Global Scientific JOURNALS

GSJ: Volume 10, Issue 7, July 2022, Online: ISSN 2320-9186

www.globalscientificjournal.com

Precipitation of Asphaltene on Reservoir Rock Surfaces Resulting From Water Injection.

Research Area: Petroleum Engineering

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Keywords
Asphaltene, Permeability, Equations of State (EOS), Precipitation, Water Injection, Rock Surfaces, PVT-Sim Software.

ABSTRACT

Asphaltene are high molecular weight components of crude oil that originally exists in the oil as colloidal suspension that is stabilized by resins absorbed on their surfaces. The precipitation of asphaltene might lead to formation damage, wellbore plugging and overall reduction in production performance. Although significant effort has been made to understand the impact of water injection on asphaltene precipitation tendency and analysing the effect of water injection on asphaltene precipitation on a field scale has not been extensively studied. Additionally, most of the study on asphaltene precipitation due to water injection has been approached experimentally and there is still contradictory opinions on the larger scale effect of water injection on asphaltene precipitation. In this study we have modelled asphaltene behaviour using a three-phase algorithm with basic equations of state. The models were validated by comparing results with fundamentally accepted principles of asphaltene precipitation in petroleum reservoirs. The model developed in this study is a compositional and robust thermodynamic consistent model better suited to understand the physics of asphaltene precipitation. The PVTSim software was used to predict the behaviour of asphaltene through the implementation of material balance, flash vaporization, fluid flow, thermodynamics and transport mechanisms. The data used for this analysis were from three fields in the Niger Delta region, namely: X, Y and Z. The results obtained shows that water saturation increase in the reservoir resulting from water injection and induce asphaltene precipitation which affect flow performance. One important observation from this analysis was that at the initial water saturation, the simulation showed a very small level of asphaltene precipitation compared to the increased value of 0.2. But at a pressure 2600 psig, significant asphaltene precipitation started as the injected water reached 0.4 pore volumes with about 0.15% of asphaltene already precipitated from the reservoir oil. Further increase in reservoir pressure through water injection, asphaltene precipitation up to a point where additional increases in injected volume causes the precipitated asphaltene to re-dissolve. This research have contributed towards a better understanding of the precipitation of asphaltene in petroleum reservoirs, which will eventually lead to the development of cost-effective strategies to mitigate the detrimental effects of asphaltene precipitation on productivity.

1.1 Introduction

Occurrence of asphaltene precipitation in producing formation constitutes one of the most serious problems currently encountered in the petroleum industry in many areas of the world (Shedid, 2005). Heavy molecules such asphaltene may separate from the mixture, resulting in precipitation problems. Severe asphaltene aggregation problems are faced in both upstream and downstream production operations. It is highly important to predict where and when in the production system such problems may arise, to prevent the consequences of unexpected asphaltene deposition (Hemanta, 2001). They are destabilized and start to precipitate when the pressure, temperature and/or composition changes occur during primary production (Hirscberg *et al.*, 1984).

Asphaltene is the heaviest component in crude oil. It is dissolved in the crude oil under the initial reservoir fluid conditions. Asphaltene are also known to contain the heaviest and the most polar components of crude oil (Li and Firoozabadi 2010). Because of these polar elements, asphaltene molecules have an inherent ability to self-associate between themselves to create larger and heavier clusters (Speight 2014). When the aggregates become too heavy, asphaltene molecules then precipitate out of the crude oil and transition into a solid phase. Because it is a phase related issue, pressure, temperature, and compositional changes are known as the main cause of asphaltene precipitation during production (Mullins *et al*, 2007; Speight, 1996).

However, the changes in reservoir pressure, temperature, and composition may cause asphaltene to precipitate from the crude oil. Therefore, asphaltene can precipitate during primary oil recovery (pressure change), stimulation (temperature and composition change), CO_2 flooding (composition change), and hydrocarbon miscible flooding (composition change). Consequently, the asphaltene precipitates separating from the oil may deposit over the pore surfaces and/or plug

the pore throats. This causes a decrease in the pore space and/or reduction of the ability of fluid to flow in the formation. Therefore, the deposition of asphaltene in petroleum reservoirs during production can induce significant formation damage and decline of productivity of the wells (Faruk *et al*, 2005).

