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CURRENT STUDIES ON ENHANCED OIL RECOVERY FOR "BACH HO" AND "RONG" FIELDS

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An overview of the fields, reservoirs characteristics, production regimes, production performances, and current studies on enhanced oil recovery (EOR) for "Bach Ho" and "Rong" fields are given in this paper. In this article, reservoir structures, reservoir conditions, rock characteristics, fluid properties, oil displacement mechanism, current production regime and production performance, the availability of chemical-technique-technology, and the preliminary results of theoretical and experimental studies on some major EOR techniques are analyzed and evaluated in order to select the most promising EOR approaches for "Bach Ho" and "Rong" fields.

Keyword: enhance oil recovery, polymer flooding, polymer injection, surfactant injection, Surfactant Flooding

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Introduction

Enhancement of oil recovery is an issue of great concern in Joint-venture Vietsovpetro company (VSP). To date, 3 major EOR projects had been approved to study and they have been studying in cooperation between VSP EOR experts and other EOR experts in Vietnam and also from abroad. The major details of each project are described in the following sections.

I. Polymer Injection to Enhance Oil Recovery for Bach Ho Low Miocene Reservoir

Reservoir Descriptions

The Bach Ho Low Miocene reservoir is a layering sandstone reservoir, which developed on almost all area of "Bach Ho" field at the depth from 2759 – 2998 m. In area, it can be divided into two blocks: Northern and Central. In cross-section, this reservoir can be divided into several separated layers such as 23, 24, 25, 26 and 27. The main production target is layer 23. In each layer, the permeability is changed drastically from several milidarcies to thousands milidarcies (2.5 - 2500 md for layer 23). The layering coefficient is relatively high (3.25) for layer 23. Average permeability is 239 md. Average porosity is 0.177. Initial static reservoir pressure is 28.8 MPa. Average value of bubble point is 27.8 MPa. Reservoir temperature varies from 80 °C to 110 °C. Reservoir oil saturation was estimated of about 0.51. Reservoir initial water-oil contact was observed at the depth of 2971 m. Original oil in place has been estimated of about 8 and 11 MMtns for Central and Northern blocks respectively[1].

Reservoir fluid properties: gas-oil ratio is 141 m^3/t. Formation oil is medium oil with API = 29 - 33. Average oil viscosity is about 1.69 cP.

Reservoir Waterflood Performance

Water was injected into both blocks at the bottom and edge of the reservoirs with the purpose of sustaining reservoir pressure and oil displacing factor to enhanced oil recovery.

Waterflood characteristics were investigated in experimentally and paralleled with monitoring, and analyzing production data. Experimental results showed that the rock is strong water-wet, and the major water-oil displacement mechanism is viscous drive. The water-oil displacement efficiency varies from 0.373 to 0.755 (average 0.577).

To the 1st November 2008, 55 wells have been drilled into this reservoir, among them 32 producers, 8 injectors and the rest are either abandoned or plugged back. For both two blocks, 4.88 MMtns of oil (3.58 and 1.29 MMtns for Northern and Central blocks respectively) was produced at relatively high watercut of 0.66 (0.82 and 0.31 for Northern and Central blocks respectively). Therefore, though the currently oil recovery is just of 0.23 [1]. The reservoir has entered its late production stage (matured).

In general, the waterflood is evaluated as an effective approach for maintaining reservoir pressure and enhancing oil recovery. Based on overall factors mentioned above, the Low Miocene reservoir can be considered as a very promising candidate for EOR polymer flooding.

Study of Polymer Flooding

Theoretical Relationships

A common feature in many clastics reservoirs is large-scale layering where adjacent geological strata have severely contrasting permeabilities. This leads to early breakthrough of water in the higher permeability layers or 'thief zones' and low vertical sweep efficiency, hence the waterflooding a reservoir proves to be inefficient. This situation can be improved by acceleration of the viscous forces and fluid cross-flow between reservoir layers using polymer.

