SIMULATION STUDY ON WAG-CO2 INJECTION IN LIGHT OIL IN THE PRESENCE OF ASPHALTENE IN SANDSTONE RESERVOIR

By

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Dissertation submitted in partial fulfillment of

the requirements for the

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Universiti Teknologi PETRONAS

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CERTIFICATION OF APPROVAL

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Petroleum Engineering Programme
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(PETROLEUM ENGINEERING)

Approved by,

____
(Mr. Ali F. Mangi Alta'ee)
Project Supervisor

UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK
AUGUST 2014

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

(MOHD ZAINUDIN P.RAMLE)

ABSTRACT

WAG-CO_2 is proven to be a better method than water flooding alone. Injecting water alternately with CO_2 helps recover more oil compared to water flooding. Water injection improves the sweep efficiency and gas flooding reduces the effect of viscous fingering. *Chen et al.* (2009) stated that water injection is used to control gas mobility in order to achieve higher sweep efficiency in macroscopic scale while gas injection gives higher sweep efficiency in microscopic scale. From field experiences, WAG-CO_2 injection in light oil will cause asphaltene precipitation problem and one of the reasons is because of pressure and composition changes. This paper is focusing on studying the effect of WAG injection pressure on the precipitation of asphaltene in Malaysian light oil (38.8 API) using sandstone model. Different WAG injection pressure is used ranging from 2000 psia to 3200 psia. Pressure of 2000psia and 2400 psia are used to simulate injection pressure below saturation pressure (2492 psia) while pressure of 2800 and 3200 psia are used to simulate injection above saturation pressure. The result shows that injection pressure higher than saturation pressure resulted in better oil recovery compared to lower injection pressure. This is supported by literature review from experiment conducted by Alian et.al (2011). At higher injection pressure, lesser asphaltene will be precipitated. But for asphaltene deposition using same WAG injection period, same amount of asphaltene is deposited for any of the pressure used due to continuous pressure support at specified pressure ensure no further asphaltene deposited. Thus, higher injection pressure is used to ensure lesser asphaltene precipitation and continuous injection at specified pressure should be made to ensure no further asphaltene deposition from the precipitated asphaltene. Different WAG cycle size was also simulated for this study. WAG cycles of 1 month, 2 months, 3 months and 4 months are used to study the impacts on WAG performance. Results showed that WAG cycle of 1 month gives a bit higher recovery compared to other WAG cycle size. From asphaltene precipitation, WAG cycle does not give significant impact especially at injection pressure higher than saturation pressure. However, other reservoirs might give different results on different WAG cycle size used depending on the reservoir and fluid properties.

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Thank you.

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CHAPTER 1: INTRODUCTION

1.1 Project Background

Water-alternating-gas or better known as WAG is a method in enhanced oil recovery (EOR) that is proven through many field experiences to cause increment in oil recovery. According to Chen (2009), WAG process had resulted to about 55% of total oil production by EOR in United States and this figure had proven the ability of WAG to extract more oil from the reservoir. The WAG process basically can be done either simultaneously or alternatively. Initially WAG was meant for increasing sweep efficiency in gas injection process (Sanchez, 1999). Sanchez added that the basic behinds the success of WAG process is because water injection increases the sweep efficiency while gas injection reduces the impact of viscous fingering.

Light oil, with low concentration of asphaltene had been proven from many field experiences to cause severe problems during WAG using CO_2 gas due to precipitation of asphaltene. Sarma(2003) reported that Boscan crude oil in Venezuela with about 17.2 wt% of asphaltene had almost no problem throughout production whereas a field in Algeria, Hass-Messaoud containing only about 0.15 wt% of asphaltene faced many production problems because of asphaltene precipitation. There are many factors that affect asphaltene precipitation including decline in pressure, CO_2 injection, properties of injected fluid and changes inside the reservoir during the WAG process.

1.2 Problem statement

WAG injection using CO_2 as enhanced oil recovery in light oil had caused several problems rising from precipitation of asphaltene in piping system, tubing, wellbore and even the reservoir itself. Porosity and permeability alteration together with change in wetability are among the major concerns from the asphaltene precipitation as these will cause severe formation damage. High cost of cleanup due to all these problems forced oil and gas companies to find solution to prevent this from occurring. Alta'ee and Saaid

(2010) cited that among the factors that may caused asphaltene precipitation are pressure drop, changes in temperature, gas injection, oil composition changes, change in pH value, acid stimulation, crude oil from different streams mixed together, turbulence flow and down hole shear, and streaming potential. Among those factors, changes in pressure inside the reservoir are of main interest in this paper. The effect of WAG injection pressure on asphaltene precipitation is still not fully understood as many other factors are involved. WAG cycle which will affect recovery should be investigated as well together with WAG injection pressure to know to what extent the impact will be on asphaltene precipitation thus oil recovery.

1.2.1 Problem Identification

The problems identified are:

1. The effect of injection pressure alone during WAG-CO2 is still not clear as other parameters might be affecting the asphaltene precipitation, flocculation and deposition in the same way like pressure does.
2. Varying injection pressure together with WAG cycle size will give impact to asphaltene precipitation problem thus oil recovery but the extent of the impacts are still not fully understood.

1.2.3 Significant of the Project

This project will be focusing on modifying the WAG parameters which are injection pressure and cycle size and study the impact on asphaltene precipitation thus oil recovery. Basically, this project will study the performance of the WAG process based on the modified parameters. Upon the completion of this project, the study conducted can be used as reference on many parts such as the procedures and expected results obtained by modifying the used parameters. Even though different reservoirs will behave differently and that there is no specific WAG scheme can be proposed as general scheme, this project can at least serve the idea of parameters affecting WAG process.

1.3 Objectives

i. To study the effect of WAG injection pressure on precipitation of asphaltene during WAG-CO_2 injection of light oil in sandstone reservoir.
ii. To investigate the impact of WAG cycle on asphaltene precipitation during WAG-CO_2 injection using light oil in sandstone reservoir.

1.4 Scope of study

This simulation project will be focusing on the effects of WAG injection pressure used during WAG-CO_2 injection on the amount of oil that will be recovered from the WAG injection. Injection pressure ranges from 2000 psia to 3200 psia are used to simulate the effect. Also, the simulation will be focusing on the impact of WAG cycle on asphaltene precipitation as well as oil recovery and also its relationship with WAG injection pressure. WAG cycle of 1 month, 2 months, 3 months and 4 months will be used for this simulation study.

1.5 Feasibility of Project within the Scope and Time Frame

There are a lot of works to be done even though this study is using simulation. From learning software manual to building reservoir and fluid model and testing several different parameters, all requires a lot of time. Nevertheless, many aspects have been taken care of for example the grid size and the model used to save more time due to lengthy simulation time. Thus, this project could be completed within the time frame and scope given.

Chapter 2: LITERATURE REVIEW AND THEORY

2.1 Water-Alternating-Gas (WAG)

Water-alternating-gas (WAG) has been greatly implemented all around the world as a successful tertiary oil recovery method or enhanced oil recovery (EOR). The process which can either be done alternately or simultaneously is a combination of water injection which improves the sweep efficiency and gas flooding which reduces the effect of viscous fingering. *Chen et al.* (2009) stated that water injection is used to control gas mobility in order to achieve higher sweep efficiency in macroscopic scale while gas injection gives higher sweep efficiency in microscopic scale. Christensen *et al.* (1998) added that water is used to control mobility ratio and stabilize water front which is the original purposes of WAG process. They also proposed that water and gas should be injected alternately. In 1984, Orr and Taber (Orr and Taber, 1984) proposed the use of carbon dioxide (CO2) gas to be used during WAG. Kulkarni and Rao (2005) had proved in their experiment that the use of CO2 in WAG had increased oil recovery.

2.2 Asphaltene in General

"Asphaltene" was first introduced by a French scientist, Boussingault in 1837 where he used it to explain certain constituents during asphalts distillation process (Alta'ee *et.al*, 2010). Asphaltene is insoluble in n-heptanes or n-pentane but soluble in dichloromethane or toluene. When heated, asphaltene will turn dark brown to black friable solids with no definite melting point, and it will swell and decompose leaving residue and volatile products (Sarma, H.K., 2003). According to Kokal *et.al* (1995), asphaltene fractions are defined as dispersed colloids in the oil phase and stay stabilized in crude oil due to the presence of resins molecules. Kokal added that destabilization of resins could result in asphaltene precipitation and deposition which could lead to many production problems in oil and gas industries. SARA analysis is one of the methods commonly used to characterize crude oil content including asphaltene. Sclumberger

Oilfield Glossary define SARA analysis as a method of characterizing heavy oil based on fractionation where heavy oil sample is separated into smaller fraction of different composition. This method is based on four solubility classes which are saturate, aromatic, resins and asphaltene. One of the most popular methods nowadays used to obtain SARA result is by using latroscan TLC-FID. Fan *et al*. (2002) had used the SARA analysis using TLC-FID method for evaluating crude oils and had effectively shown how the method is used to separate saturates, aromatic, resin and asphaltene.

2.3 WAG-CO2 Injection

Injection of gas into light oil reservoir to increase oil recovery has been a widely used enhanced oil recovery (EOR) method right after steam flooding (Deo *et.al*, 2002). Ghasemzadah *et.al,* (2011) stated that WAG using CO2 with its abundance sources, environmental friendly and can achieve miscibility with oil easier than any other gases has been the main choice of current EOR method. There are many factors that cause the use of CO2 increase oil recovery and among them are oil viscosity reduction, the swelling of oil, lowering interfacial tension, and miscibility effects (Alta'ee & Saaid, 2010). Meanwhile, Srivastava (2000) through a laboratory study has showed the main factors that contribute to oil recovery in WAG using CO2 are reduction in viscosity and swelling of reservoir oil. Srivastava also added that viscosity reduction is almost linear with concentration of CO2.

The first contact between CO2 and oil is normally immiscible due to different composition but once CO2 concentration increases and mixed with solution gas, exchange of components through multiple contacts between the gases cause the CO2 to have the same component as hydrocarbon and this will cause miscible contact between CO2 and oil (Gao *et.al*, 2010). The term "minimum miscibility pressure (MMP)" has been of great interest in laboratory investigation where it explains the minimum required pressure for CO2 flooding to be miscible process with oil. Yongmao *et al.* (2004) stated in a paper that reservoir temperature and oil composition are the contributing factors for the value of CO2 MMP. In other experiment, it is claimed that

CO_2 MMP is related to solution gas by the amount of the solution gas and the ratio of light-to-intermediate component in the gas (Dong *et.al,* 1999).

2.4 Asphaltene Problems during WAG-CO_2

It is known through various field experiences and laboratory studies that WAG process that uses CO_2 will cause precipitation of asphaltene in light oil. Many oil and gas operators underestimate the presence of small amount of asphaltene in light oil compared to large percentage in crude oil because these problems are not observed during primary and secondary recovery (Alta'ee *et.al, 2010*). The best example is crude oil from Boscan field in Venezuela that has about 17 wt% asphaltene almost have no problem while Hassi_Messaoud in Algeria that has only about 0.15 wt% of asphaltene faced so many problems in prduction because of asphaltene precipitation (Sarma, 2003). Once WAG-CO_2 is implemented, many unexpected production problems occur due to asphaltene precipitation deposition inside the tubing, wellbore, production line and even surface facilities. All these problems had caused thousands of money a year that need to be spent to control and solve the problem. Sarma also explained that the presence of asphaltene precipitate had also cause porosity alteration, reduction in permeability, wettability changes and eventually formation damage.

Khanifar *et.al* (2011) in a paper entitled "Study of Asphaltene Precipitation and Deposition Phenomenon during WAG Application" had thoroughly explained about asphaltene precipitation and also deposition in WAG-CO_2 process. The authors interestingly explained about the onset of asphaltene instability and that this factor should be the first step in understanding and thus avoid the precipitation issues. Among the factors that can be associated to this are composition changes during CO_2 flooding, pressure and temperature changes. Asphaltene particles are surrounded by resin and when CO_2 is injected through WAG process, the resin will be destabilized causing the asphaltene particle to move freely and attracted to each other. According to Sarma (2003), CO_2 injection during WAG process will cause a pH change that later causes the destabilization of asphaltene particle. The particles then tend to accumulate and flow together with oil to surface and some will settle out of oil flow and deposited on rock surfaces. Asphaltene adsorbed by rock surface has a high possibility to change the wetability of rock to oil-wet besides altering porosity and reducing permeability.

Tremendous laboratory studies and research had been conducted to understand the behavior of asphaltene during WAG-CO2 process. Khanifar (2011) mentioned that Saturates, Aromatics, Resins, and Asphaltene (SARA) analysis for example had been widely used to identify oil fraction pertaining to asphaltene stability during WAG process. Many methods have been used to determine the onset of asphaltene precipitation and among those are gravimetric, light scattering, measurement of capillary flow and filtration (Sarma, 2003).

With all these advanced techniques to solve and prevent the asphaltene precipitation during WAG-CO2 process, there is still a big down side of the techniques which is the fluid sampling. When reservoir fluids are brought to surface and then to laboratory, the fluids might not be sampled properly which makes it no longer represent the in-situ oil (Mullins *et.al*, 2007). But the current method developed by Baker Petrolite allows the detection of asphaltene content in crude oil on-site. Nevertheless, due to high cost of downhole sampling, surface sampling is still reliable provided that all the laboratory experiments are properly designed according to reservoir conditions during WAG-CO2 injection.

