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Comparison of Asphaltene Models in Two Commercial Compositional Simulators

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Abstract
The many challenges that engineers face during production from hydrocarbon reserviors due to asphaltene deposition show the importance of addressing this phenomenon in the management of reservoirs and adopting production policies. Simulation, as one of the most economic ways of reservoir studies could be done using various software packages. It is clear that each of these simulators has its own strengths and limitations that should be carefully examined and recognized. This study addresses the differences between the asphaltene models of two commercially used compositional simulators and the challenges thereof. It is done using a 3D sector model built on real data from one of the Iranian South oil reservoirs so that the final results resemble the reality of the reservoir. In addition, the simple scenario of natural depletion is considered for production from an undersaturated oil reservoir. The fluid model which is used in both simulators is the solid model implemented in WinProp and in-house software (PVT-Pro). Moreover, the same thermodynamic model has been deployed in both asphaltene models (PR-EOS). Different cases were run to demonstrate the extent of influencing the reservoir by how each simulator models the asphaltene phenomenon. As a result, porosity/permeability reduction, viscosity change, and wettability alteration were described in both simulators. Finally, both simulators are compared regarding whether can describe the final changes caused by asphaltene precipitation and deposition. In the end, the speed of each simulation run is also investigated.

Keywords: Asphaltene Precipitation, Compositional Simulator, Deposition, Porosity Effect, Wettability Alteration

Introduction
Asphaltene precipitation may occur during primary production or EOR processes due to pressure, temperature, and fluid composition changes. The precipitated asphaltene can cause problems at any point in the reservoir, wellbore, separators, and other production facilities [1].
It is assumed by a number of researchers that precipitated asphaltene would immediately attach to the surface of the reservoir rock (deposition), and it would not flow as a part of the reservoir fluid [2-4]. Still, others have also reported the opposite [5]. A fraction of precipitated asphaltene would stick to the rock surface due to rock-fluid interactions or plug the throats. Uninterrupted adsorption of asphaltene particles on pore surfaces makes the pores smaller over time. Consequently, higher fluid velocity, whenever it exceeds a critical velocity, can remove deposited asphaltene from the surface [6].
As for simulation of the asphaltene precipitation phenomenon, a couple of reservoir simulators with the capability of modeling the asphaltene deposition and formation damage have been developed by several researchers [2, 5, 7-11]. Nonetheless, asphaltene deposition principally can cause the wettability of reservoir rock to shift toward oil-wet [12-15], an issue that has not received enough attention. In this regard, a model to describe wettability alteration due to asphaltene deposition was developed by Darabi et al. in 2012, and it was implemented into UTCOMP. It has been concluded that the wettability alteration reduces cumulative oil production, especially when the water film is unstable [16]. Afterward, a model evaluating asphaltene-induced wettability alteration was suggested by Mohebbinia in 2017 [15]. The model was initially presented by Delshad et al in 1996 for surfactant and alkali-induced wettability change [18]. Recently, precipitation and deposition models implemented into a cylindrical compositional simulator were developed to investigate asphaltene deposition effects on single-well performance by Ghadimi et al. in 2019, and also the effect of wettability change induced by asphaltene deposition on the reservoir was explained by them [1].

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As regards using and comparison of common simulators in the field of modeling the asphaltene precipitation phenomenon, a comparison between three simulators of GEM, Eclipse, and UTCOMP was done using a synthetic reservoir model which is under gas injection process by Al-Qasim et al. in 2017 [19]. Their study claimed that neither GEM nor Eclipse takes porosity change into account when they simulate the asphaltene behavior. In the present research, however, it is demonstrated that this is false. It will be shown that GEM does this indirectly by including a permeability reduction model. Moreover, viscosity or wettability alteration in the aforementioned simulators have never been discussed by Al-Qasim et al. while these are two significant parameters that may affect the reservoir and its final recovery considerably. Accordingly, the change in these two has been addressed in the present study. Note that although the average reservoir pressure when the asphaltene option is active has been compared and matched for all three simulators in the Al-Qasim et al's study, this parameter has not been dealt with for no asphaltene case. Nevertheless, this is very important to see how precise each simulator is in modeling and studying the effect of asphaltene precipitation on reservoir performance. Generally, the asphaltene precipitation process in both Eclipse and CMG consists of two steps: adsorption and deposition of asphaltene on the reservoir rock and re-dissolution of asphaltene in the reservoir fluid (in terms of fines/flocs). Eclipse has two options for modeling permeability reduction: power-law and a lookup table [20]. On the contrary, GEM makes use of a Resistance Factor (RF) to do so, while one of the RF calculation options uses the same power-law [21]. One more difference is that in Eclipse, instead of asphaltene precipitation weight percent, the amount of dissolved asphaltene in terms of a table should be given as input to the simulator. This table should be prepared by the user, while GEM makes this easier by directly using the solid model parameters that have been created using WinProp. The reason for using the solid model to predict asphaltene thermodynamic behavior was that WinProp was only able to use this model. This is while the results of previous simulation studies show that the PC-SAFT model is superior to the solid model in terms of the extrapolation accuracy when the experimental data are not available for the simulation conditions (i.e., variation in temperature, pressure, and fluid composition in the reservoir/wellbore). Nevertheless, a properly tuned solid model is also able to reproduce the experimental data with the same quality as the PC-SAFT model [22].

In this study, two commercial compositional simulators are compared to evaluate their potential for asphaltene modeling and predicting its effects on reservoir properties and performance. Thereofre, a synthetic 3D reservoir model was created using the real data from one of the Iranian South oil reservoirs, and the fluid model was implemented into GEM and Eclipse using WinProp (from CMG package) and PVTPro (a commercial PVT software) respectively. In this study, the asphaltene precipitation is predicted using the solid model. Then, using an appropriate base asphaltene simulation model, the effect of asphaltene precipitation and deposition on various reservoir/fluid parameters as well as simulation run time was investigated and compared in both simulators.

