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EVALUATION OF HYDRAULIC FRACTURING STIMULATION BASED ON ENGINEERING AND ECONOMIC ASPECT AT "ADN-007" LAYER A3

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ABSTRACT

The "ADN-007" is a production well located in the "APS" Field of the South Sumatra Basin, which has been operating since 1959. In 2023, a workover and hydraulic fracturing stimulation were performed at a depth of 1280 meters, precisely in the Talang Akar Formation, which consists of sandstone. The evaluation involved collecting engineering and economic data and performing calculations such as fracture geometry using the PKN 2D (Perkins-Kern-Nordgren) manual method, Fold of Increase using the Cinco-Ley Samaniego Dominique method, production prediction using the IPR Pudjo Sukarno method, and economic analysis. Based on the geometry evaluation calculations, the fracture length (xf) formed is 85.339 m, with a fracture height of 18.9 m, and an average permeability of 56.692 mD. The effective well radius (rw') is 69.996 ft, and the total skin after hydraulic fracturing stimulation is -3.992. According to the nodal analysis results, "ADN-007" has optimal production after stimulation from 2023 to 2027, producing consecutively 330 b/d, 260 b/d, 198 b/d, 130 b/d, and 79 b/d. However, based on economic aspects, this stimulation is classified as uneconomical because the Profit to Investment Ratio value obtained is only 0.65.

Keywords: Cinco-ley Samaniego & Dominique**,** Hydraulic fracturing, PKN 2D, Pudjo Sukarno.

I. INTRODUCTION

The "ADN-007" is one of the production wells located in the "APS" field, precisely within the Prabumulih Regency area, South Sumatra. This well has undergone several workovers since 1959. In 2023, this well was again carried out a workover on Layer A3 because in the previous layer, the water cut value had reached 99.2%. The workover carried out on Layer A3 is based on the successful production of correlated wells that have been produced on Layer A3. Based on logging data, Layer A3 has a permeability of 10.8 mD where the value is categorized as low permeability. Based on the data of correlated wells producing in the same layer, the amount of production will be optimized if hydraulic fracturing stimulation is carried out, so this stimulation is also carried out at "ADN-007".

Hydraulic fracturing is a stimulation method by injecting fracturing fluid to form fractures in rock formations that aims to increase the production of a well by increasing the value of the effective radius of the well, the permeability of the reservoir rock, and improving the skin value. The fractures that have been formed will be propped up with a propping material called proppant. The fractures formed in the rock become the way for hydrocarbon fluid to flow into the wellbore. Hydraulic fracturing stimulation is performed on wells that have decreased productivity due to the small permeability of the reservoir rock and the influence of the skin.

Evaluation of hydraulic fracturing activities is very important with the aim of seeing the success rate of hydraulic fracturing activities, both in terms of engineering and economics aspect. The results of hydraulic fracturing activities can increase the radius of the effectiveness of the well, increase the value of the permeability, improve the skin value, and increase the productivity of the well so that the increase can cover the investment costs incurred for hydraulic fracturing activities.

II. METHODS

Evaluation activities are conducted by collecting field data such as reservoir data, production data, well data, hydraulic fracturing stimulation data, and rock mechanics data. Then evaluating a series of hydraulic fracturing stimulation activities consisting of the use of fracturing fluid types and proppant types as well as reading graphs from the results of hydraulic fracturing stimulation operations consisting of breakdown tests, step rate tests, mini frac, and mainfrac.

The next step is to perform manual calculations including fracture geometry calculations that can be calculated using the PKN 2D manual method as in **Equation (1)** and **Equation (2)**.

$$w(0) = 9{,}15^{\frac{1}{2n'+2}} \times 3{,}98^{\frac{n'}{2n'+2}} \left[\frac{1 + 2{,}14n'}{n'}\right]^{\frac{n'}{2n'+2}} K'^{\frac{1}{2n'+2}} \left[\frac{qi\, h_f{}^{1-n'} x_f}{E'}\right]^{\frac{1}{2n'+2}} \quad (1)$$

$$x_f(iterasi + 1) = \frac{(\overline{w} + 2Sp)q_i}{4\, C_L{}^2 \pi\, h_f}\left[\frac{1}{\beta\sqrt{\pi}} + \frac{2\beta}{\sqrt{\pi}} - 1\right] \quad (2)$$

w(0) = maximum farcture width [m]
n' = flow behavior index
K' = consistency index [pa.sec^1/2]
qi = pump rate [m^3/sec]
hf = fracture height [m]
xf = fracture half-length [m]
E' = strain modulus [pa]
Sp = spurt loss [m^3/m^2]
C_L = leak-off coefficient [m/sec^0,5]
$\beta = \frac{2C_L\sqrt{\pi t}}{w + 2Sp}$

