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Integrated Production Optimization of Mature Field Y Under Network Constraints

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ABSTRACT

The Y Field, a mature field experiencing declining reservoir pressure, the production of hydrocarbons is declining, leading to the need for production optimization. One crucial aspect of this optimization is the selection of suitable artificial lift methods. The choice of artificial lift methods in Field Y is dependent on the unique reservoir conditions of each well. The commonly utilized equipment for artificial lift methods in Field Y includes the Sucker Rod Pump (SRP) and the Electrical Submersible Pump (ESP). This bachelor thesis aims to develop an integrated production optimization strategy for maximizing well production in Structure X, a mature field. The study involves analyzing and optimizing artificial lift methods and integrating surface network simulation. The Inflow Performance Rate (IPR) curve is utilized to identify the production potential of each well in Structure X. By evaluating the pump performance and surface network in Structure X, it is possible to identify wells that utilize artificial lift or existing pumps and have the potential to be improved up to their maximum operating range, based on their gross flow rate (BFPD). Through optimization, adjusting the stroke per minute for the Sucker Rod Pump (SRP) and the operating frequency for the Electrical Submersible Pump (ESP) can lead to a significant increase in production. Specifically, with a design production rate of 2308.59 BFPD, an improvement of 82.23 BOPD can be achieved.

Keywords: sucker rod pump, electrical submersible pump, inflow performance relationship

I. INTRODUCTION

Background

As oil fields mature, the reservoir pressure decreases, resulting in a decline in hydrocarbon production. In order to optimize hydrocarbon production and maintain the target production in a developed field, production enhancement techniques are required. These techniques involve modifying existing components or adjusting the operating conditions of production equipment in order to improve the production system. The primary objective is to increase production rates while minimizing additional operating costs. Artificial lift mechanisms are commonly employed as a means to sustain hydrocarbon production over an extended period and avoid the need for drilling additional wells (Kalu-Ulu, Khamees, & Flippin, 2023). Therefore, artificial lift is a crucial mechanism for sustaining the production or reducing the decline of the field.

In this study, the author analyzed the performance of artificial lift methods that have been used in the Structure X, along with the optimization of the existing design. The structure X consists of 31 existing wells, including 8 active injection wells and 13 active production wells. Among the production wells, 10 oil wells are equipped with Sucker Rod Pump (SRP), 2 oil wells utilize Electrical Submersible Pump (ESP), and 1 gas well operates through natural flow. The objective of this optimization is to address the challenge of declining production capability resulting from reservoir pressure decline. By doing so, it aims to enhance the economic value of the wells and achieve the desired production rates.The following objectives can be reviewed in this study, namely: To analyze the Inflow Performance Relationship (IPR) of wells using commercial steady state fluid flow software; To determine the evaluation and optimization of artificial lift design for production wells in Structure X; To conduct network simulations and evaluate the optimization based on the simulation results with the surface facilities limit diagram.

Basic Theory

Production optimization aims to determine and apply the optimal values for parameters in the production system. The objective is to maximize hydrocarbon production rate or revenue while minimizing operating costs, taking into account technical and economic constraints. This optimization process can be carried out at different levels, such as the well level, platform/facility level, or field level, depending on how the system is defined (Guo, Liu, & Tan, 2017). Within the scope of this study, the systems targeted for optimization include sucker rod-pumped wells, electrical submersible-pumped wells, as well as oil and gas production fields. By optimizing these systems, it is possible to enhance their performance, increase production efficiency, and improve overall profitability.

The concept of NODAL analysis is introduced as a systems analysis approach to evaluate the performance of production systems. NODAL analysis involves assessing individual components such as electrical circuits, pipeline networks, pumps, and compressors within the larger production system. Its primary objective is to identify specific areas within the system that experience excessive flow resistance or pressure drop (Beggs, 2003). By analyzing these components individually, it becomes possible to identify and address inefficiencies, ultimately leading to an improvement in the overall performance of the production system.

1. Inflow Performance Relationship

The Inflow Performance Relationship (IPR) is widely used in production engineering to evaluate reservoir deliverability. It involves plotting the relationship between the flowing bottom-hole pressure and the liquid production rate on an IPR curve (Guo, Liu, & Tan, 2017). This curve provides a visual representation of how changes in bottom-hole pressure impact the production rate of liquids from the reservoir.

The productivity index (PI or J) is a measure of the slope of the IPR curve. It quantifies the relationship between the flowing bottom-hole pressure and the liquid production rate. PI Method's equation (Guo, Liu, & Tan, 2017) is shown by **Equation 1.** below:

$$PI = \frac{q_o}{(P_r - P_{wf})} \qquad (1)$$

One widely used empirical equation for estimating flow rate in oil and gas wells is the Vogel equation. This equation is based on the concept of Inflow Performance Relationship (IPR) and is particularly applicable for analyzing well productivity under steady-state flow conditions. Vogel's equation (Guo, Liu, & Tan, 2017) is shown by **Equation 2.**

$$q_o = q_{max}\left[1 - 0.2\left(\frac{P_{wf}}{P_s}\right) - 0.8\left(\frac{P_{wf}}{P_s}\right)^2\right] \qquad (2)$$

Equations 3-4 are used to calculate the static bottomhole pressure (Ps) and flowing bottomhole pressure (Pwf) from fluid level data:

$$P_s = 0.433 \times 3.28\, SG_{mix} \times SFL \qquad (3)$$

$$P_{wf} = 0.433 \times 3.28\, SG_{mix} \times DFL \qquad (4)$$

$$SG_{mix} = (SG_{water} \times WC) + \left(SG_{oil} \times (1 - WC)\right) \qquad (5)$$

In order to accurately model and analyze the performance of a well system, several measurements and estimates are essential inputs. The required input data for static bottomhole pressure (Ps), flowing bottomhole pressure (P_{wf}), and flow rate (q) can be obtained through various methods and alternative data sources. Table 1 provides an overview of these data sources (Production Operation Function, 2023).

Table 1. Required Input Data and Alternative Data Sources for Field Y Reserves Estimation (Production Operation Function, 2023)

Static Bottomhole Pressure (P_s)	Flowing Bottomhole Pressure (P_{wf})	Flow Rate (q)
SBHP Measurement	FBHP Measurement (MRT, MIT, etc)	Well test
SFL Measurement using Sonolog	DFL Measurement using Sonolog	Fluid Level Buildup Data
Modular Formation Dynamics Tester (MDT)	Interpolation of Wellhead Pressure using Simulator	
Interpolation of DFL	Interpolation of Downhole Pump Sensor Pressure	
Interpolation of Decline in SBHP		

For Ps, the main data source is the direct measurement of shut-in bottomhole pressure (SBHP) when the well is not flowing. However, if SBHP data is incomplete or missing, an alternative approach is to measure the static fluid level (SFL) using tools like a sonolog. Additionally, Modular Formation Dynamics Tester (MDT) measurements or interpolation techniques using dynamic fluid level (DFL) or the decline in SBHP over time can be used as alternative data sources to estimate Ps. Interpolating the dynamic fluid level (DFL) is used to predict the static fluid level (SFL) when SBHP or SFL data is not available or not reliable. This is done to determine the value of Ps when SBHP or SFL data is missing or unreliable. This interpolation technique is particularly useful in situations such as when SBHP updates have not been conducted due to injection effects, when wells exhibit negative productivity index (PI) with DFL measurements higher than recorded SFL, or when SFL data is acquired before the well reaches a truly static state due to wellbore storage.

In the case of Pwf, the primary method is measuring flowing bottomhole pressure (FBHP) using tools like Multiple Rate Test (MRT) or Multiple Interval Test (MIT) at different flow rates. When direct measurement of FBHP is not available, the dynamic fluid level (DFL) measurements from a sonolog can be used to estimate Pwf. Furthermore, Pwf can also be interpolated by simulating the pressure at the wellhead or interpolating the pressure recorded by downhole pump sensors. The interpolation of wellhead pressure (simulator) or interpolation of downhole pump sensor pressure is performed by calculating the bottomhole pressure (BHP) based on the wellhead pressure or sensor pressure. This calculation involves determining the pressure loss from the BHP to the pressure measurement point. For flow rate (q), conducting well tests to directly measure the flow rate is the preferred method. However, if direct measurement is not feasible, alternative approaches include analyzing flow buildup data or employing estimation techniques to estimate the flow rate.

