Revitalizing Heavy Oil Production: A Strategic Transition from Sucker Rod Pumps to Progressive Cavity Pumps

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Abstract

This research highlights the critical importance of the oil industry as a vital cornerstone of the global economy. It emphasizes the need for continuous improvements and innovation in oil production techniques to meet the increasing global energy demands. Oil is a key resource that fuels various industries, and its extraction and production require continuous refinement of processes. Pumps play a crucial role in oil production processes, making it essential to explore recent developments in pump technology, with a specific focus on progressive cavity pumps. These pumps represent a highly advanced and forward-thinking innovation that is gaining prominence in the oil and gas sector. The study compares progressive cavity pumps with traditional sucker rod pumps used in the Tishreen field where harsh conditions exist, such as heavy oil of 14 API with unconsolidated sand formation, using PIPESIM. The research findings unequivocally demonstrate that progressive cavity pumps outperform traditional sucker rod pumps both in terms of performance and economic efficiency. Progressive cavity pumps stand out because of their remarkable ability to effectively address challenges, such as managing high water-cut ratios and operating under low reservoir pressures while achieving greater efficiency at different production rates. However, the significance of progressive cavity pumps extends beyond superior performance. The study highlights the substantial economic benefits that arise from adopting these pumps. Replacing conventional sucker rod pumps with progressive cavity pumps has been shown to yield significant cost savings while also enhancing profitability within the oil production process.

Introduction

After well construction operations reach their final stages, production engineers assume responsibility for producing fluids. At the beginning of production, the reservoir pressure is sufficient to push the fluids from the formation to the surface using one of the drive mechanisms (water drive, gas drive, gravity drive, et al.), and then the fluids reach the separators to carry out the treatment operations for the produced oil. After a period of fluid production, the reservoir pressure begins to decrease to values at which it is not possible to push fluids to the surface. To improve the oil production process, one of the artificial lifting methods is used, including lifting using sucker rod pumps, progressive cavity pumps, submersible electric pumps, and gas lift, as these methods provide sufficient support to help convey fluids to the surface (Merey 2020; Takacs 2015). The working mechanism of these methods varies, as some rely on rotational movement to transport fluids, and others dependent on the up and down movement of the pump piston or focus on injecting gas into the tubing to reduce the weight of the liquid column and raised it to the surface (Fozao et al. 2015). In addition, each method of artificial lifting has pros and cons and conditions for applying this method. Choosing the appropriate lifting method for any well depends on several points, including depth and type of reservoir, pressure and temperature of the reservoir, GOR, WC%, viscosity and density of oil, and other important factors (Takacs 2015). This study

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will address applying progressive cavity pumps instead of sucker rod pumps used in the Tishreen oil field in terms of performance and the economic aspect of the replacement process.

Therefore, it is necessary to think carefully before choosing the appropriate lifting method to avoid repeated maintenance and repair operations and the additional economic cost resulting from the periodicity of these operations and the cost of lost production during shut shutdown of the well. Heavy oil with high viscosity represents the main problem that obstructs production operations, which requires special methods to deal with this oil and increase its production rate including thermal heating of wells, injecting fluids into the wells to reduce the viscosity of the oil, and other methods used to overcome this problem (Kantar et al. 1985). The burdens of the heavy oil production process and the economic cost associated with it increase when heavy oil is extracted from unconsolidated sand reservoirs, as the production of sand leads to its accumulation within the production pipes and the bottom of the well, thus causing damage to the subsurface equipment installed inside the wells. This then requires replacing this equipment and carrying out operations of wells washing to get rid of this sand that causes these damages and obstructions to flow and carrying out previous maintenance and repair operations requires a rig to raise the production string and replace the equipment, thus adding more economic burdens (Marchan et al. 2014; Del Pino et al. 2020). These problems and challenges require more research and studies in an attempt to overcome them. Therefore, in this study, we will simulate several scenarios to confront these challenges and work to mitigate their severity using the PIPESIM program to conduct the simulation process and show the results.

Sucker Rod Pump. About 85% of artificially lift wells in the United States are constructed with sucker rod pumping systems, which are the most common and ancient type of artificial lift for oil wells. This domination reaches parts of Canada and South America. Sucker rod pumps are the main source of power for wells, which make up around 80% of all oil wells. These figures, which reflect onshore activities and go back to about 1980, still highlight the rod pumping industry's continued dominance (Fozao et al. 2015). Sucker rod pumping systems are advised for new, low-volume wells because of their mechanical simplicity and the familiarity of the operational staff with them. Rod pumps are frequently easier for new employees to operate than other forms of artificial lift. These types of systems have the extra benefit of having a high value for repair and operating efficiency throughout a wide range of well-producing properties (Brown 1984; Moreno and Garriz 2020).

The American Petroleum Institute's standards were followed in the manufacturing of sucker rod pumping system components, guaranteeing reliability and compatibility among manufacturers. But for a longer equipment life, the system needs extensive corrosion protection because of ongoing fatigue, especially on the sucker rod string, pump components, and unanchored tubing.

Even while sucker rod pumping methods may not be compatible with wells that have severe dog-leg, they are not very good at lifting sand, and paraffin and scale can cause problems (Del Pino et al. 2020). A poor capacity for gas-liquid separation in the tubing-casing annulus might cause inefficient operation and concerns with gas lock. Even with possible inconveniences, shortcomings like leakage from the polished rod stuffing box in a beam pumping system may be minimized with careful design and operating considerations. It is essential to make sure the system is scaled according to well productivity and to minimize over-pumping without pump-off control (POC) to prevent mechanical damage and guarantee effective pump performance (Kaplan and Duygu 2014).

Major Components. **Figure 1** illustrates the major components in the sucker rod pumping systems, including 1) the prime mover, which provides power to the system; 2)the gear reducer, which reduces the speed of the prime mover to a suitable pumping speed; 3)the pumping unit, which translates the rotating motion of the gear reducer and prime mover into a reciprocating motion; 4)the sucker rod string, which is located inside the production tubing, and which transmits the reciprocating motion of the pumping unit to the subsurface pump; and 5) the subsurface pump.

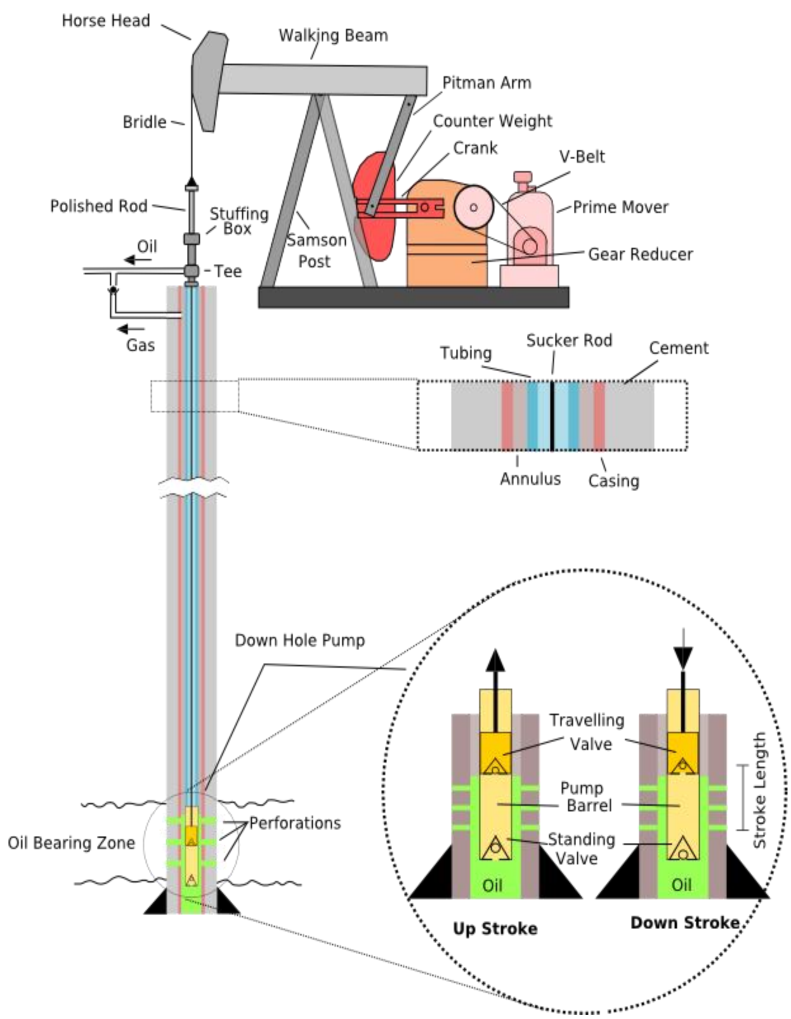

Figure 1—Sucker rod components and mechanism of work (Di Tullio and Marfella 2018).

