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Abstract

This research attempts to assess the effects of changing the injection times for CO₂ solvent injection in the Solvent Assisted SAGD process and to study the phase behavior of Steam, Solvent and Oil.

Simulations were conducted using the Computer Modeling Group simulation software STARS 2014. The research evaluates the effect of injection start time, solvent concentration and solvent selection on performance criteria such as Energy efficiency, Cumulative oil production, and Solvent recovered from the reservoir. The phase behavior over two individual horizontal study lines was investigated to try and explain the difference in solvent performance. The injection performance of the four different hydrocarbon solvents was compared to the Steam-only SAGD process. The effect of co-injecting CO₂ with hydrocarbon solvents was compared to the same solvents without the non-condensable gas.

Hexane was discovered to be the optimal solvent for energy efficiency and oil recovery at the cost of a suboptimal solvent recovery. The most optimal single-component concentration when considering the performance criteria lies in the range 20-30% by weight and an economic analysis would be needed to further narrow the range. The poor solvent recovery was remedied with Heptane which was shown to have an excellent solvent recovery and the two solvents were successfully co-injected. The proposed combination of solvents achieved better results than any single-component at the same concentration, which leads to the conclusion that there is a positive synergy between the two solvents. CO₂ co-injection was tested with the previously investigated Hexane and Heptane solvents. It was found that there is a time period after starting hydrocarbon solvent injection where CO₂ co-injection should not be initiated. There was however, a positive effect on the performance if the injection start time is delayed sufficiently.

The most interesting conclusion drawn from the research was the positive synergy between solvents when looking at multiple performance criteria in unison and the reported time period after starting hydrocarbon solvent injection where CO₂ injection should not be initiated.

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Abbreviations

SAGD	Steam-Assisted Gravity Drainage
ES-SAGD	Expanding-Solvent SAGD
CSOR	Cumulative Steam-Oil Ratio
HC	Hydrocarbon
CEOR	Cumulative Energy-Oil Ratio
CEIR	Cumulative Energi-Intensity Ratio

1 Introduction

1.1 Background of the Problem

Due to the continuous depletion of conventional hydrocarbon reservoirs and a large amount of available unconventional resources, the unconventional oil resources such as heavy oil and bitumen are getting more attention. Especially thermal recovery processes such as SAGD have been researched to recover these large unconventional resources. The quantity of bitumen in place in Canadian oil reservoirs is as large as that of conventional oil in the Middle East. (Butler, 1994) Further developing methods of recovery should be of great practical value.

One of the main problems in bitumen recovery is that it is practically immobile at reservoir conditions due to the extremely high fluid viscosity. However, the viscosity is very dependent on temperature and decreases exponentially as the temperature increases from reservoir conditions towards injected steam temperatures. This dependence on temperature makes Steam-Assisted Gravity Drainage (SAGD) very effective as the heated bitumen is not forced through a cold reservoir on its path towards the production well, but is instead kept inside a steam chamber until it is produced. To form this chamber SAGD requires a horizontal production and injection well pair with approximate 5 meters spacing between them. Steam is injected through the injector and creates the steam chamber which will expand vertically and laterally into the surrounding reservoir. Heat is transferred from the steam to the surrounding cold reservoir, condensing the steam and heating the bitumen. The now mobile bitumen is driven by gravity and can flow freely towards the production well. (Butler, 1994)

SAGD has a significant impact on the environment, especially due to water usage and the high energy costs associated with heating the water for injection. Giacchetta et al. (2015) reports that the emissions calculated for SAGD ranges from 8.71 to 13.6 g CO₂ equivalent per MJ bitumen. This is quite high compared to conventional oil production which is from 4.4 to 4.7 g CO₂/MJ bitumen. Compared to surface mining, which reaches a value of 9 g CO₂eq./MJ bitumen including the effects of land usage, SAGD environmental impact is more reasonable. (Giacchetta et al., 2015)

The cumulative Steam/Oil ratio is a measure of how many barrels of steam is used to extract each barrel of oil. Lowering this value could be a good way to reduce energy requirements and water demand without negatively impacting production. Processes such as Solvent-Assisted SAGD show great potential to both increase production and lower the CSOR beyond what is possible with steam alone. (Ardali et al., 2010) The solvent is co-injected with steam in the vapor phase, the vapor is contained within the steam chamber until it condenses at the edges and mixes with the mobile bitumen.

The use of CO₂ has also been evaluated in a study by Chukwuka et al. (2011) .For the different simulation scenarios presented, CO₂ achieved the greatest thermal efficiency, but at

the expense of having the most negative impact on oil recovery. A study performed by M.W. Hornbrook et al. (1991) presented that addition of CO₂ to the SAGD process could actually increase recovery.

1.2 Statement of the Problem

The previous section on problem background mentioned what benefits were expected for injection of solvents and CO₂ in conjunction with SAGD, but a positive outcome should not always be expected. Studies that compared Solvent-Assisted SAGD with regular SAGD revealed that some scenarios show no improvement or even produce a negative outcome in oil production rates when compared with steam only SAGD. (Chukwuka et al., 2011; W. Li et al., 2011; M. Ardali et al., 2012)

M. Keshavarz et al. (2014) show that ultimate oil recovery increased by almost 20% due to faster propagation of the ES-SAGD chamber and enhanced displacement efficiency. The same authors reported an increase in oil rate. This contrasts with previously mentioned research where there was a tradeoff between increased CSOR and a decrease in oil production.

The phase behavior of the solvents and steam at the reservoir pressure range is very complex. The co-injected solvent lowers the boundary temperature profile, which allows for a better thermal efficiency due to less temperature difference between the chamber and undisturbed reservoir. Because of the bitumen temperature-viscosity behavior this also causes the bitumen to become less mobile, but dilution effects from the solvents can counteract this effect and in some cases increase mobility. How the lower boundary temperature and solvent dilution affect the process has to be considered for various solvent types, concentrations and operating pressures. (Gates, 2007; Khaledi et al., 2015) This temperature reduction is more severe for lighter solvents, while heavier solvents have a smaller effect on the bitumen viscosity. Solvent type could potentially be determined for specific operating conditions, where reservoir and fluid properties result in an optimal solvent volatility. (Mohsen Keshavarz et al., 2015)

Computer Modeling Group's (CMG) advanced processes simulator STARS will be used to model the vapor, liquid, and gas phase flow of different cases utilizing different solvents in varying concentrations. The effects of solvent type, concentration and injection strategy will be studied for the Solvent-Assisted SAGD process. Oil and water mobility, oil production rate, pressure and temperature will be considered in the simulation. These results will then be compared to with the base cases.

As a non-condensable gas CO₂ has a significant effect on the temperature distribution and therefore the thermal efficiency, but it cannot mix in liquid form with the bitumen and lower viscosity in the same way that solvent condensates can. Law (2004) simulated a strategy where CO₂ was used for pressure maintenance towards the end of the SAGD process lifecycle. If the pure CO₂ only injection was started after 5 years in the 8 year process the loss in the recovery factor was negligible. Injecting various smaller concentrations of CO₂ in conjugation with solvents throughout the process will be compared with a late stage strategy.

1.3 Objectives of the Study

The following are the objectives proposed for this study:

- 1) To investigate current Solvent Assisted SAGD numerical studies and future issues.
- 2) To assess different modes of co-injection of a solvent and CO₂.
- 3) To study phase behavior of Steam, Solvent and Oil in Solvent SAGD process.

1.4 Scope of the Study

This study has investigated the performance of Pentane, Hexane, Heptane, Octane, and CO₂ as solvents in various configurations for the SE-SAGD process. Pentane and Octane was studied as single components while Hexane and Heptane were co-injected with each other and with CO₂. The concentrations used in this work range from 5% to 30% by weight for the hydrocarbons and 0.1% to 2% by weight for CO₂.

Several performance metrics were used to gauge how well a solvent performed alone and in a mixture such as cumulative oil production, CEIR/CEOR, CSOR, and Solvent recovery factor. There is an attempt to describe the changes in oil production by looking at the residual oil saturation after the process has completed and how quickly the chamber propagates which was illustrated by the gas mole fraction for water. Parameters that depend on location in the reservoir was simplified to two horizontal study lines, such as oil, gas, and water saturations, mole fractions, and phase mobility.

The only cases where the solvent injection was not initiated immediately was for 0.1, 0.5, and 2 percent CO₂ co-injected with 30% Hexane where the CO₂ was only added to the injection stream at 100, 200, 300 and 400 minutes respectively. The injection delay performance was measured by the cumulative oil production. Finally, the different injection times were compared to the appropriate case with no delay.

2 Literature review

2.1 Steam-assisted gravity drainage (SAGD)

The SAGD process uses a form of steamflooding where the flow of oil to the production well is caused by gravity forces. It's an in-situ thermal heavy oil process where a horizontal steam injection well is placed parallel to the production well but slightly higher. The process was first developed by Roger Butler in the 1970s. (A.M. Albahlani et al., 2008) He performed the first pilot project at Cold Lake in 1987 (Ali Azad et al., 2013) and the original concept has not changed much since its inception.

High recoveries and high oil to steam ratios relative to conventional steamflooding is possible with this method in both heavy oil and bitumen applications. Another advantage is that there is no need to conduct extensive preheating of the viscous oil. Once the oil has been heated, it remains hot while draining to the production well. During conventional steamflooding the oil is removed from the steam chamber and cools when flowing to the production well, this is not an issue in SAGD.

The viscosity of Athabasca bitumen at original reservoir conditions is in the range 1 to 5 million cp, which makes it quite immobile using gravity drainage. If the bitumen is heated to more than 200°C the viscosity declines to less than 20 cp where it can flow. To start the process, a pre-heating phase is conducted where both wells are used to circulate steam causing the bitumen to flow downwards. Eventually the mobile oil will occupy the oil bearing pores in the middle of the injector and producer pair. This works as a liquid steam trap preventing a direct flow of steam from the reservoir to the producer. When that takes place it is time to cease circulation in the producer and inject steam through the injector only. (Sharma et al., 2011)

2.1.1 The steam chamber

The injected steam forms a saturated zone known as the steam chamber. At the edges of the steam chamber a continuous heat transfer from the steam to the oil causing it to flow and the steam turns into condensate. **Figure 2.1** clearly shows how gravity causes the hot oil and condensate to flow along the steam chamber interface towards the production well.

Mechanism:

- Steam condenses at interface
- Oil and condensate drain to well at bottom
- Flow is caused by gravity
- Chamber grows upwards and sideways

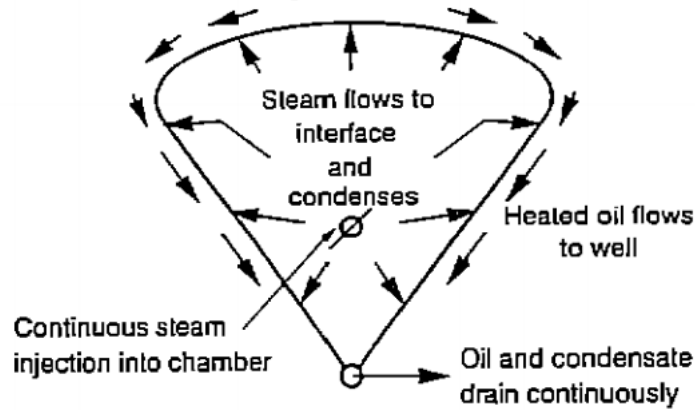


Figure 2.1: Steam chamber geometry (Butler, 1994)

The systematic displacement of oil allows the chamber to grow in the vertical and horizontal direction. Upward growth is rapid and erratic, in the shape of steam fingers with oil flowing amongst them in a chaotic fashion. The profile of the oil flow moving between the steam fingers is like a meandering river. The chamber advances more slowly and predictable in the horizontal and downward direction due to the steadying effects of gravity. The flow in these directions has a tendency to be rate-limiting and is more suited to theoretical study. **Figure 2.2** illustrates how the steam chamber advances into the original reservoir at a velocity U . This interface velocity depends on the oil rate gradient, while the oil rate depends on the temperature distribution, and finally the temperature distribution depends on the interface velocity. For example: At high interface velocities we would see a rapid temperature decrease with distance, while at low values the temperature would drop slowly. The front would be moving too quickly for the steam to finish warming the cold reservoir.

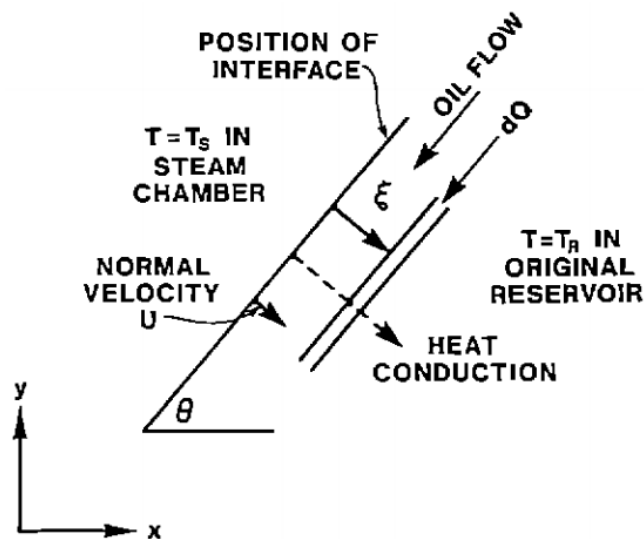


Figure 2.2: Steam interface heat transfer and oil flow (Butler, 1994)

2.1.2 Modeling the process

The original theory made several assumptions:

- The steam chamber temperature is equal to that of the injected steam
- The heat transfer occurs from conduction normal to the interface
- The temperature distribution ahead of the front corresponds to steady-state conduction.
- Drainage dQ is parallel to the interface
- Constant effective permeability

The flow rate dQ is calculated from Darcy's law

$$dq = \frac{kgsin\theta}{\nu} d\xi \quad (2.1)$$

There is a material balance considering the steam chamber cannot advance without oil flowing out of an element faster than oil flowing in. It is this difference that decides how fast the chamber can advance. If we consider a thin vertical element we get the equation below:

$$\left(\frac{\partial q}{\partial x}\right)_t = \phi \Delta S_o \left(\frac{\partial y}{\partial t}\right)_x \quad (2.2)$$

The interface velocity can be connected to equation (2.2) with the shared term $(\partial y/\partial t)_x$

$$U = -\cos\theta \left(\frac{\partial y}{\partial t}\right)_x \quad (2.3)$$

We end up with equation (2.4) and (2.5) for calculating the oil rate where the oil rate has been multiplied with $2L$ which represents drainage on both sides of the interface and horizontal well length L . The derivation can be found in the "Thermal recovery of heavy oil and bitumen" textbook by Butler. (Butler, 1991) The equation does not contain any parameters for chamber physical properties except for chamber height h . It tells us that the oil rate is independent of the interface shape or its horizontal length. In addition, all parameters are given equal weight. For example increasing the chamber height by a factor of 2 will have the same effect as halving the kinematic viscosity.

$$q = 2L \sqrt{\frac{2kg\alpha\phi\Delta S_o h}{m\nu_s}} \quad (2.4)$$

The dimensionless parameter m is introduced to include the effect of temperature on the viscosity. It is a function of the oil temperature-viscosity characteristics, reservoir temperature, and steam temperature. However, changes in T_R and T_S does not cause a large impact and in many cases m can be considered constant for a specific oil in the steam to reservoir temperature range.

$$\frac{1}{m\nu_s} = \int_{T_R}^{T_S} \left(\frac{1}{\nu} - \frac{1}{\nu_R}\right) \frac{dT}{T - T_R} \quad (2.5)$$

Where:

g	= Acceleration due to gravity [$\text{m}\cdot\text{s}^{-2}$]
h	= Steam chamber height [m]
k	= Oil effective permeability [m^2]
L	= Length of horizontal well section [m]
m	= Dimensionless parameter determined from viscosity-temperature behavior of the oil
q	= Oil flow rate [$\text{m}^3\cdot\text{s}^{-1}$]
α	= Thermal diffusivity of reservoir [$\text{m}^2\cdot\text{s}^{-1}$]
\emptyset	= Porosity
ξ	= Distance from interface
ΔS_o	= Difference between initial and residual oil saturation
ν	= Kinematic viscosity of the oil at T [$\text{m}^2\cdot\text{s}^{-1}$]
ν_R	= Kinematic viscosity of the oil at reservoir temperature T_R [$\text{m}^2\cdot\text{s}^{-1}$]
ν_S	= Kinematic viscosity of the oil at steam temperature T_S [$\text{m}^2\cdot\text{s}^{-1}$]
θ	= Inclination of the interface relative to horizontal

Supposed that the steam chamber is initially a vertical plane directly above the producer, then the horizontal displacement x is a function of time and height.

$$x = t \sqrt{\frac{kg\alpha}{2\emptyset\Delta S_o m \nu_S (h - y)}} \quad (2.6)$$

The vertical height y exists in the oil rate equation as well, but is ignored because $y = 0$ at the bottom of the steam chamber. Equation (2.6) is rearranged to provide y as a function of time and horizontal displacement.

$$y = h - \frac{kg\alpha}{2\emptyset\Delta S_o m \nu_S} \left(\frac{t}{x}\right)^2 \quad (2.7)$$

To better compare field and model data we can write the variables in their dimensionless form X, Y, and t' where the first two come from dividing x and y by height h. **Figure 2.3** illustrates Y plotted as a function of X for different values of t'. A way of looking at the results is to consider a sump of heated oil around the producing well where the production rate is adjusted to keep the sump liquid level constant. The width of this sump will increase because of the retreating interface. This retreating interface introduces some inaccuracies in the oil rate calculated by equation (2.4) from the original theory because of the factor 2 within the square root. According to the TANDRAIN theory it should be replaced with 1.5 to represent an interface that is straight at the bottom. A second alternative is the LINDRAIN theory where it's replaced by 1.3 representing interfaces that are straight. Butler notes that LINDRAIN most likely gives the best results, with the effect of reducing the predicted flow to around 80% of original calculation. (Butler, 1994)

$$Y = 1 - \frac{1}{2} \left(\frac{t'}{X} \right)^2 \tag{2.8}$$

$$t' = \frac{t}{h} \sqrt{\frac{kg\alpha}{\phi \Delta S_o m v_s h}} \tag{2.9}$$

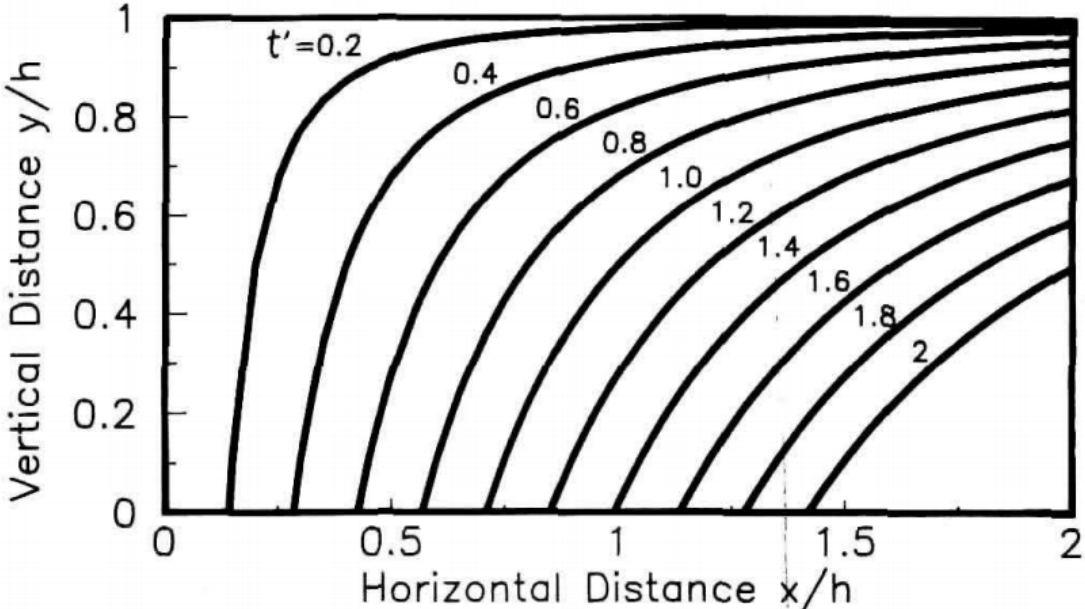


Figure 2.3: Calculated interface curves (Butler, 1991)

Certain conditions need to be fulfilled in order for there to be dimensional similarity between field trials and scale model experiments. This is important because it allows us to compare the velocity of the oil flowing along the interface adjusted for scale between model and field examples. The dimensionless time t' must be made the same for the field and the model.