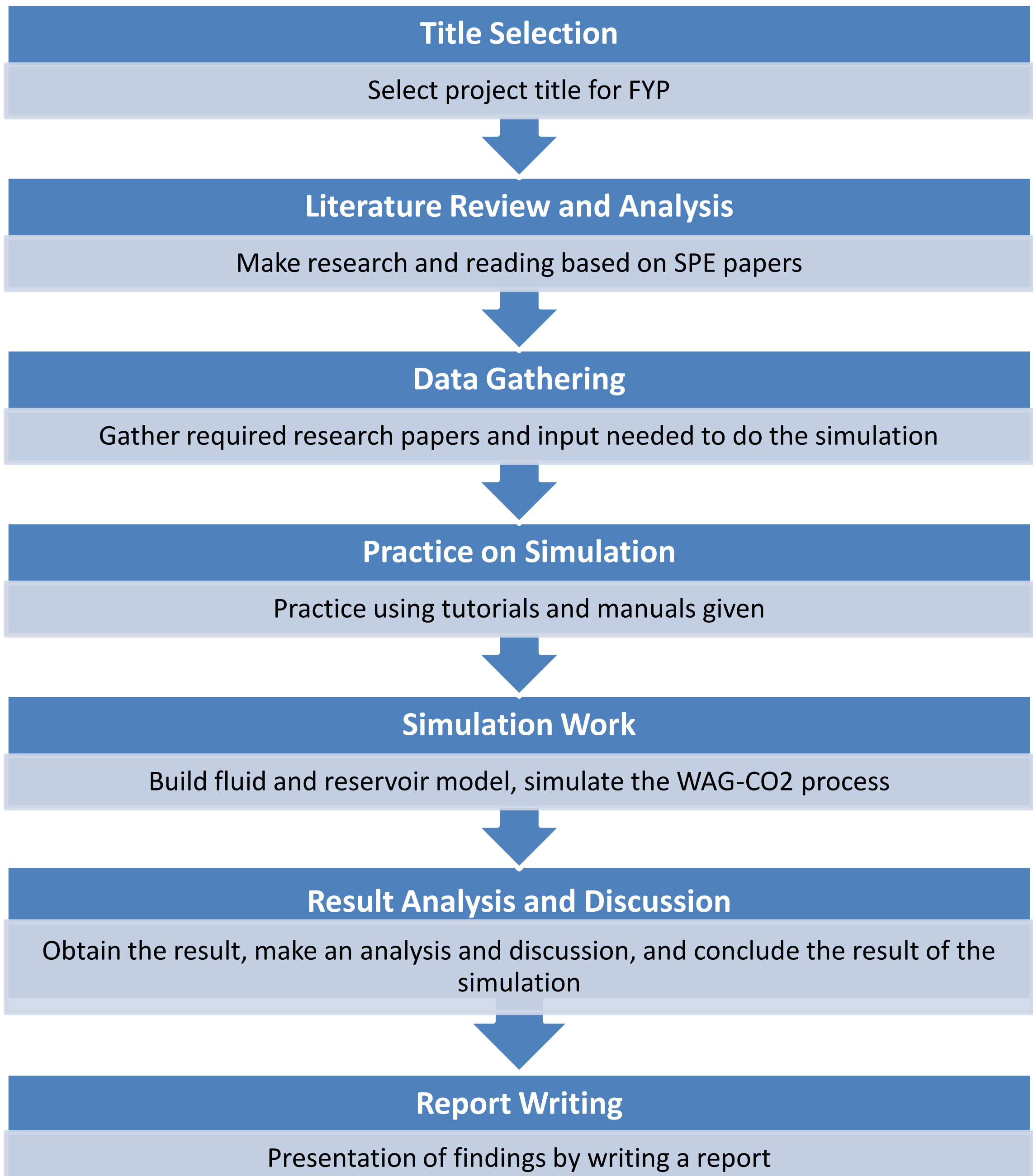
2.5 Effect of WAG Injection Pressure

Pressure changes inside reservoir plays an important role in the precipitation of asphaltene in light oil. According to Sarma, H.K. (2003) in her experiment involving Light-Scattering Techniques using near infrared, NIR technique, injection at higher pressure requires higher CO2 concentration before bulk asphaltene precipitation occur. Lower injection pressure resulted in bulk asphaltene precipitation at lower CO2 concentration. From the paper also, it can be understood that at same CO2 mole concentration injected, injection at higher pressure will prolong the time before the precipitation of CO2 occur. Alian (2011) conducted a WAG experiment by varying the injection pressure. The results showed that injection at higher pressure resulted in lower asphaltene precipitation. It was suggested that this could be because of different in the asphaltene solubility at low and high pressure. At high pressure, the asphaltene remain dissolved (high solubility) but at low pressure, the solubility decreases.

Chapter 3: METHODOLOGY

3.1 Research Methodology

Followed are the proposed methodologies to be implemented throughout the project completion.



3.2 Literature Review and Data Gathering

Gaining information regarding WAG-CO2 injection in presence of asphaltene is one of the best ways to understand the concepts and idea of the whole process. The papers also provide the best platform to know the current methods and achievement in this EOR technique. In order to get the latest information from SPE papers, only paper publish from year 1990 until current are taken as references. Data for fluid model used in the simulation are taken from Burke *et.al* (1990) paper entitled "Measurement and Modeling of Asphaltene Precipitation". From this paper, oil of different API gravity is presented as shown in table 1

Table 1 Composition and properties of oil from Burke *et.al* (1990) SPE paper

TABLE 1—COMPOSITIONS (mol%) AND PROPERTIES OF OILS USED IN INVESTIGATION

	Oil					
Component	1	2	3	4	5	6
Nitrogen	0.57	0.51	0.05	0.25	0.23	0.20
CO_2	2.46	1.42	6.47	2.03	8.53	5.45
Methane	36.37	6.04	9.58	32.44	21.72	30.90
Ethane	3.47	7.00	12.00	15.50	20.80	18.04
Propane	4.05	6.86	6.83	6.54	4.82	5.45
i-Butane	0.59	0.83	0.87	0.81	1.35	1.11
n-Butane	1.34	3.35	3.78	3.20	3.47	2.56
i-Pentane	0.74	0.70	1.42	1.15	1.68	0.38
n-Pentane	0.83	3.46	2.62	2.13	2.11	2.18
Hexanes	1.62	3.16	4.95	2.46	2.53	1.93
Heptanes plus	47.96	66.68	51.43	33.49	32.76	31.80
Total	100.00	100.00	100.00	100.00	100.00	100.00
C_{7+} molecular weight	329	281	271	223	219	197
C_{7+} specific gravity	0.9594	0.9020	0.9151	0.8423	0.8533	0.8230
Live-oil molecular weight	171.4	202.4	151.6	95.2	95.1	83.6
API gravity, stock-tank oil	19.0	24.0	30.0	38.8	37.0	40.8
Asphaltene content in stock-tank oil, wt%	16.8	9.0	2.8	1.7	0.4	0.9
Reservoir temperature, °F	212	218	225	234	225	230
Saturation pressure, psia	2,950	600	1,120	2,492	2,100	2,915

3.2 Simulation and Modeling

3.2.1 Software

The simulation of this project utilizes software known as Computed Modeling Group Ltd. (CMG). This software is used to generate the fluid and reservoir model and to simulate the WAG-CO2 injection process. There are few modules available under this software as shown in

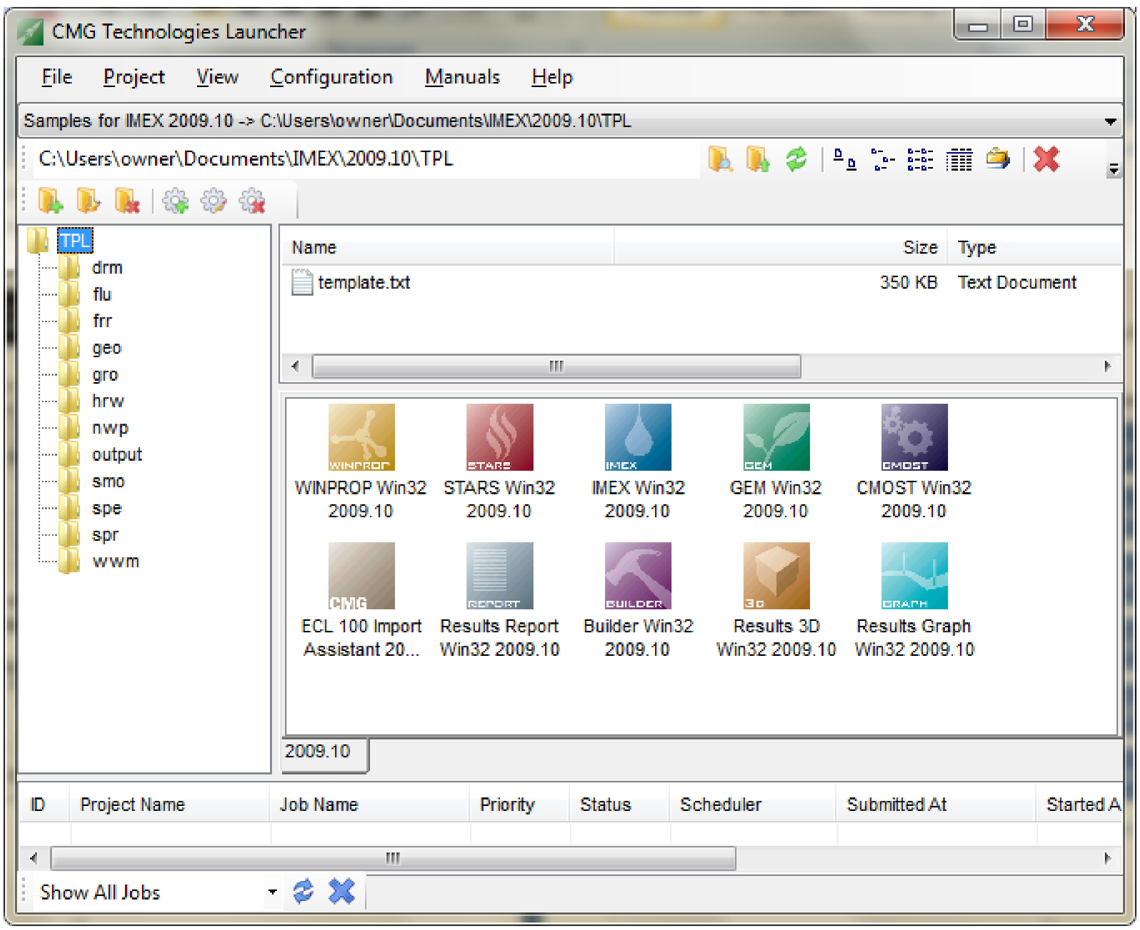


Figure 1 Interface and modules available in CMG software

Out of the ten modules available, only few are used in doing this simulation which is WINPROP, BUILDER, and GEM. Fluid model is made using WINPROP module while reservoir model is build using BUILDER module. Running the simulation requires simulator and for this simulation, GEM which is a compositional simulator, is used to run the simulation.

3.2.2 Fluid Modeling

WinProp is based on equation of state (EOS) multiphase equilibrium and also properties determination module. By using WinProp, users will be able to do splitting and lumping of heavy hydrocarbon components, match laboratory data using regression feature, simulate first and multiple contact miscibility, modeling of asphaltene precipitation and other related features. For this simulation project, oil model of API 38.8 was created based on available data taken from Burke *et.al* (1990) as shown in figure 2

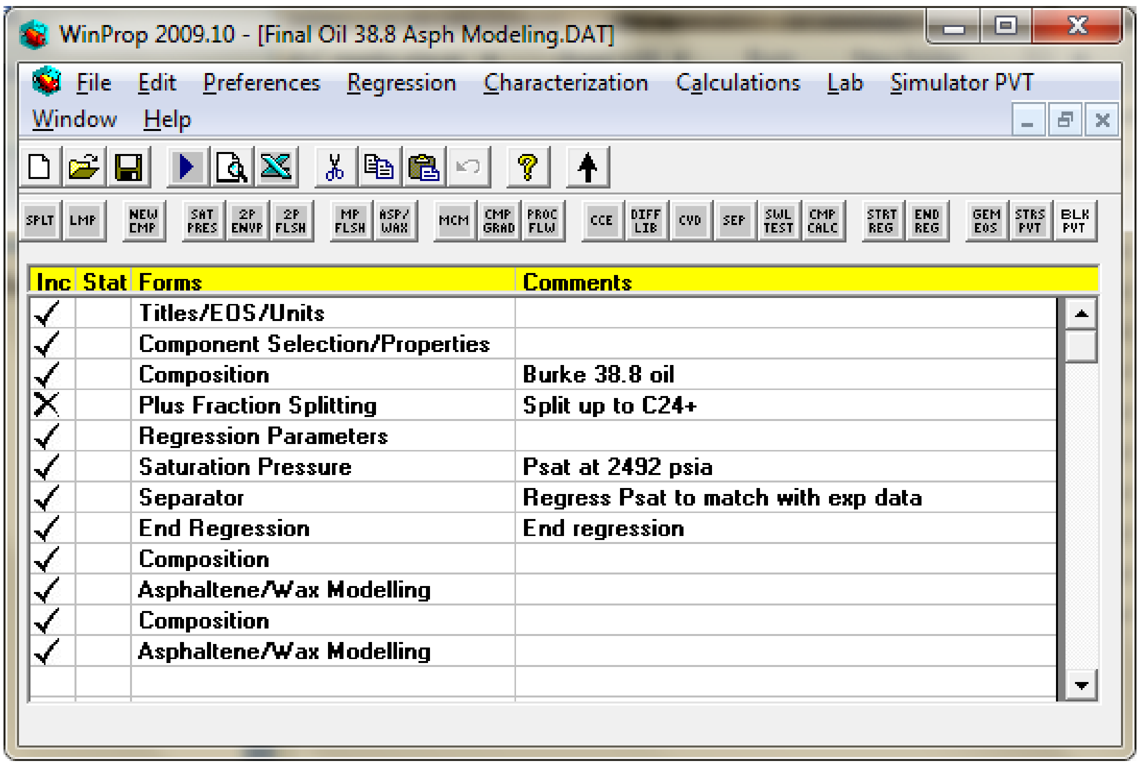


Figure 2 Data created in WinProp

3.2.3 Reservoir Modeling

This simulation studies will be using sandstone reservoir. 2D model of grid size 44*100ft x 1*10ft x 40*1ft is used for this simulation due to time constraint and simulation run time.

