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A Transient Model for Prediction of Asphaltene Deposition Along Tubing String: Enhanced Petroleum Production Implications

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Abstract

Prediction of asphaltene deposition in production system and design of production parameters adequately to control this issue is inevitable. We presented a transient model to predict asphaltene deposition along the tubing string in the production system. An accurate two-phase fluid flow model was coupled with a solid asphaltene precipitation model and a sub-layer particle deposition model in turbulent flow with the ability to predict the deposition of particles in vertical surfaces. Our procedure shows good agreement with the experimental work previously done to measure the rate of deposition of flocculated asphaltene particles via an accurate thermal apparatus at different temperatures and flow rates. The developed model was used to simulate the deposition of asphaltene in a real field. The results suggest that even with high flow rates, the deposited asphaltene caused a 2.5% reduction in wellhead pressure after 30 days of production. The developed model can predict the transient location of the asphaltene, onset pressure, and the profile of the deposited asphaltene in a wellbore versus time. In practice, the proposed model can be used for analysis of different production scenarios in a given well to minimize the possibility and extent of asphaltene deposition and enhance the production rate.

Introduction

Various issues are encountered in petroleum production system from the reservoir to the flow-lines. Asphaltene deposition is one of the major causes of formation damage, impairment of tubing string, and surface flow lines. Asphaltene molecules as the heaviest fraction of crude oils are poly-aromatic and contain heteroatoms (i.e., S, O, N) and metals (i.e., Va, Ni). The chemical structure of asphaltene particles are not exactly known, but two common structures which have been proposed are continental (Figure 1-A) and archipelago (Figure 1-B) structures [15,18,21,22,25,31–33,35, 36]. Colloidal and solution models are two general models used to describe the state of asphaltene molecules in crude oil. In the colloidal models, it is assumed that the asphaltene particles are held in suspension in the crude oil by resins and that the precipitation is not reversible. On the other hand, in the solution models, it is assumed that the asphaltene

molecules are dissolved in the crude oil like other hydrocarbon molecules and form a homogeneous solution [5,6,16,17,24–26,33].

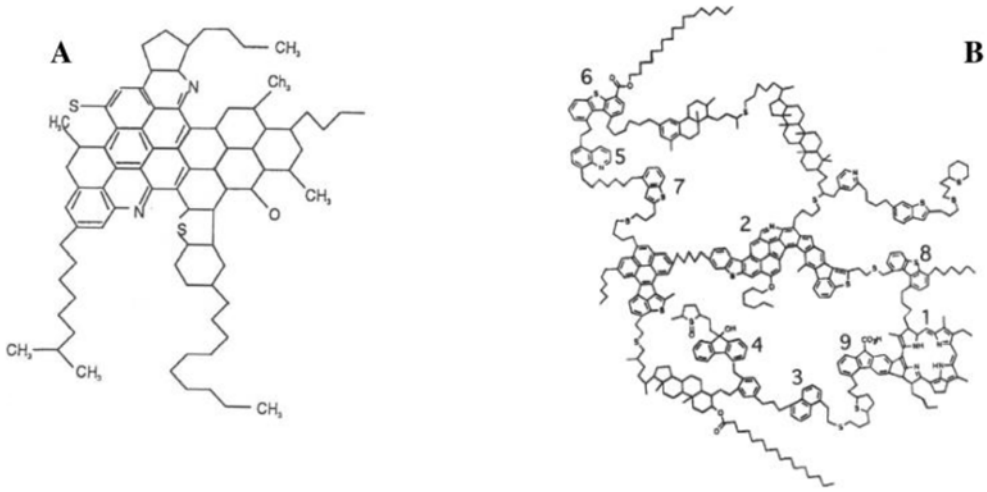

Figure 1—Proposed asphaltene structures - A) continental B) archipelago [16]

Asphaltene precipitation from crude oil occurs due to several factors such as changes in temperature or pressure, changes in the composition of crude oil, and the mixing of crude oil with light hydrocarbons and CO2 [16,17]. Asphaltene precipitation may also occur in the porous media or along the tubing. For example, the volume of crude oil especially the volume of light hydrocarbons increases by reduction in pressure, which can lead to instability and precipitation of asphaltene. The highest pressure at which asphaltene starts to precipitate is called the "onset pressure" of asphaltene precipitation. As the pressure becomes lower than the onset, precipitation increases until the bubble point pressure. At the bubble point, the amount of precipitation is at the maximum; below the bubble point, light hydrocarbon molecules evolve from the crude oil, which leads to reduction in the precipitant concentration and an increase in the solubility of the asphaltene in oil. Increased solubility reverses the trend of asphaltene precipitation until offset pressure at which all the asphaltene molecules are completely dissolved in the oil [2,21,23,34]. Figure 2 shows an example of an asphaltene precipitation trend at a constant temperature and different pressures.