The basic physics behind the polymer flooding EOR process in a high heterogeneous reservoir is that the mobilization of residual oil trapped within the flooded zones by high capillary force and oil trapped within the water-bypassed zones by overcoming the forces holding the oil in them by increasing viscous force - reducing the mobility ratio M = mokw/mwko (increasing water viscosity and reducing permeabilities to water).

In principle, polymer can act by a combination of two mechanisms: mobility control, in which the polymer slug viscosity changes fluid flow patterns within the reservoir and adsorption, leading to pore blocking and local reductions in permeability, which again alters fluid flow.

In a slug polymer flooding in a vertically stratified reservoir, polymer can reduce the harmful effects of high-permeability layers and so reduce watercut and improve areal and vertical sweep efficiencies [2].

Oil Trapped in Reservoir

Based on analyses mentioned above, it is necessary to conclude that most of trapped oil in a waterflooding high heterogeneity clastics reservoir is restrained mainly in the water-bypassed layers, and just some in the flooded layers. This trapped oil in water-bypassed layers is a promising candidate for tertiary recovery by accelerating the vertical sweep efficiency in waterflood using polymer.

Some Favorable Factors

- Large-scale layering reservoir.
- Waterflooding reservoir is at its matured production life.
- Large amount of trapped oil in reservoir (about 15 MMtns).
- Unfavorable mobility ratio (relatively high ratio mo/mw = 5).
- New polymer can stand long at high temperature T=120 °C and high salinity (sea water).

Experimental Study

Preparing core model, working fluids:

Layering core model built from two equal layers of Low Miocene rock with different permeabilities is a key factor to ensure observing and determining the effect of cross-flow occurred during slug polymer flooding experiment.

The aqueous polymer solution A-806 was synthesized by Dalat Nuclear Research Institute in Vietnam. This polymer has some advantage properties comparing to other available polymer in the market. It can stand long at high temperature T = 120 °C and high salinity (sea water).

Experiments of polymer injection EOR were conducted on layering core models under reservoir conditions using model of formation oil, sea water, and low concentration polymer solution (≤ 2500 ppm). In these experiments, after the core models flooded out, a slug of 0.25 pore volume of polymer solution will be injected into core models and following by water injection (non-stop injection regime).

Table 1

Oil displacement efficiency by water/polymer flooding

№	Model number	Oil recovery by Water Flood - $\eta 1$, fraction	Oil recovery by Polymer Flood - $\eta 2$, fraction	Increment of oil recovery - $\Delta\eta$, fraction	Permeability recovery K_{rec}, fraction
1	I-2	0.41	0.5653	0.154	0.027
2	II-1	0.3963	0.5123	0.116	0.211
3	II-2	0.5066	0.6633	0.157	0.071
4	III-1	0.4745	0.5224	0.048	0.323
5	III-2	0.4727	0.6017	0.129	0.272
6	IV-1	0.5362	0.6113	0.075	0.145
7	IV-2	0.5261	0.6916	0.166	0.278
	Average	0.4748	0.5954	0.121	0.190

Experimental Results

Experimental results are shown in Table 1 and oil - polymer solution displacement behaviors are depicted in the figure 1. Obtained results from 7 experiments used 2500 ppm polymer concentration and at slug injection

