T H E U N I V E R S I T Y O F T U L S A

THE GRADUATE SCHOOL

ARTIFICIAL LIFT APPLICATIONS TO UNCONVENTIONAL RESERVOIRS

by
Sai Praveen Adiraju

A thesis submitted in partial fulfillment of

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A THESIS

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ABSTRACT

Sai Praveen Adiraju (Master of Science in Petroleum Engineering)

Artificial Lift Applications to Unconventional Reservoirs

Directed by Drs. Hong-Quan (Holden) Zhang and Haiwen Zhu

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Unconventional reservoirs are hydrocarbon-bearing formations with low permeability and porosity consisting of complex geological formations. Hydrocarbons in these formations were formed within the rock and never migrated, whereas conventional reservoirs have porous rock formation that contains hydrocarbons that have migrated from the source rock. The unique challenges posed by these reservoirs necessitate innovative production techniques to maximize hydrocarbon recovery.

The study begins by elucidating the significance of hydraulic fracturing in stimulating unconventional reservoirs. Hydraulic fracturing creates fractures in the formation, enhancing permeability and facilitating fluid flow. The subsequent discussion focuses on the various artificial lift methods employed in unconventional reservoirs. Artificial Lift (AL) methods have emerged as indispensable tools for enhancing production rates and optimizing the performance of unconventional reservoirs. Artificial lift methods include Electrical Submersible Pump (ESP), Sucker Rod Pump (SRP), Gas Lift (GL), Progressive Cavity Pump (PCP), Plunger Lift (PL), and Jet Pumps (JP). The selection of an appropriate artificial lift method depends on several factors, including reservoir characteristics, production rates, fluid properties, and economic considerations.

engineering analysis and simulations with field data play pivotal roles in determining the optimal artificial lift strategy for each well or field.

This thesis provides a comprehensive overview of artificial lift applications to unconventional reservoirs and mainly focuses on the ESP and PCP due to their presence in the studied field. Commercial software PIPESIM is used in this study to determine well performance. All the simulations were run by using trilinear transient IPR which is mainly used for unconventional reservoirs. A novel approach has been used for this study to improve the reliability, efficiency, and applicability of artificial lifts in unconventional reservoirs. A comparison study was performed for ESP and PCP to figure out which artificial lift is optimal for the respective wells. This study gives a detailed output on implementing operational strategies based on their production rates and pump intake pressures with recommendation of al change method with the critical boundary parameters.

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INTRODUCTION

In recent years, the development of horizontal drilling techniques coupled with hydraulic fracturing has revolutionized the production of hydrocarbons from unconventional reservoirs. Horizontal unconventional wells have become increasingly prevalent in the oil and gas industry due to their ability to access larger reservoir volumes and maximize contact with low-permeability formations. However, the complex reservoir characteristics and unique production challenges of horizontal unconventional wells necessitate the implementation of effective artificial lift approaches.

Artificial lift techniques play a critical role in overcoming the inherent challenges of horizontal unconventional wells, such as declining production rates, rapid decline in reservoir pressure, and the need to optimize hydrocarbon recovery. Among them, ESPs are well known for their high lift capacities and are crucial for wells with high production rates and higher pump intake pressures. PCPs are mainly used for wells with lower production rates and pump intake pressures. This thesis aims to investigate and evaluate various artificial lift approaches specifically tailored for horizontal unconventional wells.

The study will begin by providing a comprehensive overview of unconventional reservoirs and hydraulic fracturing techniques, highlighting their significance in unconventional reservoir development. Subsequently, the focus will shift towards addressing the challenges associated with horizontal unconventional wells, encompassing concerns surrounding reservoir heterogeneity, multiphase flow dynamics, and the buildup of proppant and formation fines. Later, the thesis will explore and analyze the different artificial lift approaches that can be employed in horizontal unconventional wells. This includes a detailed examination of ESP and PCP. The selection criteria, design considerations, and operational aspects of each artificial lift method will be thoroughly discussed, along with their advantages and limitations in the context of horizontal unconventional wells.

Furthermore, the thesis will explore the impact of reservoir and wellbore characteristics on the performance of artificial lift systems in horizontal wells. Factors such as wellbore geometry, pump setting depth, horizontal lateral length, completion design, fluid properties, and production profiles will be considered in evaluating the effectiveness and efficiency of different artificial lift approaches.

The ultimate objective of this thesis is to provide insights and recommendations for optimizing the production and hydrocarbon recovery in horizontal unconventional wells through the implementation of appropriate artificial lift techniques. The findings of this research will contribute to the advancement of knowledge in the field of artificial lift for horizontal unconventional wells and aid in the development of robust production strategies for maximizing the economic viability of these valuable energy resources.

CHAPTER 1

LITERATURE REVIEW

In the oil and gas industry, the production of unconventional wells compared to the global oil production remains relatively low, at approximately 2.5% due to the challenges in in the drilling and production techniques (Stark et al., 2008).

1.1 Unconventional Reservoirs

Over the last two decades, horizontal unconventional well becomes more prolific due to the depletion and high overheads of the traditional wells. The development of unconventional resources has led to a significant increase in global hydrocarbon production, contributing to energy security and economic growth in many regions. Furthermore, the extraction of hydrocarbons from unconventional reservoirs has enabled countries to reduce their dependence on imported energy and has created new opportunities for employment and economic development (Stark et al., 2008)

Eshiet (2018) highlights that unconventional reservoir presents distinct production challenges due to their composition. These reservoirs mainly consist of tightly packed source rocks that trap hydrocarbons and hinder their migration to more permeable reservoir rocks. Unlike conventional reservoirs, where hydrocarbons migrate from source rocks, unconventional reservoirs encompass various rock types that are difficult to produce, including tight sandstones, tight limestone, and heavy oil reservoirs. Their low permeability poses additional challenges, necessitating specialized techniques for successful production. Overall, unconventional reservoirs demand unique approaches to extract hydrocarbons and overcome inherent complexities.

Unconventional reservoirs, such as shale formations, differ from conventional reservoirs in terms of burial and preservation of organic material, resulting in lower rates of organic maturation and lower porosity and permeability. Sediments containing organic material accumulate in geological basins over time. The weight of overlying Sediments leads to compaction, reducing pore space and increasing density. Heat and pressure cause thermal maturation of the organic material, converting it into hydrocarbons like oil and gas. Newly formed hydrocarbons migrate through pore spaces and fractures, driven by pressure gradients and buoyancy, eventually accumulating in suitable reservoir rocks. Unconventional reservoirs have low permeability and rely on various trapping mechanisms due to complex geological structures, and diagenesis processes further decrease porosity and permeability.

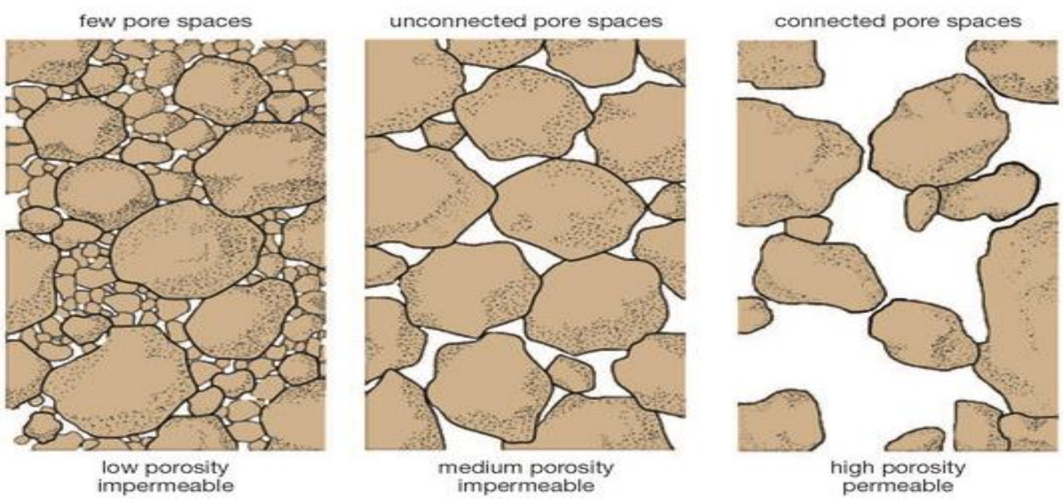


Figure 1.1 Unconventional reservoirs porous media

Some common unconventional reservoirs are shale reservoirs, tight reservoirs, coalbed methane reservoirs, oil sands/bitumen reservoirs, and gas hydrate reservoirs. Shale formations, the most common unconventional reservoirs, have low permeability, making hydrocarbon extraction challenging. Techniques like Hydraulic fracturing are employed to improve fluid flow and enhance extraction.

Overall, unconventional reservoir formation involves geological factors and complex processes, necessitating specialized techniques for successful development and hydrocarbon recovery.

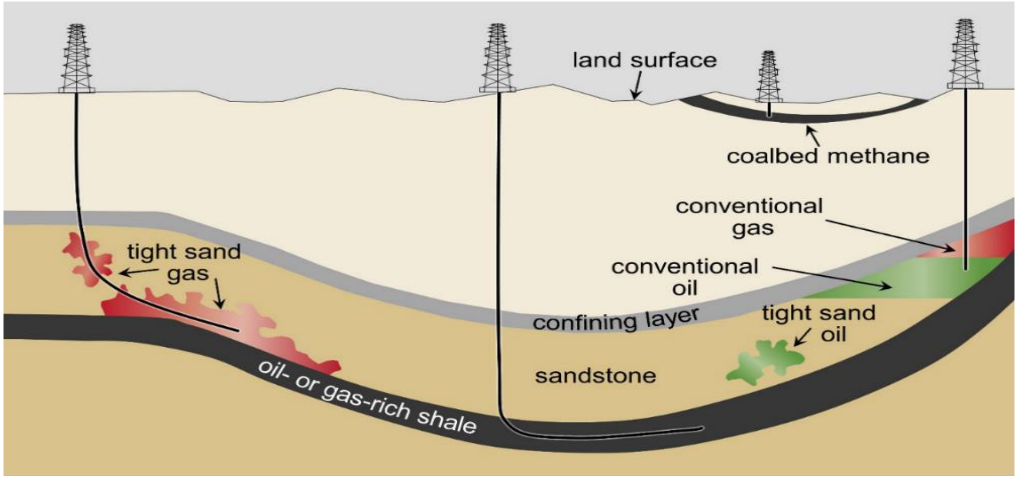


Figure 1.2 Unconventional reservoirs, source from Wikipedia

1.2 Horizontal Wells

Horizontal wells are a type of wellbore configuration that deviates from the traditional vertical orientation, allowing for a horizontal trajectory through the reservoir rock formation. The evolution of horizontal wells can be traced back to the 1930s, but significant advancements in drilling technology and techniques in the 1980s revolutionized their application in the oil and gas industry (Luo et al, 2023, Liu et al. 2023 a, b). Nowadays, it becomes a significant change in the development of unconventional reservoirs, unlocking vast reserves of hydrocarbons that were previously inaccessible using conventional vertical drilling methods (Zheng et al., 2022 a, b). The application of horizontal wells in unconventional reservoirs has revolutionized the industry by maximizing recovery and optimizing production.

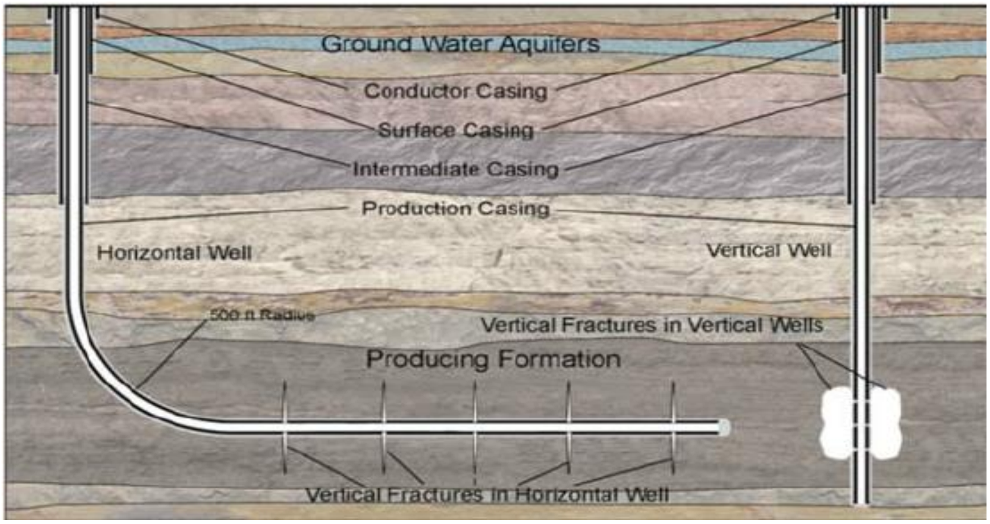


Figure 1.3 Horizontal well vs. vertical well

As shown in Figure 1.3, drilling a horizontal well starts with a vertical wellbore, and then a motor-driven drill bit creates a curved path that transitions from vertical to horizontal, allowing for drilling in a fully horizontal direction once the desired angle is reached (Rafieepour et al., 2020, Lin et al, 2022). This approach allows for the wellbore to extend horizontally within the target reservoir.

Horizontal wells have revolutionized the oil and gas industry in unconventional reservoirs by maximizing recovery and optimizing production. Key applications of horizontal wells in these reservoirs include multistage hydraulic fracturing to stimulate production and increase contact area, optimizing reservoir drainage and connectivity, managing fracture complexity, maintaining reservoir pressure, and enhancing productivity through optimized reservoir management strategies (Liu et al, 2020, Liu et al., 2021).

Horizontal wells provide a platform for multiple hydraulic fracturing stages, intersect a larger portion of the reservoir, and allow for better control of fracture growth. They also enable efficient pressure support and delay the onset of water or gas coning. Understanding pressure response in horizontal wells is crucial, especially after hydraulic fracturing, as it affects fracture properties and overall productivity (Zheng et al., 2023 a, b). Continuous advancements in drilling techniques, well completions, and reservoir simulation tools further improve the effectiveness of horizontal wells in unconventional reservoir development, enhancing the production potential of these challenging resources.

Excessive studies are focused on horizontal fracturing wells in unconventional reservoirs. Soliman et al. (1990) emphasized the importance of understanding the natural fracture network for hydraulic fracture design optimization. Mukherjee and Economides (1991) introduced the concept of a flow-choking skin factor to account for pressure drop caused by radial flow convergence. Larsen and Hegre (1991, 1994) developed analytical solutions for fractured horizontal wells, while Temeng and Horne (1995) focused on optimizing hydraulic fracture spacing. Raghavan et al. (1997) and Chen and Raghavan (1997) proposed correlations for fractured horizontal well performance. Wei and Economides (2005) compared longitudinal and transverse fractures, while Al-Kobaisi et al. (2006) and Medeiros et al. (2006, 2007) developed numerical models for pressure transient analysis. Medeiros et al. (2007) investigated the performance of fractured horizontal wells in tight unconventional reservoirs. Ozkan (2011) developed an analytical trilinear flow solution for fractured horizontal wells in unconventional reservoirs. These studies, along with others in the field, have contributed valuable insights into the behavior of fractured horizontal wells in unconventional reservoirs, including but not limited to optimizing hydraulic fracture design, determining fracture spacing, and improving overall well performance.

1.3 Trilinear Transient IPR

The Inflow Performance Relationship (IPR) is a crucial concept in reservoir engineering that helps analyze the behavior of oil and gas wells. It provides a mathematical relationship between the fluid flow rate into the wellbore and the resulting pressure drawdown in the reservoir. The IPR curve depicts the connection between wellbore flowing pressure and fluid production rate, indicating the flow regime (radial, linear, or boundary-dominated). In horizontal wells and unconventional reservoirs, the IPR is vital for understanding flow behavior, optimizing production, evaluating well performance, designing hydraulic fracturing treatments, characterizing reservoirs, forecasting production, and interpreting well test data.

Ozkan et al (2009) first developed the trilinear-flow solution assuming the unconventional tight reservoirs are characterized by micro to nano-Darcy permeability, such as shale formations and tight formations. The contribution of the reservoir beyond the stimulated volume is typically insignificant. They argue that the productive lifespan of a multi-fractured horizontal well is primarily governed by linear flow regimes.

Then the trilinear flow model, proposed by Brown et al. (2011), is specifically developed for the analysis of multi-stage fractured horizontal wells (MFHW) in unconventional reservoirs characterized by ultra-low matrix permeability. This analytical solution is derived based on several assumptions that are tailored to the unique characteristics of unconventional reservoirs.

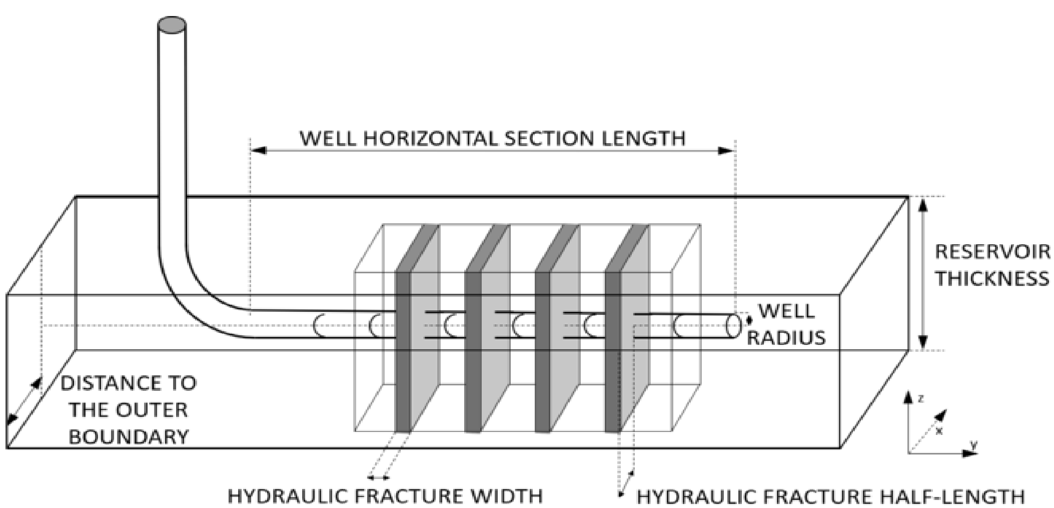


Figure 1.4 Multistage fracture horizontal well

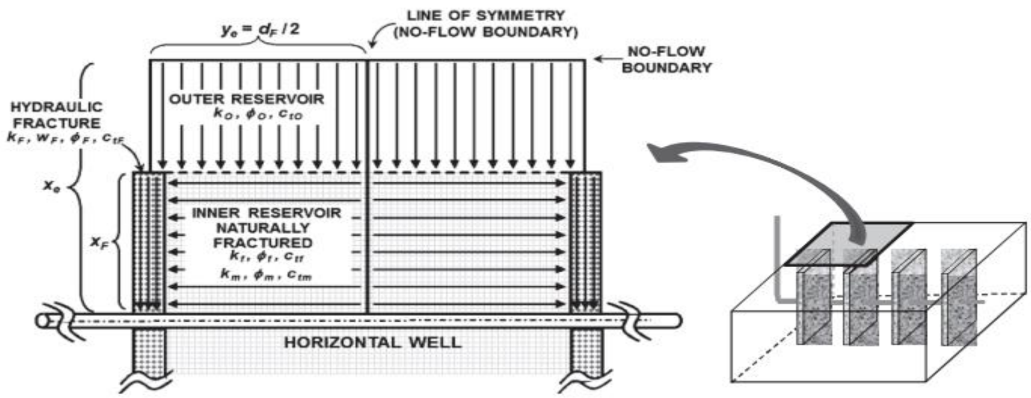


Figure 1.5 Flow pattern in Trilinear Flow Model

As shown in Figure 1.5, the trilinear flow model provides an analytical solution for analyzing the behavior of multi-stage fractured horizontal wells (MFHWs) in unconventional reservoirs. The model divides the reservoir into three regions: the hydraulic fracture region with high conductivity, the Stimulated Reservoir Volume (SRV) adjacent to the fractures (inner region), and the outer reservoir beyond the SRV (outer region). The model assumes linear flow behavior in each region and offers insights into flow rates, pressure profiles, and production performance. The trilinear flow model enables the analysis of pressure transient responses and production behaviors of multi-stage fractured horizontal wells. It provides a mathematical approach for modeling the flow from a single fracture representing multiple fractures in a rectangular reservoir section.

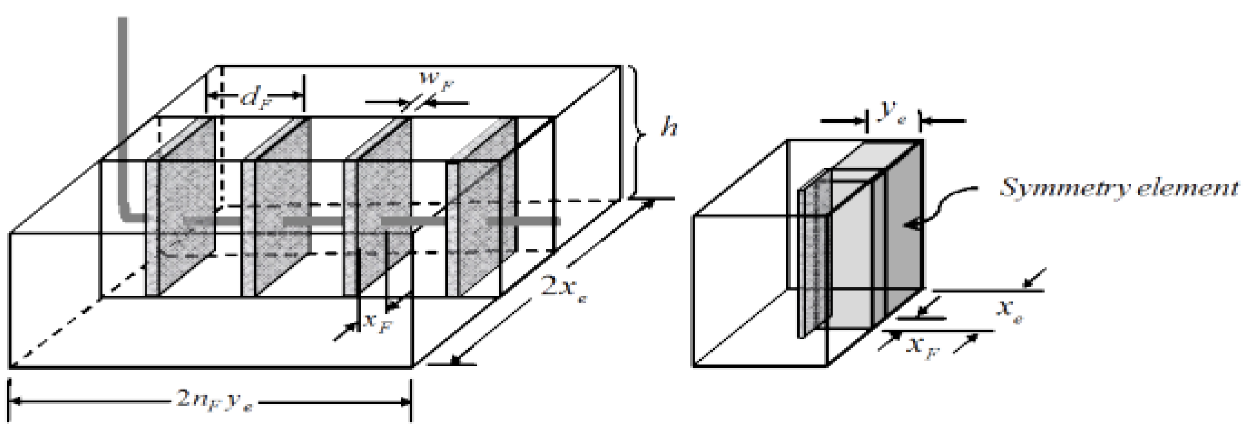


Figure 1.6 MFHW and symmetry element used in Trilinear Flow Model

As shown in Figure 1.6, the fracture is positioned centrally within the enclosed rectangular drainage area. The no-flow boundaries that run parallel to the fracture are situated at the mid-line between the two fractures, which is at a distance of $y_e = d_F/2$. The lateral boundaries that are perpendicular to the fracture plane are located at a distance of x_e from the center of the fracture. Consequently, the drainage area of the fracture accounts for $1/n_F$ of the overall drainage area of the horizontal well. The fracture possesses a half-length of x_F, a width of w_F, and extends through the entire thickness, h, of the formation. For a better understanding, the trilinear flow solution is derived in terms of consistent units and dimensionless variables. Here, definitions of the dimensionless variables used in the general form of the trilinear flow model are presented. In the following equations, “I” refers to the inner region, “O” refers to the outer region, and “F” refers to the Hydraulic Fracture. Then, dimensionless pressure and time are given by

$$p_D = \frac{2\pi k_I h_I}{qB\mu}\Delta p = \frac{2\pi k_I h_I}{qB\mu}(p_i - p), \tag{1.1}$$

and

$$t_D = \frac{\eta_I}{x^2{}_F} t, \tag{1.2}$$

where

$$\eta_I = \frac{k_I}{(\phi c_t)_I \mu}. \tag{1.3}$$

Dimensionless distances in the x- and y-directions are defined by

$$x_D = \frac{x}{x_F} \tag{1.4}$$

and

$$y_D = \frac{y}{y_F}. \tag{1.5}$$

The dimensionless distances to the reservoir boundaries are given by x_{eD} and y_{eD}. The dimensionless width of the hydraulic fracture is

$$w_D = \frac{w_F}{x_F}. \tag{1.6}$$

Dimensionless fracture and reservoir conductivities are

$$C_{FD} = \frac{k_F w_F}{k_I x_F} \tag{1.7}$$

and

$$C_{RD} = \frac{k_I x_F}{k_O y_e}. \tag{1.8}$$

Then, diffusivity ratios are defined as

$$\eta_{FD} = \frac{\eta_F}{\eta_I} \tag{1.9}$$

and

$$\eta_{OD} = \frac{\eta_O}{\eta_I}, \tag{1.10}$$

where η_I is the inner reservoir diffusivity, η_O is the outer reservoir diffusivity and η_F is the hydraulic fracture diffusivity. η_O and η_F are:

$$\eta_F = \frac{k_F}{(\phi c_t)_F \mu} \tag{1.11}$$

and

$$\eta_O = \frac{k_O}{(\phi c_t)_O \mu}. \tag{1.12}$$

Brown et al. (2011), derived the solutions for the inner region, outer region, and hydraulic fracture. Equations were expressed below for all three regions. The outer reservoir is set to be coupled with the inner reservoir solution using the outer boundary condition for the inner reservoir, ensuring pressure continuity at the boundary. The solution is shown below:

$$(\bar{P}_{OD})_{x_{D=1}} = (\bar{P}_{ID})_{x_{D=1}} \frac{\cosh\left(\sqrt{S_O}(x_{eD} - x_D)\right)}{\cosh\left(\sqrt{S_O}(x_{eD} - 1)\right)}$$

$$= (\bar{P}_{ID})_{x_{D=1}} \frac{\cosh\left(\sqrt{\frac{S_O}{\eta_{OD}}}(x_{eD} - x_D)\right)}{\cosh\left(\sqrt{\frac{S_O}{\eta_{OD}}}(x_{eD} - 1)\right)}, \tag{1.13}$$

where

$$S_O = \sqrt{\frac{S}{\eta_{OD}}} \; . \tag{1.14}$$

The inner reservoir is prepared for coupling with the hydraulic fracture solution using the outer boundary condition for the hydraulic fracture, ensuring pressure continuity at the boundary:

$$(\bar{P}_{ID})_{y_{D=w_D/2}} = (\bar{P}_{FD})_{y_{D=w_D/2}} \frac{\cosh\left(\sqrt{\alpha_O}(y_{eD} - y_D)\right)}{\cosh\left(\sqrt{\alpha_O}(y_{eD} - w_D/2)\right)}, \tag{1.15}$$

where

$$\alpha_O = \frac{\beta_O}{C_{RD} y_{eD}} + u \tag{1.16}$$

and

$$\beta_O = \sqrt{s/\eta_{OD}} \tanh\left[\sqrt{s/\eta_{OD}}\,(x_{eD} - 1)\right]. \tag{1.17}$$

Finally, the solution for the pressure distribution in the hydraulic fracture are

$$(\bar{P}_{FD}) = \frac{\pi}{s C_{FD} \sqrt{\alpha_F}} \frac{\cosh\left(\sqrt{\alpha_F}(1 - x_D)\right)}{\sinh(\sqrt{\alpha_F})} \tag{1.18}$$

and

$$(\bar{P}_{wD}) = (\bar{P}_{FD})_{x_D=0} = \frac{\pi}{sC_{FD}\sqrt{\alpha_F}\tanh(\sqrt{\alpha_F})}. \tag{1.19}$$

1.4 Artificial Lifts

Artificial lift is a crucial technique used in the oil and gas industry to maintain optimal hydrocarbon production as reservoirs mature. It involves employing various methods, such as pumps and gas lift valves, to increase reservoir pressure or reduce wellbore backpressure. By installing lift mechanisms downhole, 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). These systems play a vital role in sustaining production rates from oil and gas fields. This study mainly focuses on ESP and PCP, which are introduced in detail in chapter 1.4.1 and chapter 1.4.2. Other artificial lift methods are briefly reviewed from chapter 1.4.3 to chapter 1.4.6.

1.4.1 Electrical Submersible Pump

An Electrical Submersible Pump (ESP) is a sophisticated and widely utilized technology in the oil and gas industry. It is a multi-stage centrifugal pump specifically designed to efficiently lift significant volumes of fluids from wellbores. As an artificial lift method, ESP plays a vital role in enhancing hydrocarbon production by providing additional energy and lift to fluids within the wellbore. The ESP system operates using downhole pumps, which are supplied with electric power from the surface through cables. These downhole pumps efficiently lift the fluids, allowing for improved production rates and optimizing reservoir performance. By utilizing ESPs, oil and gas operators can overcome the natural decline in reservoir pressure and maintain or even increase production levels from their wells.

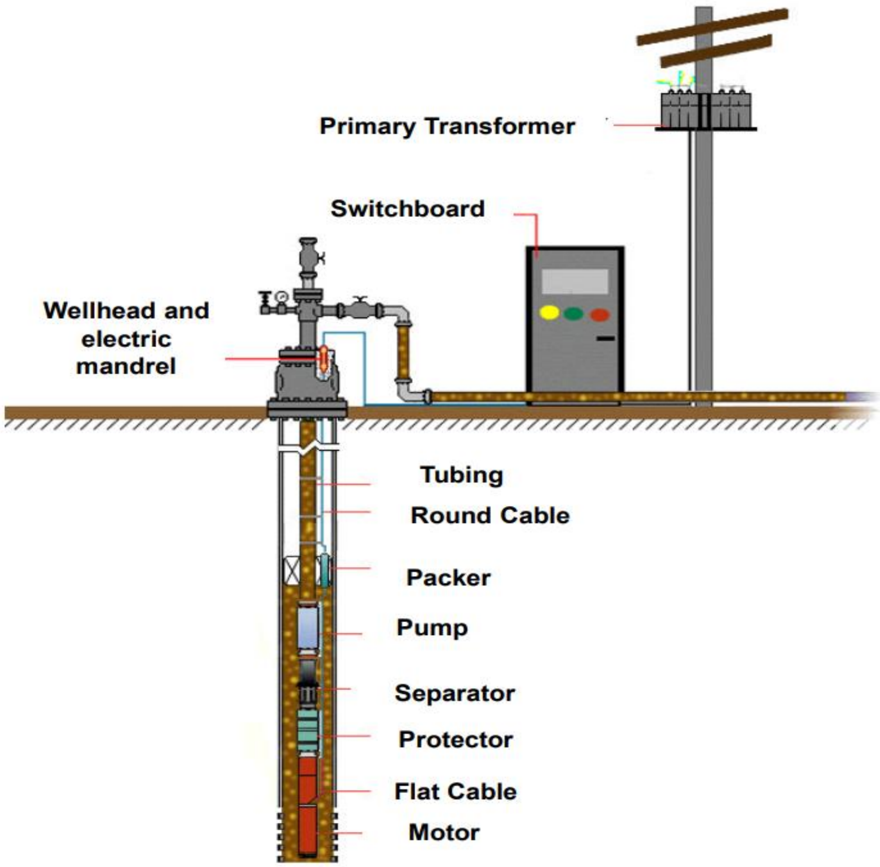


Figure 1.7 ESP system

Table 1.1 The advantages and disadvantages of ESP

Advantages	**Disadvantages**
Handling high liquid rates	Risk of proppant flowback
Compatibility with crooked wells	Unsuitability for sand and solids production
Space efficiency	Limited applicability to single zone completions
Cost-effectiveness	Depend on stable high voltage electric power
Can handle both oil and water wells	Temperature limitations

1.4.1.1 Working Principle: In a naturally flowing well, the equilibrium liquid rate (Q_e^{nf}) and flowing bottomhole pressure (P_{wf}^{nf}) are determined by reservoir pressure overcoming hydrostatic pressure and frictional losses (Figure 1.8). Without artificial lift, the Inflow Performance Relationship (IPR) and Outflow Performance Relationship (OPR) intersect at a single point, limiting production rates. However, with an Electrical Submersible Pump (ESP) near the well perforations, it creates a differential pressure, lifting the liquid column, and reducing flowing bottomhole pressure. The pump's discharge pressure matches the OPR, and its intake pressure aligns with the IPR (Figure 1.8). This allows increased production rates beyond the natural flow state, represented by the new OPR with pump intersecting the IPR at higher Q_e^{pump} and lower P_{wf}^{pump}.

