Hanoi University of Mining and Geology

Integrated Petroleum Engineering

IPE3

Hanoi, Octorber 6, 2022

ISNB: 978-604-76-2595-6

TRANSPORT PUBLISHING HOUSE

IPE3 2022

IPE3 2022

ISBN: 978-604-76-2595-6

NOT FOR SALE

Integrated Petroleum Engineering (IPE3)

Hanoi, Octorber 6, 2022

TRANSPORT PUBLISHING HOUSE

Editorial Board

TABLE OF CONTENTS

Available online at www.tapchi.humg.edu.vn

IPE 2022

IPE (2022) 071-082

International Conference on Integrated Petroleum Engineering (IPE-2022)

Oil and Gas Well Stimulation by Hydraulic Fracturing in the Oligocene of Bach Ho Field. Case study: Hydraulic fracturing for well X–MSP10

Van Tu Truong[a*], The Vinh Nguyen[a], Van Thinh Nguyen[a], Tien Hung Nguyen[a], Khac Long Nguyen[a], Tai Nguyen Trong[b]

[a]*Faculty of Oil and Gas, Hanoi University of Mining and Geology, Vietnam, truongvantu@humg.edu.vn*

[b]*Zarubezhneft E&P Vietnam*

Abstract

The Bach Ho field is located in the central updip area of the Cuu Long Basin, oil and gas have been producing from three main reservoirs which are lower Miocene sandstone, Oligocene sandstone and pre-Tertiary fractured basement. Currently the field is undergoing sharp depletion, with many wells now shut in due to water flooding. In order to maintain and prolong the oil production rate it is necessary to improve the near wellbore productivity of producing wells. Industry experience has demonstrated there are several methods to improve field production such as secondary or tertiary recovery, well stimulation or drilling infill wells in potential reservoirs. Amongst the three reservoirs, the Oligocene sandstone has a low porosity and permeability with limited fractures. Analysis results indicated that a large volume of oil trapped in reservoir has not been produced due to reservoir properties. It is proposed that the Oligocene is an excellent candidate for enhanced productivity using hydraulic fracturing and applied technology. This presentation will present the study on Hydraulic Fracturing and applied technology to improve the oil recoveries for the Oligocene. The methodology has been applied to the X-MSP 10 well in the Oligocene sandstone, Bach Ho field with a good result. Based on this success, the methodology can be applied to other wells with the same geological characteristics, not only in the Bach Ho field but also in other fields in the Cuu Long Basin or potentially other sedimentary basins offshore Vietnam.

Keywords: Bach Ho field; Oligocene; Hydraulic fracturing; well stimulation.

1. Introduction

Bach Ho is a major oil field in Block 09-1, Cuu Long Basin, Vietnam, operated by Vietso Petro (VSP). It is located about 120km from the South East of Vung Tau City. The field is producing from 3 formations consisting of the Lower Miocene sandstones, Oligocene sandstones and major reserves at fractured granitic basement. Currently, the field is reaching the end of field life with the percentage contributions from each of the producing zones as follows: about 34% from Miocene, 16% from Oligocene and 50% from basement. Over field life, the reservoir energy depleted and the water cut increased dramatically to around (49.3%) (Tran Van Vinh et al., 2016). In order to maintain the production rate and prolong the field production duration, VSP has applied many technical solutions and one of which is well stimulation to improve permeability, the well productivity index

[*]Corresponding author.
E-mail address: truongvantu@humg.edu.vn.

and oil recovery factor. There are two main techniques which can be applied for well stimulation. The first technique is the use of acidizing to clean the damage zone cause by invaded fluid and fines migration. The second method applies hydraulic fracturing (HF) which involves pumping fracturing fluid into reservoirs for increasing the permeability & porosity of the reservoirs. The first technique mainly uses chemicals such as acid, emulsion acid with difference formula, and this technique applies for high porosity and permeability formations. The second technique mainly applies for tight formations. This paper will focus on introducing the application of hydraulic fracturing in the Bach Ho field and presenting the result from a case study at well X-MSP 10 .

2. Oligocene formation

Among the three formations of the Bach Ho field, Oligocene formation includes reservoirs of the Tra Tan formation (Oligocene C, D, E) and Tra Cu (Oligocene F). The above Oligocene reservoirs consist mainly of medium-coarse to granular sandstone with small amounts of siltstone and a thin layer of limestone (Nguyen Huu Truong et al., 2015). The thickness of the Oligocene sandstone is relatively large and it has good indications of the presence of oil & gas. However, it is a tight formation with low permeability, low conductivity and connection between fractures, all leading to low production rates from this formation. As mentioned, up to now only 16% of the total production was produced from the Oligocene formation.

The reservoirs of lower Oligocene formation including sandstone, claystone, siltstone and bottom-lined sedimentary with the thickness from a few meters to several tens of meters, permeability 0.1 ÷ 20 mD, porosity about approx. 12 ÷ 16% (Table 1). The clay composition mainly contains Mica and chlorite; kaolinite and mixed montmorilonite-mica formations are of secondary composition. The rocks are quite strong, do not swell but are very brittle and less stable (Table 2).

Table 1: Formation Transmissibility Properties (Schlumberger, 2017).

