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Keywords: numerical modeling, asphaltenes precipitation, multiphase flow, enhanced oil recovery.

Highlights

- A new numerical model for predicting asphaltenes deposition is presented.
- Another model accounts for the effect of CO_2 injection on asphaltenes precipitation.
- The numerical models were in good agreement with a steady-state solution.
- Simulations revealed that asphaltenes become more unstable in the presence of CO_2.

I. INTRODUCTION

The shift in oil and gas producing systems to offshore and subsea areas in the past few decades has increased the need to study the fluid properties related to flow assurance problems (Patin, Stanislav, & Ian, 2001). Deposition and precipitation of asphaltenes are one of these potential problems, and it is often catastrophic. The general problems related to asphaltenes precipitation are fouling in extraction facilities and plugging of wells and lines (Hasanvand, Ahmadi, & Behbahani, 2015). To avoid asphaltenes deposition, proper control strategies must be developed from the beginning of production. Either a comprehensive experimental procedure or the development of a prediction model is required to understand the problems before their occurrence. The issue with modeling the prediction of asphaltenes requires a large number of parameters, which makes the model highly complex. The drawback of such a model is that its solution will require more processing power and time to achieve the desired results (Yap, et al., 2012). This effect is further enhanced in the multiphase flow because there are three different phases (i.e., gas, liquid, and solid), that must be incorporated to obtain accurate results. The phases generated in the flow path are due to various reasons such as pressure depletion or a change in the composition of the oil. The generation of the solid phase creates flow assurance problems during primary production of crude oil or in enhanced oil recovery processes involving the injection of CO_2 (Ali, Dahraj, & Haider, 2015). In previous studies, researchers have found some major parameters that affect asphaltenes deposition, such as molecular weight, solubility, temperature, and pressure. Various models have been developed, but they do not account for the effect of asphaltenes deposition on multiphase flow. This paper presents thenumerical model for the prediction of asphaltenes deposition under such conditions.

Before discussing the previous models developed by various scientists for the prediction of asphaltenes deposition, it must be taken into account that asphaltenes precipitation and deposition is not a reversible process, as indicated by various researchers (Nasrabadi, Moortgat, & Firoozabadi, 2016). The reason

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for the irreversibility of the process is the colloidal nature of asphaltenes suspensions, and this was verified by previous experimental observations. Therefore, there is an intense need to understand the possible conditions under which asphaltenes will deposit in the well. Numerical modeling provides an alternative and economical solution in the prediction of asphaltenes deposition, especially at higher temperatures and pressures under multiphase flow conditions (Attar, 2015). The modeling of asphaltenes initially started from the thermodynamic models based on the solubility parameters, leading to multiple descriptions of Statistical Associating Fluid Theory (SAFT). Various researchers have used the experimental results as the basis for the prediction of asphaltenes deposition, but it was found that an optimized numerical model produces more reliable results compared topredictions based on experimental values (Behbahani, Ghotbi, Taghikhani, & Shahrabadi, 2014).

The following section describes the various models developed for predicting asphaltenes deposition, leading to the numerical model developed and studied in this paper.

II. THE DIFFERENT TYPES OF EXISTING MODELS

The various existing models can be classified into two categories: compositional models and mechanistic models (Yap, et al., 2012). The compositional models use various forms of equations of state to predict the phase equilibrium for asphaltenes precipitation, whereas the mechanistic models are based on the formulation of homogeneous liquid hydrocarbon mixtures (e.g., crude oil).

a) The steric-stabilization model

The steric stabilization model was presented by (Leontaritis, Kawanaka, & Mansoori, 1987). The model is based on Nellensteyn's concept of asphaltenes as the solid particles produced in crude oil, which are insoluble and peptized by the resins that are absorbed on their surfaces. According to this model, the asphaltenes are produced when the chemical potential of the resin is higher than the critical value. The compositional value is expressed by the following equation:

$$\Delta\mu_2 = RT[\ln\varphi_2 - (r-1)(1-\varphi_2) + r\chi(1-\varphi_2)^2] \quad (1)$$

where $\Delta\mu_2$ is the difference between the chemical potentials of the resins in solution and in their reference state, *R* the gas constant, *T*is temperature, $\phi_2$is the volume fraction of the resins, χ is the interaction parameter between resins and solvents, and *r* is the ratio of the molar volumes of the resins to the solvent. This model was initially successful in predicting the asphaltenes precipitation up to certain limits of temperature and pressure. However, it was mainly used for data regression. This model has certain limitations. For example, multiphase systems cannot be integrated because of the assumption of a single flowing phase used in this model. Conversion to multiphase flow without modification results in undefined outcomes. For example, as proposed in the model, the presence of any resin on the surface needs to be physically tested. In numerous studies, it has been found that inaccessible asphaltenes fractions are stable in particular solvents(Arya, et al., 2017). Thus, the existence of resins is not an essential requirement for the formation and stabilization of asphaltenes (Subramanian & Simon, 2015). Due to such major drawbacks and no inclusion of multiphase flow, the model does not seem capable of predicting asphaltenes precipitation.

b) The thermodynamic models

i. *The Flory-Huggins equation*

This model is based on the Flory-Huggins equation for polymer solutions which considers the asphaltenes solvated in the liquid medium. This technique differentiates the liquid-solid apart from the vapor-liquid equilibrium during multiphase flow modeling. The procedure follows the vapor-liquid calculations at an initial stage. After that, a modification is used for the liquid phase in which the vapor phase stays unaffected. The limitation of this model is that the solid-vapor equilibrium is not taken into account. Under the action of high pressure and temperature, some gases such as CO_2 affect the asphaltenes precipitation. Thus, the model is missing vital parameters for asphaltenes prediction during multiphase flow. Further work on this model was carried out by Hirschberg and co-workers (Hirchberg & Meijer, 1984). They eliminated any chances for the presence of resin and considered asphaltenes as single dispersed solvated macromolecules (Wu & Prausnitz, 1998). Following the various generalizations for this equation, the highest volume fraction of soluble asphaltenes in the crude oil is expressed as follows:

$$\varphi_a^{max} = \exp\left[\frac{v_a}{v_l}\left(1 - \frac{v_l}{v_a} - \frac{v_l}{RT}(\delta_a - \delta_l)^2\right)\right] \quad (2)$$

where $\phi_a^{max}$is the maximum volume fraction of soluble asphaltenes in the crude, *v* is the molar volume, δ is the solubility parameter, and *a* and l refer to the asphaltenes and the liquid medium, respectively.

ii. *Cubic equations of state*

A few researchers have used the cubic equations of state for predicting the behavior of asphaltenes precipitation. Various forms of cubic equations of state are available and modified. For example, Gupta used a solid phase fugacity with a Peng-Robinson model (Nikookar, Pazuki, Omidkhah, & Sahranavard, 2008). The combination of data from Nuclear Magnetic Resonance (NMR) with Alexander's correlations and the Redlich–Kwong equation of states provides the basis for the numerical model (Jaramillo, Galeana, & Manero, 2006). Nonetheless, as observed in previous models, the selection of molar weights and heteroatom content are critical to being able to present unrelated results. The interaction parameters (i.e., pressure, volume and temperature) must be considered during asphaltenes precipitation because of the changes in the solubility with changes in these major parameters. Nonetheless, these parameters had to be tailored for each n-alkane,and all of the changes in these parameters were applied in all of the equations rather than just considering them to be constant(Stachowiak, et al., 2005). The major issue with the models based on cubic equations of states is that they cannot simulate the upper onset pressure boundary by tuning the model parameters to the lower onset pressure boundary.

c) The association EOS

The most advanced forms of the equation of states include association EOS for predicting phase equilibria based on Statistical Associating Fluid Theory (SAFT). Research has shown that the models based on SAFT are somewhat acceptable to use for predicting asphaltenes precipitation, as evident from the works of (Firoozabadi & Li, 2010), (Wu & Prausnitz, 1998), (Chapman, 1989), (Ting, Hirasaki, & Chapman, 2003), (Ting D. , 2003), and Gil-Villegas (Gonzalez, et al., 2004). The issue with the models based on the associating equation of states is the same as that of cubic EOS. That is, the model takes sufficient time for characterization of the oil, especially the heavy oil, considering all of the parameters that make the model complex. Andersen and Speight explained this in a short and concise manner: “The more realistic the model becomes, the more complex it will be. The complexity as well gives rise to an increase in unknown parameters which in turn will have to be estimated or fitted to the experimental data” (Andersen & Speight, 1999).

