Investigation Of Asphaltenes Onset Pressure (AOP) In Low Asphaltenic Light Oil Samples

by

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Supervised by

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Dissertation submitted in partial fulfilment of
the requirements for the
Bachelor of Engineering (Hons)
(Petroleum Engineering)

MAY 2012

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the

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(PETROLEUM ENGINEERING)

Approved by,

____
(Ali F.Mangi Alta'ee)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

May 2012

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.

TEOH WAN RU

ABSTRACT

Asphaltenes precipitation is common problem in many reservoir field during natural pressure depletion, as well as during gas injection processes for Improved Oil Recovery (IOR) or Enhanced Oil Recovery (EOR). Extensive field and laboratory data has proven that asphaltenes precipitated more easily from light oil rather than from heavy oil, even though the heavier oil might have much higher asphaltenes content.

This study concerns with reservoir simulation investigation of light oil samples on asphaltenes precipitation during pressure depletion and carbon dioxide (CO_2) gas injection. Simulation studies have been carried out to understand asphaltenes onset behaviour over a range of pressure at reservoir temperature. A few light oil samples with low asphaltenes content have been chosen to investigate their Asphaltenes Onset Pressure (AOP). Besides, a heavy oil sample with high asphaltenes content has been simulated for comparison purpose. In addition, the onset condition induced by different CO_2 concentrations have been investigated over the pressure change as well.

The results of this study have shown that during depressurization, asphaltenes start to precipitate in oil from upper AOP while approaching bubble-point pressure. The precipitated amount increases and reaches maximum around bubble-point pressure. After crossing bubble-point pressure, precipitated asphaltenes reduce and cease precipitation at lower AOP. By injecting higher CO_2 mole percentage, bubble-point pressure increases and more asphaltenes precipitate in oil.

In conclusion, these results presented the tendency of asphaltenes precipitation in light oil reservoirs during natural depletion as well as CO_2 gas injection. Thus, they can be applied as criteria for designing successful reservoir management strategy to mitigate asphaltenes precipitation problem in light oil reservoir condition.

ACKNOWLEDGEMENT

I am sincerely thankful to my supervisor, Mr Ali F. Mangi Alta'ee, whose encouragement, guidance and support from the initial to the final stage enabled me to develop an understanding of the subject. This final year project would not have been possible without his constructive ideas and extensive discussions which were enlightening.

Besides, enormous thanks to my coursemates, who have been helping me to learn and master the CMG software for completing this project. Last but not least, much gratitude is extended to those who have helped me in accomplishing my final year project and delivered in a timely manner.

TABLE OF CONTENT

LIST OF FIGURES

LIST OF TABLES

CHAPTER 1
INTRODUCTION

1.1 Background of Study

Asphaltenes are heavy hydrocarbon molecules which are naturally existing as colloidal suspension in petroleum reservoir fluids, and stabilized by resins adsorbed on their surface (Kokal and Sayegh, 1995; Speight, 2004; Buckley *et al.*, 2007). Asphaltenes precipitations are the common problems in reservoir field during natural pressure depletion (Hammami *et al.*, 2000; Akbarzadeh *et al.*, 2007; Afshari *et al.*, 2010), as well as during gas injection processes for Improved Oil Recovery (IOR) (Nghiem, 1999), or Enhanced Oil Recovery (EOR) (Sarma, 2003; Alta'ee *et al.*, 2010). Extensive field and laboratory data has proven that asphaltenes precipitate more easily from light oil rather than from heavy oil, even though the heavier oil might have much higher asphaltenes content (Kokal and Sayegh, 1995; Sarma, 2003; Akbarzadeh *et al.*, 2007; Alta'ee *et al.*, 2010).

1.2 Problem Statement

Asphaltenes precipitation during pressure depletion and oil recovery is a common problem occurring in many fields around the world. In reservoir, the precipitated asphaltenes can deposit onto the rock surface or remain as a suspended particles in the oil phase. The deposited asphaltenes may cause blockage of the pore throats and channels, which results in permeability reduction and porosity alteration and later leading to formation damage, furthermore plugging the wellbore and blocking the production line.

The review of asphaltenes depostion in field situations indicates that asphaltenes content in oil does not play a crucial role in the flocculation process. Asphaltenes precipitation problems are more common in lighter oil which contains only minor amount of asphaltenes in reservoir especially at pressure above the bubble-point.

1.2.1 Significant of the Project

In recent years, offshore production system has been moving to deepwater and subsea environments which increased the importance of fluid properties related to flow assurance issues. One of these potential challenges is asphaltenes precipitation and deposition problems from reservoirs up to the production line, causing reservoir formation damage and plugging wells and flowlines. The impacts are usually catastrophic while the remedial measures are expensive yet disruptive. Therefore, it is crucial to investigate the potential of asphaltenes precipitation in reservoirs prior to natural pressure depletion, especially before implementing a gas injection scheme, in order to built proper control and remediation strategies into the systems from the beginning.

1.3 Objectives & Scope of Work

- To determine Asphaltenes Onset Pressure (AOP) for light crude oil samples with low asphaltenes content.
- To investigate the tendency of asphaltenes precipitation under reservoir conditions for different CO_2 concentrations.

In this project, four light oil samples with API gravity range within 31^o to 42^o, which are low in asphaltenes content (less than 4.0 wt%) have been used for reservoir simulation studies. With known amount of fluid composition, reservoir pressure and temperature, known density and original asphaltenes weight content, the light oil samples have been tested through simulation studies to investigate their AOP. This research focuses on the phase behavior and equilibrium studies of asphaltenes precipitation in reservoir condition. Besides, a heavy oil sample with high asphaltenes content has also been simulated for comparison purpose.

Static asphaltenes test has been simulated from zero mole percentage of CO_2 gas injection until eighty mole percentage. Over series of isothermal pressure depletion, light oil samples have been simulated over pressure decline to monitor asphaltenes onset precipitation condition. This investigation mainly simulated the reservoir condition which is away from the near wellbore region, while the dynamic flow within the reservoir will not be included here. Finally, these results will be related to the expected behavior of asphaltenes in the deep reservoir and to address the uncertainties.

1.4 The Relevancy of the Project

Asphaltenes precipitation and deposition are well-known problems in many production oilfields, especially in this EOR century. This is one of the reservoir engineering studies which is related to phase behavior investigation on one of the petroleum components—Asphaltene.

1.5 Feasibility of the Project

The scope of study for this project has been limited to reservoir conditions. With the equipment available in PVT laboratory in Universiti Teknologi PETRONAS, the author initially believed that this study could be accomplished experimentally within time frame. Unfortunately, due to the circumstance of unexpected broken-down PVT cell, the author had to adjust the experiment methodologies and continue this project by using reservoir simulation software.

CHAPTER 2
LITERATURE REVIEW

2.1 Asphaltenes Definition

Compositional studies separate petroleum reservoir fluids into SARA, namely Saturates, Aromatics, Resins, and Asphaltenes. Asphaltenes are complex organic components of reservoir fluids with no defined melting point, while having the highest molecular weight hydrocarbon fraction and highest polarity among the four components. Generally, asphaltenes are characterized as soluble in aromatics (e.g., benzene and toluene), but insoluble in paraffinic compounds (e.g., n-pentane and n-heptane) to form dark color solid as shown in figure 1 below (Srivastava *et al.*, 1997; Gholoum *et al.*, 2003; Speight, 2004; Cheng, 2008; Alta'ee *et al.*, 2010).

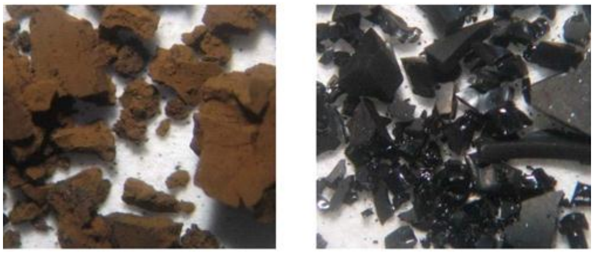


Figure 1: n-Pentane Asphaltene (left) and n-Heptane Asphaltene (right),
(Cheng, 2008)

2.2 Asphaltenes Precipitation

According to the first theoretical model of asphaltenes precipitation as proposed by Liao and Geng, (2000), asphaltenes are believed to exist dissolved in oil under dynamic stable system and this is known as solubility model. With respect to the interactions of asphaltenes-resins, they suggested the second model—colloid model. Similarly, Hirschberg *et al.*, (1984) summarized that colloidal model is the most common model for asphaltenes-resins interactions. This colloidal model was further supported by Kokal and Sayegh, (1995), Buckley *et al.*, (2007) and Alta'ee *et al.*, (2010), who also agreed that asphaltenes are heavy hydrocarbon molecules which exist naturally as dispersed colloidal suspension model in petroleum fluids.

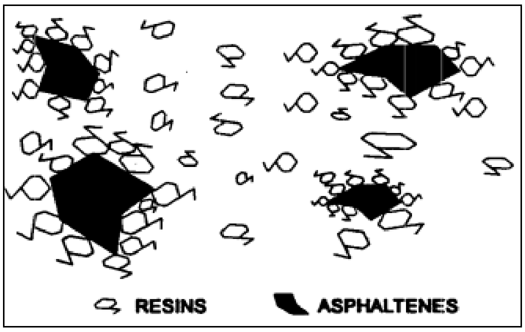


Figure 2: Peptization of Asphaltenes by Resins,
(Kokal and Sayegh, 1995; Alta'ee *et al.,* 2010)

As shown in figure 2, asphaltenes are finely dispersed in oil and stabilized by the highly polar peptizing agents—resins, which are adsorbed on their surfaces. The result of asphaltenes-resins interactions are generally termed as "micelles". Hirschberg *et al.*, (1984) advocated that resins have a strong tendency to associate with asphaltenes. This statement was strengthened by Speight, (2004) who regarded asphaltenes-resins interactions appear to be preferrable over asphaltenes-asphaltenes interactions and resins-resins interactions when both asphaltenes and resins co-exist in petroleum fluids. When incompatibility occurs among petroleum fluids, the loss of dispersability in colloidal suspension causes the higher molecular weight polar components (asphaltenes and resins) to precipitate.

Operational problems associated with asphaltenes precipitation and deposition manifest in nearly all facets of petroleum production, processing and transportation of petroleum (Hammami *et al.*, 2000; Gholoum *et al.*, 2003). The precipitation of asphaltenes from reservoirs, to near wellbore, well tubing, up to the surface facilities have detrimental effects on the economics of well development as well as oil production. The chance for these problems to happen is expected to be even higher in offshore and into deep water operations where the prevention and remediation costs increase dramatically (Hammami and Ratulowski, 2007; Afshari *et al.*, 2010).

2.3 Mechanism of Precipitation

Alta'ee *et al.*, (2010) defined the terminology of asphaltenes solidification in terms of three stages, namely precipitation, flocculation and deposition. Firstly, asphaltenes precipitate from petroleum fluids when solid particles form a distinct phase as they come out of solution. During precipitation, the quantity and size of solid particles could be quite small and they are "swimming" along with the fluid flow. Then, the flowing polar solid particles coalesce and their sizes are growing larger during asphaltenes flocculation. The quantity and size of particles are increasing. Finally, when the flocculated particles lump together as residue, they become so large until can no longer be supported by the fluid flow. These deposited asphaltenes will be settled out and adhered to solid surfaces.

Similarly, Hammami and Ratulowski, (2007) also emphasized the difference between both precipitation and deposition terminology, whereby precipitation is the formation of a solid phase out of a liquid phase, while deposition is the growth of the precipitated solids on a surface. However, as quoted by them, "Precipitation is, although a precursor to deposition, does not necessarily ensure deposition."

Thou *et al.*, (2002) explained the mechanism of asphaltene deposition in terms of four effects—Solubility, Colloidal, Aggregation and Electrokinetic effects. As illustrated by figure 3, solubility effect is due to the content of crude oil. Micellization of asphaltenes is resulted by the increase in aromaticity in fluid composition, while addition of light paraffinic compounds will result in asphaltene precipitation.

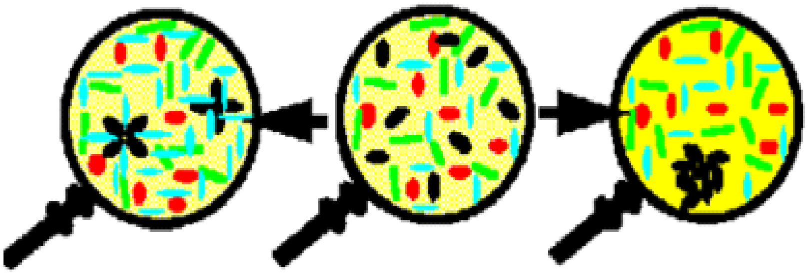


Figure 3: Asphaltene Micellization (left) and Precipitation (right), (Thou *et a.l*, 2002)

Due to colloidal effect, asphaltenes suspended in oil phase by the peptization of resins to form micelles. Increasing in light paraffinic compounds in oil content results in migration of resins from asphaltenes surface, thus breaking the micelle (asphaltene-resin) bond. Concentration variation of resins due to the addition of light saturates causes change in chemical potential balance, as illustrated in figure 4 as below.

Figure 4: Peptization by Resins (center); Change in Chemical Potential Balance (right), (Thou *et al.*, 2002)

Aggregation effect occurs as a result of insufficient resins coating around the entire surface of one asphaltene particle, causing asphaltene and asphaltene flocculate together due to their polarity (Buckley *et al.*, 2007). While electrokinetic effect is related to the electrical potential difference due to motion of charged while particles flowing in porous medium.

2.4 Major Destabilizing Factors

As summarized by most researchers based on field experience and experimental observations, the major destabilizing factors for asphaltene are pressure depletion, compositional change, as well as temperature variation (Hirschberg *et al.*, 1984; Kokal and Sayegh, 1995; Sarma, 2003; Hammami and Ratulowski, 2007; Afshari *et al.*, 2010). The general consensus is that the effect of pressure and composition change on asphaltenes precipitation are comparatively stronger than the effect of temperature.

2.4.1 Pressure Depletion

Asphaltenes precipitation and deposition problems along the production system occur near wellbore region and along well tubing below the depth at which the oil becomes saturated (Kokal and Sayegh, 1995; Hammami *et al.*, 2000; Thou *et al.*, 2002; Hammami and Ratulowski, 2007). These are the impacts of pressure drop from near wellbore region up to the production line on surface. Whereas at reservoir conditions, asphaltenes precipitation happens in the oilfield which experiences natural pressure depletion throughout the production phase (Gholoum *et al.*, 2003; Afshari *et al.*, 2010). This phenomenon is mainly related to the different compressibility of the light ends and the heavy components (e.g., resins and asphaltenes) of the under-saturated oil (Hammami and Ratulowski, 2007).

2.4.2 Compositional Change

Compositional change in reservoir fluids includes addition in light paraffinic compounds, increase in aromaticity, gas injection scheme, as well as change in gas-oil-ratio (GOR), ratio of high to low molecular weight component, asphaltenes-resin ratio, etc. (Sarma, 2003). As reviewed by Hammami and Ratulowski, (2007), asphaltenes precipitation can occur in-situ during mixing of incompatible hydrocarbon fluids, miscible flooding, CO_2 flooding, and other solvent injection operations due to the effect of compositional change.

2.5 Precipitation over Pressure Depletion

Experimental investigations and simulation studies on asphaltenes precipitation in under-saturated petroleum fluids at reservoir conditions indicate that maximum amount of asphaltenes precipitation is observed near the bubble-point pressure region (Kokal and Sayegh, 1995; Nghiem, 1999; Hammami *et al.*, 2000; Afshari *et al.*, 2010). This bulk precipitation is due to maximum density difference between asphaltenes and bulk oil at bubble-point pressure before the first gas evolved from the under-saturated oil. When the gas mole percent is about to increase from zero, there is the highest asphaltenes deposition mole percent (Alta’ee *et al.*, 2010).

According to Schlumberger Oilfield Glossary, Asphaltenes Onset Pressure (AOP) is defined as the pressure at a given test temperature which first causes asphaltenes to precipitate from reservoir fluid as pressure decreases.

Utilising the results from simulation studies, Asphaltenes Precipitation Envelope (APE) is generated as shown in figure 5 below, whereby the shaded area indicates asphaltene precipitation. When pressure is reducing, APE Upper Boundary is believed to be the onset pressure, while asphaltenes precipitation increases with the reduction of pressure and reaches to a maximum near the bubble-point (Afshari *et al.*, 2010). Hence according to Nghiem's model, asphaltene onset region is bounded by upper and lower AOP as shown below.

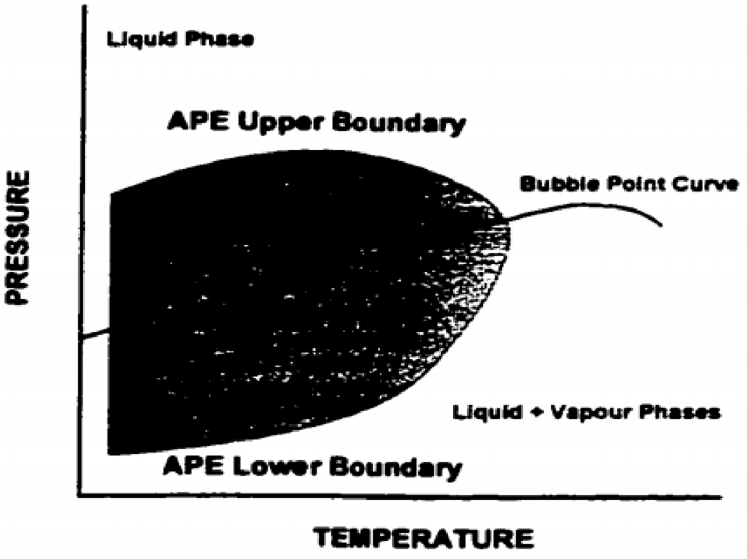


Figure 5: Pressure-Temperature APE,
(Nghiem, 1999)

2.5.1 Above Bubble-Point Pressure

Under very high reservoir pressure, the under-saturated single phase oil is exerted by very high compressibility forces from the external pressure. According to the van der Waals loop (McCain, 1990) as shown in figure 6 below, at very high pressure along the liquid part of the isotherm before point L, the molar volume (V_m) is small. In terms of chemical potential, smaller V_m is having greater chemical potential, results in stronger van der Waals bond.