The approach of calculating flow rate based on the rate of fluid level rise is used to determine the influx flow rate from the formation when it is too small to be directly measured. This method allows for the estimation of the flow rate and flowing bottomhole pressure (Pwf) based on the observed rate of change in the fluid level. By applying this method, both the flow rate and Pwf can be determined, providing valuable insights into the behavior of the well and the production characteristics of the formation.

2. Sucker Rod-Pumped Well

The beam pumping system is the oldest and most used method of artificial lift for onshore petroleum wells, with more than 85% of the world's oil wells using a sucker rod-lift system. This is mainly due to the system's low operating costs, energy efficiency, simple operation, familiarity to most operators, and its ability to adjust pumping capacity according to well conditions throughout the productive life of the well (Di Tullio & Marfella, 2018). Its primary advantage is that it allows maximum drawdown of the well, which means that the pumping unit can bring the fluid level down to the pump intake in the casing, resulting in the lowest back pressure on the reservoir. This allows for maximum inflow from the reservoir into the wellbore (Nickell & Treiberg, 2022).

Sucker-rod pumping systems are limited in their ability to produce fluid, assuming relatively incompressible fluid, by factors such as stroke length, maximum rate of rod fall, plunger diameter, sucker rod strength, torsional and structural capacity, and geometry. The critical pumping speed is the highest speed at which the minimum polished rod load becomes zero and the carrier bar just begins to leave the rod clamp during the downstroke, under a fixed set of pumping conditions. Stroke length and well forces such as friction and buoyancy, control the critical pumping speed for a given pumping unit geometry (Byrd, 1968).

The subsurface sucker rod pump displacement can be determined by several direct parameters, including the pumping speed, unit stroke length, and pump plunger diameter (Kennedy & Ghareeb, 2017). These parameters are used in a general equation shown by Eq.6 below to calculate the displacement of the pump.

$$P_D = 0.1166 \times S \times N \times D^2 \qquad (6)$$

3. Electrical Submersible-Pumped Well

The Electric Submersible Pump (ESP) is widely used for lifting fluids from low-pressure wells in depleting reservoirs due to its efficiency and economic advantages. It is effective for lifting large volumes of fluids from great depths, especially in reservoirs with high water-cut and low gas-oil ratio. The performance of an ESP is determined by pump performance curves, which shows the relationship between the pump's head and capacity under a specific rotational speed and standard fluid properties. The ESP operates with maximum efficiency within a specific flow rate range, known as the optimal operating range. Successful implementation of ESPs relies on operating within this range to ensure optimal performance and productivity. (Al Qahtani, 2013).

Understanding the well performance curve is essential for managing ESP performance effectively. The ESP operates within a recommended operating range (ROR) or operating envelope, bounded by factors such as minimum and maximum speeds, upthrust and downthrust limits, and the well performance line. Staying within these bounds ensures good ESP performance and system longevity. Operating beyond the upthrust limit causes wear and tear due to excessive flow and upward thrust on the impeller. Similarly, operating within the downthrust bounds results in reduced flow and downward thrust, leading to wear on the impeller. Any deviation from the recommended operating bounds can have detrimental effects on the ESP system and well completion. It is important to consult with application engineers before making changes to choke size or fluid composition to maintain optimal performance and prolong the ESP run life (Kalu-Ulu, Khamees, & Flippin, 2023).

4. Oil and Gas Production Fields

In large oil and gas fields, individual wells' production is typically transported to processing facilities or export points via a surface gathering system. This system is usually set up as a network of converging material streams. The design of gathering systems can vary widely based on factors such as the field layout, well and facility distribution, and geographic environment, such as offshore or land-based fields. The production from individual wells is collected and mixed in a production manifold near the wellhead cluster. In large multi-cluster fields with a single processing plant, the clusters are connected via feeder lines and main trunklines to transport and combine the production of the entire field or a major segment of it to the processing plant (Stanko & Golan, 2015).

II. METHODS

This study was conducted on production wells in Structure X to analyze and improve production optimization based on collected data. Production analysis of the wells was conducted initially, and if production was found to be suboptimal, optimization was performed on artificial lift and surface network designs. The PIPESIM is a software that is utilized for designing and analyzing multiphase fluid flow in oil and gas production systems, from the reservoir through to the processing facility. Its functions include modeling individual well performance, conducting nodal analysis, designing systems for artificial lift, modeling pipeline networks and processing facilities, and creating plans for field production. PIPESIM uses a range of correlations for fluid properties, multiphase flow, and inflow performance to produce precise and reliable descriptions of production systems (Assavanives, et al., 2023).

Production optimization using PIPESIM software can be approached from two perspectives: the well perspective and the network perspective. The well perspective focuses on optimizing the production of individual wells. On the other hand, the network perspective considers the entire production network. The workflow for this study can be seen in **Figure 1**, which outlines the step-by-step process for both the well perspective and network perspective methodologies.

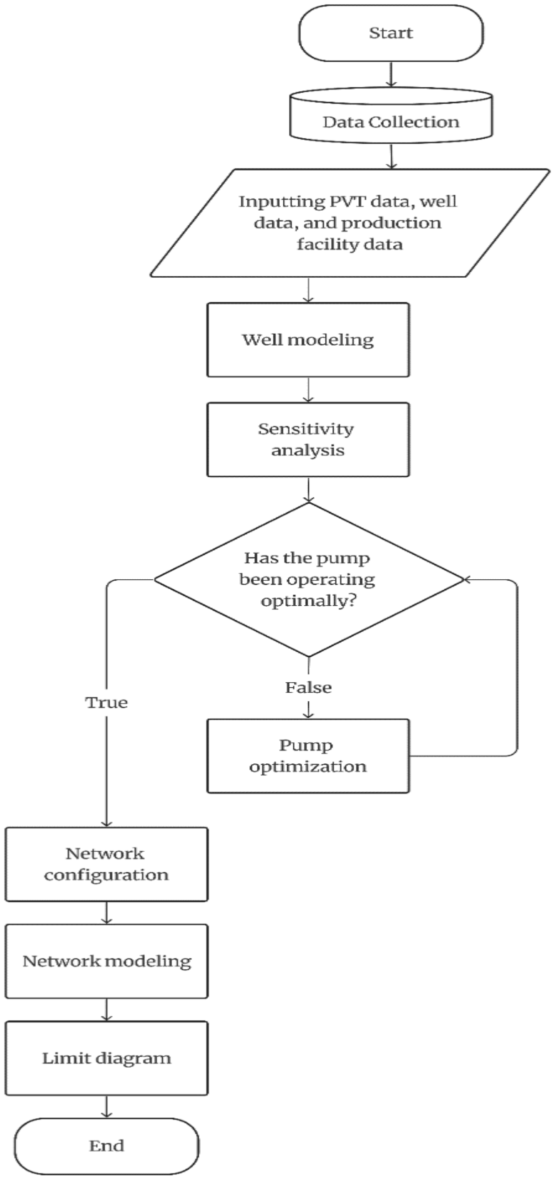


Figure 1. Flowchart Illustrating the Work Procedure

2.1. Well Perspective Production Optimization

Well Perspective Methodology:

1. Data Collection: Gather relevant data for the individual well, including reservoir properties, wellbore configuration, completion details, and production history.
2. Well Modeling: Use PIPESIM software to build a well model based on the acquired data. Validate the model using historical production data.
3. Sensitivity Analysis: Conduct sensitivity analysis by varying parameters like SRP's stroke per minute (SPM) and ESP's frequency. Identify key factors affecting well performance.
4. Optimization: Utilize optimization algorithms in PIPESIM to determine the optimal operating conditions for the individual well.

2.2. Network Perspective Production Optimization

Network Perspective Methodology:

1. Network Configuration: Develop a comprehensive model of the production network using PIPESIM, including wells, pipelines, flowlines, and surface facilities.
2. Network Modeling: Use PIPESIM to simulate the production network, analyzing its overall performance. This includes matching production flow rates and pressures and conducting sensitivity analysis by varying parameters such as well production rates and operating pressures.
3. Limit Diagram: Create a diagram that represents the operational limits of the production network, based on the results obtained from the network modeling and sensitivity analysis.

2.3. Case Study

The research study was carried out on a total of 31 production wells and 14 injections well, comprising of 8 active water injection wells,12 active oil production wells, and 1 active gas production well. Out of the 12 oil production wells, 10 were operated using either a Plunger Lift or Sucker Rod Pump (SRP), 2 were operated with an Electrical Submersible Pump (ESP), and the remaining one was a gas well. In the conducted field case study, the main focus is on evaluating the pump performance (pump efficiency) of SRP and ESP used in the production wells of the Structure X, along with their surface network. Additionally, the objective of this case study is to optimize production by redesigning the pumps and integrating them with the surface network.

