Analysis of Economy in the Improvement of Oil Production using Hydraulic Pumping Unit in X Field

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Keywords: Hydraulic Pumping Unit, Efisiensi Volumetris NPV, IRR, POT, DPI.

Abstract: The wells of X fields are vertical wells with installed pumps being the Hydraulic Pumping Unit. The wells can still be optimized by improving the performance of N and SL by trial and error method. Based on optimation analysis result at well BM 1 by changing SPM and SL parameters on pump which installed with N 6 SPM and SL 100 inch got Qt equal to 144 bfpd, then converted to N 7 SPM and SL 100 inch so that there increase of Qt become equal to 199 bfpd And pump efficiency from 67% to 80%. While in the well BM 2 by changing the parameters of SPM and SL on pumps installed with N 8 SPM and SL 100 inch obtained Qt of 284 bfpd, then converted to N 10 SPM and SL 110 inch so that there is an increase of Qt to equal to 583 bfpd pump efficiency of 65% to 90%. In the economic analysis with Production Sharing Contract system can be known with non-capital investment of MMUS $ 0.150, obtained NPV contractor MUS $ 451.07, IRR> MARR,POT < 1 year and DPI 4.00.

1 INTRODUCTION

The oil production process by using the Hydraulic Pumping Unit (HPU) on the X field does not always work optimally so that the oil flow rate cannot be fully produced optimally and makes the economic results of the production not obtained. According to the discussion of (Brown, 1984), the ability of a well to produce can be known by calculating the productivity of wells using IPR curves based on actual data in the field. Optimization of the production rate can be done by conducting a trial and error method for changes in Stroke Per Minute (SPM) and Stroke Length (SL) of the pump.

The purpose of this study is to evaluate the production performance of the installed hydraulic pumping unit, to optimize the HPU to increase the rate of production (Babbitt and Vincent, 2012; Beard, 2013; Pickford and Morris, 1989). Analyze the economy of the HPU after obtaining a new production rate.

2 METHOD

This research was conducted at X Field. Administratively, X Field is located in Siak Sri Indrapura Regency, Riau Province, Indonesia. Geologically, the X field is located in the Central Sumatra Basin. X Field has a very large oil content and shallow well depth where Original Oil In Place is 101.4 MMSTB with Recovery Factor 47.48%.The well type on X Field is vertical well and directional well. The wells to be examined in this research are BM # 1 and BM # 2 Wells.

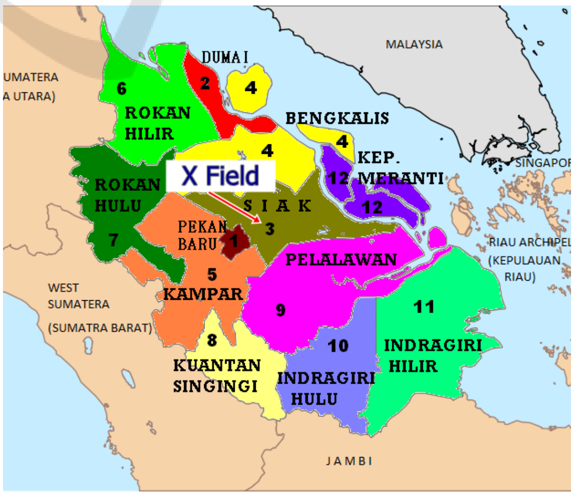

Figure 1: Research sites

The research method used is field research or this research use data from oil field. The data

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used are secondary data provided by field guides, expert opinions, principles and theories of guaranteed literature.

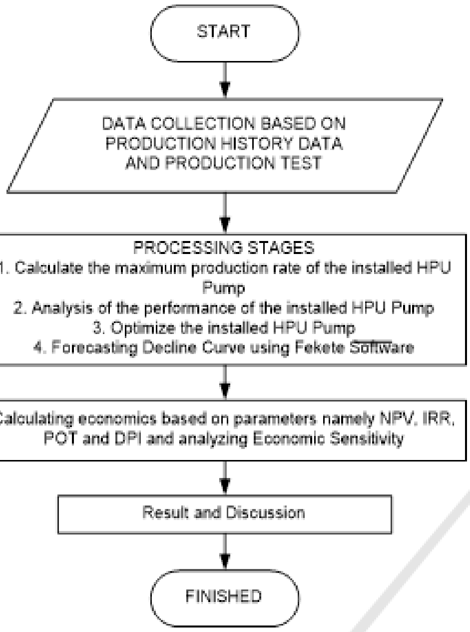

Figure 2: Research flowchart.

