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Simulation Modeling Accounting for Reservoir Fluid Properties Heterogeneity

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Current article deals with fluid properties heterogeneity. The reasons of this phenomenon are analyzed. 3D digital modeling of formation, saturated with oil having variable properties (density and viscosity) is performed. It is compared with model, built in the frameworks of classic approach, where oil has constant density and viscosity. It is shown, that accounting for oil properties heterogeneity allows making oil field design and planning of different activities more precisely.

Keywords: viscosity, density, oil properties, reservoir simulation

Introduction

Geological and simulation modeling are an important parts of oil fields development process. Models are used for different engineering calculations, prediction of field performance, 3D visualization, reserves estimation etc. In modern oil industry both oil companies and research institutes widely apply reservoir modeling.

In the frameworks of classic approach, reservoir fluid properties in model are defined as constant values. This means, that density, viscosity etc are the same for all formation modeled. Values of above-mentioned parameters are usually taken as averaged fluid samples laboratory investigation results.

However, it is proved and described in a number of sources, that reservoir hydrocarbons may have properties variation with depth due to many different reasons (Goncharov, 1986; Huc et al., 1999; Schulte, 1980; Vandecasteele, 2008; Wenger, 2002, 2002a). Obviously, this effect will influence on oil field performance and individual well behavior.

In the frameworks of this work reservoir fluid alteration processes are examined, together with both conditions for appearance of such phenomena and consequences for further oil field development. The latter is clearly shown by creation of two simulation models for comparative analysis: base case model, which is built with classical approach and modified model, which accounts for fluid properties gradient.

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Review of reservoir fluids alteration processes

According to L.M. Wenger (Wenger, 2002a) main primary controlling factors on oil chemical composition and properties are source rock characteristics:

1. Organic matter type
2. Depositional environment
3. Maturity level

Each of these parameters defines initial density, viscosity, gas/oil ratio, impurities content etc. For instance, shales as a source rocks generate lighter oil with less sulfur, than marls. Source rock level of maturity may define density and viscosity of oil – the more mature rock, the lighter and sweeter oil. (Wenger, 2002)

Therefore, determination of potential source rocks, migration path and timing is of critical importance in order to understand all processes, affecting initial oil properties.

After migration into a reservoir, oil may become affected by in – reservoir alteration processes, which are biodegradation, phase separation, water washing, gravity segregation (Huc et al., 1999) etc (Fig. 1). There should be favorable conditions for these processes, which will be described later. It should be noted, that additional influx of new generated oil will also influence oil quality in reservoir that is why it is important to reconstruct oil generation process.

The most interesting and less studied is process of biodegradation. It may cause significant variations in oil and gas density and viscosity both vertically and laterally. In the frameworks of this article biodegradation of oil is examined for instance.

Biodegradation of hydrocarbons usually occurs in reservoirs which have temperature lower than 80 °C (Wenger, 2002a). Degradation decreases presence of saturated hydrocarbons and increases concentration of asphaltene components. Thus, changing in oil quality can be described as: lowering API gravity, increasing viscosity, sulfur and carbon dioxide, moreover, changing in all of these oil properties affects on a reservoir recovery efficiency, which reduce economic value of fluid due

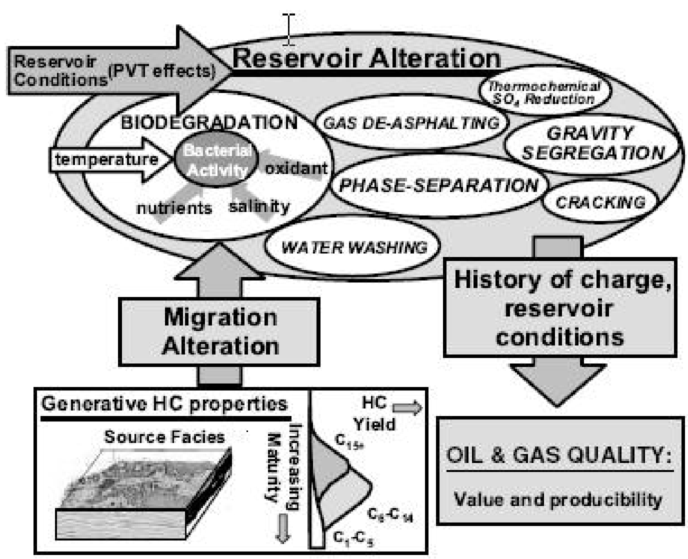

Fig. 1 In-reservoir alteration processes (Schulte, 1980)

