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A SUCCESSFUL PILOT APPLICATION OF THE COMPLEX MIXTURE SURFACTANT POLYMER VPI SP TO ENHANCE OIL RECOVERY FACTOR FOR THE LOWER MIOCENE, BACH HO FIELD

Dinh Duc Huy[1], Nguyen Minh Quy[1], Pham Truong Giang[1], Hoang Long[1], Le Thi Thu Huong[1], Cu Thi Viet Nga[1]
Pham Xuan Son[2], Nguyen Lam Anh[2], Ho Nam Chung[2], Pham Trung Son[2], Nguyen Quynh Huy[2], Tran Thanh Nam[2]
[1]Vietnam Petroleum Institute
[2]Vietsovpetro
Email: huydd@vpi.pvn.vn
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Summary

Enhanced oil recovery (EOR) implementation at field scale is complex. Therefore, pilot applications are usually conducted before field execution. This paper introduces a pilot project successfully applied for the Lower Miocene, Bach Ho field. Topics covered include: (i) pilot area selection, (ii) chemical preparation, (iii) specification and pilot design for execution, (iv) implementation, (v) pilot observation and interpretation, (vi) efficiency evaluation. The implementation of pilot projects is achieved on 23 January 2022. The evaluation shows that 2,700.2 tons of oil gained thanks to the application of the surfactant-polymer complex mixture (VPI SP).

Key words: Enhanced oil recovery, VPI SP, Lower Miocene, Bach Ho field.

1. Introduction

Bach Ho oil field started producing oil from the Miocene in 1986 while the south dome in 2011 on BH-441. The initial oil in place of the Miocene was approximately 80.05 million tons, of which 27.17 million tons came from the Lower Miocene, south dome (BK14/16). The reservoir in BK14/16 consists of 5 main sand bodies from layer 22 to layer 27 with an average depth of 2,300 mTVDss. The target layer in the pilot plan is layer 23, sandstone formation; the remaining oil volume in place is ~5 million tons. Layer 23 formation distribution is wide and thick, with medium to high permeability and support energy from the flank water (Figure 1).

2. Pilot area selection

The implementation of enhanced oil recovery plans at field scale is complex and difficult. Thus, before applying at field scale, the size of the solution should be first scaled down then increased step by step [1]. In addition, defining clear pilot objectives and execution will lead to a successful pilot. On the other hand, pilots carrying out need to weigh against the time and expense [2]. To minimise the uncertainty of chemical injections for increasing oil recovery of the Lower Miocene, Bach Ho field, a few key points need to be specified to prioritise the objects to consider.

- The preliminary screening evaluation in the pilot area is convincing technically and economically;
- Well pattern/well configuration is typical in the field with the extent of the communication between injector and producer, and effective water injection is preferable in this case;
- The volume of oil remains after the secondary stage;
- Available facilities in the pilot area are adaptable to the technology of EOR implementation.

The objective of the pilot plan is carefully selected. The results indicate that the location of injector 1609/BK16 is the likely area for EOR execution as follows:

- The results of dynamic model simulation and feasible study show the highest value [3];
- Distribution of the main reservoir (layer 23 sand body) is wide and fairly thick (23-0: 3.3 m, 23-1: 4.3 m, 23-2: 16.5 m) (Figures 1 & 3);

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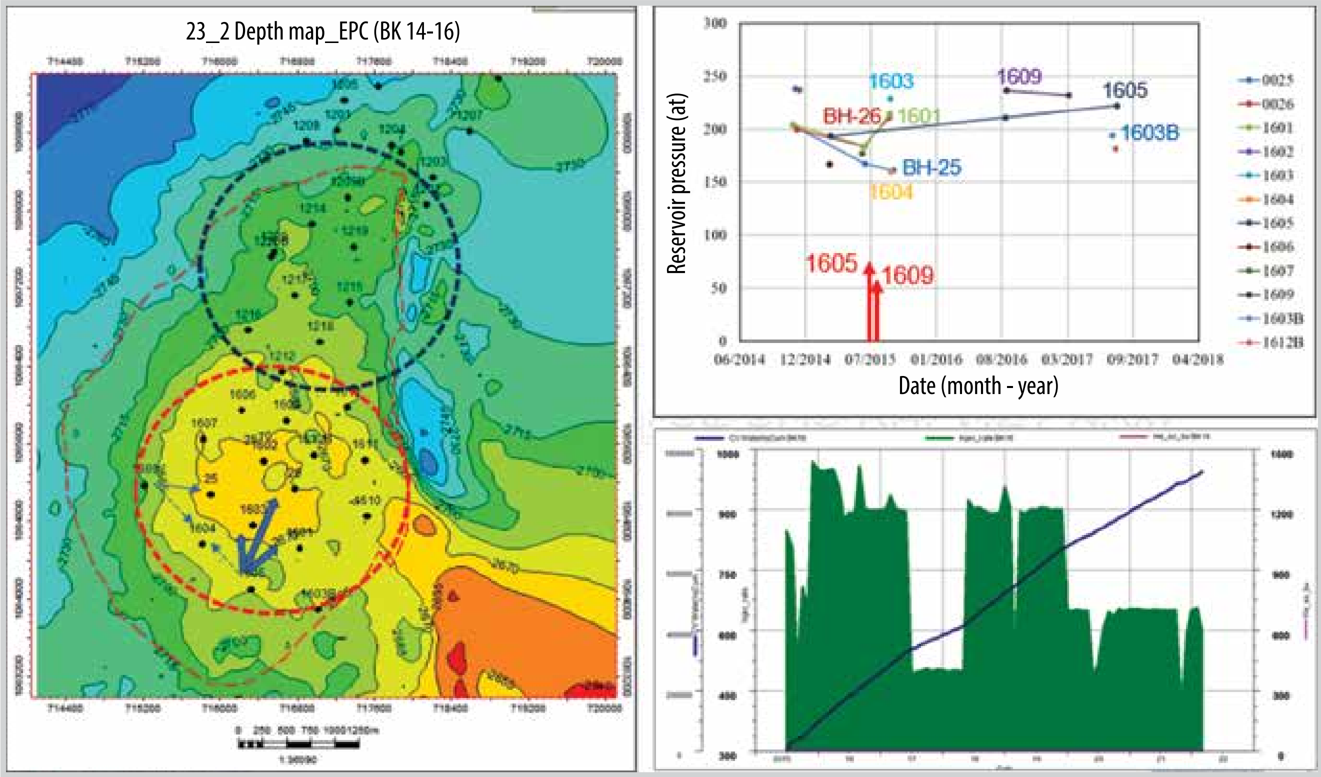


