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New Approach Studies Operating Hydraulic Fracturing Parameters Effect on Fracture Conductivity and Proppant Mass

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Abstract: In the past decades, hydraulic fracturing stimulation has widely been used to enhance oil and gas production for various reservoir properties such as low and high permeability, tight oil and gas reservoir and very low permeability reservoir, formation damage. Due to well in the Oligocene E tight oil sandstone reservoir with complicated and complex geological structure, the big challenge in the reservoir that faces low permeability and the low porosity with around 0.2-1 MD and 1-13%, respectively, leading to the fracture conductivity among the fractures are very poor. To deal with this problem, the best choice to stimulate that reservoir is hydraulic fracturing technique that allows creating new fractures and increase in conductivity. To select precisely the right type of proppant such as proppant size, proppant density for designing fracturing fluid and total fluid leak-off, the understanding reservoir properties such as temperature of 266°F and fracture closure pressure of 9137 psi, lithological compositions are necessary to success the fracturing project. In addition, the mnifrac test applying in the Oligocene with the depth range from 3501-3525 mMD, the total leak-off coefficient, fracture closure pressure and fracture model were also determined. In this research, the study has been introduced the various methods of determining minimum horizontal in the normal faulting stress regime and the effect of four operating hydraulic fracturing parameters and fracture height growth on fracture conductivity and proppant mass requirement by using Box-Behnken design and response surface methodology to design those for five parameters.

Key words: Operating hydraulic fracturing parameters, the fracture model, Box-Behnken Design (BBD), fracture conductivity, proppant mass

INTRODUCTION

The Oligocene reservoir of the Kinh Ngu Trang oil field is to be tight oil reservoir due to low permeability and low porosity of which the potential oil reservoir with Oil Initial in Place (OIIP) was approximately about 177 million tonnes. In order to produce large amount of oil reserves in this reservoir, the hydraulic fracturing technique is the best choice to increase in the conductivity among the fractures. Before treating for a fracture, the geological properties of Kinh Ngu Trang oil field has to fully understand because this plays very crucial role in order to predict these fractures direction and fracture orientation during pumping. In addition, the closure pressure as *in-situ* stress that allows to select the right fracturing fluid systems for this project. The other benefit is that the right pump horse power has been determined through the rock properties. 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, Poison's ratio and Young modulus have been obtained by various methods. Generally in the field, the geological Kinh Ngu Trang is most strike slip faulting stress regime which is to build the geological framework of the field. In order to construct of an overburden pressure profile for this wells, sonic log density is a tool to measure shale density in each well depth. On the other hand, the relationship between shale densities with the valuable sonic has been presented by experimental garner. The detail of the reservoir properties and parameters are shown in the Table 1-4 which calculate through the average values including Young modulus with 5,000,000 psi, Poison's ratio of 0.25 and closure of 9,137 psi, fracture toughness of 1000 psi-in$^{0.5}$, reservoir compressibility and other parameters that is for pressure fracture design.

Table 1: Proppant type 20/40 CARBO-Lite

Parameters	Values
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)	1500 (MD-ft)
Conductivity damage factor	0.5

Table 2: Proppant type 16/20 carbo-lite

Parameters	Values
Specific gravity	2.71
Strength	Intermediate
Average diameter	0.0394016 in
Packed porosity	26
Proppant permeability	80,000 (mD)
Conductivity at 9,137 psi closure pressure (at 1.37 lb/ft^2)	2400 (mD.ft)
Proppant damage factor	0.5
Closure pressure	9,137

Table 3: Fracturing parameters

Parameters	Values
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 End of Job [(EOJ), ppg]	8
Flow behaviour 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	

Table 4: Reservoir data of X well in Oligocene E reservoir, offshore Vietnam

Parameters	Values
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 ratio	0.25
Initial reservoir pressure (psi)	5610
Reservoir temperature (°F)	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

