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OPTIMISATION OF HYDRAULIC FRACTURING DESIGN IN LOWER OLIGOCENE RESERVOIR, KINH NGU TRANG OILFIELD

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Abstract. Kinh Ngu Trang oilfield is of the block 09-2/09 offshore Vietnam, which is located in the Cuu Long basin, the distance from that field to Port of Vung Tau is around 140 km and it is about 14 km from the north of Rang Dong oilfield of the block 15.2, and around 50 km from the east of White Tiger in the block 09.1. That block accounts for total area of 992 km^2 with the average water depth of around 50 m to 70 m. The characteristic of Oligocene E reservoir is tight oil in sandstone, very complicated with complex structure. Therefore, the big challenges in this reservoir are the low permeability and the low porosity of around 0.2 md to less than 1 md and 1% to less than 13%, respectively, leading to very low fracture conductivity among the fractures. Through the Minifrac test for reservoir with reservoir depth from 3,501 mMD to 3,525 mMD, the total leak-off coefficient and fracture closure pressure were determined as 0.005 ft/$min^{0.5}$ and 9,100 psi, respectively. To create new fracture dimensions, hydraulic fracturing stimulation has been used to stimulate this reservoir, including proppant selection and fluid selection, pump power requirement. In this article, the authors present optimisation of hydraulic fracturing design using unified fracture design, the results show that optimum fracture dimensions include fracture half-length, fracture width and fracture height of 216 m, 0.34 inches and 31 m, respectively when using proppant mass of 150,000 lbs of 20/40 ISP Carbolite Ceramic proppant.

Keywords: Fracture dimensions, hydraulic fracturing design, oligocene reservoir, Kinh Ngu Trang oilfield.

INTRODUCTION TO GEOLOGICAL PROPERTIES OF KINH NGU TRANG

The Oligocene reservoir in Kinh Ngu Trang oil field can be seen as the tight oil reservoir with both permeability and porosity being low but the oil potential with oil initially in place (OIIP) is approximately 177 million tonnes. In order to increase oil productivity, the hydraulic fracturing stimulation is the best choice to increase conductivity in the fractures. Before preparing for fracture treatment, the geology of Kinh Ngu Trang has to be fully understood and it plays the very important role in order to predict these fracture directions during pumping and allows selecting the right fracturing fluid systems for this project. The other benefit is that the right pump horsepower has been determined. Through the specific measurement in the field, overburden pressure, pore pressure, and fracture pressure, minimum in-situ stress, maximum in-situ stress, the correlation between young modulus and fracture toughness, Poisson's ratio, and young modulus have been obtained by various methods. Generally in the field, the geology of Kinh Ngu Trang is mostly strike slip faulting stress regime which is to build the geological framework of the field. In order to construct an overburden pressure profile for this well, sonic log density is a tool to measure shale density at each well depth. On the other hand, the relationship between shale densities and the valuable sonic log has been presented by Gardner's experiment. The details of the reservoir properties and parameters are shown in table 1 and table 2, which are calculated through the average values including young modulus of 5,000,000 psi, Poisson's ratio of 0.25, and closure pressure of 9,137 psi, fracture toughness of 1,000 psi-in$^{0.5}$, reservoir compressibility, and other parameters that are for fracture design.

Table 1. Fracturing parameters

Parameters	Value
Fracture height, h_f, ft.	101
Leak-off coefficient, ft/min$^{0.5}$	0.00055
Spurt loss, gal/ft^2	0.1
Injection rate, bpm	18
Injection time, min	73
Spurt loss, in	0.1
Proppant concentration at the end of job, (EOJ), ppg	8
Flow behavior index, n	0.55
Consistency index, K, lbf.s^n/ft^2	0.04
Fracturing fluid type: Fracturing Lighting 3500 (LF-3500) with the compositions as presented in fracturing fluid selection	
Pproppant type: ISP Carbolite-Ceramic , 20/40, 170 lb/ft^3, 16/20 with 170 lb/ft^3	

Table 2. Reservoir data of X well in Oligocene E reservoir, offshore Vietnam [1, 2]

Parameters	Value
Target fracturing depth, ft.	11,482
Reservoir drainage area, acres	122
Reservoir drainage radius, ft.	1,300
Wellbore radius, ft.	0.25
Reservoir height, ft.	77
Reservoir porosity, %	12.8
Reservoir permeability, md	0.1
Reservoir fluid viscosity, cp	0.5
Oil formation volume factor, RB/STB	1.4
Oil saturation, %	48
Total compressibility, psi^{-1}	1.00×10^{-5}
Young modulus, psi	5×10^6
Sandstone Poisson's ratio	0.25
Initial reservoir pressure, psi	5610
Reservoir temperature, ^oF	260
Oil API	40
Gas specific gravity	0.707
Bubble point pressure, psi	1,310
Flowing bottom hole pressure, psi	3,500
Closure pressure, psi	9,137

IN-SITU STRESSES

The orientation and magnitude of the in situ stresses determine the direction and geometry of the propagated fractures. It not only finds exactly fracture model in order to design fracture volume but also provides pump horsepower for the fracture treatment. The state of stresses is described by three principal stresses perpendicular to each other, including the maximum principal stress, the intermediate principal stress and the minimum principal stress. In addition, during pumping to produce fractures growth, the fractures propagate perpendicularly to the minimum principal stress [3]. Before designing fracture treatment, the parameters consisting of young modulus, unconfined compressive strength, closure pressure as minimum horizontal stress, maximum horizontal stress, vertical stress have been gathered. In fact there are some methods to determine minimum horizontal stress including Hubbert and Willis [3], the Matthews correlation [4], the Pennebaker correlation [5], the Eaton correlation [6], the Christman equation [7], and the MacPherson and Berry correlation [8] but these methods require more input data and take the time to determine minimum horizontal stress that is the main drawback for the treatment design. To obtain quickly the valuable closure pressure, it is predicted through the extended leak-off test instead of leak-off test or Mini-fracture test because this method predicts exactly that one.