Materials and Methods

Asphaltene Models

Precipitation Models

In E300

In E300, the precipitation process takes place based on its own calculations: The ASPREWG or ASPPW2D keyword can be used to define the maximum amount of the asphaltene that can be dissolved, Wlim, which is expressed as the weight of the precipitation component in oil as a percentage of the total weight of oil. This can be expressed as a limit on the mole fraction of the precipitation component dissolved in oil:

$$X_{\lim} = \frac{W_{\lim}}{100} \cdot \frac{m_{woil}}{m_{wp} x_p} \quad (1)$$

where W_{lim} is the maximum dissolved asphaltene in oil (wt. %) which is represented here as the maximum amount of asphaltene that can exist in dissolved form. m_{woil} (Dimensionless), m_{wp} (Dimensionless) and x_p (fraction) are the oil and asphaltene molecular weight (dimensionless) and mole fraction of precipitation component (fraction), respectively. Accordingly, if the resulting mole fraction for the precipitation component is less than this limit, the precipitation component would remain in the solution, and there would be no fines. But if the mole fraction of this component exceeds this value, the dissolved and fine fractions of the precipitation component would be as follows [20]:

$$X_{pd} = X_{\lim} \quad (2)$$

$$X_{pf} = X_p - X_{\lim} \quad (3)$$

In this approach, the asphaltene is defined as a set of component(s) that can precipitate depending on their percentage molar weight in the solution. You define the percentage limit as a function of pressure using the *ASPREWG* and *ASPHALT* (first item) keywords.

In GEM

Asphaltene precipitation is modeled using a multiphase flash calculation in which the fluid phases are described with a cubic equation of state. The fugacity of components in the solid phase is predicted using the CEOS (solid model). The precipitated phase is represented as an ideal mixture of solid components [23]. After calculating the asphaltene mole fraction by empirical asphaltene content, the same critical properties, and acentric factors are assigned to the B+ component. Still, different interaction parameters with the components C1 to C5 are required.

Therefore, a second-time regression is required to ensure the accuracy of the results of the fluid model prediction. Now, it is the time for the calculation of reference fugacity. But why is reference fugacity needed?

At the beginning of flash calculation and during conducting a stability test, it is found out that the hydrocarbon fluid is divided into two phases, and as a result,

$$\ln f_{io} = \ln f_{ig}, \ldots . i = 1, \ldots, nc \quad (4)$$

This equation suggests that the fugacity of solid components in both oil and gas phases are equal. This is true with this

assumption that there is no asphaltene in the gas phase, but this is not the case for the asphaltene one. With such a limiting condition (Eq. 4), the hydrocarbon system (whether vapor-liquid or just liquid) is observed until another solid phase appears. Suppose s1 represents the solid phase in equilibrium with the liquid and gaseous hydrocarbons. If the asphaltene fugacity in the liquid phase exceeds that of pure asphaltene ($f_{nco} > f_{s1}$), then the asphaltene would precipitate. The equation for phase equilibrium would be as follows:

$$\ln f_{n_c o} = \ln f_{s_1} \quad (5)$$

that expresses the equality of fugacity of the precipitating component in the oil phase, and in the precipitated solid s1. The fugacity of components in the hydrocarbon (including oil and gas phases) are calculated by the Peng-Robinson EOS, and the fugacity of solid S1 would be as follows:

$$\ln f_{s1} = \ln f_{s1}^{*} + \frac{V_{s1}(P - P^{*})}{RT} \quad (6)$$

According to this thermodynamic equilibrium equation (Equation 6), the precipitation process of s1 is thermodynamically reversible. Therefore, solid s1 can return to solution whenever the system is in a state outside the asphaltene precipitation envelope [24].

These parameters may all be generated using WinProp and automatically exported with the GEM fluid model. The *SOLIDMODEL, SOLIDTHERMAL, and SOLID_TREF* keywords allow users to enter parameters related to the asphaltene precipitation model into the simulator. This study used *SOLIDMODEL* to specify four parameters required by the isothermal asphaltene precipitation model implemented in GEM.

Flocculation- dissociation Models

In E300

During this process, the fines from the precipitation stage are put together into larger particles of asphaltene, namely as flocs. As it seems from the name, dissociation is exactly the reverse process that could occur depending on the permission for the reversibility of the flocculation process in the simulation study.

The following formula represents a model by which it is possible to calculate how fast the flocculation would occur after precipitation:

$$R_a = \frac{\partial C_a}{\partial t} = r_{ia} C_i - r_{ai} C_a \quad (7)$$

where R_a is the rate of flocs aggregation (dimensionless), C_i is the concentration of the fines (dimensionless), C_a is the concentration of the flocs (dimensionless), r_{ia} and r_{ai} are the aggregation rate coefficient for fines (1/day) and the dissociation rate coefficient for flocs (1/day) respectively [20]. The keyword *ASPFLRT* specifies the rates for the flocculation of fines into flocs and the dissociation of flocs.

In GEM

The asphaltene precipitation model with parameters as input using the *SOLIDMODEL* keyword exhibits complete thermodynamic reversibility; precipitated asphaltene will go back into solution if the system is returned to a thermodynamic state outside the asphaltene precipitation envelope.

Irreversibility of solid precipitates is modeled by allowing the thermodynamic asphaltene precipitate (solid s1) to be transformed via a simple reversible chemical reaction into another solid, s_2. This can be viewed as the flocculation of smaller asphaltene particles into larger aggregates. The reaction may be written as follows:

$s_1 \leftrightarrow s_2$

The reaction rate for the formation of s_2 is:

$$r = k_{12} C_{s1,o} - k_{21} C_{s2,o} \quad (8)$$

where

k_{12} is the forward rate constant of solid s2 formation from s_1 [day^{-1}]

k_{21} is the reverse rate constant of solid s1 formation from s_2 [day^{-1}]

r is reaction rate [day^{-1}]

$C_{s_1,o}$ is the concentration of suspended solid s1 in the oil phase [mol/m^3]

$C_{s_2,o}$ is the concentration of suspended solid s2 in the oil phase [mol/m^3]

The keyword *SOLID-CONV-RATE* allows users to enter forward and reverse rate constants for conver precipitated asphaltene to flocculated asphaltene. This conversion may be made reversible, fully irreversible or partially irreversible [21]. Asphaltene flocs may deposit in the porous media as described in the next section (Asphaltene deposition section).