In the present paper, a new numerical model has been developed using a novel approach to describe flow restrictions in the wellbore and near-wellbore area due to asphaltenes precipitation in multiphase flow. This model is capable of identifying and predicting potential flow assurance problems. In the wellbore numerical model described below, numerical methods (such as implicit finite difference discretization) along with a specific type of black/heavy oil and appropriate Equation of State compositional models are used. The application of Equation-of-State updates the properties and the equilibrium calculations between all of the phases (oil, gas, and asphaltenes).

The governing equations of the wellbore model consist of mass conservation of every phase and every component, momentum conservation of the liquid and gas phases, and energy conservation of the mixture of fluids. The governing equations are calculated using finite difference discretization methods. The simulation results indicate that asphaltenes deposition can begin in the middle of the well. Furthermore, they show that asphaltenes deposition is greatly influenced by CO_2, and the location of deposition is altered to the lower part of the well in systems containing CO_2.

The following section also describes the transport model based on rheological equations of state, a three-phase interacting system, and correlations for multiphase flow. The prediction model incorporates mass profiles as a function of pressure and temperature along with changes in the rheological properties of crude oil as it flows through the pipe.

III. MATERIAL AND METHODS

A simulation of asphaltenes deposition in the wellbore was performed with a heavy oil sample. In this simulation, the bubble point pressure of the fluid took place in the middle of the wellbore. Furthermore, the effect of CO_2 on asphaltenes deposition in the same sample was investigated. This simulation, however, can adequately demonstrate the effect of CO_2 on asphaltenes deposition in the production well. It applies to the discovery of CO_2 in enhanced oil recovery.

The input parameters for this case study were obtained from an Australian oil field. A 2400 m well was considered in this case study, which is at the primary production stage. The well is located in a reservoir with an initial pressure of 38 MPa and functioning at a wellhead pressure of 12.9 MPa. The multiphase flow simulation is carried out for this well to analyze its performance for flow assurance concerns. Figure-1 shows the schematic of the flow system in the well pipeline. An initial composition of oil is flowing through the pipe of height “h” and radius “r”. The crude oil is a hydrocarbon mixture of ‘’n’’ number of components. The effects of temperature and pressure are considered for equalmole fractions of three phases (i.e., liquid, solid, and gas). The crude oil enters from the bottom of the pipe, which has an inside radius of “r(a)”. The multicomponent oil flows through the pipe at a temperature “T_o” and pressure “P_o”. The oil flows in the upward direction, cools along the length of the pipe, and expands under reduced pressure. The crude oil temperature also changes with the forced convection heat transfer process. This change in temperature and pressure conditions results in asphaltenes deposition along the wall of the wellbore pipe. The radius of the pipe at this area reduces to “r(w)”. As the layer of asphaltenes grows, it faces shear removal forces due to the flow of upcoming oil and gas.

When the flow of oil “Qs” is considered as turbulent, the asphaltenes layer is assumed to form asa laminar sub-layer. Three zones are developed under such conditions: a laminar sub-layer, a transition zone, and a turbulent main.

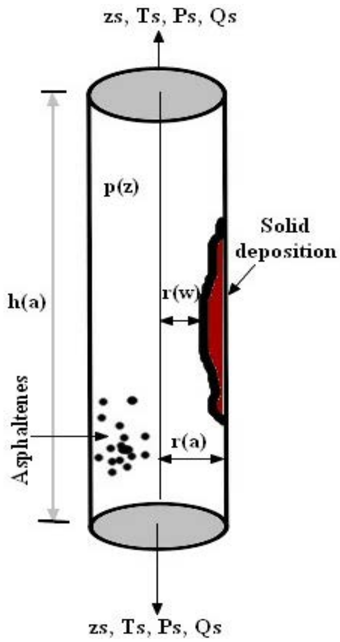


Figure 1: Modelling solid deposition in a well bore

The input parameters for this case study are obtained from tan Australian oil field, and are presentedin Table 1. Table 2 shows the composition of the fluid sample and the fluid's characteristics. These tables are used for better understanding of the simulation applied in this case study.

Table 1: Input parameters for simulation of asphaltenes deposition in the wellbore with a specific fluid sample

Well Data		Reservoir & Fluid Data	
Well Height	2400 m	Net pay zone	60 m
Max. grid size	15.2 m	Reservoir pressure	90 MPa - 922 Kg/cm^2
Top ambient temperature	15.6 °C	Reservoir temperature	320°F - 160°C
Bottom ambient temperature	100 °C		
Total heat transfer coefficient	20.4kJ/m^2.hr.°C		
Tubing ID	0.070 m		
Wellhead pressure	12.4 MPa		
Oil productivity index	2.7m^3/MPa.m.day		

Table 2: Fluid characterization and composition of the fluid sample

Component	Pc (MPa)	Tc (R)	VC (m^3 /kg.mol)	Mw (kg/kg.mol)	Acentric factor	Parachor	Volume shift	Primary composition
CO_2	7.3780	547.56	0.09408	44.01	0.225	168.17	0	0.0246
$Cl\text{-}CO_2$	4.6092	360.61	0.10258	17.417	0.015127	92.19	0	0.4041
$C_3\text{-}C_5$	3.9517	732.89	0.23784	53.516	0.1793113	195.33	0	0.0755
$C_6\text{-}C_{19}$	2.0092	1135.31	0.85649	164.423	0.655007	512.21	0	0.2719
$C_{20}\text{-}C_{30}$	1.2094	1419.29	1.81247	340.927	1.064023	1016.51	0	0.1064
C_{31+}	0.9871	1682.93	3.53022	665.624	1.371778	1944.21	0	0.0774
Asphaltene	0.9871	1682.93	3.53022	665.6224	1.371778	1944.21	0	0.0401

a) *Assumptions for proposed Multiphase Flow model*

The mass conservation equation for multiphase flow was developed using the following assumptions and was then applied for predicting asphaltenes precipitation in the well bore.

a. The single-dimensional flow was assumed along the length of the well in vertical, horizontal and deviated inclinations. The assumption is acceptable for pipelines of smaller diameters, as in our case.

b. Spatial averaging and Eulerian time were applied.

c. For the cases of the three-phase flow, water-oil slippage was considered and calculated using the well indices values for each phase.

d. The pressure for all of the phases (i.e., liquid, solid and gas) is considered to be the same. This assumption is considered reliable when the concentration of gas is negligible compared with those of the liquid and solids during multiphase flow in the pipeline.
e. A thermodynamic equilibrium is considered between the phases. Various approaches such as black oil and compositional approaches were applied to calculate the fluid properties and state relations.