3 RESULT AND DISCUSSION

3.1 Determination of Well Performance and Maximum Flow Rate (Qmax) with Vogel Method

In knowing whether 4 wells in the X field can be optimized, it is necessary to know the maximum flow rate (Qmax) in 4 wells with the HPU installed. The method used in determining Qmax is the Vogel method because the reservoir fluid flowing in the well is 2 phase and 50-80% water cut (WC) (Chase and Shaver, 2009; Ogunleye, 2012).

Table 1: The calculation results determine Sg Fluid, Gradient Fluid, Pr and Pwf.

WELL	Specific gravity fluid (SgFluid).	Gradient fluid (Gf)	Reservoir pressure (Pr)	Bottom well flow pressure (Pwf)
BM 1	0.92	0.400	146	78
BM 2	0.97	0.420	55	41
BM 3	0.977	0.423	84	33
BM 4	0.94	0.407	50.8	5.6

After obtaining Sg fluid, Gradient fluid, Pr and Pwf in table 1, the calculation of the vogel method is carried out to obtain the maximum flow rate (Qmax), the following results are obtained.

Table 2: Maximum flow rate in the well on the use of the installed HPU.

WELL	Fluid Flow Rate (Qt) BBL/D	Opt Flow Rate of oil (Qo)	Max Flow Rate (Qmax) BBL/D	*WC %*	*PI*
BM 1	144	65	216	50	2.10
BM 2	284	57	696	80	1.94
BM 3	55	8	69	85	1.07
BM 4	88	30	90	69	1.80

Based on production table 2, it can be seen that from the 4 wells it has a fluid flow rate (Qt) which has approached Qmax, that is BM3 and BM5 wells while BM4 wells have reached the economic limit. For this reason, only 2 wells can be researched to optimize and analyze the economics of BM1 and BM2 wells.

After finding out which wells to be optimized, the BM1 and BM2 wells then need to use the Inflow Performance Relationship curve to describe changes in the price of the well bottom flow pressure (Pwf) versus the flow rate (Q) produced. Then the results of changes in the bottom well pressure are obtained from the flow rate in table 3.

Table 3: Results of changes in bottom well flow pressure to flow rate.

Well	Pwf (psi)	Q, (Bfpd)	Well	Pwf (psi)	Q (bfpd)
BM 1	146	0	BM 2	55	0
	125	52		50	109
	105	95		45	209
	95	114		40	300
	85	132		35	381
	75	148		30	454
	65	162		25	517
	55	175		20	571
	45	186		15	616
	30	199		10	651
	15	209		8	663
	10	212		5	678
	0	216		0	696

HPU performance known by making IPR curves using the vogel method which aims to determine the maximum pump flow rate, because in field X has a two-phase flow, where (Wiggins et al., 1996) states the vogel method is usually used to determine the maximum flow rate of two fluid phases.

After obtaining Pwf against Q by assuming Pwf in table 3, the IPR curve (Inflow Performance Relationship) plot can be performed on BM1 and BM 2 wells.

After knowing the Qmax and Pwf assumptions towards each Q, then the next step is to know the volumetric efficiency of the HPU installed in wells BM1 and BM2.

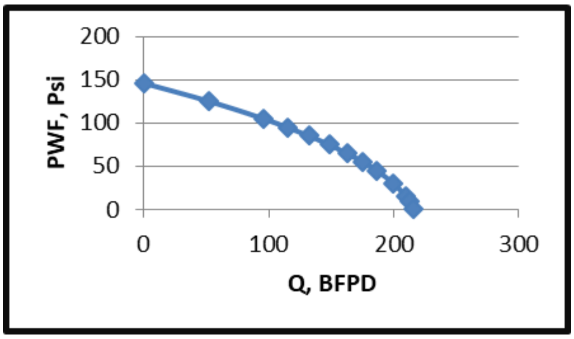

Figure 3: Pwf vs Q IPR curve in BM 1 well.

