SPE 129803

Modeling Formation Damage and Wettability Alteration Induced by Asphaltene Precipitation and Their Effects on Percolation Performances During Oil Production

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This paper was prepared for presentation at the CPS/SPE International Oil & Gas Conference and Exhibition in China held in Beijing, China, 8–10 June 2010.

Abstract
Asphaltene, which exists in crude oil, is a high molecular weight, polar component. It is widely believed that asphaltene may precipitate and plug pores of reservoir rock and induce wettability alteration for the changes in oil composition, reservoir pressure and temperature. Therefore, alphaltene precipitation in the pores of oil formation definitely leads to formation damage and wettability alteration. The mechanisms caused asphaltene precipitation have been researched in labs and the key factors to effect the precipitation have been well understood, but prediction for its quantitative damages for oil formation, wettability alteration and their effects on percolation performance are still uncertain. In this work, a mathematical model considering asphaltene precipitation and wettability alteration is presented and an oil field scaled numerical simulator is developed to predict for asphaltene precipitation problems in the development of oil field. The simulation results show that the porosity and permeability in the vicinity of production wellbore decrease dramatically for asphaltene precipitation. The water-cut increases for the increase in the effective permeability of oil phase and the decrease in the effective permeability of water for the wettability alteration induced by asphaltene deposition onto the pore surfaces.

Introduction
Asphaltene, which is the heaviest component in crude oil, is defined as n-heptane or n-pentane insolubles[1]. In general, it is dissolved in the crude oil under the initial reservoir conditions. However, any changes in reservoir pressure, temperature, and composition during oil production may leads to precipitation from crude oil. Asphaltene precipitation from reservoir oil due to the changes of reservoir conditions such as pressure, temperature and compositions may lead to serious problems. On one hand, asphaltene precipitation can buildup at the production facilities such as pumps, wellbore, tube, flow lines and other surface facilities, which leads to operational problems, and increases in cost on remediation[2-5]. On the other hand, Asphaltene precipitation and deposition on pore walls of oil formation can strongly lead to formation damages in forms of the reductions in porosity and permeability and influence production performances [6-10]. In addition, asphaltene precipitation on pore walls will also lead to wettability alteration [11-13] of pore surfaces and have an effect on oil recovery[14].

The study on asphaltene precipitation in laboratory mainly focuses on the onset of asphaltene deposition and permeability reduction caused by asphaltene adsorption on pore surfaces or asphaltene plug in the sandstone cores. Mansoori[15] presented a mathematical model used for predicting asphaltene precipitation. However, the model is not capable of simulating the process of asphaltene deposition on pore walls and plugging in porous media. Ali and Islam[16] developed a single-phase formation damage model for under-saturated oil based on Gruesbeck and Collins pathway approach. The model can deal with both asphaltene adsorption on pore surfaces and mechanical trapping in porous media. The permeability reduction was described by the Gruesbeck and Collins empirical expressions. More recently, M.Nikookar and M.R.Omidkhah[17] developed a correlation for predicting for asphaltene deposition by using the experimental data. At present, published work regarding to comprehensive mathematical models considering formation damage and wettability alteration caused by asphaltene adsorption on pore walls as well as asphaltene capture at pore throats during the multiphase flow in oil reservoir can not be found.

In this work, a new mathematical model considering asphaltene precipitation as well as wettability alteration is developed and an oil field scaled numerical simulator written in Fortran 90 codes is developed to predict for oil formation damage induced by asphaltene precipitation. The simulated results shows that oil production rates without asphaltene precipitation are higher than that with asphaltene deposition, and the water-cuts in production fluid increase after water breakthrough for the wettability is changed into oil-wetting from water-wetting caused by asphaltene adsorption on pore surfaces of oil formation. Strong formation damage caused by asphaltene precipitation occurs in the vicinity of oil production wellbores.

Mathematical model

The mathematical model is based on the following assumptions:

(1) The fluids in reservoir is assumed as black oil system.
(2) Three-phase flows in porous media are three-dimensional and isothermal.
(3) Both the rock and fluids are compressible.
(4) The flows in porous media are assumed to follow Darcy's law.
(5) Asphaltene precipitation and the changes in porosity and permeability are considered.
(6) Wettability change induced by adsorption of asphaltene is considered.
(7) The fluids are Newtonian.
(8) Both capillary and gravity forces are considered.