There also need to be a similarity in the dimensionless parameter B_3 which accounts for the possibility of compensating for a low permeability by ensuring a high thermal diffusivity. The poor mobility due to low permeability would be compensated for by deeper heat penetration below the interface which would require sufficient depth. Sufficient depth assumes that the reservoir extends to infinity which is unrealistic.

$$B_3 = \frac{t'}{F_0} = \sqrt{\frac{kg h}{\alpha \phi \Delta S_o m v_s}} \quad (2.10)$$

F_0 compares the penetration depth of isotherms into a body heated by conduction to its physical proportions.

$$F_0 = \frac{\alpha t}{h^2} \quad (2.11)$$

If t' and F_0 are equal in both the field and model then naturally B_3 will be the same as well.

2.1.3 Heat transfer by conduction and convection

The heat transfer between the steam and oil is primarily due to conduction rather than convection but there is still some debate surrounding how much convection affects the process. In the original work convection was ignored and it was assumed that the only way to transfer heat was conduction. (Butler, R.M. 1994) Improving the heat transfer at the chamber interface can be achieved by multiple means: Increasing the temperature difference between the chamber and original reservoir, raise the thermal conductivity of the oil sand, and finally increase the surface area where heat-transfer is occurring. None of these are useful ways to increase the conductive heat transfer by any large amount. Thermal conductivity mostly stays the same given that the fluid saturation and porosity is fairly constant. The injection pressure cannot be increased by too much, the chamber is in a saturated state, and consequently pressure and temperature are connected. (Sharma et al., 2011)

Nevertheless, there are other ways to increase heat transfer: convective heat transfer, in-situ combustion, and through induction by inserting ferromagnetic materials into the reservoir. Convective heat transfer is already present, at varying degrees depending on factors such as temperature and distance to the steam chamber boundary. **Figure 2.4** shows that convection is responsible for a significant part of the heat transfer at the steam chamber edges, especially at higher temperatures. However, the condensate invades the oil sand causing the oil saturation to drop which decreases the oil effective permeability. This means that increasing the heat transfer might not give increased oil drainage rates if the effective oil permeability drops.

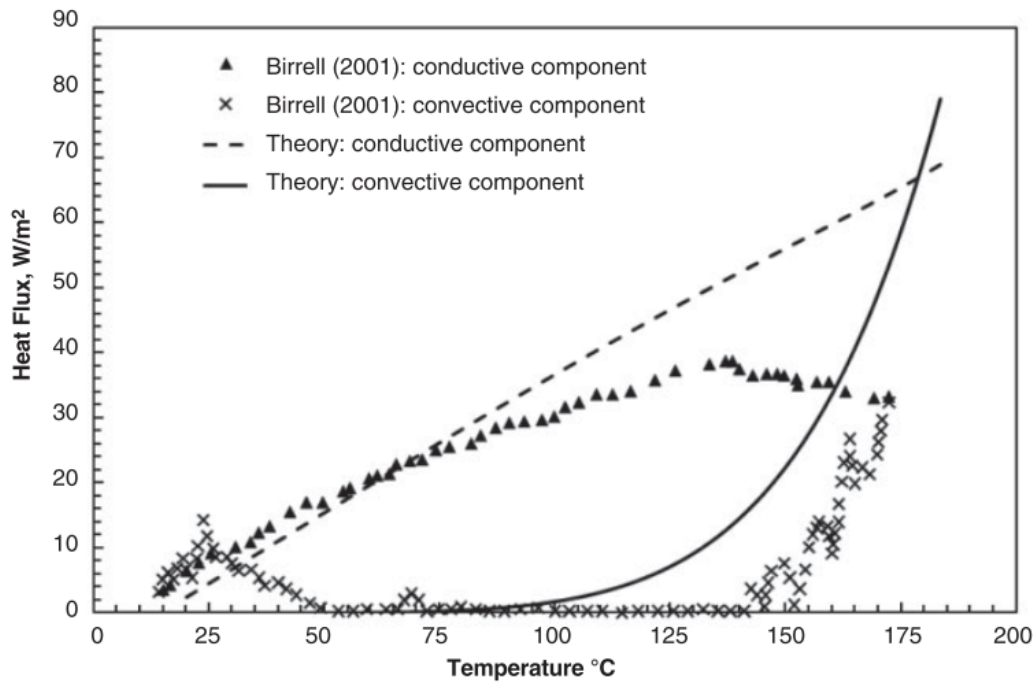


Figure 2.4: Comparison of conduction and convection individual contribution to heat flux

2.2 Solvent-Assisted SAGD

Gates (2007) demonstrates that co-injection of steam and solvents can lower cumulative steam-to-oil ratios (CSOR) compared to SAGD alone. The benefits of introducing solvents include reduced operating temperature which means less heat losses and consequently a higher thermal efficiency. Higher thermal efficiency means less steam has to be used which results in lower flue gas emissions that form from the steam generation. The research also showed that the solvent increased the production rate.

There are several commercial projects with different names for steam and solvent co-injection such as Expanding-Solvent SAGD (ES-SAGD), Solvent-Aided Process (SAP), Liquid in addition to steam enhanced recovery (LASER), and Steam alternating solvent (SAS). The goal is to minimize the energy usage per unit of bitumen recovered.

ES-SAGD is the commercial application that is most relevant to this thesis. It works by introducing solvent with thermophysical properties close to that of water to the reservoir in the vapor phase in conjunction with steam and have it condense at the chamber edges to mix with the liquid bitumen. Hexane and diluents was found to be suitable hydrocarbon solvents for co-injection with steam. It was initially introduced by Nasr et al. (2002) after conducting experimental studies at Alberta Research Council (ARC). The results were improved oil rates, Oil-Steam-Ratio and lower energy and water requirements compared to steam only SAGD.

LASER is described by Leaute (2002) as a process of injecting a C5 and higher hydrocarbon solvent as a steam additive in Cyclic Steam Stimulation (CSS). It was field tested by Imperial Oil starting from the middle CSS cycles after already having recovered 15-20% of Original

Bitumen in Place (OBIP). SAS was introduced by Zhao et al in 2004 as means to reduce energy intensity of SAGD by using mainly propane but also methane at higher pressures alternating with steam. SAP is the co-injection of butane to the regular SAGD process and it was introduced in Gupta et al. (2002) after successfully completing field tests by EnCana. (M. Ardali et al., 2012)

2.2.1 Phase behavior

M. Keshavarz et al. (2014) studied the placement of solvent near the steam chamber boundary using reservoir simulation. The solvents are transported directly to the chamber boundary in the vapor phase where the solvent accumulates. Initially concentration of solvent is higher in the vapor phase than the liquid phase, however more solvent condenses and the liquid phase solvent concentration increases. The simulation showed a solvent concentration of 0.95 in the liquid phase. From the solvent mole fraction in the liquid phase and water phase saturations it was observed that the two phases are segregated in the chamber by gravity. The condensed solvent bank is lighter and accumulates above a thinner film of hot condensed water. This phenomenon can be observed in **Figure 2.5**.

The condensate rich zone just outside the steam chamber can be explained by three individual films placed along the fluid interface. These films include the condensed water, solvent in the liquid phase as long as it is heavy enough to condense, and finally the gas phase solvent. These films form a complicated relationship where the end results is reduced condensate viscosity along the fluid interface. The lower condensate viscosity is one of the main reasons the water film is smaller during solvent-coinjection. A low water saturation is a benefit because it increases the relative permeability of the oil phase. It is also expected that the water film impedes solvent diffusion. (W. Li et al., 2010)

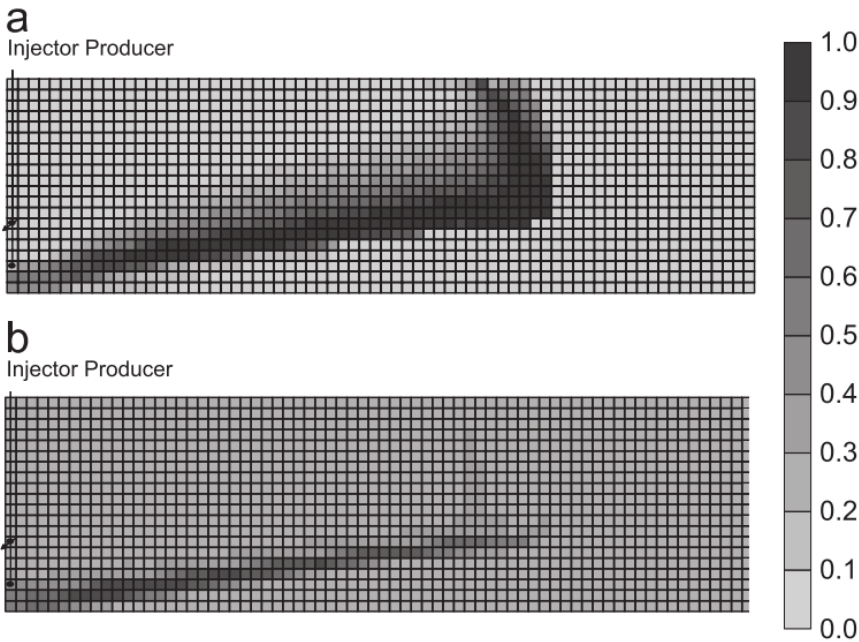


Figure 2.5: Solvent mole fraction in liquid phase and water phase saturation (M. Keshavarz et al., 2014)

Introducing the solvent changes the thermodynamic equilibrium conditions close to the chamber edge. The temperature distribution is significantly affected by solvent co-injection from that of conventional SAGD. In steam-only SAGD the chamber temperature is almost constant in the entire chamber as long as there is steam vapor present, but this is not the case in ES-SAGD. Presence of solvent causes the temperature to decrease while the vapor phase is still present, and at the edge of the steam chamber where the gas saturation quickly approaches zero the temperature is significantly lower. The research observed a difference as large as 87°C. The liquid flowing phase temperature will therefore be much lower. Decreasing temperature is detrimental to bitumen viscosity which can be seen in **Figure 2.7** and **Figure 3.3**.

In order to understand when the water and hydrocarbon solvent moves between the gas and liquid phase we need to look at a condensation temperature plot for a mixture of the two components. An example of such a plot was retrieved from Dong (2012) for a Hexane and water mixture and has been included in in **Figure 2.6**. This Water-Hexane mixture is a positive azeotrope, which can be seen by the downwards slope of the condensation temperature curve when the volume fraction increases/decreases towards the azeotrope. The mixture boils at a lower temperature than any of its individual components.

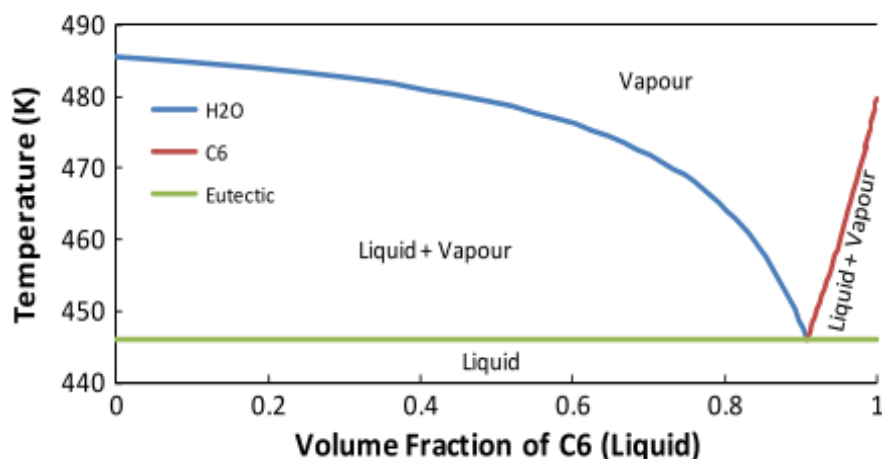


Figure 2.6: Condensation temperature versus volume fraction of solvent for mixture (Dong, 2012)

2.2.2 Viscosity reduction from solvent addition

Steam and hydrocarbon additives are recognized as the best way to reduce the viscosity of heavy oil and bitumen. (M. Ardali et al., 2012) There have been several projects aiming to combine the effects of steam and solvents in mobilizing viscous oil in-situ more efficiently both in terms of energy and solvent usage. A small amount of hydrocarbon solvent is injected together with steam to help reduce the viscosity of bitumen close to the chamber edge. **Figure 2.7** shows the viscosity reducing effect of increasing solvent volume fraction in an Athabasca bitumen mixture at different temperatures.

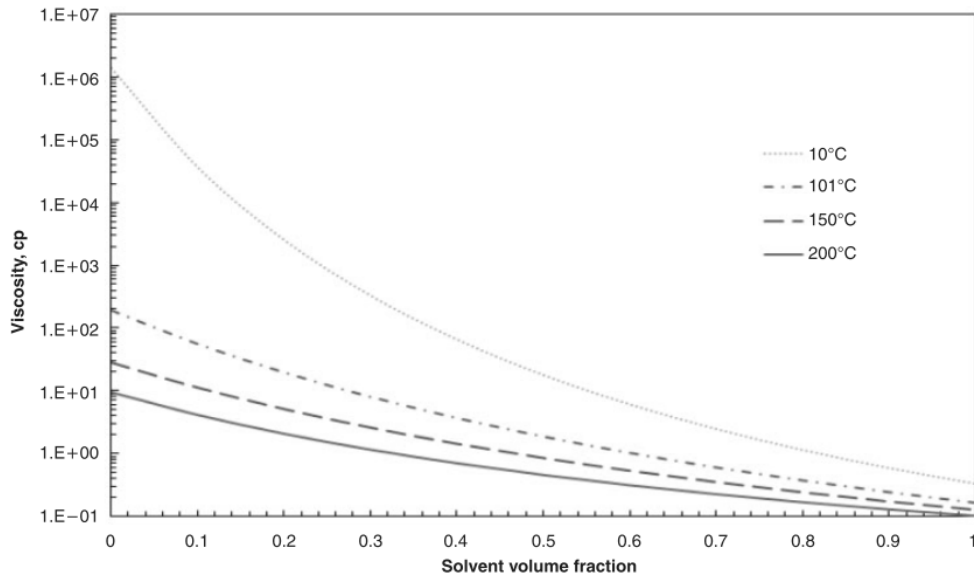


Figure 2.7: Viscosity reduction from solvent addition for Athabasca bitumen(W. Li et al., 2010)

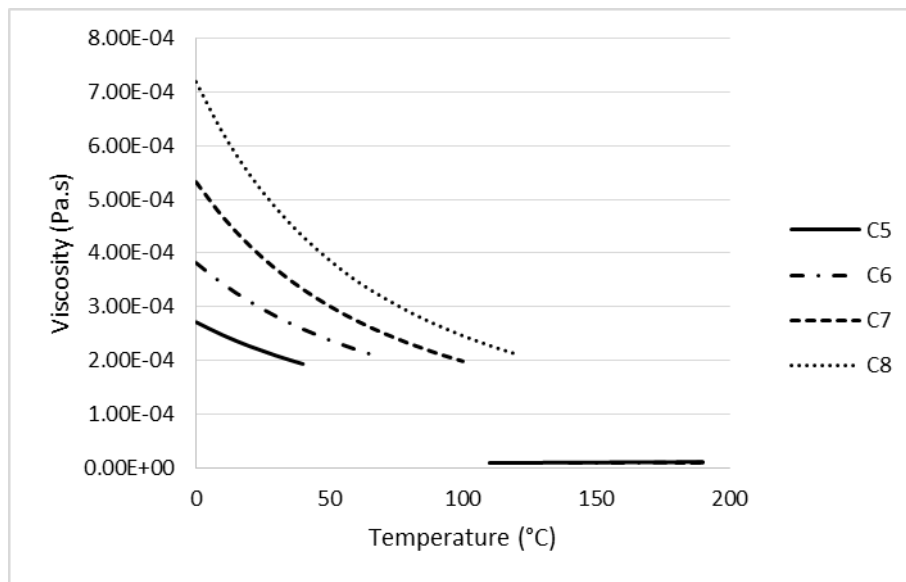


Figure 2.8: Viscosity-temperature behavior for the solvents used in this work at 6 bar. (Bronkhorst)

2.2.3 Solvent selection

Optimal solvent selection has been studied for displacement mode thermal processes. It was shown that there is much to gain by selecting the right solvent, concentration, and injection schedule. In the field the solvent will depend on available commercial products and their price. Pure single component solvents are not necessary or practical, solvent volatility, viscosity, compatibility with bitumen, and cost will be more important than component purity. Multicomponent solvent may be the best practical choice, but there is few if any synergy between the components that affect total oil recovery. However, addition of a light solvent may enhance recovery time which is very important for project profitability. (J.J Jurinak et al., 1987) (W.R. Shu et al., 1988)

Shu and Hartman (1988) present the theory that lighter solvents gives a higher oil rate with reduced loss of solvent and medium solvents gives the highest total oil recovery at the expense of more loss of solvent to the reservoir. A light solvent is a solvent with a high volatility which is a compounds tendency to vaporize. There is an optimal concentration of each solvent considering maximal possible recovery of the unrecovered solvent. There exists a point when increasing the solvent concentration where further increases will not result in improving the recovery. It will actually result in decreased ultimate recovery due to earlier steam breakthrough. The research indicates that a lower volatility solvent requires a higher concentration for optimal recovery and results in a quicker steam breakthrough than higher volatility alternatives. Heavy solvents are not recommended (Sarma et al., 1996).

