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EVALUATION OF ELECTRIC SUBMERSIBLE PUMP (ESP) BY CALCULATING THE ECONOMIC FACTOR ON WELL KGH 32

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ABSTRACT

This research was conducted by performing quantitative analysis on data from PT. Pertamina EP Cepu Regional 4 Zone 11 the data included reservoir data, well data, and production data. The objectives of this research are to determine the maximum flow rate and optimum flow rate using the Composite IPR Method in Well KGH 32, evaluate the Volumetric Efficiency of the ESP pump based on the conducted assessment in Well KGH 32, and ascertain the profitability results from the Economic Evaluation in Well KGH 32.The first step in this research was to calculate the Inflow Performance Relationship (IPR) Composite to evaluate the reservoir well's performance. This method was used to predict production rates at specific bottomhole pressures and determine desired production rate targets. Subsequently, ESP Evaluation calculations were performed to determine the effective and efficient pump design considering various aspects, including economic value. The calculation results of the IPR Composite show the IPR Composite curve of Well KGH 32, used to assess well productivity and evaluate ESP pumps. The Q value is 4942 bfpd with a Pwf of 1714.717 bfpd. The optimum Q value is 9730.09 bfpd, derived from 80% of the Qomax value. The optimized Q value is 13,500 bfpd with a Pwf of 779.710, representing 69% of the total Q value. Qomax is 12,162.60871 bfpd with a Pwf of 951.645 bfpd. The Qt max value is 19,564.95 bfpd. Additionally, volumetric efficiency calculations for the installed pump indicate 71% efficiency for pump P-31, indicating suboptimal performance requiring optimization. Economic evaluation of the ESP considers factors such as revenue, electricity costs, water injection, chemical usage, routine expenses, and facility sharing agreements. Daily profit is calculated at Rp. 157,518,753. From this research, it is concluded that the ESP pump at Well KGH 32 needs optimization to enhance efficiency and economic feasibility, potentially achieving greater daily profits. Overall evaluations not only aid in improving operational performance and efficiency but also enable better decision-making based on a deeper understanding of well conditions and potential repair needs. Future steps may involve installing a rotary gas separator to manage excessive gas and adjusting pump designs to enhance overall performance.

Keywords: Artificial lift; Electric Submersible Pump; Economic petroleum system

I. INTRODUCTION

The decline in production in the oil and natural gas industry often necessitates effective evaluation strategies to maintain stable production rates(Surya et al., 2023). One commonly used method is artificial lift technology. In this context, artificial lift refers to a series of technologies employed to enhance the flow of oil or gas from mature wells or those with low reservoir pressure(Davila et al., 2019). This process may involve the use of well pumps, gas injection, or other methods aimed at increasing pressure within the well and promoting hydrocarbon production to the surface(Sindi et al., 2023). By implementing artificial lift technology appropriately, well operators can enhance production efficiency, extend well life, and overall increase production yields. Artificial lift encompasses five methods: Sucker Rod Pump (SRP), Hydraulic Pumping Unit (HPU), Progressive Cavity Pump (PCP), Electric Submersible Pump (ESP)(Gabor Takacs, n.d.)(Banjar et al., 2022).

Evaluation of ESP through artificial lift is a crucial step in efforts to enhance production in oil or gas wells. It involves comprehensive analysis of various factors influencing well production and designing appropriate solutions to improve production performance(Sindi et al., 2024). An ESP pump is a multi-stage centrifugal pump, with each stage consisting of an impeller and a diffuser (Patra, 2014). Fluid entering through the pump inlet moves to the first stage of the pump(Ghonim et al., 2023). The impeller rotation provides thrust to the fluid, thereby imparting more energy to it than before. The diffuser directs the fluid to move to the next impeller level, and the process continues until the final stage(Jonathan1), n.d.).

This study reviews the use of Composite Method in determining the Inflow Performance Relationship (IPR) curve for wells with water cut values above 50% and reservoirs containing two-phase fluids such as oil, water, and gas(Qasem et al., 2014). Quantitative analysis is conducted using data collected from PT. Pertamina EP Cepu Regional 4 zone 11, particularly focusing on well KGH 32. The research findings indicate that well KGH 32 requires ESP evaluation due to suboptimal pump performance. Based on Composite IPR calculations, volumetric efficiency evaluation, and gas intake, it is concluded that installing a rotary gas separator is necessary to maintain stable ESP pump performance(etel vina, n.d.)(Jing Ma, 2018). Economic evaluation of ESP is also conducted, considering revenue, power consumption, costs of water injection and chemical usage, and net income potential from well KGH 32. Overall, this study provides in-depth insights into the planning and evaluation of ESP in the context of well KGH 32, with a focus on relevant technical and economic aspects(Blanco & Davies, 2001).

