

ANALYSIS OF INCREASING WELL PRODUCTIVITY USING THE ACIDIZING MATRIX METHOD IN WELL X FIELD Y

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ABSTRACT

In the well "X" has experienced a decrease in production due to skin, formation damage is usually caused by drilling and cementing operations which cause the rock permeability to be small. well "X" should be repaired in order to increase the productivity of the well by using an acidizing matrix. Matrix acidizing is the injection of acid into the pores of the productive layer where the injection pressure is under the fracture pressure of the formation so that the reaction can radially spread to the rock formation. The well "X" uses the bullhead acid method. The acid used in the "X" well is HCl-15%, whereas HCl-15% has a good enough reaction to dissolve limestone. The first step is to design acidizing in the well X with IBV (Initial Bulk Volume) data of 997.11 Cuft, NIBV (Net Initial Bulk Volume) of 897.40 Cuft, TBV (Target Bulk Volume) of 974.45 Cuft, NTCV (Net Target Carbonat Volume) of 877.00 Cuft, and the volume of carbonate that must dissolve 20.40 Cuft. The volume of acid needed is 1906.11 gallons or 45.38 barrels. The acidification of the "X" well is carried out in three stages, namely preflush, main treatment, overflush. After these steps are carried out, the "X" well is analyzed whether the matrix acidizing process is successful or not. By looking at the production rate of the well "X" has increased from 136.53 BLPD to 458.56 BLPD, oil rate from 136.53 BOPD to 444.00 BOPD and Water Cut before and after stimulation is 3.2%.

Keywords: Skin, Acidizing Matrix, HCL-15%

1 INTRODUCTION

Formation damage is a decrease in the initial permeability of the formation that occurs due to blockages in part or all of the area around the drill hole. One way to overcome formation damage is by stimulation. Stimulation is stimulating a well which is a process of repairing a well to increase the permeability of the formation so that it can increase the production rate to a greater extent. This stimulation is divided into two methods, namely acidizing and hydraulic fracturing. The formation damage that occurred in well X was caused by the presence of skin. In well The company wants to increase its production further until its well production capacity is optimal. One method to reduce or overcome formation damage is to use matrix acidizing. Matrix acidizing is the injection of acid into the pores of the productive layer where the injection pressure is below the formation pressure with the aim that the reaction can spread radially into the formation. Indicators of the success of implementing acidizing stimulation can be seen from the increase in production rate (Q), Inflow Performance Relationship (IPR) curve, and Productivity Index (PI).

2 LITERATURE REVIEW

2.1 Formation Damage

Formation Damage or formation damage is an event of an abnormal decrease in

production rate or low production rate caused by changes in rock characteristics, in this case a decrease in permeability. Formation damage is closely related to permeability and skin factors. Skin is the zone around the perforation that experiences decreased permeability. This skin results in a reduction in the permeability of the formation around the drill hole due to the collapse of the wellbore walls, sedimentation, and invasion of particles during the drilling, completion, and production processes.

2.2 Sources of Formation Damage During Well Operation

In general, formation damage during well operations can originate from drilling, completion, production or injection activities.

2.3 Stimulasi

Stimulation is stimulating the well which is a process of repairing the well to increase the permeability of the damaged formation so that it can provide a large production rate, which ultimately results in the productivity of the well being greater than before the well stimulation was held. Stimulation is carried out on production wells that experience a decrease in production due to formation damage around the wellbore by improving the permeability of the reservoir rock. Stimulation methods can be divided into Acidizing and Hydraulic Fracturing.

2.4 Hydraulic Fracturing

Hydraulic Fracturing is a method of fracturing a formation using sand as a fracture propping medium which aims to increase the production rate in the well. Hydraulic fracturing is usually used in wells that have less than optimal production rates or there are problems with the well, such as low formation permeability, damage around the well or skin factors. Apart from that, fracturing activities will be carried out if hydrocarbon reserves in the reservoir are still sufficient but the hydrocarbons produced do not meet expectations.

2.5 Acidizing

Acidizing is one of the well repair processes to overcome or reduce formation damage in an effort to increase production rates by dissolving the particles that clog the pore channels, thereby enlarging the available channels or perhaps moreover opening new channels as a result of dissolution or reaction between acid and rock.