Figure 1. Geology information and well parameters of BK16 area.

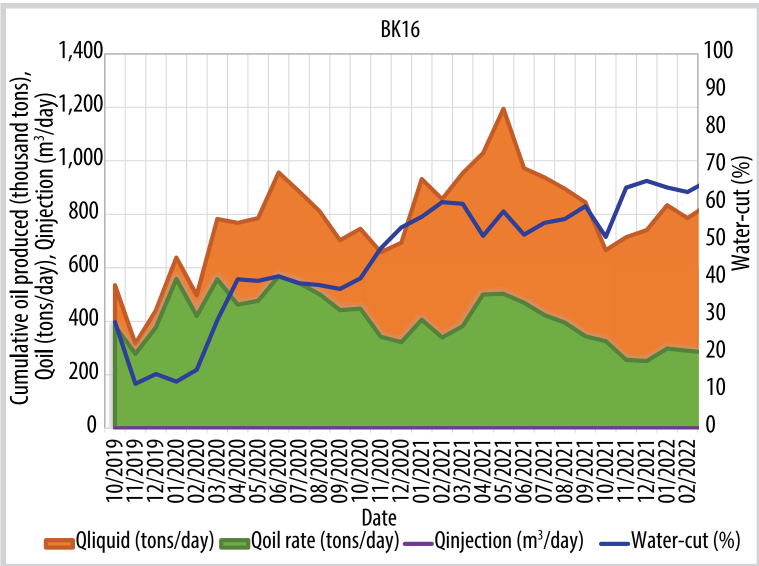


Figure 2. The production performance of BK16.

- Well spacing (500 x 500 m) and well pattern are typical for Bach Ho field while good communication between 1609 and the surrounding well is observed;

- The amount of remaining oil after production shows a high potential;

- Available facilities of BK16 are adaptable for injection chemical strategy.

Based on log interpretation results, mobile water is not observed at the initial condition of the interlayers 23_1 and 23_2, while it appears in the interlayers 23_3, 23_4 and 24, 25. In the western area (wells 1605, 1604, 1609), water saturation is higher than other locations in the interlayer 23_2. The net pay thickness of the interlayer 23_2 is quite good (12 - 16 m) but decreases rapidly toward the boundary. The net pay thickness of the interlayer 23_2 in the well area 1609 (16.5 m) is better than the well area 1605 (8.2 m).

BK16 was put into production in 2012, reaching an oil peak of 707 thousand tons per year in 2015. Producers are located at the top of the reservoir with favourable distances of 500 - 600 m to the injector. All producers have a high initial oil rate of 150 - 400 tons/day with water content less than 15% (Figure 2). In January 2022, total oil and liquid produced were 1.6 million tons and 2.8 million tons, respectively. The oil rate of all wells was lower than 20 tons/day with high water content in fluid streams (75 - 91%). The analysis of produced samples indicated that the ratio of water injection increased in water content. Survey results confirmed that all producers operated under a pressure regime which was higher than saturation pressure. Therefore, EOR is considered to maintain oil rate.