After getting the size of the fracture, the next step is to calculate the average permeability using the Howard and Fast method, as in the equation below:

$$K_{ef} = \frac{(K_i \times h) + WKf}{h} \quad (3)$$

$$K_{avg} = \frac{Log\left(\frac{re}{rw}\right)}{\left(\frac{1}{K_{ef}}\right) Log\left(\frac{xf}{rw}\right) + \left(\frac{1}{K_i}\right) Log\left(\frac{re}{xf}\right)} \quad (4)$$

Ki = initial permeability [mD]
h = net pay [m]
WKf = frac conductivity [mD.ft]
re = well drainage radius [m]
rw = well radius [m]

The next step is to determine the Fold of Increase (FOI) using the Cinco-Ley, Samaniego, and Dominique methods, assuming a cylindrical drainage area with a homogeneous reservoir bounded by an impermeable layer.

$$FOI = \frac{ln\left[\frac{re}{rw}\right]}{ln\left[\frac{re}{rw'}\right]} \quad (5)$$

The next step is to calculate the skin value, while the skin values calculated are skin damage, skin caused by perforation, skin partial penetration completion, and skin caused by turbulent flow. Skin caused by perforation is obtained by reading the graph of K.C. Hong (1975). Skin partial penetration is calculated using the equation of Aziz S. Odeh (1980), while skin caused by turbulent flow is obtained from the equations of Jones, Blount, and Glaze. This skin value is used to calculate the flow rate pressure after hydraulic fracturing stimulation. The flow rate pressure in the well is calculated using the principle of pressure loss from the reservoir to the well, which is the value of pressure loss in the porous medium and pressure loss in the completion area.

Next is to predict the value of the production fluid flow rate after stimulation. The calculation is obtained by the Pudjo Sukarno method as in **Equation (6)** and calculated over the next five years.

$$\frac{Qo}{Qt, max} = A0 + A1(Pwf/Pr) + A2(Pwf/Pr)^2 \quad (6)$$

An $= C0 + C1(WC) + C2(WC)^2$
Pwf = flow rate pressure [psi]
Pr = reservoir pressure [psi]
Qo = oil flow rate [bbl/day]
Qt, max = maximum flow rate [bbl/day]

The calculation of the flow rate in the following year is depicted on the future IPR chart; these are calculated by considering the reduction in reservoir pressure each year. The reservoir pressure drop is calculated by using the pivot point method. The next is to make a nodal analysis so that with this analysis the optimum flow rate value is obtained. This optimum flow rate will be used to calculate the amount of income obtained after stimulation. The calculation on this economic aspect consists of economic limit, Net Present Value (NPV), Rate of Return (ROR), Pay Out Time (POT), Profit to Investment Ratio (PIR), and Discounted Profit to Investment Ratio (DPIR).

NPV is the value of a project's net profit measured today. The equation to calculating NPV is as follows:

$$NPV = NCF_0 + \frac{NCF_1}{(1+r)^1} + \frac{NCF_2}{(1+r)^2} + \cdots . + \frac{NCF_n}{(1+r)^n} \quad (7)$$

NCF = net cash flow
n = year

ROR is the speed of return on capital or a relative value of the profit cost invested (capital). The calculation of ROR is done by trial and error until NPV=0 is obtained. The minimum limit of ROR is MARR (Minimum Rate of Return) and must be greater than the bank interest rate. The ROR can be calculated by the equation:

$$0 = \Sigma_{t=1}^{n} CF_0 + \frac{CF_n}{(1+ROR)_n} \quad (8)$$

The PIR is a comparison between net cash flow before discount and the amount of invested costs. A good PIR is a PIR that is more than one. The PIR can be calculated by the following equation:

$$PIR = \frac{\Sigma NCF_{undiscounted}}{Investasi} \quad (9)$$

DPIR is a comparison between net cash flow after discount and investment costs incurred. DPIR is the ability to generate overall profits. The DPIR can be calculated by the following equation:

$$DPIR = \frac{\Sigma NPV}{Investasi} \quad (10)$$

III. RESULTS AND DISCUSSION

3.1. Evaluation of the Use of Frac Fluid and Proppant

Evaluation of the planning for the use of gusher fluid and proppant types is carried out to determine their suitability for the character of the reservoir to be fractured.

3.1.1. Evaluation of the Use of Frac Fluid Type

Table 1. Frac Fluid Properties Data

Frac Fluid Properties Data		
Parameter	**Value**	**Unit**
Gel Type	Water based	
Frac Fluid Desinty	62,4	lb/ft^3
SG	1,01	
Flow Behavior Index (n')	0,4479	
Consistency Index (K')	0,031132	lbf.s^n/ft^2
Additive		
Bactericide	Xcide-102	
Clay Stabilizer	KCL	
Gelling Agent	GW-3	
Surfactant	NE-118	
Solvent	US-40	
2nd Bacteria	Bleach	

Buffer	BF-7L
X-Linker	XLW-56
Breaker	GBW-5

The reservoir in Layer A3 has a sandstone rock type with a relatively low reservoir temperature of 198 °F. The polymer used in this frac fluid is guar, this type has the advantages of being relatively cheap, environmentally friendly, and prevent fluid loss. In the process of injecting frac fluid with the addition of additive clay stabilizer KCL serves to hold clay so that it can prevent swelling problems. Bactericide with code Xcide-102 is used as anti-bacteria so that bacteria do not develop in the frac fluid. Bleach is the 2nd bactericide used to kill bacteria that develop in the water based frac fluid. A breaker is added into this frac fluid to break the polymer chain at reservoir temperature less than 225 °F.