Figure 1. Matrix stimulation treatment using a coiled tubing unit, pump truck, and fluid transport (Sumber: Economides, M and Boney, C, Reservoir Stimulation, 1989: 51)

2.6 Types of Acidizing

Well stimulation with acidizing can be divided into three types, namely:

- Acid washing is a type of acidizing to remove scale deposits which can dissolve in the acid solution contained in the wellbore to open blocked perforations.
- Acid fracturing, namely injecting acid into the formation at a high enough pressure to crack the formation or open existing fractures. Used only for carbonate formations because if done on sandstone formations it can cause the formation to collapse and result in sand problems.
- Matrix acidizing is the injection of acid into the formation at a pressure below the fracturing pressure, with the aim that the acid reaction spreads into the formation radially. Used for both carbonate rock (limestone) and sand stone. This technique will work for wells with damage 1-2 ft deep.

III METHOD

3.1 Introduction

This introduction was carried out for literature studies, interviews and field observations related to Matrix Acidizing, both from the company and from outside the company.

3.2 Collecting Data

The data needed in this final project is well data which includes well radius (r_w), drain radius (r_e), pressure (P), depth (D), skin, formation thickness (h), formation fracture gradient (G_{rf}), penetration and perforation. Next, production data is production rate (Q) and reservoir data is permeability data (k), viscosity (μ), porosity (ϕ), oil formation volume factor (B_o).

3.3 Processing Data

The data obtained is then analyzed to calculate the amount of acid that will be injected into the well, estimate the acid injection time according to the well that will be injected with acid, calculate skin, ΔP_{skin} , and FE before and after stimulation and calculate the optimum Q before and after doing it. stimulation.

4 RESULTS AND DISCUSSION

4.1 Preparation Data

In designing an acidifier, basic data is needed to be entered into the equation. Some data is unknown, so correlation and calculations must be carried out to determine it.

Table 1 Data Sumur

Wellbore Data		
Total Depth	2217	m
Casing		
20"K-40,94ppf	300	m
13 3/8"K-55 54.5 ppf	1009	m
9 5/8"N-80 40 ppf	1977	m
7"N-80 23 ppf	2525.4	m
Perforation (F)	1034.5-1036.5	m
	1042-1043	m

	1086.5-1088	m
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Table 2 Reservoir Data Sumur X

WELL DATA	
Reservoir Data	
Nama Formasi	F
Tipe	Limestone
Hydrocarbon	Oil
Temperature	240 °F
BHSP	368 Psia
Porosity Initial	12 %
Porosity Target	14 %
Impurities	10 %

The reservoir data is obtained from the oil company as the well owner and provided to the well services technical engineer for the acidification design needs to be carried out. By acidifying well X in the F formation, it is hoped that production will increase according to the target.

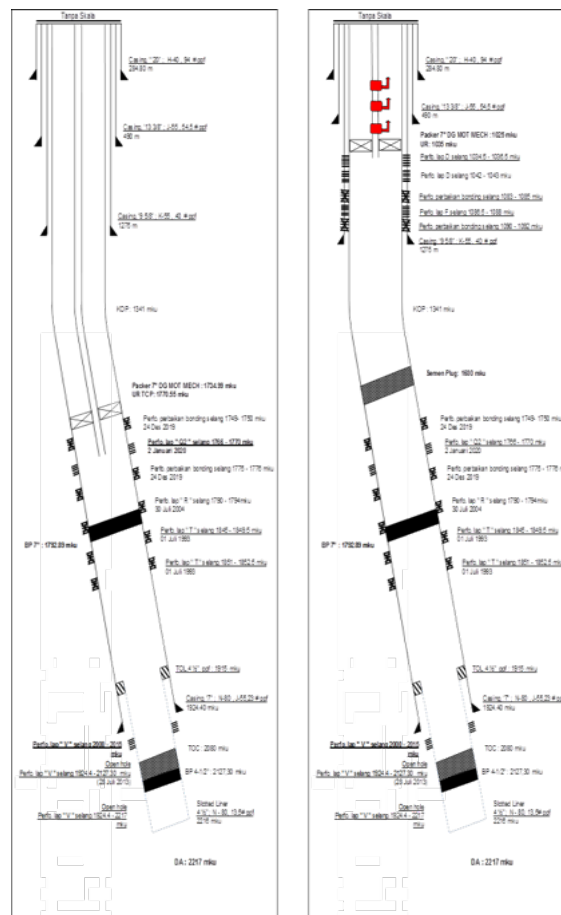


Figure 2 Well Profile Well X
(Sumber : PT.BUKIT APIT BUMI PERSADA)