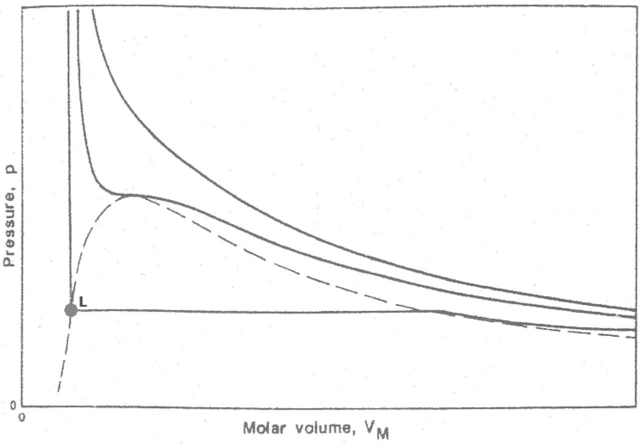


Figure 6: Van der Waals Loop, (modified from McCain, 1990)

Therefore, under very high pressure, the stronger van der Waals bond within colloidal model is believed to tighten the distance between asphaltenes and resins, and thus stabilize the suspension micelles particles in oil (Hammami and Ratulowski, 2007; Buckley *et al.*, 2007).

As reservoir pressure decreases, the weakening van der Waals bonds plus change in fluid properties disturb the stability of asphaltene-resin micelles. As the oil is depressured from reservoir pressure to bubble-point pressure, the mass and molar composition keep constant, but the molar volume of the bulk oil is increasing while the overall density is reducing. Due to the difference in compressibility, the volumes occupied by the C_{6-} components are increasing more rapidly than those of the C_{7+} fraction (Buckley *et al.*, 2007). Hence the reservoir fluids possess higher behaviour of light oil, and act more like lighter oil while pressure is decreasing.

With this increase in the volume of lighter hydrocarbon fraction, the solubility parameter between resins and evolving lighter ends decreases, meanwhile reduces the micelles solubility, as such induces resin to dissolve constantly (Alta'ee *et al.*, 2010). And later this results in the reduced solubility of asphaltenes upon reaching bubble-point pressure, causing asphaltenes precipitation (Hirschberg *et al.*, 1984).

Kokal and Sayegh, (1995) and Hammami *et al.*, (2000) have concluded that maximum difference in molar volume (density) between the asphaltenes and the bulk oil occurred at the bubble-point pressure before the first dissolved gas released.

2.5.2 Below Bubble-Point Pressure

Below the saturated pressure, composition of reservoir fluids changes when the lighter hydrocarbon fraction evaporates from the oil as gas phase, and thus changing the molar volume of the liquid phase and reestablishing some of its lost asphaltenes solubility (Kokal and Sayegh, 1995; Hammami *et al.*, 2000). As pressure is going down, light gas liberation leaves the heavier reservoir fluids with higher resins fraction, which is insufficient to peptize and stabilize the asphaltenes. Thus the change in reservoir fluids composition will result in enhanced solubility with decreasing deposition upon pressure decrease below the bubble-point (Afshari *et al.*, 2010; Hirschberg *et al.*, 1984).

The review of asphaltenes precipitation conditions over pressure depletion from reservoir pressure until below saturated pressure has explained the asphaltene field problems as addressed by Kokal and Sayegh, (1995). After the bottom hole pressure fell below the bubble-point pressure, asphaltenes precipitation problems at the Ventura Field, Hassi-Messaoud Field and Lake Maracaibo are diminishing. On the other hand, there was no deposition problem observed in Ula Field, Norway below the bubble-point pressure. Evidence of asphaltene precipitation above the bubble-point pressure and asphaltene redissolution below the saturated pressure as observed by Hammami *et al.*, (2000) could be explained by the review as above.

2.6 Precipitation in Light Oil

Extensive field and laboratory data indicate that asphaltenes precipitate more easily from light oil as compared to from heavier oil, though the heavier oil consists of higher asphaltenes content (Kokal and Sayegh, 1995, Sarma, 2003, Akbarzadeh *et al.*, 2007; Alta’ee *et al.*, 2010). Heavier oil consists of higher intermediate components with more resins and aromatics which make it becomes a good solvent to stabilize asphaltenes. While lighter oil contains higher fraction of light hydrocarbon ends which have limited solubility on asphaltenes.

The addition of light paraffinic compounds can alter the solubility of the asphaltenes component in reservoir fluids (Hammami *et al.*, 2000). In accordance to the colloidal model of asphaltenes behavior, resin molecules tend to desorb from the surface of the asphaltenes and thus breaking the micelles bond, in respond to the addition of light hydrocarbon fraction to reservoir fluids in order to reestablish thermodynamic equilibrium.

2.7 Effect of Asphaltenes Content

The review of asphaltenes deposition in field situations indicates that the quantity of asphaltenes content in oil does not play a crucial role in asphaltanes flocculation process (Kokal and Sayegh, 1995; Akbarzadeh, 2007). Asphaltenes precipitation problems are often more common in lighter oil that contains minor amount of asphaltenes in reservoir at pressure above the bubble-point.

There are two field examples to prove the fact as discussed above. The Venezuelan Boscan heavy crude oil with 17.2-wt% asphaltenes was produced nearly trouble-free, whereas Hassi-Messaoud light crude oil in Algeria with only 0.15-wt% asphaltenes has numerous production problems due to alphaltene precipitation. As recognized by Alta’ee *et al.*, (2010), light oil with small amount of asphaltenes is more likely to cause production problems which are related to asphaltenes precipitation, rather than the heavy oil with larger amount of asphaltenes fraction.

2.8 CO_2 Injection

Field data has proven that asphaltenes precipitation and deposition could have been exacerbated by gas injection, and coincidently, light oil reservoirs are the more preferrable candidates for gas injection processes (Srivastava and Huang, 1997;

Sarma, 2003). Most miscible solvents have the potential to cause asphaltenes flocculation. The investigation result from Gholoum *et al.*, (2003) revealed that CO_2 is the most effective asphaltenes precipitant followed by alkanes (C_1 to C_7).

Miscibility of CO_2 gas with the reservoir oil will contribute to the compositional change which favors the precipitation of asphaltenes. When injected CO_2 is in contact with the reservoir fluids, vaporizing gas drive process causes CO_2 gas vaporizes part of the light and intermediate components to the gas phase, which results in the loss of intermediate components (C_{3+}) in reservoir fluids (Green and Willhite, 1998). Meanwhile, resins are vaporized to the CO_2 gas phase as well. As a result, the reservoir oil phase is left with lesser resins content and lower molecular weight, acting as if light oil.

The loss of resins and the light oil characteristic destabilize asphaltenes in the reservoir fluids, then change the fluids behavior and equilibrium condition when CO_2 gas is in contact with the reservoir oil, which results in asphaltenes precipitation (Kokal and Sayegh, 1995; Sarma, 2003; Srivastava and Huang, 1997).

Alta'ee *et al.*, (2010), Srivastava and Huang, (1997) reported about their study on asphaltene precipitation at constant temperature over different CO_2 concentration. The results proved that the amount of precipitated asphaltene increases with increasing CO_2 concentration as expressed in mole percentage. Besides, the results also showed that saturation pressure increases with increasing CO_2 concentration.

Experimental investigation by Gholum *et al.*, (2003) and Sarma, (2003) demonstrated that with the addition of CO_2 mole percentage, the Power of Transmitted Light (PTL) is increasing until certain CO_2 concentration.

2.9 Summary

Asphaltenes are one of the SARA components in petroleum fluid with highest molecular weight and polarity. They are complex organic components with no defined melting point, and soluble in aromatic compounds but insoluble in paraffinic compound. Generally, asphaltenes are believed to be naturally existed in petroleum fluids as colloidal model, which are peptized by resins to form “micelles”. Once the micelles bond is broken, asphaltenes will be precipitated out of liquid phase to form small solid particles. Asphaltenes flocculation takes place when the flowing asphaltenes particles coalesce and growing bigger. When the size becomes too large, it will be settled out from liquid phase and deposited on solid surface.

The major destablizing factors of asphaltenes are pressure depletion and compositional change. When the initial reservoir pressure is far above the bubble-point, asphaltenes are soluble and finely dispersed in petroleum fluids. As pressure is declining, asphaltenes start to precipitate more and more upon reaching the bubble-point. At the saturated pressure, bulk precipitation takes place. While pressure continues decreasing, asphaltenes will slowly redissolve back to the fluids. The addition of CO_2 gas will change the composition of petroleum fluids and thus alter the bubble-point pressure and AOP value from its original composition. Commonly, light oil is the more preferrable candidate for asphaltenes precipitation, regardless the amount of asphaltenes existed in the oil content.

CHAPTER 3

METHODOLOGY

3.1 Research Methodology

Initially, this investigation was planned to be performed experimentally. Due to the unforeseen circumstances of broken-down PVT cell, simulation studies have been carried out instead, to understand the onset behaviour of asphaltenes over a range of pressure at reservoir temperature.

This study concerns with reservoir simulation investigation of light oil samples on asphaltenes precipitation during pressure depletion and CO_2 gas injection. Low asphaltenic light oil samples were chosen to investigate their Asphaltenes Onset Pressure (AOP). In addition, the precipitation onset condition induced by different CO_2 concentrations have been investigated over the pressure change as well.

3.1.1 Data Gathering

This simulation investigation was started by collecting the parameters and input data for four low asphaltenic light oil samples as well as one heavy oil sample for comparison purpose. The experimental asphaltene precipitation data for heavy oil was obtained from Burke *et al.*, (1990), while three light oil samples data were obtained from South China Sea fields (Zahidah *et al.*, 2001; Adyani *et al.*, 2011), and one light oil sample data was obtained from Iranian oilfield (Dahaghi *et al.*, 2006).

3.1.2 Simulation Modeling

The behavior of asphaltenes in both light and heavy oil was studied by using a compositional simulator known as the Computer Modeling Group (CMG) Ltd.. Static models (reservoir model & fluid characterization) was first built by WinProp package of CMG for modeling the phase behaviour and properties of oil samples. WinProp is a comprehensive equation of state engineering tool, which determines the reservoir characteristics and compositional variations of fluids for use with CMG's reservoir simulators. The Equation of State (EOS) applied in this simulation study is Peng-Robinson (PR 1978).

3.1.3 Asphaltene Precipitation Modeling

Asphaltene and Wax Precipitation Modeling is one of the features provided by WinProp package, which can be used to predict asphaltene precipitation weight percentage. WinProp has an EOS based quantitative model for multi-component description of a solid phase (asphaltene and wax) precipitation, which models the precipitate as a multi-component solid.

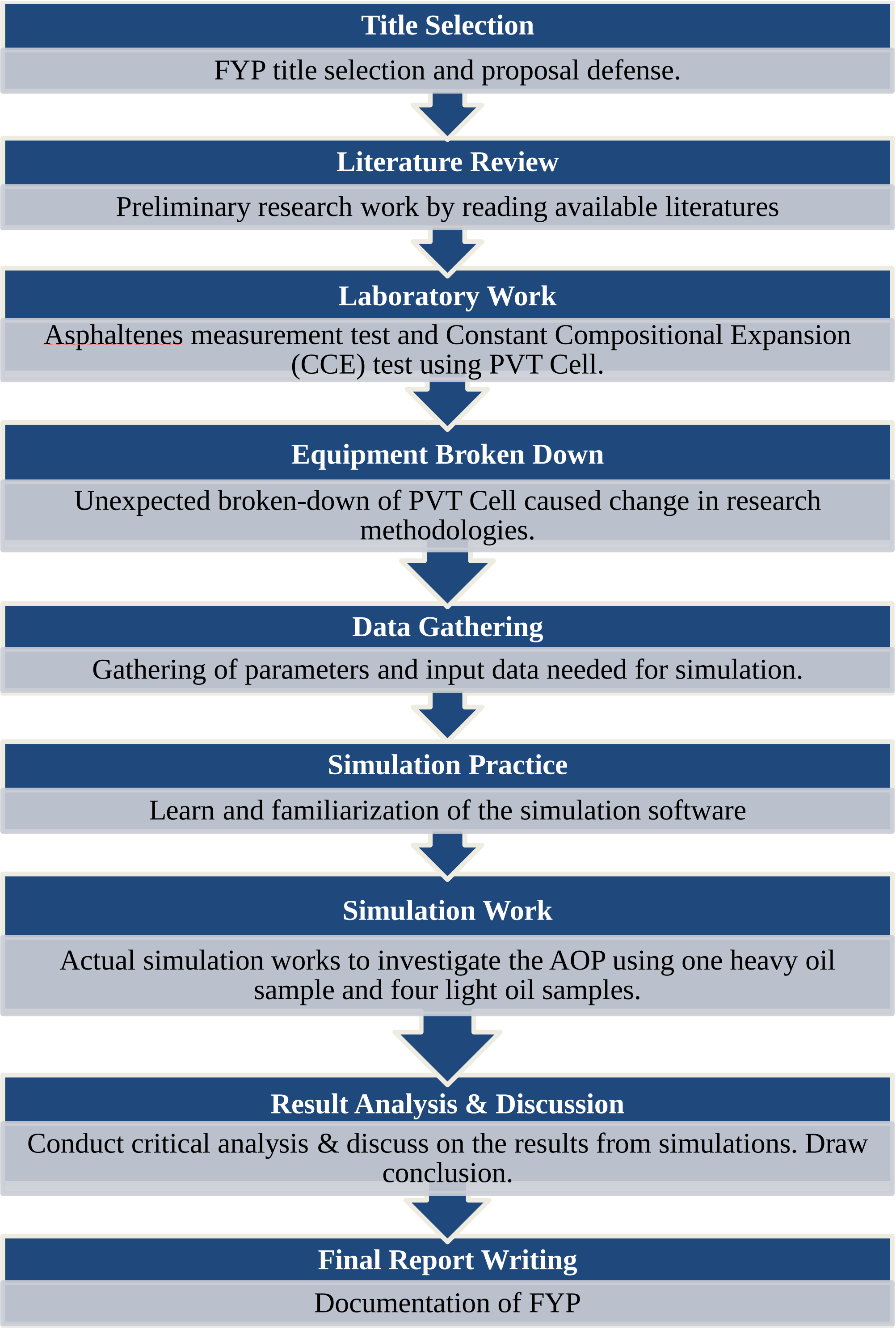
3.1.4 Carbon Dioxide Injection

After modeling the onset condition for base case oil sample, 20%, 40%, 60% and 80% CO_2 mole percentage were added to the base case oil sample to illustrate simulation of gas injection with different CO_2 concentration.

3.1.5 Asphaltene Content Measurement

To determine the weight percentage of asphaltenes in an oil sample, asphaltene separation method (ASTM D3279) have been performed on oil sample which asphaltene weight content was unknown. First, sample is dispersed in n-heptane and refluxed up to 30 minutes. After cooling to room temperature, it is filtered through a glass fiber pad. The insoluble materials will be washed, dried and weighted to get the mass percentage

3.2 Project Activities



Title Selection

FYP title selection and proposal defense.

Literature Review

Preliminary research work by reading available literatures

Laboratory Work

Asphaltenes measurement test and Constant Compositional Expansion (CCE) test using PVT Cell.

Equipment Broken Down

Unexpected broken-down of PVT Cell caused change in research methodologies.

Data Gathering

Gathering of parameters and input data needed for simulation.

Simulation Practice

Learn and familiarization of the simulation software

Simulation Work

Actual simulation works to investigate the AOP using one heavy oil sample and four light oil samples.

Result Analysis & Discussion

Conduct critical analysis & discuss on the results from simulations. Draw conclusion.