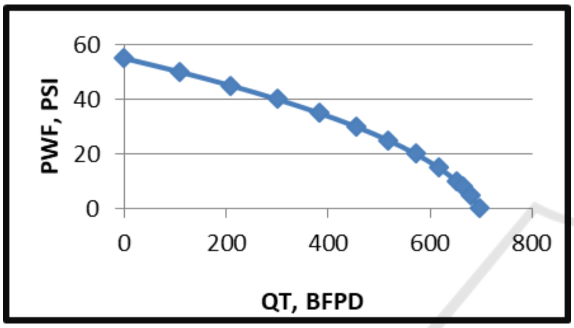

Figure 4: Pwf vs Q IPR curve in BM 2 well.

3.2 Volumetric Efficiency of HPU Installed in BM1 and BM2 Wells

The procedure in determining the design of the HPU pump uses the (Jennings et al., 1989) procedure where the author determines the Pump Depth (L) price of Plunger area (Ap), rod area (Ar), tubing area (Ar), plunger constant (K) and rod weight (Wr) and the price of the pump speed (N). In BM1 and BM2 wells, the fluid flow lane (Qt) is obtained, namely BM1 wells with 144 BFPD and BM2 with 284 BFPD.

Pump efficiency is performed to determine the optimal pump performance in BM1 and BM2 wells or not by looking at parameters such as Pump Size / Plunger diameter (Dp), Pump speed (N, SPM), Pump step length (SL, In), Acceleration factor (a), Plunger over travel (ep), Tubing (et) extension, Rod string (er), Effective plunger stroke (Sp), Pump constant (K), Pump capacity (V) and Pump volumetric efficiency (Ev) (Cui et al., 2014; Wang et al., 1995; Ye et al., 2017), then the results in Table 4 are obtained.

Based on Table 4, it can be analyzed that BM1 wells with the use of 6 SPM (Stroke per minute) and 100 SL (Stroke length) and the use of 1.75 in. Plunger diameter obtained 213 bfpd pump capacity, while Qt in BM1 wells was 144 bfpd, volumetric efficiency was obtained the pump is 67.40% While for BM2 wells with the use of 8 SPM (Stroke per minute) and 100 SL (Stroke length) and the use of plunger diameter of 2.25 in, the pump capacity of 469 bfpd was obtained, while Qt in BM2 wells was 284 bfpd, the pump obtained a volumetric efficiency of 60%.

Based on the parameters in Table 4 and the Qmax in 2 wells is quite large, the researcher tried to do optimization by changing the SPM and SL parameters in the hope of increasing Qt and the volumetric efficiency of the installed pump becoming more optimal than previously installed.

Table 4: Results of pump volumetric efficiency installed in BM 1 and BM 2 wells.

WELL BM1		WELL BM2	
Pump Size / diameter plunger (dp, In)	1.75	Pump Size / diameter plunger (dp, In)	2.25
Pump Speed (N, SPM)	6	Pump Speed (N, SPM)	8
Pump Step length (SL, In)	100	Pump Step length (SL, In)	100
Acceleration factor (a)	0.05	Acceleration factor (a)	0.09
Plunger Over Travel (ep, In)	0.02	Plunger Over Travel (ep, In)	0.06
Extention of Tubing (et, In)	0.04	Extention of Tubing (et, In)	0.09
Rod String (er, In)	0.18	Rod String (er, In)	0.40
Effectif Plunger Stroke (Sp, In)	99.80	Effectif Plunger Stroke (Sp, In)	99.58
Pump constant (K)	0.36	Pump constant (K)	0.59
Pump Capacity (V, Bfpd)	213.40	Pump Capacity (V, Bfpd)	469.80
Volumetric Pump Efficiency (Ev, %)	67.40	Volumetric Pump Efficiency (Ev, %)	60.45

3.3 Optimization of BM1 and BM 2 Wells

Optimization was carried out to increase the production flow rate in both wells using the trial and error method. the concept of trial and error is to change the parameters of SPM and SL on the installed pump in the hope of increasing the volumetric efficiency of the pump as well as the fluid flow rate in wells BM1 and BM2. Next is the efficiency of the pump installed before optimization.