4.2 Preparation Data Acid Volume Calculation

Tabel 3 Tabel volume Acid

Volume Calculation			
Initial Bulk Volume	997.11		Cuft
Net Initial Bulk Volume	897.40		Cuft
Target Bulk Volume	974.45		Cuft
Net Target Carbonat Volume	877.00		Cuft
Volume Carbonat Solve	20.40		Cuft
Volume 15 % HCl	1906.1	gal	
	45.83	bbl	

Table 4 Preflush Treatment System

	420 gall		Pre Flush	
	Concentration		TOTAL	
Water	983.0	GPT	413.0	Gall
KCL	167.0	PTG	70.0	Lbs
BMS – 50	55.0	GPT	23.0	Gall
BSU – 12N	2.0	PTG	0.8	Gall

Table 5 Main Treatment System

	4476,6 gall		Main Treatment	
	Concentration		TOTAL	
Water	514.0	GPT	944.0	Gall
HCl 32%	434.0	GPT	797.0	Gall
BCI-05	25.0	GPT	37.0	Gall
BCI-01	30.0	PTG	55.0	Lbs
BIC-30	30.0	GPT	55.0	Gall
BSU-12N	2.0	GPT	4.0	Gall
Scalin-1	15.0	GPT	28.0	Gall
BMS-50	30.0	GPT	55.0	

Table 6 Over Flush Treatment System

	420 Gall		Overflush	
	Concentration		TOTAL	
Water	963.0	GPT	404.0	Gall
BMS-50	25.0	GPT	11.0	Gall
BCI-05	10.0	GPT	4.0	Gall
BSU-12N	2.0	GPT	1.0	Gall

4.3 Well Productivity Analysis

After the job has been completed, we can assess the work that has been done, whether the work is considered successful or not. We can compare the success or failure of a stimulation job from the conditions before acidification with the conditions after acidification. The success of the matrix acidizing work can be seen from the large production rate. Below is a calculation to determine whether the stimulation process was successful or not in well standing. The standing equation is an equation used to

determine a well that has 2 phase flow and which has a Flow Efficiency (FE) value $\neq 1$ indicating that there has been damage to the well, while the Flow Efficiency (FE) value obtained is 0.9996, so the appropriate method to use is the standing method. . First we have to look for the permeability before and after and look for the skin before and after.

Table 7 Data Sumur

Depth	2217 m	7273.622 ft
Layer Thickness(h)	4.5 m	14.7645 ft
Tubing		
OD	2 7/8 inch	
ID	2.441 inch	
P reservoir (Pr)	837 Psi	
Penetration	4.6 ft	
Formation volume factor (Bo)	1.10	
Porosity (Ø)	12%	0.12
Viscosity (µ)	1.29	
Oil Flow Rate (Q) before stimulation	132.19 BOPD	
Drain Radius (re)	275 m	
Well Radius (rw)	0.354	
Pi before	127 Psi	
Pi after	621 Psi	
API	44.32	
Water Cut	3.2 %	0,032
PSD	1025 m	3362.86 ft
Top perfo	1061.3 m	3482.125 ft

Next, these data are processed to find FE before and after stimulation, ΔP_{skin} , ideal oil flow rate, maximum oil flow rate and create an IPR curve using the Standing method. First we have to look for permeability before and after and look for skin before and after. Below are the steps to find this data.