Deposition-entrainment Models

In E300

This is for when the flocs are exchanged between the oil phase and the surface of the reservoir rock. The flocs could be held on the surface by reservoir rock, can be trapped within the porous media and plug the pore throats, or could be entrained and returned to the oil phase because of high fluid velocity (in the deposition area).

In the present compositional simulator, the net deposition rate in the flow direction (i) would be described as follows [20]:

$$\frac{\partial \varepsilon_i}{\partial t} = \frac{\alpha}{d} \phi C_a + \gamma_1 |F_{oi}| C_a - \beta (|U_{oi}| - U_{cr})^{+} \varepsilon_i \quad (9)$$

where ε_i denotes the amount of deposition in i flow direction (fraction), α represents the adsorption coefficient (1/day), d is the number of dimensions (1, 2, or 3), Φ is porosity (fraction), C_a is volume concentration of the flowing flocs (dimensionless),γ_1 is the plugging coefficient (1/ft^3), Foi is the oil flowrate (ft^3/day), β is the entrainment coefficient (1/ft), U_{oi} is the oil Darcy velocity (ft/day), and U_{cr} is the critical velocity (ft/day) [20].

Note that the total volume fraction of asphaltene deposits would be the sum of the deposits in each direction [20]. The keyword *ASPDEPO* provides data for the asphaltene deposition process consisting of static deposition or adsorption coefficient α, plugging coefficient γ_1, the entrainment coefficient β, and critical velocity Ucr. These user-input parameters should be obtained from core flood experiments.

In GEM

GEM deposition model is very similar to the E300 ones. When the asphaltene precipitates, it can either flow with the reservoir fluid or deposit on the surface of the reservoir rock [25]. The amount of deposited asphaltene, which is the

product of three mechanisms of surface deposition, pore throat plugging, and entrainment of deposited asphaltene particles, is calculated by the following equation (Equation 10) [9]:

$$dV_{dep}/dt = \alpha C\varphi - \beta V_{dep}(v_o - v_{cr,o}) + \gamma u_o C \quad (10)$$

dV_{dep}/dt is rate of deposition. V_{dep} denotes the volume of deposited asphaltene per grid block volume. The first term of the above equation represents surface deposition rate, α is surface deposition rate coefficient, C is the volumetric concentration of precipitated asphaltene, and φ is porosity. The second one is entrainment of deposited asphaltenes by oil flow which has a velocity more than critical velocity, where β is entrainment coefficient, v_o is oil phase interstitial velocity, and $v_{cr,o}$ is the oil phase critical interstitial velocity. This term is ignored if the velocity is not large enough to dislodge asphaltene particles from the surface. Plugging pore throats by particles with a radius more than the throat radius is calculated by the third term. Here, u_o is Darcy velocity of oil phase. The instantaneous plugging deposition rate coefficient (γ) is calculated as follows:

$$\gamma = \gamma i\ (1 + \sigma Vdep) \quad (11)$$

where γ_i is the instantaneous plugging deposition rate coefficient, and σ is the snow-ball effect constant. For small particles which can pass through throats easily, γ get a zero value [9].

The keywords *SOLID_ALPHA, SOLID_BETA, SOLID_CRITVEL, SOLID_GAMMA*, and *SOLID_SIGMA* control the deposition of flocculated asphaltene particles.

Asphaltene Damage Models

Porosity/ Permeability Damage

In E300

In the solid deposition model, the reduction in fluid volume, which is caused by the asphaltene deposition, is modeled through oil saturation, and consequently, porosity which is directly related to saturation is reduced too. In the current simulator, the porosity is affected by the asphaltene deposition rate:

$$\phi = \phi_0 - \int_0^t \frac{d\varepsilon}{dt} dt \quad (12)$$

where ϕ_0 denotes porosity at zero time step (fraction), and ε represents the volume of asphaltene deposit (fraction) [20].

The effects of asphaltene deposition on permeability can be modeled in two ways:

It can be correlated to porosity using a power-law correlation that relates present absolute permeability with this parameter in the previous time step:

$$\frac{K}{K_0} = \left(\frac{1-\varepsilon}{\varphi_0}\right)^{\delta} \ldots\ldots\ldots (Power - law) \quad (13)$$

where k and k_0 are permeability (mD) at times t and t_0, respectively, and δ is a user input parameter (dimensionless) that comes from core flood experiments. This dependency of permeability on the deposition volume is consistent in the look-up table (second option), too [20]. This option was preferred for this study to be comparable with the GEM asphaltene model.

Another option is to provide a multiplier for permeability damage versus the volume fraction of asphaltene deposit at each pressure in a table. (Note that the data for this section were taken from the literature since there was no permeability measurement experiment for this reservoir) [20].

The keywords *ASPKDAM* and *ASPHALT* (second item) give the user this option to model permeability damage due to asphaltene deposition. However, it can only be used with the pre-2011.1 asphaltene deposition model.

In GEM

Conceptually, permeability varies with fluid porosity due to its changes from solid deposition and/or mineral precipitation:

$k_k = k_n / rf$

where the resistance factor rf is modeled by the Kozeny-Carman equation (Equation 14) or the power law relationship (Equation 15), kn and kk refer to permeability at previous and current time steps, respectively. The calculation of the resistance factor is done recursively from timestep to timestep:

$$rf = \left(\frac{\Phi_n}{\Phi_k}\right)^{rfexp} \left(\frac{1-\Phi_k}{1-\Phi_n}\right)^2 \quad (14)$$

$$rf = \left(\frac{\Phi_n}{\Phi_k}\right)^{rfexp} \quad (15)$$

It is important to note that change in permeability due to solid deposition; mineral precipitation or dissolution; or due to aqueous phase adsorption is accounted for in flow calculation which can be visualized using *OUTSRF, GRID, RFO, RFG*, and *RFW* or corresponding special history keywords in the input/output section. The permeability remains unaffected, and therefore, the user will not see any change in permeability while visualizing [21].