The governing equations for multiphase flows in porous media

Since the flows of oil (o), water (w) and gas (g) in porous media follow Darcy's law, the governing equations for describing multiphase Newtonian flow are given by the following equations:

$$div\left(\frac{kk_{rw}}{B_w\mu_w}\rho_w grad\Phi_w\right)+q_w=\frac{\partial}{\partial t}\left(\phi\rho_w s_w/B_w\right)\ , \tag{1}$$

$$div\left(\frac{kk_{ro}}{B_o\mu_{omix}}\rho_o grad\Phi_o\right)+q_o=\frac{\partial}{\partial t}\left(\phi\rho_o s_o/B_o\right), \tag{2}$$

$$div\left(\frac{kk_{rg}}{B_g\mu_g}\rho_g grad\Phi_g+\frac{kk_{ro}R_s}{B_{o}\cdot\mu_o}\rho_o grad\Phi_o\right)+q_g=\frac{\partial}{\partial t}\left(\phi\rho_g s_g/B_g+\phi\rho_o S_o R_s/B_o\right). \tag{3}$$

For flow of the three-phases of oil, water and gas, the sum of the saturations of oil, water and gas is equal to 1.

$$S_o+S_w+S_g=1. \tag{4}$$

The three parameters regarding potentials in Eq. 1~3 are defined as

$$\Phi_o=p_o+\gamma_o\cdot h\,, \tag{5}$$

$$\Phi_w=p_w+\gamma_w\cdot h=p_o+p_{cwo}+\gamma_w\cdot h\,, \tag{6}$$

$$\Phi_g=p_g+\gamma_g\cdot h=p_o+p_{cgo}+\gamma_g\cdot h\,, \tag{7}$$

Where t is time, ϕ is the porosity of porous media, S, μ and p are saturation, viscosity, and pressure of fluids, respectively, k is the absolute permeability, k_r is the relative permeability, B is the volume factor of fluid, q is the production or injection rate of fluid, R_s is the solution gas-oil ratio, γ is the specific gravity of fluids, h is the distance from reference level, and p_c is the capillary force.

Transport of asphaltene in porous media

Suppose asphaltene flocculated from crude oil exsists in approximate particle shape, and asphaltene flocculated either is supended in the oil phase or coats on the surface of pore walls. Inasmuch as the asphaltene suspended is small enough in size, diffusion should be also considered. Thus, considering Brownian diffusion effects in the process of asphaltene migration in porous media, the continuity equation for asphaltene in oil phase can be expressed as the following equation by modifying the equation[18]:

$$\frac{\partial}{\partial x}(u_{xo}C_{ao} - \phi S_o D_{xao}\frac{\partial C_{ao}}{\partial x}) + \frac{\partial}{\partial y}(u_{yo}C_{ao} - \phi S_o D_{yao}\frac{\partial C_{ao}}{\partial y}) + \frac{\partial}{\partial z}(u_{zo}C_{ao} - \phi S_o D_{zao}\frac{\partial C_{ao}}{\partial z}) + \phi S_o \frac{\partial C_{ao}}{\partial t} + R_{ao} + Q_{ao} = 0, \tag{8}$$

Where C_{ao} is the volume concentration of asphaltene flocculated in oil phase, D is the diffusivity of asphaltene, R is the netting asphaltene change rate on the pore surfaces; x, y and z are three space dimensions, Q is the rate of the change of asphaltene volume described by a source/sink term.

Hydrodynamic forces can release the asphaltene adsorbed on pore walls. Asphaltene deposition on pore surfaces will occur when the onset of asphaltene precipitation arrives and pore throats may also capture solid asphaltene particles when the size of solid asphaltene is large enough comparing to the diameters of pore throats of porous media. According to the mechanisms of asphaltene change on pore surfaces or at pore throats, the R_{ao} in equation (8) can further be written as

$$R_{ao} = R_{hao} + R_{dao} + R_{pao}, \tag{9}$$

where the asphaltene release rate from pore walls by hydrodynamic forces (R_{hao}), the deposition rate on pore surfaces (R_{dao}), and the capture rate at pore throats (R_{pao}), can be respectively defined as

$$R_{hao} = -\alpha_{hao}\delta_{ao}(v_o - v_{oc}), \tag{10}$$

where v_{oc} is the critical flow velocity of oil phase for asphaltene release from pore surface by hydrodynamic forces. That is to say, the hydrodynamic forces acted on the asphaltene adsorbed on pore walls must be high enough to trigger asphaltene release from pore walls. The minimum flow velocity needed to trigger asphaltene release is called critical flow velocity. α_{hao} is a rate constant for the release of asphaltene by hydrodynamic forces. When flow velocity oil phase satisfies $v_o < v_{oc}$, no asphaltene is released by hydrodynamic forces (i.e. $\alpha_{hao} = 0$). δ_{ao} is the volume of asphaltene deposited on the pore surfaces per unit bulk volume.

$$R_{dao} = \alpha_{dao} v_o C_{ao}, \tag{11}$$

where α_{dao} is a rate constant for asphaltene deposition on pore surfaces when asphaltene deposition onset arrives. During the transportation of asphaltene carried by flowing fluids, some asphaltene may be adsorbed on pore walls.

$$R_{pao} = \alpha_{pao} v_o C_{ao}, \tag{12}$$

where α_{pao} is a capture rate constant of asphaltene at pore throats when asphaltene deposition onset arrives. During the transportation of asphaltene in porous media, it may be captured by bridging and blocking. In this case, a coefficient, α_{pao}, is used to describe the capture rate.