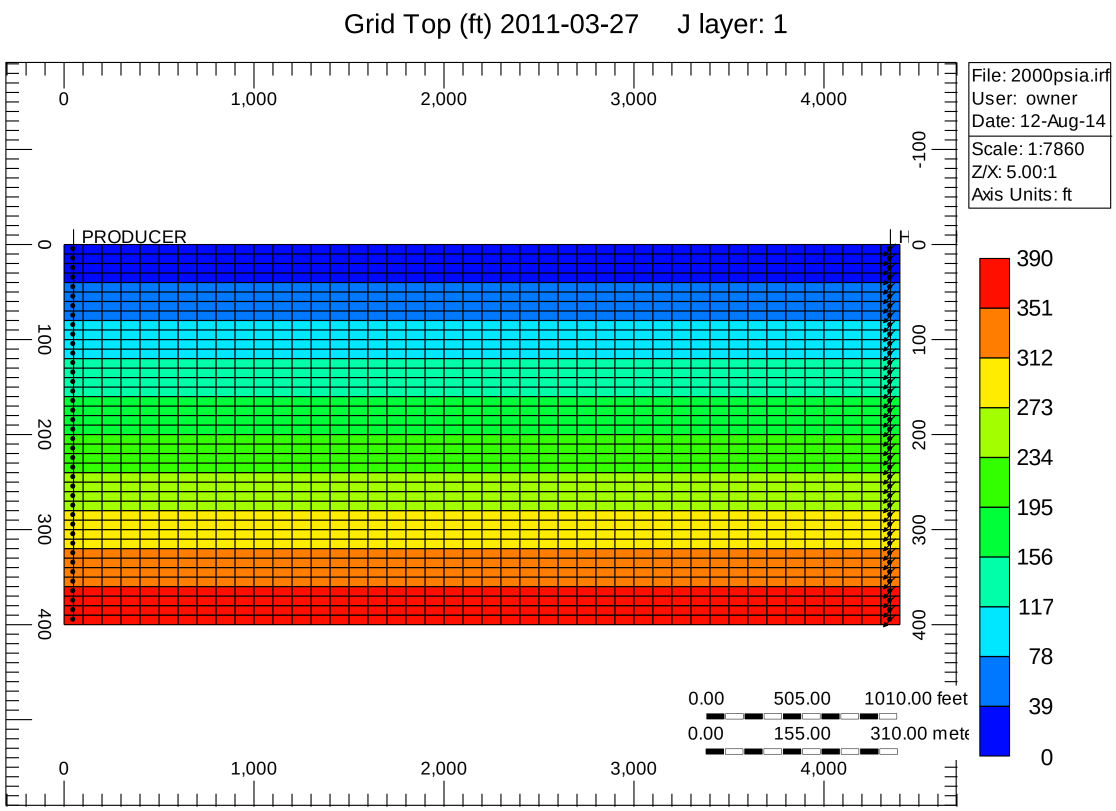


Figure 3 Reservoir model

3.2.4 Project Timeline

Based on the timeline given, the author was able to follow the suggested milestone where in week seven, a progress report was submitted to the FYP supervisor. During week 10, Pre-SEDEX poster presentation was conducted followed by dissertation report and technical paper on week 12. Viva will soon be conducted on week 13 and finally submission of hardbound on week 14. All datelines were followed and the suggested key milestone was fully accomplished.

Table 2 Timeline for FYP II

No.	Detail \ Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	Project Work Continues														
2	Submission of Progress Report														
3	Project Work Continues														
4	Pre-SEDEX														
5	Submission of Draft Final Report														
6	Submission of Dissertation (soft bound)														
7	Submission of Technical Paper														
8	Viva														
9	Submission of Project Dissertation (Hard bound)														

Suggested Milestone

Process

Chapter 4: RESULTS AND DISCUSSION

The main part of this simulation is to simulate the effect of using different WAG injection pressure in light oil in the presence of asphaltene in sandstone reservoir. Then, the impact of using different WAG cycle will also be explained

4.1 Input Data

Table 3 shows the input data keyed-in into WinProp to create the fluid model. These data are obtained from paper entitled "Measurement and Modeling of Asphaltene Precipitation" written by Burke, N. E., Hobbs, R. E., and Kashou, S. F.

Table 3 Fluid properties of Burke 38.8 oil

Burke Oil 38.8	
Components	Mol %
Nitrogen	0.25
CO2	2.03
Methane	32.44
Ethane	15.50
Propane	6.54
I-Butane	0.81
n-Butane	3.20
i-Pentane	1.15
n-Pantane	2.13
Hexanes	2.46
Hexanes plus	33.49
TOTAL	**100**
C7+ molecular weight	223
C7+ specific gravity	0.8423

Live-oil molecular weight	95.2
API gravity, stock tank oil	38.8
Asphaltene content in stock tank oil, wt%	1.7
Reservoir temperature, deg F	234
Saturation pressure, psia	2492

4.2 Asphaltene Modeling

Since oil used is light oil, the amount of asphaltene is very small and for this case is just 1.7 wt%. In simulating the precipitation of asphaltene, the asphaltene component in the light oil must be known and this is done by splitting the heavy components of the light oil. Splitting of the heavy components resulted as of table 4

Table 4 Oil 38.8 components after splitting

Components	Mol %	MW
N2	0.2500	28.013
CO2	2.0300	44.01
C1	32.4400	16.043
C2	15.5000	30.07
C3	6.5400	44.097
IC4	0.8100	58.124
NC4	3.2000	58.124
IC5	1.1500	72.151
NC5	2.1300	72.151
FC6	2.4600	86
C07-C12	15.6754	127.3588
C13-C17	7.2871	205.8394
C18-C23	4.9276	281.6448
C24A+	5.2493	461.442
C24B+	0.3507	461.442

Asphaltene component is further characterizes by precipitating and non –precipitating component/ Component C24A+ is known as non-precipitating component while C24B+ is precipitating component. Both components have the same critical properties and also acentric factors. What differ each of them is the interaction parameters with the light components in the system such that component A will have a lower interaction with the light components compared to component B.

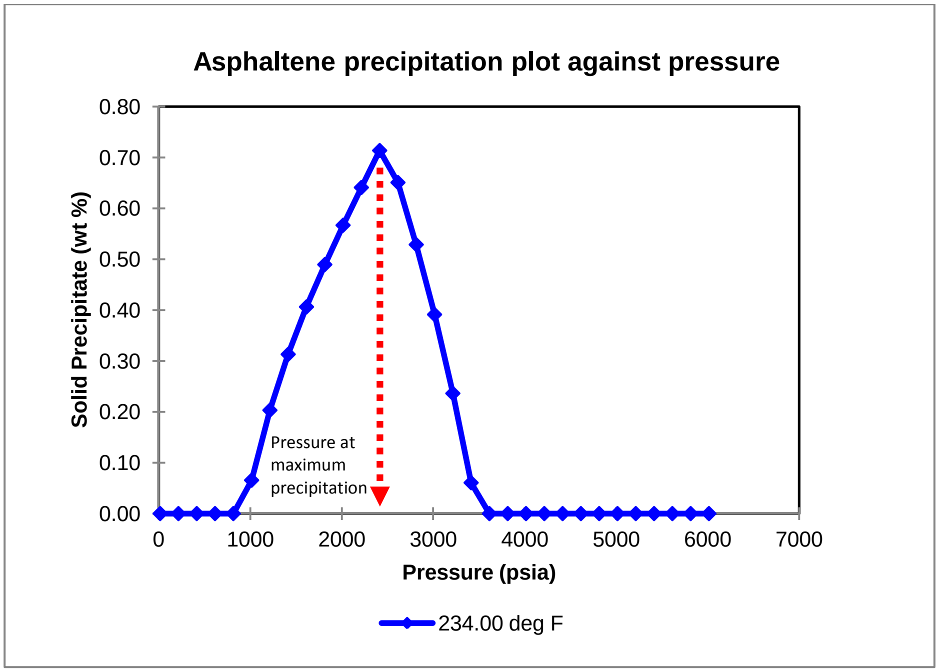


Figure 4 Weight percent of solid asphaltene precipitated vs. pressure

From figure 4, the asphaltene onset pressure (AOP) obtained for Burke oil 38.8 is 4000 psia. Saturation pressure usually is used to predict the pressure at which maximum precipitation is obtained for light oil. For this case, it can be seen that the maximum solid precipitation resulted from pressure of around 2400 psia to 2500 psia and the saturation pressure of 2492 psia falls between the pressure ranges thus making the result to be accurate.

4.3 Reservoir Model

Table 5 shows the porosity and permeability values used for every layer of the reservoir model. In total, there are 40 layers created to simulate the reservoir.

Table 5 Porosity and permeability properties of reservoir model created

Layer	Porosity	Permeability I	Permeability J	Permeability K
Layer 1	0.20	98.434	101.477	116.476
Layer 2	0.20	116.975	86.342	95.034
Layer 3	0.20	86.342	73.987	123.567
Layer 4	0.20	73.987	79.456	87.199
Layer 5	0.20	79.416	98.234	104.777
Layer 6	0.20	103.466	125.675	101.562
Layer 7	0.20	89.459	110.197	84.342
Layer 8	0.20	94.342	104.345	73.987
Layer 9	0.20	95.034	96.756	79.456
Layer 10	0.20	124.367	111.197	96.756
Layer 11	0.20	87.899	102.345	113.197
Layer 12	0.20	112.797	96.736	104.345
Layer 13	0.20	104.345	95.834	103.466
Layer 14	0.20	96.156	124.567	88.459
Layer 15	0.20	113.136	86.899	94.342
Layer 16	0.20	104.815	116.476	113.197
Layer 17	0.20	96.956	103.466	100.345
Layer 18	0.20	103.562	89.459	99.756
Layer 19	0.20	114.476	93.342	98.234
Layer 20	0.20	104.477	103.562	122.675
Layer 21	0.20	98.434	101.477	116.476
Layer 22	0.20	116.975	86.342	95.034
Layer 23	0.20	86.342	73.987	123.567
Layer 24	0.20	73.987	79.456	87.199
Layer 25	0.20	79.416	98.234	104.777
Layer 26	0.20	103.466	125.675	101.562
Layer 27	0.20	89.459	110.197	84.342
Layer 28	0.20	94.342	104.345	73.987
Layer 29	0.20	95.034	96.756	79.456
Layer 30	0.20	124.367	111.197	96.756
Layer 31	0.20	87.899	102.345	113.197
Layer 32	0.20	112.797	96.736	104.345
Layer 33	0.20	104.345	95.834	103.466

Layer 34	0.20	96.156	124.567	88.459
Layer 35	0.20	113.136	86.899	94.342
Layer 36	0.20	104.815	116.476	113.197
Layer 37	0.20	96.956	103.466	100.345
Layer 38	0.20	103.562	89.459	99.756
Layer 39	0.20	114.476	93.342	98.234
Layer 40	0.20	104.477	103.562	122.675

Table 6 Reservoir properties

Reservoir -Sandstone		
	Value	**Unit**
Temperature	234	F
Reservoir pressure	3500	psia
Porosity	20	%
Oil saturation	78	%
Connate water saturation	22	%
Grid block	44x1x40	-
X	4400	ft
Y	10	ft
Z	40	ft

Figure 5, 6, and 7 shows the rock-fluid properties for the reservoir model created.