Nasr et al. (2003) proposed that the solvents should be selected so that the injected hydrocarbon vaporization temperature is close to the injected steam temperature. The research showed an increase in oil drainage rates as the vaporization temperature of the hydrocarbon solvent increased towards that of steam, with hexane providing the highest drainage rate. The drainage rates declined as the vaporization temperature increased beyond that of the injected steam.

2.3 Co-injection of a solvent and CO₂

CO₂ is a non-condensable gas that has seen a lot of study on its use in steamflood processes. It is a likely candidate for a good solvent to be injected in the SAGD process in addition to the various hydrocarbon solvents. The gas has been injected with the goal of increasing production and improving energy efficiency. This is achieved due to the mechanics oil swelling, viscosity reduction, trapped gas effects, and miscibility effects. (M.W. Hornbrook et al., 1991) The most important mechanism is reducing the viscosity due to CO₂ dissolution in the bitumen, and the dissolution of CO₂ causes the bitumen to occupy a larger volume and reduce the Interfacial-tension is regarded as the second-most important mechanic. These effects cause the reservoir fluid saturations to change due to the oil swelling. (H. Li et al., 2013)

CO₂ has limited solubility in bitumen, and the amount of gas that can be injected before the bitumen reaches saturation is constricted. Including Alkane solvents was attempted by H. Li et al. (2013) in order to improve the viscosity and swelling characteristics of CO₂. The presence of Propane or Butane was shown to significantly improve the swelling of the CO₂ and the authors suggested that co-injecting CO₂ with a hydrocarbon solvent was a promising technique.

CO₂ addition was investigated by Chukwuka et al. (2011) and it was shown that increasing the amount of CO₂ injected reduces the ultimate oil recovery. The same study found that the CO₂ is the most effective solvent at reducing the CEOR. The model temperature decreased with increasing CO₂ concentration. A lower chamber temperature results in less heat loss to the surrounding rock formation and consequently less steam usage.

3 Research methodology

3.1 Research design and procedure

Simulations were conducted using the Computer Modeling Group (CMG) software STARS 2014. The simulation was performed for each of the specific cases outlined in section 3.1.3 using the same reservoir data and fluid properties for all cases.

The simulation ran for 61 time-steps where each step represents 10 minutes of modeling time and the simulation ends at 610 minutes. Solvent injection for all cases start immediately at the first time step which is 0 minutes. Start of CO2 Injection vary depending on the case; however it will also start at 0 minutes unless something else is specified.

3.1.1 Reservoir model

The two-dimensional reservoir model that was used resembles an ongoing experiment at the University of Stavanger. Some of the choices in this research regarding physical parameters were made so there could be a reasonable comparison with the experiment results. The different saturations, physical size, time scale, and flow constraints are all examples of parameters linked to the experimental model. The model consists of 70, 1, and 20 gridblocks in the i, j, and k direction respectively constituting a total of 1400 individual gridblocks. Gridblock size is set to 1 cm x 1 cm in the i and k direction, while the reservoir width j is one block of 5 cm length. The total reservoir size is 70 cm x 5 cm x 20 cm which gives a reservoir volume of 7000 cm³. The total volume of oil retrieved from the simulation results for calculating what fraction of IOIP has been recovered is 1203.4 cm³.

The producer is placed in block 35, 1, 18 which is 2 cm from the bottom of the reservoir, while the injector is placed 5 cm above at block 35, 1, 13. The points of interest when looking at parameters versus distance will mainly be line 5 and 15. These are the study lines selected to show how certain parameters change with horizontal distance.

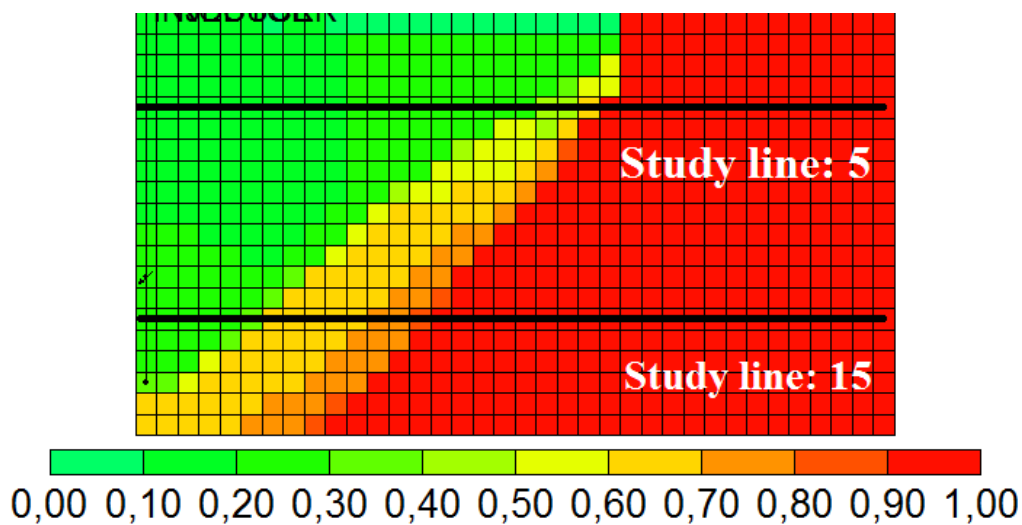


Figure 3.1: Location of study lines 5 and 15

Initial oil saturation is 0.87 in the reservoir, which is slightly below 1.0 after normalization by the simulation software. The gas saturation is zero, there is no initial gas in the model, and finally the water saturation which takes up the remaining pore space has to be very small.

Table 3.1 shows select properties of the reservoir rock and fluids and **Figure 3.2** illustrates the temperature-independent relative permeability also used in the simulation.

Properties	Values
Porosity	0.35
Horizontal permeability	126500 md
Vertical permeability	120000 md
Effective formation compressibility	0.00008812 1/kPa
Rock heat capacity	4380000 J/m ³ -C
Thermal conductivity of rock	212512.5 J/m-day-C
Thermal conductivity of water phase	55451.704 J/m-day-C
Thermal conductivity of oil phase	5812.5 J/m-day-C
Thermal conductivity of gas phase	2610 J/m-day-C

Table 3.1: Reservoir rock and fluid properties for the simulation cases.

The injected steam quality is ~0.84 and it holds a temperature of 160.14°C. A limitation is set on the injector where the bottom-hole pressure (BHP) cannot exceed 600 kPa and the injection flow rate cannot exceed 26.04 ml/min. The limitation is set to STW (Surface total water rate) for the SAGD base case and STF (Surface total phase rate) for the rest. There are also similar limitations on the producer well where it cannot exceed a BHP of 542.2 kPa or a STL (Surface total liquid rate) flow rate of 19.5 ml/min.

The rock-fluid model used is a water-wet model and the relative permeability curves have been included in the plot in **Figure 3.2**.

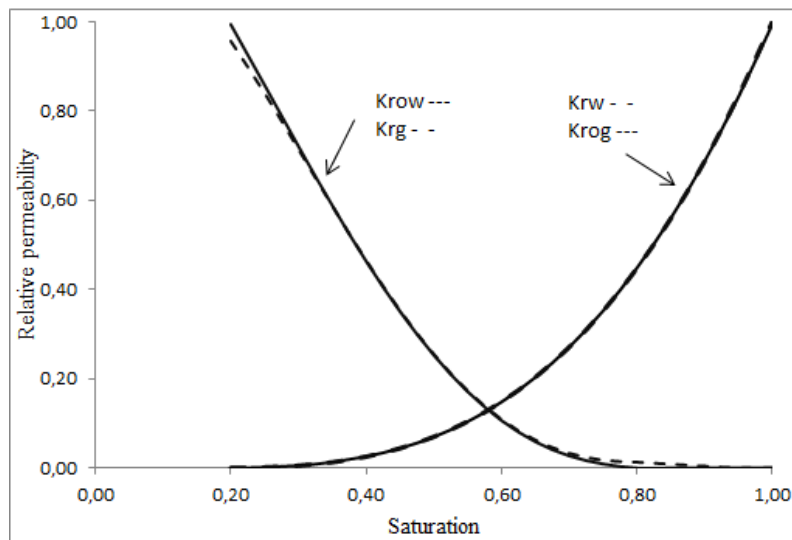


Figure 3.2: Rock-fluid properties

3.1.2 Fluid properties

The bitumen is simulated using three pseudo components, each representing a range of hydrocarbon components indicated by their carbon numbers. These three pseudo components

are C15toC20, C21toC45, C46toC70. We are simulating dead oil which means that all parameters such as Kv 1 through 5, critical temperature and critical pressure have been manually set to zero in the simulation file.

	C15toC20	C21toC45	C46toC70
Mol frac. of bitumen	0.0733	0.595	0.3317
Molecular weight	250.95 kg/kg mole	392.9 kg/kg mole	830.5 kg/kg mole
Critical pressure	0 kPa	0 kPa	0 kPa
Critical temperature	0 °C	0 °C	0 °C
Acentric factor	0.75878716	1.0733998	1.8368305
Normal boiling point	156.99 °C	230.81 °C	500.99 °C
Specific gravity	0.85	0.91	1.10
K_{surf}	16.415	0.035524	2.6979e-014

Table 3.2: Properties of bitumen pseudo components

The other components in the simulation are Pentane, Hexane, Heptane, Octane, and CO₂. These are the solvents which will be used in addition to water for injection purposes in the different simulation cases outlined in **Feil! Fant ikke referansekinden..** The $K_{surface}$ values will vary for each component when the solvents are combined, especially when CO₂ is included in the mix. The K-values have been stated for single-component injection. Previous simulation runs have shown that when CO₂ is included in the mixture the hydrocarbon solvents reference condition according to CMG STARS will change to the liquid phase. For the cases where CO₂ is added after a certain amount of time the solvent K surface was set to the same value as for the single-component cases. It was not possible to change the value during the simulation run to represent the effect that including CO₂ would have on the solvent phase behavior.

Component	Molar mass	P_c	T_c	$K_{surface}$
Pentane (C5)	72.2	3374.12	196.45	1.98
Hexane (C6)	86.2	2968.82	234.25	2.24
Heptane (C7)	100.2	2735.78	267.05	2.64
Octane (C8)	114.2	2482.46	295.65	2.88
CO ₂	44	7376.46	31.05	34.95

Table 3.3: Properties of injection components

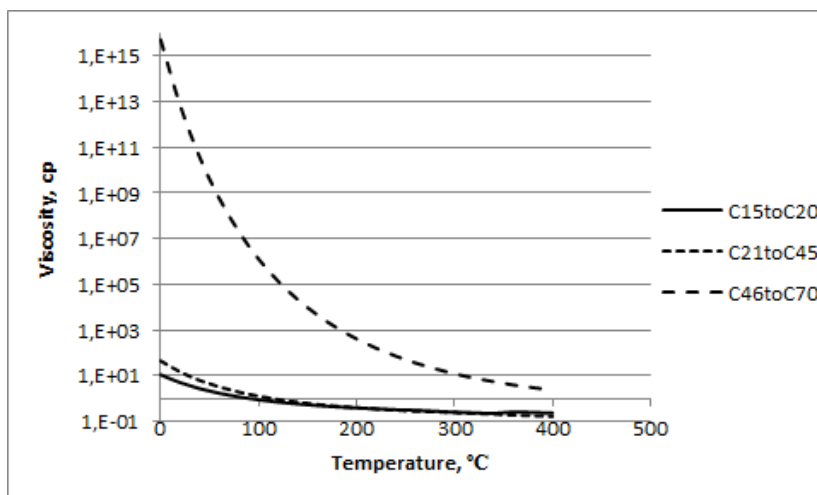


Figure 3.3: Viscosity of bitumen pseudo components at varying temperature

3.1.3 Simulation cases

For the case “Hexane + late start CO2” where the injection composition changes during the process the reported volumes are after CO2 injection has initialized. The volume percentage of Hexane injected before CO2 injection started is the same as the single component case which for 30% wt hexane is 39.2% vol.

Case	Weight percentage (%)	Volume percentage (%)
Pentane	5	7.7
	10	14.9
	15	21.8
	20	28.4
	25	34.6
	30	40.4
Hexane	5	7.3
	10	14.3
	15	21.0
	20	27.3
	25	33.4
	30	39.2
Heptane	5	7.1
	10	13.9
	15	20.4
	20	26.6
	25	32.6
	30	38.3
Octane	5	6.9
	10	13.5
	15	19.9
	20	26.1
	25	32.0
	30	37.7
Hexane + Heptane	20 C6 + 5 C7	26.8 C6 + 6.5 C7
	20 C6 + 10 C7	26.3 C6 + 12.7 C7

	30 C6 + 5 C7	38.5 C6 + 6.2 C7
	30 C6 + 10 C7	37.7 C6 + 12.1 C7
Hexane + CO2	20 C6 + 0.1 CO2	25.3 C6 + 7.4 CO2
	20 C6 + 0.5 CO2	19.6 C6 + 28.7 CO2
	20 C6 + 1 CO2	15.2 C6 + 44.8 CO2
	20 C6 + 2 CO2	10.6 C6 + 62.1 CO2
Heptane + CO2	20 C7 + 0.1 CO2	24.7 C7 + 7.5 CO2
	20 C7 + 0.5 CO2	19.0 C7 + 28.9 CO2
	20 C7 + 1 CO2	14.8 C7 + 45.0 CO2
	20 C7 + 2 CO2	10.2 C7 + 62.3 CO2
Hexane + late start CO2	30 C6 + 1 CO2 at 100 min.	22.3 C6 + 43.6 CO2
	30 C6 + 1 CO2 at 200 min.	22.3 C6 + 43.6 CO2
	30 C6 + 1 CO2 at 300 min.	22.3 C6 + 43.6 CO2
	30 C6 + 1 CO2 at 400 min.	22.3 C6 + 43.6 CO2
	30 C6 + 0.5 CO2 at 100 min.	28.4 C6 + 27.8 CO2
	30 C6 + 0.5 CO2 at 200 min.	28.4 C6 + 27.8 CO2
	30 C6 + 0.5 CO2 at 300 min.	28.4 C6 + 27.8 CO2
	30 C6 + 0.5 CO2 at 400 min.	28.4 C6 + 27.8 CO2
	30 C6 + 0.1 CO2 at 100 min.	36.5 C6 + 7.1 CO2
	30 C6 + 0.1 CO2 at 200 min.	36.5 C6 + 7.1 CO2
	30 C6 + 0.1 CO2 at 300 min.	36.5 C6 + 7.1 CO2
	30 C6 + 0.1 CO2 at 400 min.	36.5 C6 + 7.1 CO2

Table 3.4: Case outline

The solvents C6 and C7 were likely to show great improvement in the SAGD process, while C5 and C8 were included to see if the before mentioned solvents were in fact the best choice for single-component injection. Simulating for a wider range of solvents is interesting to see the effects of a lighter or heavier solvent. It is important to note that the solvents likely to be used in the field are available and economical commercial diluents and not pure single components which have been used here. (Leaute, 2002)

Hydrocarbon solvent co-injection have been included to show the effects of combining multiple components, which is likely to be done in the field. The components and concentrations was decided after completing the initial single-component cases which marked hexane as the superior solvent for energy efficiency and oil recovery, and heptane as the best component to achieve a high solvent recovery factor. This was done to find out if there can be a positive synergy between these two solvents, which surpass the alternative of using only one solvent with the same total concentration. It would be especially interesting to see if a mixture of two components can bring an improvement over one of the two components alone in one specific parameter such as total oil recovery. When the results have been established there will be an effort to look at the cause for these improvements and how this effects which solvents are better suited for co-injection.

It was decided to simulate the effect of CO2 on heptane as well as hexane. Heptane is less volatile than hexane and might benefit more from the effects of a non-condensable gas such as CO2. That is why heptane was tested as well as hexane despite the fact that hexane has shown itself to be the ideal single-component solvent to inject. The solvent that showed itself most

suited for co-injection with CO₂ was also used in testing an injection mode where the start of CO₂ injection is delayed. Hexane is injected from the start and after 100, 200, 300, and 400 minutes for each simulation run respectively CO₂ co-injection will commence and the two components will be continually injected until the end of simulation. The different CO₂ injection start times were chosen to see the effect that the gas has when injected early, and if it's possible to achieve better results by delaying it.

3.2 Instrumentation and data analysis

The data was exported to Microsoft Excel where some parameters could be plotted directly while the rest had to be calculated like cumulative energy per oil recovered so that the produced solvent in the oil phase could be taken into account. The methods used for calculating the parameters which are not directly outputted by CMG STARS are included in the sections below.

The definition of cEOR is the sum of the enthalpy of injected steam and the heating value of the net injected solvent divided by the cumulative oil produced. The net injected solvent is the amount of solvent that is left in the reservoir. (Gates, 2007) If we used the enthalpy of vaporization for the solvent like was done with water we are ignoring the fact that the solvent could be used as a fuel, and any solvent left in the reservoir represents more energy lost than what was used to heat it. For the hydrocarbon solvents the enthalpy of combustion is an order of magnitude larger than the enthalpy of vaporization so if vaporization was used the contribution from the solvents would be negligible. Likewise, only the solvent that is not returned to the surface should be included for what is returned can still be utilized. However, this does not apply to CO₂ which does not have an enthalpy of combustion. CO₂ will be treated like water, and only the energy used to heat it to 160 degrees is considered.

Cumulative net Energy Oil Ratio:

$$cEOR = \frac{H_{vap} + Heating\ Value_{solvent}}{V_{COIL}} \quad (3.1)$$

Where:

$$H_{vap} = HVR * (T_c - T)^{0.38} \quad (3.2)$$

HVR has been retrieved from Table 6: Vaporization Enthalpy for Selected Components in the 2014 CMG manual for STARS. The correlation used to obtain the Heat of Vaporization is also found on the same page. The needed parameters for the correlation is found in the same table. (CMG, 2014)

This gives a heat of vaporization of 37 kJ/mol or 2.055 MJ/kg for the water when heated to the injection temperature of 160°C. The heat of vaporization for CO₂ is 11 kJ/mol or eight times less energy used per mass than water at 0.25 MJ/kg. This will be multiplied with the amount of cumulative mass of steam and CO₂ injected during the life of the well.