Table 5: The results of pump efficiency are installed before optimization.

Well	N (SPM)	S (in)	Qt (BFPD)	Ev (%)	WC (%)
BM 1	6	100	144	67.4	50
BM 2	8	100	284	60.4	80

After that, optimization is done by changing the parameters of SPM and SL using the trial and error method. Then, it is obtained in table 6 below

Table 6: The results of installed pump efficiency after optimization.

Well	N (SPM)	S (in)	Qt (BFPD)	Ev (%)	WC (%)
BM 1	7	100	199	80	50
BM 2	10	110	583	90.4	80

Based on the results of the optimization in Table 6 in BM1 wells by changing the SPM and SL parameters on the installed pumps with N 6 SPM and SL 100 in, Qt is 144 bfpd, then converted to N 7 SPM and SL 100, in this case, there is an increase in Qt to 199 bfpd and pump efficiency from 67% to 80%, While the results of the optimization in table 6 in the BM2 well by changing the SPM and SL parameters on the installed pump with N 8 SPM and SL 100 in, Qt is 284 bfpd, then converted to N 10 SPM and SL 110, there is an increase in Qt to 583 bfpd pump efficiency from 65% to 90%.

After obtaining the optimum production flow rate, to determine the bottom well flow pressure (Pwf) in BM1 and BM2 wells is by plotting the production flow rate on the IPR curve in each well, the results are shown in the figures 5 and 6.

Based on the results of plotting the IPR curves in Figures 3 and 4 to determine the bottom well flow pressure (Pwf) with the optimal production flow (Qt) the results in table 7 on well BM1 with Qt 182 bfpd obtained pwf 30 psi while the BM2 wells with Qt 583 bfpd obtained pwf 19 psi. Based on the results of increasing production flow rates in BM1 and BM2 wells, the next step is to forecast with Decline Curve to find out when the production performance will be in the future.

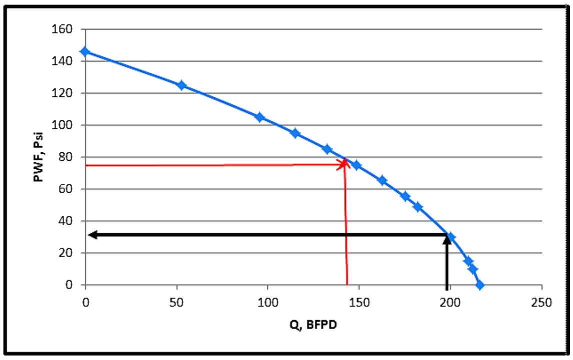

Figure 5: IPR curve determination of Pwf against Qt before and after optimization in BM 1 wells.

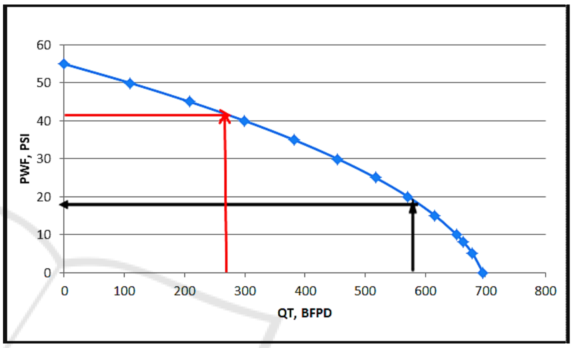

Figure 6: IPR curve determination of Pwf against Qt before and after optimization in BM 2 wells.

3.4 Decline Curve Analysis (DCA) Forecasting

After optimizing and obtaining a new oil production flow rate. Then it is necessary to do economic calculations at the new flow rate to find out what the profits are (Hong et al., 2018; John, 1996).