In the field, fracture pressure as closure pressure or minimum in-situ stress is sometimes determined through Eaton method because it takes input data consisting of overburden stress, Poisson's ratio, well depth and pore pressure. The fracture treatment also requires the Young modulus that is taken through the core tests in the laboratory or Mini-fracture test with formation breakdown test or logs. The Eaton method is to predict fracture pressure as closure pressure with the equation below:

$$FP = \frac{S_v - P_p}{D} \times \left(\frac{v}{1-v}\right) + \frac{P_p}{D} \qquad (1)$$

In which: FP is the fracture pressure, psi; S_v is the overburden pressure, psi; D is the true vertical depth, ft; P_p is the pore pressure, psi; v is the Poisson's ratio.

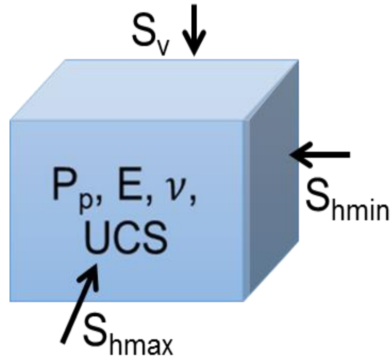

Fig. 1. Modelling in-situ stress

In order to achieve the success of the fracturing stimulation, some previous fracture treatments with the objective in the tight oil sandstone reservoir have reviewed productivity of the fractured wells. The table below shows some fracturing achievements that have fractured with different targets.

Table 3. The results of fractured wells in the White Tiger oilfield [1]

Wells	Formation	Treatment date	Production date	Production data		Oil increase (m^3/day)
				Before fracturing (m^3/day)	Post-fractured wells (m^3/day)	
X_1	Lower Oligocene	3-Sept-2011	13-Sept-2011	-	35	35
X_2	Lower Miocene	6–7-Sept-2011	13-Sept-2011	-	33	33
X_3	Lower Oligocene	8–Sept-2011	16-Sept-2011	48	88	40
X_4	Upper Oligocene	21–22-Sept-2011	2-Oct-2011	15	49	34
X_5	Lower Oligocene	28-Sept-2011	10-Oct-2011	71	251	180

YOUNG'S MODULUS

It is defined as the ratio of stress to strain for uniaxial stress and it is the stiffness of the rock. Young's modulus can significantly affect the fracture geometry and net pressure as presented by Meyer & Jacot (2001). In the Miocene sandstone reservoir, this value is about 3.45×10^6 psi (Report VSP). Poisson's ratio is defined as the lateral expansion to longitudinal contraction of a rock and it has a minor effect on the fracture propagation. The Poisson's ratio in the Miocene reservoir is about 0.23 for the sandstone and about 0.31 for the shale (Report). In the field, it is clear that the greater young's modulus as well as hard rock produces the thinner fracture, longer fracture and higher fracture during pumping under high pressure and it is difficult to make fracture width, length because it requires more pump horsepower. In contrast, lower young's modulus produces more easily fracture dimensions due to using lowest pump horsepower. To define the valuable fracture toughness, K_{IC}, this is obtained from the concept of stress intensity factor and is developed in linear elastic fracture mechanics (LEFM). In addition, fracture toughness is a measure of a material's resistance to fracture propagation. It is proportional to the amount of energy that can be absorbed by the material before propagation occurs.

LEAK-OFF COEFFICIENT

The valuable leak-off coefficient plays a crucial role in order to design fracture with high fluid efficiency and it is definitely an average rate of fluid leak-off per unit fracture area that is created during pumping. In the field, this value can be determined by mini-fracture test. In addition, leak-off coefficient variations could considerably impact not only fracture geometries, fracture length and height but also proppant placement for fracture model. The fluid leak-off rate from a hydraulic fracture influences the created area of the fracture. For example, the created fracture area decreases when fluid leak-off rate increases. In addition, the proppant concentration in the fracture increases when the leak-off is high; therefore, higher leak-off coefficient could cause poorer proppant placement.

FLUID SELECTION

In 1991, Economides et al. presented the fracturing fluid selection guide line in the petroleum industry practically. Ideally, the fracturing fluid must be compatible with the formation rock properties; also it is compatible with fluid flow in the reservoir and reservoir pressure and reservoir temperature. Fracturing fluid generates pressure in order to transport proppant slurry and open fracture, produce fracture growth during pumping, also fracturing fluid should minimize pressure drop alongside and inside the pipe system in order to increase pump horsepower with the aim of increasing a net fracture pressure to produce more fracture propagation. In fracturing fluid system, the breaker additive would be added to the fluid system to clean up the fractures after treatment and the friction reducer should be added in order to decrease the pressure loss system in the pipe that brings more benefit for net pressure. Due to the temperature of Oligocene E reservoir in Kinh Ngu Trang up to 260^{o}F, fracturing fluid of LF-3500 has these compositions including clay treatment-3C of 1ppg, clay master 5C of 1pptg, Inflo-250 of 2 pptg, BF-7L (Cross-linking Buffer) of 2 pptg, XLW-30 (Cross linker) of 3 pptg, GBW-41L(Breaker) of 2 pptg, Hiperm CRB (Encapsulated Breaker) of 1 ppg, XLFC-5C (Gel Liquid Concentrate) of 8.75 pptg for fracturing fluid system [1, 2]. To predict precisely the fracture geometry as fracture half-length, fracture width during pumping, the power law fluid model would be applied in this study. Then the most fracturing fluid model is usually given by:

$$\tau = K\gamma^n \qquad (2)$$

Where: τ- shear stress; γ- shear rate; K-consistency coefficient, n- rheological index as dimensionless flow behavior index but related to the viscosity of the non-Newtonian fracturing fluid model [9].