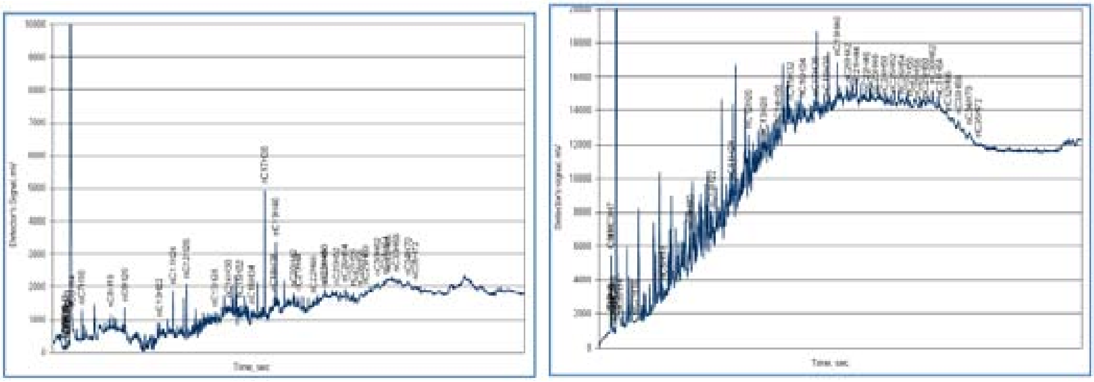

Fig. 2. Dead Oil Chromatogram (Left – conventional oil, Right – biodegraded oil)

to increasing wastes for refining. In additional, Biodegradation increases value of acids in oil and downstream technical problems can occur because of corrosion effects.

Reservoir gas cap and solution gas also can be subjected by Biodegradation. The first components which devoured by anaerobic bacteria are ethane, propane and n – butane (Wenger, 2002a). Only presence of methane increases and gas is getting drier. Also, percentage of carbon dioxide increases with increasing value of bacteria activity, which affect on equipments using in oil production due to occur risk of steel corrosion.

Recent studies show that iron, fermenting, oxide and sulfate reducing bacteria can exist only in the absence of dissolved oxygen (Wenger, 2002). Anaerobic bacteria use free or connected water for their living activities. Also, presence of adequate size of pores is required. Thus, place of activities of living organisms exist not only near from oil water contact, but throughout all hydrocarbon column. Irreducible water (if it is enough for living) can provide necessary volume of water and anaerobic living forms will use side of pores for their existence.

The impact of biodegradation on oil-quality parameters can be significant. Fig. 2 presents Gas Chromatograph illustration of conventional oil sample and oil which has been affected by Biodegradation process.

To summarize, recognizing and accounting for oil properties heterogeneity, caused by reservoir alteration processes, is essential in order to decrease exploration, production and other kinds of risk and downstream oil refinery problems. The most critical are production risks, affecting not only production characteristics, but also producing equipment and facilities, caused by increased proportion of acids, CO_2, sulfur and metals content in the oil.

Simulation of hypothetical case study

As an example, geological (static) and simulation (dynamic) models of one of the Eastern Siberia oil fields was taken as a base case. Sector was cut from original geological model and used for simulation.

Main purpose of modeling in the frameworks of this work concludes in attempt to set fluid properties (density and viscosity) variation in modified model and compare with a base case model with constant (average) value of these properties for the entire reservoir.

The problem of modeling fluid properties heterogeneity is not trivial, since simulation software doesn`t allow to set this variability in the model explicitly. All models are wrong, but more or less correct and physically explainable modeling requires a certain workflow to be followed to account fluid properties trends. It should be noted, that static geomodel is useless in the frameworks of this project, since variability of properties will impact dynamic behavior of the field. Dynamic simulation model in contrast can provide evaluation and comparison of such important parameters, as water cut, oil production rate, total oil production etc. Besides, visualization of fluids distributions before and some time after production starts can be performed.

Three dimensional digital geological models include volume grid in X, Y, Z coordinates where every cell characterized by set of properties such as net to gross, porosity, permeability and so on. Lateral dimension of 3D grid in X and Y direction is 100 meters and in Z direction is 0.4 meter. Total number of cells is about 15 millions.