- Calculation Pwf Test

$$\begin{aligned} \text{Pwf test} &= P_i \times (\text{Top Perfo} - \text{PSD}) \times (1.43 \times K_A) + (1 - K_A) \times 0.86 \\ &= 127 \text{ psi} \times (3482.125 \text{ ft} - 3362.86 \text{ ft}) \times (1.43 \times 0,032) + (1 - 0,032) \times 0.86 \\ &= 133.29 \text{ Psi} \end{aligned}$$

- Calculation Permeability before Stimulation

$$\begin{aligned} K_{\text{before}} &= \frac{P_i \times B_o \times \mu \times \ln\left(\frac{r_e}{r_w}\right)}{0.00708 \times h} \\ &= \frac{\frac{0.188 \text{ bbl}}{\text{day}} \times 1.57 \text{ bbl/STB} \times 1.29 \text{ cp} \times \ln\left(\frac{275 \text{ ft}}{0.354 \text{ ft}}\right)}{0.00708 \times 49.212 \text{ ft}} \\ &= 7.27 \text{ mD} \end{aligned}$$

- Calculation M (Slope) before stimulation

$$M = \frac{162.6 \times q_l \times B_o \times \mu}{k \times h}$$

$$= \frac{162.6 \times 136.53 \text{ bblpd} \times 1.57 \text{ bbl/STB} \times 1.29 \text{ cp}}{7.27 \text{ mD} \times 49.213 \text{ ft}}$$

$$= 121.65$$

- Calculation *Skin* before stimulation

$$S = 1.151 \left(\frac{(P_r - P_{wf})}{m} - \log \left(\frac{k}{\phi \mu c_t r_w^2} \right) + 3.23 \right)$$

$$= 1.151 \left(\frac{(837 \text{ psi} - 133.29 \text{ psi})}{121.65} - \log \left(\frac{7.27 \text{ mD}}{0.12 \times 1.29 \text{ cp} \times 145 \times 10^{-4} \times 0.354^2 \text{ ft}} \right) + 3.23 \right)$$

$$= 3.69$$

- Calculation *Flow Efficiency* before stimulation

$$\Delta P_{\text{skin}} = \frac{S_{\text{before}} \times q_l \times \mu}{2\pi \times k \times h}$$

$$= \frac{3.69 \times 136.53 \text{ bblpd} \times 1.29 \text{ cp}}{2.314 \times 7.27 \text{ mD} \times 49.213 \text{ ft}}$$

$$= 0.280 \text{ psi}$$

$$\begin{aligned} P_{wf1} &= P_{wf \text{ test}} + \Delta P_{\text{skin}} \\ &= 133.29 \text{ psi} + 0.280 \text{ psi} \\ &= 133.57 \text{ Psi} \end{aligned}$$

$$FE = \frac{\text{Ideal drawdown}}{\text{actual drawdown}}$$

$$= \frac{P_r - P_{wf1}}{P_r - P_{wf \text{ test}}}$$

$$= \frac{837 \text{ psi} - 135.77 \text{ psi}}{837 \text{ psi} - 133.29 \text{ psi}}$$

$$= 0.9996$$

- Calculation *Qo* (Oil Flow Rate Before Stimulation)

$$Q_o = \frac{0.00708 \times k \times h \times (P_r - P_{wf \text{ test}})}{B_o \times \mu \times \ln \left(\frac{r_e}{r_w} \right)}$$

$$= \frac{0.00708 \times 7.27 \text{ mD} \times 49.213 \text{ ft} \times (837 \text{ psi} - 133.29 \text{ psi})}{1.57 \frac{\text{bbl}}{\text{STB}} \times 1.29 \text{ cp} \times \ln \left(\frac{275 \text{ ft}}{0.354 \text{ ft}} \right)}$$

$$= 132.19 \text{ BOPD}$$

- Calculation *QL* (Liquid flow rate before stimulation)

$$QL = \frac{Q_o \text{ before}}{1 - 0.2 \left(\frac{P_{wf1}}{P_r} \right) - 0.8 \left(\frac{P_{wf1}}{P_r} \right)^2}$$

$$= \frac{132.19 \text{ bopd}}{1 - 0.2 \left(\frac{133.57 \text{ psi}}{837 \text{ psi}} \right) - 0.8 \left(\frac{133.57 \text{ psi}}{837 \text{ psi}} \right)^2}$$

$$= 136.53 \text{ BLPD}$$

- Calculation *PI* (Produktivity Index) before stimulation

$$PI = \frac{Q_l}{P_r - P_{wf}}$$

$$= \frac{132.19 \text{ bblpd}}{837 \text{ psi} - 133.29 \text{ psi}}$$

$$= 0.188 \text{ blpd/psi}$$

- Calculation Water Cut before stimulation

$$\text{WC} = 136.53 \text{ BLPD} - 132.19 \text{ BOPD}$$

$$= 4.41$$

$$= \frac{4.41}{136.60}$$

$$= 0.032$$

$$= 3.2\%$$

- Calculation Pwf (After Stimulation)