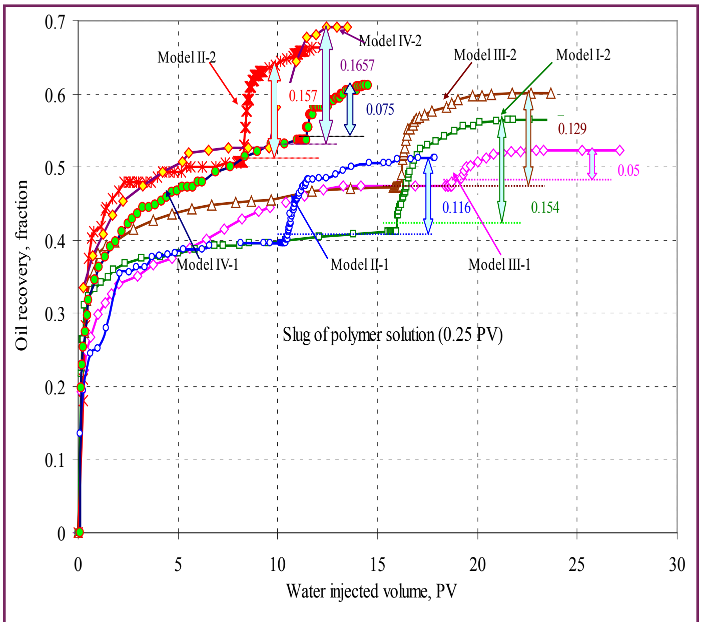

Fig.1. Oil displacement behavior at water/polymer flooding on layering core models of BH Low Miocene reservoir

regime of 0.25 pore volume showed that the average increment of oil recovery is 0.121. Oil displacement behaviors were identical for all experiments and sharp increase in oil recovery right after renewing water injection was observed [3].

II. Study of New Reservoir Pressure at the Matured Production Stage to Enhance Oil Recovery for Bach Ho Basement Reservoir

Reservoir Descriptions

Bach Ho basement reservoir is a super-giant oil reservoir with area of about 120 km². It can be divided into 2 major blocks, Northern and Central. This reservoir is an intrusive magma body composing of granite, granodiorite and diorite and complicated by two main fault systems of NE-SW and NW-SE orientations. The depth of its crest is 3050 m, gross thickness is about 1500 m and net thickness is about 490 m.

This very highly heterogeneous reservoir has dual porosity and dual permeability. Microfractures play about 0.75 of total porous space while macrofractures dominate in providing permeability. Log and core data showed that rock porosity varies in a very large range of 0.003 to 0.14 (average 0.28) and permeability can be as high as several thousands md. There is a tendency of rapid reduction of porosity and permeability with depth, the greater the depth, the poorer the rock properties. There is good hydrodynamic communication in the Central Block but quite poor in the Northern Block, and there are many high permeable zones or so-called the "thief zones" developing along faults and fault intersection areas.

Reservoir temperature changes from about 125 ^{o}C at its crest to about 160 ^{o}C at 4500 m, reservoir oil saturation was estimated of 0.85 and there was no free gas cap. Average initial reservoir pressure is 41.7 MPa and average bubble point pressure is 22.4 MPa. The OOIP has been estimated of about 450 MMtns (3.1 Bbbls) and no initial water-oil contact has been found.

Reservoir fluid properties: Formation oil is light with API = 38-41. Bubble point pressure and gas-oil ratio vary in the reservoir and reach highest values at the reservoir top and reduce with depth. Bubble point pressure changes from 23.5 MPa at the top to 19.7 MPa at the bottom. Gas-oil ratio changes from 218 at the top to 165 at the bottom [4].

Reservoir Waterflood Performance

To date, about 125 wells have been drilled into the reservoir, among them 74 producers, 26 injectors and the rest are either abandoned or plugged back. The reservoir pressure has been maintained to be a little bit higher than the bubble point by injecting water into the bottom and the edge of reservoir.

The waterflood characteristics were studied experimentally and paralleled with monitoring, and analyzing production data. Laboratory results show that the mechanism of water-oil displacement in macrofractures is piston-like viscous displacement and in microfractures is capillary imbibition. Water-oil displacement efficiency for macrofractures varies from 0.334 to 0.886 (average 0.612), and for microfractures - from 0.10 to 0.784 (average 0.462). Mean value of overall water-oil displacement efficiency is 0.56 and that of gas-oil displacement is 0.35. The ultimate oil recovery is estimated of 0.17 and 0.41 by depletion and waterflood respectively.

To the 1st January 2008, in total, 201 MMm^3 of water was injected into the reservoir and 155 MMtns of oil was produced at average watercut of 0.19. The currently approximate oil recovery is of 0.39 [4], this means that the reservoir has entered its matured production stage. In general, the waterflood is evaluated as an effective approach for maintaining reservoir pressure and enhancing oil recovery for almost all the production stages.