Zone Name	**Top TVD** (m)	**Net Height** (m)	**Perm** (mD)	**Porosity** (%)	**Res. Pressure** (kPa)	**Gas Sat.** (%)	**Oil Sat.** (%)	**Water Sat.** (%)
SHALE	3591.9	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3599.7	3.9	1.000	10.0	10501	65.0	10.0	25.0
SHALE	3603.7	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3617.7	5.0	1.000	10.0	10501	65.0	10.0	25.0
SHALE	3622.7	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3631.7	8.5	1.000	10.0	10501	65.0	10.0	25.0
SHALE	3640.2	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3645.0	3.4	1.000	10.0	10501	65.0	10.0	25.0
SHALE	3648.4	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3661.7	7.0	21.200	10.0	10501	65.0	10.0	25.0
SHALE	3668.7	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3702.5	7.2	2.800	10.0	10501	65.0	10.0	25.0
SHALE	3709.7	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3717.6	11.1	2.700	10.0	10501	65.0	10.0	25.0
SHALE	3728.7	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3741.6	7.0	1.900	10.0	10501	65.0	10.0	25.0
SHALE	3748.6	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3756.6	7.0	4.000	10.0	10501	65.0	10.0	25.0
SHALE	3763.7	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3774.6	12.0	3.400	10.0	10501	65.0	10.0	25.0
SHALE	3786.6	0.0	0.001	1.0	10501	65.0	10.0	25.0

DIRTY-SANDSTONE	3793.6	14.9	0.600	10.0	10501	65.0	10.0	25.0
SHALE	3808.6	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3814.1	3.1	1.000	10.0	10501	65.0	10.0	25.0
SHALE	3817.1	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3823.6	8.0	1.300	10.0	10501	65.0	10.0	25.0
SHALE	3831.6	0.0	0.001	1.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3838.6	5.1	6.000	10.0	10501	65.0	10.0	25.0
SHALE	3843.7	4.9	1.000	10.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3848.6	12.0	10.000	10.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3860.6	9.0	1.000	10.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3869.6	8.0	11.000	10.0	10501	65.0	10.0	25.0
DIRTY-SANDSTONE	3877.6	12.5	1.000	10.0	10501	65.0	10.0	25.0
CLEAN-SANDSTONE	3890.2	15.2	0.001	10.0	10501	65.0	10.0	25.0

Table 2: Formation Mechanical Properties (Schlumberger, 2017)

Zone Name	**Top TVD** (m)	**Zone Height** (m)	**Frac Grad.** (kPa/m)	**Insitu Stress** (kPa)	**Young's Modulus** (kPa)	**Poisson's Ratio**	**Toughness** (kPa.m0.5)
SHALE	3591.9	7.8	10.072	36218	2.689E+7	0.35	879
DIRTY-SANDSTONE	3599.7	3.9	9.627	34674	2.689E+7	0.25	769
SHALE	3603.7	14.0	10.226	36921	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3617.7	5.0	9.768	35363	2.689E+7	0.25	769
SHALE	3622.7	9.0	10.396	37707	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3631.7	8.5	10.028	36459	2.689E+7	0.25	769
SHALE	3640.2	4.8	10.337	37652	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3645.0	3.4	9.890	36066	2.689E+7	0.25	769
SHALE	3648.4	13.2	10.320	37721	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3661.7	7.0	9.282	34019	2.689E+7	0.25	769
SHALE	3668.7	33.9	10.169	37480	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3702.5	7.2	9.475	35115	2.689E+7	0.25	769
SHALE	3709.7	7.9	10.488	38948	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3717.6	11.1	9.367	34874	2.689E+7	0.25	769
SHALE	3728.7	13.0	10.378	38762	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3741.6	7.0	9.354	35032	2.689E+7	0.25	769
SHALE	3748.6	8.0	10.383	38962	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3756.6	7.0	9.289	34929	2.689E+7	0.25	769
SHALE	3763.7	11.0	10.507	39603	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3774.6	12.0	9.336	35294	2.689E+7	0.25	769
SHALE	3786.6	7.0	10.085	38225	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3793.6	14.9	9.652	36687	2.689E+7	0.25	769
SHALE	3808.6	5.5	10.407	39666	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3814.1	3.1	9.778	37308	2.689E+7	0.25	769
SHALE	3817.1	6.5	10.623	40583	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3823.6	8.0	9.623	36832	2.689E+7	0.25	769
SHALE	3831.6	7.0	10.517	40334	2.689E+7	0.35	1099
DIRTY-SANDSTONE	3838.6	5.1	9.269	35605	2.689E+7	0.25	769
SHALE	3843.7	4.9	9.460	36384	2.689E+7	0.25	769
DIRTY-SANDSTONE	3848.6	12.0	9.035	34825	2.689E+7	0.25	769
DIRTY-SANDSTONE	3860.6	9.0	9.092	35143	2.689E+7	0.25	769
DIRTY-SANDSTONE	3869.6	8.0	9.124	35343	2.689E+7	0.25	769
DIRTY-SANDSTONE	3877.6	12.5	9.178	35646	2.689E+7	0.25	769
CLEAN-SANDSTONE	3890.2	15.2	9.400	36639	2.689E+7	0.20	1319

From the above analysis, it is possible to apply the HF for oil wells in Oligocene formation of Bach Ho field in order to increase the production rate and recovery factor of the field.