There was some uncertainty if it is correct to use the net or gross enthalpy of combustion, but the net (lower) enthalpy of combustion was chosen and the values used are listed in the table below. The gross enthalpy of combustion includes the possible energy gain from the condensation of the water that evaporates during the combustion, and would overstate the energy lost from solvents for this application. When calculating the net heating value the combustion cell is not allowed to cool down, and the reading is done before the water condenses.

Component	Lower Heating Value (LHV) MJ/kg
Pentane	44.98
Hexane	44.73
Heptane	44.55
Octane	44.42

Table 3.5: Heating values used in the CEOR calculation

Cumulative Energy Intensity Ratio:

$$cEIR = \frac{Energy_{cum,inj}}{V_{COIL}} \quad (3.3)$$

Cumulative Oil recovered:

$$V_{COIL} = (V_{oil,prod} - V_{solv,oil\ phase})_{prod} \quad (3.4)$$

Solvent mass retained:

$$m_{solv} = (m_{solv,gas} + m_{solv,oil})_{inj} - (m_{solv,gas} + m_{solv,oil})_{prod} \quad (3.5)$$

Solvent recovery factor:

$$RF_{solv} = \frac{(m_{solv,gas} + m_{solv,oil})_{prod}}{(m_{solv,gas} + m_{solv,oil})_{inj}} \quad (3.6)$$

3.3 Assumptions and limitations

The research was conducted under the assumption that the bitumen is dead oil, which is a term used to describe gas-free oil. In order to be gas free the oil has to be under a low enough pressure that the gas does not dissolve in the oil or it's relatively thick oil and has lost its volatile components. Whether or not the bitumen contains dissolved gas has effects on certain parameters such as gas dissolution lowering the viscosity which is the case for CO₂ saturated oil at 2100 kPa according to Law (2004). Simulating for live oil occurs when there is specified initial solution gas present in the reservoir. This was investigated in Ardali et al. (2010) and their results showed that initial solution gas has a negative impact on oil recovery in the bitumen recovery process. The authors presented these negative effects as recovery

decline in percentage and they showed that an initial solution gas mole percentage as low as 5% would cause a recovery decline of around 4% for the Cold lake reservoir and it reached a plateau at approximately 27% production decline for an initial solution gas mole percentage of 15%. Since this research simulates a laboratory model and we can decide the gas content of the oil placed in the reservoir simulating for dead oil is a reasonable assumption.

Relative permeability is a factor of the different liquid/gas saturations in this research and its dependence on temperature is ignored. In the field the relative permeabilities will change with increasing temperature. In a paper by Butler (1991) it is stated that the main effect of the temperature dependence is that the relative permeability for the oil phase typically increases and the residual oil saturation is decreased. These are both positive changes as the higher relative permeability ensures easier flow from the interface to the production well and achieving lower residual oil saturation means that less oil is left behind in the reservoir which naturally translates to a higher total oil recovery.

Asphaltene precipitation that occurs close to the well bore, tubulars, flow lines, and miscellaneous equipment is a serious threat to the economic viability of oil recovery and is an issue for several oil recovery methods, not just for Solvent-Assisted SAGD. Including the effects of dealing with de-asphalting is beyond the scope of this research, and it is assumed that there are no issues with asphaltene. This is suitable for simulating the laboratory model that this research is emulating; the conditions are not suitable for this to be a problem in the experiment. The injection pressure is far too low for there to be asphaltene solids precipitation, but it should be taken into account for real world applications.

The reservoir is assumed to be homogenous. There are no geo-mechanics involved in the model, such as complex stress fields, cracks, etc. The possibility of water zones is not considered and solubility between water and oil has not been looked into.

Several simulation parameters were set and choices made with the recommendation of the thesis supervisor because this research was done to compare it with an ongoing experiment at UiS. The small model size, the different saturations and simulation time was chosen to simulate this experiment and it is a reasonable assumption that these choices are the reason why the quantities are not directly comparable to real life oil reservoirs. In the literature where existing oil reservoirs are simulated oil recoveries as high as 80% of IOIP is unusual, and the expected CEOR is around 5-9 GJ/m³. (Ardali et al., 2010)

Because of the experiment it was requested that this research uses weight fractions to state the simulation cases. There was a lot of discussion and uncertainty regarding at what conditions CMG specifies its volume fractions and therefore which conditions the density should be calculated for. It was decided to use the standard gravity specified by Winprop for the hydrocarbon components. For CO₂ it was decided to use its density at standard temperature with the pressure set to 6 bars which is the injection pressure used in the simulation. These decisions could potentially be serious mistakes considering that the boiling point for water, pentane and hexane occurs between standard temperature and the injection temperature for 6 bars and thus would have their actual densities severely reduced to around 10-20 kg/m³. It

was decided to include the volume fractions inputted into STARS in a table in chapter 3.1.3 Simulation cases to make up for this possible mistake. The component input into STARS was specified with these exact volume fractions, and they are the final authority for what was actually done.

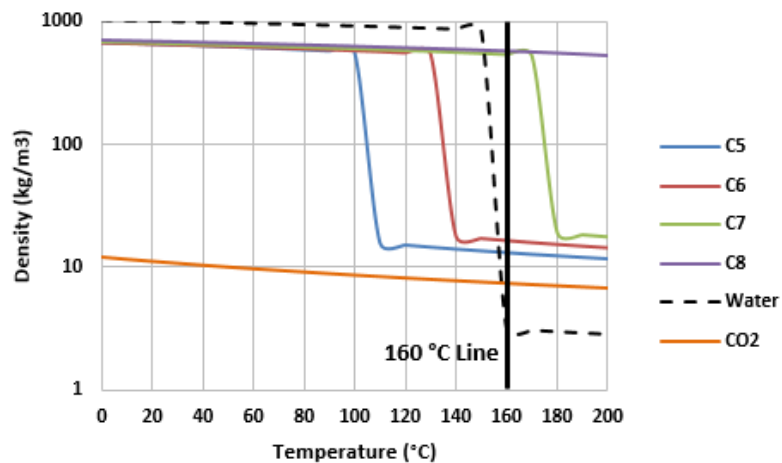


Figure 3.4: Density changes rapidly when the solvent passes its boiling point

4 Results and discussion

4.1 Single-component injection

In the following research a single hydrocarbon component has been injected into the reservoir in weight concentrations of 5 to 30% of the total injection stream. The concentration has been set in increments of five percent. The concentration increments were chosen to illustrate the results of the varying concentrations in a high enough detail, which is the reason for the five percent increments instead of say ten percent. The simulation was performed for concentrations up to 30% by weight. That is a relatively large amount of solvent; however it is still interesting to see the behavior with increasing concentration.

The main solvents in the single-component study are Hexane and Pentane, because they are expected to outperform the other solvents. Pentane and Octane was included for reference as to how the next step in the hydrocarbon number chain would perform and to check that the expected winners were actually the best performing solvents. Pentane is one hydrocarbon number lower than Hexane, and is more volatile, while Octane is one number higher and less volatile. More or less volatile solvents are also called lighter or heavier solvents for how easily they evaporate.

Solvent selection was investigated by Nasr et al. (2002). The common selection method for which solvents to investigate for the SAGD process has been how closely to the steam condensation temperature that the solvent condenses. This can be determined for a specific operating pressure range from the vapor pressure plot. The solvents Hexane and Heptane have the closest condensation temperature to steam for an operating pressure of 6 bars which applies to this research. From this solvent selection method we can assume that Pentane is a very poor solvent for the temperature and operating pressures encountered in the simulated reservoir, which is in agreement with the simulation results. However, **Figure 4.1** does not take solvent concentration into account; the figure only includes pure components. For example Pentane injection gives a very similar oil recovery to Heptane at 20%wt concentration, despite the larger deviation in vapor pressure from steam, but it drops off significantly as the concentration increases.

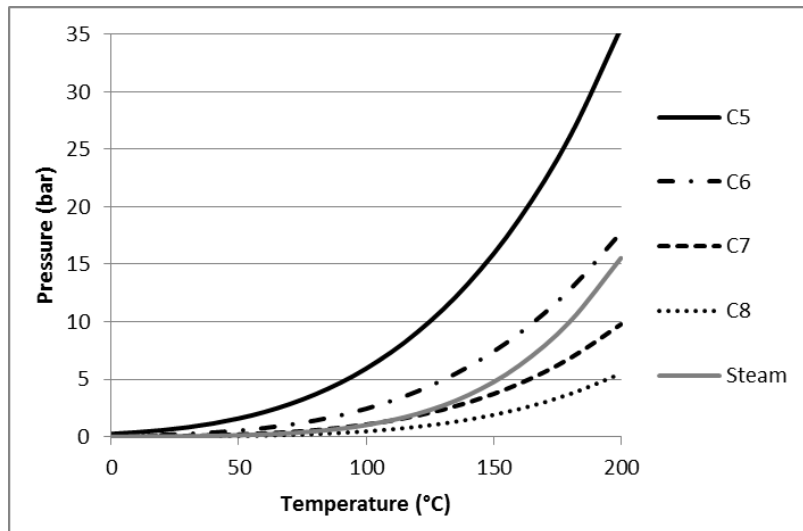
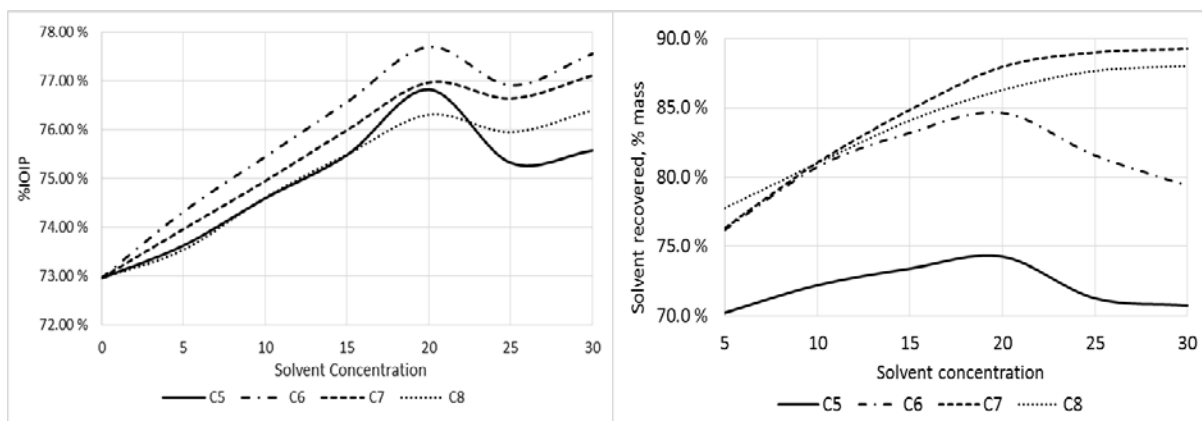


Figure 4.1: Vapor pressure of solvents and steam

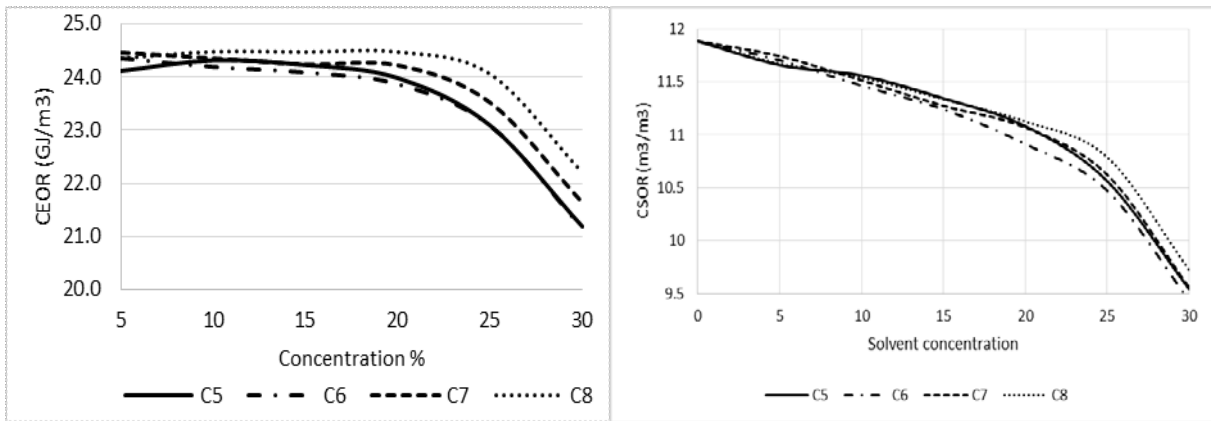
The parameter which best reflects the difference in condensation temperature from steam is the solvent mass recovery factor. Pentane has a very poor solvent recovery factor for all concentrations and differs greatly from the other components much like in the vapor pressure plot. Hexane has a condensation temperature that places it in the middle of Pentane and steam, and it follows the same trend with concentration as Pentane. The only difference is that it starts out at a higher solvent recovery factor which fits with the theory considering it is closer to steam than Pentane. The two remaining solvents, Heptane and Octane, have a higher condensation temperature than steam and they also produce a similar trend with concentration, but unlike that of Pentane and Hexane.



(a)

(b)

Figure 4.2: (a) Oil recovery in percentage of IOIP. (b) Recovered solvent fraction by mass.



(a)

(b)

Figure 4.3: (a) CEOR for different solvent concentrations. (b) CSOR for different solvent concentrations.

There is a gradual improvement in all the performance metrics with increasing concentration until 20% where several things happen. The energy efficiency measured by the Cumulative Steam-Oil Ratio and CEOR start to improve more rapidly with increasing concentration, there is a temporary dip in oil production and finally there is a negative change in the solvent recovery factor for Pentane and Hexane. What is the cause of the large changes when increasing the concentration from 20% to 25% for all solvents, but most notably for the lighter solvents Pentane and Hexane?

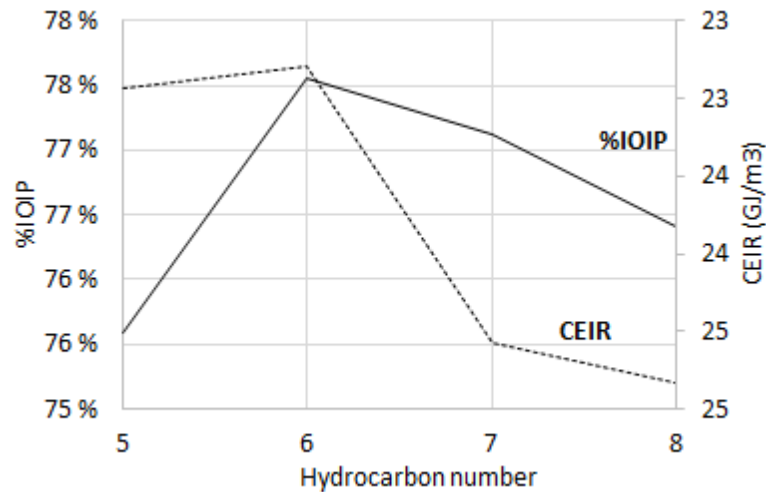


Figure 4.4: Oil recovery and CEOR at 30%w concentration.

The results for total oil recovery and energy efficiency by the way of CEIR has been shown in **Figure 4.4**. The plot largely benefits Hexane as the best single-component solvent for the simulated reservoir. Note that the secondary axis which displays CEIR is reversed so higher is better for both axes.

Figure 4.3 b shows us the variations in solvent recovery factor, which is the ratio of recovered solvent by injected solvent. If the solvent recovery ratio was 1.0, equal to 100%, then that would mean that all the solvent which was injected into the reservoir has been

retrieved and there was no solvent left in the reservoir. Solvent recovery is very important because the retrieved solvent can be used for other purposes such as upgrading the bitumen for transfer in pipelines while the lost solvent provides no further benefit. The plot gives a clear overview of the reported solvent recovery factors, but says less about how much solvent is actually left in the reservoir for the different solvents and concentrations. The before mentioned plot also makes it seem as if the amount of solvent that has not been recovered deviates from the trend by a large amount for Pentane and Hexane above 20% concentration.

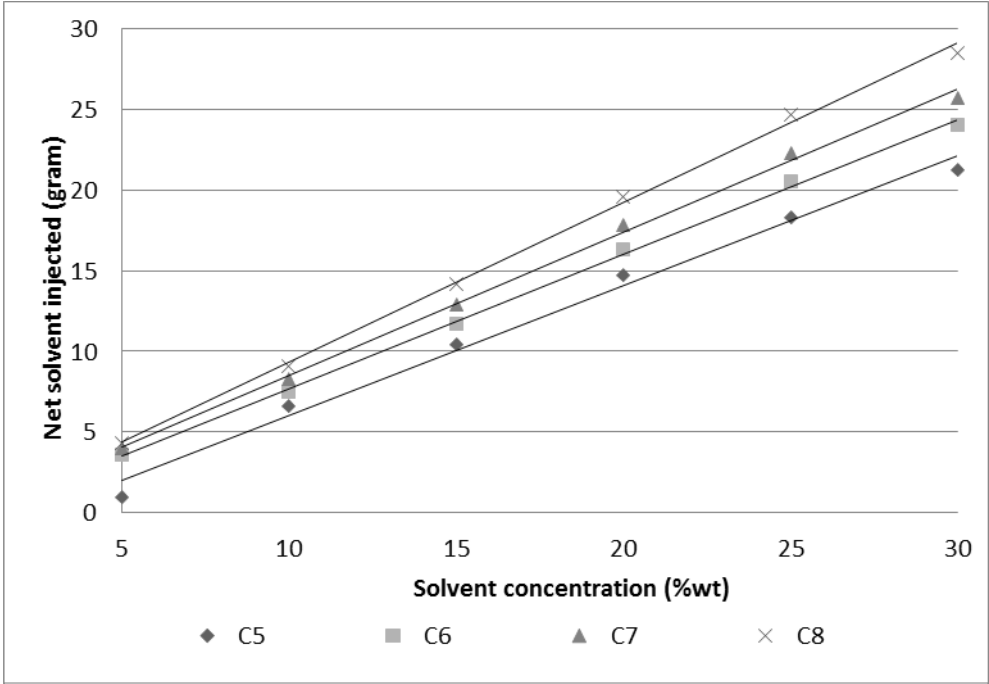


Figure 4.5: Solvent left in the reservoir has a close to linear relationship with solvent concentration.

The trend in net solvent injected with increasing concentration is in fact quite linear which can be seen by the best fit line for all data points. There is only a slight drop-off towards the end at 30% concentration. This plot illustrates that the concentration has a small effect on how much solvent is lost during the process, besides the fact that a higher weight concentration naturally means that more solvent is injected in total. There is no specific concentration which is much better or worse than the rest in regards to solvent recovery. The trend is pretty much the same for all components and the benefits of improving the oil recovery and energy efficiency would be better compared with the amount of solvent left in the reservoir, rather than the set concentration.