3.1.2. Evaluation of the Use of Proppant

Table 2. Proppant Properties Data

Parameter	Value	Unit
Proppant Type	Carbolite	
Size	20/40	mesh
Density	10,364	lb/gal
SG	2,72	
Diameter	0,029	in
Pack Porosity	35	%

Proppant selection has a significant effect on the fracture conductivity that is formed. Carbo ceramics type proppant is Carbolite which is classified as a type of low-density ceramics, which can withstand stress up to 6000 psi. Based on the results of minifrac, the closure pressure is 2431 psi, so the use of Carbolite proppant can withstand the existing closure stress. The proppant size of 20/40 mesh is appropriate because this size is recommended by API as the primary size of the proppant. In addition, in terms of the diameter of the perforation, which is 0.4 inch, the 20/40 Carbolite proppant is suitable for use to avoid deposition at the face of the perforation hole.

3.2. Evaluation of Hydraulic Fracturing Operation in "ADN-007" Layer A3

3.2.1. Breakdown Test

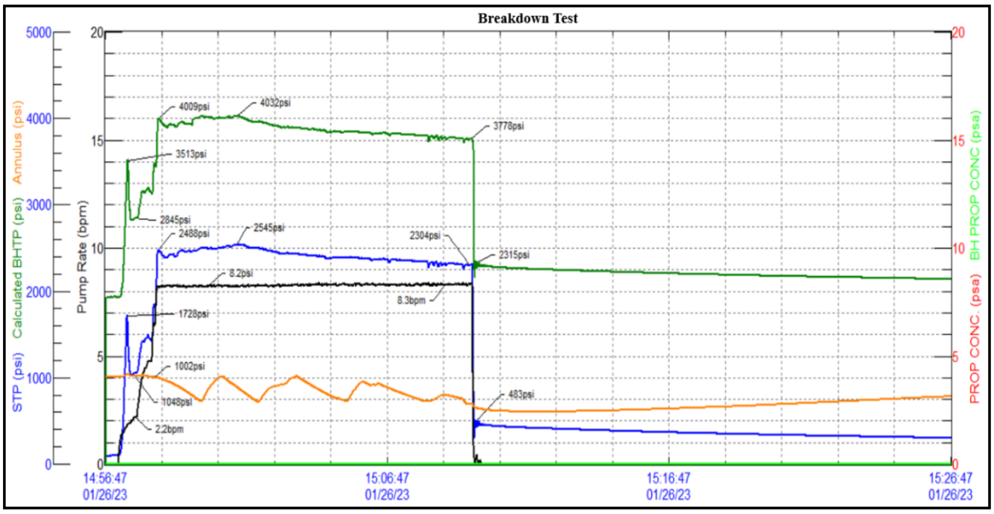

Figure 1. Breakdown Test on "ADN-007"

The breakdown test was conducted by injecting 2% KCL brine and pumping it at a rate of 8 bpm. Based on the surface treating pressure (STP) graph, the initial pressure is 1040 psi and the final pressure is 2304 psi. In addition, the instaneous shut in pressure (ISIP) value is 483 psi.

3.2.2. Step Rate Test

The step rate test is divided into two stages: step up rate test and step-down rate test. At the stage of step-up rate test, slick

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water is injected with 2% KCL. This pumping rate will gradually increase and be maintained for a certain time so that later the fracture extension pressure will be obtained. The step-up rate test in the ADN-007 Layer A3 Well is carried out by injecting 115 bbl of fluid with a pumping rate from 0.9 bpm to 16.1 bpm. while in the step-down rate test, the pumping rate will gradually decrease from 16.1 bpm to 0 bpm. Based on the Step Rate test diagnostic graph, the fracture extension pressure is 2507 psi and the near wellbore friction is 2050 psi.

