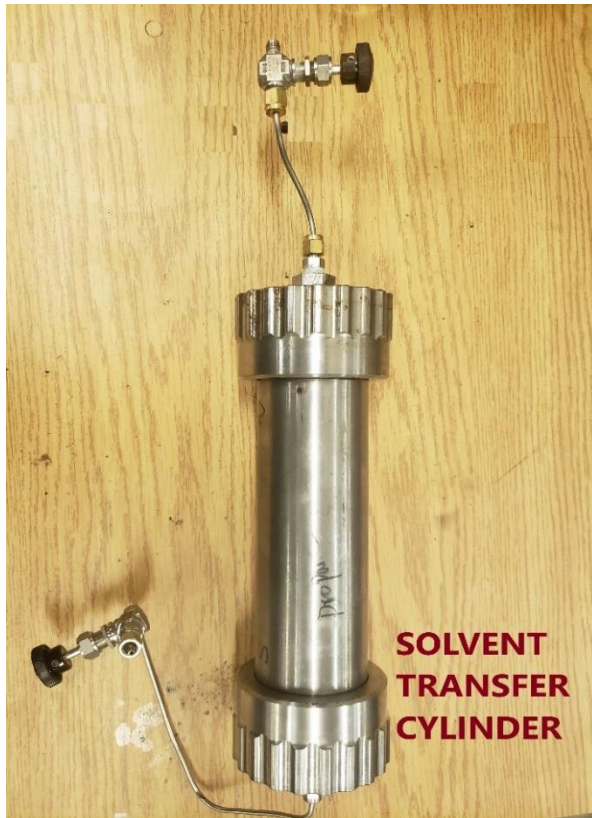
Figure 3.5: Solvent Transfer cylinder

3.1.4 Toluene transfer cylinder

Another similar transfer cylinder was used to inject the toluene. The toluene injection was used in this setup to facilitate the BPR functioning, especially in the early stage of production, when the proportion of bitumen in the produced fluid is high and may interfere with the smooth operation of the BPR. The sticky nature of bitumen can adversely affect the BPR operation, and the injected toluene dilutes the bitumen and eliminate its sticky nature. The toluene injection was upstream of the BPR and downstream of the sand pack so that it doesn't impact the experiment's performance.

3.1.5 Steam Generator

An inline steam generator was used to inject steam into the sand pack. De-ionized water was used in this flow-through steam generator for this purpose. Water passed through the annulus between three meters long stainless-steel tube of 0.95 cm diameter and a 0.48 cm diameter electrical rod heater of the same length. The water in contact with the rod heater generates the steam. A variable transformer (Variac) was used to adjust the heater for a specific flow rate of the water to produce superheated steam. The steam coming out of the steam generator was directly injected into the sand pack.

3.1.6 Cylindrical Sand-Pack Model

The sand-pack holder used in these experiments is shown in Figure 3.6. It was made from a stainless-steel pipe of 2.54 cm internal diameter, by attaching flanges to both ends. Two endcaps (one on each side) were used to seal off these flanges. The endcap on one side of the sand pack was fixed, while the other was movable by axial movement of 2.5 cm long

cylindrical stem that was concentrically attached to the flange and sealed against the internal surface of the pipe with O-rings seals. Due to this movement, the total length varied between 30.88 cm to 31.60 cm in different experiments. The purpose of the movable stem was to apply some axial stress on the sand by tightening the flange bolts. The bolts were tightened using a torque wrench to the same torque in each experiment to obtain similar stress on the sand. The sand-pack was filled using clean silica sand particles of 12-20 mesh size for all experiments. A new sand pack was prepared for each experiment. The porosity of sand packs was 36.40% ±0.46% and the absolute permeability was 358.41 ±66.7 Darcy.
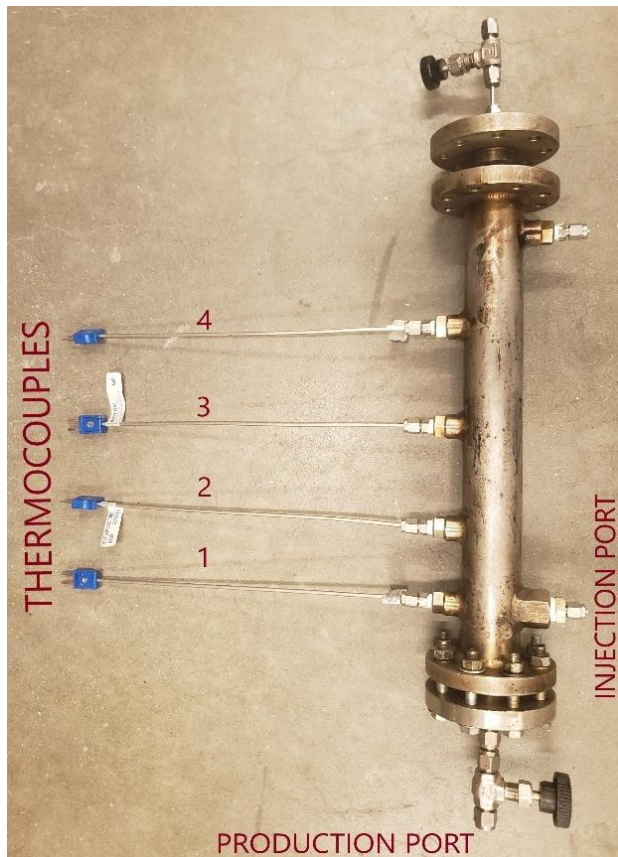
Figure 3.6: Cylindrical physical model sand pack 1D.

3.1.7 Variable Transformers (Variacs)

Variacs were used to control the power applied to heat tapes that were wrapped on the flow lines and on the bottom portion of the sand-pack. Another Variac was used to control the steam generator. All Variacs were periodically adjusted to maintain the desired temperature in the lines and the sand pack.

3.1.8 Heating Tapes

Several heating tapes were used in the rig to heat trace the flow lines. The line connecting the steam generator to the sand-pack was heated to maintain the high quality of the steam. The lines connecting the sand-pack outlet to the BPR was also heat traced to prevent the produced bitumen from cooling and becoming too viscous in the flow line. A heating tape was also used to heat up the bottom part of the sand-pack before initializing the experiment. This pre-heating was done to make the oil sufficiently mobile and avoid any obstruction in starting the experiment.

3.1.9 Thermocouples

The sand-pack was equipped with four thermocouples which were located at 2.54 cm, 7.62 cm, 15.24 cm, and 22.86 cm distance from the production port. The distance between the injection port and production port was about 2.54 cm and the injection port was on top of the production port to mimic the well configuration in the SAGD process. Figure 3.7 shows the location of thermocouples.
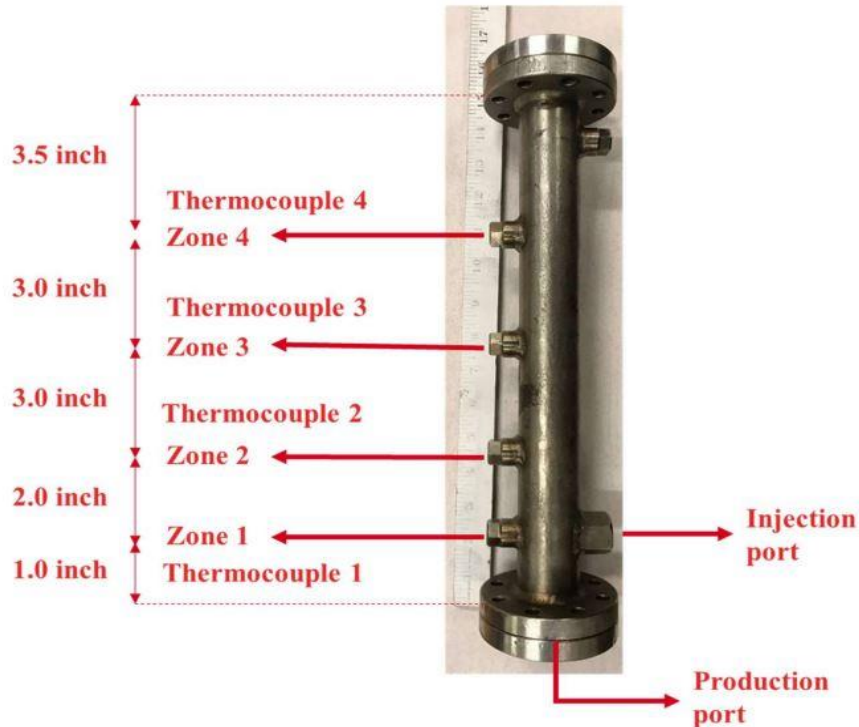
Figure 3.7: The sand holder used in this study with four ports for thermocouples.

3.1.10 Data Acquisition System

A data acquisition system was used to monitor and record the temperatures at different zones of the sand-pack, in the steam generator, and the flow lines. These monitored temperatures were used to adjust the Variacs when needed.

3.1.11 Back Pressure Regulator (BPR)

A Back Pressure Regulator (shown in Figure 3.8) was used to maintain constant pressure at the production port of the sand-pack. The BPR pressure was set at 200 psi so that pure water would be in the vapor phase when the temperature was higher than 205 ºC. To facilitate the BPR functioning, toluene was injected into the flow line going to the BPR.

This was needed especially in the early stages of the run when the bitumen production is high, and the sticky nature of bitumen affects the BPR functioning. The toluene dilutes the bitumen and maintains smooth flow of the produced fluids for sampling.

Figure 3.8: Back Pressure Regulator (BPR).

3.2 Properties of Sand and Fluids used in Experiments.

3.2.1 Sand

Clean silica sand of mesh size 12-20 was used in all experiments. The sand was supplied by AGSCO Corporation, Wheeling, Illinois, USA.

3.2.2 Fluids

Several different fluids were used to conduct the experiments. Their sources and properties are described below.

3.2.2.1 Bitumen, Water and Solvents:

The bitumen used in these experiments was Athabasca bitumen having a density of 1.026 g/cm^3 at a temperature of 23 ℃ and pressure of 400 psi. It was provided by CNOOC International from their Long-Lake operation. This bitumen was obtained by collecting a well-head sample from the SAGD operation and subsequently dehydrating it to obtain water-free bitumen. The density and viscosity of this bitumen at constant pressure and different temperatures were studied and measured in an earlier work [Esmaeili, 2020].

Figure 3.9 shows the measured density of bitumen at different temperatures where linear trends can be regressed on measured data points. The bitumen viscosity at ambient pressure and water viscosity at 380 psi pressure at different temperatures are shown in Figure 3.10.

Figure 3.9 reveals the measured density of the bitumen at different temperatures where a linear trend can be regressed on the measured data points shown in this figure and Equation (1) expresses the corresponded correlation.

$$\rho_{Bit} = 1.0414 + 6.97 \times 10^{-3}T \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \ (1)$$
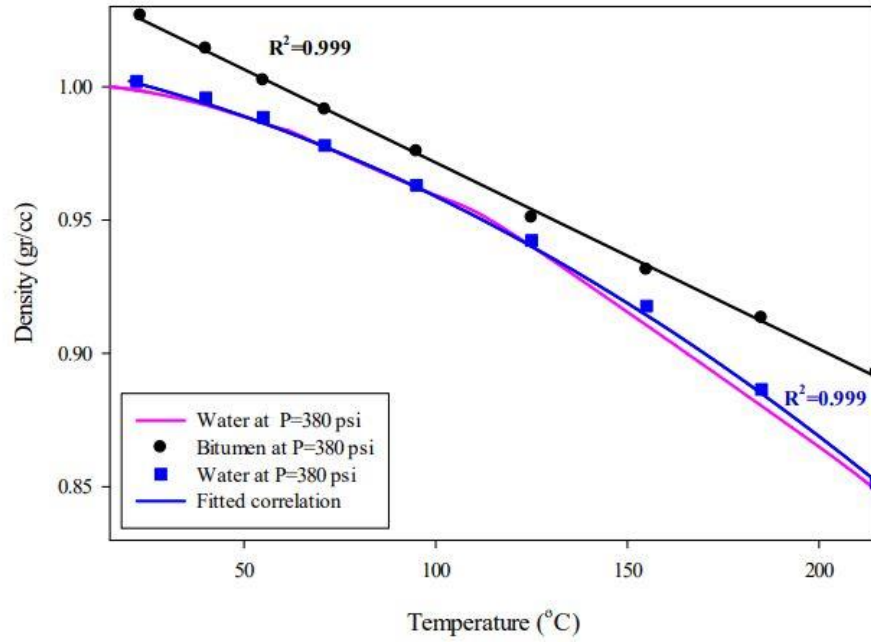
Figure 3.9: Measured density of Athabasca bitumen (at ambient pressure and 380 psi), and compressed water (at 380 psi) versus temperature [Esmaeili, 2020].
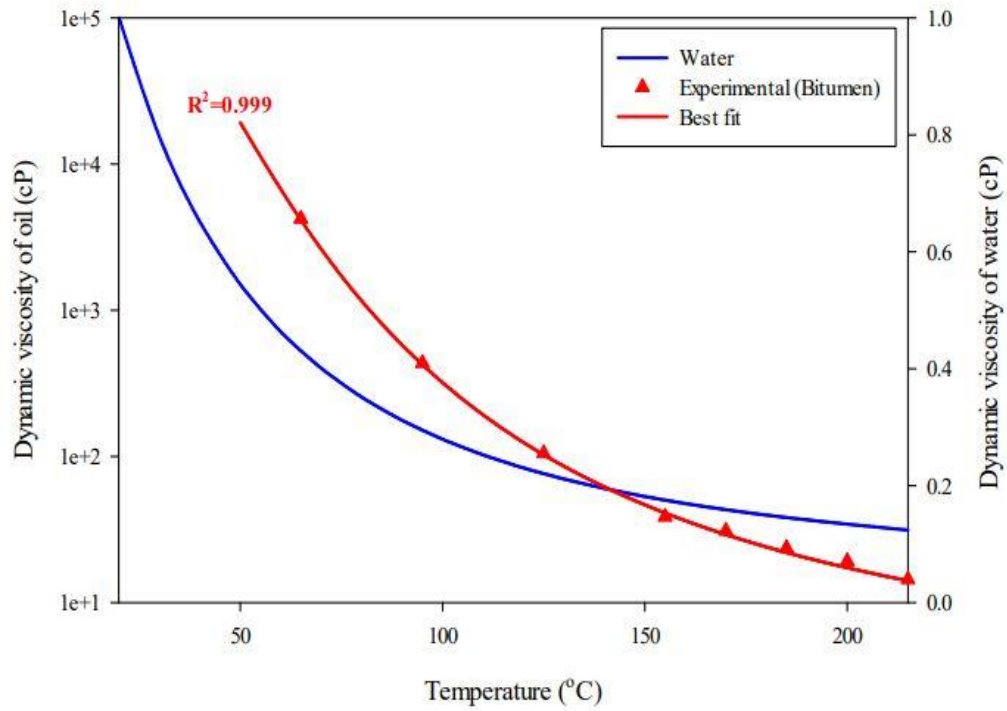

Figure 3.10: Viscosity of Athabasca bitumen (ambient pressure) and pure compressed deionized water (at 380 psi) [Likhachev, 2003].

The viscosity of bitumen viscosity at the ambient pressure at several temperatures and water viscosity at 380 psi and several temperatures are shown in Figure 3.10. Equation (2) expresses the best-fitted correlation of bitumen viscosity as a function of temperature. [Likhachev,2003], developed a non-linear empirical correlation for the pure water viscosity as a function of pressure and temperature as expressed in Equation. (3).

$$\mu_{Bit} = \exp\left(\exp\left(7.776\left(\ln\left(T\right)\right) - 1.721\left(\ln\left(T\right)\right)^2 + 0.112\left(\ln\left(T\right)\right)^3 - 8.498\right)\right) \ldots\ldots\ldots (2)$$

$$\mu_w = 2.4055 \times 10^{-2} \exp\left(4.42 \times 10^{-4} P_w + \frac{4.753 - 90.565 P_w}{8.314 \times 10^{-3}\left((T+273.15) - 139.7 - 1.24 \times 10^{-2} P_w\right)}\right) \ldots (3)$$

The aqueous phase used in these experiments was de-ionized water. The density and viscosity of de-ionized water are shown in Figure 3.9 and Figure 3.10 respectively.

In this study, two different hydrocarbon solvents, namely Propane (C3) and Butane (C4), were used. Both solvents are in the gaseous phase at ambient pressure and temperature. To keep them in the liquid phase, they were kept at sufficiently high pressure. Two 250 cm^3 transfer vessels were used to prepare the mixture of these solvents. The first transfer vessel was used to extract the gas or gas/liquid from the gas tank. Then, the transfer vessel was pressurized to more than 200 psi at the ambient temperature in order to turn the gas phase into the liquid phase. Therefore, only the liquid phase of propane or butane at the ambient temperature and 200 psi remained in the transfer vessel. Afterward, the liquefied gas was transferred to another transfer vessel to place a metered volume of the liquid phase under pressure for the experiment. Thus, the first transfer vessel was used to liquify the extracted gas from the gas tank and the second transfer vessel was used to collect the liquefied gas

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for a test or for mixing purposes. In order to prepare a known mixture of propane/butane for the experiment, the same procedure was used twice, to transfer metered volumes of the two components to the second transfer vessel. The mixture was allowed to sit at room temperature for at least 24 hours with the transfer vessel in horizontal orientation. In addition, the transfer vessel was rotated periodically to promote the mixing of the two components. In this way, the desired mixture was achieved.