The power law model can be expressed by:

$$\log\tau = \log K + n\log\gamma$$

$$Slope = \left[\left(N\sum XY\right) - \left(\sum X\sum Y\right)\right] \Big/ \left[\left(N\sum X^2\right) - \left(\sum X\right)^2\right]$$

$$Intercept = \left(\sum Y - n\sum X\right) \Big/ N$$

Where X = log γ; Y = log τ; and N = Data number; Thus n = *Slope* and K= exp(*Intercept*).

The detail of the fracturing fluid composition has been presented as the table below.

PROPPANT SELECTION

In order to select proppant, the proppant must be selected correctly as proppant type, proppant size, proppant porosity, proppant permeability and proppant conductivity, proppant strength under fracture closure pressure of 9,137 psi in the Oligocene E sequence [2]. The important factor of proppant is proppant strength that would be much larger than closure pressure. And the other factor is saving cost. In order to estimate precisely the valuable fracture conductivity among fractures in terms of proppant damage factor, closure pressure and proppant concentration in the fractures have been accurately predicted. Proppant is used to open fractures and keep the fractures always open for a long time to gain fracture conductivity after pump is shut in and fracture will be closed due to effective stress and overburden pressure forced to fractures. Ideally, proppant selection needs to have enough strength to be resistant to crushing, erosion, and corrosion in the well. Due to fracture closure pressure in Oligocene E sequence up to 9,137 psi [1, 2], proppant type should be selected with intermediate strength proppant (ISP), Carbolite Ceramic proppant with proppant size of 16/30, 20/40; proppant types that are good for optimum proppant settling in fracturing fluid and better for proppant transport and proppant slurry pumping are presented in the table below:

Table 4. Proppant selection

Parameters	Value
Proppant type	20/40 CARBO-Lite
Specific Gravity	2.71
Strength	Intermediate
Diameter	0.0287 in
Packed porosity	0.29
Proppant permeability	100,000 mD
Conductivity at 9,137 psi closure pressure (at 1.37 lb/ft^2)	1,500 mD-ft.
Conductivity damage factor	0.5
Closure pressure	9,137 psi
Proppant type	16/20 CARBO-Lite
Specific Gravity	2.71
Strength	Intermediate
Average Diameter	0.0394016
Packed porosity	26
Proppant permeability	80,000 mD
Conductivity at 9,137 psi closure pressure (at 1.37 lb/ft^2)	2,400 mD.ft
Proppant damage factor	0.5
Closure pressure	9,137

PUMP HORSEPOWER REQUIREMENT

In order to design and select the right pump horsepower for the project, it depends on the main positive factors including closure pressure, hydrostatic pressure, and the near wellbore friction pressure loss, pressure loss systems inside the pipe. After Minifrac test in the formation, this has obtained high closure pressure that selects high pump horsepower. Due to hydraulic fracturing treatment with targeted reservoir depth up to 11,482 ft, it also affects selection of high pump horsepower. These data have been given as the table below that are necessary to calculate pump horsepower requirement for this project.

$$HHP = \frac{\left(P_c + \Delta p_{loss} - HSP\right) \times q}{40.8}$$

In which: P_c is the fracture closure pressure in Oligocene Kinh Ngu Trang of 9,137 psi; HSP is the hydrostatic pressure that is calculated by the vertical depth, fracturing fluid density, psi; q is the optimum flow rate of the hydraulic fracturing project, bpm; Δp_{loss} is the total pressure loss including near wellbore friction and pressure loss via the pipe systems, psi.

The database was obtained in the field. The pump horsepower is found at 2000 HHP.

NET PRESSURE AND EXTENSION PRESSURE REQUIREMENT

The positive net pressure plays the very crucial role for producing the fracture dimensions such as fracture half-length and fracture width and fracture height. By contrast, the extension pressure allows determining fracture propagation during fracture pumping. The details of the net pressure components have been presented as the following equation:

$$P_{net} = P_s + HSP - P_c - P_{wellbore} - P_{loss} \quad (3)$$

To produce the fracture dimensions, the net pressure is positively greater than zero, therefore the total bottom hole injection pressure overcomes the closure pressure.

In which: P_{net} is the net pressure inside fracture, psi; P_s is the surface treating pressure, psi; HSP is the hydrostatic pressure, psi; P_c is the closure pressure, psi; $P_{wellbore}$ is the near wellbore friction pressure, psi; P_{loss} is the total pressure loss in the pipe systems, psi.

FRACTURE GEOMETRY MODEL

In the recent years, there are various fracture models applying fracture design that give an approximate description of real fracture geometry, which are 2D fracture model without fluid leak-off such as GDK, PKN [10] and Radial and 2D fracture model [9]. In terms of fluid leak-off rate, and power law parameters, they consist of PKN-C, GDK-C and Radial-C [9]. Also, the 2D models show that fracture height is constant during pumping, therefore, fracture geometry of 2D models without fluid leak-off could not be evaluated accurately. However, the PKN-C [10] fracture geometry model accounts for the leak-off coefficient and power law parameters with fracture length and fracture more exactly than the other fracture models like PKN, GDK and the Radial model. In this study, the 2D PKN fracture geometry model (Two dimension PKN; Perkins and Kern (1961); Nordgren (1972)) in fig. 1 is used to present the significant fracture geometry of hydraulic fracturing stimulation for low permeability, low porosity and poor conductivity as Oligocene E reservoir that requires the fracture half-length of fracture design and evaluates the fracture geometry. After incorporation of Carter's solution II, the model is known as 2D PKN-C [9], had incorporated the leak-off coefficient, in terms of consistency index (K), flow behaviour index (n), injection rate, injection time, fluid viscosity, fracture height. The model detail in is shown as table 1 [9].