This study aims to achieve the following objectives: to determine the maximum flow rate using the IPR composite method, to assess volumetric efficiency, and to calculate the economic value for Well KGH 32. Through this research, the evaluation provides a better understanding of the challenges and issues faced in well operations(Armenta & Wojtanowicz, 2005). Therefore, the researcher focuses on evaluating Well KGH 32 to plan more effective strategies for optimizing production and profitability, ensuring that the well operates optimally with minimal operational costs. Overall, this evaluation not only aids in enhancing operational performance and efficiency but also enables the company to make better decisions based on a deeper understanding of well conditions and potential improvement needs.

II. METHODS

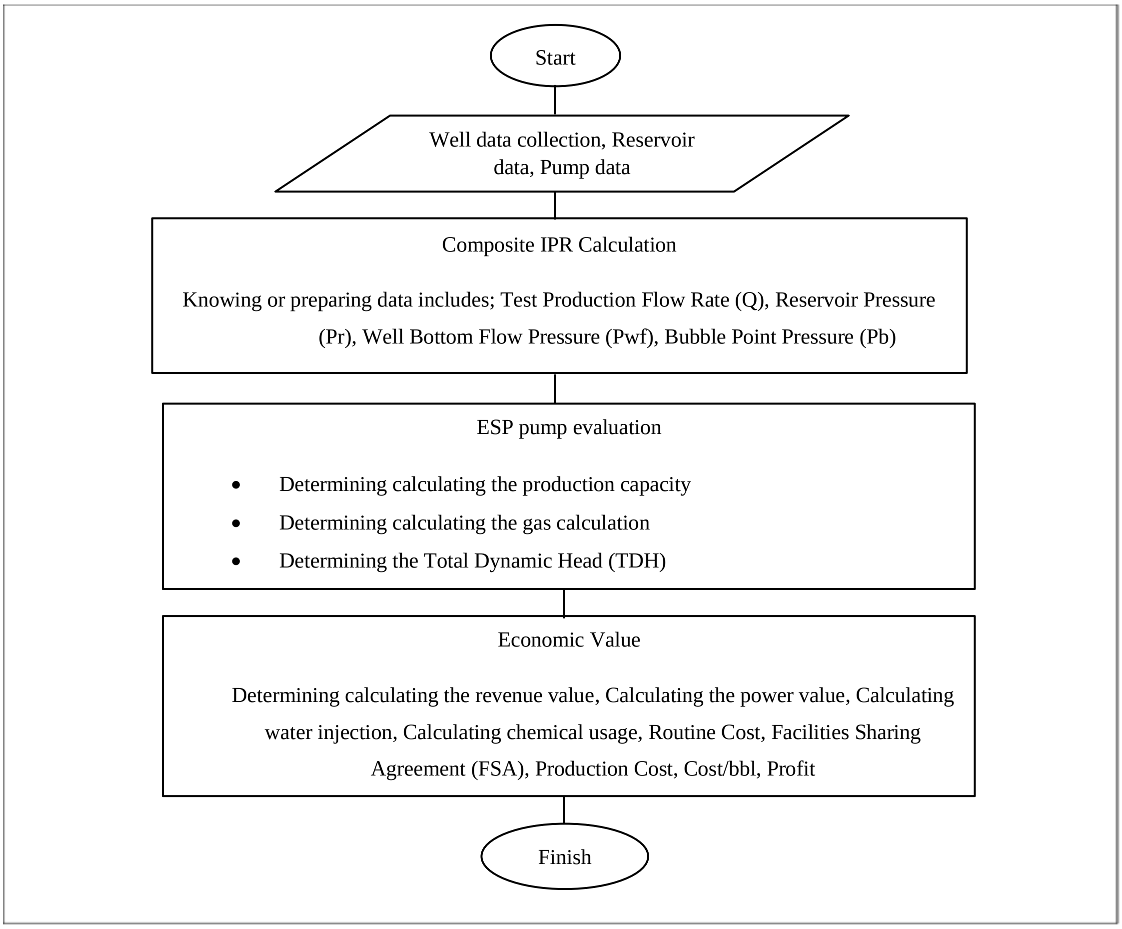

Figure 1 Flow diagram

In general, ESP planning often utilizes various methods to determine well production, one of which, in this study, involves establishing the Inflow Performance Relationship (IPR) curve using the Composite Method(Qasem et al., 2014). This method is applied to wells with high water cut above 50% and featuring two-phase reservoir fluids, including oil, water, and gas(Jonathan1), n.d.).

