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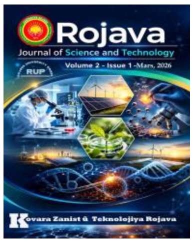


# Effect of pump frequency and wellhead pressure on oil production of ESP in Rmelan oil field

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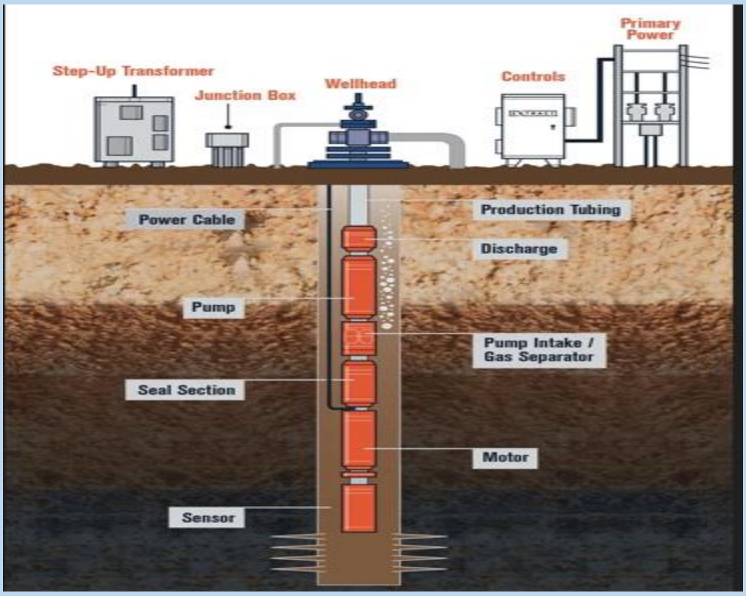
**Abstract**

In this paper. a case study for evaluating the current conditions and the performance optimization of the electrical submersible pump (ESP) for six oil wells in the Rmelan oil field. This paper presents a sensitivity analysis conducted by Nodal Analysis (Using PIPESIM Software) on the pump frequency and wellhead pressure.

The outflow tubing performance and inflow performance relationship were generated and plotted for each well. The outflow and inflow curves are investigated, indicating problems in some wells (W-12R, W-21KH, and W-21SH). The results of this study show that we can increase the flow rate by optimizing the ESP performance by decreasing the wellhead pressure to 71.58 psi and raising the frequency to a specific value of about 65 Hz based on the pump capacity. Increasing the frequency from 55 to 65 Hz resulted in increasing the production from 634 to 1092 bb//day for W-12R, from 1928 to 2806 bbl/day for W-21KH, and from 1722 to 2279 bbl/day for W-21SH.

The results of wellhead pressure sensitivity indicate a scale in the production tubing that must be removed to improve the oil production of these wells.

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## 1. Introduction

At first, naturally occurring hydrocarbons from the reservoir can flow toward the surface (natural flow); however, this state is not stable. There will come a point in time when the reservoir pressure drops, which may result in the well closing or producing less(Beggs 1991). The production of oil wells frequently uses artificial lift techniques. It is applied to maximize production(Fleshman and Lekic 1999a). For productivity to be displayed effectively, production performance must be thoroughly understood. When the reservoir driving energy is insufficient to produce oil to the surface, this technique decreases the bottom hole flowing pressure and increases the pressure difference to bring the oil up to the surface. Bottom-hole pressure is overcome with this technique. The new primary issue facing a field is choosing the best lift technique for each well or the field as a whole. A poor choice may result in excessive production costs(Astuti and Mulyono 2023b).

Artificial lift is a crucial technique used in the oil and gas industry to maintain optimal hydrocarbon production as reservoirs mature(Sucipto, Wiwaha, and Ridzki 2018). It involves employing various methods, such as pumps and gas lift valves, to increase reservoir pressure or reduce wellbore backpressure by installing lift mechanisms down hole. Artificial lift systems efficiently raise fluids to the surface, counteracting declining flow rates. The choice of artificial lift method depends on reservoir characteristics, well conditions, and production requirements. Common methods include Electrical Submersible Pump (ESP), Progressive Cavity Pump (PCP), Suck Rod Pump (SRP), Gas Lift (GL), Plunger Lift (PL), and Hydraulic Jet Pump (HJP)(Brown 1982). These systems play a vital role in sustaining production rates from oil and gas fields. This study mainly focuses on artificial lift using ESP, which is introduced in detail in this chapter. Other artificial lift methods are briefly reviewed.

## 2. Literature Review

Electric Submersible Pump (ESP) uses multiple centrifugal pump stages mounted in series within a housing mated closely to a submersible electric motor on the end of the tubing and connected to surface controls and electric power by an arm or protected cable as shown in **Figure 1**. Submersible systems have a wide performance range and are one of the more versatile lift methods. Standard surface electric drives power outputs from 100 to 30,000 B/ D [16 to 4770 m3/ d] and variable-speed drives add pump rate flexibility(Kanu, Mach, and Brown 1981). High GOR (Gas oil Ratio) fluids can be handled, but large gas volumes can lock up and destroy pumps.

The advantages are that high water cut is not restricted, can lift extremely high volume, can handle rates from 50 to 60.000 bbl/day, flexibility quick restart after shutting down. The disadvantages: not applicable in case of high GOR and sand production, tubing has to be pulled to replace the pump, high voltage (1000 V) electrical powers required, no suitable for low volume wells: <150 bbl/day, viscous crude reduce pump efficiency, and high temperature can degrade the electrical motor (HAMDI and LATRECHE) 2018)..