The traveling valve is open on the right side of the picture during the downstroke of the plunger allowing fluid above the standing valve to rise. The traveling valve closes when the plunger hits the bottom of its stroke and starts to rise on the lift side. The working barrel's capacity increases as a result of the plunger lifting the fluid above it. When the pressure in the working barrel drops as a result of this upstroke movement and falls below the pressure going through the bottom hole, the standing valve opens. Formation fluids can now go higher as a result. During the whole cycle, the plunger lifts wellbore fluids up to one complete stroke length each time it moves higher.

Advantages and Limitations. The advantages of the sucker rod pumps include 1) Ease of operation: it is easily operated by engineers and technicians; 2) Versatility: it is effective in various conditions, including heavy oil and sand-laden environments but with some constraints; 3) Surface Accessibility: Many components are located on the surface, facilitating maintenance and component replacement; 4) Suitability for Deviated Wells: it can be used in deviated wells with the right components and assembly; 5) Diverse Types: it offers over three different types, providing a wide range of options and adaptability.

The limitations include 1) Pumping Rods Interruptions: Frequent interruptions due to expansion and contraction forces during the up-and-down strokes caused by oil viscosity and liquid column weight; 2) Lower Production Rate: Relatively low production rates compared to other methods; 3) Gas-Lock Possibility Susceptibility to gas-lock phenomenon (Allison et al. 2018); 4) High Installation Costs Installation operations can be expensive.; 6) Lengthy Maintenance and Repair Time Maintenance and repair operations require a relatively long duration.

Progressive Cavity Pump. The Progressive Cavity Pump (PCP) was developed in 1932 by René Moineau and Robert Bienaimé, and it has since revolutionized the oil production industry (Klein 2002). The PCP is distinguished by its distinct positive displacement mechanism, which is the result of clever engineering and has helped it advance oil extraction technology. The two primary parts of the PCP are the double internal helical elastomer-lined stator and the helical rotor (**Figure 2**). Made of sturdy steel, the helical rotor revolves inside the stator coated with elastomers, generating a dynamic system of increasing cavities. This complex relationship between the rotor and stator is the basis of the PCP's operating concept (Delpassand 1997). The helical shape makes it easier for cavities to develop between the two parts when the rotor rotates within the stator. These voids function as separate pockets that gradually fill with liquid. In particular, heavy and viscous oils may be easily lifted and transported to the surface by the PCP thanks to its coordinated rotation and cavity creation. The PCP is unique among pumping systems in that it uses a positive displacement mechanism, which makes it particularly useful for extracting unconventional oil deposits (Alfaqih et al. 2017). The introduction of the PCP solved the problems of conventional pumping techniques in difficult reservoirs, which resulted in a paradigm change in the oil and gas sector. It is a vital instrument for increasing production rates and cutting operating expenses because of its versatility in handling different well conditions and fluids with a high solid content. One essential part of the PCP that improves its efficiency and flexibility is the elastomer-lined stator. Because of their adaptability and durability, elastomers produce a sealing effect that keeps fluid from slipping and guarantees a good lift as the pump rotates (Enríquez-Méndez et al. 2015). This functionality is especially helpful in situations when conventional pumping systems could malfunction, including when removing abrasive or heavy fluids.

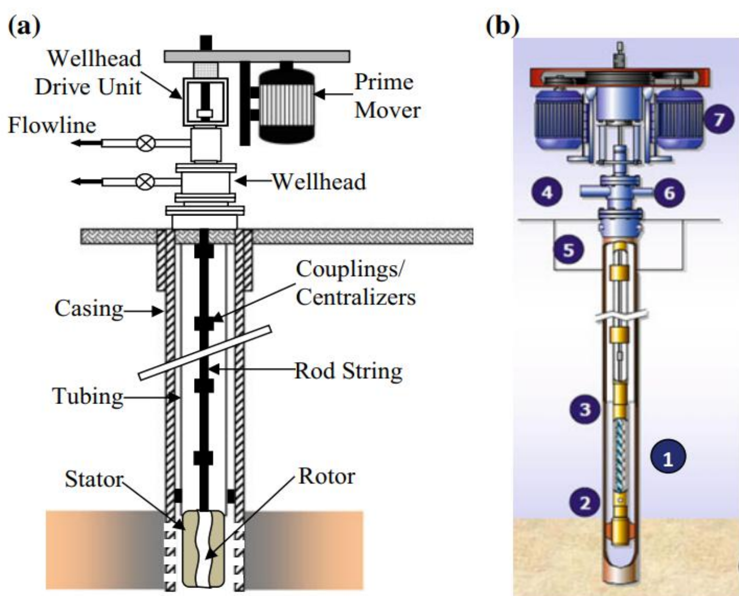

Figure 2—Surface and downhole assemblies of PC pump (Mills and Gaymard 2007).

Advantages and Limitations. PCP systems present cost savings, offering the same pump capacity at a lower capital cost compared to traditional pumps. They excel in conditions where other artificial lift systems struggle, especially when dealing with heavy oil (Lehman 2004). There’s no need for expensive foundations, and their construction is straightforward and adaptable to various wellhead configurations. Installation is both fast and dependable, reducing rig mobilization expenses. PCPs deliver cost-effective operations with extended lifespans and lower power consumption and maintenance demands compared to alternative artificial lift systems. The impressive volumetric and mechanical efficiency of PCP systems enhances field production while reducing energy requirements (Klein 2002). **Table 1** summarized and compared the advantages and disadvantages between sucker rod and progressive cavity pumps.

Table 1—Comparison between sucker rod and progressive cavity pump.

Sucker Rod Pump (SRP)		Progressive Cavity Pump (PCP)	
Advantage	**Disadvantage**	**Advantage**	**Disadvantage**
Simple design	Deviated Wells	Low Cost	Deviated Wells
Easy installation	High Solid Content	High Viscous Fluids	Sensitivity to Fluid Environment
Low-Pressure Wells	Limited Production Rate	Large Concentration of Solids	Limited Production Rate
High Temperature and High Viscous Oil	Gassy Wells	Toleration of Free Gas	Limited Temperature
Widely Availability in Different Sizes	Depth Limitation	No Valve Problems	Depth Limitation
Flexible	Paraffin Problems	High Efficiency	Corrosion Handling

Tishreen Field

The Tishreen Field in Syria was operated by the Syrian Petroleum Company (SPC) and is located approximately 65 km southeast of Deir Ezzor city (**Figure 3**). It is a significant accumulation of heavy oil containing 50 wells, of which 41 are presently producing oil with an average of 14 ° API. The field employs a water drive production mechanism, and a decline analysis conducted in multiple areas of the field indicates that the average annual decline rate is approximately 6%. The reservoir is made up of unconsolidated sand, which forms permeable networks for the transportation of fluids from the reservoir to the well. However, the production of water has increased lately, and some wells have up to 92% water content. Therefore, SPC has taken measures such as conducting cement plugs and changing perforation locations to prevent water from creeping towards the wells. The high-water content, high sand content, and high oil viscosity are the main issues facing the Tishreen Oil Field, causing a decrease in oil production and maintenance and work-over operations. These problems are due to the production of large quantities of water and the failure of surface units, such as engine burnout and gear problems. Moreover, subsurface units face problems like the piston becoming stuck due to the presence of sand. In 2011, SPC started a project to replace sucker rod pumps with the Installation of progressing cavity pumps. Unfortunately, the project stopped, so an experimental study will be conducted to replace the SRP with PCP.

Problem Statement. Sucker rod pumping (SRP) was employed at the Tishreen oil field to produce hydrocarbon storage, which is primarily composed of sand. The sand created results in issues and malfunctions with the sucker rod pump, necessitating frequent replacements with new pumps throughout the year. To make the production more economically viable, this study aims to raise the rate of oil production by substituting a sucker rod pump with a progressive cavity pump and to decrease the quantity of sand that enters the pump by employing a gravel pack. The objectives of this study consist of the following sub-objectives, 1) To compare the efficiency of the sucker rod pump with the PC Pump with/without the Gravel pack, 2) To Estimate PC pump efficiency at pressure drops and different water cuts and high speed; 3) To Conduct an economical comparison between SRP/PCP.