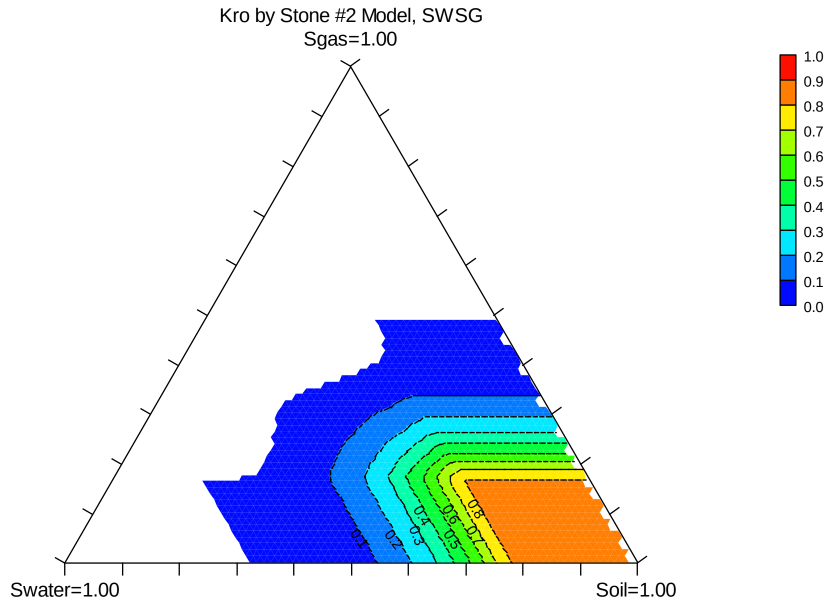


Figure 5 Fluid saturation diagram

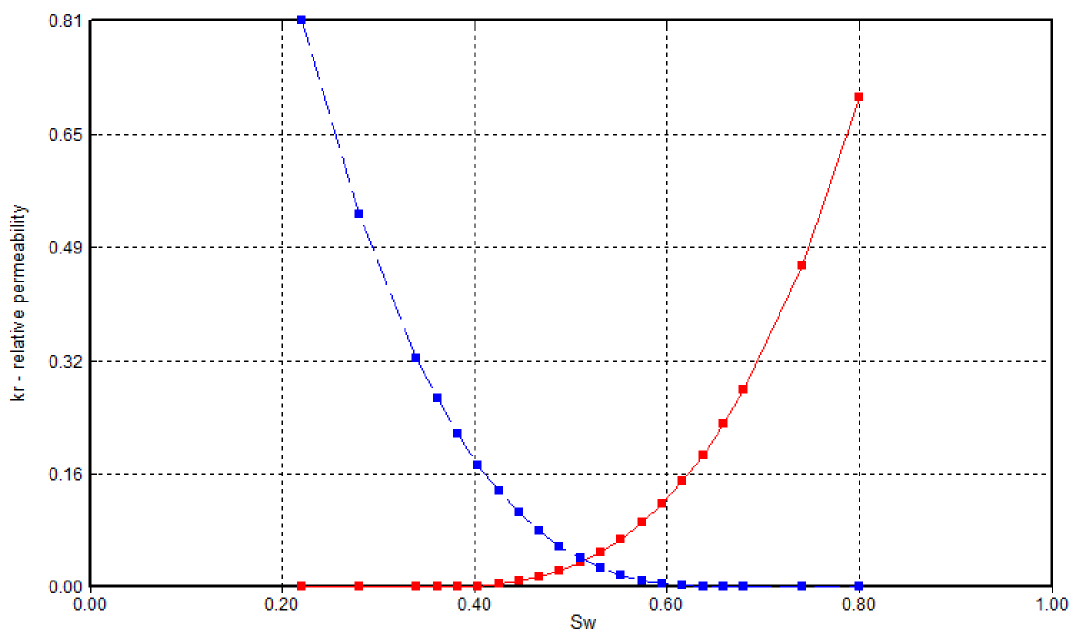


Figure 6 Relative permeability vs. water saturation

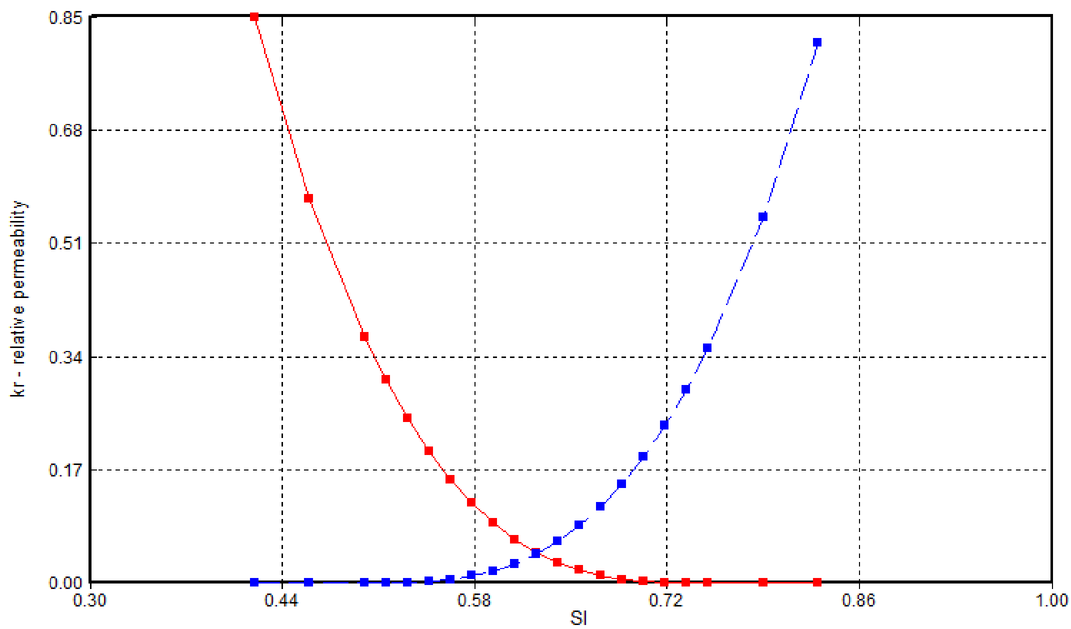


Figure 7 Relative permeability vs. fluid saturation

4.4 Simulation Results

Primary depletion was first simulated followed by water flooding and WAG–CO2 injection. From primary depletion, water flooding was conducted when the production is already plateau and no longer able to produce using natural depletion. This simulation was conducted for five years time.

4.4.1 Primary Depletion

Primary depletion is used to simulate the ability of the reservoir to naturally produce reservoir fluid before secondary and tertiary recovery is conducted. From figure 8, the reservoir stop production after about 2 months of production due to production by natural depletion is no longer supported by natural reservoir energy. It is observed that for case with asphaltene, the recovery less than 1.5% while case without asphaltene has higher recovery which is about 2.4%. Burke *et.al* (1990) stated that natural depletion is one of the field conditions conducive to asphaltene precipitation. Since the reservoir already deplete from its original pressure of 3500psia, it can be said that the different between the recoveries of the two cases is due to asphaltene precipitation is induced during the pressure depletion for case with asphaltene causing the recovery to be lower.

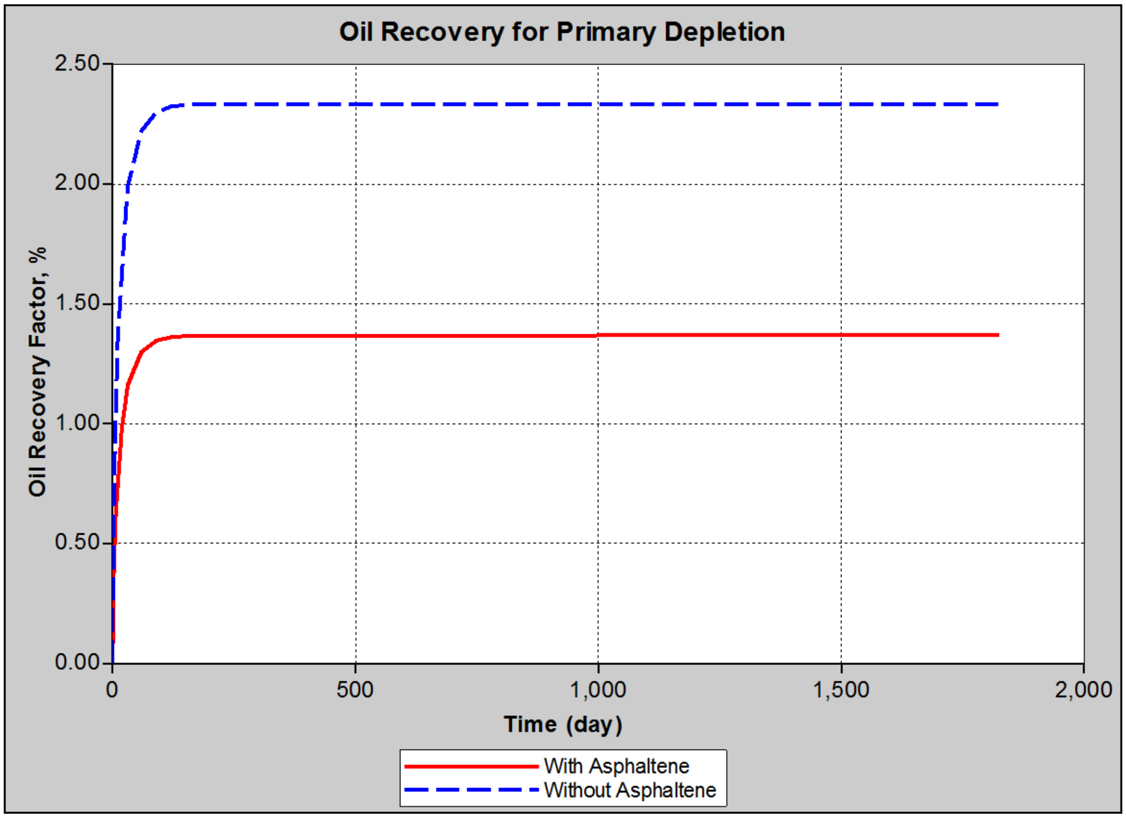


Figure 8 Oil recoveries during natural depletion

4.4.2 Waterflooding

Water flooding is started after the production becomes plateau during primary depletion. Both cases, with and without asphaltene are compared. Below are the parameters used for water flooding process.

Table 7 Parameters used for water flooding

Time of Injection	Day	59 (2nd Month)
Water Injection Rate	bbl/day	550
Producer BHP (min)	psia	2500

Figure 9 shows the oil recovery from water flooding for both cases. The oil recoveries for both cases are almost the same due to the fact that water injection helps to maintain the pressure. As pressure is maintained around reservoir pressure, asphaltene and resin will be more stabilized thus less precipitation should be expected. The small difference in the recovery is due to asphaltene precipitation formed during primary depletion which is induced by the pressure reduction. Because most of asphaltene precipitated are claimed to be irreversible, it stays precipitated during water flooding process which is why the oil recoveries are slightly different throughout water flooding.

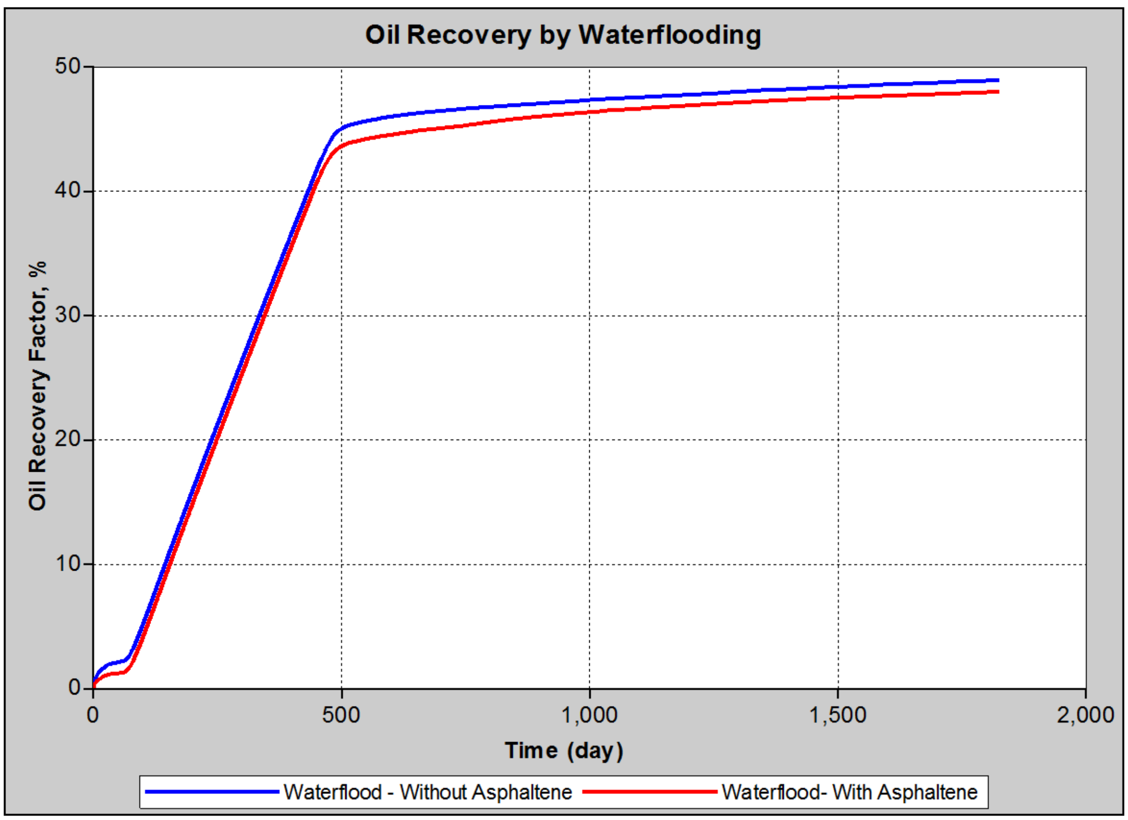


Figure 9 Oil recoveries during water flooding for cases with and without asphaltene

4.4.3 WAG-CO2 Injection

Water flooding is able to maintain the reservoir pressure thus lower the precipitation of asphaltene which can be proven from the oil recovery obtained during water flooding. Water breakthrough problem during water flooding limits the use of water flooding in recovering more oil. For this simulation, WAG-CO2 is conducted once the water cut reaches 80% during water flooding. Table 8 shows the parameters used for this WAG-CO2.

Table 8 Parameters used for WAG-CO2 Injection

Parameters	Unit	Value
Time of WAG Injection	Day	485 (16th Month)
WaterFlooding Water Injection Rate	bbl/day	550
WAG Water Injection Rate	bbl/day	400
Gas Injection Rate	Ft3/day	2246
WAG Ratio	Ratio	1:1
WAG Cycle Size	Month	1
Producer BHP (min)	psia	2500

Table 9 shows the pore volumes injected during water flooding and WAG injection. The total PV injected at the end of WAG injection is 1.2PV

Table 9 Cumulative pore volume injected from water flooding to WAG-CO2

Years	1	2		3	4	5
Injection Day	306	120	242	365	365	365
Volume Injected, bbl	168300	66000	96800	146000	146000	146000
Volume Injected, ft3/day	945004.5	370590	543532	819790	819790	819790
Cumulative injected, ft3/day	945004.5	1315594.5	1859126.5	2678916.5	3498706.5	4318496.5
Cumulative PV Injected	0.3	0.4	0.5	0.8	1.0	1.2
Cases	WATER FLOODING		WAG-CO2			

4.4.3.1 WAG Injection Pressure

Varying injection pressure parameter during WAG injection will help to understand the impact of injection pressure on WAG performance. This study uses few sets of injection pressure ranging from 2000 to 3200 psia to study the effect of pressure during the WAG process. Pressure at 2000psia and 2400 psia are used to simulate the effect of injecting WAG below bubble point pressure which is 2492psia. Pressure of 2800 and 3200 psia is used to study the effect of injecting WAG at pressure higher than bubble point pressure. All sets of injection pressure are maintained below reservoir pressure of 3500 psia as injection at higher pressure will cause fracture to the reservoir.

Figure 10 shows the effect of having different injection pressure on the oil recovery for case with asphaltene while figure 11 for case without asphaltene.