Asphaltene precipitation can essentially occur at all stages of petroleum production, which can lead to various undesired problems (Leontaritis 1989; Kokal and Sayegh 1995; Izquierdo and Rivas 1997). Inside the reservoir, asphaltene buildup can significantly reduce permeability and productivity through pore blockage, alter wettability from water-wet to oil-wet, and increase oil viscosity (Khalifeh *et al*, 2013; Leontaritis *et al*, 1994; Seifried *et al*, 2013; Tetanic 2014). The accumulation of asphaltene can also damage well tubular, downhole equipment, and pumps (Alkafeef *et al*, 2005; Limanowka *et al*, 1999). Furthermore, previous cases of flow restriction in pipelines and production facilities have been reported to be caused by asphaltene deposition (Wylde and Slayer 2010; Thawer *et al*, 1990).

Chemical composition of asphaltene varies greatly depending on the precipitation conditions (Ortega *et al* 2015; McLean and Kilpatrick 1997; Dabir *et al*, 1996). Previous studies have found that asphaltene deposits obtained from the wellbore have different characteristics compared to synthetically precipitated asphaltene through solvent addition (Klein *et al*, 2006; Rogel, Miao *et al*, 2015). However, the impracticalities associated with generating such high pressure and temperature makes precipitation by solvents much more feasible for extensive characterization of asphaltene (Gawel and Speight 2010). Hence, simulation of asphaltene precipitation behavior is conducted through onset asphaltene precipitation experiments by deliberately altering the chemical composition of the crude oil with addition of n-alkanes (Akbarzadeh *et al*. 2004).

1.2 Statement of the problem

Asphaltene deposits in reservoirs limit the oil production of wells as they block the pores of the rock. This changes the wettability and modifies the absorption of polar compounds including the deposition of organic materials which impede oil migration (Faria, 2003). During the oil production, asphaltene deposition can occur; there are several mechanisms involved in asphaltene deposition, among them, the change in reservoir pressure or temperature, and fluid compositions are considered the main mechanisms. Water injection into reservoirs changes the reservoir properties significantly which may lead to drastic asphaltene depositions.

Deposition of asphaltene in oil wells, pumps, flowlines, pipelines and production facilities can reduce well productivity, damage pumps, restrict or plug flowline and pipelines and foul production handling facilities (Cimino *et al*., 1995; Saniere *et al*., 2004). Precipitated asphaltene may also build-up in the near wellbore, reservoir rock and clog the porous matrix of the reservoir during drilling and chemical treatment (Leontaritis *et al*., 1994; Luo *et al*., 2008). Apart from causing the reservoir formation damage, asphaltene deposits could also result in reversal of the rock wettability to oil-wet, which leads to a lower recovery factor (Yan and Plancher, 1997).

1.3 Aim of the Study

The aim of this research is to develop a mathematical model for simulating the asphaltene precipitation on reservoir rock surfaces during the production and processing of petroleum crudes

1.4 Objectives of the Study

The objectives of this research are to:

i. Develop a mathematical model for analysing asphaltene precipitation and behaviour in petroleum reservoirs due to water injection.

ii. Simulate and validate the model developed above using a PVT Simulation software (PVTSIM).

iii. Analyse simulation results to understand the effect of water injection on asphaltene precipitation.

iv. Evaluate the predictive ability of the developed models and comparing results with actual data from relevant literatures and data repositories.

1.4 Significance of the Study

Asphaltene precipitation is one of the most common problems faced by the oil industry throughout the world during oil production, transportation and refinery processes. In oil recovery, especially in water injection, formation of asphaltene aggregation, following their deposition can result in plugging of the formation, well bore and production facilities and makes the process costly and sometimes uneconomical.

The significance of this research are as follows:

i. Firstly, this research will aid towards a better understanding of the precipitation of asphaltene in petroleum reservoirs, which will eventually lead to the development of cost-effective strategies for the mitigation of this flow assurance problem.

ii. Secondly, the developed model can be used to identify operating conditions which are favourable to asphaltene precipitation in petroleum reservoirs. This information is useful to be used in designing production strategies and IOR projects (Water injection).

iii. It will also serve as a yardstick for the oil and gas industries for the elimination of flow assurance issues

1.5 Scope of the Study

The main purpose of this research is to develop a mathematical model for simulating the asphaltene precipitation on reservoir rock surfaces during the production and processing of petroleum crudes and further investigate techniques for mitigating and/or eliminating this flow assurance issue. The mathematical formulation is that of a 3D fully compositional reservoir developed model to predict asphaltene precipitation. The model developed uses three dynamic governing equations namely: conversation of mass (moles), conservation of volume and equation of state (EOS).

The models were validated by comparing results with fundamentally accepted principles of asphaltene precipitation in petroleum reservoirs. The PVTSim software was used to predict the behaviour of asphaltene through the implementation of material balance, flash vaporization, fluid flow, thermodynamics and transport mechanisms. The data used for this analysis were from three fields in the Niger Delta region, namely: X, Y and Z respectively.