Final Report Writing

Documentation of FYP

3.3 Key Milestones

3.3.1 Key Milestones for Final Year Project 1 - Sept 2011

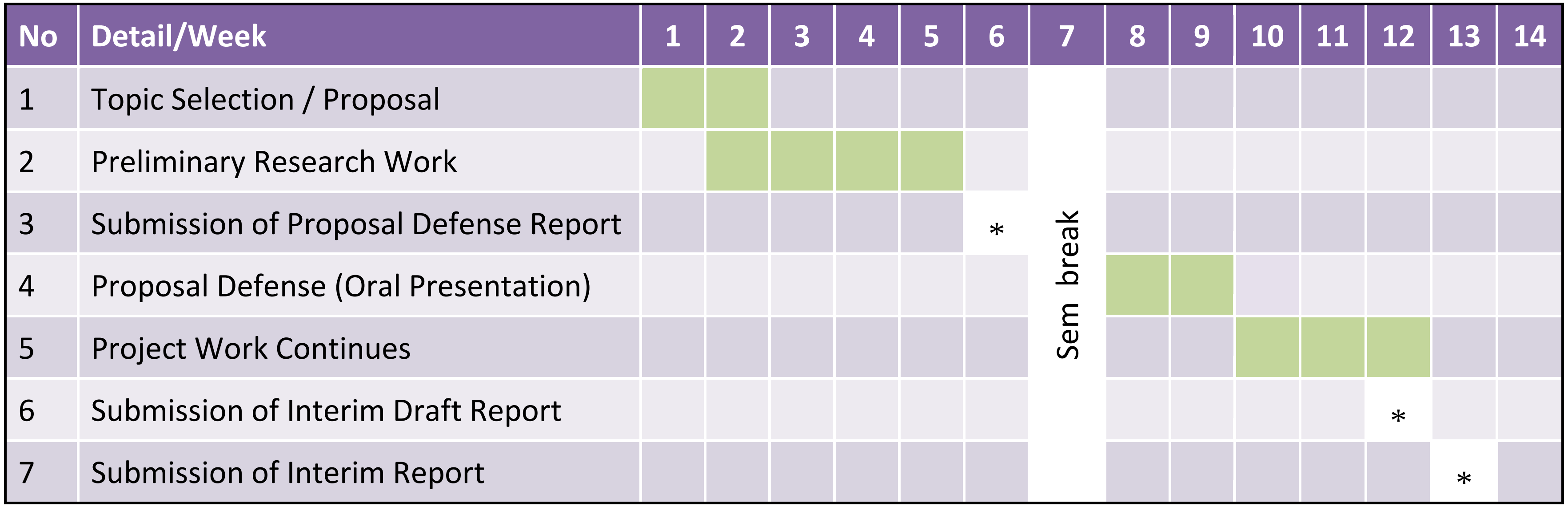
Milestone	Planned Timescale	Progress
Selection of FYP topic	Week 2	Completed
Prelim research work	Week 2 - Week 5	Completed
Submit Proposal Defense Report	3-Nov-11	Completed
Project Work (Literature Review)	Week 2 - Week 8	Completed
Proposal Defence Oral Presentation	Week 8 - Week 9	Completed
Project Work continues	Week 8 - Week 12	Completed
Fix Methodology	Week 9	Completed
Start Pre-Lab Preparation	Week 10 - Week 14	Completed
Submit Interim Report Final Draft	15-Dec-11	Completed
Oral Presentation	Week 13	Completed

3.3.2 Key Milestones for Final Year Project II - Jan 2012

Milestone	Planned Timescale	Progress
Briefing & Update on students progress	Week 3	Completed
Project Work continues	Week 1 - Week 8	Completed
Submit Progress Report	16-Mar-12	Completed
Project Work continues	Week 9 - Week 10	Completed
Pre-EDX (Seminar/Poster Exhibition)	Week 11	Completed
Submit Final Report (CD & soft bound)	16-Apr-12	Done
Final Oral Presentation	Week 14	
Submit Dissertation (hard bound)	11-May-12	

3.4 Gantt Chart

3.4.1 Gantt Chart for Final Year Project I - Sept 2011



No	Detail/Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	Topic Selection / Proposal	🟩	🟩					Sem break							
2	Preliminary Research Work		🟩	🟩	🟩	🟩									
3	Submission of Proposal Defense Report						*								
4	Proposal Defense (Oral Presentation)								🟩	🟩					
5	Project Work Continues										🟩	🟩	🟩		
6	Submission of Interim Draft Report												*		
7	Submission of Interim Report													*	

3.4.2 Gantt Chart for Final Year Project II - Jan 2012

No	Detail/Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1	Project Work Continues	🟩	🟩	🟩	🟩	🟩	🟩	Sem break									
2	Submission of Progress Report								*								
3	Project Work Continues									🟩	🟩						
4	Pre-EDX (Seminar/Poster)											*					
5	Submission of Dissertation (soft bound)													*			
6	Final Oral Presentation														*		
7	Submission of Dissertation (hard bound)																*

3.5 Tools Required

3.5.1 Software

The main software for this study is the Computer Modeling Group (CMG) compositional simulator. The license for this software is provided to Universiti Teknologi PETRONAS and available in the computer laboratory.

CMG COMPUTER MODELLING GROUP LTD.

3.5.2 Hardware

To determine the weight percentage of asphaltenes in an oil sample, laboratory experiment was conducted by using asphaltene content measurement apparatus, such as Erlenmeyer flask, magnetic stirrer, gooch crucible, filter pad, filter flask, filter tube, rubber tubing, as well as n-heptane solvent.

Figure 7 : Oil sample in n-heptane solvent inside Erlenmeyer flask

CHAPTER 4
RESULTS AND DISCUSSION

One heavy oil sample and four light oil samples have been chosen from the literature for simulation studies by using CMG compositional simulator software. The heavy oil sample is for comparison purpose, while three light oil samples from South China Sea (SCS) fields and one light oil sample from Iranian field have been selected to investigate the subject. Data gathering, results analysis and discussion are shown as below.

4.1 Data Gathering & Analysis

Initially, the experimental work was carried out by using recombined oil sample from one of the South China Sea field. Due to the unexpected broken down of PVT cell, this research was resumed with simulation studies. From previous laboratory survey and literature review (Burke *et al.*, 1990; Zahidah *et al.*, 2001; Adyani *et al.*, 2011; Dahaghi *et al.*, 2006), five oil samples have been selected as shown in table 1 below. To determine the unknown asphaltene weight percentage of the oil sample SCS oil 2, asphaltenes measurement test has been carried out in laboratory, and defined as 0.12 wt%.

Table 1: Oil properties for five oil samples chosen for simulation studies

Oil Properties	**Oil Samples**				
	Heavy Oil *	**SCS Oil 1**	**SCS Oil 2**	**SCS Oil 3**	**Iran Oil**
^{o} API Gravity	19.0	41.5	37.8	41.4	34.3
Asphaltene wt%	16.8	0.117	0.12	0.07	0.66
Reservoir Temperature (^{o}F)	212	204	215	204	160
Reservoir Pressure (psia)	N/A	3008	1815	2915	6000

**Heavy oil for comparison purpose*

Table 2 : Composition (mol%) of oil sample used in investigation

Oil Composition	**Oil Sample**				
	Heavy Oil *	**SCS Oil 1**	**SCS Oil 2**	**SCS Oil 3**	**Iran Oil**
CO2	2.46	0.44	20.74	0.46	3.71
N2	0.57	0.22	0.11	0.11	0.10
H2S	0.00	0.00	0.00	0.00	1.85
CH4	36.37	40.28	15.06	36.81	46.53
C2H6	3.47	4.83	3.01	5.61	8.76
C3H8	4.05	5.73	2.71	6.67	4.98
IC4	0.59	1.54	1.03	1.68	0.93
NC4	1.34	2.76	0.85	2.91	2.39
IC5	0.74	1.54	0.42	1.44	0.86
NC5	0.83	1.44	0.28	1.30	1.06
FC6	1.62	2.59	2.92	2.55	2.64
FC7			2.83	4.42	2.73
FC8			1.29	6.83	1.31
FC9			2.47	4.05	2.19
FC10			2.36	3.50	1.67
FC11				2.68	1.52
C12				2.16	
C13				2.42	
C14				2.42	
C15				2.29	
C16				1.49	
C17				1.34	
C18				1.45	
C19				0.87	
	C7+ 47.96	C7+ 38.63	C11+ 43.92	C20+ 4.54	C12+ 16.77
C+ MW	329	153.12	189.85	339.41	260
C+ SG	0.9594	0.78	0.836	0.895	0.8861
Oil MW	171.4	76.73	111.41	87.53	81

Using the parameters and input data as from the literature, asphaltene precipitation model for each oil sample has been generated based on Peng-Robinson (1978) Equation of State (EOS) as provided by WinProp package of CMG's simulator software. As shown in Appendices, two-phase (Pressure-Temperature) diagram and asphaltenes precipitated weight percentage vs. pressure graph have been plotted with the simulator.

By using the feature of Asphaltene and Wax Precipitation Modeling as provided by WinProp package, asphaltene precipitation weight percentage over pressure change is predicted based on the EOS based quantitative model. Asphaltene precipitation is modelled as a multi-component solid, which is later tuned with its binary interaction coefficient with other hydrocarbon components, as well as its molar volume, in order to generate the ideal graph shape as a “bell shape”.

P-T diagram and graph Asphaltenes Precipitated wt% vs. Pressure have been generated for five oil samples over five different CO_2 mole% gas injection. Appendix-A presented graph for Heavy Oil as for comparison purpose, Appendix-B, C and D consist of graph for SCS Oil 1, SCS Oil 2 and SCS Oil 3, respectively. While Appendix-E shows graph for Iranian Oil.

As shown on the right side in appendices, all the graph of asphaltenes precipitated wt% vs. pressure have been tuned in order to present the best “bell shape” to predict their asphaltenes onset condition. According to Nghiem’s APE model (1999) as shown in figure 5, asphaltenes onset pressure is bounded within the upper and lower of the shaded region. Thus, in graph asphaltenes precipitated wt% vs. pressure, the points where asphaltenes start to precipitate from zero weight percentage is defined as the Asphaltenes Onset Pressure (AOP), whereby the higher AOP is described as the “Upper AOP” while the lower one is defined as the “Lower AOP”.

Upon pressure depletion, asphaltenes start to precipitate when the van der Waals bonds within asphaltenes colloidal model become weaker, in addition to the change in fluid properties which disturb the stability of asphaltene-resin micelles (Hirschberg *et al.*, 1984; Alta’ee *et al.*, 2010). At or very near to the bubble-point pressure, the graph shows maximum precipitated weight percentage of asphaltenes, which is in accordance with the findings of Kokal and Sayegh, (1995), Hammami *et al.*, (2000), Afshari *et al.*, (2010), and Alta’ee *et al.*, (2010) who have claimed that asphaltenes precipitation reaches maximum at bubble-point pressure. After crossing bubble-point pressure, evaporization of lighter hydrocarbon fraction reestablishes the lost asphaltenes solubility (Kokal and Sayegh, 1995; Hammami *et al.*, 2000; Afshari *et al.*, 2010). When asphaltenes redissolve back to the oil, amount of precipitated decreases. Thus, the "bell shape" graph generated has portrayed asphaltenes precipitation phenomenon as described.

On the other hand, the P-T diagram as shown in appendices has been generated to find out the bubble-point pressure at reservoir temperature. For the additional CO_2 mole percentage to illustrate gas injection at different CO_2 concentration, both the graph have been generated for 20%, 40%, 60% and 80% CO_2 mole% gas injection.

4.2 Results and Discussion

The results from the graph in Appendices have been summarized in tables then presented in Pressure-Compositional Diagram as below, whereas the graph of Asphaltenes Precipitated wt% vs. Pressure for different CO_2 mole% gas injection as shown in appendices have been combined to investigate their relationship.

4.2.1 Heavy Oil

Table 3 : P_b, Lower and Upper AOP for different CO_2 mole% injection at reservoir temperature (212^{o}F) for Heavy Oil sample

Injected CO_2 (mole%)	**Pb (psia)**	**Lower AOP (psia)**	**Upper AOP (psia)**
0%	3044	3000	3100
20%	4000	3800	4200
40%	5000	4800	5200
60%	6002	5800	6200
80%	7365	7400	7800

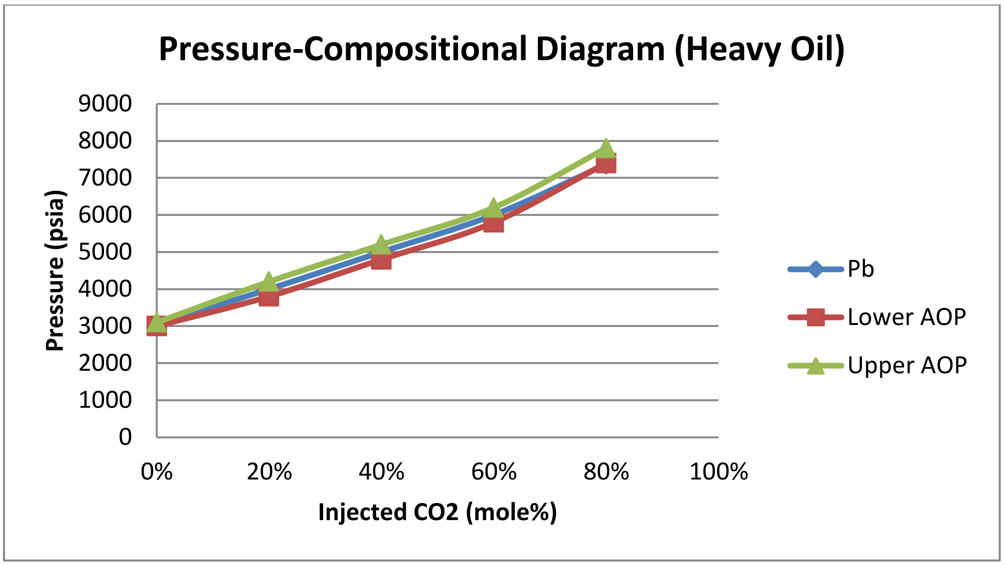


Figure 8 : Pressure-Compositional Diagram at 212°F for Heavy Oil sample

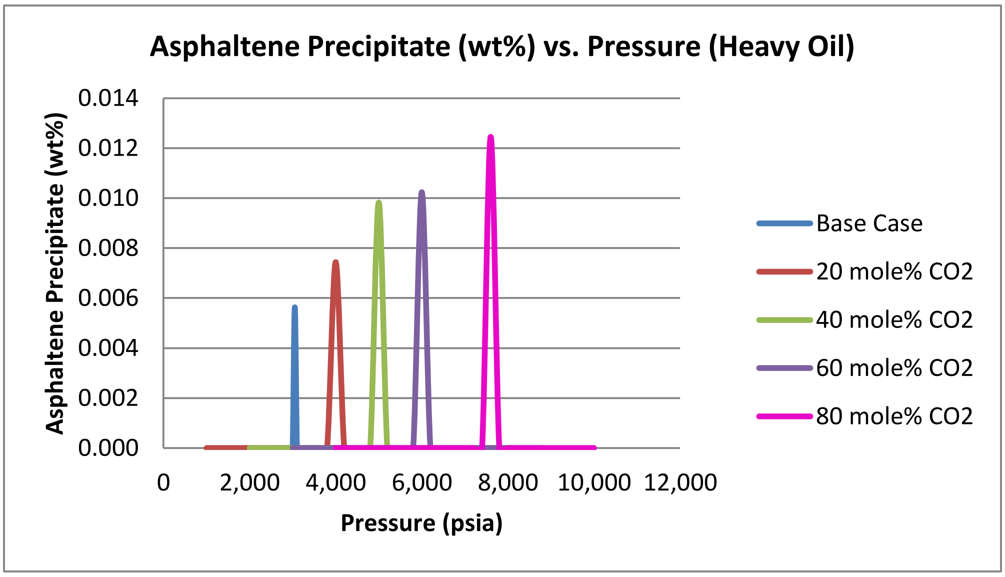


Figure 9 : Asphaltene precipitated wt% vs. Pressure at 212°F for Heavy Oil

As shown in table 2 and figure 8, bubble-point pressure is always in between the upper and lower AOP. Additional CO_2 mole% gas injection increases the bubble-point pressure, and thus raises up the upper and lower AOP values, i.e., AOP region is shifted upwards. According to figure 9, during depressurization at reservoir temperature (212°F), asphaltenes start to precipitate when approaching bubble-point region, the maximum precipitated weight percentage happened at or very near to the bubble-point pressure. After that, precipitation reduces with decreasing pressure.

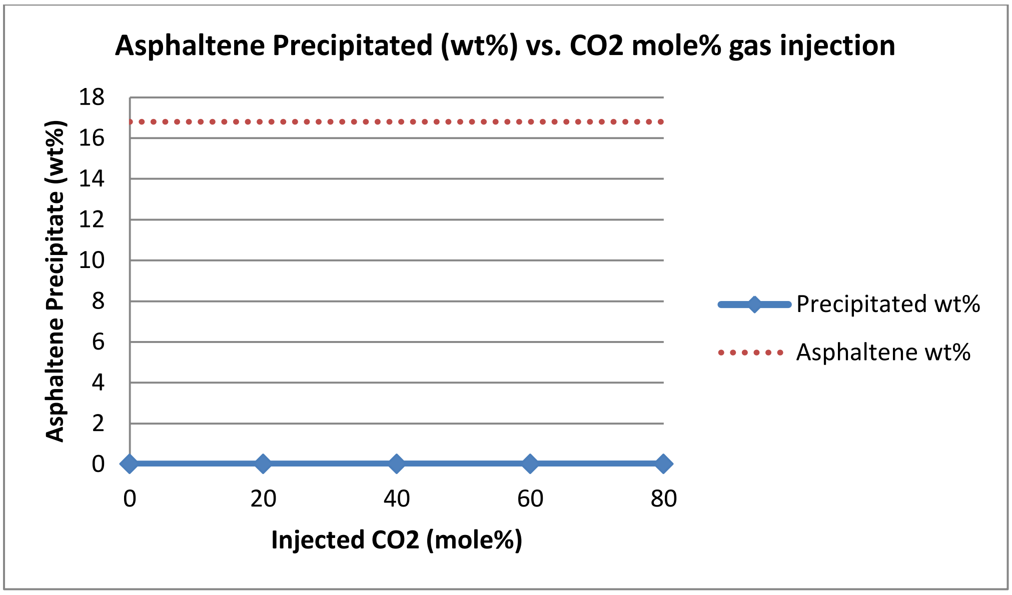


Figure 10 : Asphaltene precipitated wt% vs. Injected CO_2 mole% at 212°F for Heavy Oil

Figure 10 shows precipitated weight percentage of asphaltenes in different CO_2 mole% gas injection, as compared to its original asphaltenes weight percentage as indicated by the dotted red line above. This figure displayed that the fraction of precipitated asphaltenes out of its total asphaltenes wt% in heavy oil is very small. Heavy oil often have a high asphaltene content but this does not necessarily mean that the risk of asphaltene precipitation is high. This has also illustrated why the Venezuelan Boscan heavy crude oil with 17.2-wt% asphaltenes was produced nearly trouble-free.