Before designing fracture treatment, the parameters consist of Young modulus, unconfined compressive strength, closure pressure as minimum horizontal stress, maximum horizontal stress, vertical stress have been gathered. In fact that there are some methods to determine minimum horizontal stress including Hubbert and Willis, the Mathew and Kelly correlation, the Pennebaker correlation, the Eaton correlation, the Christman equation and the MacPherson and Berry correlation but these methods are required more input data and take the time to determine minimum horizontal stress that is the main drawback for the treatment design. The valuable closure pressure is determined rapidly through the extended leak-off test instead of leak-off test or mini-fracture test because this method predicts exactly that value. To select precisely type of propant such as size for designing fracturing fluid, the understanding reservoir properties known as temperature of 266°F and fracture closure pressure of 9,137 psi, lithological compositions are necessary to success the project. In addition, the Minifrac test applying in the Oligocene with the depth range from 3501-3525 mMD, the total leak-off coefficient, fracture closure pressure and fracture model were also determined. In the field, fracture pressure like closure pressure or minimum *in-situ* stress is sometimes predicted through Eaton method which input data consists of overburden stress, Poison's ratio, well depth and pore pressure and output is fracture pressure. The fracture design is also required the Young modulus takes through the core tests in the laboratory or Mini-fracture test with formation breakdown test. The Eaton method is to predict fracture pressure as same as closure pressure in Eq. 1:

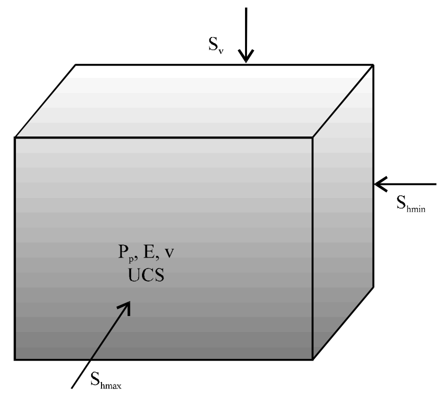


Fig. 1: Modelling *in-situ* stress

$$FP = \frac{S-P_P}{D}\times\left(\frac{v}{1-v}\right)+\frac{P_P}{D} \quad (1)$$

Where:

FP = The Fracture Pressure (psi)
S_v = The overburden pressure (psi)
D = The true vertical Depth (ft)
P_p = The Pore pressure (psi)
v = The Poison's ratio

In order to success of the fracturing stimulation, some previous fracture treatment with the objective in the tight oil sandstone reservoir has been reviewed about productivity of the fractured wells (Fig. 1). Table 1-4 shows some fracturing achievements that have fractured with different targets.

MATERIALS AND METHODS

Fluid selection: Economides *et al.* (1994) presented to select fracturing fluid selection guide line in the petroleum industry. Ideally, the fracturing fluid must be compatible with the formation rock properties, compatible with fluid flow in the reservoir and compatible with reservoir temperature. Fracturing fluid is generated pressure in order to transport proppant slurry and open fracture, produce fracture growth during pumping, also fracturing fluid should be minimized pressure drop alongside inside the pipe system in order to increase in pump horse power with the aim is increased 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 is brought more benefit for net pressure.

Due to Oligocene E reservoir in Kinh Ngu Trang having temperature up to 260°F, fracturing fluid of LF-3500 has these compositions including clay treatment- 3C of 1 ppg, Clay master 5C of 1 pptg, Inflo-250 of 2 pptg, BF-7L (Cross linking Buffer) of 2 pptg, XLW-30 (Cross linker) of 3 pptg, GBW-41 L (Breaker) of 2 pptg, Hiperm CRB (Encapsulated Breaker) of 1 ppg, XLFC-5C (Gel liquid concentrate) of 8.75 pptg for fracturing fluid system. To predict precisely the fracture geometry as fracture half-length, fracture width during pumping in term of the power law fluid model would be applied in this study. Then, the most fracturing fluid model is usually given by:

$$\tau = K\gamma^n \tag{2}$$

Where:
τ = Shear stress
γ = Shear rate
K = Consistency coefficient
n = Rheological index as flow behavior index of non-dimensional but related to the viscosity of the non-Newtonian fracturing fluid model (Valko and Economides, 1995)

The power law model can be expressed by:

$$\text{Log}\tau = \log K + n \log \gamma$$

$$\text{Slope} = \frac{[(N\sum(XY)\text{-}(\sum X\sum(Y)]}{[(N\sum x^2)\text{-}(\sum(X)^2]}$$

$$\text{Intercept} = \frac{\sum Y\text{-}n\sum X}{N}$$

Where:
X = Log γ
Y = Log τ
N = Data Number
n = Slope
K = Exp. (Intercept)

Proppant selection: In order to select right of proppant, proppant should be selected either correct technology or saving economy. According to proppant type, proppant size, proppant porosity, proppant permeability and proppant conductivity, proppant strength under fracture closure pressure of 9137 psi in the Oligocene E sequence. 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 uses 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 began closed due to effective stress and overburden pressure forced to fractures. Ideally, proppant selection needs to be enough strength to resistant crushing, erosion and resistant corrosion in the well. Due to fracture closure pressure in Oligocene E sequence up to 9137 psi, Proppant type should be selected with Intermediate Strength Proppant (ISP), Carbo Lite Ceramics proppant with proppant size as 16/30, 20/40, (Nolte, 1986) which type proppant is good for optimum proppant settling in fracturing fluid and better for proppant transport and proppant slurry pumping which presents in the table.

