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Evaluation of the Hydraulic Fracturing Implementation at Well WEA-01 Layer A3

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ABSTRACT

The WEA-01 well produces in the A3 productive layer, Talangakar Formation with a layer thickness of 32.80 ft with a perforation interval of 4340.55 – 4360.24 ftMD. From petrophysical data, this tight formation which is dominated by sandstone, has permeability about 3 mD and porosity 10%. The hydraulic fracturing was implemented to improve the production rate, and this research aims to evaluating the actual results. The 3D model and 2D PKN (Perkins-Kern-Nordgens) model were used in this evaluation. The evaluation included the geometry of the fracture and productivity index calculation using the Cinco-ley Samaniego and Dominique method. Inflow Performance Relationship before fracturing was calculated by Darcy method and after fracturing was calculated by Pudjo Sukarno method. The calculation by using 2D PKN was obtained fracture length (X_f) of 200.07 ft, fracture height (h_f) of 32.80 ft, and fracture width (w_f) of 0.23inch, fracture conductivity of 5094.70 mD-ft, and FCD 8.5, while the results of after fractured average permeability using Howard & Fast method obtained 15.71 mD. Howard & Fast method obtained increase of PI about 5.2 times from the initial conditions, while Cinco-Ley, Samaniego & Dominique method obtained increase of 3.45 times. IPR curve showed an increase in the production rate from 45BOPD to 330 BOPD. Based on the increase in the fluid production rate, the implementation of Hydraulic Fracturing that has been carried out can be said to be successful.

Keywords – conductivity, 2D PKN, fracture geometry, hydraulic fracturing, tight formation.

I. INTRODUCTION

Rock permeability is one of the factors that greatly affect the size of the productivity of a well. Small rock permeability will affect the low price of the productivity index (PI) of wells which is an indication of low well productivity. The low permeability value can occur because of the low natural reservoir permeability (tight permeability). The hydraulic fracturing method is one of the methods used in wells with low permeability to increase formation productivity. Hydraulic Fracturing is a stimulation method that aims to increase the productivity of the well by increasing the effective radius of the well (rw') by injecting high-viscosity fluid at a certain rate and pressure so that it can fracture the formation. The fracture that is formed is then propped up with prop material with the aim that the fracture that has formed does not close again.

The WEA-01 well is one of the oil production wells located in Prabumulih, South Sumatra. The WEA-01 well produces in the layer A3 where the formation is dominated by sandstone with a low permeability value (Koesoemadinata,1980) based on petrophysical data of 3 mD and a porosity of 10% and hydrocarbon reserves which are considered economic variables. Hydraulic Fracturing stimulation is carried out to increase the permeability of the layer A3 produced. The WEA-01 well is a directional well that was drilled in February 2022 and is stimulated by Hydraulic Fracturing shortly after the well is drilled.

Evaluation of the implementation of the Hydraulic Fracturing stimulation needs to be carried out to assess the success of the Hydraulic Fracturing stimulation that has been implemented so that it can be known whether the Hydraulic Fracturing stimulation activity is optimal or not. The success of the Hydraulic Fracturing implementation can be seen from several parameters including the increase in the average permeability of the formation, the increase in the productivity index (PI), and the increase in the production rate.

II. METHODOLOGY

In the evaluation of the Hydraulic Fracturing well WEA-01 is carried out by collecting the required data such as reservoir data, rock mechanics, well completion, post-job reports, and production data. The initial stage is to analyze the planning of the fracturing fluid and proppant to be used, then analyze the implementation of the frac data including breakdown test analysis, step rate test, minifrac, and main frac, then evaluate the fracture geometry with manual calculations using the 2D PKN method, then do the calculations the average formation permeability using the Howard and fast method, increasing formation productivity (J/Jo) with the Cinco-Ley Samaniego and Dominique method, and determining the inflow performance relationship (IPR) graph using the Darcy method for IPR before fracture and using the Pudjo Sukarno for IPR after fracturing.