4.2.2 SCS Oil 1

Table 4 : P_b, Lower and Upper AOP for different CO_2 mole% injection at reservoir temperature (204°F) for SCS Oil 1

Injected CO_2 (mole%)	Pb (psia)	Lower AOP (psia)	Upper AOP (psia)
0%	2645	1300	3900
20%	2800	1400	4400
40%	3032	1400	5600
60%	3360	1500	6900
80%	3884	1500	7100

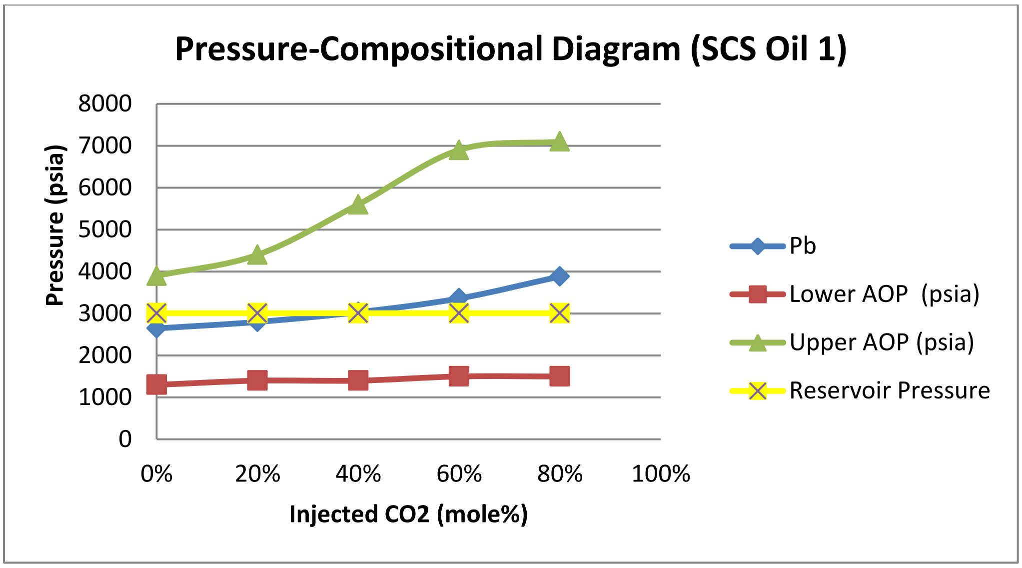


Figure 11 : Pressure-Compositional Diagram at 204°F for SCS Oil 1

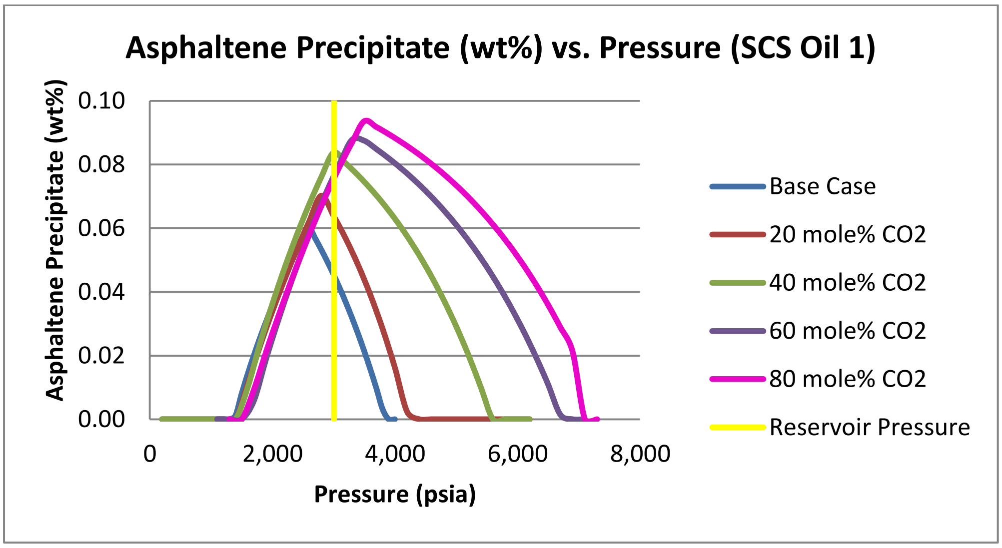


Figure 12 : Asphaltene precipitated wt% vs. Pressure at 204°F for SCS Oil 1

Similar to the heavy oil, bubble-point pressure for SCS Oil 1 is getting higher with increasing mole% of CO_2 gas injected as shown in figure 11. Whereas the asphaltenes onset region is distributed around its bubble-point pressure, and bounded by upper and lower Asphaltenes Onset Pressure (AOP). Figure 12 shows that with additional CO_2 mole% injected, the amount of precipitated asphaltenes is increasing.

In SCS oilfield 1, the reservoir pressure is denoted by the yellow line. By assuming good work in initial reservoir pressure maintenance, both figure 11 and 12 indicate that SCS oil 1 reservoir would be affected by asphaltenes precipitation problem from before CO_2 gas injection up to 80 mole% of CO_2 gas injection, as its reservoir pressure is sat within the AOP region in figure 11 and within all five "bell" in figure 12.

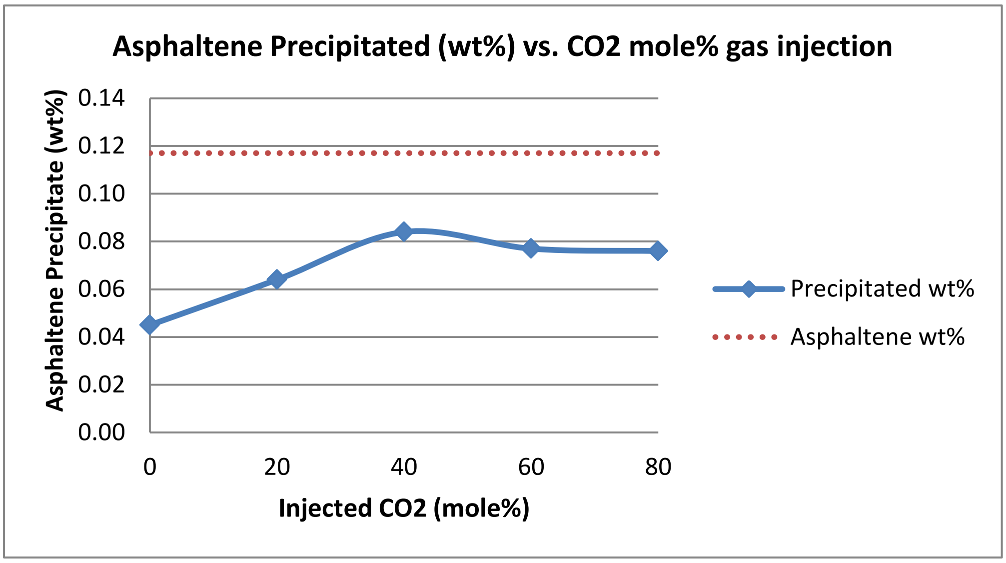


Figure 13 : Asphaltene precipitated wt% vs. Injected CO_2 mole% at reservoir condition (204°F and 3008psia) for SCS Oil 1

As shown in figure 13, at reservoir pressure and temperature as prescribed, asphaltenes precipitation occurred from zero up to 80 mole% CO_2 gas injection, while it reaches maximum near 40 mole%.

4.2.3 SCS Oil 2

Table 5 : P_b, Lower and Upper AOP for different CO_2 mole% injection at reservoir temperature (215°F) for SCS Oil 2

Injected CO_2 (mole%)	**P_b (psia)**	**Lower AOP (psia)**	**Upper AOP (psia)**
0%	1872	900	2700
20%	2552	1200	3800
40%	3294	1800	4600
60%	4186	2600	5500
80%	5297	4300	6200

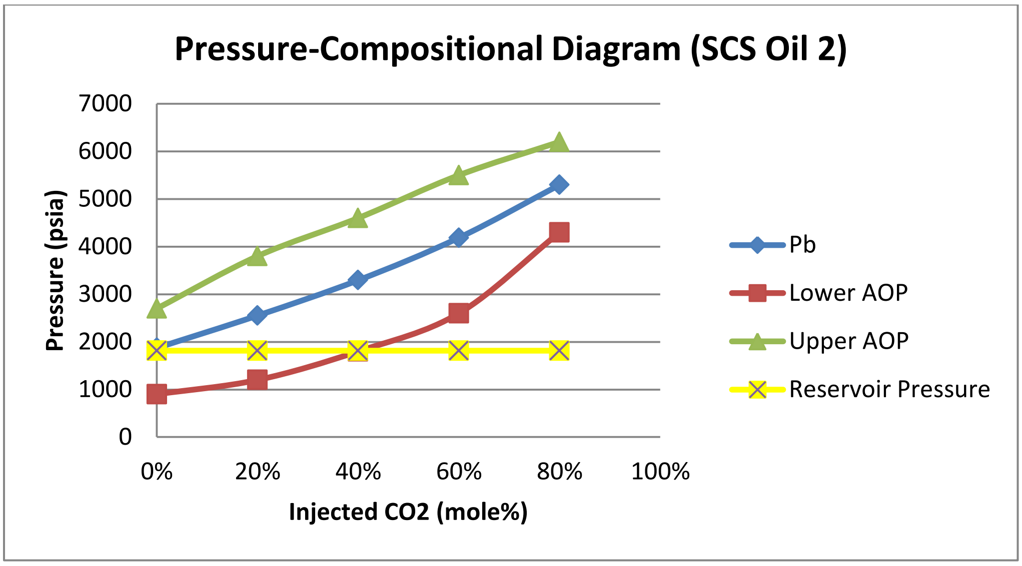


Figure 14 : Pressure-Compositional Diagram at 215^{o}F for SCS Oil 2

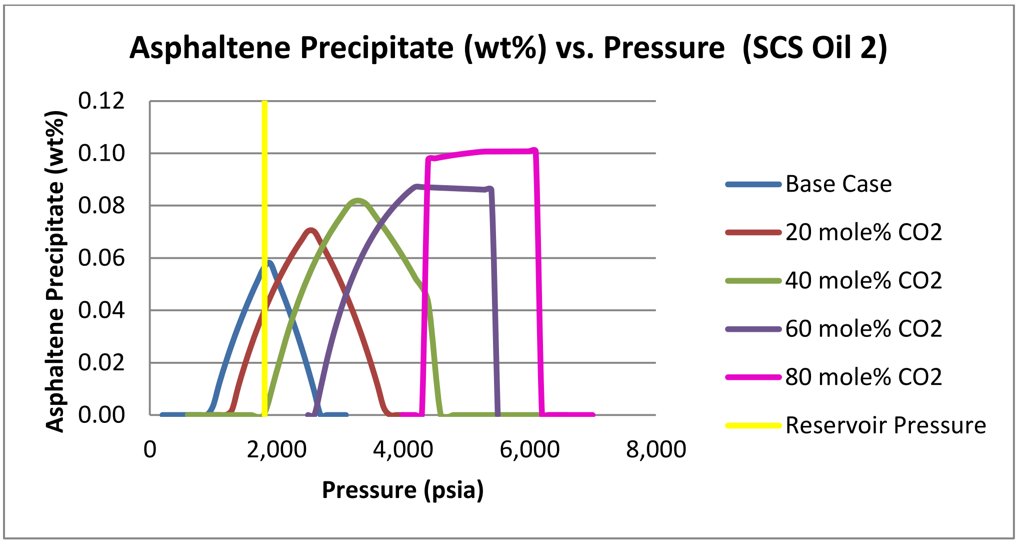


Figure 15 : Asphaltene precipitated wt% vs. Pressure at 215^{o}F for SCS Oil 2

Similar to the trend as shown in SCS oil 1, bubble-point increases with increasing CO_2 mole% injected, while the lower and upper AOP is bounded within the bubble-point pressure, as shown in figure 14. Figure 15 indicated that asphaltenes precipitation getting higher with increasing CO_2 mole%.

At reservoir pressure and temperature in SCS oilfiled 2, both figure above show that asphaltenes precipitation problem takes affect from zero CO_2 mole% up to 40 mole% gas injection. In other words, at CO_2 gas injection more than 40 mole%, AOP region is beyond the reservoir temperature and pressure zone.

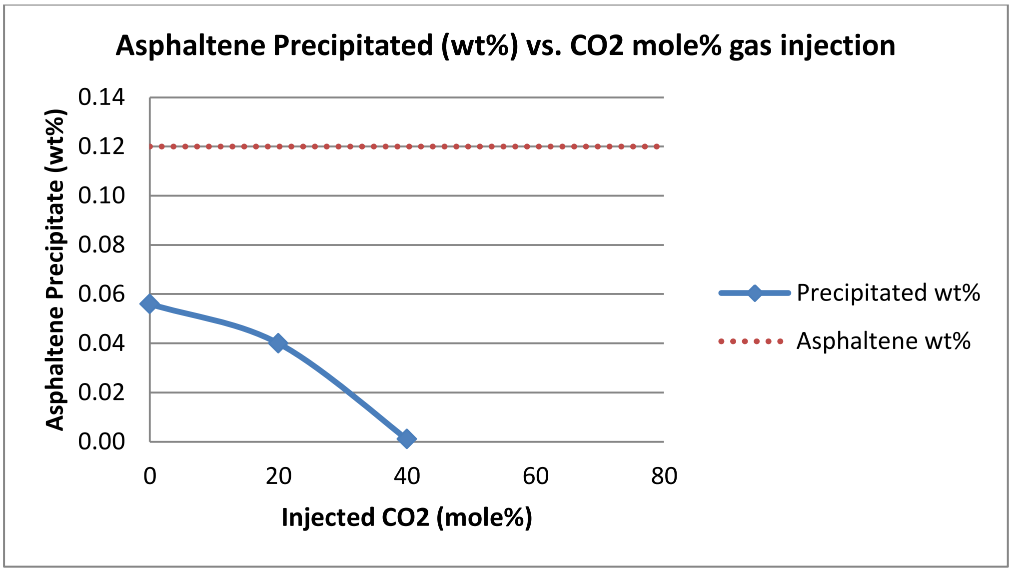


Figure 16 : Asphaltene precipitated wt% vs. Injected CO_2 mole% at reservoir condition (215°F and 1815psia) for SCS Oil 2

As shown in figure 16, at reservoir pressure and temperature as prescribed, asphaltenes precipitation occurred only from zero to 40 mole% CO_2 gas injection, with decreasing precipitated amount over increasing CO_2 gas injection until 40 mole%, where precipitation stops.

4.2.4 SCS Oil 3

Table 6 : P_b, Lower and Upper AOP for different CO_2 mole% injection at reservoir temperature (204°F) for SCS Oil 3

Injected CO_2 (mole%)	**P_b (psia)**	**Lower AOP (psia)**	**Upper AOP (psia)**
0%	2333	1200	3600
20%	2807	1600	4100
40%	3066	1800	4800
60%	3476	2000	5800
80%	3741	2400	6800

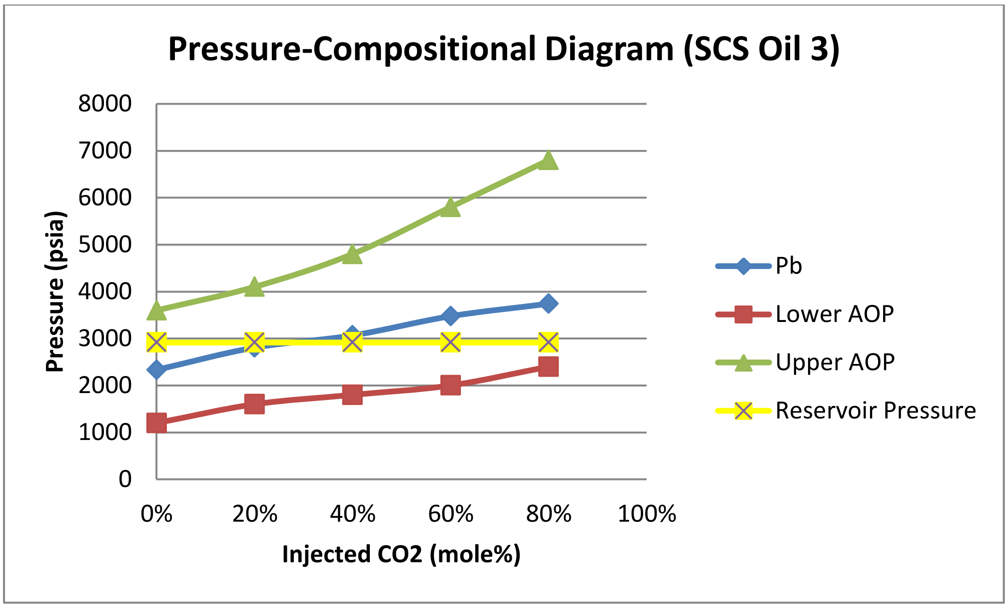


Figure 17 : Pressure-Compositional Diagram at 204°F for SCS Oil 3

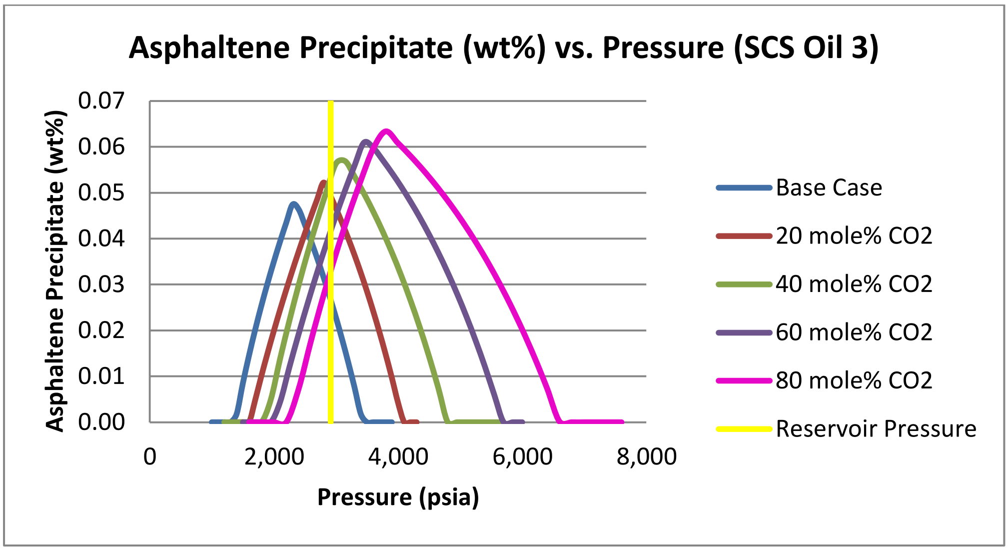


Figure 18 : Asphaltene precipitated wt% vs. Pressure at 204°F for SCS Oil 3

Similar to the trend as shown before, figure 17 and figure 18 show that increasing CO_2 mole% injected raises up the bubble-point pressure, and thus shifts up the AOP region, whereby increasing asphaltenes precipitated amount.