Fracture geometry mode: 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 is required the fracture half-length of fracture design and evaluate the fracture geometry. After incorporation of cater solution II, the model is known as 2D PKN-C had incorporated of the leak-off coefficient in term of consistency index (K), flow behaviour index (n), injection rate, injection time, fluid viscosity, fracture height. The model detail by Valko and Economides (1995) is shown as Table 3. The maximum fracture width in term of the power law fluid parameters that is given by:

$$w_f = 9.15\frac{1}{2n+2}\times 3.98\frac{n}{2n+2}\left(\frac{1+(\pi\text{-}1)}{n}\right)^{\frac{n}{2n+n}} K\frac{1}{2n+n}\times\left(\frac{\left(\frac{qi}{2}\right)^n h_f^{1\text{-}n}\times f}{E'}\right)^{\frac{1}{2n+2}} \tag{3}$$

where, E′ is the plain strain in psi:

$$\left(E' = \frac{1}{1-v^2}\right)$$

Where:
n = Flow behavior index (Dimensionless)
K = The consistency index ($Pa.sec^n$)
v = The Poisson's ratio (Pa.s)

Rahman (2008) the power law parameters are correlated with fluid viscosity of fracturing fluid as:

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

$$K = 470880\times(0.5\mu\text{-}0.0159)$$

Material balance: Cater solved the material balance is to account for leak-off coefficient, spurt loss, injection rate, injection time and in term of power law parameters as flow behaviour index of n and consistency index of K. During 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 = The total fluid volume injected to the well
V_f = The fracture volume that is required to stimulate reservoir
V_l = 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 the fluid efficiency is defined by V_f/V_i. Nolte (1986) proposed the relationship between the fluid volumes injected to the well with pad volume and also proposed a model for proppant schedule.

Fracture conductivity: The value of fracture conductivity usually is measured from laboratory data (API standard) based on proppant type, proppant size, proppant shape, proppant damage factor, proppant permeability, proppant porosity are under closure pressure that value is very important to predict the oil production. 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 is known for the each proppant type was selected, then *in-situ* fracture conductivity can be evaluated by:

$$\text{Fracture conductivity} = k_f\times wp \qquad (4)$$

For simulation fracture conductivity if the closure pressure, proppant fracture concentration in (lb/ft^2) is known by using MFrac Software also can be calculated a fracture conductivity, proppant permeability, proppant porosity under closure pressure.

Oligocene reservoir description: The vertical exploration well in Kinh Ngu Trang-Duong Dong oil field drilled with objective tight oil Oligocene sandstone reservoir in the Cuu Long Basin, offshore Viet Nam. The sequence E Oligocene is high potential 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 which reservoir depths range from of 3501-3525 m and the fracture closure pressure was up to 9,137 psi, it is determined using fracture calibration test during after well shut in period of 140 min, the leak-off coefficient depends on the fluid properties and closure times the reservoir data presented in Table 2.

Controlling fracturing parameters: It is clearly that the hydraulic fracturing treatment design could be separated into two regions. The first one is that the operating hydraulic parameters consist of injection rate, injection time and leak-off coefficient and the proppant concentration end of the job and fracture fluid system. The second region is that these parameters relate to the reservoir properties as rock properties, Young modulus, Poison's ratio, geological structural, reservoir porosity, reservoir permeability, fracture closure pressure and stress regime of the fractures in the normal fault stress regime, strike slip regime, reveres faulting stress regime. In terms of the research, the study mentions about four operating parameters consist of injection rate, injection time, leak-off coefficient and EOJ, the other is fracture height growth during pumping. In normal faulting stress regime, the fracture length propagation forwarding the minimum horizontal stress that is perpendicular with plane containing maximum horizontal stress and vertical stress. The closure pressure as known as the valuable minimum horizontal stress in the normal fault that determine via Minifract test at 9137 psi. For the injection rate should be range from 30-40 bpm because it could be minimized the pressure loss through the perforation from 100-200 psi and it covers to fracture all pay zone that needs to achieve it, the injection time should be range from 60-100 min because it could be saved the economic treatment of the project and the leak-off coefficient also should be range from 0.003-0.007 ft/min$^{0.5}$ that proposed by DD Nam, Nguyen Quoc Dung for fracturing in the Oligocene reservoir with the proppant end of the job design has to pass the perforation system without proppant bridging inside the tubing and tip screen out in the fracture with the 6 shot per foot. The number of shots for fracture treatment depends on the permeable pay zone and fracture orientation of 60°, following that the proppant concentration end of the job proposing from 8-10 ppg by DD Lam, Nguyen Quoc Dung, fractured basement, 2008. The another uncontrolled parameter is that the fracture height assumes growth while injecting slurry under high pressure into the fracture with more than 1.5 times in comparison with original fracture height of 77 ft.