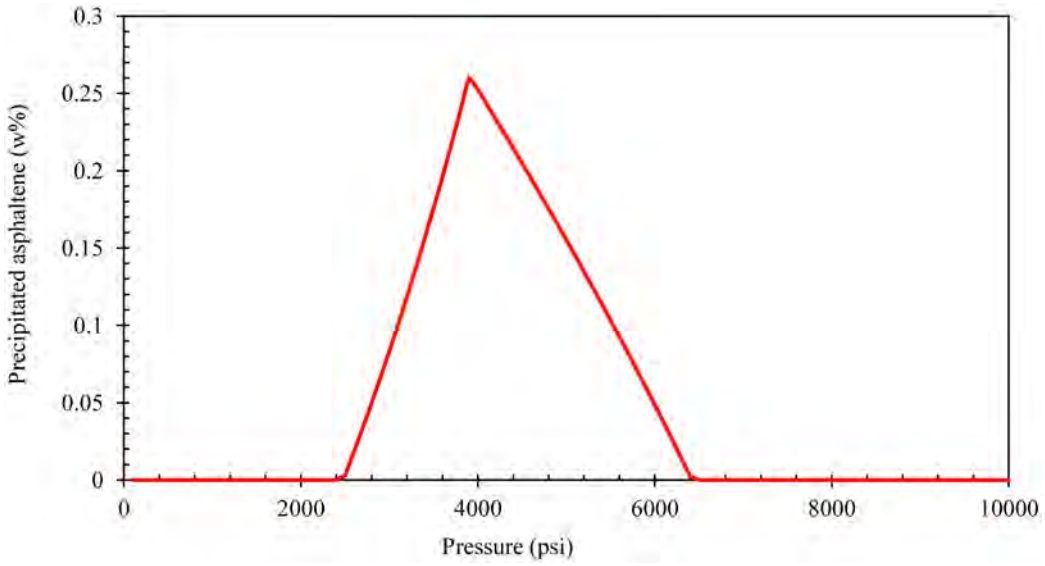

Figure 2—Asphaltene precipitation plot produced using data reported by Soulgani et al. [29].

Asphaltene deposition on the tubing wall reduces the oil production rate from the well. As an example, in Hassi-Masoud field in Algeria, deposition of asphaltene in the tubing string caused a loss of 20-25% in the wellhead pressure within 15 days, which led to a notable reduction in production. [13]. Haskett et al. [13,20] reported a comprehensive study of this issue in Hassi-Masoud field. They analyzed 322 deposition profiles along the tubing obtained by ring gauges. They concluded that the majority of the deposition took place in the single phase region of the wellbore and found that the most favorable condition for deposition was just below the bubble point. The profiles indicated that the deposition profile had a long tail toward the wellhead.

The same problem was observed in the wells of West Kuwait Marrat Jurassic field, which caused serious problems for maintaining the production within economic limits. Alkafeef et al. [3] used a caliper log to investigate the thickness of the asphaltene deposition along the tubing. They concluded that by reducing bottom hole pressure, the location of the deposition shifted towards the bottom hole. They also confirmed that the deposition occurred between the bubble point and the asphaltene onset point. In addition, wells in the Prinos field in the north Aegean Sea stopped flowing in the early stages of production due to asphaltene deposition in the tubing, separators, pumps, and strainers [1].

Asphaltene deposition along a wellbore is still not a well addressed topic in the literature. Kurup et al. [19] proposed a model and compared it to data obtained in a plugged well by asphaltene deposition. The prediction made by their model was in good agreement with field observations to predict a decreasing deposit thickness with increasing flow rates in the Hassi Messaoud field.

Escobedo and Mansoori [9] presented an analysis of the effects of diffusion on the rate of asphaltene deposition in turbulent flow. They used free flight model and the concept of stopping distance to simulate deposition of particles toward the wellbore wall. Ramirez-Jaramillo et al. [27] proposed a multiphase-multicomponent model for asphaltene deposition rate. Their model only accounts for molecular diffusion while there are other forces acting on particles affecting the deposition process like momentum, which was neglected. Jamialahmadi et al. [14] used a thermal approach to investigate mechanisms affecting deposition rate of asphaltene particles and proposed a mechanistic model based on their experimental data. Vargas et al. (2010) [30] coupled perturbed chain version of statistical associating fluid theory equation of state with transport equations and kinetic models to simulate the process of asphaltene deposition in the wellbore. The aggregation and deposition of asphaltene particles are assumed to be the first order reactions in their model. But, the model only accounts for deposition of micro-aggregates and the removal term has not been incorporated. The parameters of this model must also be obtained experimentally which may not be easily possible. Eskin et al. [10] investigated the asphaltene deposition rate experimentally and theoretically using a Couette device. They have computed particle size distribution based on a population balance model and introduced the critical size concept. Particles larger than the critical size do not deposit on the wall. They have assumed that particles are brought to the wall by the Brownian motion and turbulence. Kurup et al. [19] continued and modified the model proposed by Eskin et al. [10]. Their work also needs experimental capillary data to obtain parameters required for calculation of deposition rate, which again may not be available.

This paper, presents a model for prediction of transient location of the asphaltene, onset pressure, and the profile of the deposited asphaltene in a wellbore versus time along the tubing string in the production system. It utilizes a precise two-phase fluid flow model coupled with a solid asphaltene precipitation model and a semi-Lagrangian sub-layer particle deposition model in turbulent flow with the ability to predict the deposition of particles in vertical surfaces. The developed model was used for simulation of asphaltene deposition in a real field case. The proposed model can be used for analysis of different production scenarios in a given well to minimize the possibility and extent of asphaltene deposition to enhance the production rate.

