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Mixing of Solvent and Bitumen in Steam-Solvent Co-Injection Under

Controlled Thermodynamic Conditions

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Mixing of Solvent and Bitumen in Steam-Solvent Co-Injection Under

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Dedication

To my family.

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Mixing of Solvent and Bitumen in Steam-Solvent Co-Injection Under Controlled Thermodynamic Conditions

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The most important aspect of solvent-aided steam-assisted gravity drainage (SA-SAGD) is the interplay between phase behavior and fluid flow near the edge of a steam chamber, which is caused by the mixing of solvent with bitumen. The mixing of solvent with bitumen (i.e., dispersion) results in dilution of the bitumen and improves the energy efficiency of SAGD. However, it is often difficult to analyze this through large-scale steam injection experiments because chamber-edge thermodynamic conditions in the experiments are transient. Moreover, research studies on dispersion, along with dispersion coefficient data, in SA-SAGD are scarce.

This thesis presents a novel small-scale experimental method and a numerical model designed to study the bitumen gravity drainage with steam injection (SAGD) and solvent-steam co-injection (SA-SAGD) under controlled thermodynamic conditions, such as pressure, temperature, and composition. The dispersion coefficients for solvents with bitumen under gravity drainage with controlled boundary conditions are determined by calibrating a fine-scale numerical model with experimental data. The experiments use a 3inch diameter by 15-inch length sand-pack placed in a 25-L cylindrical pressure vessel. The sand-pack is surrounded by a one-inch annular void space, into which the vapor phase is injected under controlled pressure, temperature, and composition. Both steam only and steam and solvent co-injection experiments are performed at a pressure of 3500 kPa. Oil production and temperature profiles inside and outside the sand-pack are recorded for all experiments. Post excavated samples from the sand-pack are analyzed.

The results of the SAGD base case are history-matched using a numerical simulation model. The established parameters from the SAGD history match are then transferred to the SA-SAGD simulation model. The SA-SAGD experiments are history matched by fine-tuning the dispersion coefficient to better model the mixing between the solvent and bitumen. The dispersion coefficient for C₄ and C₈ in bitumen for SA-SAGD are determined to be 5.83×10^{-2} m²/day and 5.64×10^{-2} m²/day, respectively. The associated Péclet numbers for C₄ and C₈ dispersion coefficients are 60 and 309. The solved dispersion coefficients are analyzed and discussed. Finally, the criteria and guidelines are given for applying the determined dispersion coefficients in the field-scale simulation of SA-SAGD.

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Chapter 1: Introduction

1.1 Background

Steam-assisted gravity drainage (SAGD) is one of the most widely used and successful methods for thermal recovery of extra-heavy oil or bitumen. There are currently over 1.6 million barrels of oil per day produced using this method, accounting for over 1.7 percent of total world oil demand (AER 2021). Solvent-aided, steam-assisted gravity drainage (SA-SAGD) is an enhanced version of SAGD, in which a small amount (5-15 weight percent) of solvent, usually a mixture of n-alkanes or pure n-alkanes, are co-injected along with steam to produce extra-heavy oil. In both SAGD and SA-SAGD, engineers drill stacked horizontal well-pairs into the formation. The upper well injects the steam and solvent, while the lower well produces oil and water by gravity (Figure 1.1).



Figure 1.1: SAGD recovery scheme diagram (JAPEX 2021)

SA-SAGD enhances oil recovery by bitumen dilution with injected solvent. In addition, it has the potential to reduce heat loss by decreasing the vapor phase temperature (Keshavarz et al. 2014, 2015; Li et al. 2011ab; Nasr et al. 2003) and by speeding up the oil production due to dilution. As a result, SA-SAGD recovery schemes produce more bitumen for the same amount of steam input, lowering the steam to oil ratio (SOR). SOR is one of the most important metrics used by the oil industry in evaluating the success of in-situ bitumen recovery projects. A lower SOR in a steam-based project indicates a smaller amount of steam used in oil recovery and higher energy efficiency, which increases the project's economic returns. Moreover, a smaller amount of steam used also means that less natural gas is needed to generate the steam and therefore less greenhouse gas (GHG) emissions. The incremental oil recovery in SA-SAGD compared to SAGD is enhanced under heterogeneous petrophysical properties because of more effective dilution of bitumen through tortuous flow paths (Venkatramani and Okuno 2018ab; Sheng et al. 2021). This indicates that SA-SAGD can further help bitumen recovery from more challenging heterogeneous reservoirs with an increase in shale barriers. As a result of the many benefits of SA-SAGD, the industry has widely applied this recovery scheme on current SAGD projects (Gates 2007; Gupta and Gittins 2006; Gupta et al. 2005).

A major mechanism of SA-SAGD is the mixing of solvent and bitumen in the porous medium during the recovery process. This is where the hydrodynamic dispersion of solvent comes into play. Hydrodynamic dispersion, widely known as dispersion, is the mixing of solvent during miscible displacements caused by diffusion, heterogeneity, and mechanical mixing within pores (Lake 1989). Although SA-SAGD recovery methods, as an alternative or enhancement method to SAGD, have been studied using lab experiments and simulations, there is a lack of research regarding the mass transport of solvent in the porous medium and the effect of solvent dispersion on oil recovery.

1.2 Problem Description

An important part of SA-SAGD is the mixing of solvent with bitumen to dilute bitumen and improve oil recovery. Dispersion of the solvent into the oil is the controlling parameter in oil dilution, and the dispersion coefficients are required to evaluate the process of solvent and steam co-injection.

Some data regarding the diffusion coefficient of solvent in the vapor extraction (VAPEX) process has been reported; however, there is a lack of mechanical dispersion coefficient data for mixtures of solvents and bitumen under gravity drainage. This is mainly due to the absence of an experimental procedure to determine the dispersion coefficient.

There is currently no systematic method or procedure in determining the dispersion coefficient of solvent in bitumen. Therefore, it is of great significance to develop a method to accurately determine the dispersion coefficient to enable more accurate reservoir simulations and improve for optimizing SA-SAGD operation and solvent usage.

1.3 Research Objectives

With the research challenges presented, the main objective of the research is not only to determine the dispersion coefficient but also to validate the method of determining dispersion coefficient for solvent and bitumen systems, allowing further research in this field. The objectives of this research are the following:

- Develop a small-scale experimental setup and method in which the steam and solvent co-injection processes under gravity drainage are modeled with controlled thermodynamic conditions.
- 2. Establish a method to determine the dispersion coefficient for steam and solvent co-injection.
- Determine the dispersion coefficients of C₈ and C₄ for C₈-SAGD and C₄-SAGD, respectively.
- 4. Verify and validate the determined dispersion coefficients.

In order to achieve the objectives listed above, the following tasks need to be performed:

- 1. Propose a method to determine the dispersion coefficient of solvent in SA-SAGD.
- Develop an easy, cost-effective, and quick way to conduct SAGD and SA-SAGD experiments in which gravity drainage is physically modeled.
- 3. Perform simulations to history match all available experimental data such as temperature distribution and oil production for SAGD to fine-tune some important input parameters which will be used in SA-SAGD simulations.
- 4. Adjust only dispersion coefficient to history match SA-SAGD experiments using simulation and therefore determine dispersion coefficient of solvents.
- 5. Validate the isolation of the dispersion coefficient from the diffusion coefficient.

1.4 Overview and Structure of the Thesis

This thesis contains five chapters, and the outline of it is as follows:

Chapter 1: A general description and background information regarding SA-SAGD are introduced, a list of the research problems and objectives are presented, along with a literature review of the dispersion coefficient of solvent and its link to SA-SAGD.

Chapter 2: A PVT fluid experiment is conducted, including bubble point, density, and viscosity measurements. An EOS model is constructed and serves as input for simulation in Chapter 4.

Chapter 3: Detail description of the small-scale experiments setup, procedures, and experimental results are present, along with analysis of the oil production, material balance, and temperature data.

Chapter 4: Simulations are built, and history matched for both SAGD and SA-SAGD experiments. A method and a procedure are presented using the history matching results to determine the dispersion coefficient of solvent. The resulting dispersion coefficient is analyzed and discussed in detail.

Chapter 5: The research is summarized, and conclusions are highlighted. Suggestions for future works and recommendations are presented.

1.5 Literature Review

This section reviews the current literature to give background information and context to this thesis and research. It includes a more detailed explanation of the concept of dispersion in heavy oil production and how others have determined dispersion coefficients. In addition, it also covers experimental setups of SAGD and SA-SAGD done by others.

1.5.1 Hydrodynamic Dispersion of Solvent

Hydrodynamic dispersion has two components: molecular diffusion and mechanical dispersion. Molecular diffusion is caused by concentration gradients, while mechanical dispersion results from velocity variation in pore-scale heterogeneity (Pickens and Grisak 1981). Molecular diffusion is defined as the transport of molecules due to a concentration gradient. The process occurs until the concentration at the two locations becomes equal. Fick's first law models diffusion as a function of the molecular concentration gradient and the diffusive flux. The diffusion of solvent in heavy oil or bitumen can be modeled as a function of the mixture's viscosity. Das and Butler (1996) obtained empirical correlations for the diffusion coefficients of solvent in bitumen as a function of the mixture viscosity. In turn, the mixture viscosity is a function of solvent concentration, implying diffusivity in heavy oil is a function of solvent concentration.

Mechanical dispersion, also known as convective dispersion, is defined by mixing or spreading a component in a phase caused by microscopic imbalances of the flow velocity in a porous medium (Bear 1972). Mechanical dispersion in a porous medium is comprised of two components: longitudinal and transverse dispersion. The longitudinal dispersion is parallel to the mixture flow direction, while the transverse or lateral dispersion is perpendicular to the direction of the mixture flow direction (Greenkorn 1983). In one dimension, dispersivity is equal to the dispersion coefficient divided by the average interstitial velocity and is a characteristic value of the porous medium (Adepoju et al. 2013). Dispersivity has units of length. Dispersivity measured in laboratory experiments are often much smaller than what is observed in the field for the same type of medium due to reservoir heterogeneity (Garmeh 2010).

Solvent dispersion in bitumen recovery has been studied extensively for vaporassisted petroleum extraction (VAPEX). The idea of VAPEX was originally developed by Butler and Mokrys (1991) to overcome some shortcomings associated with SAGD, mainly because of its intensive energy consumption. It replaces steam injection with vapor solvent injection, and in addition to reducing bitumen viscosity by heating, it also lowers bitumen viscosity by dilution from solvent mixing with the bitumen. Therefore, researchers have used VAPEX to study both diffusion and dispersion of solvent in bitumen.

Nghiem et al. (2001) investigated dispersion and diffusion in VAPEX with propane using CMG's GEM simulator. The dispersion coefficient value used for propane was 5.04 $\times 10^{-4}$ m²/day, which was much larger than the molecular diffusion of propane in bitumen. The authors stated that "the growth of the vapor chamber is controlled by molecular diffusion and convective dispersion" and showed that "transverse dispersion was the dominant mechanism for the fluid mixing at the interface between solvent and heavy oil." The paper concluded that "total dispersion [including both dispersion and diffusion] can be used as a parameter for matching laboratory and field observations."

Dunn et al. (1989) studied gravity drainage of heavy oil by the injection of soluble gas of propane and butane. An analytical model for oil production was developed based on Butler and McNab (1981) SAGD equation. Nevertheless, the predicted cumulative oil production using their analytical model was much lower than the actual experimental results. In order to history match the experiment data, a much higher effective diffusion coefficient in the range of 10^{-2} m²/day had to be used, which was outside the range of 10^{-5} m²/day reported in the literature (Das and Butler 1996; Yang and Gu 2006). Dunn et al. (1989) could not definitively explain why the dispersion coefficient calculated from experimental data would be much greater than molecular diffusion. They finally concluded that significant lateral or transverse dispersion plays an important role in addition to diffusion.

1.5.2 Determination of Dispersion Coefficient of Solvent

Currently, the most common method of determining dispersion coefficient in the literature is through a combination of experiments, analytical methods, and simulations. There is a limited amount of data specifically regarding the mechanical dispersion coefficient in SA-SAGD. However, analogous data regarding dispersion in the context of VAPEX have been well documented, as described below.