RESULTS AND DISCUSSION

Box-Behnken design is a class of rotatable or nearly rotatable second-order designs based on three-level incomplete factorial designs. In addition, the study uses the Box-Behnken design for four operating fracturing parameters and one uncontrolled parameter. As a result, the number of experiments (N) required for the development of BBD could be found as equation: N = 2k (k-1)+C_0 (where, k is number of factors and C_0 is the number of central points). There are some reasons why this study uses the BBD. The first is that this could be provided higher efficiency than in the other design method such as Central Composite Design (CCD) and full factorial design. In the reality, the numbers of experiment is determined via. equation: N = 2×5(5-1)+3 = 43. In addition, the response surface method is more convenient in comparison with traditional single parameter to find optimum the response value. By using BBD, there is total of 43 runs cases of the experiment to find about what these variables of five different variables were optimized with maximizing fracture conductivity. Table 5 has been shown the result of the experimental conditions and these responses including fracture conductivity with affecting proppant damage factor and proppant mass requirement. By the response surface method simulation, the relationship between main variables and the interaction these variables on the valuable fracture conductivity are given by model:

$$\begin{aligned}C_{FD} = {} & 786.849-161.801X_1+47.2935X_2+97.6363X_3+\\ & 70.196X_4+55.1167X_5+21.0463X_1^2+8.51198X_2^2-\\ & 11.3419X_3^2+1.93611X_4^2-18.4064_5^2-11.5202X_1X_2-\\ & 39.4772X_1X_3-20.2352X_1X_4+46.7289X_1X_5+\\ & 5.49205X_2X_3+1.66994X_2X_4+4.39868X_2X_5+\\ & 9.46645X_3X_4+8.74X_3X_5+8.04946X_4X_5\end{aligned} \quad (5)$$

Table 5: Requirement proppant size and perforation diameter

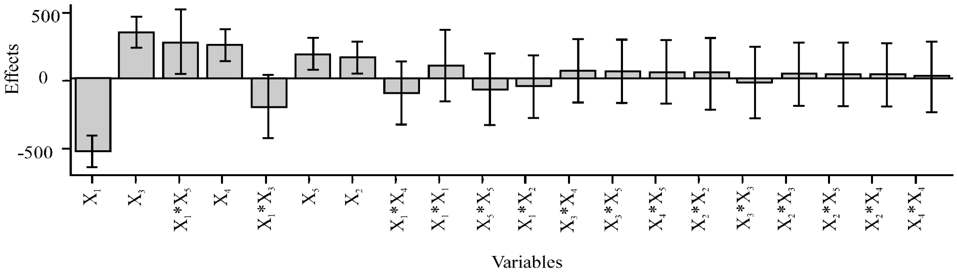
Proppant mess size	Perforation diameter (in)
6/12	0.80
8/16	0.56
12/20	0.40
16/30	0.28
20/40	0.20
30/50	0.14
40/70	0.10

Table 6: Four independent variables and their Levels for (BBD)

		Coded variables level		
Variables	Symbols	Low	Center	High
		-1	0	1
Leak-off coefficient (ft/min$^{0.5}$)	X_1	0.003	0.005	0.007
EOJ (ppg)	X_2	8	9	10
Fracture height (ft)	X_3	77	100	123
Injection time (min)	X_4	60	80	100
Injection rates (bpm)	X_5	30	35	40