Considering the asphaltene dynamics in porous media, we can further define

$$\frac{\partial \delta_{ao}}{\partial t} = R_{dao} + R_{hao} , \tag{13}$$

$$\frac{\partial \delta_{ao}^{*}}{\partial t} = R_{pao} , \tag{14}$$

where δ_{ao} is the volume of asphaltene deposited on the pore surfaces per unit bulk volume, and δ_{ao} is equal to δ_{0ao} at initial time; δ_{ao}^{*} is the volume of asphaltene trapped at the pore throat per unit bulk volume, and δ_{ao}^{*} is equal to δ_{0ao}^{*} at initial time. Production rate of asphaltene can be expressed as

$$Q_t = \sum Q_{ao} = \sum (q_o) C_{ao} , \tag{15}$$

where C_{ao} is the volume concentration of asphaltene in oil phase.

The cumulative production volume of asphaltene can be calculated by the following integral:

$$Q_a = \int_0^T \sum q_o C_{ao} dt \tag{16}$$

Evaluation forporosity and absolute permeability

Generally, the pore bulk volume is regarded as being slightly compressible and the permeability is regarded as a constant[19,20]. However, the asphaltene release from pore surfaces, the adsorption on pore surfaces, and blocking at pore throats in the process of asphaltene migration may lead to changes in local porosity and permeability. The instantaneous porosity is expressed by

$$\phi = (\phi_0 - \sum \Delta\phi) , \tag{17}$$

where $\sum \Delta\phi$ denotes the variation of porosity by release and retention of asphaltene in porous media, and it is expressed by

$$\sum \Delta\phi = (\delta_{ao} + \delta_{ao}^{*}) - (\delta_{0ao} + \delta_{0ao}^{*}) . \tag{20}$$

If $\sum \Delta\phi$ is greater than 0, the retention of asphaltene is dominant, and the porosity will decrease, (i.e. $\phi < \phi_0$). If $\sum \Delta\phi$ is less than 0, the release of asphaltene is dominant, and the porosity will increase.

The change in permeability in this study is caused by asphaltene release and mobilization. Modifying Kozeny Equation and considering the asphaltene plugging effect, and according to the study of Liu[21], the expression for instantaneous permeability changed by release and retention of asphaltene is given by

$$k = k_0 [(1 - f)\lambda_f + f\phi / \phi_0]^n , \tag{21}$$

in which k_0 and ϕ_0 are initial permeability and porosity, k and ϕ are instantaneous local permeability and porosity of porous media, and λ_f is a constant for fluid seepage allowed by the plugged pores. The range of the index, *n,* is from 2.5 to 3.5. Pore throats may be plugged by blocking or bridging, which causes some pore throats to narrow for fluid flow. A flow efficiency factor, *f*, is defined as the fraction of the original cross-sectional area open for flow. According to Ju's expression[18], the flow efficiency factor, f, as a linear function of the volume of asphaltene entrapped at pore throats, is given empirically by

$$f = 1 - \alpha_{feao} \delta_{ao}^{*} , \tag{22}$$

where α_{feao} is the coefficient of flow efficiency.

Wettability alteration

Asphaltene deposition on pore walls of sandstone formation will lead to a wettability change[22]. It has been reported that the adsorption of asphaltene may cause relative permeability curves shift from a water-wetting system to an oil-wet system[23]. This is how the wettability change is taken into account in this model. For a water saturation, S_{wj}, supposing the relative permeabilites of water and oil phases are K_{rwj} and K_{roj} respectively before asphaltene deposition and the relative permeabilites of water and oil phases are $K_{rwj}^{'}$ and $K_{roj}^{'}$ respectively after asphaltene deposition, which covers all surfaces of pores. When the surfaces per unit bulk volume of the porous media is completely occupied by asphaltene, the relative permeabilites of water and oil phases are taken as $K_{rwj}^{'}$ and $K_{roj}^{'}$ respectively; otherwise, the relative permeabilites of water and oil phases are taken as a linear function of the area occupied by asphaltene. The relative permeabilities of water and oil is given by

$$K_{rwja}^{'} = K_{rwj} + \frac{K_{rwj}^{'} - K_{rwj}}{A_{fc}} A_c \tag{23}$$

$$K_{roja}^{'} = K_{roj} + \frac{K_{roj}^{'} - K_{roj}}{A_{fc}} A_c \tag{24}$$

where A_c deposition volume of asphaltene coating on pore walls and A_{fc} the deposition volume of asphaltene much enough to cover all pore surfaces per unit bulk of sandstone.