III. RESULTS AND DISCUSSION

Fracturing Fluid and Proppant Selection

The Talang Akar Formation of the WEA-01 well has layers composed of sandstone so that Hydraulic Fracturing stimulation is carried out so that the productivity of the well can be increased. The Talang Akar - A3 Formation has a small permeability value of 3 mD, reservoir pressure of 1612 psi, 10% porosity, and reservoir temperature of 194.8 ^{o} F. Spectra Frac G-3500 fracturing fluid is a water-based fracturing fluid so it is safe to use in sandstone layers because does not cause swelling problems when used. In addition, Spectra Frac G fluid with crosslinker additive XLW-56 has resistance to high temperatures up to +/- 230°F (BJ Frac Manual, 2005) where the bottom temperature of the WEA-01 well is 194.8°F.

Table III- 1
Proppant Super HS Properties

Parameter	Value	Unit
Size	20/40	mesh
Proppant density	13.37	lb/gal
SG Proppant	2.53	
Proppant Diameter	0.029	in
Pack Porosity	35	%

The used proppant is Super HS 20/40, Resin-Coated Sand type with a bulk density of 13.37 lb/gal. Proppant Super HS 20/40 means that Proppant can pass through a 20-mesh screen but will be filtered on a 40-mesh screen. As seen in Table III-1 the diameter of the well perforation is 0.4-inch so that the proppant can enter through the diameter of the perforation, in addition, when compared to the width of the fracture formed in the post-job report, it is 0.17-inch while the diameter of the Proppant Super HS 20/40 is 0.029-inch. inch, where the width of the fracture formed, is 5.8 times the diameter of the proppant so that the size of the proppant has been adjusted so that the proppant can enter the formation so that there is no premature screen out. Proppant Super HS 20/40 has the ability to withstand a fairly good closure stress of up to 10000 psi where the initial estimate of the formation closure pressure before the frac data is 2665.11 psi while the breakdown test results are 2102.6 psi, therefore the proppant used is considered appropriate because able to withstand the closure stress of the formation that will be carried out by hydraulic fracturing.

Implementation evaluation

1. Breakdown Test

The breakdown test is a test that is conducted for the first time on the well to determine the value of the fracture pressure (breakdown pressure) and the fracture closure pressure (closure pressure) so that it can be estimated how much pressure and injection rate is needed to keep the fracture open. The breakdown test was carried out by pumping 2% KCL with an injection rate of 8 bpm until the pressure stabilized and then stopping the pump. From the implementation of the breakdown test, the results obtained in the form of the maximum pressure of the tubing surface during the breakdown test of 2450 psi, the value of BH ISIP (Bottom Hole Instant Shut In Pressure) of 2330.4 psi with a Bottom Hole Closure Pressure value of 2102.6 psi.

2. Step rate test

The Step Rate Test is divided into two: the step-up rate test and the step-down rate test. The step-up rate test was carried out by pumping Slickwater with an increased injection rate from 0.6 bpm to 18 bpm at certain intervals. The gradual increase in the fluid rate aims to determine the value of the extension point which will later determine the pressure generated when the fracture begins to open (fracture extension pressure), as well as the pumping rate or fluid injection rate that makes the fracture continue to grow (fracture extension rate). The total fluid used during the Step Rate Test is 189.9 bbl, maximum surface pressure is 3740 psi. From the step-up rate test, the frac. value is obtained extension pressure of 2540 psi or equal to 0.616 psi/ft and an extension rate of 1.5 bpm. A step-down test where the injection rate is lowered gradually aims to determine the friction pressure around the borehole (near wellbore friction pressure). At this stage, it is done by lowering the injection rate from 18 bpm to 0 bpm, and then the pump is turned off. From the step-down rate test analysis conducted by the service company, it is obtained indications of pressure loss due to perforation (perforation-dominated pressure loss).

