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Comparative Evaluation between the Pump of Electrical Submersible (ESP) and the Lift of Gas (GL) for Production Optimization

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Abstract: *The development of hydrocarbon from underground reservoirs to surface production and storage facilities through the wellbore is one of the most important aspects of the exploration and production industry. When a well is drilled, the reservoir fluid flows naturally with the reservoir's primary energy, but when this is not possible, an artificial lift system is built to assist the flow by lowering the hydrostatic pressure within the output tubing. This research compares gas lift (GL) and electrical submersible pump (ESP) for MAJNON 1, well production optimization to determine the best choice for the field. PROSPER software was used to create a natural flowing event, as well as GL and ESP simulations. The results revealed that the ESP system produces 4645.9 STB/day more than the natural flowing case, while the GL produces 785.7 STB/day more than the natural flowing case. ESP also has a higher output rate than GL (3860.2 STB/day, 85.54%). When it comes to the economy, ESP had the highest overall profit (77.46%), with a difference of 22.54% and 26.93% between the GL and natural flowing cases, respectively. However, due to other factors such as water cuts and the replacement of failed pumps, the GL system was chosen for proper field output optimization. Compared to the ESP, which had the highest output capacity, the gas lift was chosen for the MAJNON1 well due to the readily compressed gas availability, higher life expectancy, and lower operating cost.*

Keywords**:** natural flow, production optimization, economic, GL, ESP, PROSPER, and artificial lift.

1: Introduction

The development of hydrocarbon from underground reservoirs to surface production and storage facilities through the wellbore is among the most important aspects of exploration and production companies (EAPC). Though hydrocarbon operations are typically

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interdisciplinary or integrated studies involving geophysical, geology, petrophysics, drilling, completion, reservoir, development, and economics, to name a few. A school of thought claims that all other facets of petroleum engineering are fantasies, except the production staff, who are real people because they sell the reservoir's contents. The development of hydrocarbons is divided into three stages: Primary, secondary, and tertiary. The primary stage makes use of the reservoir's natural energy, but if it becomes necessary to raise the oil to the surface due to the hydrostatic head, an artificial lift system or assisted flow is needed. Artificial lift technology ALT (gas lift GL or pumping system PS) is used in oil fields when reservoirs have lost their natural means of producing their material to surface production facilities [1]. The correct artificial lift method selection is crucial to the oil well's long-term profitability; a bad option would result in low output and high operating costs [2]. Developed an optimization algorithm for the gas lift to simulate oil reservoirs on a long-term basis [3]. They presented a study on the optimization of gas lift systems under facilities constraints [4]. The gas-liquid ratio is very significant or vital in maintaining stable oil output with only minor variations in the gas-liquid ratio for offshore applications in gas lifted well construction [5], figure 1 illustrating the diagram of the (GLS).

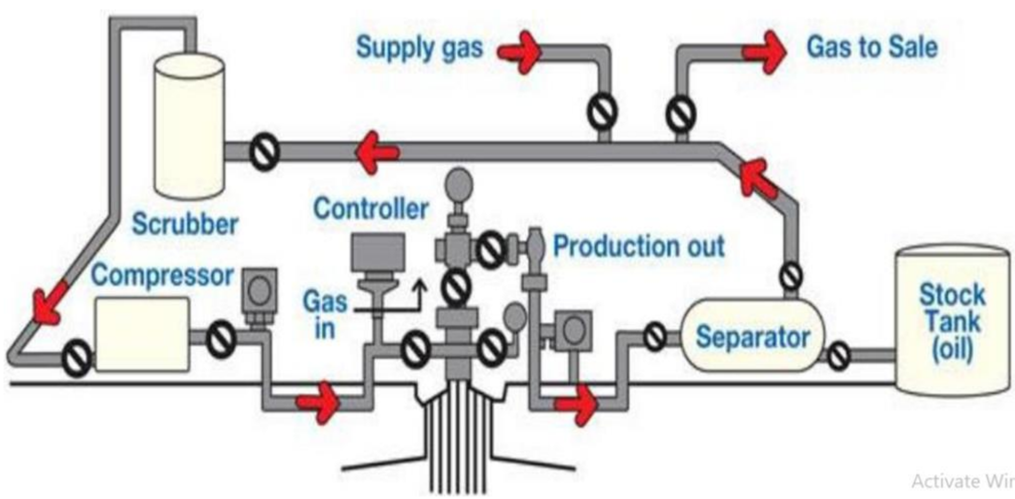

Figure 1: Showing the diagram of the gas lift system (GLS).