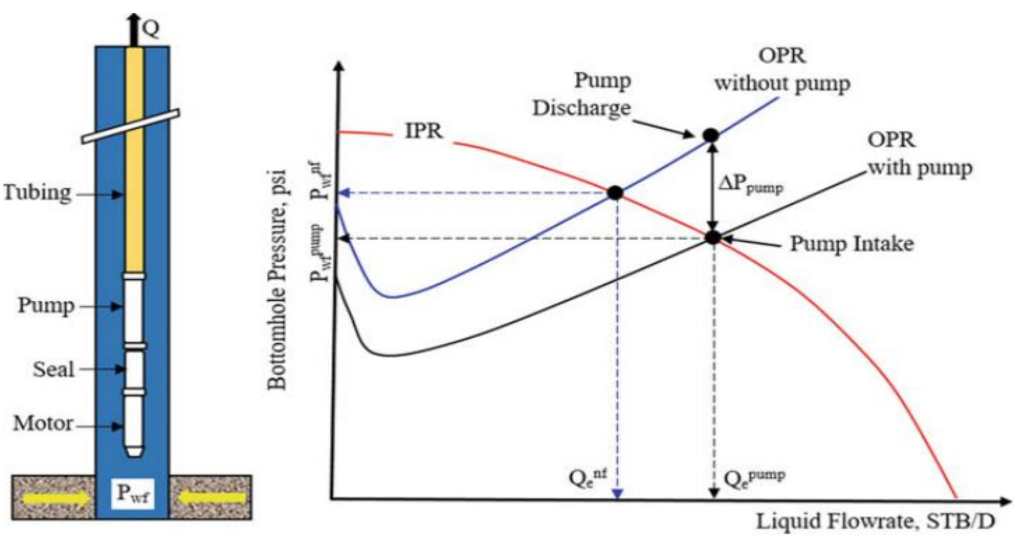


Figure 1.8 Working principle of ESP system

Electrical Submersible Pump (ESP) systems have a run life of 6 to 9 months in harsh environments but can be extended to 12 to 18 months in more benign conditions or with enabling technologies. ESPs are well-suited for horizontal well completions in unconventional reservoirs due to their small surface footprint and versatility. Setting depth and mechanical integrity evaluations are crucial, especially in high flow rate wells with potential challenges in crooked trajectories. Variable-speed drives are recommended for optimizing well production in unconventional reservoirs. Gas interference and intermittent flow pose challenges in pumping systems, with the gas volume fraction (GVF) providing a better understanding of gas-liquid mixture behavior. ESPs require adequate liquid flow rates to avoid issues like gas locking and severe wear. A minimum liquid flow rate of over 400 BPD is recommended for conventional applications, while a range of 150 BPD to 30,000 BPD is suitable for ESPs. Attention to factors such as maximum dogleg severity and access to reliable electrical power ensures efficient and effective artificial lift in gassy well conditions. (Pankaj et al., 2018; Lea et al., 2003; Clegg et al., 1993; Romer et al., 2012, Zhu et al., 2022).

1.4.1.2 Factors Affecting ESP: ESP performance can be influenced by various parameters. High-viscosity fluids pose challenges due to increased frictional losses and disk friction, leading to reduced head capacity and increased brake horsepower. Gas in the tubing alters fluid density and hydrostatic pressure, potentially causing gas-locking and hindering fluid production. Zhu et al, (2021 a, b, c) highlight the need for further understanding of gas bubble dynamics within ESPs. Downhole gas separators are commonly used to prevent gas interference, ensuring efficient pump operation. Osorio et al. (2023) studied downhole centrifugal separators, finding an overall efficiency of 79% and identifying liquid flow rate as the most critical variable. The Twister separator showed the highest performance, particularly in low gas and liquid flow rates. The study utilized a Random Forest algorithm and a Voting Regressor machine learning model to assess separator performance, providing insights into factors affecting efficiency. Managing viscosity and gas effects, along with using appropriate separators, is crucial for optimizing ESP performance and achieving effective fluid production Presence of sand can lead to erosion in pumps which can degrade ESP's performance (Zhu et al., 2017; Osorio et al., 2023; Rajkumar et al., 2023).

1.4.1.3 ESP Failures: ESP systems can fail due to various reasons. Mechanical failures, such as motor, bearing, impeller, shaft, or seal issues, can lead to reduced efficiency and breakdown. Excessive gas can cause gas locking, reducing pumping efficiency. Sand and solids can cause abrasion and wear, impacting pump performance. Electrical failures, fluid viscosity, pump off, incorrect sizing, scaling, corrosion, power supply issues, and incorrect installation or design can also lead to ESP failures. To prevent failures, regular maintenance, monitoring, and proper design are crucial. El Gindy et al. (2015) discussed case studies on implementing monitoring and surveillance systems to prevent trips and optimize ESP operation. Proper management and proactive measures can enhance the reliability and longevity of ESP systems.

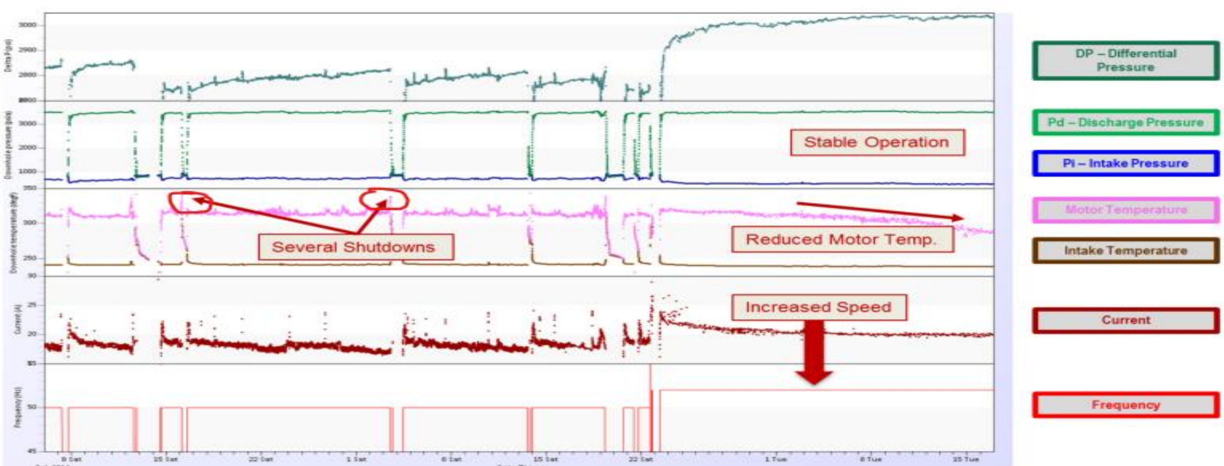


Figure 1.9 ESP trip due to low flow conditions

In Figure 1.9, the ESP faced challenges with frequent high-temperature trips due to low-flow conditions, causing elevated motor temperature. To address this, the frequency of the ESP was increased or the choke was opened to allow more liquid flow for better cooling. However, this risked increasing motor load and temperature. By carefully increasing the drive frequency, fluid flow improved, reducing motor temperature by around 15°F and ensuring reliable ESP performance without trips.

In Figure 1.10, the ESP tripped due to high motor temperature caused by severe well depletion and no-flow conditions. Temporarily shutting down the well allowed pressure buildup and restarting the well resolved the issue and prevented further tripping. This effective approach managed depletion-related challenges, ensuring the smooth operation of the ESP system. Proper analysis and timely measures were crucial in optimizing ESP performance and avoiding interruptions.

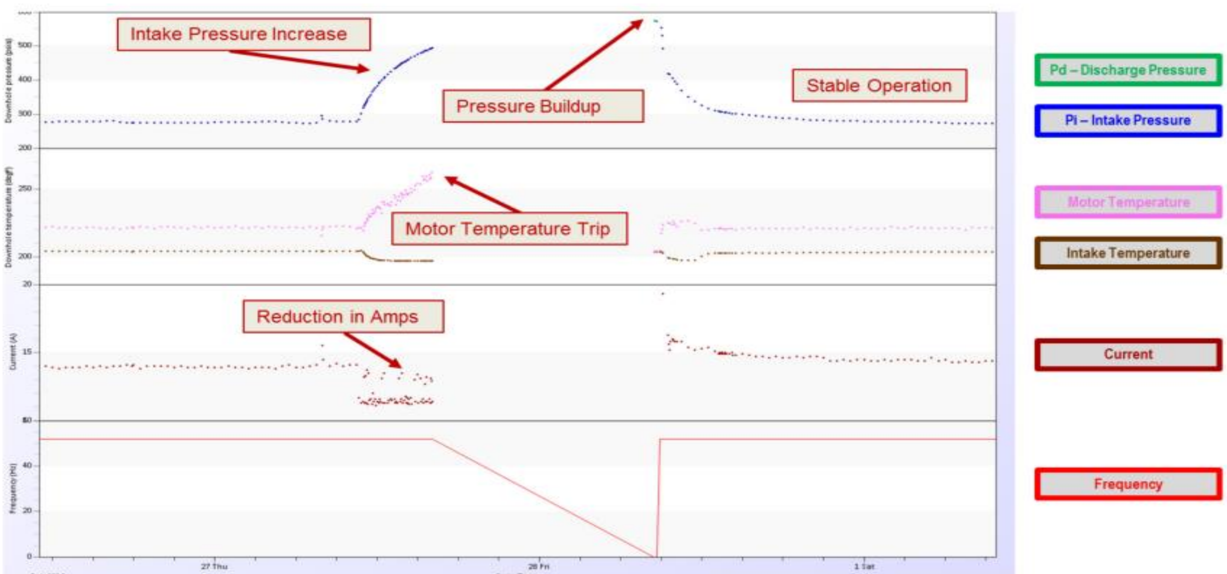


Figure 1.10 ESP tripped due to severe depletion

Scale deposition during production negatively impacts pump efficiency and motor integrity. It reduces cooling around the motor and obstructs the pump's flow path, leading to decreased efficiency. Intake plugging may occur, causing increased pump intake pressures. Motor temperature is influenced by reduced cooling, scale deposition, and decreased motor load due to reduced flow. Monitoring intake pressure, discharge pressure, and motor temperature can identify plugging and scale buildup. Acid backwash may clear plugging, but scale on the motor housing can still hinder cooling and raise motor temperature. These factors necessitate effective maintenance and monitoring to optimize pump performance and longevity.

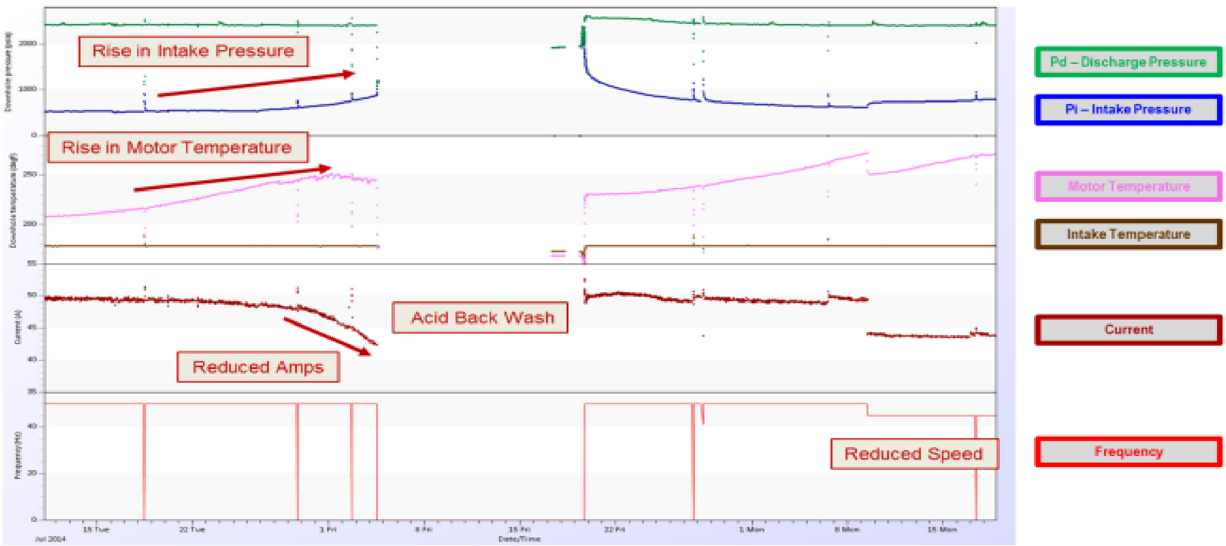


Figure 1.11 ESP trip due to scale deposition

To address the rising motor temperature issue, a temporary solution was implemented by reducing the motor speed, effectively lowering the load and the motor temperature as modeled. However, over time, the temperature continued to rise, necessitating a more permanent fix. The problem was resolved by conducting another acid backwash job, but this time with an extended soak time. The success of the second backwash is demonstrated in Figure 1.12, where the motor temperature decreased significantly by 50°F (from 285°F to 235°F). The longer soak time effectively dissolved the scale on the motor housing, leading to improved cooling conditions and ensuring more stable operation of the ESP.

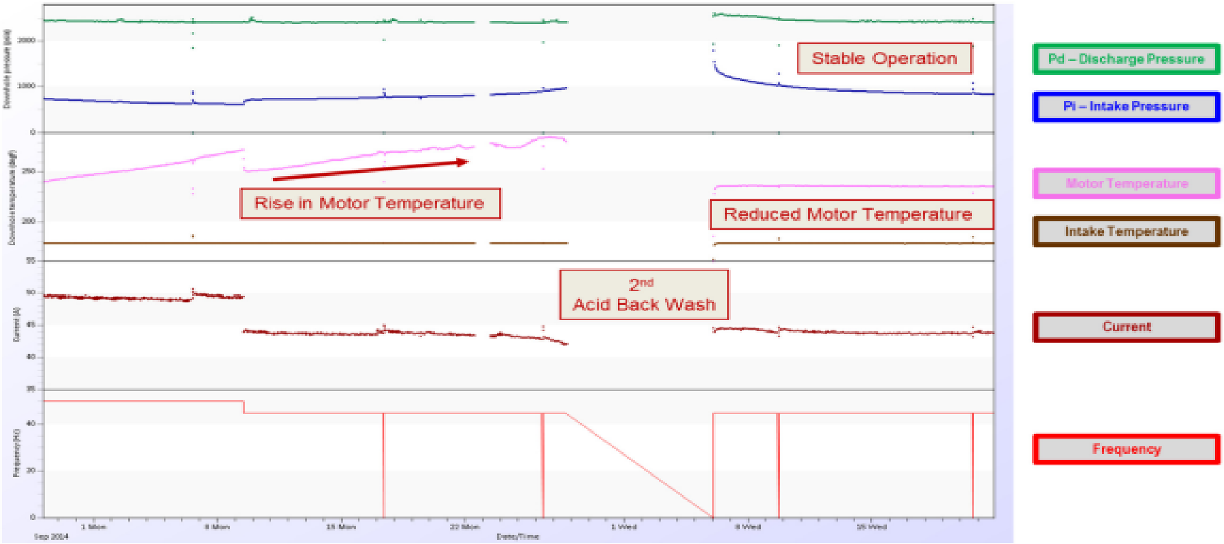


Figure 1.12 Smooth performance of ESP after second acid washback

In Figure 1.13, it can be observed that the ESP pump intake pressure began to decrease as the pump speed was increased. This increase in speed caused a corresponding rise in the current, eventually leading to an ESP trip. Prompt action was taken to address this issue by reducing the pump speed, which resulted in an increase in pump intake pressures, leading to a stable and smooth operation of the ESP.

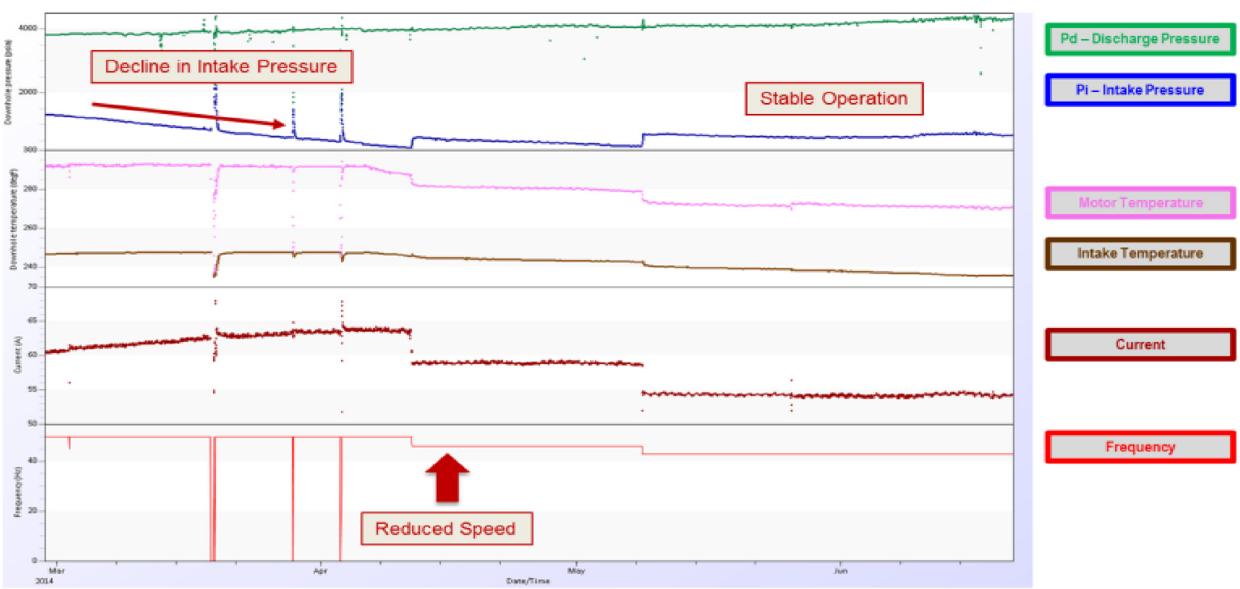


Figure 1.13 Pump off conditions

1.4.2 Progressive Cavity Pump

The Progressing Cavity Pump (PCP), also known as the Moineau pump, is a widely used artificial lift technique for extracting fluids with high viscosity and solids content. It operates through the rotation of a rotor inside a fixed stator, creating a sequence of cavities that transfer fluid without pulsation. The PCP, originally developed by René Moineau in 1930, offers advantages such as handling a wide range of fluids, including viscous and solid-laden fluids, and operating without the need for check valves or liquid priming during startup (Moineau, 1932). Recently, PCPs have been adapted to handle more challenging oil well environments, such as pumping high-temperature fluids from thermal heavy oil recovery methods like Steam Assisted Gravity Drainage (SAGD), Cyclic Steam Stimulation (CSS), or Continuous Steam Injection (CSI). Special metal stators and specific elastomer stators have been designed for use with high-temperature fluids. Furthermore, PCPs are now used for handling multiphase fluids with high gas content, employing hydraulic regulator rotor/stator setups.

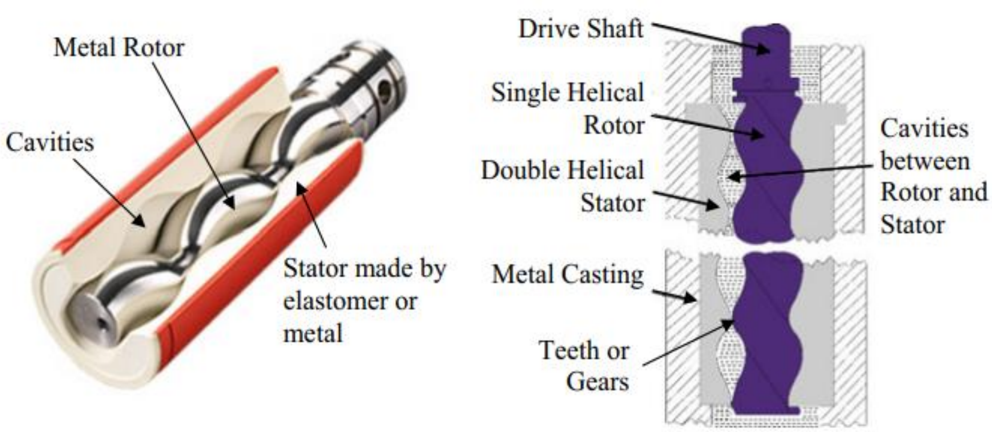


Figure 1.14 A single lobe PCP

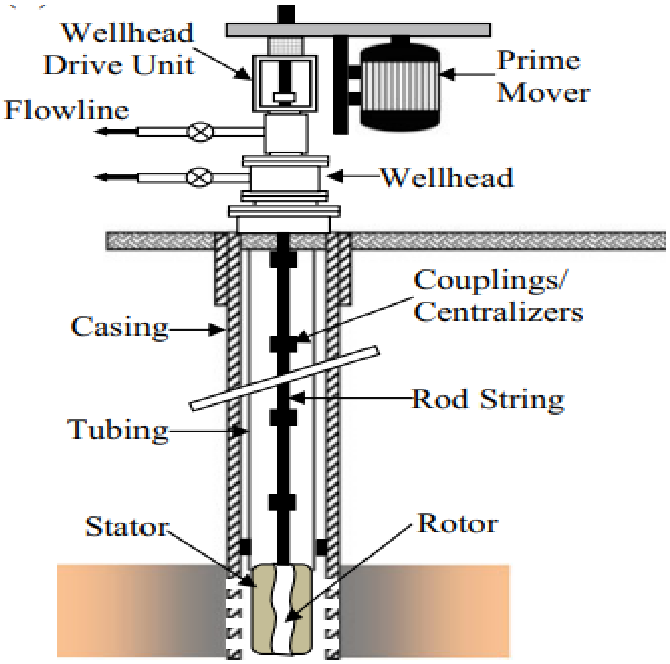


Figure 1.15 PCP system

Table 1.2 Advantages and disadvantages of PCP

Advantages	**Disadvantages**
Used for heavy viscous fluids	Not applicable to deeper wells
Maintains uniform flowrate without pulsation	Cannot achieve higher liquid rates
Higher efficiency	Limited temperature range
Can handle solids and gas	Not suitable for high DLS wells
Low operating and maintenance cost	Less efficient with gas and solids production

1.4.2.1 Working Principle: The Progressing Cavity Pump (PCP) is a type of rotary positive displacement pump that consists of two main components: a rotor and a stator. In the case of a single lobe PCP type 1-2, a single external helical rotor rotates eccentrically inside an internal double helical stator with the same minor diameter and twice the pitch length.

The rotor is a metallic rod with a single helical profile, while the stator is made of an elastomeric material that is permanently bonded by injection process inside a steel tube support with end threading. The elastomeric stator forms a double helical internal profile with a pitch length twice that of the rotor's helix. As the number of rotor and stator lobes differs by one, it creates fluid-filled cavities between the rotor and stator. PCP 1-2 has one lobe rotor and two lobes stator, while PCP 2-3 has a two lobes rotor and three lobes stator.

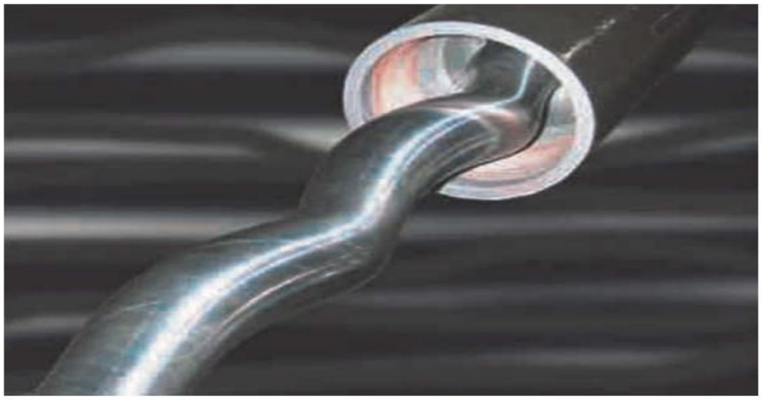


Figure 1.16 Single lobe PCP 1-2, rotor and stator view

A positive seal or compression contact line exists between the metallic rotor and the elastomeric stator, which is known as the seal line. Each completely sealed cavity represents a closed volume located between the single helical rotor and the double helical internal stator for a 360° rotation of the stator helix. The number of progressing sealed cavities from suction to discharge increases with the stator and rotor length, leading to higher pressure capabilities of the pump. As the rotor rotates at a constant rpm inside the stator, one cavity is opening while the other is closing, resulting in a non-pulsating and constant flow rate for the PCP. The flow rate depends on the cavity volume and the rotational speed of the rotor.

1.4.2.2 Factors Affecting PCP: PCP systems are employed in various applications, each presenting unique operational challenges. Customized equipment configurations, precise installation procedures, suitable sizing standards, and appropriate operating practices are crucial for success. High-viscosity oil production poses challenges due to substantial flow losses in the production tubing and surface piping. To handle these challenges, the design process must consider worst-case flow losses when selecting the pump, rod string, and prime mover.

Well-designed PCP systems and proper operating procedures are necessary to effectively handle high sand production. Sudden sand influx, known as slugging, can be avoided by making gradual adjustments in pump speed and avoiding practices that cause rapid changes in bottomhole pressure. Gassy well conditions can be addressed by preventing free gas from entering the pump intake, positioning the intake below the perforations, and avoiding seating the stator within or above the perforation interval. Low-productivity wells require careful management to prevent pumped-off conditions, which result in low volumetric pump efficiency.

Operating the pump within the fluid's flow capacity and considering the narrow pump cavities' limitations are crucial, especially for highly viscous fluids. Lower bottomhole pressures and pump inflow constraints are primary causes of efficiency decline in heavy oil well applications. By addressing these challenges, PCP systems can effectively handle various operational conditions, ensuring efficient fluid transfer in the oil and gas industry.

1.4.2.3 PCP Failures: Analyzing PCP failures and their root causes can extend pump run-life and reduce premature failures. Employing a systematic approach of identification, description, analysis, and tracking enables effective strategies for improved PCP performance and reliability. Utilizing sensors and production data aids in identifying operating problems, enhancing lift performance, and reducing costs. Common pump failures include rotor wear due to abrasive particles in the pumped fluid, leading to surface or severe wear on the rotor's crest. Regular monitoring and maintenance can address these issues, ensuring optimal rotor performance and longevity.

Figure 1.17 Crest of rotor wear

Abrasive wear alters the stator elastomer, leading to a clearance fit between rotor and stator, impacting pump performance, and reducing flow rate. Stator failure occurs when the pump operates without liquid, causing excessive heat buildup, making the elastomer brittle and prone to cracking. Elastomer thermal swell causes expansion due to increased temperature, leading to higher friction between rotor and stator, resulting in higher torque and power requirements. Gas permeation causes gas to enter the elastomer matrix, expanding upon pressure reduction, forming blisters or bubbles, and potentially causing rupture. Proper monitoring and maintenance are crucial to prevent these issues and ensure optimal pump performance.

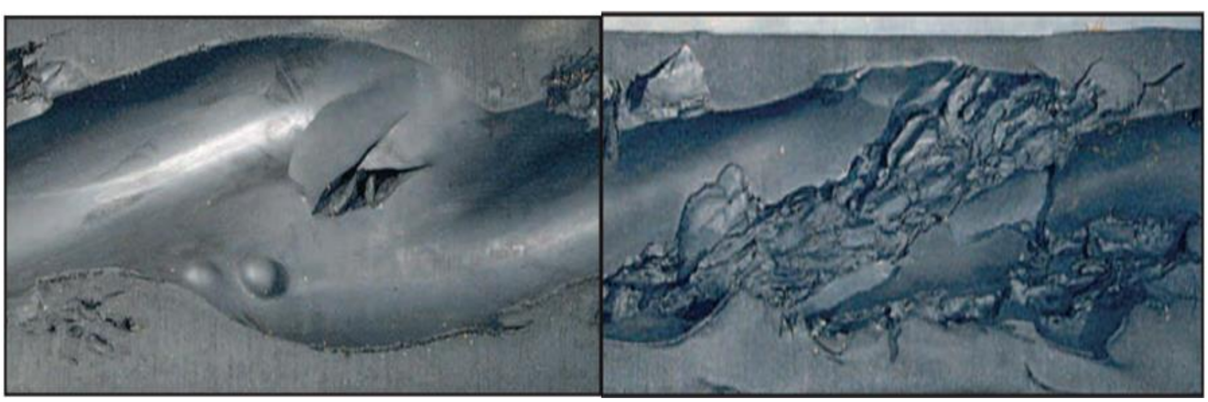


Figure 1.18 Elastomer damage by high GOR and bubble (left image) and by high discharge pressure and excess heat (right image)

Rod string failure is due to the excessive torque and fatigue are among the reasons for rod string failures. Proper installation and load management can prevent premature failures and ensure efficient rod string operation. Similarly, tubing string failure is due to wear, corrosion, and other environmental factors that may lead to tubing string failures. Regular inspections and appropriate protective measures can prolong the tubing's service life. Other failures include well head and pump drive failures: Ensuring the wellhead and pump drive components are well-maintained and operating within design parameters can prevent potential failures and maintain system integrity. By addressing these failures through timely maintenance, effective solutions, and improved operating practices, PCP systems can achieve longer run life, and improved overall performance.

1.4.3 Gas Lift

Gas lift (GL) is an effective artificial lift method used to increase fluid production rates in oil and gas wells. It involves injecting gas into the wellbore to reduce hydrostatic pressure and lift the fluids to the surface. Gas lift is utilized in wells with inadequate natural reservoir pressure or declining pressure over time. The process includes injecting gas through valves or mandrels at specific depths, creating a buoyant force that lifts the fluids. Gas lift systems can be continuous or intermittent, maintaining a steady flow or injecting gas in cycles to optimize production (Clegg et al., 1993; Lea et al., 2003).

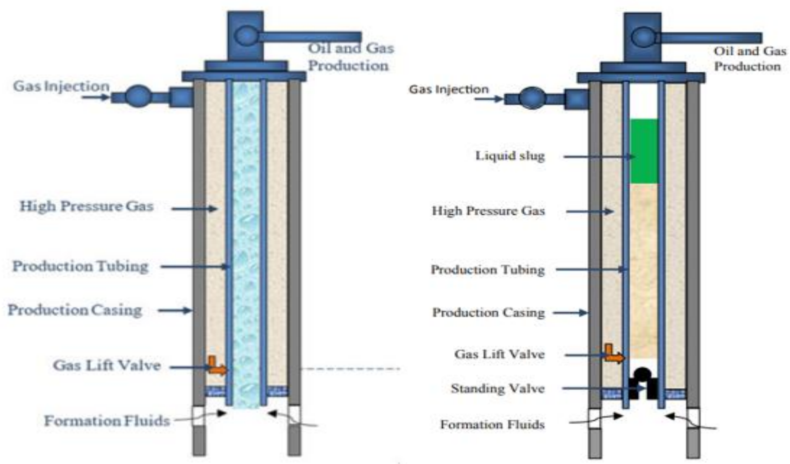


Figure 1.19 Continuous gas lift (left image) and Intermittent gas lift (right image)

Table 1.3 Advantages and disadvantages of gas lift

Gas lift	Advantages	Disadvantages
Continuous	For high sand production and GLR Easy to install and operate Inexpensive and minimum space Applicable in offshore Continuous produce with gas injection	Incredibly low bottom hole pressure Prolong life of a well
Intermittent	Expensive if formation gas is limited Inefficient for large size casing/tubing less efficient for small number of wells Not recommended for heavy oil wells Efficiency is low	Only applicable for low production Less efficient than continuous gas lift Causes high sand productions Optimization is complex

1.4.4 Rod Pump

The sucker rod pump (SRP), or rod pump, is a widely used artificial lift method for oil wells, particularly in regions with vertical wells producing less than 10 barrels of oil per day, known as stripper wells. It utilizes a system of rods to connect a downhole positive displacement plunger pump with a surface driving unit, converting rotational motion into reciprocating motion.

This reciprocating motion drives the downhole pump plunger, creating suction on the upstroke to allow formation fluid to flow into the working barrel and producing oil through the annulus between the rod strings and production tubing. As the plunger moves upward (upstroke) the travelling valve moves downward, during the upstroke period, the liquid volume in the working barrel increases and the pressure decreases. In this way, the formation fluid flows in the annulus between the rod strings and the production tubing.