As denoted by the yellow line as reservoir pressure, it has been observed that asphaltene precipitation happened from zero mole% up until 80 mole% crossing reservoir pressure.

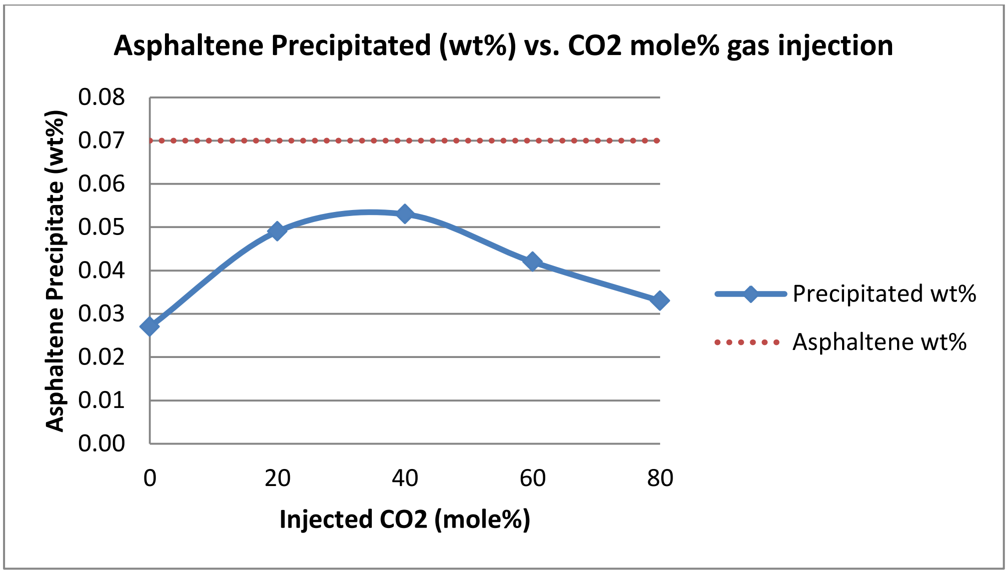


Figure 19 : Asphaltene precipitated wt% vs. Injected CO_2 mole% at reservoir condition (204°F and 2915psia) for SCS Oil 3

As shown in figure 19, at reservoir pressure and temperature as prescribed, asphaltenes precipitation occurred from zero up to 80 mole% CO_2 gas injection, while it reaches maximum while increasing from 20 to 40 mole%.

4.2.5 Iranian Oil

Table 7 : P_b, Lower and Upper AOP for different CO_2 mole% injection at reservoir temperature (160°F) for Iranian Oil sample

Injected CO_2 (mole%)	P_b (psia)	Lower AOP (psia)	Upper AOP (psia)
0%	3722	1400	6000
20%	4130	1500	6500
40%	4657	1800	6800
60%	5154	2000	7500
80%	5594	2000	7750

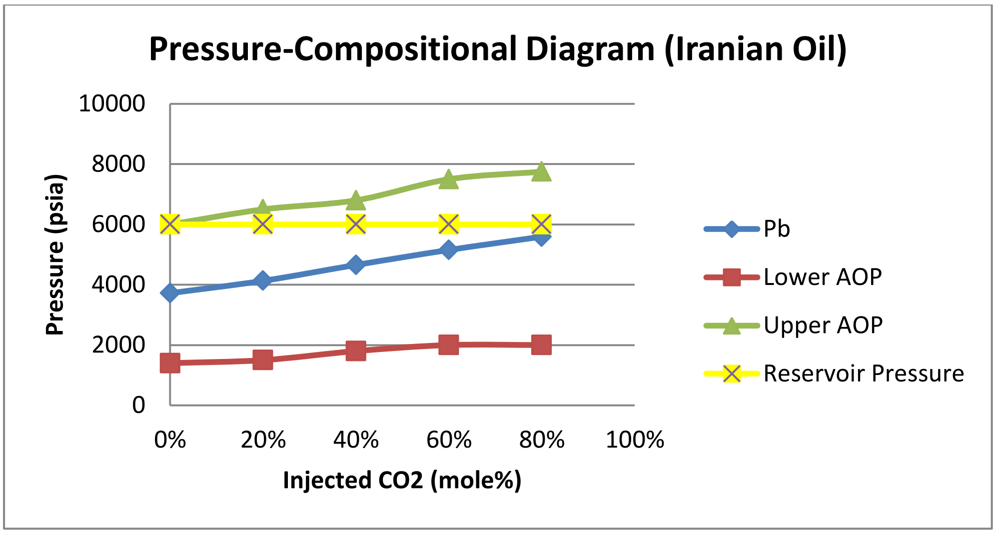


Figure 20 : Pressure-Compositional Diagram at 160°F for Iranian Oil sample

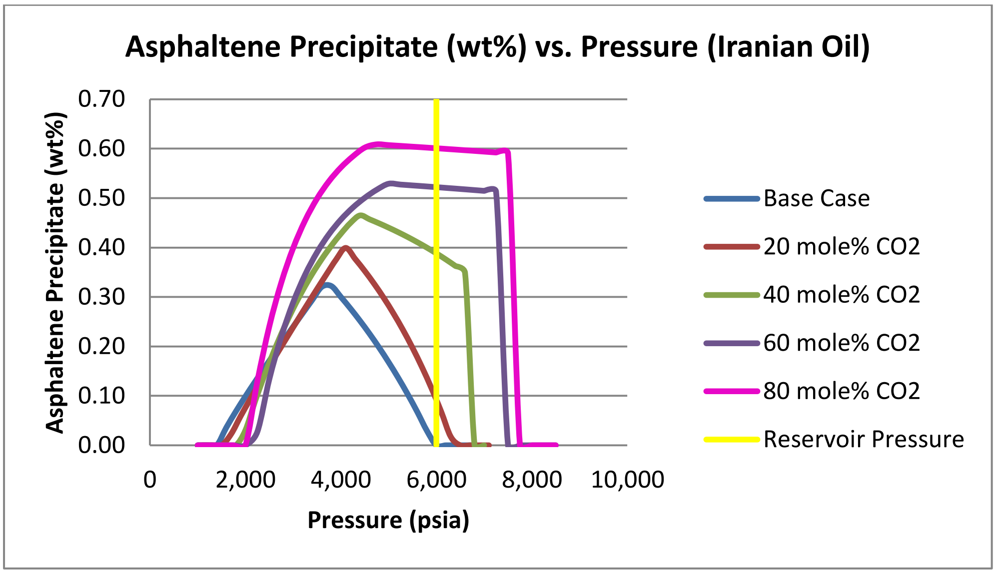


Figure 21 : Asphaltene precipitated wt% vs. Pressure at 160°F for Iranian Oil

Though the reservoir temperature for Iranian oil is comparatively lower than those previous oil samples, figure 20 and 21 show that the trend of increasing CO_2 mole% injection still follow the same as all previous oil samples. Similar to SCS Oil 2, both figure 15 and 21 show that at higher CO_2 mole%, the ideal “bell shape” graph might be harder to be achieved for CO_2 gas injected more than 40 mole%. This indicates that the extreme portion of compositional change might cause asphaltenes onset behaviour to be slightly different.

As denoted by the yellow line as reservoir pressure, it has been observed that asphaltene precipitation happened starting from zero mole% up until 80 mole%

crossing reservoir pressure. The precipitation condition is further shown as in figure 22 below.

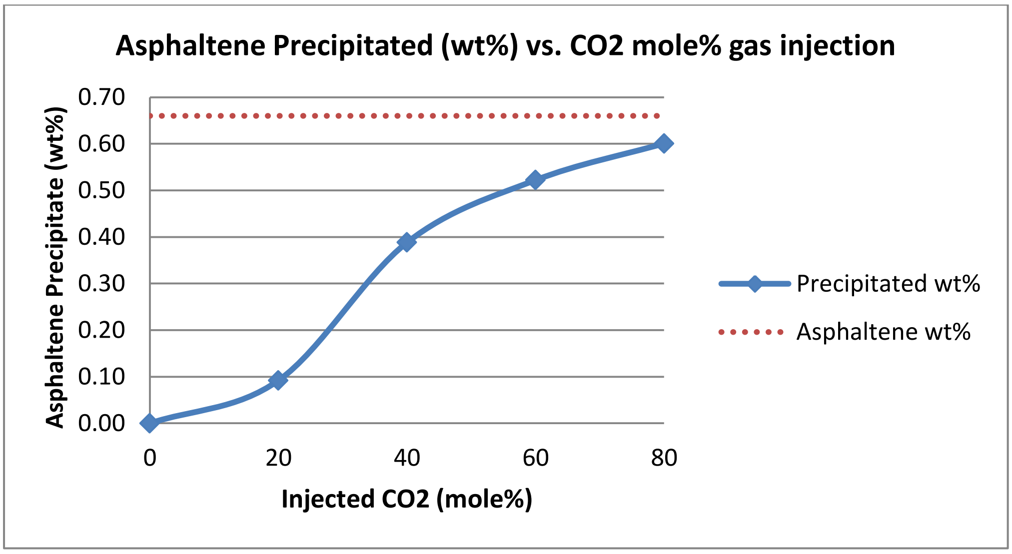


Figure 22 : Asphaltene precipitated wt% vs. Injected CO_2 mole% at reservoir condition (160°F and 6000psia) for Iranian Oil

From zero mole% CO_2 gas injection, asphaltenes precipitation started and continued to increase until 80 mole% CO_2 injection. This has shown that at reservoir temperature and pressure, the higher CO_2 mole% gas injection, the more asphaltenes precipitated in the reservoir.

In review of the results of simulation studies above, all five oil samples have shown the same trend, which indicated that asphaltenes onset region is distributed around the bubble-point pressure, and bounded by upper and lower AOP. During depressurization, asphaltenes start to precipitate from upper AOP and cease precipitation after crossing lower AOP, where maximum precipitation happened at or very near to bubble-point pressure. By additional mole% of CO_2 injected, bubble-point pressure increases and shifts up AOP region, and more asphaltenes are precipitated with increasing CO_2 mole%.

As compared the results obtained from heavy oil sample to the four light oil samples, the AOP region as bounded in heavy oil is comparatively smaller. The pressure range for asphaltenes precipitation is much shorter in heavy oil, as compared to the AOP range in light oil. By comparing the graph of asphaltene precipitated wt% vs. injected CO_2 mole% (figure 10 vs. figure 13, 16, 19 & 22) at reservoir temperature and reservoir pressure, heavy oil has shown extremely small fraction of precipitated asphaltenes out of its total asphaltenes wt% as indicated in figure 10. Whereby the same graph as generated by other light oil samples show almost half portion or more of the precipitated asphaltenes out of their total asphaltenes weight content.

This results show that heavy oil has lower impact towards asphaltenes precipitation, which gives much smaller onset region, causing its influence towards asphaltenes precipitation becomes insignificant. As heavy oil consists of higher Aromatic-Saturate ratio and Resin-Asphaltene ratio, it becomes a good solvent to stabilize asphaltenes in micelles form in oil (Kokal and Sayegh, 1995, Sarma, 2003, Akbarzadeh *et al.*, 2007; Alta'ee *et al.*, 2010).

In contrast, due to the limited resin content and abundance lighter component in light oil, asphaltenes behave less stable in light oil. Thus, SCS oil 1, 2, 3 and Iranian light oil samples become more easily to precipitate asphaltenes, and take longer pressure range to redissolve asphaltenes solid back to the light oil as compared to heavy oil. These results have clearly shown that even though it is low in asphaltenes content, light oil reservoir is always associated with the tendency of asphaltenes precipitation risk (Kokal and Sayegh, 1995; Akbarzadeh, 2007; Alta'ee *et al.*, 2010).

Additional CO_2 gas injection has altered the oil composition, contributing higher bubble-point pressure as well as asphaltenes onset pressure region. This compositional change also favors the precipitation of asphaltenes (Kokal and Sayegh, 1995; Sarma, 2003; Srivastava and Huang, 1997). Injected CO_2 which is in contact with light oil induced vaporizing gas drive process, where CO_2 gas vaporizes part of the light and intermediate components to the gas phase, results in the loss of intermediate components (C_{3+}) as well as resins in reservoir fluids (Green and Willhite, 1998). Hence, the more CO_2 mole% injected, the more loss in vaporized intermediate components and resins, which causes higher amount of asphaltenes precipitation.

By assuming isothermal reservoir condition, the initial reservoir pressure is denoted as the yellow straight line crossing the graph. It has been observed that at reservoir temperature and pressure, the amount of asphaltenes precipitated may vary from before CO_2 gas injection up until increment to 80 mole% injection, as shown in figure 13, 16, 19 and 22. Besides, the trend of the graph is different from sample to sample.

For SCS oil 1 and 3 as portrayed by figure 13 and 19, both graph have shown the similar trend of precipitated asphaltenes amount over the compositional change at reservoir pressure and temperature. Their precipitated asphaltenes amount is increasing from 0 mole% CO_2 gas injection up to 40 mole%, then it decreases with additional mole% of CO_2. This similarity is due to the similar oil properties and reservoir condition as exhibited by SCS oil sample 1 and 3.

For SCS oil 2 as shown in figure 14, there is a huge increment in bubble-point pressure by adding more CO_2 mole%. Thus, from 40 mole% CO_2 gas injection onwards, reservoir pressure has become so much lower than the bubble-point pressure. This condition is pretty much similar with the scenario of Ula Field in Norway, where the bubble-point pressure is far away from its reservoir pressure.

As illustrated in figure 16, due to the formation of AOP region beyond its reservoir temperature and pressure zone, precipitated asphaltenes amount is decreasing with additional CO_2 gas injection, and ceases precipitation after 40 mole% and more. The main reasons for this phenomena are because of the comparatively lower reservoir pressure, plus the large increment in bubble-point pressure over additional CO_2 gas concentration, as compared to SCS oil 1 and 3.

As opposed to reservoir condition in South China Sea, the reservoir temperature and pressure in Iranian oilfield is quite different. In terms of the oil samples selected for this research, in South China Sea, reservoir temperature usually range above 200^{o}F, and reservoir pressure usually range within 1800 to 3000 psig; while the reservoir temperature and pressure for the Iranian field are 160^{o}F and 6000 psia.

As the bubble-point pressure for Iranian oil is comparatively much lower than its reservoir pressure, by assuming good work in pressure maintenance, asphaltenes might or might not be precipitated in virgin oil. When CO_2 concentration increases, AOP region is shifted up, thus the reservoir condition has gone within the trouble zone for asphaltenes precipitation. As shown in figure 22, the amount of precipitated asphaltenes is increasing with additional CO_2 gas injection up until 80 mole%.

When planning for reservoir management strategy, it is crucial to know the initial temperature and pressure in reservoir condition, as well as the bubble-point pressure, prior to designing field development operation as to mitigate asphaltenes precipitation problem in reservoir.

For the scenario of SCS oil 1 and 3, the zone where maximum asphaltenes precipitation is when CO_2 gas injection approaching 40 mole%. Thus, this area should be avoided to reduce asphaltenes precipitation problem. This scenario is based on good pressure and temperature maintenance in reservoir condition.

On the other hand, for the case of SCS oil 2, it has been simulated that asphaltenes precipitation no longer takes effective with CO_2 gas injection more than 40 mole%. So, it might be problem free if CO_2 gas injection is above 40 mole% at such reservoir condition.

As for the case of Iranian oil, it seems that the problem of asphaltenes precipitation is mininal at the original oil composition. Yet if natural pressure depletion occurred, asphaltenes precipitation becomes problem in reservoir as well. Hence, this oilfield might not be recommended to have CO_2 gas injection scheme at such reservoir pressure and temperature.

By investigating asphaltenes onset pressure for a reservoir oilfield over different mole% of CO_2 gas injection, optimum scheme for CO_2 gas injection could be designed in order to minimize problem of asphaltenes precipitation and deposition in reservoir.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

The results of this study have shown the tendency of asphaltenes precipitation in low asphaltenic light oil reservoirs with different mole percentage of CO_2 gas injection. After data analysis and discussion in previous chapter, the results are concluded as below:

1. Asphaltenes Onset Pressure (AOP) is surrounding the bubble-point pressure, as bounded within asphaltene precipitation region range between the upper AOP and lower AOP.

2. Amount of precipitated asphaltenes increases when approaching bubble-point pressure, where it reaches maximum at or very near to bubble-point pressure.

3. With addition to injected CO_2 mole%, bubble-point pressure increases, and thus shifting up AOP region, whereby the amount of maximum precipitated asphaltenes increases with more CO_2 mole% injected near bubble-point pressure.

4. At specific reservoir temperature and pressure, the amount of precipitated asphaltenes in different CO_2 gas injection scheme (mole%) vary from one field to another field.

5. For the case of SCS oil 1 and 3, CO_2 gas injection near 40 mole% should be avoided. Besides, reservoir management scheme should be taken into account for handling asphaltenes precipitation problem in such reservoir condition.