Naturally, oil and gas companies find it difficult to maintain their peak output levels for an extended period. As a result, they are faced with an excessive drop in pressure, a rise in water cut, and a decrease in well deliverability, among other things, all of which have a direct impact on the rate of output, and this is a current problem for the oil and gas industry. The Well loss or mismanagement, excessive pressure drops in the production system, Large tubes or small tubes, and inappropriate process of perforation, among other things, may all contribute to a decline. Since the various components are interactive, the variation in one component of the production system can result in the variation of the pressure drop conduct of the other components.

Furthermore, when natural means of production are no longer sufficient, an artificial lift is installed to increase production. However, several issues are considered, including the number of wells drilled in the field, solid/sand handling, corrosion/scale handling**,** high GOR, water cut, flowing pressure and temperature limitations, well depth, room, and production rate, flexibility, and well depth. Sensitivity analysis will be performed on some of these variables to maximize performance in this study.

Electric Submersible Pump systems (ESPS), as shown in Figure 2, include an electric motor and centrifugal pump unit mounted at the reservoir via the output series connected to the surface of the control mechanism and the transformer by an assistance electric power cable. The pump's downhole components (PDHC) are hanged above the well perforations. With the pump and seal directly above it, the motor is often found at the bottom of the work string. The power cable is clamped to the tubing and connects to the motor's tip. As the fluid flows through the well, it must pass through the motor and pump, and the fluid cools the motor during this process. The fluid then passes through the intake and into the pump. Each stage (combination of impeller and diffuser) adds pressure or head to the fluid at a set pace. If the fluid reaches the top of the pump, it can build up enough pressure to rise to the surface, then to the flow line.

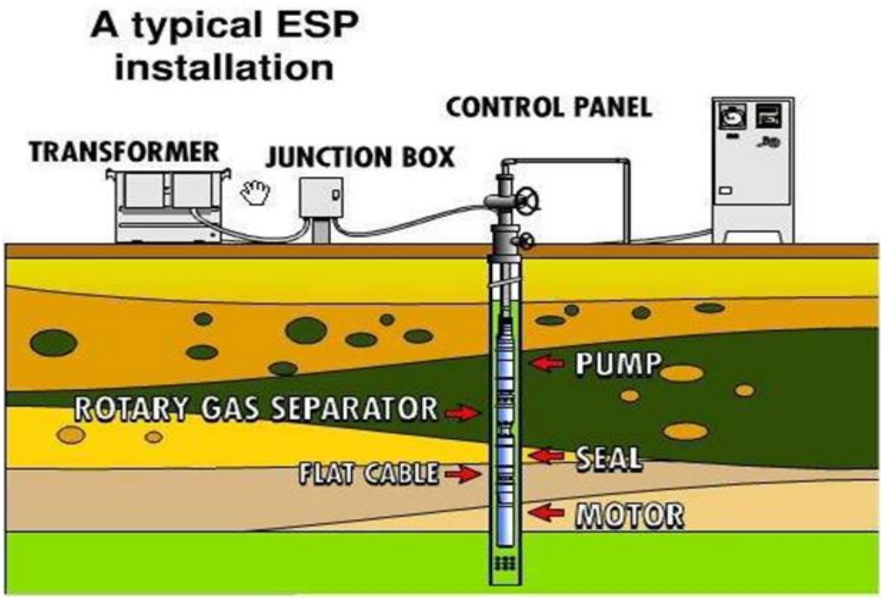

Figure 2: Showing the diagram of the ESP system [6].