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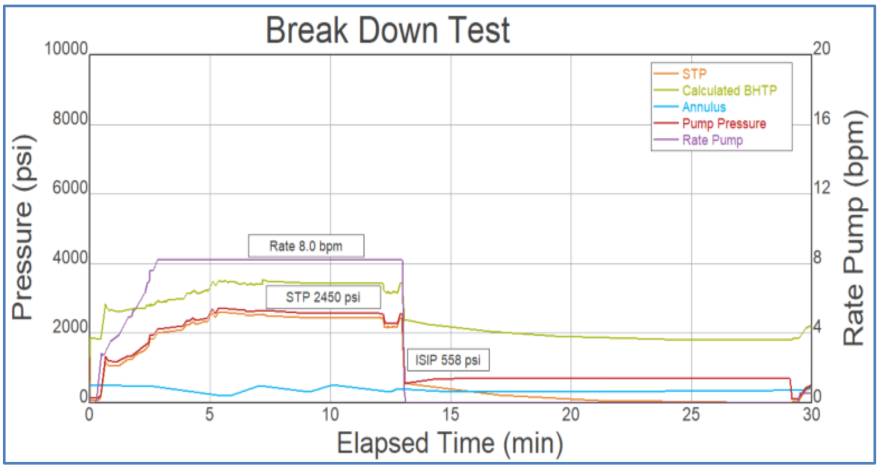

Figure 1. Breakdown Test on WEA-01 Well
(Post job report, 2022)

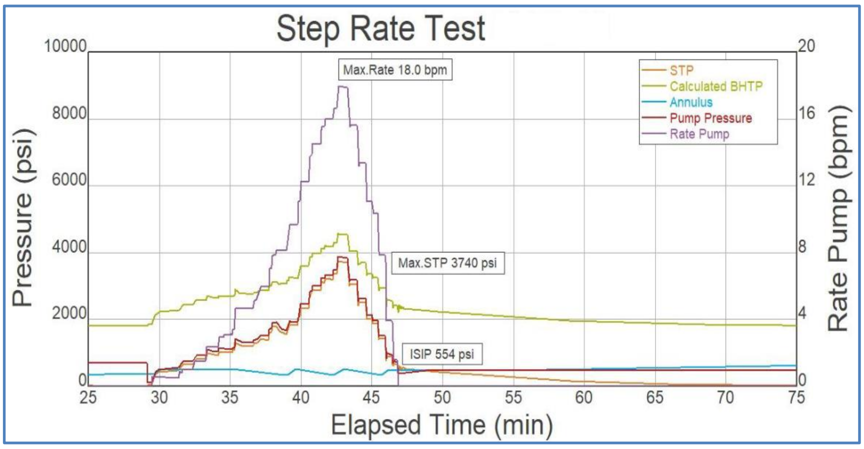

Figure 2. Step rate test on WEA-01. Well
(Post job report, 2022)

3. Minifrac

Minifrac is carried out by pumping the Spectra Frac G-3500 fracturing fluid as much as 221 bbls using an injection rate of 18.3 bpm with a maximum surface pumping pressure of 3550 psi then flushing using Slickwater amount 29.1 bbls. The pump rate is kept constant at 18.3 bpm so that the fracture remains open. Then the pump is turned off as indicated by the injection rate line which is equal to 0 and the ISIP surface is 812 psi. For the closure pressure surface value of 464.4 psi, BH ISIP obtained a value of 2602.7 psi and BH closure pressure of 2269.4 psi, with maximum pumping pressure when flush is 3754. These processes are figured at **Figure 3**.

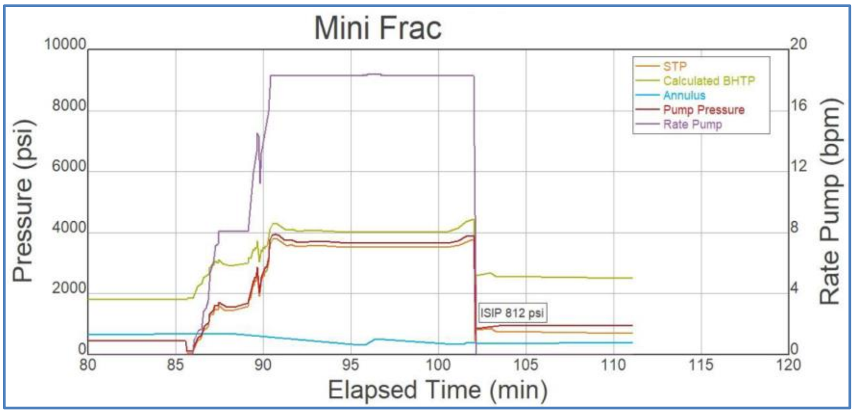

Figure 3. Minifrac on Well WEA-01
(Post job report, 2022)