b) Development of the Mathematical Model

Based on these assumptions, the flow equations developed for the liquid and gas phases are as follows:

$$\frac{\partial(\rho_O\alpha_O)}{\partial t}+\frac{1}{A}\frac{\partial(A\rho_O\alpha_O u_O)}{\partial x}=\psi_O-\Gamma_g \quad (3)$$

$$\frac{\partial(\rho_g\alpha_g)}{\partial t}+\frac{1}{A}\frac{\partial(A\rho_g\alpha_g\mu_g)}{\partial x}=\psi_g+\Gamma_g \quad (4)$$

where ψ_o and ψ_g are the oil and gas mass influx terms, and ρ_g and ρ_o are the oil and gas mass densities. Along with an appropriate definition of the interphase transfer term, Equations 3 and 4 result in decreasing the number of primary unknowns. This approach leads to a faster simulation runtime as well as application of the state relations using either compositional phase property calculations or black oil property calculations. The addition of solid particles to the fluid flow results in new sets of mass conservation equations, which are as follows:

$$\frac{\partial(A\hat{\rho}_O\alpha_O x_{nc}+Ac_a\alpha_O)}{\partial t}+\frac{\partial(A\hat{\rho}_O\alpha_O u_O x_{nc}+Au_O c_a)}{\partial x}=A\left(\dot{\hat{\psi}}_{O,nc}+\dot{\hat{\gamma}}_a-\dot{\hat{m}}_{da}\right) \quad (5)$$

where c_a is the asphaltenes concentration in the crude oil, γ is the flocculation of solid particles from the reservoir, and m_d is the deposition rate of the solid particles. Equation 5 is applied to fluids that contain asphaltenes and cause asphaltenes flow assurance problems. Equation 6 is used for fluids with precipitation potentials.

$$\frac{\partial\left(\sum_{i=1}^{NWA\,X}A\hat{\rho}_O\alpha_O x_i+Ac_w\alpha_O\right)}{\partial t}+\frac{\partial\left(\sum_{i=1}^{NWAX}A\hat{\rho}_O\alpha_O u_O x_i+Au_O c_w\right)}{\partial x}=A\left(\sum_{i=1}^{NWAX}\dot{\hat{\psi}}_{O,i}+\dot{\hat{\gamma}}_w-\dot{\hat{m}}_{dw}\right) \quad (6)$$

Here, c_w is the wax concentration in the crude oil. To solve Equations 5 and 6 for asphaltenes and wax mass conservations, a similar approach for the solution component concentration (mole per volume) at a specific time is considered. Solving the equation in grid block "*i*" (the goal of gridding is to transform the model into a discrete system to solve the flow equations), we obtain the following equation:

$$\begin{aligned}N_{k,i}^{n+1}&=N_{k,i}^{n}+\frac{\Delta t}{V_b^n}A_{i-1}^n\left[(\hat{\rho}_O\alpha_O u_O)_{i-1}^{n+1}x_{k,i-1}^n+\left(\hat{\rho}_g\alpha_g u_g\right)_{i-1}^{n+1}y_{k,i-1}^n\right]\\&-\frac{\Delta t}{V_b^n}A_i^n\left[(\hat{\rho}_O\alpha_O u_O)_i^{n+1}x_{k,i}^n+\left(\hat{\rho}_g\alpha_g u_g\right)_i^{n+1}y_{k,i}^n\right]\\&+\Delta t\left[\dot{\hat{\psi}}_{Ok,i}^{n+1}+\dot{\hat{\psi}}_{gk,i}^{n+1}+\dot{\hat{\gamma}}_{a,i}^{n+1}-\dot{\hat{m}}_{da,i}^{n}\right]\end{aligned} \quad (7)$$

When the number of moles of component *k* per bulk volume (N$N_{k,i}^{n+1}$) is obtained, the overall mole compositions of the hydrocarbon phases in the grid block *i* are updated. The next step involves the flash calculations of the concentration of asphaltenes at a new time step. In Equation 6, the solid deposition rate $m_{da,i}^n$ is used for the old time step. The process can be reiterated using a new deposition rate and new solid concentrations until convergence is achieved. The new concentrations are used for updating the concentrations of fluid species and solid precipitates in grid block *i using* PHREEQC module, which is a specialized geochemical model(Parkhurst & Wissmeier, 2015)for the reaction among rocks, water and solid precipitates (asphaltenes in our case). The next concern is the evolution of asphaltenes deposits, finally resulting in complete clogging of the wellbore. The cross-sectional area of well bore pipe decreased due to solid deposition, resulting in production loss. The cross-sectional area at the new time step is calculated as follows:

$$A_i^{n+1}=A_i^n+\frac{V_{s,i}^n}{\Delta_{xi}} \quad (8)$$

Equation 8 can follow the progress of solid deposition in each wellbore grid block. The model is used for predicting the decline in the flow of crude oil due to solid deposition.

c) Effect of CO_2 injection

According to (Darabi, 2014), additional flow assurance issues are introduced into the reservoirs and the wellbores by applications of CO_2 and light hydrocarbon gas injections for the enhanced oil recovery process. Most conventional oil fields have reported asphaltenes deposition as the most challenging issue during the CO_2 flooding process, and there is the need to conduct proper studies of that effect. As evident, the presence of light components can upsurge the bubble point pressure and the onset pressure of asphaltenes in the crude oil. (Vargas, et al., 2009)Applied PCSAFT EOS in the description of the impact of light components on the behavior of the asphaltenes phase. As in the case of the asphaltenes precipitation modelling approach, the impact of composition on the asphaltenes onset pressure is not rigorously included. Instead, the pressures of different temperatures are well defined as input variables for use in the process. PCSAFT EOS may not be recommended for the entire variety of compositions because the Cubic Equation of State is modified to only one set of compositions for asphaltenes precipitation. This is because it applies to the binary interaction coefficients. To reduce modification errors for asphaltenes precipitation models, experimental values are used for the asphaltenes onset pressure. Table 3 shows the onset pressure of the fluid for different molar ratios of CO_2 to oil.

Table 3: Asphaltenes onset pressure and temperature for different mixing ratios of CO_2

Onset Temperature (°F) – (°C)	0% CO_2	5% CO_2	10% CO_2	15% CO_2
100 - 37.7778°C	4600	4770	4930	5100
93 - 33.8889°C	5045	5165	5285	5400
88 - 31.1111°C	5450	5545	5640	5735
82 - 27.7778°C	5960	6000	6045	6085
77 - 25°C	6660	6625	6590	6560
71 - 21.6667°C	7580	7445	7310	7170
66 - 18.8889°C	8650	8430	8210	7995
63 - 17.2222°C	9545	9175	8810	8440

Table 4: Reservoir fluid composition for different mixing ratios of CO_2

Component	0% CO_2	5% CO_2	10% CO_2	15% CO_2
CO_2	0.0246	0.07337	0.12214	0.17091
Cl-C2	0.4041	0.383895	0.36369	0.343485
C3-C5	0.0755	0.071725	0.06795	0.064175
C6-C19	0.2719	0.258305	0.24471	0.231115
C20-C30	0.1064	0.10108	0.09576	0.09044
C31+	0.0774	0.07353	0.06966	0.06579
Asphaltenes	0.0401	0.038095	0.03609	0.034085

d) Development of the Computational Model

A comprehensive computational model is designed for the evaluation and prediction of asphaltenes in wellbores, as shown in Figure-2. The model incorporates asphaltenes prediction with and without injection of CO_2 in the well. The model starts with defining and inputting the variables that affect asphaltenes precipitation. The assumptions are also included in the next step, which defines the flow of the model. The next step is to update the temperature and pressure in the loop for evaluating the asphaltenes precipitation later on. Equations 2 and 3 are used to calculate the phase equilibria in the next step. All the physical properties, such as the density, viscosity, and temperature of crude oil, are determined in this step, and the diameter of the pipe is updated. Equations 5 and 6 are used for evaluating for asphaltenes precipitation in the next stage. If precipitation doesn't occur under the given conditions, the loop is repeated for changed values of temperature and pressure. If asphaltenes are present, further calculations are made for its verification and are matched with the original data obtained from the Halibut oil field (Australia). If asphaltenes are formed, and the nominal diameter of the pipe decreases to a reduced size, the simulation is stopped, confirming the asphaltenes precipitation. If no asphaltenes are formed, the loop is repeated back for the changing temperature and pressure values. After the initial determination of asphaltenes under the given conditions, the effect of CO_2 injection is also studied. This loop can be run or stopped as required. With the injection of CO_2, the asphaltenes mass calculations are made along with changes in the nominal diameter of the wellbore. Upon confirming the asphaltenes precipitation, the loop stops. In the case of no change in pipe diameter, the loop is repeated to change the CO_2 concentration pressure and temperature for a new iteration. Figure-2 is the schematic for the computational model used for asphaltenes deposition and precipitation in multiphase flow.

