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Asphaltene Precipitation Modeling of Sadi Formation in Halfaya Iraqi Oil Field

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ABSTRACT

Asphaltene is a component class that may precipitate from petroleum as a highly viscous and sticky material that is likely to cause deposition problems in a reservoir, in production well, transportation, and in process plants. It is more important to locate the asphaltene precipitation conditions (precipitation pressure and temperature) before the occurring problem of asphaltene deposition to prevent it and eliminate the burden of high treatment costs of this problem if it happens. There are different models which are used in this flow assurance problem (asphaltene precipitation and deposition problem) and these models depend on experimental testing of asphaltene properties. In this study, the used model was equation of state (EOS) model and this model depends on PVT data and experimental data of asphaltene properties (AOP measurement) and its content (asphaltene weight percent). The report of PVT and flow assurance of the live oil from the well (HFx1) of the zone of case study (Sadi formation in Halfaya oil field) showed that there is a problem of asphaltene precipitation depending on asphaltene onset pressure (AOP) test from this report which showed high AOP greater than local reservoir pressure. Therefore this problem must be studied and the conditions of forming it determined. In the present work, the asphaltene precipitation of Halfaya oil field was modeled based on the equation of state (EOS) by using Soave-Redlich-Kwong (SRK) equation which gave the best matching with the experimental data. The main result of this study was that the reservoir conditions (pressure and temperature) were located in the asphaltene precipitation region which means that the asphaltene was precipitated from the oil and when the pressure of the reservoir decreases more with oil production or with time it will cause asphaltene deposition in the reservoir by plugging the pores and reducing the permeability of the formation.

Keywords: asphaltene precipitation, asphaltene deposition, asphaltene stability.

نمذجة ترسب الاسفلتين لطبقة السعدي في حقل حلفاية

الخلاصة

الاسفلتين عبارة عن تركيب معقد يترسب احيانا من النفط على شكل مادة لزجة ومتماسكة مسببا مشاكل للمكمن او البئر او خلال عمليات النقل او المعالجة للنفط بعد الانتاج. لذلك من الضروري دراسة الظروف التي تترسب بيها مادة الاسفلتين قبل حدوثها

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لمنعها تجنبا لتكاليف المعالجة الهائلة بعد حدوثها. هناك انواع كثيرة من طرق النمذجة التي استخدمت في دراسة مشكلة ترسب وتصلب الاسفلتين. في هذه الدراسة تم استخدام معادلة الحالة وهذه الطريقة تعتمد على بيانات (الضغط-الحجم-الحرارة) للمائع وكذلك التجارب الحقلية لخصائص الاسفلتين (قياس اول نقطة يترسب بها الاسفلتين) و قياس نسبة الاسفلتين. ظهرت مشكلة الاسفلتين لطبقة السعدي في حقل حلفاية من خلال بيانات (الضغط-الحجم-الحرارة) لنموذج النفط المستخلص من البئر لذلك تمت دراسة هذه الظاهرة لغرض تحديد الظروف التي يتكون بها. في هذه الدراسة تمت نمذجة ترسب الاسفلتين من خلال استخدام معادلة الحالة (SRK) وكانت النتائج مطابقة للبيانات الحقلية وكانت الظروف المكمنية (الضغط والحرارة) لهذا البئر تقع في منطقة ترسب الاسفلتين وهذا يعني ان الاسفلتين يترسب من النفط وممكن يسبب مشاكل انسداد الطبقة بمرور الوقت.

الكلمات الرئيسية: ترسب الاسفلتين وتصلب الاسفلتين واستقراية الاسفلتين.

1. INTRODUCTION

The ability of a multiphase production system to transport produced petroleum from the reservoir rock through pipelines and facilities to the sales point in a predictable manner over the life of the project refers to flow assurance. Plugging or formation damage due to asphaltenes degrades this capability. Flow assurance also includes other hindrance factors such as wax deposition, hydrate formation, scale, slugging, and corrosion. In this scheme, asphaltenes problems are the least understood among the main flow assurance issues**, Rodriguez, 2008**. Asphaltenes are the heaviest and the most polarizable components of the crude oil. They are defined in the Standard Test Method for n-Heptane insoluble in terms of solubility as the components of the crude oil that are insoluble in low molecular weight alkanes, specifically n-heptane, and soluble in aromatic solvents like toluene or benzene. Asphaltenes are composed of a polydisperse mixture of molecules containing polynuclear aromatic components, which contain few alkyl groups per aromatic ring. Their structures also contain oxygen, sulfur, nitrogen, and certain metals (iron, vanadium, and nickel). Asphaltenes macromolecules have an average carbon number in the range of about 40 to 80 and their elemental analysis usually shows H/C ratios between 1.1 and 1.2. Asphaltenes are not crystallized and cannot be separated into individual components**, Rodriguez, 2008**. Asphaltene stability depends on pressure, temperature, and composition of the fluid and changing which of them will cause asphaltene destabilization and precipitation. The effect of composition and pressure on asphaltene precipitation is generally stronger than the effect of temperature**, Gonzalez, et al., 2007**.

There are different models of asphaltene precipitation, **Chamkalani, 2011**.