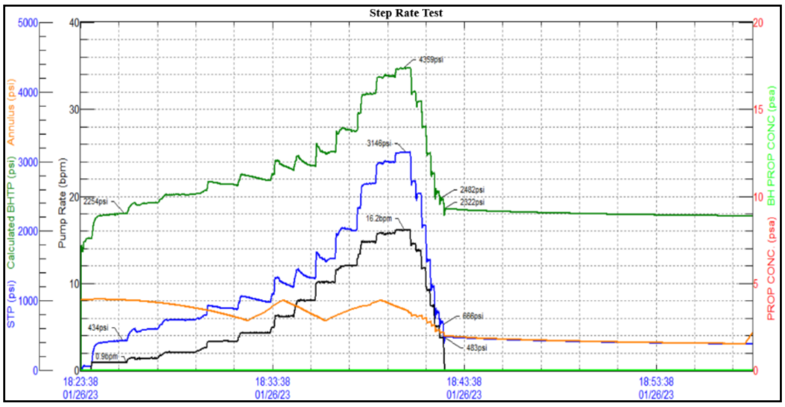

Figure 2. Step Rate Test on "ADN-007"

3.2.3. Minifrac

The minifrac stage is carried out to create small fractures so that data can be obtained that can represent the mainfrac. This minifrac stage focuses on calculating the fluid that enters the formation or fluid leak-off. The frac fluid used in the minifrac stage is the same as the frac fluid that will be used in mainfrac. The fracturing fluid used in the ADN-007 Layer A3 is Spectra Frac G-3500 without the addition of proppant. In the minifrac stage, 170.9 bbl of fracturing fluid was injected at a pump rate of 16.9 bpm. The injection rate of 16.9 bpm was maintained for 10 minutes to form fractures in the rock, then there will be a rapid increase in pressure which is read as the final surface pressure of 4118 psi. After that, the pump is turned off so that the pump rate is 0 bpm, and then the surface ISIP is obtained, which is 671 psi. The amount of total friction is 3447 psi. Next is to analyze the regression of bottom hole pressure with Nolte G time and obtain results such as closure time for 28 minutes, closure pressure of 2431 psi, stress gradient of 0.57, and fluid efficiency of 42%.

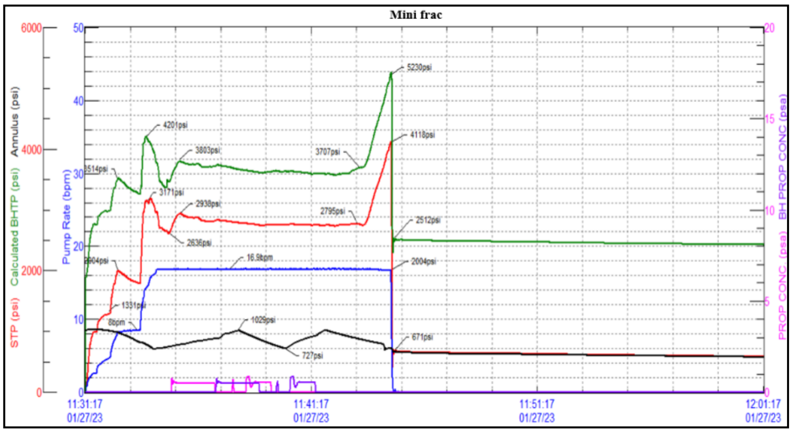

Figure 3. Minifrac Test on "ADN-007"

3.2.3. Mainfrac

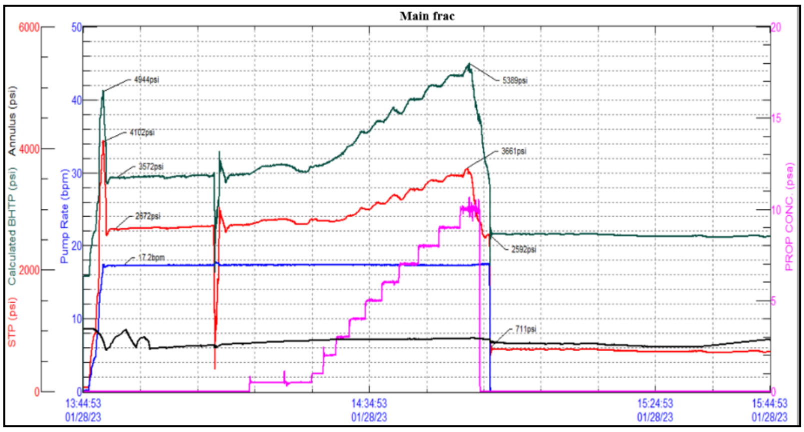

Figure 4. Mainfrac Test on "ADN-007"

Mainfrac is the main process in the series of hydraulic fracturing stimulation. The data used in the mainfrac stage is data that has been adjusted with the results of the previous stages. To reduce the amount of friction that has been known at the step-down rate test stage, the next step is to inject a slug (100 mesh). Next is to inject a frac fluid with proppant (20/40 mesh) as much as 1169.1 bbl which is divided into 11 stages. These stages are divided based on the concentration of proppant added to the frac fluid, the addition of proppant is carried out at a concentration of 0.5 ppa to 10 ppa. This slurry injection is carried out at a pump rate of 17.2 bpm. From the reading of the mainfrac graph, the fracture breakdown value at the surface treating pressure is 4102 psi and the fracture propagation is 2672 psi. After all the frac fluid injection steps are complete, the next step is to turn off the pump, then the pressure will drop to the ISIP value is 711 psi.