According to [7], investigated the use of production management techniques (PMT) in oil field operations, developing a method for allocating the optimum production rate, the rate of gas lift GLR, and the simultaneous connection of wells to surface pipeline systems. The researchers [4] worked on deploying a high-horsepower electrical submersible pump to expand the Brent field in the North Sea in Scotland. Their ESP collection found both downhole and topsides facilities and discusses some of the most recent developments in ESP operations. The paper discusses the use of downhole chokes and variable speed drives to optimize ESP operations. Intelligent well technology, i.e., they focused on the remotely controlled device and downhole parameter monitoring. Table 1 summarizes the general guidelines for each form of artificial lift, including common characteristics and applications [8]. These are general guidelines that differ from manufacturer to manufacturer and researcher to others. Each application should be assessed on its own merits.

Table 1: Operating Parameters ESP and Gas Lift System (GLS) [8].

Operating Parameter	**ESP**	**Gas Lift System (GLS)**
Typical Operating Depth (TVD).	-	5000 to 10000ft.
Maximum operating depth	15000ft.	15000ft

(TVD).		
Typical operating volume	100 to 30000 BFPD.	100 to 10000 BFPD
Maximum.	40000	30000
Operating volume.	BFPD	BFPD
Typical Operating Temp.	-	100-250 ° F [40-120 ° C].
Maximum Operating Temp.	400 ° F [205 ° C]	400 ° F [205 ° C].
Typical Wellbore Deviation	-	0 to 50 deg
Maximum Wellbore Deviation.	0 to 90 degrees.	70 Short to Medium Radius
Corrosion Handling.	Good	Good to Excellent
Gas Handling.	Fair	Excellent
Solids Handling.	Fair	Good
Fluid Gravity.	>10°API	>15 °API
Servicing	Workover or Pulling Rig (PR).	Wireline or Workover Rig
Prime Mover (PM).	Electrical Motor(EM).	Compressor
Offshore Application (OA).	Excellent	Excellent
System Efficiency (SE).	35 to 60%	10 to 30%.

2: Aim of the Research.

This paper aims to identify the best artificial lift techniques for MAJNON 1 so that maximum production/profit can be following these procedures. To reduce the weight of the fluid column in the tubing, allowing the well's bottom hole pressure to raise the column sufficiently and overcome resistance in the tubing, pipes, and connections, using GL and ESP, determine the highest output rate can be achieved. Then calculate the best lift gas injection rate and depth build the loading and unloading valves, conduct an economic analysis of GL and EPS, and a cost-benefit analysis of adjusting different system components as a result of the production system optimization.

3: Materials and Method.

Figure 3 (Prosper workflow) depicts the methodological design technique (MDT) used in this paper to equate the natural flowing well and artificial lift well (ALW). As a result, in the prosper model, three basic scenarios will be developed as below.

1. Build a natural-flowing oil well as a test case.
2. Create a gas lift system for the same well and assess its results.

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3. Create an ESP framework for the same well in order to assess its performance.

PROSPER is the wellbore modeling tool (WMT) that can handle all aspects of wellbore modeling, including PVT (fluid characterization), VLP correlations (for calculating flow line and tubing pressure loss), and IPR (internal pressure loss) (reservoir inflow). The User may check each model subsystem's output by modeling each part of the well generating system. PROSPER can confidently model the well in various scenarios, as showing in Figure 3 and make forward reservoir pressure projections (RPP) based on surface production data once a model of the well system has been calibrated to the data of the real field.