3. Hydraulic fracturing (HF) models

Hydraulic fracturing (HF) is a technique that is applied to stimulate oil and gas production wells to increase the permeability near the well bore and increase oil recovery (Blundell, 2005). This process involves injecting fluid at high pressure to create and expand the fracture in reservoirs, then inject a mixture of liquid and proppant into the reservoir to maintain the fracture therefore maintain reservoir permeability and to ensure a good productivity after the completion of the HF job. HF creates fractures through the damaged zone around a wellbore. This applies to the case for a reservoir with fine particles (clay, loose sand, etc.) which are carried with the fluid into the near well bore zone and cause a damaged zone surrounding the well. The new fractures will provide a good permeability zone that change the flow of fine particles; the reservoir with alternating sand-shale layer, connection is limited between the reservoir and perforated well. In this case, HF will create a vertical connection between the reservoirs and layers. The weak formation can be broken during production. The fractures which created the high drainage flow will create low pressure difference, reducing stress on the reservoir.

The fractures created from HF process is able to be developed in a three dimension model. However, simple HF models can only determine two dimensions, length and width, at the same time. The value of height parameter is usually assigned with assumptions based on the experience of the engineer. In fact, the simple HF model accepts the fractures that are created in either vertical or horizontal direction and distributed symmetrically around the wellbore. Horizontal fractures are mainly created during HF for a well whose the depth is less than 600m. On the other side, vertical fractures are only considered for the a well whose depth is more than 600m (Tu Thanh Nghia et al., 2017).

Currently, there are two two-dimensional simulation models to predict the development of the shape of factures have been widely applied: PKN model (proposed by Perkin, Kern and Nordgren) and KGD model (proposed by Kristianovich and Zeltov, Geertsma and Deklerk) (Tu Thanh Nghia et al., 2017; Michael et al., 2007; Jennifer and Miskimins, 2019). The main differences between these two models are detail as below:

In PKN model, the cross-section of the fractures in the vertical cross-section which is perpendicular to the longitudinal axis of the fractures mainly keeps the ellipse shape with unchanged height, but the deep fractures edge in the reservoir bends inside. (Figure 1).

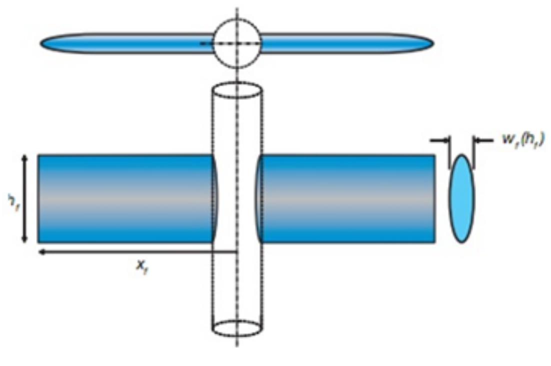

Fig. 1. PKN Model (Michael et al., 2007).

In the KGD model, the horizontal section is elliptical, and the vertical section is rectangular (Figure 2).

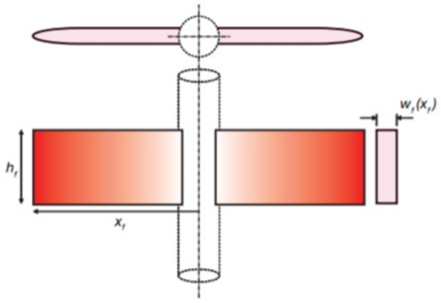

Fig. 2: KGD Model (Michael et al., 2007).

When studying on the PKN model, the width of the crack is represented by its height:

$$W(0,t) = \frac{P.h_f}{E} \quad (1)$$

In which: P- pressure in the fracture; E- elasticity modulus; h_f - fracture height.

For the KGD model, the fracture width is represented by its length:

$$W(0,t) = \frac{P.x_f}{E} \quad (2)$$

Using the Newton fluid flow equation in the fracture, we have:

- With PKN model:

$$P = \frac{(E^3.\mu.q_i X_f)^{1/4}}{h_f} \quad (3)$$

- With KGD Model:

$$P = \frac{(E^3.\mu.q_i X_f)^{1/4}}{h_f^{1/4} x_f^{1/2}} \quad (4)$$

In which: µ-viscosity of the liquid; q_i-intensity of injection.

Thus, according to the PKN model, the fracture pressure increases proportionally to ¼ exponentiation, while in the KGD model, the fracture pressure proportional to ½ exponentiation. The fracture width calculated by the PKN model is usually smaller than the width calculated by the KGD model. Therefore, the biggest difference of the PKN model is that it can create fractures with a larger length compared to the KGD model when using same fracturing fluid volume and pressure, and other input parameters remain the same at the two models.

Planar 3D models were developed mostly in the 1980s, with the appearance of significantly increased computing power, and these simulations were increasingly used to determine how fractures grew in length, width, and height over time for a created fracture that propagates in a vertical plane. 3D models can be broadly divided into three categories: pseudo-3D models (P3D), parameterized or lumped 3D models, and fully meshed 3D models (Jennifer and Miskimins, 2019).