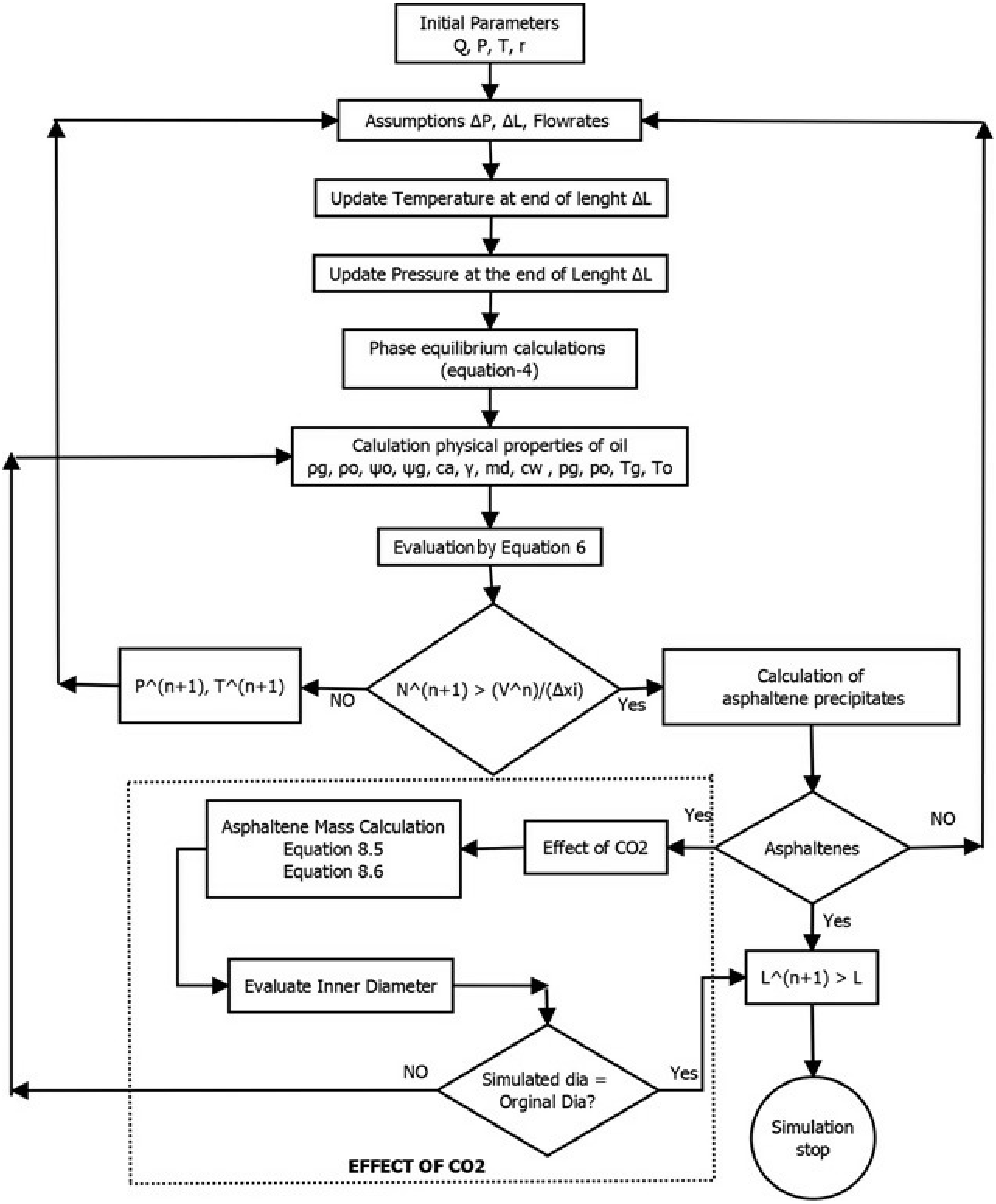


Figure 2: Computational model for solid deposition in a well bore for both cases (with and without CO_2)

IV. RESULTS AND DISCUSSION

This study has considered a working example of Tan oil field for the analysis of asphaltenes deposition problems. The data of pressure-temperature profiles was available. The natural fractured reservoir has the pressure of 922Kg/cm^2 and temperature of 160 °C. The average oil produced by this well is 32°API and the average bubble point pressure is 132Kg/cm^2. The data of impact of phase behavior on asphaltenes deposition is already available from experiments conducted by the industry. This data includes the extended compositional analysis and asphaltenes phase boundaries. The SARA analysis provides a complete PVT analysis for the fluid. Table-2 provides the fluid characterization and composition of the fluid sample. Matlab was used for solving the equation 7 and 8 for asphaltenes deposition in every grid block. The programming in Matlab has been done according to the developed computational model in figure-2. The conditions for simulation are based on the assumptions described in section 3.1. Following are the results from simulations for the developed numerical model.

Figure-3 indicates that the maximum asphaltenes precipitation takes place at approximately the bubble point pressure, in which the solubility of asphaltenes is at a minimum. In fact, when gas is released from the crude oil, the asphaltenes components increase their stability and solubility in the oil.

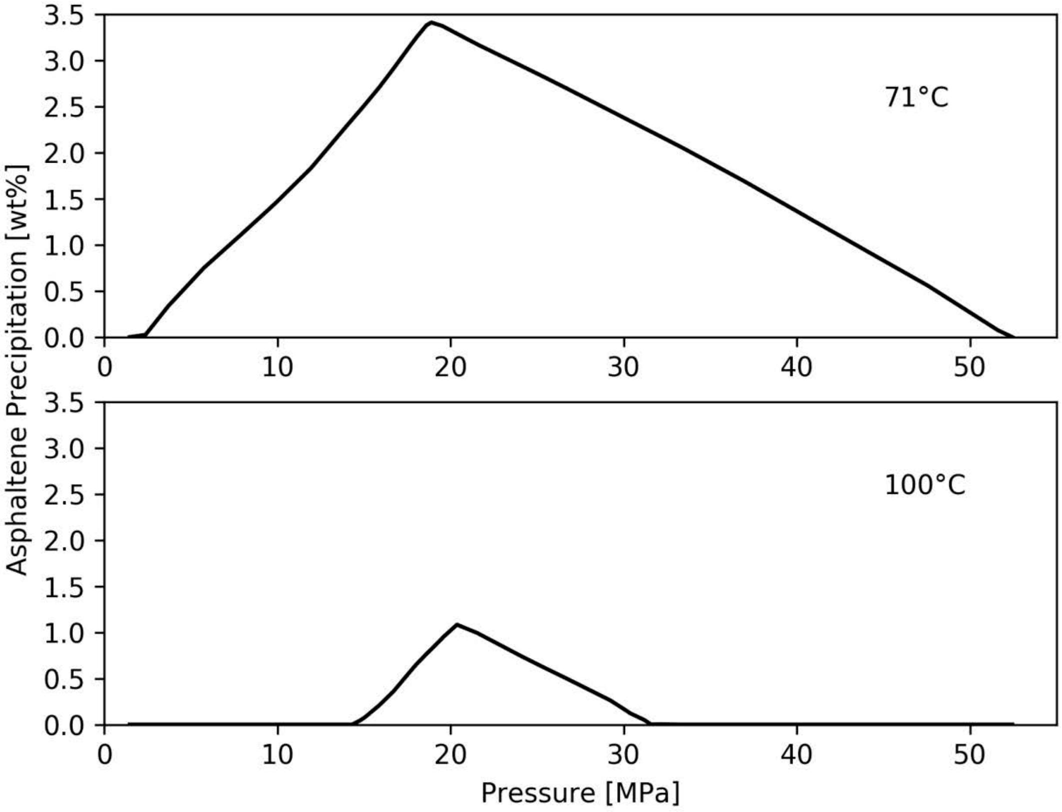


Figure 3: Weight percent of asphaltenes precipitation as a function of pressure at different temperatures.