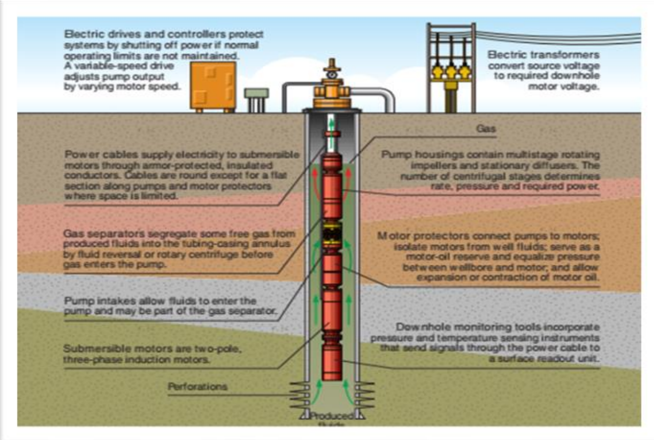


**Figure 1: Electric Submersible Pump (Fleshman and Lekic 1999b)**

Saurabh Goswami1 and Dr. Tej Singh Chouhan studied artificial lift to boost oil production (Goswami and Chouhan 2015). Artificial lifts improved profitability and efficiency by improving the production cycle of oil and gas reservoirs and raising flow rates. The purpose of artificial lift solutions was to reduce bottom-hole pressure and enable a well to produce at the desired flow. Usually, this included pumping gas or using a pump to decrease the hydrostatic pressure to give more lift pressure downhole. The authors of this study found that artificial lifts were a practical way to increase oil production, and they were also the most efficient by increasing the natural well flow and allowing the reservoir to accelerate production while delaying the operator's option to abandon a producing well, artificial lifts offered a chance to decrease back pressure on the well.

Hamdi Youcef studied an artificial lift ESP well on the BRN field (a case study of SFNE 13 oil well in Algeria) to raise the production (HAMDI and LATRECHE) 2018). The thesis has been separated into three sections: the first discussed the advantages and disadvantages of each artificial lift method as well as the criteria to be used when choosing between them; the second part gave general information about ESP; and the last part focused on the design investigation and action evaluation of ESP on oil wells with high salinity and high WC using nodal analysis software (Prosper). The work finished by mentioning a few issues of ESP wells on BRN fields. The results showed the ESP's flexibility 100% WC handling capacity, and it could be used for both vertical and horizontal wells. It also offered us roughly 60% of the oil rate from a single well (SFNE 13). In addition, the disadvantage of the ESP system was the significantly short-run life (2 years) which made it the most cost-effective artificial lift method.

Xiaolei Wang et al. studied the optimization of the well start-up procedure and operating parameters for ESP gas well dewatering (Wang et al. 2023). Two gas wells had Electrical Submersible Pump (ESP) systems installed in to remove the gas from the wells. The well start-up operation recorded for the first problem showed that the ESP noticed gas locking. To prevent this, an accordingly suggested optimization method for the ESP well's start-up process with a check valve was designed. In the second, a set of optimization techniques for ESP operating parameter changes was provided in the nodal analysis method. The results showed a new well start-up technique for ESP removed the gas from wells by a check valve with the use of this process, workover procedures can be avoided to prevent ESP start-up failure, saving the operators money, time, and effort. Furthermore, an optimization technique for production rate and ESP operating frequency was offered based on the nodal analysis method. The well's production capacity was increased through hydraulic fracturing. In addition, the computation results showed that the optimal pump efficiency might be achieved by an increase of 12.2–33% over the prior value.

Carlos Andrés et al studied the optimization of an electrical submersible pump artificial lift system for extra heavy oils through an analysis of the bottom dilution scheme (Díaz-Prada et al. 2010). To analyze the unknown behavior of the variables through their responsiveness in the vertical flow modeling used for a Chi Chimene Field well, this study presented the analysis of the variables that had the greatest effect on the energy requirements for an artificial lift system applied to extra heavy crude oils. The well depth, the flow rate of produced fluids, the reduction percentage, the viscosity and fluid density, and the necessary artificial lift system pressure difference were the variables that had been chosen. The results of this study showed that, for the extra heavy oil, the Modified correlations were more suitable for the calculations of the PVT parameters. Representing the computation of the GOR in solution and the bubble pressure, as well as the adjusted Vázquez-Beggs for the calculation of the oil compressibility including the adjustment of the IPR curve had been studied. Additionally, the oil had a high GOR value in solution when compared to the forecast made using correlations from traditional usage, suggesting that the oil might reach supersaturating conditions. Furthermore, the most important consideration in estimating the system's energy need was the dilution's effect on the oil density's drop. The concept considers a primary system such as rod pumping or ESP combined with gas lift as a secondary system. The design provided a wide operating range, allowing individual operation of the primary, the secondary, and the combined system, reaching the optimal technical and economic performance while the combined system was operating. The operating envelope was framed in terms of production rate and power consumption.

Weny Astuti and Wahyu Tri Mulyono investigated the production optimization in well A and well B using an electric submersible pump (ESP) in the field of West Java, Indonesia (Astuti and Mulyono 2023a). Their research discussed the optimization of production carried out in Well A and Well B. The two wells were production wells with three production layers (multilayer) that had different characteristics for each layer. Based on the performance evaluation of the production well, well A and well B were no longer able to produce naturally (natural flow). They used an electric submersible pump. The results showed that an electric submersible pump was used for the two wells to achieve the production target of 4088 stb/d for well A and 2712 stb/d for well B. In addition, the best scenario for well A was to use the REDA D4300 pump which was operated at a frequency of 60 Hz and 156 stages, while well B used the REDA DN3100 pump which was operated at a frequency of 70 Hz and 188 stages. Furthermore, with the pump used, well A could produce a liquid of 4087.42 stb/d with a pump efficiency value of 70.04%. Then, well B could produce a liquid of 3163.37 stb/d with a pump efficiency value of 67.04%.

Dedy Kristanto*, Dyah Rini R. researched the selection & optimization of artificial lift using Delphi, TOPSIS, and SAW methods for natural flow oil wells at HAS Field 2022 (Kristanto et al. 2022). The Reduced oil production and increased water production were detrimental to the HAS field. The increased production of water is the cause of the production decline. A higher water cut and a decrease in reservoir pressure were the main causes of the production decline. The Delphi methodology, which merged the Topsis method with 21 screening characteristics, was employed in the artificial lift selection process. The electrical submersible pump (ESP) was the artificial lift technique employed at the HAS Field. The result showed that by optimizing the number of stages and setting the frequency to 45 Hz, they achieved an increase in production with the electric submersible pump (ESP). The results were encouraging. Another method of optimization involved gradually increasing the pump frequency to 60 Hz, without any modifications to the type of pump. Also, the HAS field's economic analysis determined that the most advantageous option was to employ an ESP pump.