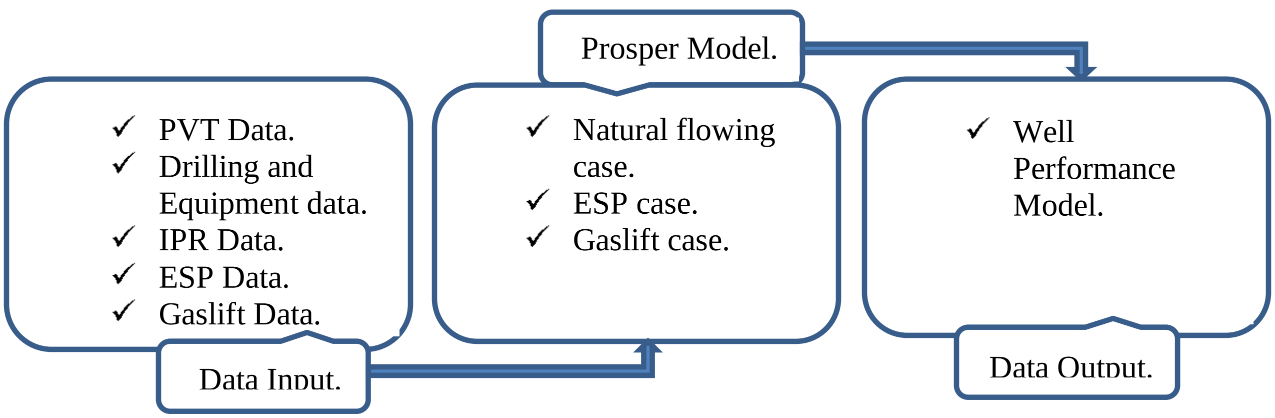

Figure 3: Prosper Model case scenarios.

The following are some additional considerations that will be considered during the selection of the design process.

1. Capital Cost (CC).
2. Operation Cost (OC).
3. Lift Gas Availability (LGA).
4. Service frequency (maintenance cost).

3.1: Design factors.

1. For desired production, gas injection depth, pressure, and GLR
2. Unloading operations principles.
3. Well-defined gradients.
4. Principles of Gas Lift Valve Spacing.

5. Different kinds of gas lift valves (GLV).
6. The valve of Gas Lift service mechanics.
7. Efficiency-related factors.

3.2: Workflow during the PROSPER.

1. Production data from wells and collection.
2. From the available data constructing a single well model.
3. Using prosper to building a base case without artificial lift.
4. Development of the inflow and outflow implementation.
5. Using prosper to building the ESP option and gas lift GL.
6. Compare the production rate (PR) of the well using ESP as the artificial lift method (ALM) and GL.
7. Evaluate the tubing effect and or the water cut, subsurface safety valve sizing, reservoir pressure (RP), skin, productivity index (PI), and gas-oil ratio (GOR).
8. Selecting the best option from these two models.

3.3: MAJNON 1 input data.

The PVT data, inflow performance, laboratory, PVT data for MAJNON 1, and flow test data are shown in Tables (2 to 5).

Table 2: Inflow performance data.

Parameter	Value
Res temp (RT).	200 ˚F
Water cut.	0
Total (GOR).	400 scf/stb.
H	100 ft
Rest K	150 md
Dietz shape	31.5
Rw	0.355 ft
S	2
Area	340 acre

Table 3: Laboratory PVT Properties.

Pressure (Psi)	**Oil Gas Rat OGR (scf/stb)**	**Oil FVF (rb/stb)**	**Oil velocity (cp)**
4000	400	1.198	1.11
3000	400	1.207	1.05
2500	400	1.214	1.01
2000	237	1.178	1.14
1500	324	1.38	1.12

***Table 4: PVT data for* MAJNON 1**

Property	**Value**
Gas-oil ratio (GOR)	400 scf/stb
Oil gravity	30 ^{0}API
Gas gravity	0.75
Water salinity	80000 PPM
Reservoir pressure	4000 Psi
Bubble point pressure	2500 Psi
Temperature	200 ^{0}F

***Table 5: Flow test data*.**

Parameter	**Value**
Test comment.	Min of Flow test.
Head flowing pressure of Well.	1000 Psig.
The temperature of the Flowing tubing head.	153 ˚F.
Water gas ratio WGR.	5 stb/MMscf.
Condensate gas ratio CGR.	5 stb/MMscf.
rate of Gas flow GFR.	15 stb/MMscf/d
depth of Measured gauge.	4500 ft.
The pressure of the measuring gauge.	1920 Psig.
The pressure of Static reservoir / top perforation.	2300 Psig.