Lim et al. (1996) used a 53-L (bulk volume) sand-pack model to study solventassisted gravity drainage process for Cold Lake heavy oil. The diffusion coefficient was solved analytically based on Butler's SAGD equation and the peak oil production rate when the solvent chamber reached the top of the reservoir model. The effective diffusion solved by the authors for ethane and propane was 100 times higher than molecular diffusion. As a result, Lim et al. (1996) pointed out that mechanical dispersion was the most likely process for bitumen recovery in solvent-assisted gravity drainage. Ramakrishnan (2003) used a glass bead pack experimental model to measure the effective diffusion coefficient of propane in bitumen. The experimental pack had permeabilities ranging from 25 to 220 and a porosity of 0.38. Butler's gravity drainage equation was applied to solve for diffusion coefficient based on the experimental oil production rates. The author also developed a correlation of the diffusion coefficient of propane with a function of bitumen/solvent mixture viscosity as equation 1.1:

$$D_{eff} = 1.85 \times 10^{-9} \mu^{-0.9}$$
 1.1

where D_{eff} is the effective diffusion coefficient in m²/s, and μ is the viscosity of bitumen/solvent mixture cp at a given temperature.

Das (2005) used reservoir simulation for the history matching of VAPEX using propane to find dispersion coefficient using CMG's GEM simulator. The size of the fieldscale 2-D section simulation model is 20 m by 60 m. The grid block size used in the simulation is 0.4 m in all directions in an attempt to control the numeral dispersion. He studied the mixing between injected solvent and bitumen for some cases using hydrodynamic dispersion coefficients. Very large dispersion coefficients on the order of 10^{-2} cm²/s or 8.64×10^{-2} m²/day were needed to match production rates for all cases.

Abukhalifeh (2010) developed an experiment and analytical workflow to determine a concentration-dependent dispersion in VAPEX. A cylindrical sand-pack model experiment was performed with various model heights and permeabilities. Then, pure propane was injected at the top of the model 0.76 MPa and 25°C to ensure that the propane remains in the vapor phase. The produced fluids were collected and separated to measure oil recovery. An analytical model based on the continuity equation was used to match the experimental production data. The author incorporated optimal control theory in the matching process to determine the desired dispersion function that would minimize the difference between the model-predicted and the experimental values of cumulative oil produced. Using the combination of physical model experiments and analytical solutions, the author determined the concentration-dependent dispersion coefficient of propane in VAPEX.

Ji et al. (2015) reported that the diffusion coefficient for C₆ of $4.32 \times 10^{-5} \text{ m}^2/\text{day}$ in SA-SAGD was obtained using experimental data. The authors then investigated the sensitivity of diffusion coefficient on oil recovery and production rate. They showed that for solvent steam co-injection, solvent diffusion coefficient in the ranges of 4.32×10^{-6} m²/day to $4.32 \times 10^{-3} \text{ m}^2/\text{day}$ was ineffective in changing oil recovery. A diffusion coefficient of at least $4.32 \times 10^{-2} \text{ m}^2/\text{day}$ was needed to impact oil recovery and production rates significantly. This value of $4.32 \times 10^{-2} \text{ m}^2/\text{day}$ is outside the range of reasonable diffusion coefficient value for C₆ (Huang et al. 2020) and has reached the reasonable magnitude of dispersion coefficient.

1.5.3 Lab-scale experiment of SAGD and SA-SAGD

There have been numerous physical model experiments of SAGD and SA-SAGD performed, ranging from larger-scale sand-packs to micro-scale level models. The earliest SAGD experiment was performed by Buter (1994), where a sand-pack 2-D model was used to investigate SAGD. Later, Yazdani and Maini (2005) and Moghadam et al. (2009) used

sand-pack porous media models to study VAPEX. Co-injection of solvents with steam was studied in recent years by a few publications, including Ayodele et al. (2008), Deng et al. (2010), and Khaledi et al. (2012).

More recently, Al-Murayri et al. (2016) conducted investigations of SA-SAGD using a large-scale sand-pack 2-D cross-section model. The model of the sand-pack had a bulk volume of 24 L with porosity of 0.32 and permeability of 555 D. Four experiments were conducted, including one SAGD and three condensate-SAGD with different solvent volumes (5%, 10%, and 15%). A pressure of 2100 kPa was kept constant for all cases, and the gas condensate used in the experiment was cracked naphtha. Temperature propagation profiles were monitored using 240 thermocouples. This was the first SA-SAGD sand-pack experiment using real field bitumen samples and condensate samples. It confirmed that the usage of 10% volume of solvent in the field effectively lowered SOR, increased oil production rate, and had a lower temperature profile compared to SAGD, while the usage of 10% solvent limited input cost.

Kim (2017) studied SAGD with chemical solvent additives using a lab-on-chip scale technology called microfluidics. It comprises of a 10 cm by 10 cm glass micromodel chip fabricated by photolithography which mimics a reservoir's porous medium. The advantage of the technology is that any fluid flow can be visualized under a microscope camera. The pore network consists of different grain sizes range of 260–380 μ m with a porosity of 0.44 and permeability of 149.4 D. Five tests were performed, including SAGD, condensate-SAGD, C₆-SAGD, C₄-SAGD, and C₃-SAGD. The co-injection pressure and temperature conditions were controlled at constant 1 MPa and 185°C. From the

temperature profile data and visual camera, discrete regions within the SAGD process could be distinguished, including steam chamber, hot water zone, mobile oil zone, and virgin bitumen zone. The interface between the zones could also be clearly identified. This method showed that solvent SAGD could be observed and studied on a micro-level without the requirement of complex and large-scale experimental setups. Condensate-SAGD, C₆-SAGD, and C₄-SAGD all showed improvement in total oil recovery compared to SAGD. Only C₃-SAGD had a lower oil recovery factor compared to SAGD.

The most recent detailed 3-D physical model experiment of SA-SAGD was conducted by Sheng et al. (2021), in which multi-component condensate was used and analyzed. The experimental setup used a 190 L cylindrical vessel packed with unconsolidated sand with a permeability of 5.6 D and a porosity of 0.33. An injector and a producer were inserted along the length of the vessel. The condensate used in the experiment contained C_1 , nC_4 , nC_8 , and nC_{12} and was co-injected with steam at a constant pressure of 3500 kPa. The experiment showed that solvent components condensed at different distances at the steam chamber edge due to their volatilities. Thus, lighter components propagated farther beyond the steam chamber edge, while heavier components propagated closer to the chamber edge.

Chapter 2: Fluid Characterization for Solvent-Assisted SAGD

This chapter covers the fluid characterization and the resulting fluid model used in the simulation of the lab-scale gravity drainage experiments. The first section contains details of the PVT experiments conducted, such as constant mass expansion, density, and viscosity measurements. The second section describes how to characterize the bitumen using an equation of state (EOS) and build the density and viscosity models from experimental data.

2.1 Fluid Property Experiments

This section covers the lab PVT experiments in detail, including summarized procedures and data collection of both the bitumen and the synthetic solvent that mimics the condensate used to diluent the bitumen. Mixtures of bitumen and solvent are used to measure bubble points, which are used to determine the critical properties (Tc, Pc, ω) of bitumen components.

2.1.1 Bitumen and Solvent Properties

The bitumen used in the experiments comes from the Hanginstone field in the northern Alberta Athabasca region. It has a molecular weight of 560 g/mol with a density of 1015.24 kg/m³ at 15°C and 101.3 kPa. The synthetic solvent used in this experiment is a mixture of C_1 , nC_4 , nC_8 , and nC_{12} with a molar weight of 111.15 g/mol. The synthetic solvent is formulated by adding methane gas into a mixture of nC_4 , nC_8 , and nC_{12} prepared

by the vendor Praxair Distribution Inc. The compositions of the bitumen and synthetic solvent are shown in Tables 2.1 and 2.2, respectively. Bitumen sample viscosity and density at various temperatures are shown in Table 2.3.

2.1.2 Constant Mass Expansion (CME) Test

CME tests are performed for four solvent/bitumen mixtures (40.1 to 94.4 mol% solvent) and one for 100% solvent to measure the bubble point of a single phase (see Table 2.4). The tests are conducted at 100°C, 150°C, and 200°C. The CME test is performed with PVT 200/350 FV HT from Sanchez Technologies, and the PVT cell schematic is shown in Figure 2.1. The visual chamber of the cell has a maximum volume of 200 cm³. It can withstand pressure up to 35 MPa with an accuracy of \pm 10 kPa and temperature up to 250°C with an accuracy of \pm 0.1°C.

In order to prepare the mixture sample, the bitumen is first injected into the PVT cell through the lower actuated valve, and then the solvent is gradually injected at high pressure to achieve the desired molar concentration. The mixture sample is heated to the desired temperature and pressurized to make sure that the mixture is in the single liquid phase.

In order to measure the equilibrium volume of the solvent/bitumen mixture at each pressure level, the pressure in the PVT cell is gradually decreased at a step size of 100 kPa in the single-phase region and 20 kPa in the two-phase region. The mixture sample is stirred by a mixer tool inside the PVT cell for 30 seconds between each pressure/volume measurement, and the system is left for 50 minutes to wait for reaching an equilibrium

state. At each pressure level, the equilibrium volume is measured. The pressure and measured equilibrium volume data for 60.9 mol% solvent mixture at 100°C are shown in Figure 2.1, as an example.

By plotting the pressure and corresponding equilibrium volume data for a given temperature, two straight lines can be distinguished on the PV plot, one for the single-phase region data points and another for the two-phase region data points. For each line, a regression equation is used to fit the data points. Bubble point pressure can be obtained by solving the intersection of the two fitted lines. An example of this plot is shown in Figure 2.1 for 60.9 mol% solvent mixture at 100°C.

2.1.3 Density and Viscosity Measurement

The density and viscosity of bitumen and synthetic solvent are measured, respectively, by a density meter and viscometer embedded inside a temperature-controlled oven (Despatch LAC2-18-8). A scheme of the setup is shown in Figure 2.3. Both the density meter and the viscometer have a control/monitor device outside the oven to provide the data readings. The sample is pumped from the accumulator into the system by the inlet pump and then is heated to the desired temperature by the oven. The pressure of the system is monitored by a pressure gauge (Omega PX459-2.5KGI-EH). Once the sample has filled up the system, the density and viscosity measurement test can be conducted.

Densities and viscosities are measured at temperatures ranging from 65°C to 200°C and pressures ranging from 1 MPa to 10 MPa for this research. The density meter is capable of measuring fluid density from 0 to 3000 kg/m³ with an accuracy of ± 1 kg/m³. Viscosity

is measured using the Cambridge Viscosity VISCOpro 2100 viscometer, which can measure viscosity ranging from 0 to 10,000 cp with an accuracy \pm 0.1%. Maximum operation pressure is 10.3MPa for temperatures under 150 °C and up. Densities and viscosity data collected for bitumen are contained in Tables 2.5 and 2.6, respectively. Densities and viscosity data of synthetic solvent are listed in Tables 2.7 and 2.8, respectively. Solvent bitumen mixtures viscosity and density data are tabulated in Table A1 and Table A2 in Appendix A.

2.2 Fluid Modeling

Phase behavior of bitumen and solvent is characterized by the Peng-Robinson equation of state (PR EOS, 1978). The EOS models of the synthetic solvent and the bitumen/solvent mixture are characterized respectively by matching their own bubble points. Viscosity and density models are calibrated by matching the experimentally measured viscosity and density data collected from the previous section.

2.2.1 EOS Model for Synthetic Solvent

The synthetic solvent consists of C₁, nC₄, nC₈, and nC₁₂, which mimics the condensate used in field SA-SAGD operation. The critical properties of the synthetic solvent used in constructing the EOS model come from pure n-alkane critical properties (critical temperature, Tc, critical pressure, Pc, and acentric factor, ω), which are extracted from NIST (National Institute of Standards and Technology) database and are listed in Table 2.9. The binary interaction parameters (BIP) between each component of the

synthetic solvent are calculated according to Kumar and Okuno's correlations (Kumar and Okuno, 2016), and the results are listed in Table 2.12. The parameters of the synthetic solvent EOS model are listed in Table 2.9. C_1 mol% was adjusted because bubble point pressures predicted by the EOS model were slightly different from measured data. The resulting phase diagram predicted by the EOS model for the synthetic solvent is shown in Figure 2.5.

2.2.2 EOS Model for Bitumen

The bitumen used for this research contains carbon numbers from C_{11} up to C_{120+} and has a molecular weight of 560 g/mol. In order to build the EOS model, bitumen is split into four equally mass-weighted pseudo-components: B1, B2, B3, and B4, using the carbon number distribution analysis done for the bitumen shown in Figure 2.4. A representative carbon number of each pseudo component is determined by interpolating the center of mass from the cumulative mass fraction curve of Figure 2.4, and the carbon numbers are tabulated in Table 2.10. Thus, the molecular weight of n-alkanes can be written as

$$MW_i = \beta (14 CN - 4)$$
 2.1

where MW_i is component molecular weight, CN is the carbon number, and β is a common constant.

$$\sum_{i=1}^{n=4} MW_i \times x_i = MW_{bitumen}$$
 2.2

$$\sum_{i=1}^{n=4} \alpha (14 CN_i - 4) \times x_i = MW_{bitumen}$$
 2.3

By substituting equation 2.1 into equation 2.2, equation 2.3 is formed, where x_i is the mole fraction of each component, and MW_{bitumen} is the molar weight of bitumen. The common parameter β is adjusted to match the molecular weight of the bitumen, which is 560 g/mol. The resulting α is equal to 1.08133. The calculated molecular weight and mole fraction of each pseudo-component are summarized in Table 2.11.