1-Molecular thermodynamic models in which asphaltenes are dissolved in crude oil and crude oil forms a real solution. These models contain a regular solution and cubic equations of state (EOS) which are mostly used to model asphaltene precipitation, **Pedersen, and Christensen, 2007**:

a-The Soave-Redlich-Kwong (SRK) Equation: Soave (1972) observed that the pure-component vapor pressures calculated from the Redlich–Kwong equation (1949) (RK) to be somewhat inaccurate, therefore, he suggested replacing the term $\frac{a}{\sqrt{T}}$ in the RK equation by a more general temperature dependent term, a(T), giving an equation of state of the form, **Pedersen, and Christensen, 2007**:

RK equation $$P = \frac{RT}{V-b} - \frac{a}{V(V+b)\sqrt{T}} \tag{1}$$

SRK equation $$P = \frac{RT}{V-b} - \frac{a(T)}{V(V+b)} \tag{2}$$

where:

$$a(T) = a_c \alpha(T) \tag{3}$$

$$a_c = 0.42747 \frac{R^2 {T_c}^2}{P_c}$$
(4)

$$b = 0.08664 \frac{RT_c}{P_c} \tag{5}$$

$$\alpha(T) = \left(1 + m\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)^2 \tag{6}$$

$$m = 0.3796 + 1.54226\omega - 0.2699\,\omega^2 \tag{7}$$

b-Peng-Robinson (PR) Equation

2-Colloidal models in which asphaltene is suspended in crude oil and peptized by resins.

3-Models based on scaling equation in which the properties of complex asphaltenes are not involved.

The mentioned models above were used in the previous studies as follows:

Jamaluddin, et al., 2002, developed an equation-of-state (EOS) based model to describe the experimentally measured onset of asphaltene precipitation pressures (Poap) by using Soave-Redlich-Kwong (SRK) with volume (Peneloux) correction model and matched the results with experimental data to identify the first pressure and/or temperature conditions at which the asphaltene will start to precipitate for two reservoir oils (the Middle East and the Gulf of Mexico).

Tharanivasan, et al., 2010, determined the required parameters of their model experimentally and used regular solution approach to model asphaltene precipitation caused by compositional changes and depressurization.

Tavakoldavani, and Ashoori, 2017, determined asphaltene deposition profile in the wellbores' column. They performed flash calculations using Peng-Robinson EOS (Winprop software) and used the thermodynamic model of Hirschberg et al. (1984) to predict asphaltene precipitation. As a result, they found that a decrease in temperature increases the solubility parameter and a higher deposition amounts to remain dissolved in the oil while a decrease in pressure decreases solubility parameter until reaching bubble point pressure, and it increases with further reduction of pressure below the bubble point.

Siyamak et al., 2012, presented new scaling model and experimental investigation of asphaltene precipitation account at reservoir condition of the live oil from the southwest Iranian oil reservoir and studied the effect of changing pressure and temperature for the following two cases: the conventional pressure depletion process and gas injection process (methane injection). They concluded that methane injection increases asphaltene precipitation more than three times compared to natural depletion.

In the present study, the fluid and asphaltene precipitation envelopes were plotted depending on PVT data of the live oil from a well (HFx1) in Halfaya oil field and matched with experimental data by using the cubic equation of state. Soave-Redlich-Kwong (SRK- EOS) was chosen to generate the EOS model because it has been found to give a better agreement with experiential data.

2. WORK PROCEDURE

The flow chart of building the model of asphaltene precipitation envelope was shown in **Fig.1**. As mentioned previously, the required data for this model is PVT report of a well from the desired field. It contains main reservoir characteristics such as local pressure and reservoir temperature, fluid properties such as bubble point pressure and GOR as shown in **Table 1**, composition analysis of the reservoir fluid (Live oil) which illustrated in **Table 2**, main PVT experiments such as flash liberation, differential liberation, swelling and viscosity, and asphaltene experiments (Onset pressure measuring and asphaltene content measuring). All of these data had been entered to the software (PVTsim) to apply the equation of state (EOS) by using Soave-Redlich-Kwong (SRK) Equation on them to get the model of asphaltene precipitation.