This research will be conducted through quantitative analysis, involving the collection and analysis of data relevant to this thesis. Specifically, the data required for this thesis research includes: Reservoir data consisting of water cut 96.56%; oil cut 3.43%; SG water 0.98; SG oil 0.83; SG gas 2.71; API oil 38.7 API; Bubble Point Pressure 2590 psi; Reservoir Temperature 271°F. Well data includes production casing 9 5/8 inches; Tubing 3 ½ inches; measured depth 4942.13 ft; top perforation 7460 ft; middle perforation 7469 ft; and bottom perforation 7478 ft. Production data comprises fluid production rate 4942 Bfpd; dynamic fluid level 4126.5 ft; static fluid level 2595 ft; GOR 2204 scf/stb; water cut 96.56%; Bottom hole temperature (BHT) 271°F.

III. RESULTS AND DISCUSSION

The data in this paper is sourced from quantitative results provided by PT. Pertamina EP Cepu Regional 4 zone 11 during research conducted. The first step involved calculating the Composite Inflow Performance Relationship (IPR) to assess the capability or performance of a reservoir well. Subsequently, evaluating ESP was conducted to determine the optimal pump design considering various factors, ensuring effective and efficient pump usage(Syarifah Junaida Al Idrus, n.d.). Lastly, economic considerations were factored into the evaluation of the Electrical Submersible Pump (ESP).

Table 1 Reservoir Characteristic Data

Data	KGH 32
Water Cut %	96,56
Oil Cut%	3,44
Reservoir pressure (Pr), psi	2217,34
Wellbore Flowing Pressure (PWF), psi	1520,61
Bubble Point Pressure (Pb), psi	2590
Reservoir Temperature (Tr), ◦F	250
Oil API gravity, API	38,7
Oil Specific Gravity	0,8314
Gas Specific Gravity	0,83
Gas Oil Ratio, scf/stb	2204

3.1. Inflow Performance Relationship (IPR)

The IPR curve is a method used to assess the capability or performance of a reservoir well in production engineering. It also serves to predict production rates under specific flowing bottomhole pressures and determine desired production rate targets. The Inflow Performance Relationship (IPR) method employed here is the composite method. IPR Composite is used for wells characterized by reservoir conditions where the water cut exceeds 50% and produced fluids include oil, gas, and water(Tarek Ahmed, n.d.). The Composite Method is applied for calculating IPR under such conditions, particularly when reservoir pressure is lower than the bubble point pressure.

- Determining the J value or Productivity Index using the Composite Method when the tested flowing bottom-hole pressure (Pwf) is below the bubble-point pressure, It is determined by the constant J* (Banjar et al., 2022; Ghonim et al., 2023; Sadeed & Al-Nuaim, 2017).

$$J^* = \frac{q_o}{(\bar{p}-p_b)+ +\frac{p_b}{1.8}\left[1-0.2\left(\frac{p_{wf}}{p_b}\right)-0.8\left(\frac{p_{wf}}{p_b}\right)^2\right]}$$

$$J^* = \frac{4942}{(2217{,}34-2590)+ +\frac{2590}{1.8}\left[1-0.2\left(\frac{1520{,}61}{2590}\right)-0.8\left(\frac{1520{,}61}{2590}\right)^2\right]}$$

$$= 9{,}874312\ bpd/psi$$

- Calculating the value of Base flow rate (Qb) (Pb=Pr)

$$Q_b = J \times (P_r - P_{pwf})$$
$$Q_b = 9{,}874312 \times (2217{,}34 - 2217{,}34)$$
$$Qb = 0\ bfpd$$

- Calculating the value of Maximum flow rate (Qomax) (Pb=Pr)

$$\mathrm{Q_{o\ max}} = \mathrm{Q_b} + \left(\frac{\mathrm{J \times P_b}}{1{,}8}\right)$$

$$Q_{o\,max} = 0 + \left(\frac{9{,}874312 \times 2217{,}34}{1{,}8}\right)$$
$$Q_{o\,max} = 12.163{,}75 \text{ bopd}$$

