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Evaluation of HPU Performance in High GLR Oil Well BNG-X3 Benuang Field South Sumatera

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ABSTRACT

Nowadays, producing BNG-X3, a well in Benuang Field, is relatively easy due to its natural drive which is bottom water aquifer combined with high associated gas content. Hence, most of the wells are flowing naturally from reservoir to surface facilities. However, issues most likely to occur overtime, especially when the pressure depletes due to production hence could not supply enough energy for the fluid to flow naturally. In this study, analysis was conducted to address this future problem by implementing a suitable artificial lift for this kind of circumstances. To get a more sustainable and continuous result, post installation evaluation was carried out to define key parameters that can lead to success and optimization in future application of Hydraulic Pumping Unit (HPU) in Benuang Field.

The analysis consists of reserve calculations, economic feasibility, and step by step design for artificial lift HPU. The HPU installation and production performance monitoring for well BNG-X3 were conducted thoroughly to assess whether the implementation was optimized based on the well's potential. Reserve calculations were performed using the Decline Curve Analysis (DCA) method and Pipesim software, while the HPU design was developed using Microsoft Excel. Field data was utilized for monitoring and evaluating the results.

Based on the analysis, well BNG-X3 still holds significant potential. From an economic perspective, it has a positive Net Present Value (NPV) of $615,000 and a Payback Period (POT) of less than one year. Production observations indicate that well BNG-X3, with a Gas-Liquid Ratio (GLR) of up to 1000 SCF/STB and a high gas production rate, can be reactivated. The use of a 2.5" pump, along with SPM 5 and SL 155-inch parameters, has been fairly successful in restoring lost production. However, the achieved production rate has not yet reached the well's optimal potential due to the pump efficiency still being below the target (67%).

Keywords: depleted Pressure, hydraulic pumping unit, artificial lift

I. INTRODUCTION

The study was conducted at the Benuang field in Prabumulih City, focusing on the Benuang structure within the operational area of Adera Field, PT Pertamina Hulu Rokan. Prabumulih City is located southwest of Palembang, South Sumatra, approximately 112 km away by land. BNG-X3 is characterized by high pressure and oil GLR oil well, thus naturally flowing from the Talang Akar Formation (TAF).

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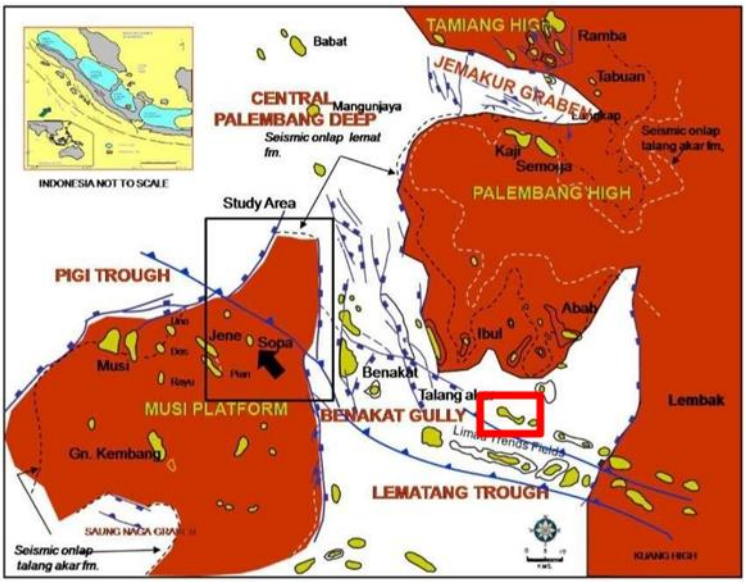
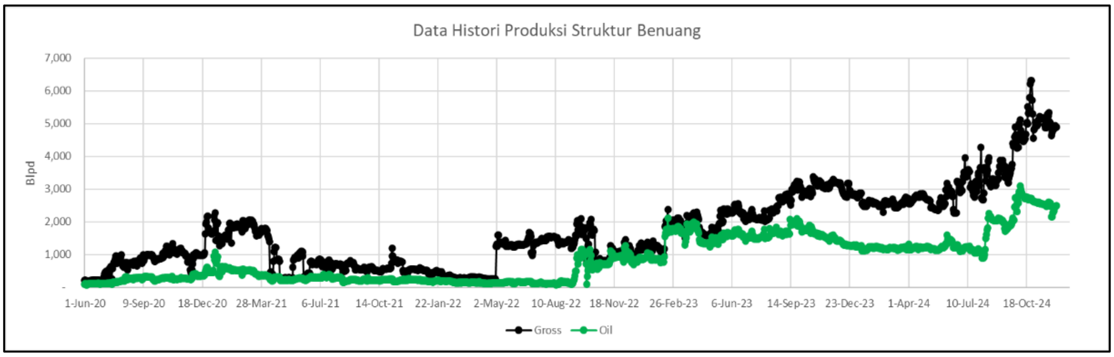


The Benuang field has shown notable production trends over the years. Between 2022 and 2024, production significantly increased due to drilling activities. However, this increase was accompanied by a rise in Water Cut (WC), indicating increasing dominance of aquifer contribution. BNG-X3 is among the wells in this field.