The steady-state solution of the well is obtained at the initial time and then drawn on the vapor/liquid equilibrium and asphaltenes onset curve, as illustrated in Figure4.

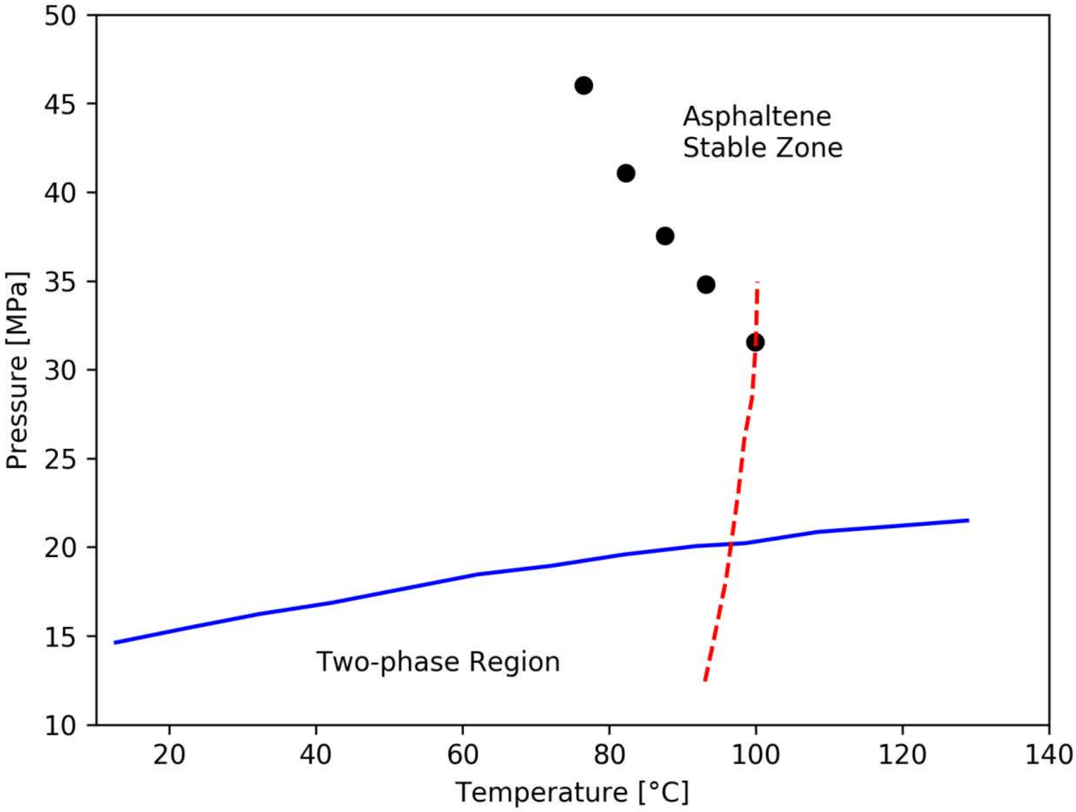


Figure 4: Pressure and temperature route from the bottom of the well to the surface at zero time (dashed red line), asphaltenes onset pressure (black dots) and fluid saturation line (solid blue line)

As evident, the pressure-temperature (P-T) path at initial conditions, as indicated by the blue line, shifts from the asphaltenes stable zone towards the asphaltenes unstable zone. At the same time, the blue line shifts towards the two-phase region. Therefore, according to this study, it is understandable that the well can hypothetically experience asphaltenes precipitation. Moreover, the study proceeds with the simulations for calculating the asphaltenes deposition rate and with measuring the quantity of asphaltenes precipitation accumulated in the well. A graph of asphaltenes precipitation as a function of depth is plotted for different temperatures in Figure-5.

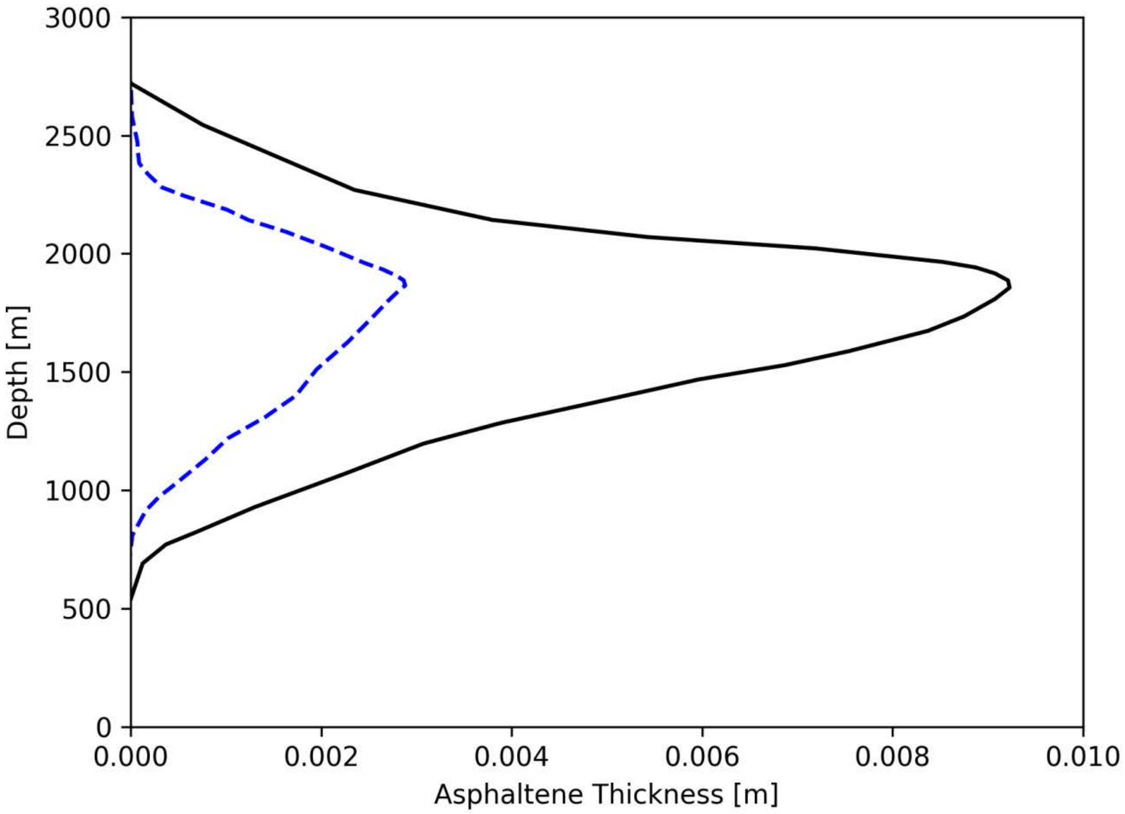


Figure 5: Thickness of asphaltenes deposit on the inner surface of the wellbore at 20 days (dashed blue line) and 90 days (solid black line)

It is expected that more asphaltenes precipitation will be evident in the upper part of the well. This is because of the fact that temperature changes drastically in the wellbore, and the temperature of the wellbore is lower in the upper section.