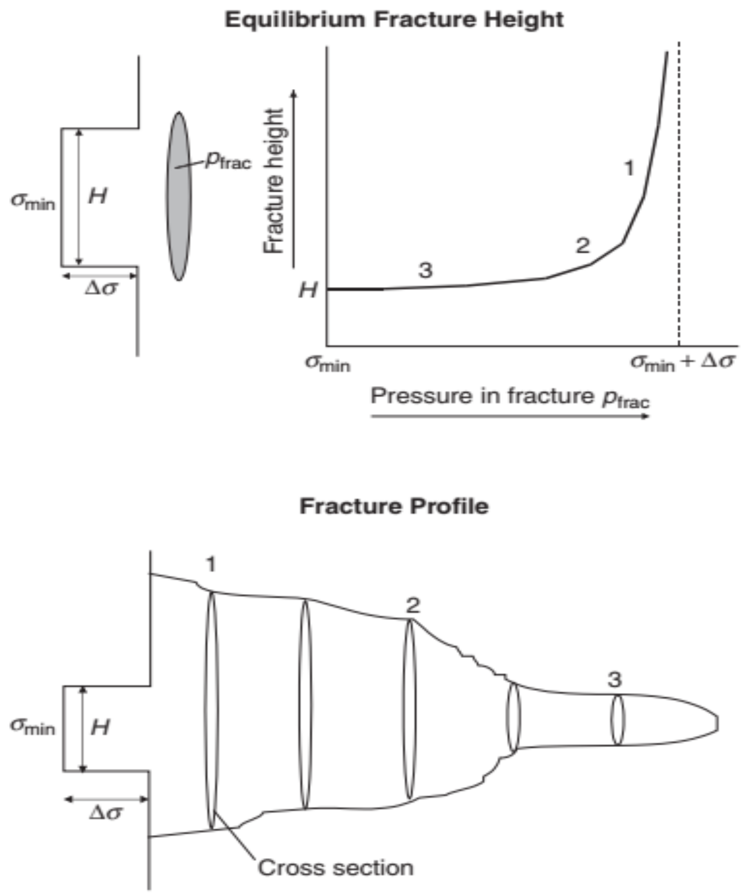

Fig. 3 : Equilibrium fracture height calculation in pseudo- 3D models

While the constant-height assumption made it possible to establish relatively simple equations for growth in fracture length and width as a function of pumped volume, it also provides a major constraint for the applicability of these models. In some situations, for example in thick rock strata with little closure stress contrast, the fixed height assumption is unrealistic (Jennifer and Miskimins, 2019).

$$w = C.Pnet = \frac{\gamma.R_f}{E}Pnet \quad (5)$$

In which: w: fracture width; P_{net}- pressure in the fracture; γ: average shear rate, t-1, s-1, E- elasticity modulus; R_f - fracture height.

4. Case study of hydraulic fracturing for well X – MSP10 of Bach Ho field

4.1. Calculation of hydraulic fracturing for well X –MSP10 of Bach Ho field

The well X is at MSP10 platform, located in the Northern area of Bach Ho field. The major production target of the well is lower Oligocene with the main composition of clay, muddy sandstone from the depth of 3875m to 4184m as per the wellpath (Vietnam - Russia joint venture Vietsovpetro, 2013).