6. SCS oil 2 reservoir is free from asphaltenes precipitation when it is produced at CO_2 gas injection higher than 40 mole%.

7. Iranian oil is not recommended for CO_2 gas injection scheme to avoid asphaltenes precipitation.

By understanding the asphaltene onset trend behaviour of light oil in reservoir condition over different CO_2 gas injection scheme, the author concluded that the findings from this study can be applied as criteria for designing successful reservoir management strategy. To avoid the asphaltenes onset region, pressure maintenance scheme should be planned and manipulated prior to oil production. Therefore, asphaltenes precipitation problem could be mitigated, and thus minimizing technical uncertainties and economical losses in light oil reservoir.

5.2 Limitation & Recommendation

Part of the input parameters used in this investigation were based on EOS calculation and estimation as generated by CMG simulator. Hence, this might need further verification by experimental measurement in laboratory, such as Constant Compositional Expansion (CCE) test with Solid Detector System (SDS). Thus, more detailed laboratory work is recommended to gain more accurate input data for this simulation studies.

Observation from laboratory work has shown that part of the flocculated asphaltenes cannot be redissolved back to the oil and remained insoluble at the end of CCE test. Yet, CMG asphaltenes precipitation model has assume complete reversibility of solubility for asphaltenes, whereby there is zero precipitation at pressure below Lower AOP. Therefore, the author suggested that the flocculated amount of asphaltenes collected from laboratory experimental survey, which can no longer be redissolved back to oil, should be considered as well.

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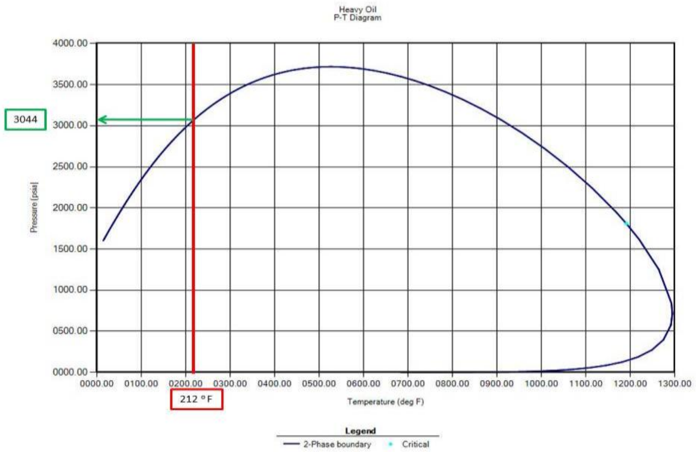
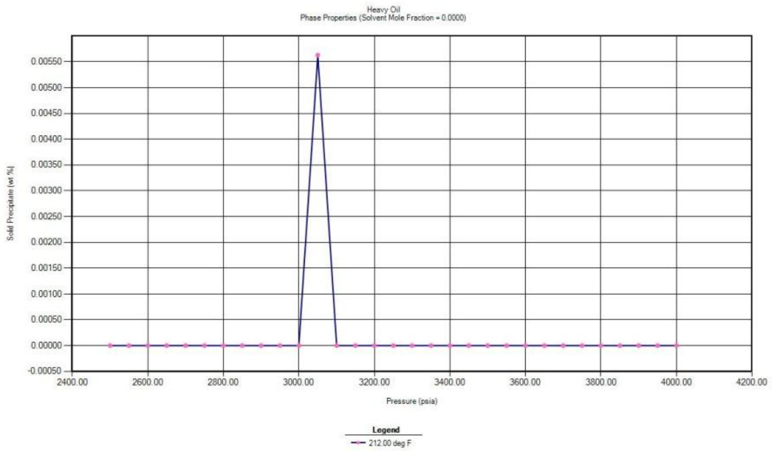
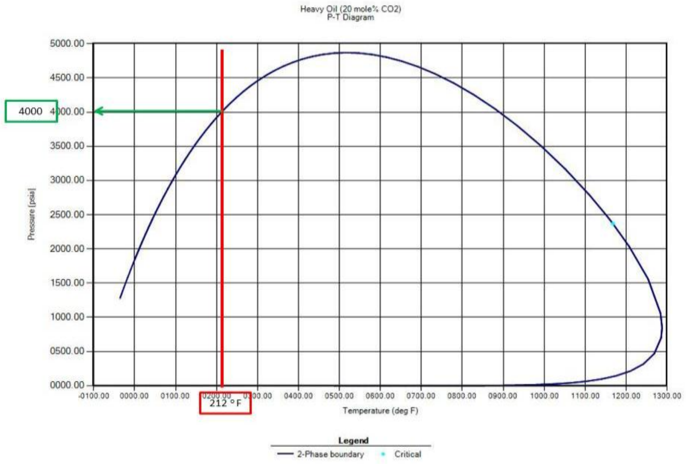
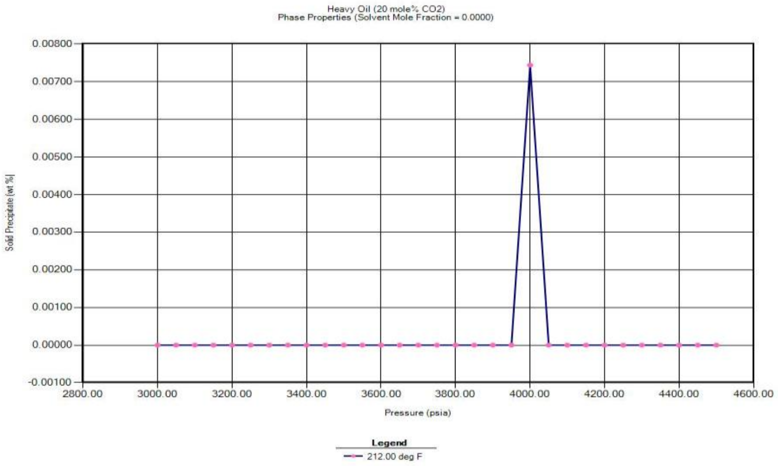
APPENDICES

APPENDIX – A :	Graph for Heavy Oil
APPENDIX – B :	Graph for South China Sea (SCS) Oil 1
APPENDIX – C :	Graph for South China Sea (SCS) Oil 2
APPENDIX – D :	Graph for South China Sea (SCS) Oil 3
APPENDIX – E :	Graph for Iranian Oil

APPENDIX – A1

P-T DIAGRAM FOR HEAVY OIL	ASPHALTENE PRECIPITATION PRESSURE FOR HEAVY OIL
 Base Case	
 20 mole% CO_2	

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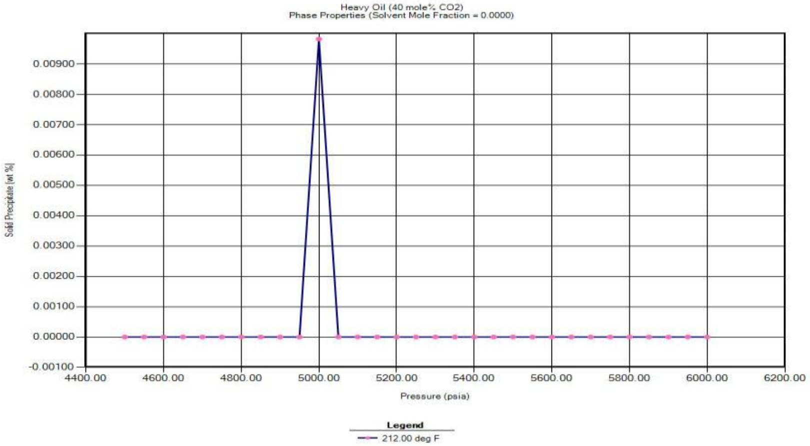
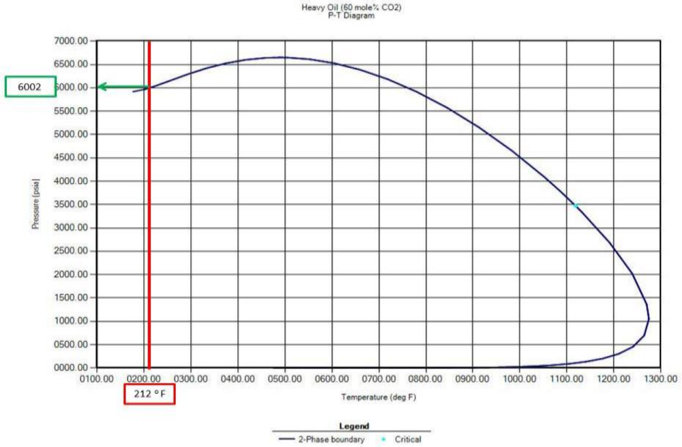
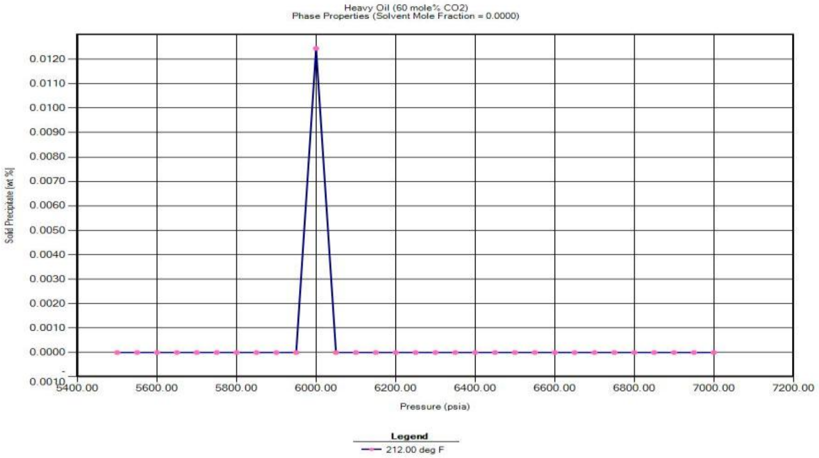
40 mole% CO$_2$</td><td> </td></tr>
<tr><td>
60 mole% CO$_2$</td><td> </td></tr>
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APPENDIX – A3

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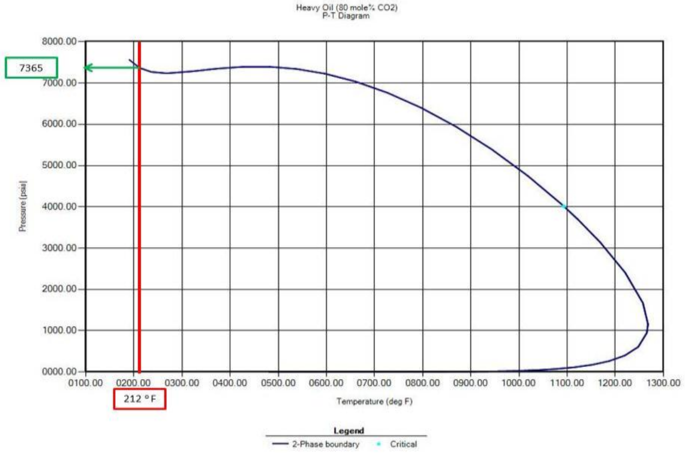

80 mole% CO_2

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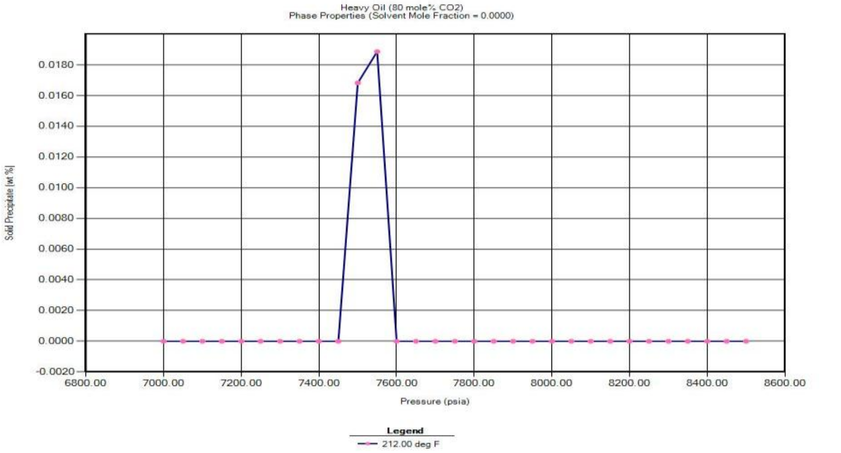

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APPENDIX – B1

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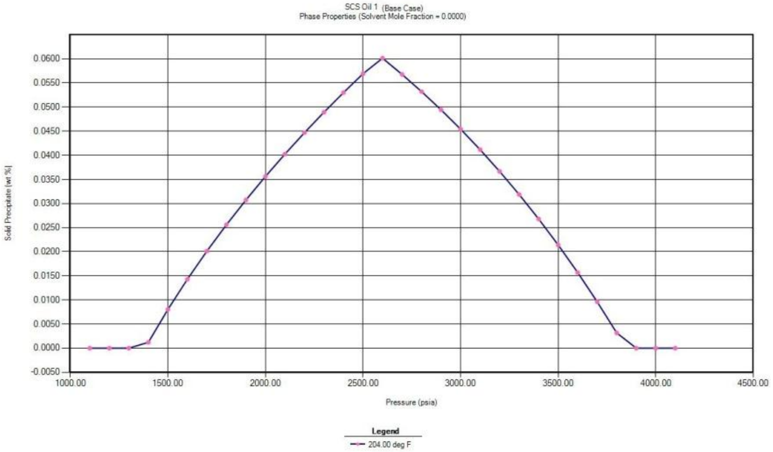
Base Case</td><td>
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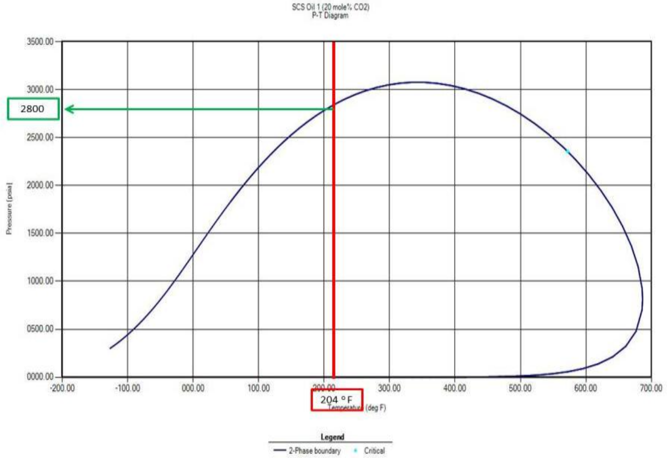
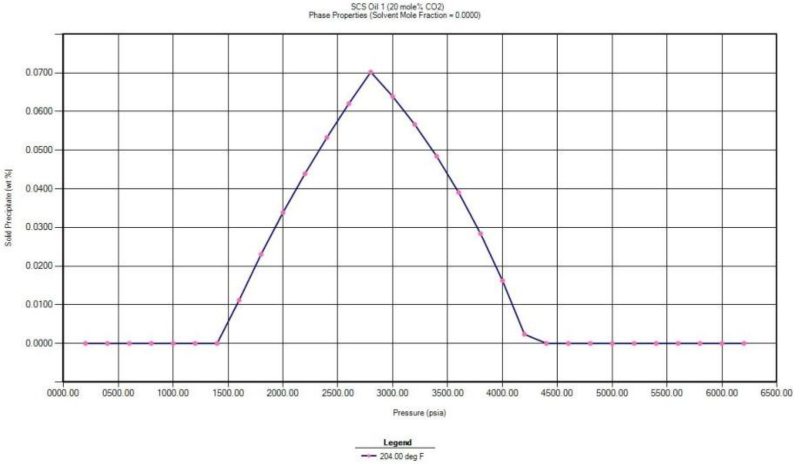
<tr><td>