The magnitude of asphaltenes deposition and the rate of deposition in the wellbore can be obtained through conducting simulation runs for the wellbore. The wellbore's cross-sectional area is considerably changed by the asphaltenes deposition within the wellbore, as evident in Figure-5, which displays the profile of the inner radius of the well as a function of time. Evidently, the wellbore's cross-sectional area begins to shrink below 2030 m depth, although a minimum asphaltenes thickness is attained at 846 m below the surface. Small dents are observed at the surface of the precipitated asphaltenes as a result of the elimination of asphaltenes by shear forces. The remnant profiles of asphaltenes flocculated in the wellbore are shown in Figure-6. Indeed, the concentration of asphaltenes attains a maximum value at 846 m depth, and this behavior substantiates the maximum deposition at that instant.

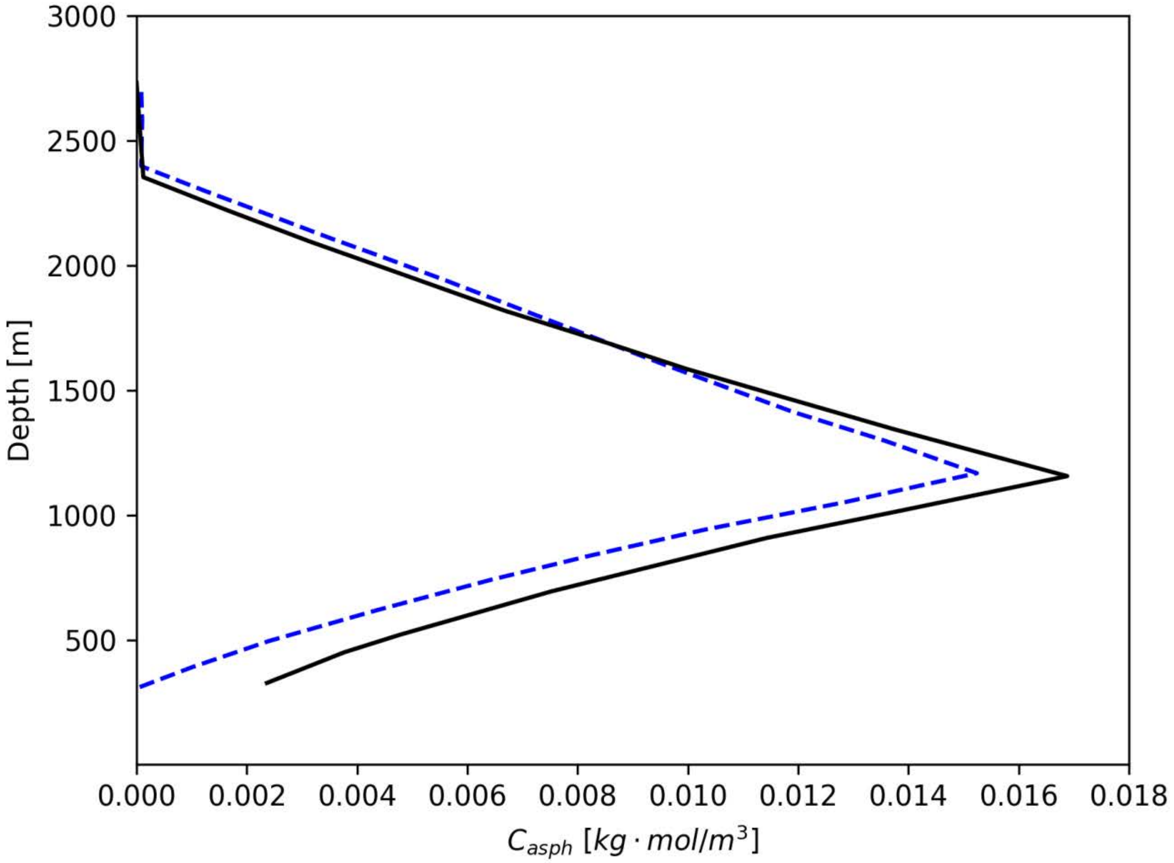


Figure 6: Concentration profiles of asphaltenes flocculate in the wellbore at 20 days (dashed blue line) and 90 days (solid black line).

Parameters such as pressure, temperature, and velocity profiles in the wellbore can subsequently change due to the deposition of asphaltenes particles. For that reason, it also impacts the volume of fluid influx coming from the reservoir. It is important to note that the bottom-hole is pressurized by asphaltenes deposition because of blockage of the wellbore. This pressurization is also contributed to by the rise of frictional forces existing between the surfaces of accumulated asphaltenes and the flowing fluid. As a result, asphaltenes deposition minimizes the influx from the reservoir through the wellbore.

Variations in the fluid temperature inconsistently increase the asphaltenes precipitation while reducing the probability of asphaltenes sticking on the surface of the well. The variation of pressure at bottom-hole as a function of time is shown in Figure-7.

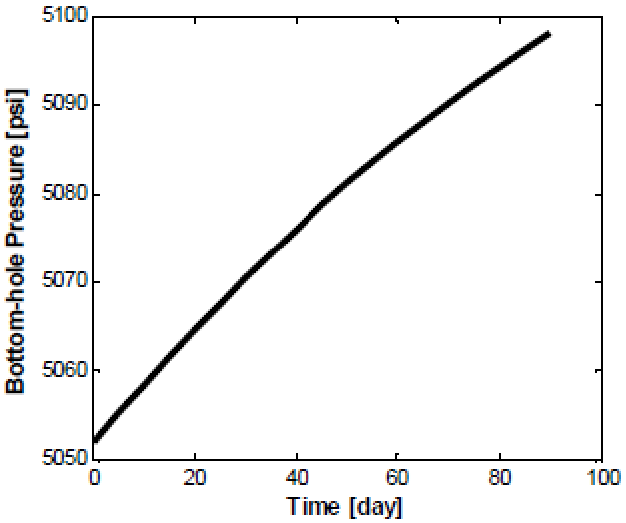


Figure 7: Variation of bottom-hole pressure due to asphaltenes deposition with time elapsed.

The asphaltenes particle blockage in the wellbore increases the pressure exerted at the bottom-hole as time elapses.

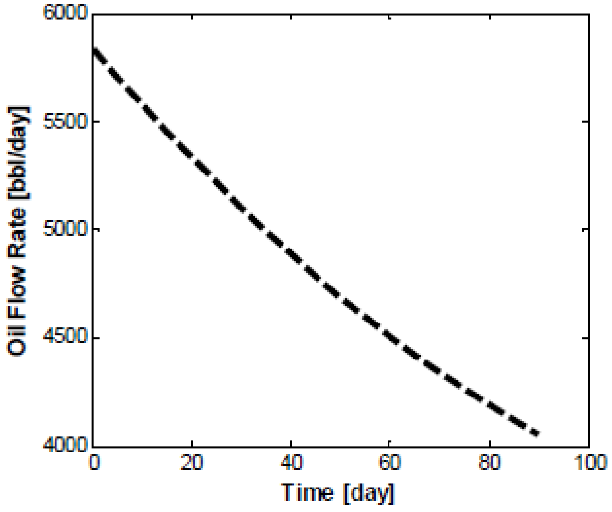
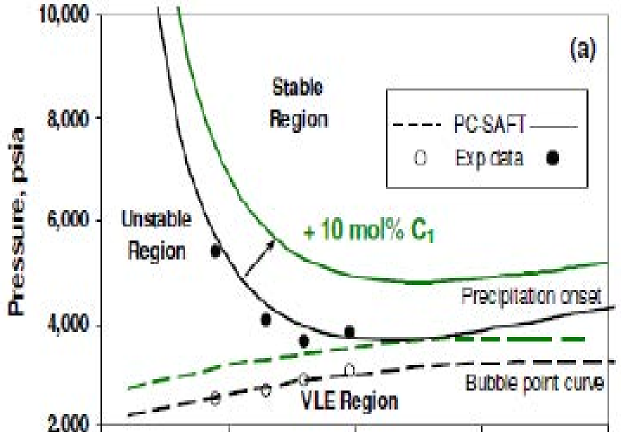


Figure 8: Variation of oil flow rate due to asphaltenes deposition with time progression

a) *Effect of CO_2 on asphaltenes deposition*

This section shows the simulation of the effect of CO_2 on asphaltenes precipitation and deposition in the wellbore in general. Additionally, the simulation process targets capturing the condition where CO_2 is extracted in the production well and is combined with the crude oil. In a previous study, Vargas (2009) demonstrated that the presence of light components or impurities in crude oil significantly alters the phase behavior of oil. The author has also claimed that asphaltenes lose stability when natural gas or CO_2 is injected with the oil. In Figure-9, it is clear that the results for the effect of CO_2 on the P-T phase are in accordance with Vargas's claims. Additionally, the input onset pressures as shown in Figure-9 (c)follow the same trend as the composition of oil after mixing with CO_2in Table 4.