The keywords *RFCALC* (*and its options like K-C and POWER*) and *RF_EXPONENT* specify the computation of resistance factor in the fluid section of a GEM simulation model. In this study, the power-law was used for calculating rf to ease the comparison between GEM and E300 asphaltene models.

Viscosity Change

In E300

Oil viscosity changes are due to two competing effects:

- The precipitation, as modeled above, tends to increase the oil viscosity
- The deposition of heavier component(s) tends to make the oil lighter, reducing its viscosity.

This can be checked by running a case with deposition parameters set to zero and running the same case with non-zero deposition parameters.

In Eclipse, the change in viscosity can be modeled by using three options, all of which make use of a parameter called mass fraction of asphaltene precipitate, including both fines and flocs, Cp:

$$C_p = \frac{m_{wp} X_{pf} + m_{wf} x_f}{m_{woil}} \quad (16)$$

The first model is the Generalized Einstein model:

$$\frac{\mu}{\mu_0} = 1 + aC_p \quad (17)$$

where μ_0 denotes the oil viscosity (cP) at Cp=0 (this was the choice for this study with the default value for a which is equal to 2.5).

The Krieger and Dougherty model is the second option available that takes two parameters of μ_0 and η (intrinsic viscosity), where C_{p0} is the maximum packing concentration [20]:

$$\frac{\mu}{\mu_0} = (1 - \frac{C_p}{C_{p0}})^{-\eta C_{p0}} \quad (18)$$

Third, viscosity could be similarly modeled using a table consisting of a viscosity multiplier for each value of asphaltene precipitate mass fraction at a specific pressure step [20].

The keywords *ASPVISO* and *ASPHALT* (item 3) provide data for modeling the oil viscosity change when asphaltene precipitation occurs.

In GEM

It seems that GEM has not considered any mathematical model and keyword in its asphaltene model to display and account for the viscosity change during the asphaltene precipitation.

Wettability Alteration

In E300

Asphaltene deposition can trigger a wettability change.

The exact physics of how this alteration occurs is still a research topic, however it has been reported that some of its effects can be captured by a relative permeability shift from a water-wet system to an oil-wet system.

It is assumed that the wettability can be determined from the water-oil capillary pressure values provided that the water-oil capillary pressure is zero or negative, the grid cell is assumed to be oil-wet, and there will be no wettability change.

If the grid cell is water-wet, i.e., it has a positive water/oil capillary pressure, the relative permeabilities (entered using, for example, *SWFN* and *SOF3*) are combined with the oil-wet saturation functions entered using the *ASPKROW* keyword as follows:

1. The weighting factor F is determined as a function of the volume fraction of asphaltene deposit (S_s *or* ε), provided using the *ASPWETF* keyword.
2. The critical oil in water and water saturations are scaled

$S_{ocr} = FS_{ocra} + (1\text{-}F)\, S_{ocri}$

$S_{wcr} = FSwcra + (1\text{-}F)\, Swcri$

where S_{ocr}a and S_{ocri} are the critical oil in water saturations from the *ASPKROW* table and *SOF3* tables, respectively, and *Swcra* and *Swcri* are the critical water saturations from the *ASPKROW* and *SWFN* tables, respectively.

3. Then, a lookup for relative permeability is carried out on the scaled saturations from step 1, followed by linear interpolation between the resulting water-wet and oil-wet relative permeabilities as:

$krw = Fkrwa + (1\text{-}F)\, krwi$

$krow$=Fkrowa + $(1\text{-}F)\, krowi$

where *krwa* and *krwi* and the oil-wet and water-wet relative permeabilities to water respectively (from *ASPKROW* and *SWFN*), and krowa and krowi and the oil-wet and the water-wet relative permeabilities to oil respectively (from *ASPKROW* and *SOF3*) [20].

In GEM

It seems that GEM (at least the current version in use, 2018) has not any wettability alteration models to represent the wettability alteration phenomenon during asphaltene precipitation.

Case study

Fluid Model

The fluid sample was taken from an under-saturated fractured oil reservoir. Reservoir fluid components and calculated volume fraction of the asphaltene component are given in Table 1.

The oil gravity is 31.23 ° API.

SARA test analysis was also available for this oil sample. According to this test, the amount of asphaltene in the dead oil is 0.56 wt.%. WinProp was used to simulate routine PVT experiments. The results showed good agreements with the lab measurements, where perfect matches were obtained for all critical parameters such as the relative volume (as shown in Figure 1). In Fig. 2, the asphaltene precipitation curve generated by CMG-WinProp is demonstrated. Since it was not available experimentally, the upper Asphaltene precipitation onset pressure was obtained by modeling, which is equal to 4850 psi, while the bubble point pressure is 3600 (both experimentally and computationally). As a result, we can claim the reservoir is not yet in the range of asphaltene precipitation. Additionally, Figure 3 presents the asphaltene phase envelope for the reservoir fluid with the plots of the bubble point and upper and lower onset pressures as a function of temperature. As can be seen, there is a good agreement between the calculated and experimental results. Export of the fluid model from PVTPro was employed to provide the E300 simulation model with the required input. It is possible to do so because both WinProp and PVTPro use the PR-EOS to model the fluid behavior [23,26]. In this regard, the usual procedure of E300 asphaltene modeling entails assuming the same molecular characteristics of the heaviest fluid component as the asphaltene ones. Therefore, it would cause some level of uncertainty in the results. We decided to remove the source of this error by implementing an asphaltene thermodynamic model in WinProp and then exporting it into an E300 compatible fluid model format using PVTPro. Of course, to clarify tackling the differences between asphaltene models in GEM and Eclipse, the parameters of the E300 asphaltene model were specified manually using relevant keywords (the WinProp asphaltene model was used indirectly). It was just tried to generate actual molecular characteristics of the asphaltene component by doing asphaltene modeling in WinProp first and then using those characteristics in E300 to help Eclipse results become as close as possible to the GEM results. Note that in the Eclipse asphaltene simulation model, the asphaltene weight percent obtained from the experiment is given to the simulator in the form of a table (using ASPREWG keyword) instead of getting solid model parameters by GEM.