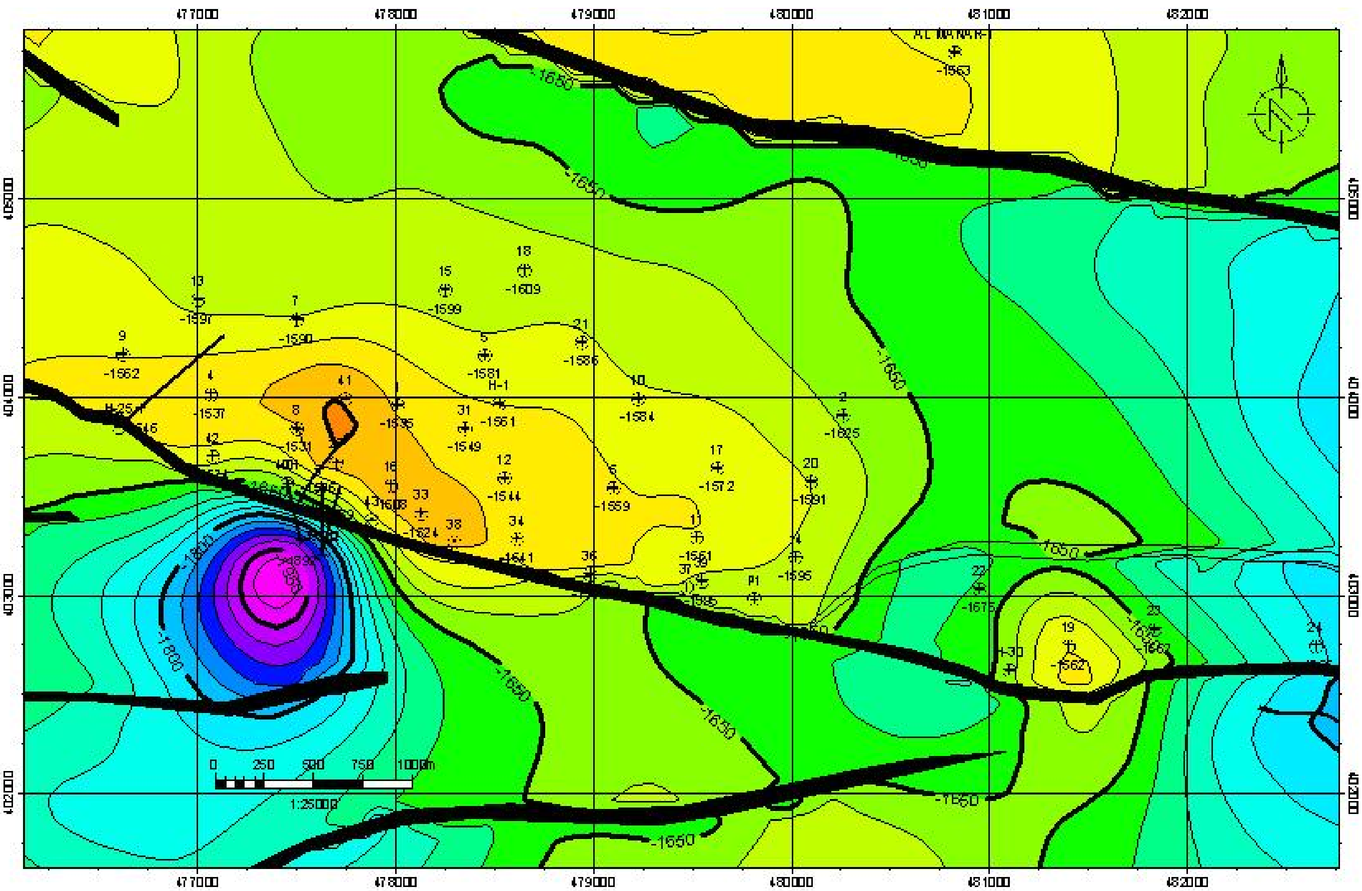

Figure 3—Structural map of Tishreen field with the location of the wells.

Case study

The change from conventional SRP systems to PCP artificial systems represented a revolutionary change in oil production in Colombia's Teca and Nare Oil Fields. PCP technology was used because of the difficulties in handling heavy crude oil (12 API), high viscosity (12000 cp), and a production rate of 250 bbl/day. Additionally, the inherent problems of sand sticking and rod failures in SRP structures were the main contributing factors. The change greatly increased operating efficiency, especially when it came to handling the challenges brought on by the crude oil's high viscosity. The switch to PCP systems not only improved oil extraction but also resulted in significant cost savings by lowering energy usage and well downtime. In these locations, PCP systems showed extraordinary adaptation to the unique viscosity properties of the oil, exhibiting a noteworthy 78-88% energy reduction over the preceding SRP (Ramirez et al. 2007).

Tables 2 and **3** provide essential parameters, including those related to reservoir characteristics, equipment specifications, and production rates, among others, illustrating the comprehensive nature of the data and offering valuable insights into the field's operational dynamics, including reservoir temperature (158 °F), oil viscosity (100 cp), reservoir thickness (150 ft), casing size (7 inches), tubing size (4 ½ inches), and production rates (288 bbl/d for liquid and 204 bbl/d for oil with sucker rod pump), contribute crucial insights for understanding and addressing these challenges. By leveraging this data and optimizing production techniques, SPC aims to enhance the long-term productivity and sustainability of the Tishreen Oil Field.

Table 2—Data of Tishreen field.

Parameters	Value
Reservoir pressure	2000 psi
Oil viscosity@ reservoir temp	100 cp
Reservoir temperature	158 °F
Oil gravity	14 API
Water cut	29 %
Gas-oil ratio	0
Reservoir thickness	150 ft
Borehole diameter	8.5 in
Reservoir permeability	300 mD
Drainage radius	1500 ft

Table 3—Data of Tishreen-well 3.

Parameters	Value
Casing length	4888 ft
Tubing length	3280 ft
Casing size	7 inches
Tubing size	4 ½ inches
Perforation	3930 ft
Liquid pro/SRP	288 bbl/d
Oil pro/SRP	204 bbl/d
PCP type	42 K 1200
RPM	150-300

PIPESIM Program. For modeling and simulating multiphase flow in oil and gas production systems, Schlumberger released a commercial software, PIPESIM, a flexible piece of software. It carries out duties such as fluid flow simulation, analysis of pressure drops, forecasting the formation of hydrates and wax, production system optimization, well performance evaluation, and flow assurance concerns resolution. Engineers may maximize hydrocarbon recovery and reduce operational expenses by using PIPESIM to assist them in making informed decisions about the design and use of production systems. For the oil and gas sector, it is a useful instrument to guarantee reliable and effective production operations. PIPESIM is utilized in this case study to perform Nodal analysis profiles, (pressure/temperature) profiles, and model PC pump efficiency with and without gravel pack mechanism.

Result Analysis

Simulation Of PCPs. Modeling wells in PIPESIM involves a comprehensive series of stages. Within these stages, crucial factors were considered. These encompass identifying the well type (production or injection), determining well deviation, specifying depths and dimensions of casing and tubing, taking into account formation temperature, reservoir pressure, and downhole equipment such Additionally, perforation places, fluid properties, surface equipment, including chokes.

In this study, the 42 K 1200 progressive cavity pump was selected (**Figure 4**). This choice was made because it meets the requirements of our wells. After inputting parameters and designing the wells, we perform a Nodal analysis for the well to assess its condition and pre-existing issues.