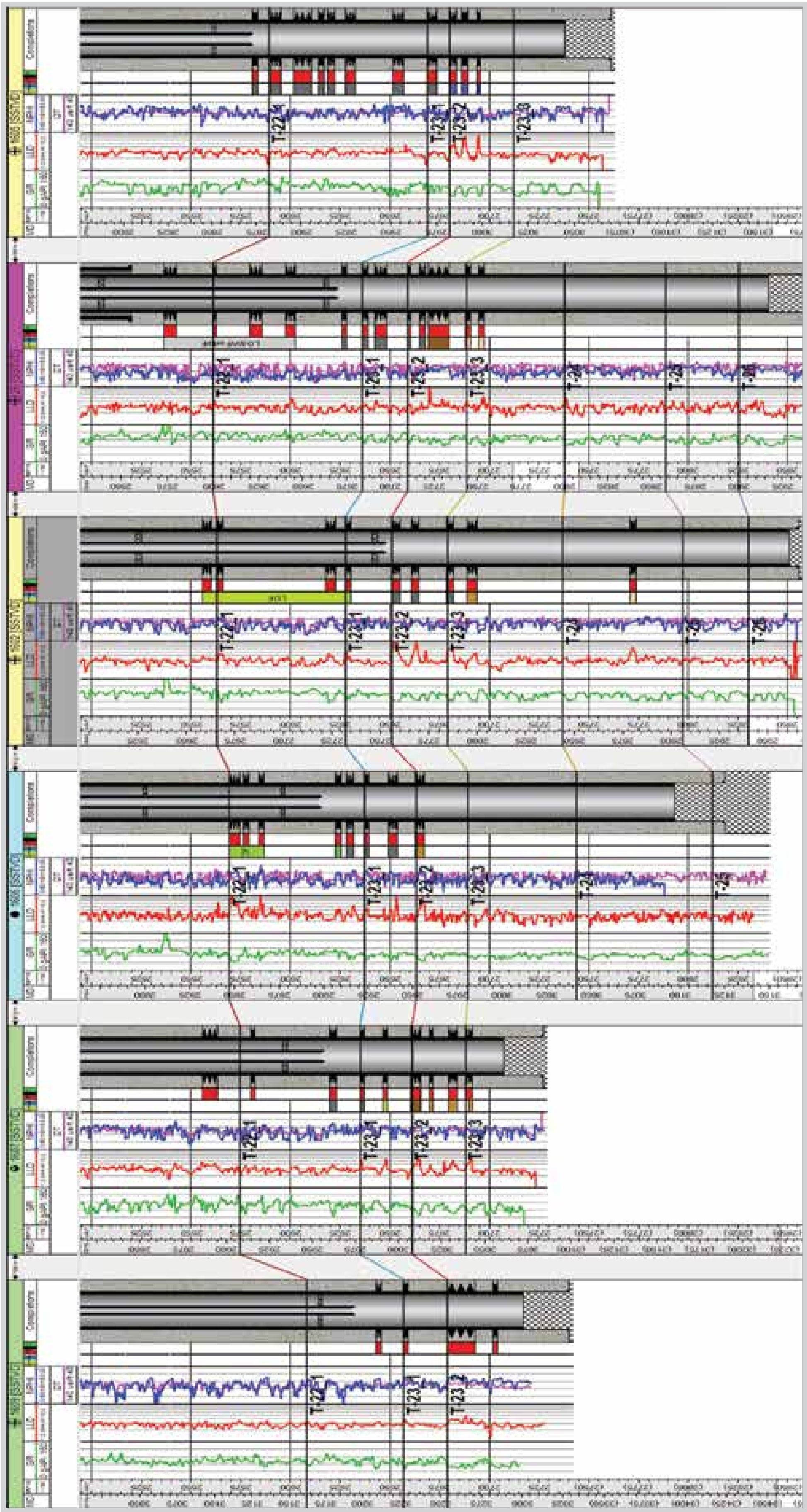


Figure 3. Well correlation of 1609/BK16 and the surrounding wells

3. Chemical preparation

The main components of the complex mixture surfactant-polymer made by VPI (VPI SP) consist of sodium olefin sulfonate (SOS), alkyl olefin sulfonate (AOS), and nonylphenol ethoxylate (NPEO) [4]. Before producing VPI SP at the pilot scale, the chemical is quality-checked in the laboratory at critical concentration with a stepwise increase in mixing volume (1 ton, 2 ton scale) [4, 5]. Laboratory results indicate that the complex chemical mixture is of high quality under tolerant reservoir conditions (110°C, 300 bar), maintaining properties for a long time (resistance ability and viscosity ~104 weeks), and increasing recovery factor in core flooding (21 - 32%) [5]. A dynamic model of the pilot selection is built in accordance with test results and the area sweep efficiency is evaluated. The simulation result indicates that with the reduction of capillary number Nc (E10^{-8} to E10^{-5}) and IFT (20 - 35 mN/m to 0,07 - 0,01 mN/m), the produced oil is maximised [4]. In consideration of the chemical injection strategy in terms of both timing and expense, a matrix box is established to scale up the concentration and volume of the chemical. Consequently, 100 tons of VPI SP is optimally mixed