3.3. Evaluation of Fracture Geometry

The evaluation of fracture geometry consists of calculating the stress in the rock and manually calculating the fracture geometry. The fracture geometry calculated is about the fracture length (xf), fracture width (wavg), and fracture height (hf). After calculating these data, the next step is to compare and analyze the differences between Mfrac design data, actual data, and manual calculation results.

3.3.1. Rock Stress Calculation

Based on the calculation of stress in rocks carried out manually, the results are obtained as **Table 3.**

Table 3. Rock Stress data

Parameter	Value	Unit
Vertical Stress	4208.136	psi
Minimal Horizontal Stress	1934	psi
Maximum Horizontal Stress	3034	psi

Based on the calculation of the values of the three pressure directions $\sigma Hmin < \sigma Hmax < \sigma V$. So, when the fracture is formed horizontally then the pump pressure must be greater than the vertical pressure which is equal to 4208.136 psi.

3.3.2. Fracture Geometry Calculation

The calculation of fracture geometry formed in hydraulic fracturing stimulation is done by manual calculation of PKN 2D. Based on this method, the values of fracture length, average fracture width, and fracture height were obtained. The data from this calculation is compared with the design data and actual data obtained from the service company so that the comparison results are obtained as shown in Table 4.

Table 4. Comparison of Fracturing Geometry Calculation

Parameter	**Design Data**	**Actual data**	**Manual Data**	**%**
xf max (meter)	63.124	63.551	85.339	26.03%
wavg (inch)	0,18	0,2	0,124	45,27%
hf (meter)	5,85	4,816	5,761	1,59%

The percentage of the difference in calculations in the table above can occur because the manual calculation does not take into account variations in the physical properties of the rock, the manual calculation of the PKN 2D method only focuses on increasing the fracture length (xf), while in actual circumstances there is development in the fracture height, as well as the fracture width, besides that the pumping rate at the time of injection of the fracturing fluid is not 100% guaranteed to be constant or following the design.

3.4. Evaluation of Well Productivity

Evaluation of the productivity of Well ADN-007 was carried out by calculating the increase in permeability that occurred after stimulation, total skin after fracturing, calculation of flow rate pressure (Pwf), Tubing Intake Performance (TIP) calculation, and nodal analysis to obtain the optimum flow rate**.**

3.4.1. Calculation of Permeability After Hydraulic Fracturing

The increase of permeability is done by looking at the results of the calculation with the Howard & Fast method. The permeability results obtained will be compared with the permeability before stimulation. This increase of permeability is only in the area around the fracture not permeability in all reservoir rocks.

Table 5. Comparison of Fracturing Geometry Calculation

Parameter	Value	Unit
Permeability Before Frac (Ki)	10.8	mD
Frac Conductivity	5297.06	mD.ft
re	820.209	ft
Formation Thickness	20.505	ft
rw	0.8596	ft
xf	85.339	m
	279.983	ft

Based on the data in **Table 5** and calculations using **Equations 3** and **4**, the permeability after stimulation is as follows:

$$K_{ef} = \frac{(10{,}8\ mD \times 20{,}505\ ft) + 5297{,}061\ mD.ft}{20{,}505\ ft}$$

$$K_{ef} = 269.127\ mD$$

$$K_{avg} = \frac{Log\left(\frac{820{,}210\ ft}{0{,}8596\ ft}\right)}{\left(\frac{1}{269{,}127\ mD}\right)Log\left(\frac{279{,}9836\ ft}{0{,}8596\ ft}\right)+\left(\frac{1}{10{,}8\ mD}\right)Log\left(\frac{820{,}210\ ft}{279{,}9836 ft}\right)}$$

$$K_{avg} = 56.692\ mD$$

The average permeability (Kavg) of 56.692 mD is the average permeability of the permeability in the formation rock and the permeability in the fracture area.

3.4.2. Calculation of Production Increase or Fold of Increase (FOI)

The calculation of Fold of Increase (FOI) with the Cinco-Ley Samaniego Dominique method begins with finding the value of the effective well radius (rw') by reading the graph as in the **Figure 5**