Since the bitumen is a dead oil and directly measuring its bubble point is not practical, the bitumen/solvent mixture bubble points are measured and then used to build the bitumen EOS model. Critical properties of bitumen components are characterized using Kumar and Okuno's method (2016). In the iteration procedure of this method, the initial critical properties Tc, Pc, ω of pseudo-component are assigned with critical properties of equivalent n-alkanes in terms of carbon number. Then, the critical properties of the pseudo-components are systematically adjusted in the direction of increasing aromaticity until the bubble points predicted by the EOS model can match the experimental data. BIPs between bitumen and solvent components are calculated according to Kumar and Okuno's correlations (Kumar and Okuno, 2016) and listed in Table 2.12. The resulting phase diagrams predicted by the EOS model of two bitumen/solvent mixtures are shown in Figure 2.6.

For the practical purpose of simulation, a 2-component model of bitumen is used to save computational time. B1 is kept unchanged, and B2 through B4 in the 4-component model are grouped into a new pseudo component B2. Critical properties, molecular weights, and BIPs are calculated by the weighted average of molar fractions. The resulting 2-component bitumen model is summarized in Table 2.11. Pressure-temperature phase diagrams and the match results are shown in Figure 2.5. The average relative errors for the bubble point matching of bitumen/solvent mixture and the solvent are 11.1% and 5.6%, respectively. The average absolute errors are 55 kPa and 91 kPa for the bitumen/solvent mixture and the solvent, respectively.

2.2.3 Viscosity Model

The bitumen viscosity is modeled by using a log-linear mixing model. The loglinear mixing rule used is shown as follows:

$$\ln(\mu_L) = \sum_{i=1}^{Nc} x_i \ln(\mu_i)$$
 2.4

where N_c is the total number of components in the oleic phase, x_i , μ_i is the mole fraction and viscosity of pure component i in the oleic phase, respectively. μ_L is the overall viscosity of the oil as a mixture. The viscosity of each bitumen pseudo-component is different since viscosity behavior between B1 and B2 is quite different due to a significant difference in molar weight. Variables within each component's correlations are then used as tuning parameters until the experimental data is matched. In this case, the reciprocal of viscosity is matched with the experimental data to better reflect the effects of changes in viscosity on fluid flow.

The viscosity of the B1 pseudo-component is modeled by equation 2.5 (Aboul-Seoud and Moharam, 1999):

$$\ln\left(\ln\left(\frac{\mu_{i}}{\rho_{i}} + 0.8\right)\right) = a_{1} + a_{2}\ln(T)$$
 2.5

$$a_1 = K_1 (T_{bi} \gamma_i)^{0.2} + K_2$$
 2.6

$$a_2 = -3.7$$
 2.7

where μ_i is the component viscosity, ρ_i is density of the component, T is temperature in K, T_{bi} is bubble point temperature, μ_i and γ_i is the specific gravity of the component. K1 and K2 are the tuning parameters. Default values for K₁ and K₂ from the paper are 4.3414 and 6.6913, respectively, and are used as initial values for regression.

The viscosity model of the B2 pseudo-component follows the correlation from Nourozieh (2013), which is used to model extra heavy oils:

$$\ln(\mu_{Bit}) = \exp[b_1 + b_2 \ln(T)] + b_3 P_g$$
 2.8

where P_g is gauge pressure in MPa; b_1 , b_2 , and b_3 are fitting parameters of the model. The values of b_1 , b_2 , and b_3 are initially set to be 26.65193, -4.04208, 0.031101, respectively, which are originally from Nourozieh (2013).

In order to build the viscosity model of the bitumen, regression should be done to match the reciprocal of viscosity from experimental data by simultaneously adjusting a₁ from equation 2.5 and b₁, b₂, and b₃ from equation 2.8. The goal of the regression is to minimize the relative absolute difference error between the model and experimental data. The average absolute deviation (AAD) between the model and the data is defined as follows:
$$AAD = \frac{1}{n} \sum_{i=1}^{NC} \left| \frac{1}{\mu_{i,model}} - \frac{1}{\mu_{i,exp}} \right|$$
 2.9

The parameters of the viscosity model of bitumen after regression are listed in Table 2.14. The resulting viscosity curve of bitumen, along with experimental viscosity data, are shown in Figure 2.8. The AAD of the reciprocal of viscosity of bitumen is 1.1 cp⁻¹. The absolute average relative deviation (AARD) is also calculated to gauge the quality of the regression. The AARD for the reciprocal of viscosity of bitumen is 7.4%.

The viscosity of the synthetic solvent, as a mixture, is modeled using equation 2.4. The liquid viscosity of each pure component uses the following correlation from Baek et al. (2019),

$$\mu_{i} = A \exp(-BT)$$
 2.10

where A and B are tuning parameters, and T is the temperature in K. Viscosity data of pure components (C_1 , C_4 , C_8 , C_{12}) of the synthetic solvent comes from the corresponding saturated liquid viscosity data listed in the NIST database. Once again, regression is performed on the tuning parameters to reduce the AAD. Table 2.14 presents the parameters of the solvent viscosity model. Figure 2.7 shows the viscosity of bitumen and solvent components as a function of temperature with the data points tabulated in Table 2.15.

2.2.4 Density Model of Oil Phase

The density model of the oil phase uses the following mixing formula:

$$\frac{1}{\rho_j} = \sum_{i=1}^{Nc} \frac{\mathbf{x}_{ij}}{\rho_{ij}}$$
 2.11

where ρ_j is the molar density of liquid phase j, and x_{ij} is the mole fraction of component i in liquid phase j, and Nc is the number of components. ρ_{ij} is the molar density of pure component i in phase j at T and P, which can be calculated with the formula below:

$$\rho_{ij} = \rho_{iref} \times \exp\left[-a_1(T - T_{ref}) - \frac{a_2}{2}(T^2 - T_{ref}^2) + a_3(P - P_{ref}) + a_4(P - 2.12)\right]$$

$$P_{ref}(T - T_{ref})$$

where ρ_{iref} , P_{ref} , and T_{ref} are molar density, pressure, and temperature at reference conditions (15.6°C and 101 kPa), respectively. The parameters, a_1 to a_4 , are componentspecific fitting parameters. The regression process for the density of bitumen and solvent is similar to that for the viscosity model, where fitting parameters are adjusted to match experimental density data. The regression parameters are shown in Table 2.16. Figure 2.9 shows the density for each component as a function of temperature. Figure 2.10 shows the bitumen density matching of experimental data at various temperatures and pressure.

The AAD for bitumen, solvent, and bitumen/solvent mixture are 1.1, 4.1, 6.4 kg/m³, respectively, and AARDs for all cases are under 1%.

The developed EOS, density, and viscosity models of bitumen and solvent accurately represent the experimental data and will all be used in SAGD and SA-SAGD simulations conducted in Chapter 4.

SARA	Weight %
Asphaltenes	17.82
Saturates	18.79
Aromatics	38.98
Resins	17.69
Recovered	93.28
Unrecovered	6.72

Table 2.1: Bitumen sample SARA analysis.

Component	MW, g/mol	Mol%	Weight %
C1	16.04	1.20	0.17
nC ₄	58.12	9.90	5.18
nC ₈	114.23	82.38	84.66
nC ₁₂	170.30	6.52	9.99

 Table 2.2:
 The synthetic solvent composition, including molar weight and mole percent.

Properties	Values	
Density at 15°C, kg/m ³	1015.24	
Density at 40°C, kg/m ³	999.42	
Density at 80°C, kg/m ³	974.10	
Viscosity at 15°C, cp	1000000	
Viscosity at 40°C, cp	24000	
Viscosity at 80°C, cp	675	

Table 2.3: Bitumen (dead oil) densities and viscosities at different temperatures and pressure of 101 kPa.



Figure 2.1: PVT 200/350 FV HT cell control interface.



Figure 2.2: Bubble point pressures and volumes from CME test for 60%mol solvent mixture at 100°C.

Mixture/Temperature	50°C	100°C	150°C	200°C
40.1 mol% Solvent	-	552	724	993
60.9 mol% Solvent	-	629	820	1138
90.0 mol% Solvent	-	644	931	1271
94.4 mol% Solvent	-	653	995	1322
100 mol% Solvent	643	868	1074	1450

Table 2.4:Summary of measured bubble point pressures (in kPa) at 100°C, 150°C, and
200°C for solvent/bitumen mixtures.



1)Inlet pressurization pump	5)Density meter		
2)Sample accumulator	6)Viscometer		
3)Oven	7)Density meter controller device		
4)Pressure monitor	8)Viscometer controller device		

Figure 2.3: Schematic diagram of the experimental setup for measuring density and viscosity.

Pressure,	Temperature, °C						
MPa	58.9	64.7	79.4	98.9	119.5	149.9	169.2
1.0	4599	2526	988.2	224.4	79.51	27.89	-
2.0	4798	2644	1017	235.4	82.33	29.03	15.92
4.0	5082	2850	1102	247.4	85.68	30.23	16.87
6.0	5394	2986	1161	267.2	90.04	31.42	17.81
8.0	5851	3203	1221	273.3	94.87	_	_
10.0	6055	3397	1304	283.5	98.82	_	_

Table 2.5:Experimental data for bitumen viscosities with pressure from 1.0 MPa to 10.0MPa, temperature ranging from 59°C to 169°C.

Pressure,	Temperature, °C						
MPa	66.5	81.0	100.0	119.9	151.0	170.9	199.3
1.0	982.79	974.76	963.25	949.70	929.92	916.95	-
2.0	983.35	975.48	963.88	950.49	930.78	917.85	899.41
4.0	984.59	976.72	965.32	951.94	932.47	919.77	901.53
6.0	985.67	977.86	966.64	953.37	934.15	921.49	903.58
8.0	986.73	979.02	967.90	954.75	935.74	923.23	905.54
10.0	987.85	980.26	969.20	956.17	937.26	924.99	907.41

Table 2.6: Experimental data for bitumen densities from 1.0 MPa to 10 MPa, with temperatures ranging from 66°C to 199°C.

Pressure,	Temperature, °C						
MPa	58.9	64.7	79.4	98.9	119.5	149.9	169.2
1.0	0.4179	0.3029	0.2575	0.1717	0.1332	0.1068	0.0815
2.0	0.4186	0.3031	0.2589	0.1729	0.1338	0.1072	0.0818
3.0	0.4207	0.3054	0.2607	0.1738	0.1341	0.1078	0.0819
4.0	0.4237	0.3068	0.2622	0.1741	0.1348	0.1081	0.0823
6.0	0.4342	0.3101	0.2638	0.1749	0.1356	-	-
8.0	0.4351	0.3115	0.2671	0.1755	0.1368	_	-
10.0	0.4376	0.3124	0.2704	0.1753	-	-	-

Table 2.7:Experimental data for synthetic solvent viscosities from 1.0 MPa to 10 MPa,
with temperature ranging from 59°C to 169°C.

Pressure,	Temperature, °C							
MPa	23.5	51.5	65.0	99.3	125.1	148.9	168.78	199.1
2.0	698.54	674.77	663.97	634.17	609.82	585.98	563.42	563.42
3.0	699.16	675.65	664.93	635.30	612.25	587.01	565.39	565.39
4.0	700.00	676.83	665.91	636.48	613.73	589.67	567.38	567.38
6.0	701.65	678.61	667.96	639.06	616.89	595.02	574.47	574.47
8.0	703.20	679.89	669.95	641.28	619.55	599.11	581.24	581.24
10.0	704.80	681.16	671.84	644.00	622.92	603.07	586.68	549.51

Table 2.8:Experimental data for synthetic solvent densities from 2.0 MPa to 10.0 MPa,
with temperature ranging from 23.5°C to 199°C.



Figure 2.4: Cumulative mass fraction curve of component used to bitumen splitting resulted in 4-component bitumen model.