Figure 4. *VPI SP chemical in ISO IBC tank.*

Figure 5. *VPI SP stored in Vietsovpetro's base.*

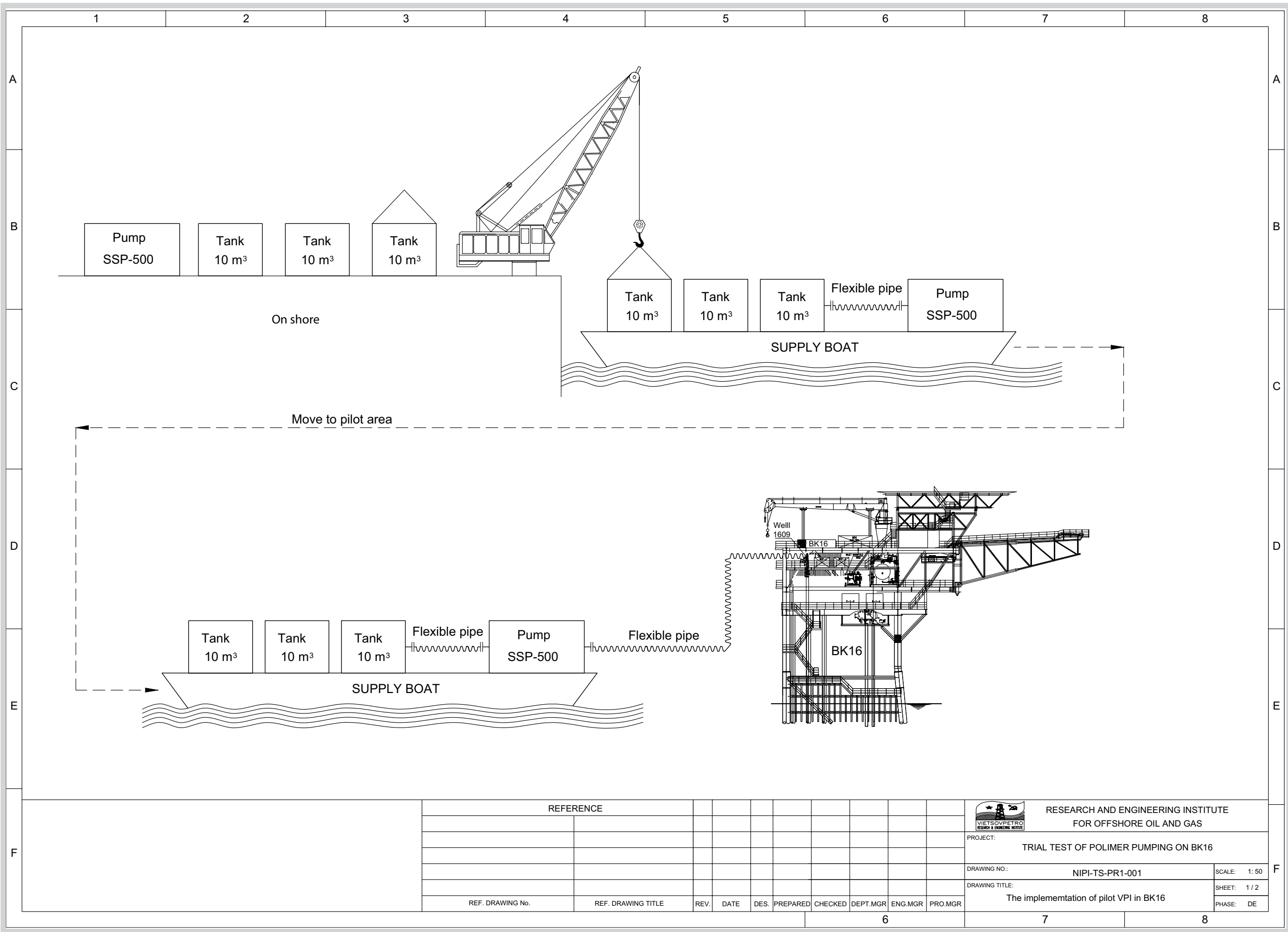


Figure 6. *The pilot implementation of VPI SP to enhance oil recovery factor.*

from the main ingredients surfactants and polymers (Figures 4 & 5) [4]. Additional tests of the new mixing are conducted to identify what happens during the interaction between oil and the chemical. The result shows that most of the products are emulsion-favoured, which is not only stable in the reservoir but also increases the sweep efficiency.

4. Pilot execution design

For more than 30 years of operation, Bach Ho field currently has offshore facilities supporting exploration, production, and transportation. According to preliminary site surveys, due to a long time of use, some equipment is reduced in operating capacity or broken during operation. The implementation using the current facilities shows

Figure 7. Injection of VPI SP to 1609/BK16.

some disadvantages, therefore, a system of equipment supporting the chemical injection is designed and made up. Being inspected and tested with the chemical, the obtained results show that the system satisfies the requirement.