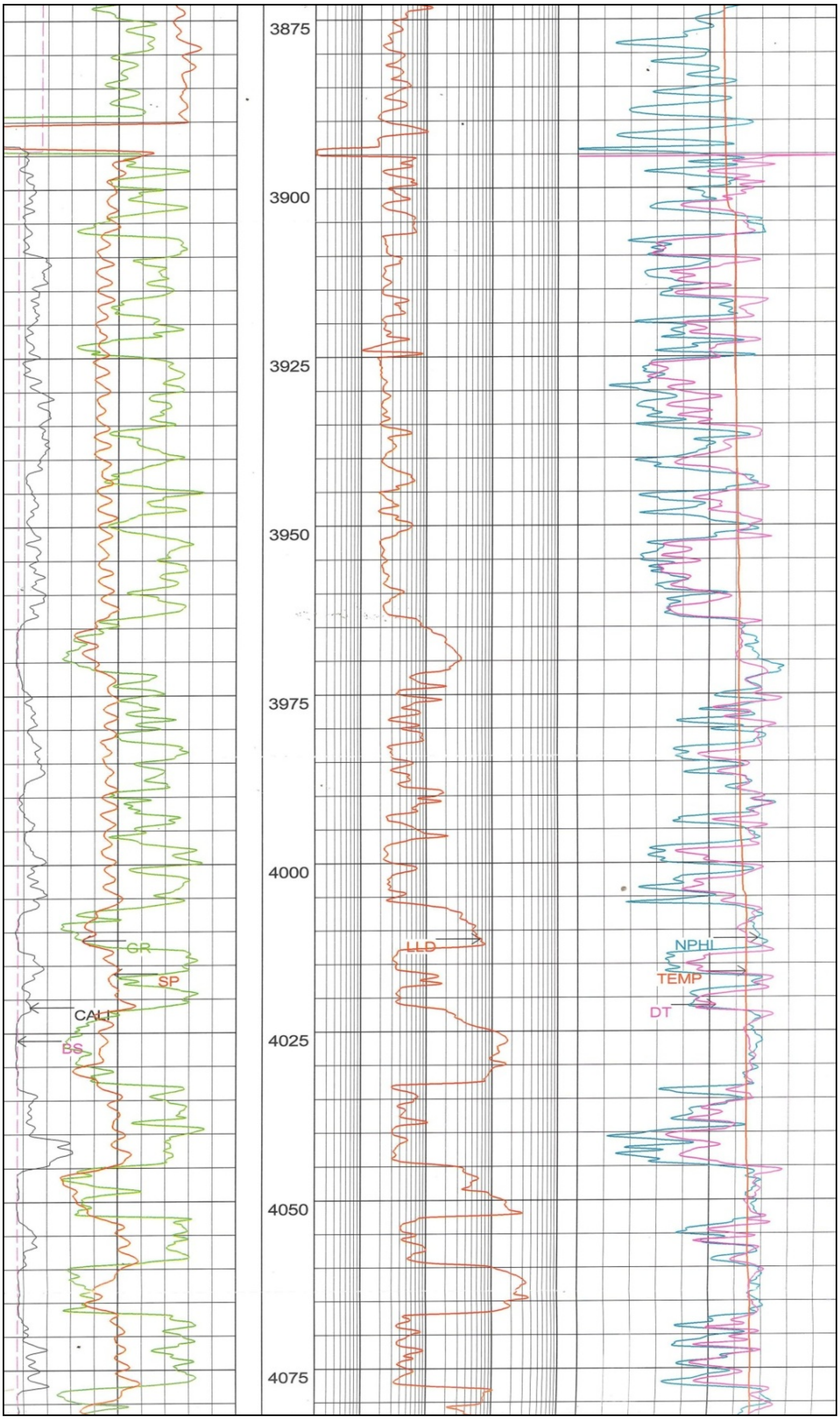

Figure 4. Well Log results at HF (3875m-4075m) (Vietnam - Russia joint venture Vietsovpetro, 2013).

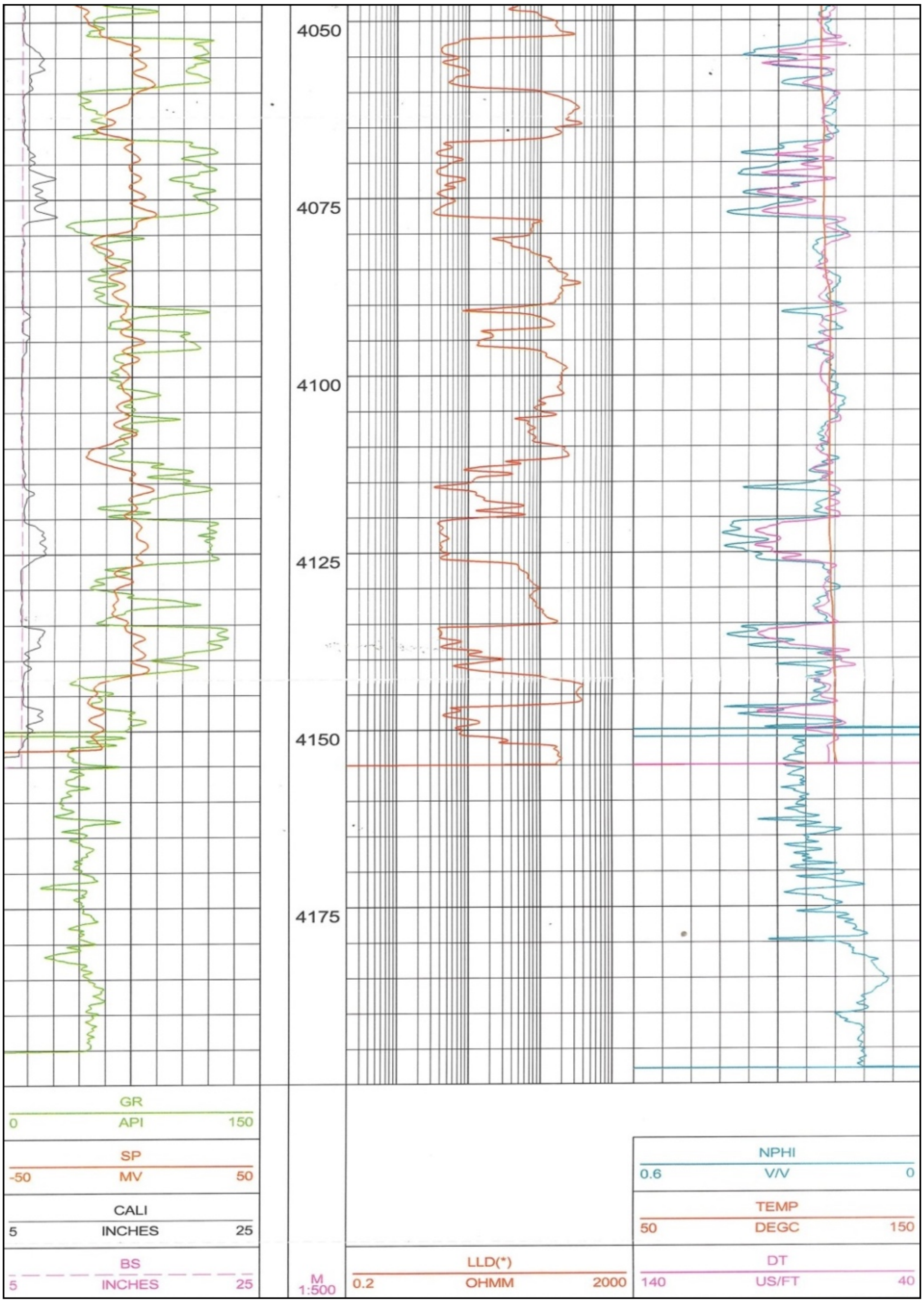

Figure 5. Well Log results at HF (4050m-4195m) (Vietnam - Russia joint venture Vietsovpetro, 2013).