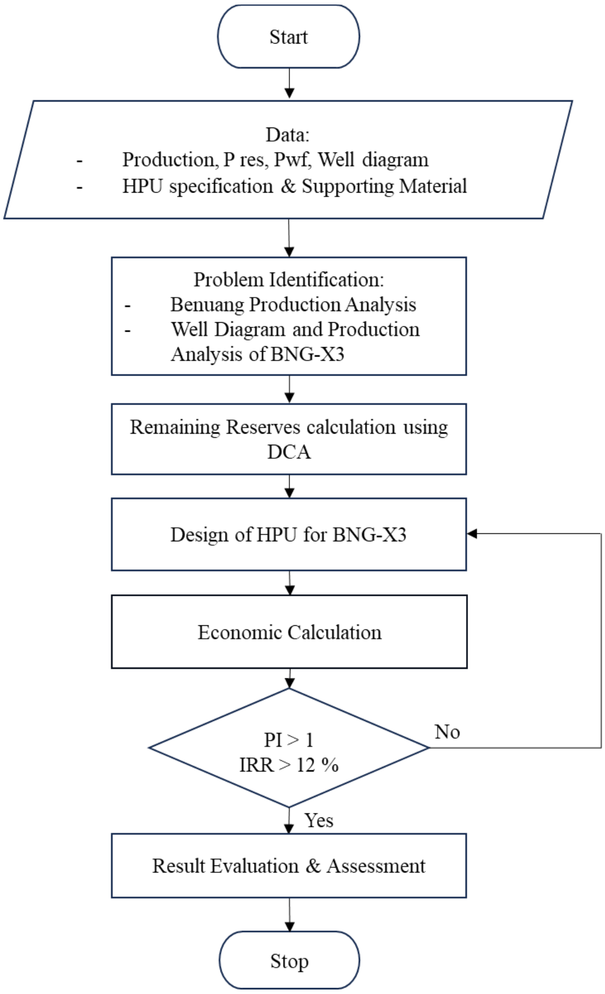


As performance declines due to reservoir pressure depletion, artificial lift methods are required. Well BNG-X3 has shown such decline, having ceased production since April 2023. Despite this, it retains remaining reserves of 60.18 MBO, with economic calculation it is justify to install artificial lift implementation.

Hydraulic Pumping Unit (HPU) is a widely used artificial lift method in Benuang due to its operational simplicity and reliability. The subsurface mechanism same with Sucker Rod Pump (SRP), utilizing a downhole pump with a Standing Valve and Travelling Valve. However, HPU differs on the surface, utilizing a hydraulic tower operated by oil-filled pistons. Diverse power sources such as gas, electricity, or diesel. Compared to SRP, HPU installation is simpler and requires less space. This study explores HPU performance and engineering design in detail. Liquid Loading, a phenomenon where declining gas velocity fails to lift liquids to surface, commonly occurs in high gas-water production fields. Most solution for this problem is Plunger Lift, though plunger lift systems can address this, their operational compatibility with HPU must be evaluated.