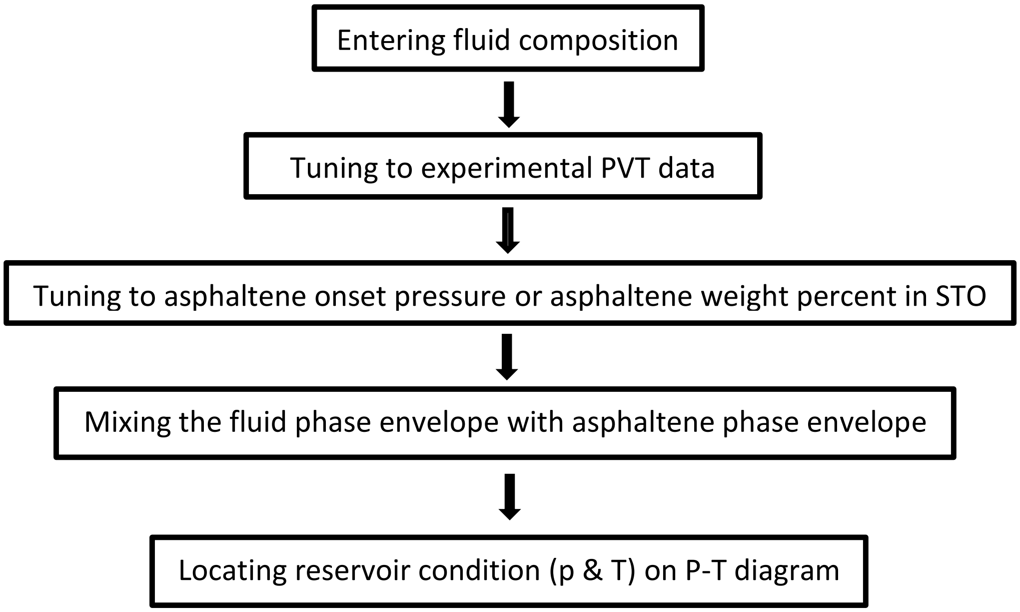


Figure 1. The flow chart of modeling.

Table 1. Reservoir and fluid main properties.

Property	**Its value or detail**
Type of sample	BHS
Sampling depth	2500
Formation	Sadi
Sampling date/Time Hrs.	8-Sep-11/10:30
Reservoir conditions (Psia / ˚C)	4406.6/86.1
Sample volume (CC)	600
Opening pressure in the lab at 23 ˚C (Psia)	2381
Water content	<1
Nature of Sample	Black Oil
Bubble point pressure (psia)	3125
GOR (scf/stb)	813
Density (g/cc)	0.898
API	25.8
Compressibility at Reservoir Pressure ($psia^{-1}$)	11.21×10^{-6}

As shown in **Fig. 1,** the following procedure has been used in asphaltene precipitation modeling of the selected study area:

1-Entering Fluid composition: The monophasic reservoir fluid composition from PVT and flow assurance report of the well (HFx1) as illustrated in **Table 2** has been entered firstly to PVTsim software.

2- Tuning to experimental PVT data: Tuning or regression process in the software was made for matching the simulated data resulted by the cubic equation of state (SRK- EOS) to the experimental PVT data.

After entering the fluid composition, there are three processes to characterize the pseudo-component (C7+) and match (tune) the experimental PVT data as follows:

1- Splitting: is the procedures of breaking down the C7+ fractions into hydrocarbon groups with a single carbon number which they described by the same physical properties used for pure components. Pedersen et al. (1983, 1984) proposed that reservoir fluids for carbon numbers (CN) above C6 exhibit an approximately linear relationship between carbon number and the logarithm of the corresponding mole fraction, ZN, as the following equation, **Pedersen, and Christensen, 2007**:

$$CN = A + B \ln ZN \qquad (8)$$

In heavy oils (for asphaltene precipitation envelope), components as heavy as C200 may influence the phase behavior.

2- Lumping: The characterized mixture of fluid sample now consists of 203 pure and pseudo-components. It is desirable to minimize this large number of components before performing phase equilibrium calculations. Lumping consists of grouping specific carbon number fractions into a desirable number of pseudo-components. Averaging Tc, Pc, and ω of the individual carbon number fractions to one representative Tc, Pc, and ω for the each lumped pseudo-component.

3- Regression: is the process of calibrating (tuning) an EOS model against measured data generated at pertinent conditions for specific reservoir fluid because phase behavior models based on EOS may predict highly erroneous results even for well-characterized model fluids. Real reservoir fluids, which composed of thousands of components, are described by a limited number of carbon groups and pure substances. To minimize the difference between the predicted and measured values, some inaccurate values of input data to the phase behavior model are adjusted. The parameters that are often used in tuning are binary interaction parameters, parameters of EOS and properties of pseudo-components, particularly the critical properties.

The fluid composition and its critical properties (critical pressure, critical temperature and acentric factor) after the above processes (splitting, lumping and regression) are shown in **Table 3**.

Table 2. The monophasic reservoir fluid composition.

Components	Mole %
N_2	0.46
CO_2	1.11
H_2S	0
C_1	38.23
C_2	8.72
C_3	5.87
i- C_4	1.07
n-C_4	3.44
i-C_5	1.67
n-C_5	1.91
C_6	3.29
C_7+	34.24

Table 3. The fluid composition and its critical properties after splitting, lumping and regression processes.

Component	Mol %	Mol wt	Liquid Density lb/ft³	Crit T °F	Crit P psia	Acentric factor -
N2	0.46	28.014		-229.958	469.65	3.73E-02
CO2	1.11	44.01		94.041	1020.61	0.21
C1	38.226	16.043		-112.736	636.48	7.47E-03
C2	8.719	30.07		96.225	675.73	9.15E-02
C3	5.869	44.097		213.448	587.41	0.1419
iC4	1.07	58.124		283.162	504.69	0.1643
nC4	3.44	58.124		314.288	525.72	0.1802
iC5	1.67	72.151		378.36	468.24	0.2119
nC5	1.91	72.151		395.105	466.84	0.2343
C6	3.29	86.178	41.4522	463.91	410.77	0.2763
C7	2.731	96	49.879	693.203	407.68	0.4247
C8	2.513	107	50.7169	743.445	403.89	0.4389
C9	2.313	121	51.456	791.898	392.63	0.4517
C10-C13	7.547	152.83	52.9613	879.519	361.86	0.4774
C14-C16	4.223	205.114	54.6485	972.818	322.21	0.5057
C17-C19	3.291	249.613	55.7904	1030.573	298.63	0.5243
C20-C22	2.564	289.502	56.7608	1075.073	283.37	0.5398
C23-C26	2.561	336.83	57.7185	1118.349	269.76	0.5547
C27-C31	2.208	399.679	58.7683	1165.215	256.66	0.5707
C32-C38	1.89	481.371	59.927	1215.749	244.97	0.5877
C39-C48	1.352	595.508	61.255	1273.205	234.32	0.6064
C49-C200	1.043	843.337	63.5055	1373.404	222.01	0.6356