The research study is based on certain assumptions that form the basis for the analysis and optimization strategies employed. However, it should be acknowledged that these assumptions may not fully represent the actual conditions and characteristics of the wells, which introduces uncertainties in the obtained results and optimization outcomes. The study assumes specific values and conditions for various factors, such as:

1. The Vogel coefficient is assumed to be 0.8.
2. Gas separators in wells using ESPs are assumed to have 80% efficiency.
3. Wells using SRPs are assumed to not have gas separators.
4. The Gas-Liquid-Ratio (GLR) for ESP wells is assumed to be 0 SCF/STB, and for SRP wells, it is assumed to be below 70 SCF/STB.

In the evaluation of pump performance and optimization of production in Structure X, it is crucial to acknowledge the existence of certain limitations. These limitations have the potential to impact the findings and optimization strategies, thus it is essential to take them into consideration for a comprehensive and precise analysis. These limitations include:

1. The study focuses on evaluating the pump performance of specific types of pumps, Sucker Rod Pump (SRP) and Electrical Submersible Pump (ESP), used in the production wells of Structure X. The findings and optimization strategies proposed in the study may not be directly applicable to other types of pumps or production systems.
2. The research study is conducted on a specific mature/brown field with a limited number of wells (31 production wells and 14 injection wells). The findings and recommendations may not be generalizable to larger or different oil and gas fields with varying reservoir characteristics, production systems, and operating conditions.
3. The study focuses on optimizing the stroke per minute (SPM) for SRPs and the frequency for ESPs in Well Perspective Production Optimization. For Network Perspective Production Optimization, the adjustable parameters are the well production rates and operating pressures. Other potential optimization parameters or factors may not be explored in this study.
4. The research study primarily addresses pump performance evaluation and optimization within the production wells and surface network. Other aspects of production optimization, such as reservoir management strategies, field development plans, or economic considerations, may not be extensively covered in the study.

2.4. Field Overview

The Y field, located in Jambi, Sumatra Province, has an average daily oil production of 4085 barrels of oil per day (BOPD) and a gas production of 3.74 million standard cubic feet per day (MMSCFD). This mature/brown field covers an area of 5751 km2 and has a depleted reservoir pressure. The field has 14 active structures and 6 inactive structures, with subsurface characteristics that include sand, corrosive & scale problems, and variations in artificial lift condition. The PSC for the Y field was signed on September 17, 2005, and is set to expire on September 17, 2035. However, there are several challenges to the field's operations and maintenance, such as surface facilities of the Y field are aging, corrosive, and located near settlements. Additionally, there is a need to upgrade the water treatment and injection plan (WTIP) to achieve zero discharge. The HSSE concerns for the Y field include potential oil spills, illegal drilling & tapping, and facilities' proximity to settlements. Furthermore, the pandemic COVID-19 and man-hours pose additional challenges.

The production and operating costs of the Y field are relatively high, and the field is facing triple shocks from fluctuations in ICP, exchange rate, and the pandemic. Given these challenges, it is crucial to develop strategies to maintain the Y field's production and ensure its sustainable operation. Such strategies could include technological innovations, improved safety measures, community engagement, and increased collaboration with stakeholders.

2.5. Field History

Field Y is a mature oil field that has been producing oil for over 50 years, with its peak production occurred between 1952 and 1956 when the daily output reached 30,000 barrels per day. However, the production has been declining significantly since then. In January 2010, new wells were added to increase production, which resulted in an increase of approximately 2,000 barrels per day. Among the artificial lift methods used in Field Y, Plunger Lift (PU) is the most commonly used method, employed in 115 wells due to its low operating cost and suitability for the field's characteristics. On the other hand, Natural Depletion (SA) is the least used method, implemented in only 19 wells. Additionally, Progressive Cavity Pump (PCP) is used in 74 wells, Electrical Submersible Pump (ESP) in 45 wells, and Hydraulic Pump (HPU) in 27 wells.

Field Y has three Main Gathering Stations (MGSs): MGS T, MGS K, and MGS X, which collect all the oil produced from each well. The collected oil is then transported to Main Oil Station (MOS) A for processing at Refinery Unit (RU) III Plaju. Although Field Y also produces gas, the gas is not profitable for sale, and therefore, it is used as fuel for power generation to run activities within the field. In the wells located in Structure X, all 0.3 million standard cubic feet per day (MMscfd) of gas produced is used as fuel for the Power Plant in Structure X. This approach ensures that no gas is wasted or burned.

III. RESULTS AND DISCUSSION

3.1. Well Perspective Production Optimization

To gain a thorough understanding of individual wells, an extensive data collection process is undertaken. Reservoir properties, including API classification of the reservoir fluid, SG (Specific Gravity), WC (Water Cut), reservoir pressure, and reservoir temperature, are carefully gathered. These properties provide valuable insights into the reservoir's composition, density, water content, and thermodynamic conditions. Additionally, wellbore configuration and completion details are collected to assess well performance. Information such as datum depth, perforation depth, casing, tubing, and liner size helps determine the dimensions and specifications of the wellbore. The type of artificial lift method used, such as ESP or SRP, is noted for its significant impact on production efficiency. Furthermore, measurements of SFL and DFL are recorded to evaluate fluid levels during different operational stages.

The data collection process also extends to the production facility, where various parameters are gathered, including the horizontal length of the pipeline, nominal diameter, elevation, wall thickness, roughness, and ambient temperature. These details contribute to understanding the physical characteristics and environmental factors that influence production operations. Moreover, historical production data is collected to establish a comprehensive production history profile. This data encompasses flow rates, fluid composition, and any notable production changes or trends over time. Analyzing the production history provides valuable insights into the well's productivity, performance, and potential challenges. By integrating and analyzing this diverse range of data, a comprehensive understanding of individual wells is obtained. This information serves as a foundation for making informed decisions regarding well management, optimization strategies, and maximizing production efficiency.

In well modeling, the Vogel method is used to analyze the Inflow Performance Relationship (IPR) by calculating the maximum flow rate (q_{max}) for each measured flow rate (q) obtained from well monitoring data on February 20th, 2023, along with the flowing pressure (Pwf) and static pressure (Ps). The calculated production potential values using the Vogel method are then used as inputs in the PIPESIM software to determine the Absolute Open Flow Potential (AOFP). By using a Vogel coefficient of 0.8, the PIPESIM software automatically generates the Inflow Performance Relationship curves. IPR matching is performed to validate the accuracy of the created IPR using actual test data. This involves conducting sensitivity analysis by adjusting the gas-liquid ratio (GLR) parameter, which is considered uncertain due to unknown actual data. Other well parameters are also validated against the actual data during sensitivity analysis. By comparing the matching IPR curves with the actual data, the accuracy and reliability of the IPR model can be evaluated. Once the IPR is determined and validated, the gross potential of the well can be estimated by multiplying 80% of the Absolute Open Flow (AOF) value obtained from the corresponding IPR. The flow rate results from Vogel method nodal analysis are displayed in **Table 2**. The comparison between the result and the actual flow rate obtained from well monitoring data for each well on February 20th, 2023, is shown in **Figure 2**.

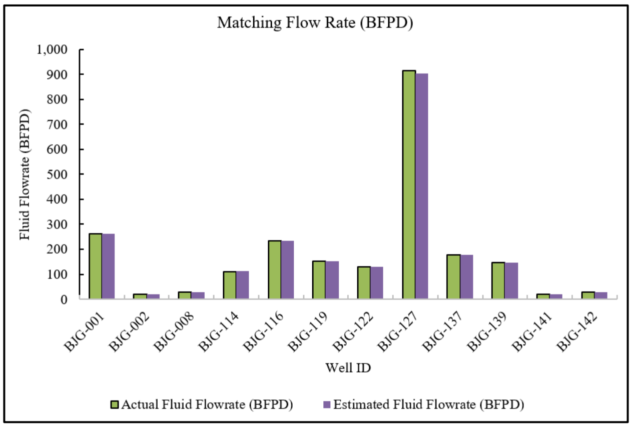


Figure 2. Cluster Column of Fluid Flow Rate (q) in barrels per day (BFPD)

Table 2. Comparison of Flow Rate between Actual Flow Rate (BFPD) and Vogel Method Flow Rate (BFPD)