The maximum fracture width in terms of the power law fluid parameters is given by:

$$w_f = 9.15^{\frac{1}{2n+2}} \times 3.98^{\frac{n}{2n+2}} \left(\frac{1+(\pi-1)n}{n} \right)^{\frac{n}{2n+2}} K^{\frac{1}{2n+2}} \times \left(\frac{(q_i/2)^n h_f^{1-n} x_f}{E'} \right)^{\frac{1}{2n+2}} \tag{4}$$

Where: E' is the plain strain in psi, ($E' = \dfrac{1}{1-\nu^2}$).

Where n is flow behaviour index (Dimensionless) and K is the consistency index (Pa.sec^n), ν is in the Poisson's ratio and μ is in Pa.s., the power law parameters are correlated with fluid viscosity of fracturing fluid as:

$$n = 0.1756 \times (\mu)^{-0.1233}$$

$$K = 47{,}880 \times (0.5\mu - 0.0159)$$

By using the shape factor of $\pi/5$ for a 2D PKN [10] fracture geometry model, the average fracture width (w_a) is given by $\pi/5 \times w_f$ as equation.

$$w_a = \frac{\pi}{5} \times 9.15^{\frac{1}{2n+2}} \times 3.98^{\frac{n}{2n+2}} \left(\frac{1+(\pi-1)n}{n} \right)^{\frac{n}{2n+2}} K^{\frac{1}{2n+2}} \times \left(\frac{(q_i/2)^n h_f^{1-n} x_f}{E'} \right)^{\frac{1}{2n+2}} \tag{5}$$

Carter solution II is used for material balance in terms of injection rate to the well. At the injection time t_e, the injection rate is entered in one wing of the fracture area, the material balance is presented by injection rate (q) that is the relationship between the total fracture volume and fluid volume losses to fractures. The material balance is presented as equation below.

$$q = 2\int_0^t \frac{C_L}{\sqrt{t-\tau}} \times \left(\frac{dA}{d\tau} \right) d\tau + 2S_p \times \frac{dA}{dt} + w \times \frac{dA}{dt} + A\frac{dw}{dt} \tag{6}$$

By an analytical solution for constant injection rate (q), Carter solved the material balance that is given by the fracture area for two wings as:

$$A(t) = \frac{w_a + 2S_p}{4C_L^2 \pi} \times q \left[\exp(\beta^2) erfc(\beta) + \frac{2\beta}{\sqrt{\pi}} - 1 \right] \tag{7}$$

Hence fracture half-length with the fracture surface area ($A(t) = 2x_f h_f$) is given by:

$$x_f = \frac{(w_a + 2S_p)}{4\pi C_L^2 h_f} \times \frac{q}{2} \left[\exp(\beta^2) erfc(\beta) + \frac{2\beta}{\sqrt{\pi}} - 1 \right] \tag{8}$$

Where is $\beta = \frac{2C_L \sqrt{\pi t}}{w_a + 2S_p}$.

Equation (6) presents the fracture half-length during proppant slurry injection into the fractures and that equation also describes the fracture propagation alongside the fractures with time, in which fracture half-length depends on several parameters as injection rate (q), injection time (t), leak-off coefficient (C_L) [11, 12], spurt loss (S_p), and fracture height (h_f), the average fracture width (w_a). From the close of equation (6) it can be easy to determine the valuable fracture half-length by using iterative method calculation. The PKN-C fracture geometry model is shown in fig. 1.

MATERIAL BALANCE

Carter solved the material balance to account for leak-off coefficient, spurt loss, injection rate, injection time, and in terms of power law parameters as flow behaviour index of n and consistency index of K. Proppant slurry is pumped to the well under high pressure to produce fracture growth and fracture propagation. Therefore, the material balance is expressed as equation; $V_i = V_f + V_l$, where V_i is the total fluid volume injected to the well, V_f is the fracture volume that is required to stimulate reservoir, and V_l is the total fluid volume losses to the fracture area in the reservoir. The fracture volume, V_f, is defined as two sides of the symmetric fracture of $V_f = 2x_f h_f w_a$, the fluid efficiency is defined by V_f/V_i. In 1986, Nolte proposed the relationship between the fluid volumes injected to the well and pad volume, and also proposed a model for proppant schedule. At the injection time t, the injection rate is entered into two wings of the fractures with q, the material balance is presented as the constant injection rate q that is the sum of the different leak-off flow rate and fracture volume as [9]:

$$q = 2\int_0^t \frac{C_L}{\sqrt{t-\tau}} \times \left(\frac{dA}{d\tau}\right) d\tau + 2S_p \times \frac{dA}{dt} + w \times \frac{dA}{dt} + A\frac{dw}{dt} \tag{9}$$

The fluid efficiency of fractured well of the post fracture at the time (t) is given by:

$$\eta = \frac{w_a h_f x_f}{qt} \, or \, \eta = \frac{w_a h_f (w_a + 2S_p)}{4\pi C_L^2 t} \times \left[\exp(\beta^2) erfc(\beta) + \frac{2\beta}{\sqrt{\pi}} - 1 \right] \tag{10}$$

Where, $\beta = \frac{2C_L \sqrt{\pi t}}{w_a + 2S_p}$, and C_L is the total leak-off coefficient in ft/min$^{0.5}$, w_a is the average fracture width in the fractures in inch, S_p is the spurt loss in the fractures in gal/ft^2.

THE UNIFIED FRACTURE DESIGN (UFD) APPROACH

The UFD concept includes:

Calculating the proppant number from the given amount of proppant.

Determining the optimal dimensionless fracture conductivity and maximum dimensionless productivity index from the proppant number.

Calculating the fracture length and width from the dimensionless fracture conductivity.

Determining the injection time and pumping schedule in order to achieve fracture geometry design.

For a given mass of proppant, first the proppant number is calculated.