2.0 Asphaltene Precipitation, Properties and Compositon.

Asphaltene precipitation is caused by a number of factors including changes in pressure, temperature, and composition. The two most prevalent causes of asphaltene precipitation in the reservoir are decreasing pressure and mixing of oil with injected solvent in improved oil recovery (IOR) processes. Drilling, completion, acid stimulation, and hydraulic fracturing activities can also induce precipitation in the near-wellbore region. Changes in pressure, temperature, and composition may alter the initial equilibrium state and cause asphaltene precipitation. The region in which precipitation occurs is bounded by the asphaltene precipitation envelope (APE), also sometime called the asphaltene deposition envelope (ADE). Figure 2.1 shows a typical pressure composition APE and a pressure temperature APE. For purposes of this page, precipitation refers to the formation of the asphaltene precipitate as a result of thermodynamic equilibrium and deposition refers to the settling of the precipitated asphaltene

onto the rock surface in a porous medium. The onset conditions correspond to points on the APE. Within the APE, the amount of precipitated asphaltene increases as pressure decreases from the upper onset pressure to the saturation pressure of the oil. The precipitation reaches a maximum value at the saturation pressure and decreases as pressure decreases below the saturation pressure.

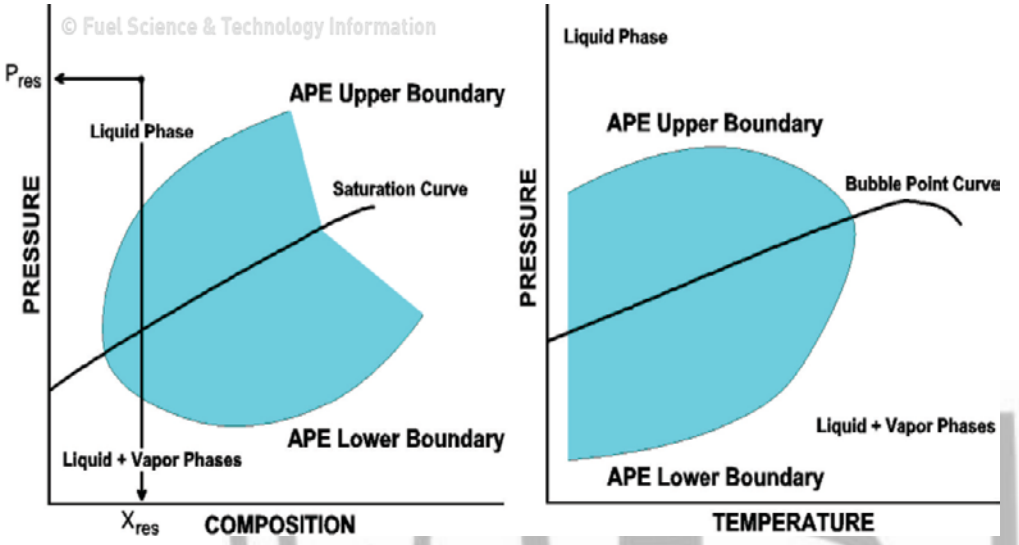

Figure 2.1: Pressure-composition and pressure-temperature APEs (Hirschberg *et al*, 1984).

Asphaltene are usually defined as a solubility class of petroleum, which precipitate from crude oil by the addition of an excess amount of *n*-alkane solvents such as *n*-heptane or *n*-pentane and are soluble in aromatic solvents such as toluene or benzene.

2.1 **Properties of Asphaltene**

Both thermodynamic and dielectric properties of asphaltene have been studied in the literature. Thermodynamic properties include molar volume or density, solubility parameter and heat capacity (Laštovka *et al.*, 2008). Dielectric properties include permittivity or dielectric constant and dipole moments (Sheu *et al.*, 1994; Pedersen, 2000). The two most significant properties of asphaltene for this research are density and solubility parameter.

2.1.1 Density

Gravimetric measurements are normally used to obtain the density of asphaltene. The densities of solid asphaltene from crude oil were reported to be between 1170 and 1280 kg/m³ (Rogel and Carbognani, 2003). The density of asphaltene with a smaller H/C ratio (more aromatic) was larger than the asphaltene with a larger H/C ratio. The effective liquid density of asphaltene in mixtures was measured using an indirect method (Yarranton and Masliyah, 1996). In this approach, the densities of solutions of different concentrations of asphaltene in toluene were measured. The asphaltene density was back-calculated assuming zero excess volumes of mixing. The reported density by this method ranged from 1100 to 1200 kg/m³ for asphaltene from a variety of sources.