Modeling Procedure

Here we present a transient coupled model to simulate asphaltene deposition along the tubing during production. A multiphase fluid flow model in the wellbore [12] is coupled with the asphaltene precipitation model to predict the deposition of the asphaltene and its effects on oil production. A sub-layer model for deposition of suspended particles in turbulent flow conditions is used, as well. This model accounts for diffusion and inertia forces acting on the particle moving toward the wall similar to the model proposed by Fan and Ahmadi [11].

Eskin et al. [10] showed that the asphaltene particle size growth was stopped after approximately 3 hours as shown in Figure 3.[1] Hence, using a single size assumption is valid after this transient period. In our model, as the time is much greater than the time needed to reach a constant particle size, we assumed that the asphaltene particle size is constant to reduce the computation efforts. Our calculations showed that the mentioned simplifications do not affect the simulation results, noticeably.

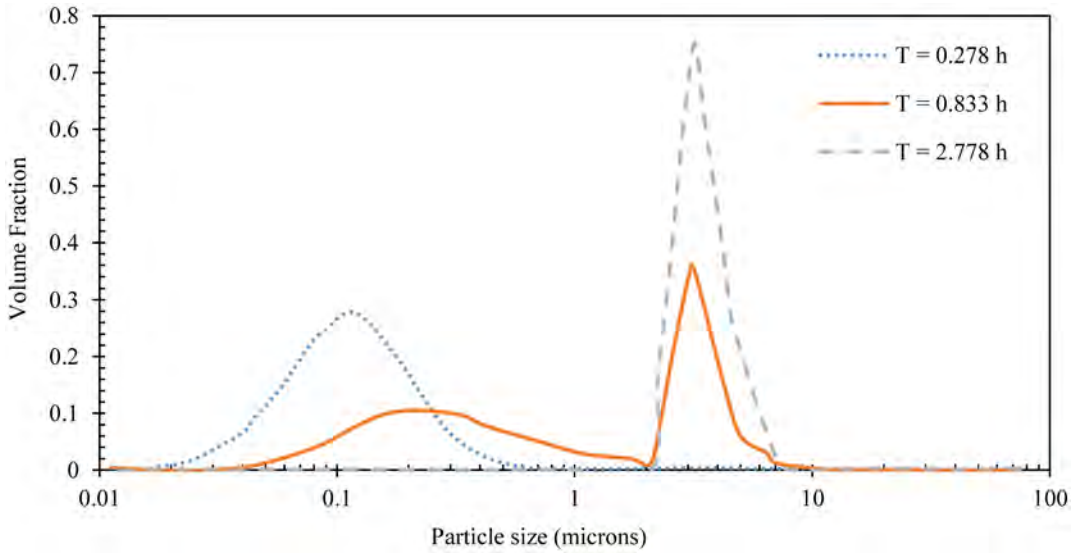

Figure 3—Particle size distribution obtained by using a Couette device [1]

Shirdel et al. (2012)[28] have reviewed models that consider deposition of particles in the turbulent flow conditions and concluded these models can be used to simulate deposition process in the oil production systems as well as deposition of particles from the gas streams. They have also concluded that models such as models proposed by Beal (1970)[4], Escobedo and Mansoori (1995)[9], and Cleaver and Yates (1975)[7] are suitable for calculation of rate of deposition in the oil wells due to the small relaxation time encountered and have suggested to use these models to simulate asphaltene deposition [28]. In this paper, the model presented by Escobedo and Mansoori (1995)[9] is used to model the deposition rate of asphaltene particles on the wall of the production string.

In our model, heavy components of oil are divided into two precipitating and non-precipitating groups. The precipitating components have a higher binary interaction coefficient with light hydrocarbons compared with the non-precipitating ones. Due to the high binary interaction coefficient value, the precipitating components are more unstable in the mixture. Hence, increase in the amount of light hydrocarbons leads to precipitation of these unstable components. The amount of asphaltene precipitation is obtained by equating the fugacity values of asphaltene component in the liquid and solid phases. The fugacity of asphaltene in the solid phase is calculated by using the experimental data at the point of onset pressure. Using an expression proposed by Kohse et al. [17] the calculated reference fugacity can be used in different pressures and temperatures to predict the amount of precipitated asphaltene in the mixture. The binary interaction coefficients of precipitating component and light hydrocarbons and molar volume of solid are used for

tuning of the model [17,24]. To simulate the deposition of the asphaltene particles on the tubing surface, a model is needed to predict the deposition velocity. In our approach, the model proposed by Fan and Ahmadi [11] is used which accounts for stokes drag, the Saffman lift force, and gravitational force, alongside the Brownian diffusion to estimate the deposition velocity.

The first step in the modeling is calculation of the deposition rate of particles. For a broad range of particle sizes and deposition regimes, deposition rate consists of two terms, diffusion and inertia, as:

$$V_d^+ = V_{d,inertia}^+ + V_{d,diffusion}^+ \tag{1}$$

where V^+_d is the dimensionless deposition velocity and defined as:

$$V_d^+ = \frac{V_d}{u^*} \tag{2}$$

In this equation, V_d is the deposition rate of asphaltene particles on the surface of the tubing depends on the concentration of the particles in the fluid (C_{ave}) and the particle flux to the surface (J) as:

$$V_d = \frac{J}{C_{ave}} \tag{3}$$

u* is friction velocity which is a measure of turbulence intensity as:

$$u^* = U_{ave}\sqrt{\frac{f}{2}} \tag{4}$$

where U_{ave} is the average fluid velocity and f is the Fanning friction factor (30,33).