In 2002, Valkó Economides et al., (2002) [13] had introduced the concept called Unified Fracture Design (UFD). It offers a method to determine the fracture dimensions providing the maximum reservoir performance after fracturing with the limited amount of proppant to determine a proppant number (N_{prop}) being used as a correlating parameter. In terms of economics, achieving the maximum reservoir performance means maximizing the production rate. The parameter represents the production rate very well such as the maximum dimensionless productivity index at the optimum dimensionless fracture conductivity ($C_{fD,opt}$). The higher productivity index is, the more production gains. As a result, in the UFD, the dimensionless productivity, J_D, is obtained.

The proppant number, N_p, is an important parameter of the UFD. The proppant number is a dimensionless parameter.

N_{prop}, is calculated by:

$$N_{prop} = I_x^2 C_{fD} \tag{11}$$

Where I_x is a penetration ratio and C_{fD} is dimensionless fracture conductivity. The penetration ratio is the ratio of the fracture length, $2X_f$, to the equivalent reservoir length, x_e.

Therefore, the penetration ratio (I_X) and the dimensionless fracture conductivity have been presented as:

$$I_x = \frac{2x_f}{x_e} \tag{12}$$

$$C_{fD} = \frac{w_p k_f}{k_r x_f} \tag{13}$$

Where: X_f is the fracture half length, x_e is the side length of the square drainage area of that reservoir, k_r is the reservoir permeability, k_f is the proppant pack permeability, and w_p is the average (propped) fracture width.

The combination of equations (11), (12) and (13) is the result of proppant number:

$$N_{prop} = \frac{4k_f w_p x_f^2}{k_r x_f x_e^2} = \frac{2k_f}{k_r}\frac{2x_f w_p}{x_e^2} x \frac{h_n}{h_n} = \frac{2k_f}{k_r}\frac{V_p}{V_r} \tag{14}$$

The propped fracture volume in the pay zone V_p is obtained as:

$$V_p = \frac{M_{prop}}{\rho_p\left(1-\Phi_p\right)}\left(\frac{h_n}{h_f}\right) \tag{15}$$

Under the assumption of the pseudo steady-state flow regime, the maximum dimensionless productivity index (PI) and the optimum dimensionless fracture conductivity for a given mass of proppants (M_{prop}) are functions of the proppant number as [13]:

$$J_{D.max}\left(N_{prop}\right) = \begin{cases} \dfrac{1}{0.990-0.5ln\left(N_{prop}\right)} & ;if\ N_{prop} \le 0.1 \\ \dfrac{6}{\pi} - exp(\dfrac{0.423-0.311N_{prop}-0.089N_{prop}^2}{1+0.667N_{prop}+0.015N_{prop}^2} & ;if\ N_{prop} > 0.1 \end{cases} \tag{16}$$

$$C_{fD,opt}\left(N_{prop}\right)=\begin{cases}1.6 \quad if \quad N_{prop}<0.1\\ 1.6+exp(\dfrac{-0.583+1.48ln\left(N_{prop}\right)}{1+0.142ln\left(N_{prop}\right)} \quad if \quad ;0.1\le N_{prop}\\ N_{prop} \quad if \; ;N_{prop}>10\end{cases} \tag{17}$$

Once the optimum dimensionless fracture conductivity is known, the optimum fracture dimensions, i.e., propped fracture half length ($x_{f,opt}$) and propped fracture width ($w_{p,opt}$), are set [13]:

$$x_{f,opt}=\sqrt{\frac{k_f V_p}{C_{fD,opt} h_n k_r}} \tag{18}$$

$$w_{f,opt}=\sqrt{\frac{C_{fD,opt} k_r V_p}{h_n k_f}}$$

FRACTURE CONDUCTIVITY

The value of fracture conductivity is usually measured from laboratory data (API standard) based on proppant type, proppant size, proppant shape, proppant damage factor, proppant permeability, proppant porosity under closure pressure, that value is very important to predict the oil production and oil productivity after fracturing wells. The API standard for a test such as data to measure linear flow through the proppant pack between steel plates under specific pressure is applied to it. Then the standard API is usually tested at a proppant concentration of 2 lb/ft^2. This theory most published data measured by API test. If the proppant permeability under closure pressure which is known for the specific proppant type has been selected, then the in-situ fracture conductivity can be evaluated by equation:

$$Fracture\,conductivity=k_f\times w_p \tag{19}$$

For simulation fracture conductivity, if the closure pressure and proppant fracture concentration in (lb/ft^2) are known by using Mfrac software, the fracture conductivity, proppant permeability, and proppant porosity under closure pressure can also be calculated.

DIMENSIONLESS FRACTURE CONDUCTIVITY

The dimensionless fracture conductivity, F_{CD}, can be defined as and is given by:

$$F_{CD}=\frac{k_f\times w_p}{k\times x_f} \tag{20}$$

In which: k is the reservoir permeability in mD; x_f is the fracture length of fractured well in ft; k_f is the proppant permeability under closure pressure applied on the proppant laden; w_p is the propped fracture width at end of the job.

TRANSIENT PRODUCTION FLOW REGIME

Based on the constant bottom hole pressure situation, the oil production from fractured well in transient flow regime can be calculated by [14].

$$p_i-p_{wf}=\frac{162.6q_0 B\mu}{kh}\left(logt+\log\left(\frac{k}{\phi\mu c_t r_w^{'2}}\right)+s_f-3.23\right) \tag{21}$$

In which: $r_w^{'}$ is the effective wellbore radius as given by: $r_w^{'}=r_w e_f^{-s}$, s_f is pseudo-skin and calculated by the relationship [9]: $s_f=F-\ln\left(\frac{x_f}{r_w}\right)$, where x_f is the fracture half-length, and r_w is the wellbore radius. The F factor can be calculated by:

$$F=\frac{1.65-0.328u+0.116u^2}{1+0.18u+0.064u^2+0.005u^3} \tag{22}$$

Where: $u = \ln(F_{CD})$ and F_{CD} is the dimensionless fracture conductivity which is calculated by $F_{CD} = \frac{k_f w_p}{k x_f}$, also F_{CD} is related to proppant number which is along the penetration ratio $I_x = 2x_f / x_e$ and $k_f w_p$ is the fracture conductivity which can be calculated by laboratory experiment or conductivity simulation when a proppant fracture concentration in lb/ft^2 inside fracture under closure pressure applied on the proppant laden is known. Basically, the proppant number is defined by Economides et al., (2001).

$$N_{propp} = \left(\frac{2k_f}{k_{res}} \right) \times \frac{V_{prop}}{V_{res}} \qquad (23)$$

Where: k_f is the effective proppant pack permeability; k is the reservoir permeability; V_{prop} is the propped volume in the pay zone (two wings, including void space between the proppant grains); and V_{res} is the drainage volume. In the transient production period is often short time of oil production.