New Reservoir Pressure Regime at the Matured Production Stage

Theoretical Relationships

Naturally fractured reservoirs are typically considered as a dual-porosity and dual-permeability system, which is composed of two distinct media: microfractured matrix and macrofractures. The microfractured matrix has high porosity but low permeability, and macrofractures have very high permeability and low porosity.

Mechanisms of water-oil displacement for this kind of reservoirs are capillary imbibition by wetting force in the microfractures and piston-like viscous displacement in the macrofractures by viscous force. The expulsion of oil from microfractures to the surrounding macrofractures by capillary imbibition is one of the most important oil recovery mechanisms, since in this type of reservoirs the conventional methods of production, such as building a pressure difference across microfractured blocks, were failed because of high-permeability macrofracture network [5]. Therefore, in a typical flooding fractured reservoir, most of trapped oil is restrained in microfractures and water-bypassed zones, just some in macrofractures. This trapped oil in microfractures and water-bypassed zones is a promising candidate for tertiary recovery by accelerating the microscopic displacement utilizing gas separation process.

The basic physics in new reservoir production regime at the matured flooded reservoir to EOR is that the mobilization of residual oil trapped within microfractured blocks in the flooded zones by high capillary force and oil trapped within the water-bypassed zones by overcoming the forces holding the oil in them by increasing viscous and gravity forces by gas separation process at reservoir pressure lower than bubble point.

In principal, when reservoir pressure is reduced to value lower than bubble point, solution gas will be separated formation oil. Gas separation process will occur mainly and drastically in the microfractured blocks and in the water-bypassed zones, where the remained oil is prevalent. In microfractures, immediately after gas generated, one part of gas will go directly into the adjacent macrofractures and carry some oil along with it; another part will take place within the microfractures themselves and displace some oil from them into the same surrounding macrofractures, and microscopic displacement efficiency will be improved. In macrofractures, those oil and gas and gas separated within the macrofractures themselves will move upward to the top of the reservoir by means of viscous and gravity forces, and hence forming gas-oil cap. The improvement of microscopic displacement efficiency and the magnitude of gas-oil cap crucially depend on applied differential pressure, gas-oil ratio, and of course, also on amount of oil remained.

Concept of New Reservoir Pressure Regime

The proposed approach is to depressurize the overall reservoir pressure to lower than bubble point at the matured production stage in order to utilize the effect of gas separation as supplemented drive factor for the oil resided in the low permeable zones and water-bypassed zones by increasing gravity forces, so the microscopic displacement efficiency will be improved.

Some Favorable Factors:

- Massive fractured reservoir with totally closed hydrodynamic system.
- Enormous amount of unrecoverable oil by existing designed waterflood (≈ 250 MMts).
- Bubble point pressures are top-down reduced.
- The relatively high gas-oil ratio (average 190 m^3/t),
- Specific pore structure composing of macrofractures and microfractures (macro-fractures play important role in providing flow paths and stored space for gas-oil in this production regime).

Some Predicted Results

For gas cap, preliminary calculation showed that if reducing the reservoir pressure from current value (about 23 MPa) down to values of 18 and 15 MPa, the potential amounts of gas cap will be about 5.5 and 11 Bm3 respectively.

For the oil production, following the currently accepted unswept efficiency by waterflood is 0.3, the potential recoverable oil calculated for just the unswept oil zones (about 130 MMts) will be about 22 MMts (accepting oil recovery in depletion regime of 0.17).

The Simplified Procedure of Reservoir Depressurizing Process

Firstly, forming gas cap: the oil production zone needs to be transferred a little bit down-dip from the reservoir top section to create a "free" space for forming the secondary gas cap. Then, pressure at near top of reservoir will be reduced lower than bubble point by reducing production or reducing injection or both in order to allow separate gas from oil (fig.2a).

Secondly, for the purpose of expanding the newly formed gas cap: it is necessary to produce only gas and stop injection for a certain period aiming to keep separating gas continuously in reservoir deeper parts (fig.2b).