Upon the results of well log results in Figures 4 and 5, we can see that the oil is potentially distributed at the depth from 3965m- 4164m. However, variations of Gamma Ray log show that this interval is not a clean sands interval and also from the deflection of Spontaneous Potential (SP) log, the permeability of this interval might be low .Therefore, HF method is potentially a suitable solution to improve oil recovery in this lower Oligocene reservoir.

4.2. Selecting a HF calculation model

4.2.1. Selecting a HF calculation model

As above discussion, using the P3D model, the dimensional reduction technique makes the P3D model computationally efficient and feasible for fracture design and post-fracture analysis. Because the simulation can be run faster than real-time operations, P3D models can be used for field treatment optimization. The beneficial running speed enables actual field-measured quantities, such as the injection rate, fluid viscosity, and wellhead pressure, to be fed to the model to achieve an increased accuracy of the final crack geometry, and the treatment schedule can be modified accordingly.

4.2.2. Result and Discussion

The HF model for the X-MSP10 well, using a Pseudo-3D vertical model, the conductivity of the fracture is calculated based on the well perforation range and reservoir thickness. Figure 6 shows the propant in the fracture to the single-side hydraulic fracturing length.

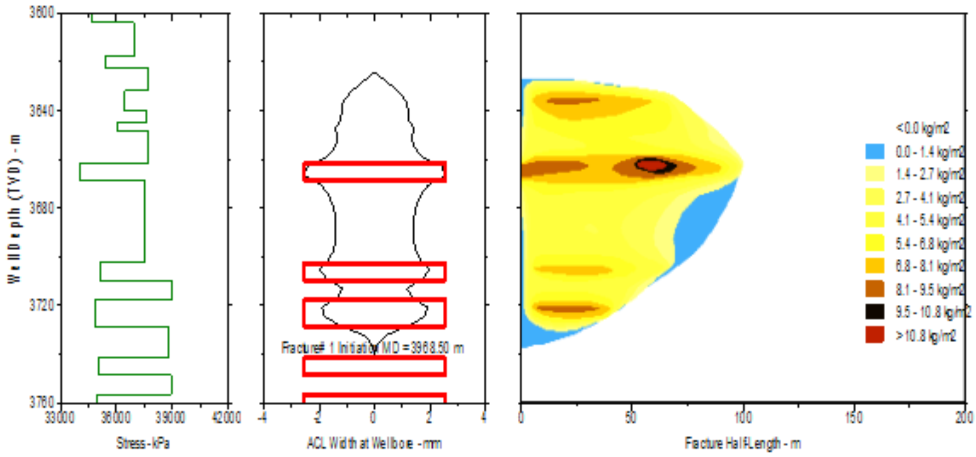

Figure 6. Diagram of the content of propant filled in fracture (Schlumberger, 2017).

The model results show that during the HF processing, the surface pressure remains constantly at 39000 kPa, while the well bottom pressure decreases continuously during the pumping time (Figure 7). The reason is that the propant mixed with hydraulic fluid enter into the fractures at the period of 127p, the pressure of the well bottom gradually decreases to 0. This is the time the material has been completely penetrated into the reservoir while the surface pressure also decreased but not significantly (Figure 7).

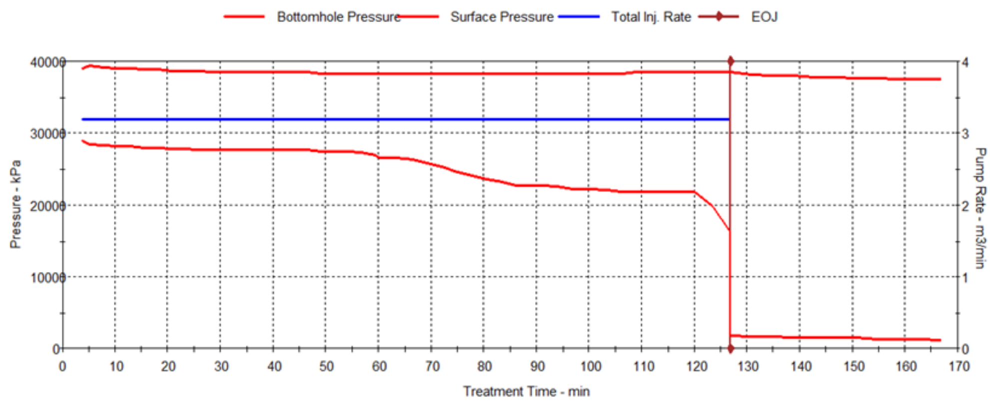

Figure 7. HF Processing flow chart for well X-MSP10 (Schlumberger, 2017).

The results from the HF model for the well X-MSP10 are detailed in Table 4.

Table 4. Results from HF model for well targets of X-MSP10 (Schlumberger, 2017).