Table 1 Reservoir fluid composition and properties.

ComponentName	Mole fraction	MW	Tc (R)	Pc (psia)
N2	0.001	28.013	227.16	492.314
CO2	0.033702	44.01	547.56	1069.865
H2S	0.017202	34.08	671.76	1296.182
CH4	0.440135	16.043	343.08	667.196
C2H6	0.089207	30.07	549.72	708.344
C3H8	0.054104	44.097	665.64	615.76
IC4	0.011001	58.124	734.58	529.054
NC4	0.030302	58.124	765.36	551.098
IC5	0.010301	72.151	828.72	490.844
NC5	0.011401	72.151	845.28	489.375
FC6	0.033102	86	913.5	477.03
FC7	0.035003	96	977.76	455.133
FC8	0.013701	107	1026.9	427.946
FC9	0.025402	121	1077.3	395.909
FC10	0.019302	134	1119.78	367.546
FC11	0.018502	147	1158.48	340.505
C12-C17	0.062226	198.35	1298.85	291.472
C18-C22	0.032493	338.402	1501.507	203.161
C23-C28	0.024592	295.922	1478.091	211.331
C29-C34	0.014821	471.807	1425.993	170.34
C35	0.001819	470.965	1438.883	160.261
C36A+	0.019962	582.883	1808.83	130.933
C36B+	0.000721	641.437	1698.121	125.836

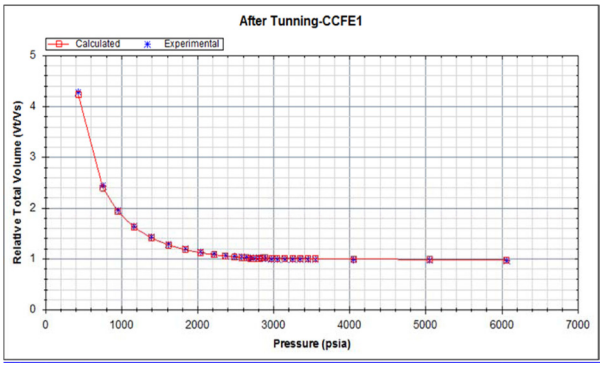

Fig.1 Matching the CCE test results for the fluid sample.

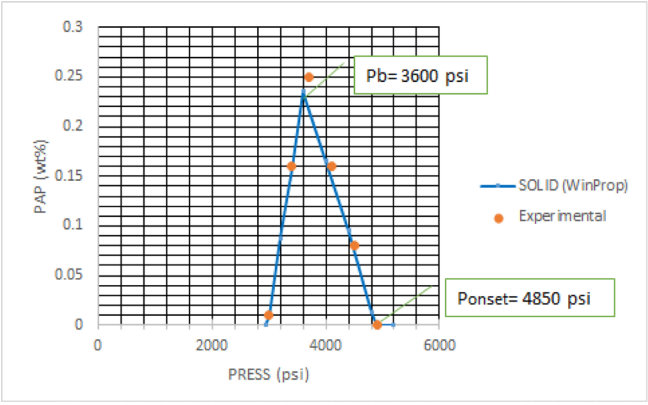

Fig. 2 Asphaltene precipitation curve generated using WinProp.

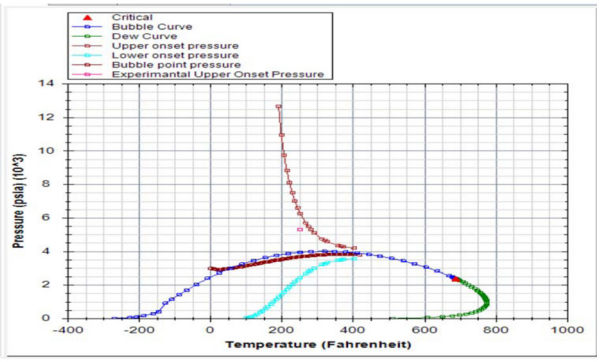

Fig. 3 Asphaltene precipitation phase envelope for the reservoir sample (250 °F).

Simulation Model

A sector model was created in the Cartesian system to begin. The 3D grid discretization is shown in Figure 4. Initial reservoir conditions are summarized in Table 2, and the overall grid description can be found in Table 3.

Two production wells were located in two different corners of the reservoir with a minimum bottom-hole pressure of 3900 psi. The initial reservoir pressure is 7448 psi, and the reservoir temperature is 250 °F (In this study, it is assumed that during production, the temperature remains constant throughout the reservoir since some studies have shown that the solid model cannot precisely predict the asphaltene behavior when there is temperature gradient [27]). Parameters of the deposition model were taken from the published literature because they were not available for this reservoir [28].

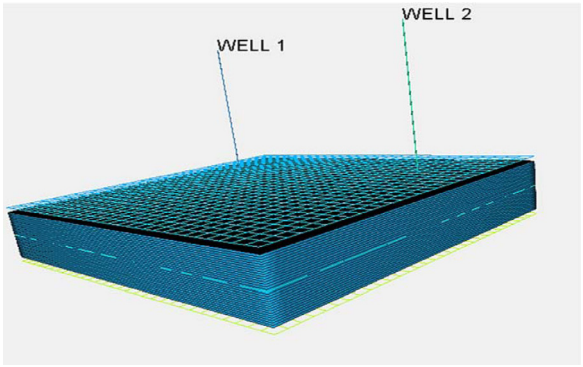

Fig. 4 3D reservoir discretization in Cartesian system.

Table 2 Simulation Sector model input data.

Property	value
Matrix Porosity(fraction)	0.034
Fracture Porosity (fraction)	0.001
Matrix K_h (mD)	0.0186
Fracture K_h (mD)	100
Matrix K_v (mD)	0.0073
Fracture K_v (mD)	20
Matrix block height (ft)	20
Sigma (ft^{-2})	0.05
Rock Compressibility (psi^{-1})	3e-6
Saturation Pressure (psi)	3597
Initial reservoir pressure (psi)	7448
Present reservoir pressure (psi)	5450
Reservoir temperature (^0F)	250
Water-oil contact (ft)	15355
No. of SCAL and PVT (-)	1

Table 3 General sector model characteristics.