In order to ensure operability and mobility during the implementation, the equipment system will be placed on floating devices or ships near marine structures. Besides, to ensure a smooth transportation and support from the existing system, the chemical will be mixed onshore with high concentration. High pressure pumps, ISO tanks, auxiliary equipment, equipment control devices, and spare parts are all placed on large service ships, moving to the pilot location (Figure 6).

By 2022, the chemical tanks and high-pressure pump will be installed directly in the ship and moved to BK16. The connection is established between the pump and well head injector 1609 via a flexible pipe. Pressure test is conducted up to 250 bar before injection to ensure the sealing of the system. The chemicals flow directly from the tank to the injector by high pressure pump.

5. Pilot implementation

All VPI SP in IBC tank was transferred to ISO tank of 10 m^3 and stored at room condition. During the process, properties of the chemical were observed to detect any abnormalities. Each ISO tank was covered after free gas was removed to eliminate the effect of oxygen to the quality of the chemical. To ensure the adaptability of the equipment to the injected fluid, a pumping trial was conducted with a small volume of the chemical. The procedure trial test is a scaled-down of the injectant strategy.

During 23 - 24 January 2022, the equipment system and the chemical were delivered to the pilot area (Figure 7). All of 100 tons VPI SP was successfully injected to 1609/BK16 in a strict compliance to the Vietsovpetro guidelines of safety and EOR chemical injection procedure. After the chemical injection, the injector was turned back working at the same condition as during water flooding. Pressure out of the VCO was recorded. It proved that the sealing between tubing and the reservoir was secured and all the volume of chemical was completely injected to reservoir. The implementation was carried out successfully without any safety issue.

6. Pilot observation

6.1. The well performance after VPI SP injection

After completing the implementation, a schedule of monitoring, sampling, and analysing fluid samples was jointly constructed by VPI and Vietsovpetro specialists. The post-injection observation is conducted in 6 months, in which the producer parameters and analysis results of the produced samples are tightly integrated. Production analysis is guided before and after chemical injection to compare the performance of the surrounding wells. Water analysis results confirm a clear effect of injector 1609 to the 1604, 25, 1607 and a fair effect to the 1602, 1606, 26.

Injector 1609 worked with a cycle of 10 days on and 10 days off before injection and then with the optimal cycle of 15 days on and 15 days off. Parameters of the injector are collected to evaluate the effect of the chemical to the near wellbore and the injectivity of the injection well. Data showed that the injectivity is stable and increases at the early time of the turnback. Furthermore, the wellhead pressure reduces when the injector turns back with the same injection rate (~400 m^3/day) as before. It suggests that the injector wellbore is not damaged by VPI SP (Figure 8).

Based on the analysis results, production performance was monitored carefully and analysed each week to predict any abnormal changes. Frequently, 1 sample of oil and 1 sample of water were taken from 6 production wells during monitoring. Samples were gathered in the VPI laboratory in Hanoi and analysed by a specialised device (UV-Vis). The fluid samples were carefully prepared, filtered to remove solid materials, and stored in a test tube. Then, the samples were analysed in series, each including 12 fluid samples.

Once again, the analyses confirmed the positive effect of injector 1609 to 6 wells. According to the results, the chemical appeared first in well 25 (1 March 2022), and then in wells 1604 (29 March 2022), 1607 (15 March 2022),