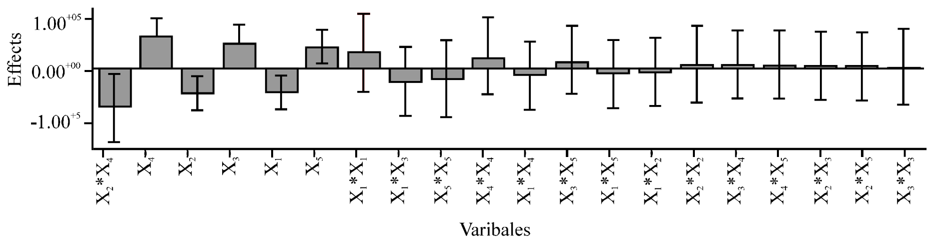
Table 6 has been shown the ANOVA table of the quadratic regression model, the determination coefficient of R^2 = 0.901 which model indicates that fracture conductivity model is a little bit percent of the total variations were not explained of the fracture conductivity model (5). Meanwhile, the value of adjusted determination coefficient (Adjusted coefficient (Adjusted coefficient R^2 = 0.803) according to confirm that valuable fracture conductivity model (5) was highly significant.

Main effect plots on the fracture conductivity: Figure 2 has been shown the effects plots of these variables and these interaction parameters on the fracture conductivit (Fig. 3). According to the fracture conductivity model, the figure can be divided into two categories. The first region is presented the negative variables and the interaction variables on fracture conductivity including X_1, $X_3.X_3$, $X_5.X_5$, $X_1.X_2$, $X_1.X_3$, $X_1.X_4$ which variables are to reduce the valuable conductivity. In addition, the one of the biggest variable effect on the negative fracture conductivity is the total leak-off coefficient. This is due to higher leak-off coefficient during fracturing that is produced the short fracture half-length as well as narrow fracture width, resulting low fracture conductivity. This is the explanation that during hydraulic fracturing with high leak-off coefficient, the treatment produces a limited fracture area as the problem is a higher fracturing fluid volume lost into the fracture areas, leading to shorter fracture half-length of course shorter fracture width and low fluid efficiency. It is therefore that the result of fracture conductivity is too low. In the second region of the fracture conductivity model, these variables with factors are greater than the zero. While fracturing treatment which variables could be increased the fracture conductivity including proppant concentration end of the job, injection time, injection rate and the growing fracture



N = 41, R^2 = 0.901, R^2 Adj.= 0.803
df = 20, Q^2 = 0.484, RSD = 105.4601, Conf. lev. = 0.95

Fig. 2: The effects plots of the five different variables and the interactions between these variables on conductivity



N = 41, R^2 = 0.595
df = 20, Q^2 = 0.043, RSD = 36868.7344, Conf. lev.= 0.96

Fig. 3: The effects plots of the five different variables and the interactions between these variables on proppant requirement

Table 7: Independent variables and results from conductivity simulation observed by (CCD)

Run	Coded level of the variables X_1	X_2	X_3	X_4	X_5	Actual of level variables Leak-off Cefficient (ft/min$^{0.5}$)	EOJ (ppg)	Fracture height (ft)	Time (min)	Injection rate (bpm)	Response (Simulation and observed) Conductivity MD (ft)	Proppant mass (lbs)
1	-1	-1	0	0	0	0.003	8	100	80	35	1091.51	212877
2	1	-1	0	0	0	0.007	8	100	80	35	515.3	84007.4
3	-1	1	0	0	0	0.003	10	100	80	35	1307.5	266096
4	1	1	0	0	0	0.007	10	100	80	35	613.3	105009
5	0	0	-1	-1	0	0.005	9	77	60	35	532.9	87750.3
6	0	0	1	-1	0	0.005	9	123	60	35	765.9	138419
7	0	0	-1	1	0	0.005	9	77	100	35	706.3	125271
8	0	0	1	1	0	0.005	9	123	100	35	1036.3	199902
9	0	-1	0	0	-1	0.005	8	100	80	30	611.2	104557
10	0	1	0	0	-1	0.005	10	100	80	30	731	130697
11	0	-1	0	0	1	0.005	8	100	80	40	816.9	149781
12	0	1	0	0	1	0.005	10	100	80	40	981.7	187227
13	-1	0	-1	0	0	0.003	9	77	80	35	761.1	137345
14	1	0	-1	0	0	0.007	9	77	80	35	457.2	71750.5
15	-1	0	1	0	0	0.003	9	123	80	35	1376.3	284574
16	1	0	1	0	0	0.007	9	123	80	35	668.1	116899
17	0	0	0	-1	-1	0.005	9	100	60	30	550.2	91442.9
18	0	0	0	1	-1	0.005	9	100	100	30	732.7	131081
19	0	0	0	-1	1	0.005	9	100	60	40	760.6	137247
20	0	0	0	1	1	0.005	9	100	100	40	1025.6	197403
21	0	-1	-1	0	0	0.005	8	77	80	35	568.4	95350.3
22	0	1	-1	0	0	0.005	10	77	80	35	678.6	119188
23	0	-1	1	0	0	0.005	8	123	80	35	824.2	151417
24	0	1	1	0	0	0.005	10	123	80	35	990.6	189272
25	-1	0	0	-1	0	0.003	9	100	60	35	1007.2	193119
26	1	0	0	-1	0	0.007	9	100	60	35	484.2	77433
27	-1	0	0	1	0	0.003	9	100	100	35	1369.3	282636
28	1	0	0	1	0	0.007	9	100	100	35	637.5	110243
29	0	0	-1	0	-1	0.005	9	77	80	30	524.4	85952.4
30	0	0	1	0	-1	0.005	9	123	80	30	760.4	137203
31	0	0	-1	0	1	0.005	9	77	80	40	727.4	129913