The deposition velocity is dominated by the diffusion when the particles are small. In this case, deposition by diffusion is calculated as (33):

$$V_{d,diffusion}^+ = 0.084 Sc^{-\frac{2}{3}} \tag{5}$$

where Sc is Schmidt number as:

$$Sc = \frac{\mu}{\rho D_B} \tag{6}$$

The Brownian diffusivity of a particle in a fluid can be calculated as:

$$D_B = \frac{k_B T}{3\Pi d_p \mu} \tag{7}$$

where kB is Boltzmann's constant (1.38×10^{-23} J/K).

If the particles are large or the roughness is high, then the inertia term must also be accounted for calculation of the deposition velocity using the following empirical model (29):

$$V_{d,inertia}^+ = \frac{1}{2}\left[\frac{\left(0.64k^+ + \frac{d^+}{2}\right)^2 + \frac{\tau^+ 2g^+ L_1^+}{0.01085\left(1+\tau^+ 2+L_1^+\right)}}{3.42 + \frac{\tau^+ 2g^+ L_1^+}{0.01085\left(1+\tau^+ 2+L_1^+\right)}}\right] \times \left[0.037\left(\tau^+ 2 + L_1^+\right) + \tau^+ 2g^+ L_1^+\right] \tag{8}$$

In Eq. (8), the dimensionless particle relaxation time, τ^+, is computed by dividing particle relaxation time by the average lifetime near-wall turbulent eddies as follows:

$$\tau^+ = \frac{\tau_p}{\tau_e} = \frac{\rho_p d_p^2 u^{*2}}{18\mu v} \tag{9}$$

where ν is the kinematic viscosity of the fluid. Particle relaxation time, τ_p, shows the characteristic time required for a particle with initial velocity, V_p, to stop in a viscous fluid due to Stokes drag force. This parameter is calculated as:

$$\tau_p = \frac{\rho_p d_p^2}{18\mu} \tag{10}$$

where ρ_p is the particle density, d_p is the particle diameter and μ is the fluid viscosity. Also, k^+ is a dimensionless roughness number:

$$k^+ = u^* k / v \tag{11}$$

with g+ being a dimensionless gravitational acceleration, calculated as follows:

$$g^+ = \frac{v}{u^{*3}} g \tag{12}$$

L_1^+ is the coefficient for Saffman lift forces induced by the flow shears in the main flow direction and equals:

$$L_1^+ = \frac{3.08}{S_d^+} \tag{13}$$

Thus, by adding these two terms, the total deposition rate will be:

$$\begin{cases} 0.084 Sc^{-\frac{2}{3}} \frac{1}{2} \left[\frac{\left(0.64k^+ + \frac{d^+}{2}\right)^2 + \frac{\tau^+ 2g^+ L_1^+}{0.01085\left(1+\tau^+ 2+L_1^+\right)}}{3.42 + \frac{\tau^+ 2g^+ L_1^+}{0.01085\left(1+\tau^+ 2+L_1^+\right)}} \right] \times \left[0.037\left(\tau^+ 2 + L_1^+\right) + \tau^+ 2g^+ L_1^+\right] & V_a^+ < 0.1 \\ 0.14 & V_d^+ > 0.14 \end{cases} \tag{14}$$

After calculation of the dimensionless deposition velocity, Equations 2 and 4 can be used to calculate the deposition velocity. The amount of deposition mass rate will be:

$$m = SPV_d C_{ave} \tag{15}$$

where SP is the sticking portability, which is related to adhesion and drag forces acing on the particles. Here, an Arrhenius-type expression proposed by Watkinson and Epstein (1988) was used:

$$SP = k_d \frac{e\left(-\frac{E_a}{RT}\right)}{u_{ave}^2} \tag{16}$$

where E_a and k_d are the activation energy of adhesion and deposition constant, respectively [4,7,8,11,14,28,29].

Now, by coupling these models in an iterative approach, the transient profile of the deposited asphaltene can be calculated. At the first iteration, the wellbore two-phase fluid flow is modeled and pressure and temperature profiles in the tubing are calculated. The available data from the wells are used to check the accuracy of the model. By calculating the pressure profile along the wellbore, the position of the onset pressure is defined. Based on the onset, offset, and bubble point pressure, we can specify a region where the precipitation occurs in the tubing.

The solid model is then applied to calculate the amount of the precipitated asphaltene between the onset and offset pressure positions. At the next step, the deposition model is used to simulate the deposition rate. Hence, we can calculate the amount of transient deposition in a time step. Our modeling showed that the time step equal to one day was the optimal selection. Using a bigger time step reduced the accuracy of the multiphase flow modeling due to changes in the tubing diameter as a result of the asphaltene deposition. By coupling the three models mentioned, it was possible to solve the problem for one time step. Then, we were able to continue on to the next time step. At each time step, the radius of the tubing was updated due to the deposition of asphaltene. Figure 4 summarizes the workflow of the transient procedure calculations.