Last, when the gas-oil cap is large enough, then start producing gas and oil in combination with water injection (fig.2c)[6].

III. Surfactant Injection to Enhance Oil Recovery for South-East Dragon Basement Reservoir

Reservoir Descriptions

The South-east Dragon fractured basement reservoir is a massive reservoir with thickness is about 900 m and spreading on the area of about 20 km^2. This reservoir is a very highly heterogeneous with dual porosity and dual permeability. The microfractured matrix dominates in porosity and plays about 0.75 of total porous space while macrofractures dominate in providing flow path with permeability varies from several milidarcy to several darcy. Average porosity is 0.06. Initial static reservoir pressure is 29.7 MPa. Reservoir temperature is 91 °C. Initial oil saturation is 0.55. There are many high permeable zones developing along the faults and the fault interception areas. Reservoir initial water-oil contact was observed at the depth of 2950 m. Original oil in place has been estimated of about 35 MMtns (0.25 Bbbls) [1] .

Reservoir fluid properties: low bubble point pressure and low gas-oil ratio. Average value of bubble point is 6.8 MPa. Gas-oil ratio is 50 m^3/t. Formation oil is light with API = 31-34. Oil viscosity is about 1.97 cP.

Reservoir Waterflood Performance

This reservoir is divided into 3 production zones: Central, Eastern and Western. The reservoir has been produced at depletion regime in period of 1996 - 1998. From the end of 2000, water was injected into bottom and edge of the reservoir with the purpose of sustaining reservoir pressure high higher than bubble point. To the beginning of 2007, 4.18 MMtns of oil has been produced [7].

Waterflood characteristics were investigated

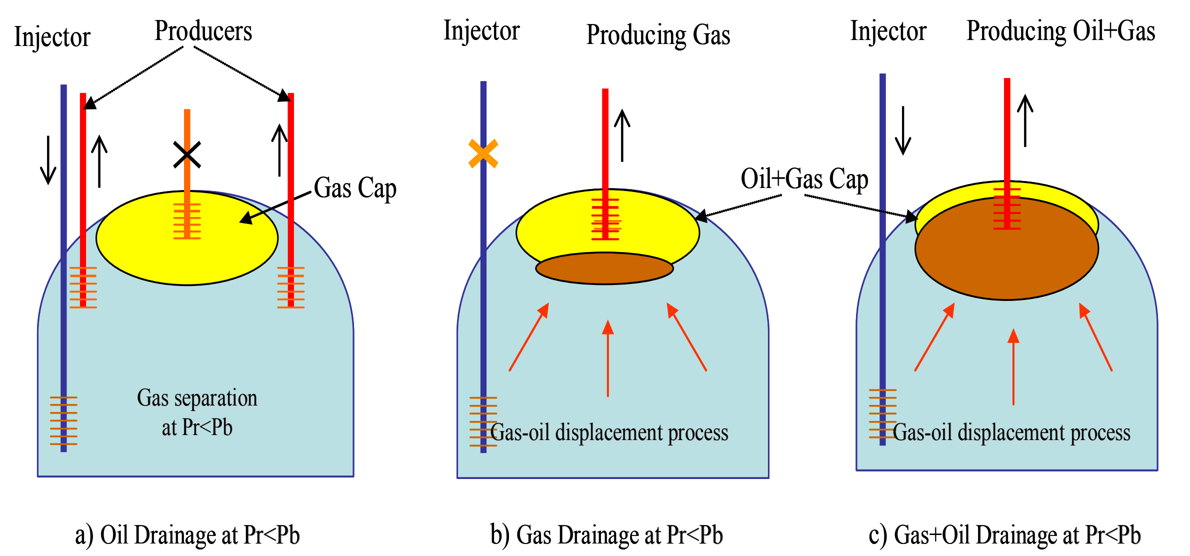

Fig.2. Scheme of producing Bach Ho basement reservoir at pressure lower than bubble point

in experimentally and paralleled with monitoring, and analyzing production data. Experimental results showed that the basement rock has neutral wettability with the contact angles vary from 82° to 100°, and the water-oil displacement mechanisms are piston-like in macrofractures and capillary imbibition in microfractures. The water-oil displacement efficiency for macrofractures varies from 0.341 to 0.671 (average 0.55), and that for microfractures varies from 0.025 to 0.495 (average 0.377).