Solution procedure for model

The mathematical model used here consists of a set of nonlinear equations, which mainly includes the continuity equations of oil (o), water (w), and gas (g) phases, the convection-diffusion-adsorption equation, and a set of auxiliary equations. The finite-difference method is used to solve the nonlinear equation system since the analytical solutions of the system are intractable. In this work, the IMPES (Implicit-Pressure and Explicit-Saturation) and self-adaptive LSOR (Line Successive Over Relaxation) iterative technique was used to solve the pressure-saturation equation, and an explicit method was employed to solve the continuity equations of the transport of asphaltene in porous media. The procedure of the solution is shown in **Fig.1**

Numerical results and discussions

This section gives the numerical simulation results of a five-spot well pattern example, which is initially assumed to be a homogeneous geological model with 305m in length, 305m in width and 28.5m in thickness. The main parameters are given in **Table 1** and the parameters regarding to asphaltene precipitation are list in **Table 2**. **Fig.2** gives the relative permeability of oil and water phases at the cases of non-asphaltene deposition and asphaltene deposition that cover all surfaces of pore walls. Four oil production wells locate at four corners and a water injection well locates the center of the region. Perforated intervals of the all oil production wells locate the top layer and perforated interval of the water injection well locates the bottom layer (**Fig**.3). The production rates for the four oil wells are equal and each well keeps a constant rate during the whole production history. The water injection rate is also kept to as a constant.

Fig.4 shows the total production rates of the four oil wells during 25-year production history at two cases of non-asphaltene precipitation and asphaltene precipitation on the surfaces of pores in sandstones. The production rates are equals before water break through to oil wells, and after that oil production rates without asphaltene precipitation are higher than that with asphaltene deposition. The water-cuts are also same before water breakthrough at two cases (see **Fig**.5), however the water-cuts without asphaltene deposition become less than that with asphaltene precipitation. The reason for those phenomena is wettability change caused by asphaltene deposition onto the pore walls of sandstone formation. The wettability of the pore walls of sandstone oil formation is water-wetting originally. However, asphaltene adsorption onto pore surfaces of sandstone formation leads to wettability change from water-wetting to oil-wetting. More flow portion of water and less flow portion of oil will percolate in oil formation at the same of water saturation for oil-wetting systems. Therefore the less oil recovery will be expected for asphaltene deposition in oil formation during the production history in theory. The simulated results verify the expection in **Fig.6**.

On the other hand, asphaltene deposition onto the pore walls and solid asphaltene plug at pore throats will induce the decrease in pore spaces and permeability. Some reports on formation damage caused by asphaltene precipitation and plugging were found in published works. The production rates of oil wells decrease dramatically for this kind of formation damage in Cheng.B. Oil field, Bohai Bay, China. To describe the oil formation damage quantitatively, a definition of permeability ratio is adopted.

$$k_{ratio} = \frac{k}{k_o} \tag{25}$$

where k is permeability at a time t, and k_o is original permeability of an oil reservoir. When k_{ratio} is less than 1.0, it indicates that permeability at a time t becomes lower than its original permeability and formation damage occurs. **Fig.7** gives the distribution of permeability ratios of the 1st oil layer at four time points. It shows that permeability ratios becomes lower and lower with simulation time elapsed. And the formation damage in the vicinity of oil production wellbores is more stronger that other regions in five-spot well pattern.

Conclusion

1. A mathematical model considering asphaltene transport and precipitation in a three-dimensional porous medium has been developed. It can be used to describe the changes in porosity, permeability, wettability and production performance.
2. An oil field scaled numerical simulator was developed to predict for asphaltene precipitation problems in the development of oil field.
3. The numerical simulation results show that oil production rates without asphaltene precipitation are higher than that with asphaltene deposition, and water-cuts increase for wettability changed into oil-wetting from water-wetting caused by asphaltene adsorption on pore surfaces of oil formation.
4. Formation damage caused by asphaltene precipitation in the vicinity of oil production wellbores is more stronger that other regions.
5. The oil recovery of the simulation with asphaltene precipitation at elapsed 25th year is lower 2.7% than that without asphaltene precipitation.

Nomenclature

A_c	=	deposition volume of asphaltene coating on pore walls
A_{fc}	=	deposition volume of asphaltene enough to cover all pore surfaces
B	=	volume factor of fluid
C_{ao}	=	volume concentration of asphaltene in oil phase
D	=	diffusivity of asphaltene in oil phase (m^2/s)
f	=	flow efficiency factor
h	=	distance from reference level (m)
k	=	transient absolute permeability of a porous media (m^2)
k_r	=	relative permeability of a porous media
n	=	index for modifying permeability
p	=	pressure (Pa)
q	=	production/injection rate (m^3/s)
R	=	net asphaltene change rate on the pore surfaces or at pore throats (1/s)
R_s	=	solution gas-oil ratio
S	=	saturation
T	=	time (s)
U	=	Darcy velocity of flow in porous media (m/s)
v	=	real flow velocity in porous media (m/s)
v_{oc}	=	critical velocity (m/s)
x	=	distance in x direction (m)
y	=	distance in y direction (m)
z	=	distance in y direction (m)
α_{dao}	=	rate constant for asphaltene deposition on pore surfaces (m^{-1})