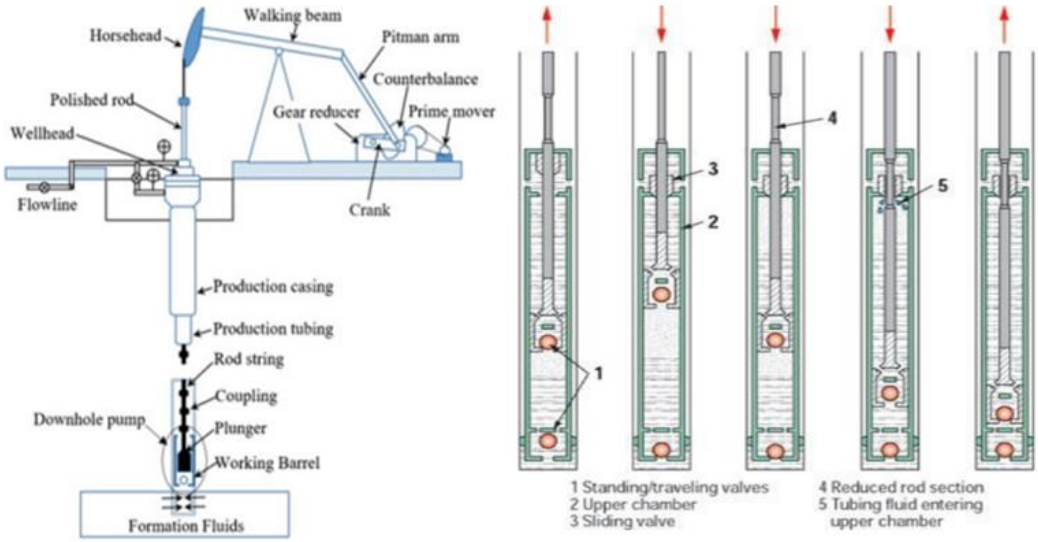


Figure 1.20 SRP system

Table 1.4 Advantages and disadvantages of rod pumps

Advantages	**Disadvantages**
Reduce bottomhole pressure to an extremely low level	Only applicable to shallow or medium depths
Simple to design and operate, easy to maintain	Space restrictions, not feasible for offshore
Quick replacement	Cannot obtain higher flowrates
Easy to handle corrosion and scale treatments	Excessive friction in deviated wells
Low operating and maintenance cost	Less efficient with gas and solids production

1.4.5 Plunger Lift

Plunger lift (PL) is a commonly employed artificial lift method for vertical gas wells that produce liquids. Its purpose is to remove liquids from the wellbore and maintain gas production. Plunger lift is typically implemented when slugging occurs in the production tubing. The well is often set up to flow intermittently using a controller and valve for a few weeks. The well is initially shut in to allow pressure to build up, after which a control valve is opened to lift large fluid slugs and enable flow.

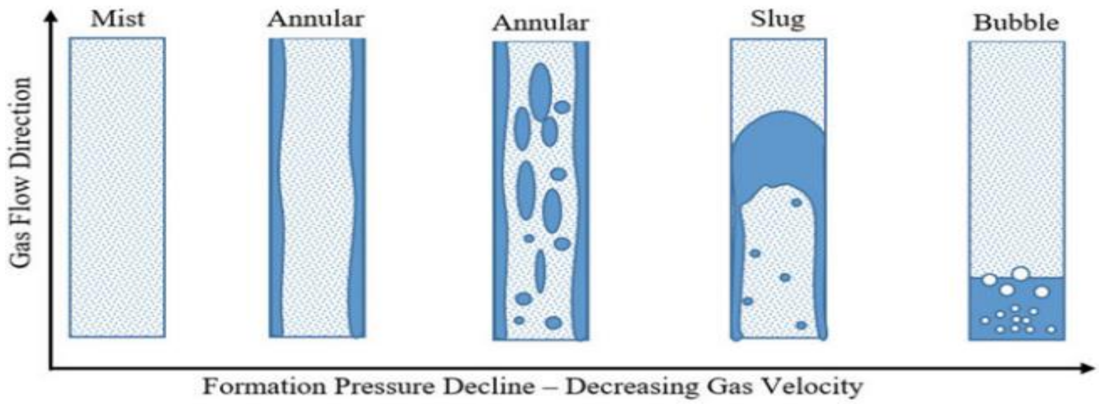


Figure 1.21 Potential flow patterns in gas wells

However, this approach is inefficient as there is significant liquid fallback when the slug is lifted. Gas quickly breaks through the slugs, and the falling liquid creates new slugs as the mixture travels up the production tubing. This churning effect results in the wastage of a substantial amount of pressure energy. Plunger lift is utilized to prevent liquid fallback and enhance fluid lifting efficiency. A plunger is employed as a mechanical interface between the gas and the liquid slug. This solid interface helps prevent gas breakthroughs and reduces liquid fallback. The entire slug is lifted at once, allowing the well to flow for a period with minimal bottomhole pressure.

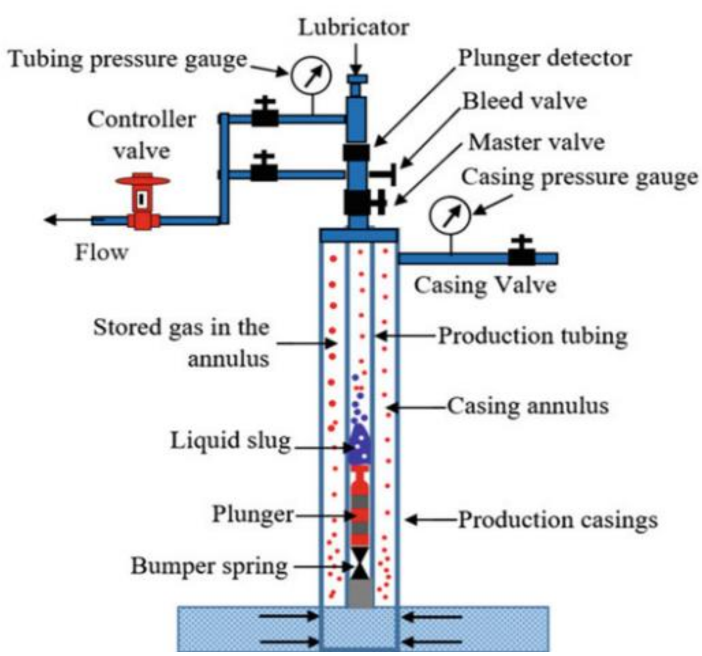


Figure 1.22 Plunger lift system

Table 1.5 Advantages and disadvantages of plunger lift

Advantages	Disadvantages
It is used for high gas wells	Troubleshooting and optimizing is difficult
Cost effective, easy to install and operate	Low liquid rates, limited to reservoir pressures
Can produce at low liquid rates	Cannot run in horizontal sections > 60^o
High tolerance to paraffin in tubing	Sensitive to sand production
Easy to repair and replace	Not suitable for continuous production

1.4.6 Jet Pump

Jet pumps (JP) offer several advantages, including their ability to handle solids and gas, flexibility in adjusting production rates, cost-effectiveness, and ease of replacement. They have no moving parts downhole, can handle high volumes, and are scalable to changes in production rates. Jet pumps can be deployed in deviated wells and are often used in conjunction with centrifugal horizontal surface pumps for improved efficiency. However, jet pumps have limitations in well-drawdown capability and exhibit low overall efficiency due to high-power requirements and system losses. They require a minimum bottomhole flowing pressure to prevent gas breakout and cavitation. The larger footprint of jet pump systems can be a constraint for offshore applications.

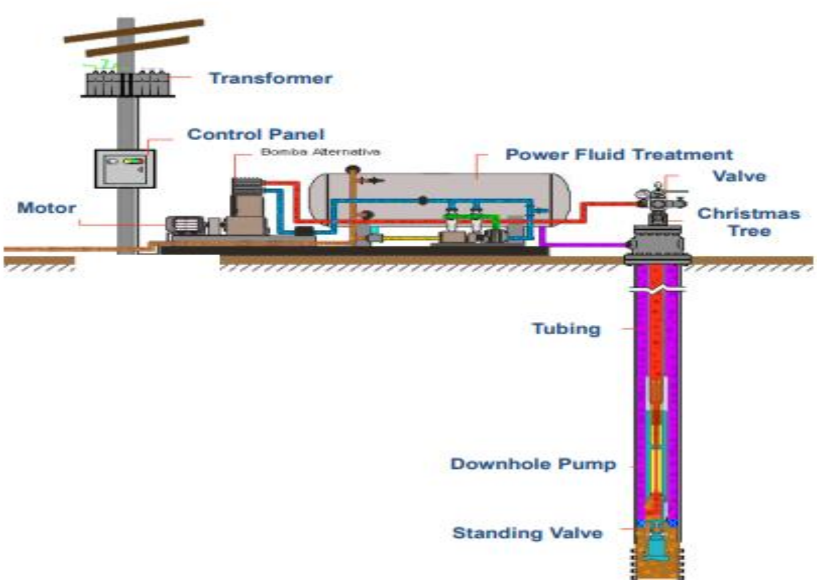


Figure 1.23 Jet pump system

Jet pumps are favored by operators in the US due to their ability to handle solids and gas, flexibility in adjusting production rates, cost-effectiveness, and ease of replacement. They have no downhole moving parts, can handle high volumes, and are scalable by adjusting the nozzle-throat ratio. While their well-drawdown capability is limited, the use of centrifugal horizontal surface pumps alongside jet pumps is becoming popular for improved efficiency. Jet pumps have low overall efficiency due to power requirements and system losses, requiring a minimum bottomhole flowing pressure to prevent gas breakout and cavitation. Their larger footprint can be challenging for offshore applications, although successful deployments have occurred.

Table 1.6 Advantages and disadvantages of jet pump

Advantages	Disadvantages
No moving parts in downhole	Space limitations for offshore applications
Flexible production rates	High energy cost, low efficiency, complex design
High tolerance to corrosive fluids, long run life	Sensitive to back pressure
Applicable to highly deviated wells	Cavitation if more production than planned
No gas locking, can handle solids and sands	Free gas can cause cavitation

1.5 Artificial Lift Selection

Unconventional reservoirs, such as shale and tight formations, have limited storage capacity and low conductivity, requiring stimulation techniques for economical hydrocarbon recovery. However, production rates in wells located in these reservoirs decline significantly within a year after completion and fracturing operations, ranging from 40% to 80% (Pankaj et al., 2018). This highlights the need for effective artificial lift (AL) strategies to sustain production in unconventional reservoirs.

AL systems are crucial in maximizing production rates and economic viability in unconventional wells. Designing AL systems for deep and horizontal wells is a complex task that plays a vital role in optimizing production. AL becomes necessary to ensure economic production in the well's lifespan.

However, challenges such as unstable flow rates, solids damage, gas interference, and liquid slugging arise when dealing with fluid flow in horizontal wellbores. Horizontal wellbores have shown productivity improvements, but their drilling and completion costs are approximately three times higher than vertical wellbores (Kolawole et al., 2019, 2020).

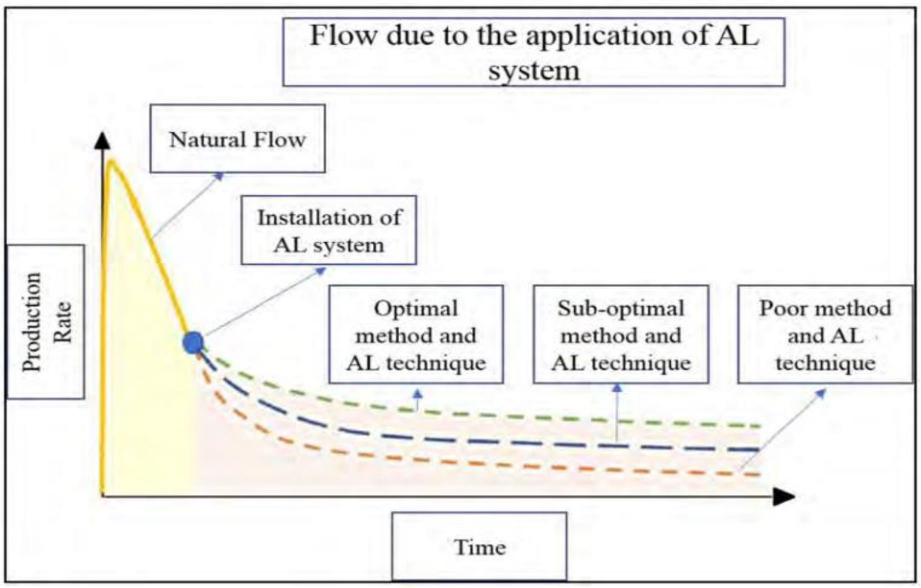


Figure 1.24 Impact of artificial lifts on production rates (Pankaj et al., 2018)

Figure 1.24 portrays the influence of the Artificial Lift (AL) system on the well’s production rate throughout its operational life. As production declines, the AL strategy may involve one, two, or even three different techniques, depending on the initial production rate. Zhao et al. (2018) reported that Gas Lift (GL) is used in approximately 40% of unconventional wells, Electrical Submersible Pumps (ESPs) in 36%, Sucker Rod Pumps (SRPs) in 13%, Plunger Lift (PL) in 7%, and Jet Pumps (JETs) in 4%.

These AL systems combat excessive liquid accumulation at the well bottom, reducing backpressure and enhancing production rates. Selecting suitable AL systems is vital for maintaining optimal production levels. To aid this process, Oyewole (2016) presents a comprehensive workflow (Figure 1.25) encompassing technical, surface, drilling, reservoir, geological, geophysical, and economic factors for designing and selecting artificial lift systems in unconventional wells.

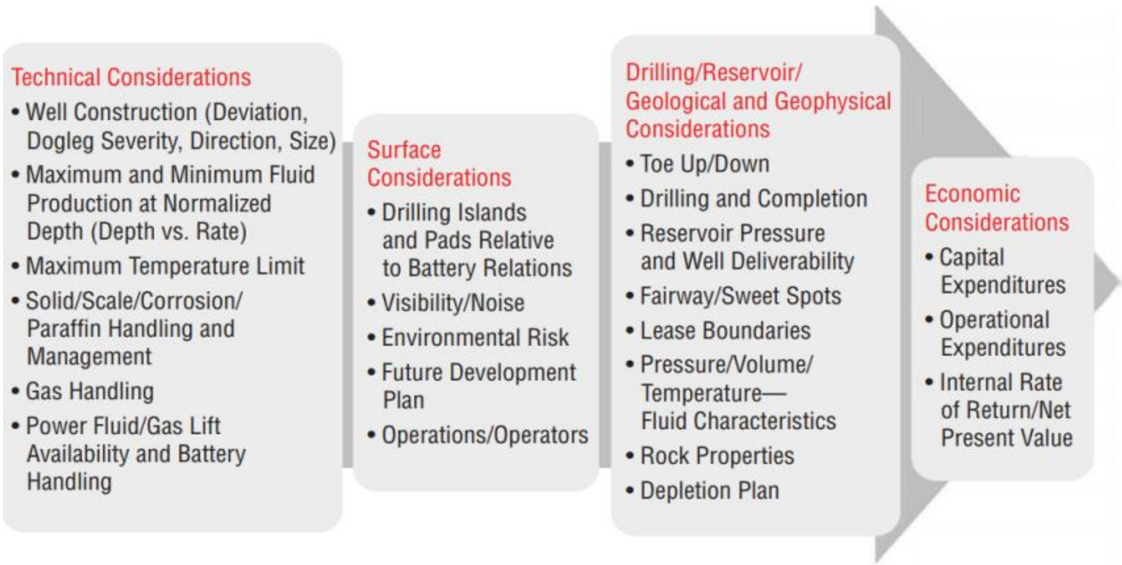


Figure 1.25 Artificial lift design considerations (Oyewole, 2016)

Patron et al. (2017) proposed a workflow to evaluate the suitability of different artificial lift methods based on well characteristics, with the results depicted in Figure 1.26. Artificial lift systems were assessed on a scale of 0 to 100, where 0 indicated inapplicability and 100 denoted optimal efficiency. The findings indicated that rod pumps were unsuitable for the studied wells in the Eagle Ford due to their depth and required flow rates. Rod pumps have limitations regarding production rates as well depth increases. The selected well in this study, operating at a depth of approximately 12,120 ft with an initial liquid production of 2,500 B/D during fracturing fluid flowback, surpassed the operating range of rod pumps. Similarly, plunger lift, progressing cavity pumps (PCPs), and rod-less PCP (RLPCP) exhibited similar limitations. Although not specifically analyzed in this study, PCP and RLPCP were considered in the artificial lift selection workflow.

Table 1. 7 Input design parameters for sensitivity analysis

Input design parameters	Value	Unit
Setting depth	12,120	ft
Initial liquid production rate	2500	BLPD
DLS @ setting depths	7-9	^{o}/100 ft
KOP	11,600	ft
WC	24	%
GLR	450	SCF/STB
Oil gravity	42	^{o}API
Reservoir fluid temperature	270	^{o}F
Later production rate	300	BLPD

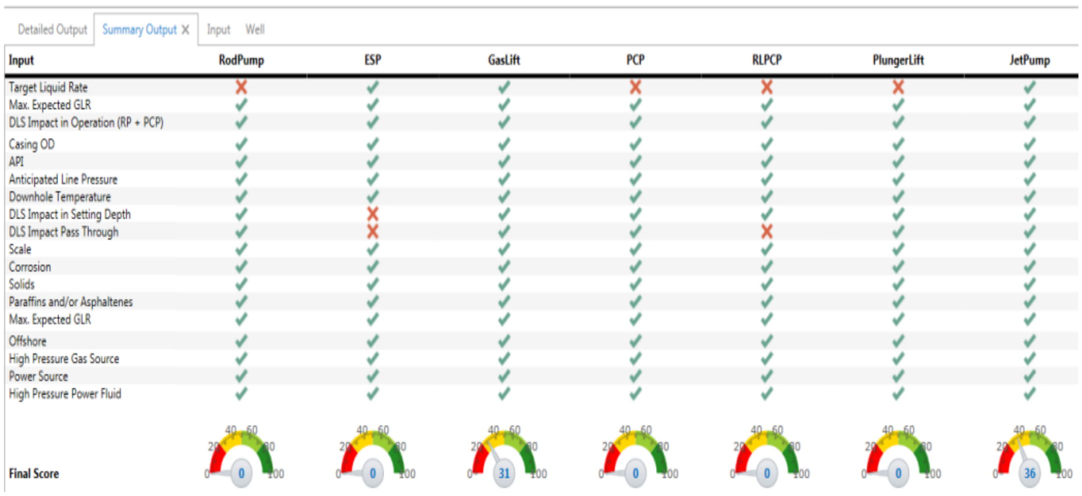


Figure 1.26 Main outputs of artificial lift selection software used by Patron et al. (2017)

According to the study conducted by Patron et al. (2017), rod pumps, plunger lift, PCPs, and RLPCPs were not suitable for the studied wells in the Eagle Ford due to depth and required flow rates. ESPs were also disregarded due to excessive dogleg severity (DLS) at the selected setting depth. Gas lift and jet pumps were the only artificial lift systems that met the operational criteria, with gas lift having a 31% likelihood of success and jet pumps having a 36% likelihood of success, considering the presence of solids that may reduce system efficiency.

The base case scenario in the study involved a toe-up trajectory with an initial liquid production rate of 2,500 B/D and a setting depth of 12,120 ft. Sensitivity cases were conducted for different wellbore trajectories, including toe-up with trap, toe-down, and toe-down with trap.

Despite variations in scores obtained as the production rate changed for each trajectory, gas lift and jet pumps remained the only applicable artificial lift systems due to considerations of wellbore DLS and production conditions.

In a separate study by Zein El Din Shoukry et al. (2020), a set of screening parameters and their corresponding values were proposed to facilitate the selection process of an appropriate artificial lift system. These parameters, presented in Table 1.8.

Table 1.8 Screening Parameters for AL selection, Zein El Din Shoukry et al. (2020)

Parameter	**GL**	**PL**	**SRP**	**PCP**	**ESP**	**JET**
Max. Depth (ft)	18,000	19,000	16,000	<9,000	15,000	20,000
Max. Vol.(bpd)	75,000	200	6,000	5,000	60,000	35,000
Max.Temp.(°F)	450	550	550	302	482	550
Corrosion Handling	Good to Excellent	Excellent	Good to Excellent	Good	Good	Excellent
Gas Handling	Excellent	Excellent	Fair to Good	Good	Fair	Good
Solids Handling	Good	Fair	Fair to Good	Excellent	Sand < 40 ppm	Good
API	> 15°	> 15°	> 8°	8° - 15°	Visc. < 400 cp	≥ 6°
Servicing	WL or Workover Rig	Wellhead Catcher or Wireline	WO or Pulling Rig	WL or WO Rig	WL or WO Rig	Hyd. or WL
Prime Mover	Compressor	Well Natural Energy	Gas or Electric	Gas or Electric	Electric	Gas or Electric
Offshore	Excellent	N/A	Limited	Good	Excellent	Excellent
System Efficiency	10-30%	N/A	45-60%	55-75%	35-60%	10-30%

Oyewole (2016) in his study implemented an Artificial lift selection strategy for the unconventional oil wells. This strategy has been put forth to maximize the value of their unconventional oil and gas assets. This strategy serves as a guideline for producers to make important decisions when selecting the most suitable artificial lift (AL) system. By following this strategy, it can optimize production and enhance the economic viability of their operations. The following table is the recommended AL strategy in his study for 5 wells parameters.

Table 1.9 AL strategy for unconventional wells (Oyewole, 2016)

Well type	Well description	Recommended lift method
1	Undersaturated reservoir	ESP only is highly recommended for the life of well. SRP may be used if well performance does not meet expectation
	Black oil type—PVT	
	High water cut (>80%)	
	Low production decline rate	
	High liquid production (>500 BLPD)	
	Low GLR (<750 Scf/bbl)	
2	Undersaturated reservoir	SRP only is highly recommended for the life of well. There is only managed flow back and managed depletion periods in the well life
	Black oil type—PVT	
	High water cut (>80%)	
	High production decline rate	
	Low liquid production (<500BLPD)	
	Low GLR (<750 Scf/bbl)	
3	Undersaturated reservoir	Jet pump for early production then SRP for later production when reservoir pressure is low
	Black oil type—PVT	
	High reservoir pressure	
	High TVD	
	Low GLR (<750 Scf/bbl)	
4	Saturated reservoir	SRP only is highly recommended for the life of well. Managed flow back and managed depletion periods in the well life
	Volatile oil type-PVT	
	High watercut (> 80%)	
	High production decline rate	
	Low liquid production (<500 BLPD)	
	Low GLR (< 750 Scf/bbl)	
5	Undersaturated reservoir	Plunger lift and gas lift only. Operation will include plunger lift assists gas lift and gas lift assists plunger during the well life
	Volatile oil type-PVT	
	Low watercut (< 80%)	
	High production decline rate	
	Low liquid production (<500 BLPD)	
	Low GLR (< 750 Scf/bbl)	
	High gas production	

The recommended Artificial Lift Selection Strategy encompasses several key steps. Firstly, a thorough evaluation of well characteristics and production requirements is conducted. This includes analyzing factors such as flow rates, fluid properties, well depth, and reservoir conditions. The purpose of this step is to gather essential data that will inform the subsequent selection process.

Based on the gathered data and the assessment of AL systems, a shortlist of potential AL methods is created. These options are carefully reviewed, considering factors such as their performance in similar reservoirs, success rates in similar wells, and industry best practices. These recommendations consider the performance and compatibility of different AL systems with the specific well conditions. The aim is to select an AL method that not only meets the production requirements but also addresses the technical and economic challenges associated with the well.

CHAPTER 2

FIELD DATA INTRODUCTION

This study investigated the artificial lift system design in an unconventional reservoir from TUALP sponsor companies. This collaboration between TUALP and KOC aims to enhance the understanding and effectiveness of artificial lift methods specifically tailored for unconventional reservoirs, which present unique challenges in terms of reservoir characteristics and production techniques.

KOC, being a prominent oil company with vast experience in oil and gas exploration and production, provided TUALP with a significant amount of valuable field data for their horizontal wells in an unconventional reservoir, including but not limited to their fluid properties, well profiles, well performance, production data and operational challenges. The data covers a wide range of wells that are producing from <100 stb/d to 1000 stb/d.

2.1 Field Introduction

The M-field, located in the western region of Arabian Gulf area (Figure 2.1), is an anticline that stretches in a north-south direction. This field encompasses six significant reservoirs, which span from the Early Jurassic to the Late Cretaceous period. Its initial discovery dates to 1959. Among these reservoirs, the Early Cretaceous (Neocomian) M-Oolite Formation serves as the primary reservoir, holding approximately 84 percent of the field's reserves. Furthermore, it has accounted for more than 80 percent of the field's overall production. In terms of future development plans, the focus remains on the Oolite Formation, with aspirations of achieving a four-fold increase in production from the M-field by 2001 (Al-Ajmi et al., 2001).

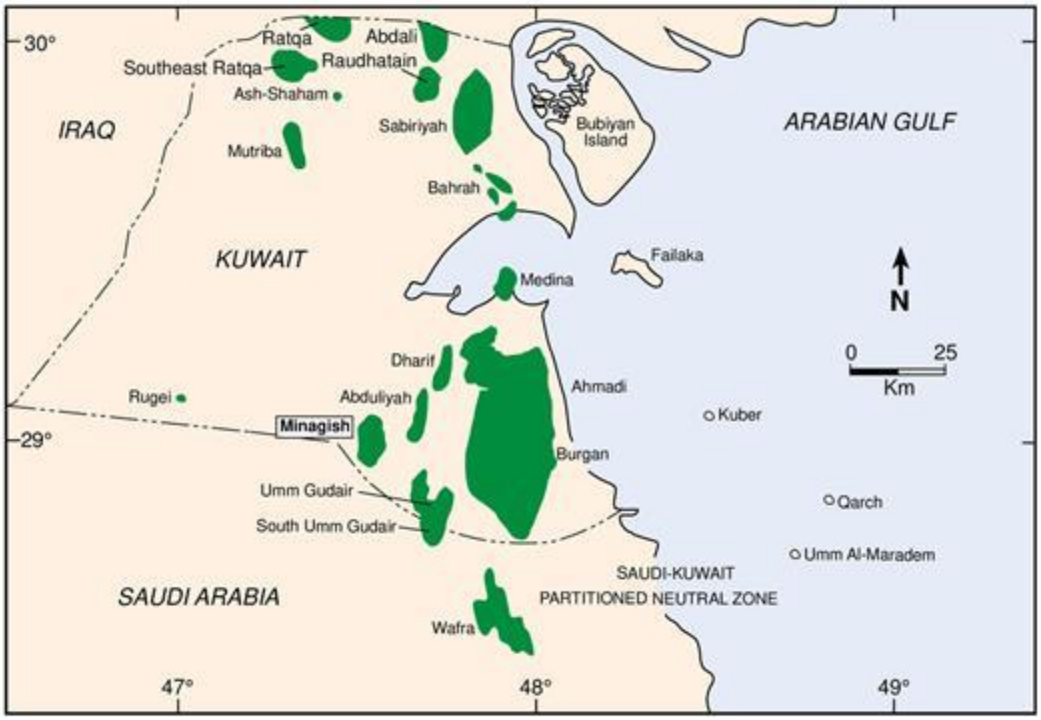


Figure 2.1 Location Map of M-field in Kuwait

The M-Oolite reservoir remains largely undeveloped despite being mature, with less than 10% of reserves exploited in almost 40 years. Primary production is through depletion, with minimal aquifer support, indicated by over 1000 psi pressure decline since inception. The field is sensitive to high production rates, as shown by significant pressure drop during the Iraqi invasion blowouts. To conserve reservoir energy, production is maintained at modest levels, around 60 mbopd.

To address pressure decline and increase production from 60 to 210 mbopd, a peripheral water flood plan is proposed for the field. The plan includes 12 to 16 water injectors to support around 50 producer wells, strategically located from mid-flank to crestal regions. The average density of producer wells will be approximately 1 well per 240 acres in accordance with the development scheme (Singh et al., 1997).

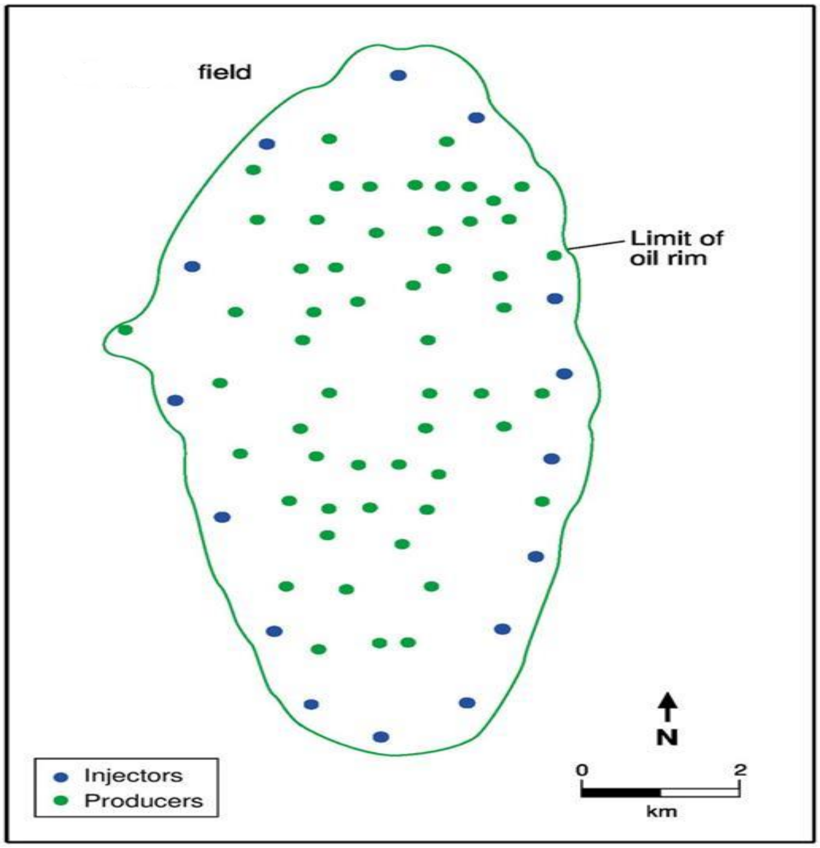


Figure 2.2 Producing and injector wells in M-field

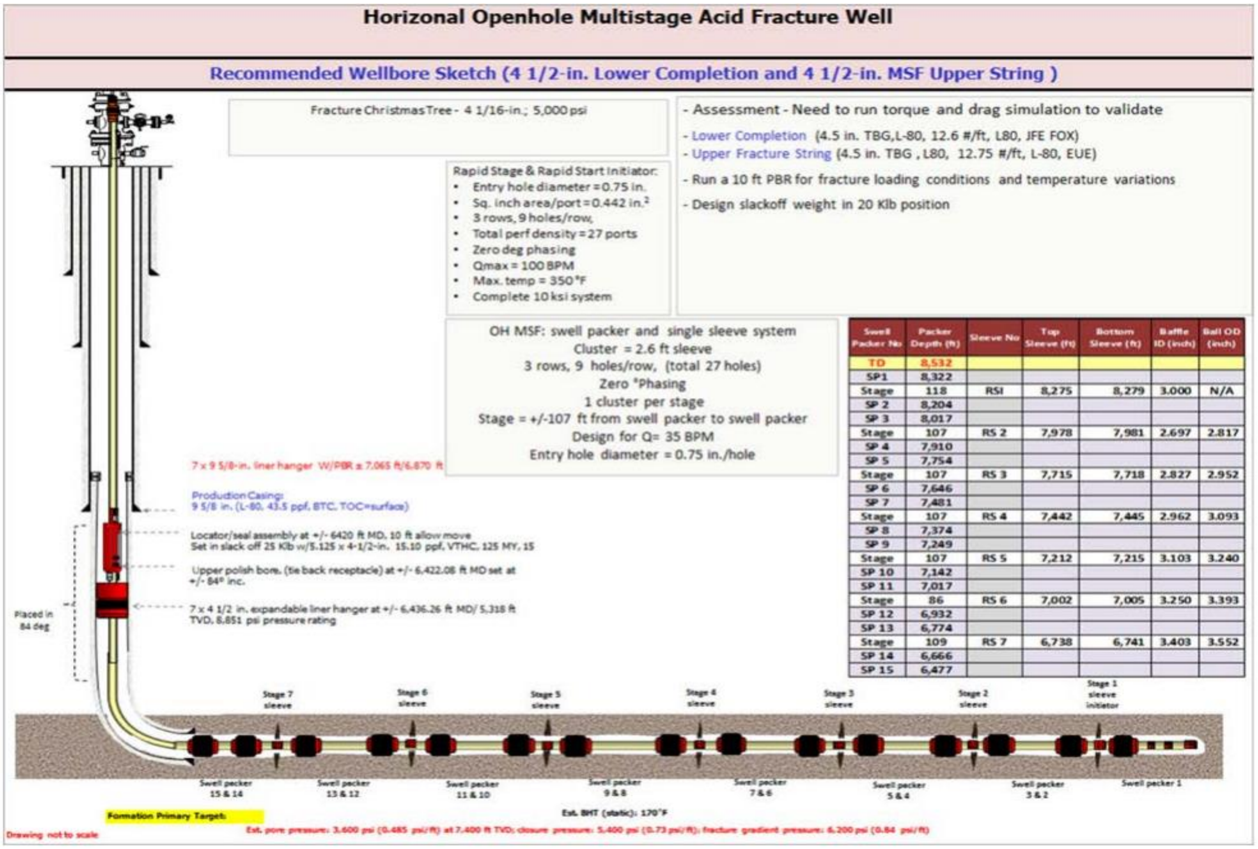
The M-Oolite reservoir is a carbonate reservoir with favorable permeability (200 to 2000 md) and porosity (17 to 23 percent) located at a depth of 9,000 to 10,000 ft. It exhibits microporosity in mudstone to wackestone intervals. Oolitic grainstones, with the highest reservoir quality, were deposited in extensive facies belts on a shallow-gradient carbonate ramp. The reservoir consists of 13 well-defined layers, influencing tar mat distribution and development. While layering remains consistent on a broader scale, there is significant heterogeneity within each layer. This heterogeneity may impact the efficiency of water flood techniques and overall reservoir performance. Managing these factors is crucial for successful production and development in the M- Oolite reservoir.