Table 7: Continue

	Coded level of the variables					Actual of level variables					Response (Simulation and observed)	
Run	X_1	X_2	X_3	X_4	X_5	Leak-off Cefficient (ft/min$^{0.5}$)	EOJ (ppg)	Fracture height (ft)	Time (min)	Injection rate (bpm)	Conductivity MD (ft)	Proppant mass (lbs)
32	0	0	0	0	1	0.005	9	123	80	40	1051	205335
33	-1	0	0	0	-1	0.003	9	100	80	30	1010.5	193894
34	1	0	0	0	-1	0.007	9	100	80	30	475.9	75675.5
35	-1	0	0	0	1	0.003	9	100	80	40	693	287323
36	1	0	0	0	1	0.007	9	100	80	40	657.2	114535
37	0	-1	0	-1	0	0.005	8	100	60	35	595.0	101069
38	0	1	0	-1	0	0.005	10	100	60	35	710.7	126336
39	0	-1	0	1	0	0.005	8	100	100	35	796.1	145136
40	0	1	0	1	0	0.005	10	100	100	35	956.5	181420
41	0	0	0	0	0	0.005	9	100	80	35	770.6	139469

Table 8: ANOVA analysis

Conductivity (MD.ft)	df	SS	MS	F-value	p-value	SD
Total	41	2.77471e+007	676758			
Constant	1	2.54945e+007	2.54945e+007			
Total connected	40	2.25264e+006	56315.9			237.31
Regression	20	2.0302e+006	101510	9.12709	0.000	318.606
Residual	20	222437	11121.8			105.46
Lack-off fit	20					
Pure error	0					

N = 41, DF = 27; R^2 = 0.901, R^2Adj.= 0.803; Cond. no. =16.9824, Y-miss = 0, RSD =105.4601

height and these interaction among these variables of X_1. $X_1.X_1$, $X_2.X_2$, $X_4.X_4$, $X_1.X_5$, $X_2.X_3$, $X_2.X_4$, $X_2.X_5$, X_3X_4, X_3X_5, X_4X_5. This is due to the higher injection rate and longer injection time which longer fracture half-length sas wider fracture width because the two variables of injection rate, injection time are directly proportional to fracture half-length of course directly proportional to fracture width. This results show increased in the fracture conductivity. Through the fracture conductivity model has been built, it shows significantly coefficient confident factor of R^2 reached to 90.1%. By using RSM tool, the optimum operating fracturing parameters were obtained including leak-off coefficient of 0.0031 ft/min$^{0.5}$, proppant concentration end of the job of 10 ppg, fracture height at 122 ft, injection time of 87 min, injection rate of 40 bpm and the maximum fracture conductivity at 1462.32 MD.ft.

CONCLUSION

By applying BBD and RSM for four operating fracture parameters and one variable fracture height during fracture growth of the fracture treatment in the tight oil reservoir like Oligocene, this could be summarized these good points of the study as the following.

The PKN-C fracture model is suitable for fracture treatment like tight oil sand reservoir where the growing fracture length is higher than in the fracture height. During pumping with proppant slurry into the fracture under high pressure, the fracture geometry is gradually growing in terms of these variables but the positive variables and negative variables are considered. It means that the negative parameter as leak-off coefficient is to reduce the fracture conductivity.

By using response surface methodology, the optimization of operating fracturing parameters and fracture height have been obtained in which the fracture conductivity is maximized of 1462.32 MD.ft

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