Component	Mol%	MW, g/mol	Tc, °C	Pc, kPa	ω, Acentric			
					factor			
	Synthetic solvent							
C1	2.3	16.0	-82.55	4600	0.0080			
nC ₄	9.8	58.1	152.05	3800	0.1930			
nC ₈	81.5	114.2	295.65	2482	0.3940			
nC ₁₂	6.4	170.3	385.15	1824	0.5620			

Table 2.9: The PR EOS model for synthetic solvent calibrated with experimental data.

Pseudo-component	Carbon Number (CN)
B1	19
B2	34
B3	58
B4	129

Table 2.10: Bitumen Pseudo-component representative CN number.

Pseudo-	Mol %	MW, g/mol	Tc, °C	Pc, kPa	ω, Acentric
component					Factor
		2-PC bit	umen		
B1	49.5	283.0	526.35	2000	0.3996
B2	50.5	831.1	976.62	1314	0.8712
		4-PC bit	umen		
B1	49.5	283.0	526.36	1997	0.3996
B2	27.4	510.5	718.87	1543	0.6836
B3	15.9	877.9	949.71	1309	0.9652
B4	7.2	1953.9	1343.67	1181	0.9647

Table 2.11: The PR EOS model for bitumen calibrated with experimental data.

Components	C_1	nC ₄	nC ₈	nC ₁₂	B1	B2	B3	B4
C_1	0	-	-	-	-	-	-	-
nC ₄	0.0420	0	-	-	-	-	-	-
nC ₈	0.0500	0.0337	0	-	-	-	-	-
nC_{12}	0.0536	0.0482	0	0	-	-	-	-
B1	0.0599	0.0625	0	0	0	-	-	-
B2	0.0734	0.0755	0	0	0	0	-	-
B3	0.0953	0.0827	0	0	0	0	0	-
B4	0.1592	0.0877	0	0	0	0	0	0

 Table 2.12:
 BIP parameters used for the 4-component bitumen model.

Components	C_1	nC ₄	nC ₈	nC ₁₂	B1	B2
C_1	0	-	-	-	-	-
nC ₄	0.0420	0	-	-	-	-
nC ₈	0.0500	0.0337	0	-	-	-
nC_{12}	0.0536	0.0482	0	0	-	-
B1	0.0599	0.0625	0	0	0	-
B2	0.0925	0.0795	0	0	0	0

 Table 2.13:
 BIP parameters used for the 2-component bitumen model.



Figure 2.5: Bubble point matching of pure synthetic solvent.



(b) Two-phase envelope of 60.9 mol% synthetic solvent + 39.1 mol% bitumen.

Figure 2.6: Bubble point matching of synthetic solvent/ bitumen mixtures.

Components	Equation number	Parameters
C1	2.5	A = 0.003656 $B = 0.022308$
nC ₄	2.5	A = 0.214700 $B = 0.011622$
nC ₈	2.5	A = 0.705021 $B = 0.011109$
nC ₁₂	2.5	A = 1.297313 $B = 0.008953$
B1	2.2	$a_1 = 22.04965$ $a_2 = -3.7$
B2	2.3	$b_1 = 26.739668$ $b_2 = -4.156146$ $b_3 = 0.504361$

 Table 2.14:
 Matching parameters for pure components of the viscosity model that results in the best match.



Figure 2.7: Viscosity for bitumen in log-scale and solvent components at 3500 kPa.



Figure 2.8: Viscosity of the bitumen in log-scale as a function of the temperature. (The model is represented as a curve line; the markers are the experimental data).

T, ℃	C1	nC ₄	nC ₈	nC ₁₂	B1	B2
10	2.924 E-3	1.911 E-1	6.309 E-1	1.186	1.972 E+1	1.656 E+12
20	2.340 E-3	1.702 E-1	5.646 E-1	1.085	1.315 E+1	4.761 E+10
30	1.872 E-3	1.515 E-1	5.052 E-1	9.917 E-1	9.250	2.427 E+09
40	1.497 E-3	1.349 E-1	4.521 E-1	9.068 E-1	6.794	1.971 E+8
50	1.198 E-3	1.201 E-1	4.045 E-1	8.291 E-1	5.170	2.345 E+7
60	9.586 E-4	1.069 E-1	3.620 E-1	7.581 E-1	4.052	3.818 E+6
70	7.670 E-4	9.517 E-2	3.239 E-1	6.932 E-1	3.256	8.066 E+5
80	6.136 E-4	8.472 E-2	2.899 E-1	6.338 E-1	2.671	2.117 E+5
90	4.909 E-4	7.543 E-2	2.594 E-1	5.796 E-1	2.230	6.664 E+4
100	3.927 E-4	6.715 E-2	2.321 E-1	5.299 E-1	1.891	2.445 E+4
110	3.142 E-4	5.978 E-2	2.077 E-1	4.845 E-1	1.6243	1.021 E+4
120	2.514 E-4	5.322 E-2	1.859 E-1	4.430 E-1	1.412	4.758 E+3
130	2.011 E-4	4.738 E-2	1.663 E-1	4.051 E-1	1.240	2.436 E+3
140	1.609 E-4	4.218 E-2	1.489 E-1	3.704 E-1	1.098	1.352 E+3
150	1.287 E-4	3.755 E-2	1.332 E-1	3.387 E-1	9.8076 E-1	8.037 E+2
160	1.030 E-4	3.343 E-2	1.192 E-1	3.097 E-1	8.8227 E-1	5.072 E+2
170	8.240 E-5	2.976 E-2	1.067 E-1	2.831 E-1	7.9886 E-1	3.371 E+2
180	6.593 E-5	2.650 E-2	9.546 E-2	2.589 E-1	7.2763 E-1	2.343 E+2
190	5.274 E-5	2.359 E-2	8.541 E-2	2.367 E-1	6.6632 E-1	1.694 E+2
200	4.220 E-5	2.100 E-2	7.643 E-2	2.164 E-1	6.1319 E-1	1.267 E+2
210	3.376 E-5	1.870 E-2	6.839 E-2	1.979 E-1	5.6686 E-1	9.764 E+1
220	2.701 E-5	1.664 E-2	6.120 E-2	1.810 E-1	5.2622 E-1	7.727 E+1
230	2.161 E-5	1.482 E-2	5.477 E-2	1.655 E-1	4.9038 E-1	6.259 E+1
240	1.729 E-5	1.319 E-2	4.901 E-2	1.513 E-1	4.5861 E-1	5.174 E+1
250	1.383 E-5	1.174 E-2	4.386 E-2	1.383 E-1	4.3033 E-1	4.356 E+1
260	1.106 E-5	1.045 E-2	3.924 E-2	1.265 E-1	4.0504 E-1	3.728 E+1
270	8.854 E-6	9.311 E-3	3.512 E-2	1.156 E-1	3.8233 E-1	3.236 E+1
280	7.083 E-6	8.289 E-3	3.143 E-2	1.057 E-1	3.6187 E-1	2.845 E+1
290	5.667 E-6	7.380 E-3	2.812 E-2	9.670 E-2	3.4336 E-1	2.530 E+1
300	4.534 E-6	6.570 E-3	2.516 E-2	8.842 E-2	3.2656 E-1	2.273 E+1

 Table 2.15:
 Component Viscosity vs. temperature relationship for CMG STARS input based on viscosity models.

Parameters	C1	nC ₄	nC ₈	nC ₁₂	B1	B2
$\rho_{ref}, kg/m^3$	320.21	583.37	705.41	752.73	836.00	1092.08
$CP, kPa^{-1}(a_3)$	5.13 E-5	4.82 E-6	3.44 E-6	1.61 E-6	9.47 E-7	6.71 E-8
$CT1, K^{-1}(a_1)$	1.32 E-3	5.65 E-5	5.95 E-5	5.04 E-5	1.50 E-4	6.34 E-4
CT2, $K^{-2}(a_2)$	5.77 E-6	7.93 E-6	3.63 E-6	2.87 E-6	1.12 E-6	7.48 E-8
CPT, $kPa^{-1}K^{-1}(a_4)$	4.05 E-8	1.20 E-8	4.56 E-9	9.50 E-9	4.16 E-9	2.17 E-10

Table 2.16: Parameters of the density model of each component.



Figure 2.9: Density for each solvent and bitumen component at 3500 kPa.



Figure 2.10: Density matching for bitumen. Open circles are the experimental data, while the lines are values from the density model.

	Bitumen	Synthetic solvent	Bitumen/solvent mixture
AARD, Density	0.10%	0.66%	0.77%
AAD, Density, kg/m3	1.1	4.1	6.4

Table 2.17: Density matching results measured in AAD and AARD.

Chapter 3: Small Scale Gravity Drainage Experiments

This section will describe a set of novel gravity drainage experiments along with the operating procedures and results. Large-scale experiments and field data of SAGD and SA-SAGD provide important data of transient mass and energy balances. However, it is difficult to confirm detailed mechanisms that occur through the interplay between phase behavior and gravity drainage. For example, chamber-edge conditions should be influential to the gravity drainage along the edge of a steam chamber because they are the boundary conditions for the mixing of solvent with bitumen. However, such boundary conditions vary with time in a way that is indefinite, but specific to the experimental conditions. This inherent limitation in the large-scale experiments is addressed by more precisely controlled experiments at a small scale in this chapter.

The purpose of the experiments is to investigate the effects of the chamber conditions (pressure, temperature, and solvent/steam composition) on oil recovery and its mechanisms under controlled thermodynamic conditions. The important points of investigation include:

- Bitumen drainage rate and recovery factor.
- Condensation of solvent and water and the subsequent mixing of solvent with bitumen.
- Properties of the produced bitumen.

Three experiments are presented: SAGD, C_8 -SAGD with 10 mol% n C_8 , and C_4 -SAGD with 20 mol% n C_4 . This is a new type of gravity drainage experiment that is

relatively simple and easy to set the thermodynamic conditions. It allows for a comparative study of multiple solvent co-injections in a relatively short time frame. The drainage of one experiment usually takes a few hours compared to a few days of the large-scale experiments shown by Sheng et al. (2020, 2021).

3.1 Experimental Setup

A detailed schematic of the overall experimental setup and equipment used are shown in Figure 3.1. The main component of the experiment is a 25-L steel cylinder vertical vessel of 24 inches in length and 4.5 inches in outer diameter, shown in Figure 3.2. It accommodates a sand-pack of 15 inches in length and 3 inches in diameter. The sandpack is placed at the upper portion of the steel vessel attached to the vessel lid and held in place by a thin steel mesh. The lower portion of the vessel is a liquid collection container that is about 8 inches in height. There is also about one inch of void space (annular space) between the sand-pack and the inner wall of the steel vessel.

Inside the vessel, there are an injector, a top producer, and a bottom producer. With just one opening, the injector is inserted into the void space towards the top of the liquid collection container. The injector opening is oriented towards the inner wall of the vessel, away from the sand-pack. The top producer is connected to the outlet line and used to produce excess vapor. The bottom producer consists of the liquid collection container and the liquid drainage line. Produced oil and water are first drained from the sand-pack into the liquid collection container and pumped out of the vessel via a liquid drainage line.

There are two fluid lines connect to the top lid of the vessel. The first line is the inlet line, one end of which is connected to the injector. The upstream of the inlet line is connected to a steam generator and injection pump. The second line is the outlet line, one end of which is connected to the top vapor producer. The downstream of the outlet line is connected to a pressure control valve, a coil tubing condenser, a wet test meter. The pressure valve is used to maintain pressure by regulating any excess vapor inside the vessel. Any excess vapor is measured by a wet test meter and collected with cylinders or production tanks.

There are also four thermocouple lines used to monitor the temperature inside the vessel. Three thermocouple lines are placed inside the sand-pack, with one in the middle and two on the side of the sand-pack. The fourth thermocouple line is inserted into the annular void space. Each thermocouple line contains five thermocouples reading points, providing a total of 20 temperature reading locations inside the vessel, with 15 locations inside the sand-pack. The steel vessel is covered by three band heaters used to control heat loss from the vessel.

Below is a list of the equipment used along with more detailed specifications, which are shown in Figure 3.1:

- Isco 500D and Isco 1000D syringe pump up to 34.0 MPa of max operating pressure.
- One steam Generator with a power rating of 15 kW at 480 V.
- One flow control air-actuated valve controlled by the custom digital-to-analog system.

- Five band heaters with the top two heaters with power ratings of 360 W of power at 208 V and bottom three heaters with power ratings of 2.0 kW at 208 V.
- A Custom-made stainless-steel condenser connected to a glycol chiller.
- A Drum Type Gas Meter, Max Flow: 900 L/hr.
- Four sets of custom-made, multi-point (five reading points on each set) thermocouples.

