A new investigation on modeling of permeability reduction during CO2 flooding processes in sandstone oil reservoirs

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Abstract

   Permeability reduction in oil reservoirs during primary oil recovery and using the enhanced oil recovery methods are complicated problem which most of the oil field in worlds has encountered. In this work, a modified model based on four phase black oil model (oil, water, gas, and asphaltene) was developed to account permeability reduction during CO2 flooding in cylindrical coordinates around a well in a reservoir. The developed model was verified using data given in literature. The existing models use only two material balance equations based on asphaltene and oil phases in the porous media sample. Subsequently, this model has been used for examining the effect of well production rate and the initial reservoir permeability on the asphaltene deposition behavior in a typical reservoir during CO2 injection process. The results show that the developed model is more accurate than those obtained from previous models and is in good agreement with the experimental data reported in literature.

   Also, the results of proposed model indicate that at a fixed permeability, with increase in the production rate, the amount of asphaltene deposits will increase. However, an increase in the reservoir permeability will decrease the deposition rate because of the existence of further channels for flow.

1. Introduction

   CO_2 flooding is one of successful EOR (Enhanced Oil Recovery) methods applied in oil fields. CO2 can improve oil production by reducing the interfacial tension and viscosity
or increasing mobility. One common problem during CO2 injection is asphaltene instability, which induce deposition and adsorption of asphaltene and may cause pore-throat-plugging or wettability alteration [1]. Field and laboratory data confirm that the asphaltene solubility is lower in the light oil. Asphaltenes tend to precipitate more easily in light oils rather than in heavy oils. For instance, the Venezuelan Boscan crude with 17.2 wt% asphaltene was produced with nearly no troubles whereas Hassi-Messaoud in Algeria has numerous production problems with only 0.15 wt% asphaltene[2]. Since light-oil reservoirs are more often candidates to gas injection processes, the danger is

even bigger. Due to the complexity of asphaltene deposition phenomena during CO2 injection, the majority of existing works study the asphaltene deposition during CO2 flooding using the injection of mixture of recombined oil (mixture dead oil and associated gas) and CO2 to the core and or with static systems and in the absence of a reservoir rocks[3]. Zanganeh et al. [4] studied asphaltene deposition during CO2 injection by a novel experimental set up to employ a high pressure visual cell using synthetic oil .Also, Okwen et al. [5] studied the chemical influence of formation water in decreasing the rate or amount of asphaltene deposition during CO2 injection and suggested the relevant parameters necessary to determine the formation type that is appropriate for CO2 injection. Nobakht et al. [6] investigated mutual interactions between crude oil and CO2 under different pressures and found that the measured crude oil - CO2 equilibrium interfacial tension (IFT) is reduced almost linearly with the equilibrium pressure. It is observed that if the equilibrium pressure is high enough, the light components in the

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original crude oil are quickly extracted from the oil drop to CO_2 phase at the beginning. Wang et al. [7] proposed a model for permeability reduction in rock samples. Hamouda [8] studied miscible and immiscible flooding and proposed a model based on the solubility theory to account for the effect of CO_2 flooding. The asphaltene deposition is governed by four mechanisms; surface deposition, entrainment, plugging and adsorption. Ali and Islam [9] investigated the effect of asphaltene deposition on carbonate rock permeability in single-phase flow. A model was coupled to deposition and adsorption mechanisms and the results were compared to experimental data of carbonate rocks. Gruesbeck and Collins[10] proposed a model that has been used for mechanical entrapment of solids and developed the equation for the deposition of fines in porous media. Minssieux et al. [11] investigated the flow properties of crude oils at reservoir temperature in different rocks. Leontaritis [12] developed a simplified model for prediction of formation damage and productivity decline by asphaltene deposition under saturated conditions in radial flow. The hydraulic diameter was estimated by the ratio of the total pore volume to the total pore surface area of the flow channels. Civan [13] developed a two-phase model to predict paraffin and asphaltene deposition. The permeability of plugging and non-plugging pathways was given by the empirical relationships. Wang et al. [14] proposed a deposition model including the static and dynamic pore surface deposition and pore throat plugging. The model incorporates the features of Civan's dual-porosity model for a single-porosity treatment in the laboratory core flow tests. The oil, gas and solid phases were assumed at thermal equilibrium. Nghiem et al. [15] proposed a model to study compositional simulation of asphaltene precipitation. They used the developed equation of Kumar and Todd [16] based on Kozeny–Carman equation. Kocabas et al. [17] developed a wellbore model coupled to asphaltene adsorption model based on Langmuir equation for linear and radial systems. The coupled model predicts permeability damage owing to mechanical trapping and adsorption. The model proposed by Ali and Islam was used and the equation was solved analytically through Laplace transform. Almehaideb [18] developed a model to simulate asphaltene precipitation, deposition, and plugging of oil wells during primary production. A four-component, four-phase limited compositional formulation was described. The model was implemented in cylindrical coordination to match the flow direction around the well. Monteagudo et al. [19] used network modeling to simulate one phase flow in porous media in order to predict the change in petroleum m flow by asphaltene deposition. The network model is used to predict formation damage caused by asphaltene deposition. The adsorption of asphaltenes on solids is the result of favorable interactions of the

asphaltene species or its aggregates with chemical species on or near the mineral surface, a number interaction forces, individually or in combination with each other, can be responsible for it. The major forces that can contribute to the adsorption process include electrostatic (Coulombic) interactions, charge transfer interactions, Van der waals interactions, repulsion or steric interactions and hydrogen bonding [20].The majority of existing models proposed monolayer adsorption behavior of asphaltenes on mineral surfaces that is studied by surface excess or Langmuir theory [21].