4: Result and discussion.

Performance Match of Outflow (VLP) and Inflow (IPR)

The prosper model was modified to replicate well test results, and the calibrated model was then used to investigate the effects of tubing size and reservoir pressure on well efficiency. The test point, as shown in Figure 4, is outside of the solution envelope. This can happen for various reasons, and it is the engineer's job to figure out exactly what is

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causing this action. In order to match the vertical lift output showing in Figure 5, the multiphase flow connection was adjusted to corresponding to the downhole pressure (DHP) while the GOR was tuned, also that the crossroads VLP/IPR corresponded to a well test rate of production. The IPR model in use determines the parameters for matching. Permeability, skin, or pressure may be used in the Darcy-IPR model for this analysis. Since the reservoir is still under-saturated, the pressure was changed to fit the IPR, and the GOR was checked to ensure test data matched PVT data. The fluid's bubble point pressure at reservoir temperature is 2500 Psig in this case of MAJNON 1, while the reservoir pressure is 3800 Psig. At 3800 psig, this indicates that the Oil is already under-saturated. As a result, the produce gas oil ratio GOR must be equal to the GOR of the initial solution, which is 400 SCF/STB. The measured and determining rates and pressures of MAJNON 1 as showing in Table 6.

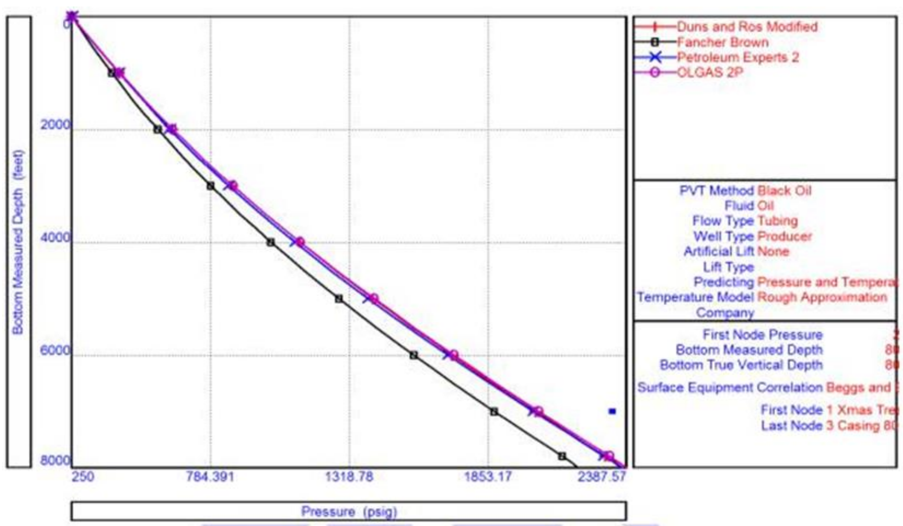

Figure 4: Showing the VLP correlation comparison.