- Determining Tan α using the Casing Gauge (CG)/ Casing Diametr (CD) calculation

$$CD = F_w\left(\frac{0{,}001Q_{o\,max}}{J}\right) + F_o(0{,}0125)F_w\left[-1 + \sqrt{81 - 80\left(\frac{0{,}999Q_{o\,max} - Q_b}{Q_{o\,max} - Q_b}\right)}\right]$$
$$CD = 0{,}96561\left(\frac{0{,}001 \times 12163{,}75}{9{,}874312}\right)$$
$$+ 0{,}03439(0{,}0125)0{,}96561\left[-1 + \sqrt{81 - 80\left(\frac{0{,}999 \times 12163{,}75 - 0}{12163{,}75 - 0}\right)}\right]$$
$$CD = 1{,}1896611$$
$$CG = 0{,}001Q_{o\,max}$$
$$CG = 0{,}001 \times 12163{,}75$$
$$= 1{,}216375$$
$$\tan\alpha = \frac{CG}{CD}$$
$$\tan\alpha = \frac{1{,}216375}{1{,}5634008}$$
$$= 1{,}022455$$

- Calculating the value of tan Beta (β)

$$\tan\beta = \frac{1}{\text{Tan }\alpha}$$
$$\tan\beta = \frac{1}{1{,}022455}$$
$$\tan\beta = 0{,}9780382$$

- Calculating the value of Qtmax

$$Q_{t\,max} = Q_{o\,max} + F_w\left(P_r - \left(\frac{Q_{o\,max}}{J}\right)\right)(\text{Tan }\alpha)$$
$$Q_{t\,max} = 12163{,}75 + 0{,}96561\left(2217{,}34 - \left(\frac{12163{,}75}{9{,}874312}\right)\right)(1{,}022455)$$
$$= 13.136{,}716 \text{ bfpd}$$

- Calculating QOptimum is 80% of the value of Qtmax.

$$Q_{Optimum} = Q_{o\,max} \times 80\%$$
$$Q_{Optimum} = 12163{,}75 \times 80\%$$
$$= 9.730{,}9996 \text{ bopd}$$

- Determining the IPR curve with flow rate (Q) as the assumption(Armenta & Wojtanowicz, 2005; Davila et al., 2019; Qasem et al., 2014).
  1. Assuming Pwf, if (Qb < Qt < Qomax)

$$P_{wf} = F_w\left(P_r - \frac{Qt}{J}\right) + F_o(0{,}0125)F_w\left[-1 + \sqrt{81 - 80\left(\frac{0{,}999Q_t - Q_b}{Q_{o\,max} - Q_b}\right)}\right]$$

  2. Assuming Pwf, if (Qomax < Qt < Qtmax)

$$Q_{t\,max} = F_w\left(P_r - \left(\frac{Q_{o\,max}}{J}\right)\right) - (Q_t - Q_{o\,max})(\text{Tan }\beta)$$

Based on the assumption equation above, the values of wellbore flowing pressure (Pwf) and flow rate (Q) are determined to create the IPR curve. Here is the Q vs Pwf table:

Table 2 The results of the Composite IPR calculation for Well SKW 32.

Pwf Psi	Q Bfpd
2.217,34426	0
2.116,120	1.000
2.014,596	2.000
1.912,888	3.000
1.810,963	4.000
1.714,717	**4.942**
1.606,291	6.000
1.503,412	7.000
1.400,027	8.000
1.219,335	**9.730,09**
1.190,827	10.000
1.101,110	11.000
951,645	**12.162,60871**
779,710	**13.500**
715,430	14.000
0	**19.564,95**

Based on the results from table 1 Reservoir Characteristic Data, the assumed flow rate (Q) and assumed flowing bottom hole pressure (Pwf) were obtained can be seen in table 2. From these assumed Q and Pwf data, they will be plotted to generate the IPR Composite curve (Q vs Pwf) for Well SKW 32. This IPR curve will be used to determine the productivity of Well KGH 32 and evaluate the ESP pump. The calculation of the IPR Composite for Well KGH is depicted in figure 2 . Here is the IPR Composite curve for Well KGH 32:

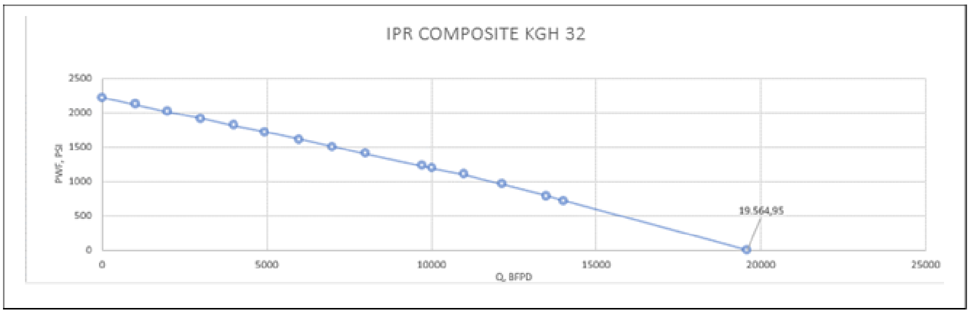

Figure 2 The Composite IPR Curve for Well KGH 32.