3.3 Experimental Method and Procedure

This section describes the experimental procedure used for SAGD or ES-SAGD experiments conducted in this study.

3.3.1 Packing of Physical Model and Measuring its properties

For conducting the experiment, the sand-pack model described earlier was used. The model was thoroughly cleaned to ensure there was no residue from the previous experiment. Only then it was considered ready for packing.

3.3.1.1 Sand Packing

After cleaning the sand-pack holder, the first step was to attach the non-movable endcap on one side and tighten the bolts. Then all four thermocouples were inserted and secured by tightening the Swagelok fittings. The sand-pack holder was then weighed with the other flange and bolts to determine the weight of the empty holder. The sand-pack holder was then placed in a vertical position with the open end at the top. Clean silica sand of 12-20 mesh size then slowly poured into the holder. While the sand was being poured, the sand-

pack holder was lightly tapped with a brass hammer to promote good settling of the sand. This procedure was continued until the sand reached its desired level (about 1 cm from the top) in the holder.

The stem of the movable endcap was then inserted into the holder and all bolts were inserted and hand tightened. Then a torque wrench was used to tighten the bolts. The bolts were tightened several times to a pre-set torque. After each tightening, the holder was tapped with a brass hammer to promote further settling of the sand. After the sand packing was completed, the sand-pack was weighed to determine the mass of sand in the model.

3.3.1.2 Carbon Dioxide (CO_2) Flush

When the dry sand-pack is ready, it is then flushed with carbon dioxide (CO_2) for 20 minutes, to remove the air inside the sand pack. The air is replaced with carbon dioxide, to make it easier to subsequently remove any trapped gas phase by dissolution in water.

3.3.1.3 Vacuuming

After the sand pack has been flushed with carbon dioxide gas, it is then vacuumed using a vacuum pump to evacuate all the gases present inside the sand.

3.3.1.4 De-Ionized Water Saturation

After evacuation, the sand pack is saturated with de-ionized water under pressure, so the remaining carbon dioxide gas gets dissolved. The volume of water imbibed is measured using the pump readings. In addition, the mass of the sand-pack after imbibing water is

also measured. The difference between the weight of the dry sand-pack and the wet sand pack is the weight of imbibed water into the sand pack. In case of any small discrepancy between the water volume determined from weighing and the pump reading, the weight is considered more reliable. The volume of water imbibed is used as the pore volume in the calculation of porosity.

3.3.1.5 Permeability Measurement

Absolute permeability is measured by flowing deionized water through the sand-pack and measuring the pressure drop across its length with a differential pressure transducer. The sand-pack after the absolute permeability measurement is placed in an oven at 75 °C for at least two hours to preheat it before oil flooding.

Permeability is the measure of flow conductivity through a particular porous medium and is measured in units "Darcy" with the dimension of "area". This porous medium's property can be measured having flow properties (i.e., The area, which is the cross sectional area perpendicular to flow direction "A", the volumetric flow rate donated by "Q", the pressure gradient, " $\Delta P/L$", and the fluid viscosity, "μ", using the Darcy equation as follows:

$$Q = \frac{KA}{\mu} \times \frac{\Delta P}{L} \qquad \text{and} \qquad K = \frac{Q\mu L}{A\Delta P}$$

$$\ldots\ldots\ldots\ldots (4)$$

3.3.1.6 Bitumen Flood to Measure Initial Oil Saturation

As mentioned above, the sand pack is preheated to 75 °C. It is then connected to the oil transfer vessel, which is also heated to 75 °C, to make the bitumen mobile. The bitumen is injected into the sand pack at 75 °C with a 1 cm^3/min flow rate until the oil breakthrough

occurs. The oil flooding is terminated after the oil breakthrough and the mass of produced water is measured to determine the irreducible water saturation and the initial oil saturation in the sand-pack.

3.3.2 SAGD or SA-SAGD Experiment

After the sand-pack preparation is completed and the permeability, porosity, irreducible water saturation, and initial oil saturation have been measured, the sand-pack is placed in the experimental rig and the steam injection and oil production lines are connected. The rig is then ready for initiating the test, which involves the following steps.

3.3.2.1 Pre-Heating

Before starting the experiment for steam injection or solvent added steam injection, the bottom part of the sand pack (zone 1) is pre-heated with a heating tape wrapped on the outside of the sand-pack holder between the injection port and the production port. This part of the model is heated until the temperature reaches 80 ºC. This is necessary to ensure sufficient mobility of the oil between the injection and production ports. When the oil is mobile, it allows injection of steam or steam-solvent into the sand-pack without needing excessively high pressure.

3.3.2.2 Bypass Flow

During the preheating, the steam flow is started through the bypass line to preheat the lines and stabilize the steam generator. The steam bypasses the sand-pack and flows directly to

the BPR. This bypass flow is continued until the bottom zone of the sand-pack becomes heated and the steam temperature coming out of the steam generator is at the superheated level.

3.3.2.3 Steam Injection Experiment

After sufficiently heating the system and stabilizing the steam generator, the steam (or steam plus solvent) injection into the sand-pack is started at a constant total flow rate of 2.0 cm³/min. The heating of the lower part of the sand-pack is turned off immediately after starting the steam injection. Injection of steam or solvent steam is continued for more than 6 hours. During this part of the experiment, the temperatures of different zones are monitored and recorded for post-experiment analysis. Several samples of the produced fluid mixture are collected in glass sample bottles during the experiment for later analysis. The procedure used for sample analysis is described in the next section.

3.3.3 Fluid Sample Analysis

Fluid samples are collected from the production port of the BPR. Due to the design of the BPR employed in this study, a significant shear gets applied on the produced effluent when the BPR valve opens, resulting in the formation of a strong emulsion of bitumen and water which cannot be easily broken. Both, in the base-case SAGD experiment and the SA-SAGD experiments, we were unable to easily separate the produced water from the oleic mixture, regardless of the presence of the solvent. Therefore, the mixture including the condensed water phase and oleic phase was transferred to a round flask for the Dean-Stark

analysis. Since the amount of toluene added to the mixture for the BPR operation is known, the presence of this toluene does not affect the bitumen weight measurement at the end of our analysis. By conducting the Dean-Stark analysis, all the aqueous phase is extracted from the mixture: hence, the weight of water in the mixture is accurately determined.

Figure 3.11: Dean-Stark Distillation

After this stage, the remaining mixture (including toluene and bitumen) at the bottom of the round flask is subjected to a Rotary Evaporation process. A consistent procedure is applied to evaporate and recover the toluene from the mixture, as much as possible.
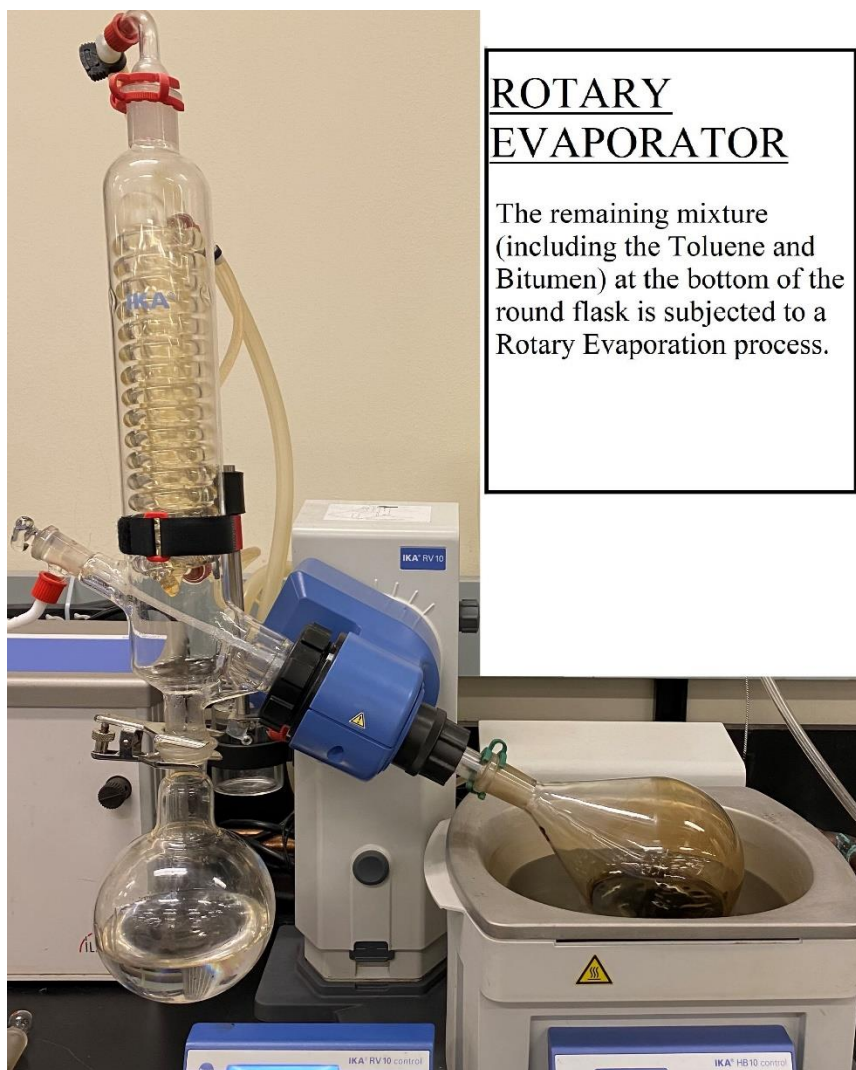
ROTARY EVAPORATOR

The remaining mixture (including the Toluene and Bitumen) at the bottom of the round flask is subjected to a Rotary Evaporation process.

Figure 3.12: Rotary Evaporator

The procedure described here was developed by [Esmaeili et al., 2019 and 2020]. They reported a near-perfect toluene recovery when the performance of this procedure was checked with several prepared samples. The reported material balance error was less than 1%. The difference between the dry weight of the flask and the weight of the flask with the remaining bitumen provides us the mass of collected bitumen. Thus, the fraction of produced water and bitumen is evaluated accurately using the solvent extraction technique.

The mass of produced water and oil can be converted to the volume at the test condition based on the density of the fluids. The proposed procedure can work effectively for both SAGD and SA-SAGD produced effluents.

CHAPTER- 4: RESULTS, ANALYSIS, AND DISCUSSION

This chapter presents the results of all experiments conducted during this study. Seven different SAGD or SA-SAGD experiments were successfully carried out. Pure propane and pure butane with a purity of approximately 99.9% were used individually for SA-SAGD experiments. Four additional SA-SAGD experiments were conducted using four different compositions of propane/butane mixture, (20 vol% C3-80 vol% C4, 80 vol% C3-20 vol% C4, 40 vol% C3-60 vol% C4, 60 vol % C3-40 vol% C4,), made at around 200 psi and 23 ℃, to examine the effect of solvent composition on SA-SAGD performance.

Before conducting the experiments for SAGD and SA-SAGD it was necessary to conduct some preliminary tests to initiate and calibrate the rig. Some of these tests are described in section 4.1.

4.1 Preliminary tests for tuning and calibrating the rig

Below described tests were conducted for calibrating and tuning the experimental rig.

4.1.2 Sand Selection, Packing, and Permeability Tests

Sand mesh size selection is an important factor in this study, the mesh size alters the results due to changes in permeability, which controls the rate of drainage and thereby the run time. It also affects the final recovery factor in SAGD tests. Clean silica sand with a mesh size of 12-20 was found to work best. Finer sand made the run time too long and sand coarser than 12-20 size made the SAGD recovery factor so high (>90%) that there would

be little room left for the solvents to show their effectiveness by improving the performance. The packing procedure and the measurement of absolute permeability by flowing deionized water through the sand-pack and measuring the pressure drop across its length were described in detail in section 3.3.1 earlier.

4.1.3 Testing Heating Tapes

Heating tapes were tested for the optimum setting of the Variacs to obtain the desired temperature in heat traced flow lines.

4.1.4 Steam Generator Test

An inline steam generator was used to inject steam in these experiments. The steam generator was tested for around 4-5 hours to verify its capacity to generate superheated steam at the desired flow rate. The steam was continuously passed through the BPR set at the test pressure and the superheated nature of the steam was confirmed by the temperature of the steam coming out of the steam generator.

4.1.5 Solvent Mixture Preparation

The solvent preparation method was described in Section 3.2.2.3. Each prepared solvent was tested by compressing it to a high pressure to make sure that the transfer vessel contains the solvent in 100% liquid phase.

4.1.6 Base Case Experiment (SAGD)

The base case experiment was a test in which only steam was injected into the sand pack model. It serves as the baseline for relating or assessing the performance of solvent co-

injection SA-SAGD experiments. The following Table 4.1 shows the main characteristics of the sand pack and the flow rate used during this experiment.

Table 4.1: Properties of the sand pack, Solvent, and Flowrate used in the base case SAGD test.

	Experiment Base Case SA-SAGD
Properties	
Mass of sand (g)	278.5
Volume of sand (cm^3)	105.1
Length of the sand pack (cm)	31.60
Pore volume (cm^3)	54.92
Porosity (%)	36.40
Permeability (D)	365.4
Solvent composition	None
Steam flow rate (cm^3/min)	2.0
Solvent flow rate (cm^3/min)	Zero

As mentioned before, the lower section of the sand pack model was pre-heated to 80 °C prior to the start of the experiment. As the experiment proceeded the temperature inside the sand pack also started to increase. During the experiment, the temperature profile was constantly monitored, and the recorded temperature profiles are shown in Figure 4.1 below.
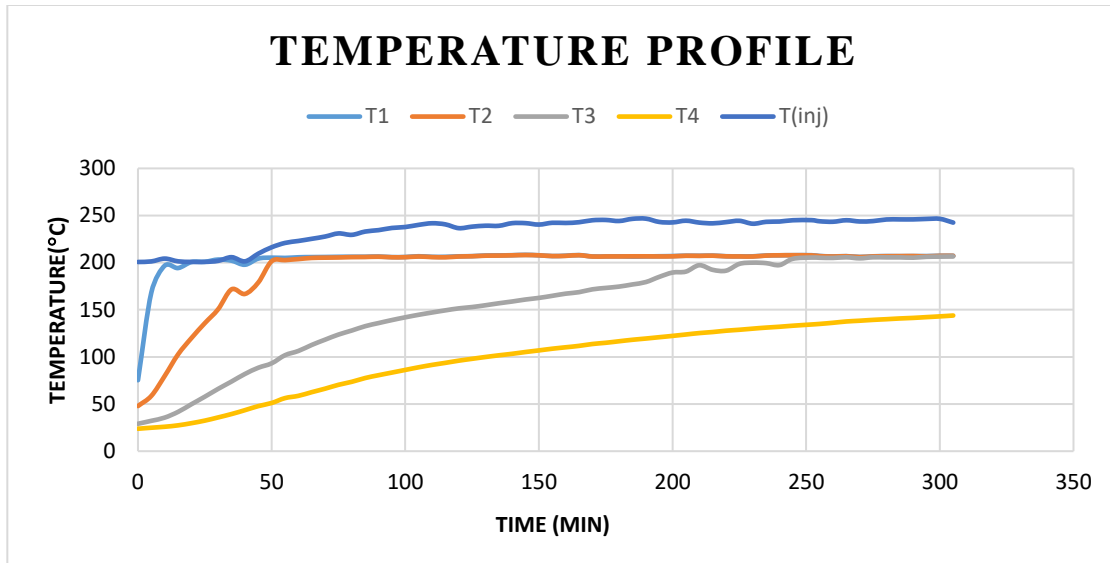
Figure 4.1: Temperature profiles for the first test (BASE CASE)

Figure 4.1 shows the temperature profile for the steam-only case i.e., the SAGD experiment. T1 represents the temperature of zone 1 (between the injection and production points), which was preheated to around 80 °C. It can be seen that, within a few minutes, the temperature increased to 200 °C, which was the saturated steam temperature at the operating pressure. Later, the second zone also reached 200 °C around 50 minutes after the start of the experiment. The third and fourth zone can also be seen to display increasing temperatures, but the third zone took 250 minutes to reach that point, while the fourth zone only reached the temperature of around 100 °C after five hours of steaming.