Abbas Khaksar Manshad Mehdi Jabbari and Amir H Mohammadi studied oil production optimization via optimum artificial lift design (Manshad, Jabbari, and Mohammadi)2017). That study presented optimization of the production conditions of three wells by using artificial lift method ESPs (Electric Submersible Pump). For that purpose, the single well model was created to predict future production conditions in the well drainage area and the recommended optimum production conditions. According to the results of that study, a total gas of 4.75 MMscf/day at a high pressure of 2000 psig could increase the total production of these three wells from 1032 to 6000 stb/day. Furthermore, the total power of 350 HP was required to run ESP for these wells to achieve the same oil production rate as that was considered in the gas lift design. In addition, for the effect of gas injection pressure and the gas specific gravity the authors referred that an increase in the injection pressure was not always beneficial for gas-lift operation if it exceeded the limit wanted, it might increase the compression cost and at a constant gas injection rate, the higher the gas specific gravity was not always good too, it might cause the lower oil production rate if it exceeded the limit wanted because it caused an increase in the bottom hole pressure.

Agung Wahyudi Biantoro and Bambang Darmono studied the performance analysis of DN1750 and DN1800 electric submersible pumps for production optimization on the oil well (Biantoro, Darmono, and Pranoto 2022). In their research, an analysis of pump performance and optimization of ESP pumps were carried out using the Nodal Variable Speed Drive to determine the production capacity of the oil well and the pump speed according to the desired flow rate at frequency changes. The results showed the DN1750 pump at a frequency of 50 Hz with a pump speed of 3000 rpm and a frequency of 55 Hz with a pump speed of 3300 rpm worked under the desired optimum production rate. The DN1750 pump at a frequency of 60 Hz with a pump speed of 3600 rpm, a frequency of 65 Hz with a pump speed of 3900 rpm, and a frequency of 70 Hz with a pump speed of 4200 rpm operating above the optimum limit of the desired production rate. The DN 1750 Pump was not good capability of the oil well because it worked under conditions that were not optimal. In addition, the DN 1800 Pump at a frequency of 55 Hz with a speed of 3300 rpm was in the range of fluid flow rates desired by the oil well, which was 1936,698 Barrels Per Day (BPD) with a wellbore pressure (PWF) of 629 psi by the production capacity of the oil well so a suitable pump was obtained and expected to work at optimum conditions.

Mohammed A. Al-Hejjaj et al. studied a review of the electrical submersible pump development chronology (AL-Hejjaj, Sadeq, and Al-Fatlawi 2023). The main objective of this study was to deliver a general review of the development of the ESP Optimization problem and the available studies and applications to solve the problem at hand. After reviewing a fair number of studies and papers on the problem of ESP Optimization the following conclusions were made: The solutions available for the ESP optimization problem evolved rationally with the rising computational power and the computer abilities that were available to be utilized to the solution of the problem. Moreover, under gassy flow conditions with different amounts of surfactants, extensive experimental evaluations of ESP stage pressure increment should be done.

Njeudjang studied the optimization of field X's eruptive well X-1 by using the nodal analysis and PIPESIM software (Njeudjang et al. 2022). Achieving a production rate that is profitable economically was the aim of this article. The well X-1's production was increased by using the nodal analysis and PIPESIM software, completion data, pressure-volume-temperature (PVT) data, and reservoir data. By making changes, several optimization options were considered, including the tubing diameter, wellhead pressure, water cut, and flow line diameter. The main findings showed that by raising the flow line's diameter from 2.5 to 4 inches and lowering the wellhead pressure from 350 to 100 psia, the production flow rate could have increased from 850 to 2030.472 barrels per day.

Mohammed Saeed Mohammed et al. studied the comparison of the productivity of the gas lift and Electrical submersible pump (ESP) in Mishrif formation in Rami Ali Altam studied production optimization by nodal analysis (Mohammed, Al Dabaj, and Lazim 2019). It was important to make sure that every component of the production system, from the separator to the downhole completion, was running as efficiently as possible given the high cost of developing gas fields. Field optimization was intended to determine the ranges of operational parameters that would enable and help the operator reach the desired result, such as maximizing the field's total production rate. Nodal analysis offered a practical means of helping in the decision-making process for optimization. The initial step was to optimize each well's tubing size. After that, the wells and surface facilities were integrated into a field-wide network model. The "X" field was critically analyzed using the available field data, and the following conclusions were reached when modeling every well using nodal analysis using a 2.75-inch tubing size was less advantageous than 3.5" tubing size when reservoir pressure and flow rate dropped; as a result, 3.5" tubing size was suggested. The duration of the perfect gas rate could also be extended by employing a compressor to decrease the minimum allowed backpressure at the wellhead. In addition, drilling new wells increased the gas recovery factor by around 14% and produced a longer and more stable production rate.

Sardam Ahmed et al. studied the optimization of oil and gas production using nodal analysis techniques in the Kurdistan field (Sardam, Khalid, and Las 2019). The authors observed that the petroleum production optimization was managed through well deliverability analysis that was determined by the combination of well inflow performance and wellbore flow performance. Using nodal analysis to find the effect of each parameter on the pressure drop and flow rate at different nodes in the production system. Examination of the inflow performance relationship with vertical flow performance will be carried out for steady-state flow regimes. The results showed that increasing the value of the reservoir temperature led to an increase in the production rate. Moreover, decreasing the value of the skin led to an increase in the production rate, and having a higher tubing diameter led to an increase in the production rate. In addition, increasing the value of the reservoir permeability led to an increase in the production rate, and decreasing the value of the tubing roughness led to an increase in the production rate. Finally, increasing the value of the perforation interval led to an increase in the production rate.

Muhab Abeed and Maamar Khalleefah investigated Nodal analysis calculation for the estimation of the best operating conditions using two wells Z1&Z2 in Libya 2023 (Mahmud and Abdullah 2017). In that study, two wells (Z1 and Z2) in the AL_Nafoora field in Libya were tested with a sensitivity analysis to simulate the IPR and OPR model using PIPESIM software. This enabled researchers to determine the optimal operating conditions for flow rate and flowing bottom hole pressure, the maximum water cut ratio, and the maximum wellhead pressure value that should not be exceeded to preserve the natural flowing phase for as long as possible. The findings demonstrated that a higher productivity index, which raised the flow rate, relates to a larger pressure differential between the reservoir's pressure and the bottom hole pressure. Additionally, the flow rate value increases with decreasing pipe diameter for inner diameters. Furthermore, the productivity value increased with decreasing wellhead pressure. Finally, a drop in flow rate results from a higher bottom hole pressure value matching with a larger water cut value.