3.2. Calculation of the evaluation of the installed Electric Submersible Pump (ESP).

This section will calculate and present the evaluation of the electric submersible pump by determining the volumetric efficiency value of the pump at Well KGH 32. According to the data available in table 1, the pump installed in Well KGH 32 is P31 with a capacity of 500 – 5,000 bfpd, 92 stages, and a pump set depth of 4,533 ft. To determine the volumetric efficiency, we compare the actual flow rate value with the theoretical flow rate value, where the theoretical flow rate uses the known production flow rate data from the well and pump. The actual flow rate value is calculated using the total dynamic head (TDH) calculation. The TDH value will be used to find the head per stage to plot on the pump curve performance graph, which determines the actual flow rate. The steps for calculating the ESP pump evaluation begin with calculating the production capacity(Jaya et al., n.d.).

- Steps in calculating the production capacity(Ghonim et al., 2023)
  1. Determining the specific gravity (SG) of the fluid (Sgfluida)

$$SGfluida = (SGoil \times Fo) + (SGwater \times Fwater)$$
$$SGfluida = (0{,}83137 \times 0{,}03439) + (0{,}98299 \times 0{,}96561)$$
$$SGfluida = 0{,}978$$

  2. Determining the fluid gradient (Gf) value

$$Gf = SG\ Fluida \times 0{,}433$$
$$Gf = 0{,}978 \times 0{,}433$$
$$Gf = 0{,}423$$

  3. Determining the Pressure Fluid Gradient (PGF) value

$$PGf = \frac{(middle\ perforation - PSD) \times SGF}{2{,}31}$$
$$PGf = \frac{(7478 - 4533) \times 0{,}978}{2{,}31}$$
$$PGf = 1242{,}755\ Psi$$

  4. Determining the Pump Intake Pressure (PIP) value

$$PIP = Pwf - PG\ fluida$$
$$PIP = 1415{,}144237 - 1242{,}755$$
$$PIP = 172\ Psi$$

- Steps in calculating the gas calculation
  1. Determining the Gas Solubility in Oil (Rs) value

$$Rs = SGgas \times \left(\frac{PIP}{18}\right) \times \left(\frac{10^{0{,}0125 \times API}}{10^{0{,}00091 \times T}}\right)^{1{,}2048}$$
$$Rs = 2{,}71 \times \left(\frac{172}{18}\right) \times \left(\frac{10^{0{,}0125 \times 38{,}7}}{10^{0{,}00091 \times 271}}\right)^{1{,}2048}$$
$$Rs = 4{,}088\ Scf/Stb$$

  2. Determining the Z value using the Dranchuk method(Sadeed & Al-Nuaim, 2017).
     a. Calculating the Pseudo Critical Pressure (Ppc) and Pseudo Critical Temperature (Tpc) values

$$Ppc = 709{,}6 - (58{,}7 \times SG\ gas)$$
$$Ppc = 709{,}6 - (58{,}7 \times 2{,}71)$$
$$Ppc = 550{,}48$$

$$Tpc = 170{,}5 - (307{,}3 \times SGgas)$$
$$Tpc = 170{,}5 - (307{,}3 \times 2{,}71)$$
$$Tpc = 1003{,}366$$

b. Calculating the Pseudo Reduced Pressure (Ppr) and Pseudo Reduced Temperature (Tpr) values

$$Ppr = \frac{PIP}{Ppc}$$
$$Ppr = \frac{172}{550{,}48}$$
$$Ppr = 0{,}313$$

$$Tpr = \frac{T+460}{Tpc}$$
$$Tpr = \frac{271 + 460}{1003{,}366}$$
$$Tpr = 0{,}728$$

c. Calculating the Z value using the Dranchuk method

$$Z = 1 - \left(\frac{3{,}52 \times Ppr}{10^{0{,}9813 \times Tpr}}\right) + \left(\frac{0{,}274 \times Ppr^2}{10^{0{,}8157 \times Tpr}}\right)$$
$$Z = 1 - \left(\frac{3{,}52 \times 0{,}313}{10^{0{,}9813 \times 0{,}728}}\right) + \left(\frac{0{,}274 \times 0{,}313^2}{10^{0{,}8157 \times 0{,}728}}\right)$$
$$Z = 0{,}794$$