The simulated data matched with the measured field data are as follows:

1- Bubble point pressure: the experimental value was 3125 psi while the simulated value by the equation of state (SRK) was 3081 psi (error = 1.4 %).

2- Constant mass expansion test containing relative volume as shown in **Fig. 2** which showed the best agreement between the simulated data (By the model) and experimental data of the relative volume of the reservoir fluid.

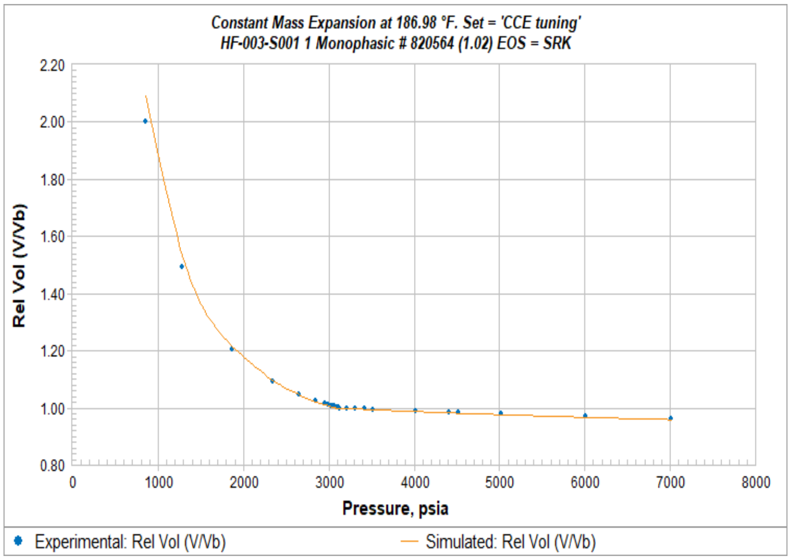


Figure 2. Relative volume tuning.

3- Viscosity tuning (oil and gas viscosity) as shown in **Fig. 3** and **Fig. 4** which also showed that the viscosity of the fluid (oil and gas) in two cases (simulated and experimental data) was matched.

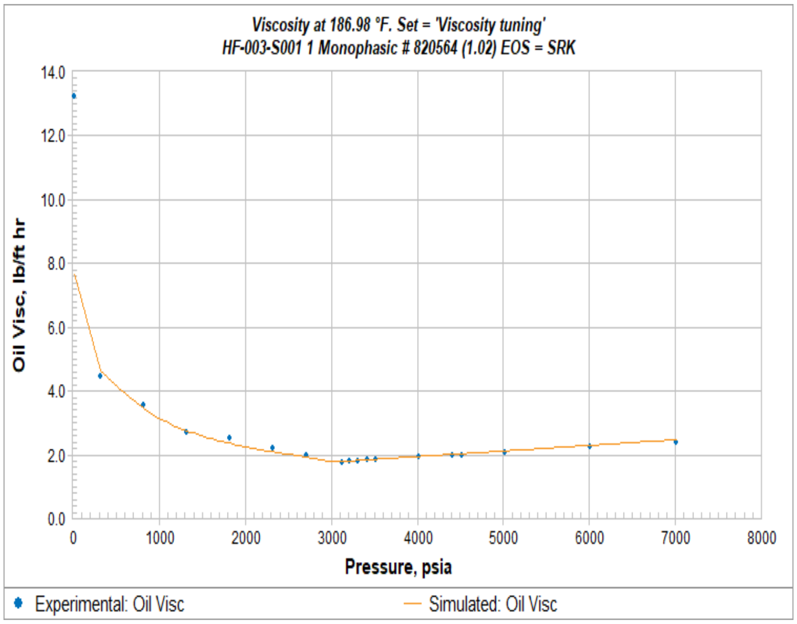


Figure 3. Oil viscosity tuning.