The use of artificial lift techniques in an oil field in the Rmelan field is examined in this communication. Electrical submersible pumps (ESP) are one useful method in this field because of their high production compared with other artificial lift methods(Sucipto, Wiwaha, and Ridzki 2018). Six oil field wells are examined for this purpose based on what is currently known in this field. Water drive is the primary reservoir energy source. Therefore, a quick pressure reduction will take place in the well drainage area as a result of oil production. Many parameters are involved in a successful artificial lift operation. This study uses the PIPESIM Software as an attempt to specify these parameters in such a way that the production and the operation's net present values are maximized by changing the frequency of the ESP pump and decreasing the wellhead pressure between the wells and the facilities to find the best operating condition for each tested well.

## 3. Results and Discussion

### 3.1 The specification of ESP used in the Rmelan field.

In this paper, we are trying to evaluate the current well performance of the tested wells operated by ESP at 50 HZ and trying to optimize the flow rate of the ESP pump through the sensitivity analysis on the pump frequency and wellhead pressure using PIPESIM Software version 2022.1. We selected six wells artificially lifted and operated with ESP pumps in the Rmelan field. The specification of ESP used in the Rmelan field is not included in PIPESIM software so, we selected the nearest specifications of pumps in PIPESIM to represent, evaluate, and optimize the ESP used in the Rmelan field as presented in **Table 1**.

**Table 1: Specifications of ESP used in the Rmelan field.**

| Pump in Rmelan field | Pump in PIPESIM software |
|---|---|
| H-300/167stages | (1500-2500 bbl/day) ODI-RA22/167stages |
| H-200/148stages | (600-1800 bbl/day) (Alkhorayef /WG1600/) and (centre lift P16) (148 stages)) |

So, all tested runs on PIPESIM software were carried out on the selected pumps from PIPESIM manufacturers. The current operating conditions for the tested wells are listed in **Table 2**. This table shows the tested wells operated at a constant current pump frequency of 50 Hz, wellhead pressure changed from one well to another and the actual flow rate wasn't constant for the tested wells.

**Table 2: Current Conditions for the Tested Wells**

| Well | No. of Stages | Frequency (Hz) | wellhead pressure(psi) | Actual flow rate (bbl/day) |
|---|---|---|---|---|
| 7SV | 167 | 50 | 142.71 | 1228 |
| 12RV | 167 | 50 | 171.15 | 515 |
| 21KH | 167 | 50 | 185.3 | 2020 |
| 21SH | 148 | 50 | 142.71 | 1730 |
| 32KV | 148 | 50 | 228.05 | 1375 |
| 155KV | 148 | 50 | 199.6 | 1139 |

### 3.2 Well Modelling.

Two parameters control the well performance: Inflow performance relationship (IPR) and Vertical Lift Performance (VLP). IPR is known as the relationship between well-flowing bottom-hole pressure ($P_{wf}$) and production rate so it represents the flow from the reservoir to the inside wellbore(Beggs 2003).

Many correlations and methods can be used to describe the reservoir performance. Each correlation has specific conditions to be applied according to reservoir characteristics and flow type. The most important methods that could be used for black oil reservoirs are Vogle, Darcy, and Fetkovich methods. In this work, the productivity index (PI) is already calculated from PLT data of the tested wells, therefore it can be used directly in Nodal analysis(Salaudeen, Bopbekov, and Abdulkarim 2022).

The VLP depends on many parameters such as fluid PVT properties, tubing inside diameter, surface pressure, well depth, water cut, and gas oil ratio.

ESP components are key parameters in ESP design. Any change in one or more of them will affect the overall ESP performance. ESP components are motor frequency which is the system prime mover and electric motor with different types and sizes of ESP motors that give different values of horsepower required.

The objectives of well modeling & analysis in this research are as follows:

1. To evaluate the current well conditions and when it might be ceased to produce. This could be due to the timing of reservoir pressure depletion or ESP problems such as up-thrust and down-thrust conditions (the pump works outside the range of pump performance).
2. To determine the optimum flow rate at which the well will flow with known wellbore conditions and completion.
3. To study the effect of changing the motor frequency and wellhead pressure on the well productivity.
4. To evaluate the well completion to determine if there is any restriction to flow unnecessarily.
5. To make a sensitivity analysis of motor frequency and wellhead pressure and choose the best controlling one for each tested well.

- **3.3 Nodal analysis for the Current system**

The systems analysis approach represents a method for analysing the tested wells that allow the determination of the producing capacity for any combination of components (reservoir pressure, well productivity, wellbore completion, tubing string, surface choke. The essential principle of this method is to determine the location of the studying node. In this thesis, it is preferred to select the bottom hole pressure ($P_{wf}$) as the studying node to divide the production system into two parts: the piping system as the outflow curve and reservoir performance as the inflow curve. The initial node is the reservoir, and the final node in this study is the wellhead pressure (WHP).

**Figures (2)** to **(7)** illustrate the IPR (representing what the reservoir can deliver in terms of oil quantity) versus the VFD (Variable frequency drive) relationship.

In these Figures, the blue line represents the inflow performance, and the red one represents the well vertical flow performance. The intersection point of those two lines represents the operating point for the tested well, which represents the flow rate the well can deliver. The analysis shows that well-7SV, well-12R, well-21Kh, well-21SH, well-32K, and well-155K have production rates of 1319,634,1927,1722,1443 and 1213 STB/Day respectively as presented in **Table (2)**.