3. Determining the Oil Formation Volume Factor (Bo) value

a. Calculating the value of F

$$F = RS \times \left(\frac{SGgas}{SGoil}\right)^{0{,}5} + 1{,}25 \times T$$
$$F = 4{,}088 \times \left(\frac{2{,}71}{0{,}83137}\right)^{0{,}5} + 1{,}25 \times 271$$
$$F = 345{,}658$$

b. Determining the Oil Volume Factor (Bo) value

$$BO = 0{,}972 + 0{,}000147 \times F^{1{,}175}$$
$$BO = 0{,}972 + 0{,}000147 \times 271^{1{,}175}$$
$$BO = 1{,}133\ Rb/Stb$$

4. Determining the Gas Volume Factor (Bg) value

$$Bg = 5{,}048 \times Z \times \frac{T}{PIP}$$
$$Bg = 5{,}048 \times 0{,}794 \times \frac{271}{172}$$
$$Bg = 15{,}655\ bbl/mcf$$

5. Determining the Total Gas Volume

$$Total\ Gas = \frac{BOPD \times GOR}{1000}$$
$$Total\ Gas = \frac{4942 \times 0{,}03439 \times 2204}{1000}$$
$$Total\ Gas = 374{,}547\ Mcf$$

6. Determining the Solution Gas value

$$Solution\ Gas = \frac{BOPD\ \times Rs}{1000}$$
$$Solution\ Gas = \frac{(1 - 0{,}96561) \times 4942 \times 4{,}088}{1000}$$
$$Solution\ Gas = 0{,}695\ Mcf$$

7. Determining the Free Gas Volume

$$Free\ Gas = Total\ Gas - solution\ gas$$
$$Free\ Gas = 374{,}547 - 0{,}695$$
$$Free\ Gas = 373{,}852\ Mcf$$

8. Determining the Total Volume at Intake (Vt)

a. Calculating the Oil Volume at Intake (Vo)

$$Vo = BOPD\ \times Bo$$
$$Vo = 4942 \times 0{,}03439\ \times 1{,}113$$
$$Vo = 189{,}198\ Bopd$$

b. Calculating the Water Volume at Intake (Vw)

$$Vw = Qtest\ \times \%water$$
$$Vw = 4942\ \times 0{,}96561$$
$$Vw = 4772{,}061\ Bwpd$$

c. Calculating the Gas Volume at Intake (Vg)

$$Vg = Free\ gas\ \times Bg$$
$$Vg = 373{,}852 \times 15{,}655$$
$$Vg = 5852{,}809\ Mcfd$$

d. Calculating the Total Volume at Intake (Vt)

$$Vt = Vo + Vw + Vg$$
$$Vt = 189{,}198 + 4772{,}061 + 5852{,}809$$
$$Vt = 10814{,}067\ Bfpd$$

9. Determining the Gas Percentage at Intake

$$\%Free\ gas = \frac{Vg}{Vt} \times 100\%$$
$$\%Free\ gas = \frac{5852{,}809}{10814{,}067} \times 100\%$$
$$\%Free\ gas = 54{,}122\ \%$$

10. Determining the Turpin value (ϕ)

a. Calculating the density of the liquid phase (ρl)

$$\rho l = \ 62{,}4\ \times \left(\frac{SGoil\ \times 1}{Bo\ \times 1 + WOR} + \frac{SGwater\ \times WOR}{BW\ \times 1\ \times WOR}\right)$$
$$\rho l = \ 62{,}4\ \times \left(\frac{0{,}83137\ \times 1}{1{,}113\ \times 1 + 28{,}08094} + \frac{0{,}98299\ \times 28{,}08094}{1{,}02 \times 1\ \times 28{,}08094}\right)$$
$$\rho l = 4.732{,}44385\ lb/cuft$$

b. Calculating the density of the gas phase (ρg)

$$\rho g = \frac{0{,}0764 \ \times SGgas}{Bg}$$

$$\rho g = \frac{0{,}0764 \ \times 2{,}71}{Bg15{,}655}$$

$$\rho g = 0{,}01322507 \ lb/cuft$$

c. Calculating the gas flow rate (qg)

$$qg = Qo \ \times (GOR - Rs) \times Bg$$

$$qg = 4942 \times 0{,}03439 \ \times (2204 - 4{,}088) \times (15{,}655/1000)$$

$$qg = 5.852{,}80854 \ bpd$$

d. Calculating the liquid phase sucked by the pump (ql)