3.2 Experimental Overview

Three experiments were conducted, one SAGD and two SA-SAGD with the following solvents: C₈ at 10 mol% and C₄ at 20 mol% (see Table 3.1). The pressure of the vessel is controlled at 3500 kPa after pressure ramp up, and the temperature of the injected vapor phase ranges from 229°C to 241°C depending on the composition of the injection vapor. These saturation temperatures for SA-SAGD are determined using the method one proposed by the authors (Venkatramani 2014; Venkatramani and Okuno 2015) to model saturation conditions for n-alkanes/water binary mixtures

The experiment is designed not to inject the fluid directly into the sand-pack but to let the injected gaseous phase saturate the void space. The thermal and compositional mechanisms mobilize the oil, and then the oil is drained under gravity. The injected fluid then saturates the volume of the drained oil in the sand-pack.

The injection rate for all experiments is set to 3987 cm³/min at in-situ conditions (3500 kPa and saturation temperature for each experiment). This rate translates to 70 cm³/min (cold-water equivalent, CWE) of steam for SAGD at the pump conditions (101

kPa, 22°C). SA-SAGD injection rates at pump conditions are then calculated from the determined in-situ rate of 3987 cm³/min. This rate ensures that all SA-SAGD experiments can have a steady composition in the void space, and therefore, the molar concentration of the injected solvent stays constant. The SAGD experiment is first performed and served as the baseline for further SA-SAGD experiments. This way, one can compare the effectiveness of adding solvent in bitumen recovery.

3.3 Model Packing and Oil Saturation

The sand-pack has a diameter of 3 inches and a height of 15 inches. It is packed into a thin steel mesh sleeve and then inserted into the saturation core-holder. The sand-pack comprises unconsolidated quartz sand and has a bulk volume of approximately 1700 cm³, with about 570 cm³ of the pore volume. Figure 3.4 shows the size distribution of sand grains used for the sand-pack. Deionized water at room temperature (22°C) is used to saturate the sand-pack and also used to measure porosity and permeability, which are 0.33 and 76 D, respectively. Then the heated bitumen (from Chapter 2) at 70°C is injected into the sand-pack, displacing the water out. Connate water saturation ranges from 7.2% to 8.7%. Different sand-packs have slightly different pore volumes and initial saturations of water and oil (Table 3.2). Once the sand-pack is finished with bitumen saturation, it is transferred to the experimental steel vessel and sealed with the top lid.

3.4 SAGD Experiment

Before the start of each experiment, the air in the void space of the vessel is purged with N_2 gas. This N_2 gas will then be produced along with the initial injected steam through the top producer. The next phase is preheating the entire vessel using the band heaters attached to the outside of the vessel wall. The band heaters are turned on to the maximum power for 5 mins, increasing the temperature readings in the void space to 70°C, and the sand pack temperatures to 30 - 35°C. The cumulative energy input from the band heaters during the entire experiment is about 1.5 kWh and is shown as a function of time in Figure 3.5. The initial energy output from the band heaters minimizes the condensation during the initial steam injection while ensuring bitumen is not mobilized by heating from the band heaters. After preheating, the band heaters are set to 5°C above the saturation temperature to limit the heat losses from the vessel. The steam is injected at a constant rate of 70 cm³/min CWE at 3500 kPa and 241°C. The pressure is ramped up at a rate of 200 kPa per minute until the vessel reaches the target pressure of 3500 kPa. The pressure relief valve is opened on the top producer line to regulate the vessel's pressure and ensure the pressurization rate is steady. It controls the pressure in the vessel afterward to maintain the target pressure of 3500 kPa. During this time, some condensation will still occur and will be captured by the bottom collection container.

The first batch of the produced liquid is drained by the bottom producer right after the pressure has reached 3500 kPa to clear out the condensed fluid from the collection container. Drainage for produced liquids in the collection container is done every 30 minutes in the first two hours and every one hour afterward. During a single drainage period, the drainage valve on the bottom producer line is turned on and off multiple times until all fluid accumulated is collected. Typically, the drainage period lasts for 5 to 10 minutes and is reflected by a momentary pressure drop in the steel vessel system.

After the last drainage period, the fluid injection is stopped, the band heaters are turned off, and the vessel system is cooled and depressurized. The entire SAGD test lasted for five hours in total. Finally, the model is dismantled. The sand-pack is extracted, excavated, and divided into three segments: top, middle, and bottom of the model. A sample of sand-pack from each segment is taken for each experiment and is measured for asphaltene mass concentration and Dean-Stark analysis to determine oil/water/solid analysis. The produced liquids are also measured for carbon number distribution, density, viscosity, molecular weight, and asphaltene mass concentration in the produced oil.

3.5 SA-SAGD Experiment

The experimental procedure for SA-SAGD is similar to that of SAGD, except in three main areas. Firstly, the solvent (C_8 or C_4) is co-injected with water at a pressure of 3500 kPa and temperature of 7°C into the steam generator, at which the solvents are in a liquid phase. The steam generator then heats the injection fluid to the corresponding saturation temperature at a pressure of 3500 kPa (236°C for C₈-SAGD and 229°C for C₄-SAGD) and injects it into the experiment vessel through the inlet line.

Secondly, the band heaters are set 5°C above the injection saturation temperature, which varies for each experiment due to their different mixture compositions. Thirdly, liquid drainage at the bottom producer is performed more frequently for SA-SAGD compared to SAGD because the SA-SAGD experiments recover oil faster than SAGD. Liquid drainage is conducted every 15 minutes for the first hour and every 30 minutes afterward. For the C₄-SAGD case, a large production tank is used instead of cylinders to collect the vapor from the top producer line.

3.6 Experiment Results

3.6.1 Oil Production, Pressure Data, and Material balance

Figure 3.8 shows the pressure data for both SAGD and SA-SAGD experiments. The pressures in the ramp-up phase are similar between the three experiments, with the target pressure of 3500 kPa achieved no later than 20 mins after the commencement of injection. Pressure drops of up to 500 kPa after reaching the target pressure indicate the time of liquid drainage.

The material balance results are given in Table 3.4 also show that the top producer and bottom producer effectively recover both the injected steam and solvent. The reasonable material balance and stable pressure profiles illustrate success in the overall operation of the experiments.

The oil production rate as a function of time is compared for all cases in Figure 3.6. In all three experiments, the oil rate peaks within the first half-hour of injection, then decline rapidly and level off after 1.5 hours. C₈-SAGD experiment has the highest peak oil rate at 31.2 cm^3 /min and declines fastest. In contrast, the oil rate of SAGD declines slowest. Total oil production volumes and recovery factors for each experiment are shown in Table 3.3 and Figure 3.7. Since OOIPs are slightly different for all experiments, the oil recovery factor, which is the ratio of the total produced oil to the OOIP, is used to compare oil production among experiments. The total recovery factors for SAGD, C4-SAGD and C8-SAGD are 0.78, 0.84, and 0.89, respectively. C8-SAGD has the highest total recovery factor, following by C4-SAGD and SAGD. Compared to SAGD, the addition of solvent in SA-SAGD increases bitumen mobilization and decreases the remaining oil, which greatly improves the oil recovery factor. C4 as a solvent is vaporized too quickly, not giving enough time to mix with the bitumen fully. Meanwhile, solvent C8 condenses easier and can fully mix with the bitumen, diluting in the process. The clear difference in recovery and oil production profile between the two solvents (C4 and C8) also illustrates the effectiveness of the experiment in the differentiation of solvent types.

3.6.2 Temperature Profiles

Figure 3.9 shows the temperature profile of the void space and central sand-pack thermocouples for all three experiment cases. The void space temperature increases rapidly after injection, while the temperature inside the sand-pack increases more slowly. The temperature change in the void space is also directly proportional to the pressure change in the system. The void space temperature profiles for all cases are similar. The temperature inside the void space after the transient period matches with the injection temperature, which indicates that the composition of the injection fluid is steady and that our predicted saturation temperatures are accurate. For the internal sand-pack, the temperature at the top thermocouple is higher than that at the subsequent lower thermocouples. In addition, the temperature increase at the top thermocouple is faster compared to that at the lower thermocouples. The temperature of the internal sand-pack for SAGD and C₄-SAGD increases smoothly in the transient period.

As for C₈-SAGD, the internal sand-pack temperature rises smoothly at first, then vertically gaps up at a particular time. This event indicates the arrival of the steam front at this location. By observing the temperature gap-up time on temperature profiles (Figure 3.7b) at different thermocouple locations, one can confirm with a high degree of confidence the advancement of the steam front from top to bottom. In this case, thermocouple data can clearly show the advance of the steam front and support the observation that C₈-SAGD produces oil much faster than SAGD and C₄-SAGD.

3.6.3 Compositional Analysis of Produced and Excavated Samples

The produced oil samples from each experiment are analyzed for density and CN number distribution. The produced oil density for SAGD, C₈-SAGD, and C₄-SAGD is 1020.30 kg/m³, 1021.40 kg/m³, and 1022.23 kg/m³ (at 15°C), respectively. They deviate slightly from the original bitumen density, which is 1015 kg/m³.

Figure 3.10 shows the carbon number distribution analysis for the produced oil samples. The weight percentage of light components (CN < 20) in the produced oil sample for SAGD are higher than that for C₈-SAGD and C₄-SAGD. The weight percentage of heavy components (20 < CN < 60) in the produced oil for SAGD is lower than that for C₈-SAGD and C₄-SAGD. Beyond a carbon number of 60, the weight percentage distribution

is similar among all cases. This observation indicates that the solvent has the ability to mobilize heavier components in the bitumen compared to SAGD.

After the experiment, Dean-Stark and asphaltene analysis are performed on the excavated sand-pack, with the results summarized in Tables 3.6, 3.7, and 3.8. The remaining oil saturation in the sand-pack is lower in C₈-SAGD and higher in C₄-SAGD and SAGD. This reflects the higher total oil recovery factor for C₈-SAGD.

Furthermore, for all cases, the bottom of the sand-pack contains the highest water saturation compared to the middle and the top of the sand-pack due to capillary end-effect. For all experiments, the oil saturation increases from the top to the bottom of the sand-pack because the top of the sand-pack contains more steam, and the bottom contains more hot water. Thus, top oil saturation is residual oil to steam, while the bottom oil saturation is residual oil to hot water.

Asphaltene weight percentage in residual oil for SAGD and C₄-SAGD ranges from 20 to 26%, slightly higher than 17% in the original bitumen. In sharp contrast, C₈-SAGD residual oil contains 40 to 70% asphaltene by weight. The extremely low residual oil saturation and high asphaltene content in the residual oil for C₈-SAGD indicate that most of the remaining oil is asphaltene, which is difficult to recover. Therefore, most of the non-asphaltene oil has been produced by C₈-SAGD. It also demonstrates that the C₈ is an effective solvent in bitumen recovery.

The excavated sample photos for SAGD, C₄-SAGD, and C₈-SAGD experiments are shown in Figures 3.11, 3.12, and 3.13, respectively. The color of the samples gradually changes from dark to light in the direction from top to bottom of the sand-pack for each

case. The SAGD sample photo shows the darkest color throughout the sand-pack, while the sample colors for C₄-SAGD are slightly lighter, and the ones for C₈-SAGD are the lightest, with the top and the middle samples showing colors similar to that of original sand. The excavated photos and saturation analysis all show the evidence that SA-SAGD is better SAGD in terms of recovery factor, and the solvent C₈ is more effective in diluting bitumen compared to C₄.



Figure 3.1: Schematic of the small-scale experimental setup.



a) Experimental vessel components side view



b) Experimental vessel top view

Figure 3.2: Detail schematic of the experimental vessel and its components inside.



Figure 3.3: Experimental vessel and thermocouple locations dimensions in inches.

Experiment case	Temperature,	Steam rate at	Solvent rate at	Total in-situ
	°C	pump condition	pump	condition
		(CWE),	condition,	rate,
		cm ³ /min	cm ³ /min	cm ³ /min
SAGD	241	70	0.00	3987
C8-SAGD 10 mol%	236	61.86	62.03	3987
	230	01.00	02:05	5701
C4-SAGD 20 mol%	229	54.06	72.93	3987

Table 3.1:Injection rates and saturation temperatures. Pump condition for steam is at
22°C and 3500 kPa, while the pump condition for solvent is at 7°C and 2500
kPa.

Figure 3.4: Grain size distribution of the sand-pack.

Experiment case	Pore volume, cm ³	Oil sat, %	Water sat, %	OOIP, cm^3
SAGD	519.13	92.85	7.15	482.03
C ₈ -SAGD	485.67	89.81	10.19	436.17
C ₄ -SAGD	524.74	91.89	8.11	482.2

 Table 3.2:
 Sand-pack pore volumes and saturation.