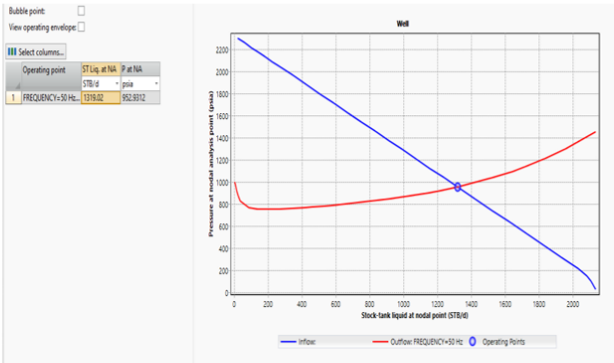

**Figure 2: VLP/IPR relationship for the existing system for Well 7SV**

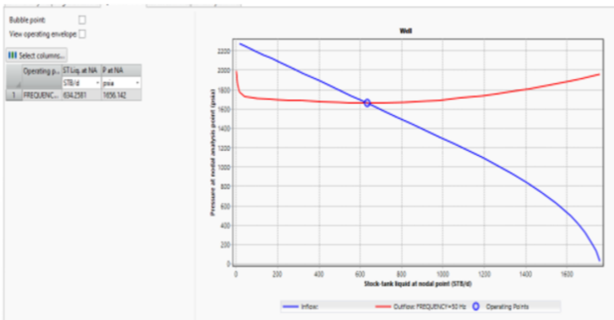

**Figure 3: VLP/IPR relationship for the existing system for Well-12R**

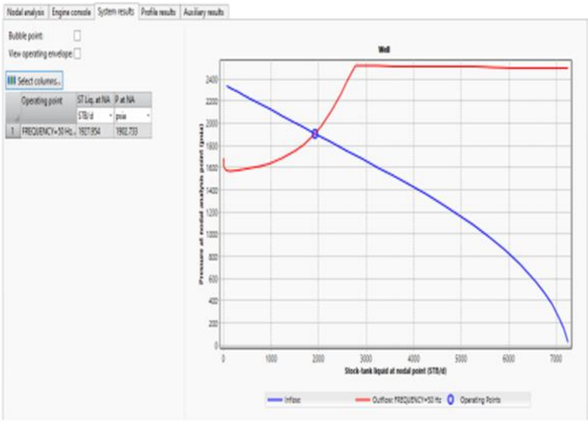

**Figure 4: VLP/IPR relationship for the existing system for Well-21KH**

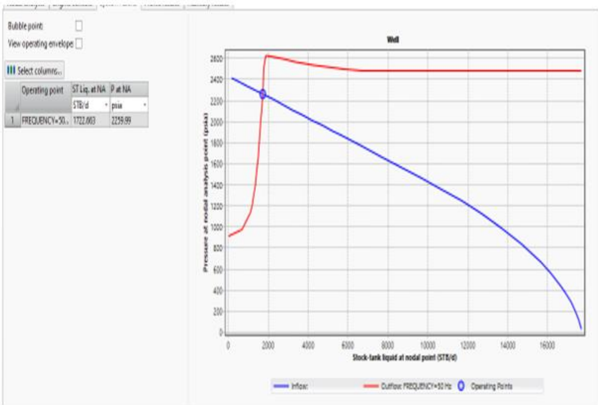

**Figure 5: VLP/IPR relationship for the existing system for Well-21SH**

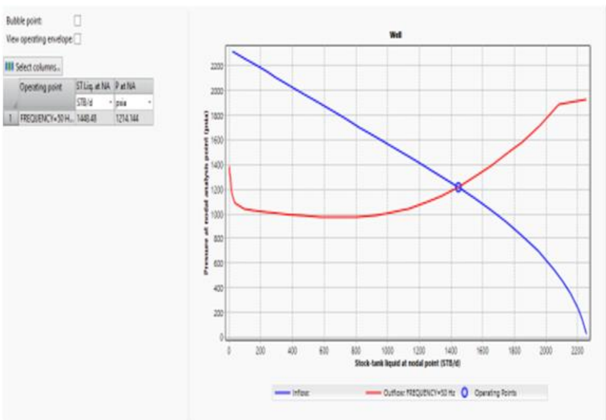

**Figure 6: VLP/IPR relationship for the existing system for Well 32K**

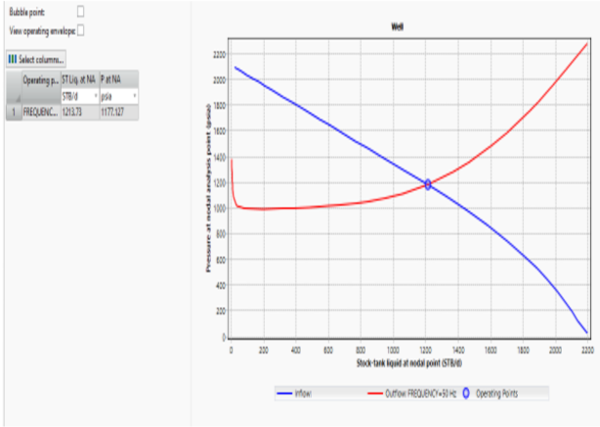

**Figure 7: VLP/IPR relationship for the existing system for Well 155K**

**Figures (3)** to **(5)** show that the intersection points (operating points) are close to the Y-axis. This means that the tubing sizes in these wells are too small to meet the reservoir production. Even though the reservoir may be capable of producing a large amount of fluid, if too much pressure drop occurs in the tubing, the well performance suffers. So, it is recommended to use PIPESIM software to optimize the tubing size to a large one relative to reservoir conductivity.

### 3.4 Sensitivity on Pump Frequency:

ESP is one of the artificial lift methods for the production of large production rates as well as for deep wells. ESP regulates the production rate by operating frequency of electricity supplied to pump operation(Al-Qasim et al. 2019).

The frequency of electricity supplied can be changed by **VSD** (Variable Speed Drive) or VFG (Variable Frequency Drive) devices. Pump rate and pump power are proportional to the operating frequency(Lingom et al. 2021). When the operating frequency of the pump increases, the pump rate and capacity will also increase, which is clearly shown in the equations. (1) and (2).