$$ql = Qo \ \times (BO + BW + WOR)$$

$$ql = \left(4942 \times (1 - 0{,}96561)\right) \times (1{,}113 + 1{,}02 + 28{,}08094)$$

$$ql = 5.056{,}70005 \ bpd$$

e. Calculating the liquid flow velocity (Vsl)

$$Vsl = 6{,}5 \ \times \ 10^{-5} \ \times \frac{ql}{A} \times \left(\frac{Bo}{1+WOR} + BW \ \times \frac{WOR}{1+WOR}\right)$$

$$Vsl = 6{,}5 \ \times \ 10^{-5} \ \times \frac{5056{,}70005}{979582} \times \left(\frac{1{,}113}{1+28{,}08094} + 1{,}02 \ \times \frac{28{,}08094}{1+28{,}08094}\right)$$

$$Vsl = 0{,}98493 \ ft/s$$

f. Calculating the Turpin value (ϕ)

$$\phi = \frac{2000 \ \times \frac{Qgas}{Qliquid}}{3 \ PIP}$$

$$\phi = \frac{2000 \ \times \frac{5852{,}80854}{5056{,}70005}}{3 \ \times 172}$$

$$\phi = 4{,}47605$$

11. Determining the Total Mass Production Fluid (TMPF) value

$$TMPF = (BOPD \times SGoil + (BWPD \times SGWater) \times 62{,}4 \times 5{,}6146) + (GOR \times BOPD \times SGgas \times 0{,}0752)$$

$$TMPF = (4942 \times 0{,}03439 \ ) \times 0{,}83137 + (4772{,}061 \times 0{,}98299) \times 62{,}4 \times 5{,}6146) + (2204 \times (4942 \times 0{,}03439) \times 2{,}71 \times 0{,}0752$$

$$TMPF = 1.769.292{,}917 \ lbs/day$$

12. Calculating the Specific Gravity Composite (SGcomposite) value

$$SGcomposite = \frac{TMPF}{(BFPD \ \times 5{,}6146 \ \times 62{,}4)}$$

$$SGcomposite = \frac{176929{,}917}{(10814{,}067 \times 5{,}6146 \times 62{,}4)} = 0{,}467$$

Based on the gas calculation results for Well KGH 32 with the installed pump P-31, the Turpin (ϕ) value is calculated to be 4.47605, with the parameter condition <1, and the free gas intake value is 54.122%, with the parameter condition <10%. Therefore, for Well SKW 32, which has ESP pump P-31 installed, it is necessary to install a rotary gas separator due to the high gas content, which can adversely affect the pump's performance and potentially lead to pump instability.

- Determining the Total Dynamic Head (TDH)(Ergun et al., 2018; Ghonim et al., 2023; Xiao et al., 2016)

1. Calculating the Vertical Lift (HD) value

$$Hd = Pump\ Depth - \left(PIP \times \frac{2,31}{SGc}\right)$$
$$Hd = 4533 - \left(172 \times \frac{2,31}{0,467}\right)$$
$$Hd = 3680,263\ ft$$

2. Determining the Tubing Fraction (Ft) value

$$Ft = \frac{2,083 \times \left(\frac{100}{c}\right)^{1,85} \times \left(\frac{Q}{34,3}\right)^{1,85}}{ID^{4,8655} \times \left(\frac{PSD}{1000}\right) \times SGc}$$
$$Ft = \frac{2,083 \times \left(\frac{100}{10}\right)^{1,85} \times \left(\frac{4942}{34,3}\right)^{1,85}}{ID^{4,8655} \times \left(\frac{4533}{1000}\right) \times 0,467}$$
$$Ft = 40.003,263\ ft$$

3. Determining the Tubing Head (HT) value

$$Ht = Pwh \times \frac{2,31}{SGc}$$
$$Ht = 230 \times \frac{2,31}{0,467}$$
$$Ht = 1.137,713\ ft$$

4. Calculating the Total Dynamic Head (TDH) value

$$TDH = Hd + Ft + Ht$$
$$TDH = 3680,263 + 40003,424 + 1137,713$$
$$TDH = 44.821,399\ ft$$

- Determining the Volumetric Efficiency (EV) value

$$EV = \frac{Qactual}{Qteoritis} \times 100\%$$
$$EV = \frac{4942}{7000} \times 100\%$$
$$EV = 71\%$$

From the evaluation of the installed electric submersible pump, the actual production rate obtained was 4942 bfpd, while the theoretical production rate was 7000 bfpd. This resulted in a volumetric efficiency (EV) percentage of 71%, indicating that the pump's performance is not optimal. Therefore, optimization of the ESP pump at Well KGH 32 is necessary.