In petroleum literature, only limited amounts of experimental data on the permeability reduction under reservoir conditions due to conducting laboratory tests on core samples is time-consuming and expensive. Carrying out field experiments for the recognition of this phenomenon is difficult and even impossible. Further developments of both the modeling and experimental measurements should be conducted to design comprehensive reservoir management strategies. The complexity of the process of permeability reduction and formation damage, make impossible to present a fully predictive model in the short term time frame, and the experimental data will need to be collected and then used to tune the models.

Modeling of the asphaltene deposition in oil reservoirs still has room for further improvements. From a mathematical and numerical point of view, it is important to apply improved solution approaches that produce reliable results with reduced simulator runtime. . In this work, a new model based on four phases (oil, asphaltene, gas and water phase) and single well model in a cylindrical coordinate was developed to account permeability reduction on core sample during CO_2 flooding and the model was verified using experimental data given in literature. A conventional finite difference, implicit pressure–explicit saturation) formulation is used. The objective of developing such model is to obtain an improved black-oil formulation. This formulation is straightforward, requires less arithmetic per time step than other formulations, and has much smaller storage requirements than a fully implicit formulation. The main idea of the present study is to study the influence of the well production flow rate and formation permeability on the permeability reduction caused by asphaltene deposition.

2. Theoretical Calculation

In this study, the developed model is formed by combination of thermodynamic and permeability reduction models in a black oil four phases simulator around a well in a reservoir. The various parts of this developed model are:

2.1. Thermodynamic Model for Asphaltene Precipitation

According to Flory- Huggins theory [22], the chemical potential of asphaltene component is calculated as follow:

$$\frac{(\mu_p - \mu_p^0)}{RT} = \ln\Phi_p + \left(1 - \frac{V_p}{V_s}\right)\Phi_s + \frac{V_p}{RT}[(\delta_p - \delta_s)\Phi_s]^2 \quad (1)$$

where μ_p, Φ_P, and δ are, respectively chemical potential, volume fraction and solubility parameter. The solubility parameter in Eq. (1) is written as below:

$$\delta_i = \left(\frac{\Delta u}{v}\right)^{0.5} \quad (2)$$

where u is internal energy. The values of Δu and v are calculated by the SRK EOS. In this study, it is assumed that the asphaltene phase is as a pure liquid pseudo-component in which asphaltene precipitation has no effect on liquid–vapor equilibrium. Also, crude oil is considered as a binary homogeneous mixture of asphaltene and solvent. By equating the fugacity of asphaltene in liquid and solid phase we have:

$$\Phi_p^L = \exp\left(\frac{v_p^L}{V^L} - 1\right)\Phi_s - \frac{v_p^L}{RT}(\delta_p - \delta_s)^2\Phi_s^2 \quad (3)$$

The weight fraction of asphaltene precipitation is calculated as below:

$$W_{SAL} = \frac{(1-\Phi_p^L)(M_w^L/V^L)}{(1-\Phi_p^L)(M_w^L/V^L)+(\Phi_p^L)(M_{wp}/V_P)} \quad (4)$$

where Mw is molecular weight.

2.2. Asphaltene Deposition Modeling

There are the two permeability reduction mechanisms on porous media, adsorption and mechanical plugging.

The asphaltenes adsorption mechanism, which is related to the interactions between the asphaltenes functional groups and the rock surface, involves surface polarity, affinity or others attractive forces. Asphaltene is a polar component therefore formations have ability to adsorb asphaltene. The asphaltene adsorption was modeled using Zhu and Gu (ZG) model[35] based on multilayer theory of asphaltene adsorption. Although the model proposed by Zhu and Gu was used for hemimicelles of amphiphiles, it will be shown here that the model is justified for the asphaltene molecule as well, due to its amphiphilic character to aggregate and adsorb to rock interfaces [23]. ZG model is as follows:

$$\Gamma = \frac{\Gamma_\infty\, k_1\, C(n^{-1}+k_2 C^{n-1})}{1+k_1\, C(1+k_2 C^{n-1})} \quad (5)$$

where Γ, k_1, k_2 and n are, the amount of adsorbed asphaltene, the first adsorption step parameter (this step is taken to be adsorption of asphaltenes in solution to the surface of the rock), the second adsorption step parameter (this step is taken to be the adsorption of asphaltenes in solution to those asphaltenes already adsorbed to the rock) and the mean aggregation number of the adsorbed asphaltenes .

Also, the asphaltene adsorption was modeled using a Langmuir isotherm equation that shows monolayer type of asphaltene adsorption:

$$W_{sa} = \frac{W_{sa,max}\,.K_a\,.C_{sf}}{K_a\,.C_{sf}+1} \quad (6)$$

where K_a and c_{sf} are the ratio of adsorption/ desorption rate constants and the mass of suspended asphaltenes per mass of the oil phase.