Experiment case	Total oil	Total oil	Recovery	Time to total
	produced,	recovery	factor at one	recovery,
	cm ³	factor	hour	hours
SAGD	375.44	0.78	0.71	5.05
C ₈ -SAGD	406.49	0.89	0.85	4.93
C ₄ -SAGD	422.05	0.84	0.80	4.78

Table 3.3:Total oil production and production duration of SAGD and SA-SAGD along
with recovery factor at 1 hour and ultimate recovery factor.

Figure 3.5: Cumulative power input from band heater and steam for SAGD as a function of time.

Figure 3.6: Oil production rate of SAGD and SA-SAGD experiments.

Figure 3.7: Recovery factor of SAGD and SA-SAGD experiments.

Figure 3.8: The pressure inside the vessel for both SAGD and SA-SAGD experiments.

Experiment case	Water injected	Steam produced	Material balance
	$(CWE), cm^3$	$(CWE), cm^3$	difference
SAGD	21364	20339	4.80%
C ₈ -SAGD	18297	18270	0.15%
C ₄ -SAGD	15893	17054	7.30%

a) Injected and produced water in cold-water equivalent volumes.

Experiment case	Solvent	Solvent	Material balance
	injected, cm ³	produced, cm ³	difference
C ₈ -SAGD	18262	18464	1.11%
C ₄ -SAGD	21960	22269	1.41%

b) Injected and produced solvent volumes at pump conditions of 7°C and 3500 kPa.

Table 3.4:Material balance of injected fluids.


a) SAGD temperature profile.



b) C₈-SAGD temperature profile.



- c) C₄-SAGD temperature profile
- Figure 3.9: The temperatures of void space thermocouples and center internal thermocouples. The solid lines represent the temperatures of the void space thermocouples, while the dotted lines represent the temperatures of the center internal thermocouples. Thermocouple 5 is located at the top, while thermocouple 2 is located at the bottom.

Experiment case	Produced oil	Density of produced oil sample	
	sample number	at 15°C, kg/m ³	
SAGD	2	1020.30	
C ₈ -SAGD 10 mol%	3	1021.40	
C ₄ -SAGD 20 mol%	3	1022.23	

Table 3.5:The density of produced bitumen for both SAGD and SA-SAGD
experimental cases.



Figure 3.10: Produced bitumen carbon number distribution for SAGD and SA-SAGD cases.

Lavar	Saturat	tion % at 2	Asphaltene wt%	
Layer	Water	Oil	Gas	in oil
Тор	1.6	8.6	89.7	22.8
Middle	1.7	13.0	85.3	23.4
Bottom	2.2	15.3	82.5	22.5

Table 3.6:Oil/water/gas analysis for the excavated sand-pack and asphaltenes contentin the remaining oil for the SAGD experiment.

Lavan	Saturat	tion % at 2	Asphaltene wt%	
Layer	Water	Oil	Gas	in oil
Тор	1.1	8.1	90.9	22.0
Middle	1.1	10.8	88.1	24.7
Bottom	1.1	24.3	74.5	26.4

Table 3.7:Oil/water/gas analysis for the excavated sand-pack and asphaltenes content
in the remaining oil for the C4-SAGD experiment.

Lover	Saturat	tion % at 2	Asphaltene wt%	
Layer Water		Oil	Gas	in oil
Тор	2.1	1.6	96.3	43.3
Middle	2.6	0.5	96.9	73.6
Bottom	2.6	4.7	92.7	43.9

Table 3.8:Oil/water/gas analysis for the excavated sand-pack and asphaltenes content
in the remaining oil for the C8-SAGD experiment.



Figure 3.11: Photos for the excavated sand-pack sample in the SAGD experiment. Samples from left to right goes from the bottom to the top of the sand-pack.



Figure 3.12: Photos for the excavated sand-pack sample in the C₄-SAGD experiment. Samples from left to right goes from the bottom to the top of the sand-pack.



Figure 3.13: Photos for the excavated sand-pack sample in the C₈-SAGD experiment. Samples from left to right goes from the bottom to the top of the sand-pack.

Chapter 4: Small Scale Experiment Simulation and Dispersion Coefficient Determination

This chapter will detail how the small-scale experiment is simulated using CMG STARS (CMG 2018) and history matched to experimental data. The SAGD experiment serves as the baseline benchmark and is first matched by fine-tuning input parameters. Then, the experiments of C₈-SAGD and C₄-SAGD cases are matched with the established parameters from the matched SAGD simulation and by adjusting the dispersion coefficient. The dispersion coefficient is finally determined. The results of the simulation and determined dispersion are analyzed and discussed.

4.1 Simulation Setup

The simulation is performed with CMG STARS . Important inputs of the simulation model include gridblock sizes and coordinates, well placement, petrophysical properties throughout the whole physical model space, fluid properties, and well and heater controls. The simulation model is assigned two sets of properties, one for the sand-pack and one for the void space according to the physical experimental model setup.

4.1.1 Gridblock and Dimensions

The simulation model uses a cylindrical coordinate system in the up-right direction with the sand-pack located in the middle wrapped by void space around its radius and below (Figure 4.1 and Figure 4.2). In the cylindrical coordinate system, horizontal, radial, and vertical directions are represented by I, J, and K, respectively.

The gridblock dimension in the sand-pack area and the annular void space wrapped around the sand-pack is 0.22 cm, 360°, 0.24 cm in I, J, and K directions, respectively, with the number of gridblocks of I = 22, J = 1, and K =144. Therefore, the sand-pack has 22 radial cylindrical rings layered sequentially, with a distance of 0.22 cm between the circles. Then the model is divided into 144 vertical gridblocks with a height of 0.24 cm. The gridblock dimensions of the void space under the sand-pack are 0.22 cm, 360°, 0.3 cm in the I, J, K direction, respectively, with the number of gridblocks of I = 22, J = 1, and K= 56. In total, the model comprises of 4400 gridblocks (I = 22, J = 1, K = 200).

4.1.2 Heater and Well Control

The injector is a single gridlock placed in the annular space under the sand-pack. There are two producers in the physical experiment; the top producer continuously produces gas, while the bottom producer produces only liquid. To simplify the simulation model, just one producer is used to mimic the experimental top and bottom producers. All fluids (liquid and gas) are produced by it. The bottom producer in the simulation comprises a series of gridblocks at the very bottom of the model.

The bottom hole drawdown pressure of the producer in the simulation model uses experimental pressure data shown in Figure 4.3. The injector is set to inject the fluid at a constant pressure of 3500 kPa and the corresponding saturation temperature. The outermost gridblock of the model is set to be the band heater with steel thermal conductivity. These gridblocks have zero porosity and permeability, hence only allow heat transfer and no mass transfer. The experimental band heater temperature data are exported into the simulation model as the input parameters for the band heater.

4.1.3 Petrophysical and Rock-Fluid Properties

A porosity of 0.33 and a permeability of 75.7 D are populated to the whole sandpack area in the model. The maximum allowed porosity of 0.999 and permeability of 999 D are set to the gridblocks in the void space area.

The fluid models of bitumen and solvent used in this simulation are directly imported from the fluid models (EOS, viscosity, and density models) developed in Chapter 2. Meanwhile, the distribution of fluid saturations is from the experimental data of the sand-pack in Chapter 3.

The thermal conductivities of the sand-pack, water, oil, and gas phases used in the simulations are 1.5, 0.36, 0.072, and 0.02 J/(cm×min×°C), respectively. The steel thermal conductivity of 20 J/(cm×min×°C) is used for the band heater.

The relative permeability curves of the two phases for the sand-pack and the void space are shown in Figures 4.4 and 4.5, respectively. Those curves are finalized after fine-tuning to match the SAGD experiment results. The three-phase relative permeability calculations use Stone I correlation with the detailed parameters listed in Table 4.1. Residual water saturation value comes from the oil imbibition process in the experiments.

Meanwhile, the residual oil saturation is determined by the oil recovery factor of the SAGD experiment.

During the oil gravity drainage process in our SAGD and SA-SAGD experiment, capillary forces are comparable to gravity forces. This is shown by calculating the Bond number (N_b) in equation 4.1, which compares the gravity forces with capillary forces (Rashid et al. 2012).

$$N_b = \frac{\Delta \rho g r^2}{\sigma} \tag{4.1}$$

where σ is interfacial tension, $\Delta \rho$ is the density difference between phases, g is the gravitational acceleration, and r is the radius of the pore. The calculated Bond number for our system is 4.88, indicating that capillary forces are comparable to gravity forces and that capillary forces cannot be ignored in the simulation.

The capillary pressures for water/oil and oil/gas shown in Figure 4.6 are calculated by the bundle-tube capillary model. Pore diameters are calculated by using the Carman-Kozeny equation with the sand-pack grain size distribution given in Chapter 3. The interfacial tensions for water/oil and gas/liquid oil are assumed to be 30 dynes/cm and 15 dynes/cm, respectively.

4.2. History Matching of SAGD and SA-SAGD Experiments

Firstly, SAGD experimental temperature profile and oil production data are history matched with the simulation model. Then the established input parameters from the SAGD

history match are transferred to the SA-SAGD simulation model. Lastly, SA-SAGD experiment data is matched with only the input dispersion coefficients.

4.2.1 SAGD History Matching

Since the main mechanism of oil production in SAGD comes from viscosity reduction by temperature, many simulation runs are required to, first of all, match the system's temperature profile in the SAGD experiment. Most of the matching is achieved by inputting the correct minute-by-minute pressure into the simulations because the system's temperature is a function of the saturation pressure of the injection fluids. Then a thermal conductivity of sand is adjusted to 1.5 J/(cm×min×°C), with reasonable values for sand ranging from 1.2 to 2 J/(cm×min×°C), to improve in matching the temperature of the SAGD experiment. Finally, a log-linear temperature mixing rule for sand, oil, water, and gas thermal conductivity is used to better represent the temperature profile at the interface of the steam chamber. Figures 4.6a and 4.6b show temperature profile matching results at void space and center sand-park for the SAGD experiment, respectively. We can see from those two figures that the simulated temperature profile well matches the experimental data.

After the temperature data is matched well, then efforts in simulation runs are made to match oil production history. The oil production history of the SAGD case is shown in Figure 4.7. Matching the oil production requires mainly adjusting the relative permeability curve of the oil phase to favor more oil production within the first hour. This is achieved by reducing the exponent on the k_{ro} curve from a normal value of 2.0 to 1.4. The final simulated oil product profile shown in Figure 4.7 excellently matches the experimental data of the SAGD case.

The oil, water, and gas saturation distribution in the history-matched simulation model at the end of the 5-hour production are shown in Figure 4.8. From this figure, the capillary end-effect is observed in the simulation in which higher water saturation distributes towards the sand-pack's bottom. Residual oil saturation in the simulation model is also lower in the areas saturated by steam compared to that in the regions saturated. The oil/water/ gas analysis experimental data of the excavated samples of the sand-pack in Chapter 3 also supports all these observations from above.

4.2.2 SA-SAGD History Matching

In the SA-SAGD process, a solvent is co-injected with steam to the reservoir. The main mechanism for solvent injection to accelerate and increase oil recovery in comparison to SAGD is the viscosity reduction of bitumen by solvent dispersion in the bitumen of the mobile zone. Thus, in the simulation of the SA-SAGD process comparing to SAGD, it is important to model the mass transfer of solvent by dispersion in the porous media. The value of dispersion coefficient of a solvent has a wide range and some uncertainty; its valid value for a particular solvent should obtain by fine-tuning during history matching of SA-SAGD simulation.

With the same thermal conductivity and relative permeability curves established from SAGD, the simulations of both C₈-SAGD and C₄-SAGD cases need to adjust the

dispersion coefficient of the solvent in order to history match oil production. From this match, we can determine the dispersion coefficient of the solvent.

In this thesis, the dispersion coefficient is assumed to be homogenous and isotropic in all directions; namely, the longitudinal and traverse dispersion coefficients have the same value. This assumption is used to reduce the computational time needed for history matching. The temperature and oil matching results are shown in Figures 4.9 and 4.10, Figures 4.11 and 4.12, respectively.

From Figure 4.13, we can compare the effects of the dispersion coefficients on SA-SAGD oil production. The dash-line curve in Figure 4.13 shows the predicted oil production using initial dispersion coefficient values of 1.5×10^{-4} cm²/min for C₈-SAGD and 2.5×10^{-4} cm²/min and C₄-SAGD. These initial values are in the range for the dispersion coefficient reported in the literature. The solid curve shows the predicted oil production after history matching with the final dispersion coefficient values of 0.392 cm²/min for C₈-SAGD and 0.405 cm²/min and C₄-SAGD. We can see that using the final values of dispersion coefficients; the history match is significantly better. Thus, the excellent quality of the match serves as a solid basis for the dispersion coefficient determination, which will be performed in the next section.