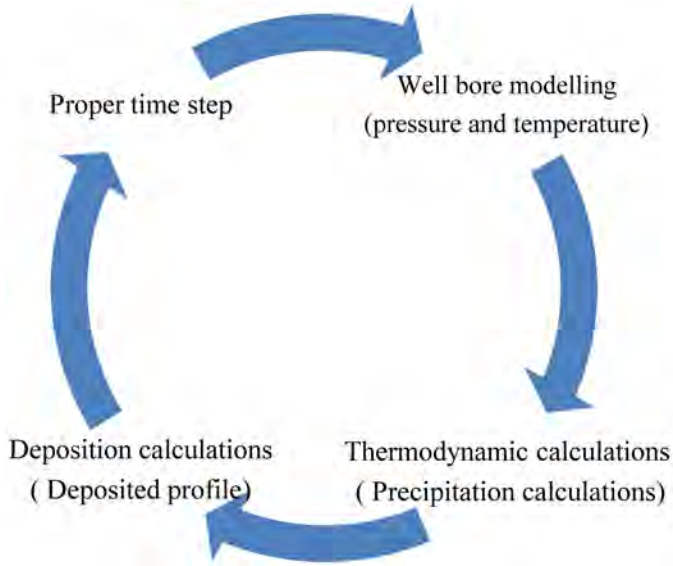

Figure 4—Procedure of the transient modeling of the deposition of asphaltene on the tubing surface.

Model Validation and Application

We used the experimental data reported by Jamialahmadi et al. [14] to validate the proposed model. The most important part of the transient simulation is to accurately predict the rate of asphaltene deposition on the tubing surface. Jamialahmadi et al. [14] reported the asphaltene deposition rate from a crude oil at different Reynolds numbers. In their experiments, as deposition of the asphaltene changes the thermal properties of the surface, the transient buildup of the asphaltene on the surface based on a thermal approach was measured. They reported two sets of data referring to asphaltene deposition rate. In the first data set, the flow rate is changing and other operational parameters are kept constant; while, in the second data set, the surface temperature changes and other parameters are kept constant. These data sets are outlined in Tables 1 and 2.

Table 1—Rate of asphaltene deposition with changing flow rate [14].

velocity (cm/s)	Deposited experimental data * 10^{-6} kg/m^2.s	Other parameters	
35	9.2	T_b (°C)	85
61	5.3	T_s (°C)	120
92	3.2	C_{ave} (kg/m^3)	3.5
125	2.4		

Table 2—Rate of asphaltene deposition with changing temperature [14].

Temperature (°C)	Deposited experimental data * 10^{-6} kg/m^2.s	Other parameters	
110.8	1.95	C_{ave} (kg/m^3)	3.5
115.2	2.42	T_b (°C)	85
120	3.15	Velocity (cm/s)	92
125.3	4.1		

Figures 5 and 6 show the deposition rate of the asphaltene at different fluid flow velocities and different temperatures simulated by our model.

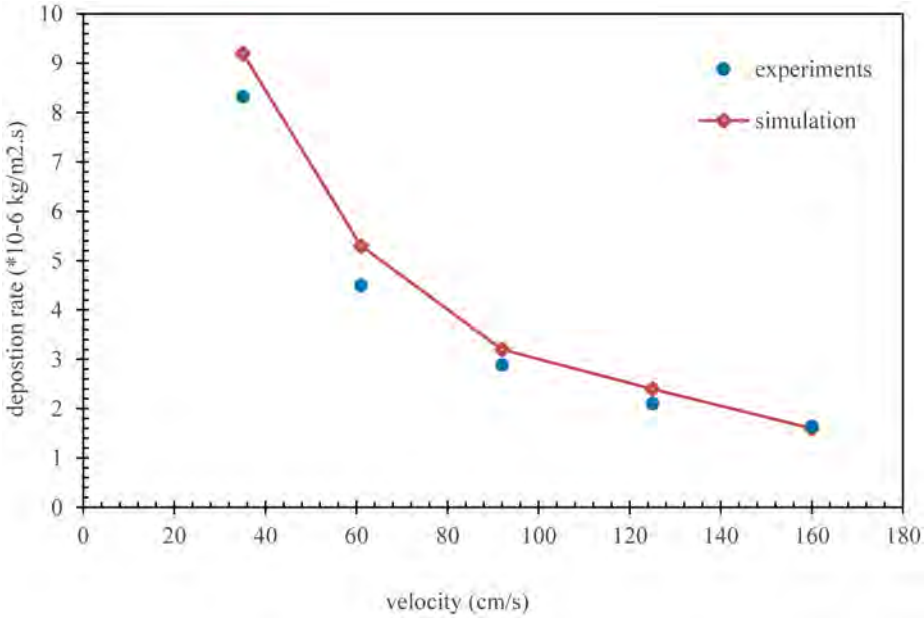

Figure 5—Changes in rate of deposition of asphaltene as a function of flow rate.