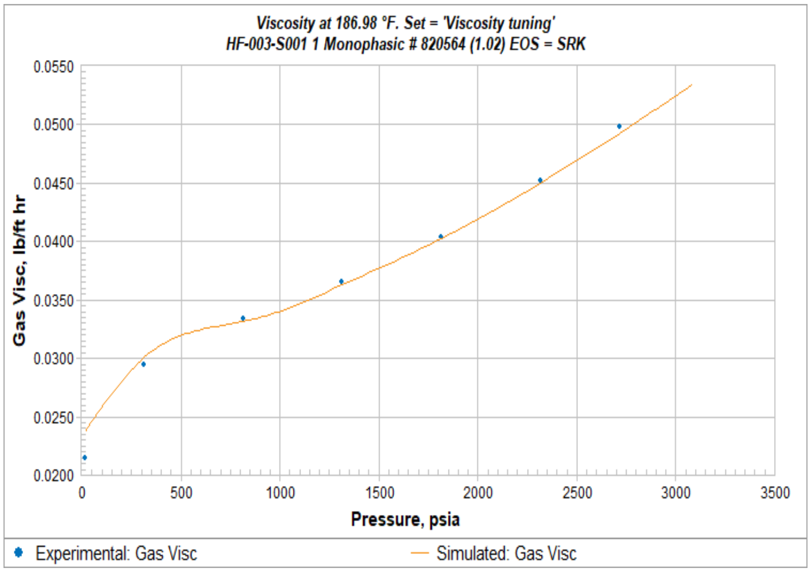


Figure 4. Gas viscosity tuning.

All of the previous tuning or matching processes as shown in **Fig. 2**, **Fig. 3** and **Fig. 4** results in a good match between the simulated data by SRK equation in PVTsim software and experimental data of PVT experiments of the reservoir fluid and this supported the accuracy of entering the composition of the reservoir fluid after three processes (Splitting, lumping and regression processes).

3- Tuning to asphaltene onset pressure or asphaltene weight percent in Stock Tank Oil

If asphaltene precipitation is considered to be a conventional liquid-liquid split, it is at least in principle possible to simulate gas-oil-asphaltene phase equilibria including asphaltene onset pressures using a cubic equation of state (SRK and PR), **Pedersen, and Christensen, 2007**.

Having characterized the oil composition, each pseudo-component heavier than C_{49} is split into an asphaltene and a nonasphaltene component, **Pedersen, and Christensen, 2007**.

Table 3. Default Asphaltene Component Properties Used, **Pedersen, and Christensen, 2007**.

T_cA	1398.5 K
P_cA	14.95 bar
ωA	1.274

The critical temperature T_{ci}^{no-A} of the nonasphaltene fraction ($Frac_i^{no-A}$) of pseudo-component i is found from the relation, **Pedersen, and Christensen, 2007**:

$$T_{ci} = Frac_i^{no\text{-}A}\, T_{ci}^{no\text{-}A} + Frac_i^{A}\, T_{ci}^{A} \qquad (9)$$

The critical pressure P_{ci}^{no-A} of the non-asphaltene forming fraction of pseudo-component i is found from the equation, **Pedersen, and Christensen, 2007**:

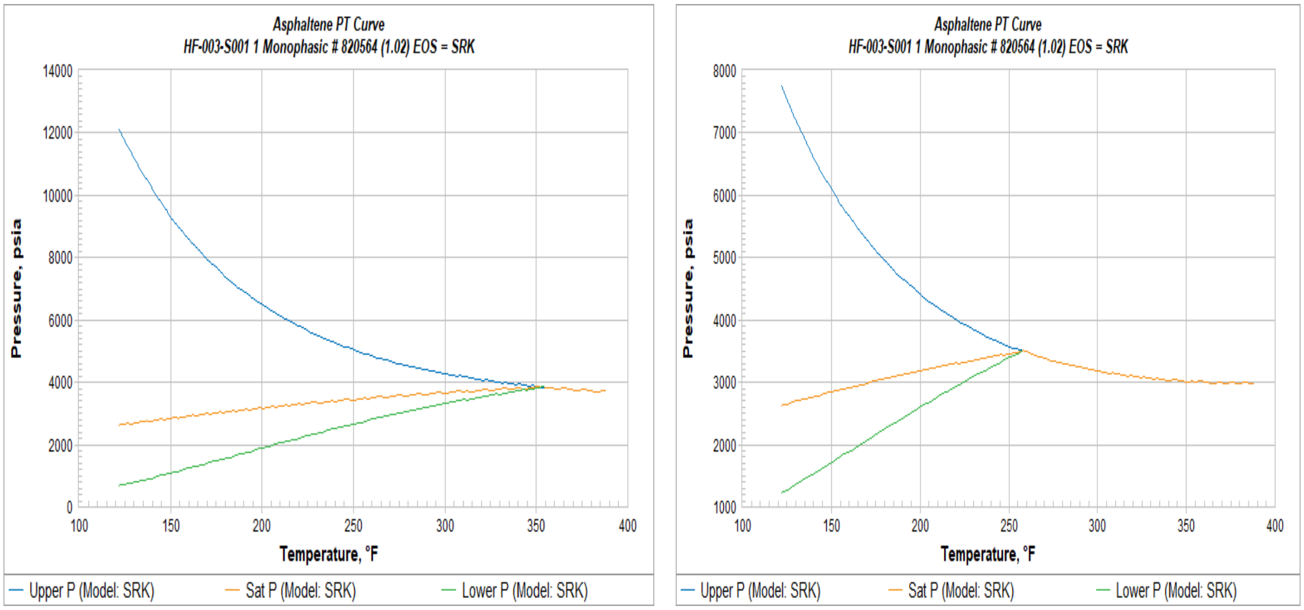
$$\frac{1}{P_{ci}} = \frac{(Frac_i^{no-A})^2}{P_{ci}^{no-A}} + \frac{(Frac_i^{A})^2}{P_{ci}^{A}} + \frac{2Frac_i^{no-A} * Frac_i^{A}}{\sqrt{P_{ci}^{no-A}}\sqrt{P_{ci}^{A}}} \qquad (10)$$

Whereas the acentric factor of the non-asphaltene forming fraction of pseudo-component i is found from, **Pedersen, and Christensen, 2007**:

$$\omega_i = Frac_i^{no-A}\, \omega_i^{no-A} + Frac_i^{A}\, \omega_i^{A} \qquad (11)$$

Equations from (9) to (11) ensure that a and b parameters of the equation of state are in only marginally influenced from splitting up the C50+ components in an asphaltene and a nonasphaltene component. This has the advantage that approximately the same bubble point and gas/liquid ratios will be simulated before and after the split.