2.1.2 Solubility Parameter

The definition of solubility parameter (δ) is given by the following equation (Hildebrand and Scott, 1950):

$$\delta = \left(\frac{-E}{V}\right)^{\frac{1}{2}} \quad (2.1)$$

Where, *E* is the cohesive energy of the liquid and *v* is the molar volume at a given pressure and temperature. The unit of the solubility parameter is the square root of pressure units. Physically, the extent of miscibility of two components depends on the closeness of solubility parameter of those components. At temperatures below the normal boiling point and low pressures, the most used expression for solubility parameter is given by:

$$\delta = \left(\frac{\Delta H^{vap\,*} - RT}{V}\right)^{\frac{1}{2}} \quad (2.2)$$

Where $\Delta Hvap^*$ is the molar heat of vaporization (J/mol), *R* is the universal gas constant (8.314 J/molK), *v* is the molar volume (cm^3/mol), and *T* is the absolute temperature (K). For these units, the solubility parameter is reported in $MPa^{0.5}$.

2.2 Equation of State (EOS) Models

Equations of state like Soave-Redlich-Kwong and Peng-Robinson EOS are popular in oil industry for calculation of phase equilibria values since they have good accuracy and relatively low mathematical complexity (Firoozabadi, 2010).

Soave-Redlich-Kwong (SRK) EOS (Soave, 1972).

$$P = \frac{RT}{v-b} - \frac{a}{v(v+b)} \tag{2.3}$$

Peng-Robinson (PR) EOS (Peng, 1976).

$$P = \frac{RT}{v-b} = \frac{a}{v(v+b)+b(v-b)} \tag{2.4}$$

Where, a and b are the constants of the corresponding EOS and v is the molar volume.

Solid models fall under the category of models utilizing cubic EOS approach. In solid models, precipitated asphaltene are represented in the form of a pure dense phase (solid phase) while the oil and gas phases are modelled using cubic EOS.

3 Materials and Method

3.1 Materials

The materials used for this research are PVT Software, field data and reservoir fluid properties as shown in the tables below.

3.1.1 Data for Analysis

The data used for this analysis were from three fields in the Niger Delta region, namely: X, Y and Z Table 3.1 show the properties of crude samples and Table 3.2 is a description of the composition of the oil samples. The analysis of the effect of water injection on the precipitation of asphaltene can be properly carried through compositional modelling which requires the components of the flowing stream and their weight percent.

Table 3.1: Properties of Crude Oil Samples used for the analysis

Properties	**X**	**Y**	**Z**
Density of Crude (lb/gal)	6.51	7.01	6.92
API Gravity (^{o}API)	49.91	36.95	38.80
BSW	0.6	0.72	0.7
Average Water Content (% by volume)	0.2	0.23	0.18
Viscosity	0.33	0.42	0.38

Table 3.2: Crude Oil Sample Compositions

Component	**Mol % (X)**	**(Y)**	**(Z)**

N_2	0.86	0.75	0.94
CO_2	0.10	0.12	0.16
Sulphur	0.16	0.22	0.19
C_1	24.05	34.05	28.65
C_2	1.2	0.77	1.01
C_3	3.560	2.450	3.89
i-C_4	1.300	0.98	0.87
N-C_4	5.702	3.60	4.56
I-C_5	1.2	0.9	01.3
N-C_5	2.33	3.5	2.96
C_6	1.34	2.9	1.70
C_7	1.3	1.9	2.1
C_8	2.34	3.4	2.80
C_9	3.42	2.98	3.24
C_{10}	0.6	1.1	1.23
C_{11+}	48.33	35.90	40.80
Resin	1.1	1.9	2.30
Asphaltenes	1.108	2.58	0.40
Total	100	100	100

Table 3.3: Reservoir Properties used for the analysis

Parameter	**Value**

Porosity	0.12
Permeability	400
Rock Compressibility	3.7×10^{-6} psi^{-1}
Initial Water Saturation	0.15
Depth of (GOC)	2000 ft
Depth of (WOC)	4080 ft
Fluids	Gas, Oil and Water

3.2 Modelling Approach

The mathematical formulation is that of a 3D fully compositional reservoir developed to predict asphaltene precipitation using the VLE method. This methods uses the three governing equations:

i. Conservation of mass (moles)
ii. Conservation of volume, and
iii. Equation of State

3.2.1 Model Assumptions

The main assumptions on which this model development is based are:

i. Darcy's Law for multiphase and multicomponent flow is applicable
ii. Isothermal reservoir system
iii. Gravitation effects is negligible
iv. No flow boundary condition
v. Peng-Robinsons EOS of Instantaneous thermodynamic equilibrium is applicable
vi. Asphaltene precipitation is irreversible

vii. A control volume for precipitated asphaltene (precipitated asphaltene are immobile)

viii. An understated oil with no gas cap (to isolate asphaltene precipitation due to gas evolution).