The produced fluid analysis showed high-rate production in the initial samples, but the production rate became lower in later samples, as shown in figure 4.2. The first sample (at one hour after the start) produced the highest amount of bitumen, which was more than 9 g out of 31.2 g of total production.
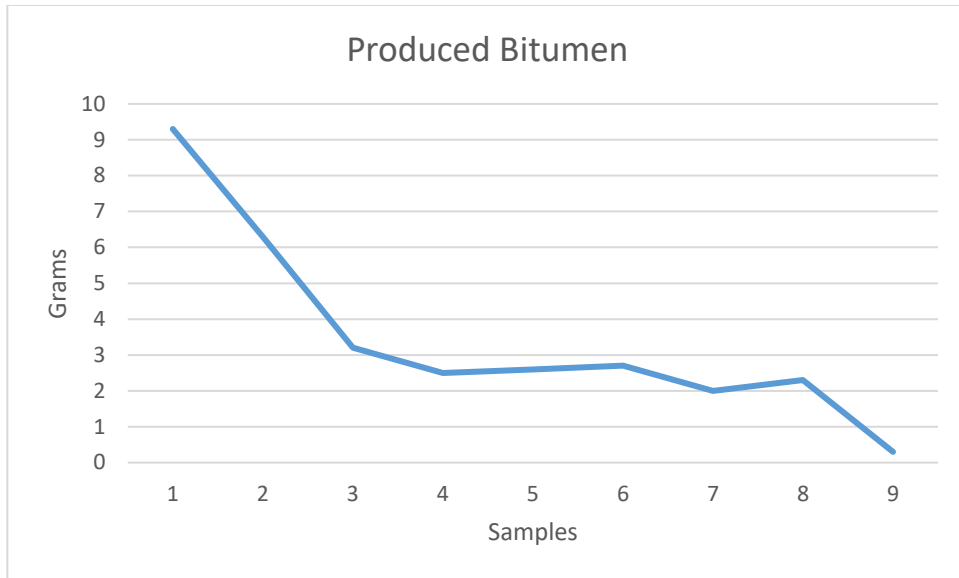
70

Figure 4.2: Bitumen produced in each fluid sample in test #1

Figure 4.3 shows the cumulative oil produced during this experiment. The total oil production was 31.2 g, and the final recovery factor was around 63%.
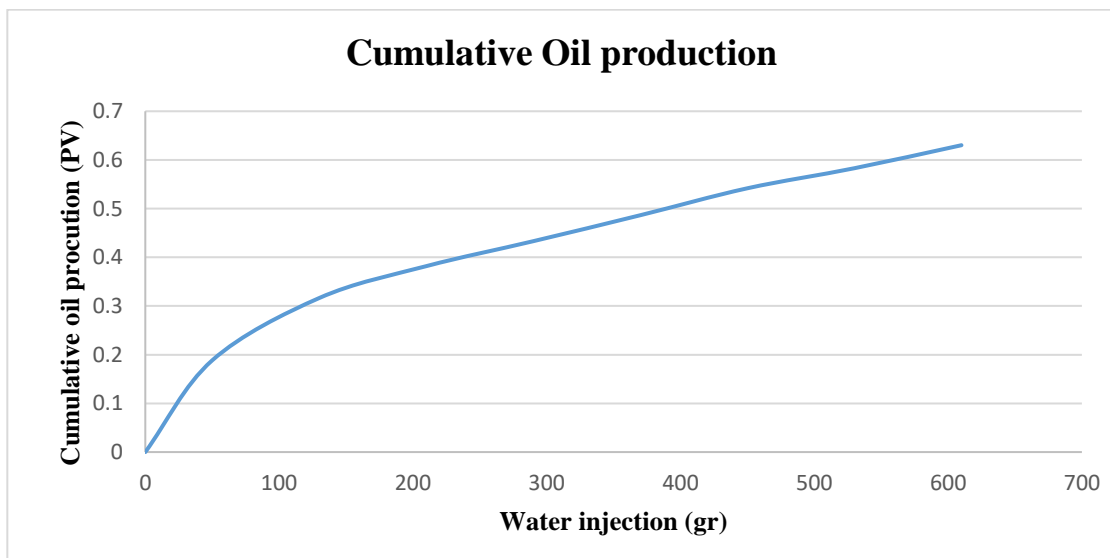

Figure 4.3: Cumulative bitumen production versus amount of water injected in test #1

Table 4.2: The Initial Oil in Place, cumulative bitumen produced, final recovery, and final water cut in the base case test.

Properties	Initial Oil in Place (mL)	Cum. produced bitumen (gr)	Final Recovery Factor (%)	Final water cut
SAGD	49.5	31.2	63	97.2

The water cut graph in figure 4.4 shows that initially the water produced in early samples was around 0.88 grams which was raised up in second and third sample and reached up to 0.96 grams in 3rd sample. The trend of water cut did not fluctuate more than 0.3 grams starting from 3rd sample until the last sample.
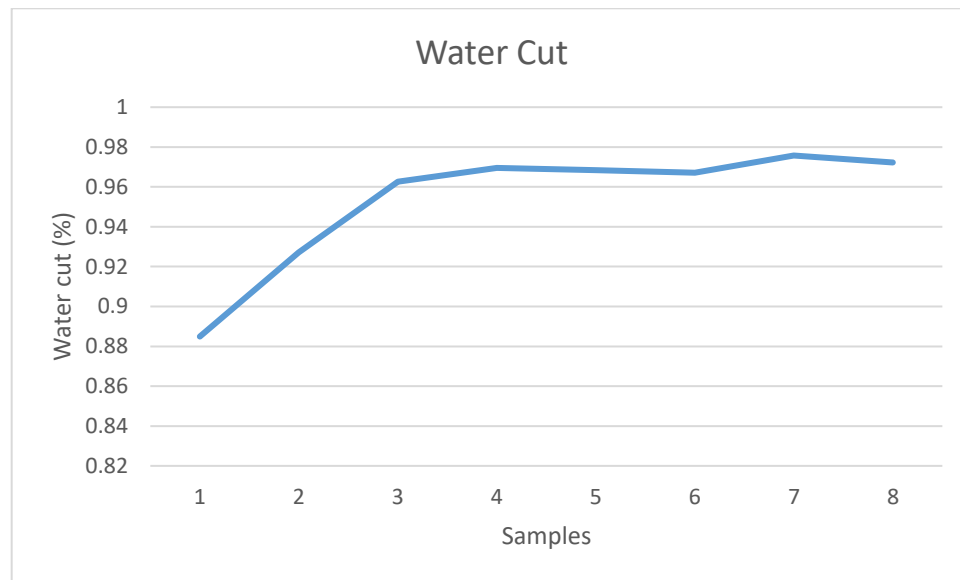
Figure 4.4 Water cut (SAGD)

4.1.7 SA-SAGD Test (C3 = 100%)

Following the SAGD test, a solvent was introduced in this experiment. For this test, the characteristics of the sand pack are shown in table 4.2. The solvent used was 99.99% propane. The total injection rate for this case was the same i.e., 2 cm^3/min but the steam injection was 1.7 cm^3/min, while the solvent was injected at a rate of 0.3 cm^3/min. Thus, the solvent injection rate was 15 vol% of the total injection rate.

Table 4.3: Properties of the sand pack, Solvent, and Flowrate used in the second test (SA-SAGD with 100% propane).

	Experiment SA-SAGD (C3=100%)
Properties	
Mass of sand (g)	283.6
Volume of sand (cm^3)	107
Length of the sand pack (cm)	31.0
Pore volume (cm^3)	55
Porosity (%)	35.79
Permeability (D)	388
Solvent composition	C3 (100%)
Steam flow rate (cm^3 /min)	1.7

Figure 4.5 shows the monitored temperature profiles for this test. Zone 1 reached 200 °C, Zone 3 and 4 recorded lower plateau temperatures in this case. Zone 2 reached approximately 160 °C, while Zone 3 reached only 112 °C. The lower plateau temperatures

were caused by the accumulation of the solvent vapor, which reduced the partial pressure of steam, and thereby the steam saturation temperature.
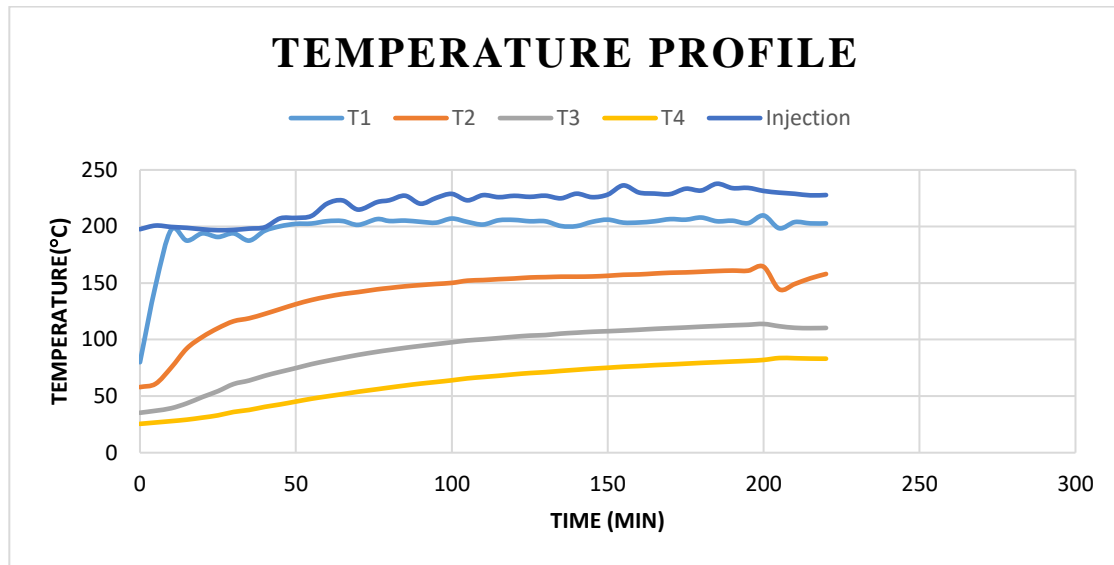

Figure 4.5: Temperature profiles for the second test (C3 = 100%)

As the experiment proceeded the bitumen production in each sample decreased. Figure 4.6 shows the mass of produced bitumen in each sample.
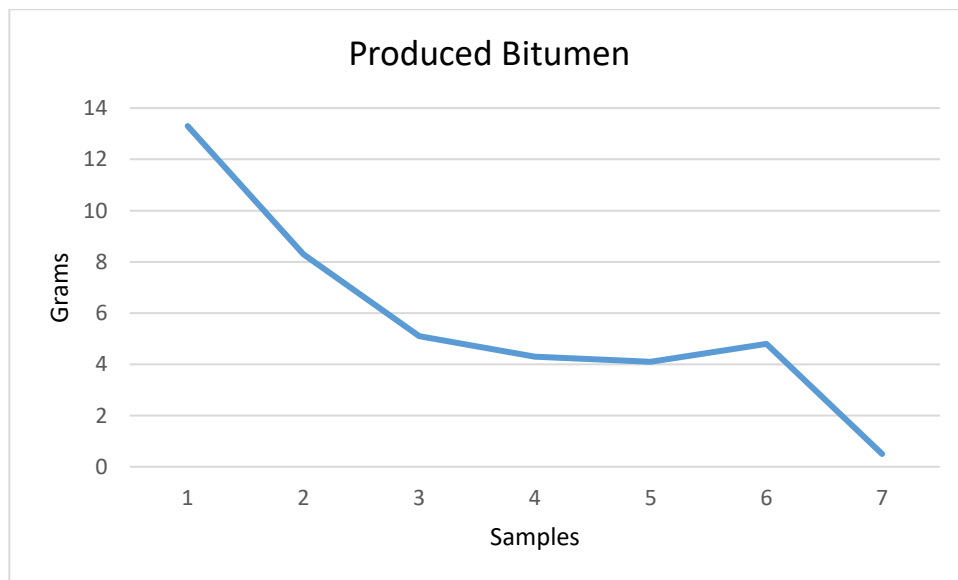

Figure 4.6: Bitumen produced in each fluid sample in test #2

The cumulative oil production obtained from this test is shown in the graph below (Figure 4.7) which shows the final recovery factor around 79%. The total oil production was 40.4 g. The trend of bitumen production in fig 4.6 shows an overall downward flow but in sample no. 6 the production raised it was due to temperature decreased after sample no. 5 was collected then again temperature was raised back to normal, so the time taken for this sample was a bit higher due to which this sample gave higher production than sample no. 5.
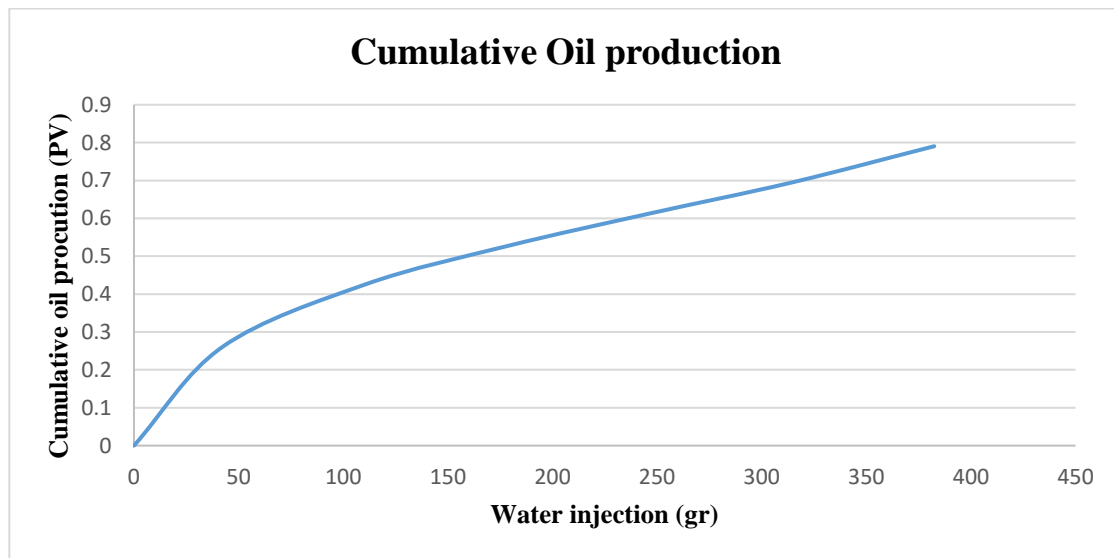

Figure 4.7: Cumulative bitumen production versus amount of water injected in test #2

Table 4.4: The Initial Oil in Place, cumulative bitumen produced, final recovery, and final water cut in the second test.

Properties	Initial Oil in Place (mL)	Cum. produced bitumen (gr)	Final Recovery Factor (%)	Final water cut
SA-SAGD (100%C3)	51.1	40.4	79	93.5

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The water cut graph in figure 4.8 shows that initially the water produced in early samples was around 0.84 grams when solvent was introduced, which was raised up in second and third sample and reached up to 0.925 grams in 3rd sample. The trend of water cut did not fluctuate more than 0.3 grams starting from 3rd sample until the last sample. The addition of solvent proved to lower down the water cut in this experiment.
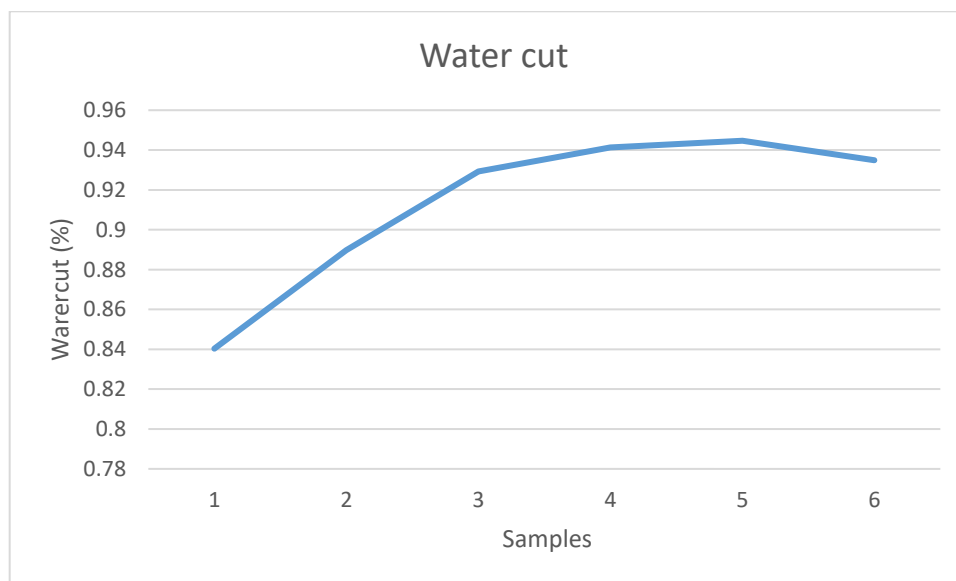

Figure 4.8 Water cut (SA-SAGD, C3=100%)

4.1.8 SA-SAGD Test (C4 = 100%)

For this test, the solvent used was 99.99% Butane and the characteristics of the sand pack are shown in table 4.5. The injection rate for this case was the same i.e., 2 cm^3/min total rate with 1.7 cm^3/min steam and 0.3 cm^3/min solvent.