Well ID	Gas Liquid Ratio (SCF/STB)	q_{actual} (BFPD)	q_{Vogel} (BFPD)	Error (%)
BJG-001	10	260.69	261.12	0.16%
BJG-002	10	21.47	21.33	0.64%
BJG-008	60	27.60	27.61	0.02%
BJG-114	20	111.36	111.58	0.20%
BJG-116	0	233.09	234.02	0.40%
BJG-119	13	153.35	153.15	0.13%
BJG-122	37	130.24	130.33	0.07%
BJG-127	0	913.57	903.57	1.09%
BJG-137	10	177.88	177.31	0.32%
BJG-139	11	147.22	146.86	0.24%
BJG-141	10	19.21	19.22	0.04%
BJG-142	10	27.60	27.67	0.24%

An evaluation was carried out to identify potential candidates for production optimization based on the production potential values obtained from the Vogel Inflow Performance Relationship (IPR) correlation and the pump efficiency of each well. The ratio of the actual oil flow rate received by the pump (q_{actual}) to the maximum achievable flow rate (q_{max}) serves as an indicator of pump efficiency and well productivity. Additionally, pump efficiency provides insights into the performance of pumps under different operating conditions. Among the 31 wells evaluated, 12 oil production wells were classified into the following categories:

- Quadrant 1: Wells with high flow rate efficiency and low pump efficiency.
- Quadrant 2: Wells with high flow rate efficiency and high pump efficiency, currently operating at optimum conditions.
- Quadrant 3: Wells with low flow rate efficiency and low pump efficiency.
- Quadrant 4: Wells with low flow rate efficiency and high pump efficiency.

Figure 3 displays the Quadrant map representing the relationship between q_{actual}/q_{max} and Pump Efficiency for the current operating condition. The map reveals the distribution of wells across different quadrants: Quadrant 1 contains five wells, Quadrant 2 contains three wells, and Quadrant 3 contains four wells. The selection of candidate wells for production optimization is based on their quadrant classification, particularly focusing on wells in Quadrant 3 (low flow rate efficiency and low pump efficiency) and Quadrant 4 (low flow rate efficiency and high pump efficiency). The classification of wells into different quadrants enables the identification of specific wells that require optimization interventions. Quadrant 3 and Quadrant 4 wells present potential areas for improvement, as enhancing both flow rate efficiency and pump efficiency can significantly enhance overall production performance.

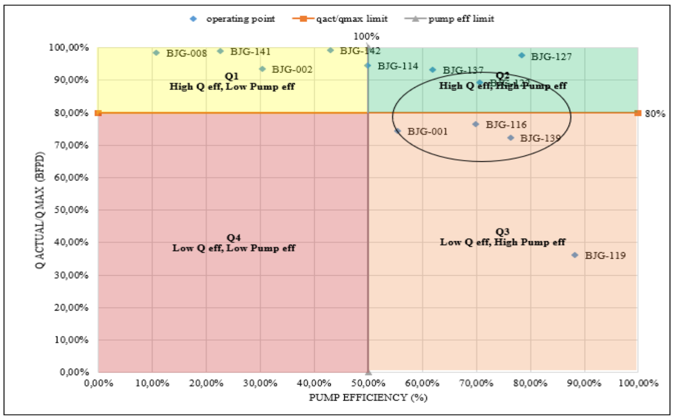
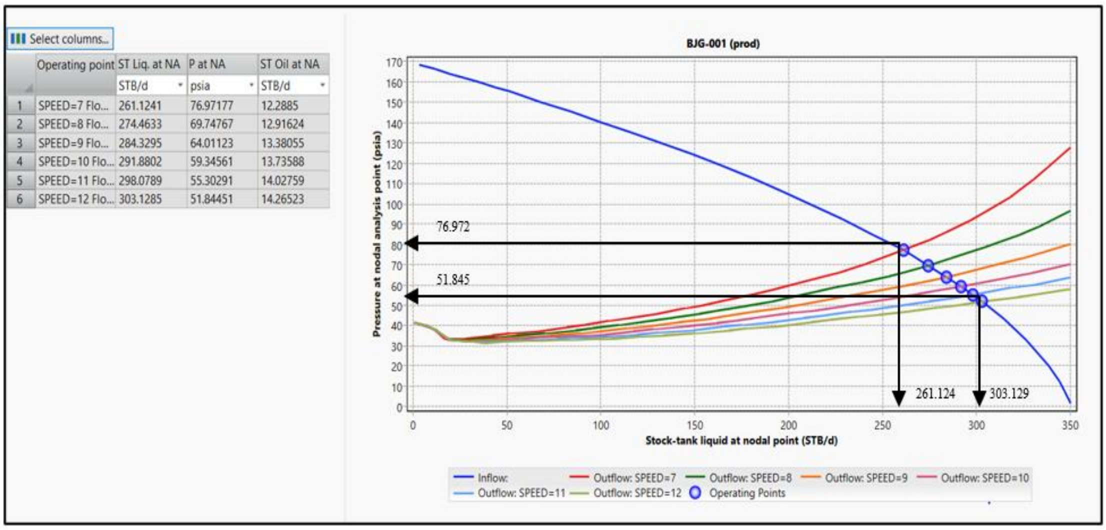


Figure 3. Quadrant Map of q_{actual}/q_{max} vs Pump Efficiency for Current Operating Condition

Therefore, BJG-001, BJG-116, and BJG-139 are identified as candidate wells for production optimization. However, no production optimization will be carried out on BJG-119 due to its 100% water cut. Although BJG-122 is currently operating at optimal conditions with high flow rate efficiency and high pump efficiency in Quadrant 2, there is still potential for further optimization in terms of increasing its production flow rate (q) based on the inflow performance curve (IPR) graph. To evaluate the impact of parameter variations on production, sensitivity analyses will be performed using PIPESIM software. These analyses will involve adjusting parameters such as the stroke per minute (SPM) for SRPs and the f (ESP frequency) for ESPs. The following section presents the results obtained from the production optimization simulation scenarios.

A sensitivity analysis was performed for well BJG-001 using a Sucker Rod Pump (SRP) with a 2.5" RWBC downhole pump, as shown in **Figure 4**. The analysis involved varying the stroke per minute (SPM) parameter from 7 to 12. This range was determined based on the fact that another well (BJG-073) utilizes the same RWBC downhole pump at a speed of 12 SPM. In the current operating condition, the stroke per minute for the sucker rod system is set at 7 SPM, resulting in a gross actual flow rate of 260.69 BFPD and a net actual flow rate of 12 BOPD. To optimize production, it is recommended to increase the stroke per minute to 12 SPM, which is estimated to yield a gross flow rate of 303.13 BFPD and a net flow rate of 14.27 BOPD.



	Operating point	ST Liq. at NA	P at NA	ST Oil at NA
		STB/d	psia	STB/d
1	SPEED=7 Flo...	261.1241	76.97177	12.2885
2	SPEED=8 Flo...	274.4633	69.74767	12.91624
3	SPEED=9 Flo...	284.3295	64.01123	13.38055
4	SPEED=10 Flo...	291.8802	59.34561	13.73588
5	SPEED=11 Flo...	298.0789	55.30291	14.02759
6	SPEED=12 Flo...	303.1285	51.84451	14.26523

Figure 4. SRP's Stroke Per Minute Sensitivity Nodal Analysis on Well BJG-001

A sensitivity analysis was performed for well BJG-116 using a CENTRILIFT B11W 400 ESP pump, with frequency variations ranging from 40 to 45 Hz. The nodal analysis presented in **Figure 5** illustrates the sensitivity of the system to changes in the ESP frequency parameter. The graph reveals a divergence in the operating points when the frequency falls within the range of 43 to 45 Hz, indicating that the pump is unable to operate effectively within that frequency range. Currently, the ESP system operates at a frequency of 40 Hz, resulting in a gross actual flow rate of 233.09 barrels of fluid per day (BFPD) and a net actual flow rate of 9.20 barrels of oil per day (BOPD). To optimize production, it is recommended to increase the frequency to 42 Hz. This adjustment is projected to increase the gross flow rate to 260.25 BFPD, with a corresponding flow rate of 10.28 BOPD.