20 mole% CO_2</td><td>
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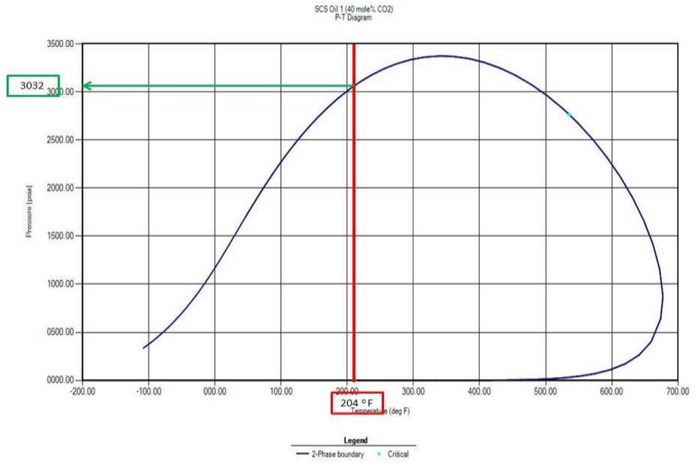
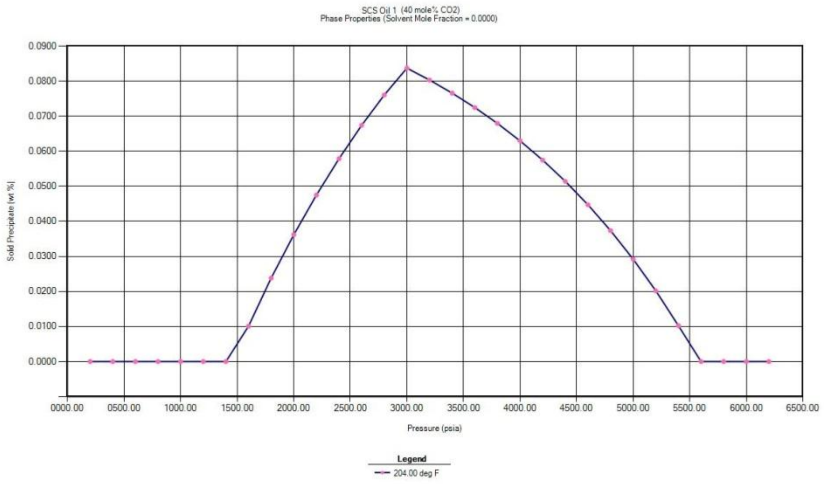
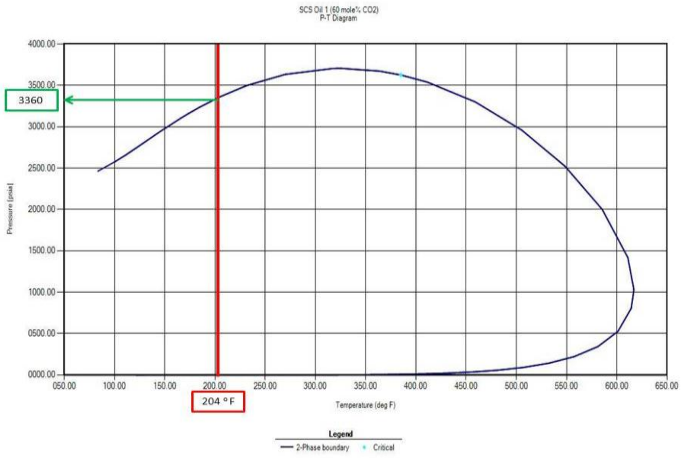
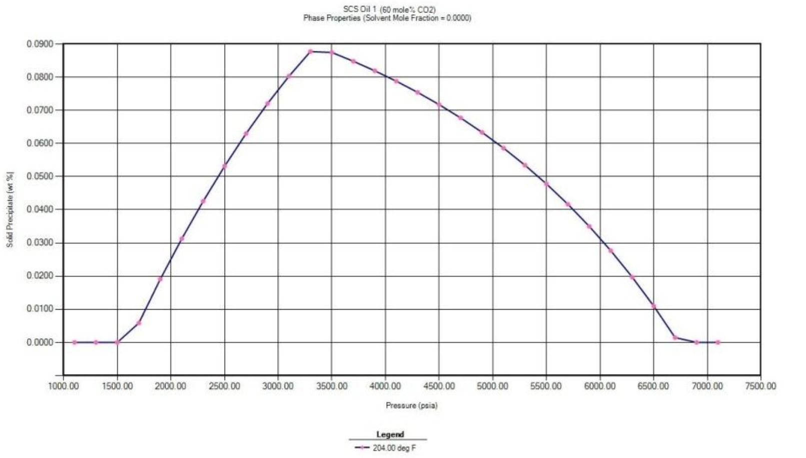
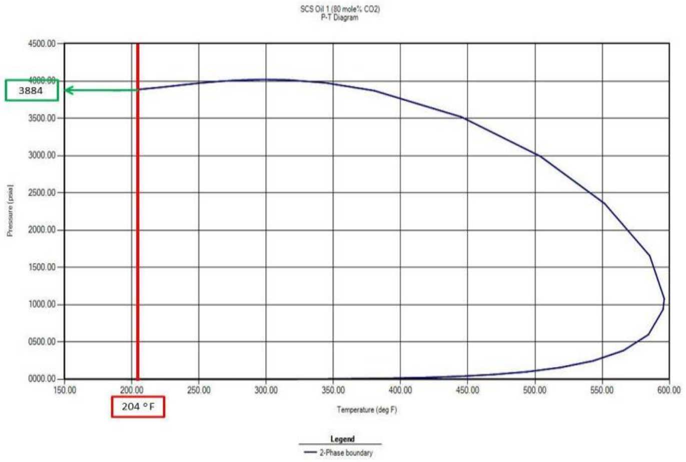
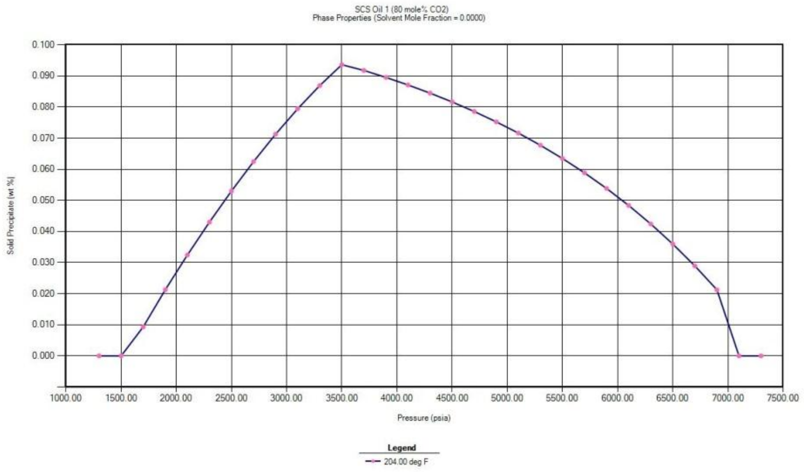
P-T DIAGRAM FOR SCS OIL 1	ASPHALTENE PRECIPITATION PRESSURE FOR SCS OIL 1
 40 mole% CO_2	
 60 mole% CO_2	

P-T DIAGRAM FOR SCS OIL 1



80 mole% CO_2

ASPHALTENE PRECIPITATION PRESSURE FOR SCS OIL 1



APPENDIX – C1

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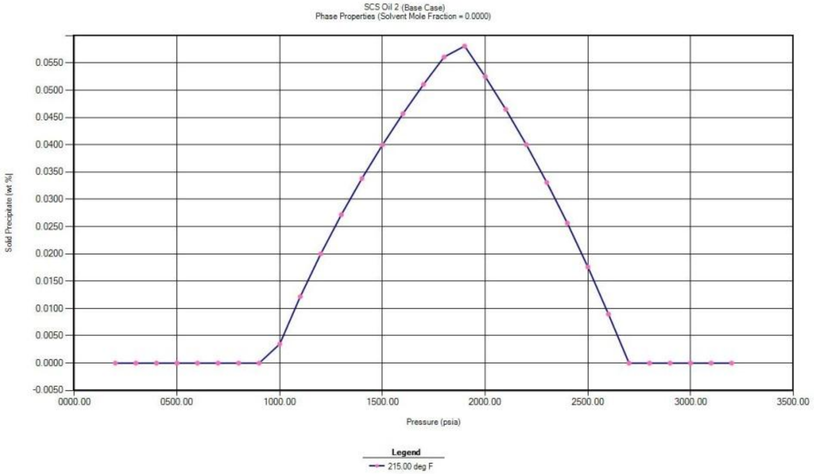
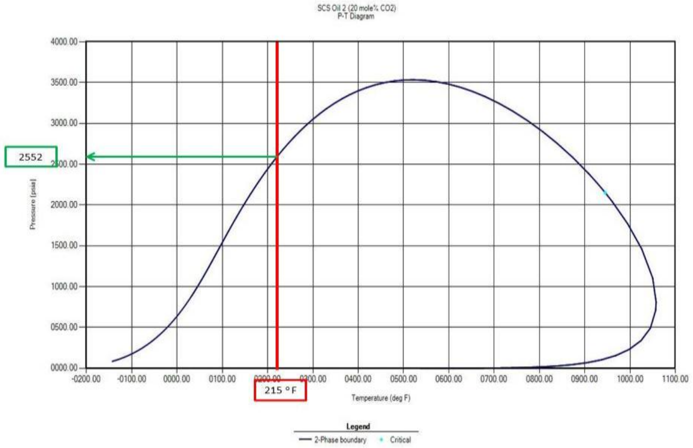
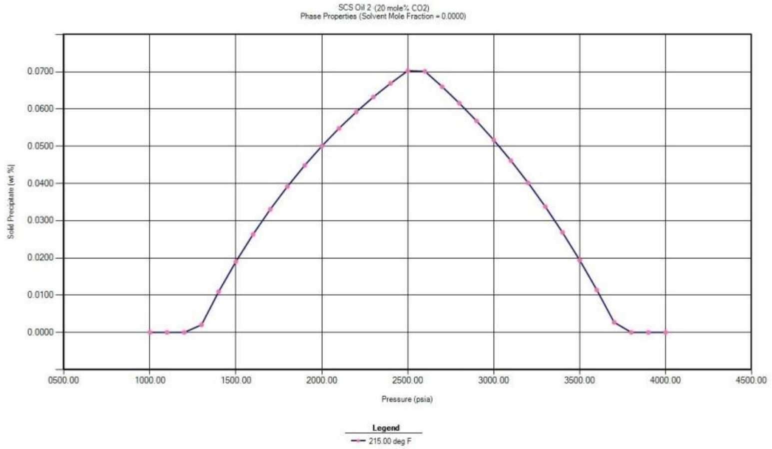
 Base Case	
 20 mole% CO_2	

APPENDIX – C2

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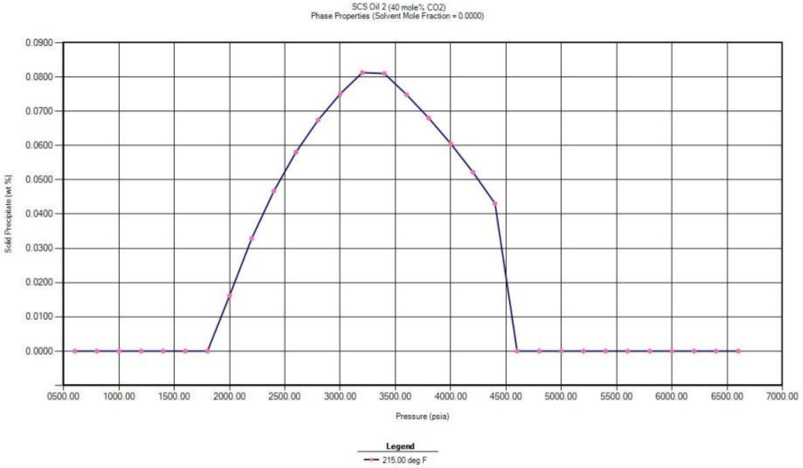
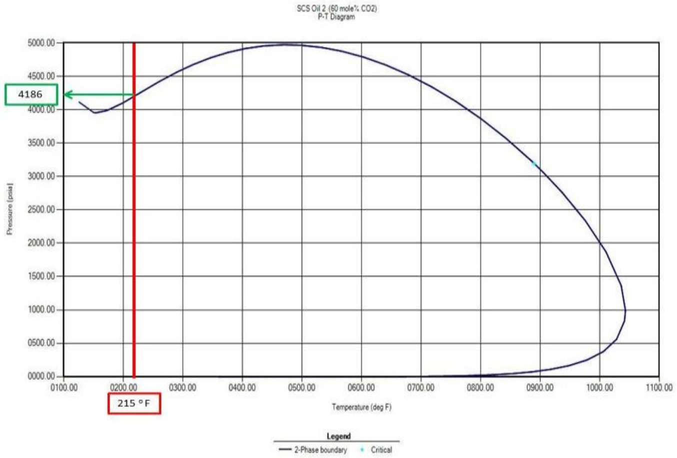
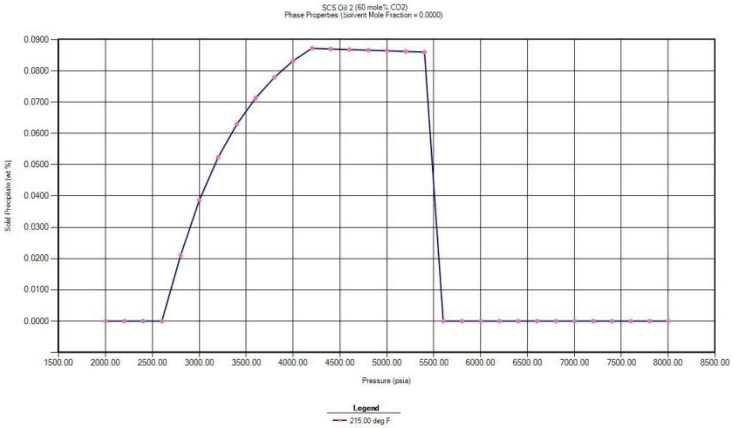
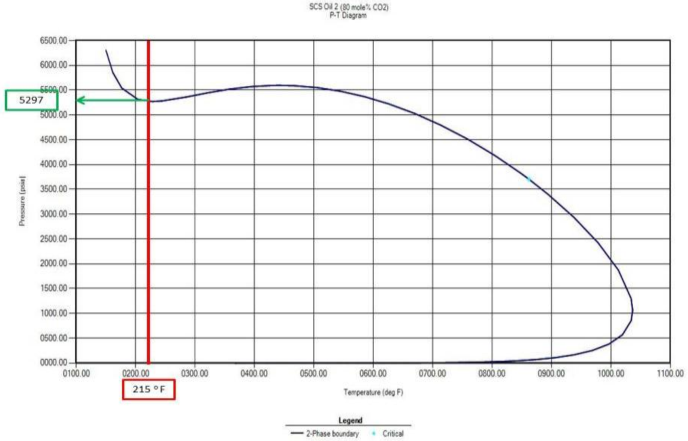
 40 mole% CO_2	
 60 mole% CO_2	

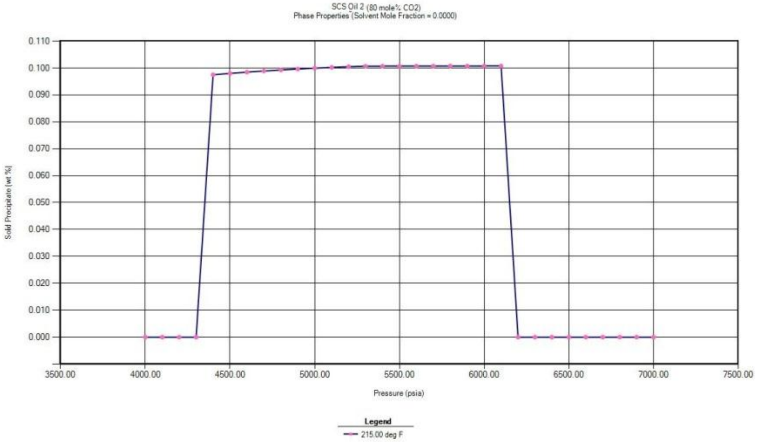
APPENDIX – C3

P-T DIAGRAM FOR SCS OIL 2



80 mole% CO_2

ASPHALTENE PRECIPITATION PRESSURE FOR SCS OIL 2



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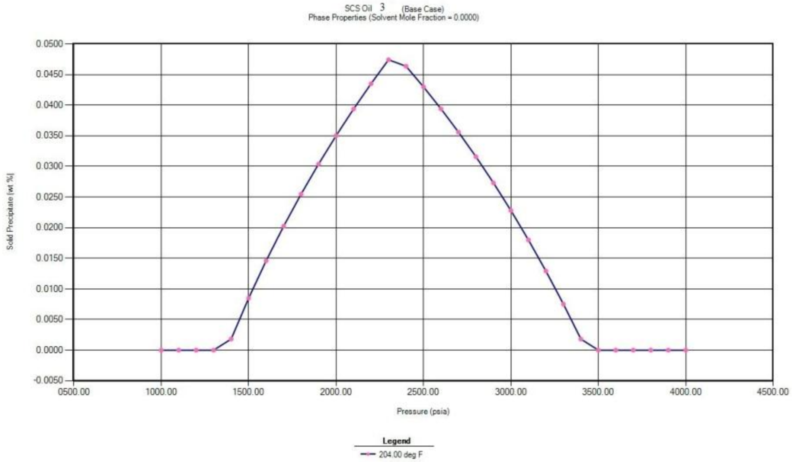
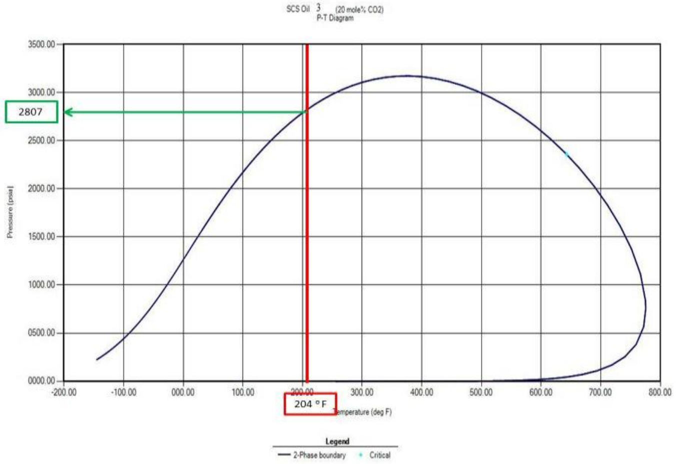
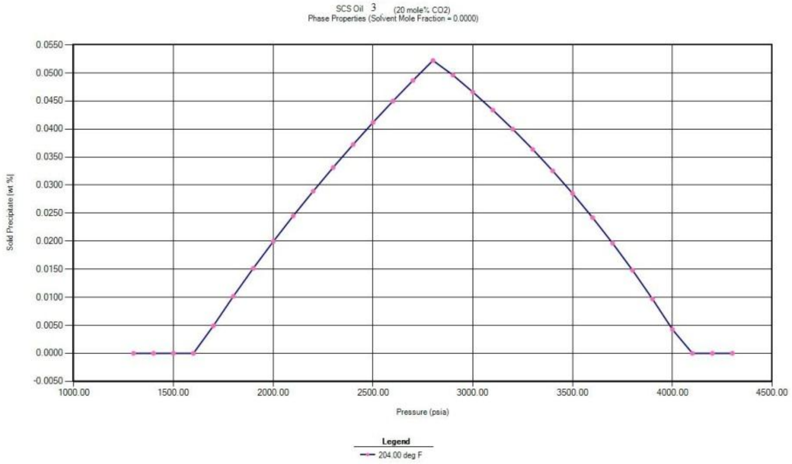
 Base Case	
 20 mole% CO_2	