Similar to the SAGD case, the capillary end-effect causes higher hot water saturation towards the bottom of the sand-pack. The bottom area of the sand-pack has higher water and oil saturation and extremely low gas saturation. This is observed in both the simulation (Figures 4.14 and 4.15) and the oil/water/gas analysis for the excavated sand-pack conducted in Chapter 3. The increase in oil recovery from SA-SAGD over

SAGD depends mainly on the solvent's ability to dilute bitumen and to reduce bitumen viscosity further.

By splitting the produced oil from the simulation into its components B1 and B2, shown in Figure 4.16, we can observe that much of the incremental oil recovery by C₈-SAGD comes from heavy component B2. The light component, B1, only contributes marginally to the incremental oil recovery by C₈-SAGD since B1 can already be easily recovered by SAGD. As for C₄-SAGD, the incremental oil production compared to SAGD comes from a small addition recovery of both B1 and B2. As a result, C₈-SAGD has the highest oil recovery, followed by C₄-SAGD and then by SAGD.

4.3 Dispersion Coefficient Determination

In SA-SAGD simulation, accurate modeling of the solvent mass transport in porous media is important to precisely predict oil production. For constant porosity system, onedimensional and single-phase incompressible flow, the convection-dispersion equation (CDE) is the following (Shrivastava 2003):

$$-u\frac{\partial C}{\partial z} + \phi D\frac{\partial^2 C}{\partial z^2} = \phi\frac{\partial C}{\partial t}$$

$$4.2$$

where C is the mass concentration of solvent, u is the Darcy flow velocity, ϕ is the porosity of the porous media, and D is the mechanical dispersion or dispersion coefficient of solvent. In the simulation, D is the input parameter measured conventionally in the lab by fitting the solution of the one-dimensional CDE to the effluent concentration from a coreflood test. Therefore, it is known as the input dispersion coefficient. Solving the convective dispersion equation 4.2 numerically using a finitedifference technique like in the SAGD and SA-SAGD simulations could introduce numerical dispersion. The sum of the input and numerical dispersion becomes the actual dispersion coefficient. Thus, equation 4.2 becomes equation 4.3 (Shrivastava 2003):

$$-u\frac{\partial C}{\partial z} + \phi (D_{input} + D_{num})\frac{\partial^2 C}{\partial z^2} = \phi \frac{\partial C}{\partial t}$$

$$4.3$$

$$D_{input} = \frac{D_o}{\tau} + \alpha \frac{u}{\phi} \tag{4.4}$$

where D_o is molecular diffusion, and τ is the tortuosity of the porous medium. The molecular diffusion is omitted in our case since molecular diffusion is negligible compared to dispersion, and this omission will be explained in detail later in this chapter. D_{input} is equal to dispersivity, α , multiplied by interstitial velocity, $\frac{u}{\phi}$.

In equation 4.3, D_{num} is the numerical dispersion coefficient:

$$D_{num} = \left(\frac{u}{\phi}\right) \frac{\Delta z}{2} \left[1 - N_{co}\right]$$

$$4.5$$

where u is Darcy velocity, Δz is the grid block size in the z-direction, and N_{co} is the Courants number, which indicates the number of cells or fraction of a cell the solvent advances in one timestep.

$$N_{co} = \left(\frac{u}{\phi}\right) \frac{\Delta t}{\Delta z} \tag{4.6}$$

If $\left(\frac{u\Delta t}{\phi}\right) \ll \Delta z$ then $(1 - N_{co}) \approx 1$, D_{num} becomes the following:

$$D_{num} = \left(\frac{u}{\phi}\right) \frac{\Delta z}{2} \tag{4.7}$$

The numerical dispersion is calculated based on equation 4.7, and the maximum numerical dispersivity is 50% of gridblock size in the direction of the velocity for a one-dimensional system.

For our two-dimensional system, the numerical dispersion becomes the following (Russel and Wheeler 1983):

$$D_{num} = \frac{|u_x|}{\phi} \frac{\Delta x}{2} + \frac{|u_z|}{\phi} \frac{\Delta z}{2}$$

$$4.8$$

where Δx and Δz are the gridblock sizes in the x and z directions, respectively, and u_x and u_z are Darcy velocities in the x and z directions, respectively. In these experiments, Δx and Δz are approximately equal. However, u_z is about 15 times greater than u_x , and for simplicity, the numerical dispersion in the x-direction is neglected. Thus equation 4.8 becomes equation 4.9:

$$D_{num} = \frac{|u_z|}{\phi} \frac{\Delta z}{2} \tag{4.9}$$

Generally speaking, if equation 4.9 is used to solve the numerical dispersion in 2-D, it will underestimate the actual dispersion coefficient. However, the underestimation of numerical dispersion caused by using equation 4.9 is minuscule for our research cases.

Since our grid block size in the z-direction is 0.24 cm, the maximum dispersivity would be 0.12 cm. By adding both numerical and input dispersion coefficients, the total dispersion coefficient is determined for each SA-SAGD case and shown in Table 4.3. The total dispersion coefficient is determined to be 5.64×10^{-2} m²/day for C₈-SAGD and 5.83 $\times 10^{-2}$ m²/day for C₄-SAGD. This is achieved by carefully fine-tuning input parameters in SA-SAGD simulations to history match oil production profiles shown in Figure 4.13. The proposed method and procedures to determine the dispersion coefficient of solvent are demonstrated and outlined in Figure 4.17. Lastly, we can convert the total dispersion coefficient to dispersivity by dividing it by interstitial velocity. The calculated dispersivities for C₈-SAGD and C₄-SAGD are listed in Table 4.4.



Figure 4.1: 2D section view of the simulation model. The model is symmetrical, and only half of the model is shown.



Figure 4.2: 2D top planar view of the simulation model.





Figure 4.3: Pressure data of the experimental vessel and simulation input for SAGD, C₈-SAGD, and C₄-SAGD.



Figure 4.4: Relative permeability curves used for both SAGD and SA-SAGD.



b) gas/ liquid

Figure 4.5: Void space relative permeability curves.

D	X 7 - 1
Parameter	value
Swr	0.08
Sor (oil/water, oil/gas)	0.22
Sgr	0
Kro(Sw = Swr)	1
Krw(Sw = 1 - Sor)	0.6
Krg(Sl = 1 - Sgr)	1
Exponent, Krw	1.86
Exponent, Kro	1.4
Exponent, Krg	3

 Table 4.1:
 Stone I relative permeability parameters.



Figure 4.5: Capillary pressure curve used both SAGD and SA-SAGD.



b) Center sand-pack temperature

Figure 4.6: SAGD temperature match.



Figure 4.7: SAGD oil production match.



Figure 4.8: SAGD saturation profiles at the end of the 5-hour experiment.



b) Center sand-pack temperature

Figure 4.9: C₈-SAGD temperature match.



b) Center sand-pack temperature

Figure 4.10: C₄-SAGD temperature match.



Figure 4.11: C₈-SAGD oil production.



Figure 4.12: C₄-SAGD oil production.



Figure 4.13: SA-SAGD oil production simulation results before and after history matching with dispersion coefficient.



Figure 4.14: C₈-SAGD saturation profiles at the end of the 5-hour experiment.



Figure 4.15: C₄-SAGD saturation profiles at the end of the 5-hour experiment.



Figure 4.16: B1 and B2 oil component recovery factors for SAGD and SA-SAGD simulation cases.

Parameter	Value
Volumetric flow rate Q (cm ³ /min)	3.29
Porosity ϕ	0.33
Cross-sectional Area A (cm ²)	9.07
Darcy velocity <i>u</i> (cm/min)	3.30
Interstitial velocity v (cm/min)	1.10

a) C₈-SAGD

Parameter	Value
Volumetric flow rate Q (cm ³ /min)	1.50
Porosity ϕ	0.33
Cross-sectional Area A (cm ²)	9.07
Darcy velocity <i>u</i> (cm/min)	1.50
Interstitial velocity v (cm/min)	0.50
Darcy velocity u (cm/min) Interstitial velocity v (cm/min)	0.50

b) C₄-SAGD

 Table 4.2:
 Parameters for calculating interstitial velocity.

Experiment case	Numerical dispersion, cm ² /min	Input dispersion, cm ² /min	Total dispersion, cm ² /min	Total dispersion, m ² /day
C ₈ -SAGD 10 mol%	0.242	0.15	0.392	5.64×10^{-2}
C ₄ -SAGD 20 mol%	0.055	0.35	0.405	5.83×10^{-2}

Table 4.3: Dispersion coefficients for both C₈-SAGD and C₄-SAGD.

Experiment case	Numerical,	Input dispersivity,	Total dispersivity,
	cm	cm	cm
C ₈ -SAGD 10 mol%	0.12	0.068	0.178
C ₄ -SAGD 20 mol%	0.12	0.700	0.810

Table 4.4: Dipersivities for both C₈-SAGD and C₄-SAGD.



Figure 4.17: The prosed procedure and workflow chart of determination of dispersion coefficient of solvent in bitumen.

4.4 Results of Dispersion Coefficient Determination and Discussion

This section will explain why a lab-scale velocity criterion is needed to isolate the dispersion coefficient from molecular diffusion. Furthermore, we will demonstrate the application and usage of our dispersion coefficient data for field-scale simulation.

4.4.1 Velocity Criteria for Lab-Scale Experiments using Péclet Number

Hydrodynamic dispersion comprises of both molecular diffusion and mechanical dispersion (Lake 1989; Pickens and Grisak 1981). Molecular diffusion is the spreading of the solute particle caused by concentration gradients, while mechanical dispersion is mixing resulting from velocity variation along and across streamlines within the pore space.

If the flow velocity is small, there might be time for diffusion to act in the mass transfer process. On the other hand, if the velocity is large enough, there would be insufficient time for diffusions to equalize the concentration for a given pore space (Meng et al., 2018). According to Perkins and Johnston (1963) and Meng et al. (2018), one can calculate the Péclet number using equations 4.10:

$$N_p = \frac{vd_p}{D_o} \tag{4.10}$$

$$N_p > 10^{-2}$$
 4.11

where v is interstitial velocity, d_p is grain size, and D_o is diffusion coefficient. If the Péclet number is much larger than 10^{-2} in the context of a solvent bitumen system (Meng et al. 2018), then dispersion will dominate, and diffusion can be neglected.

Below we show the Péclet number for our experiment using equation 4.10. The calculated. For the C₄-SAGD case, the Péclet number is calculated below:

$$N_p = \frac{vd_p}{D_o} = \frac{(7.2 \ m/day)(5 \times 10^{-4} \ m)}{6.05 \times 10^{-5} \ m^2/day} = 59.5 > 10^{-2}$$

where the interstitial velocity is 0.5 cm/min (7.2 m/day), the grain size is 500 μ m for C₄-SAGD, and molecular diffusion of $6.05 \times 10^{-5} \text{ m}^2/\text{day}$ for C₄ from Zhao et al. (2018). The following Péclet number is calculated for C₈-SAGD:

$$N_p = \frac{vd_p}{D_o} = \frac{(15.8 \, m/day)(5 \times 10^{-4} \, m)}{2.56 \times 10^{-5} \, m^2/day} = 308.6 > 10^{-2}$$

where the interstitial velocity is 15.8 m/day, and the diffusion coefficient for C₈ in bitumen is 2.56×10^{-5} m²/day from Guerrero-Aconcha (2009). The calculated Péclet number (N_p) for C₄-SAGD and C₈-SAGD cases are 59.5 and 308.6, respectively. The calculated N_p value is much larger than 10⁻². It means the mass transfer process in this experiment is dispersion dominant, and that diffusion can be neglected. Moreover, the calculated Péclet numbers in our SA-SAGD experiments which gives context to the dispersion coefficient.

Much smaller velocities are used for similar lab-scale experiments conducted in the literature (Lim et al. 1996; Reza et al. 2011). According to Reza et al. (2011), where diffusion coefficient has been reported for a propane-bitumen system under the VAPEX process, the calculated Péclet number is 7.78×10^{-3} .

$$N_p = \frac{vd_p}{D_o} = \frac{(3.541 \times 10^{-3} \, m/day)(2 \times 10^{-4}m)}{9 \times 10^{-5} \, m^2/day} = 7.87 \times 10^{-3} < 10^{-2}$$

where the average velocity is 0.014756 cm/hour (3.541×10^{-3} m/day) and grain size is 200 μ m. The calculated Péclet number is still not large enough to neglect diffusion, and the mass transfer mechanism in the experiments is diffusion dominant. Therefore, the calculated coefficient is not well isolated as diffusion coefficient or dispersion coefficient.