Horizontal wells in the tight carbonate Mishrif reservoir of the West Kuwait M-fields have shown significant benefits, with increased reservoir contact area leading to higher production rates and improved hydrocarbon recovery. However, the large wellbore radius has introduced challenges related to increased friction losses during production. To address this, flow equalizing completion techniques have been employed, stabilizing early-phase production, and enhancing overall recovery.

Despite these achievements, the long horizontal laterals make accessing and treating the entire reservoir section difficult. Coiled tubing acidizing treatments have been limited in their impact on lower-permeability sections, resulting in insufficient radial penetration. Additionally, bullheading treatments have primarily targeted the heel section of the horizontal well, leaving significant portions of the lateral unproductive due to inefficient acid distribution. Understanding these issues is crucial for optimizing stimulation strategies and maximizing reservoir recovery in the Mishrif reservoir (Al-Sabea et al., 2023).

Mofti et al. (2019) in their study focuses on the Mishrif reservoir in the M-field of western Kuwait, a tight carbonate formation with suboptimal reservoir quality and low pressure. Openhole completions have been traditionally used. Positive results from acid stimulation treatments have led to adopting multistage acid fracture stimulation for shorter horizontal wells. As longer horizontal wells are pursued for production enhancement, addressing challenges in effective stimulation during completion is crucial.

To optimize hydrocarbon production in long horizontal open holes, multistage acid fracturing stimulation is necessary. Selective completion tools segment the wellbore's annular space into isolated intervals based on petrophysical and reservoir properties. These isolated sections can be selectively stimulated, maximizing productivity through continuous intervention.



Swell Packer No	Packer Depth (ft)	Sleeve No	Top Sleeve (ft)	Bottom Sleeve (ft)	Baffle ID (inch)	Ball OD (inch)
TD	8,532					
SP1	8,322					
Stage	118	RSI	8,275	8,279	3.000	N/A
SP 2	8,204					
SP 3	8,017					
Stage	107	RS 2	7,978	7,981	2.697	2.817
SP 4	7,910					
SP 5	7,754					
Stage	107	RS 3	7,715	7,718	2.827	2.952
SP 6	7,646					
SP 7	7,481					
Stage	107	RS 4	7,442	7,445	2.962	3.093
SP 8	7,374					
SP 9	7,249					
Stage	107	RS 5	7,212	7,215	3.103	3.240
SP 10	7,142					
SP 11	7,017					
Stage	86	RS 6	7,002	7,005	3.250	3.393
SP 12	6,932					
SP 13	6,774					
Stage	109	RS 7	6,738	6,741	3.403	3.552
SP 14	6,666					
SP 15	6,477					

Figure 2.3 Horizontal multistage acid fracture

The Figure 2.3 illustrates the multistage acid fracturing plan in the Mishrif Reservoir. The well has a total depth of 8532 ft and a bottomhole temperature of 170°F. The open hole completion zone has an 8-inch diameter, and the tubing has a 4 ½-inch ID. The horizontal openhole section is 1800 ft, divided into 7 stages of varying lengths. The objective is to generate a single long fracture in the low permeability reservoir, ensuring effective stimulation and sustained productivity. Specific isolated short sections, averaging 106 ft, were chosen based on porosity and water saturation data from log information. Stages 2 and 3 have higher water saturation and shale content, while the completed stages exhibit similar properties.

Figure 2.4 Before acid job (left) vs. after acid job (right)

A core sample from Mishrif tight carbonate reservoir has been collected for core analysis. From the above Figure 2.4 Before acid job (left) vs. after acid job (right), core sample has gone through acid etching test. The image on the left side represents a core sample before acid etching test and the right-side image is taken after acid etching test.

The acid etch test plays a crucial role in determining the suitability of acid fracturing stimulations in carbonate formations. It is a critical test that helps assess whether the acid treatment can create flow channels on the fracture face and if the rock stability is affected by the acid system. If the acid etching process fails to generate flow channels or if it compromises the stability of the rock, acid fracturing may not be a viable stimulation technique in such carbonate formations. In such cases, the primary method of stimulation may rely on creating fractures with proppant injection.

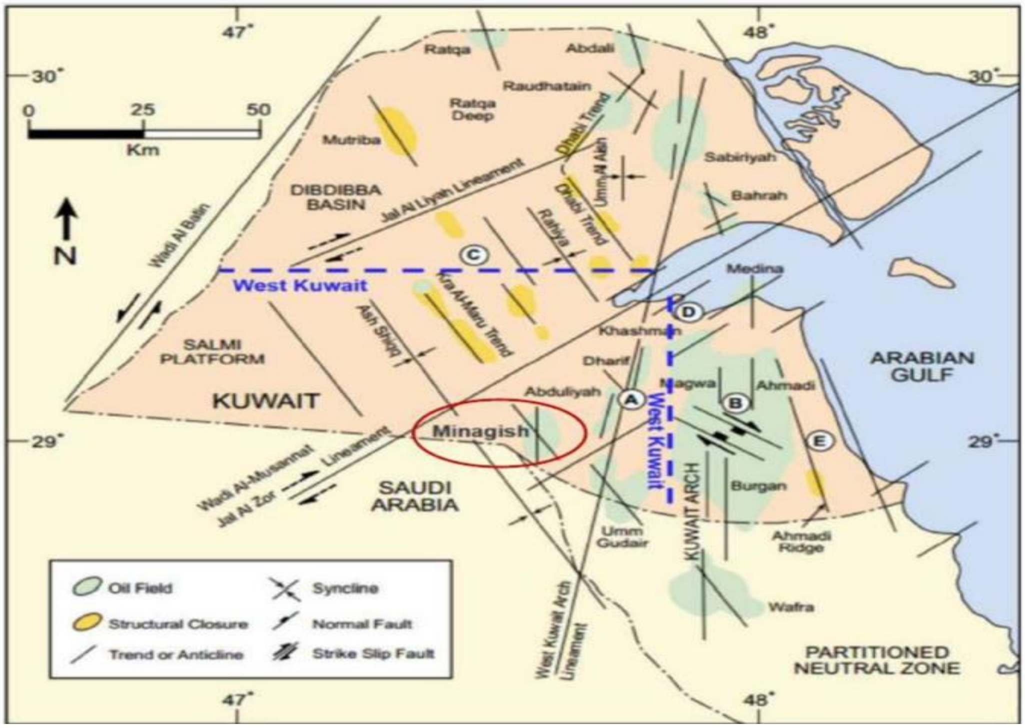


Figure 2.5 Map of M-field in Kuwait

KOC has provided a large amount of data which consists of 26 horizontal wells that are producing in a wide range from 100 stb/d to 1000 stb/d. The M-field was categorized into two field, i) North Field and ii) South Field.

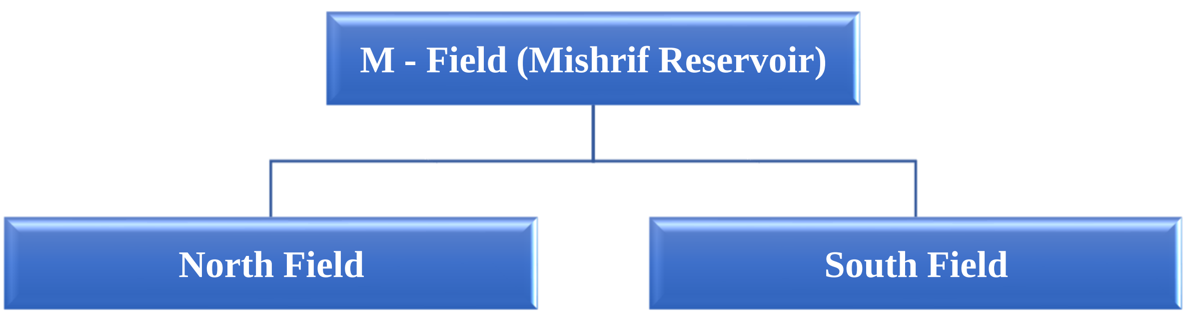


Figure 2.6 Fields in Mishrif formation

The data consists of various information, and this has been divided into three data sets: well information, reservoir properties and production data.

The dataset includes 26 wells, with 25 being horizontal and 1 directional. Each well provides detailed information on wellbore deviation survey data, casing, tubing, and material specifications. Notably, no downhole tools like packers or sssv are installed, and all wells utilize artificial lift methods due to low reservoir pressure. Among the operational wells, 21 use Electrical submersible pumps (ESP), 3 employ Progressive cavity pumps (PCP), and 2 are equipped with Rod pumps (SRP). All wells have undergone acid fracturing stimulation to enhance production by creating fractures in the tight carbonate reservoir.

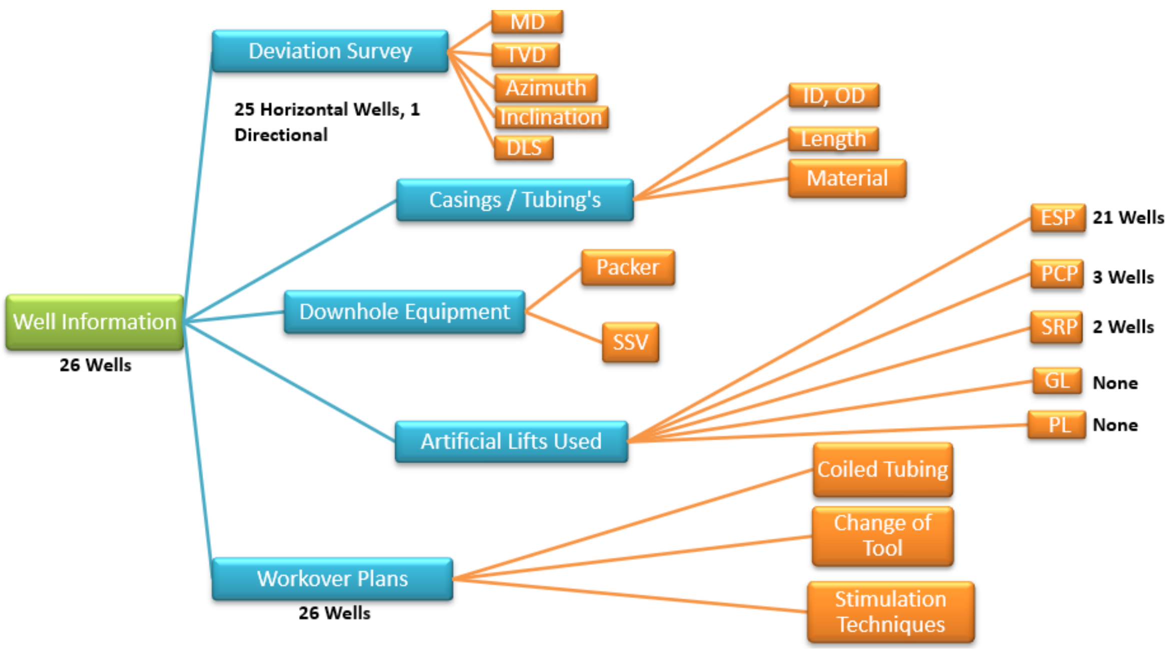


Figure 2.7 Well Information

The provided data concerns the “Mishrif Reservoir,” an unconventional tight carbonate reservoir. It includes crucial parameters such as reservoir pressure (1800 psia), temperature (138 F), and reservoir depth (ranging from 4832 ft to 5500 ft). Permeability data for all 26 wells within the reservoir have been provided. The fluid properties include viscosity (35 cp to 37 cp), API oil gravity (20 to 23), gas oil ratio (16 scf/stb to 80 scf/stb), water cut (20% to 40%), water specific gravity (1.16 to 1.18), gas specific gravity (1), bubble point pressure (100 psia), and no indications of solids production, wax depositions, or emulsions. This information is essential for reservoir characterization and production optimization in the Mishrif Reservoir.

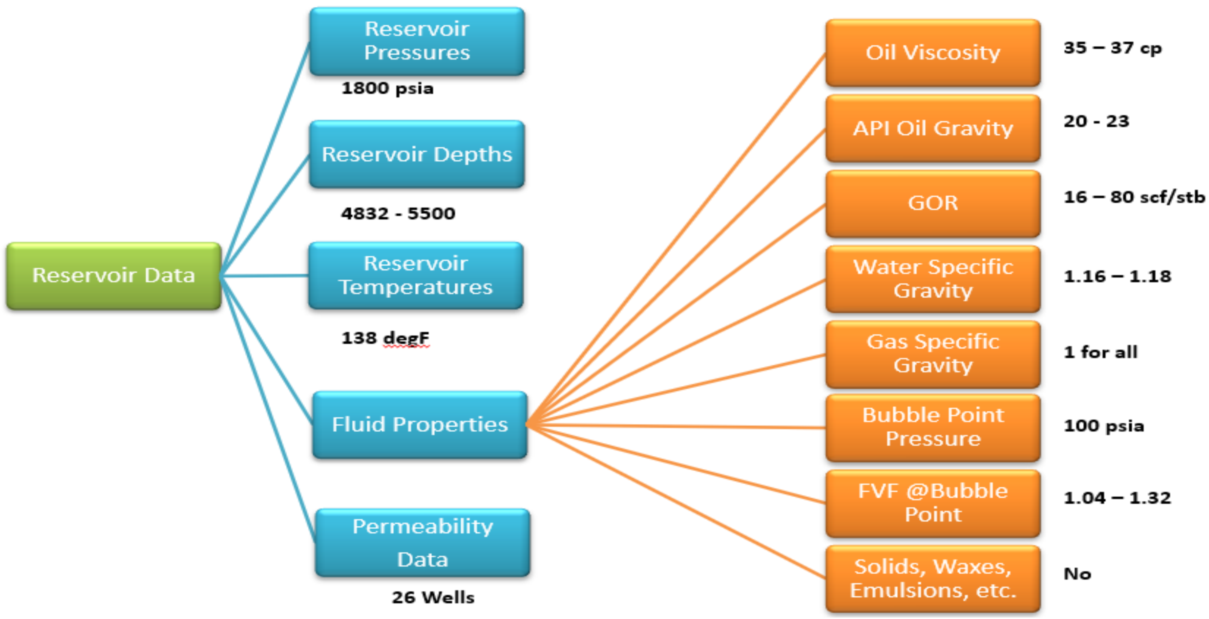


Figure 2.8 Reservoir properties

Likewise, comprehensive production data has been provided for the 26 wells under consideration. This dataset encompasses the production rates recorded for each well, ranging from the initial production until the most recent data available. Analyzing this production data is crucial for evaluating the performance of each well, as the production rates differ from well to well. Several factors can influence the performance of the wells, such as the trajectory of the wellbore, pressure losses occurring in the tubing, performance of the artificial lift, lower reservoir pressures, variations in fracture properties, poor completions, skin factor, and the fluid properties.

Within this production data, various parameters have been given, including liquid flow rates ranging from 100 stb/d to 1000 stb/d, water cut ranging from 20% to 40%, GOR ranging from 16 scf/stb to 80 scf/stb, productivity index of the well, pump intake pressures, pump discharge pressures, fluid salinity, and the choke size employed to optimize production rates.

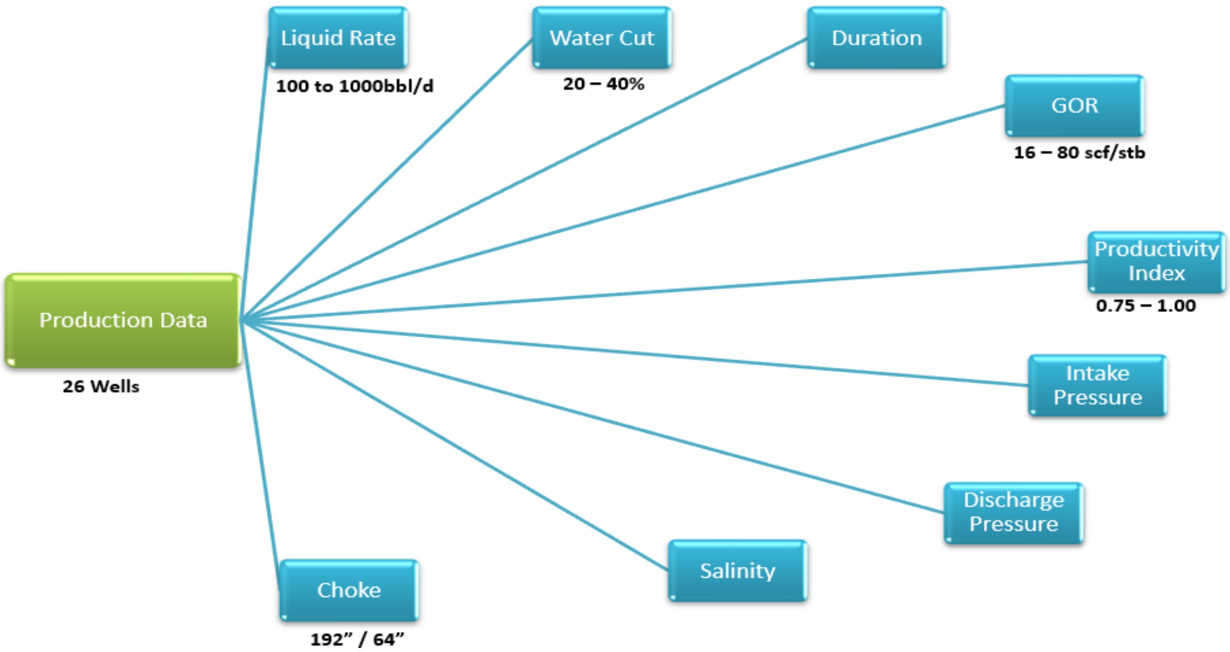


Figure 2.9 Production data

M-field has a total of 26 wells and these wells were classified into north field and south field. The majority of wells in M-field were present in North field which are 17. South field has a total of 9 wells. In both the fields, wells are producing in a wide range of production rates, there are few wells that are producing < 100 stb/d and more than 1000 stb/d.

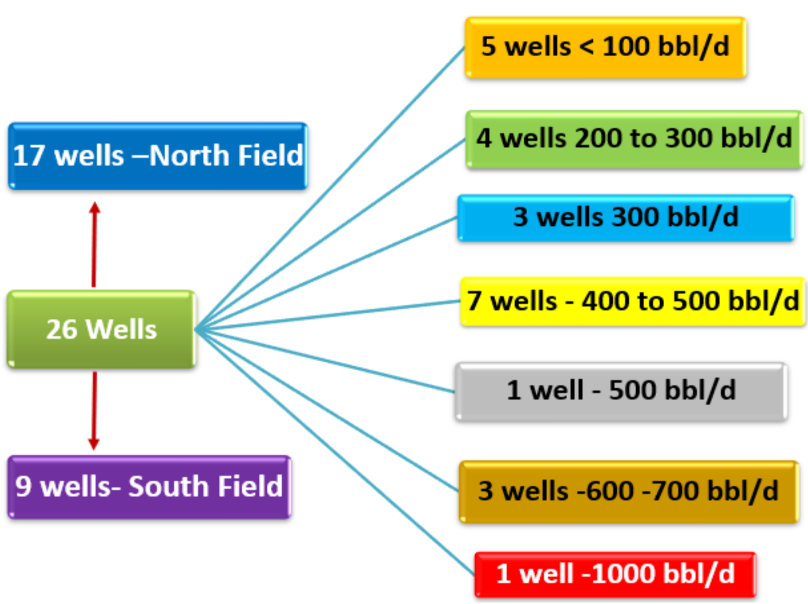


Figure 2.10 Wells production rates in the M-field

An updated M-field map has been added with the total number of wells including north field and south field.

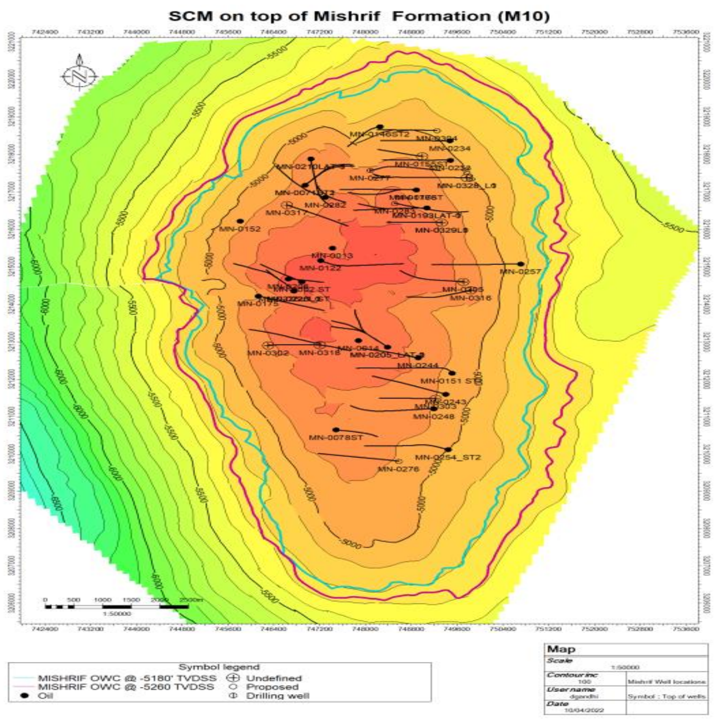


Figure 2.11 Updated wells information in Mishrif formation

2.2 North Field

In M-field and Mishrif formation, the northern part of the area is categorized as North field. This field has a total of 17 wells out of which two wells are under evaluation and 1 well is closed. Currently 14 wells are operational with proper artificial lift methods.

These wells have a wide range of production rates, 3 wells are producing < 100 stb/d, 3 wells are producing in between 200 stb/d to 300 stb/d, 3 wells are producing 300 stb/d, 4 wells are producing at a rate of 400 stb/d and finally one well is producing at a higher rate from 600 stb/d to 700 stb/d.

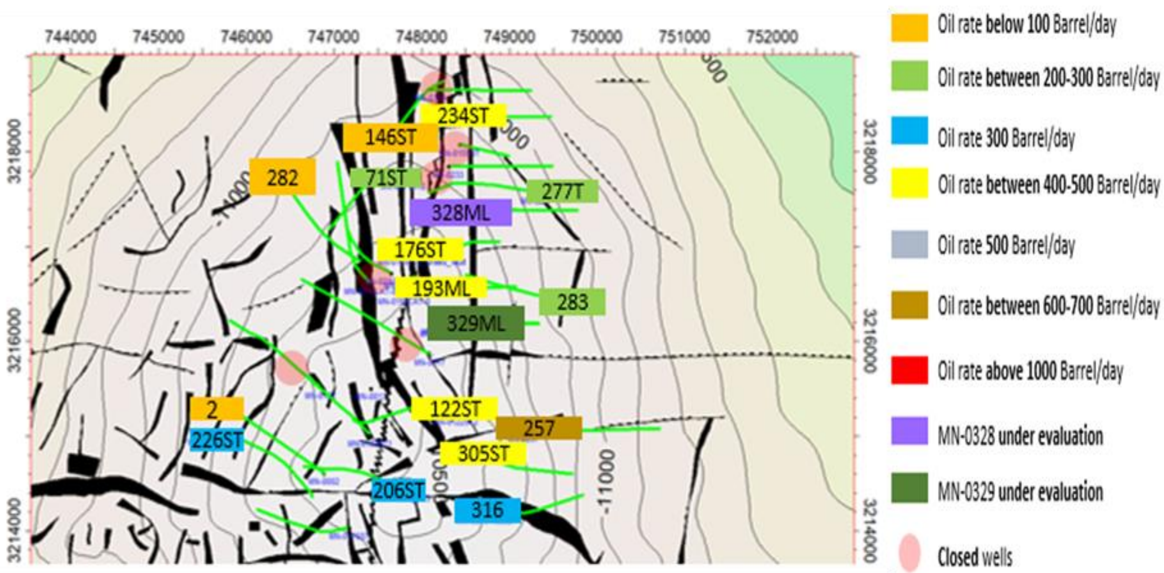


Figure 2.12 North field wells locations

The wells that are producing at different rates were highlighted in different colors along with the wells that are under evaluation and closed wells.

Table 2.1 North field wells

Well Name	Current Status	Production Range (bbl/d)	Field	AL
Well-A	**Open**	**< 100 stb/d**	North	SRP
Well-B	**Open**		North	PCP
Well-C	**Open**		North	ESP
Well-D	**Open**	**200 - 300 stb/d**	North	ESP
Well-E	**Open**		North	ESP
Well-F	**Open**		North	ESP
Well-G	**Open**	**300 stb/d**	North	ESP
Well-H	**Open**		North	ESP
Well-I	**Open**		North	ESP
Well-J	**Open**	**400 - 500 stb/d**	North	ESP
Well-K	**Closed**		North	ESP
Well-L	**Open**		North	ESP
Well-M	**Open**		North	ESP
Well-N	**Open**		North	ESP
Well-O	**Open**	**600 - 700 stb/d**	North	ESP
Well-P	**Open**	**Under Evaluation**	North	NA
Well - Q	**Open**	**Under Evaluation**	North	NA

These 17 wells were equipped with different artificial lift methods. Mostly, 13 wells were equipped with an electrical submersible pump (ESP), 1 well is equipped with progressive cavity pump (PCP) and 1 well is equipped with rod pump (SRP). From this north field, based on the wells production rates the average production rate that can be achieved in this field can be obtained by calculating means. The mean of all the wells based on their production rates is 315 stb/d and the median of all these wells is 300 stb/d.

2.3 South Field

The southern region within the M-field contains the South field, comprising a total of 9 wells, with 8 currently operational and equipped with artificial lift mechanisms. Production rates vary widely, with one well producing less than 100 stb/d, another in the range of 200 to 300 stb/d, two consistently at 400 to 500 stb/d, one at 500 stb/d, two at 600 to 700 stb/d, and one with the highest production rate of 1000 stb/d. The diversity in production rates indicates variations in well performance and highlights the importance of efficient artificial lift implementation in the Mishrif formation of the M-field.

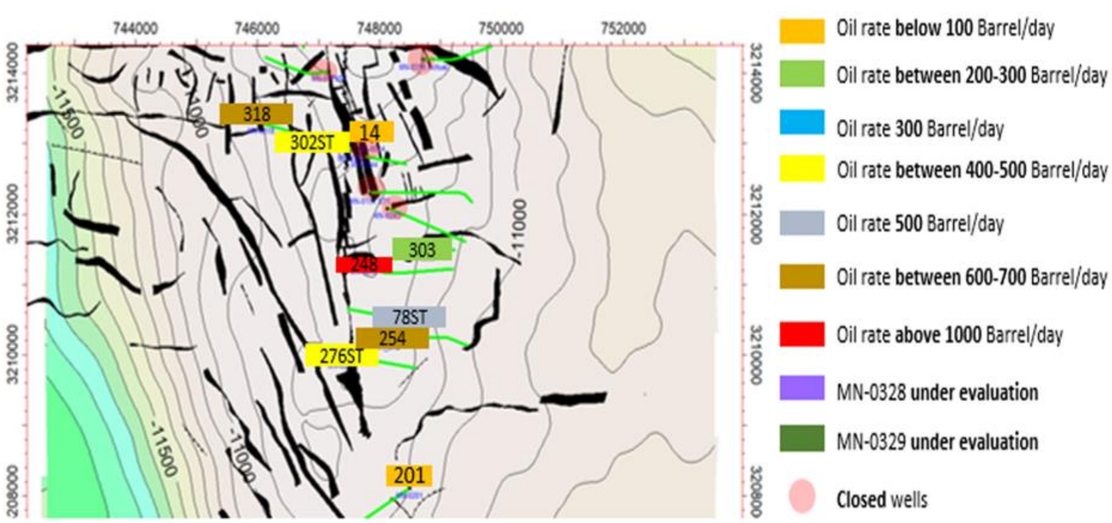


Figure 2.13 Wells locations in South Field

Table 2.2 Wells in South Field

MF Well Name	Current Status	Production Range (bbl/d)	Field	AL
Well-R	**Open**	**< 100 stb/d**	South	SRP
Well-S	**Closed**		South	ESP
Well-T	**Open**	**200 - 300 stb/d**	South	ESP
Well-U	**Open**	**400 - 500 stb/d**	South	PCP
Well-V	**Open**		South	PCP
Well-W	**Open**	**500 stb/d**	South	ESP
Well-X	**Open**	**600 - 700 stb/d**	South	ESP
Well-Y	**Open**		South	ESP
Well - Z	**Open**	**> 1000 stb/d**	South	ESP

The array of 9 wells within this region were endowed with various artificial lift mechanisms to facilitate production. Predominantly, 6 wells were operating with an electrical submersible pump (ESP), while 2 wells were equipped with a progressive cavity pump (PCP), and a single well with a rod pump (SRP).

Drawing from the production rates of these wells in the South field, it is possible to derive the average production rate for this area by calculating the mean. The mean production rate across all the wells amounts to 450 stb/d, signifying the average performance achieved. Additionally, the median production rate among these wells stands at 450 stb/d, providing a measure of central tendency for the distribution.

CHAPTER 3

PIPESIM SIMULATION

In this study PIPESIM software is incorporated for well performance analysis, offering tools to model and simulate oil and gas wells. PIPESIM is widely used in the industry for steady-state simulation in wellbore systems and pipelines, optimizing hydrocarbon transportation systems. Its applications include well performance assessment to enhance oil and gas production efficiency.

Table 3.1 PIPESIM applications in this study

Application	Uses
P/T profile	PIPESIM analyzes pressure and temperature profiles in the wellbore, considering fluid properties, flow rates, and geometry. This aids in diagnosing flow issues, optimizing equipment, and ensuring efficient well performance.
Production Forecasting	PIPESIM is utilized for production rate prediction and analysis at both well and field levels. Nodal analysis allows understanding of the entire system's behavior, providing inflow-outflow plots to estimate production rates over time. This aids in optimizing production strategies and assessing well productivity potential.
Artificial Lift Optimization	PIPESIM aids in optimizing artificial lift systems like ESPs and PCPs for evaluating their efficiency and performance, helping to select the most suitable lift system for each well in the field.
Sensitivity Analysis	PIPESIM enables sensitivity analysis to identify production enhancement opportunities by varying system parameters. It assesses the impact of factors like wellbore configuration, completion design, production rates, and fluid properties, aiding in informed decisions to optimize well performance.

The objective is to optimize well performance by selecting the best design parameters. PIPESIM analyzes various factors, such as flow rates, pressures, power, and temperatures, to optimize lift design, maximize production, and minimize operating costs in the entire system.

3.1 Background

PIPESIM is trusted and widely used for production system design and offers workflows for production optimization, including well selection, flow assurance, and system optimization. Its versatility and accuracy have made it the leading steady-state multiphase flow simulator in the industry, empowering engineers to enhance production efficiency and profitability.