Feature	Characterization		
Number of grid blocks	X	Y	Z
	30	30	30(60)
No. of wells	2		
Wells location in reservoir	NE / NW		
OIP	2.46e8		
Aquifer	1-AQUCT		
Hysteresis	SATOPTS/HYSTER		
Prediction time interval	30 Years (2020-2050)		

Results and Discussion

After running various cases listed in Table 4 with the deposition parameters in Table 5, a few differences were identified and elaborated in the followings:

Porosity/Permeability Reduction (due to reservoir depletion)

To investigate this effect, we should look at the bottom-hole pressure of wells first. As a result, it sounds like GEM overestimates the bottom-hole pressure in its asphaltene model (Figure 5). It can be seen there is a pressure discrepancy between the non-asphaltic and asphaltic models in which only the precipitation mechanism was active, and there was not any flocculation and deposition. While under normal circumstances, it is expected for the bottom-hole (and, of course, reservoir) pressure to be affected only by asphaltene deposition, and precipitation would only cause a change in the oil viscosity (which will be seen in the next section that is not the case for GEM), and not in the wellbore pressure. By assuming no compressibility, then, the issue was solved, and the pressure parameters for both cases were finally matched (Figure 6). Therefore, it can be concluded that this difference is due to ignoring the effect of porosity on permeability for the non- asphaltic model in GEM. Meanwhile, this effect has been considered in the asphaltic model in the computation of phase resistance factors using either a modified form of power-law or a Kozeny-Carmen type formula [21]. In Eclipse, however, the discrepancy in the bottom-hole pressure decline for two simulation cases of no asphaltene and the asphaltic precipitation-only does not exist. As expected, there was no pressure difference between these two cases, as seen in Figure 7.

Table 4 Various cases for comparison of two simulators.

Simulator	Simulation Case
GEM	No Asphaltene
	Precipitation-only
	Full Asphaltene
E300	No-asphaltene
	Precipitation-only
	Full Asphaltene

Table 5 Surface deposition model parameters.

Parameter	Value (Ecl)	(GEM)	unit
Deposition rate coefficient (α)	0.01	0.01	(day/1)
Plugging coefficient (γ)	0.01	0.01	(ft^3/1)
Entrainment coefficient (β)	0	0	(ft/1)
Critical velocity (Ucr)	2500	2500	(ft/day)
Slope for Einstein model	2.5	-	dimensionless
Power-law exponent	10	-	dimensionless
RF exponent	-	10	dimensionless

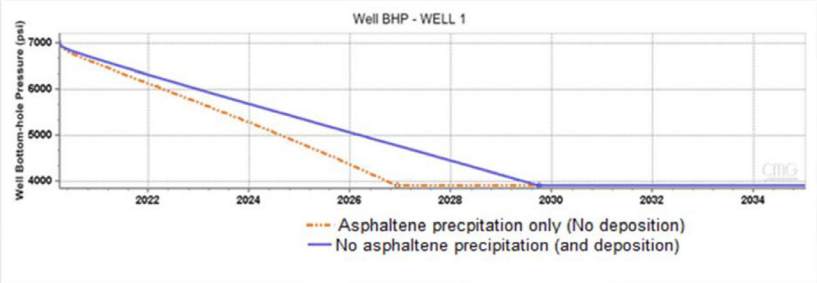

Fig. 5 Comparison of declining bottom-hole pressure in two simulation cases: no asphaltene and asphaltene precipitation–only in GEM.

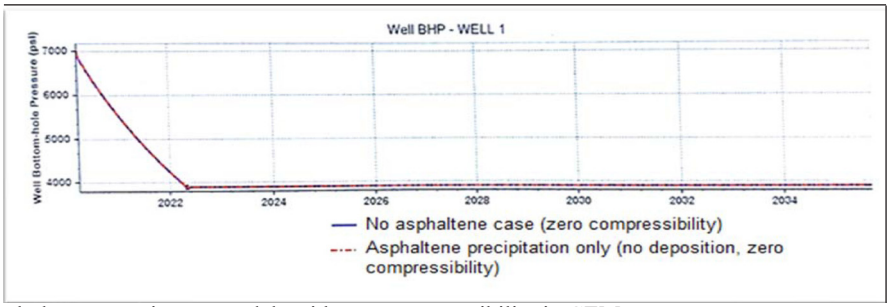

Fig. 6 Matching bottom-hole pressure in two models with zero compressibility in GEM.

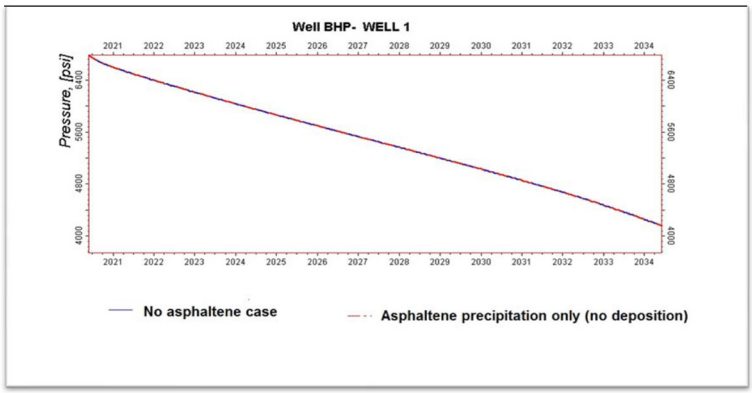

Fig. 7 Comparing pressure status in two simulation cases: no asphaltene and asphaltene precipitation–only in Eclipse.

Although there is a basic difference between modeling procedures of permeability reduction in these two simulators, the noteworthy thing is the basis of models used for this purpose. In other words, a significant difference in this respect is that, by default, Eclipse takes the permeability reduction due to declining pressure and porosity into account in neither model (although it is possible to do so by including specific keywords). Therefore, the final decline in permeability would be totally due to asphaltene precipitation. In GEM, however, this effect is combined with the asphaltene effect, and if the user is going to study only the effect of asphaltene precipitation, they must ignore rock compressibility to avoid the effect of porosity change; an assumption that has to be carefully made in reservoirs in which, rock expansion mechanism plays a major role as a production drive. It can be explained clearly by looking a look at their formulas in the previous section (Porosity/ Permeability Damage)
Indeed, GEM takes a more sensible approach to asphaltene modeling, which is closer to the reality of the reservoir.