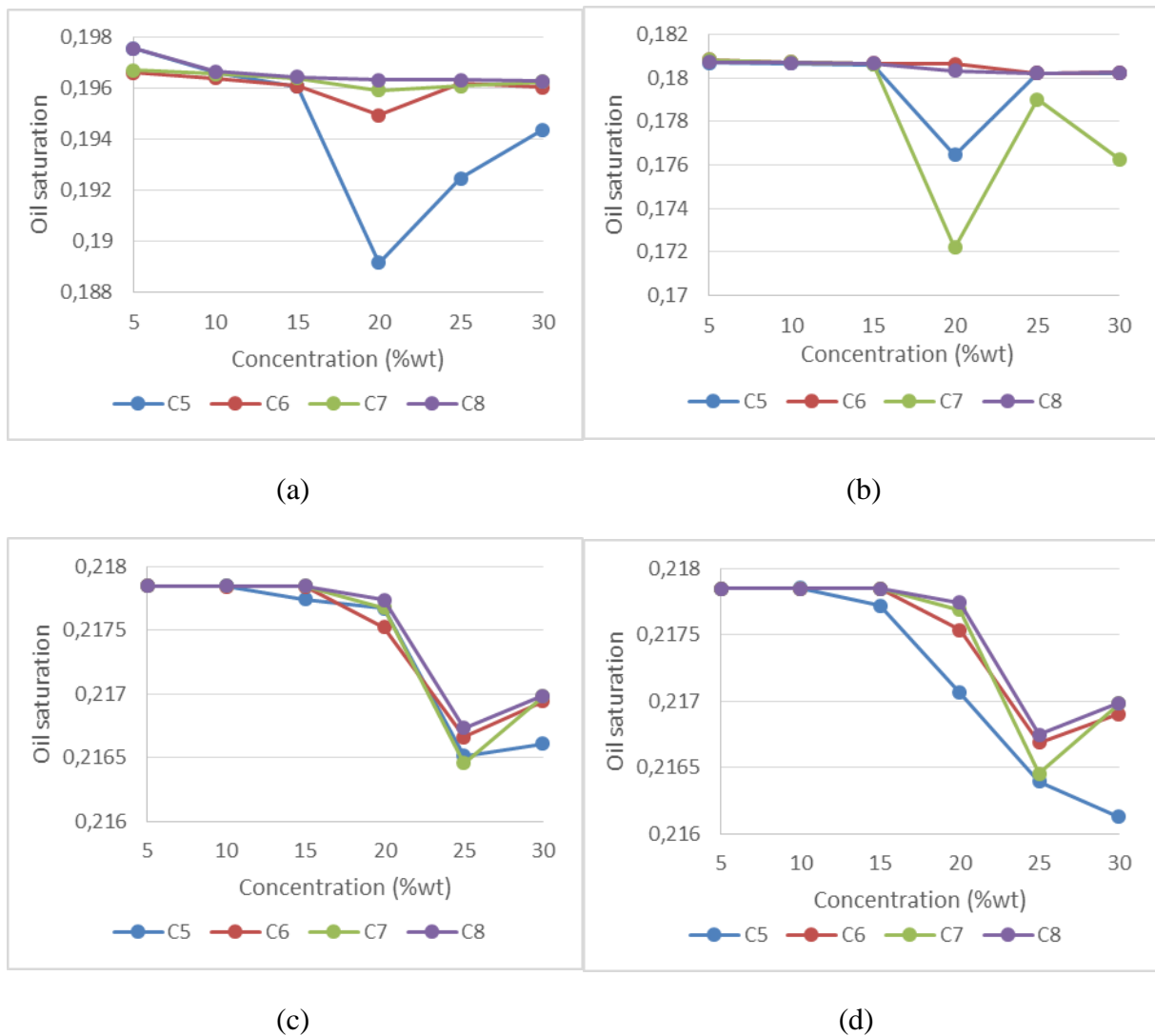


Figure 4.6: a) Residual oil saturation at block 35,1,5 for time 200 min b) Residual oil saturation at block 35,1,5 for time 200 min. c) Residual oil saturation at block 35,1,15 for time 610 min. d) Residual oil saturation at block 35,1,15 for time 610 min.

The difference in oil saturation between the different single-component cases can be as large as 0.01, which equals a change in the oil saturation of ~5%. Decreasing the residual oil saturation, which is the amount of oil that is left behind in the reservoir, is one way to increase oil production. Such a large difference only occurs early in the simulation. At the end of the process at 610 minutes the difference is much smaller. At 610 minutes the difference between the highest and lowest residual oil saturation is five times less at ~0.002, so there is not as much to gain in terms of residual oil saturation from selecting the right injection mixture if the process runs to completion. Even a one percent decrease in residual oil saturation will have a desirable impact on cumulative oil production, and should be able to explain some of the increased production from the solvent additives. The plots also show that the solvent concentration has a much larger impact on the residual oil saturation than solvent selection.

A different mechanism for increased oil recovery is faster propagation of the steam chamber, which will be illustrated using the gas mole fraction (Water) in this work. It is a suitable

indicator for where the developed steam chamber ends which is when the mole fraction starts to decrease from 1.0. Extending from the steam chamber is the chamber boundary which approximately ends when the mole fraction reaches around 0.1-0.0.

The cases plotted below shows the same trend over distance with the possible exception of the 100% steam base case where the gas mole fraction is higher than the rest in the beginning of the boundary. This is most notable in the 5% concentration plot, which is also the only plot where the base case did not propagate the slowest. Generally, adding solvents will increase the chamber velocity and increasing the solvent concentration is effective up to a point. In the case of Hexane the chamber propagation advances further when increasing concentration up to 20% wt, but if increased to 30%wt the chamber velocity actually decreases. This is consistent with the change in behavior when going from 20-25% concentration displayed in other parameters like cumulative oil production, K-value, pressure and temperature.

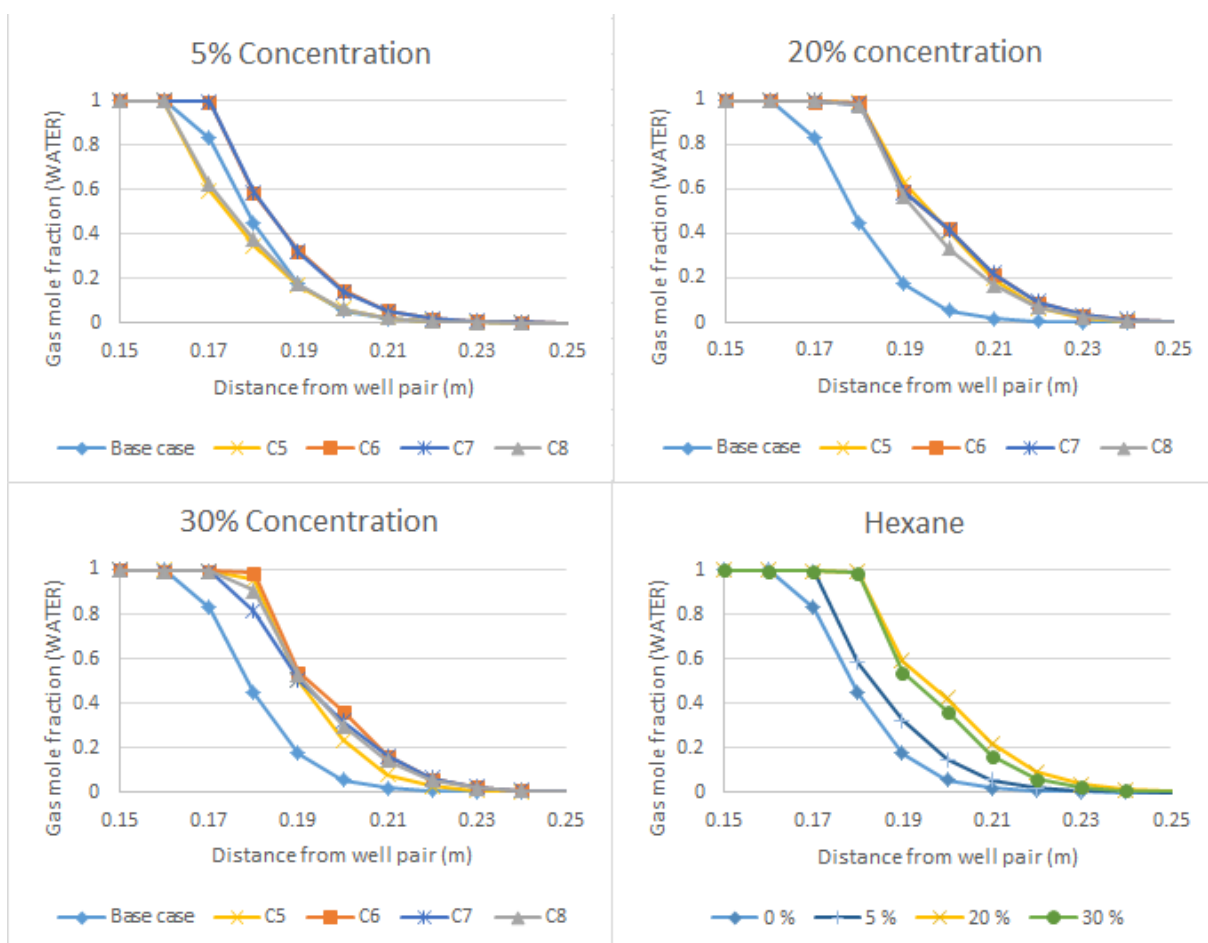


Figure 4.7: Gas mole fraction used to depict the advancement of the chamber boundary for different solvent types and concentrations

Phase behavior at interface

The following data is taken from the case Hexane 30%wt at a simulation time of 200 minutes. The parameters were plotted over a horizontal distance represented by two study lines, where the first study line to be looked at is line 5.

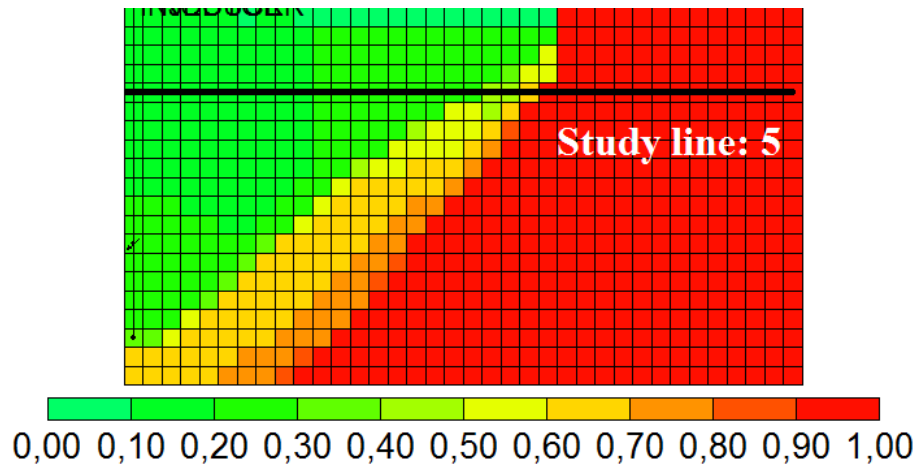


Figure 4.8: Cross section showing oil saturation for line 5 at 200 minutes.

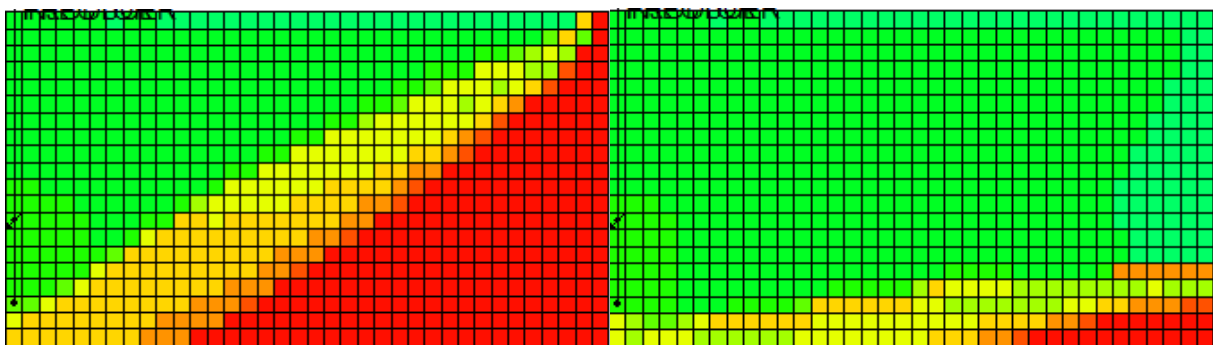


Figure 4.9: Cross section showing oil saturation for line 5 at 300 minutes and 610 minutes

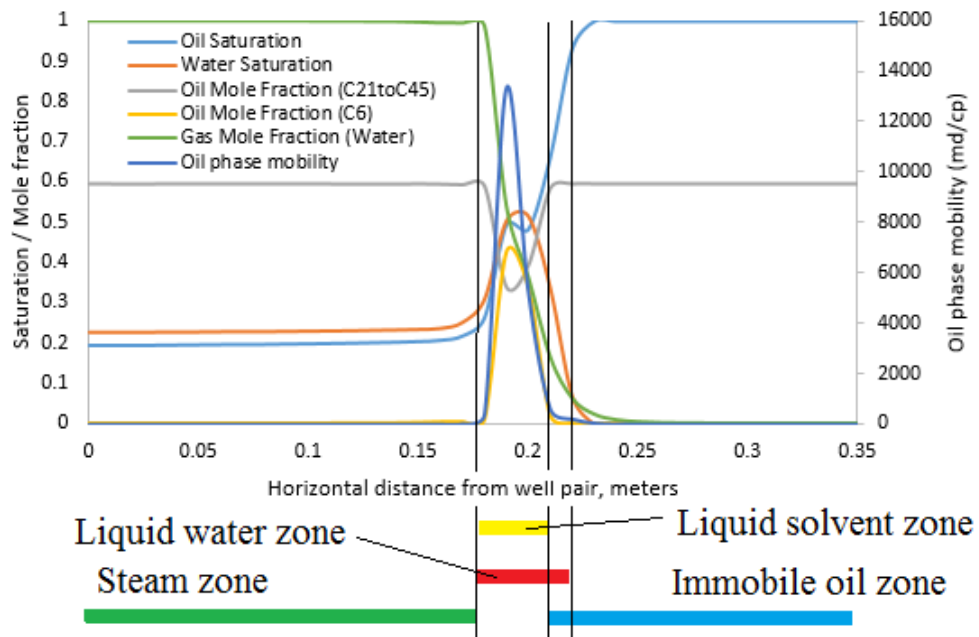


Figure 4.10: Different saturations and mole fractions versus distance at time 200 for line 5.

A good representation of the shape of the steam chamber at this time has been included in **Figure 4.8**. The chamber has been developed, but at 200 minutes it is still quite early in the lifespan of the process. It has developed enough to see the position of the solvent, steam, and bitumen during the process which has been illustrated in **Figure 4.10** and expanded upon in the following plots. For the second cross-section the boundary has just about reached the edges of the reservoir at 300 minutes, and the final image shows the steam chamber condition at the end of the process at 610 minutes.

The steam, represented by the gas mole fraction for water, is prevalent in the already produced parts of the steam chamber. Its decline marks the beginning of the chamber interface, the boundary between the produced zones and the untouched bitumen in the reservoir. When looking at the oil, gas, and water saturations three distinct events occur in the chamber boundary. The gas saturation decreases rapidly from the saturated steam chamber value at around 0.55 to approximately 0 inside the boundary and beyond. This tells us that all the steam and gaseous solvent condenses at the boundary. There is little to none convective heat transfer from the injection gas to the bitumen.

The solvent, represented by the oil mole fraction for Hexane, is only present in notable quantities in the liquid solvent zone marked in the plot. The water saturation indicates that the liquid water extends further into the reservoir than the liquid solvent. This is because the steam interface is set at an angle that is not perpendicular to the study line. The effects of the lowest part of the boundary will appear further away from the well pair. The solvent with its lower than water density tends toward floating to the top with the liquid water draining below. This is also corroborated by the oil saturation with its temporary slump at the position where the water saturation reaches its peak. At the specified time and study line, liquid water accumulates 20 cm in horizontal distance from the well pair.

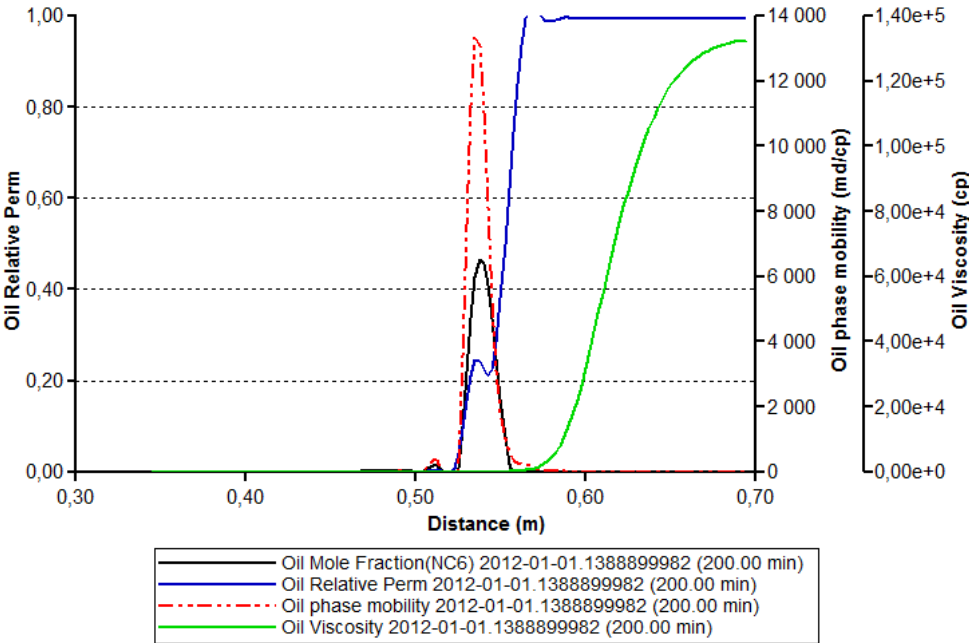


Figure 4.11: Liquid solvent accumulation and oil mobility 30%wt C6 line 5 at 200 minutes

The oil phase mobility increases proportionally to the mole fraction of liquid solvent present in the chamber boundary, and simultaneously the mole fraction of the three pseudo components represented by C21toC45 decreases. This just indicates that the liquid oil in the boundary zone consists of bitumen and solvent and that the presence of liquid solvent increases the oil phase mobility.