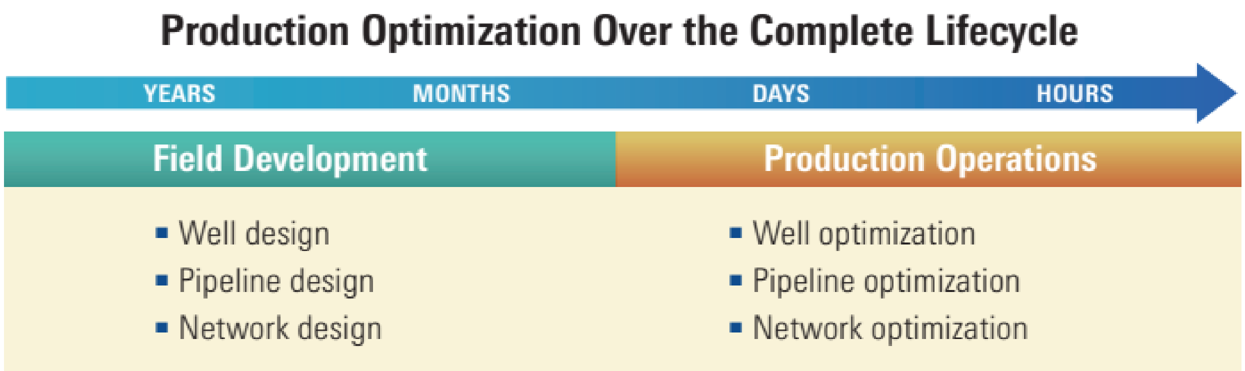


Figure 3.1 Lifecycle of field from development to operation

3.2 PIPESIM Case Setup

Setting up a case in PIPESIM involves configuring various parameters and input data to accurately simulate the behavior of a production system. The case setup process in PIPESIM can be divided into several key steps, each contributing to the overall accuracy and reliability of the simulation. This chapter will delve into the details of the case setup process in PIPESIM.

3.2.1 Fluid Characterization

Defining fluid properties is the initial step. It involves specifying fluid composition (oil, gas, water, etc.) and accurately characterizing density, viscosity, and phase behavior. The software offers different fluid characterization options, such as black oil, compositional, and equation of state models, based on system complexity and needs.

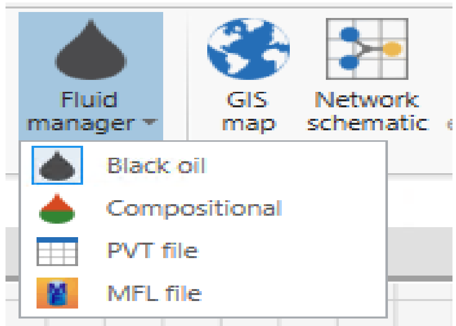


Figure 3.2 Fluid models in PIPESIM

In PIPESIM, the black oil and compositional models are two different approaches used for fluid characterization in multiphase flow simulations. Based on the available fluid properties data from the field, the black oil fluid model is selected in this study.

The black oil model is a simplified approach commonly used for reservoir fluids that exhibit relatively low compositional complexity. It assumes that the fluid can be represented by three phases: oil, gas, and water. The black oil model is primarily based on pressure-volume-temperature (PVT) data and empirical correlations. It simplifies the fluid behavior by assuming that the oil and gas phases are in thermodynamic equilibrium, neglecting detailed compositional effects. This model is suitable for simulating reservoirs with predominantly volatile oil and simple fluid behavior.

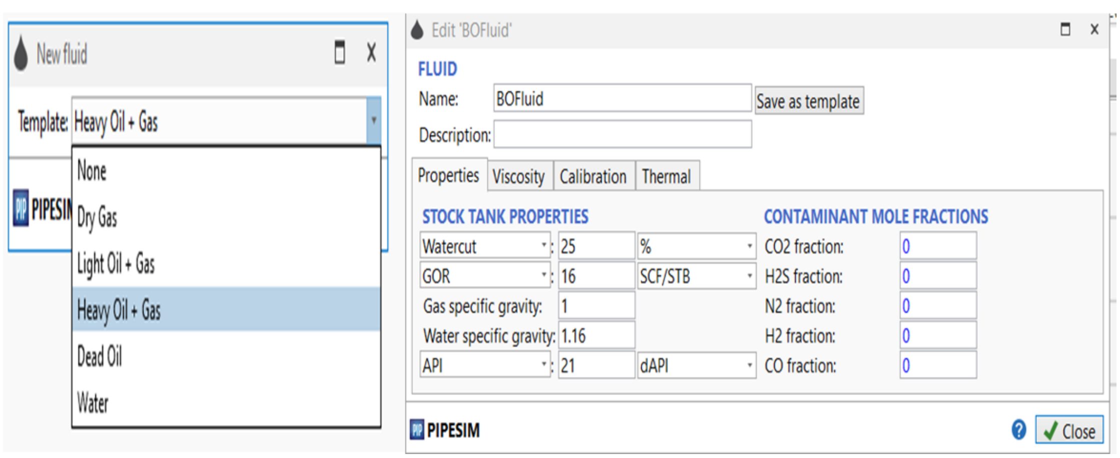


Figure 3.3 Black oil fluid model in PIPESIM

3.2.2 Well Setup

The well setup process begins with specifying the wellbore deviation survey and then adding casing/tubing values and downhole equipment. It is observed that wells in the north and south fields lack downhole equipment like packers and SSSV. The addition of ESP or PCP to the wells is being considered. Since all the wells are horizontal, distributed completions, including trilinear transient IPR, are used in this study. Finally, reservoir properties should be defined. This is the general procedure for setting up a well for simulation. An example of a complete well setup is shown in the figure.

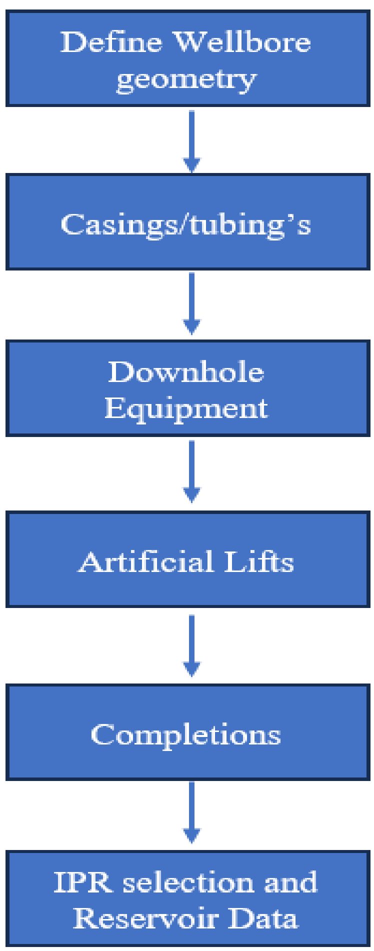


Figure 3.4 Well setup process

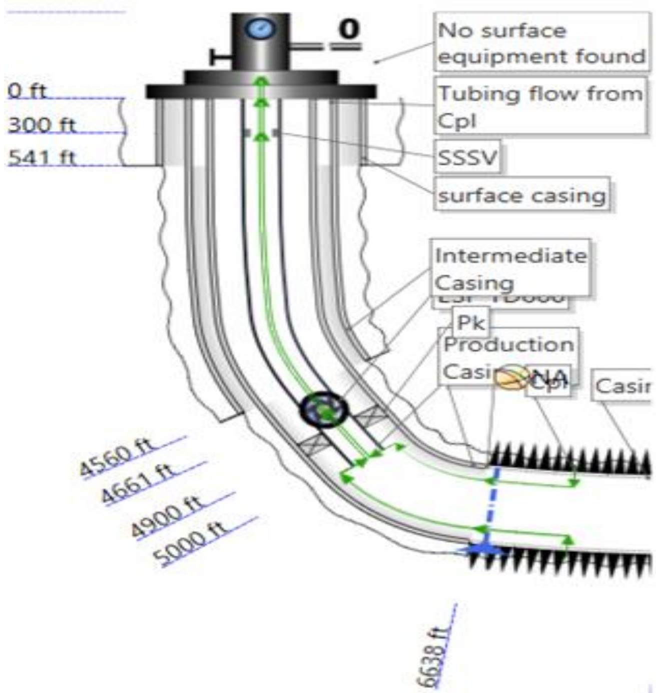


Figure 3.5 General horizontal well

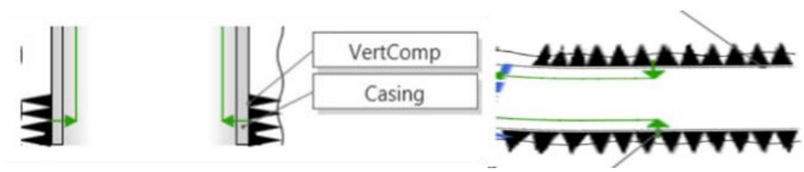


Figure 3.6 Vertical completions (left) and horizontal completions (right)

Well completions vary depending on the well's geometry profile, whether it is vertical or horizontal. Different completion methods are used for each profile. In Pipesim, vertical completions have a single fluid entry, requiring consideration of various IPR models for the reservoir. In contrast, horizontal completions can have either single point entry or distributed entry, with limited IPR models available. In this study, the trilinear transient IPR model is utilized from the distributed completion, which is used in all simulations.

Geometry Profile	Interval type	Completion method
Vertical	Cased hole	• Perforated • Perforated and gravel packed • Frac packed
	Open hole	• Open hole • Open hole gravel packed
Horizontal	Cased hole	• Perforated • Perforated and gravel packed
	Open hole	• Open hole • Open hole gravel packed

Figure 3.7 Types of completion methods

In the table below, both horizontal and vertical completions were explained with the fluid entry and their IPR models.

Table 3.2Vertical & Horizontal Completions with IPR Models

Geometry Profile	**Fluid Entry**	**IPR Model**
Vertical Completions	Single Point	Well PI (gas & liquid) Vogel (liquid only) Fetkovich (liquid only) Jones (gas & liquid) Forchheimer (gas only) Backpressure (gas only) Hydraulic Fracture Model (gas & liquid) Darcy Model (gas & liquid)
Horizontal Completions	Single Point	Joshi (liquid, gas) Babu & Odeh (liquid, gas)
	Distributed	Joshi (liquid, gas) Babu & Odeh (liquid, gas) Well PI Trilinear Transient IPR

3.2.3 ESP Design

In PIPESIM, ESP has a broad range of models with manufacturers, ESP can be applicable with a wide range of production rates.

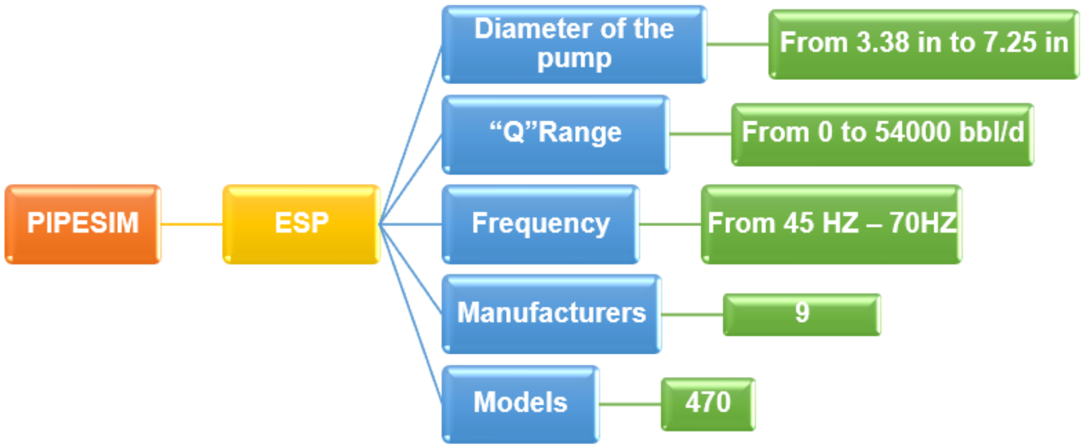


Figure 3.8 ESP data in PIPESIM

Conventional ESP designing is a cumbersome task, whereas in PIPESIM designing an ESP is simple and accurate. ESP can be designed for new wells or for wells with existing ESPs or any other artificial lift method to replace them. A simple flow chart can explain designing ESP in PIPESIM. The below Figure 3.9 ESP design proceduredescribes designing an ESP with a step-by-step process.

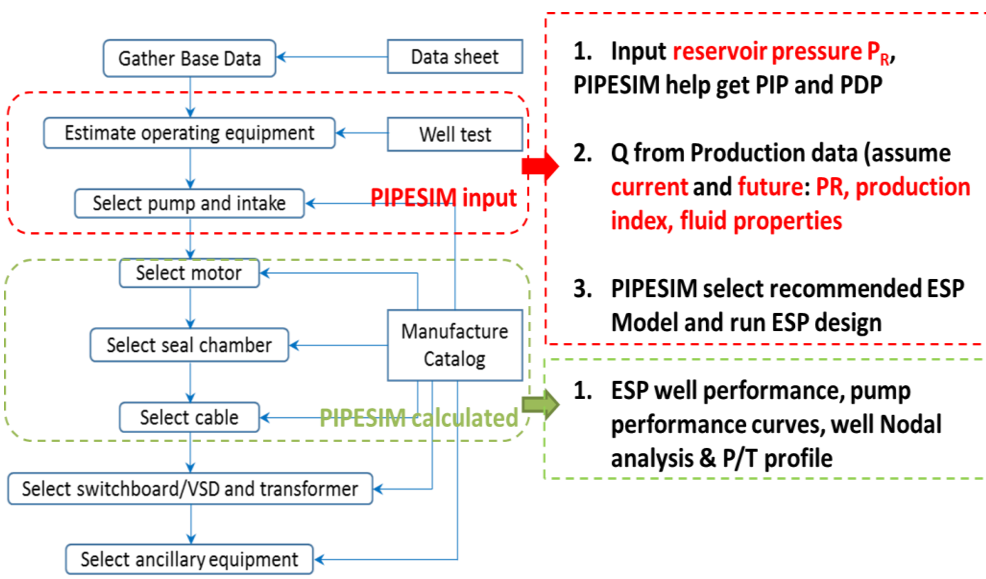


Figure 3.9 ESP design procedure

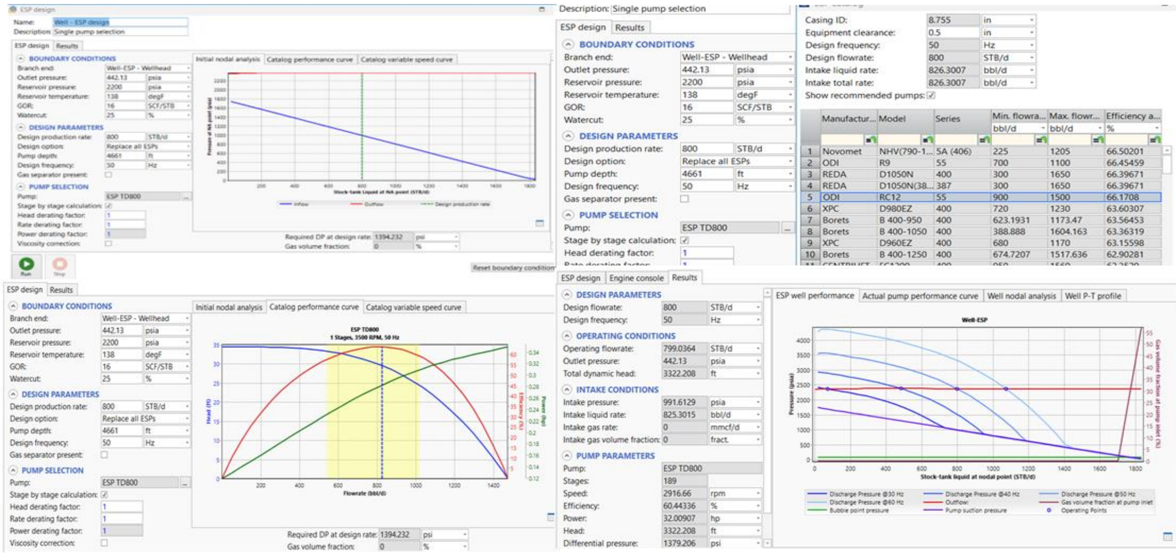


Figure 3.10 Design simulation

3.2.4 PCP Design

In PIPESIM, PCP has a broad range of models with different manufacturers, various pump diameters & Rpm. PCP can be applicable to a wide range of production rates.

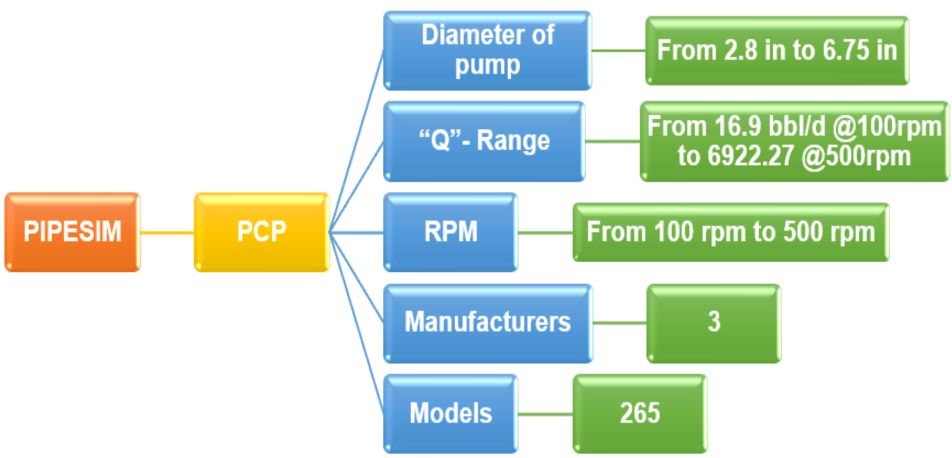


Figure 3.11 PCP data in PIPESIM

Designing a Progressive Cavity Pump (PCP) system differs from designing an Electrical Submersible Pump (ESP) system. To ensure optimal performance, it is crucial to consider the pump head or well lift when selecting a PCP. Calculating the required head for the well and choosing a PCP from the catalog that offers sufficient head and design flowrate is recommended.

Opting for a PCP with a higher head capacity ensures the desired design flowrate can be achieved. By considering the well's lifting requirements and selecting the appropriate PCP, the system can be designed to achieve optimal performance and the desired flowrate.

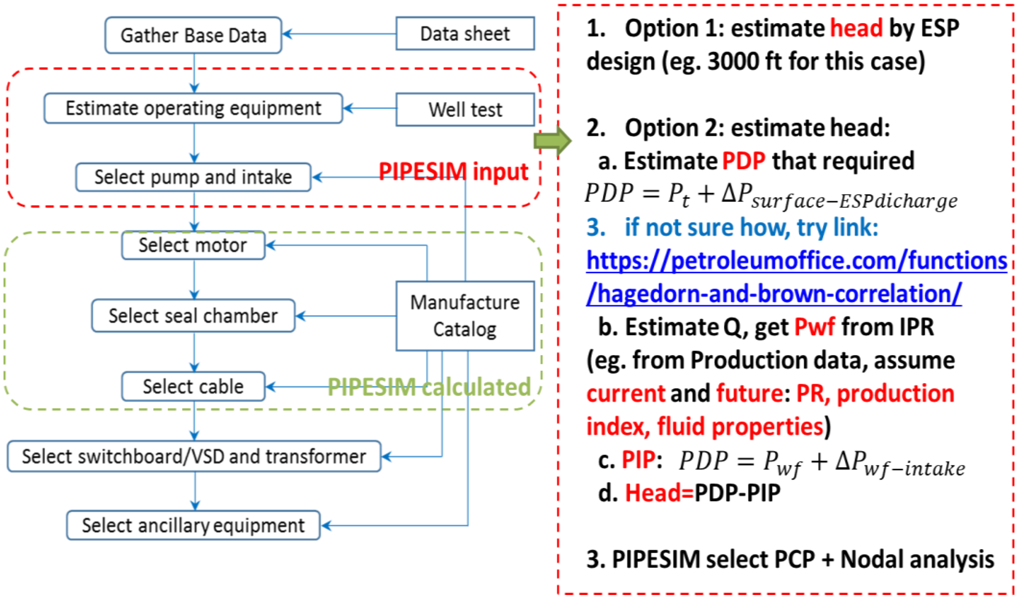


Figure 3.12 PCP design procedure

Once the required head is calculated, then PCP should be selected in PIPESIM based on the manufacturer's catalog provide. But the PCP catalog is not as accurate as the ESP catalog in PIPESIM.

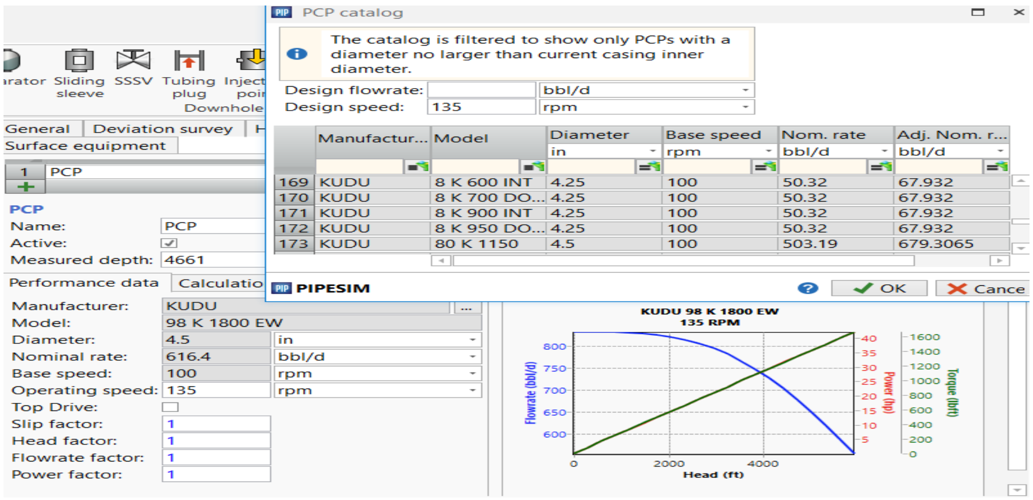


Figure 3.13 PCP design

3.3 Analysis Methodology

This thesis introduces an innovative approach to well simulations, focusing on conducting a comprehensive evaluation of well performance within a specified timeframe. The methodology employed in this study is straightforward and encompasses six distinct steps, each contributing to a detailed understanding of the well's behavior and the effectiveness of the chosen artificial lift system. These steps include:

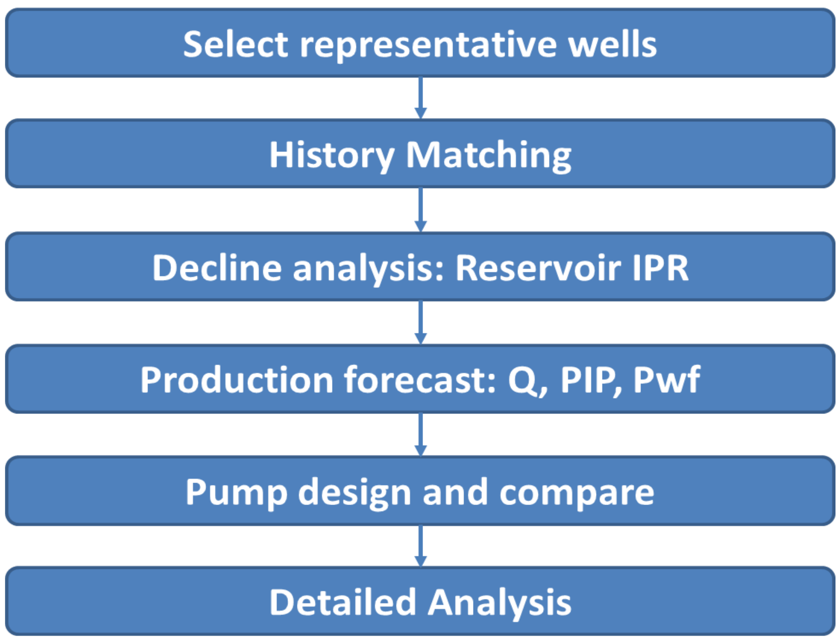


Figure 3.14 Simulation methodology

This initial step involves carefully selecting a set of representative wells from the field data that accurately represent the range of production rates observed in the reservoir. These wells serve as the basis for conducting the subsequent analysis.

After selecting a well, the process of History Matching is crucial in well simulation. It aligns simulated production data with actual production history to accurately determine reservoir and fracture parameters. Key incidents in production history are identified to initiate the process. By iteratively adjusting parameters, it can improve the simulation's accuracy. Calibration involves refining reservoir parameters within the Trilinear Transient IPR model. Sensitivity analysis further refines the model by changing fracture properties to match historical data. Once achieved, calibrated properties provide reliable inputs for future simulations, enhancing the prediction of well behavior and performance.

When reservoir parameters are matched, decline analysis and production forecast can be conducted together. The Inflow Performance Relationship (IPR) plot is generated to understand the reservoir's behavior and forecast future production rates. It shows the relationship between bottom-hole flowing pressure and production rates. Analyzing the IPR curve over the production period provides insights into the reservoir's potential. In the initial stages, higher production rates are achieved, but over time, the reservoir's ability to deliver fluid decreases. Then, a Nodal Analysis is conducted to understand the well's flow dynamics and performance.

Using the Trilinear Transient IPR Model, Nodal Analysis evaluates pressure and flow relationships along the production system. Sensitivity analysis is performed by varying parameters like time to study how the well's behavior and production rates change over time. This analysis helps predict the decline in production rates and pump intake pressures over time. A production forecast is generated, plotting future production rates and pump intake pressures for production optimization, reservoir management, and artificial lift strategies.

To help increase or maintain stable production, an appropriate artificial lift system should be designed based on the required design flowrate. The process involves selecting and configuring a suitable pump for the well, pump’s specifications, such as operating frequencies and speeds over time, are determined through parametric studies. A comparison is made between the new pump’s performance and the current pump’s performance in the well, considering production decline rates and pump intake pressures. The objective is to select the pump that generates higher flowrates and maintains higher pump intake pressures to optimize the well’s production performance.

The final stage involves a comprehensive analysis to assess the overall well performance and the effectiveness of the selected artificial lift system, guiding the artificial lift change strategy. Factors considered include production rates and pump intake pressures from previous simulations.

The objective is to determine the optimal pump that delivers higher production rates while maintaining higher intake pressures, maximizing overall well performance. Based on the analysis results, the pump is selected to achieve desired production rates and ensure satisfactory pump intake pressures. This careful evaluation optimizes the artificial lift system and enhances the well's overall performance.

CHAPTER 4

RESULTS AND DISCUSSIONS

This section comprises two case studies that aim to provide insights into different aspects of artificial lift methods in the oil and gas industry. The first case study focuses on the strategy for changing the artificial lift method from Electrical Submersible Pump (ESP) to Progressive Cavity Pump (PCP) in a specific well. The objective is to identify the conditions and operating limits that warrant a change in the artificial lift method. By analyzing factors such as well productivity, and pump intake pressures, the study aims to determine the optimal timing and circumstances for transitioning from ESP to PCP. This analysis will contribute to the development of guidelines and recommendations for artificial lift selection and optimization.

The second case study investigates the underlying causes of poor performance in a particular well, which is experiencing suboptimal production compared to two other wells in the same sector. The study aims to identify the factors that are negatively impacting the well's performance and hindering its productivity. Through a comprehensive analysis of well properties, completion design, and any potential mechanical or reservoir-related issues, the study seeks to pinpoint the root causes of the well's underperformance. This analysis will provide valuable insights for troubleshooting and implementing remedial measures to improve the well's productivity and overall performance.

Both case studies contribute to the understanding of artificial lift systems and well performance in the oil and gas industry. The findings from these studies will serve as valuable references for well optimization, artificial lift selection, and production enhancement strategies.

4.1 Case Study-1: Artificial Lift System Design

In the studied field, most wells use ESP initially as their artificial lift equipment. However, ESPs have limitations in handling lower flow rates and pump intake pressures, making it challenging for them to operate efficiently under these conditions for extended durations. On the other hand, PCPs have demonstrated the capability to operate smoothly and consistently, maintaining steady flowrates even at lower pump intake pressures. Therefore, it is important to establish critical conditions and define a transition zone between the use of ESPs and PCPs.

In the first case study, two wells are selected for simulation, each representing a distinct field within the Mishrif formation. The first well, named Well-A, is selected from the South Field, while the second well, named Well-B, is selected from the North Field. Both wells are horizontally drilled, and Multistage horizontal fractures were present.

The primary objective of this case study is to determine the optimal timing for transitioning from an ESP to a PCP. Given the characteristics of the reservoir, including its low reservoir pressure and low permeability, it is crucial to identify the most suitable artificial lift systems that can effectively operate under these conditions. By examining these wells individually, can gain insights into the unique behaviors and production dynamics of the North and South Fields.

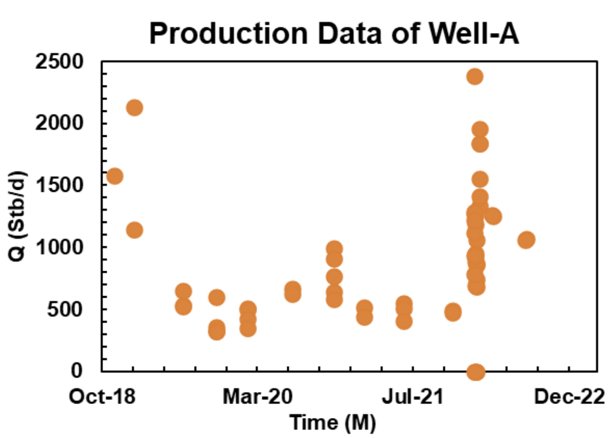
Table 4.1 Well-A and Well-B properties

Parameter	**Well-A**	**Well-B**
Reservoir Pressure	1800 psia	1800 psia
Reservoir Temperature	138°F	138°F
Water Cut	2%	49%
Wellhead Temperature	130°F	127°F
Wellhead Pressure	152 psia	167 psia
Measured Depth	9204 ft	8550 ft
True Vertical Depth	5425 ft	5613 ft
GOR	30 scf/stb	64 scf/stb
API Oil Gravity	20.8	21.47

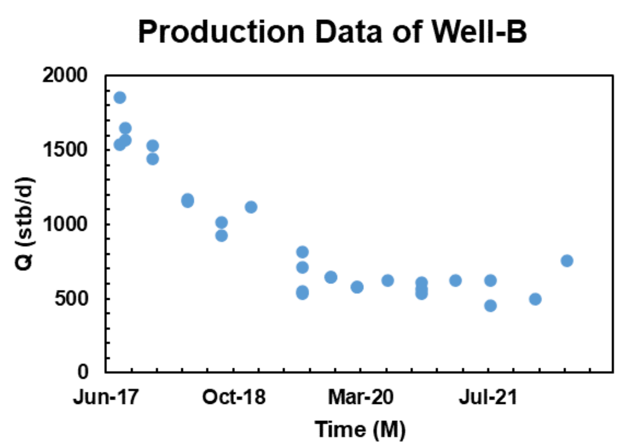
Well-A, located in the South field, stands out as the most productive well in both the North and South fields. With an impressive production potential of 1000 stb/d (stock tank barrels per day), it demonstrates exceptional performance. The well has a measured depth of 9204 ft and a True Vertical Depth (TVD) of 5425 ft. Furthermore, Well-A exhibits a low water cut of only 2% and possesses a Gas-Oil Ratio (GOR) of 30 scf/stb.

On the other hand, Well-B is situated in the North field and exhibits slightly lower production rates compared to Well-A, producing 500 stb/d. The measured depth of Well-B is 8550 ft, with a TVD of 5613 ft. Unlike Well-A, Well-B has a higher water cut of 49% and a GOR of 64 scf/stb.

These two wells provide contrasting production characteristics, with Well-A outperforming Well-B in terms of production rates, water cut, and GOR. By analyzing these differences, insights on the reservoir dynamics can be gained and optimize the field development strategy accordingly.



(a) Well-A production data



(b) Well-B production data

Figure 4.1 Production history of (a) Well-A and (b) Well-B

According to the Artificial Lift Pump Failure Reports, it has been documented that the pump in Well-A experienced three instances of tripping since the early stage of production. It is to know that the well has been in production since December 2018 and has undergone three replacements of the Electric Submersible Pump (ESP) due to voltage drops.