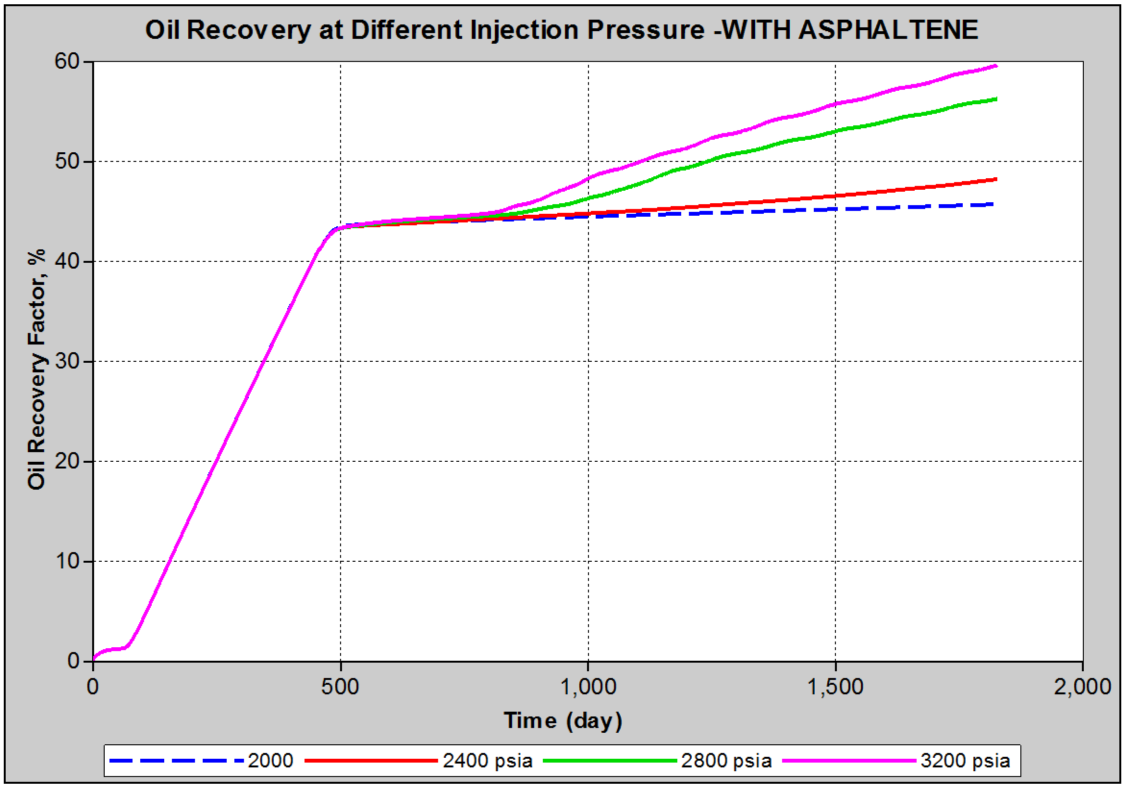


Figure 10 Recovery at different injection pressure – With Asphaltene

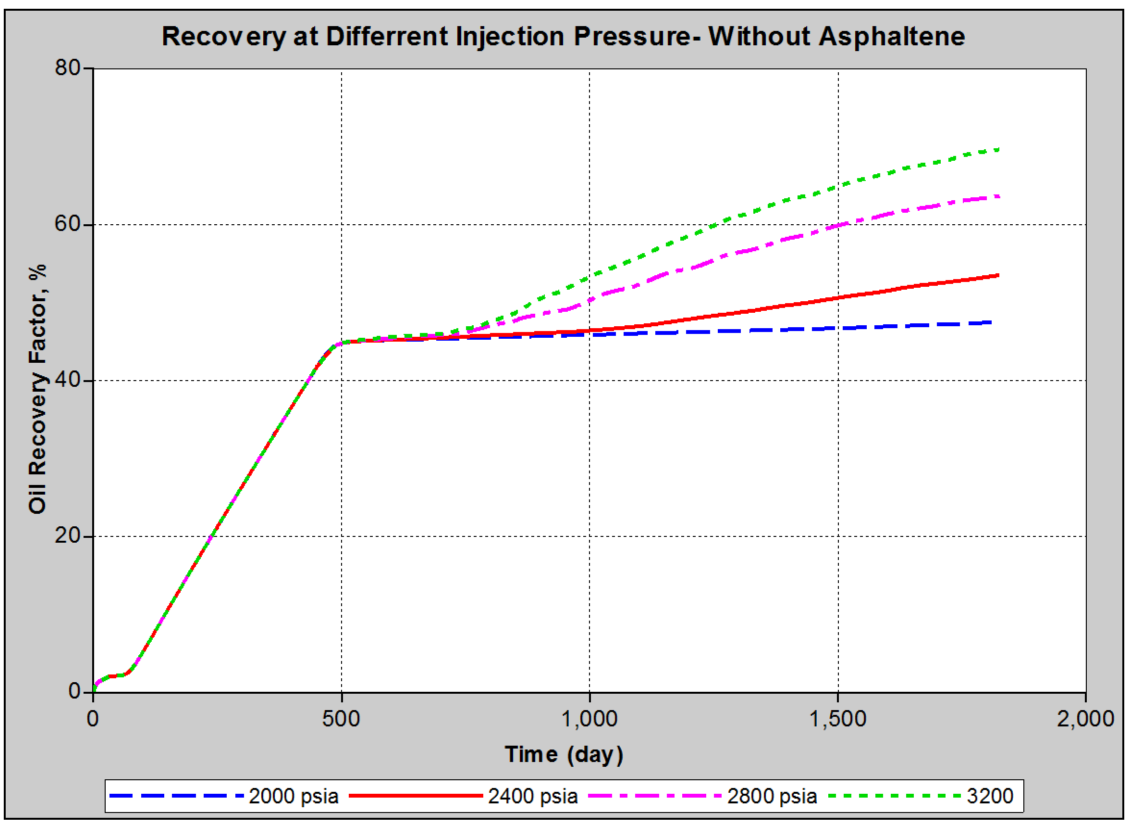


Figure 11 Recovery at different injection pressure – Without Asphaltene

Both cases showed significant differences in term of recovery at different injection pressure. The higher the injection pressure, the higher the recoveries for both cases, with and without asphaltene. Injection pressure close to initial reservoir pressure give the highest recovery compared to lower injection pressure as displayed by both cases. For the case of injection pressure below saturation pressure, it can be seen that the recovery for pressure 2000 and 2400 psia shows small increment compared to recovery at pressure 2800 and 3200 psia. This can best be explained through the saturation pressure point of view.

When the reservoir is still above saturation pressure or bubble point pressure, the solution gas still stay in oil phase thus able to maintain the pressure in the oil phase. In addition, oil still retains most of its light and intermediate components inside the oil phase that keep asphaltene and resin particles in stabilized state. When the reservoir pressure drops below saturation pressure, solution gas start to form bubbles in the oil phase and come out of oil once it reached critical point. At this point, oil composition started to change with the release of light and intermediate components causing destabilization of asphaltene and resin particle thus causing asphaltene precipitation. Thus, higher asphaltene precipitation should be expected when injecting at lower pressure.

Injection of WAG-CO2 at pressure above saturation pressure helps to maintain the reservoir pressure above saturation pressure thus we should expect more oil recoveries. In term of asphaltene precipitation, injection at higher pressure resulted in lower asphaltene precipitation due to pressure is maintained around reservoir pressure thus causing the asphaltene and resin particles to become stable thus preventing further precipitation.

Figure 12 shows the comparison of oil recovery for both cases, with and without asphaltene at different injection pressure as can be interpreted from Figure 10 and 11. The different between the cases is obvious such that case with asphaltene yields lower recovery due to asphaltene precipitation problem and case without asphaltene with no precipitation problems have higher recovery.

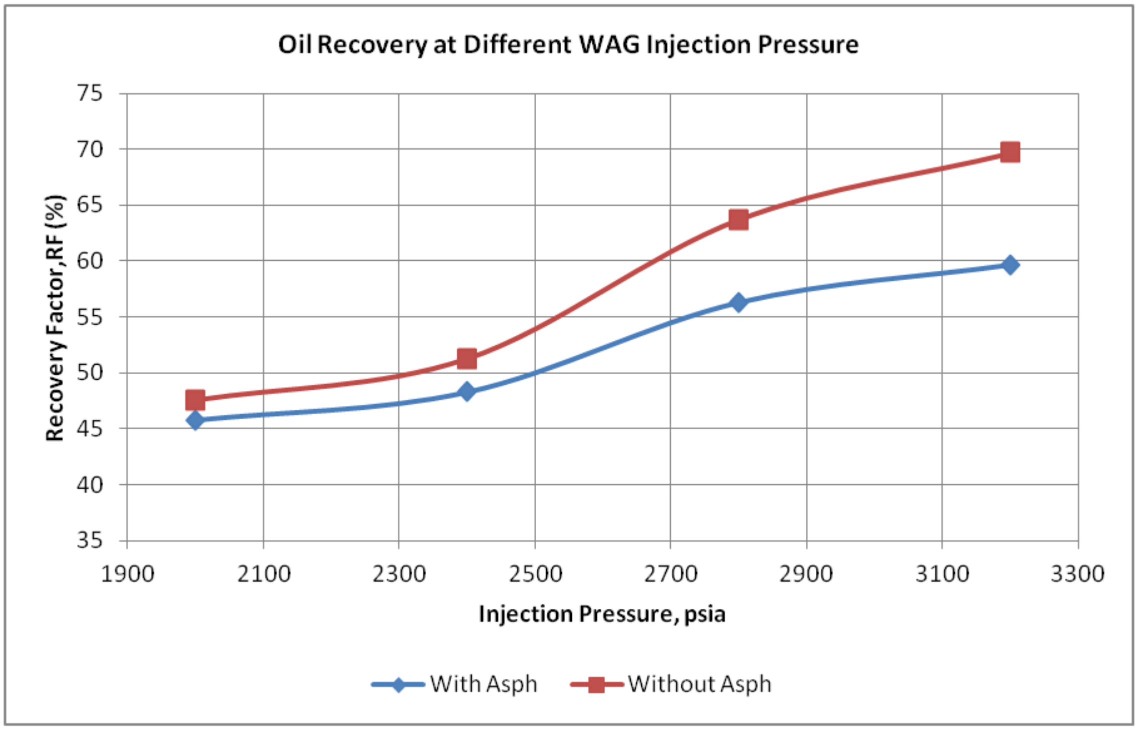


Figure 12 Comparison between case with and without asphaltene

4.4.3.2 WAG Cycle

WAG cycle is the duration of injecting the water and gas alternately for one complete cycle. WAG cycle of one month mean water will be injected for one month followed by one month of gas injection for required number of cycle. In this study, 1-month, 2-month, 3-month and 4-month WAG cycles are used to study the effect on asphaltene precipitation and oil recovery. As can be seen from figure 13, for both cases with and without asphaltene, WAG cycle of one month resulted in the highest recovery compared to other WAG cycles.

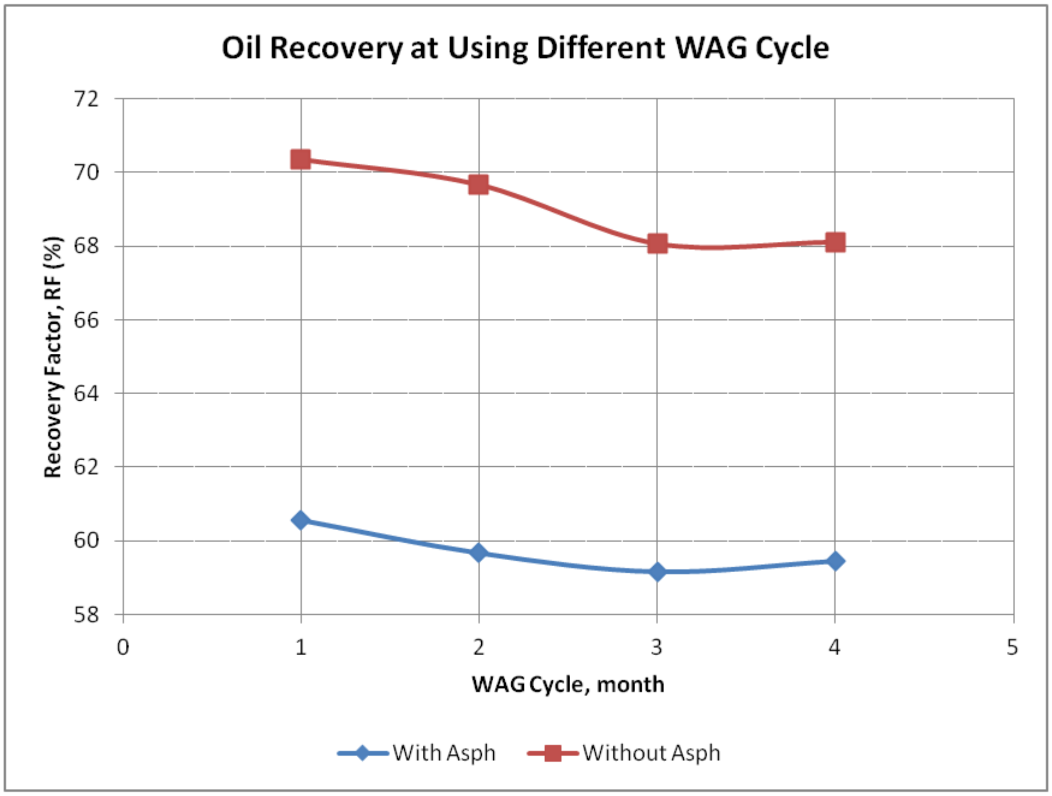


Figure 13 Recovery at different WAG cycle for case with and without asphaltene

Injecting water for a month followed by CO2 the next one month for required number of cycle yielded better recovery. This is due to fact that CO2 mobility can be controlled by water in a better way due to less amount of CO2 injected for one cycle. When, for example, 2 months cycle of WAG injection is used, more CO2 will be injected, thus resulting in much more earlier gas breakthrough which is not desired in WAG injection. The earlier breakthrough means less CO2 had reacted with oil and just bypass the oil without achieving multiple contact miscibility. If this is the case, less injected CO2 is utilized during the WAG process.

4.4.3.3 WAG-CO2 Using Optimum Parameters

Based on the previous result, high injection pressure is used together with WAG cycle that yields highest recovery to further understand the impacts of the two parameters. Table 10 shows the parameters used for this optimized case.

Table 10 Parameters used for optimized WAG-CO2 case

Parameters	**Unit**	**Value**
WaterFlooding Water Injection Rate	bbl/day	550
WAG Water Injection Rate	bbl/day	400
Gas Injection Rate	Ft3/day	2246
WAG Ratio	Ratio	1:1
WAG Cycle Size	Month	1
Injection Pressure	psia	3200

Figure 13 shows the recovery for both cases using an optimized WAG parameter as stated in table 10.