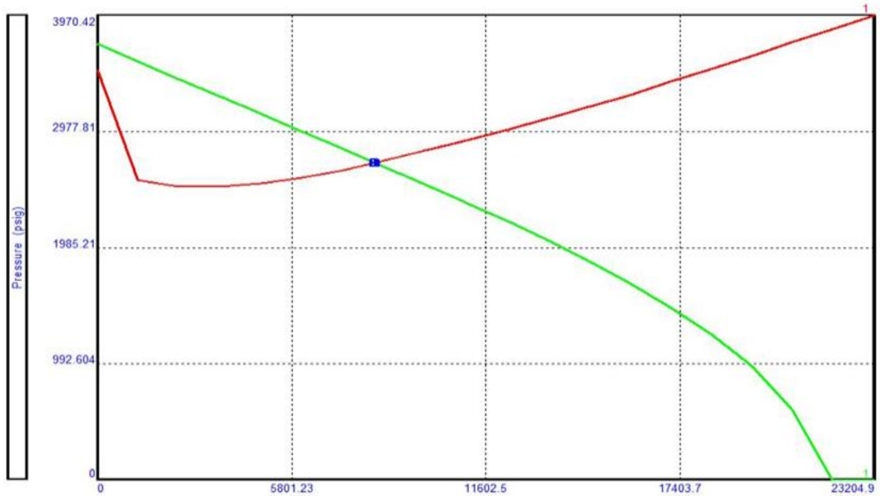

Figure 5: Showing the outflow performance and Inflow performance match with test data.

Table 6: VLP/IPR plot analysis.

Liquid Rate (STB/day)			Bottom Hole Pressure (Psig)		
Measured	Calculated	Different %	Measured	Calculated	Different %
8290	8300	0.11886	2706	2706.7	0.02517

4.1: Gas Lift Performance Result.

MAJNON 1 had 10 MMscf/day of injection gas available, but the optimum gas lift rate (GLR) for this well is evaluated as 8.323 MMscf/day, as shown in Table 7. As a result, since the available gas exceeds the optimum gas needed, the software can only inject the optimum gas into the well, which is 8.323 MMscf/day. The real available gas value will be used if the available gas is less than the optimum gas value; table 8 displays the GL design rate.

Table 7: Outcome of gas lift evaluated rate.

Injected of GLR	Liquid Rate	Oil Rate	Pressure of VLP	Pressure of IPR	Stander Deviation	Design Rate	Oil Rate
Scf/stb.	Stb/d	Stb/d	Psig	Psig	-	MMscf/d	Stb/d
1399	9075.6	1815	2279.86	1905.5	34.36	8.323	1599.2

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Table 8: Outcome of gas lift design rate.

Liquid Rate	Oil Rate	Injection Gas Rate IGR	Injection Pressure
Stb/d	Stb/d	MMscf/d	Psig
7154.95	1431	5.942	1287.5

4.2: Well Gas lift Design of MAJNON 1.

The MAJNON 1 well gas lift configuration valve setting depths are showing in Figure 6. Table 9 shows the values of the different valves. The first unloading valve is set at 2975.3 feet, while the second and third unloading valves are set at 4835.1 feet and 5884.5 feet, respectively, according to Figure 6. The operating valve is the orifice, which is set at 6161.4 ft.

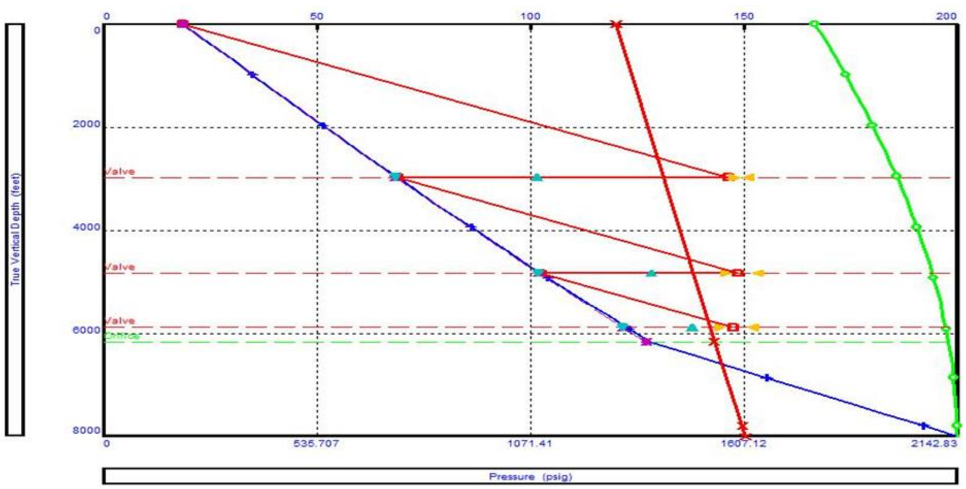

Figure 6: Showing the gas lift valve design MAJNON 1.