α_{feao}	=	coefficient of flow efficiency
α_{hao}	=	release rate of asphaltene by hydrodynamic forces (m^{-1})
α_{pao}	=	capture rate constant of asphaltene at pore throats (m^{-1})
δ_{ao}	=	volume of asphaltene deposited on the pore surfaces per unit bulk volume
ϕ	=	porosity of the porous media
δ^*_{ao}	=	volume of asphaltene trapped at throats per unit bulk volume.
γ	=	specific gravity of fluids.
λ_f	=	constant for fluid seepage allowed by the plugged pores
μ	=	viscosity of fluid (Pa·s)

Subscripts

0	=	Initial value
ao	=	asphaltene in oil phase
c	=	critical value or capillary pressure
d	=	deposition
e	=	entrainment
f_e	=	flow efficiency
g	=	gas
h	=	hydrodynamics
o	=	oil
p	=	pore throat
w	=	water

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Table 1 Parameters of the field example

Parameters of the geological model	Value	Parameters of the geological model	Value
The node numbers	11×11×3	Initial oil saturation	0.80
The size of grid of x and y, m	30.45	Initial porosity	0.30
The size of grid of z, m	9.50	Initial horizontal permeability for all grids of the 1st layer (top), $10^{-3}\mu m^2$	500.0
Initial reservoir pressure, MPa	28.87	Initial horizontal permeability for all grids of the 2nd layer, $10^{-3}\mu m^2$	50.00
Viscosity of water, mPa·s	0.50	Initial horizontal permeability for all grids of the 3rd layer (top), $10^{-3}\mu m^2$	200.00
Viscosity of oil, mPa·s	5.20	Initial vertical permeability for all layers, $10^{-3}\mu m^2$	5.01

Table 2 Parameters regarding to asphaltene precipitation

Parameters related to asphaltene precipiation	Value	Parameters related to asphaltene precipitation	Value
Initial volume concentration of asphaltene in oil	0.05	α_{pao}, m^{-1}	1.1E-4
δ_{0ao} at initial time	0.00	α_{feao}	100.0
δ^{*}_{0ao} at initial time	0.00	λ_f	0.50
α_{hao}, m^{-1}	1.0E-4	n	3.00
α_{dao}, m^{-1}	2.5E-4	A_{fc}	5.0E-3