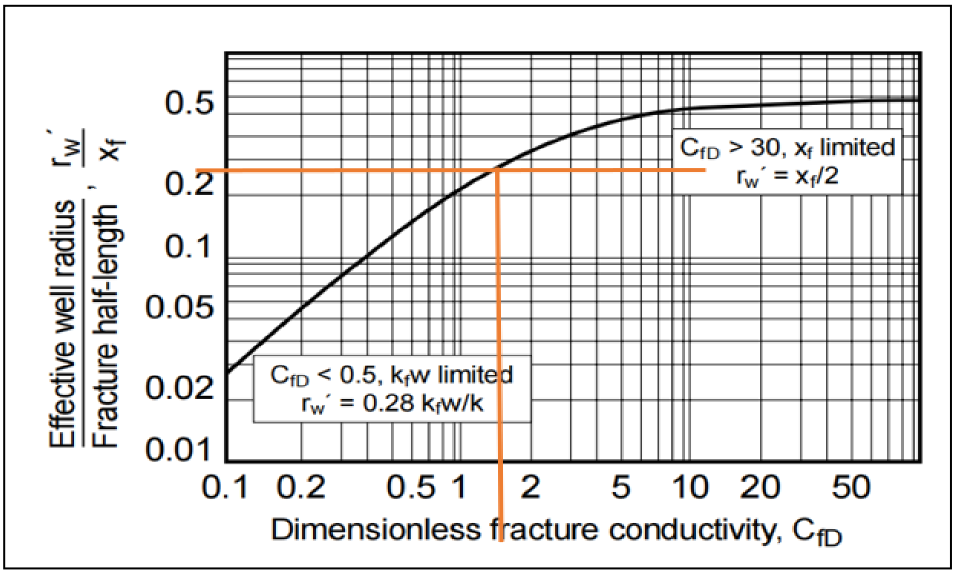

Figure 5. CFD vs rw'/xf

Based on the graph, the value of rw' is 69.996 ft. The next step is to calculate FOI with **Equation 5.**

$$FOI = \frac{ln\frac{820{,}2099ft}{0{,}8596\ ft}}{ln\frac{820{,}2099\ ft}{69{,}996ft}}$$
$$FOI = 2.787$$

The predicted production increase in "ADN-007" is 2.787 greater than production before the stimulation.

3.4.3. Calculation of Skin Factor

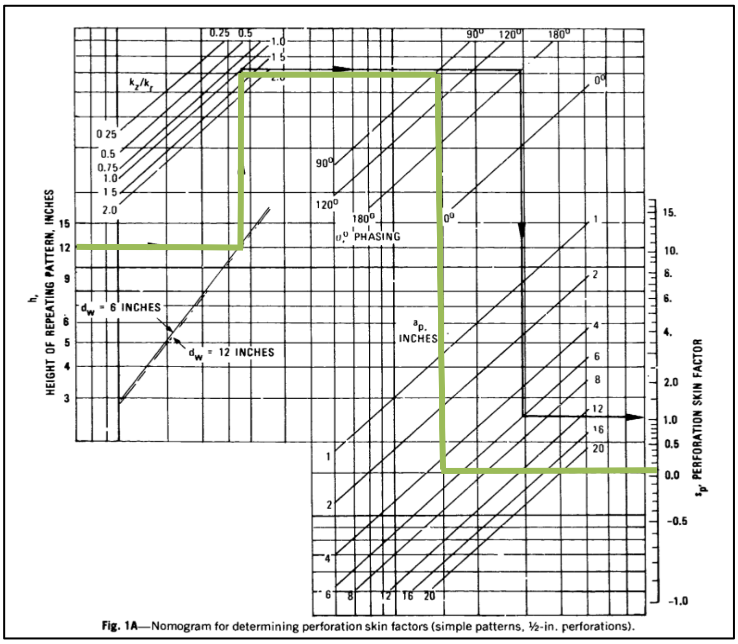

Figure 6. Skin Factor Caused by Perforation

The skin factor caused by perforation is done by reading K.C. Hong's graph as in **Figure 6.** By using data on the height of repeating perforation patterns, well diameter, vertical and horizontal permeability, perforation angle, and perforation penetration, the skin factors caused by perforation is +0,1.

Skin factor caused by partial penetration calculated using Aziz S. Odeh's equation as follows:

$$Spp = 1{,}35\left(\frac{h}{hp} - 1\right)^{0{,}825}\left[ln\left(h\sqrt{\frac{Kh}{Kv}} + 7\right) - 1{,}95 - ln\,rwc\left(0{,}49 + 0{,}1\,ln\left(h\sqrt{\frac{Kh}{Kv}}\right)\right)\right] \quad (11)$$

$$Spp = 1{,}35\left(\frac{20{,}505\,ft}{16{,}404\,ft} - 1\right)^{0{,}825}\left[ln\left(20{,}505\,ft\,\sqrt{0{,}769 + 7}\right) - 1{,}95 - ln\,1{,}716\,ft\,\left(0{,}49 + 0{,}1\,ln\left(20{,}505\,ft\,\sqrt{0{,}769}\right)\right)\right]$$

$$Spp = 0{,}554$$

Based on the calculation with this method, the value of skin factor due to partial penetration is + 0.554. In addition to these two types of skin factors, the skin factors caused by turbulent flow were also obtained using the Jones, Blount, and Glaze methods, which are 0 and skin damage -4.546. So, from some of these values, a total skin value is -3.992. A negative value indicates that there is an improvement in the formation.