From the reports, it is mentioned that Well-B has faced a recent ESP failure due to low pump intake pressures and a new ESP has been deployed. To achieve an accurate match between the simulation model and actual production data, history matching was performed using sensitivity analysis in PIPESIM for both wells. Multiple fracture parameters, including the number of fractures, fracture width, fracture half-length, fracture permeability, and fracture porosity, were iteratively adjusted during the analysis.

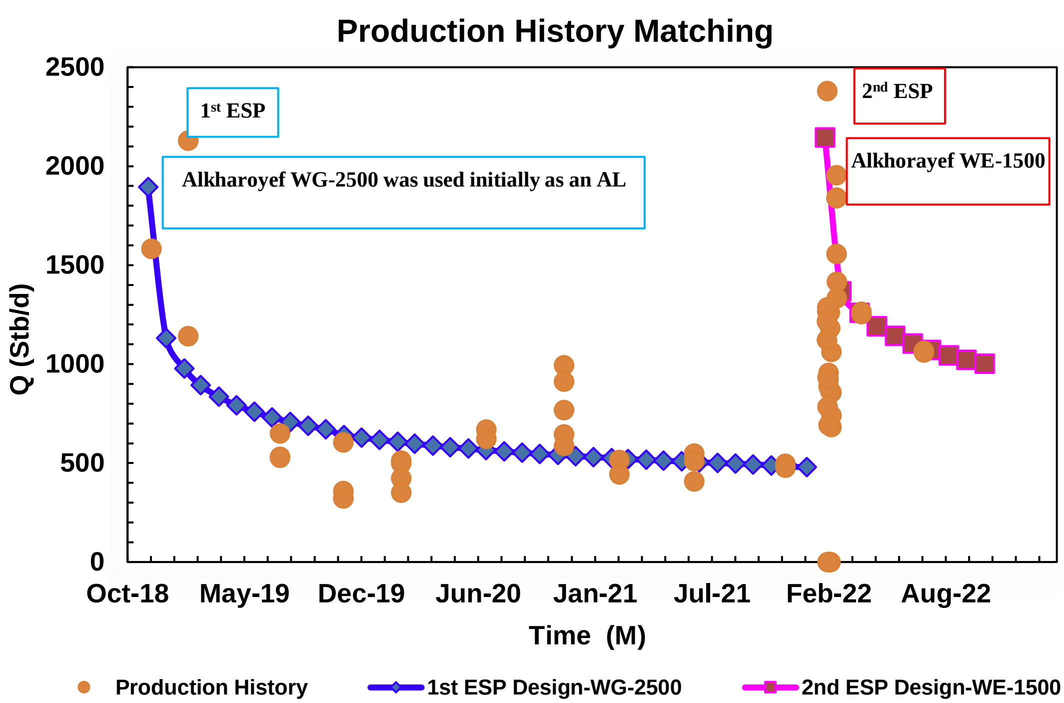


Figure 4.2 History matching of Well-A

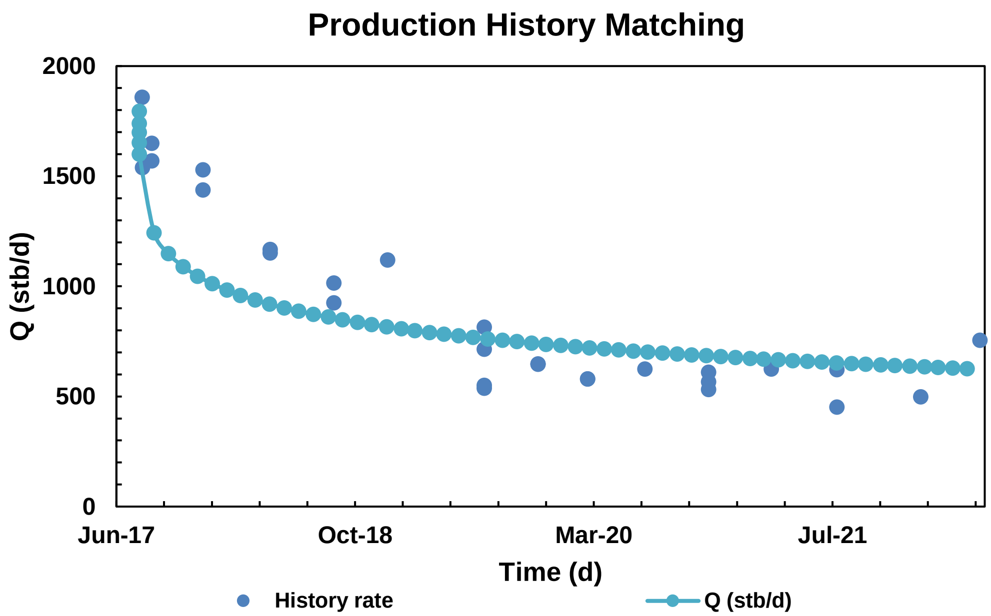


Figure 4.3 History matching of Well-B

Since fracture properties were determined, the IPR of the wells can be obtained in PIPESIM by using Trilinear Transient IPR. IPR can be obtained by using time as a function through performing nodal analysis.

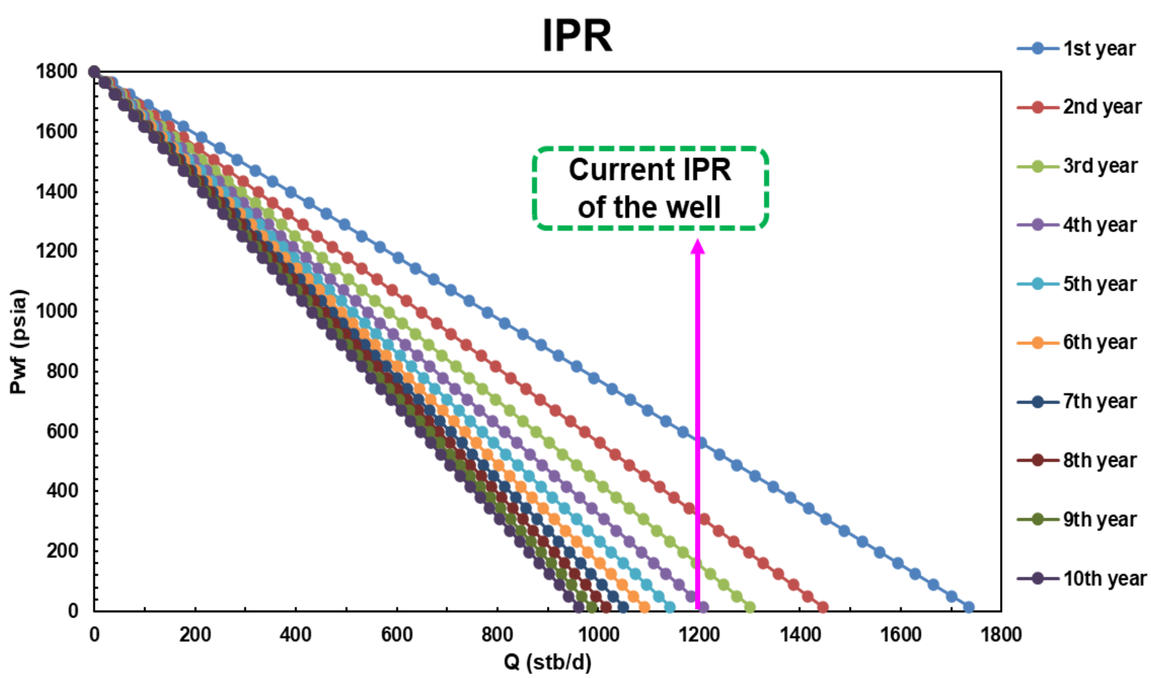


Figure 4.4 IPR of Well-A

The Inflow Performance Relationship (IPR) of Well-A has been plotted for 10 years, starting from December 2018. Based on the analysis of the plotted IPR curve, it is evident that the well has the potential to produce at a rate of 1200 stb/d.

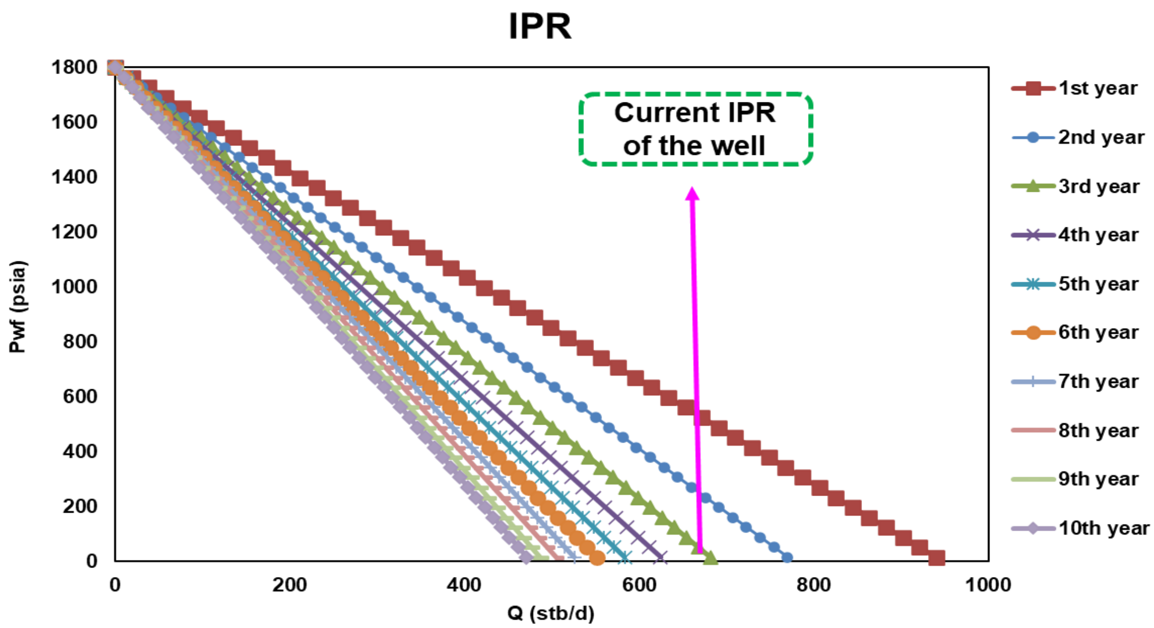


Figure 4.5 IPR of Well-B

The Inflow Performance Relationship (IPR) of Well-B has been plotted for 10 years, starting from June 2017. Based on the analysis of the plotted IPR curve, it is evident that the well has the potential to produce at a rate between 500-600 stb/d.

Currently, both wells have undergone a new PCP design in PIPESIM based on their well flowrate. To assess the effectiveness of PCP, a comprehensive comparison was conducted against the performance of the current ESP. Sensitivity analysis was performed on both wells, varying the operating frequencies and speeds of the pumps. This analysis aimed to generate forecasted production rates and pump intake pressures, enabling a thorough evaluation of the pump performance. Based on the results obtained, the performance of the PCPs was compared to that of the ESPs, ultimately determining the most suitable artificial lift system for each well.

4.1.1 Well-A

In Well-A, an ESP is installed at a depth of 5500 ft.

Table 4.2 ESP details for Well-A

Manufacturer	**Alkhorayef**
Model Name	WG-1600
Diameter	5.13 in
Minimum Flowrate	800 stb/d
Maximum Flowrate	1800 stb/d
Operating Frequency	50 HZ
Stages	104
Speed	2916.66 rpm
Series	513

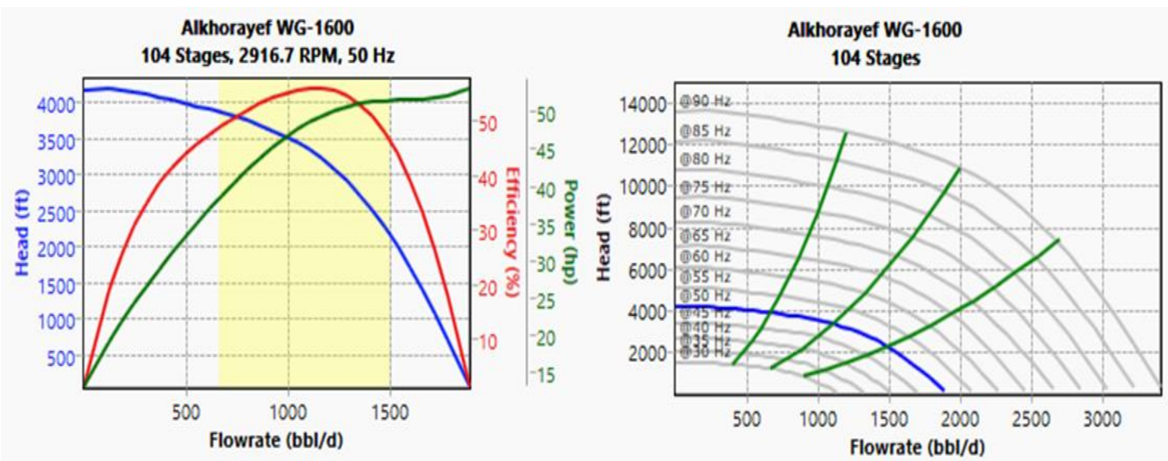


Figure 4.6 Pump performance curve and variable speed curve for Well-A

Nodal analysis has been performed for this well with the current ESP and observed that the current well is producing at a flowrate of 698 stb/d, whereas, from our latest production history, our well is producing 700 stb/d, which is satisfying our simulation.

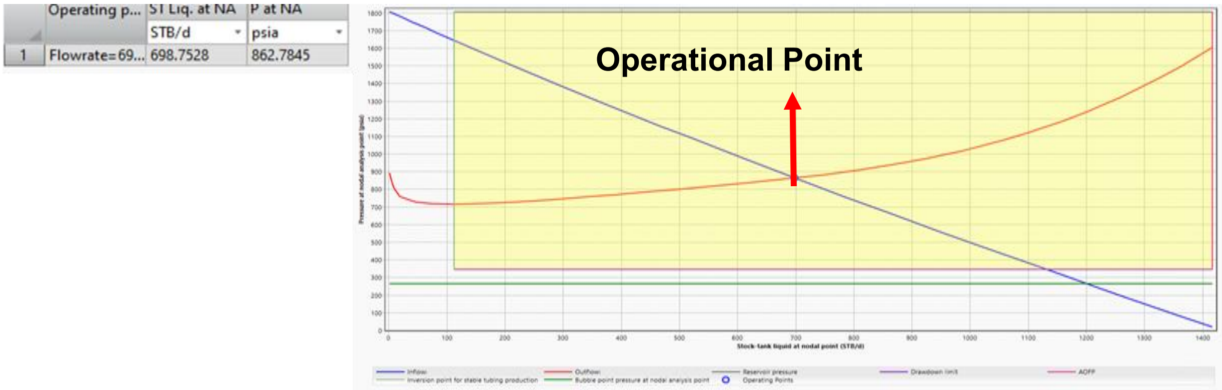


Figure 4.7 Nodal Analysis of Well-A with ESP

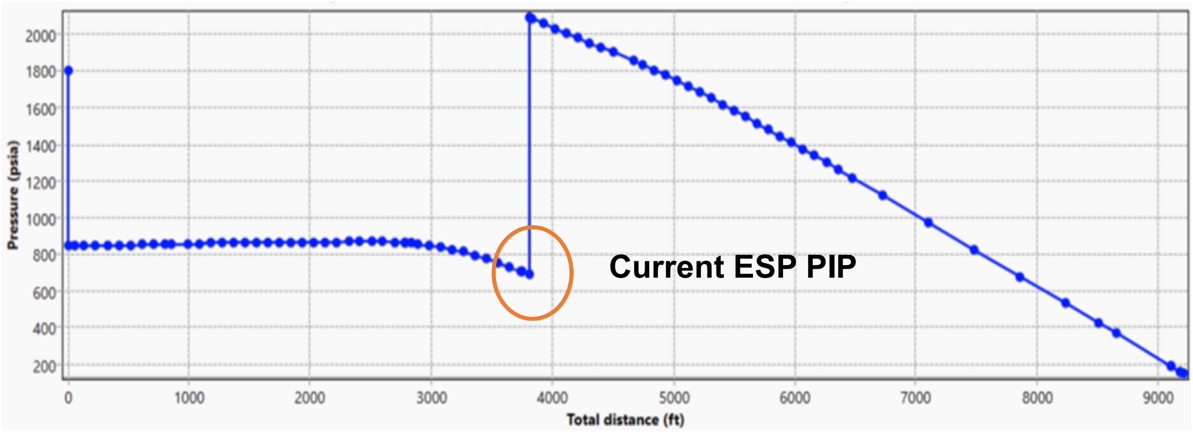


Figure 4.8 Well pressure profile of Well-A with ESP

From the P/T profile, it is observed that Well-A with ESP has a pump intake pressure of almost 700 psia and pump discharge pressure of more than 2000 psia.

Simultaneously, a new PCP is designed based on the current well flowrate which can produce 650 to 700 stb/d. PCP is installed at a depth of 5500 ft.

Table 4.3 PCP design properties

Manufacturer	**Properties**
Model Name	500-200E860
Diameter	5.43 in
Nominal Flowrate	1205.104 stb/d
Base Speed	100 rpm
Operating Speed	100 rpm
Slip Factor	1
Head Factor	1

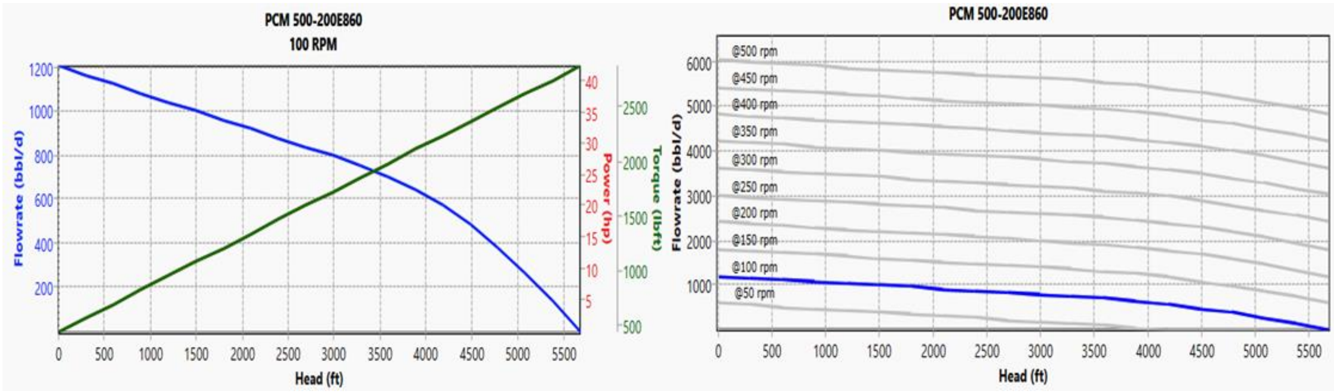


Figure 4.9 PCP pump curve and variable speed curves for Well-A

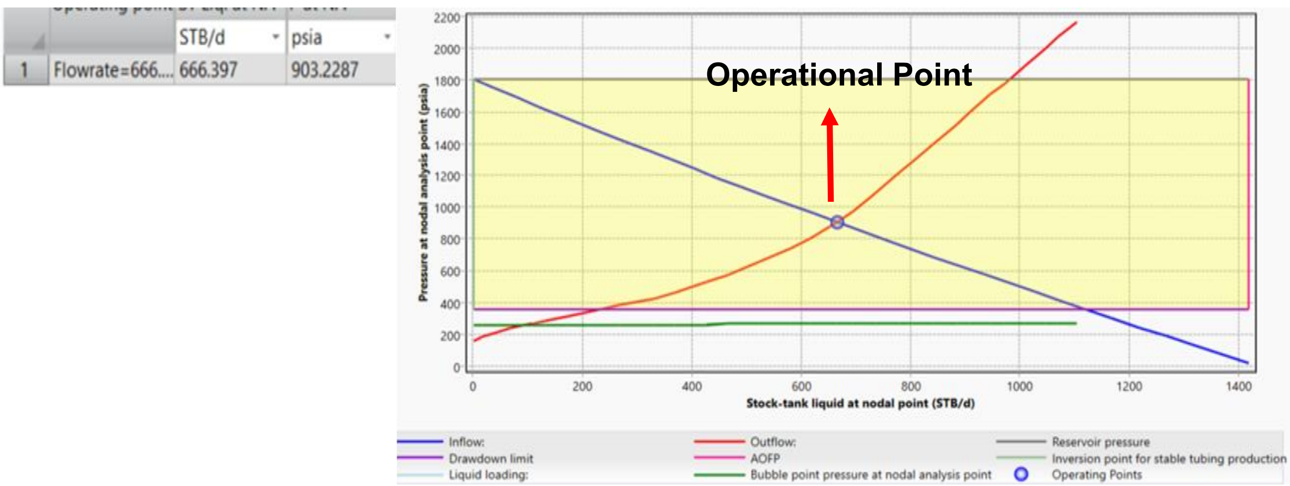


Figure 4.10 Nodal Analysis for Well-A with PCP

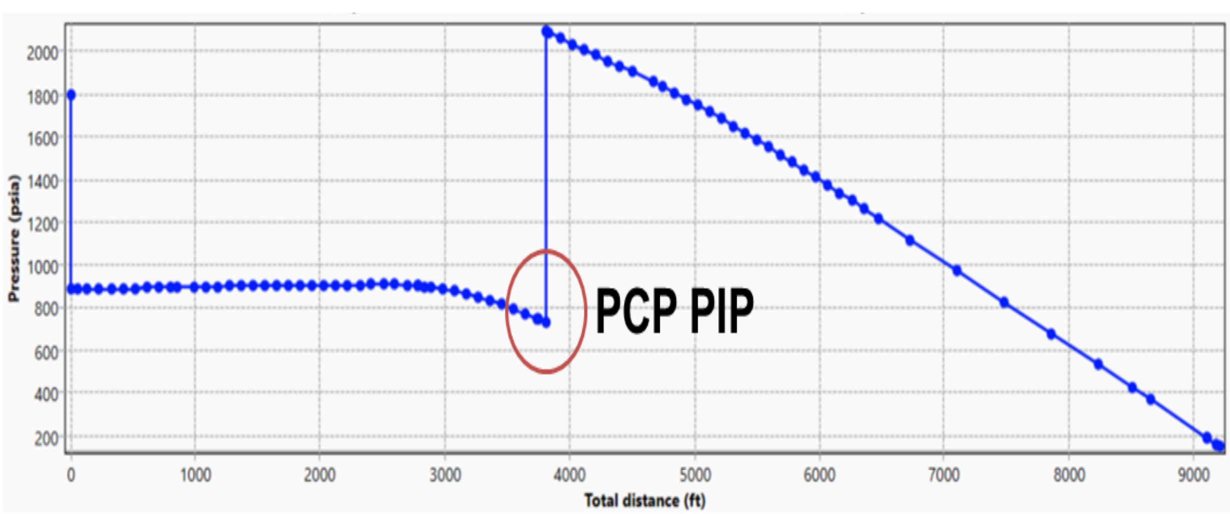


Figure 4.11 Well Pressure profile for Well-A with PCP

Nodal Analysis was run for the Well-A to observe the well performance and the well can produce 666 stb/d currently with new PCP design. From the wellbore pressure profile, PCP has a pump intake pressure of 700 psia similar to ESP and has a pump discharge of more than 2000 psia.

For both ESP and PCP, forecasting is done with time as a function of production rates, pump intake pressures, bottom hole pressures, pump efficiencies, pump heads, pump power, and torque.

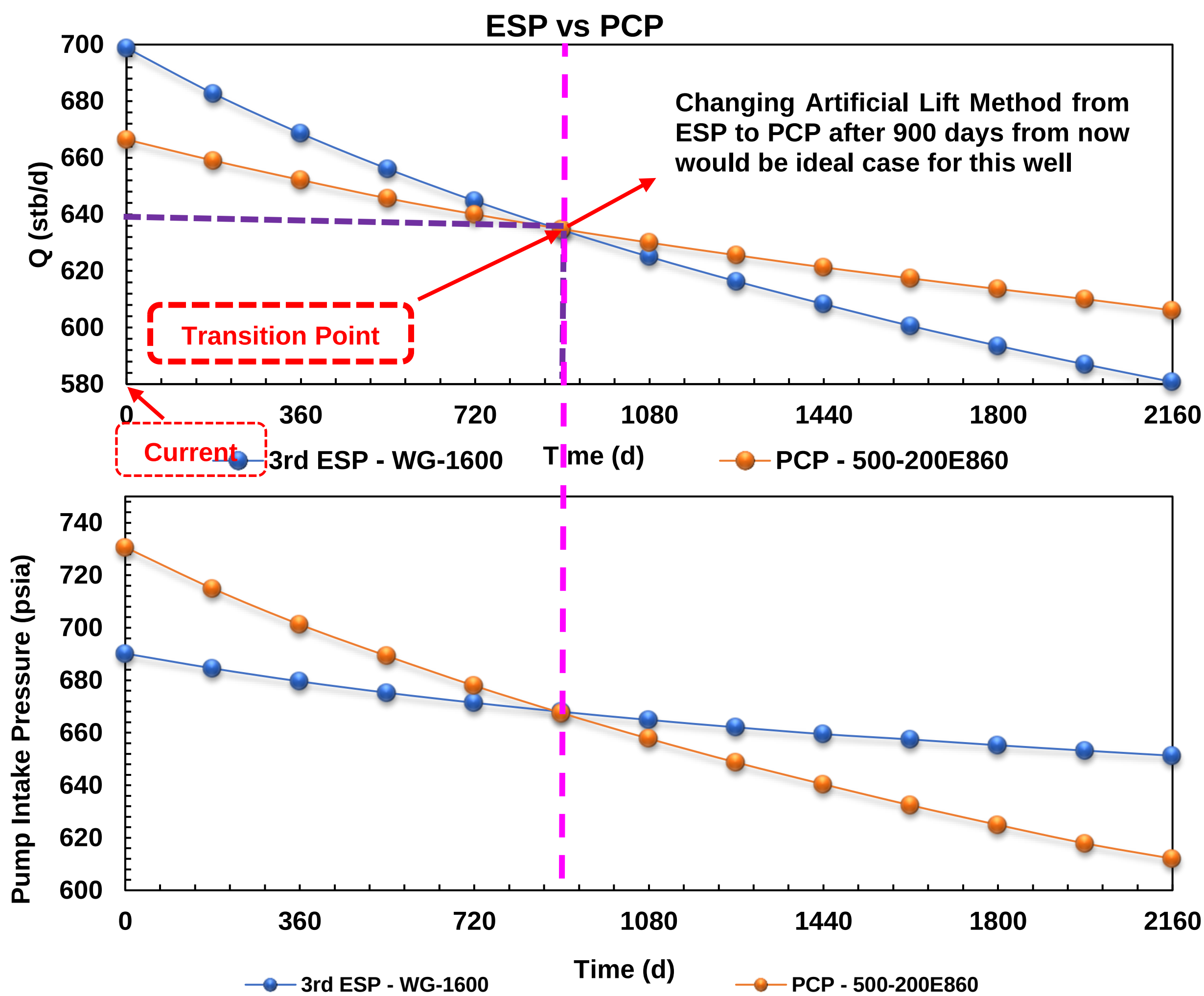


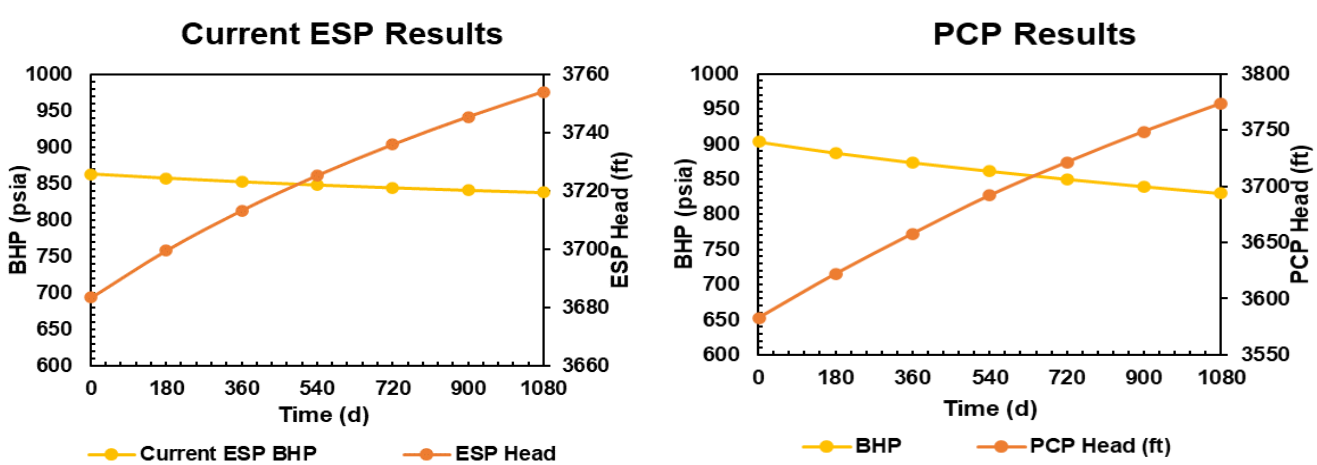
Figure 4.12 Forecasted rates and PIP of ESP & PCP for Well-A

The above Figure 4.12 illustrates a comprehensive comparison of the forecasted production rates and pressure at the pump intake (PIP) between an Electrical Submersible Pump (ESP) and a

Progressive Cavity Pump (PCP) over 6 years. It can be observed that initially, both the ESP and PCP exhibit similar production rates, with a slight difference of 33 stb/d at the start. During the first 900 days of production, the ESP outperforms the PCP, yielding higher production rates.

However, after the initial 900 days, the production rates of the ESP and PCP converge, resulting in almost identical production rates, which is considered as a transition point. As time progresses, the ESP experiences a gradual decline in production rates, while the PCP consistently maintains its production rates. Consequently, it can be concluded that both the ESP and PCP demonstrate comparable production rates and minimal differences in PIP. Based on these results, there is no immediate need to switch from the current ESP to a PCP, as they yield similar production rates and PIP.

However, it is important to note that if the ESP had experienced a significant decline in production rates, it would have been more favorable to consider utilizing the PCP after the initial 900 days of production. The decision to switch to a PCP would be warranted if the ESP's decline in production rates was substantial, and the PCP could maintain a more consistent level of production.



(a) (b)

Figure 4.13 (a) BHP vs, ESP head and (b) BHP vs. PCP head

From the above Figure 4.13, it can be observed that the Bottom Hole Pressure (BHP) with the PCP initially starts at a higher value and then gradually declines compared to the BHP with the ESP. Over the next three years, the PCP shows an increase in BHP from 3600 ft to 3780 ft, while the ESP demonstrates a smaller increase from 3680 ft to 3760 ft. Despite these variations, both the ESP and PCP yield similar outcomes in terms of BHP and Head for Well-A.

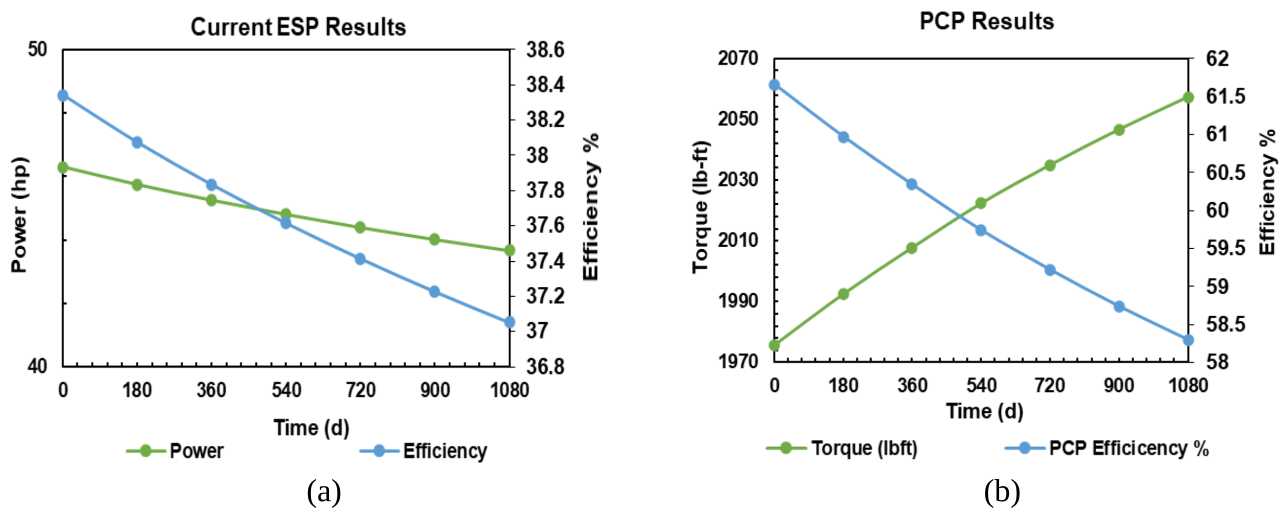


Figure 4.14 (a) Power vs. efficiency with ESP for Well-A and (b) Torque vs. efficiency with PCP for Well-A

In Figure 4.14 (a), it can be observed that as the efficiency of the pump decreases, the power output of the ESP also decreases. On the other hand, in Figure 4.14 (b), as the efficiency of the PCP decreases, the torque required by the PCP increases.