2.3. The Mechanical Plugging Rate Model

The mechanical plugging rate for asphaltene is given according to Wang model based on Gruesbeck and Collins [10] as follow:

$$\partial E_A / \partial t = \alpha S_L C\, \phi - \beta E_A(\upsilon_L - \upsilon_c) + \gamma\, S_L u_L C \quad (7)$$

where the first term represents the surface deposition rate. The second term represents the entrainment of deposited asphaltene by the flowing phase when the interstitial velocity is larger than a critical interstitial velocity. This term shows that the entrainment rate of the asphaltene deposition is directly proportional to the amount of asphaltene deposits present in porous media, and also, the difference between the actual interstitial velocity and the critical interstitial velocity necessary for deposited asphaltene mobilization. The last term indicates the pore throat plugging rate, which is directly proportional to the product of the superficial velocity and the asphaltene precipitate concentration in the liquid phase. The value of β is described as:

$$\beta = \beta_i\,, \text{when } v_L > v_c$$
$$\beta = 0\,, \text{otherwise}$$

$$v_L = \frac{u_L}{\emptyset} \tag{8}$$

The value of γ is set as:

$$\gamma = \gamma_i(1 + \sigma E_A), when\ D_{pt} < D_{ptcr} \tag{9}$$
$$\gamma = 0\ , otherwise$$

Thus, the pore throat plugging deposition rate increases proportionally with the total deposits. When D_{pt} is less than D_{ptcr}, pore throat plugging deposition will occur.

In the above equations, E_A , α, β, γ and σ volume of asphaltene deposited per unit initial volume, the surface deposition rate coefficient, the entrainment rate coefficient, the plugging deposition rate coefficient and the snowball-effect deposition constant. Also, v_L , v_c and u_L are the interstitial velocity of liquid phase , the critical interstitial velocity of liquid phase and the flux of the liquid phase.

2.4. Single Well Model

In this work, the mass conservation equations for the four phases flow through the porous media are used to model the permeability damage in petroleum reservoirs. The proposed model in this work is an extension of the traditional black oil equations described by Wang and as follow:

Oil phase:

$$\frac{1}{r}\left[r\lambda_0 \left(\frac{\partial p_0}{\partial r} - \gamma_0 \frac{\partial D}{\partial r}\right)\right] + \frac{\partial}{\partial z}[\lambda_0 \frac{\partial p_0}{\partial z} - \gamma_0 \frac{\partial D}{\partial z})] - q_0 = \frac{\partial}{\partial t}(\varphi S_0 / B_0) \tag{10}$$

Water phase:

$$\frac{1}{r}\left[r\lambda_w \left(\frac{\partial p_w}{\partial r} - \gamma_w \frac{\partial D}{\partial r}\right)\right] + \frac{\partial}{\partial z}[\lambda_w \frac{\partial p_w}{\partial z} - \gamma_w \frac{\partial D}{\partial z})] - q_w = \frac{\partial}{\partial t}(\varphi S_w / B_w) \tag{11}$$

Gas phase:

$$\frac{1}{r}\left[r\lambda_g \left(\frac{\partial p_g}{\partial r} - \gamma_g \frac{\partial D}{\partial r}\right) + rR_s\lambda_0 \left(\frac{\partial p_0}{\partial r} - \gamma_0 \frac{\partial D}{\partial r}\right)\right] + \frac{\partial}{\partial z}\left[\lambda_g \frac{\partial p_g}{\partial z} - \gamma_g \frac{\partial D}{\partial z} + R_s\lambda_0 \left(\frac{\partial p_0}{\partial z} - \gamma_0 \frac{\partial D}{\partial z}\right)\right] - q_g - R_s q_0 = \frac{\partial}{\partial t}(\frac{\varphi S_g}{B_{wg}} + R_s\varphi S_0 / B_0) \tag{12}$$

Asphaltene phase:

$$\frac{1}{r}\left[r(\lambda_A + R_A\lambda_0) \left(\frac{\partial p_0}{\partial r} - \gamma_0 \frac{\partial D}{\partial r}\right) +\right] + \frac{\partial}{\partial z}\left[r(\lambda_A + R_A\lambda_0)(\frac{\partial p_{g0}}{\partial z} - \gamma_0 \frac{\partial D}{\partial z}\right)q_0 = \frac{\partial}{\partial t}(\frac{\varphi S_A}{B_A} + \frac{R_{As}\varphi S_0}{B_0} + \frac{E_A}{B_A}) \tag{13}$$

where P, S, q and B are, respectively, the pressure, saturation, production rate, formation volume factor of each of the fluid phases; D is the depth (positive downward); r and z are the radial and vertical dimensions; S_A indicates the suspended asphaltene saturation and R_A is the volume ratio of soluble asphaltene in the oil phase. The saturation equations for the flowing phases are related through:

$$S_o + S_w + S_g + S_A = 1 \tag{14}$$

The phase pressures are related through the capillary pressures, which are functions of saturations as:

$$P_{cow} = P_o - P_w \tag{15}$$

$$P_{cgo} = P_g - P_o \tag{16}$$

The mobility of each phase is calculated based on the following equation:

$$\lambda i = \frac{kk_{ri}}{B_i\mu_i} \tag{17}$$

where λ is the phase mobility and i denotes each of the fluid phases. By assuming the velocity of oil and precipitated asphaltene are the same, the mobility of oil and asphaltene can be shown as follows:

$$\lambda_0 = \frac{kk_{ro}}{\mu_o}\left(\frac{S_o}{S_o + S_A}\right) \tag{18}$$

$$\lambda_A = \frac{kk_{ro}}{\mu_o}\left(\frac{S_A}{S_o + S_A}\right) \tag{19}$$

where k, k_r and μ are, respectively, the absolute permeability, relative permeability, and viscosity of the denoted phases.
Also,, the gravity term is determined by following equation:

$$\gamma_i = \rho_{i,std} \times \frac{g}{g_c}\sin(\theta) \tag{20}$$

where $\rho_{i,\ std}$ is the phase density under standard condition; and θ is the deviation angle.