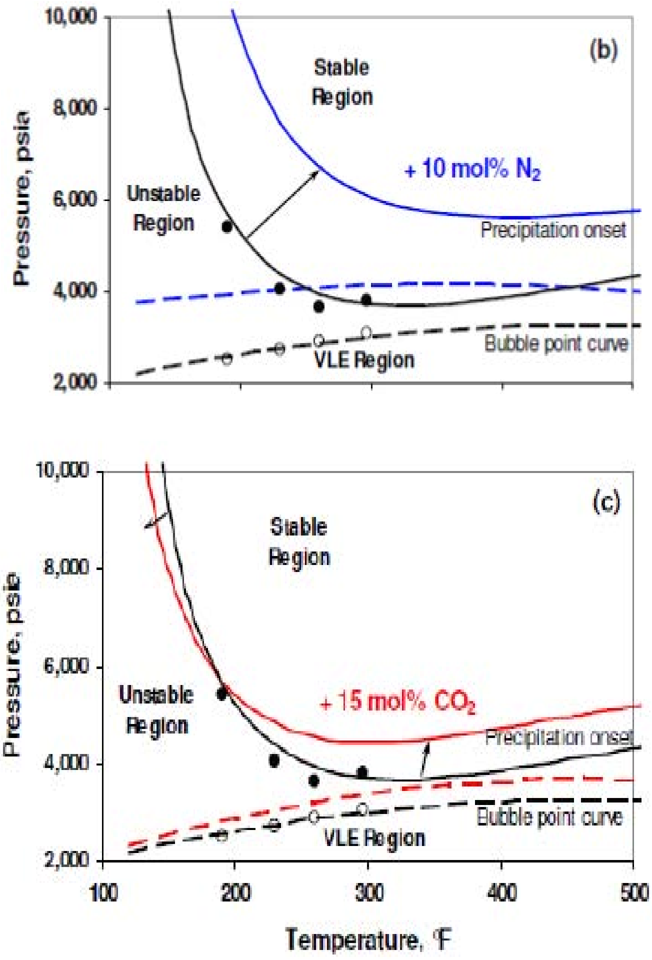


Figure 9: Effect of light hydrocarbons mixing on the stability of asphaltenes in crude oil. (a) Effect of methane, (b) effect of nitrogen (c) effect of CO_2 (from Vargas, 2009).

The amount of asphaltenes precipitation can be calculated from the asphaltenes precipitation module with the help of new ratios of the oil and the input of onset pressures of asphaltenes. Additionally, the amount of asphaltenes precipitation is shown in Figure-10 for different molar ratios of CO_2 at a temperature of 100°C. Figure-10 shows that greater asphaltenes precipitation is expected with higher contents of CO_2. Subsequently, multiphase flow simulations were performed in the wellbore for an extended period with significant amounts of CO_2 in the reservoir fluid.

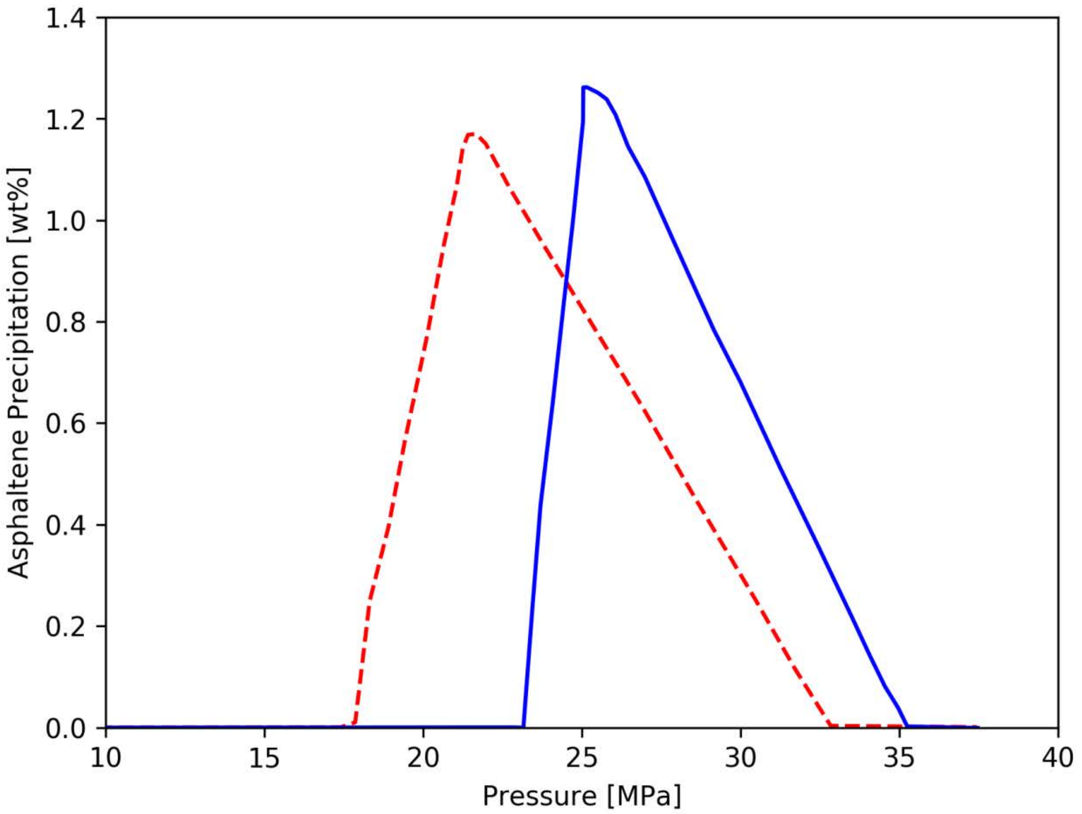


Figure 10: Weight percent of asphaltenes precipitation in the presence of CO_2 with 5% CO_2 (red dashed line) and 15% CO_2 (blue solid line) at 100 °C.

Similar input data were also used for the wellbore and reservoir geometries to ascertain the credibility of the results. The temperature of 100°C, the asphaltenes concentration profiles for different compositions of the reservoir oil were sampled and illustrated, as shown in Figure-11. It is clear that the asphaltenes concentration is zero in the presence of perforations, and it begins to flash out from crude oil at lower temperatures and pressures within the upper sections of the wellbore. It is observed that the presence of higher amounts of CO_2 lowers the starting point of asphaltenes precipitation in the wellbore, as shown in Figure-11.