Since ESP is decided to use, A sensitivity analysis was conducted for Well-A using an ESP, focusing on the parameter of operating frequency. Parametric studies were performed, varying the operating frequencies at 45 Hz, 50 Hz, and 55 Hz for three years to assess the performance of the ESP. The analysis aimed to observe how different operating frequencies would impact the production rates and pump intake pressures performance of the ESP in the well over the specified timeframe.

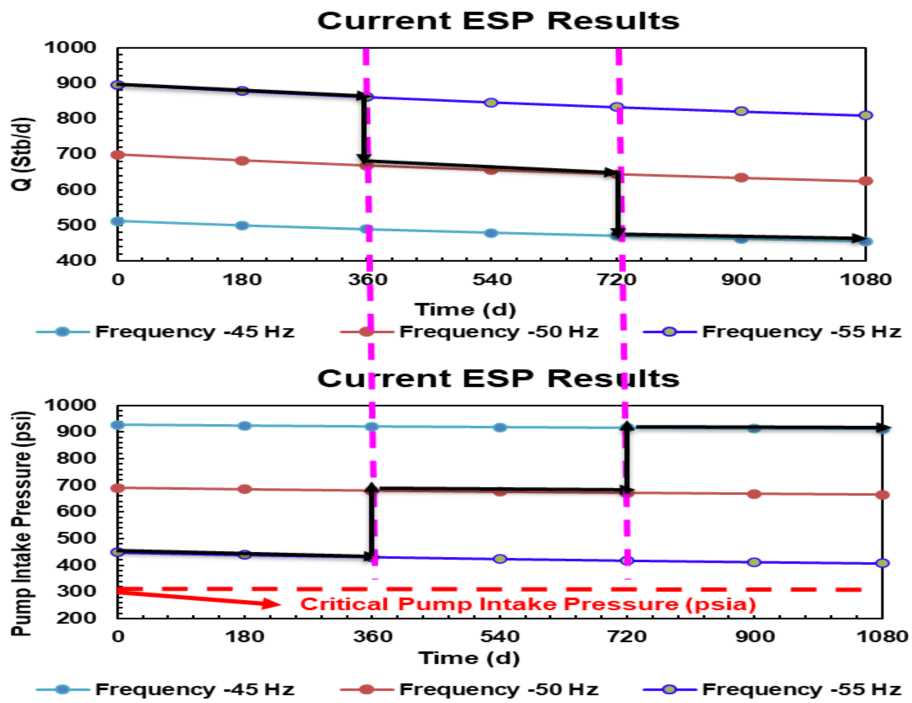


Figure 4.15 Parametric studies of Well-A with ESP

Based on the depicted Figure 4.15, it is evident that an operating frequency of 55 Hz results in higher production rates ranging from 900 stb/d to 850 stb/d over the next three years. However, it should be noted that this higher operating frequency obtained lower pump intake pressures compared to the operating frequencies of 50 Hz and 45 Hz. Despite this, all the operating frequencies ensure that the pump intake pressures are maintained above the critical threshold of 300 psia.

An operational strategy can be implemented to optimize production rates and pump intake pressures over the next few years. In the first year, the ESP operating frequency can be set at 55 Hz, resulting in production rates of approximately 900 stb/d and pump intake pressures of 400 psia throughout the year. Moving into the second year, the operating frequency can be reduced to 50 Hz, which will increase pump intake pressures. This adjustment allows for production rates in the range of 600 to 700 stb/d, with increasing pump intake pressures over the entire second year.

For the third year, further reducing the operating frequency to 45 Hz will lead to higher pump intake pressures. During this period, the well is expected to produce at rates ranging from 400 to 500 stb/d, with increasing PIP (Pump Intake Pressure). It is important to note that the IPR (Inflow Performance Relationship) of the well indicates the potential for production rates of up to 1000 stb/d.

This operational strategy can be repeated for subsequent years, adjusting the operating frequency to maintain the desired production rates, and gradually increasing pump intake pressures. The objective is to sustain optimal production while ensuring that the pump intake pressures do not drop below a critical PIP threshold of 300 psia. By continuously monitoring and adjusting the operating frequency, the well's performance can be effectively managed to maximize production rates and maintain desirable pump intake pressures.

Well-A has a total of 3 ESPs till now, the total production history with all ESPs and forecasted production rates are plotted.

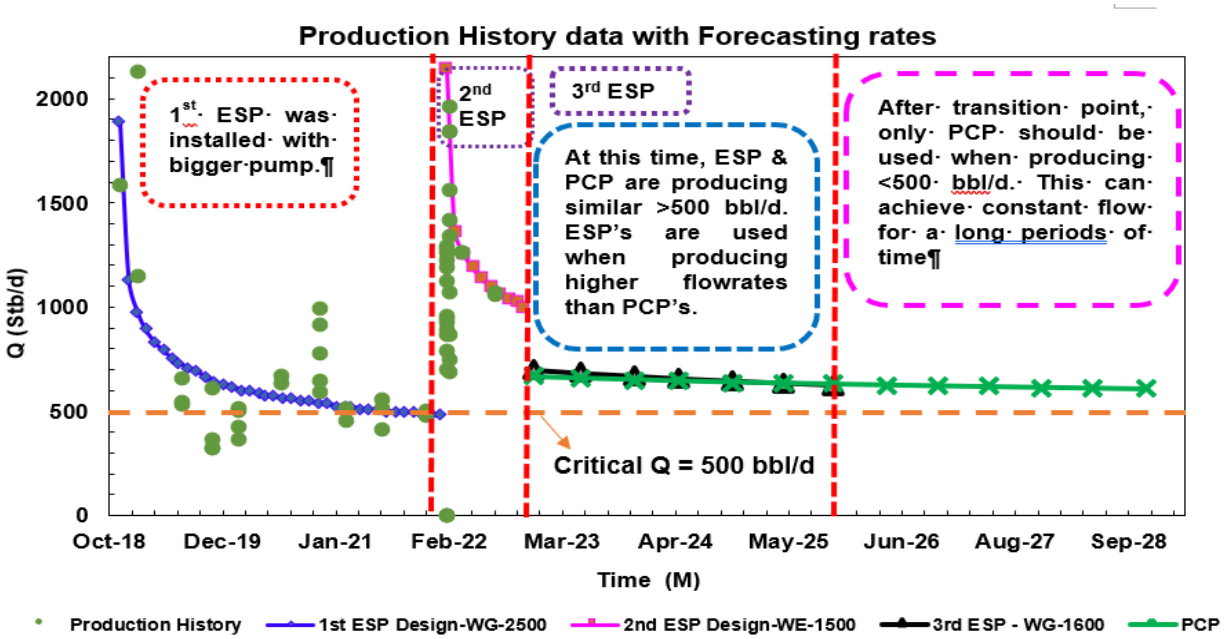


Figure 4.16 Total production rates of Well-A with all ESP's used in the entire lifespan of the well with forecasted production rates

The analysis indicates that replacing the electrical submersible pump (ESP) with a progressive cavity pump (PCP) would be necessary after reaching the transition point. However, in the current scenario, our current ESP (3^{rd} ESP) can produce well above 500 stb/d in the future. Therefore, there is no immediate need to switch from ESP to PCP unless the pump intake pressures fall below the critical threshold of 300 psia and the production rates drop below 500 stb/d. Only then would it be advisable to consider using PCP to maintain consistent flowrates with lower pump intake pressures over an extended period.

4.1.2 Well-B

Well-B has experienced an ESP failure due to low pump intake pressures, prompting a simulation to identify the cause. Currently, it produces around 500 stb/d using a Novomet ESP model NHV (790-1000) with 393 stages at a depth of 5630 ft. To explore alternatives, a new PCP design, similar to Well-A, has been developed with a capacity of 500-600 stb/d and 100 rpm speed. Recent production data for Well-B in the North field indicates a pump intake pressure of approximately 210 psia, below the critical threshold (< 300 psia). Simulations were conducted for the next three years to assess the performance of the current ESP and the newly designed PCP, forecasting production rates and pump intake pressures.

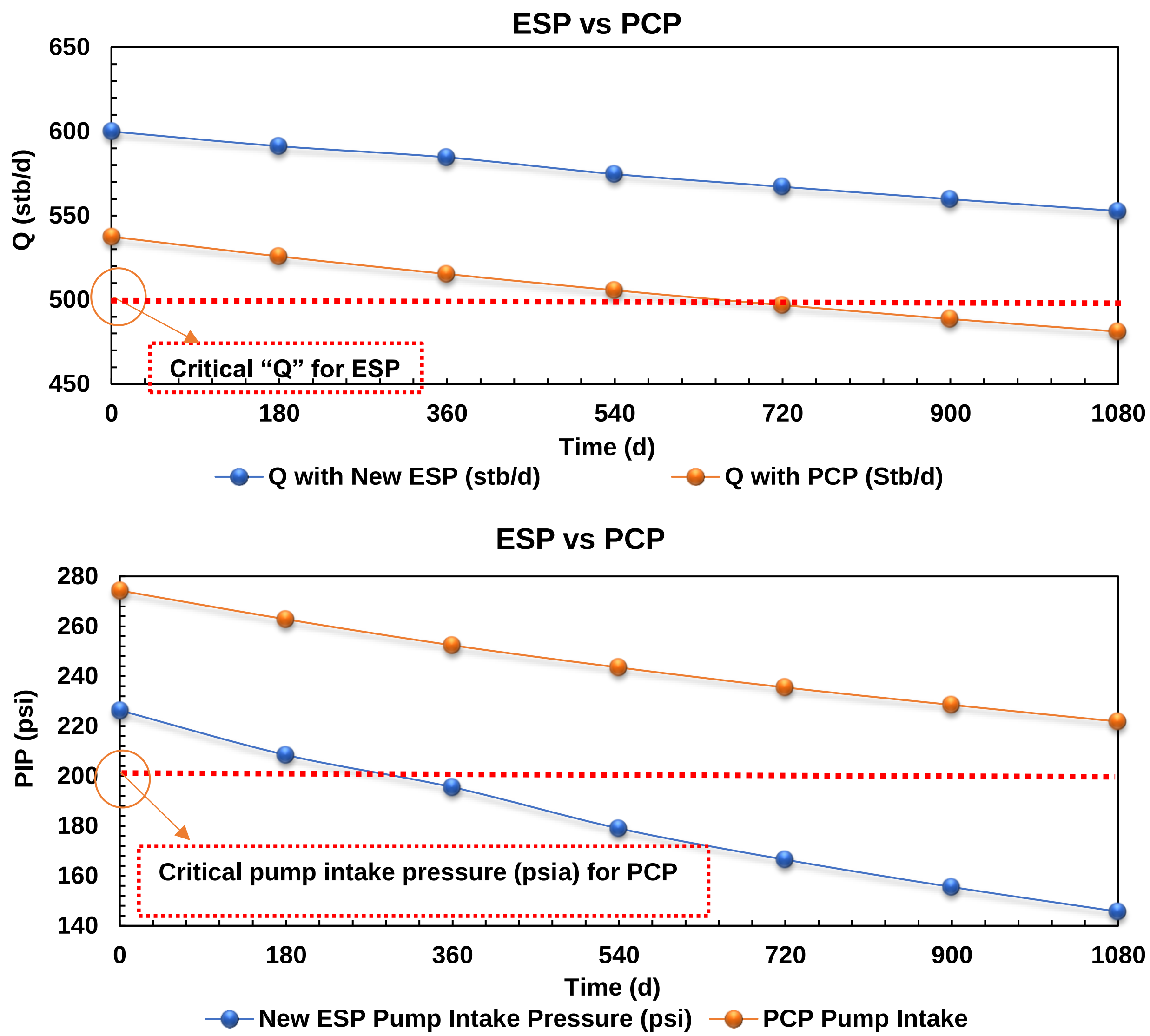


Figure 4.17 Forecasted rates and PIP of Well-B

From the above Figure 4.17, it can be depicted that ESP is producing higher rates than PCP with a difference of 50 stb/d. However, ESP is operating with lower pump intake pressures which is < 300 psia, whereas PCP is operating above critical pump intake pressures > 200 psia.

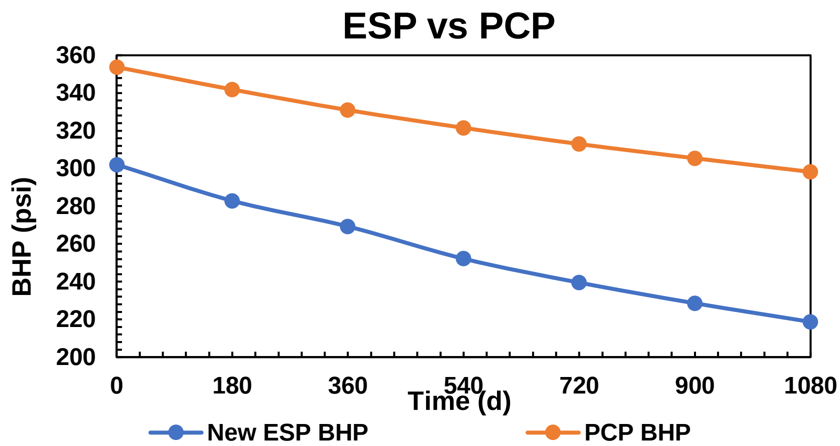
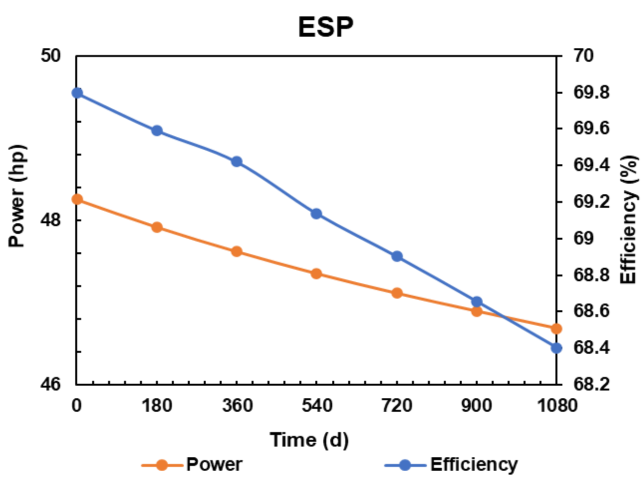
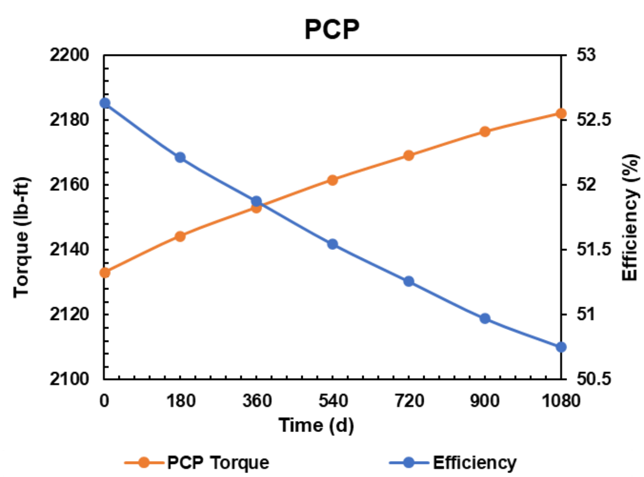


Figure 4.18 BHP with ESP vs PCP for Well-B

In Figure 4.18, Bottom hole pressures were higher with PCP than ESP. ESP has a rapid decline in BHP from 300 psia to 220 psia which is very low. However, PCP has decreased in BHP from 350 psia to 300 psia.



(a)



(b)

Figure 4.19 (a) Power vs. efficiency with ESP for Well-B and (b) Torque vs. efficiency with PCP for Well-B

Figure 4.19 (a) and (b) show the power vs. efficiency relationship for ESP and torque vs. efficiency for PCP, respectively. In Figure 4.19 (a), as ESP efficiency decreases, its power output also declines. Similarly, Figure 4.19 (b) depicts that as PCP efficiency decreases, the torque needed to lift Well-B's liquid increases. These plots offer insights into ESP and PCP performance, aiding in understanding their efficiency and power/torque requirements.

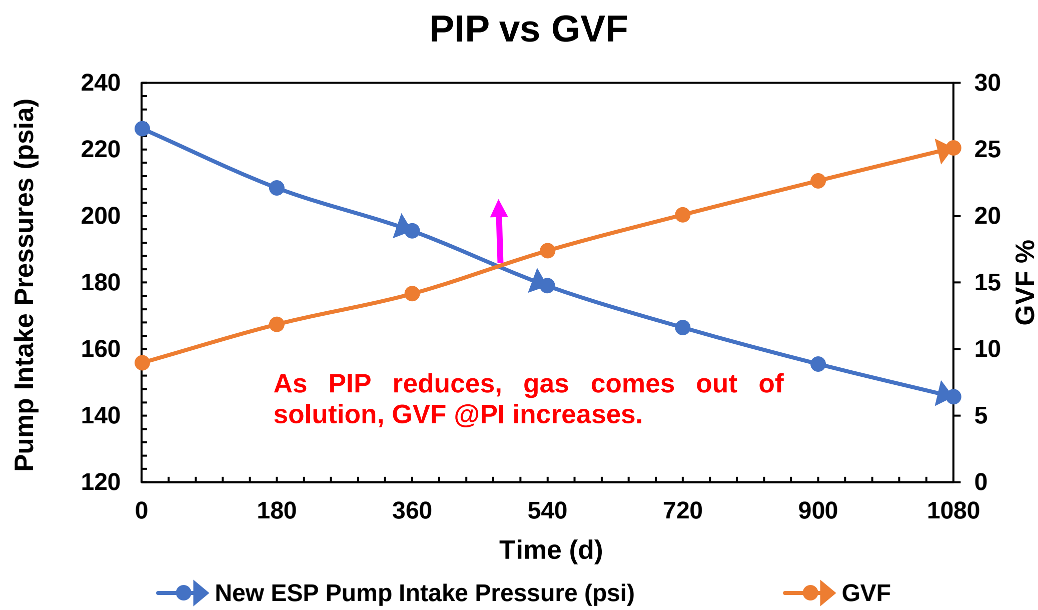


Figure 4.20 PIP vs. GVF with ESP for Well-B

The Figure 4.20 above illustrates the relationship between pump intake pressures and gas volume fraction at the pump intake for the ESP over a three-year forecast period. It is evident from the plot that when the pump intake pressures are at 225 psia, the gas volume fraction at the pump intake is already 9%. As the pump intake pressures decline from 225 psia to 145 psia over the next three years, there is a rapid increase in the gas volume fraction at the pump intake, reaching 25%.

This observation indicates that as the pump intake pressures decrease, the gas is coming out of the solution due to the lower pressures experienced at the pump intake. This phenomenon can be occurred due to the decrease in PIP, which leads to the release of dissolved gas from the fluid, resulting in an increased gas volume fraction at the pump intake.

The presence of gas in the ESP intake can lead to several issues affecting system performance and reliability. These include reduced pump efficiency due to gas bubbles coming out of the liquid, which occupies space within the pump and hinders fluid transfer. Additionally, gas bubbles can cause cavitation when the pressure drops below the fluid's vapor pressure, leading to erosion and damage to pump components, reducing pump performance and increasing wear. Gas locking can also occur, where excessive gas in the pump intake prevents fluid flow, causing the pump to lose its prime and operate ineffectively. This leads to reduced production rates and the need for frequent interventions.

Based on failure reports, it was determined that Well-B experienced ESP failure due to low pump intake pressures. The PIPESIM simulation identified adverse consequences arising from low pump intake pressures and elevated gas volume fraction (GVF), including cavitation, gas locking, and poor pump performance as the cause of the failure. In this case for Well-B, replacing ESP with PCP is the best solution to avoid pump failures, and reduce production downtime.

Progressive cavity pumps (PCP) are well known to maintain constant flowrates due to their pump characteristics. PCP can operate efficiently at lower pump intake pressures and can continue to deliver satisfactory production rates, Due to its working mechanism, PCPs are less sensitive than ESP, and PCPs are known for their ability to handle high gas volume fractions (GVF) without experiencing significant performance issues. As the gas content in the well increases, PCPs maintain their efficiency and continue to operate effectively, ensuring consistent production rates.

4.1.3 Discussion and Recommendations

After analyzing the outcomes from Case Study-1 for Well-A and Well-B, AL recommendations can be made. In the M-field, the main focus is on optimizing the effectiveness of ESP and PCP as primary artificial lift systems through a Well-designed operational strategy. The aim is to extend well productivity, minimize downtime, and ensure efficient reservoir exploitation. When recommending an artificial lift method, the decision between ESP and PCP goes beyond flow rate (Q) considerations. Parameters like pump intake pressures (PIP) are crucial in the selection process. The pressure profile of a well, from reservoir drawdown to wellhead pressure, involves fixed and varying terms that require careful analysis and consideration.

To gain a detailed understanding of the fixed and varying terms along the well's pressure profile, Well-B is used as an example and plot its pressure profile in PIPESIM. As the Well-B has low pump intake pressures, it would be an ideal case to understand these terms in depth.

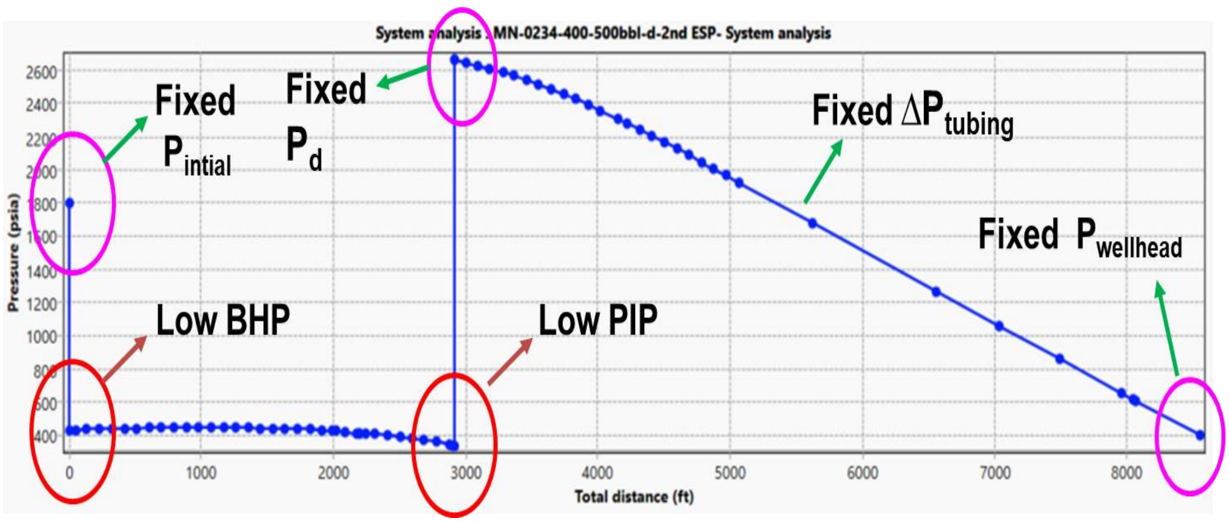


Figure 4.21 Well-B pressure profile with ESP

The above Figure 4.21is the P/T profile of Well-B run in PIPESIM. Pressure profile: from reservoir to well head. Fixed terms are $P_{R\ initial}$, $P_{wellhead}$, P_d, ΔP_{tubing}, and declining/varying terms are BHP and PIP. It should be noted, the average reservoir pressure is hard to be obtained in unconventional reservoirs. Instead, the initial reservoir and producing time are used in trilinear IPR and this study. Therefore, there are no straightforward reservoir pressures plotted in the above Figure 4.*21*, but as explained, PIP, BPD, and near-well pressure (which are not shown here) are changing with time.

Starting from the reservoir, the pressure profile exhibits fixed terms, such as the initial reservoir pressure, which marks the beginning of the profile. As going to the top of the well, pump discharge pressure and the tubing head pressure remain almost constant throughout the well's production life, representing another fixed term. It should be noted, although flow rate has some effect on pipe flow pressure loss, it is neglectable in our case due to low GVF and density changes. The gravity pressure loss dominates the pipe flow behavior, which does not change significantly with flow rate. The pressure profile incorporates tubing pressure loss, which arises from the frictional resistance of the fluid within the tubing and also, the wellhead pressure can be maintained from the surface facilities. This factor contributes to the fixed terms and influences the pressure at different depths within the well.

Bottom hole pressures (BHP) and pump intake pressures (PIP) are essential terms in well production. BHP declines over time due to reservoir depletion, and maintaining optimal BHP is vital for efficient production. As a result, PIP decreases as well, but it must be Well-managed to avoid issues like gas breakout, pump cavitation, or reduced efficiency.

While preventing PIP decline is challenging, it can be maintained by operating the artificial lift system at lower RPMs, reducing stage numbers, and managing production rates. During workover operations, the time after ESP failure, pump intake pressures can increase temporarily due to reservoir pressure buildup in the absence of fluid production. Maintaining suitable PIP levels through effective strategies is crucial for optimal well performance and artificial lift system efficiency.

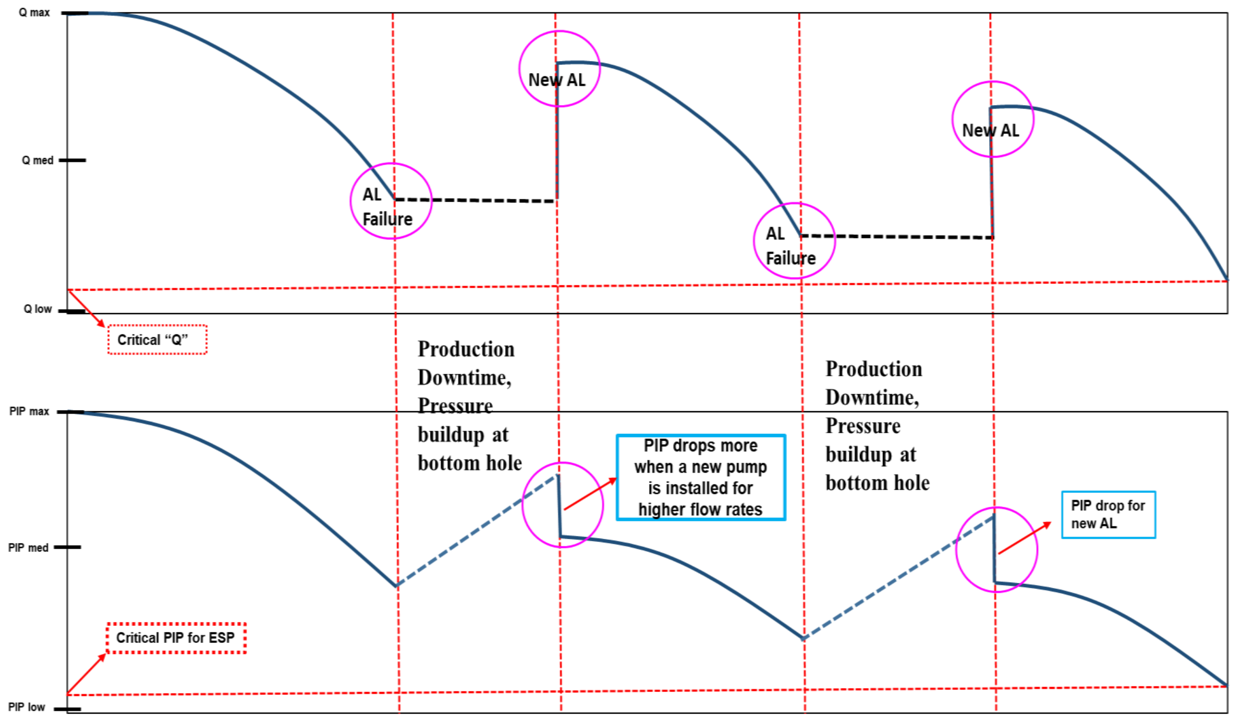


Figure 4.22 PIP pressure buildup during workover operations

The temporary increase in pump intake pressures during workover operations is attributed to the absence of fluid production, allowing reservoir pressure to build up at the pump intake. Once a new ESP is installed and production resumes, pump intake pressures decrease over time due to declining reservoir pressure. This process continues until the artificial lift system reaches its critical flowrates and pump intake pressures. Although the temporary pressure increase boosts artificial lift system performance, it is essential to consider long-term well behavior influenced by reservoir dynamics and production rates.

ESP demonstrates good performance at higher flowrates and pump intake pressures but faces challenges at low flowrates and PIP. On the other hand, PCP proves more suitable for low-rate wells with low PIP, maintaining stable flowrates and making it the preferred choice for wells facing declining production rates and lower PIP.

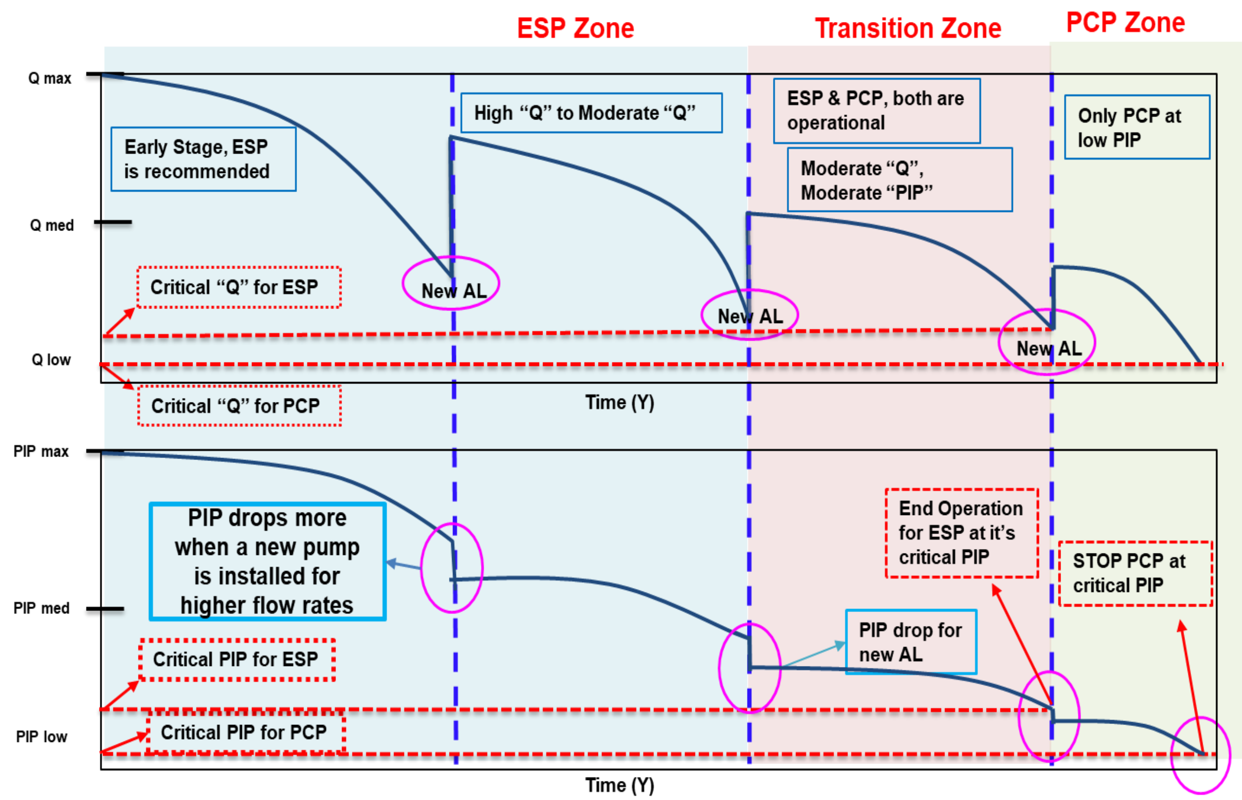


Figure 4.23 Selection of ESP and PCP in the well's entire life

The proposed artificial lift recommendation involves utilizing both ESP and PCP throughout the well's operational life, divided into three zones: ESP zone, Transition Zone, and PCP zone. Each zone corresponds to a specific production phase, guiding the selection of the optimal artificial lift system to maximize well performance and production efficiency.