3.4.4. Calculation of Flow Rate Pressure and Reservoir Pressure

The calculation of the flow rate pressure (Pwf) is based on the Darcy equation by considering the skin factor and perforation. The flow rate pressure is obtained from calculating the pressure loss on the sand face (ΔP1) as in **Equation (8)** and calculating the pressure loss around the completion (ΔP2) as in **Equation (9).**

$$\Delta P1 = \mathrm{Pr} - Pwfs \quad (8)$$

$$\Delta P2 = Pwfs - Pwf \quad (9)$$

Based on calculations using the equation, the results are obtained as shown in **Table 6**.

Table 6. The Results of Flow Rate Pressure Calculation

Parameter	Value	Unit
reservoir pressure	1863,1	psi
pressure loss on the sandface	100,683	psi
pressure loss around the completion	708,028	psi
flow rate pressure	1054,389	psi

The calculation of reservoir pressure drop is carried out using the pivot point method as in **Figure 7.**

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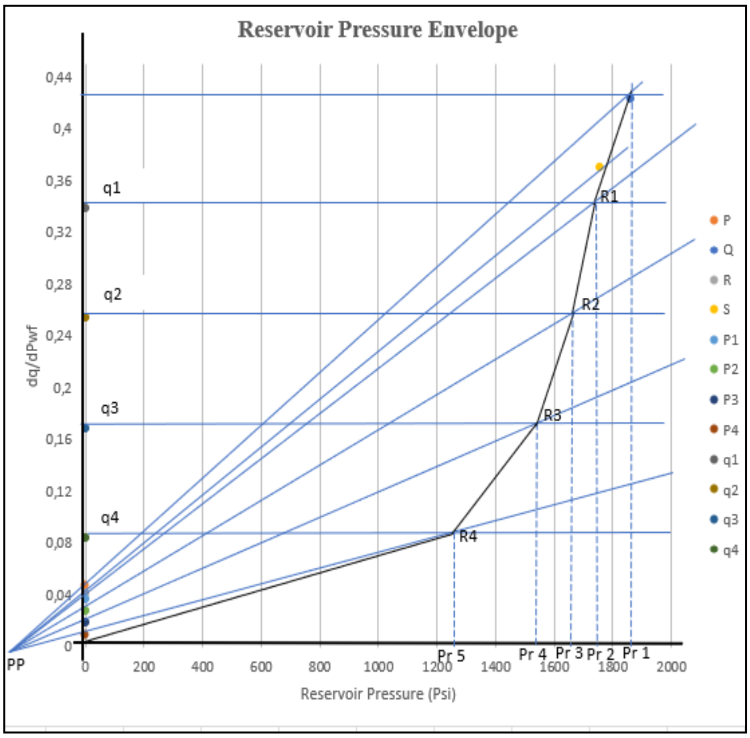

Figure 7. Reservoir Pressure Envelope

Based on this method, the results of reservoir pressure drop calculation over the next five years are as follow:

Table 7. Reservoir Pressure Drop

Year	Reservoir Pressure	Unit
2023	1863,1	psi
2024	1745	psi
2025	1650	psi
2026	1535	psi
2027	1260	psi

3.4.5. Calculation of Inflow Performance Relationship (IPR) and Nodal Analysis

Based on reservoir data, the ADN-007 Layer A3 is a well that is produced in a water drive mechanism reservoir, so the calculation of present and future IPR is carried out using the Pudjo Sukarno method as in **Equation 6**. The calculation of IPR and future IPR is carried out by considering the reservoir pressure drop every year from 2023 to 2027, the amount of constant water cut is 80%, and the use artificial lift which is hydraulic pumping unit (HPU). To determine the amount of optimum flow rate in well ADN 007 after hydraulic fracturing, the calculation of Tubing Intake Performance (TIP) is carried out. The intersection points between the IPR and TIP curves is the optimum flow rate.