4. Mainfrac

Main Frac is the main stage of Hydraulic Fracturing operation, Main Frac is implemented by applying a well-prepared design including fracturing fluid selection, Proppant selection, fracture model and shape, and pumping schedule. In the Main Frac implementation, a fluid that complies with the final design is used, namely Spectra Frac G-3500 and uses Proppant Super HS 20/40 and a pumping rate of 16 bpm. These processes are described on **Figure 4** and **Figure 5**. Based on the analysis, the fracture geometry obtained in the actual condition of the WEA-01 well, namely fracture length (Hf) 355.15 ft, average fracture width (w) 0.17673 inch, and fracture height (hf) 53.9731 ft.

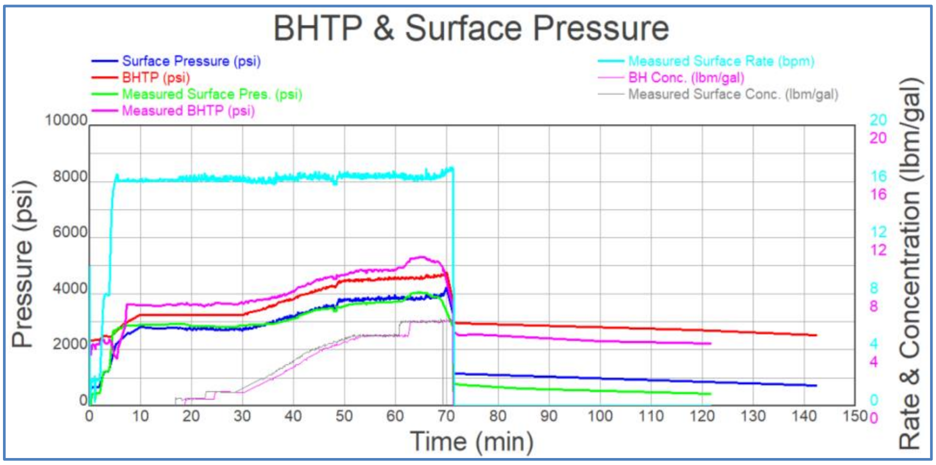

Figure 4.
Mainfrac on Well WEA-01
(Post job report, 2022)

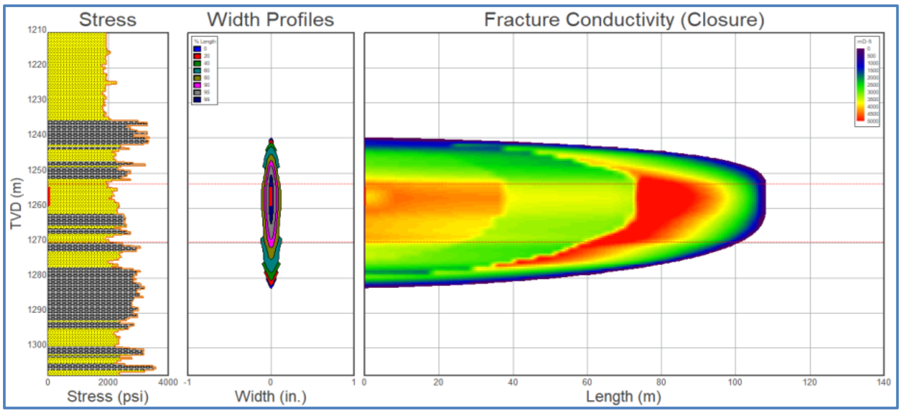

Figure 5. Main Frac at Well WEA-01
(Post job report, 2022)

Evaluation of implementation results

The evaluation of the fracture geometry formed from the Hydraulic Fracturing of the WEA-01 Well was carried out by manual calculations using the Perkins, Kern, and Nordgren fracture geometry model (PKN 2D) the long one. With a large permeability of the fracture formed, an increase in conductivity will be achieved so that the flow of fluid from the reservoir to the wellbore becomes better. Fracture geometry analysis results in a comparison of fracture geometric parameter values between planning, actual conditions, and manual calculations using the 2D PKN method are provided on **Table III-1**.