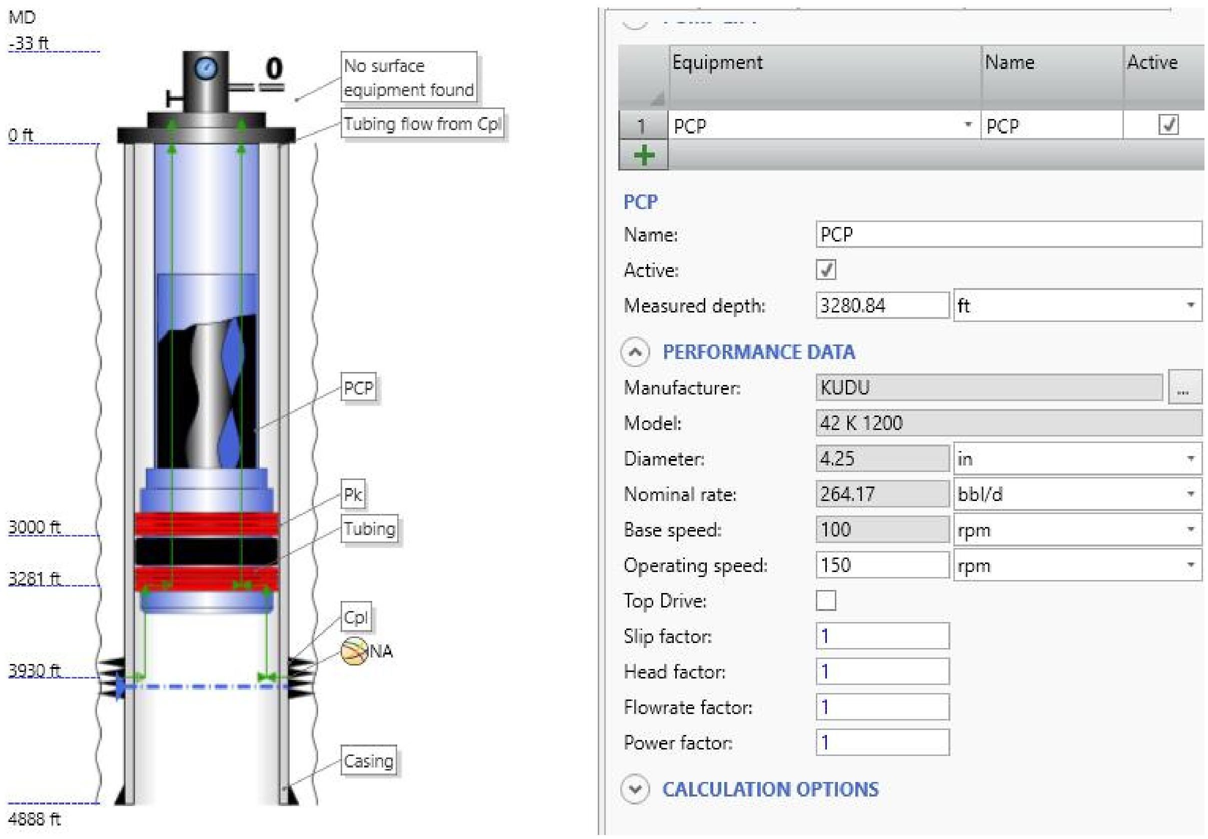

Figure 4—Progressive cavity pump simulation using PIPESIM.

In the oil and gas sector, nodal analysis is an essential and modern method that enables engineers to accurately evaluate pressure decreases at different nodes in the production system. It is possible to accurately compute pressure differences from the bottom hole to surface separation units by altering factors like as pipe diameter, pressure, and temperature (Mahmud and Abdullah 2017). This optimizes the production from current wells cost-effectively and efficiently. The intersection of the Inflow Performance (IPR) and Outflow Performance (OPR) curves (**Figure 5**), which aim to maximize hydrocarbon output while reducing operating expenses within budgetary limitations, was where conclusions regarding petroleum production was based (Hashmet et al. 2012). Traditional nodal analysis, however, has drawbacks since it is static and ignores time-dependent variables and Inflow Performance Relationship (IPR) models in shale gas wells. Furthermore, multi-well interference was ignored. Analytical and numerical models were being developed to solve these problems (Zhou et al. 2016). Finding a location in the production well, segmenting the system, and figuring out pressures in both directions are all steps in the Nodal analysis procedure (Shah and Hossain 2015).

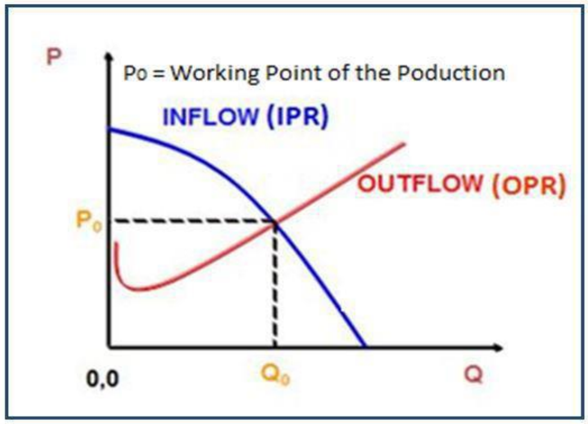

Figure 5—Intersection of IPR and VLP (Igwilo et al. 2018).

Enhancing oil production processes is crucial for the oil and gas industry to reduce operational and maintenance costs while increasing overall oil production, ensuring profitability and meeting global market demands. To maximize these improvements, effective planning is essential to ensure efficiency and cost-effectiveness. Data analysis plays a key role in identifying areas for enhancement, requiring swift implementation of necessary changes. Staying updated with the latest technologies is equally vital to maintain peak efficiency. Finally, the implementation of oil production improvements should be carried out diligently, with adequate time and attention devoted to execution (Shah and Hossain 2015). Optimizing oil and gas production from a wellbore involves meticulous consideration of various parameters such as tubing diameter, wellhead pressure, choke type and size, surrounding area density, and perforation configuration (Igwilo et al. 2018).

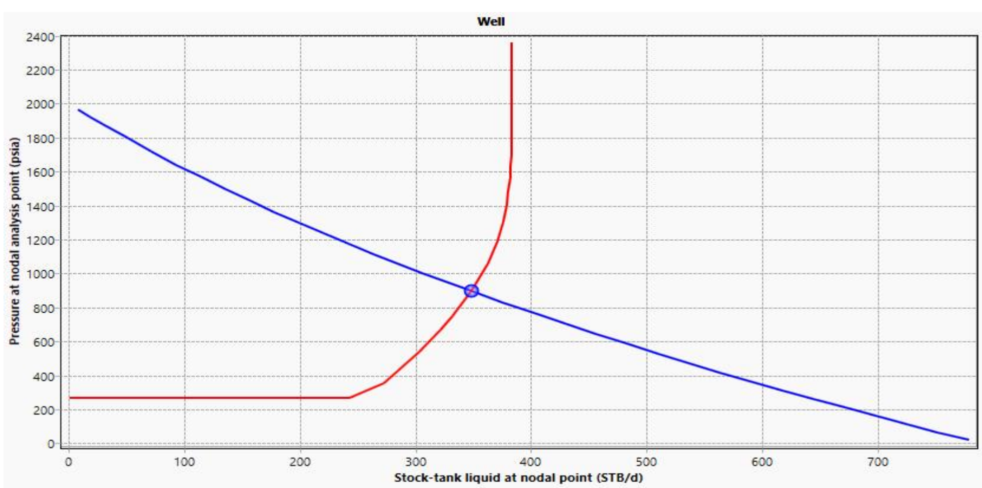

Figure 6—Nodal analysis (operation point).

When comparing pressure and flow rate, two curves will be plotted (**Figure 6**). The point where these curves intersect will meet two criteria: 1) the flow into the node will be equal to the flow out of it, and 2) there will only be one pressure present at the node. This is because the pressure drop in any component varies with the flow rate. The node in the bottom hole has been selected to measure the pressure in this instance. A lower pressure in the bottom hole will result in a higher efficiency of the PC pump (**Table 4**).

Table 4—Oil production rate using PCP without gravel pack.

Item	Liquid production, bbl/day	Pressure at NA	Oil production, bbl/day	Efficiency, %
Speed = 150 RPM	348	894	247	74

Simulation Of PCPs with Gravel Pack. The gravel pack technique is extensively utilized for sand-control purposes. It allows only very small particles to pass through, while simultaneously stabilizing the borehole and filtering out sand from the liquid (**Table 5**). By making full use of gravel packs and pre-packed wire-wrapped sand screens, sand control can be optimized, thereby maximizing productivity (**Figure 7**).

Table 5—Properties of a gravel pack.