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The amount of asphaltene deposited in porous media (in Eq. (14)) was calculated as follows:

$$E_A = E_A + \left(\frac{\partial E_A}{\partial T}\right)\Delta T \qquad (21)$$

2.5. Initial and Boundary Conditions

The initial and boundary conditions are need for calculation a well located in a reservoir. Because at the start point of production usually reservoir pressure is above the upper asphaltene precipitation pressure then, at t=0, the volume fraction of suspended asphaltene in the whole of the reservoir is zero. In this work, the following initial and boundary conditions were used:

$$C\_A = 0 \qquad\qquad 0 < r < r\_e, 0 < z < h, t = 0 \qquad (22)$$

$$E_A = 0 \qquad\qquad 0 < r < r_e, 0 < z < h, t = 0 \qquad (23)$$

$$\varphi = \varphi_0 \qquad\qquad 0 < r < r_e, 0 < z < h, t = 0 \qquad (24)$$

$$k = k_0 \qquad\qquad 0 < r < r_e, 0 < z < h, t = 0 \qquad (25)$$

where r_e is the drainage radius of well; and h is the height of oil zone. The inner boundary condition is defined by constant total oil flow rate for the well. Based on this condition, the phase mobility is determined as follow:

$$T_{Re} = \frac{n\Delta z C_1 1}{\ln\left(\frac{r1}{r_w}\right)} \qquad (26)$$

$$T_0^n = T_{Re}^n \times \lambda_0^n \qquad (27)$$

where T_{Re} is the geometric factor for the layer n, C_1 is a conversion factor for units other than S.I, T_0 is the oil transmissibility and r_w is the well radius. Therefore, the oil flow rate at each layer for a well block is calculated as follow:

$$Q_0^n = \frac{T_0^n}{\sum_n T_0^n} Q_{0,tot} \qquad (28)$$

where $Q_{0,tot}$ is the total oil flow rate for all layer of the reservoir. Having the analogous definition with T_0 for other

three phases, we can calculate the production rate of each phase in each layer.

$$Q_g^n = \frac{T_g^n}{T_0^n} Q_0^n + R_s^n Q_s^n \qquad (29)$$

$$Q_w^n = \frac{T_w^n}{T_0^n} Q_0^n \qquad (30)$$

$$Q_A^n = \frac{T_A^n}{T_0^n} Q_0^n + R_A^n Q_0^n \qquad (31)$$

where R_s n is the solution gas oil ratio in each layer. The following equation for representing the behavior of permeability drop as a porosity function was used:

$$k = f_p f_w k_0 \left(\frac{\emptyset}{\emptyset_0}\right)^3 \qquad (32)$$

3. Solution Method

A conventional finite difference, (implicit pressure–explicit saturation) (IMPES) formulation is used to solve the proposed model. The IMPES solution scheme is a hybrid method in reservoir simulation which updates the pressure variables and saturation variables of Equation separately, using an implicit method for the pressure update and an explicit method for the saturation update. This is obtained by solving for new pressures based on the saturations from the previous iteration, and then updating the saturation based on these new pressures. The objective of the IMPES method is to obtain a single pressure equation for each grid block by combining all flow equations to eliminate the saturation unknowns. By this method, capillary pressure, and transmissibilities will be evaluated explicitly (at time level n). The key advantage of the IMPES method is that it is more stable than a fully explicit method, but less costly than a fully implicit method. As the saturation update is the only explicit part of the procedure, the previously restrictive condition becomes looser and allows larger time steps for the same spatial discretization size, which is desirable. In this method, first pressure (oil pressure) distribution in the whole of reservoir is determined implicitly. To determine the oil pressure, Esq. (10) – (14) is recombined to obtain one linear equation with only one unknown for each grid block that is the oil pressure. With having all necessary variables in the previous time step and solving the pressure equation, the pressure distributions around a well are calculated. Then, the saturation distributions for all four phases are determined explicitly. With having pressure in all block, thermodynamic model calculates the volume fraction of

asphaltene dissolved in the oil and precipitated from oil. Then, the deposition model calculates the amount of deposited asphaltene on the rock. Porosity and permeability distribution are then determined by the plugging model. Finally, other model parameters are calculated and these values of the model parameters are used in the new time step with repetition of the computations. The IMPES Flow Chart is shown in Figure 1.

Iterative coupling was used for coupling of equations. The main objective of the iterative coupling method is to achieve both accuracy and efficiency at the same time. Iterative coupling differs from sequential methods in that saturations are not solved implicitly. Iterative coupling is an operator-splitting technique that decouples the multiphase system into pressure and saturation equations. At each time step a series of iterations are computed that involve solving both pressure and a linearized saturation equation using specific tolerances that are iteration dependent and sequential. Following convergence of iteration, phase concentrations and mass balances are checked to determine if a time-step convergence is satisfied. If not, nonlinear coefficients are updated and iteration tolerances are tightened. The sequential iteration is then repeated. This concept is illustrated in Figure 1. Also, coupling method of the equations was presented in Figure 2.

4. Case Studies

Two sets experimental data of asphaltene precipitation at different pressure presented by jafari behbahani et al. [32, 33] and Solaimany-Nazar et al. [34] are used to verify the accuracy of the asphaltene thermodynamic model. Composition and properties of these samples are listed in Tables 1 and 2. Also, in order to verify the accuracy of the proposed model, the model is run using the data given by Minssieux [11] as denoted GF3.