In addition, the decrease in pressure discharge of the pump means that the pump power is reduced, so the friction of the IPR curve or the VLP curve depends on the selected node position concerning the selected node intake or discharge of the pump. Thus, determining the optimal operating frequency is very important in order to produce the maximum oil flow without affecting the life cycle of the ESP and this section will detail the optimization of operating frequency in this section. The relationship between the well production and the pump frequency may be expressed as:

$$\frac{Q_1}{Q_2} = \frac{F_1}{F_2} \qquad (1)$$

$Q_1$ (STB/D): Production well at frequency $F_1$ (Hz)

$Q_2$ (STB/D): Production well at frequency $F_2$ (Hz)

**Figures (8)** to **(13)** represent the relationship between productivity and pressure at the point of nodal analysis at different frequencies for the tested wells. It is observed from these figures that, in general, as the frequency increases, productivity also increases. Also, the change in frequency has a good influence on the productivity for all tested wells except Well 21 SH as shown in **Figure (11)**. It is observed from this Figure that, the operating points are close to each other this explains that the change in frequency has little effect on the productivity for this well.

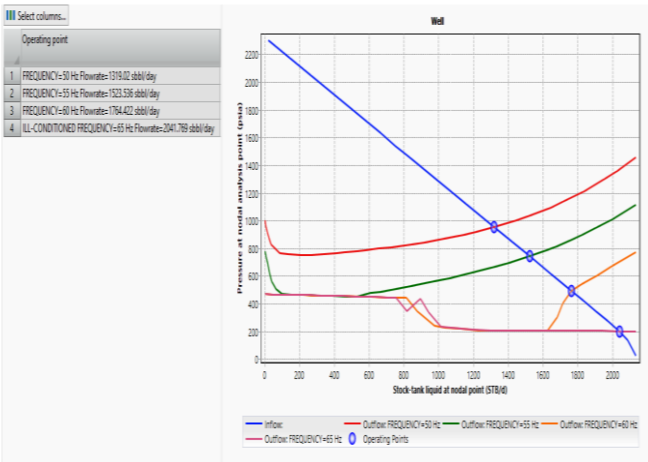

**Figure 8: Sensitivity on pump frequency for well 7SV**

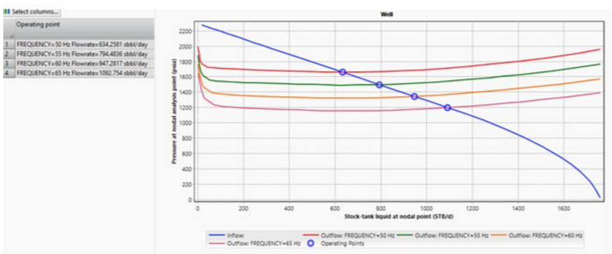

**Figure 9: Sensitivity on pump frequency for well 12RV**

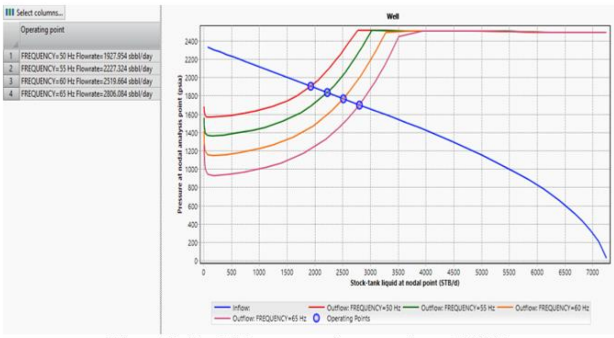

**Figure 10: Sensitivity on pump frequency for well 21KH**

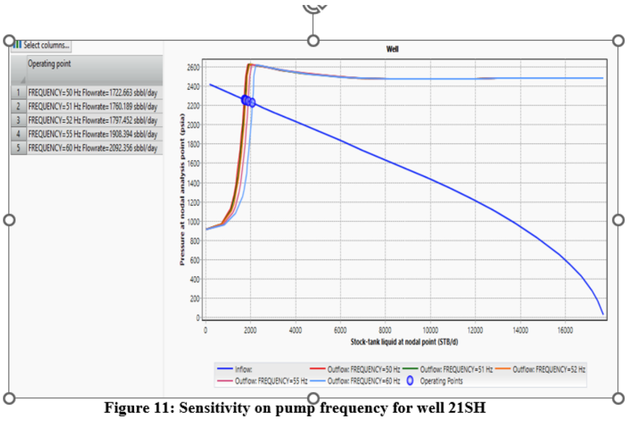

**Figure 11: Sensitivity on pump frequency for well 21SH**

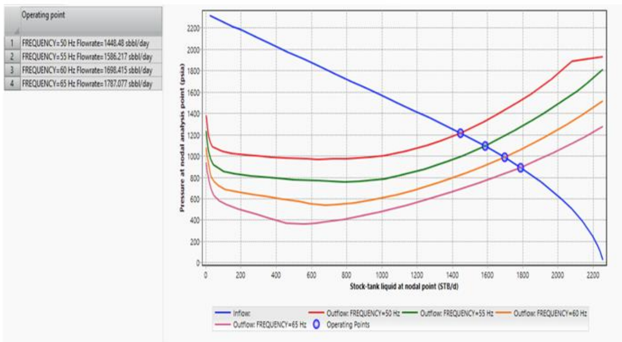

**Figure 12: Sensitivity on pump frequency for well 32KV**

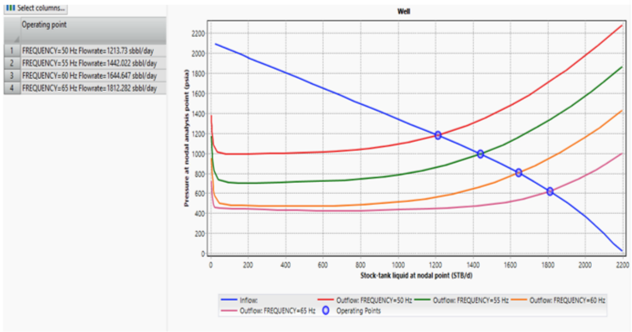


**Figure 13: Sensitivity on pump frequency for well 155 KV**

For the same number of stages of ESP, the production rate increases when frequency increases this means that there is a direct relation between production rate and pump frequency as the pump will rotate more with high frequency. For example, the well 7SV produced 1319 STB/Day with 50 Hz then the flow rate increased to 2041.76 STB/Day with 65 Hz (number of stages equal to 167 stages). For the same frequency, well-155KV produces less fluid when the number of stages decreases. For the same frequency equal to 50Hz, the well produces 1448 STB/Day with 148 stages then the production rate increases to 1812 STB/Day with 65 Hz.