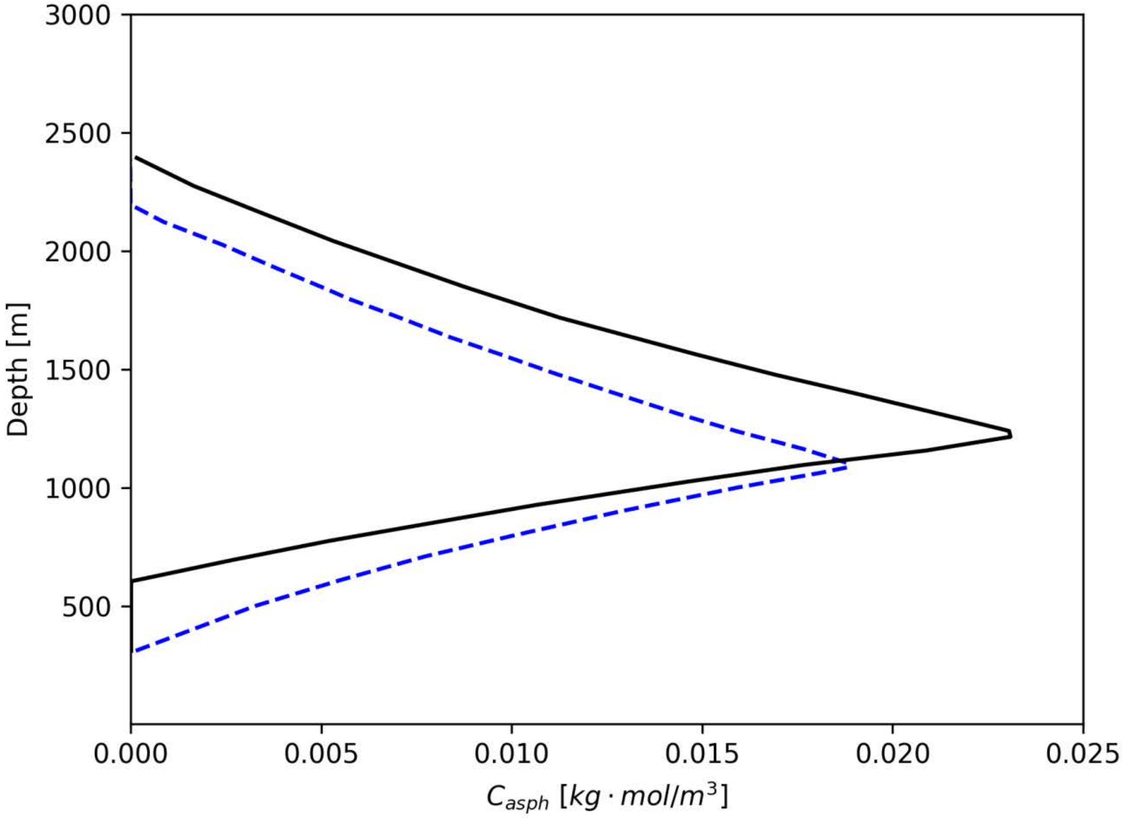


Figure 11: Asphaltenes concentration profiles at the end of 90 days of production in the wellbore with 5% CO_2 (blue dashed line) and 15% CO_2 (black solid line)

Therefore, more asphaltenes accumulated at the bottom of the well when more CO_2 was in the production well.

This simulation reveals that CO_2 can indirectly alter the pressure and temperature profiles through varying the velocity fields within the wellbore. As a final point, this section considers the propagation of asphaltenes deposition on the surface of the wellbore as illustrated in Figure-12.

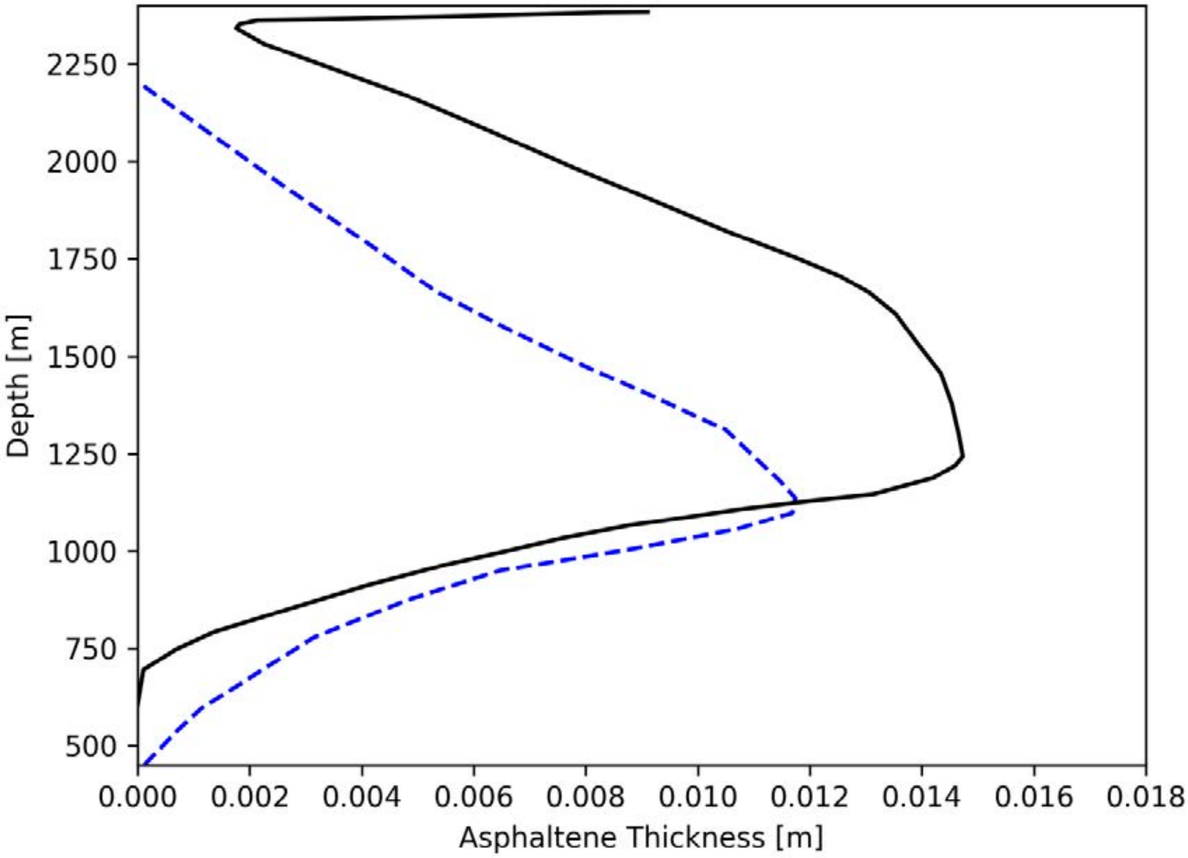


Figure 12: Asphaltenes deposition thickness profiles at the end of 90 days of production in the wellbore with 5% CO_2 (blue dashed line) and 15% CO_2 (black solid line).

The presence of CO_2 can cause plugging of the wellbore to occur at a faster rate than if CO_2 is absent, and itspresence also moves the maximum plugged cross-section toward the bottom of the well during the deposition process.

V. CONCLUSION

The asphaltenes prediction model was developed based on the finite difference method. The deposition problems in wells with proven records were simulated using the developed numerical model. It was observed from the results that the deposited layer of asphaltenes has more thickness at the upper part of the well due to the low temperature and pressure area, favoring the instability of the dissolved asphaltenes. It is noted that the maximum asphaltenes precipitation takes place near the bubble point pressure. The effects of velocity changes, pipe diameter, and pressure variations were investigated in this paper. It is found that a decrease in velocity decreases the heat exchange rates of the wellbore fluid and surroundings. Blockage in the wellbore increases the bottom-hole pressure with time. Additionally, the effect of CO_2 injection for enhanced oil recovery was studied, and it was found that asphaltenes become more unstable in the presence of CO_2.

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