OLIGOCENE RESERVOIR DATA

The vertical exploration well in Kinh Ngu Trang-Duong Dong oil field is drilled with objective of tight oil Oligocene sandstone reservoir in the Cuu Long basin, offshore Vietnam. The Oligocene E sequence has high potential for oil and gas reserves. However, the reservoir is very tight and the geological property of that reservoir is the heterogeneous structure of course, the fracture conductivity is very poor. In this study, the reservoir data is obtained from the field of Oligocene reservoir, whose depths range from of 3,501 m to 3,525 m and the fracture closure pressure is up to 9,137 psi [1, 2], it is determined using fracture calibration test during well shut in period of 140 minutes, the leak-off coefficient depends on the fluid properties and closure times, the reservoir data are presented in table 4.

PUMPING SCHEDULE

During proppant slurry pumping into the wells under high pressure, it produces fracture growth including fracture half-length and fracture width. This fracturing fluid stage can be divided into three main parts, the first part is pad volume which only pumps fracturing fluid and fluid additives without proppant for initially opening fracture, the second part is pumped proppant slurry with proppant concentration being added to fracturing fluid during pumping since proppant concentration at end of the job (8 ppg) as seen in fig. 1, which describes the proppant loading schedule. Nevertheless, the material balance describes the relationship between total fluid volume injection with time and fracture volume plus with fluid volume loss that allows calculating parameters including fluid efficiency of 34, pad volume of 27,000 gallons, injection volume of 55,802 gallons, slurry volume of 28,802 gallons. The detailed pump schedule and added proppant, and fluid volume requirement have been presented in table 2, fig. 2–3, respectively.

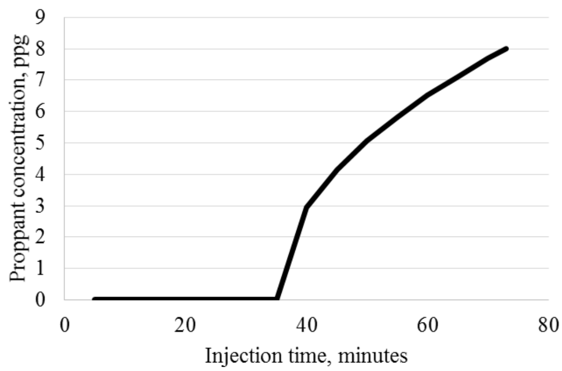

Fig. 2. Proppant concentration schedule

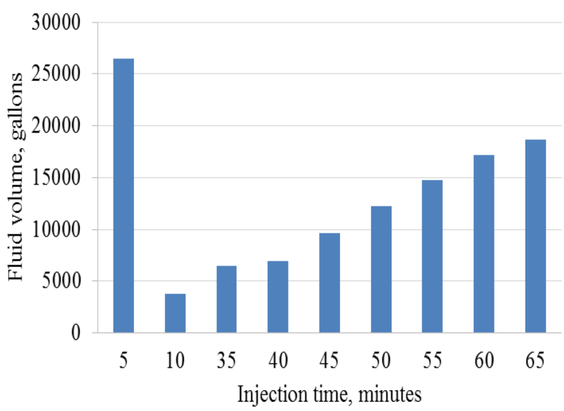

Fig. 3. Fluid volume schedule

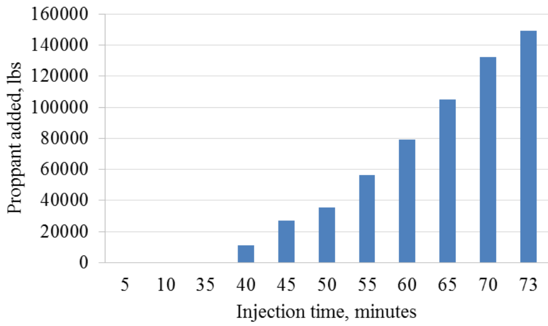

Fig. 4. Proppant added to fracturing fluid schedule

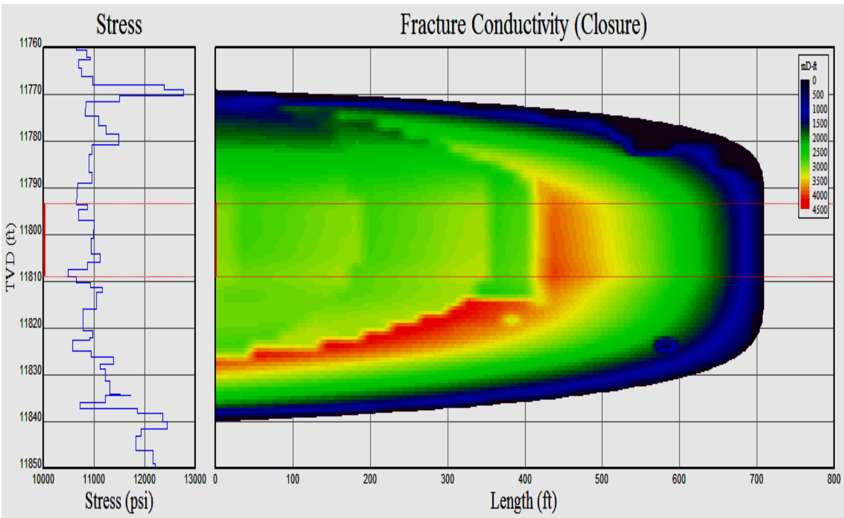

Fig. 5. Fracture conductivity and fracture half-length during pumping of using Carbolite Ceramic proppant, 20/40