II. METHODS

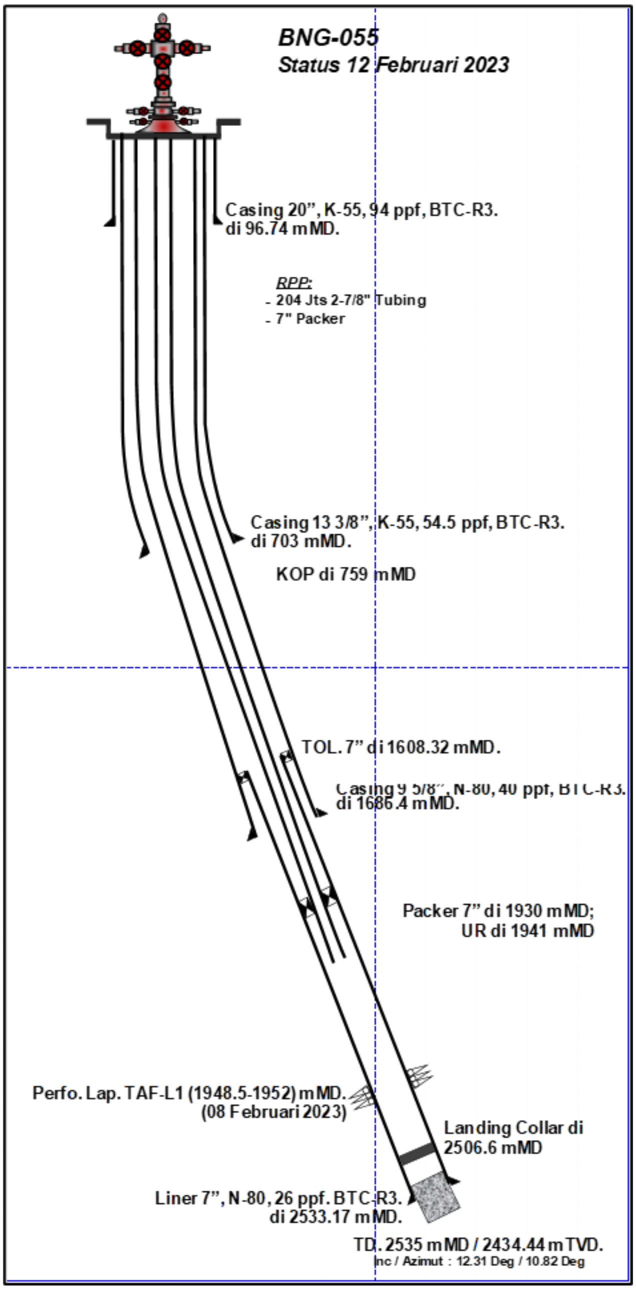
The objective of this research is to evaluate HPU usage in well BNG-X3. The study identifies the cause of production decline, estimates technical and economic potential, designs an HPU system, and assesses its implementation (Methodology Diagram as picture below). Data Preparation and Processing: The research uses flow rate, pressure (Pwf), well diagram, and HPU specifications. Supporting data includes production history, Pipesim simulation results, and relevant literature.



III. RESULTS AND DISCUSSION

Data preparation and Processing

Data Preparation and Processing: The research uses flow rate, pressure (Pwf), well diagram, and HPU specifications. Supporting data includes production history, Pipesim simulation results, and relevant literature. BNG-X3 was drilled in March 2023 targeting layer L1 (interval 1948.5 – 1952 mMD), produced via natural flow with 2 7/8" tubing set at 1941 mMD. The well uses directional drilling with a 12.3° angle and a 7" liner.



From production data history, using Decline Curve Analysis (DCA), Estimated Ultimate Recovery (EUR) is 171.98 MBO with annual decline rate 37.44%.

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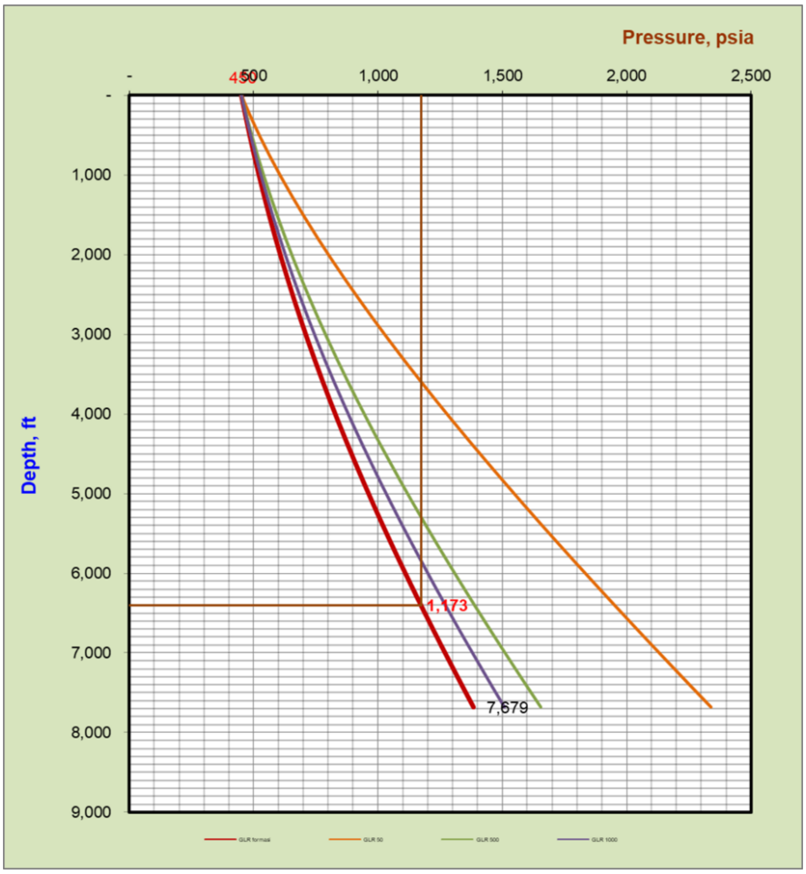
As of now, 111.729 MBO has been produced, leaving 60.18 MBO still potentially be produced.