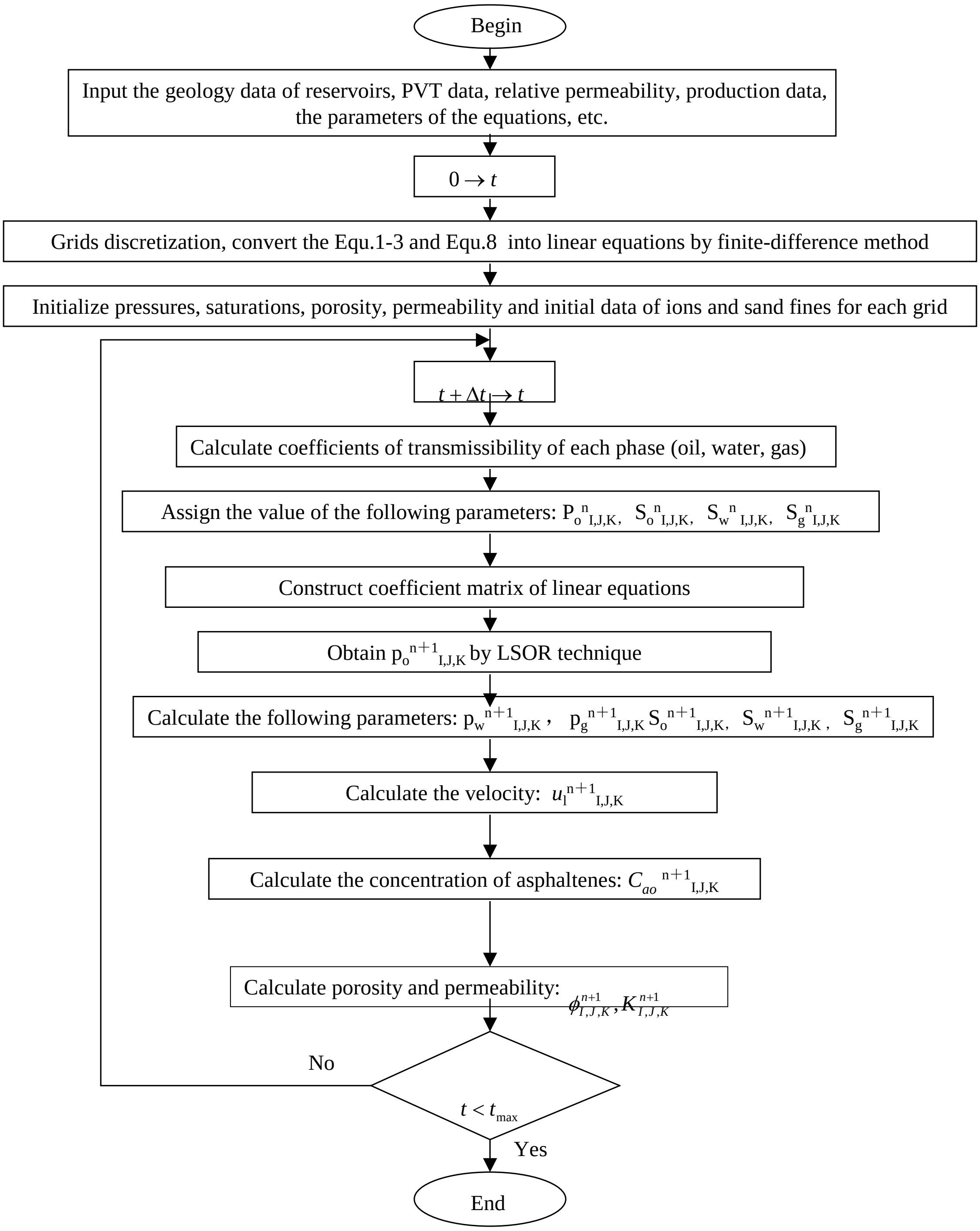

Fig.1 The procedure of numerical solution for the mathematical model

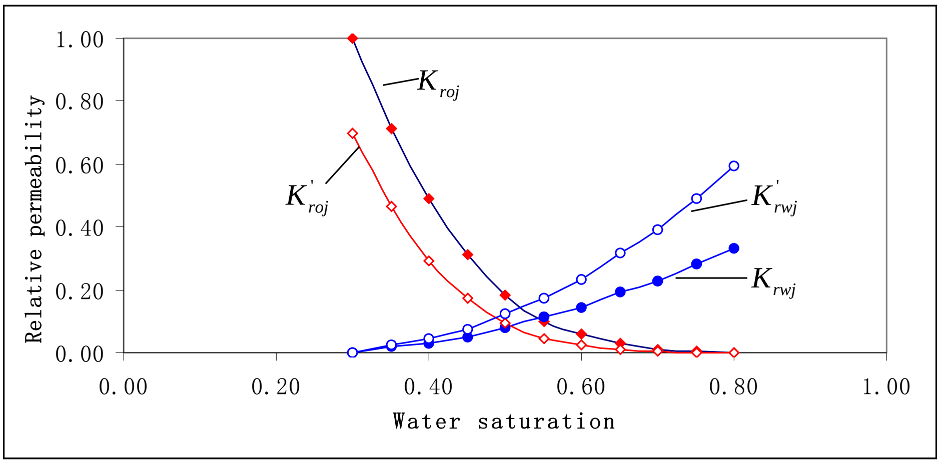

Fig.2 Relative permeability of oil and water phases