3.2.2 Equation of State (EOS)

In the analysis of asphaltene precipitation in multiphase PVT simulators, several cubic equations of state are applied. These equations enables the possibility of establishing relationships between flow parameters and make necessary estimations. An equation of state (EOS) is a functional relationship between fluid state functions describing the equilibrium state of a system (Miftachul, 2010). The two most widely used equation of states for the estimation of fluid properties and model phase behavior in compositional reservoir simulators are:

i. Soave-Redlich-Kwong equation

ii. Peng-Robinson equation

The equations of state calculates system pressure using the gas constant, R, Temperature, T, molar volume, v_m is molar volume, constant parameters a and b, representing repulsion and volume at infinite pressure. This helps in the estimation of component pressure required in the discretized conservation of volume expression.

3.2.2.1 Soave-Redlich-Kwong equation

The Soave-Redlich-Kwong equation is conventional compositional equation of state originally developed by Redlich and Kwong (1949) and further modified by Soave in 1972 to obtain the expression for pressure as:

$$p = \frac{RT}{v_m - b} - \frac{a}{v_m (v_m + b)} \tag{3.1}$$

In terms of compressibility factor, equation 3.1 can also be written as:

$$Z^3 - Z^2 + (A - B - B^2)Z - (AB) = 0 \quad (3.2)$$

$$A = \frac{ap}{(RT)^2} \quad (3.3)$$

$$B = \frac{bp}{RT} \quad (3.4)$$

For pure components, the parameters are estimated in terms of the critical properties of the components as follows:

$$A = 0.45724 \times R^2 \left(\frac{T_c^2}{P_c^2} \times [1 + (0.480 + 1.574\omega - 0.17\omega^2)]\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)_i^2 \quad (3.5)$$

$$B = 0.07780 \times R\left(\frac{T_{ci}^2}{P_{ci}^2}\right)_i \quad (3.6)$$

For non-ideal fluids such as that considered in this study, it makes sense to express equation 3.6 in terms of the fugacity coefficient as:

$$\ln\left(\frac{f_i}{p}\right) = (Z - 1) - \ln(Z - B) - AB^{-1}\ln(1 - BZ^{-1}) \quad (3.7)$$

Where f is the fugacity term. It is important to introduce the fugacity coefficient in other account for the movement of gas between phases and how it affects the chemical equilibrium of the entire system with regards to asphaltene precipitation.

The precipitation of asphaltenes in the crude oil as a result of water injection is due to an interaction between the components in the flow stream. An extension to the EOS parameters is one that estimates the parameters a, b with molecular interactions put under considerations. For a mixture of several components, the parameters can be estimated as a summation of the binary interactions between the components as follows:

$$a = \sum_{i=1}^{n_c}\sum_{i=j}^{n_c} y_i\, y_j\left(1 - \epsilon_{ij}\right)\sqrt{a_i a_j} \quad (3.8)$$

$$b = \sum_{i=1}^{n_c} y_i\, b_i \tag{3.9}$$

Where a_i, a_j, and b_i are component based parameters calculated using the expression for pure components described above. Similarly, for equilibrium calculations the liquid phase mixture fugacity must be calculated as well. The liquid phase fugacity equation is a little modification for the set of equation for the gas phase described above and is written as:

$$\ln\left(\frac{f_i}{y_i p}\right) = (Z_l - 1)b_e - \ln(Z_l - B) - AB^{-1}(a_e - b_e)\ln\left(BZ_l^{-1}\right) \tag{3.10}$$

Where:

$$b_e = \frac{b_i}{b} \tag{3.11}$$

$$a_e = \frac{= \sum_{i=1}^{n_c}\sum_{i=j}^{n_c} y_i\, y_j\left(1 - \epsilon_{ij}\right)\sqrt{a_i a_j}}{\left([1 + (0.480 + 1.574\omega - 0.17\omega^2)]\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)^2} \tag{3.12}$$

3.2.2.2 Peng-Robinson equation

Peng and Robinson, (1976) modified the SRK EOS model by improving the liquid density predictions. The resulting pressure equation is written as:

$$p = \frac{RT}{v_m - b} - \frac{a}{v_m(v_m + b) + b(v_m - b)} \tag{3.13}$$

Which can further be written in terms of compressibility factor as:

$$Z^3 - (1 - B)Z^2 + (A - 2B - 3B^2)Z - (AB - B^2 - B^3) = 0 \tag{3.14}$$

A and B are estimated using the same equations described in (3.13) and (3.14).