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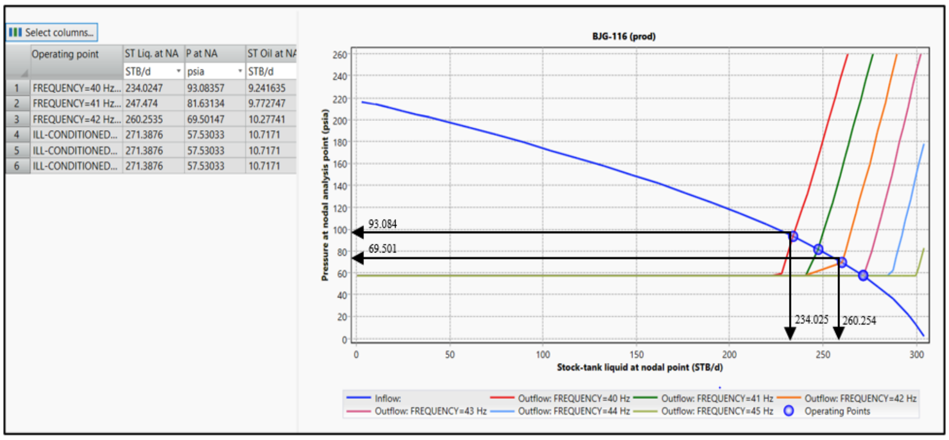

Figure 5. ESP's Operating Frequency Sensitivity Nodal Analysis on Well BJG-116

A sensitivity analysis was conducted for well BJG-122 using a Sucker Rod Pump (SRP) with a 2" THBC downhole pump, as shown in **Figure 6**. The analysis focused on varying the stroke per minute (SPM) parameter from 6 to 10. The range was determined based on the fact that another well (BJG-139) utilizes the same THBC downhole pump at a speed of 10 SPM. Currently, the well operates at 6 SPM, resulting in a gross actual flow rate of 130.24 BFPD and a net actual flow rate of 5.28 BOPD. To optimize production, it is recommended to increase the stroke per minute to 7 SPM. This adjustment is estimated to yield a gross flow rate of 138.74 BFPD and a net flow rate of 5.63 BOPD.

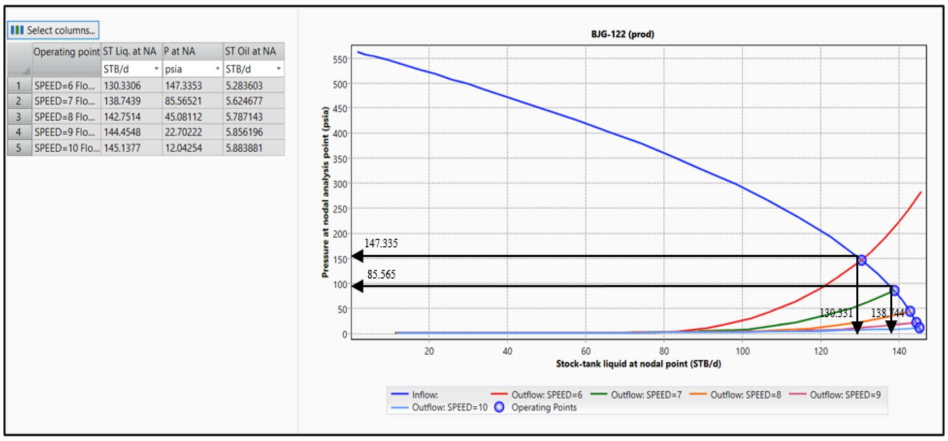

Figure 6. SRP's Stroke Per Minute Sensitivity Nodal Analysis on Well BJG-122

A sensitivity analysis was conducted for well BJG-139 using a Sucker Rod Pump (SRP) with a 2" THBC downhole pump, as shown in **Figure 7**. The analysis focused on varying the stroke per minute (SPM) parameter from 10 to 15. Currently, the well operates at 10 SPM, resulting in a gross actual flow rate of 147.22 BFPD and a net actual flow rate of 6.13 BOPD. To optimize production, it is recommended to increase the stroke per minute to 12 SPM. This adjustment is estimated to yield a gross flow rate of 165.04 BFPD and a net flow rate of 6.87 BOPD.

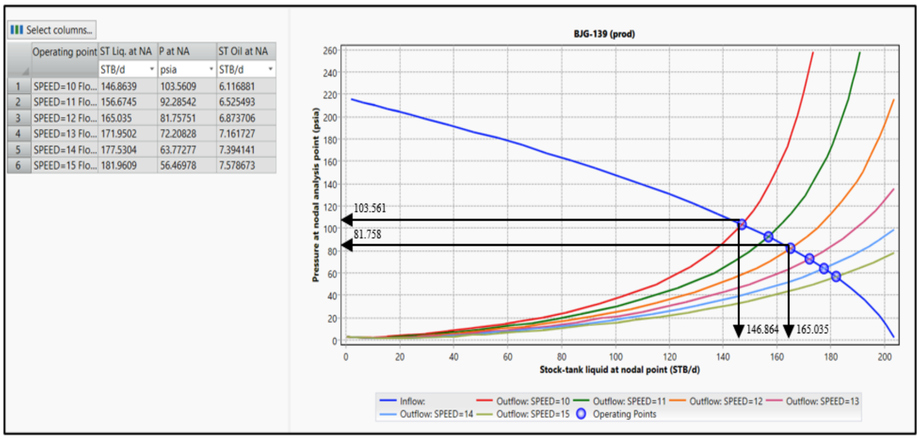

Figure 7. SRP's Stroke Per Minute Sensitivity Nodal Analysis on Well BJG-139

A comparison between the gross production (BFPD) and net production (BOPD) of the production wells in the current operating condition and the optimized simulation condition can be observed in **Table 3**. Meanwhile, in **Table 4**, the oil production in the current operating condition is recorded as 78.13 BOPD within the production optimization scenario using PIPESIM software. After conducting the optimization simulation scenario, the oil production increases by 4.10 BOPD to reach 82.23 BOPD. This indicates a 5.25% increase in oil production compared to the previous production. These results highlight the effectiveness of the optimization simulation scenario in significantly improving oil production in the Structure X.

Table 3. Comparison of Gross Production (BFPD) and Net Production (BOPD) for Production Wells in Current Operating Condition and Optimization Simulation Condition

Well	Condition	Lift	SPM/ Frequency	Gross Rate (BFPD)	Net Rate (BOPD)	q_{max} (Vogel)	q/q_{max}
BJG-001	Actual	SRP	7 SPM	260.69	12.27	350.83	74%
	Optimized	SRP	12 SPM	303.13	14.27	350.83	86%
BJG-116	Actual	ESP	40 Hz	233.09	9.20	304.41	77%
	Optimized	ESP	42 Hz	260.25	10.28	304.41	85%
BJG-122	Actual	SRP	6 SPM	130.24	5.28	145.81	89%
	Optimized	SRP	7 SPM	138.74	5.63	145.81	95%
BJG-139	Actual	SRP	10 SPM	147.22	6.13	203.66	72%
	Optimized	SRP	12 SPM	165.04	6.87	203.66	81%

Table 4. Summary of Production Optimization Simulation Results for Structure X

Data	Gross Rate (BFPD)	Net Rate (BOPD)
Normal	2223.27	78.13
Optimized	2308.59	82.23
Increased	85.32	4.10
Percentage	4.13%	5.25%

After performing well perspective production optimization, an update to the Quadrant map in **Figure 8** is conducted to illustrate the distribution of wells based on their qactual/qmax ratio (maximum flow rate to actual flow rate) and pump efficiency under the optimized operating condition. The map categorizes the wells into four quadrants. Quadrant 1 includes five wells characterized by high flow rate efficiency but low pump efficiency. In Quadrant 2, six wells demonstrate both high flow rate efficiency and high pump efficiency, indicating that they are currently operating at optimum conditions. Quadrant 3 represents a single well with low flow rate efficiency and low pump efficiency. Notably, no wells are classified under Quadrant 4, indicating the absence of wells with low flow rate efficiency but high pump efficiency. A comparison between the Quadrant map before and after well perspective production optimization is presented in **Table 5**. Comparison of Quadrant Maps Before and After Well Perspective Production Optimization.