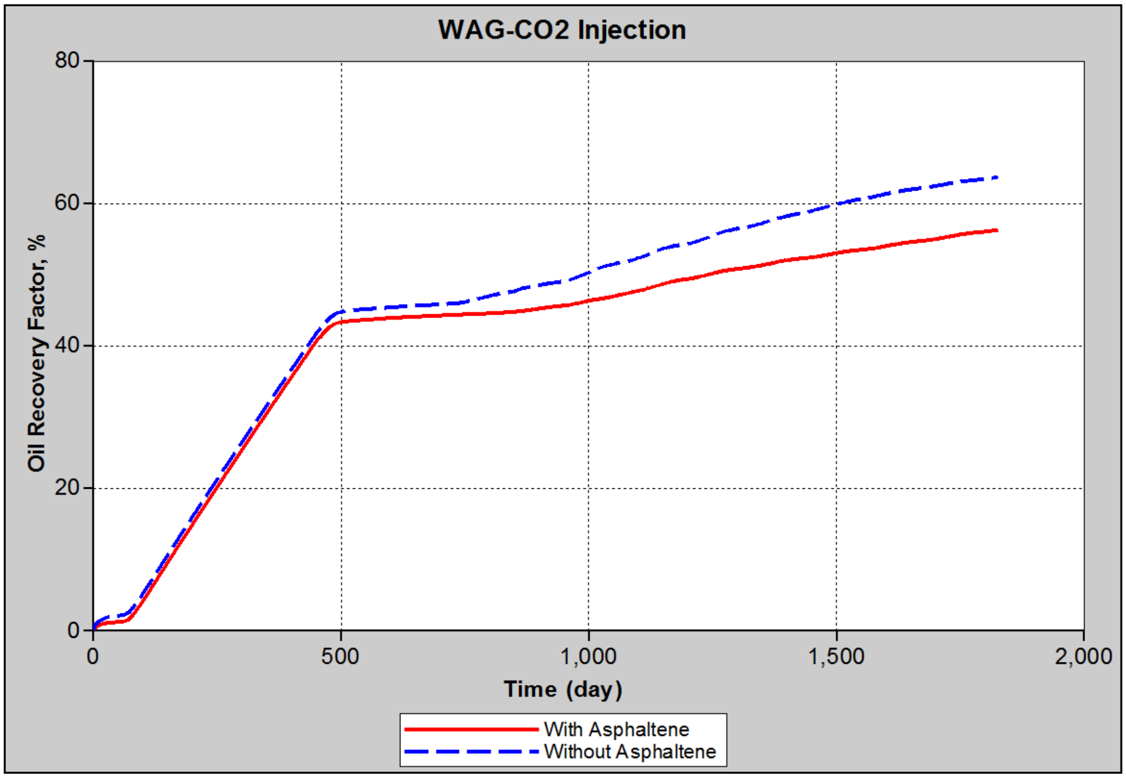


Figure 14 Comparison between case with and without asphaltene- Optimized case

During WAG process, the pressure is maintained as well but from figure 14, there is a very significant different between the recovery for both cases For the case without asphaltene, the recovery is about 70% while for case with asphaltene, the recovery is much lower at about 60%. These big differences can be explained by the use of the CO2 during WAG injection. Injection of CO2 affects the precipitation of asphaltene as experienced by many fields that uses WAG-CO2 injection. Multiple contact miscibility of CO2 with oil causes the change in the oil composition thus causing destabilization of asphaltene and raisin in oil. This will promote the precipitation of asphaltene thus lower the oil recovery as can be seen from figure 13. As the WAG process continues, more CO2 is injected into the reservoir causing the CO2 concentration inside the reservoir to increase. Vaporization of light and intermediate component of the oil into gas phase will leave behind heavier components. This composition changes will cause the destabilization of asphaltene-resin particles in the oil. This is the reason why more asphaltene will be precipitated as seen from the different in the final recovery of the two cases.

4.4.4 Mass of Asphaltene Precipitated and Deposited

Mass of asphaltene precipitated and deposited in the reservoir or well could be seen from the simulation.

4.4.4.1 Primary Depletion

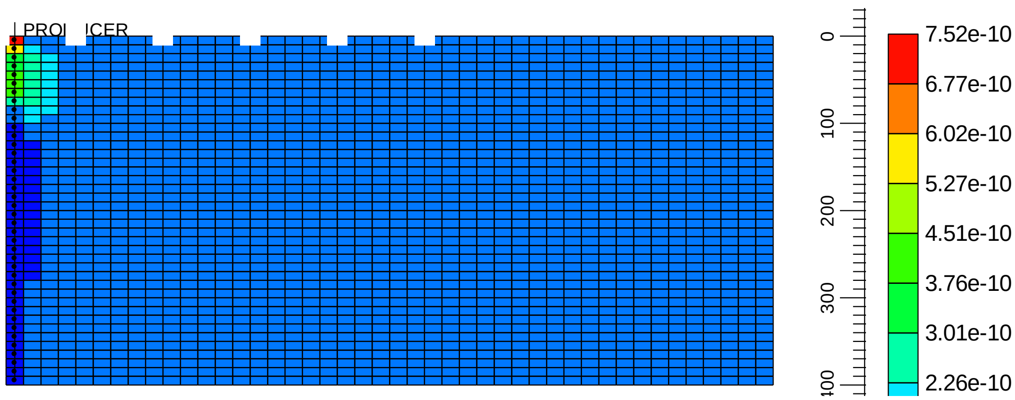


Figure 15 Mass of Asphaltene Precipitated per Bulk Volume during primary depletion

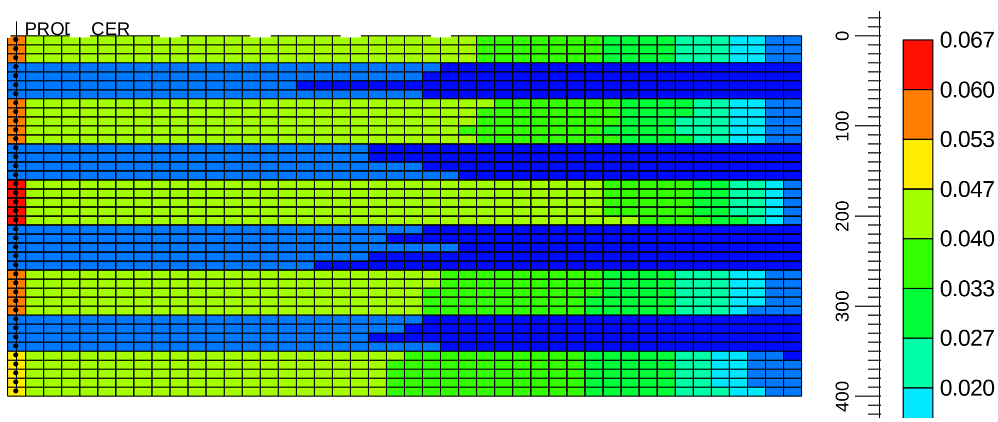


Figure 16 Mass of Asphaltene Deposited per Bulk Volume during primary depletion

From figure 15 and 16, it can be seen that reduction in pressure during primary depletion results in the asphaltene precipitation and deposition that causes the lower recovery.

4.4.4.2 Waterflooding

From figure 17, there is very small amount of asphaltene precipitated at the end of water flooding as pressure is maintained. But since there are asphaltene already deposited during primary depletion, it stays deposited during water flooding as shown in figure 18 and continues to give impact on recovery

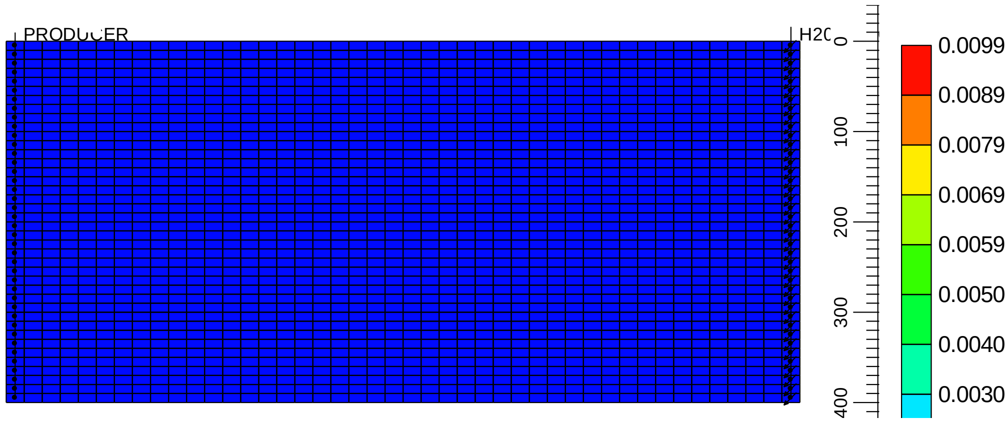


Figure 17 Mass of Asphaltene Precipitated per Bulk Volume during water flooding

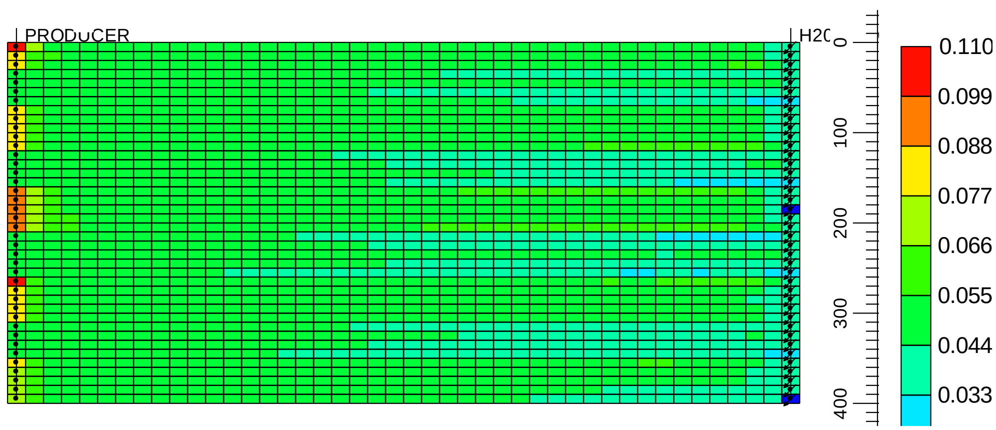


Figure 18 Mass of Asphaltene Deposited per Bulk Volume during water flooding

4.4.4.3 WAG-CO2 Injection at Different Pressure

Figure 19, 20, 21 and 22 show the mass of asphaltene precipitated at different injection pressure from 2000psia to 3200psia. As the injection pressure is higher, the asphaltene precipitation decreases. The result is obvious at injection pressure of 3200 where the mass precipitated is much more less than other injection pressure

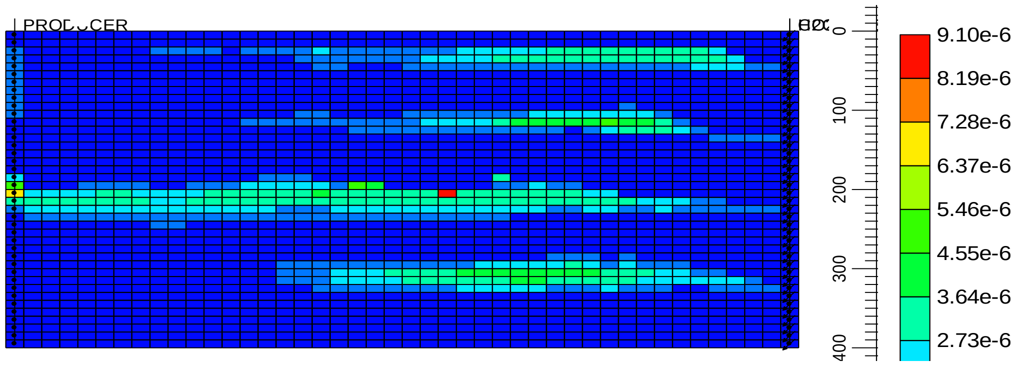


Figure 19 Mass of asphaltene precipitation at injection of 2000 psia

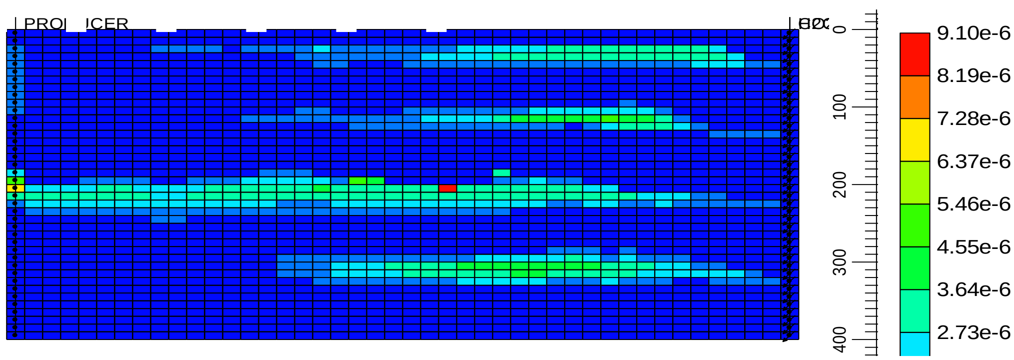


Figure 20 Mass of asphaltene precipitation at injection pressure of 2400 psia

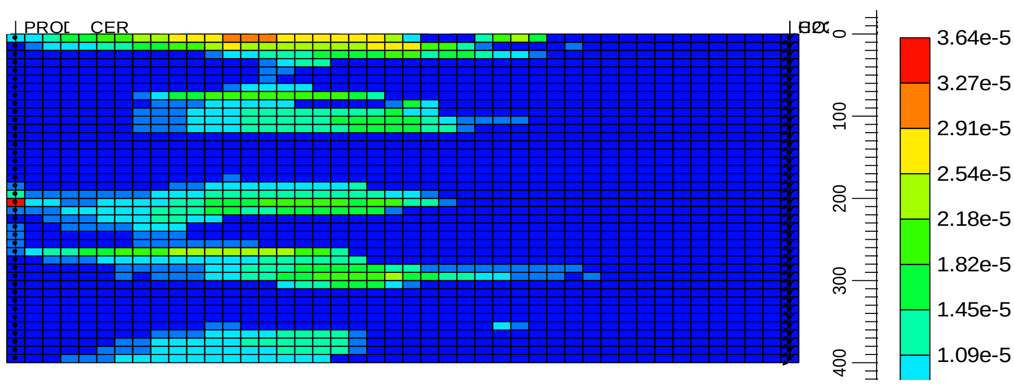


Figure 21 Mass of asphaltene precipitation at injection pressure of 2800 psia

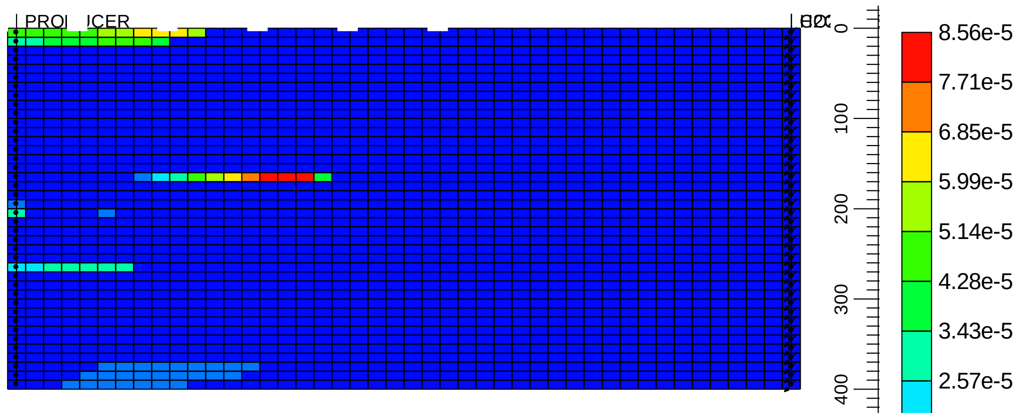


Figure 22 Mass of asphaltene precipitation at injection pressure of 3200 psia

Figure 23, 24, 25 and 26 shows the mass of asphaltene deposited at different injection pressure. Interestingly, mass of asphaltene deposited is almost the same for all injection pressure as can be seen from the range of values on the right hand side legend. This is because continuous injection at any of the pressure will ensure the stabilized state of asphaltene-resin particles and ensure no further asphaltene deposited and at the end of WAG-CO2 injection, same amount of asphaltene will be deposited. This is supported by figure 19, 20, 21 and 22 that lesser asphaltene is precipitated and because of continuous injection at specified pressure, that precipitated asphaltene does not continuously deposited. If the reservoir does not receive continuous pressure support, then more asphaltene will be deposited from the precipitated asphaltene.