From PVT and flow assurance report of HFx1 well, asphaltene onset pressure (AOP) equals 7015 psia at a temperature of 186.98 ºF and asphaltene content of fluid 2.1 %. Tuning the model to an experimental asphaltene onset pressure (AOP) may either be accomplished by tuning the asphaltene Tc and Pc or by tuning the asphaltene content in the oil as shown in **Fig. 5**.



a-Tuning to asphaltene onset pressure (AOP). b-Tuning to asphaltene weight percent in STO.

Figure 5. Tuning to asphaltene onset pressure (AOP) and tuning to asphaltene content in STO (wt%)

After applying the tuning methods to both asphaltene onset pressure (AOP) and to its content in the reservoir fluid and comparing the results of asphaltene tuning process, the tuning to experimental value of asphaltene onset pressure (AOP) was the best one because at reservoir temperature (186.98 ºF), simulated AOP by the SRK model was 7015 psia which equaled the experimental value of AOP while the tuning process to asphaltene content (Asph. wt%) decreased AOP at reservoir temperature and warped the curve of bubble point pressure as shown in **Fig. 5**.

4- Mixing the fluid phase envelop with asphaltene phase envelope

By plotting the P-T diagram of the fluid which obtained by PVT modeling of the fluid composition and adding the plot of P-T curve of asphaltene which also found by the modeling after tuning process and the result was shown in **Fig. 6**.

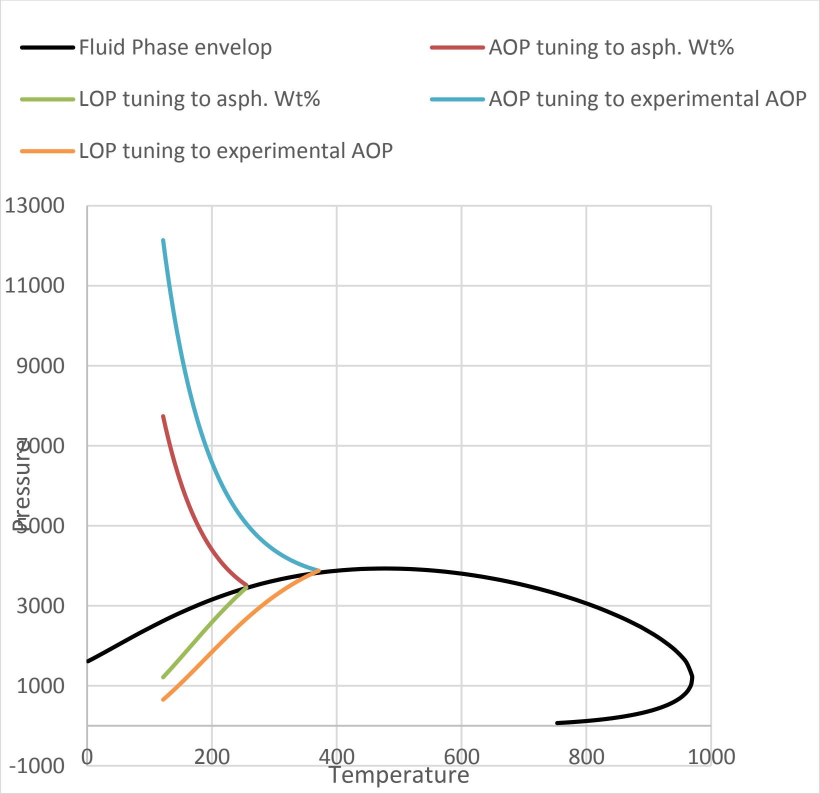


Figure 6. P-T diagram of the fluid and asphaltene

5- Locating reservoir condition (p & T) on P-T diagram

Reservoir pressure and temperature are 4406 psi and 186.98 ºF respectively. The reservoir location as shown in **Fig. 7** was in the region of the asphaltene precipitation zone (asphaltene precipitation envelope) and this accepted with experimental results which showed that the asphaltene precipitated due to decreasing the pressure of reservoir (4406 psia) below the asphaltene onset pressure (First pressure at which asphaltene starts to precipitate which equals 7015 psia).