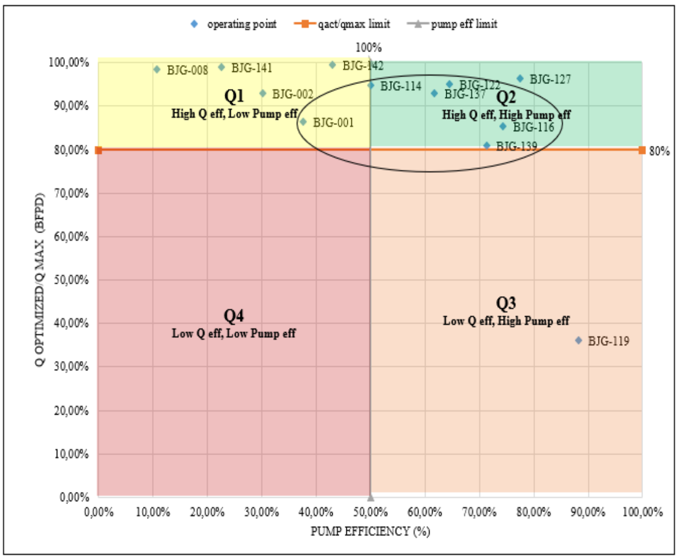

Figure 8. Quadrant Map of $q_{optimized}/q_{max}$ vs Pump Efficiency for Optimized Condition

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Table 5. Comparison of Quadrant Maps Before and After Well Perspective Production Optimization

Well ID	Lift	Pump Capacity (BFPD)		Pump Efficiency		Gross (BFPD)		q_{actual}/q_{max}		Quadrant	
		Act	Opt	Act	Opt	Act	Opt	Act	Opt	Act	Opt
BJG-001	SRP	470.53	806.63	55.40%	37.58%	260.69	303.13	74.31%	86.40%	Q3	Q1
BJG-002	SRP	70.90	70.90	30.28%	30.09%	21.47	21.33	93.48%	92.88%	Q1	Q1
BJG-008	SRP	257.32	257.32	10.73%	10.73%	27.60	27.61	98.44%	98.46%	Q1	Q1
BJG-114	SRP	223.32	223.32	49.87%	49.97%	111.36	111.58	94.65%	94.84%	Q1	Q1
BJG-116	ESP	333.33	350.00	69.93%	74.36%	233.09	260.25	76.57%	85.49%	Q3	Q2
BJG-119	SRP	173.69	173.69	88.29%	88.17%	153.35	153.15	36.19%	36.15%	Q3	Q3
BJG-122	SRP	184.42	215.15	70.62%	64.49%	130.24	138.74	89.32%	95.15%	Q2	Q2
BJG-127	ESP	1166.67	1166.67	78.31%	77.45%	913.57	903.57	97.57%	96.50%	Q2	Q2
BJG-137	SRP	287.13	287.13	61.95%	61.75%	177.88	177.31	93.19%	92.89%	Q2	Q2
BJG-139	SRP	192.99	231.59	76.28%	71.26%	147.22	165.04	72.29%	81.04%	Q3	Q2
BJG-141	SRP	85.07	85.07	22.58%	22.59%	19.21	19.22	99.04%	99.08%	Q1	Q1
BJG-142	SRP	64.33	64.33	42.90%	43.01%	27.60	27.67	99.26%	99.50%	Q1	Q1

3.2. Network Perspective Production Optimization

The network configuration process entails creating a detailed model of the production network using PIPESIM software. This model incorporates the various components of the network, such as wells, pipelines, flowlines, and surface facilities from Structure X. The integration of these components allows for a comprehensive representation of the production process within Structure X. **Figure 9 to 12** present schematic flow diagrams of the production surface facilities in Structure X, depicting the sub-gathering station, gathering station, and main gathering station.