In terms of the critical flow parameter, a can be estimated using different models depending on the range of values for the acentric factor, ω.

For values of $\omega \leq 0.5$, the

$$a = 0.45724\, R^2 \left(\frac{T_c^2}{P_c^2} [1 + (0{:}\,037464 + 1.5422\omega - 0.26992\omega^2)] \left(1 - \sqrt{\frac{T}{T_c}}\right) \right)_i^2 \qquad (3.15)$$

For values of $\omega > 0.5$,

$$a = 0.45724 R^2 \left(\frac{T_c^2}{P_c^2} [1 + (0{:}\,0374 + 1.485\omega - 0.1644\omega^2 + 0.0167\omega^3)] \left(- \sqrt{\frac{T}{T_c}} \right) \right)_i^2 \qquad (3.16)$$

Parameter b is calculated using equation (3.14) described above.

In terms of fugacity, equation (3.18) can be written as:

$$\ln\left(\frac{f_i}{p}\right) = (Z - 1) - \ln(Z - B) - 0.3536 A B^{-1} \ln\left(\frac{Z - 2.414B}{Z - 0.414B}\right) \qquad (3.17)$$

The component based model for predicting the system parameters a and b is the same as described in equations (3.16) and (3.17) for the SRK EOS.

The fugacity expression for the liquid mixture is written as:

$$\ln\left(\frac{f_i}{y_i p}\right) = (Z_l - 1) b_e - \ln(Z_l - B) - 0.3536 A B^{-1} (a_e - b_e) \ln\left(\frac{Z - 2.414B}{Z - 0.414B}\right) \qquad (3.18)$$

Where:

$$b_e = \frac{b_i}{b} \qquad (3.19)$$

$$a_e = \frac{\sum_{i=1}^{n_c} \sum_{i=j}^{n_c} y_i\, y_j \left(1 - \epsilon_{ij}\right) \sqrt{a_i a_j}}{\left([1 + (0{:}\,037464 + 1.5422\omega - 0.26992\omega^2)] \left(1 - \sqrt{\frac{T}{T_c}}\right) \right)_i^2} \quad \text{for } \omega \leq 0.5 \qquad (3.20)$$

$$a_e = \frac{\sum_{i=1}^{n_c}\sum_{i=j}^{n_c} y_i\, y_j\left(1-\epsilon_{ij}\right)\sqrt{a_i a_j}}{\left(\left[1+(0{:}\,0374+1.485\omega-0.1644\omega^2+0.0167\omega^3)\right]\left(1-\sqrt{\frac{T}{T_c}}\right)\right)_i^2} \text{ for } \omega > 0.5 \quad (3.21)$$

For this study, both the SRK and PR EOS would be exploited in the analysis to determine how they affect asphaltene precipitation calculations. The same procedure used in this analysis can be applied to other cubic equations of state.

4 Results and Discussion

4.1 Asphaltene Precipitation Analysis

Asphaltene precipitation by weight was simulated to validate the performance of the model. It can be observed from figure 4.1 that asphaltene precipitation increases with depressurization of the reservoir system which is in line with findings from several studies which suggest that during the pressurization of a reservoir system with significant asphaltene content, that asphaltene precipitation can occur and increase up to a certain pressure, known as the equilibrium pressure where the precipitated asphaltene begins to re-dissolve with further depressurization.

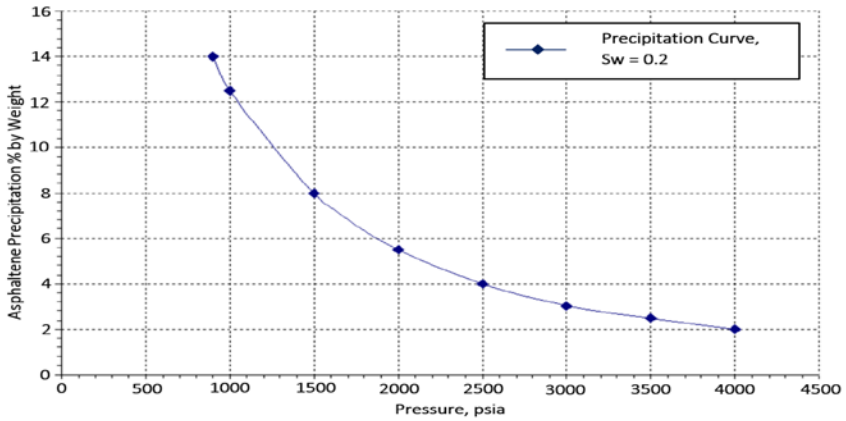

Figure 4.1**:** Asphaltene Precipitation by weight for varying pressures.