Study of Surfactant Flooding

Theoretical Relationships

As mentioned in section 2, the expulsion of oil from microfractures to the surrounding macrofractures by capillary imbibition is one of the most important oil recovery mechanisms. In a typical flooding fractured reservoir, most of trapped oil is restrained in microfractures and water-bypassed zones, just some in macrofractures. This trapped oil in microfractures and water-bypassed zones is a promising candidate for tertiary recovery by accelerating the imbibition water soak process using surfactant.

The basic physics behind the surfactant flooding EOR process in a fractured reservoir is that the mobilization of residual oil trapped by high capillary forces within the microfractured blocks by decreasing the forces holding the oil in them (decreasing capillary pressure $P_c = (2*s_{o\text{-}w}*cosq)/r$).

The principal mechanisms of interaction between surfactant and rock-fluids system in a fractured reservoir can be depicted as follows [5]:

- Surfactant can help reduce significantly the interfacial tension between oil-water phases $s_{o\text{-}w}$ by dispersing the sharp changes in cohesive energy density between a pure water-oil interfaces, hence reduce capillary pressure. For microfractures, the decrease of capillary pressure will lead to improve effectiveness of water-oil capillary displacement. For macrofractures, the decrease of IFT between oil-water phases and the fines detach from oil coated macrofracture walls due to surfactant will bring in the increase of relative permeability to oil, and thus improve the effectiveness of water-oil viscous displacement.

Surfactants can help alter rock wettability from oil-wet or neutral-wet to water-wet, thus create and accelerate the spontaneous imbibition process, and hence improve capillary displacement efficiency. The chemical reaction takes place between the rock surfaces and the adsorbed polar organic components or carboxylates in the surfactant which alters rock wettability toward water wet.

Some Favorable Factors

- Massive fractured reservoir.
- Large amount of unrecoverable oil by existing designed waterflood (about 30 Mtons).
- Relatively low reservoir temperature T = 91 °C.
- Relatively high oil viscosity (about 2 cP).
- Rock has neutral wettability.

Experimental Study

Preparing core model, working fluids:

Core models were built from the rock of South-east Dragon fractured basement reservoir, which contains natural fractured system (macrofractures and microfractures) with different macrofracture fraction.

The aqueous surfactant solution IAMS-M2 was synthesized by Institute of Application Material Science in Vietnam. It has some advantage properties comparing to other available surfactants on the market. That means it can stand long at high temperature T = 91 °C and high salinity (sea water).

Experiments of surfactant injection EOR was conducted on core models under reservoir conditions using formation oil, sea water, and low concentration surfactant solution (≤ 1000 ppm). In these experiments, after the core models flooded out, a slug of 0.15 pore volume of surfactant solution will be injected into core models and then core models aged at given test conditions for 36 hrs before resuming water injection (temporary stop injection regime). Aging time is necessary to accelerate the capillary spontaneous imbibition process for improving microscopic displacement efficiency.

Experimental Results

Experimental results are shown in Table 2 and surfactant-oil displacement behavior is depicted in the figure 3. Obtained results from 3 surfactant injection experiments used 1000 ppm surfactant concentration and at temporary stop injection regime showed that the average increment of oil displacement efficiency is 0.068. Oil displacement behaviors were identical for all the experiments and the sharp increase in oil displacement efficiency right after renewing water injection was also observed [7].