$$\text{Pwf} = P_i + (\text{Top Perfo} - \text{PSD}) \times (1.43 \times K_A) + (1 - K_A) \times 0.86$$

$$= 621 \text{ psi} + (3482.13 \text{ ft} - 3362.86 \text{ ft}) \times (1.43 \times 0.032) + (1 - 0.032) \times 0.86$$

$$= 627.29 \text{ psi}$$

- Calculation permeability after Stimulation

$$K_{\text{after}} = \frac{P_i \times B_o \times \mu \times \ln\left(\frac{r_e}{r_w}\right)}{0.00708 \times h}$$

$$= \frac{0.631 \frac{\text{blpd}}{\text{psi}} \times 1.57 \frac{\text{bbl}}{\text{STB}} \times 1.29 \text{ cp} \times \ln\left(\frac{275 \text{ ft}}{0.354 \text{ ft}}\right)}{0.00708 \times 49.212 \text{ ft}}$$

$$= 24.40 \text{ mD}$$

- Calculation M (Slope)

$$M = - \frac{162.6 \times q_i \times B_o \times \mu}{k \times h}$$

$$= - \frac{162.6 \times 458.56 \text{ blpd} \times 1.29 \text{ cp} \times \frac{1.57 \text{ bbl}}{\text{STB}}}{86.17 \text{ mD} \times 49.213 \text{ ft}}$$

$$= -36.25$$

- Calculation Skin after Stimulation

$$S_{\text{after}} = 1.151 \left(\frac{(P_r - P_{wf})}{m} - \log\left(\frac{k}{\phi \times \mu \times C_t \times r_w^2}\right) \right) + 3.23$$

$$= 1.151 \left(\frac{(887 \text{ psi} - 627.29 \text{ psi})}{-36.25} - \left(\log\left(\frac{24.40 \text{ mD}}{0.12 \times 1.29 \text{ cp} \times (1.45 \times 10^{-4}) \times 0.354^2 \text{ ft}}\right) \right) \right) + 3.23$$

$$= -10.477$$

- Calculation FE after stimulation

$$P_{\text{skin } 2} = \frac{S_{\text{after}} \times q_{\text{after}} \times \mu}{2\pi \times k \times h}$$

$$= \frac{-10.477 \times 458.56 \text{ blpd} \times 1.29 \text{ cp}}{2 \times 3.14 \times 24.40 \text{ mD} \times 49.213 \text{ ft}}$$

$$= -0.24 \text{ Psi}$$

- Calculation Pwf 2 after Stimulation

$$\text{Pwf } 2 = \text{Pwf test} + P_{\text{skin } 2}$$

$$= 133.29 \text{ psi} + (-0.24 \text{ psi})$$

$$= 133.05 \text{ Psi}$$

$$\text{FE} = \frac{\text{ideal drawdown}}{\text{actual drawdown}}$$

$$= \frac{P_r - P_{wf2}}{P_r - P_{wf \text{ test}}}$$

$$= \frac{837 \text{ psi} - 133.05 \text{ psi}}{837 \text{ psi} - 133.29 \text{ psi}}$$

$$= 1.00$$

- Calculation Qo (Oil Flow Rate after Stimulation)

$$Q_o \text{ after} = \frac{0.00708 \times k \text{ after} \times h \times (P_r - P_{wf2})}{B_o \times \mu \times \ln\left(\frac{r_e}{r_w}\right)}$$

$$= \frac{0.00708 \times 24.40 \text{ mD} \times 49.213 \text{ ft} \times (837 \text{ psi} - 133.05 \text{ psi})}{1.57 \text{ bbl/STB} \times 1.29 \text{ cP} \times \ln\left(\frac{275 \text{ ft}}{0.354 \text{ ft}}\right)}$$

$$= 444.00 \text{ BOPD}$$

- Calculation QL (Liquid Flow rate after Stimulation)