Viscosity Change

When precipitation occurs, asphaltene particles can be considered as colloids in the oil phase, which can alter the oil viscosity [20].
In Figure 8, viscosity versus pressure for three cases of no asphaltene, asphaltene precipitation-only, and full asphaltene cases in GEM are compared. In all cases, precipitation has been modeled using the solid model described in previous sections, and deposition parameters have been taken from the literature. It is observed that the oil viscosity does not change during asphaltene precipitation modeled using GEM.
Conversely, Figure 9 and Figure 10 (exported from Eclipse runs) show that during asphaltene precipitation and deposition, the oil viscosity increases. In this case, since the maximum asphaltene content is not high enough, the level of viscosity change is not considerable. Obviously, in severe asphaltene precipitation, change in the oil viscosity can dramatically affect the daily and cumulative oil production [29].

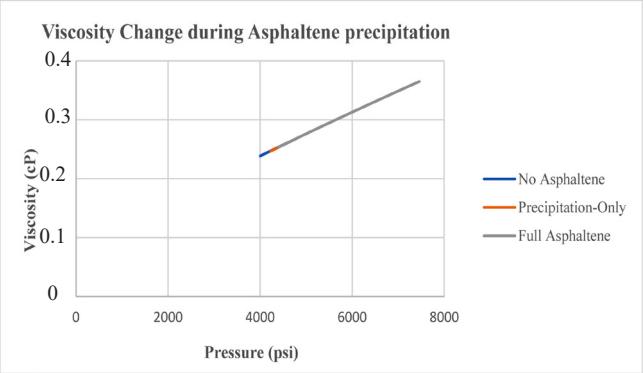

Fig. 8 Comparison of viscosity in three simulation cases: No asphaltene, precipitation-only, and Full-asphaltene precipitation/ deposition in GEM.

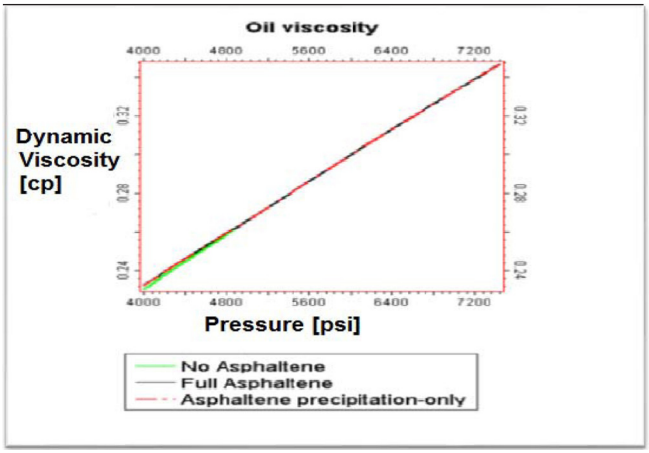

Fig. 9. Comparing viscosity in three simulation cases: No asphaltene, precipitation-only, and Full-asphaltene in Eclipse (showing viscosity alteration due to asphaltene precipitation).

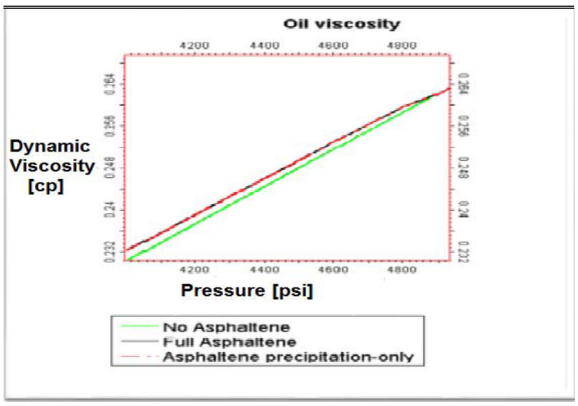

Fig. 10 A closer view of the difference in viscosity of three simulation cases: No asphaltene, precipitation-only, and Full Asphaltene in Eclipse.

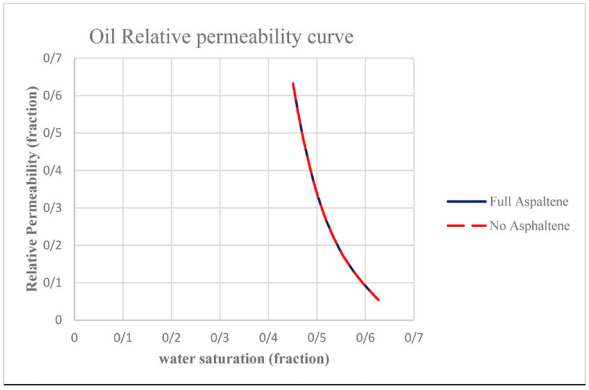

Fig. 12 Comparing relative oil permeability for two simulation cases: No Asphaltene and Asphaltic in GEM (indicating unchanged wettability due to asphaltene deposition).

Wettability Change

Another reservoir property that the asphaltene phenomenon might influence is the reservoir rock wettability that limits the movement of the oil phase. Asphaltene can reduce the mobility of reservoir fluid by adsorbing onto the surface of the reservoir rock, thereby altering wettability unfavorably and plugging the small pathways between pores [30]. Moreover, according to former studies, wettability is the main cause of reducing the wells' production rate [1]. Therefore, it is important to consider this mechanism while modeling the asphaltene phenomenon and its effects on reservoir rock quality.

In Eclipse, the user has to provide the simulator with oil-wet relative permeability values for krw and kro to capture wettability change due to asphaltene precipitation. Given that wetabilitty information was unavailable for the studied reservoir, they were taken from the literature [20].