Table 9: Outcome of gas lift valve depth design.

Valve Type	Measured Depth	True Vertical Depth	Tubing Pressure	Valve Opening Pressure	Valve Closing Pressure	Opening CHP	Opening CHP
	Feet	Feet	Psig	Psig	Psig	Psig	Psig
Valve	2975.3	2975.3	737.25	1618.6	1585.13	1500	1466.5

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Valve	4835.1	4835.1	1097.2	1642.8	1563.6	1450	1370
Valve	5884.5	5884.5	1313.3	1630.8	1547.5	1370.5	1287.5
Orifice	6161.4	6161.4	1414.4	-	-	1287.5	-

4.3: ESP Performance Result.

The prosper software includes a variety of pumps, cables, and motors from various manufacturers. Centurion G110 5.38 inches (6000-14000 rb/day) was chosen from a suitable pump list in the first design. At the design pace, the pump needs 71 stages and a power rating of 426.22 HP. Centrilift 562 450HP 2460V 10A was chosen from the list of appropriate motors, and Figure 7 depicts the superimposed design operating point at the output curve of the pump. Figure 7 indicates that the selected pump will fail soon after installation because it runs at or near its full operating performance.

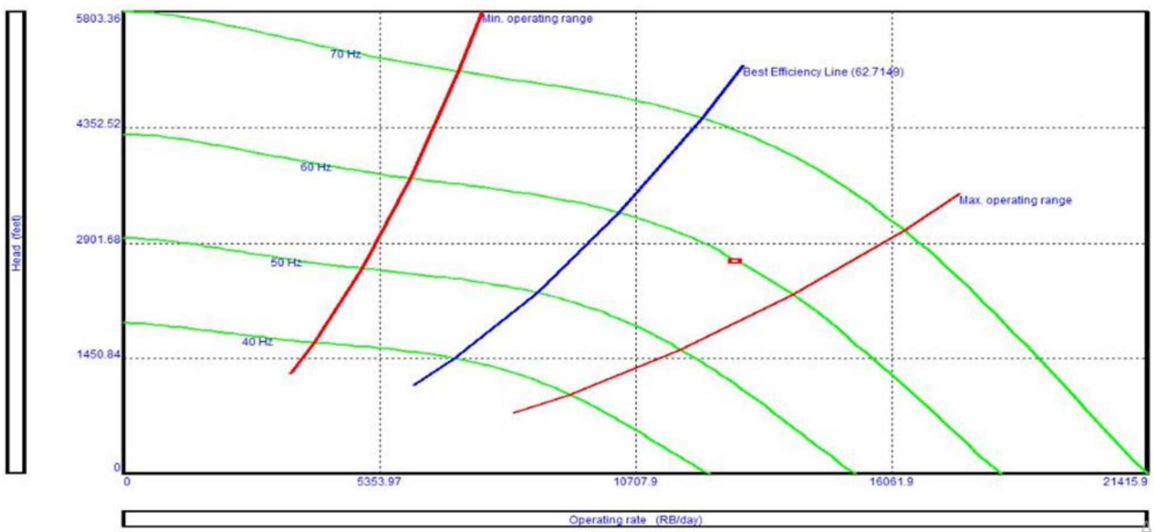

Figure 7: Showing the Centurion G110 5.38-inches (6000-14000 RB/day) operating point.

Furthermore, since the Centurion, G110 5.38 inch pump is nearing maximum production, the following largest pump perhaps the better option, particularly whether the pump is predictable to handle a higher lift duty because of increased water cut over the life of the pump. As a result, the motor REDA 540 90.0 Int 400HP 2116V 113A and the same cable

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shown in Figure 8 were chosen with the REDA HN150005.63 inches (12000-18000 RB/day) with 61 stages. This pump is operating at a low-efficiency level and has some excess head. As a result, it should be considered for MAJNON 1 as well.