Permeability	120000 mD
Screen Diameter	4 in
Tunnel	10 in

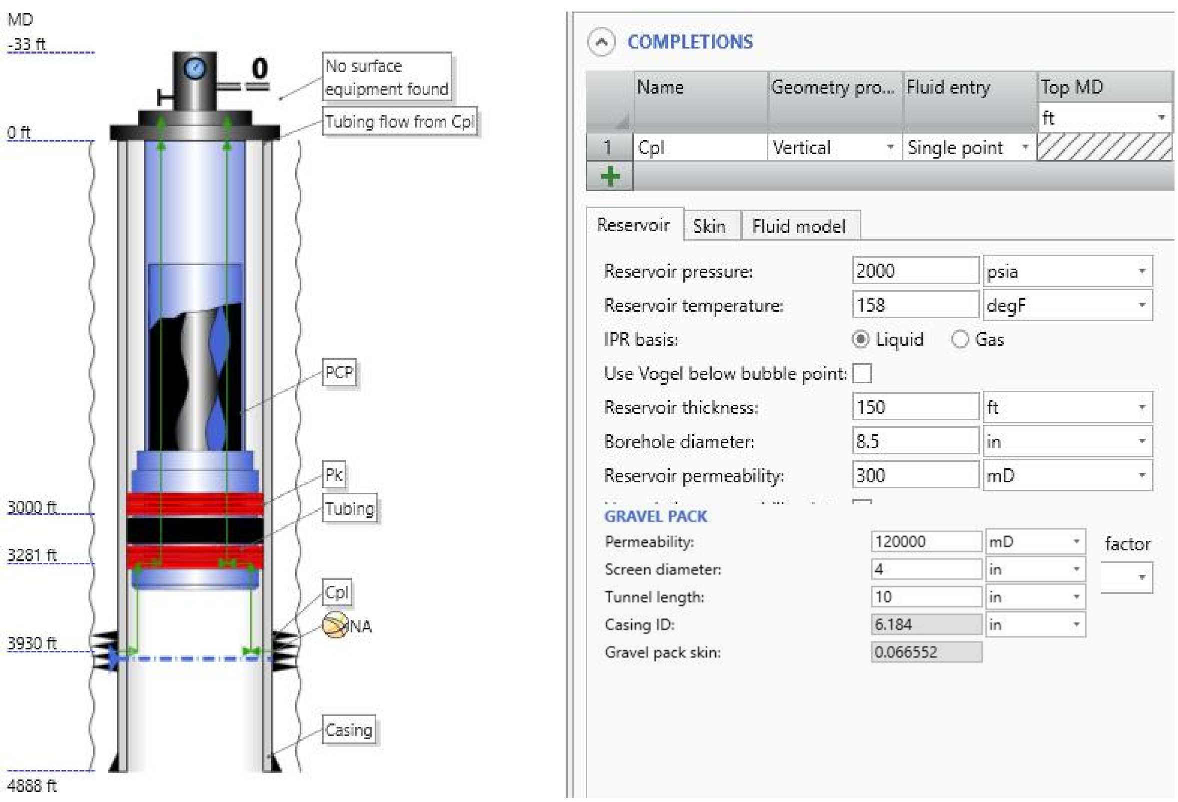

Figure 7—Simulation PCP with gravel pack.

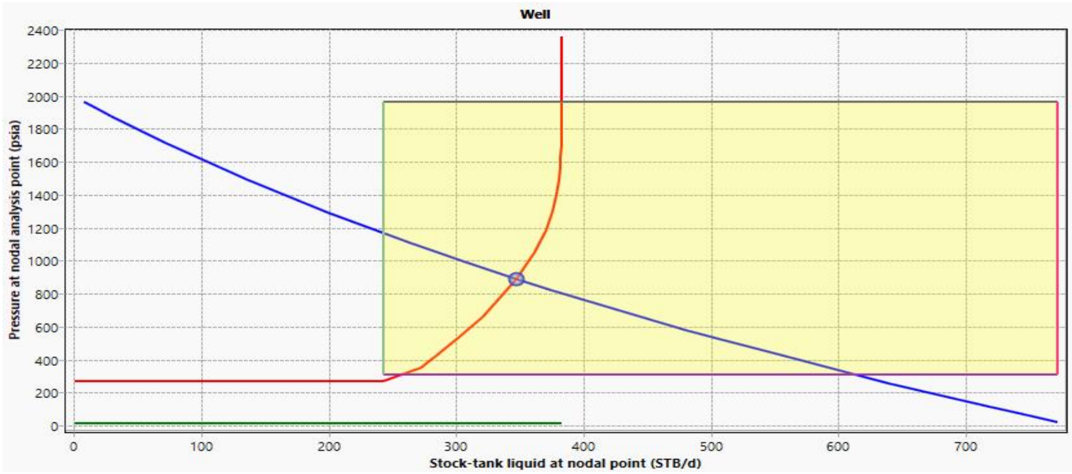

Figure 8—Nodal analysis (IPR versus VLP).

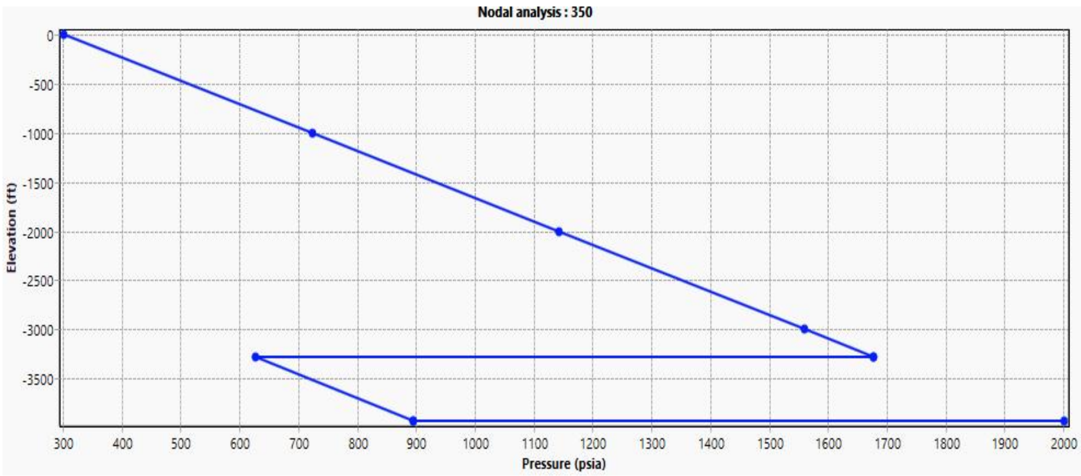

Figure 9—Nodal analysis profile.

When the inflow reservoir pressure increases, the flow rate will also increase accordingly (**Figure 8**). The pressure and temperature are directly proportional, meaning that their ratio remains constant. Elevation is closely associated with temperature and pressure (**Figure 9**). Higher temperatures can negatively impact the stator and elastomer's performance and reduce the efficiency of the PC pump.

Table 6—Oil production rate at PCP with gravel pack.

Item	Liquid production, bbl/day	Pressure at NA	Oil production, bbl/day	Efficiency %
Speed = 150 RPM	347	888	246	73.4

Table 6 at a pump speed of 150 RPM, the system achieves a liquid production rate of 347 bbl/day, an oil production rate of 246 bbl/day, with a pressure at the nozzle of 888 units, and an efficiency of 73.4%. These values provide insights into the performance and productivity of the pumping system under specific operating conditions. It was observed that there were only slight changes in the flow rates and efficiency of the well without a gravel pack as compared to the well with a gravel pack. It was observed that there were only slight changes in the flow rates and efficiency of the well without a gravel pack as compared to the well with a gravel pack (**Table 7**). However, it is necessary to use a gravel pack to limit the amount of sand produced with oil.

This helps in reducing the damage caused by sand accumulation inside the tubing and ultimately results in reduced maintenance costs and work-over operations. Such operations could include replacing subsurface equipment or performing well-washing operations to reduce the sand content.

Table 7—Compare the production rate of SRP/PCP.

SRP		PCP with Gravel pack	
Liquid, STB/D	Oil, STB/D	Liquid, STB/D	Oil, STB/D
288	204	347	246

Pressure and Temperature with Gravel Pack Results (Permeability Sensitive). Increased permeability of gravel packing directly impacts flow rate. As permeability increases, the efficiency of PCP operation also increases (**Figure 10**).

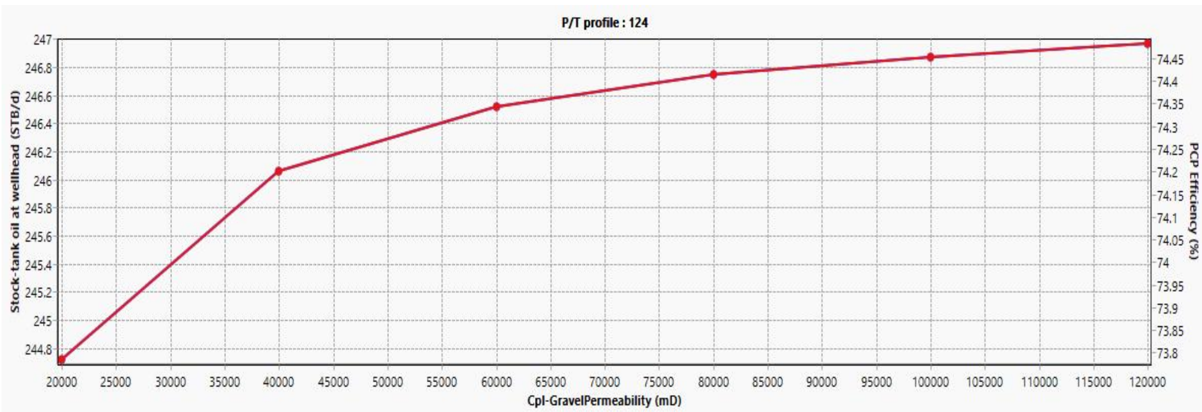

Figure 10—Oil production and efficiency at different permeability of the gravel pack.