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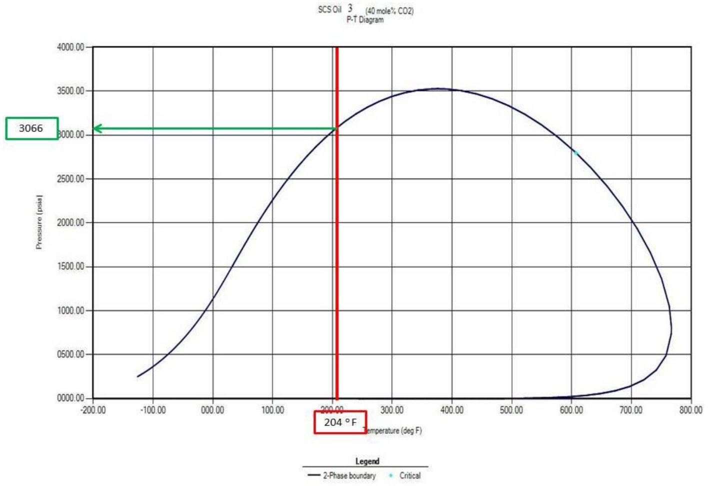
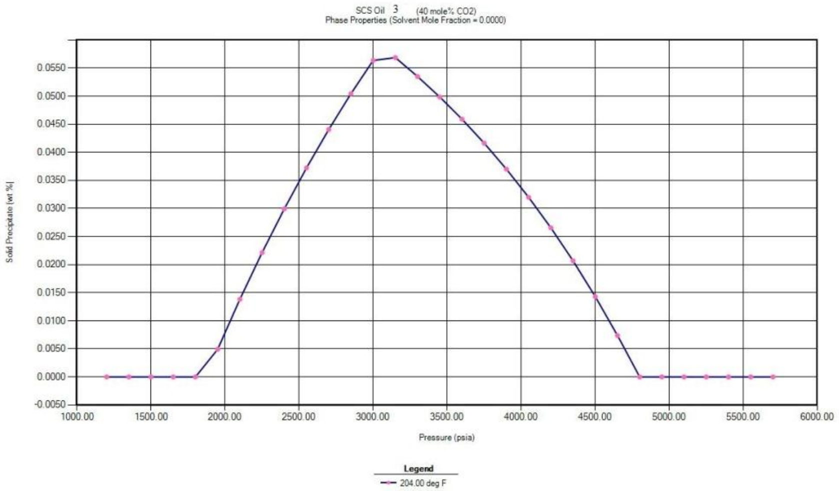
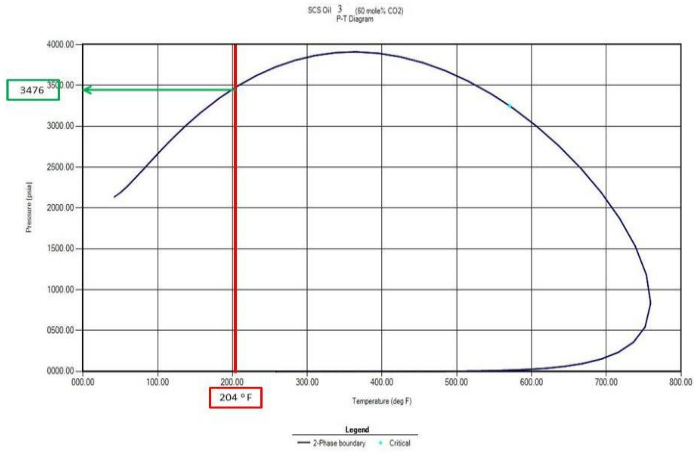
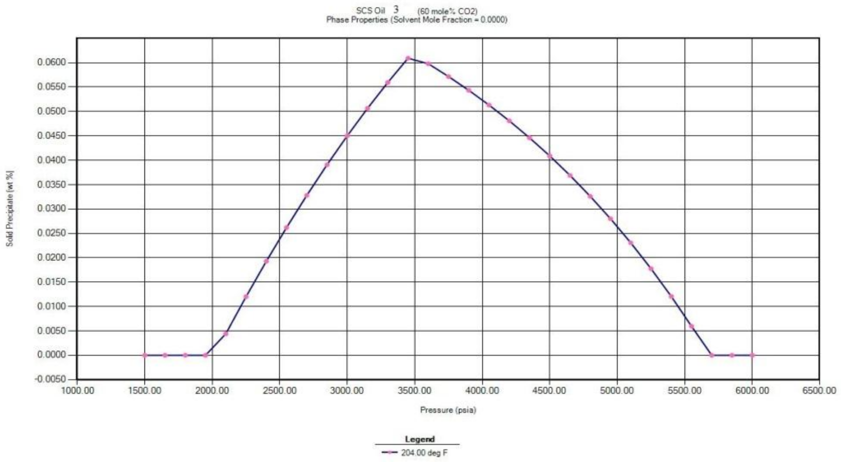
 40 mole% CO_2	
 60 mole% CO_2	

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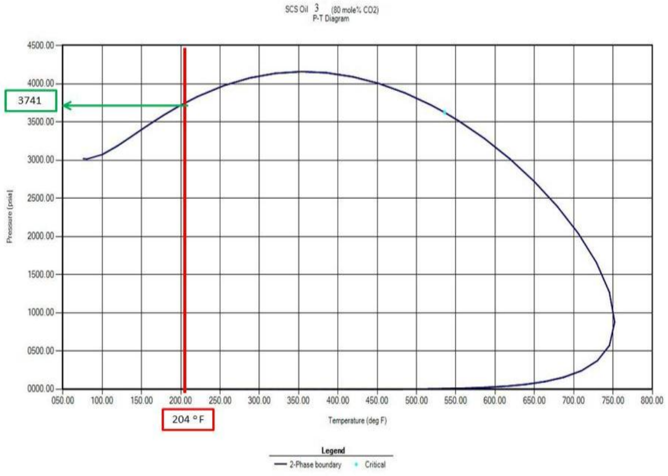
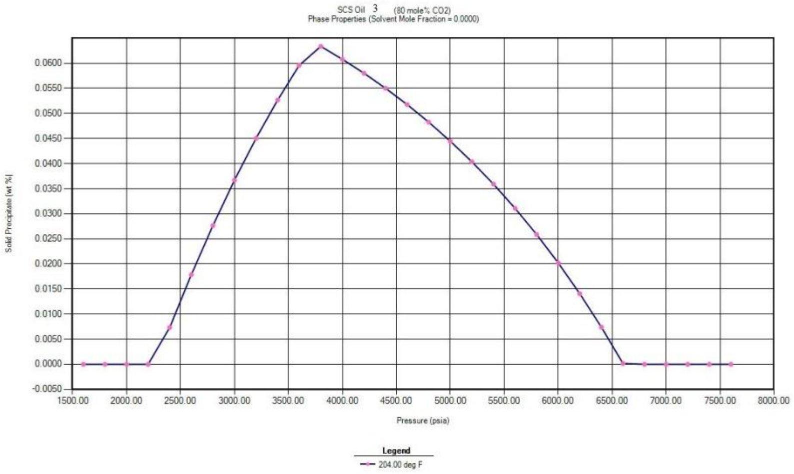
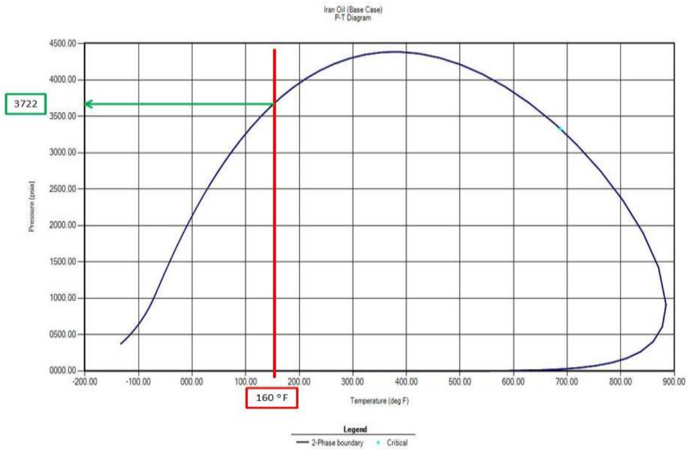
 80 mole% CO_2	

P-T DIAGRAM FOR IRANIAN OIL

ASPHALTENE PRECIPITATION PRESSURE FOR IRANIAN OIL



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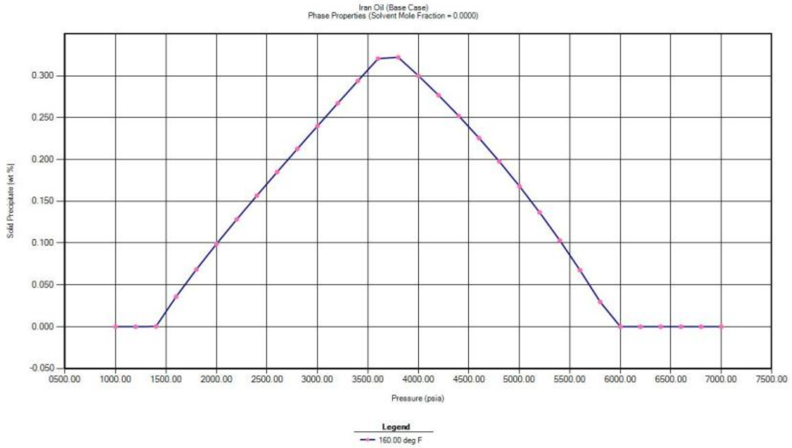
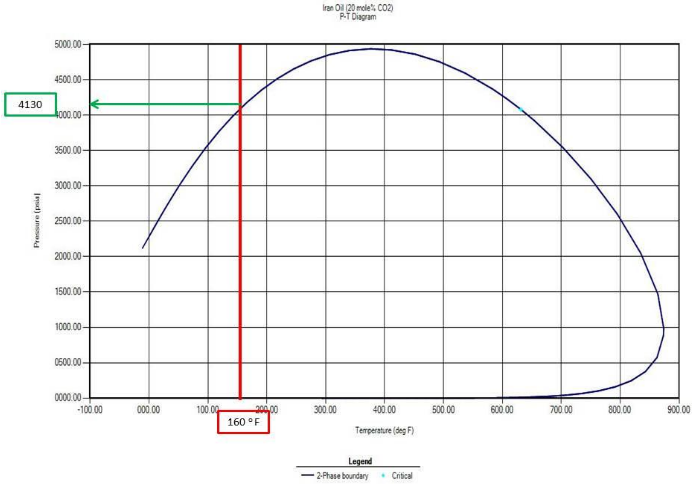
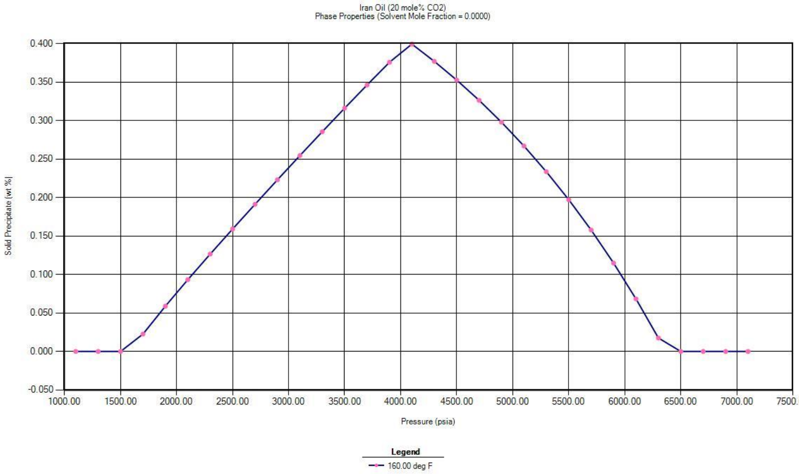




20 mole% CO_2



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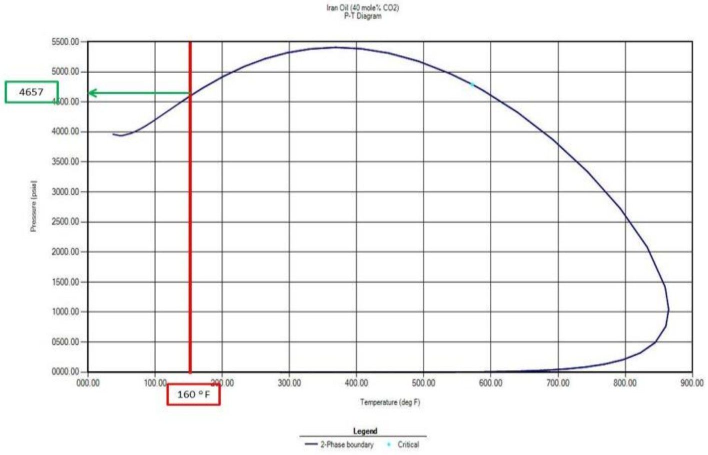
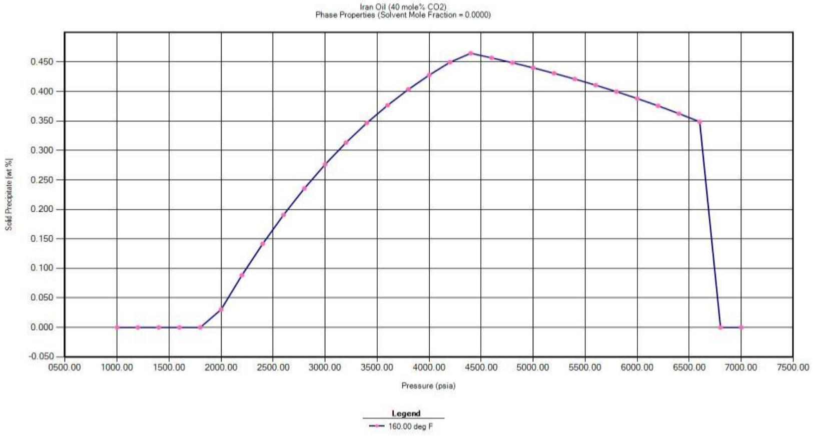
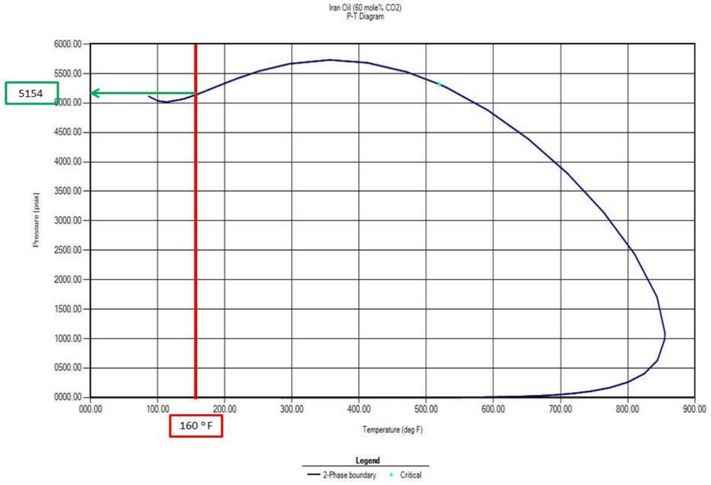
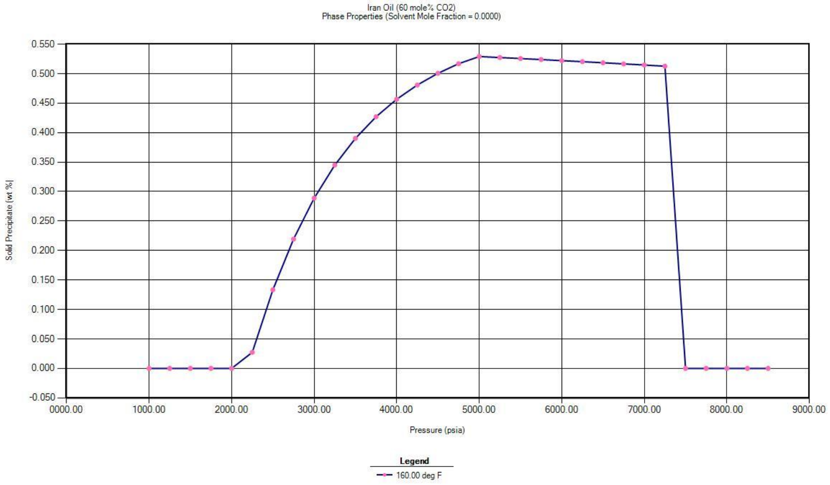
 40 mole% CO_2	
 60 mole% CO_2	

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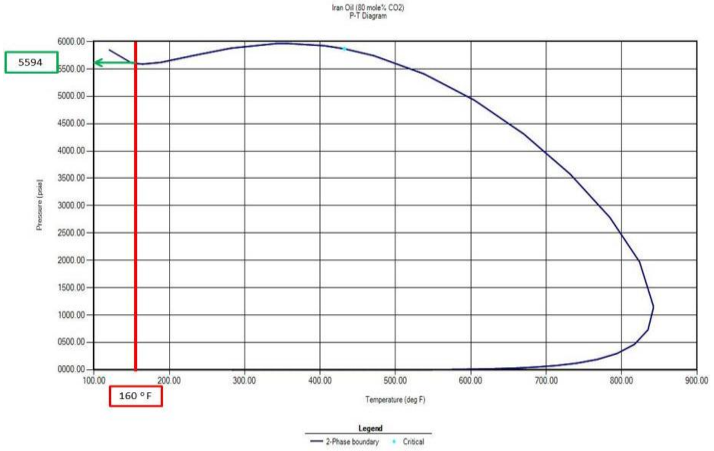 80 mole% CO_2