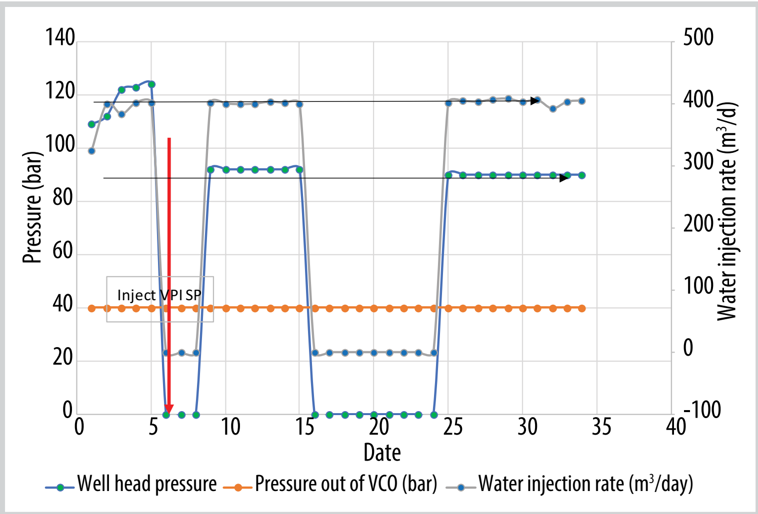


Figure 8. *Parameters of injection well 1609 after injecting VPI SP chemicals.*

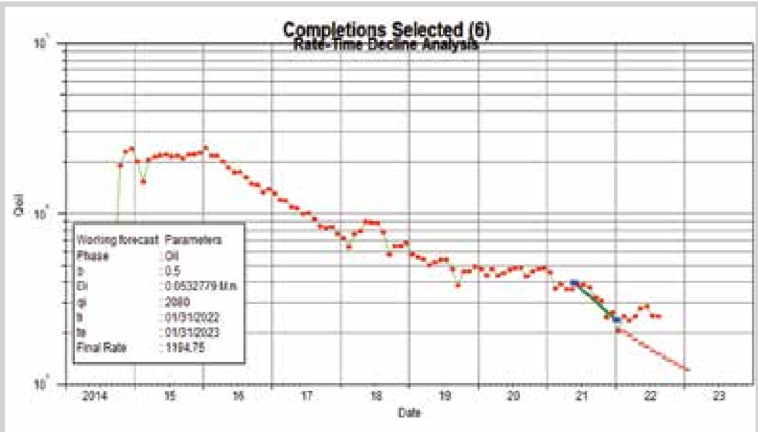


Figure 9. *Forecasting results of the DCA method.*

1602 (26 April 2022), 26 (17 May 2022) and 1606 (24 May 2022). The concentration of the chemical VPI SP at initial condition was observed to be high in wells 25 and 1067, it became less in well 1604 and very little in wells 1602, 26 and 1606. Parameters and chemical analysis confirm the positive effect of VPI SP to all producers.

6.2. Pilot interpretation

In order to evaluate the efficiency of injection to enhance oil recovery, it is necessary to predict the baseline oil rate assuming that all wells and the reservoir are maintained as before VPI SP injection. Based on suggestions from papers and experts [1, 2, 6], multiple methods are used to reduce the uncertainty during making a baseline oil rate. Tools used to predict baseline oil rate are OFM, VPI-KT-1 and simulation dynamic model.

6.2.1. EOR evaluation by decline curve analysis (DCA)

The DCA method is widely used in production forecast. This method has high reliability in some cases: Water cut is higher than 50%; number of wells, injection and production rate fluid, and the remaining reservoir energy are stable. The OFM software is applied in production forecasts given that the performance of the well is the same as before VPI SP is injected. Several adoptions are made to extrapolate the oil rate over time and results (Figure 9):

- Slope of prediction: recent history trendline

- Initial oil rate: oil rate in January 2022

- Declining factor "b": b = 0.5

- Prediction period: February - December 2022

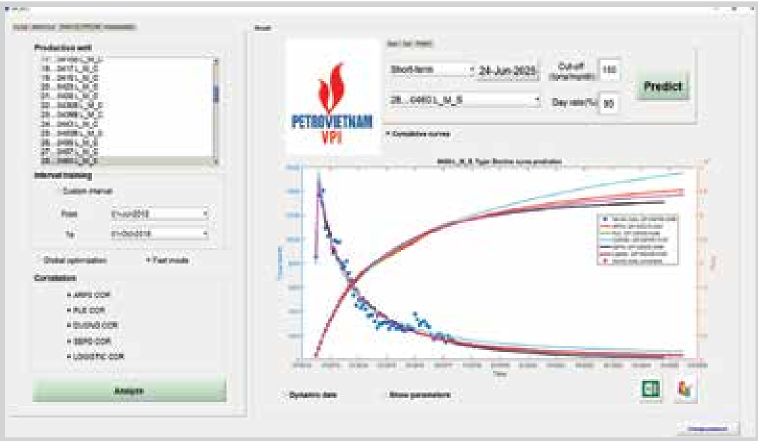
6.2.2. EOR evaluation by advanced DCA using VPI-KT-01

Based on the same assumption, the VPI-KT-01 is used to evaluate the efficiency of the chemical. VPI-KT-01 is a production forecasting software in advanced DCA techniques with 5 declining main functions: power law exponential (PLE) decline, logistic growth model (LGM), stretched exponential production (SEP) decline, Duong, and ARP. It was developed by VPI in 2020, containing the interior-point algorithm to automate the process of history matching and forecasting [7]. The LGM (logistic function) is most used for history matching of the baseline oil rate and the SEP function has the most optimal correlation coefficient (R^2 > 0.8). Results of production forecast are shown in Figure 10.

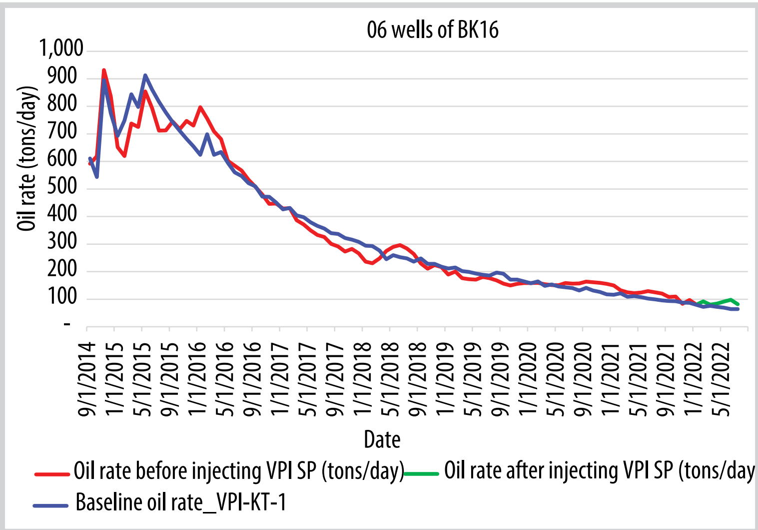
6.2.3. EOR efficiency evaluation by simulation models