Table III- 1
Comparison of Fracture Geometry Formed by WEA-01. Well

Parameter	Planning	Actual 3D	PKN 2D Manual	Unit
x_f	343.11	355.15	200.07	ft
$\bar{w}$	0.174	0.176	0.23	inch
h_f	54.03	53.97	32.80	ft

The difference of the fracture geometry parameter values between the manual calculations and the actual results in the field dues to the parameter values from manual calculations are obtained from certain assumptions such as the uniform distribution of proppant throughout the area that fractures without deposition and the flow rate is constant throughout the fracture. In addition, the actual implementation uses the 3D method which also consider the development of the fracture in the vertical direction, while the manual calculation uses the 2D PKN method in which the fracture development in the vertical direction is considered constant.

Another reason why the difference exist is the assumption of 2D PKN method that the fracture height is the same as the layer thickness so that it does not penetrate the upper and lower shale layers of the target layer. Therefore, the planning data and actual BHTP values are quite high up to ± 4700 psi when compared to the fracture pressure of the targeted formation with a fracture pressure of ± 2300 psi causing the fracture height to penetrate the shale layer above and below the target layer, this is done so that the length of the fracture formed can be more optimal. **Table III-2** shows the comparison of surface injection pressure and Horsepower pumps needed during the fracture treatment process between actual 3D result and 2D PKN method approach.

Table III- 2
Comparison of Surface Injection Pressure and Pump Horsepower at WEA-01 Well

Parameter	Planning	Actual 3D	PKN 2D Manual	Unit
STP	3266.1	4231.3	1936.15	psi
Pump Power	1280.3	1645.7	759.27	HHP
BHTP	3790.8	4782.9	2539.38	psi

Production evaluation

1. Evaluation of formation permeability

Calculation of fracture permeability (k_f) and formation average permeability (kavg) uses the Howard and Fast equations.

a. Fracture permeability (k_f)

$$K_f = \frac{(k \times h)+Wk_f}{h}$$
$$K_f = \frac{(3(32.80))+5094.70}{32.80}$$
$$K_f = 158.28 \text{ mD}$$

b. Average formation permeability (K_{avg})

$$K_{avg} = \frac{\log\left(\frac{re}{rw}\right)}{\left(\frac{1}{k_f}\times\log\frac{x_f}{r_w}\right)+\left(\frac{1}{k_i}\times\log\frac{r_e}{x_f}\right)}$$
$$K_{avg} = \frac{\log\left(\frac{820.209973}{0.2615}\right)}{\left(\frac{1}{158.28}\times\log\frac{200.07}{0.2615}\right)+\left(\frac{1}{3}\times\log\frac{820.209973}{200.07}\right)}$$
$$K_{avg} = 15.71 \text{ mD}$$

In the calculations that have been carried out, it is seen that there is an increase in the average permeability value of the formation in the WEA-01 well after Hydraulic Fracturing, the initial well permeability value of 3 mD after the Hydraulic Fracturing calculation is 15.71 mD. This means that there is an increase in rock permeability of 5.23 times from the initial permeability value.

2. Increased productivity index (PI)

In the evaluation of the WEA-01 Hydraulic Fracturing well, the calculation of the productivity index used the Cinco-Ley Samaniego and Dominiquez methods. The results are shown on Table III-3. Parameter values from the manual calculation results are lower than the actual results of the Mfrac software in the post job report, this occurs because the manual fracture geometry calculation uses a different method from the mfrac software where manual calculations use the 2D PKN method while the Mfrac software uses the P3D method so that it affects the geometry of the resulting fracture and causes differences in the values of Fcd, FOI, and skin which are calculated using the Howard and Fast equations.