Saturation of given geological model includes three phases: water, oil and gas cap. Thickness of oil saturation part of reservoir is 45 meters and gas cap is 15 meters in the thickest part of formation.

In addition to models, as a hard input data pressure gradients, measured in two wells were used (Fig 3). Values of fluid density change from top reservoir to bottom and situated approximately on one level of depth.

Although, average density can be estimated as 850 kg/m^3 (for base case model), it is obvious that variation of oil density in wells sufficiently large and using average value should be very careful due to ability of non correct estimation of production rate or economic value of flowing fluid.

In general, simulation model grid consists from 610560 cells and has dimension 48 x 53 x 240 and it responses a square 5 thousand meters on side and about 96 meters of thickness. Model characterized by the following attributes:

- Oil water contact situated at 1645 meters below sea level
- Free water level situated at 1655 meters below sea level

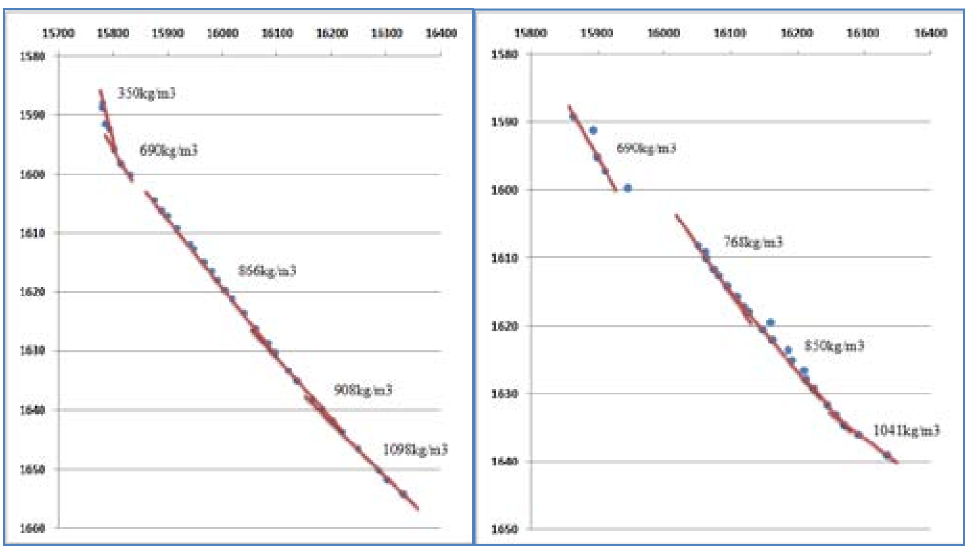

Fig. 3. Pressure gradients for real wells A and B (X axis – Pressure, kPa; Y axis – Absilute Depth, Meters)

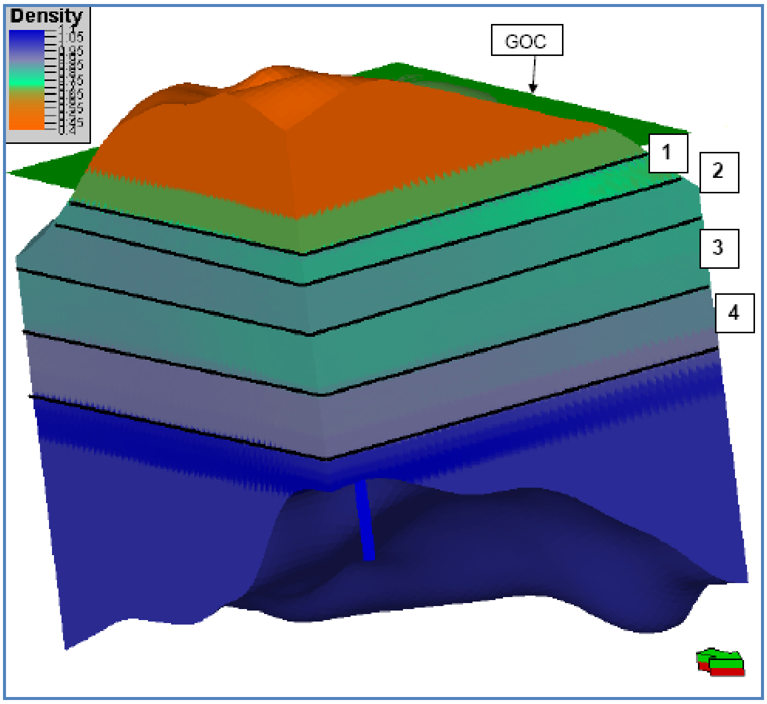

Fig. 4. Regions with different PVT properties

- Gas oil contact – 1600 meters below water level
- Average density in reservoir conditions is 850 kg/m^3, at standard condition is 903 kg/m^3
- Initial solution gas oil ratio equals to 50 m^3/m^3
- There is live oil in the reservoir
- There is an active aquifer in the formation V