Figure 11 delineates the wettability alteration (shifting to oil-wet) triggered by the asphaltene deposition, which means a consequent decrease in oil relative permeability and an increase in the residual oil saturation. Factors that can, in turn, lead to less oil production and lower reservoir recovery (Note: that in this study, since the asphaltene weight percent is small, the resulting wettability alteration is also insignificant).

Nevertheless, it seems that GEM has not implemented a model to explain this change (Figure 12).

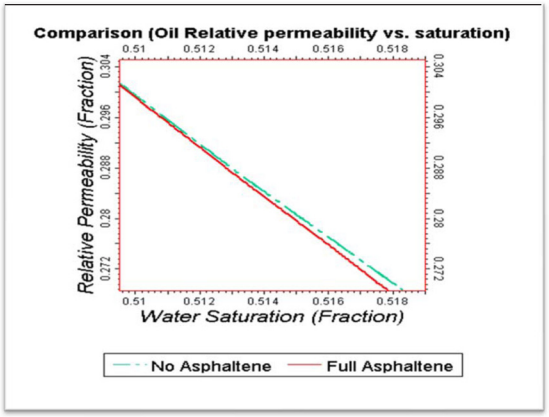

Fig. 11 Comparing relative oil permeability for two simulation cases: No Asphaltene and Asphaltic in Eclipse (indicating a slight wettability alteration due to asphaltene deposition).

Simulation Run Time

As to the comparison of run time, the time step was first adjusted to be the same in both simulators. In this respect, although GEM seems to be vastly superior to its rival because of its capability of running simulations with the maximum number of core processors (This is, however, not feasible in Eclipse due to restricting the number of processors that must be less than the number of grid nodes in the x-direction). Nevertheless, this ability has not brought about a high speed in running asphaltic simulations for GEM. In other words, Eclipse is a much more optimum simulator in this case. Of course, in E300 itself, in cases where a permeability reduction table is used, this limitation makes the condition differently, and the speed of simulation would be almost halved (Table 6). This is because it is not possible to run these models with more than 2 core processors. Notwithstanding, as it is clear from the process CPU time, it is much more optimum than GEM even with this restriction.

Table 6 Comparison of simulation run-time in two simulators of Eclipse and GEM

Case	No. of CPU	CPU Time(s)
E300 (Ktab)	2	39585
E300_(Kexp3)	14	21164
GEM (RF=3)	32	351376.5

Conclusions

It is necessary to conduct more studies on reservoirs with higher asphaltene content in order to better see the effect of changes in some parameters. After all, some differences between the asphaltene models of the two simulators were identified. To name a few, Eclipse does not take the effect of porosity change into account in its asphaltene model, while GEM does. As a result, this caused an unrealistic pressure difference between the non-asphaltic and asphaltic ones in GEM. Additionally, Eclipse models viscosity change during asphaltene precipitation and deposition, but GEM ignores it As a result, the oil viscosity increases during asphaltene deposition in this reservoir. Furthermore, Eclipse considers wettability alteration as another effect of the asphaltene deposition. As explained above, rock wettability changes to oil-wet due to contact with the asphaltene. This is while GEM does not have any option to model this effect. Finally, despite using fewer CPUs for its computational runs, Eclipse has a

shorter run time than GEM for simulation of the asphaltene effect. This issue should be considered when choosing a simulator for the asphaltene modeling task.

Nomenclatures

W_{lim} =maximum dissolved asphaltene in oil, wt.%
m_{woil} = oil and asphaltene molecular weight, dimensionless
m_{wp} = asphaltene molecular weight, dimensionless
x_p =mole fraction of precipitation component, dimensionless
R_a =rate of flocs aggregation, dimensionless
C_i =concentration of fines, dimensionless
C_a =concentration of the flocs, dimensionless
r_{ia} =aggregation rate coefficient for fines, 1/day
r_{ai} =dissociation rate coefficient for flocs, 1/day
k_{12} = forward rate of solid s2 formation from s1 , day-1
k_{21} =reverse rate of formation of solid s1 from s2, day-1
r = reaction rate, day-1
$C_{s1}o$ =concentration of suspended solid s1 in oil phase, mol/m^3
C_{s2},o =concentration of suspended solid s2 in oil phase, mol/m^3
ε_i =the amount of deposition in i flow direction, fraction
α =adsorption coefficient, 1/day
d =number of dimensions (1, 2, or 3)
Φ =porosity, fraction
C_a =volume concentration of the flowing flocs, dimensionless
γ_1 =the plugging coefficient, 1/ft^3
F_{oi} =oil flowrate, ft^3/day
β =entrainment coefficient, 1/ft
U_{oi} =oil Darcy velocity, ft/day
U_{cr} =critical velocity, ft/day
dV_{dep}/dt =rate of asphaltene deposition, 1/day
V_{dep} =volume of deposited asphaltene per grid block volume, wt. %
C =volumetric concentration of precipitated asphaltene, wt. %
v_o=oil phase interstitial velocity, ft/day
$v_{cr,o}$ = oil phase critical interstitial velocity, ft/day
γ_i = instantaneous plugging deposition rate coefficient, 1/ft^3
σ = snow-ball effect constant, dimensionless
ϕ_0 = porosity at zero time step, fraction
ε = volume of asphaltene deposit, fraction
k = k0 permeability at times t, mD
k_0 =permeability at time t0, mD
δ = a user input parameter that comes from core flood experiments, dimensionless
rf = resistance factor, dimensionless
Cp = mass fraction of asphaltene precipitate, wt. %
μ_0 = oil viscosity at Cp=0, cP
η = intrinsic viscosity, cP
C_{p0} = maximum packing concentration,
S_{ocra} and S_{ocri} = critical oil in water saturations, fraction
S_{wcra} and S_{wcri} = critical water saturations, fraction
k_{rwa} = oil-wet relative permeability to water, mD
k_{rwi} = water-wet relative permeability to water, mD
wt. %.= weight percent of asphaltene, percent
Tc= Critical temperature, °F
Pc= critical pressure, psi
MW= molecular weight, dimensionless
CCE= constant composition test
CPU= central processor unit

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