Increasing flow rate due to changing the frequency calculated from Eq. (2) and illustrated in **Figure (14)**.

$$IR = \frac{Q_{tested\ frequency} - Q_{current\ frequency}}{Q_{current\ frequency}} \% \qquad (2)$$

Where:

IR: Percent in increasing flow Rate due to change of frequency

$Q_{tested\ frequency}$ : Flow rate at tested frequency, Hz

$Q_{current\ frequency}$ :Flow rate at current frequency, Hz

**Figure (14)** illustrates the relationship between changing the frequency and increasing the production rate for tested wells. It is noticed from this figure that, the increasing flow rate for Well-12RV is the highest one for all tested frequencies. This means that the productivity of the well is affected more by changing the pump frequency.

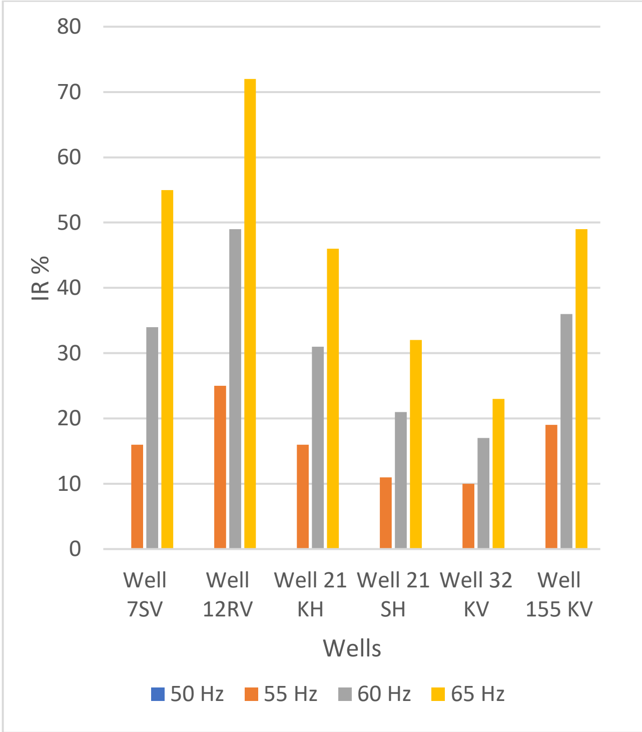


**Figure 14: Effect of frequency change on productivity**

### 3.5 Sensitivity on wellhead pressure:

The wellhead pressure has a direct influence on bottom hole pressure by the hydrostatic pressure. **Figures (15)** to **(20)** showed the relationship between the wellhead pressure and the well productivity.

According to these Figures, it instantly appears that the wellhead pressure is inversely proportional to the overall production rate. This can be explained by the fact that increasing wellhead pressure implies an increase in bottom-hole pressure. An optimal flow rate requires a significant drawdown (difference between reservoir pressure and bottom-hole pressure). The best value of interest on wellhead pressure here differs from one well to another. Also, it is observed that. The production rate decreases when wellhead pressure increases and this is due to more WHP, leading to more $P_{wf}$ and less pressure drop across the reservoir causing a low production rate. The change in wellhead pressure has little effect on the productivity of Well-7SV and Well-21KH.

It is noticed also that, the operating point in **Figure (18)** is the same for all tested wellhead pressures this means that any change in wellhead pressure does not affect the well productivity for well-21SH.

It is obvious from these figures that, there is an inverse relationship between the wellhead pressure and IR. As the wellhead pressure decreases, the IR increases. The percentage of IR varies from one well to another as shown in these tables. For example, for well-12RV the production increased by 5.4 % when WHP decreased to 128.41 psi then increased to 12.9 % when WHP decreased to 71.58 psi. Well-21SH is less influenced by the change in wellhead pressure than the other wells. The increase in production rate is expressed as equation 3:

$$IR = \frac{Q_{\text{tested value(psi)}} - Q_{\text{current condition (psi)}}}{Q_{\text{current condition (psi)}}}\,\% \qquad (3)$$

Where:

IR**:** Percent in increasing flow rate due to change wellhead pressure %.

$Q_{\text{tested value (psi)}}$: Flow rate at tested wellhead pressure, bbl/day.

$Q_{\text{current condition (psi)}}$: Flow rate at the current operating well head, bbl/day.