Also, active analytical Carter – Tracy aquifer was used, which has thickness about 40 meters and permeability, which is equals to 450 mD. For reducing number of active cells only one layer of aquifer have been lost, all cells with 100% water saturation have been cut and changed on constant inflow.

There were set up 4 wells in highlighted section. Simulation was made during 40 years and the following basic parameters were obtained: FOPR (Field Oil Production Rate), FPR (Field Pressure), FWPR (Field Water Production Rate), FOPT (Field Oil Production Total), FWPT (Field Water Production Total), FGPR (Field Gas Production Rate), FGPT (Field Gas Production Total), FWCT (Field Water Cut). Also all these parameters are available for each well.

The modified model was separated into 4 regions with different PVT properties according to measured pressure gradients (Fig 4):

Region 1- 1602 -1608 meters with density 780 – 810 kg/m^3

Region 2 – 1608 – 1618 meters with density 825 – 845 kg/m^3

Region 3 – 1618 – 1629 meters with density 850 – 872 kg/m^3

Region 4 – 1629 – 1645 meters with density 880 kg/m^3

Having done regression on mole fractions of hydrocarbons, tables of Live Oil and Dry Gas can be obtained for using in the modified simulation model. These tables reflect changing chemical composition throughout part of the reservoir, which was chosen for simulation model. Hence, three table of Live Oil were created.

The API Tracking option (Beraldo et al., 2007) facility enables the model to mix different types of oil. Without the API Tracking facility, the presence of different types of oil in the reservoir could be handled with the aid of PVT region numbers. Oil in PVT region 1 would have its properties determined from PVT table number 1, and so on. However, this method cannot model the mixing of oil types. Oil flowing from region 1 into region 2 would appear to take on the properties associated with region 2.

The API Tracking (Beraldo et al., 2007) facility essentially replaces the concept of PVT regions for oil. The PVT tables used for determining the oil properties are selected at each time step according to the average API of the oil in each grid block (or to be more precise, its average surface density). A mass conservation equation is solved at the end of each time step to update the oil surface density in each grid block, to model the mixing of the different oil types.

Based on chemical composition, for each region appropriate live oil table was created. Having calculated range of densities in every region, average value was chosen for every area of propagation. This method gives opportunity to take into account vertical distribution and variation of oil density. Moreover, every region has different viscosity of oil and thus, fluctuation of viscosity is also takes into account. As well, this type of presentation used different PVT tables, which can be interpreted as more exact method for accounting rate and economic value of oilfield.

Comparison of Results

Having done with both simulations model in Eclipse (c) software (see Fig. 6 and Fig.7), results can be compared.

As imaged in Fig. 5, when density of oil has constant value, all part of perforations will be working and depletion of reservoir will be uniform. But when there is a difference in density between parts of reservoir (Biodegradation effect), flow will be also different. It is obvious that part of formation with lower density and viscosity will be depleted greatly than part with higher density and viscosity after defined time interval. Since average permeability of formation is very high, viscous forces will be dominated. This situation can explain all differences which occur in the models. Next perforations interval has been chosen: 4 meters below GOC and 2 meters above OWC.

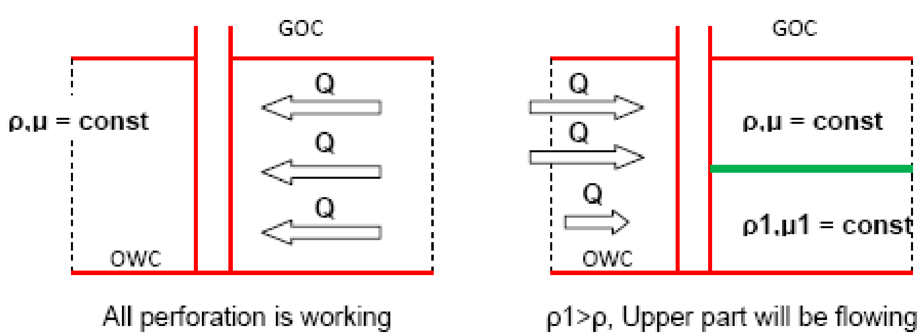

Fig. 5. Schematic explanation of fluid flow (Q – Flow Rate, m3; μ – viscosity of the fluid, sp; ρ – density of the fluid, kg/m3; GOC – Gas-Oil Contact; OWC – Oil-Water Contact)