In a realistic field-scale of SA-SAGD with a typical chamber edge velocity of 0.05 m/day (Venkatramani and Okuno 2018), and typical grain size of 300 μ m (Oldakowski 1994), the Péclet number will be 0.248, which is greater than 10⁻².

$$N_p = \frac{vd_p}{D_o} = \frac{(0.05 \ m/day)(3 \times 10^{-4} \ m)}{6.05 \times 10^{-5} \ m^2/day} = 2.48 \times 10^{-1} > 10^{-2}$$

Therefore, in field-scale, velocities are large enough to reach a dispersion dominant regime beyond diffusion dominant regime.

From this analysis, it is shown that in the lab-scale experiments, interstitial velocity must be set in the range of at least 0.1 m/day or greater so that it will be large enough to be away from the diffusion-dominant regime. From the calculated Péclet number, it is reasonable to assume that molecular diffusion is negligible in our SA-SAGD experiments. Therefore, the coefficient obtained in this thesis for SA-SAGD is the dispersion coefficient. All in all, in order to correctly solve for dispersion coefficient using lab-scale experiment, one must carefully consider experimental flow velocities of fluid.

4.4.2 Application of Dispersion Coefficient in Field-Scale Simulation

Dispersivity and dispersion coefficient are both scale-dependent variable. Dispersivity on a field scale often reflects reservoir heterogeneity, such as the result of
shale barriers. Meanwhile, lab-scale dispersivity mainly reflects the pore-scale tortuosity (Bear 1972; Sternberg et al 1996). The dispersion coefficients found in this experiment reflect the mixing characteristics of solvent at the pore scale. In order to directly use the dispersivity found in our small-scale experiment in a field-scale simulation, upscaling of the dispersivity is required

During our dispersion coefficient determination process, we considered the input dispersion and numerical dispersion to obtain a reliable physical dispersion coefficient. After upscaling, the total dispersion coefficient can be applied in field-scale simulation and can guide the user in determining the appropriate gridblock size for field-scale simulation. The numerical dispersivity in the simulation cannot exceed the upscaled total dispersivity, and that the maximum gridblock size for the simulation is two times the numerical dispersivity. If a smaller gridblock size is used, an additional input dispersion coefficient will be needed in the simulation to model the dispersion process and accurately predict oil production correctly.

4.5 Chapter Summary

In this chapter, a method of determining the dispersion coefficient of a solvent for the SA-SAGD process was established. The dispersion coefficient for C₈-SAGD and C₄-SAGD were determined using this method. The results were analyzed and verified. The usage of the coefficients in field-scale applications was demonstrated. The contents covered in the chapter, including the method, results, and analysis, add novelty to the current research field and literature.

Chapter 5: Summary, Conclusions and Recommendations

5.1 Summary and Conclusions

SA-SAGD, as an alternative or enhancement to SAGD, has been studied and viewed as one of the most promising methods for bitumen recovery. This thesis focused primarily on determining the dispersion coefficient of solvent, which is a key parameter in the design of the solvent-steam co-injection process, based on the small-scale lab experiment and simulation.

Firstly, physical properties were measured for bitumen, and the data were used in the lab-scale gravity drainage experiments and simulations. Constant mass expansion, density, and viscosity experiments were conducted. Then, bitumen and solvent were characterized based on the Peng-Robinson equation of state (EOS), the density and viscosity models of bitumen and solvent were developed by matching the experimental data. Secondly, a set of novel gravity drainage experiments was performed to investigate the effects of the chamber conditions (pressure, temperature, and solvent/steam composition) on oil recovery and its mechanisms under controlled thermodynamic conditions. Thirdly, the small-scale SAGD and SA-SAGD experiments were simulated, and history matched using CMG STARS by fine-tuning input parameters. A method was proposed to determine the dispersion coefficient of solvent based on those simulations. The dispersion coefficients of C₈ and C₄ were finally determined by the established method, and the results of the determined dispersion were analyzed and discussed.

The following conclusions can be drawn based on the studies:

- The novel lab-scale gravity drainage experiment setup presented here can effectively model chamber edge conditions of the SAGD and SA-SAGD processes. This novel experimental method provides a convenient way to quickly test potential solvents by examining their condensing capability, diluting bitumen, and facilitating oil flow at chamber edge conditions.
- 2. In both C₈-SAGD and C₄-SAGD experiments, the solvent could dilute the bitumen and further reduce oil viscosity during the oil drainage process. The C₈ solvent in C₈-SAGD was more effective for oil recovery compared to C₄ in C₄-SAGD due to its ability to mobilize and recover heavy components (B2 in the history matched simulation) in the bitumen.
- 3. A method of determining the dispersion coefficient of solvent was developed using simulation. It entailed history matching small-scale experimental data of SA-SAGD using dispersion coefficient to model the mixing of solvent in bitumen accurately. This generalized method can be utilized to determine the dispersion coefficient of solvent at a given pressure and temperature for solvent and steam co-injection under gravity drainage.
- 4. The dispersion coefficient of C₄ and C₈ for C₄-SAGD and C₈-SAGD determined by the proposed method were $5.83 \times 10^{-2} \text{ m}^2/\text{day}$ and $5.64 \times 10^{-2} \text{ m}^2/\text{day}$, with Péclet numbers of 59 and 309, respectively, under our set temperature and pressure.
- 5. The determined dispersion coefficients can be used for gridblock size selection in field-scale simulation. The criteria and guidelines for the gridblock size selection

were proposed to ensure that the numerical dispersion does not exceed the hydrodynamic dispersion.

- 6. The interstitial velocity of the small-scale experiment must be designed with cautions to ensure that the determined coefficient is a dispersion coefficient and not the diffusion coefficient. For our small-scale SA-SAGD experiments, the velocities were in the range of 10 m/day and were confirmed that the solvent mass transfer in the porous medium was in the region of dispersion dominant comparative to diffusion.
- 7. The EOS parameters, including Tc, Pc, ω, and the developed density and viscosity models for bitumen accurately represent the experimental data and provide a solid basis for simulating SAGD and SA-SAGD cases conducted in Chapter 4. They also can be used in other similar bitumen experiments and simulations.

5.2 Recommendations for Future Research

The research in this thesis opens a new area not studied previously in detail. Recommendations for future research of using small-scale experiments and simulation to determine dispersion coefficient are as follows:

 This research did not investigate in detail the effect of longitudinal and transverse dispersion coefficients on SA-SAGD as the dispersion coefficient used was isotropic. However, it should be anisotropic in general; commonly, the longitudinal dispersion is about 3 to 10 times larger than the transverse dispersion (Gelhar et al. 1992; Grane and Gardner 1961). Establishing the appropriate ratio between longitudinal and transverse dispersion coefficients would further increase the validity of the results and reflect the physics of the experiment.

- 2. In this research, the dispersion coefficient was found for a pure component solvent. However, in an actual SA-SAGD operation, a condensate or multi-component solvent is commonly used. Therefore, a research study is needed to verify whether pure component dispersion coefficient can be directly applied to model multicomponent solvent and steam co-injection process.
- Field-scale simulation studies are needed to investigate whether the currently determined dispersion coefficient can be used to history match oil production of SA-SAGD.

	100°C		150°C		200°C	
	Pressure,	Density,	Pressure,	Density,	Pressure,	Density,
40.1 mol%	kPa	kg/m ³	kPa	kg/m ³	kPa	kg/m ³
	968	900.2	1092	870.9	1,444	841.4
Solvent	750	899.7	919	869.7	1,305	840.7
	625	899.4	804	868.9	1,163	840.3
	558	899.2	786	868.9	1,035	839.8
	100°C		150°C		200°C	
	Pressure,	Density,	Pressure,	Density,	Pressure,	Density,
CO O 10/	kPa	kg/m ³	kPa	kg/m ³	kPa	kg/m ³
60.9mol%	1,360	857.4	1,961	826.8	1,812	793.8
Solvent	1,015	856.8	1,201	825.1	1,320	792.5
	859	856.4	1,064	824.7	1,185	792.0
	713	856.1	905	824.2	1,148	791.2
	100°C		150°C		200°C	
	Pressure,	Density,	Pressure,	Density,	Pressure,	Density,
90.0	kPa	kg/m ³	kPa	kg/m ³	kPa	kg/m ³
mol%	1,223	724.3	1,351	685.9	2,078	644.9
Solvent	1,031	723.9	1,203	685.5	1,739	644.0
	889	723.6	1,136	685.4	1,461	643.1
	741	723.3	1,030	685.2	1,300	642.3
	100°C		150°C		200°C	
	Pressure,	Density,	Pressure,	Density,	Pressure,	Density,
94.4	kPa	kg/m ³	kPa	kg/m ³	kPa	kg/m ³
mol%	1,379	689.8	1,625	649.4	1,940	599.7
Solvent	1,052	689.0	1,451	648.9	1,704	599.6
	886	688.7	1,293	648.4	1,564	599.1
	719	688.3	1,062	647.5	1,391	598.4

Appendix

 Table A1:
 Density of the four bitumen/solvent mixtures calculated from constant mass expansion experiment.

40.1 mol% solvent mixture	Pressure, MPa	72°C	100°C	130°C	150°C	170°C
	2.0	44.35	17.66	7.52	5.05	3.54
	3.0	44.99	17.94	7.61	5.13	3.59
	4.0	45.91	18.25	7.73	5.18	3.62
	6.0	47.53	19.12	7.95	5.31	3.70
	8.0	49.12	19.92	8.12	-	-
	10.0	50.49	20.88	8.26	-	-
	Pressure, MPa	72°C	100°C	130°C	150°C	170°C
	2.0	16.41	7.13	3.82	2.63	1.91
(0,0,,10/	3.0	16.81	7.22	3.89	2.68	1.93
60.9 mol% solvent mixture	4.0	16.98	7.35	3.93	2.72	1.95
	6.0	17.46	7.48	3.99	2.79	2.01
	8.0	17.97	7.73	4.06	-	-
	10.0	18.36	8.02	4.15	-	-
	Pressure, MPa	72°C	100°C	130°C	150°C	170°C
90.0 mol% solvent mixture	20.0	0.829	0.541	0.357	0.291	0.221
	30.0	0.830	0.542	0.358	0.292	0.222
	40.0	0.831	0.543	0.359	0.293	0.222
	60.0	0.833	0.544	0.359	0.293	0.223
	80.0	0.834	0.545	0.360	-	-
	100.0	0.836	0.546	0.361	-	-

Table A2:Viscosity of different concentration solvent/bitumen mixtures with
temperatures ranging from 72°C to 170°C and pressures ranging from 2.0
MPa to 10.0 MPa.

Glossary

Abbreviations

SAGD	Steam-Assisted Gravity Drainage
SA-SAGD	Solvent-Aided Steam-Assisted Gravity Drainage
SOR	Steam-to-Oil Ratio
CMG	Computer Modelling Group
VAPEX	Vapor Extraction
EOS	Equation of State
BIP	Binary Interaction Parameter
CME	Constant Mass Expansion
PVT	Pressure Volume Temperature
AAD	Average Absolute Deviation
AARD	absolute average relative deviation
CDE	Convection-Dispersion Equation

Greek

μ	Viscosity, cp
ρ	Density, kg/m ³
ω	Acentric factor
α	Dispersivity, cm
ϕ	Porosity
ν	Interstitial velocity, cm/min

τ	Tortuosity
σ	Interfacial tension, dynes/cm

Latin

Do	Diffusion, m ² /day
D	Dispersion, m ² /day
Т	Temperature, °C
Tc	Critical temperature, °C
T _b	Boiling point temperature, °C
Р	Pressure, kPa
Pc	Critical pressure, kPa
Pg	Gauge pressure, kPa
K	Absolute permeability, D
Kr	Relative permeability
Pc	Critical pressure, kPa
MW	Molar weight, g/mol
CN	Carbon number
Xi	Mole fraction of component i
T _b	Boiling point temperature
V	Volt
N _b	Bond number
N _p	Péclet number
g	Acceleration of gravity, m/s ²
A	Cross-sectional Area A, cm ² 101

u	Darcy flow velocity, cm ³ /min
d _p	Diameter of pore size, µm
D _{input}	Input dispersion, m ² /day
D _{num}	Numerical dispersion, m ² /day
Δt	Time step size, s
Δz	Gridblock size, cm

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