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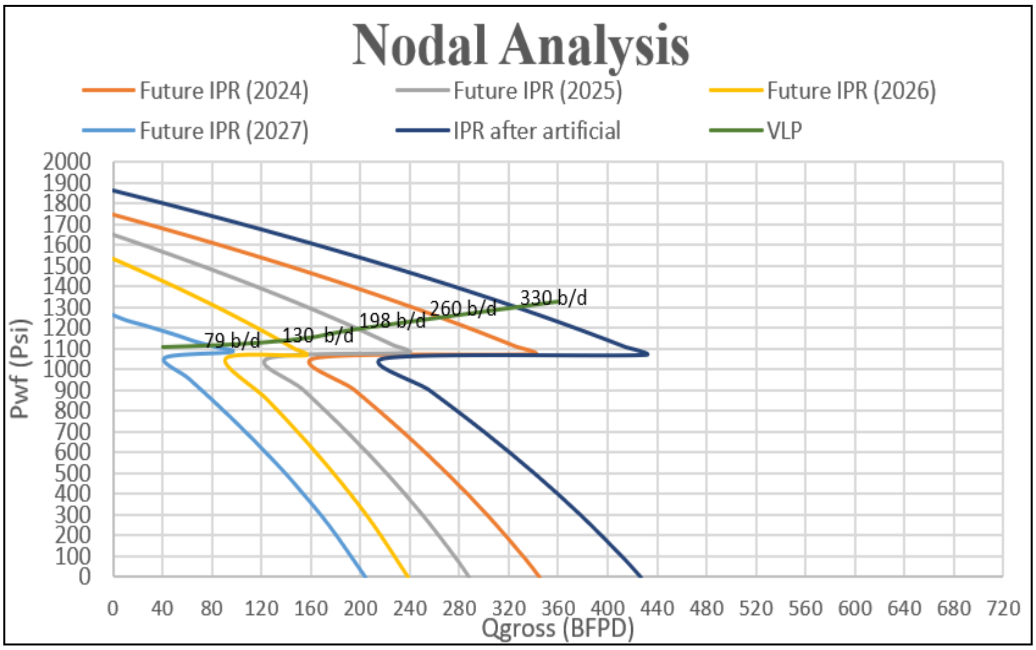

Figure 8. Nodal Analysis

Based on the intersection of the curve, the results are obtained as follows :

Table 8. Optimum Flow Rate

Year	Optimum Rate	Unit
2023	330	bbl/d
2024	260	bbl/d
2025	198	bbl/d
2026	130	bbl/d
2027	79	bbl/d

3.5. Evaluation of Economic Aspect

The first step is to calculate the economic limit value to know the minimum flow rate so that the amount of income received from sales is equal to the amount of costs needed for stimulation and production activities. In this activity, the economic limit value was 7.735 bbl/day. This is a prediction of the amount of oil that can be produced by considering the water cut of 80%.

Table 9. Oil Rate

Year	Flow Rate	Unit
2023	20,13	MSTB
2024	18,98	MSTB
2025	14,454	MSTB
2026	9,49	MSTB
2027	5,567	MSTB

The next is to calculate several economic parameters such as the value of NPV, ROR, PIR, and DPIR at the oil price of 76.06 USD/stb. This economic calculation is carried out when the dollar exchange rate of 1 USD is equal to Rp 15,301.05. The calculation of economic indicators is carried out using **Equations (7)** to **(10).** A sensitivity test is also performed on this calculation. Some of the values carried out by sensitivity are oil price, oil production, lifting cost, and investment. Based on these calculations, the resultsof as follow are obtained:

Table 10. Sensitivity Test Results

Oil Price Sensitivity						
Sensitivity	**Oil Price (usd/bbl)**	**NPV (MUSD)**	**ROR**	**POT (year)**	**PIR**	**DPIR**
80%	60,85	267,75	5,58%	1,24	0,48	0,3
100%	76,06	394,72	12,20%	0,76	0,65	0,5
120%	91,27	648,1	26,80%	0,38	1,03	0,82
Oil Production Sensitivity						
Sensitivity	**Oil Prod. (MSTB)**	**NPV (MUSD)**	**ROR**	**POT (year)**	**PIR**	**DPIR**
80%	55,057	284,09	7,88%	1,07	0,49	0,36
100%	68,821	394,72	12,20%	0,76	0,65	0,5
120%	82,585	505,35	18,62%	0,53	0,81	0,64
Lifting Cost Sensitivity						
Besar Sensitivias	**Lifting Cost (usd/bbl)**	**NPV (MUSD)**	**ROR**	**POT (year)**	**PIR**	**DPIR**
80%	13,26	425,54	13,72%	0,69	0,7	0,54
100%	16,57	394,72	12,20%	0,76	0,65	0,5
120%	19,88	363,91	10,84%	0,84	0,61	0,46
Investment Sensitivity						
Besar Sensitivias	**Investment (MUSD)**	**NPV (MUSD)**	**ROR**	**POT (year)**	**PIR**	**DPIR**
80%	630,15	465,44	22,40%	0,45	0,93	0,74
100%	787,68	394,72	12,20%	0,76	0,65	0,5
120%	945,22	324	7,75%	1,07	0,47	0,34

The red color is a sign that the value is smaller than the economic limit. From the results in **Table 10** Stimulating activities will be economically valuable if oil prices increase by 20% from normal prices (91,27 USD/bbl).

IV. CONCLUSION

Hydraulic fracturing stimulation activities are considered successful from an engineering perspective because the stimulation can increase permeability, improve skin, and boost oil production. However, the stimulation activities are considered a failure from an economic perspective because the amount of oil produced is not sufficient to cover all the costs incurred for the stimulation activities. The stimulation can be economically successful if oil prices increase by 20% from the normal price to 91.27 USD/bbl.

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