Table.1: Studied bottom hole live oil compositions [24, 25]

Components	Bottom hole live oil (mol %)	Components	Bottom hole live oil (mol %)
H2S	0	n–C5	1.59
N2	0.3	C6	6.95
CO2	1.83	C7	4.1
C1	22.7	C8	3.88
C2	8.24	C9	2.49
C3	6.14	C10	4.03
i–C4	1.19	C11	2.85
n–C4	3.61	C12+	28.74
i–C5	1.38	Total	100

Fractions that to be higher-boiling than heptane are grouped in one pseudo component. The determined molar value and solubility parameters of both crudes and asphaltene by matching the experimental data are calculated. The formation volume factor of asphaltene is set equal to 1 due to it is assumed that asphaltene is an incompressible phase. The solution gas–asphaltene-ratio is assumed to be equal zero, as we know, compositionally, that heavy hydrocarbons components present in asphaltenes. It can be assumed that the amount of gas in asphaltene is negligible.
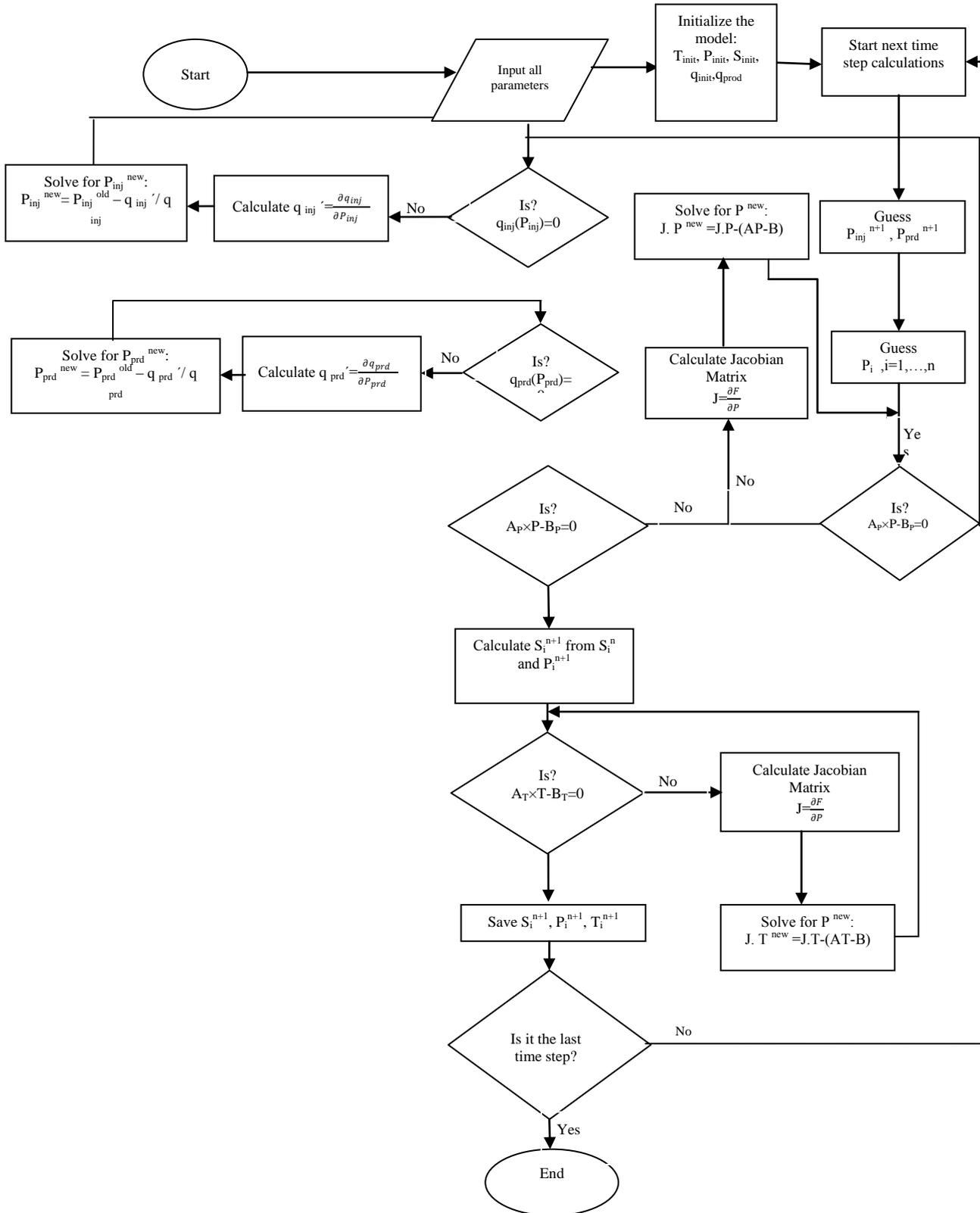
Table.2: Studied bottom hole live oil compositions [26]

Components	Bottom hole live oil (mol %)	Components	Bottom hole live oil (mol %)
H2S	0.03	n–C5	1.49
N2	0.27	C6	7.38
CO2	1.65	C7+	41.19
C1	30.24		
C2	7.86		
C3	5.49		
i–C4	0.87		
n–C4	2.5		
i–C5	1.03	Total	100

5. Result and Discussion

In the majority of previous models, the permeability reduction during CO_2 flooding is modeled based on two material balance equations. In this work, a modified model based on four phase black oil model (oil, water, gas, and asphaltene) was developed to account permeability reduction during CO2 flooding in cylindrical coordinates around a well in a reservoir and the model was verified using data given in literature.