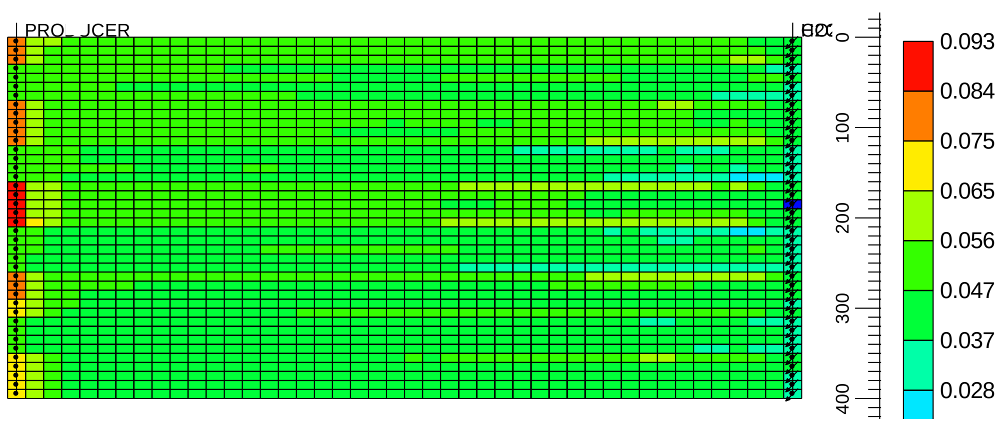


Figure 23 Mass of asphaltene deposited at injection pressure of 2000 psia

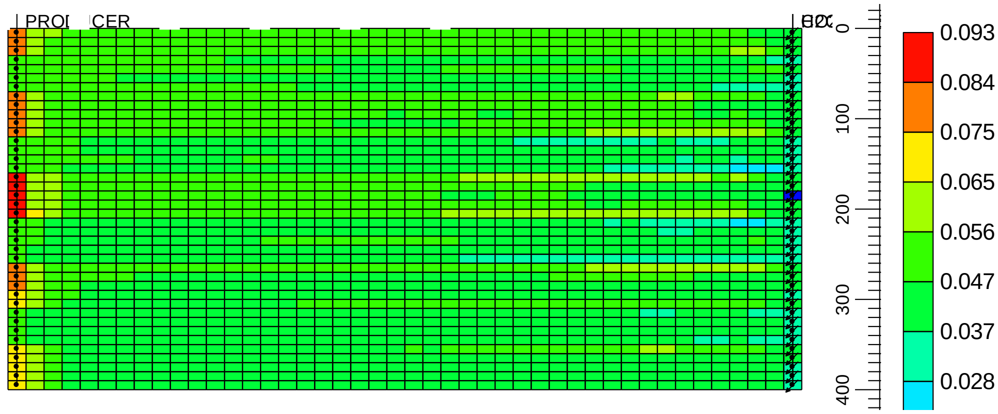


Figure 24 Mass of asphaltene deposited at injection pressure of 2400 psia

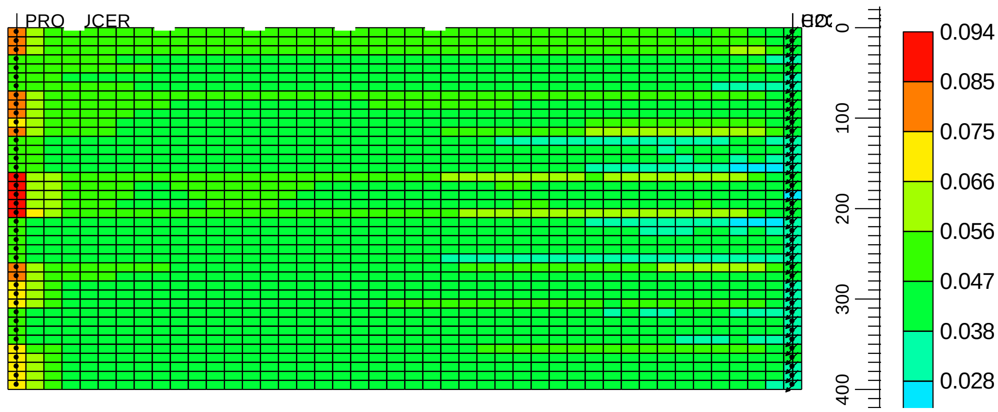


Figure 25 Mass of asphaltene deposited at injection pressure of 2800 psia

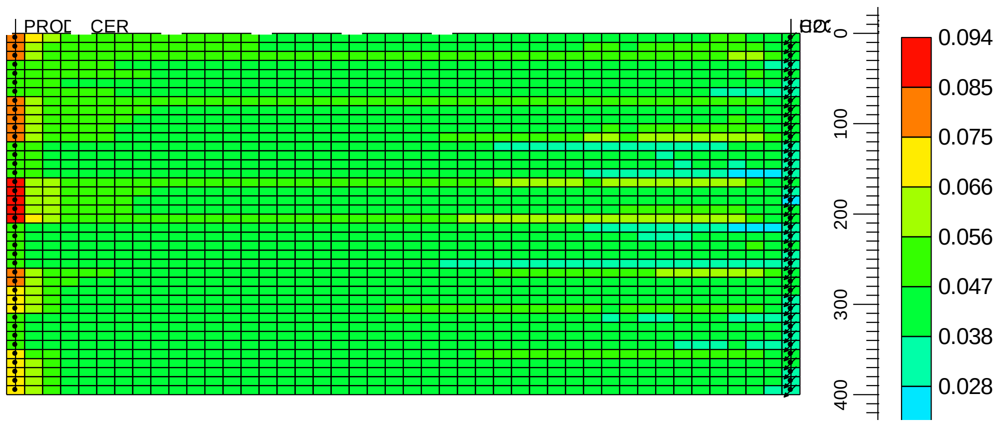


Figure 26 Mass of asphaltene deposited at injection pressure of 3200 psia

4.4.4.3 WAG-CO2 Injection at Pressure Higher Than AOP

As stated before, the asphaltene onset pressure (AOP) for this oil is around 4000psia. Since the initial reservoir pressure (not reservoir pressure during WAG) is more than 5000 psia, an injection pressure of 5000psia is used to simulate injection pressure higher than AOP. Figure 27 shows the asphaltene precipitation at injection pressure of 5000psia.

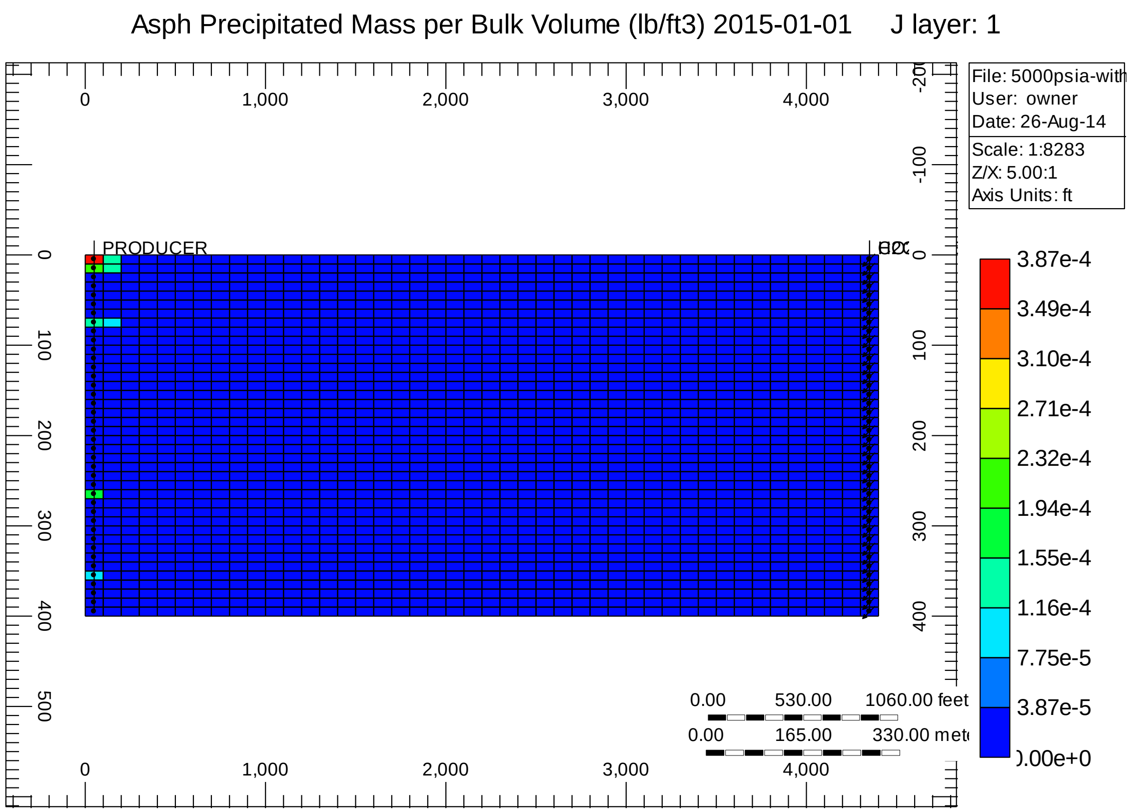


Figure 27: Asphaltene precipitation at 5000psia injection pressure

It is observed that very minimum asphaltene is precipitated and it is not significant to bring asphaltene production problems. Even though high CO2 concentration has been injected at the end of WAG, due to high injection pressure which maintains the reservoir pressure above AOP, there will be no significant asphaltene precipitation problems. Thus, it is very important to inject above AOP to avoid asphaltene problems.

4.4.4.3 WAG-CO_2 Injection Using Different WAG Cycle

1) At 2400psia Injection Pressure (Below saturation pressure)

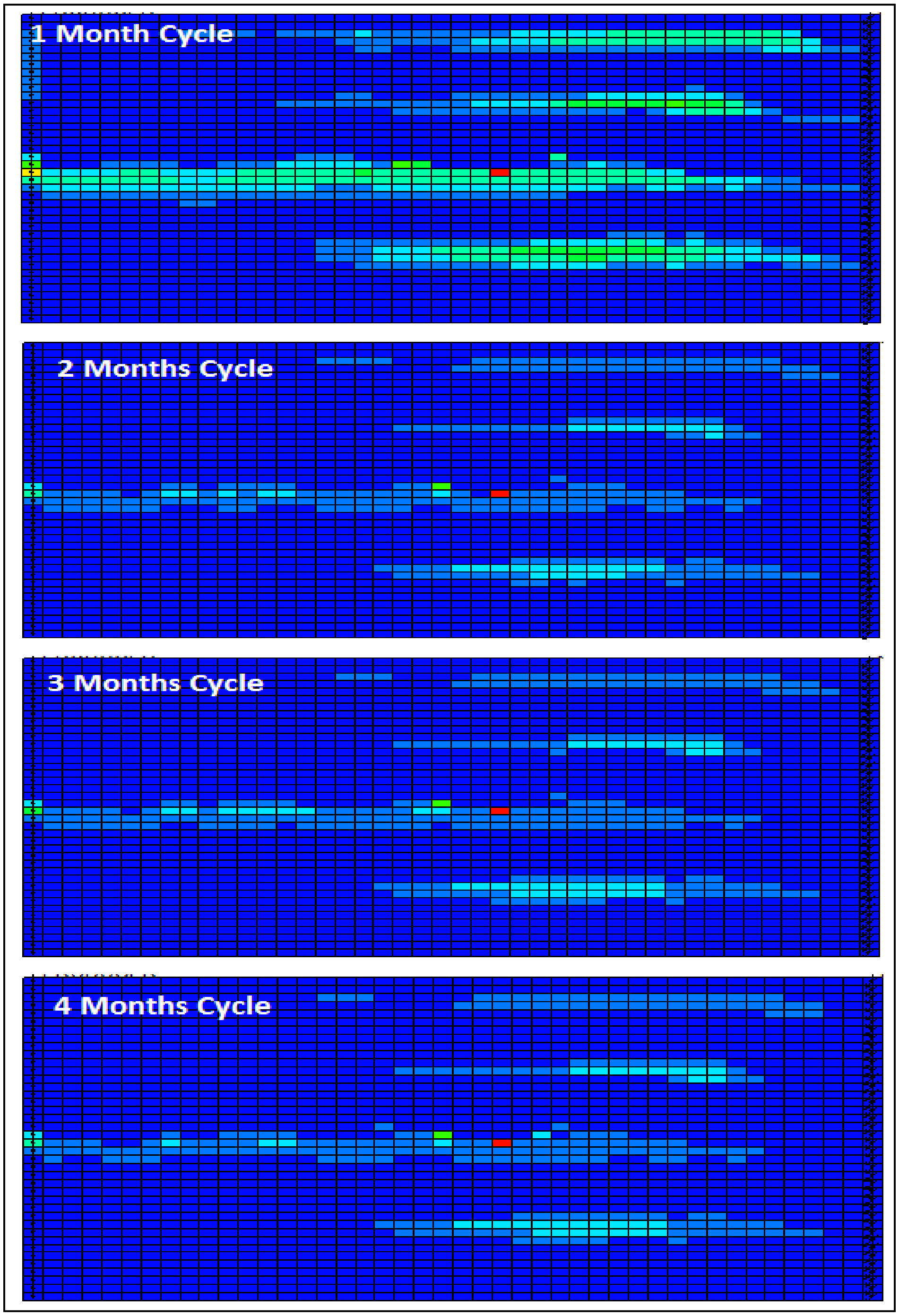


Figure 28: Asphaltene precipitation using different WAG cycle at 2400psia injection pressure

Figure 28 shows the asphaltene precipitation using different WAG cycle at 2400psia injection pressure to simulate the impact of WAG cycle at low injection pressure below saturation pressure. From the figure, only 1 month cycle shows the difference in term of asphaltene precipitation and the rest show almost the same asphaltene precipitation. Thus, WAG cycle gives a low and less significant impact at low injection pressure below saturation pressure.