After, Inflow Performance Relationship (IPR) curve was constructed using Vogel's equation with available surface pressure data (Pwh), rate (Q) and Pwf using conversion of Hagedorn-Brown correlation Chart. Below is the chart for Hagedorn Brown Correlation.



This correlation using IPR in one-time condition to build as data below:

$$X = \frac{N_{vg} {N_l}^{0.38}}{{N_d}^{2.14}}$$

$$Y = \frac{H_l \varphi}{0.575}$$

$$N_{vl} = v_{sl} (\frac{\rho l}{g\sigma})^{1/4}$$

$$N_{vg} = v_{sg} \left(\frac{\rho l}{g\sigma}\right)^{\frac{1}{4}}$$

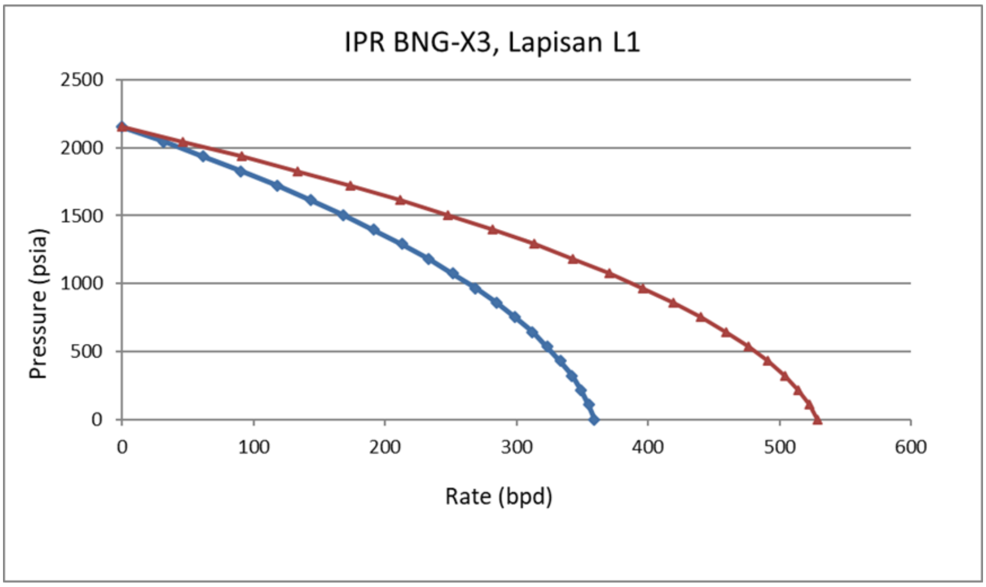
$$N_d = d \left(\frac{\rho l g}{\sigma}\right)^{\frac{1}{2}}$$

$$N_l = \mu_l (\frac{g}{\rho l \sigma^3})^{1/4}$$

$$\varphi = \left(\frac{P}{P_{atm}}\right)^{0.1} (\frac{N_l}{N_d})^{0.0277}$$

Where:

Vsl,Vsg	= Superficial liquid & gas velocities(ft/s)
ρl	= Liquid density (lb/ft³)
σ	= Surface tension (dyne/cm)
d	= Pipe diameter (ft)
μl	= Liquid viscosity (cP)
g	= Gravitational acceleration (32.17 ft/s²)
Hl	= Liquid Hold Up (dimensionless)



From the data of P Res, Q and Pwf, IPR can be constructed as above (blue line) the red line is the IPR from initial condition, Qmax is estimated at 368 BLPD. A target production of 294 BLPD (80% of Qmax) was set, aiming for 100 BOPD net oil with 66% WC.

HPU Design Process

The HPU design process begins with several steps:

1. Determination of Pump Setting Depth (PSD)
2. Selection of Pump Size
3. Design of Stroke Length (SL) and Strokes Per Minute (SPM)
4. Specification of HPU Type

1. Determination of Pump Setting Depth (PSD)

The PSD is calculated using the gross target production, converted into a target flowing bottomhole pressure (Pwf) to determine the dynamic fluid level. For HPU, a safety factor of 50 psi is added to establish the PSD. The calculations are as follows:

a) Target Gross: 294 BLPD with Pwf = 860 psi
b) Conversion to Fluid Gradient:
   - Fluid SG Calculation:

     SGmix = (SGoil × (1−WC)) + (SGwater × WC)

     SGmix = 0.833 × (1− 0.66) + (1.01 × 0.66) = 0.95
   - Pressure Gradient Calculation:

     GradPress = 0.433 × SGmix = 0.433 × 0.95 = 0.411 psi/ft
c) Fluid Column Height Calculation:

$$Fluid\ Height = \frac{860\ psi}{0.411\ psi/ft} = 2092\ ft$$

d) Pump Setting Depth Calculation:

   PSD = Mid Interval (MD) − Fluid Height

   PSD = (1950.25×3.281) – 2092 = 4306.77 ft ≈ 4307 ft

   With Safety Factor (50 psi → 121.65 ft)

   PSD max=4307+121.65=4429 ft

   Maximum PSD: Mid perforation depth minus 50 psi safety factor → 6277 ft

   The required PSD ranges between 4429 ft (minimum) and 6277 ft (maximum) to achieve the target gross of 294 BLPD

   Available pump sizes in stock:

   a) 2" (Plunger size: 1.75")

   b) 2.5" (Plunger size: 2.25")

   c) 3" (Plunger size: 2.75")

The selection is based on maximum Stroke Length (SL = 168") and SPM (5 SPM). The volumetric calculation is as follows:

$Q = \frac{\pi}{4} x D^2 x\ S\ x\ N\ x\ E$ (4-7)

Where,

Q = Volumetric displacement (BLPD)

D = Plunger diameter (inches)

S = Stroke length (inches)

N = Pumping speed (SPM)

E = Pump efficiency (60%)

Put in Maximum SPM SL Data, using 2.5" pump:

Q per stroke = $\frac{\pi}{4}$ x 2.25^2 x 168 = 667.64 Inch^3 (4-8)

$\frac{667.64}{5615}$ = 0.119 barrel per stroke

Stroke Count:

Stroke per day = SPM x 60 x 24 (4-9)

Stroke per day = 5 x 60 x 24 = 7200

Total Daily Production:

bbl per day = Q per stroke x Stroke per day (4-10)

bbl per day = 0.119 x 7200

bbl per day = 856.1 blpd

Multiply with 60 % pump efficiency yielding 513.66 Blpd ~ 514 blpd, this means that with a 2.5" pump, the maximum SPM and SL design can achieve a gross production of 514 BLPD. The same calculation method was applied to the 2" and 3" pump sizes, yielding the results shown in the table below.

Pump Diameter (inch)	Q (Blpd)
2	311
2.5	514
3	768

Based on this analysis, a 2.5" pump was selected to allow flexibility for future optimization opportunities if needed.

The selection of Strokes Per Minute (SPM) and Stroke Length (SL) is influenced by several factors, including:

1. Well Type (Vertical or Directional), for directional wells, the lowest possible SPM should be used to minimize rod and tubing wear.
2. Tubing Condition: If used tubing is installed, it is recommended to operate at the lowest feasible SPM to reduce fatigue and extend service life.
3. Target Gross Production:If the maximum SL still does not achieve the target rate, SPM adjustment should be considered to increase production

A sensitivity analysis of volumetric calculations was performed to determine the optimal strokes per minute (SPM) for the 2.5" pump configuration. The results are presented in the calculation table below.

SPM	Q (Blpd)
2	206
3	308
4	411
5	514

For Well BNG-X3 with a target gross production rate of 294 barrels of liquid per day (BLPD), the analysis shows that using a 2.5" pump with Stroke length (SL) = 168 inches and SPM = 3 provides sufficient pumping capacity to achieve the target production rate of 294 BLPD.

Based on field data and manufacturer specifications (see attached brochure), two types of Hydraulic Pumping Units (HPU) are available:

1. HPU with 18,000 lbs maximum Peak Polished Rod Load (PPRL)
2. HPU with 27,000 lbs maximum PPRL

Design Result Parameters:

1. Rod String Configuration: 3-Tapered SR (1", 7/8", and 3/8")
2. Pump Setting Depth (PSD): 4,429 ft MD
3. Operating Parameters: 3 SPM × 168" stroke length
4. Pump Size: 2.5"

PPRL Calculation Results: 16,364.92 lbs (detailed calculation is provided in the appendix). This confirms that the 27,000 lbs HPU is the optimal unit for this well application. While the 18,000 lbs model could theoretically handle the calculated 16,364.92 lbs PPRL, applying the standard 10% safety factor (resulting in 18,001 lbs) would push this unit to 100% of its rated capacity. Therefore, engineering best practices dictate the selection of the 27,000 lbs HPU to maintain proper operational.

Economic Calculation

Economic Evaluation Under Production Sharing Contract (PSC) Terms,

Cost Parameters:

1. Capital Expenditure (CAPEX):

Rig & Material Costs: $67,770 USD

2. Operating Expenditure (OPEX):

Production Cost: $27 USD per barrel of oil

Production Forecast:

1. Gross Production: 294 BLPD (Barrels Liquid Per Day)
2. Estimated Net Oil Gain: 60 BOPD (Barrels Oil Per Day)
3. Annual Decline Rate: 38% (First Year)

Result:

1. Profitability Index (PI): 574% (significantly exceeding the 100% threshold)
2. Net Present Value (NPV): $320,000 USD
3. Pay Out Time (POT): < 1 year

This analysis justifies HPU installation as a high-return, fast-payback opportunity. The results exceed all standard economic benchmarks for upstream projects

Result Evaluation

Following the successful installation of the Hydraulic Pumping Unit (HPU) in Well BNG-X3, production performance was closely monitored.