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Fig.1: The IMPES method Flow Chart

Start

Input all parameters

Initialize the model: T_{init}, P_{init}, S_{init}, q_{init}, q_{prod}

Start next time step calculations

Guess P_{inj}^{n+1}, P_{prd}^{n+1}

Guess P_i, $i=1,\ldots,n$

Is? $q_{inj}(P_{inj})=0$

No

Calculate $q_{inj}' = \frac{\partial q_{inj}}{\partial P_{inj}}$

Solve for P_{inj}^{new}: $P_{inj}^{new} = P_{inj}^{old} - q_{inj}'/q_{inj}$

Solve for P^{new}: $J.\ P^{new} = J.P-(AP-B)$

Is? $q_{prd}(P_{prd})=\hat{}$

No

Calculate $q_{prd}' = \frac{\partial q_{prd}}{\partial P_{prd}}$

Solve for P_{prd}^{new}: $P_{prd}^{new} = P_{prd}^{old} - q_{prd}'/q_{prd}$

Calculate Jacobian Matrix $J = \frac{\partial F}{\partial P}$

Is? $A_P \times P - B_P = 0$

No

No

Yes

Is? $A_P \times P - B_P = 0$

Calculate S_i^{n+1} from S_i^n and P_i^{n+1}

Is? $A_T \times T - B_T = 0$

No

Calculate Jacobian Matrix $J = \frac{\partial F}{\partial P}$

Save S_i^{n+1}, P_i^{n+1}, T_i^{n+1}

Solve for P^{new}: $J.\ T^{new} = J.T-(AT-B)$

Is it the last time step?

No

Yes

End

Fig.2: The iterative coupling approach for solving pressures and saturations

Figures 3 to 13 compare the results of the pressure drop, deposited asphaltene in the rock, remaining asphaltene concentration in the flowing oil, permeability and porosity profiles at various times using the proposed model with those obtained from the Wang and Civan[7] model and the model based on monolayer adsorption equilibrium mechanism.
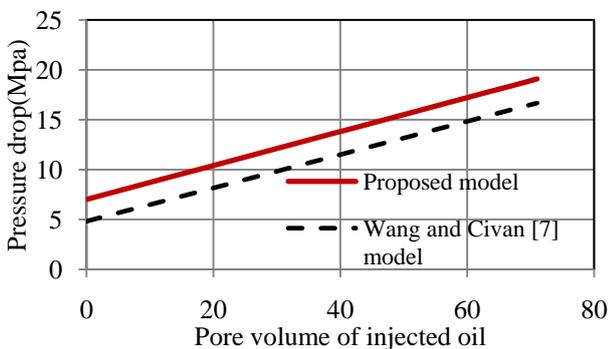
Fig.3: Pressure drop versus pore volume oil injected for oil GF3 [11]
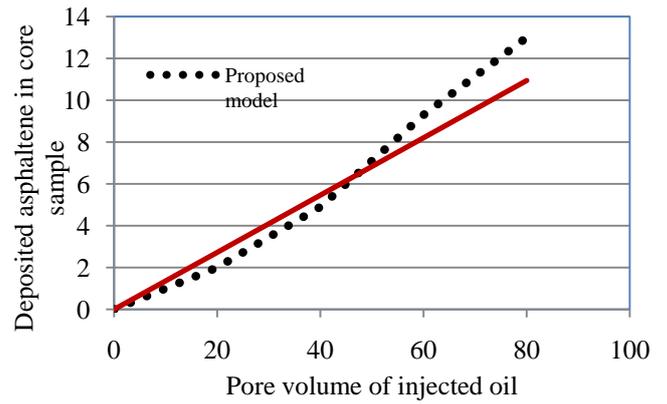
Fig.4: Deposited asphaltene in core sample versus pore volume of injected oil[11]
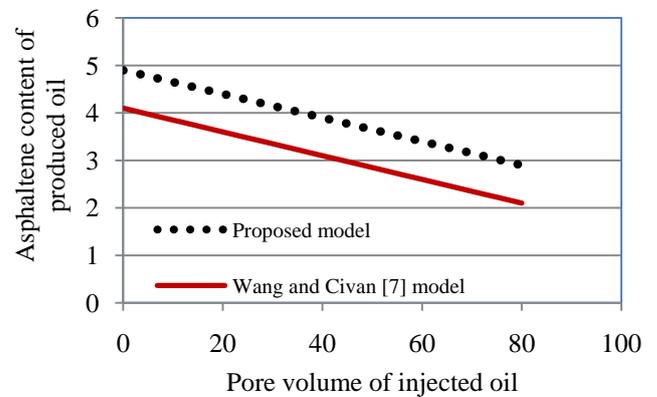
Fig.5: Asphaltene content of produced oil versus pore volume of injected oil[11]
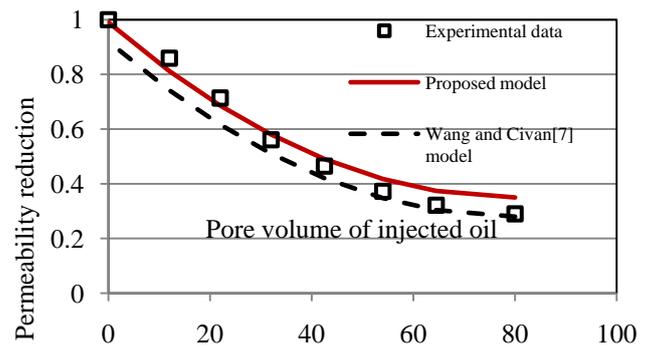
Fig.6: Permeability reduction versus pore volume oil injected for oil GF3[11]