Table 2

Oil displacement efficiency by water/surfactant flooding

№	Model number	Oil recovery by Water Flood - $\eta 1$, fraction	Oil recovery by Surf Flood - $\eta 2$, fraction	Increment of oil recovery - $\Delta\eta$, fraction
1	XII	0.3843	0.4672	0.0829
2	XIV	0.3696	0.4316	0.0620
3	XVI	0.3851	0.4458	0.0607
	Average	0.380	0.448	0.069

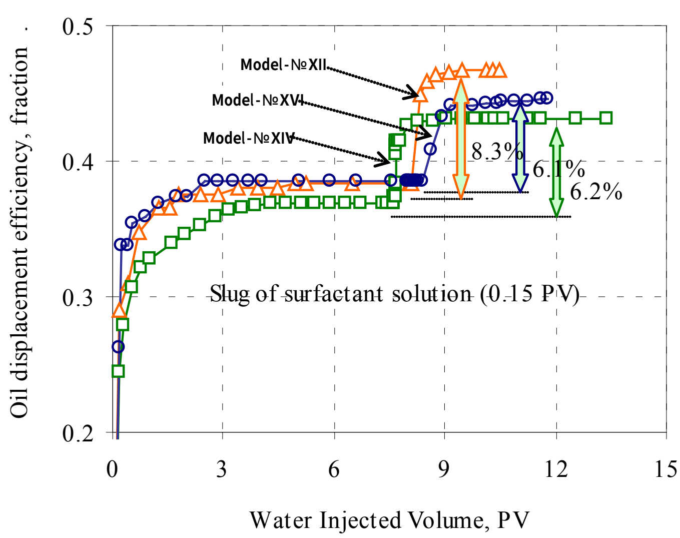

Fig.3. Oil displacement behavior at water/polymer flooding on layering core models of BH Low Miocene reservoir

Conclusions

Polymer injection in slug regime may be a very promising EOR approach for Bach Ho Low Miocene reservoir. The experimental results showed that the increment of oil recovery varies from 0.048 to 0.166 (average 0.121) comparing to conventional waterflooding.

Theoretically, new reservoir production regime is likely the best EOR option for Bach Ho basement reservoir at its matured production stage. It is necessary to study this EOR approach thoroughly, theoretically, experimentally and numerically in order to evaluate the effectiveness of this approach.

Surfactant injection in slug regime may be a suitable EOR approach for South-east Dragon fractured basement reservoir. The experimental results showed that the increment of oil displacement efficiency varies from 0.061 to 0.083 (average 0.069) comparing to conventional waterflooding.

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Исследования повышения нефтеотдачи на месторождениях "Бах Хо" и 'Ронг"

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Реферат

В статье дан обзор месторождениий, коллекторских свойств, режима добычи, эксплуатации месторождений, а также текущих исследований по повышению нефтеотдачи пластов (ПНП) на месторождениях "Бах Хо" и "Ронг". При этом, анализируются и оцениваются строение залежи, пластовые условия, характеристика горных пород, свойства жидкости, механизм вытеснения нефти, режим текущей добычи и эксплуатационная характеристика месторождения, наличие химических технологий, а также предварительные результаты теоретических и экспериментальных исследований по ряду важных методов повышения нефтеотдачи пластов с целью выбора наиболее перспективных подходов для повышения нефтеотдачи пластов на месторождениях "Бах Хо" и "Ронг".

"Bah Ho" və "Ronq" yataqlarında neftveriminin artırılması üçün aparılan cari tədqiqatlar

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Xülasə

Məqalədə yataqların kollektor xassələrinin, hasilat rejiminin, yataqların istismar xüsusiyyətlərinin, həmçinin "Bah Ho" və "Ronq" yataqlarında neftveriminin artırılması üçün aparılan cari tədqiqatların xülasəsi verilmişdir. Burada, yatağın quruluşu, lay şəraitləri, dağ süxurlarının xüsusiyyətləri, mayenin xassələri, neftin sıxışdırılma mexanizmi, cari hasilatın rejimi və yatağın istismarının xüsusiyyətləri, kimyəvi texnologiyaların olması, həmçinin "Bah Ho" və "Ronq" yataqlarında layların neftveriminin artırılması üçün daha perspektivli yanaşmaların seçimi məqsədi ilə layların neftveriminin artırılmasının bir sıra mühüm metodlarının nəzəri və sınaq tədqiqatlarının ilkin nəticələri təhlil edilərək qiymətləndirilir.