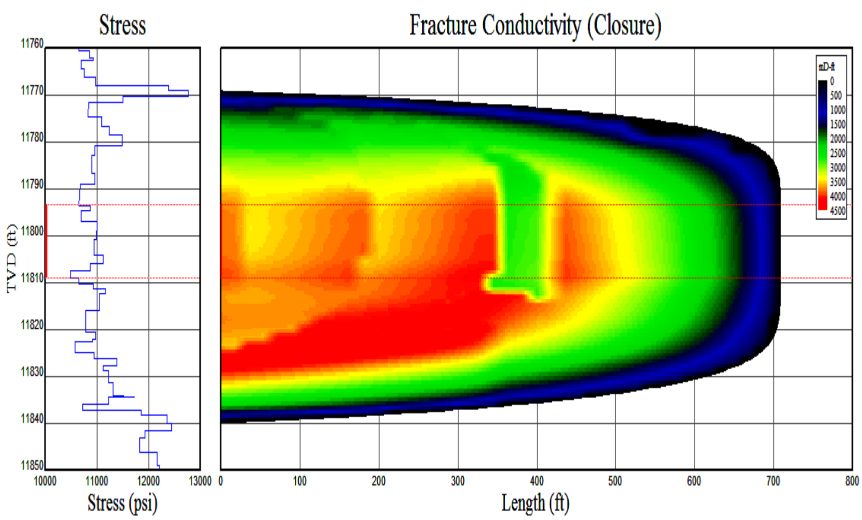

Fig. 6. Fracture conductivity and fracture half-length during pumping of using couple of Carbolite Ceramic proppant, 20/40 and tail pumping Carbolite Ceramic proppant, 16/20

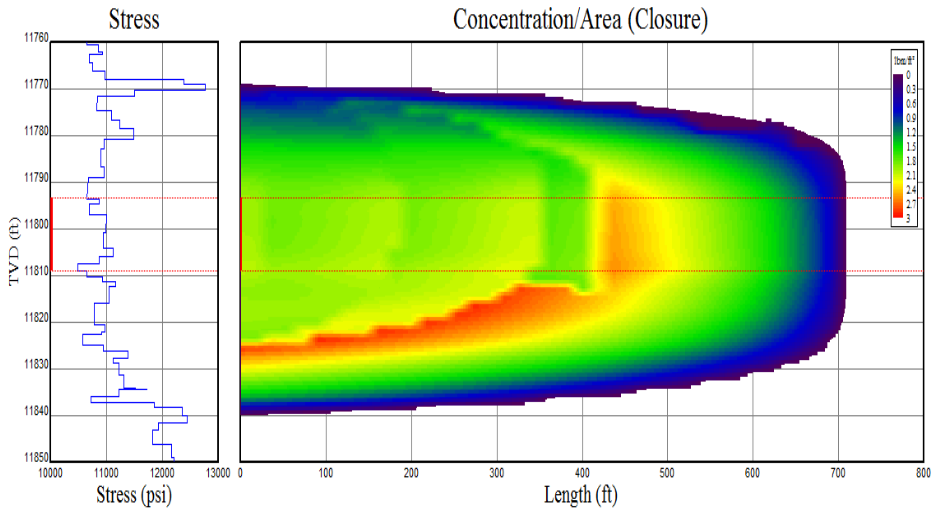

Fig. 7. Proppant concentration among fractures during pumping of using couple of Carbolite Ceramic proppant, 20/40 and Carbolite Ceramic proppant, 16/20

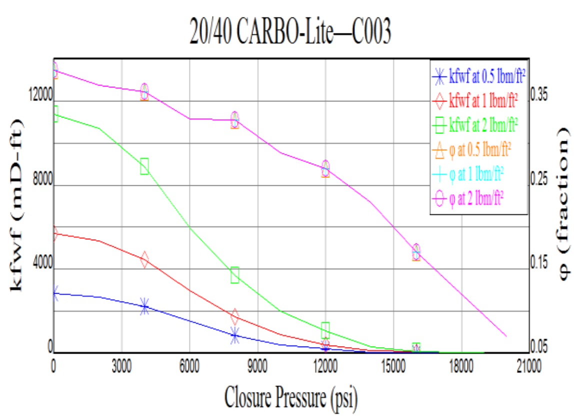

Fig. 8. Valuable fracture conductivity, fractional porosity under closure pressure and proppant concentration among the fractures

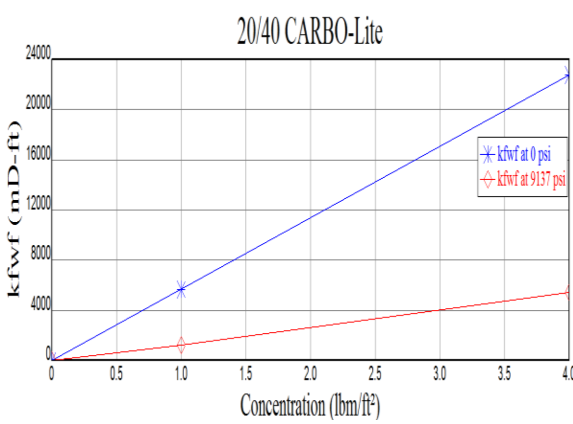

Fig. 9. Estimating fracture conductivity under closure pressure and actual proppant concentration among the fractures