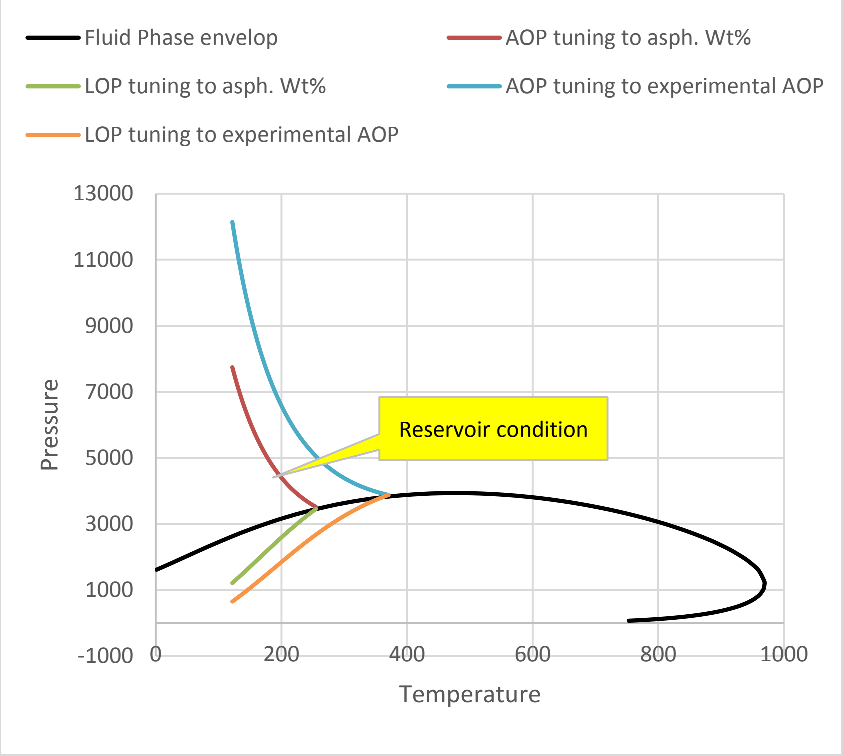


Figure 7. Locating reservoir condition.

As shown in **Fig. 7**, the asphaltene precipitation region (asphaltene phase envelope) composed of upper onset pressure (AOP), lower onset pressure (LOP) and the bubble point curve lies between them. The reservoir conditions located in the asphaltene precipitation zone by two tuning processes for asphaltene but the tuning process to asphaltene onset pressure (AOP) gave the best match with the experimental value of AOP which equals 7015 psia as in the PVT and flow assurance report.

3. RESULTS AND DISCUSSION

Before presenting the final result of the asphaltene precipitation modeling, the PVT data must be checked to predict the possibility of precipitation of asphaltene depending on the method introduced by **Ahmed, 2007**. By plotting the saturated oil density data from the differential liberation (DL) test and those of the undersaturated density from the constant composition expansion (CCE) test. A steep increase or erratic density values around the saturation pressure (bubble point) might indicate flow assurance problems; for example, asphaltene precipitation as shown in **Fig. 8**. The steep increase in the density was the cause of the asphaltene precipitation because of the expanding of the gas in the fluid before the bubble point pressure which decreased the density of the fluid and evolving of it and leaving the oil after this point which increased density. This huge transformation of the density before and after the bubble point pressure cause the asphaltene precipitation.

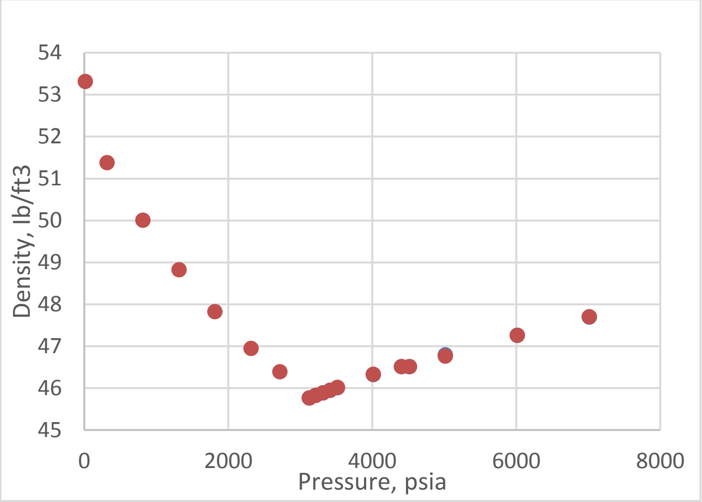


Figure 8. Checking of asphaltene precipitation problem.

This case supported and agreed with the experimental results of the asphaltene precipitation which was shown from the upper onset precipitation pressure (AOP) measurement of the asphaltene there was a problem of asphaltene precipitation as a flow assurance of Sadi formation in Halfaya oil field. The last result of the asphaltene precipitation modeling was shown in **Fig. 9**. The best asphaltene tuning process was with the upper asphaltene onset precipitation pressure because it gave the best match with the experimental data of asphaltene precipitation conditions (pressure and temperature).