At the new production flow rate, it is predicted that the production rate will decline in the future. Decreasing the rate of production is seen by using

Table 7: Results of PWF by plotting the optimal IPR curve against Qt.

Well	Qt Before optimization bfpd	Pwf Before optimization psi	Qt After optimization bfpd	Pwf After optimization psi	Qmax, Bfpd
BM1	144	78	199	30	216
BM2	284	41	583	19	696

Fekete software. Production history data on BM1 and BM2 wells are input to Fekete and exponential decline types are chosen. The selection of exponential types is seen from the production history in the last 4 years. Decline obtained on BM1 wells is 11% / year and BM2 is 17% / year. Then assuming the water cut does not change and decreasing the production rate of each well can be known. After that, economic calculations were carried out on two wells after being optimized for BM1 and BM2 wells.

Declining forecasting for production is carried out for the next 2 years, from March 2017 to March 2019. The reason why the next 2 years are adjusted to the rental period of the pump from the company with the contractor, which is per 2 years leasing. Based on the results total production for the next 2 years increased after the optimization of pumps in BM1 wells in the first year of 31121.2 bbl and the second year 29663.4 bbl for 2 years and in the first year BM2 wells 42418.35 bbl and the second year 35501.7 bbl for 2 years. Optimization is needed to get greater profits.

Table 8: The results of total production forecasting in the next 2 years.

DATE	Well BM1 (BBL/Y)	Well BM2 (BBL/Y)
March 2017 – March 2018	31121.2	42418.3
April 2018 – March 2019	29663.4	35501.7
Total Production	138.704 BBL	

3.5 Economic Analysis

Some economic indicators used to analyze the production results of the flow rates for the next 2 years on the BM1 and BM2 wells in the 6th generation PSC (Production sharing contract) system are: Net Present Value (NPV); Pay Out Time (POT); Rate of Return (ROR); Discounted Profit to Investment Ratio (DPIR) and Economic sensitivity.

According to (Lubiantara, 2012) FTP or first tranche petroleum is the Government and the contractor is entitled to first take 20% of production before deducting returns or recovery of operational costs (cost recovery). The DMO is basically the contractor's obligation to supply a certain volume of domestic needs. For the first five years (more precisely the first 60 months when production begins, the volume for this DMO is valued at the market price of the crude oil, known as the DMO holiday. After the DMO holiday period, the price of the DMO oil will be discounted as stated in the contract , 10%, 15% or 25% of the crude oil market price.

Parameters and Assumptions Used

- Based on the contract model between the Contractor and the Government assumptions are used in calculating the production flow rate for the next 2 years in wells BM1 and BM2Price of 1 BBL of US $ 52 / Bbl.
- The Contractor's portion is 26.7857% (after tax).
- Government portion is 73.2143% (after tax).
- Government tax is determined at 44%.
- FTP = 20%.
- Cost recovery = 100%.
- DMO = 25%.
- DMO fee = 15%.
- Operating costs are considered fixed at US $ 20 / Bbl
- Pump rental costs = US $ 103 / d

Based on Production sharing contract model, investment parameters, calculation assumptions, and incremental production Scenarios, the economic evaluation of the use of the HPU on the BM1 and BM2 wells in the X field was conducted. Complete results of economic calculations are presented in Table 9.

Based on the calculation and results of table 9, it can be seen that the production for the next 2 years on BM 1 and BM 2 wells in accordance with the HPU rental time is 0.136 MMBBL multiplied by the oil price of US $ 50 / Bbl MMUS $ 7,213. The PSC system can be identified by non-capital investment amounting to MMUS $ 0.150, obtained NPV contractor MUS $ 451.07, IRR¿ MARR, POT <1 year and DPI 4.00. Based on these results, the optimization results of production in BM 1 and BM 2 wells for the next 2 years are still very economical to produce.

3.6 Sensitivity Analysis

Sensitivity analysis on the NPV of the contractor is used to see what parameters affect NPV. The parameters used are: a) Oil prices; b) Production cost and c) Production results.