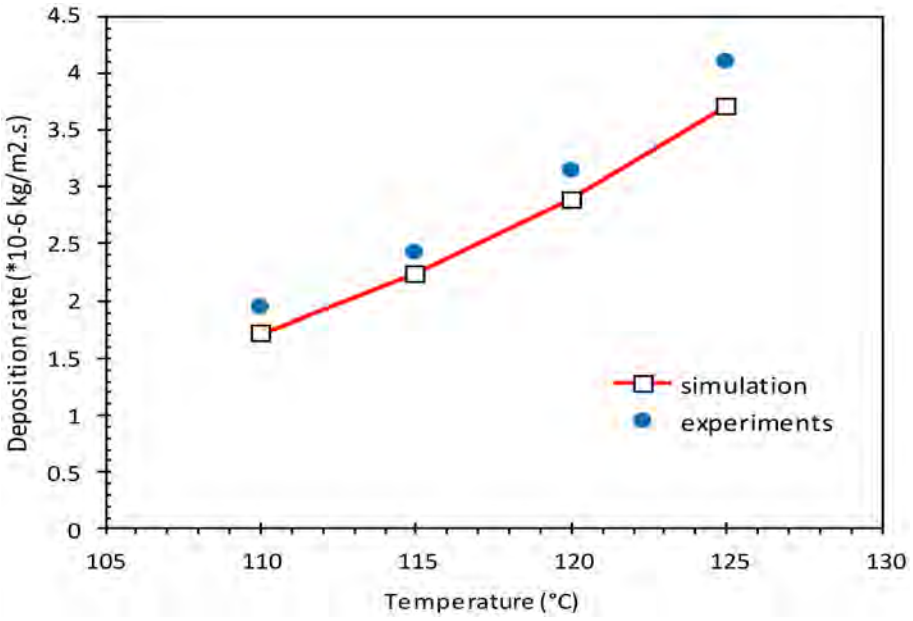

Figure 6—Changes in deposition rate of asphaltene as a function of surface temperature.

As can be seen form Figures 5 and 6, the proposed model can predict the deposition rate with accurately with an average of 4% error. It should be noted here that the simplifications made to the model did not affect the calculations and the overall calculated deposition rate. It can be concluded that by simplifying the procedure and using more simple models the results do not change, abruptly. Nevertheless, in the developed model, we use a simple and yet accurate sub-layer deposition model to calculate the amount of the deposited asphaltene which requires less experimental data and less computational effort. The verified model was used to model the asphaltene deposition for a real case. Soulgani et al. [29] reported problems for asphaltene deposition in a well in an Iranian oil reservoir. The composition of the reservoir oil is reported in Table 4. The other reservoir parameters are shown in Table 5.

Table 3—Reservoir fluid composition [29].

Components	H_2S	N_2	CO_2	C_1	C_2	C_3	IC_4	NC_4	IC_5
Mole %	1.87	0.31	3.37	43.6	8.58	6.27	1.64	4.89	2.2
Components	NC_5	FC_6	FC_7	FC_8	FC_9	FC_{10}	FC_{11}	C_{12+}	
Mole %	2.49	1.91	0.89	3.01	2.05	1.84	1.39	13.7	

Table 4—Reservoir characteristics [29].

Saturation pressure (psi)	3950
GOR (SCF/STB)	1520
API gravity (°)	31.28
Asphaltene Content (wt%)	0.99
Reservoir temperature (°F)	250
Reservoir pressure (psi)	6400

The two-phase wellbore model and asphaltene precipitation models are tuned to match the data in the well. The computed concentration of the asphaltene particles and the position of asphaltene onset pressure are in good agreement with the reported data as can be seen in the Figure 7. Then, using the procedure described, the deposited profile of the asphaltene is calculated after 30 days of production. The results of the simulation are shown in Figure 8.

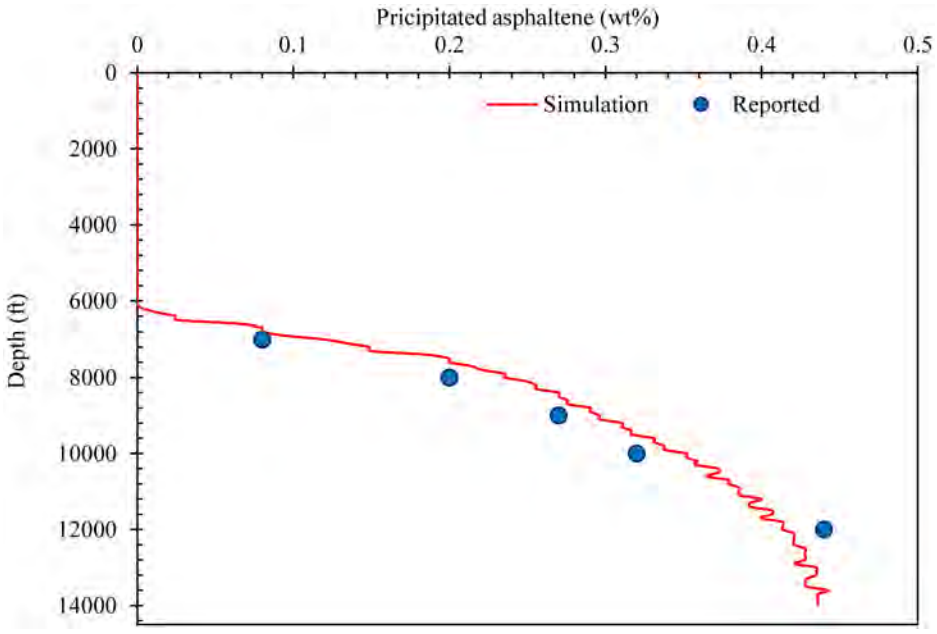

Figure 7—Concentration of precipitated asphaltene vs. depth in the wellbore in the studies real case.