Table 4.5: Properties of the sand pack, Solvent, and Flowrate used in the third test (SA-SAGD with pure butane).

	Experiment SA-SAGD (C4=100%)
Properties	
Mass of sand (gr)	278.6
Volume of sand (cm^3)	105.1
Length of sand pack (cm)	31.45
Pore volume (cm^3)	55.3
Porosity (%)	36.37
Permeability (D)	278.6
Solvent composition	C4 (100%)
Steam flow rate (cm^3 /min)	1.7
Solvent flow rate (cm^3 /min)	0.30

The monitored temperature profiles for this experiment show that the steam at Zone 1 reached 200 °C around 45 minutes after the experiment was started. Zone 2 was close to 200 °C at some point while Zones 3 and 4 were lower but almost steady in later stages. Figures 4.9: illustrates the temperature profile for this case.
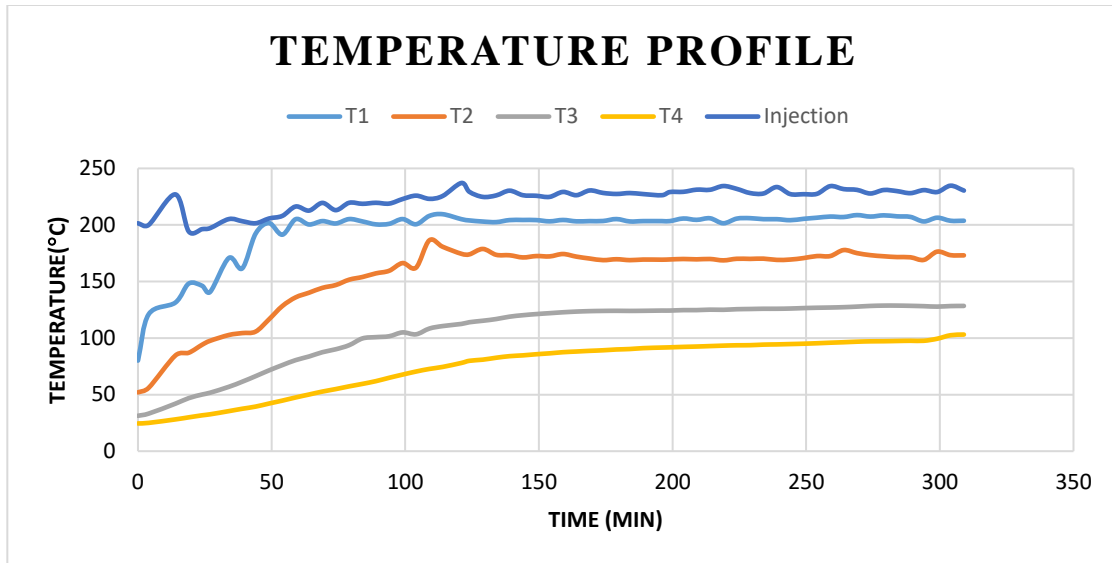
Figure 4.9: Temperature Profiles for the third test (C4 = 100%)

Bitumen produced in each sample is shown below (Figure 4.10). In this experiment, it was found that sample 2 had the highest amount, around 15 grams, which was due to the reason that the temperature in zone 1 reached 200 °C a bit late. Figure 4.10 shows the bitumen production where the 2nd sample was raised higher due to raise in temperature at this time of experiment, this rise indicates that higher temperature can increase the bitumen production but in order to make stable chamber temperature needed to be controlled.
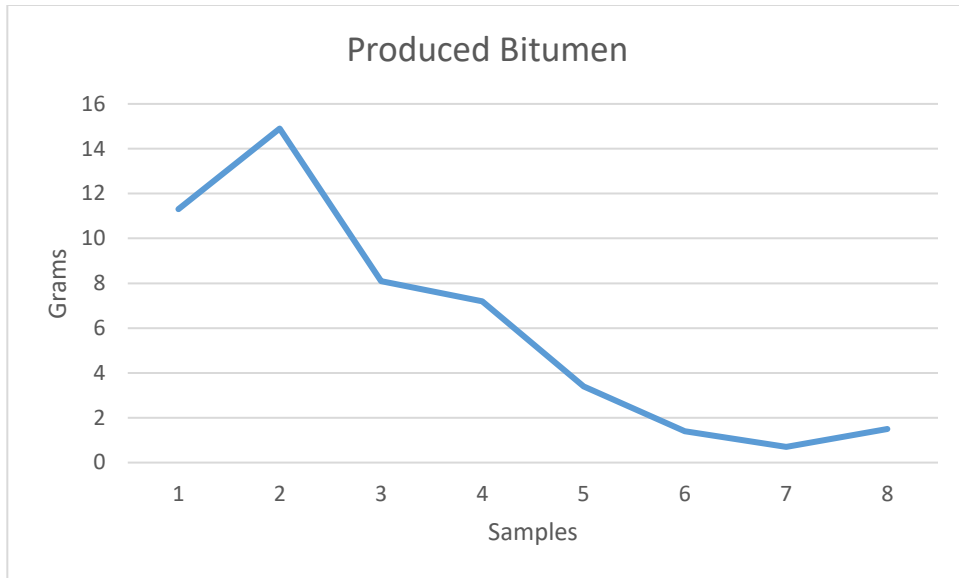
Figure 4.10: Bitumen produced in each fluid sample in test #3

The cumulative oil produced in this experiment is shown in Figure 4.11, which was 48.9 grams and makes the final recovery factor to be around 92.9%.
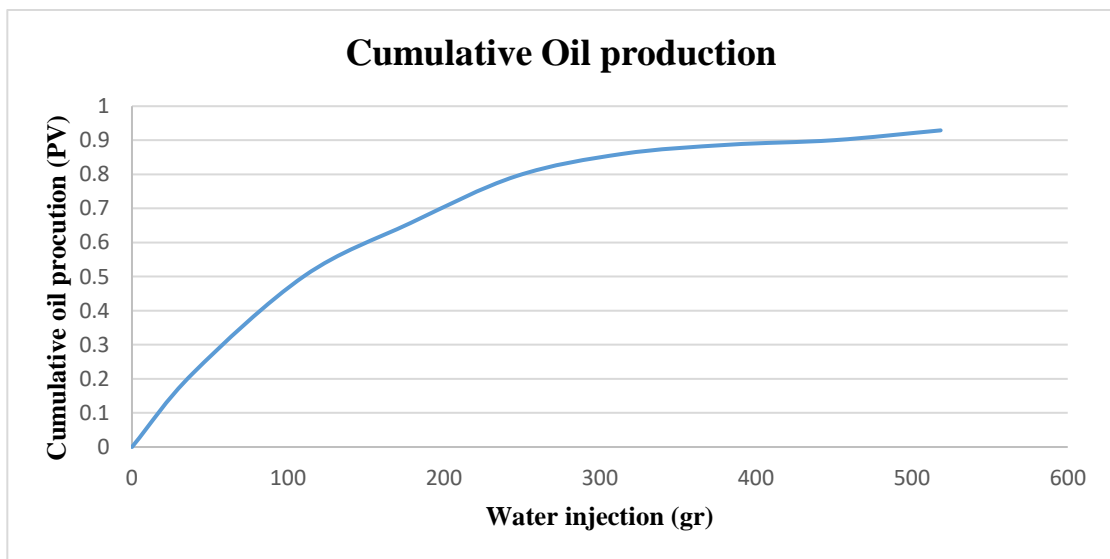

Figure 4.11: Cumulative bitumen production versus amount of water injected in test #3

Table 4.6: The Initial Oil in Place, cumulative bitumen produced, final recovery, and final water cut in the third test.

Properties	Initial Oil In Place (mL)	Cum. produced bitumen (gr)	Final Recovery Factor (%)	Final water cut
SA-SAGD (100%C4)	52.2	48.5	92.9	97.9

The water cut graph in figure 4.12 shows that initially the water produced in first sample was around 0.75 grams when butane solvent was introduced, which was raised up in later samples and reached up to 0.97 grams. The trend of water cut raised almost in upward direction as shown in the figure until the last sample. This trend initially gave less water cut but raised in the last samples.
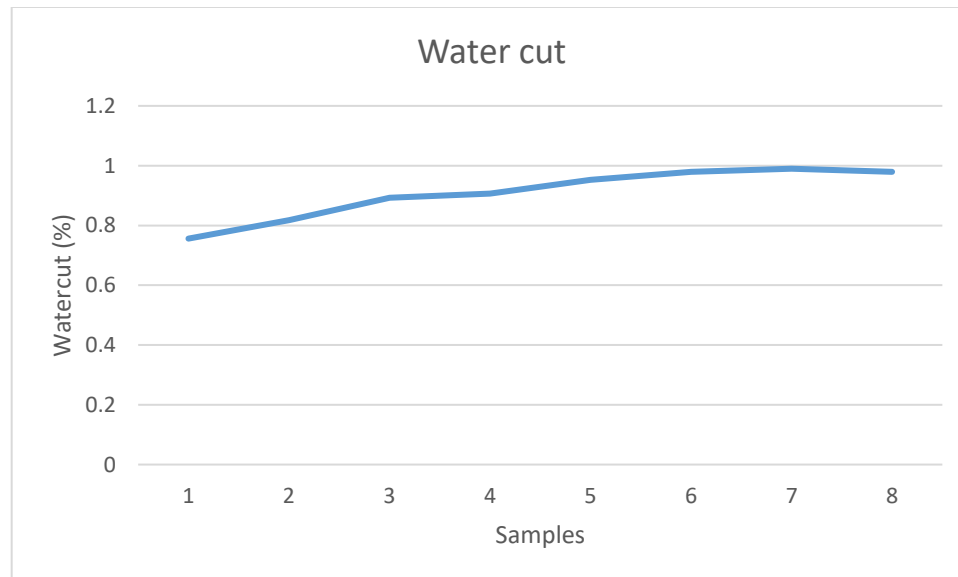

Figure 4.12 Water cut (SA-SAGD, C4=100%)

4.1.9 SA-SAGD Test (C3 ≅ 20% and C4 ≅ 80%)

For this test, the characteristics of the sand pack are shown in Table 4.7. The solvent used was 20%C3 and 80%C4. The injection rate for this case was the same i.e., 2 cm^3/min total with a steam injection rate of 1.7 cm^3/min and solvent rate of 0.3 cm^3/min.

Table 4.7: Properties of the sand pack, Solvent, and Flowrate used in the fourth test (SA-SAGD with 20% C3 and 80% C4).

	Experiment SA-SAGD (C3 ≈ 20% and C4 ≈ 80%)
Properties	
Mass of sand (g)	285.3
Volume of sand (cm^3)	107.7
Length of sand pack (cm)	30.88
Pore volume (cm^3)	56.20
Porosity (%)	36.60
Permeability (D)	382.7
Solvent composition	C3 ≈ 20% and C4 ≈ 80%
Steam flow rate (cm^3 /min)	1.7

The temperature profile record shows that Zone 1 reached 200 °C faster in this experiment. Zone 2 was close to 175 °C while Zones 3 and 4 were lower but steady in the later stages of the experiment. The temperature profile when matched with sample shows that bitumen production with almost stable temperature went down, while the 7th sample raised due to smaller degree of temperature jump int the profile.

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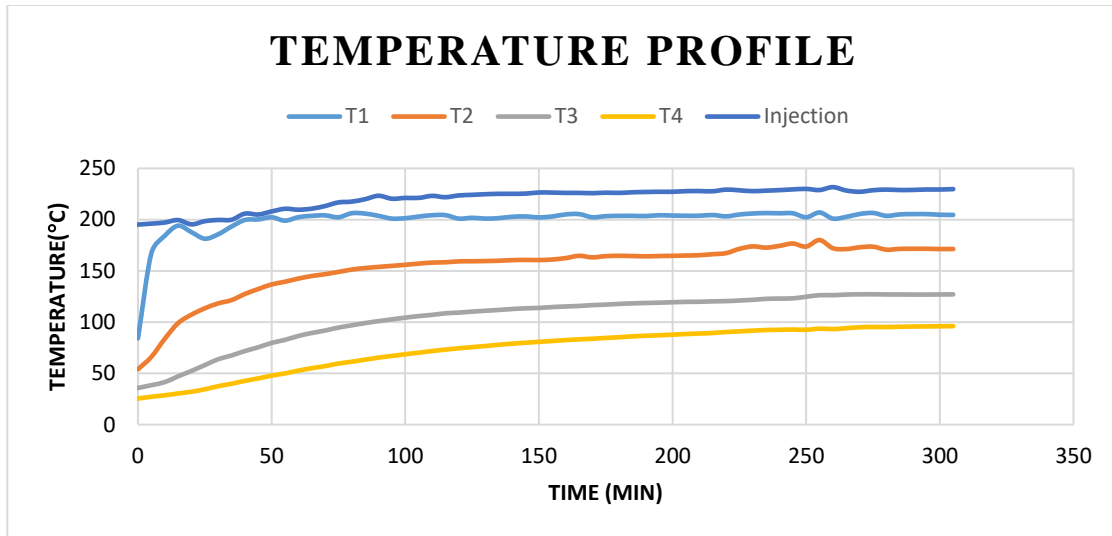
Figure 4.13: Temperature Profile (C3 $\cong$ 20% and C4 $\cong$ 80%)

Figure 4.14 shows the mass of produced bitumen in each sample. In this graph, the first sample shows the highest production while subsequent samples show progressively lower amounts. Sample 7 showed a bit of the spike, causing the other two samples to be even lower.

Figure 4.14: Bitumen produced in each fluid sample in test #4

Cumulative oil produced in this case was highest compared to all previous experiments. 52 grams of oil was produced in this case, making the final recovery factor to be 99%. Based

on temperature profile, bitumen production and final water cut this set of experiment gave the better results than all the above experiments.
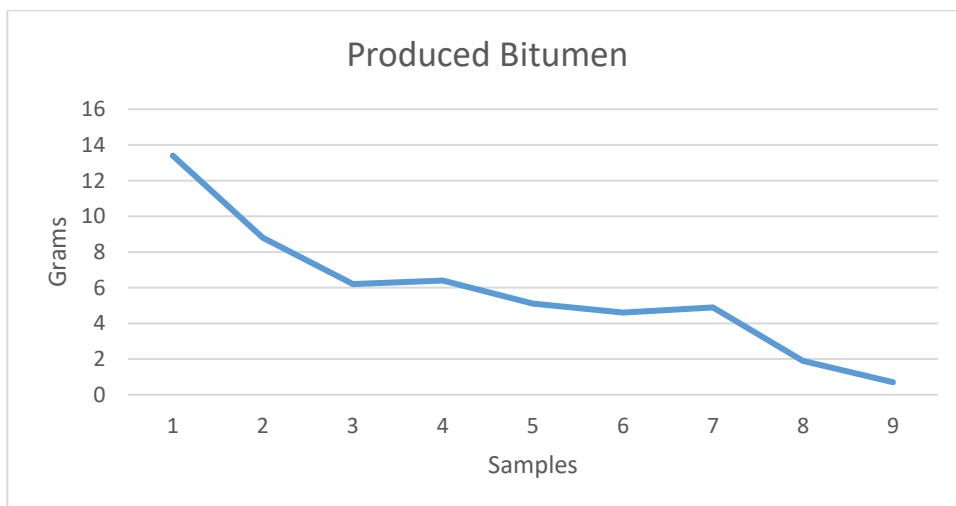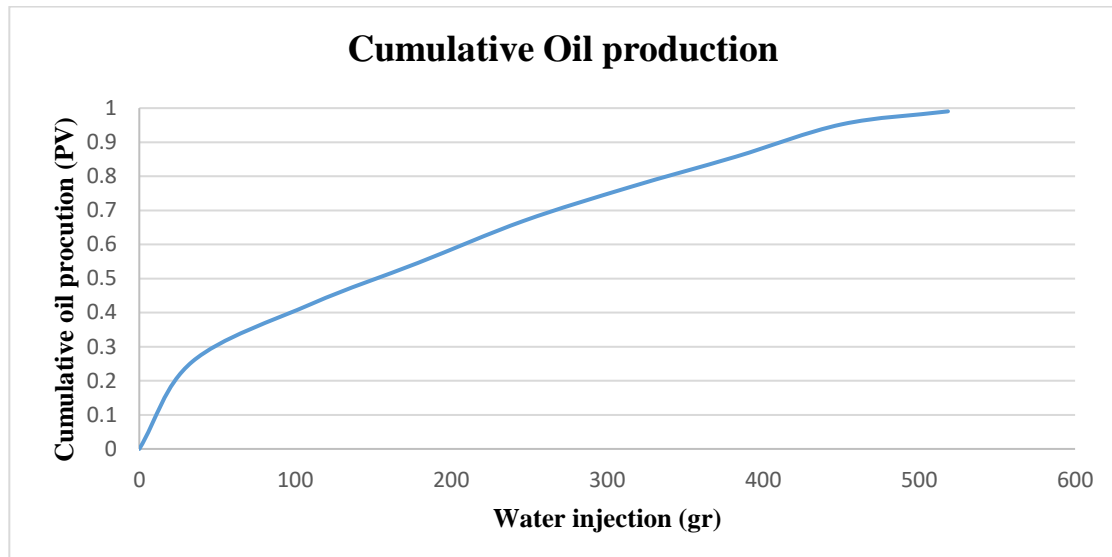

Figure 4.15: Cumulative bitumen production versus amount of water injected in test #4

Table 4.8: The Initial Oil in Place, cumulative bitumen produced, final recovery, and final water cut in the fourth test.