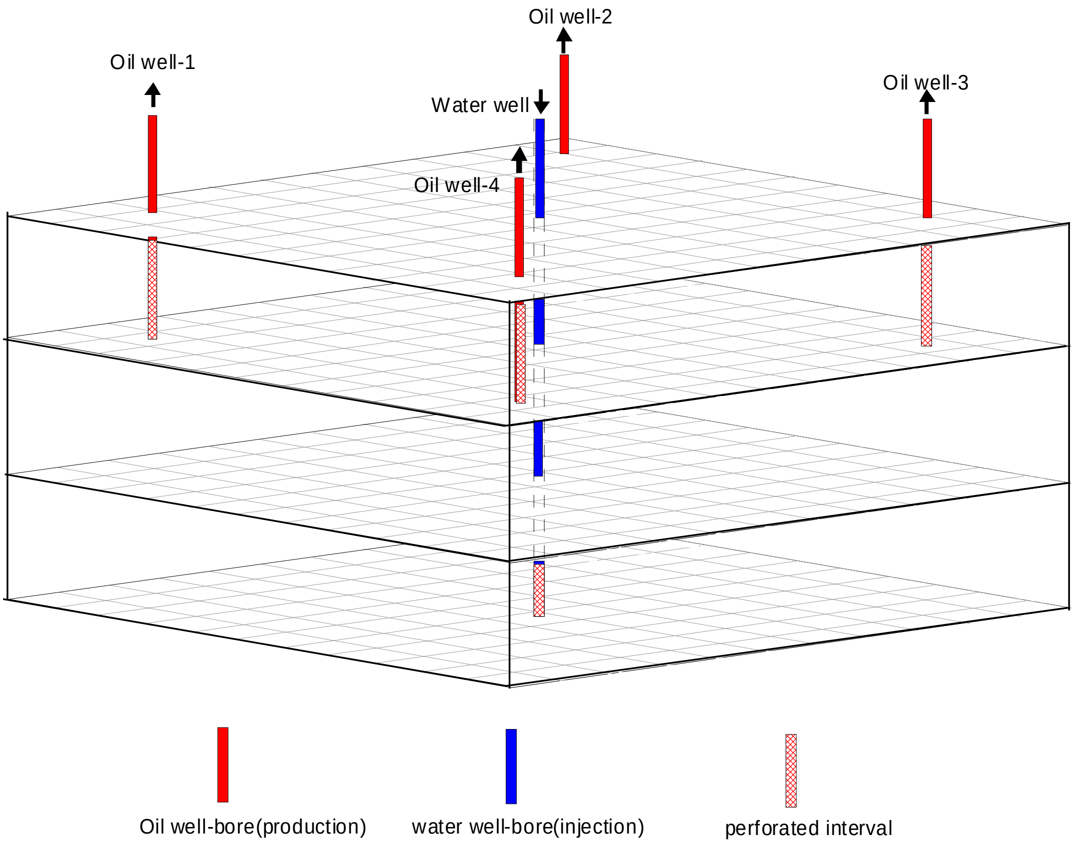

Fig.3 Geological model and well locations

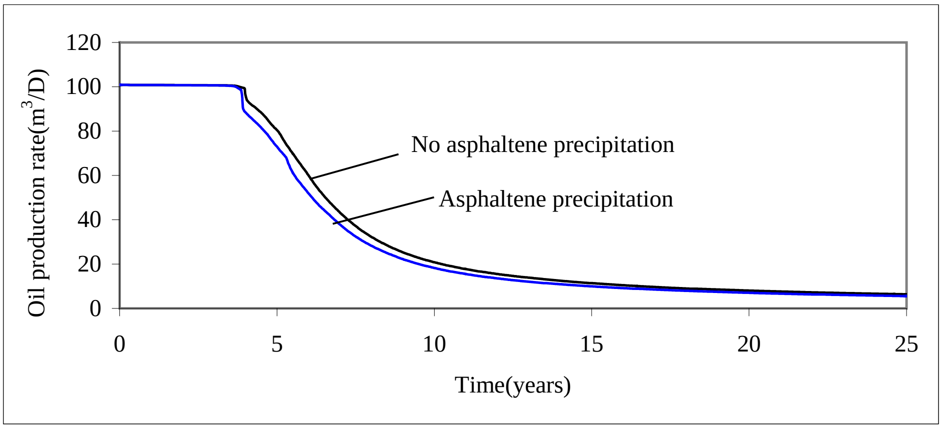

Fig.4 Oil production rates vs. time

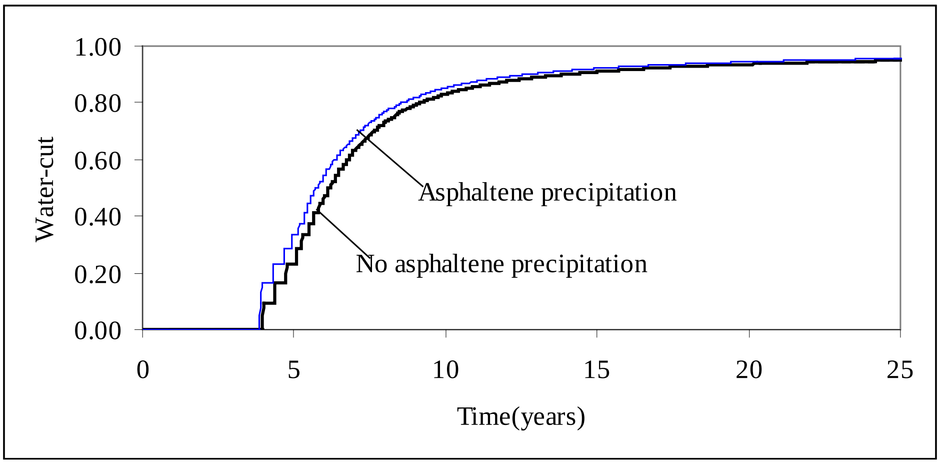

Fig.5 Water cut of production fluid from oil wells vs. time