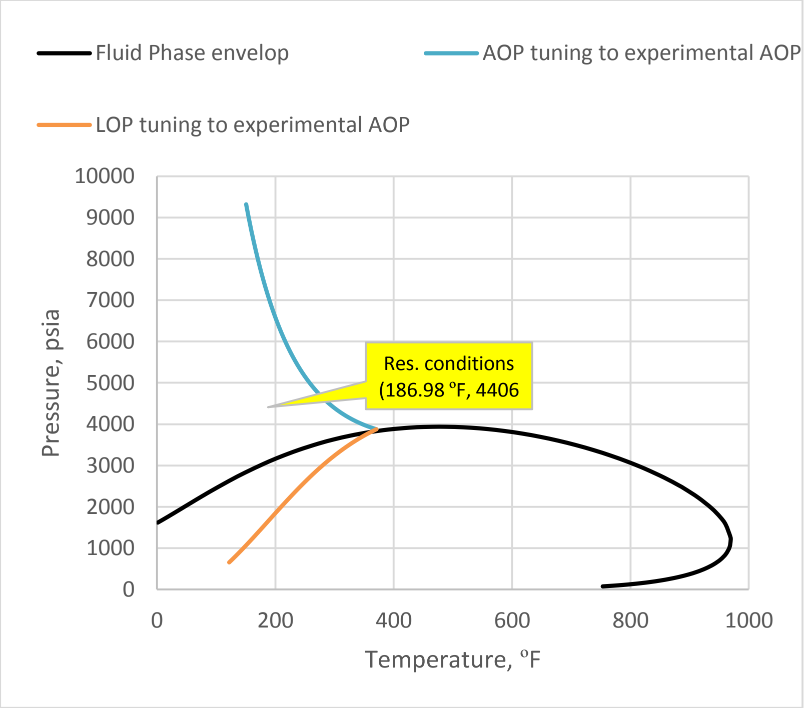


Figure 9. Asphaltene precipitation phase envelope.

As shown in **Fig. 9**, the asphaltene precipitation region (asphaltene phase envelope) composed of upper asphaltene onset pressure (AOP), lower asphaltene onset pressure (LOP) and the bubble point curve lies between them. At a pressure above the upper onset of asphaltene precipitation pressure (AOP), the asphaltenes are dispersed in solution. While below the bubble point pressure (Pb), the oil becomes denser as solution gas is removed from the oil (the amount of precipitated asphaltene increases as pressure decreases from the reservoir pressure and reaches maximum value at bubble point because of gas expansion and decreases as the pressure drops below the bubble point pressure because of evolving the gas from the fluid). This observation was also seen in **Jamaluddin et al., 2002,** study.

The asphaltene precipitation zone was located between upper AOP and Pb and the reservoir conditions (reservoir pressure and temperature) was located in the asphaltene precipitation zone. This result agrees with the experimental data and checking method of asphaltene precipitation problem. Since this reservoir may form the asphaltene deposition problem (such as plugging formation pores) in the future if this problem doesn’t considered with the treatment methods of asphaltene precipitation. The asphaltene precipitation problem of this reservoir fluid was because of the high ratio of methane (CH_4) in this fluid which equaled 38 % of the total weight of the reservoir fluid. Methane causes the asphaltene precipitation problem because it desorbs the resin around the asphaltene molecules and allows them to aggregate causing the precipitation problem of asphaltene according to the study of **Siyamak, et al., 2012**.

4. CONCLUSIONS

1- The checking method of asphaltene precipitation which introduced by **Ahmed, 2007,** was used in this reservoir fluid and gave the tendency for asphaltene precipitation because of a steep increase in the fluid density from differential liberation (DL) test to constant composition expansion (CCE) test.

2- The PVT model observed that the reservoir fluid precipitates asphaltene because it was located in the asphaltene precipitation zone and this accepted with the experimental result of measuring asphaltene onset point and checking method of asphaltene precipitation.

3- The asphaltene precipitation was because of the depressurization process (Decreasing the pressure of the reservoir below the asphaltene onset pressure). A decrease in pressure decreases solubility parameter until reaching bubble point pressure (Increases asphaltene precipitation), and it increases with further reduction of pressure below the bubble point (Increases asphaltene solubility).

4-The relationship between temperature and AOP is indirect at which AOP decreases with temperature increase and this means that increasing the temperature decreases asphaltene precipitation problem, therefore heating the fluid is one of the treatment methods.

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NOMENCLATURE

AOP = asphaltene onset pressure.

CN = carbon number.

EOS = equation of state.

$Frac_i^{A}$ = asphaltene fraction.

$Frac_i^{no-A}$ = nonasphaltene fraction.

LOP = lower onset pressure.

P = pressure.

P_cA = critical pressure of asphaltene.

P_{ci} = the critical pressure of pseudo-component i.

Poap = onset of asphaltene precipitation pressures.

PR = Peng-Robinson.

PVT = pressure, volume, and temperature.

P_{ci}^{A} = the critical pressure of asphaltene fraction.

P_{ci}^{no-A} = the critical pressure of nonasphaltene fraction.

R = universal gas constant.

RK = redlich-kwong.

SRK = soave-redlich-kwong.

STO = stoke tank oil.

T = absolute temperature.

Tc and Pc = critical temperature and critical pressure, respectively.

T_cA = critical temperature of asphaltene.

T_{ci} = the critical temperature of pseudo-component i.

T_{ci}^{A} = the critical temperature of the asphaltene fraction.

T_{ci}^{no-A} = the critical temperature of the nonasphaltene fraction.

V = molar volume.

ZN = mole fraction.

ω = acentric factor.

ω_i^{A} = acentric factor of asphaltene fraction.

ωA = acentric factor of asphaltene.

ω_i^{no-A} = acentric factor of nonasphaltene fraction.