Properties	Initial Oil in Place (mL)	Cum. produced bitumen (gr)	Final Recovery Factor (%)	Final water cut
SA-SAGD (20%C3-80%C4)	52.5	52	99	97.2

The water cut graph in figure 4.16 shows that initially the water produced in first sample was around 0.79 grams when butane and propane solvent mixture was introduced, which was raised up in later samples and reached around 0.93 grams in almost every sample. Last

sample shown the highest of 0.97 grams of water cut. But the trend and average water cut

was lower than the last experiments where only butane and only propane were used in the

experiments.

Figure 4.16 Water cut (SA-SAGD, C3=20%, C4=80%)
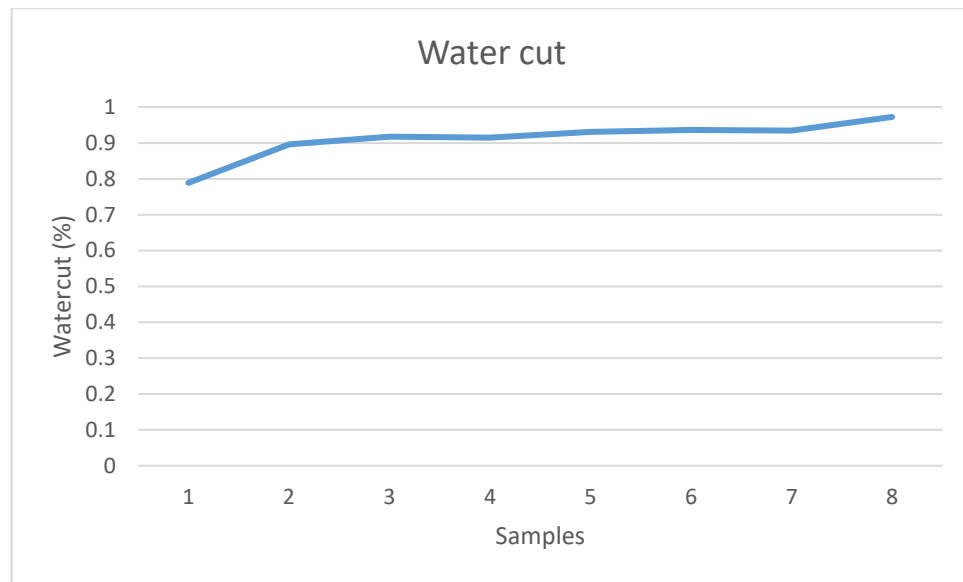
4.1.10 SA-SAGD Test (C3 ≅ 80% and C4 ≅ 20%)

For this test, the characteristics of the sand pack are shown in Table 4.9. The solvent used was 80% C3 and 20% C4. The injection rate for this case was the same i.e., 2 cm3/min total with 1.7 cm3/min of steam and 0.3 cm3/min of solvent. The solvent injection was again 15% of the total injection.

Table 4.9: Properties of the sand pack, Solvent, and Flowrate used in the fifth test (SA-SAGD with 80% C3 and 20% C4).

	Experiment SA-SAGD (C3 ≈ 80% and C4 ≈ 20%)
Properties	
Mass of sand (g)	284.1
Volume of sand (cm^3)	107.2
Length of sand pack (cm)	30.98
Pore volume (cm^3)	56.2
Porosity (%)	36.18
Permeability (D)	334.4
Solvent composition	C3 ≈ 80% and C4 ≈ 20%
Steam flow rate (cm^3 /min)	1.7

In this experiment, the temperature profiles were as expected, and the first zone reached 200 °C in 50 minutes. Beyond this point, the remaining zones show increasing temperatures and all zones reached steady temperatures.
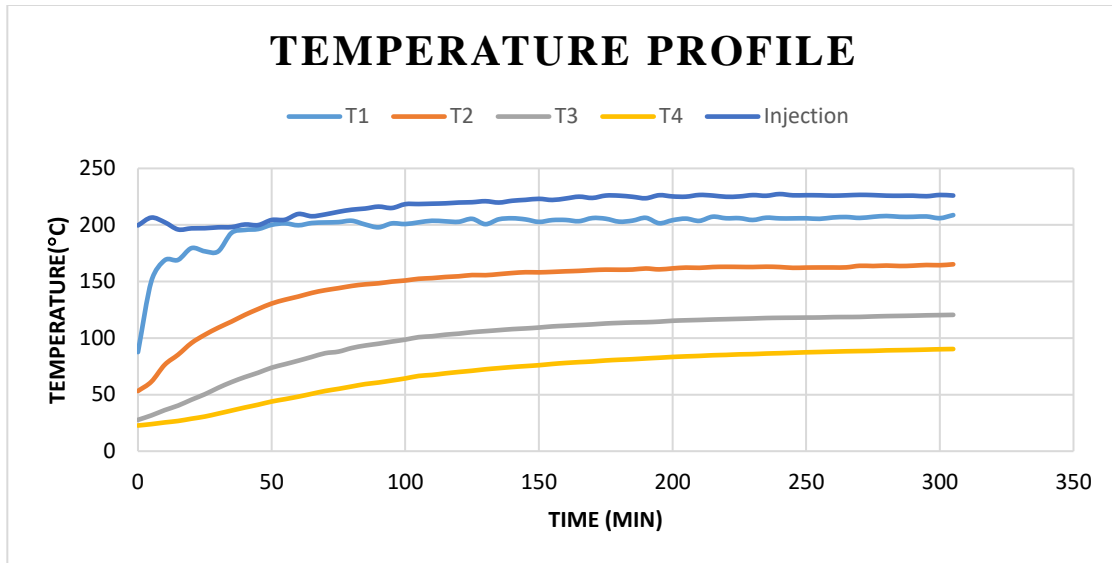
Figure 4.17: Temperature profiles in the fifth test (C3 ≅ 80% and C4 ≅ 20%)

The oil produced shows the trend of declining production from the first sample onwards.

The last sample was mostly water in this test. The comparison of the two figure i.e., figure

4.17 and 4.18 of temperature profile and bitumen produced respectively, can be seen as the

early samples were in large amount but went lower later sample 5 and 7 were almost of

same amount but the drop down of sample 6 was due to water injection was increased by

the system and increasing the water cut in this sample.
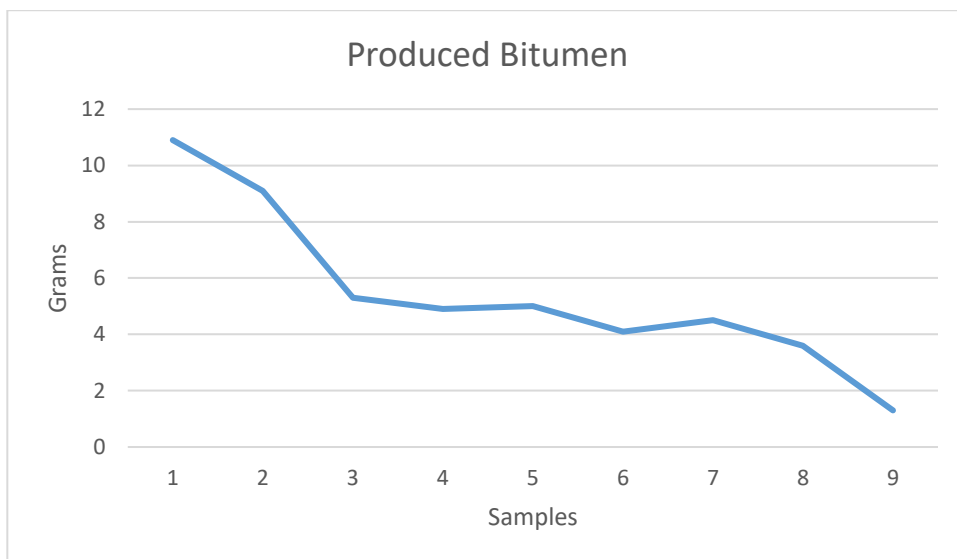
Figure 4.18: Bitumen produced in each fluid sample in test #5

Cumulative oil produced is illustrated in the following graph and the final oil recovery in this case reached 95%.
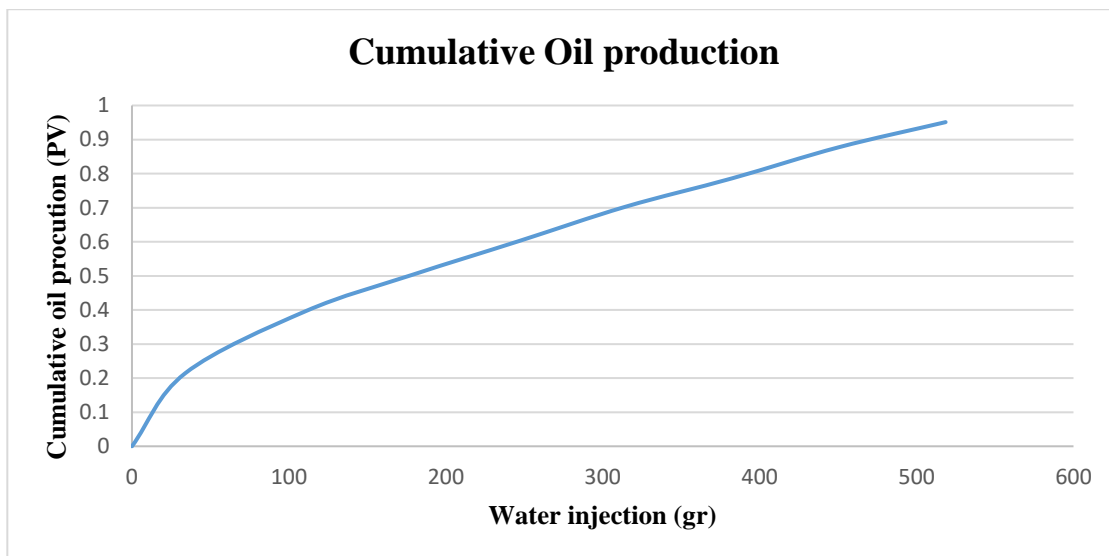
Figure 4.19: Cumulative bitumen production versus amount of water injected in test #5

Table 4.10: The Initial Oil in Place, cumulative bitumen produced, final recovery, and final water cut in the fifth test.

Properties	Initial Oil in Place (mL)	Cum. produced bitumen (gr)	Final Recovery Factor (%)	Final water cut
SA-SAGD (80%C3-20%C4)	51.2	48.7	95	94.7

The water cut graph in figure 4.20 shows that initially the water produced in first sample was around 0.79 grams when butane and propane solvent mixture was reverted to that of

last mentioned experiment and in this experiment instead of 20% propane, 80% of propane was introduced and similarly butane concentration of 20% used. Water cut raised up in later samples and reached around 0.93 grams in almost every sample. Last sample shown the highest of 0.94 grams of water cut. But the trend and average water cut was lower than the last experiments when opposite concentration used.
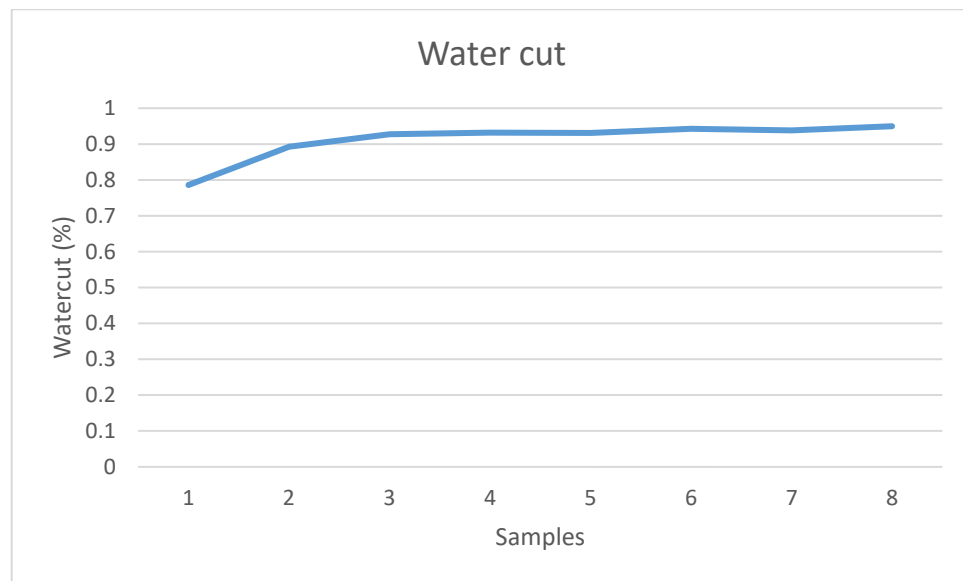
Figure 4.20 Water cut (SA-SAGD, C3=80%, C4=20%)

4.1.11 SA-SAGD Test (C3 ≅ 40% and C4 ≅ 60%)

For this test, the characteristics of the sand pack are shown in Table 4.11. and the solvent used was 40%C3-60%C4. The total injection rate for this case was the same, i.e., 2 cm^3/min, with steam at a rate of 1.7 cm^3/min and solvent at a rate of 0.3 cm^3/min.

Table 4.11: Properties of the sand pack, Solvent, and Flowrate used in the sixth test (SA-SAGD, with 40%C3 and 60% C4).

	Experiment SA-SAGD (C3 ≈ 40% and C4 ≈ 60%)
Properties	
Mass of sand (g)	279.6
Volume of sand (cm^3)	105.5
Length of sand pack (cm)	31.45
Pore volume (cm^3)	55
Porosity (%)	36.32
Permeability (D)	303.8
Solvent composition	C3 ≈ 40% and C4 ≈ 60%
Steam flow rate (cm^3 /min)	1.7
Solvent flow rate (cm^3 /min)	0.30

Figure 4.21 shows the temperature profiles with time. Zone 1 reached 200 °C in less than 50 minutes while Zone 4 stayed below 100 °C to the end of the test. The small degree of fluctuations in the temperature caused smaller magnitude of fluctuation in the production in each sample.
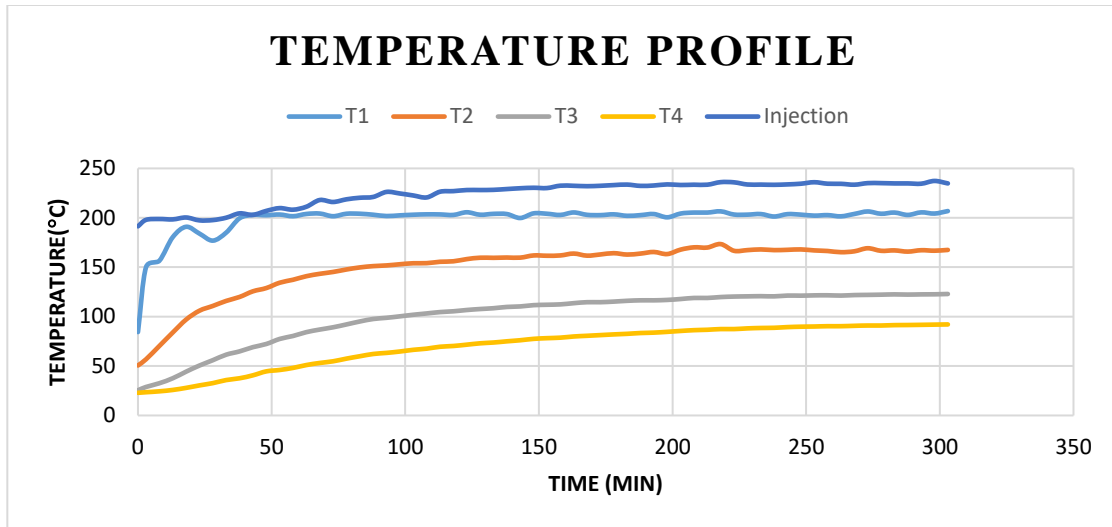
Figure 4.21: Temperature Profile (C3 $\cong$ 40% and C4 $\cong$ 60%)