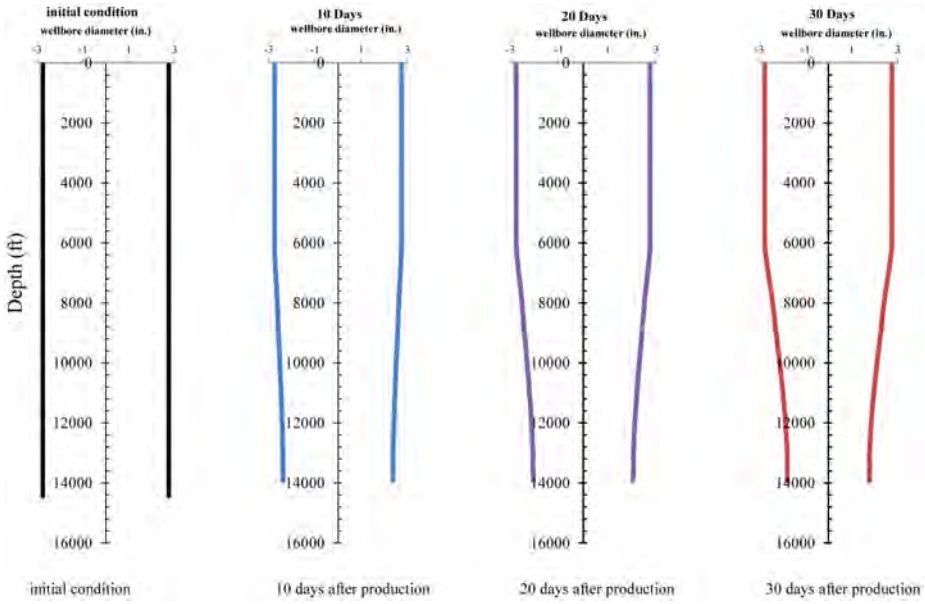

Figure 8—Transient deposited asphaltene profile. Depth (ft) vs. wellbore diameter (in.). From left to right, the figures show wellbore profile (inner diameter) after 0, 10, 20, and 30 days of oil production with deposition of asphaltene along the wellbore.

As it can be seen from the profiles obtained by this modeling, as time progresses, the thickness of the deposited asphaltene increases as expected. Also, the deposited asphaltene tends toward the bottom of the hole as the production continues. This is because the location of the onset pressure changes with increase in friction pressure caused by an increase in the amount of deposited asphaltene on the wall.

As presented in the Figures 9-11, the effect of time on deposited thickness and the effect of deposition on the wellhead pressure and average velocity of fluid flow is investigated. Obviously, as time passes the amount of deposited asphaltene increases, which leads to an increase in the frictional pressure drop and a decrease in the wellhead pressure. In addition, a reduction in the cross-section area of the pipe increases the fluid velocity. This shows the importance of the transient modeling of asphaltene deposition and its transient effects on two-phase fluid flow parameters such as transient profiles of deposited asphaltene on the wall, pressure, and flow velocity.

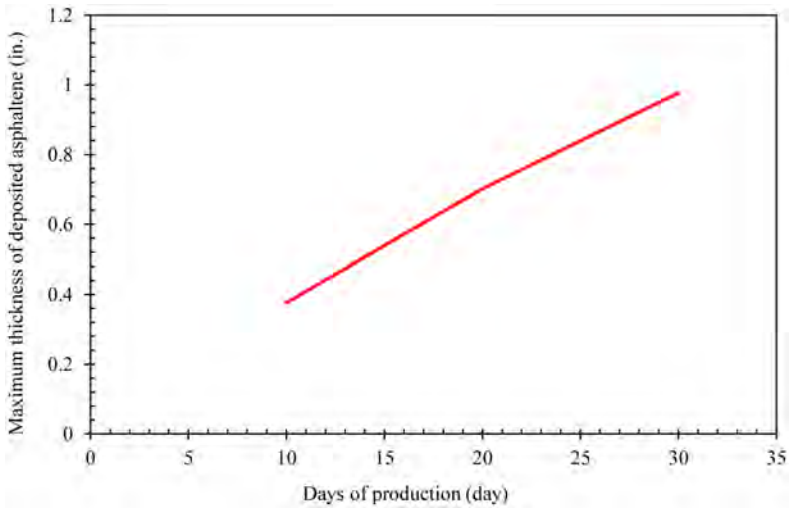

Figure 9—Maximum thickness of the deposited asphaltene along the wellbore during production.

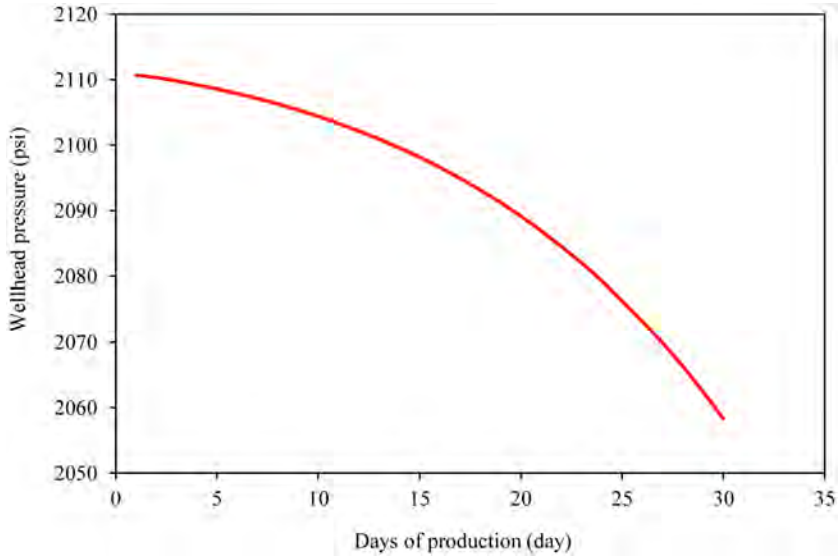

Figure 10—Wellhead pressure variation due to asphaltene deposition during production.