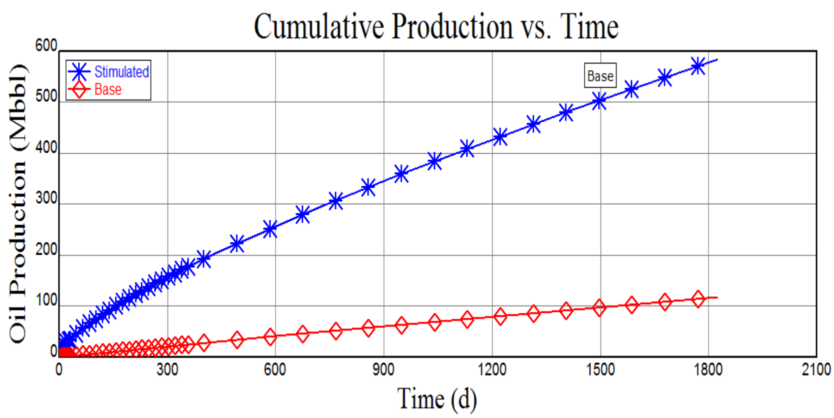

Fig. 10. Comparison about cumulative oil production between base case and stimulated case

Table 5. Pump schedule of using Cabolite Ceramic proppant, 20/40 [14]

Stage number	Slurry rate, bpm	Stage volume, gals	Cumulative volume	Stage time, minutes	Stage type	Proppant type	Proppant con, ppg	Cumulative proppant, lbs	Stage propp
1	18	26,460	26,460	35	Pad	0	0	0	0
2	18	3,780	30,240	5.6	Prop	20/40	3	11,136.5	11,340
3	18	3,780	34,020	5.9	Prop	20/40	4	26,804.6	15,120
4	17	1,680	35,700	2.9	Prop	20/40	5.1	35,307.5	8,568
5	17	3,570	39,270	6.3	Prop	20/40	5.8	56,126.6	20,706
6	17	3,570	42,840	6.4	Prop	20/40	6.5	79,364.3	23,205
7	17	3,570	46,410	6.6	Prop	20/40	7.1	104,785.3	25,347
8	17	3,570	49,980	7	Prop	20/40	7.7	132,211.6	27,489
9	17	2,142	52,122	4.1	Prop	20/40	8	149,347.6	17,136
10	17			0	flush	0	0	0	0

Table 6. Pump schedule of using Cabolite Ceramic proppant, 20/40 and Carbolite Ceramic proppant, 16/20 [14]

Stage number	Slurry rate, bpm	Stage volume, gals	Cumulative volume	Stage time, minutes	Stage type	Proppant type	Proppant con, ppg	Cumulative proppant, lbs	Stage propp
1	18	26,460	26,460	35	Pad	0	0	0	0
2	18	3,780	30,240	5.6	Prop	20/40	3	11,136.5	11,340
3	18	3,780	34,020	5.9	Prop	20/40	4	26,804.6	15,120
4	17	1,680	35,700	2.9	Prop	20/40	5.1	35,307.5	8,568
5	17	3,570	39,270	6.3	Prop	20/40	5.8	56,126.6	20,706
6	17	3,570	42,840	6.4	Prop	16/20	6.5	79,364.3	23,205
7	17	3,570	46,410	6.6	Prop	16/20	7.1	104,785.3	25,347
8	17	3,570	49,980	7	Prop	16/20	7.7	132,211.6	27,489
9	17	2,142	52,122	4.1	Prop	16/20	8	149,347.6	17,136
10	17			0	Prop	0	0	0	0

Table 7. Result of optimum fracture dimensions

Parameters	Values
Fracture half-length, x_f , ft.	709
Max fracture width, $w_{w;0}$, in.	0.34
Average fracture width, $\bar{w}$, in.	0.27

Table 8. Results from material balance

Parameters	Values
Fracture area, ft^2	109,186
Total volume required, V_i, gals	55,802
Efficiency, %	34
Pad volume, gal	29,789
Time to pump pad volume, min	35
Average slurry conc., ppg	5.4
Mass of proppant, lbs	150,000
Prop. conc. in fracture, lb/ft^2	1.37

Table 9. Results from conductivity model and production model

Parameters	Values
Closure stress, psi	9,137
Fracture conductivity, mD-ft.	1,900
Dimensionless fracture cond., F_{CD}	13.4
Pseudo-skin	-7.15
Effective wellbore radius, in.	320
Productivity ratio, J/Jo	6.1

CONCLUSIONS

Through this study, it is possible to summarize these good views of the hydraulic fracturing design optimization as the follows:

These factors include proppant concentration in the fractures, fracture closure pressure, proppant type, size, and density, which strongly affect the valuable fracture conductivity, fractional porosity, and fracture permeability of the fractures in the lower Oligocene reservoir. Specially, the higher fracture closure pressure is up to 9,137 psi in that reservoir, resulting in reducing fracture conductivity of 1,900 mD.ft and fracture half-length of around 709 ft when using 150,000 lbs proppant. By rising proppant concentration, the higher proppant density, and proponent diameter, it leads to increase in the conductivity.

Proppant mass and total leak-off coefficient have been affected by those of the fracture half-length, and fracture width, and fluid efficiency of the post fractured wells.

The fracturing fluid system including polymer concentration with fluid additive is important to transport proppant slurry and it also controlls the total fluid leak-off through the wall building effect. By adding more polymer concentration into the fracturing fluid systems, the total fluid leak-off has been lower, resulting in the high fluid efficiency of fractured wells.

In the further work, in order to increase the net pressure for the main fractures (which provides good fracture conductivity of the main fractures) of the reservoir during pumping, it is necessary to isolate the second fracture (which is not useful for producing oil and gas production after fractured wells because fracture conductivity is poor). The second part of research of reducing pressure loss during pumping is to gain net pressure.

By pumping couple of Carbolite Ceramic proppant 20/40 and 16/20, both fracture conductivity and proppant concentration are higher than in the pumping with only single Carbolite Ceramic proppant 20/40. This has the benefit to prevent proppant flow-back in the post fractured wells.

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