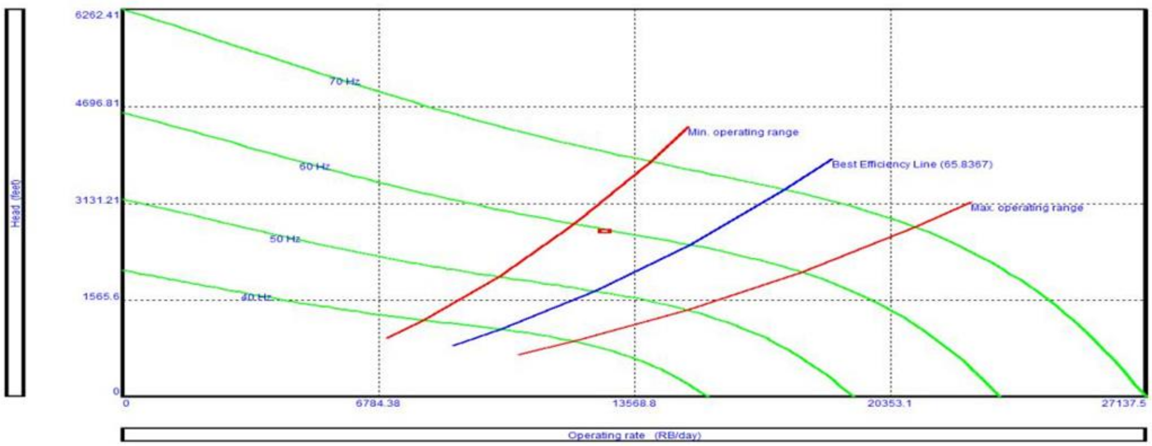

Figure 8: Showing the read HN15000 5.63 inches (12000-18000 RB/day) production performance operating point comparison.

The performance forecast in Table 10 shows that the ESP solution outperforms GL and the natural flowing case "base case" in terms of production volume. It is also worth noting that the GL well produces more gas than the natural flowing. As a result, ESP is by far the better choice for gas lifting and flowing the well using the reservoir's natural energy, but one cannot leap to a conclusion without considering many other variables that could contribute to the installation's overall failure or success. While ESP provides a higher production capacity, it may fail to achieve its purpose rate due to the perhaps changes in the reservoir properties, necessitating the addition of else pump to handle the conditions of the current reservoir. When the ESP unsuccessful in the cut of the higher water, the whole system is shut down, and a new pump is installed to suit the current reservoir requirements.

Table 10: Production performance Comparison.

Liquid Rate (Stb/day)			Pressure (psi)		
Natural Flowing	**Gaslift**	**ESP**	**Natural Flowing**	**GL (VLP Pressure)**	**ESP (Discharge Pressure)**
8290	9076	12936	2706	2279	3207

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Conclusions:

The following conclusions were drawn after considering the production rate, rate of the desired, advantages and disadvantages of the GL, and the ESP for output optimization, and match the better suitable methods of the artificial lift for the MAJNON 1 field.

1. The results revealed that the ESP and GL systems produce 4645.9 STB/day, and 785.7 STB/day respectively, both systems produces more than the natural flowing case.

2. Both GL and ESP increase output significantly compared to the natural flowing scenario, but ESP has a higher production potential than GL for the MAJNON 1 well. This leads to conclude that a full-field artificial lift campaign would show the same difference. In this analysis, the implementation of ESPs outperforms the implementation of GL of output, and overall profit is a flaw in choosing ESPs.

3. There is a nearby gas compression station for MAJNON 1. As a result, installing a GL is the better choice in this area or field.

4. Because of the size of the equipment and its short lifespan, ESP implementation carries a higher risk. When ESPs fail, a complete workover is needed, which is more costly than the wireline operation due to the rig operation required.

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