3.3. Determining the Economic Value

In determining the economic viability of ESP, several aspects need to be considered. This ensures that the well can be evaluated economically, whether it is viable or not. This study will explain and calculate the profit gained after conducting the ESP evaluation(Blanco & Davies, 2001; WYNATA APRIANDRI, n.d.). The following are the steps in calculating the ESP economics:

- Calculating the revenue value (Rp.)

$$Reveneu\ Rp. = \ Evaluasi\ Vo\ \times mudi\ mix\ to\ oil\ price \times Rp.to\ Dolar$$
$$Revenue\ Rp. = \ 189{,}20 \times 88{,}81\ \times 14.800$$
$$Revenue\ Rp. = 353.866.473\ /day$$

- Calculating the power value (Rp.)

$$Power\ Rp. = Power\ Evaluasi\ \times\ Rate\ Power\ Purchase$$
$$Power\ Rp. = \ 1.036{,}6898\ \times 1.320$$
$$Power\ Rp = 1.368.431\ kWH$$

- Calculating water injection

$$Water\ Inj.Rp. = (Voil + Vwater) \times Rate\ Water\ Injection$$
$$Water\ Inj.Rp. = (189{,}20 + 4.772{,}06) \times 460$$
$$Water\ Inj.Rp. = 2.282.179\ bbl/day$$

- Calculating chemical usage
  1. Scale Inhibitor

$$SI = \ Nilai\ SI\ pada\ sumur\ (gal) \times 3{,}9 \times harga\ Scale\ Inhibitor\ (L)$$
$$SI = 3{,}5\ \times 3{,}9\ \times 25.875$$
$$SI = \ 284.386\ L/day$$

  2. Corossion Inhibitor

$$CI = Nilai\ CI\ pada\ sumur\ (gal) \times 3{,}9 \times harga\ Corossion\ Inhibitor\ (L)$$
$$CI = 0{,}7\ \times 3{,}9\ \times 20.700$$
$$CI = 56.511\ L/day$$

  3. Demulsifier

$$DML = \ Nilai\ DML\ pada\ sumur\ (gal) \times 3{,}9 \times harga\ Dwmulsifer\ (L)$$
$$DML = 2{,}5\ \times 3{,}9\ \times\ 57.040$$
$$DML = 142.600\ L/day$$

- Routine Cost
  The daily routine cost used by the company for this well has been set at Rp. 86,785.00/day.

- Facilities Sharing Agreement (FSA)
  The Facilities Sharing Agreement (FSA) used by the company for this well has been set at Rp. 242,145 per day.

- Production Cost

$$Production\ Cost\ = Power \times Chemical\ Usage \times Routin\ Cost \times FSA$$
$$Production\ Cost\ = 1.368.431\ \times 48.497\ \times 86.785.000 \times 242.145$$
$$\text{Production Cost} = \text{Rp. } 91.161.251\ \text{/day}$$

- Cost/bbl

$$\frac{Cost}{bbl} = Prod.cost\ /\ Nilai\ Evaluasi\ Vo$$
$$\frac{Cost}{bbl} = \frac{91.161.251}{189{,}20}$$
$$\frac{Cost}{bbl} = Rp.\ 481.829\ \text{/day}$$

- Profit

$$Profit = \ Revenue\ /\ Production\ Cost$$
$$Profit = \frac{248.680.004}{91.161.251}$$
$$Profit = Rp.157.518.753\ /day$$

IV. CONCLUSION

This study titled "Evaluation of Electric Submersible Pump (ESP) by calculating the economic factors at Well KGH 32," the following conclusions were drawn.

1. The value of Q is 4942 bfpd with a Pwf value of 1714.717 bfpd. The optimum Q value is 9730.09 bfpd taken from 80% of Qomax value. The optimization Q value is 13,500 bfpd with a Pwf value of 779.710, and a percentage value of 69% of the total Q value. The Qo max value is 12,162.60871 bfpd with a Pwf value of 951.645 bfpd. The Qt max value is 19,564.95 bfpd.
2. In the evaluation calculation, a Volumetric Efficiency value of 71% was obtained, indicating the need for optimization to increase production rates.
3. In the free gas calculation, a value of 54.122% was obtained, where Free gas > 10%, and a Turpin value of 4.47605 was found, indicating Turpin (ϕ) > 1. Therefore, it is necessary to install a rotary gas separator to stabilize pump performance, as excessive gas content can disrupt pump operation.
4. Based on the profit evaluation, the profit obtained from Well KGH 32 is Rp. 157,518,753 per day.

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