Table 8—Efficiency with the permeability of gravel pack.

GP permeability, mD	20000	40000	60000	80000	100000	120000
Oil flow rate, stb/d	244.8	246.5	246.1	246.5	246.8	247
Efficiency, %	73.8	74.2	74.3	74.4	74.5	75

Sensitive of the Water Cut. The results of simulations of production rates at different water cuts showed a significant superiority of progressive cavity units against sucker rod units, which showed a significant decrease in the production rate with an increase in the water cut (**Figure 11**). This can be explained by the high efficiency of the progressive cavity pumps in dealing with high water rates and the great ability of these pumps to maintain the production system is stable and does not suffer from the turbulent flow that causes the production group to vibrate and thus go out of service over time as a result of interruptions in the pumping rods (**Figure 12**).

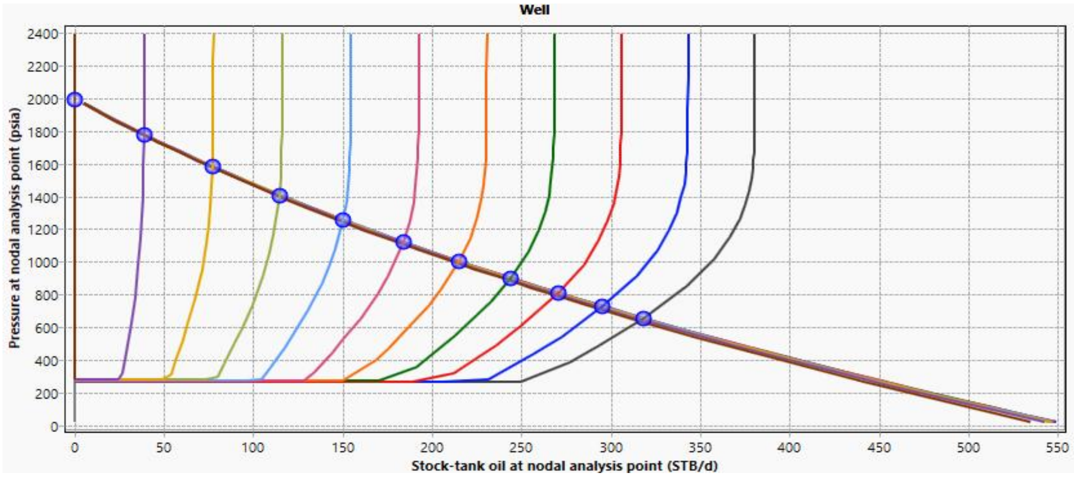

Figure 11—Nodal analysis (water cut sensitive).

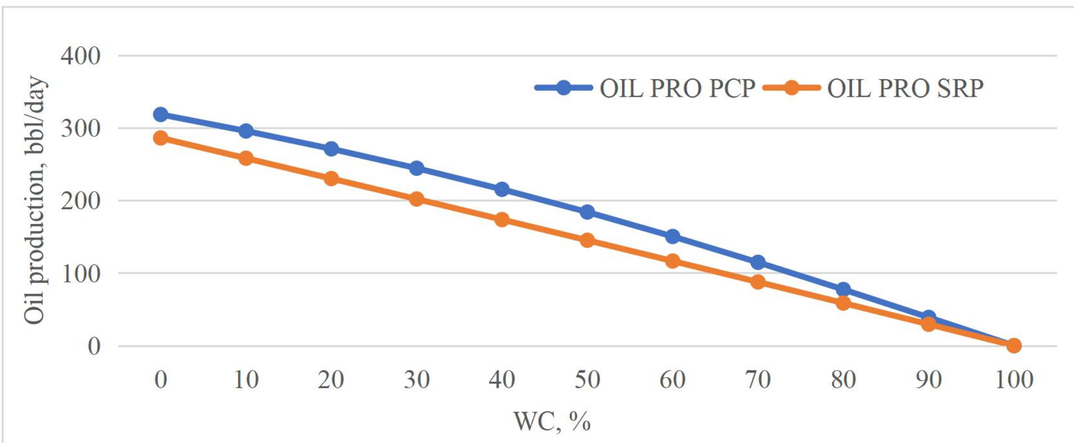

Figure 12—Oil production of SRP/PCP at water cut.

Pressure Drops Sensitive of PCP. The production rates of different water cuts were simulated and it was found that progressive cavity units were significantly better than sucker rod units. Sucker rod units showed a considerable decrease in production rate as the water cut increased (**Figure 13**). This can be attributed to the high efficiency of progressive cavity pumps in dealing with high water rates and their great ability to maintain a stable production system (**Figure 14**). They do not suffer from turbulent flow, which causes the production group to vibrate and eventually go out of service due to interruptions in the pumping rods.

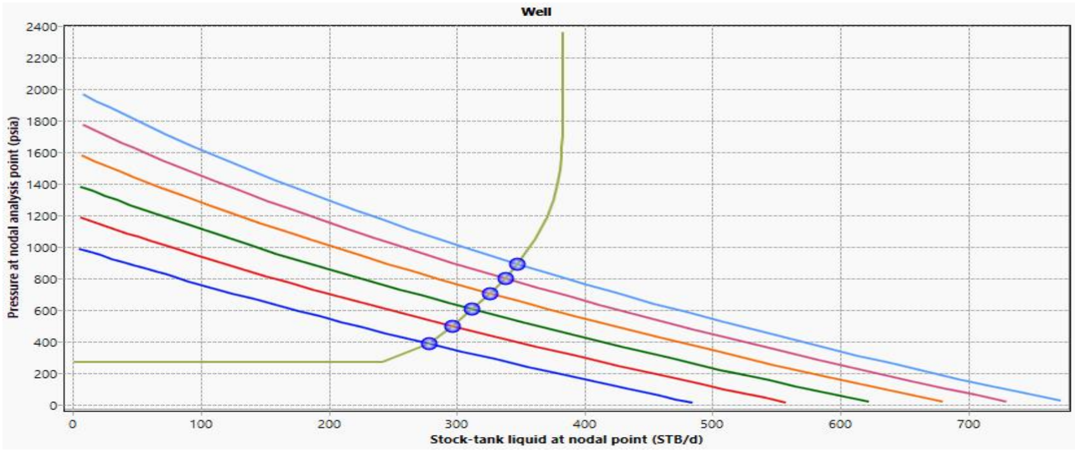

Figure 13—Nodal analysis (pressure drop sensitive).

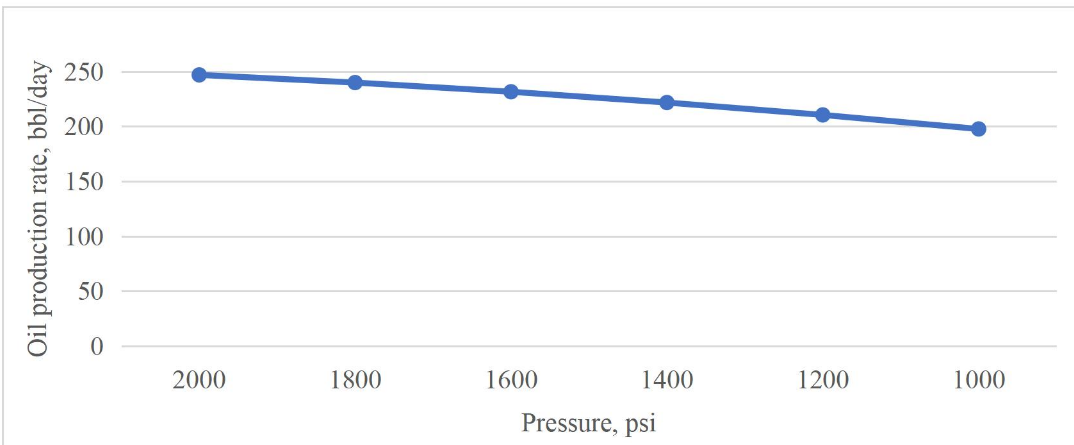

Figure 14—Oil production rates of PCP at pressure drops.