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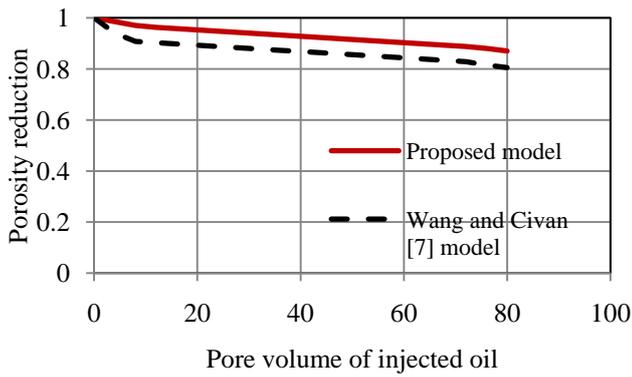
Fig.7: Porosity reduction versus pore volume oil injected for oil GF3[11]

As shown in results; modified model can predict better the experimental permeability reduction data during flooding in comparison to those obtained using previous model. Table 3 shows average absolute deviation of the predicted permeability reduction from the experimental data based on developed and previous model.

Table .3: Absolute Deviation of the correlated permeability reduction from the experimental results by the modified model and the model based on two phases black oil.

No.	Absolute Deviation of asphaltene deposition modeling (%)	
	Modified model	previous model
[11]	3.4	5.3
[32,33]	4.1	7.8
[34]	5.2	9.8

As shown in Figures, the permeability reduction behavior is far from two phase black oil model and is closer to modified model which is based on four phase black oil. The asphaltenes adsorption mechanism, which is related to the interactions between the asphaltenes functional groups and the rock surface, involves surface polarity, affinity or others attractive forces. It is known that asphaltenes surface groups may be acidic (carboxylic, benzoic, phenolic), and/or basic (pyridine, pyrazine, dimethylsulfoxide).
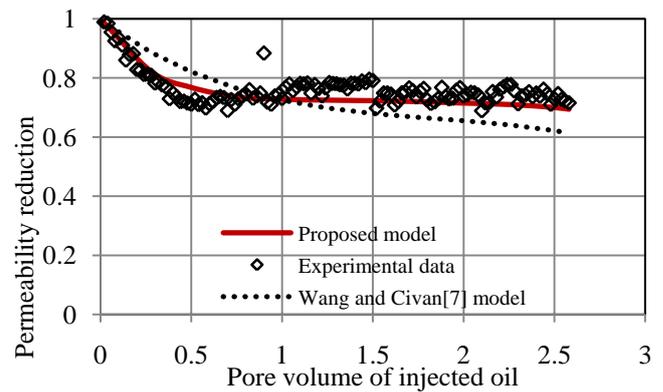

Fig.8: Experimental and simulated permeability reduction during primary deposition (Q=1 cc/hr) in sandstone core sample [24, 25]
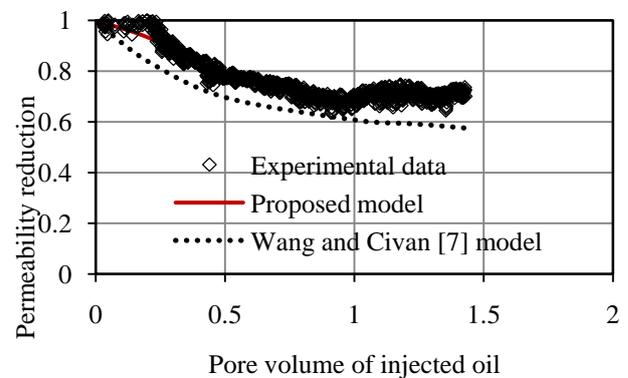

Fig.9: Experimental and simulated permeability reduction during primary deposition (Q=1 cc/hr) in carbonate core sample [24, 25]
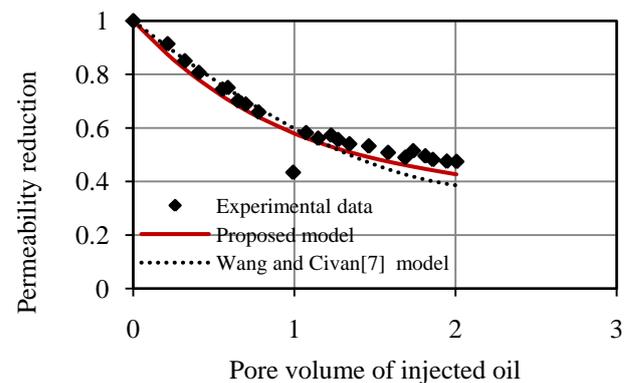