Zone Name	**Top MD** (m)	**Top TVD** (m)	**Gross Height** (m)	**Net Height**	**Fracture Width** (mm)	**Fracture Length** (m)	**Fracture Conductivity** (md.m)
SHALE	3895.3	3591.9	7.8	.0	0.000	.0	0
DIRTY-SANDSTONE	3903.1	3599.7	3.9	3.9	0.000	.0	0
SHALE	3907.0	3603.7	14.0	.0	0.000	.0	0

Zone Name	Top MD (m)	Top TVD (m)	Gross Height (m)	Net Height	Fracture Width (mm)	Fracture Length (m)	Fracture Conductivity (md.m)
DIRTY-SANDSTONE	3921.0	3617.7	5.0	5.0	0.000	.0	0
SHALE	3926.0	3622.7	9.0	.0	0.0583	59.7	152
DIRTY-SANDSTONE	3935.0	3631.7	8.5	8.5	1.195	80.7	312
SHALE	3943.5	3640.2	4.8	.0	1.634	87.8	427
DIRTY-SANDSTONE	3948.3	3645.0	3.4	3.4	1.814	92.0	481
SHALE	3951.8	3648.4	13.2	.0	2.418	102.2	632
DIRTY-SANDSTONE	3965.0	3661.7	7.0	7.0	3.903	105.4	1027
SHALE	3972.0	3668.7	33.9	.0	2.208	99.8	577
DIRTY-SANDSTONE	4005.9	3702.5	7.2	7.2	2.058	81.1	538
SHALE	4013.1	3709.7	7.9	.0	1.427	68.4	373
DIRTY-SANDSTONE	4021.0	3717.6	11.1	11.1	1.221	55.2	319
SHALE	4032.0	3728.7	13.0	.0	0.411	40.6	107
DIRTY-SANDSTONE	4045.0	3741.6	7.0	7.0	0.000	.0	0
SHALE	4052.0	3748.6	8.0	.0	0.000	.0	0
DIRTY-SANDSTONE	4060.0	3756.6	7.0	7.0	0.000	.0	0
SHALE	4067.0	3763.7	11.0	.0	0.000	.0	0
DIRTY-SANDSTONE	4078.0	3774.6	12.0	12.0	0.000	.0	0
SHALE	4090.0	3786.6	7.0	.0	0.000	.0	0
DIRTY-SANDSTONE	4097.0	3793.6	14.9	14.9	0.000	.0	0
SHALE	4111.9	3808.6	5.5	.0	0.000	.0	0
DIRTY-SANDSTONE	4117.4	3814.1	3.1	3.1	0.000	.0	0
SHALE	4120.5	3817.1	6.5	.0	0.000	.0	0
DIRTY-SANDSTONE	4127.0	3823.6	8.0	8.0	0.000	.0	0
SHALE	4135.0	3831.6	7.0	.0	0.699	56.7	355
DIRTY-SANDSTONE	4142.0	3838.6	5.1	5.1	2.175	77.0	1201
SHALE	4147.1	3843.7	4.9	4.9	3.944	84.7	2151
DIRTY-SANDSTONE	4152.0	3848.6	12.0	12.0	5.676	86.4	3055
DIRTY-SANDSTONE	4164.0	3860.6	9.0	9.0	5.957	85.8	3267
DIRTY-SANDSTONE	4173.0	3869.6	8.0	8.0	5.426	82.3	2965
DIRTY-SANDSTONE	4181.0	3877.6	12.5	12.5	3.852	77.8	1848
CLEAN-SANDSTONE	4193.5	3890.2	15.2	15.2	1.372	57.7	437

5. Production Forecast and Actual Production

PIPESIM software was used to predict the production rate after applying the HF. The input parameters are: fracture length which filled with propant, fracture height, reservoir permeability, reservoir thickness, fracture permeability, drainage radius. Calculation results from PIPESIM software are shown in Figures 8 and 9.

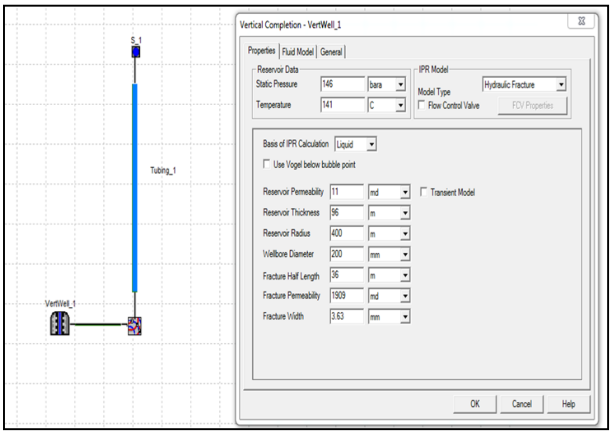

Fig. 8. The results of model forecast after applying HF

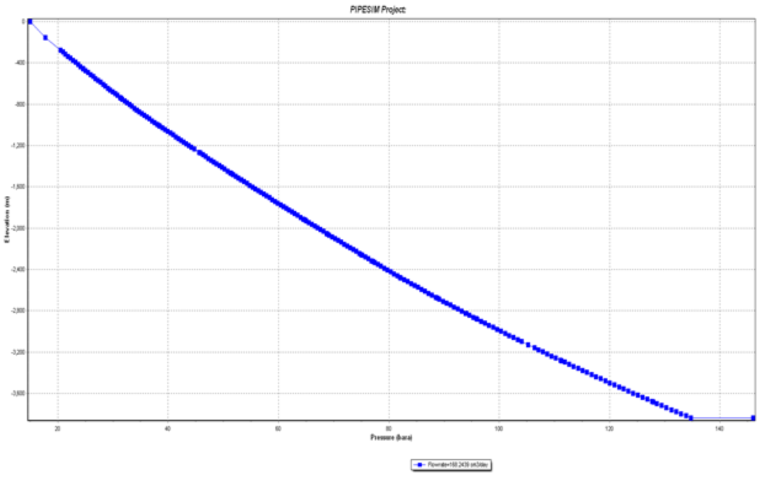

Fig. 9. Pressure along the wellbore from bottom to surface.