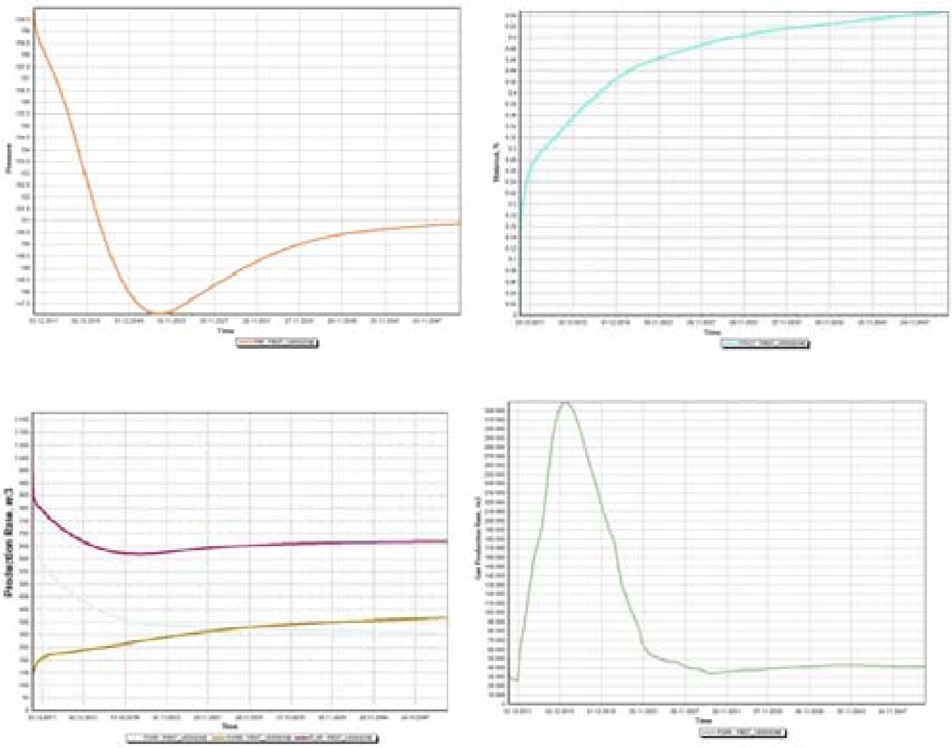

Fig.6. Base Model Results: (FPR – Field Pressure; FWCT – Field Water Cut; FWPR – Field Water Production Rate; FLPR – Field Liquid Production Rate; FGPR – Field Gas Production Rate)

Field Pressure

It is necessary to mark that only 4 wells were in models and pressure maintains is not required (sector is about 5 square km). Pressure behavior in both models is almost the same and a little difference in modified model explained by high flow rate of oil.

Field Water cut and Field Water Production Rate

Base model gives high value of production water relates to oil production. It explained by that fact, when magnitude of perforations the same in the both cases, in the base model all part of the reservoir is working and in the model with density variation almost only part with lower value of density gives flow of oil and water. At the same time, lower part of the reservoir (where density is higher), almost doesn't working and OWC stays at initial position. Thus, value of mobile water is greater in the first case than in the second one.

Field Oil Production Rate

Since in modified model there is density of oil which less than average value, in equal conditions (depression, perforation and etc.) oil with lower density will be flowing instead of oil with higher density. Thus, rate of production will be differed in to the large side. Higher value of viscosity and density in the lower part of the formation bring to reducing mobile. And it seems in the case of industrial production, there is a danger to lose oil in that part.