Produced fluid samples showed the same trend as in other experiments. The first sample contained the highest amount of oil, and the trend went down with each sample while the experiment proceeded. Comparing figure 4.21 and 4.22 the production in each of the sample lowered down and almost trend as mentioned dropped down, small fluctuation in sample 5 shown was due to little raise in the temperature at that time.
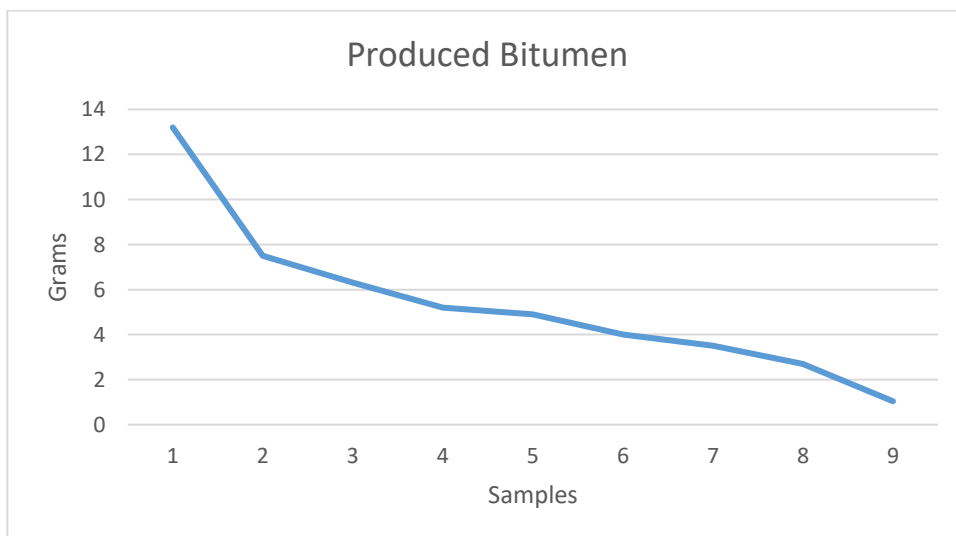
Figure 4.22: Bitumen produced in each fluid sample in test #6

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Cumulative oil produced reached 48.3 grams leading to a final recovery of 94% in this case. Figure 4.23 shows the cumulative oil produced with water injection.
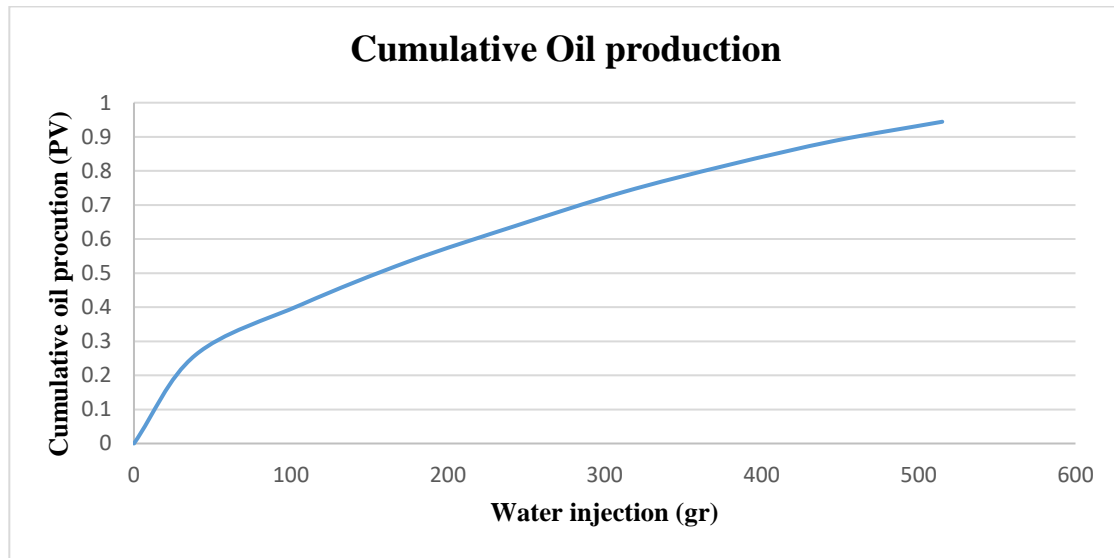
Figure 4.23: Cumulative bitumen production versus amount of water injected in test #6

Table 4.12: The Initial Oil in Place, cumulative bitumen produced, final recovery, and final water cut.

Properties	Initial Oil in Place (mL)	Cum. produced bitumen (gr)	Final Recovery Factor (%)	Final water cut
SA-SAGD (40%C3-60%C4)	51.2	48.3	94	96.3

The water cut graph in figure 4.24 shows that initially the water produced in first sample was around 0.79 grams when butane and propane solvent mixture used in different concentration for this set of experiment. The concentration in this experiment was 40%

propane, and 80% butane used. Water cut raised up in later samples and reached around

0.96 grams in the last sample. But the trend and average water cut was almost the same,

but the total water cut was little higher than last two experiments.
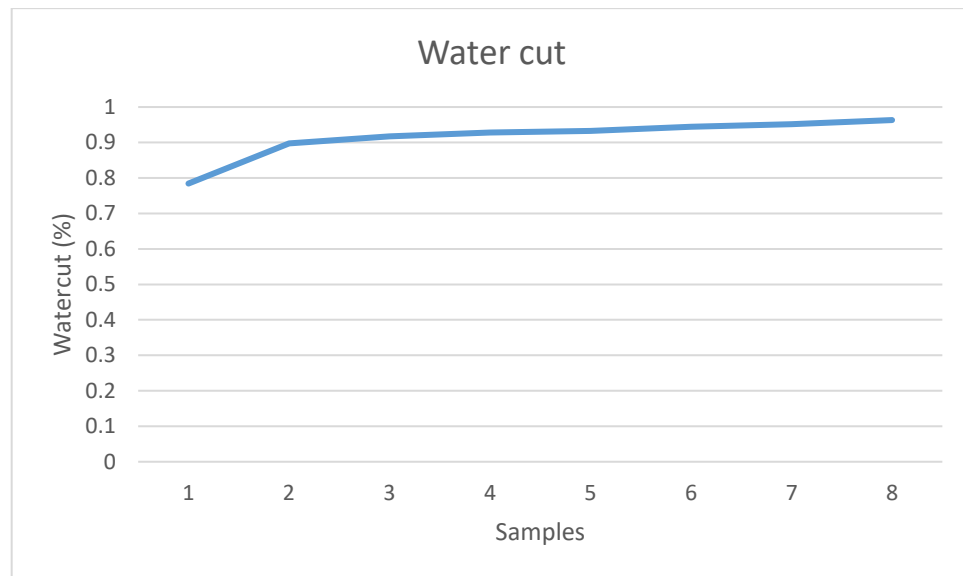
Figure 4.24 Water cut (SA-SAGD, C3=40%, C4=60%)

4.1.12 SA-SAGD Test (C3 ≅ 60% and C4 ≅ 40%)

For this test, the characteristics of the sand pack are shown in table 4.2 and the solvent used was 60%C3-40%C4. The total injection rate for this case was the same i.e., 2 cm^3/min, but the steam injection rate was 1.7 cm3/min, the rest being the solvent. Thus, the solvent was 15% of the total injection in this experiment also.

Table 4.13: Properties of the sand pack (SA-SAGD), Solvent, and Flowrate.

	Experiment SA-SAGD (C3 ≈ 60% and C4 ≈ 40%)
Properties	
Mass of sand (g)	281.30
Volume of sand (cm^3)	106.5
Length of sand pack (cm)	31.45
Pore volume (cm^3)	56.9
Porosity (%)	37.16
Permeability (D)	462.7
Solvent composition	C3 ≈ 60% and C4 ≈ 40%
Steam flow rate (cm^3/min)	1.7
Solvent flow rate (cm^3/min)	0.3

Temperature profiles of this experiment are shown in Figure 4.25 and show that the temperatures in all zones became steady by the time the test ended. Zone 1 reached 200 °C in less than 50 minutes while zone 4 remained below 100 °C up to the end of the test. Zone 2 and 3 reached around 170 °C and 130 °C respectively.
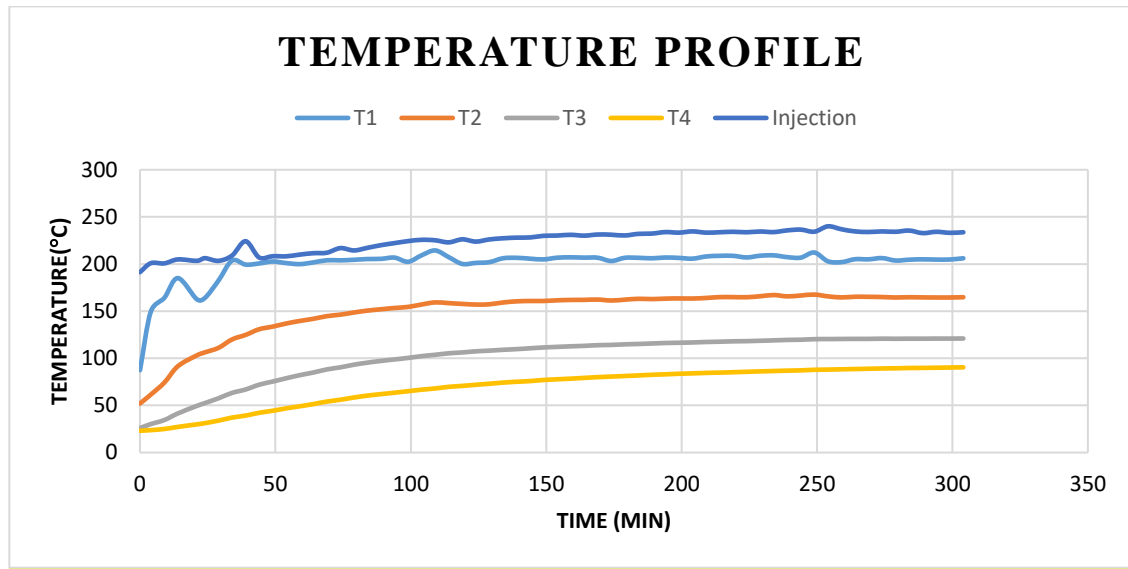
Figure 4.25: Temperature Profile (C3 ≅ 60% and C4 ≅ 40%)

The mass of oil in each produced fluid sample is shown in Figure 4.26. The first sample produced more than 13 grams of oil. The trend of oil produced in subsequent samples was like other tests. The comparison of the temperature profile and that of bitumen production in figure 4.25 and figure 4.26 shows that bitumen production shown depletion trend but the quick drop in sample 2 was due to temperature drop at that time in zone 1. Later sample shown better results comparing to that of temperature profile.
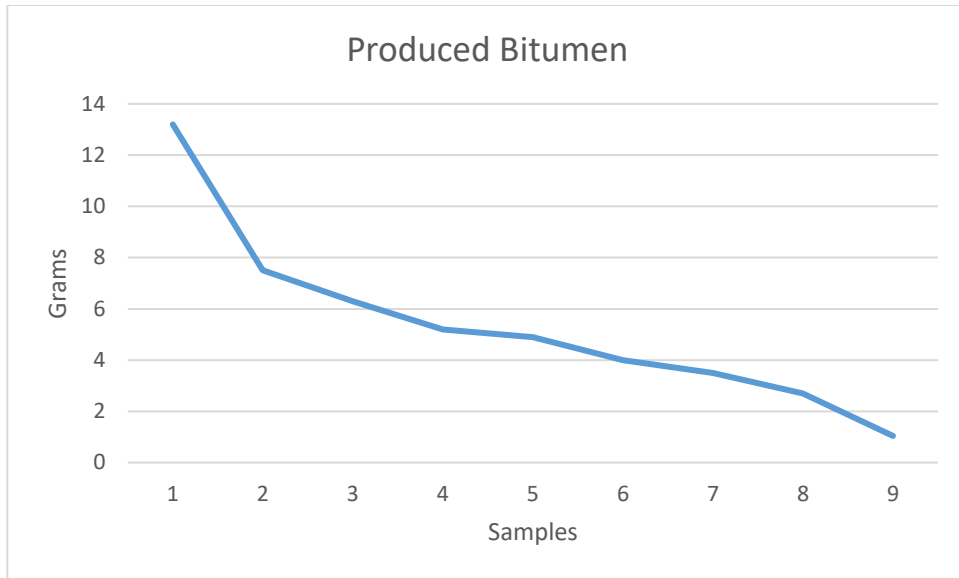
Figure 4.26: Bitumen produced in each fluid sample in test #7

Cumulative oil production in this experiment is shown in Figure 4.27. It reached 45.9 grams at the end, making a final recovery factor of 88.5 %.
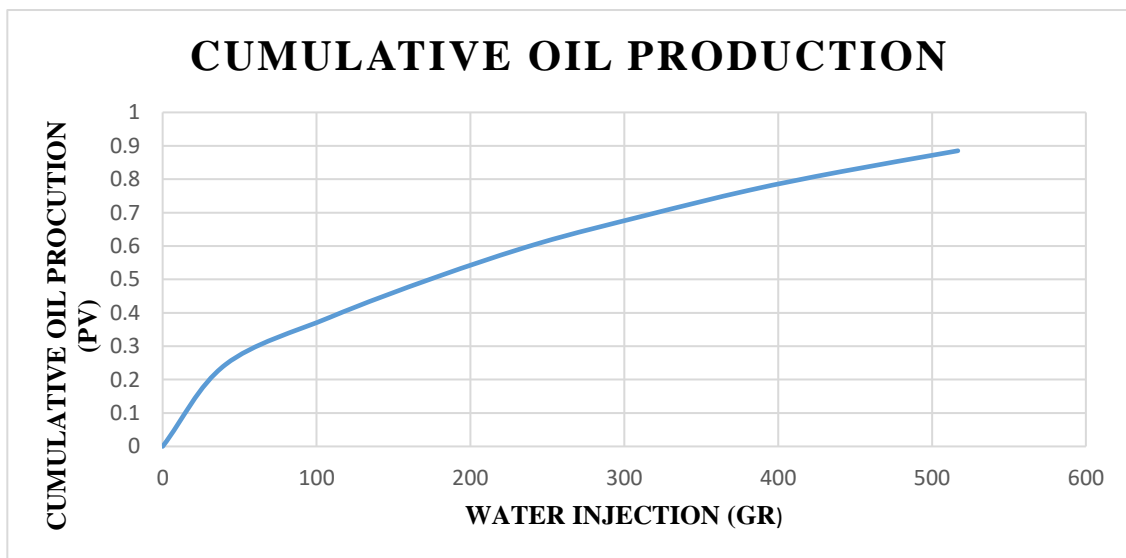
Figure 4.27: Cumulative bitumen production versus amount of water injected in test #7

Table 4.14: The Initial Oil in Place, cumulative bitumen produced, final recovery, and final water cut.