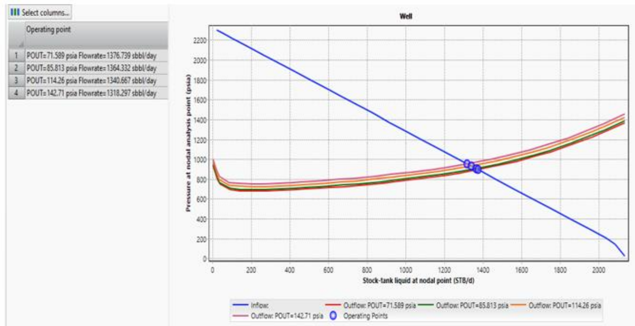

**Figure 15: Sensitivity on wellhead pressure for well 7 SV**

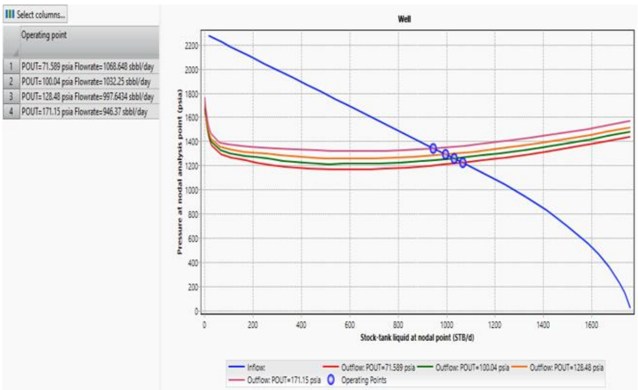

**Figure 16: Sensitivity on wellhead pressure for well 12RV**

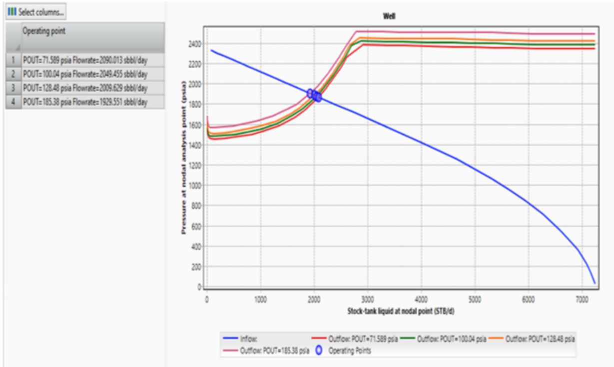

**Figure 17: Sensitivity on wellhead pressure for well 21KH**

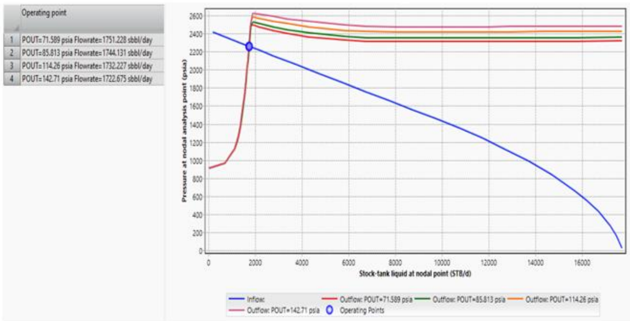

**Figure 18: Sensitivity on wellhead pressure for well 21SH**

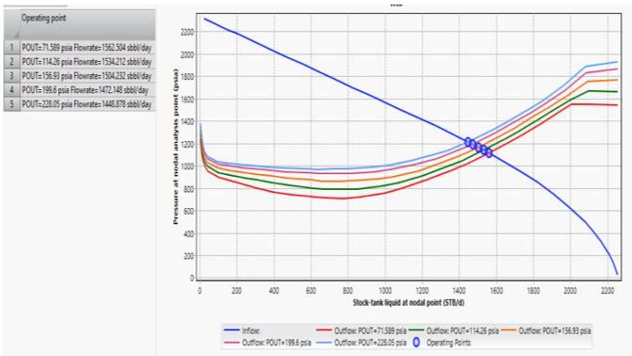

**Figure 19: Sensitivity on wellhead pressure for well 32KV**

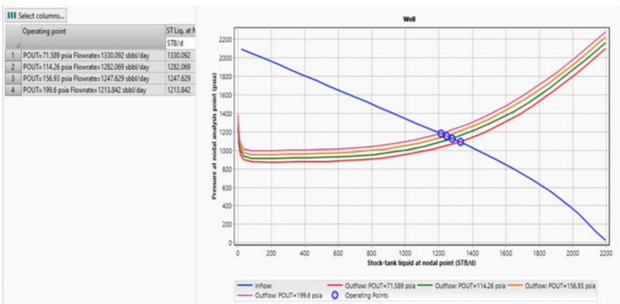

**Figure 20: Sensitivity on wellhead pressure for well 155KV**

ESP regulates the production rate by the operating frequency of electricity supplied to pump operation so this study suggests that the operating company can install one of the following devices to control the electricity to the pump and consequently change the frequency:

1- Variable frequency drive (VFD) device. The pump rate and pump power are proportional to the operating frequency. When the operating frequency of the pump increases, the pump rate and capacity will also increase.

2- Setting up a variable speed drive (VSD) with the submersible pump (ESP) on the wellhead to control the supply power to the motor and then control the frequency and the revolution per minute (RPM) of the pump (Schmehl et al. 2014).

Variable speed drives (VSDs) are used to control electrical ESP systems. They enable adjustments to be made to production parameters and ESP output when downhole conditions change. Increasing and decreasing motor speed may be used to optimize the pump performance, speed, or slow production, and avoid gas locking and system cycling. VSDs setting up have another advantage of protecting the pumps and motors by reducing electrical stress on startup and by adjusting to dynamic conditions as they change.

For this to be achieved, the operating company must use the appropriate method for each well according to the type of crude oil from the methods mentioned in the literature review (Section 2.5) to reduce the pressure drop in flow lines and thus lead to reducing the wellhead pressure for each well and consequently increasing the production rate.

## 4. Conclusions

From this study, the following conclusions may be drawn:
-The production rate increases when wellhead pressure decreases for the most tested wells.
-The wellhead Pressure can be decreased to the value that allows the fluid to flow through the flow line to process facilities.
-For ESP well, the production rate increases when ESP frequency increases and/or the number of stages increases.
-The change in ESP frequency differs from one well to another according to the well conditions and number of stages of ESP and the range between 55-65Hz.
-Some wells such as Well-21SH don't respond to changing pump frequency or the reduction of wellhead pressure may be due to any restrictions in well completion or organic or inorganic deposits.

**Acknowledgment**

We would like to thank colleagues who supported us.

**Abbreviations:**

AL: Artificial Lift.
API: American Petroleum Institute.
D: Darcy.
ESP: Electric Submersible Pump.
GL: Gas Lift.
GOR: Gas Oil Ratio (SCF/STB).
HJP: Hydraulic Jet Pump.
IPR: Inflow Performance Relationship.
IR: Percent in Increasing Flow Rate %.
P/T: Pressure (Psi)/Temperature (F°).
PCP: Progressing Cavity Pumps.
PI: Production Index (STB/day.psi).
PL: Plunger Lift.
Pr: Reservoir Pressure (psi).
PVT: Pressure, Volume and Temperature.
Pwf: Wellbore Flow Pressure (psi).
Qo(max): Max Oil Production Rate (STB/Day).
Qo: Oil Production Rate (STB/Day).
RPM: Revolution Per Minute.
SRP: Sucker Rod Pump.
SSSV: Subsurface Safety Valve.
TVD: Total Vertical Depth, ft.
VFD: Variable Frequency Drive.
VLP: Vertical Lift Performance.
VSD: Variable Speed Drive.
VSD: Variable Speed Drives.
WC: Water Cut %.
WHP: Well Head Pressure (Psi).

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