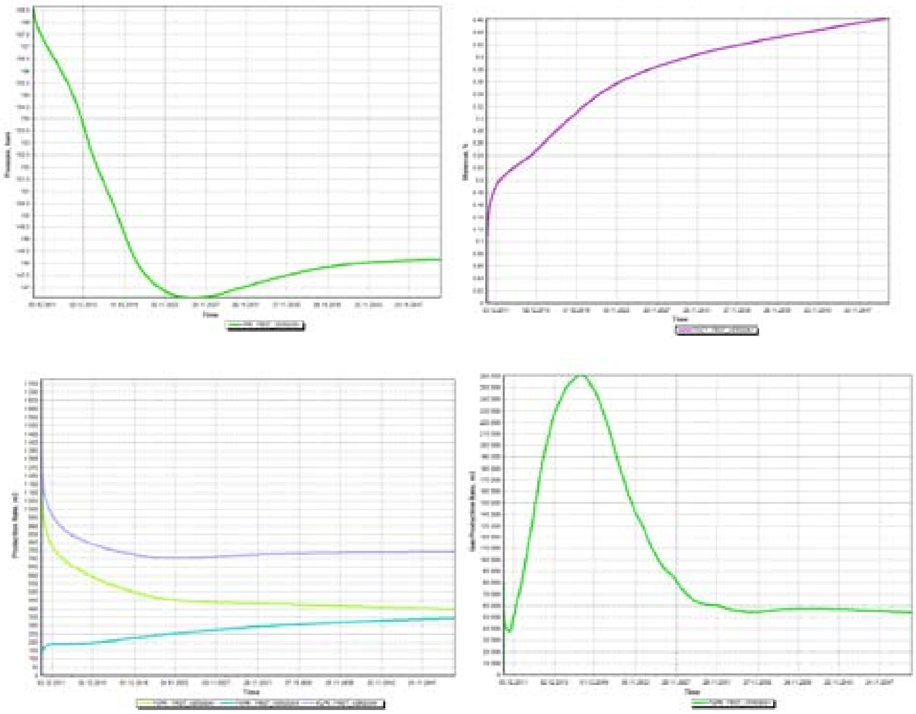

Fig.7. Modified Model Results (FPR – Field Pressure; FWCT – Field Water Cut; FWPR – Field Water Production Rate; FLPR – Field Liquid Production Rate; FGPR – Field Gas Production Rate)

Field Gas Production Rate

Early gas breakthrough occurs in the both cases. There is only difference between models in the peak and length of production gas rate. In the first model, oil near from gas oil contact has higher density and gas breakthrough starts a little earlier than in the second model where there is 'layer' of oil with less density. In the case of heavy oil near from gas oil contact, gas almost not dissolved in oil and that is why gas conning occurs early and has great peak. Also for the second model Field Gas Production Total has the greater value.

In conclusion, it is necessary to add that in the beginning modified model starts at the higher flow rate and during 40 years FOPR higher for the second model and FWCT and FLPR is less than in the first model, but tendency the following: during time interval difference in activities decreases and after one critical moment, the first model will be more economic attractive than the second one. This tendency not so obvious in this case due to small number of active wells, but for case with hundreds wells it will be more noticeably.

Conclusions

The main conclusions can be marked after review of the effect of oil properties heterogeneity and its modeling:

- fluid properties alteration gives density and viscosity fluctuation in the reservoir which affects production rate, watercut and other parameters of production;
- there is a risk to lose resource with heavy oil density;

- primary flow rate of oil higher in case of using different oil densities in the reservoir;
- after defined interval of time, model with average value of density gives higher flow rate and less watercut;
- lateral trends of changing density and viscosity are also possible in addition to vertical trends;
- it is possible to get gas conning and water conning due to heavy oil in the reservoir;
- it is desirable to perforate interval at least 10 meters below gas oil contact and 5 meters above water level for prevention of water and gas breakthrough;
- using formation fluid sampling it is possible to construct 3D distribution of density for more precise modeling.

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Создание гидродинамической модели месторождения с учетом неоднородности свойств флюидов

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В работе проанализированы причины возникновения изменчивости свойств флюидов. Выполнено трехмерное цифровое моделирование разработки пласта, насыщенного нефтью с переменными по разрезу свойствами (вязкостью и плотностью). Проведено сопоставление с моделью, построенной в рамках классического подхода, с постоянными значениями вязкости и плотности флюида. Показано, что учет неоднородности свойств нефти в модели позволяет осуществлять более корректное проектирование разработки месторождения и планирование различных мероприятий.

Ключевые слова: вязкость, плотность, свойства нефти, гидродинамическое моделирование.