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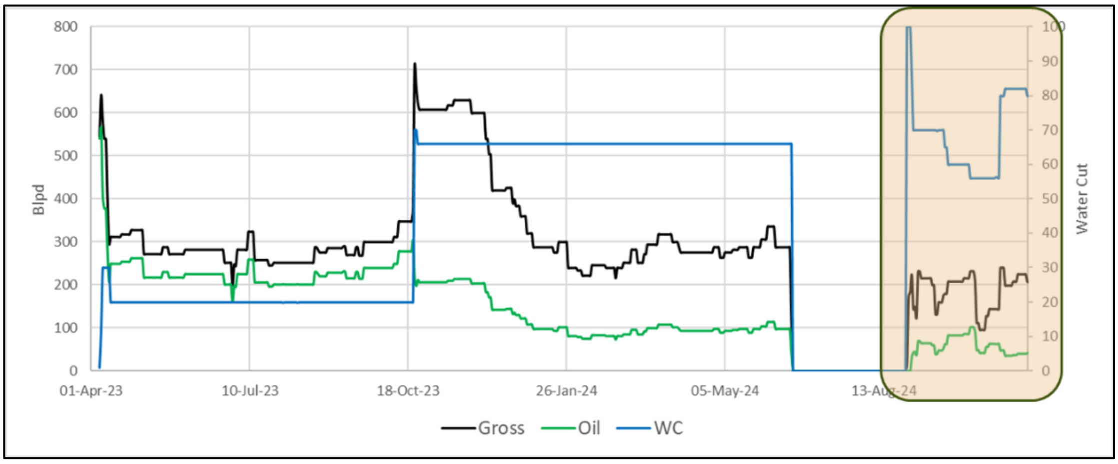

he HPU-installed Well BNG-X3 demonstrated the following production characteristics during the five-month monitoring period. Average gross production: 200 BLPD (barrels liquid per day) and water cut fluctuation: 57% to 87% (showing significant variability). Three engineering perspectives study was held to assess the result:

1. Volumetric Design Benchmarking
2. Gas-to-Liquid Ratio (GLR) Comparative Study
3. Advanced Diagnostic Analysis (Sonolog & Dynagraph)

Volumetric Design Benchmarking

The volumetric design analysis reveals a significant discrepancy between the designed and actual production performance of the HPU system in Well BNG-X3. Based on the specified pump parameters of 5 SPM × 155" stroke length, the system was designed to achieve 294 BLPD gross production. However, field data from August to December 2024 shows an average production of only 194 BLPD, representing just 66% of the designed capacity. This substantial 34% shortfall (100 BLPD deficit) strongly suggests either suboptimal pump performance or external constraints limiting system effectiveness. The underperformance indicates the pump is not operating at full efficiency, potentially due to mechanical issues, improper configuration, or reservoir-related factors restricting fluid delivery to the wellbore. This performance gap warrants thorough investigation to identify and address the root causes of the production

Gas-to-Liquid Ratio (GLR) Comparative Study

The analysis of GLR (Gas-Liquid Ratio) and WC (Water Cut) trends over time, comparing periods before and after HPU installation, reveals important insights into well performance. The data shows a clear water cut increase occurring in October 2023, with this rise being observed both before and after HPU implementation. Notably, the installation of the HPU system did not appear to significantly impact this WC behavior pattern. Meanwhile, the GLR values remained remarkably stable throughout the observation period, consistently maintaining values between 1000-2000 SCF/STB without showing any substantial fluctuations. This stability in GLR was maintained both before and after the HPU installation, indicating that the gas production characteristics of the well were not materially affected by the artificial lift system. The persistent GLR range of 55-88% further confirms that the gas production dynamics remained largely unchanged despite the water cut variations observed in October 2023. These findings suggest that the factors influencing water cut increases in this well operate independently of both the natural flow regime and the HPU-assisted production phase.