It is essential that details of the reservoir simulation model of the pilot are built in advance to optimise the pilot design, monitor the program and evaluate the EOR efficiency. Based on the UV-vis results, the geological and dynamic model is adjusted accordingly. The key points of geological formation that affect the results are identified. The model is optimised gridding to remove numerical dispersion before building and history matching.

Model of BK14/16 is history matching with data available until 23 January 2022.



(a)



(b)

Figure 10. *The interface of VPI-KT-1 software (a) and the forecasting results (b).*

Results show that the discrepancy between the model and history is acceptable (Figure 11) and adequate for production forecast.

From April 2022, Vietsovpetro reduced the injection rates of wells 1605 (250 m^3/day) and 1609 (400 m^3/day) to 200 m^3/day and 250 m^3/day, respectively. Work cycle changed from 10 days on/10 days off to 15 days on/15 days off. According to the actual production performance in the period from February - July 2022, the lack of gas in the gaslift system and the increase of reservoir energy resulted in the gaslift active valve pushing up, causing most of the wells operating under capacity. After the operator conducted efficiency assessments, such as separating the gas pipeline in gaslift system and optimising the working regime, the wells started to operate stably again from the end of June 2022. Therefore, it is essential to evaluate separately the efficiency of each activity in the field. For that purpose, 4 options were proposed to assess the efficiency of water injection and gaslift optimisation:

- Option 1: Assuming the same condition as before 23 January 2022.

- Option 2: Simulating the water injection with decreasing rate and optimising the water injection process in the period from January - July 2022.

- Option 3: Simulating the gaslift optimisation and Option 2 in the period from January - July 2022.

- Option 4: Option 3 + Justification of chemical properties to match oil rate of observed wells from February - July 2022.

6.2.4. Efficiency evaluation of the EOR using VPI SP

Using several techniques to clarify the performance of each activity showed the consistency between the DCA method and Option 1 of the dynamic model. The reliable results prove that if the wells continue producing as before 23 January 2022, the produced oil is lower than actual 3067.2 tons in the period of February - July 2022. In addition, the efficiency of optimised water injection and gaslift in the period of February - July 2022 is evaluated subject to the actual data and the production forecast of the Options 2 and 3. Results show that oil production increased by 250 tons and 117 tons thanks to the optimised water injection and effort of gaslift regulation, respectively. Consequently, the oil gained from VPI SP application is 2700.2 tons (Table 1, Figure 12).

Due to optimisation activities simultaneously conducted by the operator, the dynamic model is a useful tool to simulate and evaluate separately the efficiency of each solution. Simulation results show high reliability and confidence. The incremental oil production in the period February - July 2022 is 2700.2 tons thanks to VPI SP, excluding the incremental production from gaslift regulation and water injection optimisation.

7. Conclusions

All 100 tons of VPI SP chemical is successfully injected to injector 1609/BK16 in the Lower Miocene, south dome of Bach Ho field. After injection, the results of production