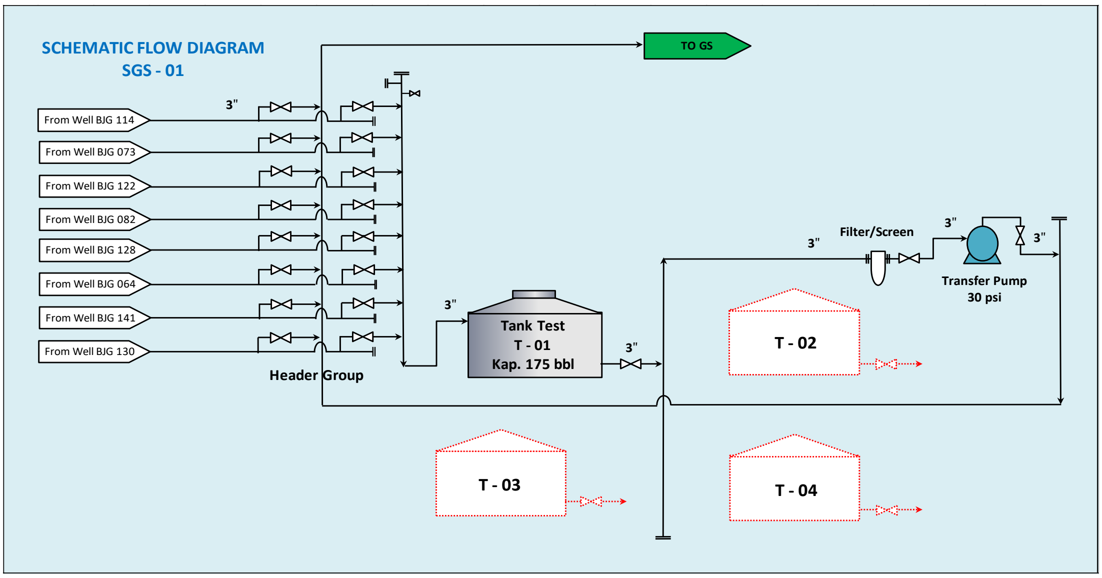

Figure 9. Schematic Flow Diagram SGS-01

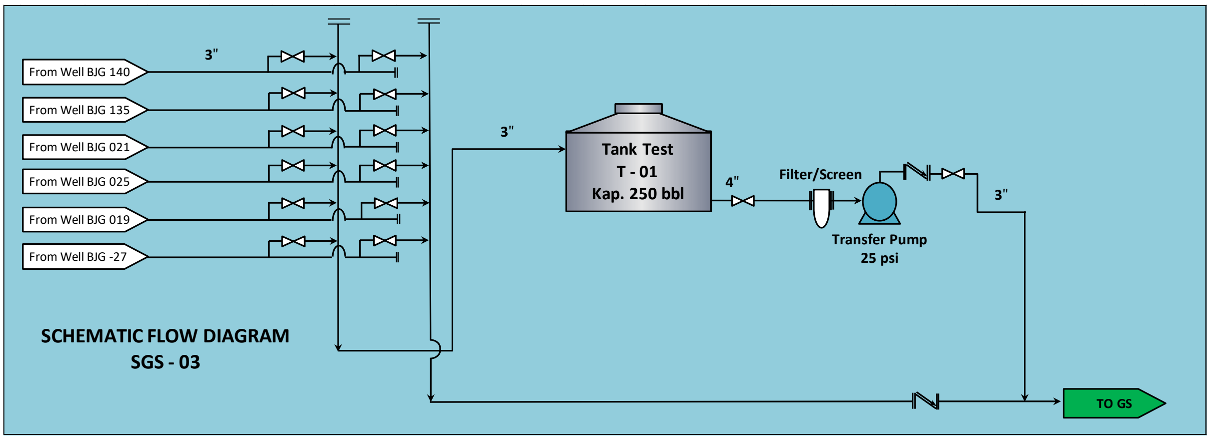

Figure 10. Schematic Flow Diagram SGS-03

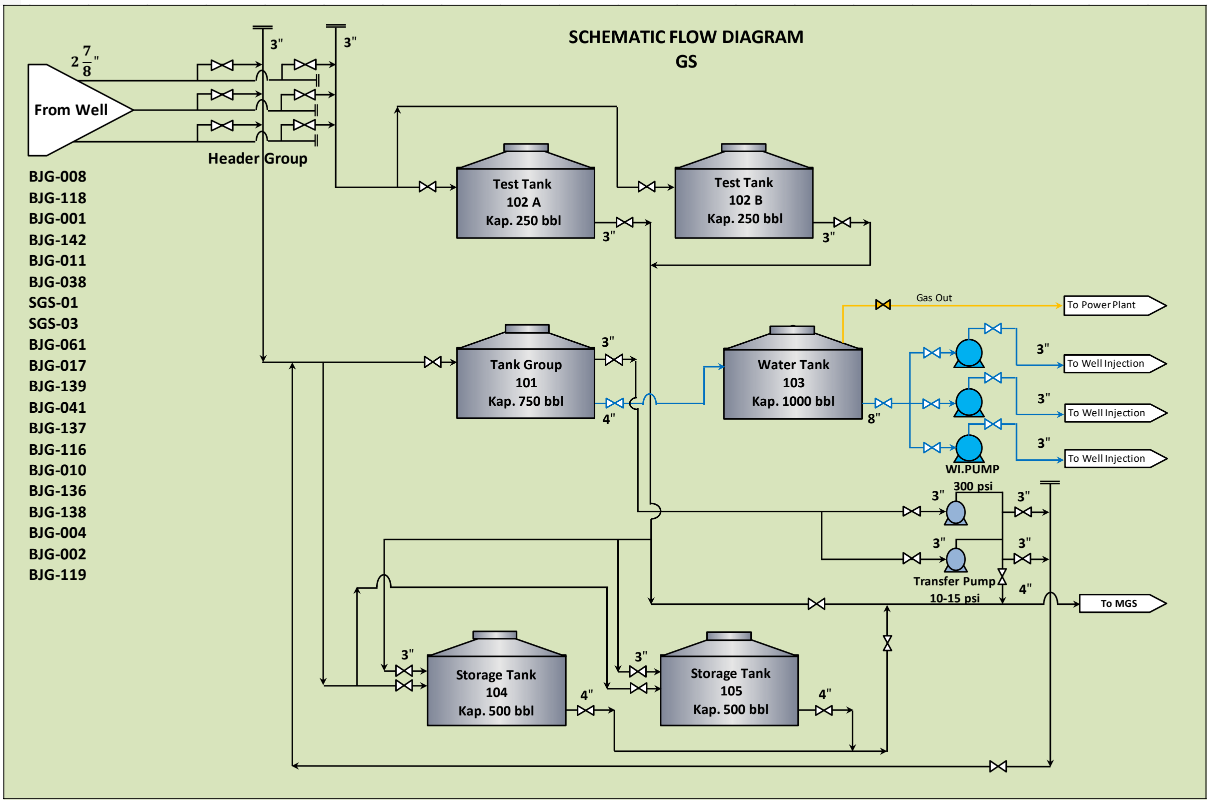

Figure 11. Schematic Flow Diagram GS

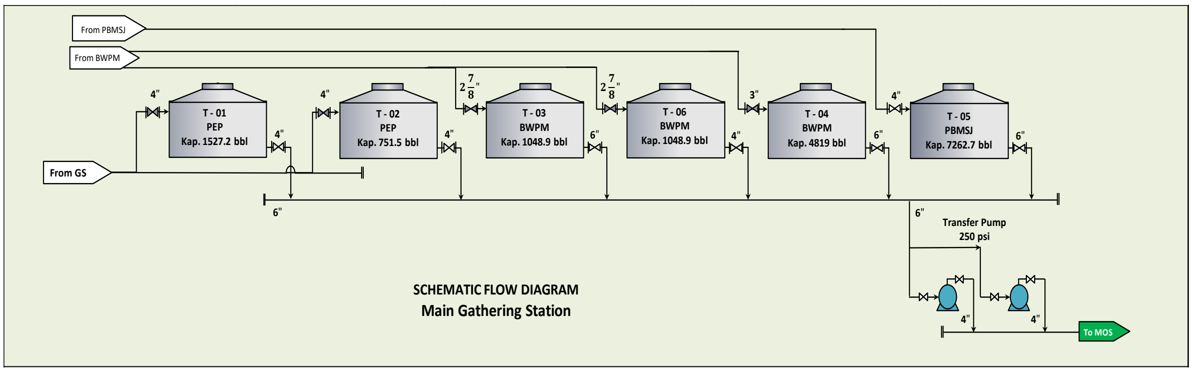

Figure 12. Schematic Flow Diagram MGS

Figure 13 displays the network schematic that has been developed as part of the simulation process. This schematic provides an overview of the interconnected wells, pipelines, flowlines, and surface facilities within the system. It serves as a visual representation of the configuration of the production network in Structure X. In addition, **Figure 14** presents the GIS map display, showcasing the geographical layout and spatial distribution of the network components. This map offers a comprehensive view of the network's physical location, allowing for a better understanding of the network's spatial relationships and potential operational considerations.

During the network modeling, a detailed analysis is performed to simulate the behavior of the production network. The simulation aims to determine and evaluate the pressure distribution along the various components of the network, including the pipelines, production wells, gathering stations, power plants, and injection wells. By simulating the flow dynamics and interactions within the network, the simulation provides valuable insights into the system's performance.

The simulation results include the pressure profiles at different locations within the network. The pressure (out) results obtained from each production well are presented in **Table 6**. This table provides a comprehensive overview of the simulated pressures at different wells within the production network. To validate the simulation results, a comparison is made with the actual pressures measured at the tubing head of each production well. This provides a means to assess the accuracy and reliability of the simulation.

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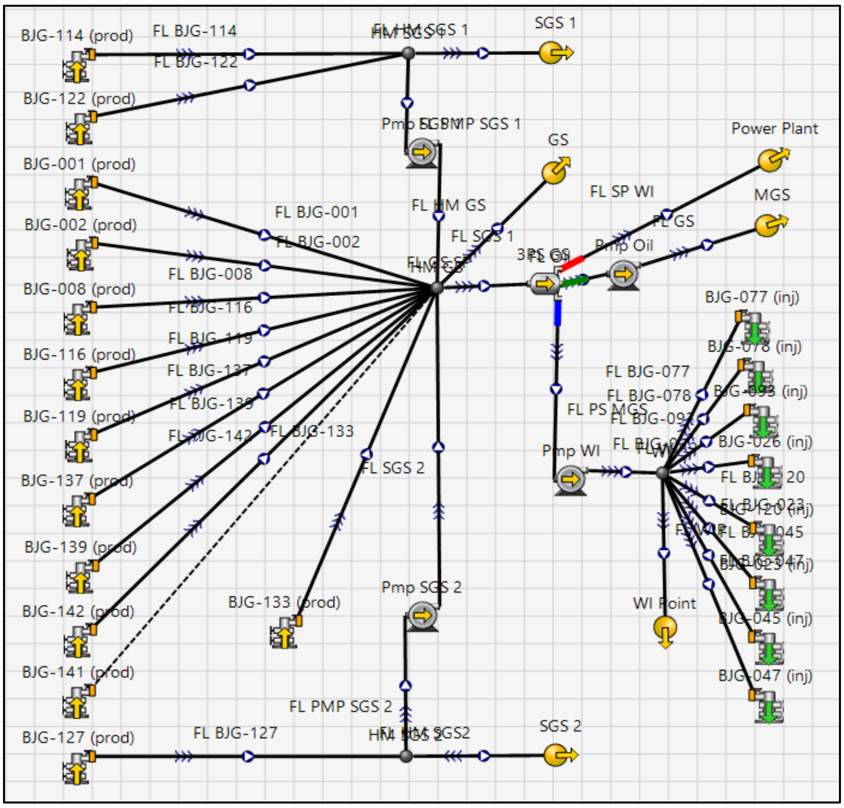

Figure 13. Network Schematic of Structure X

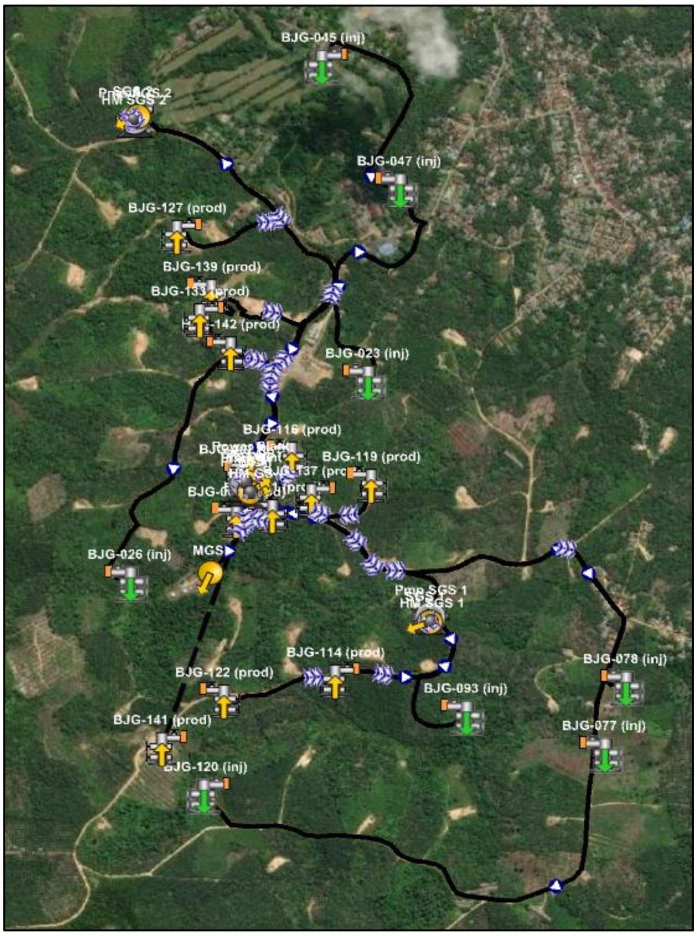

Figure 14. Visualization of the GIS Map Display

Table 6. Comparison of Pressure (Out) Results between Network Simulation and Actual Pressure Data