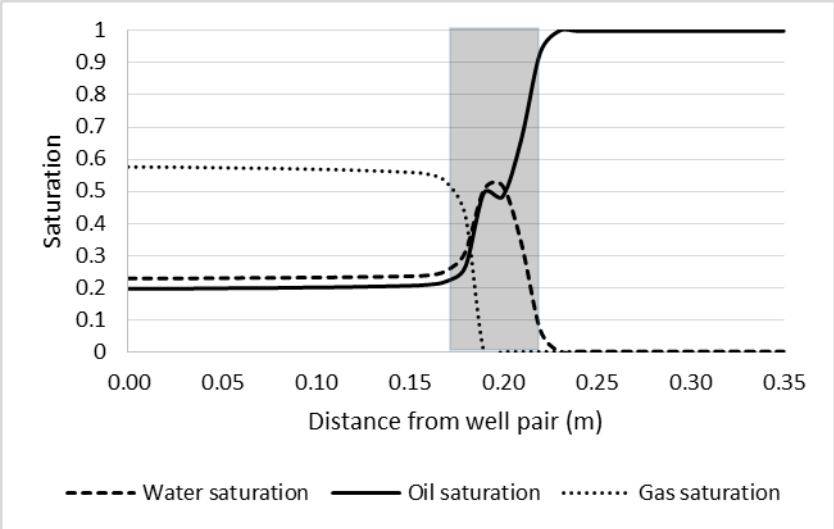


Figure 4.12: Oil, water, and gas saturation for 30%wt Hexane at line 5 for time 200.

The reason for the temporary increase in water saturation is a layer of condensed water moving along the steam chamber interface.

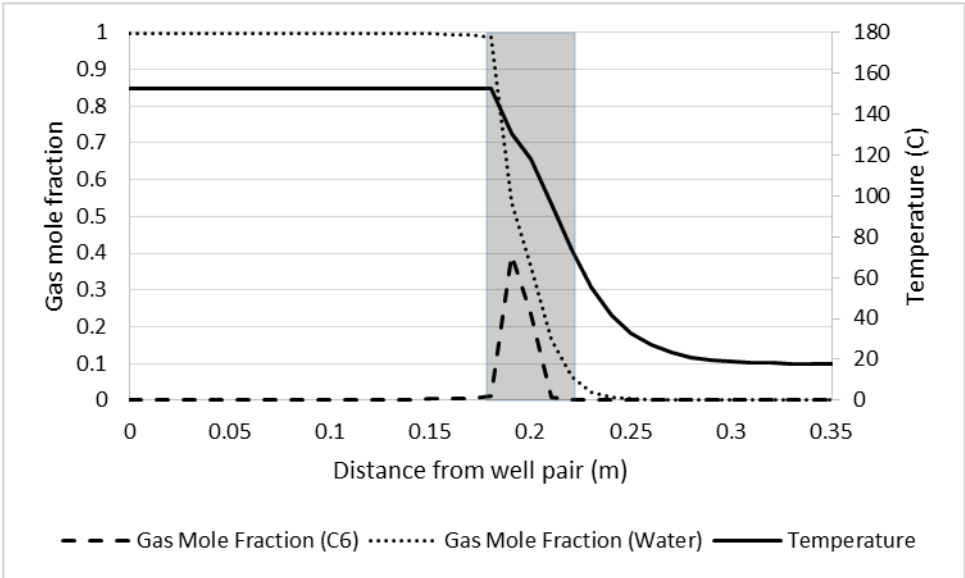


Figure 4.13: Solvent gas and steam position in the steam chamber relative to temperature

The solvent is injected in gas form and transported to the chamber boundary where it accumulates as illustrated in **Figure 4.13** until it can condense into liquid solvent.

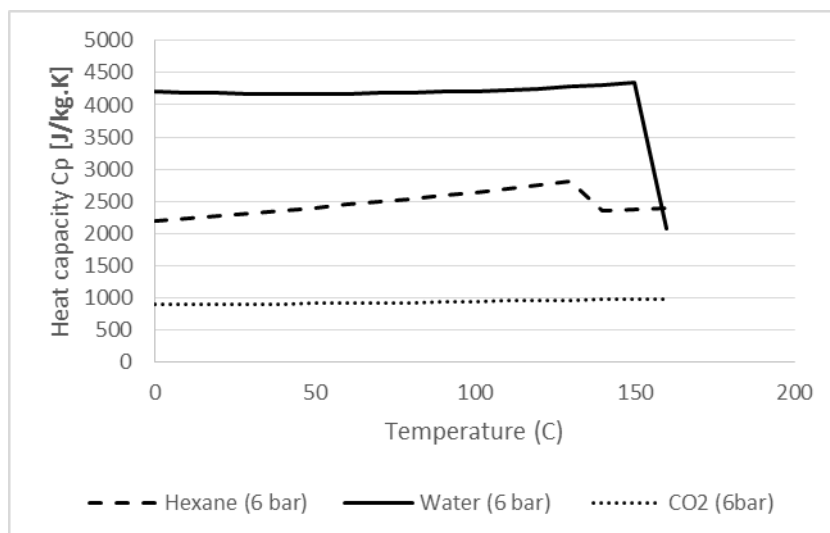


Figure 4.14: Heat capacity for pure components at different temperatures for 6 bar pressure

As indicated by the above plot the specific heat capacity for Hexane and water is almost the same at the injection temperature of ~160 degrees Celsius. The difference in their heat carrying capacity per unit volume comes from the different densities of steam and gaseous Hexane. The specific heat capacity gives heat capacity per unit mass, so it reasons that the heat capacity is greatest where there are liquids as they are denser. This is why the heat capacity reaches its highest point inside the chamber boundary.

HC Concentration (%wt)	5	10	15	20	25	30
C6	599,6	599,6	599,6	599,6	544,3	542,5
C8	599,6	599,6	599,6	599,6	543,8	542,6
C5	599,6	599,6	599,6	594,2	542,5	542,5
C7	599,6	599,6	599,6	599,6	542,6	542,5
C6 20%wt + C7	542,6	542,6				
CO2 Concentration (%wt)	0,1	0,5	1,0	2,0		
C6 30%wt + CO2	599,7	600,1	542,4	542,3		

Table 4.1: Pressure for block 35,1,15 at time 200 for different solvents and concentrations

The pressure also displays the interesting change in characteristics between 20% wt and 25% wt. The change in behavior appears to occur sooner for the lightest compound C5 with a pressure of 594.2 kPa at 20% concentration instead of the 599.6 kPa which is the pressure for the other components. There are still some irregularities for 25% until the pressure settles at a new baseline of 542.5 kPa at 30% wt.

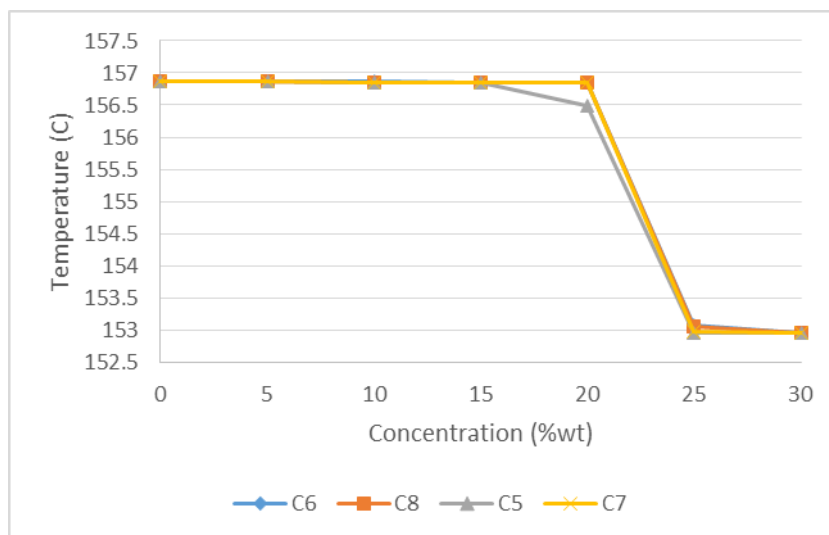


Figure 4.15: Temperature versus concentration for block 35,1,15 for different solvents

If the solvent concentration is increased sufficiently the reservoir will experience a significant drop in temperature. In this research this occurs between 20 and 25% wt concentration for all cases. The temperature drops from 157 to 153 Celsius and the pressure decreases from 600 to 542 kPa. The following plot indicates that it does not occur because of the high solvent concentration in the injection stream, but rather that it occurs when enough solvent has been accumulated in the reservoir.

The temperature for 20% wt C6 and C5 starts to drop off at around 550 and 350 minutes respectively. For C6 injection the temperature drops by 2 degrees Celsius towards the end of the simulation run while the same happens for C5 with a drop of four degrees.

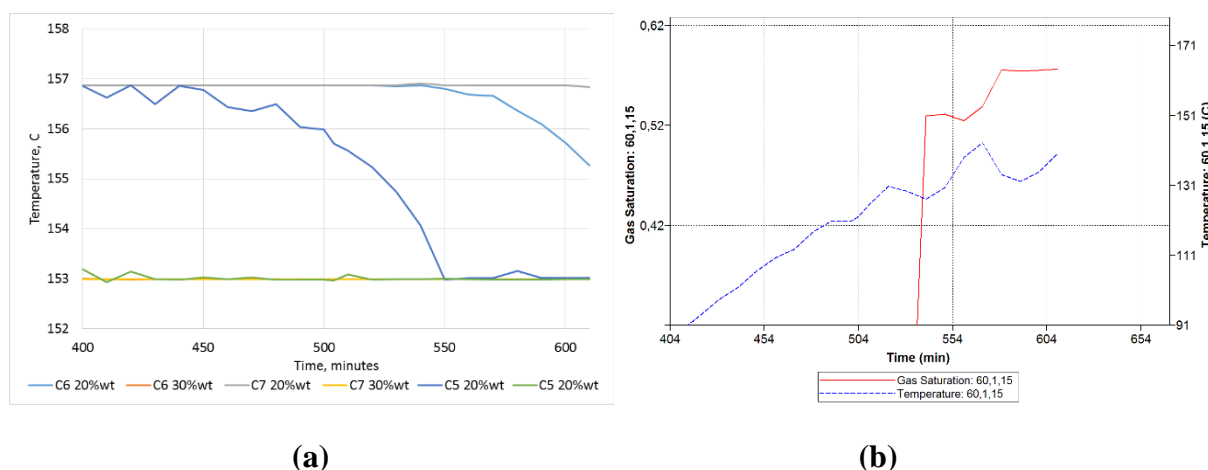


Figure 4.16: (a) Injector block temperature for the most interesting single-component solvents, C6 and C7 at 20 and 30% weight concentration. (b) Temperature decreases as the gas saturation increases towards the end of the simulation run for 20% wt C6.

The temperature decrease corresponds to an increase in gas saturation for block 60,1,15 which can be seen in **Figure 4.16 b**.

K-value varies with solvent concentration

The results included in **Figure 4.17** show that temperature has a major effect on K-value. The K-value follows a similar trend with temperature for all concentrations of C6 and C7, but only the effects on C7 have been included in the figure. If we choose different temperatures and only compare the K-values for the same temperature we can observe other parameters effect on the K-value. It would otherwise be hidden by the higher impact of temperature changes.

CMG reports the temperature and K-value over distance in the reservoir; in this case the distance stretches from the injector and producer well pair towards the reservoir edge in a straight horizontal line known as line 5 from the top. The quantities are not reported frequently enough or at the same intervals as to get the needed readings at the specified temperatures 150, 130, 110, and finally 90 degrees Celsius. Linear interpolation was used to get the K-value for the same exact temperature for all concentrations. This means that there could be significant error if the K-value deviates strongly from a linear relationship with the temperature in the areas where the difference between the temperatures we had K-value data for and the temperature we needed was greatest.

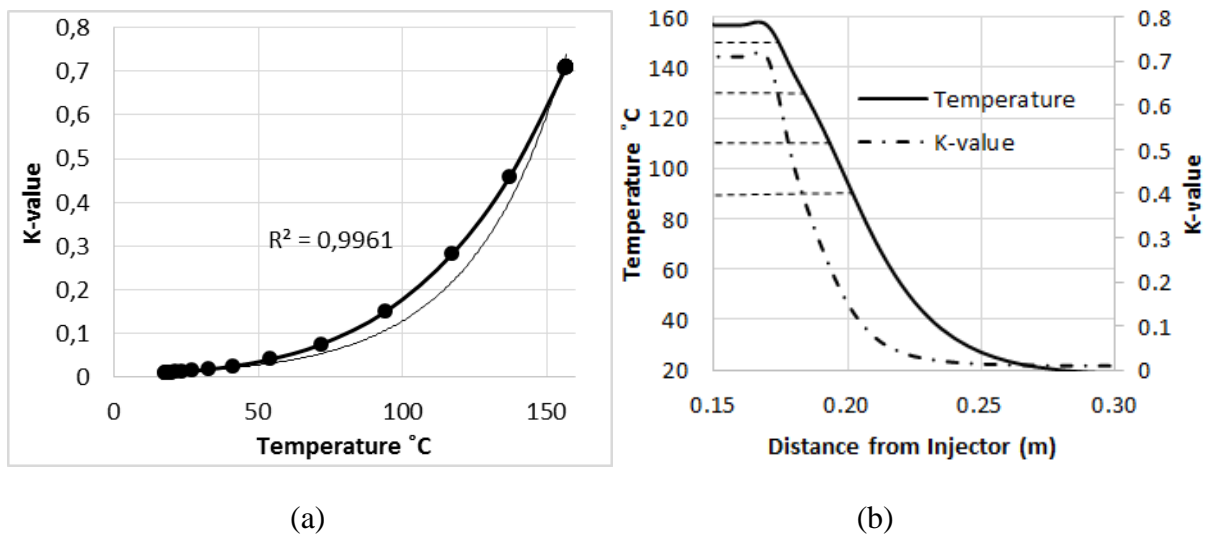


Figure 4.17: (a) K-value increases exponentially as the temperature is raised. (b) Temperature during 5% C7 injection to show which area the K-values have been taken from.

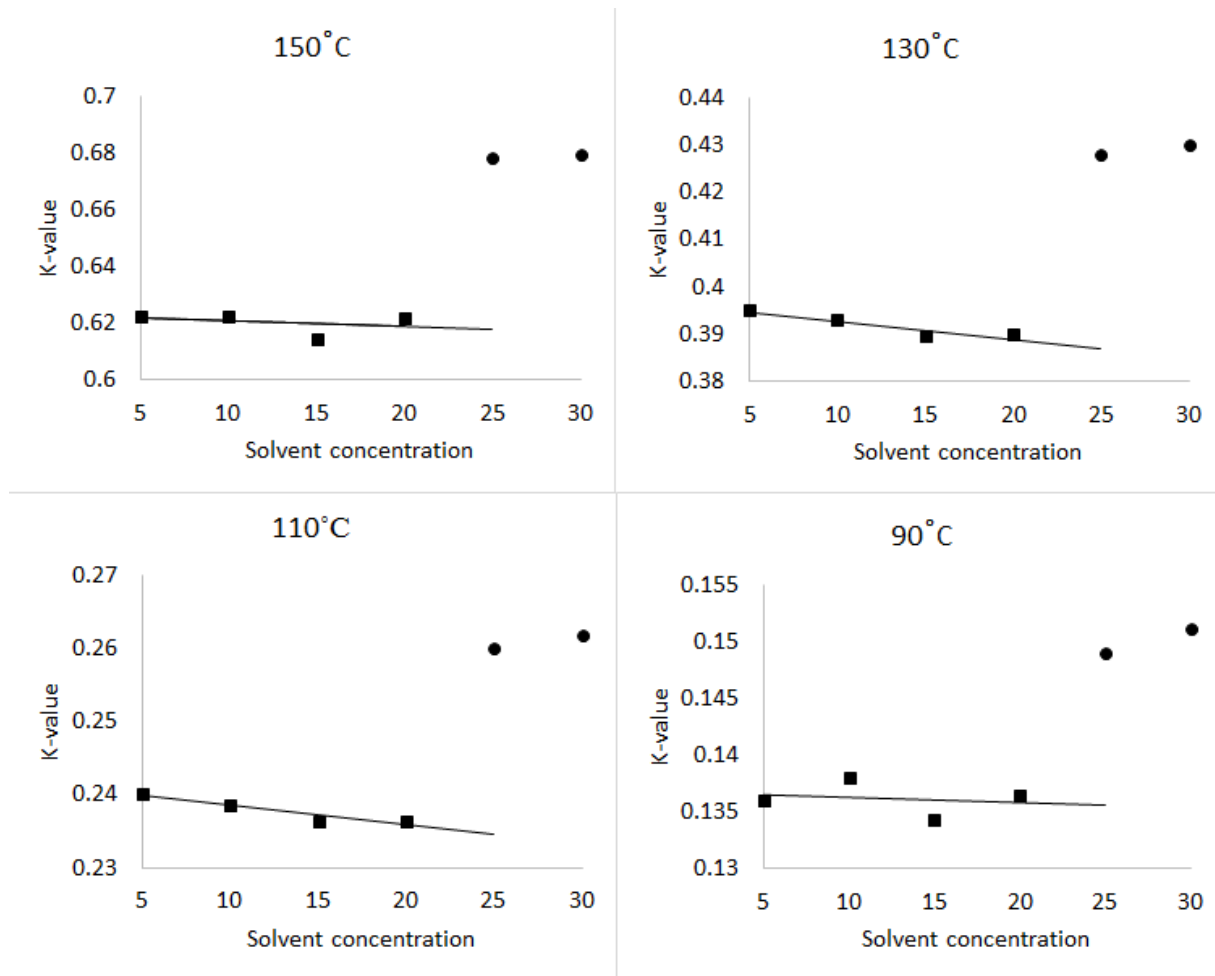


Figure: K-value at reservoir line 5 at 200 minutes versus concentration at different temperatures

The same data was plotted for line 15, but has not been included. It showed that it does not matter if the data is presented for line 5 or line 15 in the reservoir. The trend in K-value versus concentration was the same for the two study lines checked as long as the temperature remained the same.

The sudden jump in K-value from 20% to 25% solvent weight concentration could explain the change in behavior for the different performance metrics when moving from 20 to 25 percent. When compared to 5 to 20 percent weight concentration, which produces a close to linear plot for all metrics just like the K-value, there is likely a connection between the change in K-value and the change in other parameters.