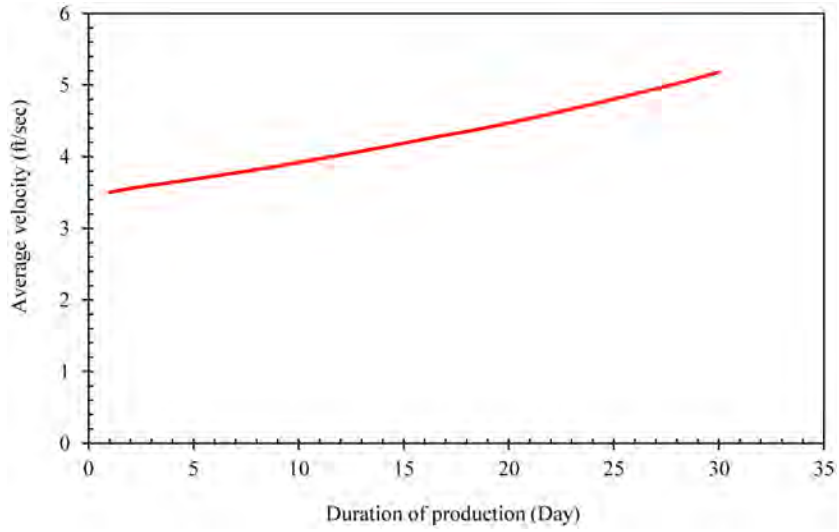

Figure 11—Average velocity variation due to asphaltene deposition during production.

The presented model can be used in any pressure-temperature range as long as the solid model for the precipitation of asphaltene is available to be tuned. As, in the modeling procedure, a single size asphaltene model is required, the asphaltene size distribution computation is eliminated which decreases the number of inputs in the model. In addition, because of the nature of the coupling process, various models of two-phase flow and asphaltene precipitation can be used as auxiliary models.

Conclusions

A coupled model is developed and presented in this paper aiming at prediction of transient precipitation of asphaltene on the tubing string during petroleum production. An accurate two-phase fluid flow model was coupled with a solid asphaltene precipitation model and a semi-Lagrangian sub-layer particle deposition model in turbulent flow with the ability to predict the deposition of particles in vertical surfaces. Based on the results obtained in this study the following conclusions can be drawn:

1. The developed model is validated against experimental data and shows good agreement with the experiments. In addition, the model was used to simulate the asphaltene deposition in the real wells where asphaltene deposition is a major problem.
2. This proposed model can provide the asphaltene profile along the wellbore at different production conditions.
3. Our simulation results suggest that asphaltene deposition has a transient trend as the pressure inside the wellbore changes during production.
4. The proposed model is capable of capturing the changes in the two-phase fluid flow parameters in the wellbore and the asphaltene thickness on the wellbore.
5. The results suggest that even with high flow rates, the deposited asphaltene caused a 2.5% reduction in wellhead pressure after 30 days of production from 2110 to 2058 psi in the case studied here.
6. The developed model can be considered a powerful tool to predict the transient location of the asphaltene, onset pressure, and the profile of the deposited asphaltene in a wellbore versus time.

Nomenclature

V_d^+	Dimensionless Deposition Velocity
$V_{d,inertia}^+$	Inertia Related Dimensionless Deposition Velocity
$V_{d,diffusion}^+$	Diffusion Related Dimensionless Deposition Velocity
V_d	Deposition Velocity, m/s
u^*	Friction Velocity, m/s
f	Fanning Friction Factor
U_{ave}	Bulk Average Velocity in a Pipe, m/s
J	Particle Flux, kg/m^{2}s
C_{ave}	Concentration Of Particles in the Pipe, kg/m^3
D_B	Brownian Diffusion Coefficient of a Particle, m^2/s
k_B	Boltzmann's Constant, 1.38×10^{-23} j/k
T	Absolute Temperature, k
d_p	Particle Diameter, m
μ	Dynamic Viscosity, kg/m.s
Sc	Schmidt Number
ρ	Density, kg/m^3
k^+	Dimensionless Roughness of a Surface
d^+	Dimensionless Diameter
τ^+	Dimensionless Particle Relaxation Time
g^+	Dimensionless Gravitational Acceleration
L_1^+	Coefficient for Saffman Lift Forces
τ_p	Particle Relaxation Time, s
τ_e	Average Lifetime of Near-Wall Turbulent Eddies, s
v	Kinematic Viscosity of Fluid, m^2/s
k	Roughness of Surface, M
g	Gravitational Acceleration, 9.81 m/s^2
S_d^+	Dimensionless Stopping Distance
SP	Sticking Portability
E_a	Activation Energy of Adhesion, kj
k_d	Deposition Constant, m/s

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