Table III- 3
Productivity Index Value Comparison

Parameter	Actual 3D	PKN 2D Manual
Fcd	3.7	8.5
Skins	-6. 13	-5.72
FOI	4. 2023	3.4595

3. Inflow Performance Relationship (IPR)

Determination of the Inflow Performance Relationship (IPR) is an analysis that aims to find the optimum production rate which is determined by looking at the intersection of the inflow performance curve rate and outflow performance rate (**Figure 6**). IPR which is before hydraulic fracturing was carried out, was calculated due to the absence of production data, while the Pudjo Sukarno method was used to determine the IPR after hydraulic fracturing.

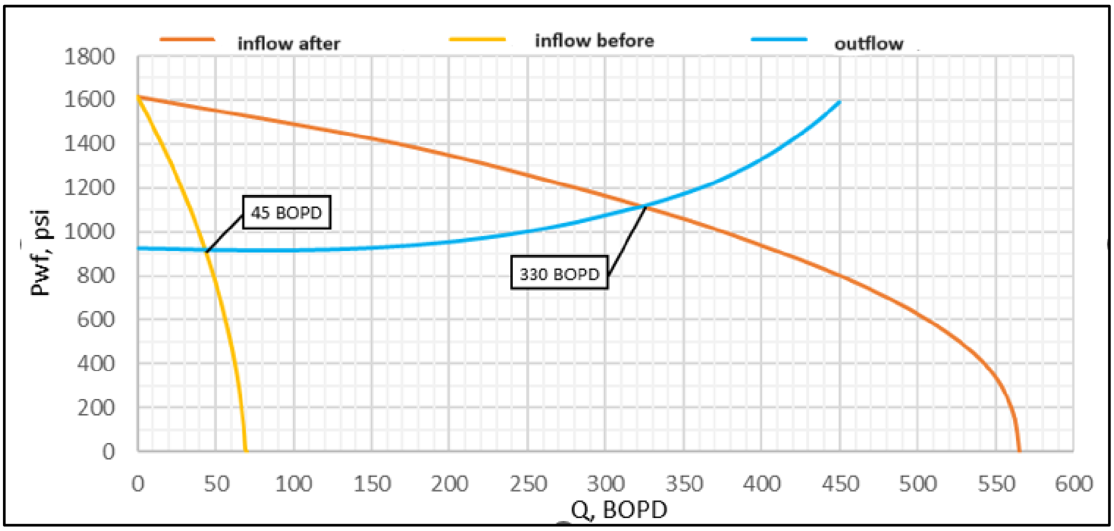

Figure 6. IPR Before and After Fracturing WEA-01

Based on the IPR graph (**Figure 6)**, the rate of oil obtained after fracturing at the WEA-01 using the IPR Pudjo Sukarno method was 330 bopd. Therefore, the implementation of hydraulic fracturing in the WEA-01 well can be said to be successful because there was increases in the production rate from 45 bopd to 330 bopd.

IV. CONCLUSION

Based on the results of the evaluation carried out on the WEA-01 Well, several conclusions were obtained from the implementation of Hydraulic Fracturing stimulation at the WEA-01 Well as follows:

1. Evaluation of WEA-01 Well Hydraulic Fracturing was carried out using the 2D PKN method which resulted in a fracture length (xf) of 200.07 ft, an average fracture width ($\bar{w}$) of 0.23 inch, and a fracture height (hf) of 32.80 ft. As well as the value of the fracture conductivity of 5094.70 mD-ft.
2. Calculation of the average permeability of the formation using the Howard & Fast method after Hydraulic Fracturing in the WEA-01 Well has an increase of 5.2 times from the initial permeability of 3 md to 15.71 md.
3. The calculation of the productivity index using the Cinco-ley, Samaniego, and Dominique methods showed an increase in well productivity of 3.45 times for the fractures resulting from the manual calculation of PKN 2D.
4. From the evaluation that has been done, it can be said that the implementation of Hydraulic Fracturing was successful in increasing the productivity of the well because the fracture was successfully formed and the Proppant could be transported properly to form fracture conductivity which could increase the production rate to 330 BOPD.

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