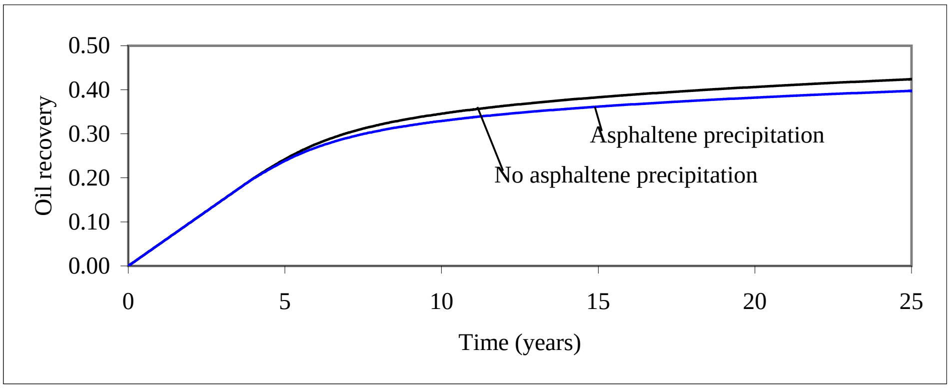

Fig.6 Oil recovery during production history

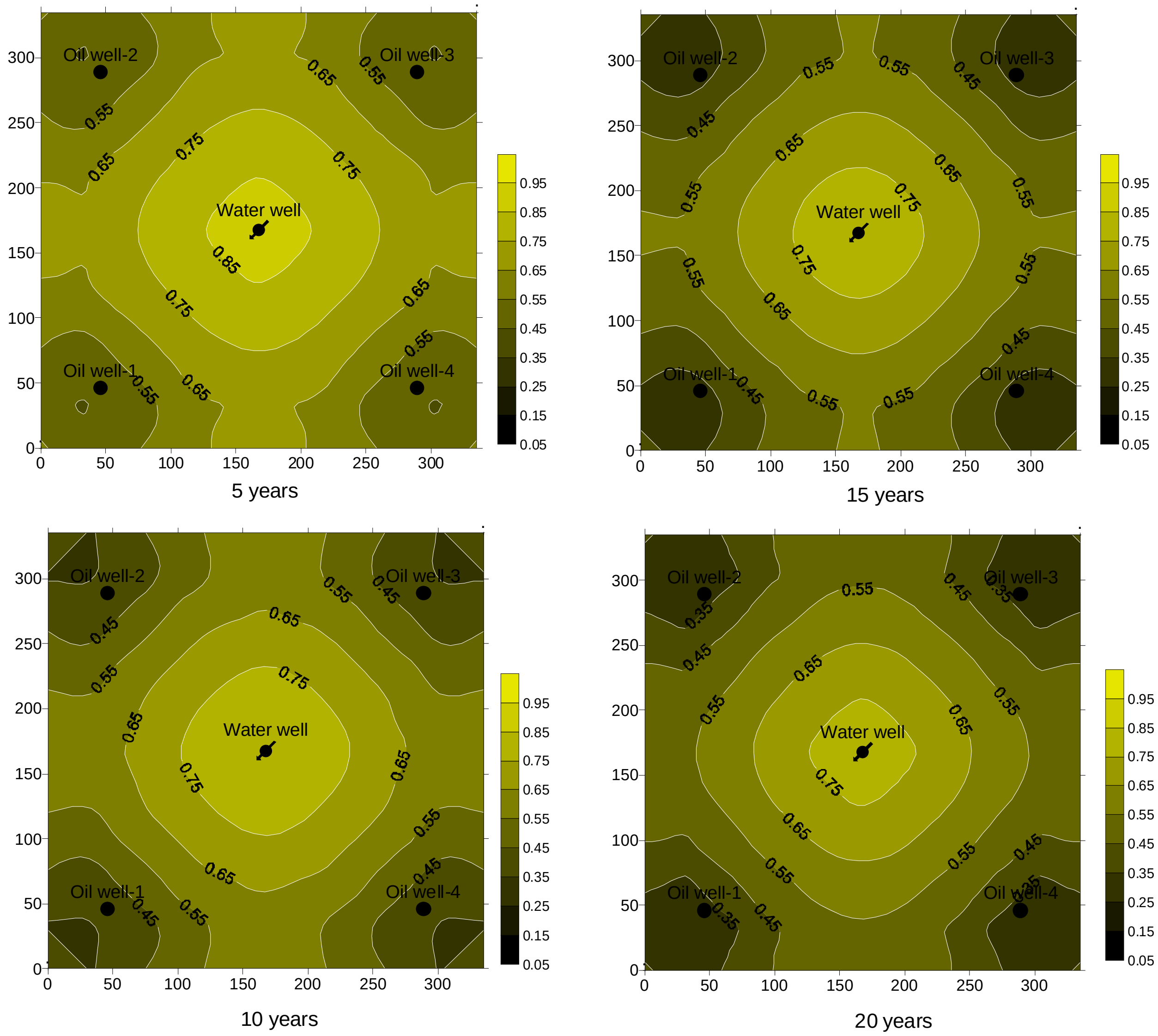

Fig.7 The distribution of permeability ratio at different elapsed time