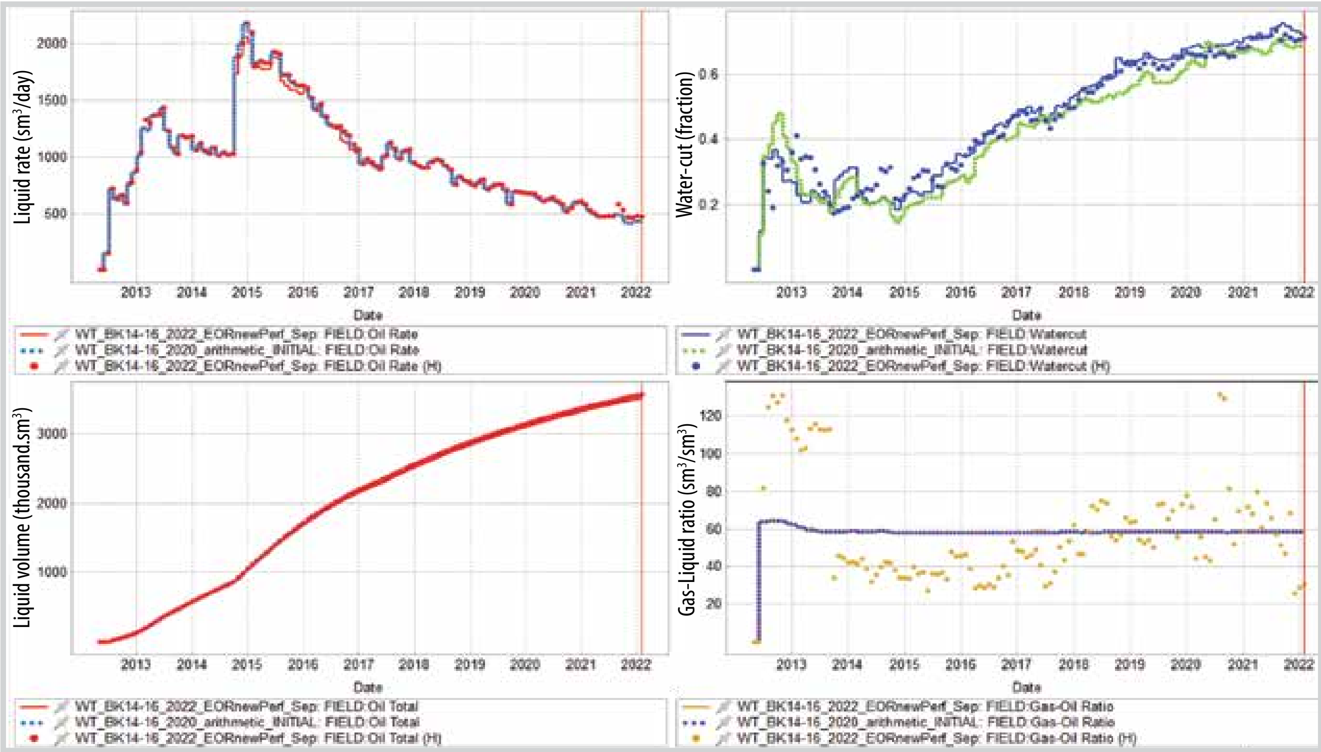


Figure 11. *Results of history matching BK16.*

Table 1. *Efficiency of incremental oil production of VPI SP*

Date	Producer	Injector	DCA		Option 3 of dynamic model (Water injection & Optimisation gaslift)			Actual data			Oil incremental (tons)
			OFM	VPI-KT-01	Oil rate (tons/day)	Oil produced per month (tons/month)	WC (%)	Oil rate (tons/day)	Oil produced per month (tons/month)	WC (%)	
January 2022	6	1			79.92	2,080.00	79.0	79.9	2,080	79.0	-
February 2022	6	1	77.09	72.05	75.52	2,114.68	82.9	91.86	2,494	80.3	379.3
March 2022	6	1	73.11	74.75	73.52	2,279.03	83.4	79.09	2,372	80.8	93.0
April 2022	6	1	69.56	71.05	75.85	2,275.56	83.0	84.09	2,512	80.8	236.4
May 2022	6	1	68.21	68.41	67.55	2,090.19	85.0	90.79	2,793	81.0	702.8
June 2022	6	1	64.9	64.94	67.71	2,020.43	84.9	98.08	2,870	82.3	849.6
July 2022	6	1	62.37	61.94	67.16	2,081.84	85.1	82.01	2,521	82.7	439.2
Sum											**2700.2**

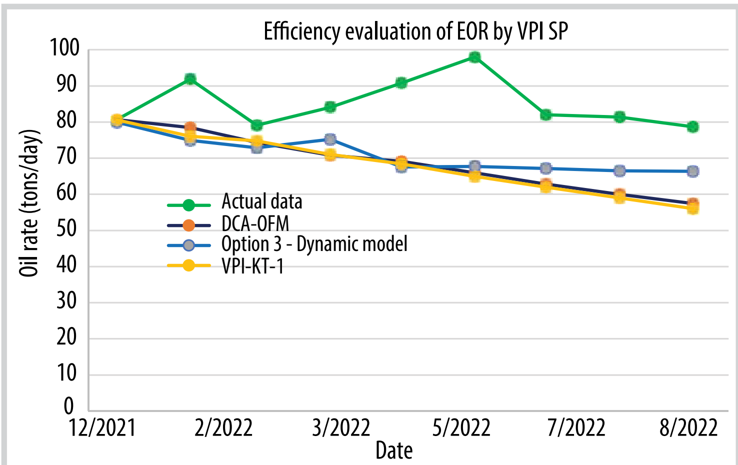


Figure 12. *Results of EOR efficiency evaluation of VPI SP.*

monitoring, sampling, and analysis of the produced fluids showed that the chemicals appeared first at well 25, and then at wells 1604, 1607, 1602, 26, 1606. Chemical concentration was observed to be high in fluids from 25 and 1067, less in fluid from 1604 and very little in those from 1602, 26 and 1606.

Analysis of injector performance parameters proved that VPI SP chemical did not cause any negative effect or damage near the wellbore of the injection well. The evaluation of VPI SP efficiency by various tools proved an incremental oil gain of 2,700.2 tons after 6 months, and the performance of the surrounding producers continue showing positive effect.

The procedure of the pilot plan is proposed as a scaled-down of the full field EOR application. It can be used as a guide when considering similar applications in nearby fields.

Acknowledgement

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