Speed Sensitive of PCP. It has been observed that by utilizing gravel packs with pump speed as sensitive data, the flow rate and efficiency increase from 50 RPM to 250 RPM. However, above a certain speed, the flow rate and PCP efficiency decrease, indicating that the system is in ill condition (**Figure 15**). Additionally, increasing the rotation speed of the PCP from 50 RPM to 300 RPM results in an increase in production rate from 90 BBL to 450 BBL (**Figure 16**). However, this increase in production rate is accompanied by a decrease in efficiency from 81.77% to 67.89% at a rotation speed of 300 RPM (**Figure 17** and **Table 9**). It should be noted that 300 RPM is considered one of the prohibited speeds that must not be applied, as illustrated in **Figure 18**.

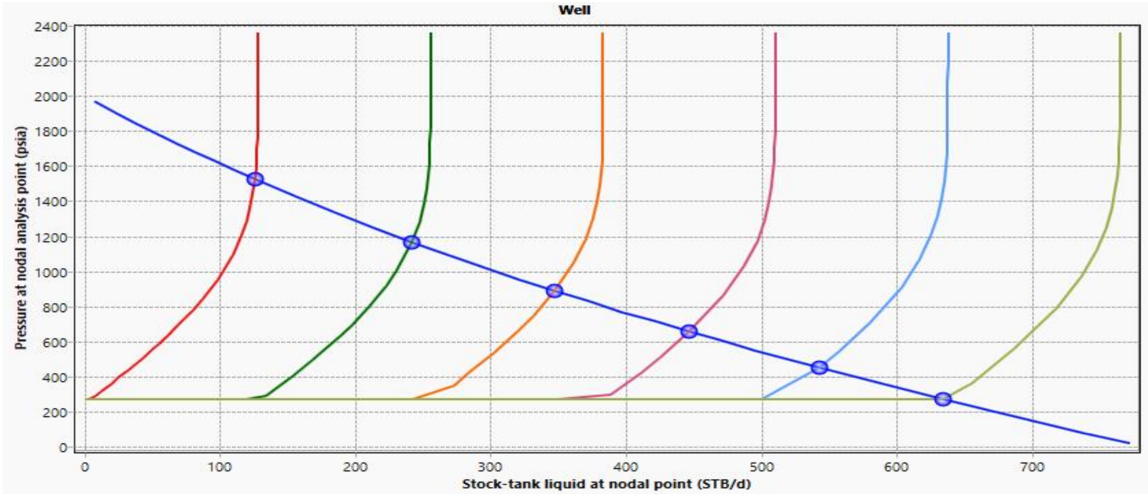

Figure 15—Nodal analysis (speed profile).

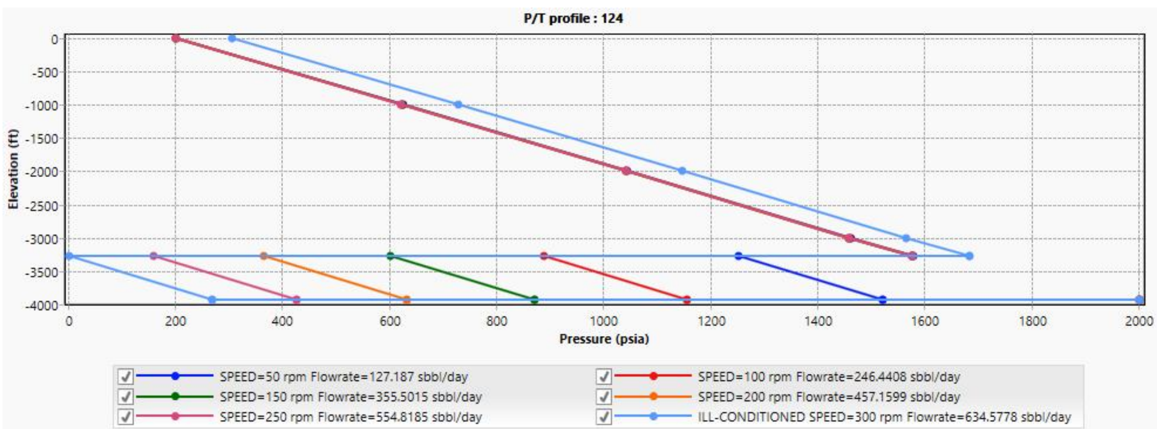

Figure 16—P/T profile at different speeds of PCP .

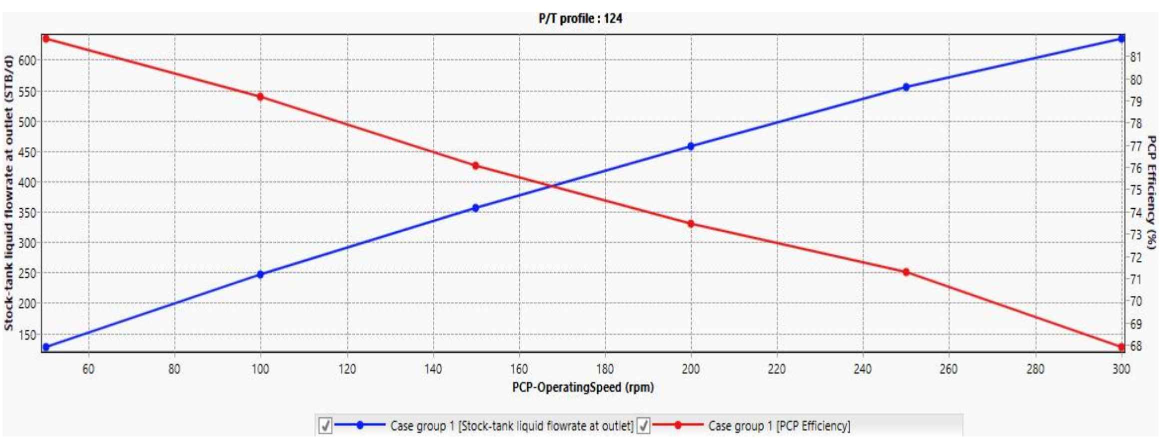

Figure 17—Liquid production versus PCP efficiency.

Table 9—Production of PCP at a different speed.

Speed, rpm	System DP, psi	Liquid, stb/d	Oil, stb/d	Water, stb/d	Efficiency, %
50 rpm	1799.024	127.187	90.30278	36.88423	81.77261
100 rpm	1800.04	246.4408	174.973	71.46783	79.17566
150 rpm	1799.732	355.5015	252.4061	103.0954	76.0468
200 rpm	1800.144	457.1599	324.5835	132.5764	73.42209
250 rpm	1799.868	554.8185	393.9211	160.8974	71.27541
300 rpm (Ill-conditioned)	1693.902	634.5778	450.5502	184.0276	67.89398

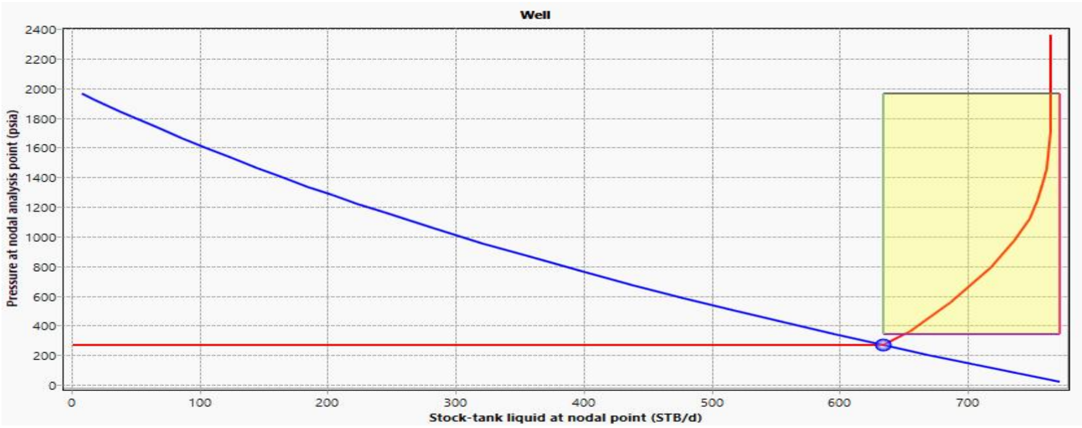

Figure 18—Nodal analysis (ill condition).