Properties	Initial Oil in Place (mL)	Cum. produced bitumen (gr)	Final Recovery Factor (%)	Final water cut
SA-SAGD (80%C3-20%C4)	51.8	45.9	88.5	95.9

The water cut graph in figure 4.28 shows that initially the water produced in first sample was around 0.75 grams when butane and propane solvent mixture used in opposite to that of the last experiment. The concentration in this experiment was 60% propane, and 40% butane used. Water cut raised up in later samples and reached around 0.94 grams in most of the samples and reached to 0.95 grams in the last sample. But the trend and average water cut was almost the same, the final water cut was lower than last experiment but still not good enough than that of C3=20%, C4=80%.
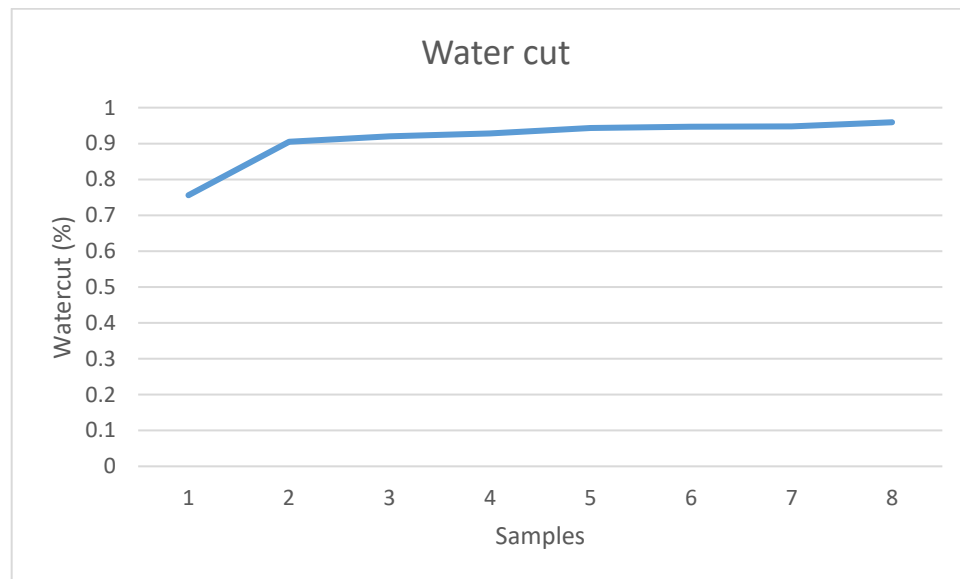
Figure 4.28 Water cut (SA-SAGD, C3=60%, C4=40%)

4.2 Test Comparisons and Summary

This study aimed to investigate the effect of solvent composition on the performance of the SA-SAGD experiment, including oil recovery, temperature profile, and production rate. A linear sand-pack model packed with silica sand, Athabasca bitumen, deionized water, pure butane, and propane were used in this study. Four different compositions of the propane/butane mixtures were employed to evaluate the effect of the mixture composition.
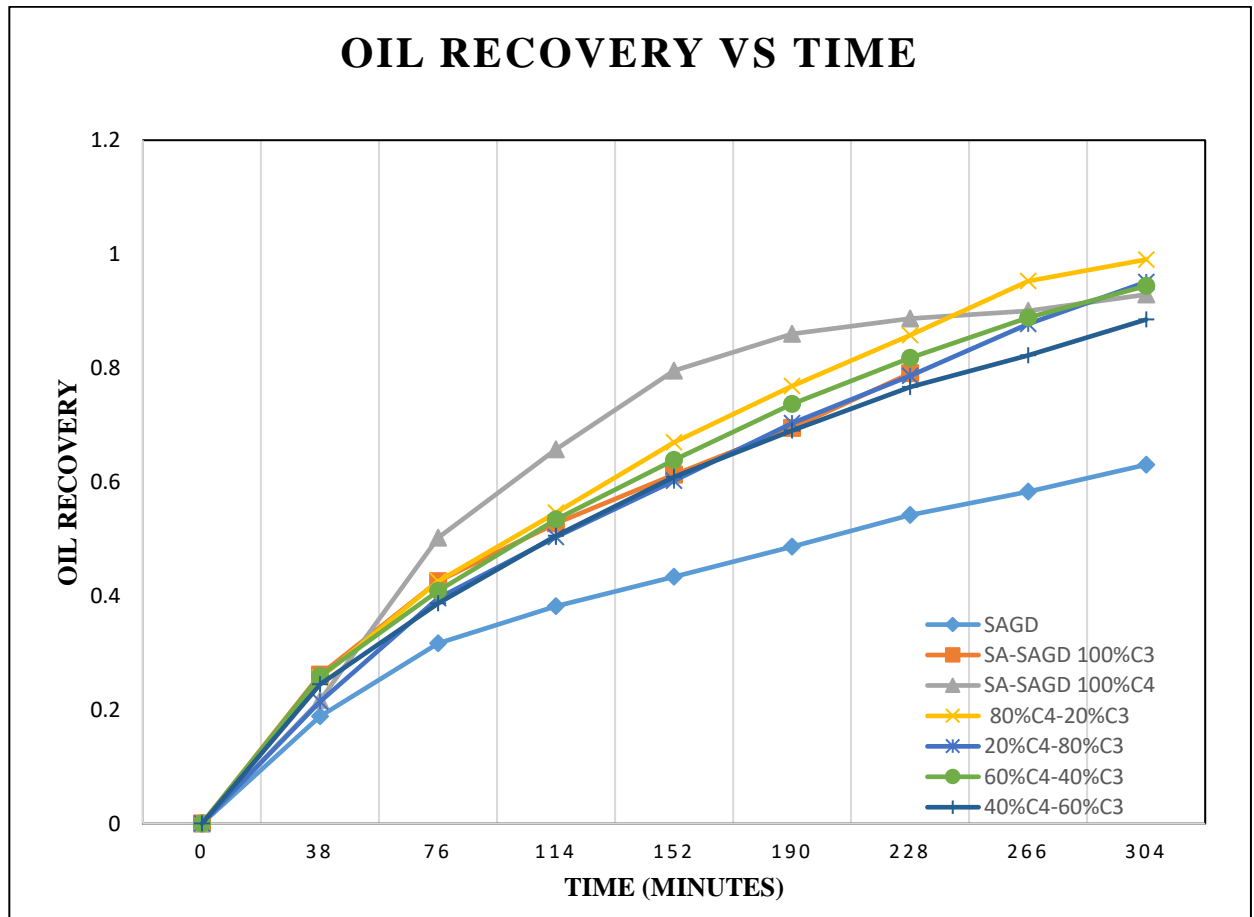
Figure 4.29: Comparison of Oil Recovery with Time in All Tests

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All experiments were conducted under the same operational condition in which the outlet pressure was 200 psi. The temperature of the steam chamber was higher in the base-SAGD experiment in which the temperature of three zones reached the temperature of injected fluid. The steam chamber temperature was lower when the steam was co-injected with pure propane. When butane was employed besides the steam, the temperature of the chamber was 21 ºC higher than the propane case. This observation was attributed to the partial pressure of steam in the gaseous phase which affected the rate of condensation. There was a significant improvement in the performance of the SAGD experiment when a light hydrocarbon solvent was introduced to the system, regardless of the type of hydrocarbon. However, adding butane to steam can increase the oil recovery more effectively compared with propane. The steam-to-oil ratio for all experiments, including SAGD or SA-SAGD, was very high at the end of the experiment, where it hit 20 gr/gr. The higher value of SOR in the current study compared with the typical value of SOR in the field is attributed to the large heat loss from the sidewall of the sand-pack holder and the absence of room for lateral expansion of the steam chamber. The SOR was 40% lower for the SA-SAGD experiment using 80%C4-20%C3 mixture compared with the SAGD experiment It shows how adding a solvent can improve the SAGD performance. The butane/propane mixture containing 80% butane and 20% propane provided the maximum oil recovery. The oil recovery reached 99% with the 80%C4-20%C3. However, the rate of oil production was highest in the pure butane SA-SAGD case. The water cut of the produced effluents was high in all cases due to the nature of the SAGD well configuration. The highest level of water cut was observed in the base-SAGD experiment. On the opposite side, the lowest water cut at the beginning of the experiment was in the experiment with 100% of butane. An Approximate

acceptable error of around ± 3% can be assumed in these experiments. The water cut for the solvent containing 20% C3 and 80% C4 was lower than other experiments at the late stage of production.
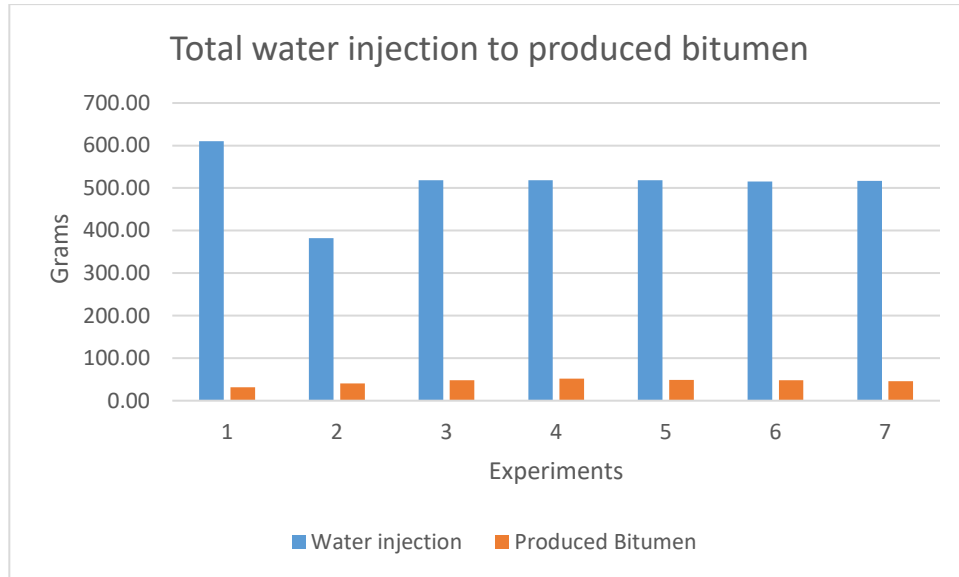
Figure 4.30 Total water injection to Produced bitumen

Figure 4.23 shows the water injected in each of the experiment and total produced bitumen. The second experiment shows less water injection due to lower total experiment time. Experiment 3 and later experiments used the same amount of total water injection and experiment 4 gave the best result for total oil recovery.

4.2.1 Effect of butane concentration on temperature of different zones

Temperature in Zone 1

The temperature at Zone 1 for all experiments are shown in Figure 4.31 below. It seems that the temperature in Zone 1 is similar in all tests. The reason is that the thermocouple for Zone one is very close to the steam injection port and measures essentially the

injected steam temperature. All of the experiments shown a stabilized temperature for all

of the different butane concentration.
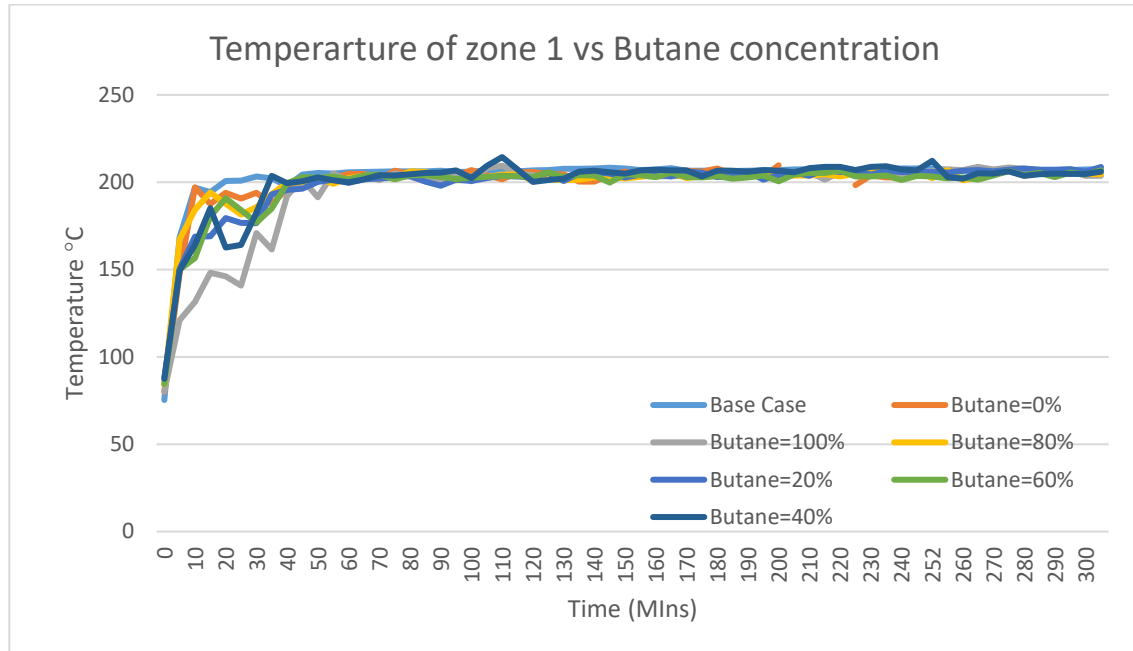
Figure 4.31 Temperature at zone 1

Temperature in Zone 2

Figure 4.32 shows the temperature of Zone 2 for all experiments. This zone shows a

small difference in each of the experiments with different butane concentration. Pure

SAGD experiment shows the highest stabilized temperature and all solvents produced a

significant temperature reduction in this zone. In general higher concentration of propane

resulted in larger reduction of the zone temperature. The 100% butane has the highest

temperature amongst all SA-SAGD tests, reaching up to 180 °C but later in the test 100%

butane and 80% butane displayed similar temperatures in Zone 2.
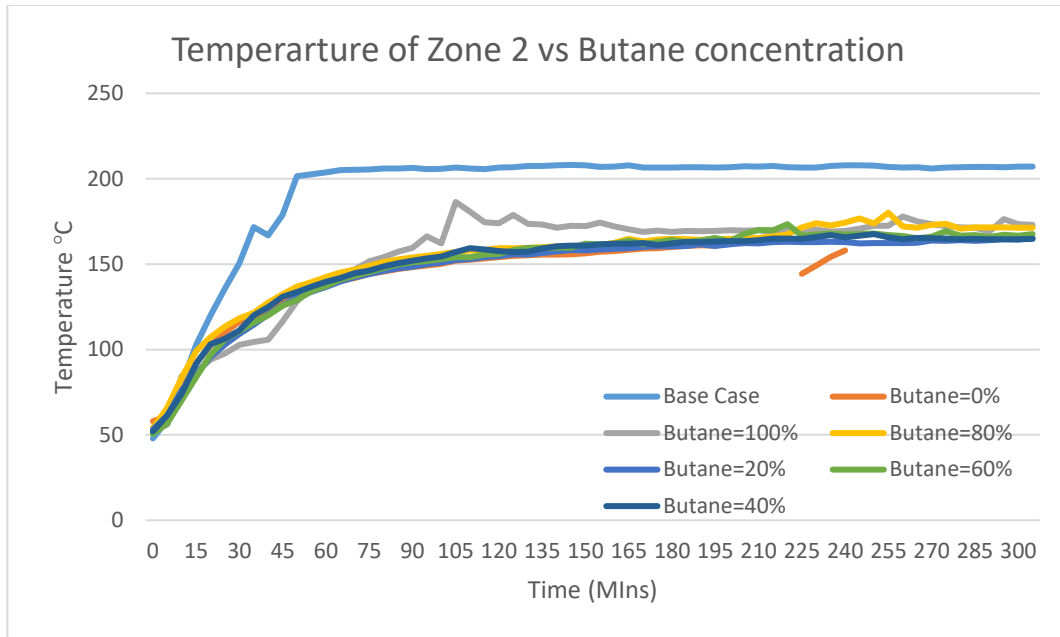
Figure 4.32 Temperature at zone 2

Temperature in Zone 3

Zone 3 temperatures of all experiments with different butane concentration are shown in Figure 4.33. As expected, the temperature of pure SAGD experiment was again the highest. There were small differences in the temperatures displayed by different solvent and the higher concentration of butane resulted in somewhat higher temperature in this zone also. However the temperature differences were not large.
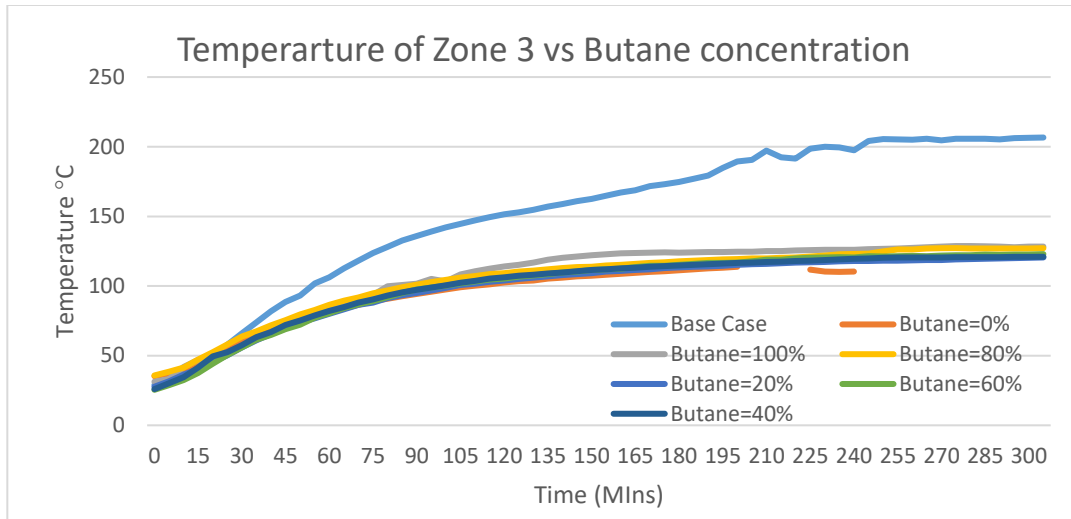
Figure 4.33 Temperature at zone 3