$$QL \text{ after} = \frac{Q_o \text{ after}}{1 - 0.2 \left(\frac{P_{wf2}}{P_r} \right) - 0.8 \left(\frac{P_{wf2}}{P_r} \right)^2}$$

$$= \frac{444.00 \text{ bopd}}{1 - 0.2 \left(\frac{133.05 \text{ psi}}{837 \text{ psi}} \right) - 0.8 \left(\frac{133.05 \text{ psi}}{837 \text{ psi}} \right)^2}$$

$$= 458.56 \text{ BLPD}$$

- Calculation PI (Produktivity Index) after Stimulation

$$PI = \frac{Q_l}{P_r - P_{wf}}$$

$$= \frac{458.56 \text{ blpd}}{837 \text{ psi} - 627.29 \text{ psi}}$$

$$= 0.631 \text{ blpd/psi}$$

- Calculation Water Cut before and after Stimulation

$$\text{Water Cut After} = 458.56 \text{ BLPD} - 444.00 \text{ BOPD}$$

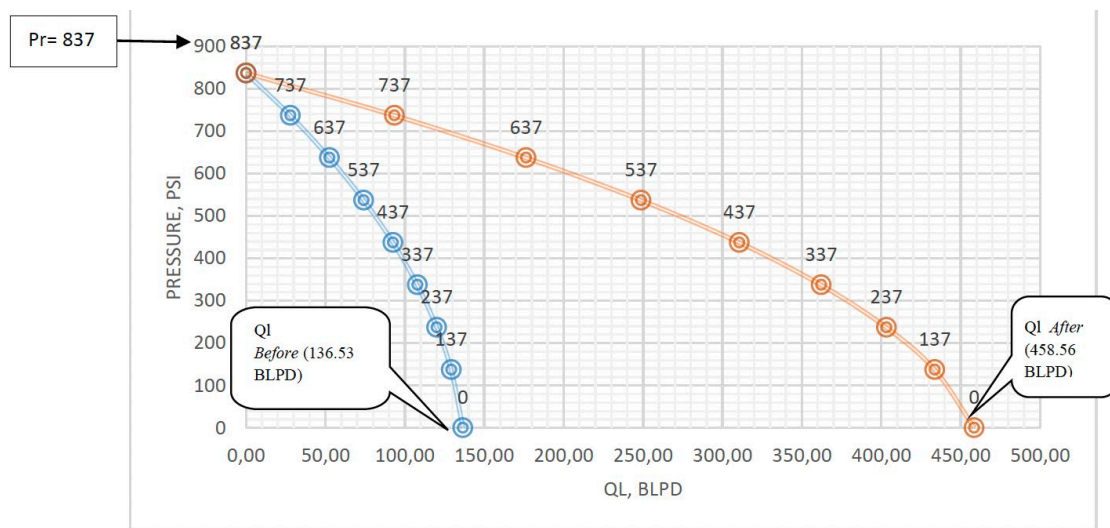
$$= 14.92$$

$$= \frac{14.92}{462.23}$$

$$= 0.032 = 3.2\%$$

Tabel 8 Comparison *Skin*, ΔP_{skin} , FE, PI, Qo and Qmax

	Before Stimulation	After Stimulation
Skin	3.69	-10.477
ΔP_{skin}	0.280	-0.24
FE (Flow Efficiency)	0.9996	1.00
PI (Produktivity Index)	0.188 <i>blpd/psi</i>	0.631 <i>blpd/psi</i>
QL (liquid flow rate)	136.53 BLPD	458.56 BLPD
Qo (Oil flow rate)	132.29 BOPD	444.00 BOPD
Water Cut	3.2%	3.2%



Grafik 1 Curve IPR before and after Stimulation

5 RESULTS

Well "X" is a well that is still producing, seen from the resulting production rate, namely 136.53 BLPD, but this well is still categorized as a well that has a high production rate because formation damage causes the production flow rate to decrease. After selecting the candidate Well "X" it was identified that it had experienced damage to the D & F formation, this was seen from the results of the last PBU test which showed that there was a skin value (formation damage factor) which had an effect on the permeability of the formation, causing a decrease in pressure and speed. production of well "X" and it was determined that the stimulation method to be carried out was the Matrix Acidizing method. in the "D & F" formation is limestone. The type of acid that may be used to remove formation damage in limestone rock is 15% hydrochloric acid (HCl).