4.2 Effect of Asphaltene Precipitation on Permeability

In several studies, cases of permeability reduction have been identified due to asphaltene precipitation. This concept have not been extended to fields with water injection operation. In this analysis, a step further was taken to understand how water injection affects permeability reduction and the influence of asphaltene precipitation in this regard. To achieve this, PVT simulation study was carried out for cases of with and without asphaltene precipitation; and monitoring the permeability response. To validate the model, the first analysis was to obtain the effect of asphaltene precipitation saturation on the permeability. As can be observed from figure 4.2, asphaltene precipitation reduces the permeability of the system.

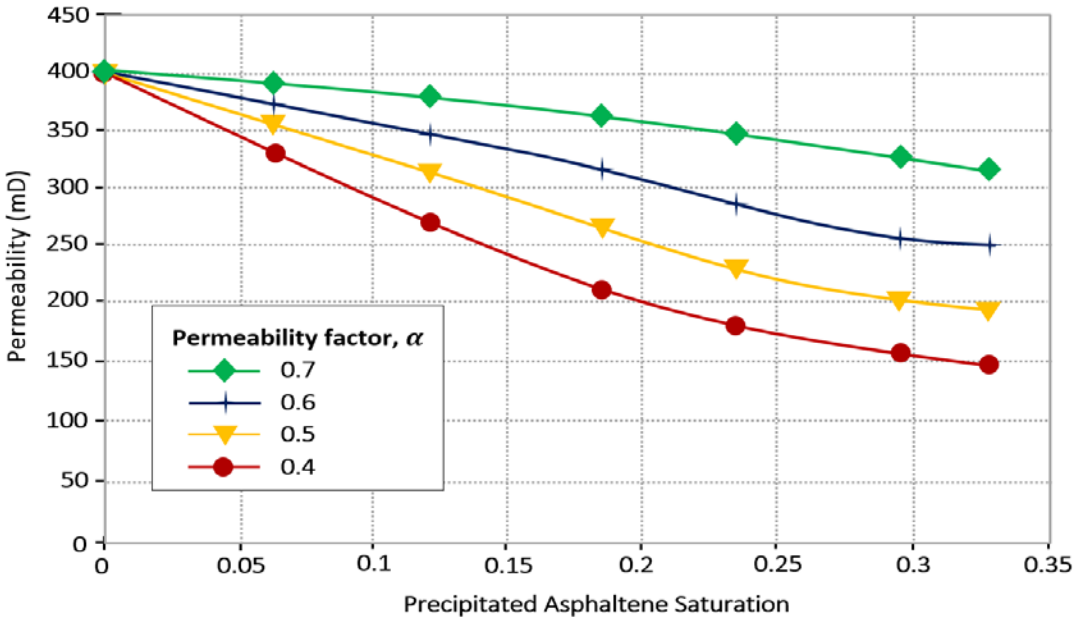

Figure 4.2: Permeability behavior with asphaltene precipitation in the reservoir plotted as a function of the permeability factor.

Figure 4.2 shows the relationship between permeability and precipitated asphaltene for different values of the permeability factor. It can be observed that for high values of asphaltene precipitation, the permeability is reduced, with higher percentage of reduction witnessed for reservoirs with low permeability factor values; high values yields a linear and gentle permeability reduction slope. Analysis on asphaltene precipitation effect on flow capacity was carried out with permeability as a test parameter.

4.3 Effect of Asphaltene Precipitation on Cumulative oil Production

One of the major effect of asphaltene precipitation in petroleum reservoirs is the alteration of flow properties of the rock (for example effective and relative permeabilities) and directly affecting flow performance. The effect of asphaltene precipitation due to water injection can be further analysed by comparing cumulative oil production for different cases of with and without asphaltene precipitation. For the first case (Water Injection and no asphaltene in crude) the maximum cumulative production obtained after 1400 days was about 0.84MMbbl. For the second case (Water injection and asphaltene in crude) it can be observed that the presence of asphaltene during the water injection operation caused a decrease in total production after 1400 days to 0.76, a 9.5% decrease from the 0.84 MMbbl. A similar result was observed for the third (No water injection and no asphaltene) and the fourth (no water injection, with asphaltene) cases, which showed a 7.6% decrease in total cumulative production due to the presence of asphaltene during water injection. The cumulative production for the last two cases were lower than those of the first two typically because water injection increases the pressure of the reservoir and hence more fluid recovery.