Figure 10 shows that when the flowing starts, due to the pressure difference in the well at 136 bar, the flow rate is at 166,2439 (m3/day). This result is quite match with the actual maximum flow rate on October 1, 2017 as of 146.19 (ton/day).

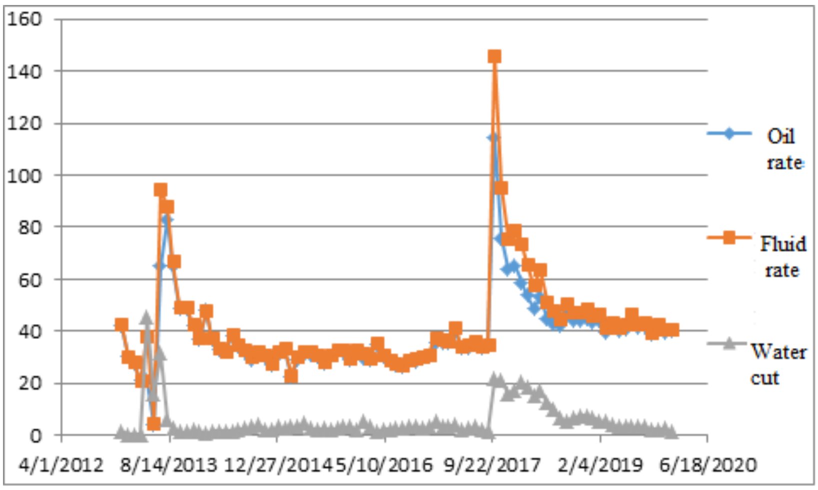

Fig. 10. Production rate increase significantly from 36 (ton/day) to 149,6 ton/day

6. Conclusion

The Oligocene reservoirs of the Bach Ho field are tight with low porosity and low permeability, thus the oil production rate from these formations is low. Up to now, there is still a significant amount of oil remaining in this formation. Thus the Oligocene formation is a target for production and oil recovery factor improvement in the Bach Ho field. Hydraulic fracturing is one of the most effective solution to enhance oil recovery from the Oligocene formation. Among diferrent hydraulic fracturing models, Pseudo-3D model has shown its potential uses and its efficiency in the calculation and prediction of the length and distribution of fractures created by HF process. Results from a case study of the application of HF to the well X-MSP10 have demonstrated conclusively that the oil production of the well has been increased significantly. The success of applying the HF method to the X-MSP10 well can be used as a reference to apply to wells having similar target/formations in Bach Ho field.

References

Blundell, D., 2005. Processes of tectonism, magmatism and mineralization: Lessons from Europe. Ore Geology Reviews. 27.

Jennifer, M., 2019. Hydraulic Fracturing: Fundamentals and Advancements. Society of Petroleum Engineers, pp.798.

Michael, J., Tony, M., BJ Services Company., 2007. Modern Fracturing Enhancing Natural Gas Production_CD for computer. Houston, TX: ET Publishing.

Nguyen Huu Truong., Wisup, B., Hoang Thinh Nhan., Phan Cong Boi., 2015. Optimisation of hydraulic fracturing design to improve oil production from Oligocene reservoirs by maximising net present value. Petrovietnam Journal , volume 12, p.28-37.

Pham Duc Thang., Nguyen Van Minh., Tran Dinh Kien., Cao Ngoc Lam., Nguyen The Vinh., Nguyen Manh Hung., Hoang Linh Lan., 2013. A study on model and production forecast for Miocene formation, Bach Ho field. Journal of Mining Science and Technology - Geology, No. 43, p.14-21

Schlumberger, 2017. Fraccade Stimulation Proposal, X-MSP10 well.

Tran Van Hoi., Cao My Loi., Nguyen Van Kim., Le Viet Hai., 2008. Technological solutions for well processing to improve the oil recovery factor in the final production stage of Bach Ho field. Collection of reports of the 19th National Mining Science and Technology Conference , p.11-17.

Tran Van Vinh., Le Viet Hai., Pham Ba Hien., Nguyen Quoc Dung., Pham Minh Cuong., 2016. Solutions to increase oil production in the final stage of Bach Ho field of Vietsovpetro joint venture. Collection of scientific conference reports at the 35th anniversary of the establishment of the Vietsovpetro Vietnam-Russia Joint Venture and the 30th anniversary of the first oil production, Vung Tau, volume 2, p. 23–30.

Tu Thanh Nghia., Nguyen Thuc Khang., Le Viet Hai., Duong Danh Lam., Nguyen Quoc Dung., Nguyen Van Trung., Phan Duc Tuan., 2017. Technology to process the near-bottom zone of oil and gas fields in the South China Sea of Vietnam. National University Publishing House, Ho Chi Minh City. 1270 pages.

Vietnam - Russia joint venture Vietsovpetro, 2013. Technological diagram for correction, production and construction of Bach Ho Field. Episode 1,3.