Temperature in Zone 4

Figure 4.34 shows the temperature comparison in zone 4, i.e. near the top of the steam chamber, for all experiments. The SAGD experiment again shows the highest temperature. Here the differences in different solvent compositions are easier to see. The decrease in the top zone temperature compared to the pure SAGD tests increases with increasing concentration of propane and the pure butane case has the highest top zone temperature amongst all SA-SAGD tests.
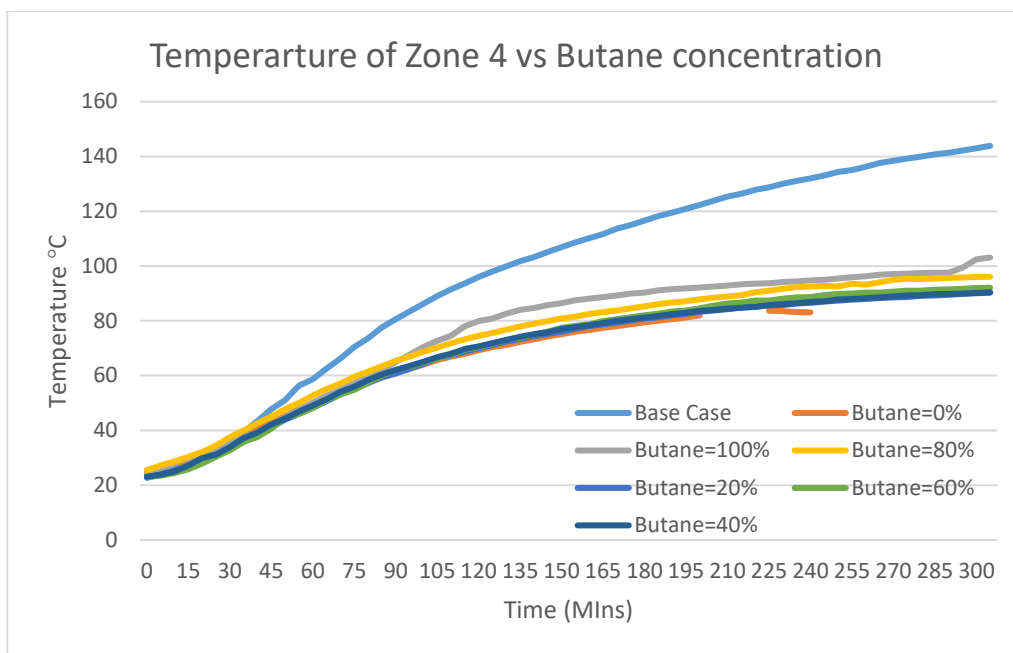
Figure 4.34 Temperature at zone 4

4.2.2 Effect of Butane Concentration on Oil Production at Different Stages of the Test

In addition to the final oil recovery, the timing of the oil recovery is also important for profitability of the process. Solvents that give higher recovery near the start of the tests would be considered better than those that give additional recovery near the end. The following graphs illustrates the effect of butane concentration in different stages of the tests.
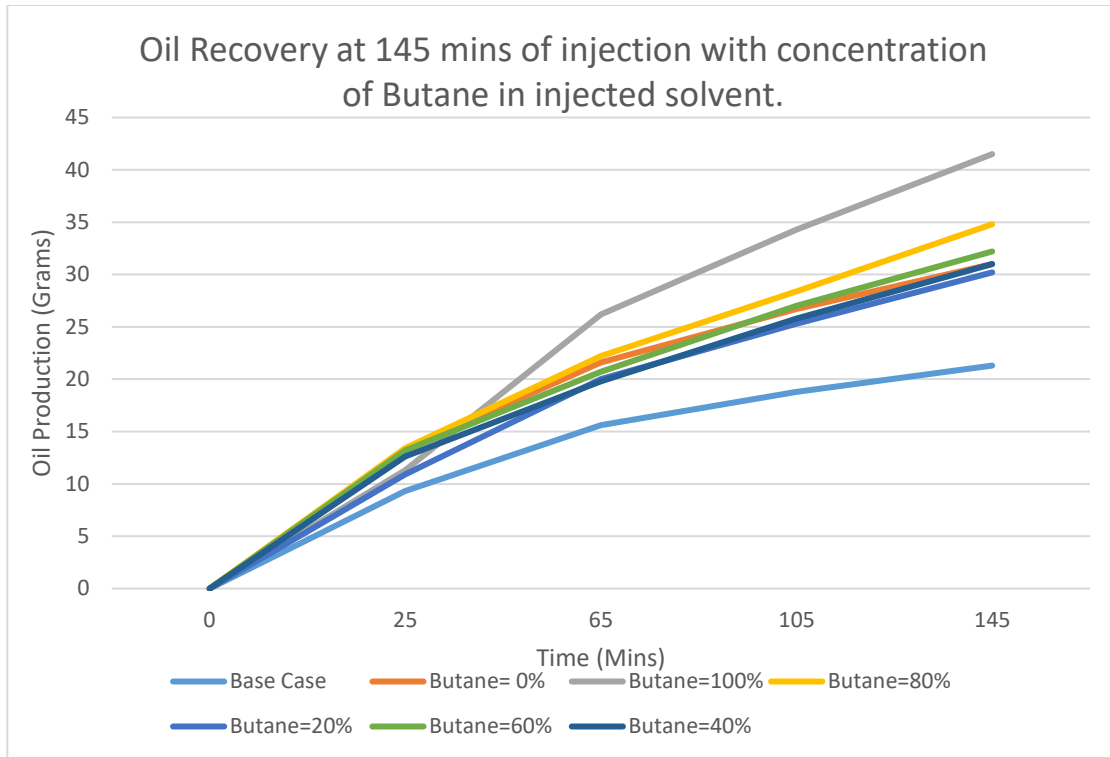
Figure 4.35 Oil Recovery at 145 mins of injection with concentration of Butane in injected solvent.

Figure 4.31 shows the cumulative oil production of different concentrations of butane till 145 minutes of injection. In this figure butane at 100% concentration gave the highest recovery which exceeded 40 grams of oil production. While the base case SAGD experiment produced the lowest amount of oil of around 21 grams. 80 % butane had the second highest oil recovery at this stage. All other experiments at different butane concentrations were almost in the same range of oil production.
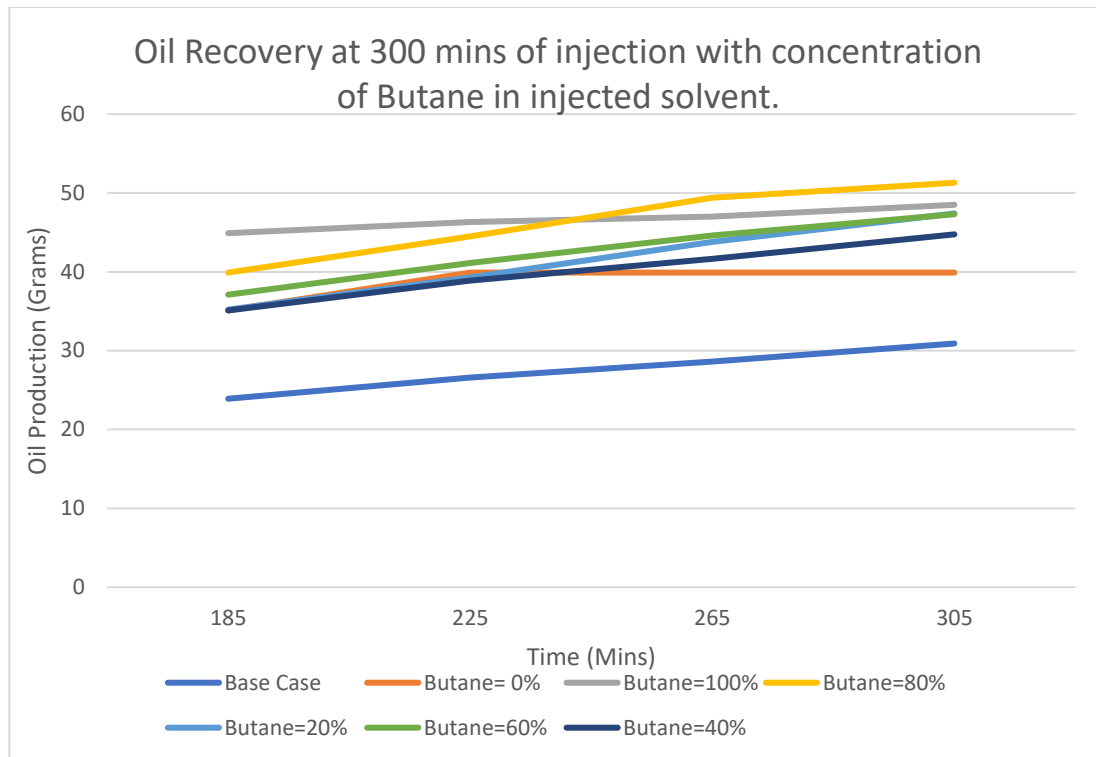
Figure 4.36 Oil Recovery at 300 mins of injection with concentration of Butane in injected solvent.

Figure 4.36 shows the oil production after the time of 145 mins and until the end of experiment. In this figure the 100% butane solvent shows very little oil production allows the 80% butane solvent to catch up in oil production and then go ahead to end up displaying the highest production. It means it might be better to have a higher concentration of butane in earlier stages of SAGD and then reduce its concentration in later stages.

Figure 4.37 shows the total oil recovery in "%" for the total time of injection. This graph shows that butane with 80% concentration gave the highest recovery. The recovery performance of 100%, 20% and 60% butane was similar, while the 40% butane displayed somewhat poorer performance. Considering the much higher cost of butane compared to

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propane, it would appear that 20% butane would provide the best economic performance

from the perspective of the final recovery. However, the final recovery in these tests is

much higher than what would be expected in the field, partly because these tests were

continued for much larger value of pore volumes injected. The expected recovery in the

field is only around 60%. Therefore, it would be useful to compare the steam oil ratio

needed to get to 60% recovery in these tests.
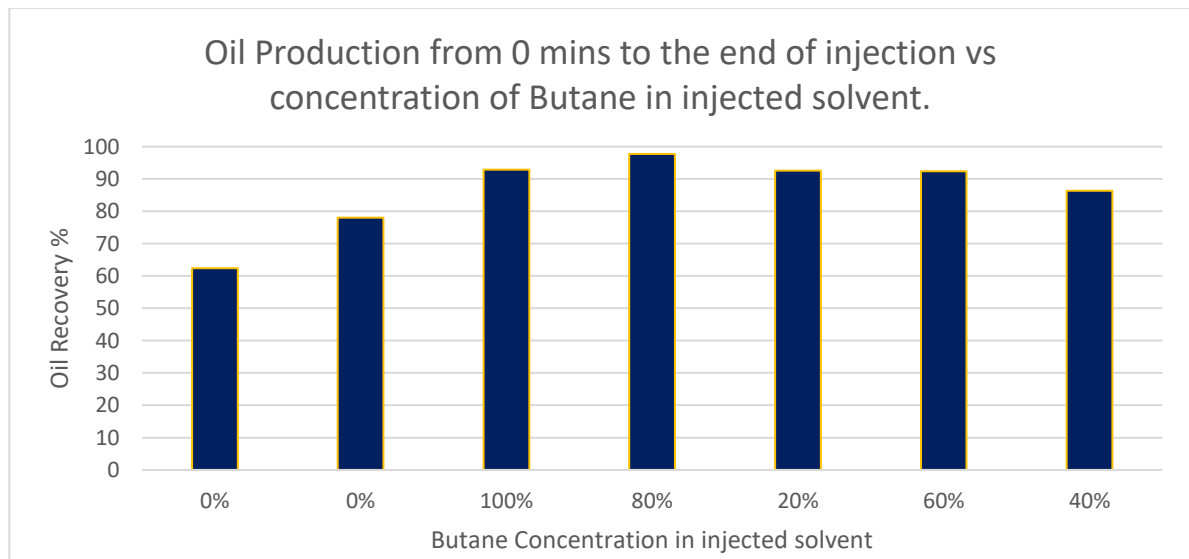
Figure 4.37 Total oil recovery for total time vs butane concentration.

4.2.3 Steam Oil Ratio when Oil recovery reaches 60%.

Figure 4.38 shows the cumulative Steam Oil Ratio when oil recovery reaches 60%. It

shows that the SOR for pure SAGD experiment was much higher than all other

experiments in which solvents were introduced. The lowest SOR was observed in the

case of 100% butane. Surprisingly, 60% butane and 80% butane had very similar SOR at

this stage of oil recovery, while the remaining other SA-SAGD tests had higher SOR that

all appeared to be nearly equal. This analysis shows that from purely SOR perspective,

pure butane is the best solvent but if the solvent cost is to be reduced while keeping SOR low, 60% butane concentration would be the best choice.
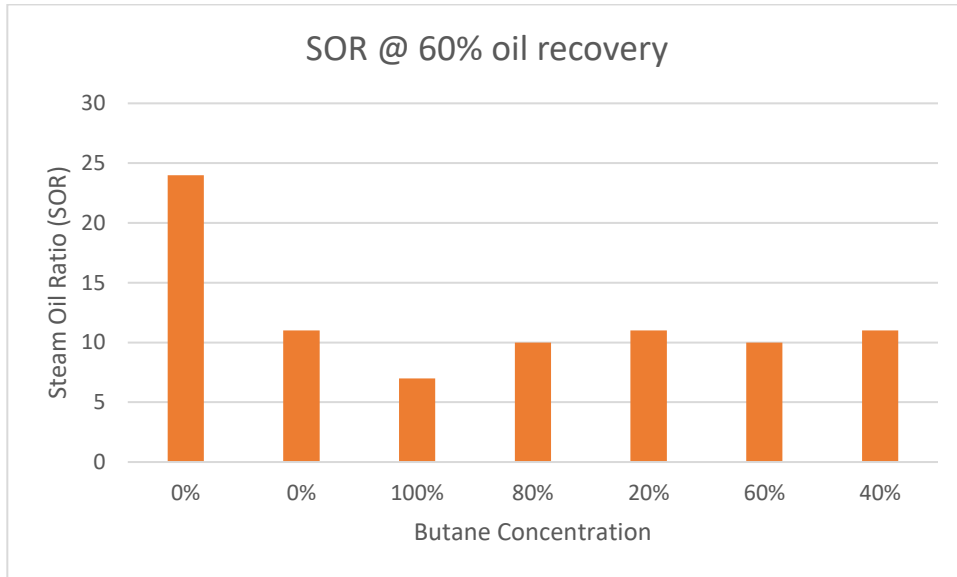
Figure 4.38 SOR to get 60% oil recovery vs Butane concentration

The foregoing analysis shows that from performance perspective, pure butane is the best solvent (amongst all tested compositions) for SA-SAGD. However, the solvent selection would also depend on the cost versus benefit analysis of adding butane to the solvent mix. The performance gain by adding less than 60% butane is only marginal and probably will not even cover the extra cost of butane. Hence it appears that if propane is considerably less expensive, it would be better to use pure propane, rather than a mixture of propane and butane.

CHAPTER- 5: CONCLUSIONS, AND RECOMMENDATIONS

5.1 Conclusions

The present study investigated the effect of adding light hydrocarbon solvents on the performances of SAGD, including oil recovery, temperature profile, and the production rate. A linear sand-pack model packed with silica sand was used with Athabasca bitumen, deionized water, butane, and propane. Four different compositions of the propane-butane mixtures were employed to evaluate the effect of the mixture composition. All experiments were conducted under the same operational conditions, in which the outlet pressure was kept at 200 psi. The following are the conclusions derived from the results.

- The temperature of the steam chamber was higher in the base-SAGD experiment, in which the temperature of three zones reached the temperature of the injected fluid. The steam chamber temperature decreased considerably when the steam was co-injected with pure propane. Moreover, the temperature was not uniform in the steam chamber in SA-SAGD tests and decreased with vertical height above the injection point.

- When pure butane was the injected solvent, the temperature of the chamber was 21 ºC higher than the pure propane case. This observation was attributed to the higher solubility of butane in the oil and its impact on the partial pressure of steam in the gaseous phase which affected the saturation temperature.

- There was a significant improvement in the performance of the SAGD experiment when a light hydrocarbon solvent was introduced to the system, regardless of the type of hydrocarbon solvent. However, adding butane to steam can increase the oil recovery more effectively compared with propane.

- The steam-to-oil ratio for all experiments, including SAGD or SA-SAGD, was very high at the end of the experiment, where it hit 20 gr/gr. The higher value of SOR in the current study compared with the typical value of SOR in the field is attributed to the large heat loss from the sidewall of the sand-pack holder and the absence of room for lateral expansion of the steam chamber. Moreover these experiments were continued to much higher values of pore volumes injected, which increased the final cumulative SOR.

- The cumulative SOR for reaching 60% recovery factor was lowest for the case of pure butane and considerable better than the next best solvent. It means that from purely technical perspective, pure butane is a better SA-SAGD solvent than any mixture of propane and butane.

- Using less than 60% butane in mixtures of propane and butane provided only marginal improvement over the pure propane case.

- The performance of pure propane SA-SAGD was also much better than solvent free SAGD, though not as good as pure butane. The choice between the two solvents would depend on the difference in their cost. If butane is considerable more expensive, using 100% propane may actually be more cost effective than using any mixture of propane and butane.

5.2 Recommendations

The experimental work can be extended to assess the SA-SAGD performance as follows:

- To further improve the interpretation of these experimental results, history matching numerical simulations of the current test can be undertaken.

- These tests can be repeated in a more realistic 3D model that will allow lateral expansion of the steam chamber.

- Insulation around the sand-pack needs further improvement to achieve better results.

- Other solvents can also be used as a mixture to test the performance i.e., other than propane and butane mixtures, e.g., mixtures of C3, C4, and C5 in different concentrations.

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