The reason 15% HCl was chosen is because 15% HCl has a pretty good reaction to dissolve limestone. The level of solubility of 15% HCl with limestone can be determined based on tests on cores carried out in the laboratory.

The first step in designing acidification is to determine and collect data about the well, with the existing data and correlations you can carry out calculations to determine the right design. To find out the volume of acid needed to deal with formation damage problems is to carry out calculations using the equation obtained from the field supervisor. With an acid penetration radius value of 4.6 feet (oil company request) and existing data, the initial bulk volume value is 997.11 cuft with a net initial bulk volume of 897.40 cuft. The calculated Bulk Volume Target is 974.45 Cuft with a Net Bulk Volume Target of 877.00, so the volume of carbonate that must be dissolved is 20.40 Cuft. With the provisions of the Society of Petroleum Engineers (SPE), namely that every 1000 gallons of 15% HCl can dissolve 10.7 cuft of carbonate, so it can be seen that the volume of acid needed for acidification is 7215.4 gallons or 45.38 barrels. The estimated time required to carry out acid injection (main treatment) at the maximum injection rate is 20,629 minutes.

Acidification of well "X" is planned to go through several stages, namely. Preflush, Main Treatment, Overflush. At each stage of acidification, the fluid is injected with the addition of various kinds of additives. The amount and concentration of

additives used depends on the core unit in the laboratory. Core tests that need to be carried out include petrographic tests, solubility, immersion, effects on porosity, flow and clay content analysis as well as testing the production fluid for the acid used. From this test, an acidifying fluid mixture system was obtained. For Preflush needs, the mixture used is 413 gallons of water, 70 Lbs KCl, 23 gallons of BMS-50/Mutual Solvent which functions to make the formation water-wet, reducing surface tension. 0.8 gallon BSU-12N to prevent emulsion formation and can also make limestone water-wet

The mixture used for Main-Treatment is 944 gallons of water, 797 gallons of 32% HCl, 37 gallons of BCI-05 to reduce corrosion in the production line to a tolerable limit at a temperature of 2200F, 55.0 gallons of BCI-01 to increase the durability of BCI-05 to temperature, 133 gallons of BCI-03 to slow down the reaction between HCl and limestone so that the acid penetrates deeper. 133 Lbs BIC-30 to prevent iron deposition. 9 gallon BSU-12N and 133 gallon BMS-50. The mixture used for overflush is 2294 gallons of water. 133 gallons of BMS-50 to facilitate cleaning the well from residual acid and carbonate solution. Meanwhile, for the initial injection before acidification, 4200 gallons of water are needed with a concentration of 2% KCL or 701.4 Lbs.

For the needs of overflush activities, 404 gallons of water are used, 11 gallons of BMS-50, 4 gallons of BCI-05, and 1 gallon of BSU-12N.

Analysis of the production rate resulting from acidification for well "X" obtained a Production Rate of 458.56 BLPD, with no change in water content, namely before stimulation of 3.2% and after stimulation of 3.2%, oil production before stimulation was 132.19 BOPD and after stimulation was 444.00 BOPD, and gas production of 0.47 MMSCFD. Based on the calculation of the IPR curve using the Vogel method, it can be said that job stimulation using the acidizing method was successful.

5 CONCLUSION

From the results of the analysis of this final project that has been carried out, it can be concluded as follows:

- a. The amount of acid used in the stimulation work using the Acid Matrix method is 1906.1 gal HCl 15% / 45.38 bbl.
- b. The maximum liquid production rate before acidizing was 136.53 BLPD and the liquid production rate after stimulation was 458.56 BLPD, the oil production rate before stimulation was 132.19 BOPD and after stimulation was 444.00 BOPD, the water content did not change, namely before stimulation and after stimulation was 3.2%, Flow Efficiency (FE) before stimulation was 0.999 and after stimulation 1.001, Skin before stimulation was 3.69 and after stimulation was -10.477, and Productivity Index (PI) before stimulation was 0.188 bbl / day / psi and after stimulation 0.631 bbl / day / psi, then by looking at the calculation of the four indicators it is identified that the stimulation process in well X was successful.

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