Based on the Tables 10, 11, 12 above, a plot is carried out on the curve to see which parameters affect NPV.

Table 9: Summary of Calculation Results The Economics of BM1 and BM2 wells.

No.	Parameter		Satuan	Jumlah
1	Oil Production		MMBBL	0.139
2	Time oil production		*Year*	2
3	Price (Bbl)		US$/Bbl	52
4	*Gross Revenue*		MMUS$	7.213
5	FTP		MMUS$	1.443
		Contractor FTP	MMUS$	0.386
		Government FTP	MMUS$	1.056
6	Investment		MMUS$	0.150
		Tangible	MMUS$	0.000
		Intangible	MMUS$	0.150
7	Operating cost	Operation	MMUS$	2.774
		Abandonment	MMUS$	-
8	*Cost Recovery*		MMUS$	2.924
		(% Gross Revenue)	%	41%
	Unrecovered Cost			-
		(% Gross Revenue)	%	0%
9	*Investment Credit (IC) 10%*		MMUS$	-
10	*Equity to be Split*		MMUS$	2.846
		Contractor Equity	MMUS$	0.762
		Government Equity	MMUS$	2.083
11	*Contractor Take*			
		Net Cash Flow	MMUS$	0.553
		(% Gross Revenue)	%	8%
		IRR	%	¿ MARR
		NPV @15%	MUS$	451.07
		POT	*Year*	¡ 1
		DPI	Fraksi	4.00
12	*Government Take*			
		FTP + Equity	MMUS$	3.140
		Tax	MMUS$	0.434
		Net Cash Flow	MMUS$	3.736
		(% Gross Revenue)	%	52%
		NPV @10%	MUS$	3,05

Table 10: Sensitivity analysis to oil prices

Sensitivity (%)	Oil price (US$)	NPV at Discount factor 15% (US$)
80	41	296.01
90	46	380.59
100	52	451.07
110	57	521.55
120	62	592.03

Table 11: Sensitivity analysis to operational costs.

Sensitivity (%)	Oil price (US$)	NPV at Discount factor 15% (US$)
80	16	504.57
90	18	477.82
100	20	451.07
110	22	424.32
120	24	397.97

4 CONCLUSIONS

Optimization of installed pumps by changing SL and SPM on BM1 wells from N = 6 and SL = 100 to N = 7 and SL 100 production rates increased from 144 BFPD to 199 BFPD with EV = 80% while in well BM2 from N = 8 and SL = 100 to N = 10

Table 12: Sensitivity analysis to production.

Years	80% (Bbl/Y)	90% (Bbl/Y)	100% (Bbl/Y)	110% (Bbl/Y)	120% (Bbl/Y)
2017	58830	66190	73540	80890	88250
2018	52130	58650	65170	71680	78200
NPV @15%	357.97	404.52	451.07	497.62	544.17

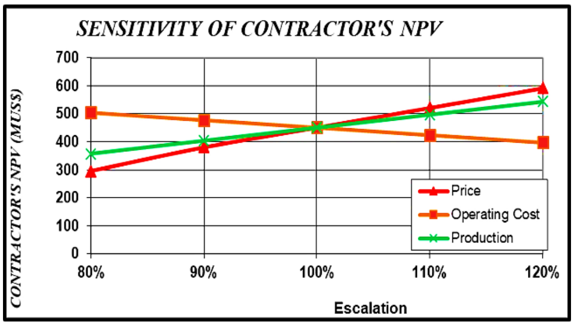

Figure 7: Sensitivity analysis.

and SL = 110 the production rate increased from 284 BFPD to 583 BFPD with EV = 90%. Based on the results of production optimization for the next 2 years according to the time of HPU leasing, oil production is 0.139 MMBBL, if it is assumed that oil prices of US $52/BblareMMUS$ 7,213. Based on the revenue sharing using the PSC system with non-capital investments of MUS \$ 0.150, the NPV contractor MUS \$ 451.07, IRR¿ MARR, POT <1 year and DPI 4.00 are obtained. From these results, it can be seen for the next 2 years BM 1 and BM 2 wells are still economical to produce.

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