4.2 Heptane co-injection with Hexane

It is clear that Hexane achieves good oil recovery at 20% wt and 30% wt, but the best energy efficiency is achieved at 30% wt while the best solvent recovery is achieved at 20% wt. Considering C7 is the best choice for solvent recovery it might be possible to include some C7 in a solvent mix consisting mainly of around 30% wt C6 to improve the total solvent

recovery while still maintaining the excellent oil recovery and energy efficiency properties of the original solvent.

This was investigated and the results were very good. The results of co-injecting 5% and 10% by weight of the solvent Heptane with 30% wt Hexane is showcased in the plots below:

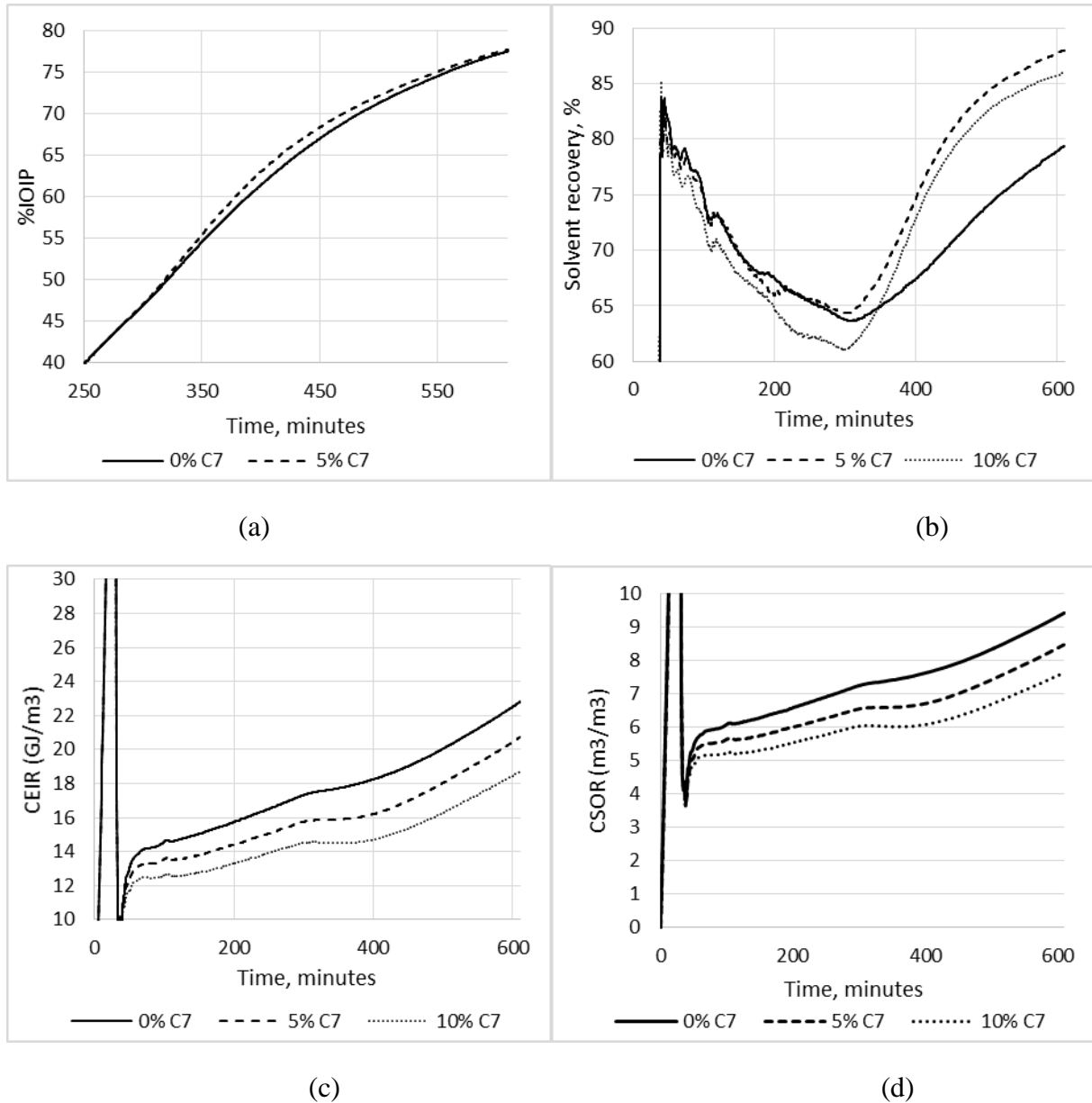


Figure 4.18: All plots are for 30%w C6 injection with associated C7 concentration **(a)** Total oil recovery as %IOIP. **(b)** Solvent recovery factor in mass **(c)** Cumulative Energy Intensity Ratio (Cum. Energy injected / Cum. Oil) **(d)** Energy efficiency illustrated by the CSOR.

There is almost no change in ultimate oil recovery. Adding 5% wt or 10% wt makes little difference and the increase in %IOIP is less than 1%. However, 5% does give the best cumulative oil production which suggests that the composition has reached its limit in terms of how much solvent is actually useful.

CEOR improves with increasing solvent concentration as expected. The energy efficiency is the best when injecting 10% C7 which makes a case for choosing the higher concentration, but that would depend on the situational economics of energy efficiency versus solvent recovered.

The above figures illustrated the effects of adding Heptane, while the four figures included below show the effects of changing the solvent composition but still having the total solvent concentration remain the same. The results for solvent recovery showed that the recovery factor is higher for solvent co-injection than for same concentration but single component. There is definitely a positive synergy between Heptane and Hexane in regards to solvent recovery.

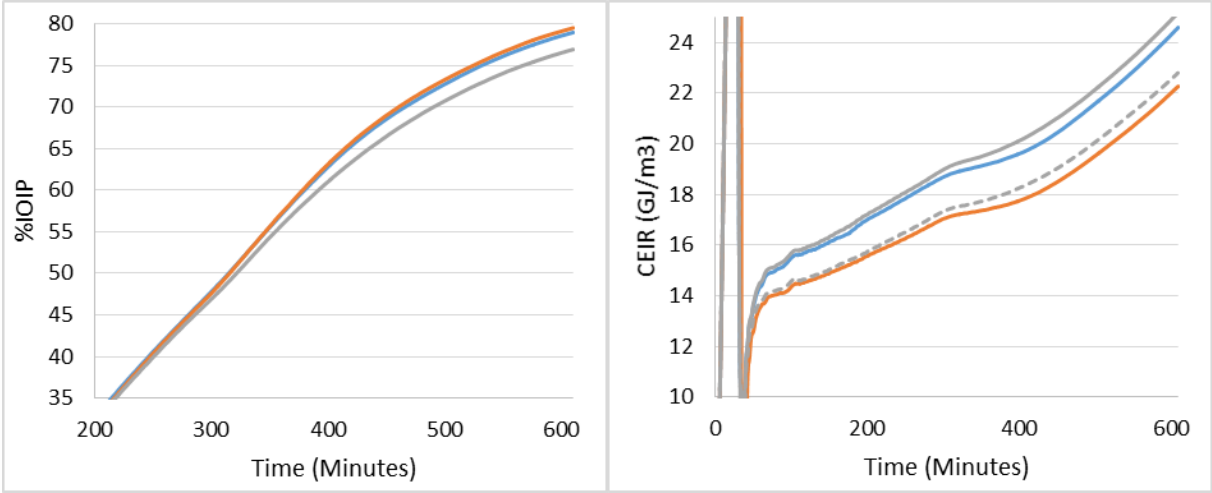


Figure 4.19: %IOIP and CEIR over time for Heptane and Hexane mixture and the hexane reference cases 25 and 30%wt C6 they should be compared to.

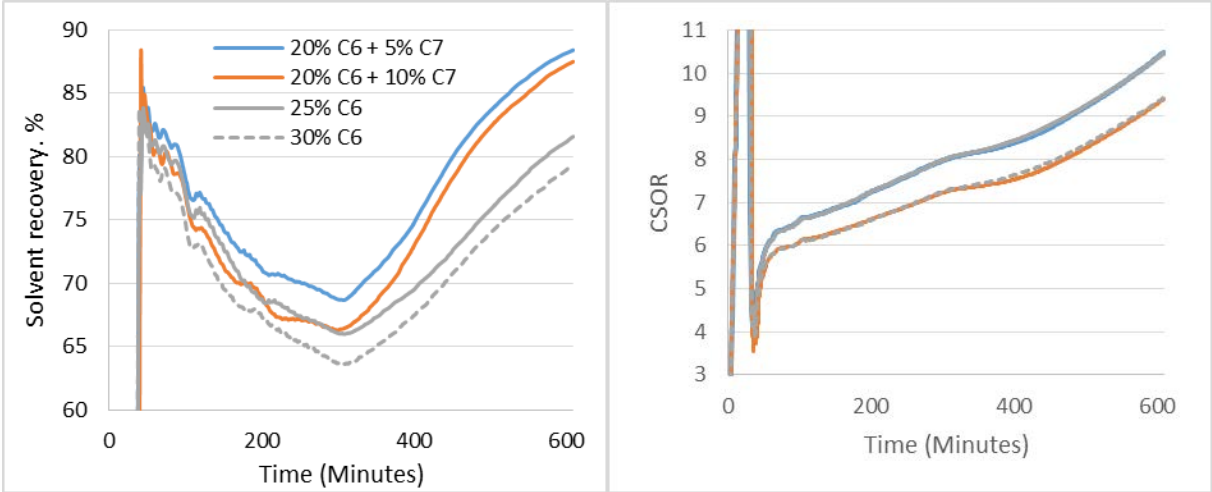


Figure 4.20: Solvent recovery in percent of total injected mass and CSOR for the solvent co-injection cases.

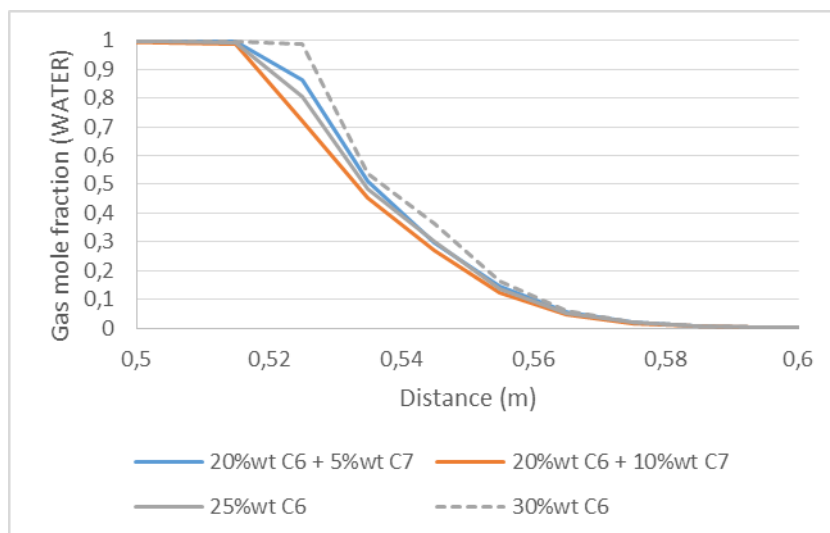


Figure 4.21: Gas mole fraction used to depict the advancement of the chamber boundary for the solvent co-injection cases and the reference cases 25 and 30% wt C6.

Hexane alone produced a higher chamber velocity than co-injecting Hexane with Heptane, so the increased oil production has to be caused by something else. Including Heptane in the 30% wt mixture is detrimental to chamber velocity.

	25% C6	20% C6 + 5% C7	30% C6	20% C6 + 10% C7
Line 5, 200 min	0.19622	0.19625	0.19606	0.19655
Line 5, 610 min	0.1802	0.18023	0.18021	0.18027
Line 15, 200 min	0.21666	0.21659	0.21694	0.21696
Line 15, 610 min	0.21668	0.21659	0.2169	0.21696

Table 4.2: Residual oil saturation for the solvent co-injection cases and the reference cases 25 and 30% wt C6.

As was shown in the single-component section of the results, solvent selection does not have a large impact on residual oil saturation compared to solvent concentration. This is also the case for solvent co-injection; there is no proven benefit to combining solvents in terms of decreasing residual oil saturation.

4.3 CO₂ co-injection with hydrocarbon solvent

The following research looks at how to best co-inject CO₂ with a hydrocarbon solvent both in regards to which solvent and concentration, and in regards to when to start the CO₂ injection to achieve the desired results.

The hydrocarbon solvents to be tested with CO₂ and the appropriate concentrations were decided when looking at the best performing cases in the previous section. Hexane has been shown to be a very good solvent for this application and is the natural choice. It is interesting to see if CO₂ co-injection can further improve the oil recovery, solvent recovery and energy efficiency of Hexane in the Solvent-Aided SAGD process. Heptane has also been tried with CO₂ to investigate if it would be beneficial to use a heavier solvent than Hexane. The

difference in results between Hexane and Heptane are not that significant, so these two solvents will be co-injected with CO₂, but the results will mainly focus on hexane.

The recovery rate is expected to increase from the addition of CO₂ due to among other things viscosity reduction and oil swelling. Previous research has indicated that the ultimate recovery is likely to decrease. (M.W. Hornbrook et al., 1991)

The third and final case is an initial injection of Hexane with steam at 30% weight concentration where CO₂ is eventually added to the mixture. After a set amount of time the initial composition will have CO₂ co-injected at 0.1% weight concentration. This is expected to improve the total oil recovery, which usually suffers from CO₂ injection.

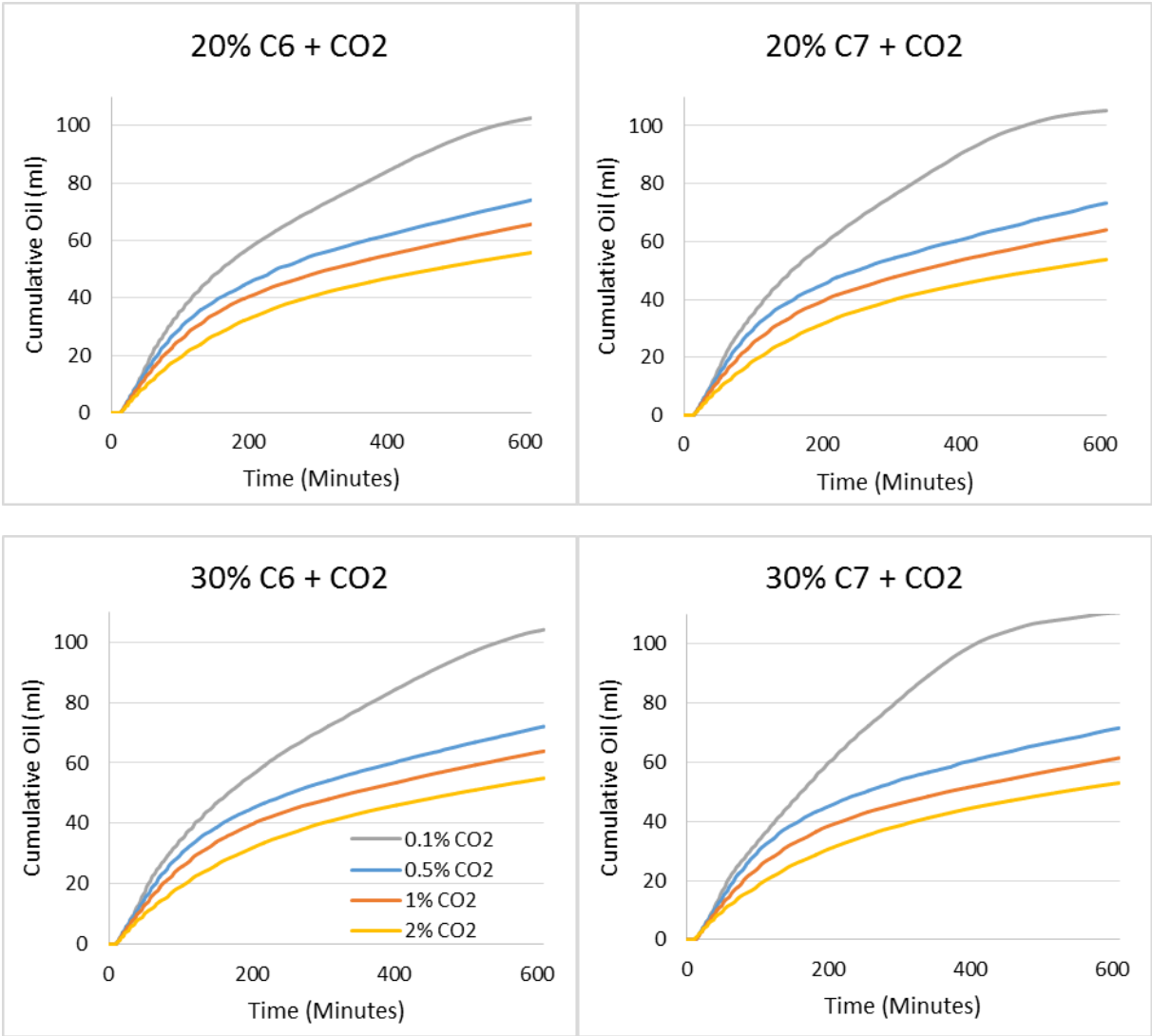


Figure 4.22: Cumulative Oil production in milliliters for CO₂-Solvent co-injection.

The injection compositions where CO₂ is present at quantities of one to two percent by weight with the associated densities produce a very poor total oil recovery. When injecting CO₂ from the beginning of the simulation it needs to be at a very small fraction of the total well stream or the oil production will suffer significantly.

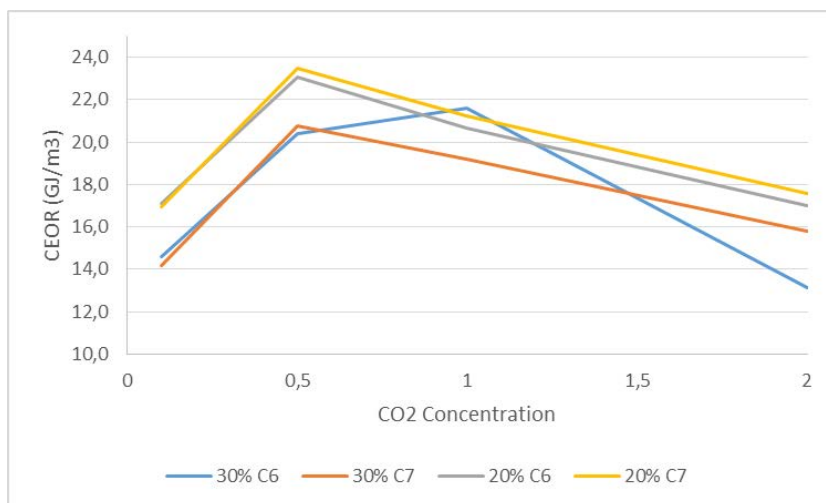


Figure 4.23: CEOR for CO2 co-injection with HC solvent

The energy efficiency measured by the CEOR is greatest for the lowest and highest concentration of CO2 by weight, 0.1% and 2% respectively. At low CO2 concentrations the benefit to the CEOR comes from a high oil recovery, while for high concentrations the improvements to CEOR is due to low steam usage and less net injected solvent.