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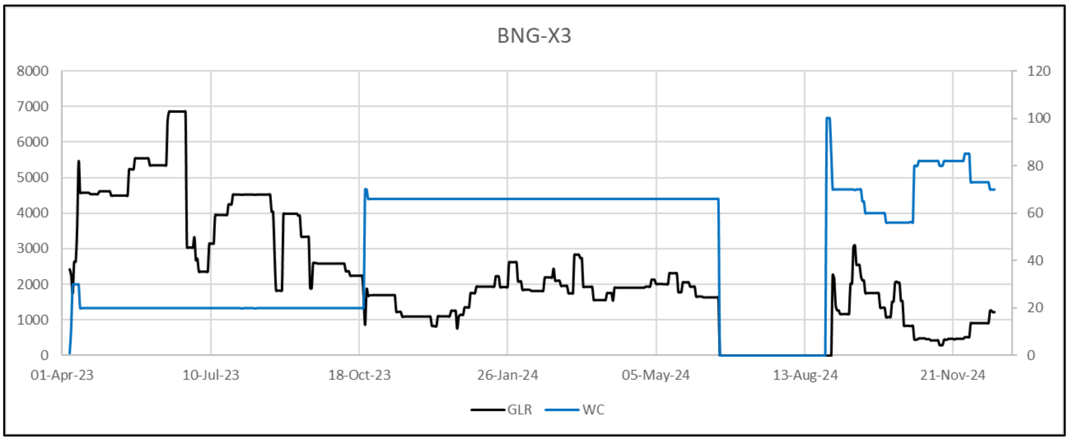
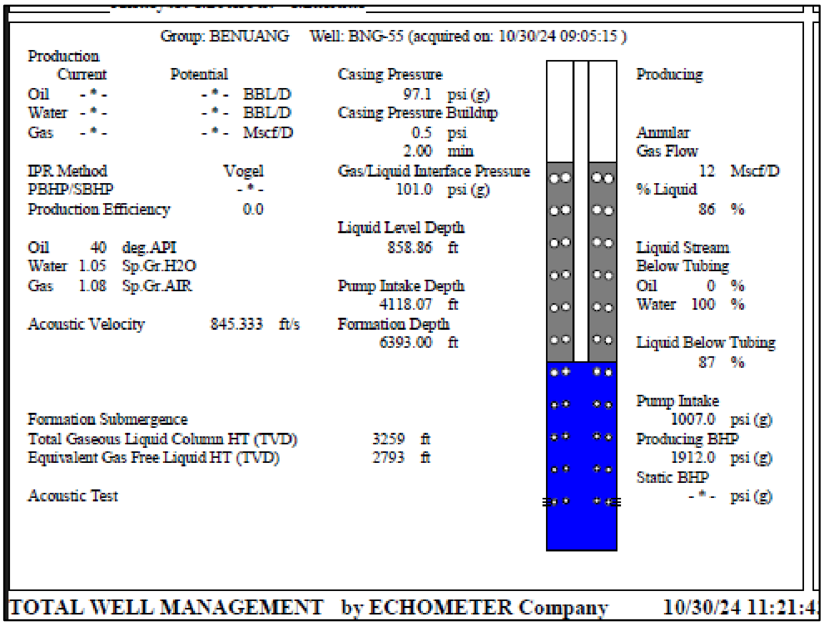
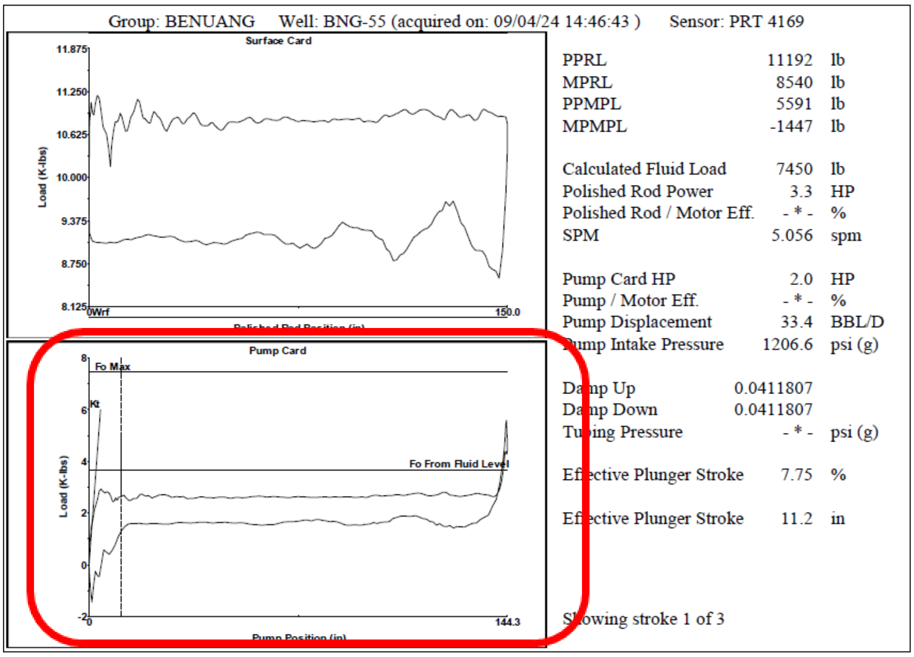