Figure 29 shows the asphaltene precipitation using different WAG cycle at 3200psia injection pressure to simulate the impact of WAG cycle at high injection pressure above saturation pressure. From the figures, there is no significant different in term of asphaltene precipitation at different WAG cycles.

From this, it can be concluded that WAG cycles gives less significant impact at low injection pressure below saturation pressure and no significant impact at high injection pressure above saturation pressure. Wag cycle, when compared to injection pressure, gives very little impact on asphaltene precipitation and oil recovery.

2) 3200psia Injection Pressure (Above saturation pressure)

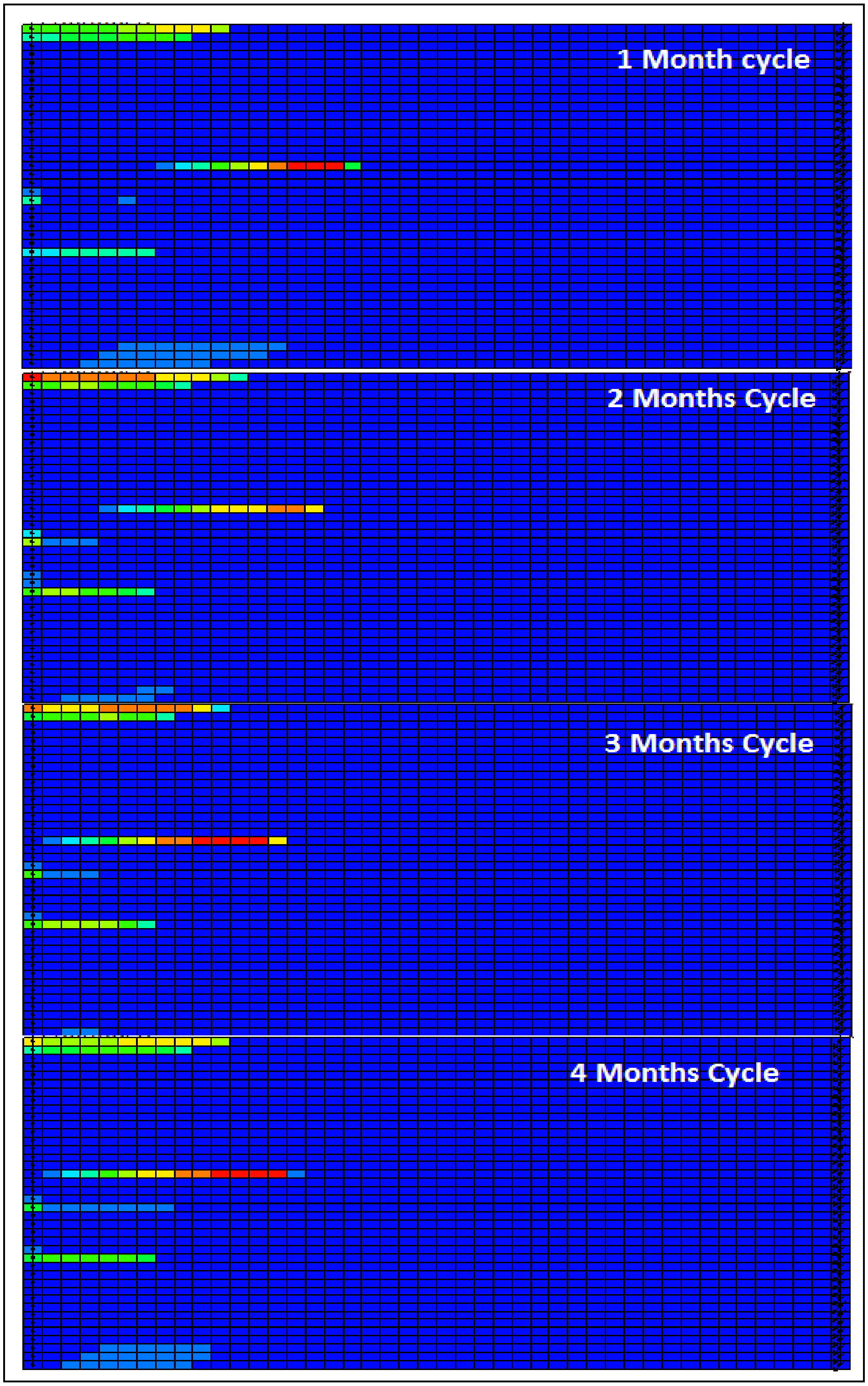


Figure 29: Asphaltene precipitation using different WAG cycle at 3200psia injection pressure

4.4.5 Effect of Permeability on Asphaltene Precipitation

Figure 30 shows the reservoir cross-section with permeability distribution in I-K direction. When comparison is made with the asphaltene precipitation in figure 18, 19, 20 and 21, it is obvious that asphaltene will be deposited at high permeability zone and not in the low permeability zone

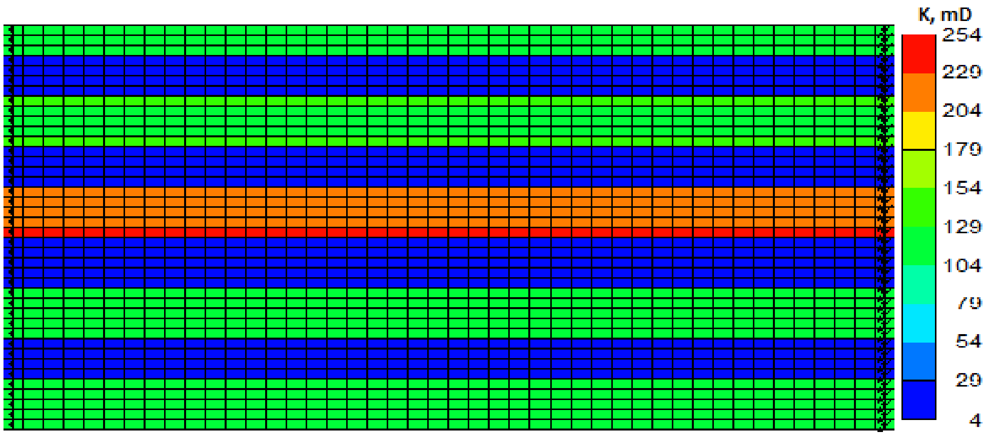


Figure 30: Permeability distribution in I-K direction

Figure 30 shows the result of asphaltene precipitation at 2800 psia with comparison to permeability distribution. From this comparison, it can be seen that asphaltene precipitation will be more pronounced at high permeability zone. Thus, more asphaltene precipitation should be expected at wellbore perforated zone having comparatively high permeability compared to low permeability. The reason behind this could be due to CO2 gas injected tends to follow high permeability zone causing the asphaltene to be precipitated at high permeability zone first.

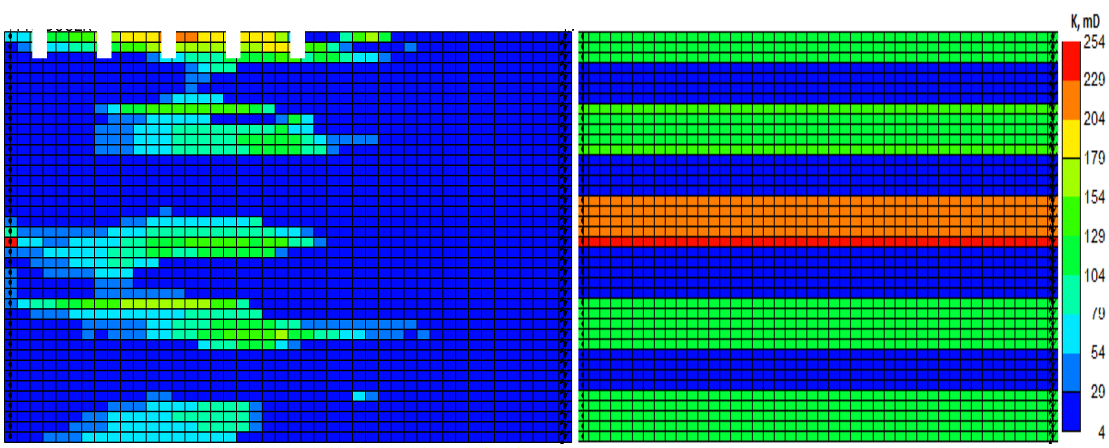


Figure 31: Reservoir cross section showing asphaltene precipitation (left) and permeability distribution (right)

Chapter 5: Conclusion

Asphaltene precipitation during WAG-CO2 injection in light oil is a very serious problem that can cause thousands of money to be spent just to solve the problems but not stopping it from occurring again. From the simulation conducted, higher injection pressure resulted in better recovery which conforms to the theory obtained in literature review. Based on this simulation result, the closer the injection pressure to the initial reservoir pressure, the higher the recovery will be and lesser asphaltene will be precipitated. As for asphaltene deposition, for same period of WAG injection, almost same amount of asphaltene will be deposited at any injection pressure because of continuous injection at specified pressure able to maintain reservoir pressure and ensure no further asphaltene deposition. If the reservoir does not receive continuous pressure support, then more asphaltene will be deposited from the precipitated asphaltene. Thus, what should be controlled is the asphaltene precipitation in the crude oil and to do this, higher injection pressure should be used. Also, injection pressure higher than AOP resulted in no significant asphaltene precipitation.

As for WAG cycle, injecting water alternately by one month each resulted in better recovery compared to other WAG cycle because of gas mobility control. Longer injection cycle will cause early gas breakthrough thus injected CO2 will not be fully utilized in increasing the oil recovery. For WAG injection pressure lower than saturation pressure, WAG cycles gives little impacts only, especially for month WAG cycles while at injection pressure higher than saturation pressure, WAG cycles gives no significant impact towards asphaltene precipitation. Wag cycle, when compared to injection pressure, gives very little impact on asphaltene precipitation and oil recovery.

Based on permeability distribution, asphaltene precipitation is more pronounced at high permeability zones due to injected CO2 follows the high permeability path thus causing more asphaltene to be precipitated at this high permeability zones. Hence, more asphaltene should be expected to be precipitated at wellbore having high permeability.

Simulation study alone is not enough to make a direct conclusion. Combination of experimental work with simulation could serve a better insight of the impact of varying different WAG parameters. Thus, it is recommended for experimental work to be done along with this simulation to give a better view in different perspectives. Given the time constraints of completing this project, this is the best that could be achieved. Nevertheless, this simulation results which tally with literature review could serve as reference for further research in this area of study.

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APPENDIXES

APPENDIX 1 Recovery for case with and without asphaltene at different injection pressure

APPENDIX 2 Cumulative pore volume injected

APPENDIX 3 Pore volume calculation

APPENDIX 4 Pore volume calculation

APPENDIX 1 Recovery for case with and without asphaltene at different injection pressure

	RECOVERY FACTOR, %				
PRESSURE	2000	2800	3200	10000	12000
WITH ASPH	48.2653	56.3086	59.6784	59.6743	58.7614
WITHOUT ASPH	51.2352	63.7042	69.6642	69.9774	69.6721

APPENDIX 2 Cumulative pore volume injected

Year	1	2		3	4	5
Injection days	306	120	242	365	365	365
Volume injected, bbl	168300	66000	96800	146000	146000	146000
Volume injected,ft3	945004.5	370590	543532	819790	819790	819790
cumulative injected, ft3	945004.5	1315594.5	1859126.5	2678916.5	3498706.5	4318496.5
PV injected	0.2685	0.3737	0.5282	0.7611	0.9940	1.2268

APPENDIX 3 PV, STOIIP and GIIP

	Unit	WITH ASPHALTENE	WITHOUT ASPHALTENE
Total Bulk Reservoir Volume,	RES FT3	17600000	17600000
Total Pore Volume,	RES FT3	3520000	3520000
Total Hydrocarbon Pore Volume,	RES FT3	2745600	2745600
Original Oil in Place, OOIP	STD BBL	318447	322409
Original Gas in Place, OGIP	STD FT3	281829000	277836000

APPENDIX 4 Pore volume calculation

waterflood	Inj Rate	Time	Water injected	Gas injected	Reservoir PV	PV inj
	bbl/d	days	bbl	ft3	ft3	
	100	426	42600	239199	3520000	0.067954
	200	426	85200	478398	3520000	0.135909
	300	426	127800	717597	3520000	0.203863
	400	426	170400	956796	3520000	0.271817
	500	426	213000	1195995	3520000	0.339771
	550	426	234300	1315594.5	3520000	0.373748
	600	426	255600	1435194	3520000	0.407726

WAG	Inj Rate	Time	Water injected	Gas injected	Reservoir PV	PV inj
	bbl/d	days	bbl	ft3	ft3	
	100	1340	134000	752410	3520000	0.213753
	200	1340	268000	1504820	3520000	0.427506
	300	1340	402000	2257230	3520000	0.641259
	400	1340	536000	3009640	3520000	0.855011
	500	1340	670000	3762050	3520000	1.068764