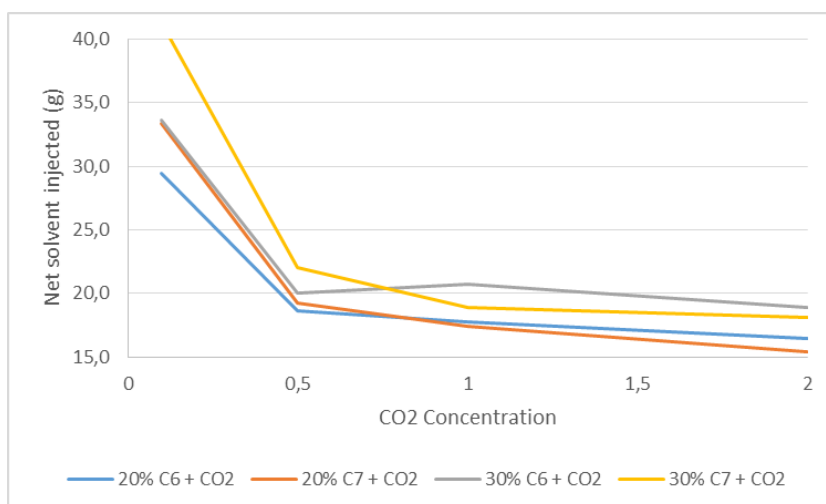


Figure 4.24: Net injected solvent for the different CO2 and HC solvent cases

When CO2 is included in the injection stream it affects the HC solvent phase behavior so that it is skewed towards the liquid phase. This is represented by making individual fluid models in Winprop for each fluid composition. The solvent density decreases and more solvent mass can be injected. For the case with 20% C6 co-injected with 0.1% CO2 the results were 1,738 kg solvent injected and 1,71 kg solvent recovered which leaves 0,028 kg or 28 grams of solvent in the reservoir. The injected solvent take up mass that otherwise would have been water and strongly reduce the cumulative mass of injected water. The injected mass of solvent for the CO2 cases far surpass any of the other cases where the amount of solvent injected is closer to 20 grams, and because the recovered solvent is not counted in the CEOR we get a good energy efficiency.

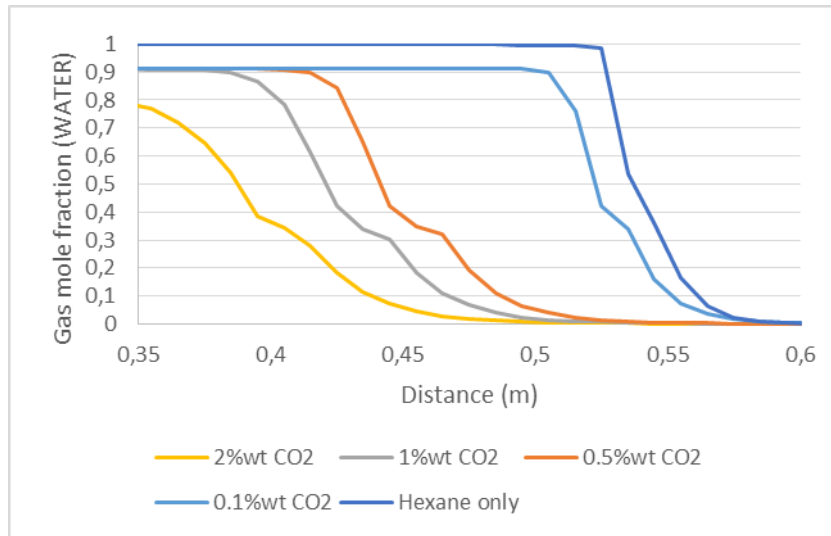


Figure 4.25: Gas mole fraction used to depict the advancement of the chamber boundary for different concentrations of CO₂ combined with 30% Hexane.

CO₂ is detrimental to chamber velocity when co-injected with Hexane and there is no concentration simulated for in this research where CO₂ has a positive effect on chamber propagation.

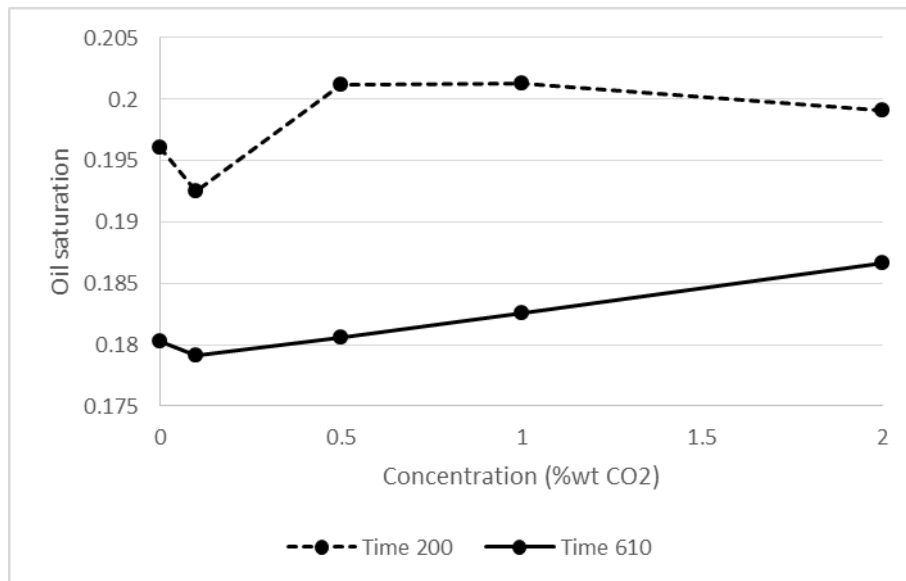


Figure 4.26: Residual oil saturation for different concentrations of CO₂ combined with 30% wt Hexane

When co-injected with Hexane at low concentrations CO₂ can cause the residual oil saturation to decrease. In this research that only occurred for 0.1%wt CO₂. The higher concentrations of CO₂ caused a larger fraction of the oil to be left behind in the reservoir.

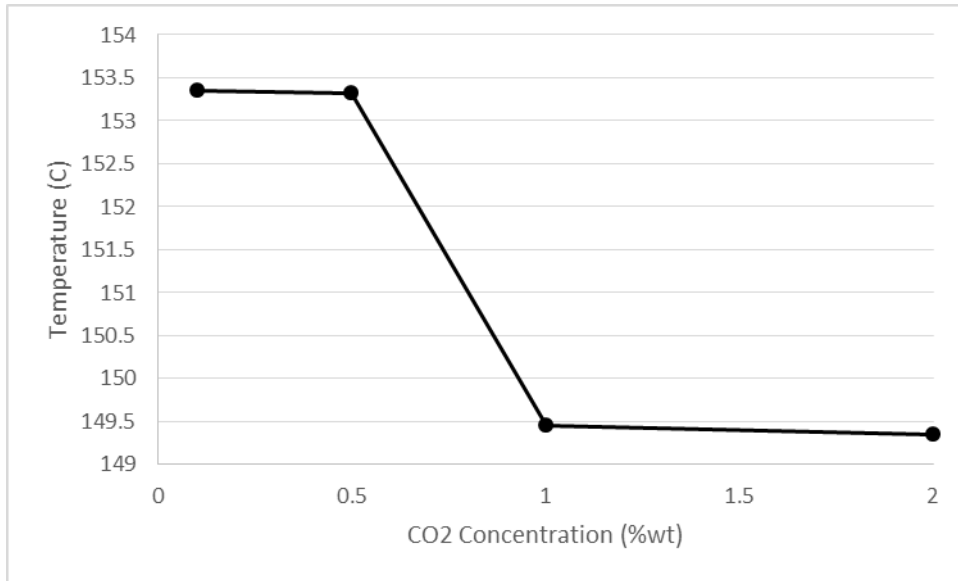


Figure 4.27: Temperature for block 35,1,15 for different concentrations of CO₂ combined with 30% wt Hexane

Compared to 30% wt Hexane only there is almost no difference in temperature for 0.1% and 0.5% wt CO₂ co-injection. The 30% Hexane case with no CO₂ achieves a chamber temperature of 153 degrees Celsius, the same as 0.1% CO₂. When the concentration of CO₂ was increased to 1% or 2% the temperature drops by almost four degrees. Coincidentally, that is the same temperature differential as when increasing the concentration of any hydrocarbon solvent from 20% to 25% wt.

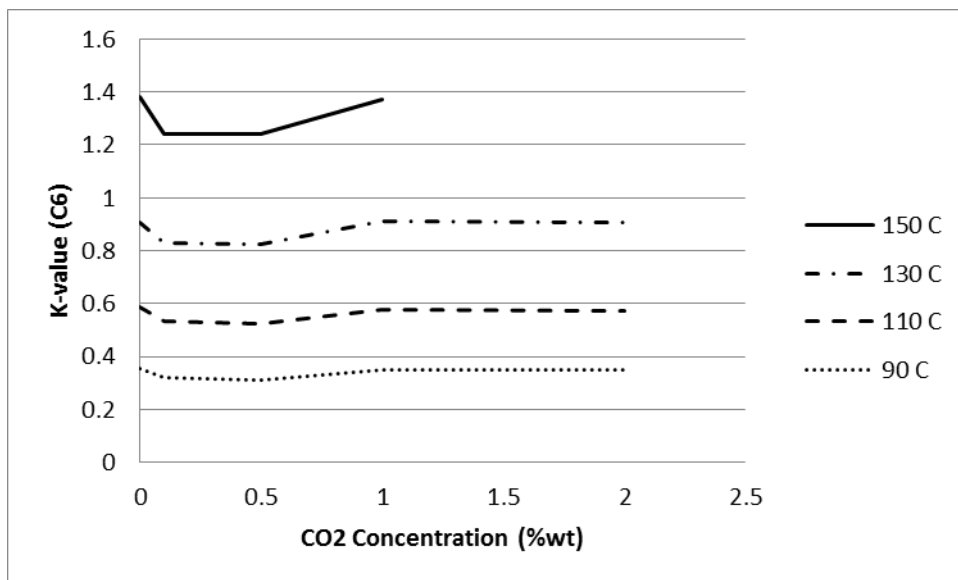


Figure 4.28: CO₂ content affects the hydrocarbon solvent K-value at different temperatures.

The change in K-value of Hexane was plotted as a function of CO₂ concentration for four different temperatures experienced along the chamber boundary inside the reservoir. For hydrocarbon single-component solvents the same plot showed a possible explanation for the change in behavior between 20% and 25% solvent concentration.

There is no indication in the K-value of which specific concentration would yield the highest oil recovery or give the best performance in general, but it might give a broad depiction of which solvent concentrations are viable for the specific injection conditions. The cases with 0.1% and 0.5% CO₂ experienced the lowest K-values.

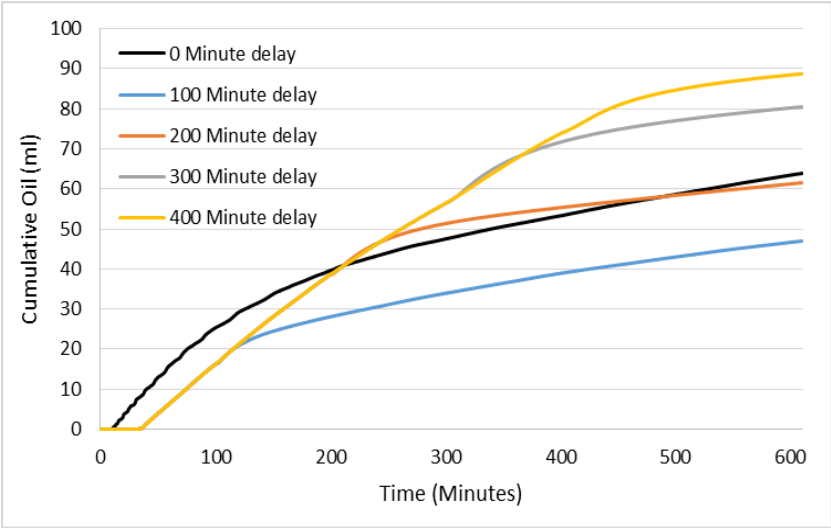


Figure 4.29: Cumulative oil when delaying 1% wt CO₂ injection for 30% C₆

The plot illustrates that if CO₂ is not initially included in the injection stream it should not be included until after enough time has elapsed. If CO₂ injection is initialized before 200 minutes it has a negative impact on the cumulative oil production. When CO₂ is present in the injection stream from the start the oil production starts quickly in terms of early oil production and a high initial flow rate seen by the steep slope of the cumulative oil curve. The downside is a quick drop-off and a moderate slope towards the end which results in a low total oil production. Similar results were reported when the CO₂ concentration was changed to 0.5% wt.

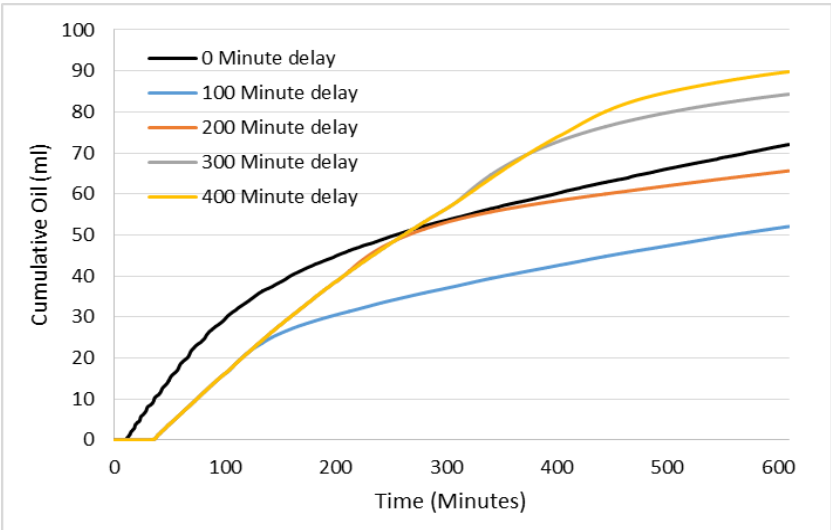


Figure 4.30: Cumulative oil when delaying 0.5% wt CO₂ injection for 30% C₆

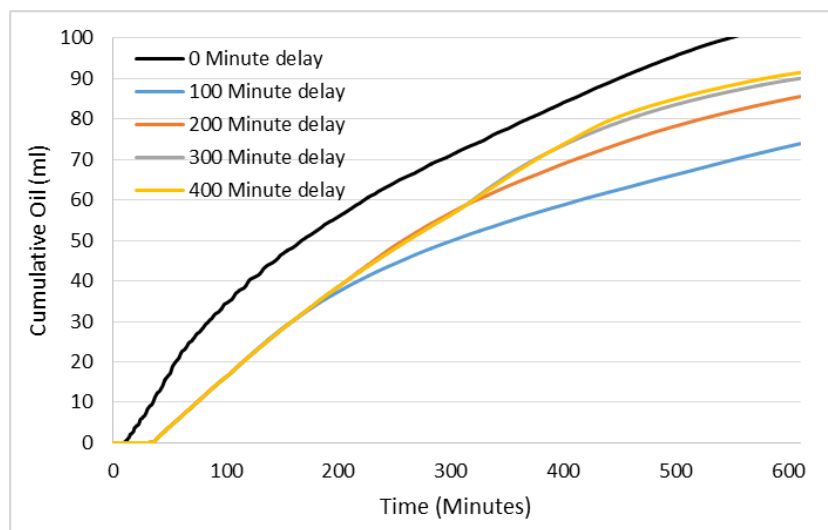


Figure 4.31: Cumulative oil when delaying 0.1% wt CO₂ injection for 30% wt C₆

The simulation results showed an exception for 0.1% wt CO₂, where the injection timing with no delay was by far the best alternative. There was also less spread between the reported cumulative oil for the different injection timings. This indicates that for lower concentrations of CO₂ it is better to start the injection right away, while for higher concentrations it could be beneficial to delay the start of CO₂ injection for a significant amount of the simulation period.

The most efficient injection mode for the proposed reservoir is immediate CO₂ co-injection with a low concentration; in this research 0.1% wt gave good results. Higher concentrations or the effect of delaying the start time did not give any improvements to the oil production. The low concentration case with 0.1% wt CO₂ co-injected with 30% wt C₆ produced 104ml oil cumulative, which compared to 30% wt C₆ alone with an oil production of ~94 ml, is a significant increase of 10%. According to these findings, CO₂ is best utilized in low concentrations and mixed with a larger quantity of suitable hydrocarbon solvent. The plot of cumulative oil versus time in **Figure 4.29**, **Figure 4.30**, and **Figure 4.31** shows that the inclusion of CO₂ in the injection stream improves the speed of oil recovery, the oil rate, in the beginning of the simulation period. The oil production starts quicker, and the slope of the cumulative oil plot is steeper at the beginning.

5 Conclusion

SAGD is a well-established and successful method of recovering bitumen. When co-injected with steam, solvents can help by increasing the oil production rate as well as total recovery, and lower the steam usage. Lowering the energy requirement for producing steam is even more relevant in this day and age where the environmental impact has to be considered.

Introducing a new component to the process makes it more complicated and introduces new mechanisms that need to be studied. Chapter 4 of this thesis includes attempts to make it clearer how the solvent behaves when introduced to the reservoir, where does it accumulate and how does it affect the bitumen mobility. It is important to look at the phase behavior of the different components to explain the effects of introducing solvents.

The following conclusions have been reached from this research:

1. There was a reasonable agreement with current Solvent Assisted SAGD numerical studies and the notable differences could likely be explained by the differences in operating conditions and reservoir model.
 - a. Hexane is the most beneficial single-component solvent for injection in the proposed reservoir with Heptane as a close second.
 - b. The amount of solvent left in the reservoir had a close to linear relationship with solvent concentration.
 - c. A solvent with excellent solvent recovery properties was successfully co-injected with a second solvent to improve the total solvent recovery factor.
2. CO₂ can be successfully co-injected with a hydrocarbon solvent but the mode of injection depends on CO₂ concentration.
 - a. There exists a time period after starting hydrocarbon solvent injection where CO₂ co-injection should not be attempted.
 - b. For low concentrations of CO₂ there is no benefit in delaying.
3. Between 20% and 25% solvent weight concentration there was a significant change in reservoir temperature, pressure, K-value at a specific temperature, and several other parameters.
 - a. These changes have a negative effect on the cumulative oil production and a positive effect on the energy efficiency.

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