Advanced Diagnostic Analysis (Sonolog & Dynagraph)

The sonolog survey conducted on Well BNG-055 provides insights into the current reservoir performance. The measurements reveal a substantial fluid column height of 858 feet, with submergence depth of 2,793 feet, indicating strong reservoir pressure support that is effectively maintaining the well's gross production rate of 200 barrels per day. This fluid column suggests minimal drawdown pressure, implying that the reservoir continues to deliver fluids at a stable rate under the current production conditions. The data obtained from this sonolog reading enables the calculation of an Inflow Performance Relationship (IPR) curve for the well, reflecting its most recent production characteristics. By analyzing the annular pressure data, we can determine the flowing bottom hole pressure (Pwf) corresponding to specific gross production rates, providing crucial information for optimizing well performance and forecasting future production potential under various operating scenarios. The sustained reservoir pressure and fluid delivery capability demonstrated by these findings suggest that Well BNG-055 maintains good productivity, with potential for optimized production through appropriate artificial lift management.



The dynagraph analysis reveals clear indications of gas interference, as evidenced by the characteristic patterns shown in Figure below. The dynagraph card displays distinct signatures that closely match the typical profile of severe gas influence (highlighted by the red circles and squares in the analysis). These telltale patterns demonstrate that gas is substantially affecting pump performance, likely causing incomplete pump fillage and reduced efficiency. The pronounced gas interference explains the observed production shortfall and suggests the need for gas mitigation measures to optimize pump operation and restore expected production levels. This finding is particularly important as it identifies the root cause of the well's underperformance and provides direction for potential remedial actions to improve system efficiency.



3. Result and Discussion

Well BNG-X3 is a high-pressure natural flow producer in the Talang Akar Formation (TAF) of Benuang Field, operated by PT Pertamina Hulu Rokan. Reservoir analysis revealed a maximum flow potential (Qmax) of 368 BLPD, with shut-in pressure (Pr) of 500 psi and flowing bottomhole pressure (Pwf) of 1,173 psi. These parameters guided the HPU design, which was configured with a 2.5" pump, 168" stroke length (SL), and 3 strokes per minute (SPM) to achieve the target production rate of 294 BLPD. The 27,000 lbs HPU unit was selected over the 18,000 lbs model due to the calculated peak polished rod load (PPRL) of 16,364.92 lbs, requiring a 10% safety margin.

The HPU installation demonstrated strong economic viability, with a profitability index (PI) of 574% and net present value (NPV) of $320,000 USD. The project's pay-out time (POT) of under one year confirmed its financial attractiveness. Post-installation monitoring from August to December 2024 showed an average production of 200 BLPD with water cut (WC) fluctuating between 57-87%. Notably, the gas-liquid ratio (GLR) remained stable at 1,000-2,000 SCF/STB, consistent with pre-HPU conditions, while the system restored average production rates of 54 BOPD (90 % from target) and 0.2 MMSCFD of gas.

While the HPU successfully restored production, the 200 BLPD output fell below the 294 BLPD target, suggesting potential optimization opportunities. The consistent GLR indicates the HPU did not significantly alter the well's gas production characteristics. Further analysis of the water cut variability and production shortfall is recommended to identify potential mechanical or reservoir constraints. The project's technical and economic success supports consideration of similar HPU applications in analogous wells within the Adera Field. Continued monitoring will be essential to evaluate long-term performance and decline characteristics.

IV. CONCLUSION

1. Liquid Loading Identification and Solution

   The study confirms Well BNG-X3 was experiencing liquid loading issues, as evidenced by the restored production following HPU installation. The well's natural flow had become insufficient to lift fluids to surface, demonstrating the need for artificial lift intervention to maintain production.

2. Reservoir Potential and Project Economics

   Analysis reveals substantial remaining reserves of 80.52 MBO, indicating significant future production potential. The HPU installation proved highly economical, delivering an exceptional NPV of $615,000 USD with a pay-out time (POT) under one year, validating the project's financial viability.

3. HPU Design and Performance

   The implemented HPU system features:

   a. 27,000 lbs capacity unit
   b. 2.5" downhole pump
   c. Operating parameters: 5 SPM and 155" SL
   d. While achieving 200 BLPD (66% of design capacity), the system successfully restored production to:
   e. 54 BOPD oil & 0.2 MMSCFD gas

4. Efficiency Challenges

   Diagnostic tools identified significant gas interference (via sonolog and dynagraph data) as the primary factor reducing pump efficiency. This explains the gap between actual and designed production rates.

5. Project Success

   The HPU installation has demonstrably revived well productivity, confirming artificial lift as the appropriate solution for liquid loading in BNG-X3. The results support consideration of similar applications for other wells exhibiting comparable production challenges.

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