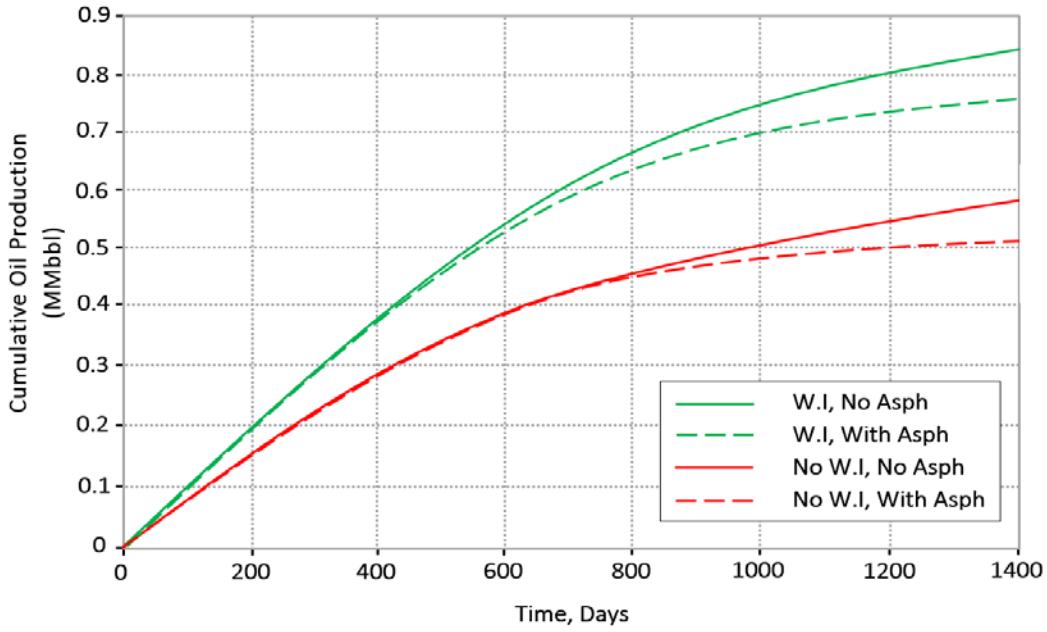

Figure 4.3: Cumulative oil production against time for different cases of water injection and asphaltene precipitation.

Conclusion.

In this study we have modelled asphaltene behavior using basic Equations of state (EOS). The models were validated in the previous chapter by comparing results with fundamentally accepted principles of asphaltene precipitation in petroleum reservoirs.

From the findings of this study it can be concluded that:

i. Water saturation increase in the reservoir resulting from water flooding can induce asphaltene precipitation which can affect flow performance.
ii. By increasing the pore volume of injected fluid in the reservoir, asphaltene precipitation will increase up to a point where additional increases in injected volume causes the precipitated asphaltene to re-dissolve.
iii. The injection pressure affects asphaltene precipitation; increasing the water injection pressure causes less precipitation

iv. The presence of asphaltene in crudes during the water injection operation results to significant decrease in total production, an occurrence that can be attributed to reduction in permeability caused by precipitation of asphaltene in the reservoir system

Recommendations

Experimental investigation into the concept of asphaltene precipitation during water injection should be considered for future studies because in this study, a mathematical modelling approach was adopted. In such study, the advantage of physical filtration experiments where asphaltenes are induced, extracted and separated from the crude oil, thus allowing for further characterization can be carried out thereby solidifying the knowledge about asphaltene precipitation in reservoirs undergoing water injection.

Contributions to Knowledge

In this context, the major contributions of current work can be summarized as**:**

i. The developed Asphaltene model can be used to identify operating conditions which are favourable to asphaltene precipitation in petroleum reservoirs. This information is useful to be used in designing production strategies and IOR projects (Water injection).

ii. The research have contributed towards a better understanding of the precipitation of asphaltene in petroleum reservoirs, which will eventually lead to the development of cost-effective strategies for the mitigation of this flow assurance problem.

Acknowledments

First of all, I would like to express my deep and profound gratitude to my main and co-supervisors, Engr. Dr. O. F. Wopara and Prof. K. K Dagde for their continuous support, timely encouragement and excellent guidance throughout my research writing.

In a special way I thank Engr. Shiyanbade, Damola Sunday for his support and constant encouragement and all departmental lecturers for their contributions. To all my brothers and sisters, thank you for your words of prayers and support.

Finally, I would like to express my sincere thanks to my parents (Sir/Mrs. Dabuna Basi, ODB) for their constant encouragement and financial support. God bless you all!

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