Fig.10: Experimental and simulated permeability reduction during primary deposition (Q=3 cc/hr) in dolomite core sample [24, 25]
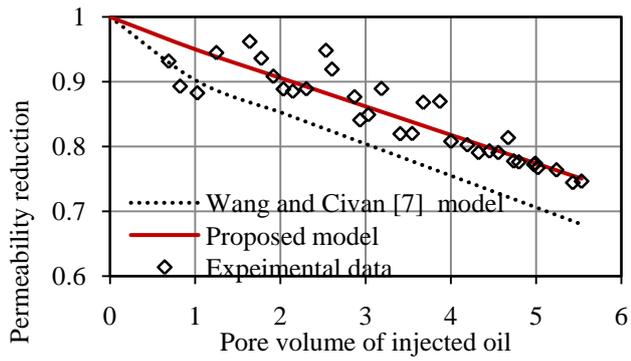
Fig.11: Experimental and simulated permeability reduction during primary deposition (Q=10 cc/hr) in sandstone core sample [24, 25]
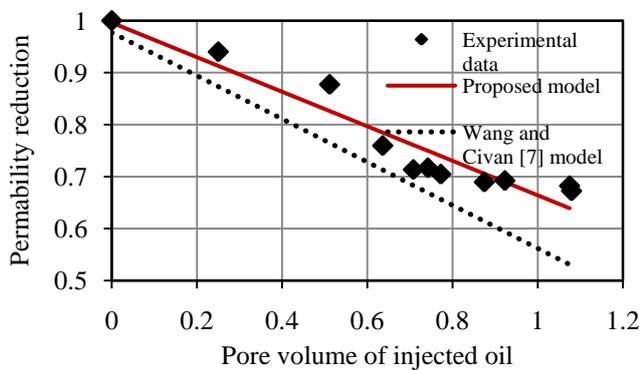

Fig.12: Experimental and simulated permeability reduction during primary deposition (Q=10 cc/hr) in carbonate core sample [24, 25]
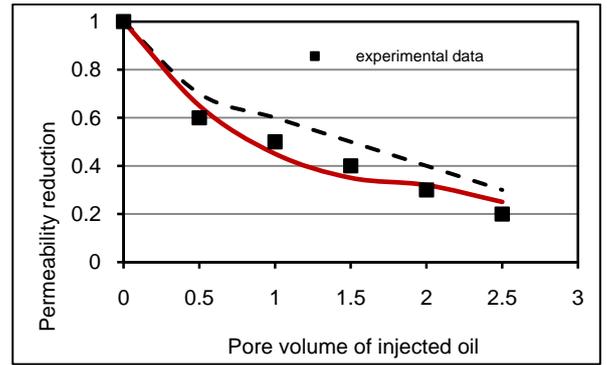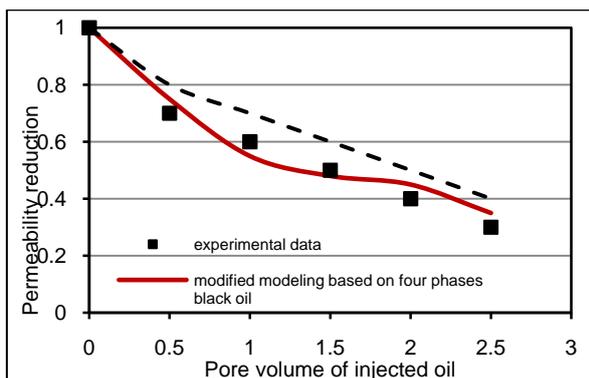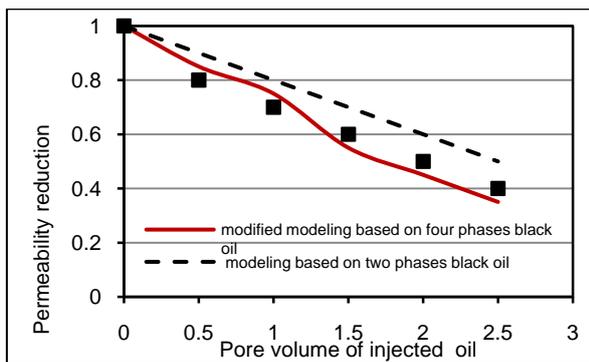

Fig.13: Comparison of the performance of the proposed model and model based on two phases black oil [24, 25]

The water and live oil saturation profiles was studied and its results was shown in Figure 14. The water saturation increases through the core sample. The water saturation increases from an initial value of 0.44 toward the value of 0.62. The oil saturation decreases through the core sample .The oil saturation reduces from an initial value of 0.56 toward the value of 0.4.
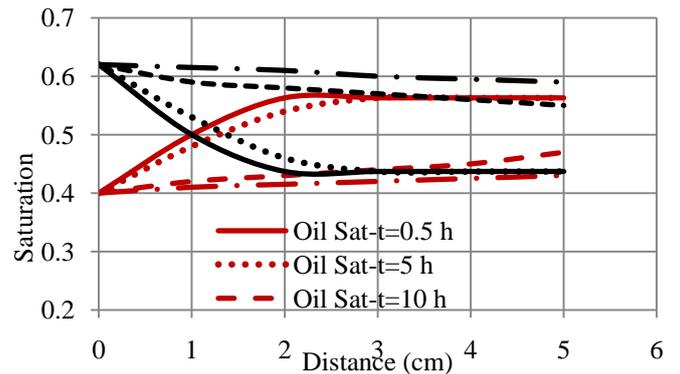

Fig.14: Saturation profiles at different time steps in carbonate core sample (Q=1 cc/hr) [24, 25]

6. Conclusion

In this work, a new model based on four phases black oil (oil, asphaltene , gas and water phase) was developed to account permeability reduction in porous media during CO2 injection flooding. The proposed model was verified using experimental data given in literature. The modeling results of permeability reduction during CO2 flooding resulted in several conclusions, as follows.

-The results show that an increase in CO_2 injection flow rate is followed by an increase in permeability reduction of rock.

-The proposed model based on four phases black oil is found to be more accurate than the model based on two phases black oil.

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