Well ID	THP actual (psig)	Pressure (out) (psig)	Error (%)
BJG-001	30	58.53	95.11%
BJG-002	5	62.82	1156.46%
BJG-008	10	73.82	638.16%
BJG-114	40	32.32	19.19%
BJG-116	40	53.70	34.25%
BJG-119	20	56.19	180.96%
BJG-122	35	32.32	7.65%
BJG-127	120	117.78	1.85%
BJG-133	50	66.49	32.98%
BJG-137	60	55.84	6.93%
BJG-139	60	85.71	42.85%
BJG-141	5	66.49	1229.85%
BJG-142	10	62.70	527.03%

Figure 15 presents a visual comparison between the simulated pressure values and the actual pressure values obtained from the field. The presence of significant pressure differences between the simulation and the field measurements can be attributed to various factors. These may include limitations in the modeling assumptions, or potential discrepancies in the measurement techniques. Limitations in the modeling assumptions made during the simulation process, such as simplifications and ideal condition assumptions, can impact the accuracy of the results. Potential discrepancies in the measurement techniques used to obtain the actual pressure values from the field can contribute to the observed differences.

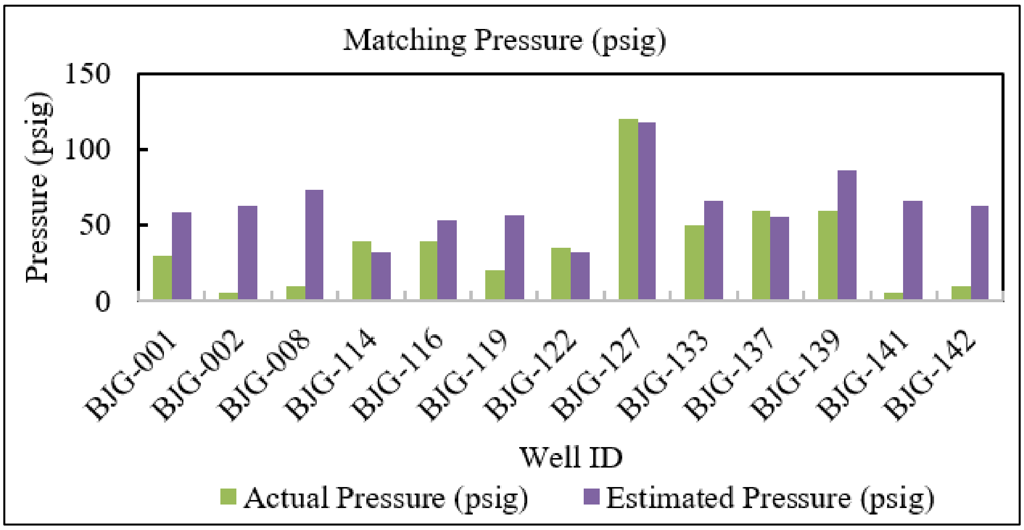

Figure 15. Cluster Column of Pressure (THP) Results

The limit diagram is a graphical representation that depicts the production limits of a system. It helps analyze the performance of the production system and assess its capacity to handle different production scenarios. In the case of Structure X, the limit diagram was constructed by considering the current production and the optimized production resulting from the optimization process. The optimization aimed to find the optimal production scenario that maximizes the production while ensuring the system's integrity and efficiency.

The analysis of the limit diagram presented in **Figure 16 to 18 indicates** that the current gathering system in Structure X is sufficiently capable of accommodating both the gross and net production from the optimized scenario. This implies that the system possesses enough capacity to handle the increased production rates and pressures without compromising its performance or surpassing its design limits. The remaining spare capacity for oil (net) is 93%, for water is 44%, and for fluid (gross) is 50%. Based on this evaluation, it can be inferred that the optimization scenario can be implemented for the surface facility of Structure X. This suggests that the system can be enhanced to improve its overall performance and maximize production while adhering to the safe operating limits of the system.

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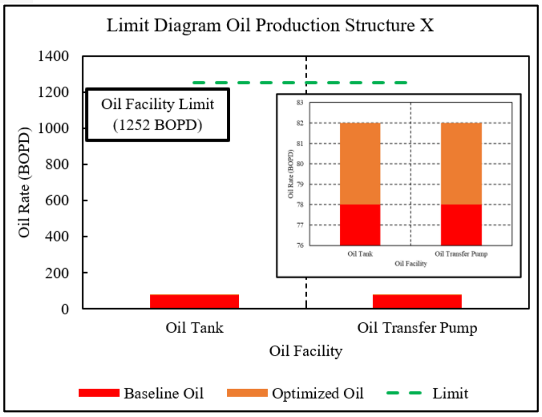

Figure 16. Limit Diagram Oil Production

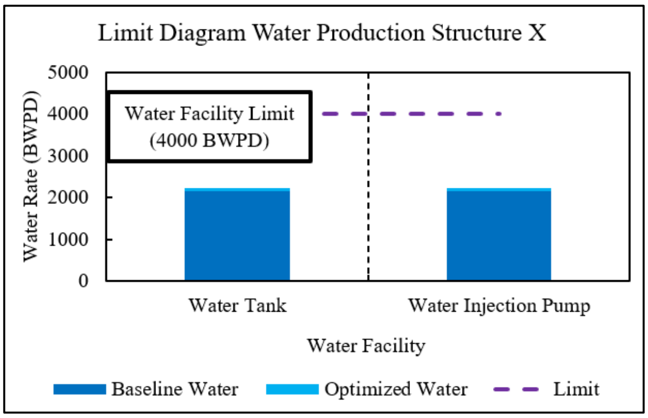

Figure 17. Limit Diagram Water Production for Fie

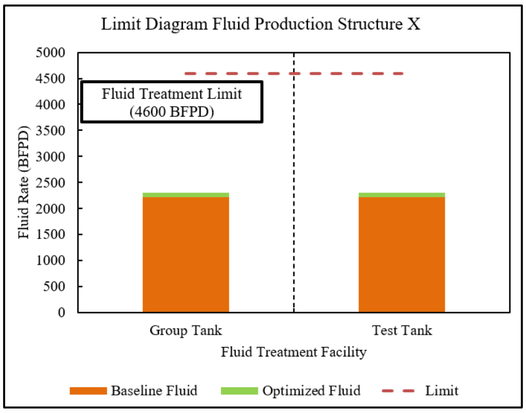

Figure 18. Limit Diagram Fluid Production for Structure X

IV. CONCLUSION

In summary, the study on Structure X Field Y using PIPESIM software resulted in the following key findings:

1. Application of Software: The PIPESIM software was successfully applied to analyze and optimize the performance of 13 active production wells, including sucker rod pumps (SRP), electric submersible pumps (ESP), and gas wells. It also considered eight active injection wells.
2. Production Optimization: By optimizing the operating parameters of four production wells using higher speed sucker rod pumps and increased frequency for electric submersible pumps, a significant improvement of 5.25% in oil production was achieved. This highlights the effectiveness of optimization strategies in enhancing production rates.
3. Gathering System Capacity: The analysis of the Limit Diagram for the Gathering System and Central Facility in Structure X Field Y concluded that the capacity of the Gathering Station was still sufficient even after implementing the optimization scenarios. This ensures the smooth and efficient operation of the gathering infrastructure.

These results demonstrate the value of digital commercial steady state fluid flow software, such as PIPESIM software, in optimizing oil production and maximizing the performance of production wells in mature fields. This is the final part containing conclusions, limitations and recommendations. The conclusions will be the answers of the hypothesis or research question, the research purposes and the research discoveries. The conclusions should not contain only the repetition of the results and discussions. It should be the summary of the research results as the author expects in the research purposes or the hypothesis. Research limitations and recommendations contain deficiency in the research and suggestions associated with further ideas from the research.

Suggestion

To enhance the research, it is recommended to digitally measure the pressure of each well at the header/manifold to identify optimization opportunities in the surface pipeline network. This is crucial to prevent back pressure, which can adversely impact production. The observed discrepancy between actual tubing head pressure (THP) data and simulation results highlights the need for accurate pressure measurements. By implementing this recommendation, the production efficiency of the field can be further improved by addressing potential issues in the surface pipeline network, leading to optimized production processes, and increased overall performance.

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