In this well, it is impossible to use the progressive cavity pump at a speed of 300 RPM, as this speed exceeds the pump's performance square (yellow square) at the lower and right sides, which represents the permissible limit for fluid withdrawal. Applying this value of speed accelerates the process of the production system getting out of stability as a result of the vibrations accompanying the rotation process. Thus, interruptions occur in the pumping rods.

Economic Evaluation

The decision-making process of introducing new technologies into the oil and gas business revolves around economic appraisal. The primary goal of calculating possible financial savings entails a thorough analysis comparing the outcomes obtained using the new technology to those obtained using the previous approach. This assessment procedure takes into account several significant factors as follows, each of which contributes to a comprehensive evaluation of the technology's economic viability and overall cost-effectiveness.

1. Fixed capital expenses: This category includes both surface- and underground-based assets that were purchased as original investments. The initial outlay of fixed capital expenses is necessary for establishing the new technology.
2. Installation expenses: The process of putting new technology into use frequently has accompanying installation costs. These expenses are required to incorporate the technology into the current operational or infrastructure architecture.

3. Operational expenses: There are ongoing operational costs to take into account after the device is installed. These costs cover everything needed to run and maintain the technology daily, including labor, supplies, and regular servicing.
4. Costs of energy: Energy consumption is a crucial factor in the oil and gas sector. For a thorough economic analysis, it is essential to examine the new technology's energy needs and associated expenses.
5. Number of wells: The number of wells to which the new technology will be applied must be determined. The overall economic impact is directly influenced by the implementation's scale.
6. Production rate: A crucial factor is the production rate of the involved wells. Economic evaluation requires an understanding of how technology impacts daily production rates and, in turn, the revenue earned.
7. Costs for maintenance and make-goods: The operating costs also include ongoing maintenance and potential work-over procedures. These expenses play a crucial role in the economic evaluation since they affect the technology's long-term viability and profitability.

However, before implementing new technology in the oil and gas industry, completing a full economic review while taking these crucial factors into account is essential. Decision-makers can use it to evaluate the technology's prospective economic benefits, cost savings, and general viability, ensuring that investments are made properly and that the sector continues to develop effectively and sustainably.

Equipment and Operating Requirements. The economic feasibility study covers ten years and involves ten wells with a production rate of 5000 barrels per day (bbl/day) of oil, and the cost represent approximately values and estimated in dollars (**Table 10**).

Table 10—Cost of the equipment and operating requirements.

Capital Costs	PCP, $	SRP, $	Savings, $	Savings, %
Equipment description				
Capital Investment	60,000	124,000	64,000	51.60
Installation Costs	11,375	34,125	22,750	66.67
Total,$	86,750			
Operation Cost				
Power Consumption	43,362	56,370	13,008	23.1
Gas Locking	0	1,896	1,896	100
Preventative Maintenance	614	3,148	2,534	80.5
Yearly Total	43,976	61,414	17,438	28.4
10-year Total	439,760	614,140	174,380	28.4
Total savings *	$104,188			39.9
Total savings**	$261,130			10
Total savings***	$2,611,300			

*After 1-year operation;**In a 10-year life cycle of the well. Assuming no equipment changes; ***Assuming that there are 10 wells.

Table 11—Cost details of SRP/PCP.

Comments	PCP	SRP	Savings
Capital Investment	Includes the drive head, motor, VFD, and pump. Excludes rods and tubing.	Includes the pump Jack, pad, piles, and downhole pump. Excludes rods and tubing.	
Installation Costs	Installation time of the PCP system is 1 day. The cost of lost production at the volume is $11,375 per day.	The average installation time is 3 days (1-day pad piles, 1-day jack install, 1-day pump install)	1-2 Days
Power Consumption	Annual power consumption: 481,800 kWh @$0.09/kWh. Assuming 100% uptime of equipment.	Annual power consumption: 626,340 kWh @$0.09/kWh. Assuming 100% uptime of equipment.	144,540 kWh
Gas Locking	0 hrs. The PCP will not gas lock as the gas is free to pas s through the pump.	2x/year @ 2hr each. The amount of time it will take to put the well on tap, remove all gas built up in the pump, and take the well off tap. The cost of lost production is $474/hour of downtime. (* A well with excessive gas will need more.)	4 hours per year
Preventative Maintenance	Oil change & grease	Oil change & grease	
	1 hr. labor*, $125/hr. $474 lost production * Labor rates vary	1 hr. labour including a VAC truck, $200/hr. $474 lost production.	1 hour
	1.5 gallons of oil@ $10/gallon* *Prices of oil may vary	750 gallons of oil @ $10/gallon.	178.5 gallons

Maintenance and Work-over Costs. These maintenance and repair costs need to be considered in the overall economic evaluation of the project. From **Table 12**, it is evident that covering 40% of the costs for SRP enabled the implementation of PCP in the Tishreen field, achieving equivalent production rates. Furthermore, it took only 158 days to recover the total costs for the progressive cavity pumps.

Table 12—Maintenance and workover costs.

Item	PCP, $	SRP, $	Saving, $	Saving, %
Equipment and Operation	1,153,510	2,195,390	1,041,880	47.45
Work-over cost	49,350,000	82,250,000	32,900,000	86.4
Cost of lost production	7,770,000	12,950,000	5,180,000	13.6
Total	58,273,510	97,395,390	39,121,880	40.17

The Period Required to Recover Costs. PCP systems have a faster cost recovery time of 158 days, compared to SRP systems which require 264 days for cost recovery (**Figure 19**). The total costs encompass the sum of expenses associated with equipment, operating requirements, maintenance, and repair operations. **Table 13** and **Figure 20** provide a comprehensive overview of the financial aspects involved in the project evaluation .

Figure 19—Time required to recovery the cost.

Table 13—Saving costs analysis.

Item	Saving, $	Saving, %
Equipment and Operation	1,041,880	2.7
Work-over cost	32,900,000	84
Cost of lost production	5,180,000	13.3
Total	39,121,880	

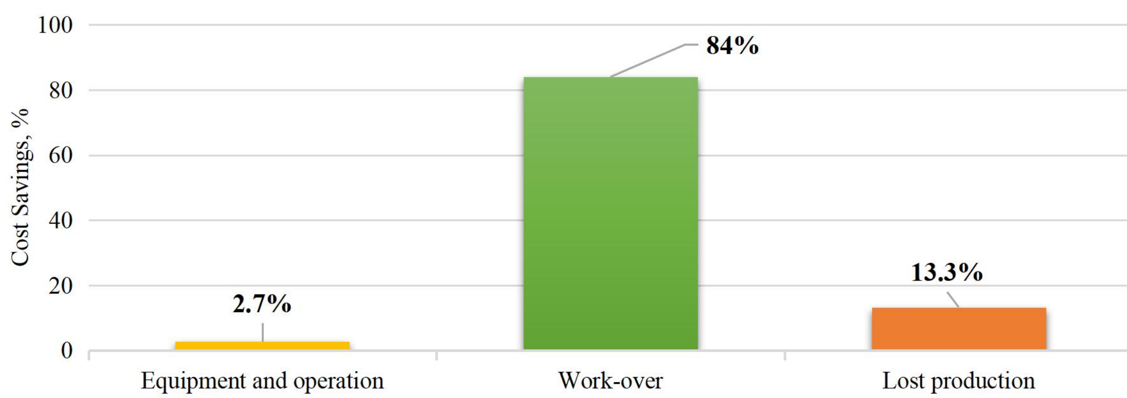

Figure 20—Saving details.

Conclusions

The investigation in Tishreen was aimed at analyzing the performance of a PCP and improving it against sand effect and premature failure. To achieve this, PIPESIM software was used to compare the effectiveness of the pump with and without a gravel pack. The study concludes that gravel packs can help preserve PC pump efficiency and prevent premature failure. Based on previous results, here are the conclusions about switching from SRP to PCP:

1. The use of gravel packs did not significantly affect the flow rates and efficiencies of PCP.
2. At high speed, there were some ill conditions with the use of a PCP with gravel pack at speed sensitives.
3. PCP systems have a faster cost recovery time of 158 days, compared to SRP systems which require 264 days for cost recovery.
4. PCP systems offer cost savings right from the start, with lower capital costs for equipment and installation compared to SRP systems.

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Conflicting Interests

The authors declare that they have no conflicting interests.

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