ESP Zone: the ESP zone in the Figure 4.*23*represents the initial production phase, where the electrical submersible pump (ESP) is the preferred artificial lift method. This phase encompasses early production with higher flowrates and pump intake pressures. ESPs efficiently maintain steady production during this period, from higher to moderate production rates, by ensuring optimal pump intake pressures.

Transition Zone: The Transition Zone represents an intermediate phase in the well's production life, characterized by declining reservoir pressure, reduced production rates, and pump intake pressures. ESP and PCP can produce similar rates in this zone, but ESP's performance may deteriorate due to flowrate fluctuations and declining pressures. To prevent failures and maintain production, a transition from ESP to PCP is recommended when ESP reaches a critical PIP of 300 psia, ensuring continuous and efficient production.

PCP Zone: When the ESP’s performance declines significantly, and production rates fall below its efficiency range, the well enters the PCP zone. A progressive cavity pump (PCP) is then deployed as the new artificial lift system. PCPs are suitable for lower flowrates and can maintain higher pump intake pressures effectively. They extend well production life, ensuring consistent flowrates with lower pump intake pressures for an extended period. The PCP zone ends when pump intake pressure (PIP) falls below 200 psia, the threshold for PCP operation.

The optimal well performance relies on determining the right transition timing between ESP and PCP zones. Utilizing their strengths at the appropriate phases enhances productivity and cost-effectiveness. Continuous monitoring and analysis of production data, bottom-hole pressures, and pump intake pressures are essential for informed decision-making and effective implementation of the artificial lift strategy.

4.2 Case Study-2: Troubleshooting of a Low-production Well

The second case study focuses on three closely located wells within the south M-field of the Mishrif reservoir. Well-A, previously analyzed in case study 1, remains the primary focus. Studying Well-C alongside neighboring Well-A and Well-B provides valuable insights into its behavior and performance under varying conditions. Analyzing this well group allows us to understand reservoir dynamics and tailor artificial lift strategies for this specific sector. By collectively examining these wells, can gain comprehensive understanding and optimize production strategies based on reservoir behavior and artificial lift performance in this particular area.

Upon thorough examination, it can be observed that there is a significant disparity in well performance within this sector. While Well-A and Well-D are achieving production rates equal to or exceeding 500 stb/d, Well-C is producing only ≤ 200 stb/d. This discrepancy led us to conduct an in-depth analysis of Well-C to understand the underlying reasons for its suboptimal performance. Through simulation techniques, our main objective in this case study is to identify the root cause of Well-C's poor productivity and gain valuable insights to enhance its performance. By pinpointing the contributing factors, it can aim to optimize production strategies and improve overall productivity in this sector.

The study began with a comparative analysis of Well-A and Well-C to identify any distinct well properties. Surprisingly, a notable difference was observed in the pump setting depths, with Well-A at 5550 ft and Well-C at a considerably lower 4436 ft. This led to the hypothesis that the lower pump intake pressures in Well-C could be attributed to the variation in pump setting depths.

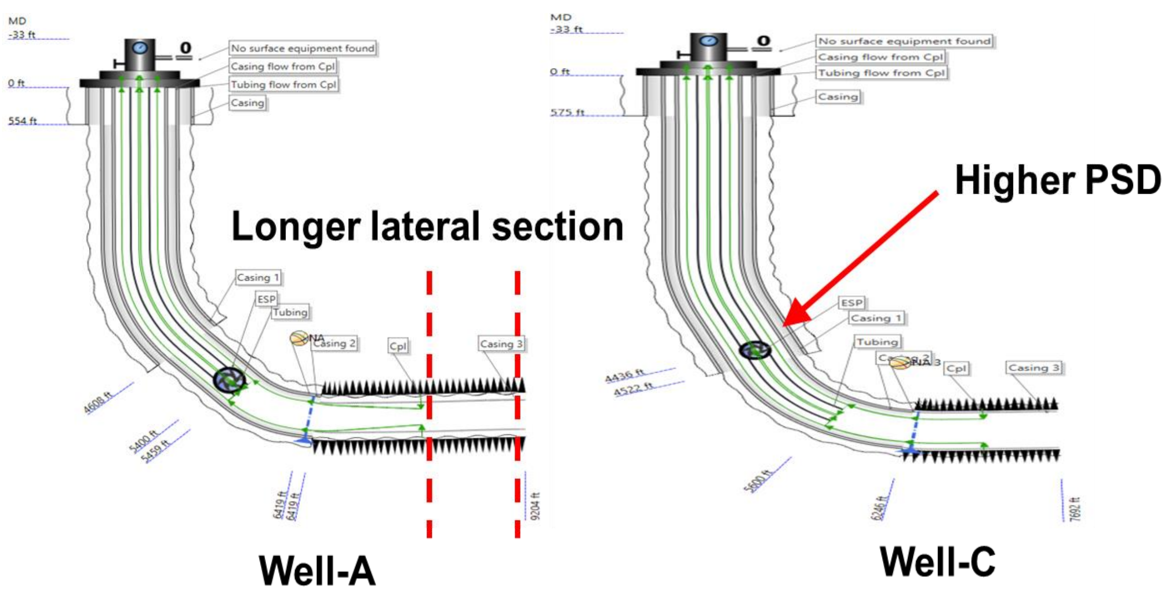


Figure 4.24 Well-A and Well-C geometry

Furthermore, it was observed that Well-A has a horizontal lateral section of 2785 ft, whereas Well-C's horizontal lateral section is only 1447 ft, nearly half of Well-A's lateral section. This led to the consideration that Well-A may have a higher number of fractures compared to Well-C. Another hypothesis emerged, suggesting that the production rate disparity between Well-A and Well-C could be linked to differences in fracture properties due to their varying horizontal lateral sections. To validate these hypotheses and devise effective strategies for enhancing Well-C's performance to match Well-A's, a comprehensive and detailed analysis is necessary. This analysis aims to uncover crucial factors influencing Well-C's performance and optimize its productivity, thus bridging the performance gap between the two wells.

A novel approach discussed in chapter-3 is used for running simulations. Simulations were run till history matching to obtain fracture properties of Well-C. and compare it with Well-A fracture properties.

Table 4.4 General Properties of Well-C

Total Rate	186 stb/d
Oil Rate	138 stb/d
Water Rate	48 stb/d
GOR	16 scf/stb
WHP	137 psia
ESP (Centrilift)	P6 Model 202 stages
Total Depth	7692 ft
True Vertical Depth	5462.5ft

Well-C was equipped with ESP (Centrilift) and started its production in April 2022. From the production history data and Artificial lift failure data, Well-C has not faced any AL failure so far. Also, this well is in its early stage of production. This simulation aims to analyze the factors contributing to the lower production rates of Well-C and apply suitable strategies to enhance its productivity.

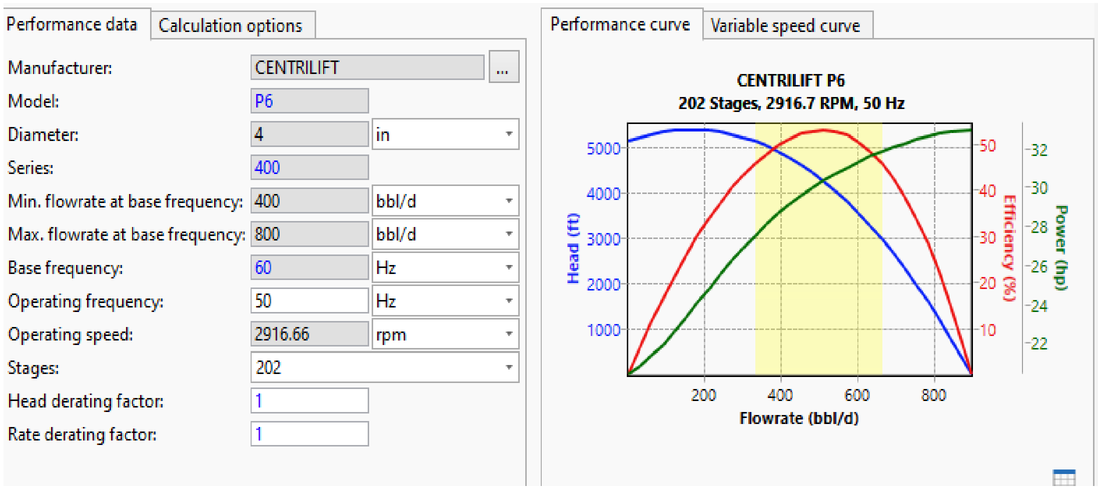


Figure 4.25 Well-C ESP with pump performance curve

Based on the data presented in the Figure 4.25 above, it is evident that the current ESP can produce flow rates ranging from a minimum of 400 stb/d to a maximum of 800 stb/d. However, our well is currently producing less than 200 stb/d, which indicates that the low production rates cannot be attributed to the performance of the ESP.

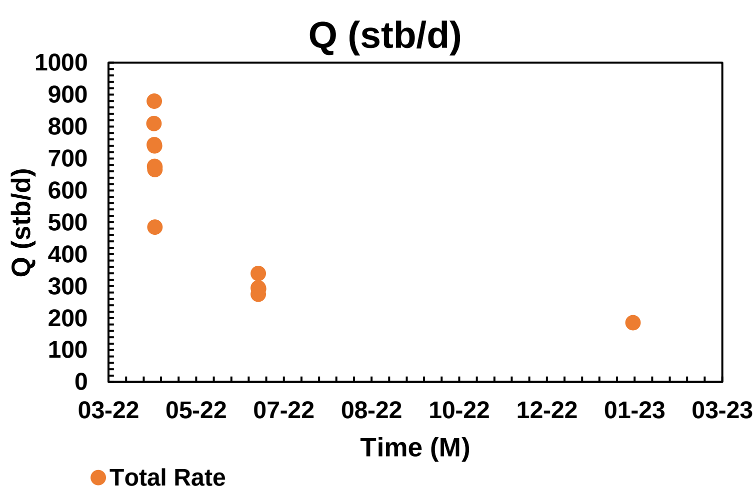


Figure 4.26 Production data of Well-C

The above Figure 4.26 is the production data for Well-C. The data is from April 2022 to Jan 2023, there are only 3 days of data available, so it is difficult to match the history with simulations. However, a close match can be obtained through repetition.

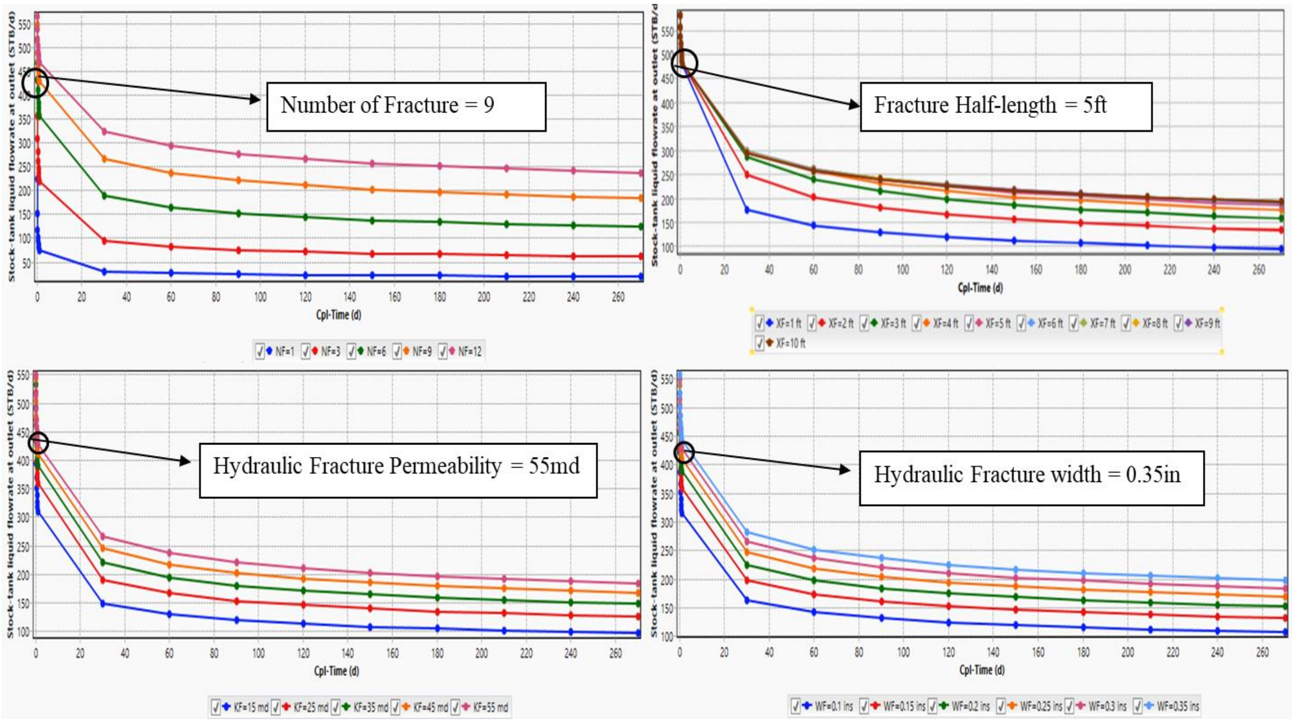
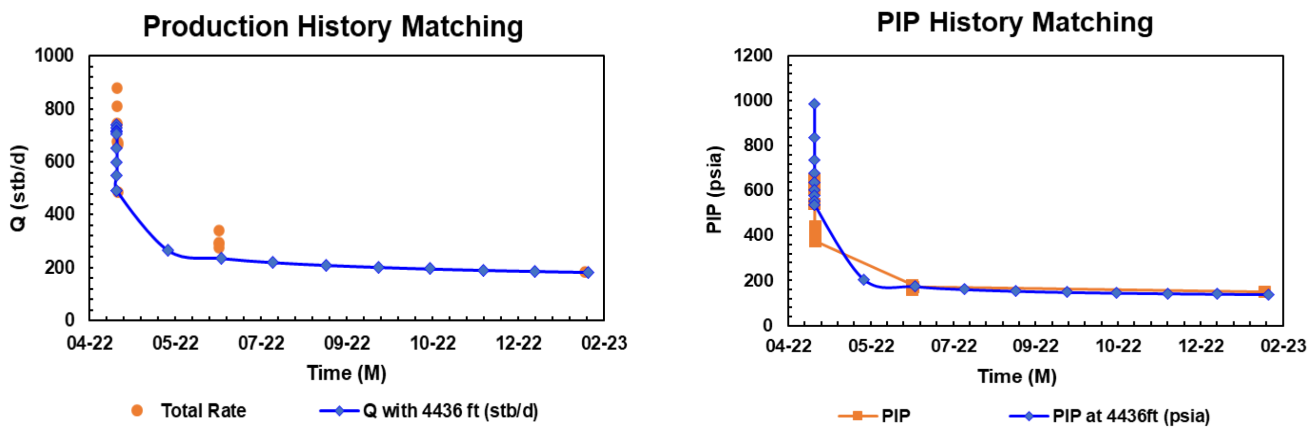


Figure 4.27 Fracture properties obtained through sensitivity analysis.

History Matching is an effective method to derive a reservoir model, but it can be challenging to obtain accurate reservoir fracture properties. However, this can be addressed by conducting parametric studies that involve varying fracture properties. Through these studies, valuable information about the reservoir fractures can be obtained, facilitating a more comprehensive understanding of the reservoir's behavior, and aiding in the calibration of the reservoir model.

After conducting a sensitivity analysis, fracture properties were successfully obtained. These determined values provided the closest match to the production history and also aligned with the history of pump intake pressures of Well-C.



(a) (b)

Figure 4.28 (a) Production history match of well -C and (b) PIP history matching of Well-C

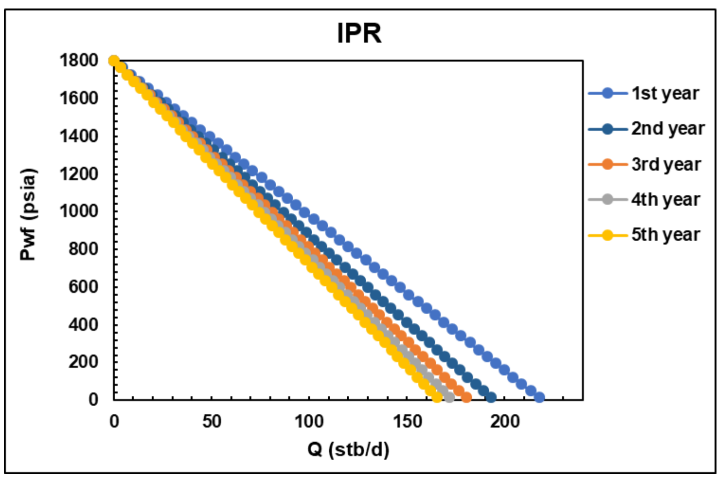


Figure 4.29 IPR of Well-C

The graph above illustrates the IPR (Inflow Performance Relationship) of Well-C projected for the next five years. Currently, the well can produce over 200 stb/d and IPR shows clearly that our reservoir's current deliverability is only around 200 stb/d. It can be inferred that the low production in Well-C is due to its reservoir properties.

However, since other wells in the same sector have the same reservoir and similar reservoir properties, it indicates that the difference in fracture properties, especially fracture number, might be the key factor affecting well deliverability and production rates. According to history matching on reservoir properties, Well-C has 9 facture, and Well-A has 20, which is comparable to their lateral wellbore length, i.e., 1446 ft and 2785 ft separately in Figure 4.24.

To validate this hypothesis, simulations need to be conducted for Well-C using the same fracture properties as Well-A. By replicating the fracture properties of Well-A in Well-C, it can be assessed if the performance improves and matches that of Well-A. This comparison will help us determine the significance of fracture properties in influencing well productivity. Therefore, in this section, simulations were done for four distinct scenarios in Well-C. These scenarios involve conducting simulations with various combinations of pump setting depth and fracture properties.

Table 4.5 Scenarios for case study-2

Scenario	**PSD**	**Fracture Properties**	**Notes**
1	4436 ft	Well-C	Original Well-C configuration
2	5550 ft	Well-C	Pump setting depth effect: Used pump setting depth of Well-A Keep fracture properties of Well-C
3	4436 ft	Well-A	Fracture properties effect: Used fracture properties of Well-A Keep pump setting depth to Well-C
4	5550 ft	Well-A	Hybrid effect: Used fracture properties of Well-A Keep pump setting depth to Well-A

By comparing the results of these four scenarios, the most influential factors affecting the well's performance can be obtained and the best approach to enhance its productivity can be determined.

4.2.1 Scenario-1

In this scenario-1 is the original study as shown previously for Well-C. From the Nodal analysis, it can be observed that the well is currently producing 186 stb/d with ESP intake pressure of almost 140psia which is operating below our critical condition.

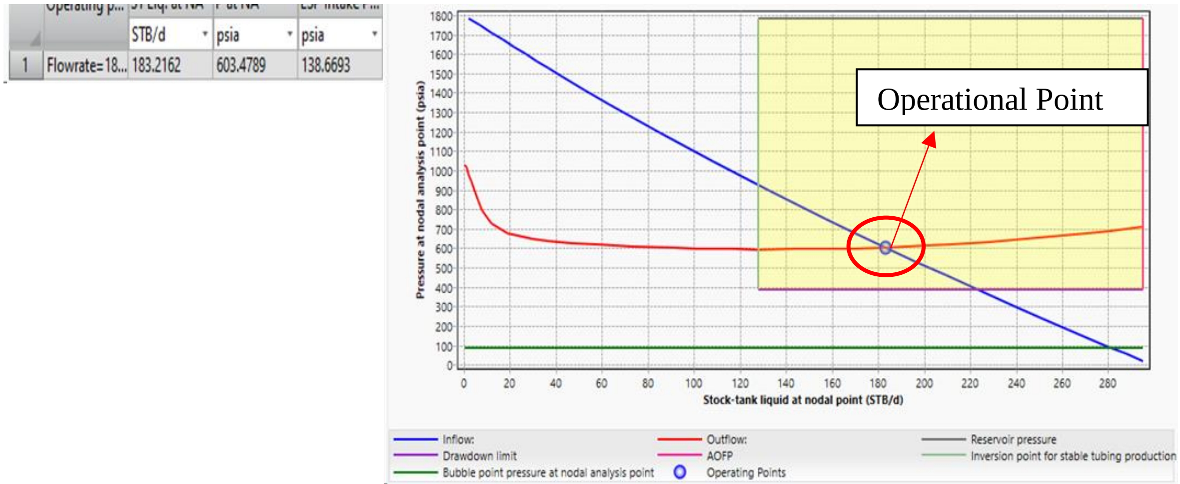


Figure 4.30 Nodal Analysis for scenario-1 in Well-C

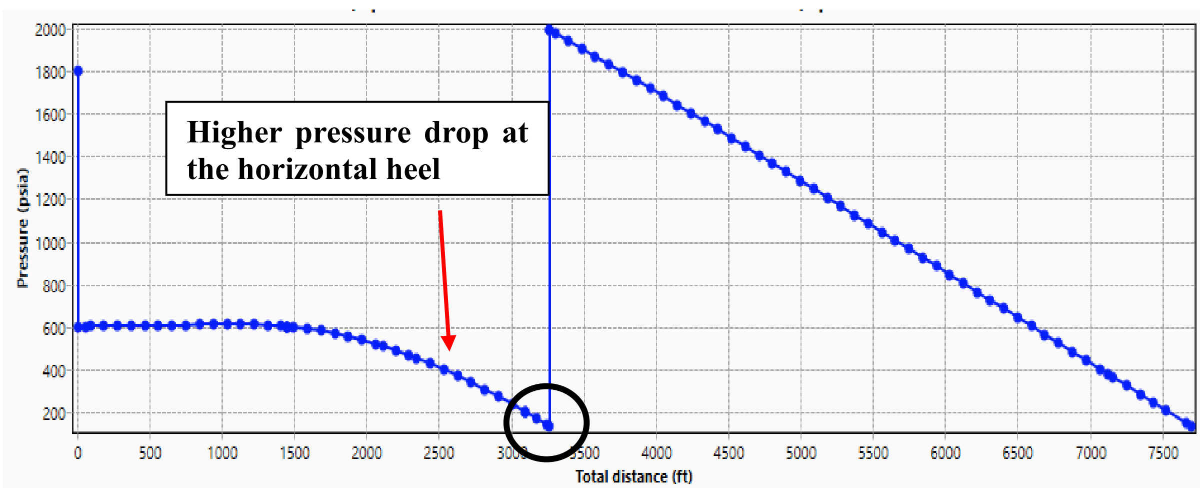


Figure 4.31 Well pressure profile of Well-C in scenario-1

The well profile has been plotted to understand the pressure behavior of Well-C in scenario-1. From the graph, it can be inferred that the pressure drop at the horizontal heel is higher at the original pump setting depth of 4436 ft. From the graph, it can be understood that the pump intake pressures are almost 140 psia indicating there is a pressure drop of almost 460 psia from the bottom hole to the tubing where the pump is located.

4.2.2 Scenario-2

In this scenario, the simulation was run for Well-C with changing pump setting depth from 4436 ft to 5500 ft. From the Nodal analysis it can be inferred that; the well is currently producing 181 stb/d with ESP intake pressure of 514 psia which is operating above our critical PIP.

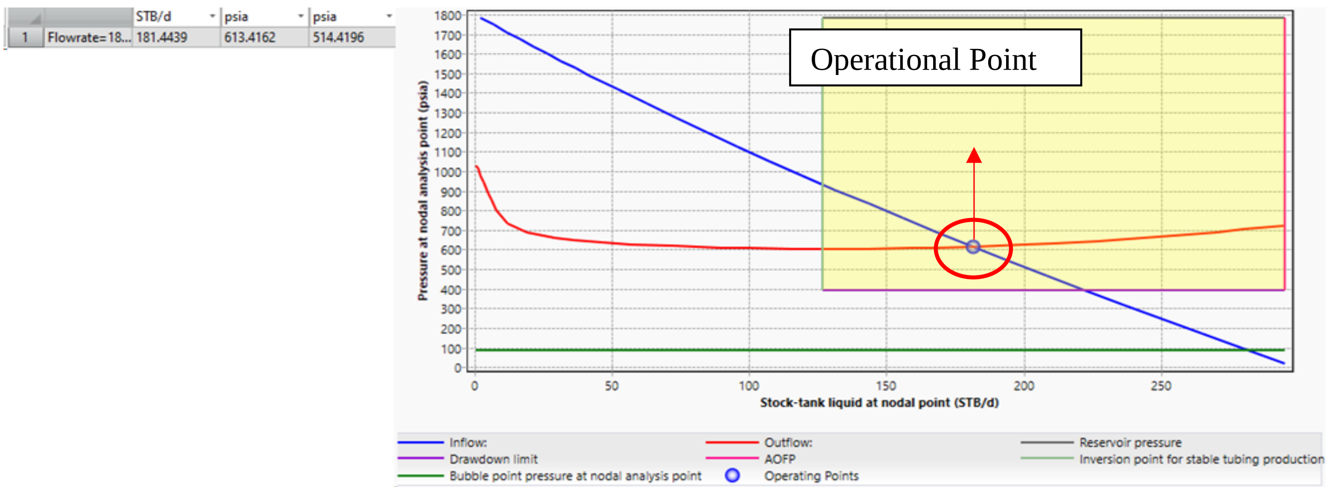


Figure 4.32 Nodal Analysis of Well-C in scenario-2

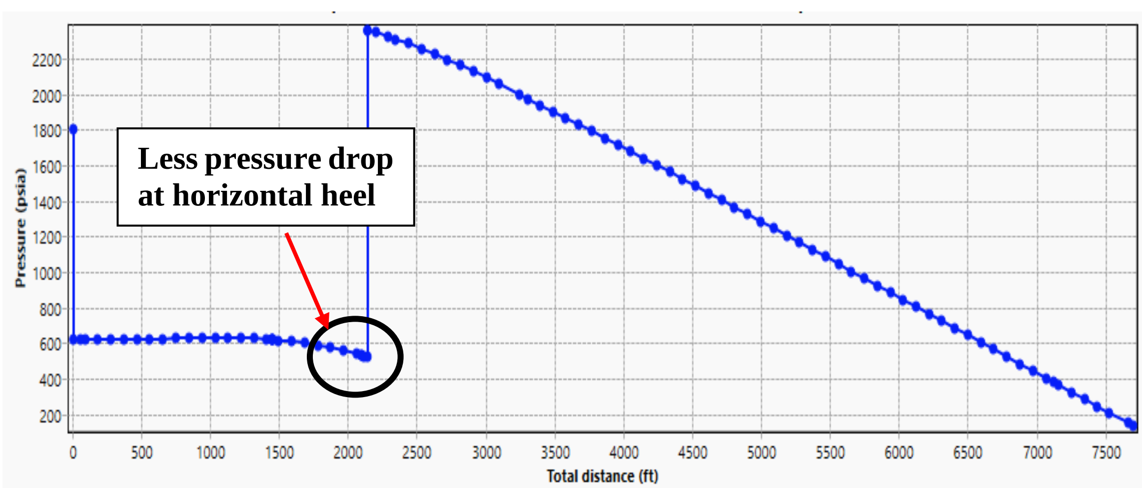


Figure 4.33 Well pressure profile of Well-C in scenario-2

The Figure 4.33 above shows that the pump intake pressure at the ESP is 514 psia, while the pump discharge pressure is 2300 psia. This confirms our assumption that the pump setting depth at the bottom of the tubing like Well-A can maintain the pump intake pressures above the critical PIP.

4.2.3 Scenario-3

In scenario-3, the simulations were run Well-A Fracture Properties with Original Pump Setting Depth of 4436 ft. Now, the fracture properties should be changed to Well-A's fracture properties.

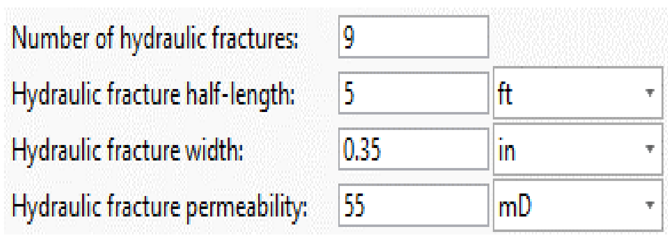


Figure 4.34 Well-C fracture properties (scenario-1 and scenario-2)

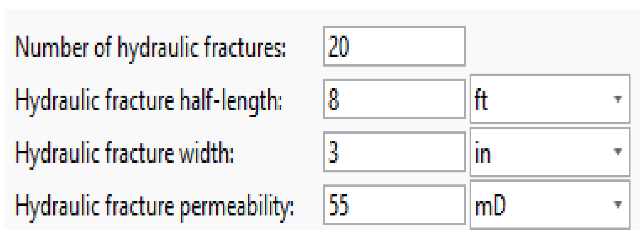


Figure 4.35 Well-A fracture properties (scenario-1 and scenario-2)

From Figure 4.34and Figure 4.35, it can be observed that the fracture properties of Well-A and Well-C differ significantly. The number of fractures in Well-A is nearly double compared to Well-C. Moreover, the fracture half-length in Well-A is also considerably longer. Another notable difference lies in the fracture half-width, which is approximately six times greater in Well-A when compared to Well-C. These variations in fracture properties are crucial factors that may impact the well's performance and production rates.

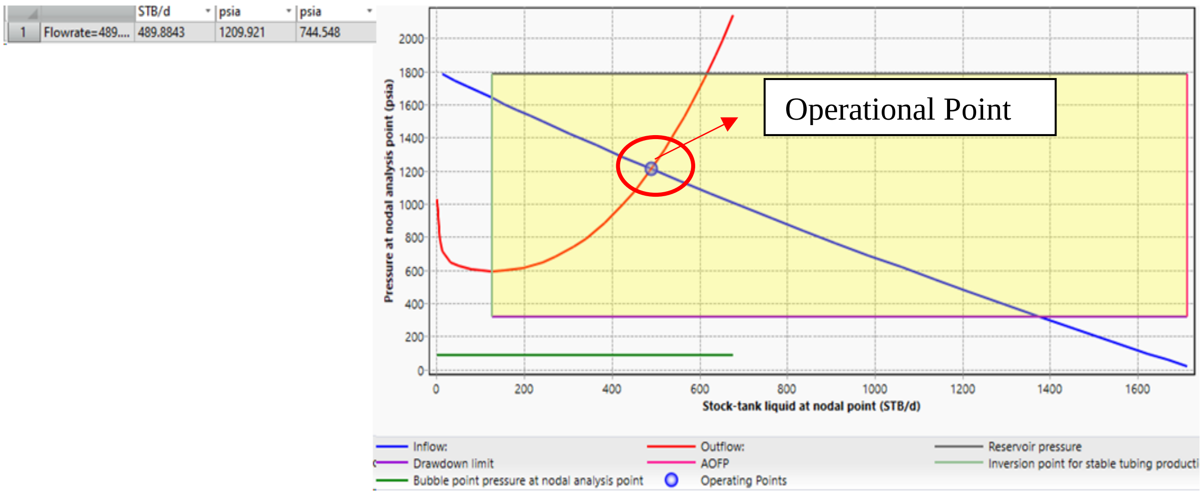


Figure 4.36 Nodal Analysis of scenario-3

The results obtained from Nodal analysis indicate that the well is currently producing at a rate of 490 stb/d, with an ESP intake pressure of approximately 745 psia. It is crucial to note that the ESP is operating above our critical intake pressure, which is a favorable condition. After changing the well's fracture properties to match those of Well-A, Well-C has the potential to produce as high as 500 stb/d at the present moment. This finding suggests that aligning the fracture properties with Well-A has positively influenced Well-C's production rates.

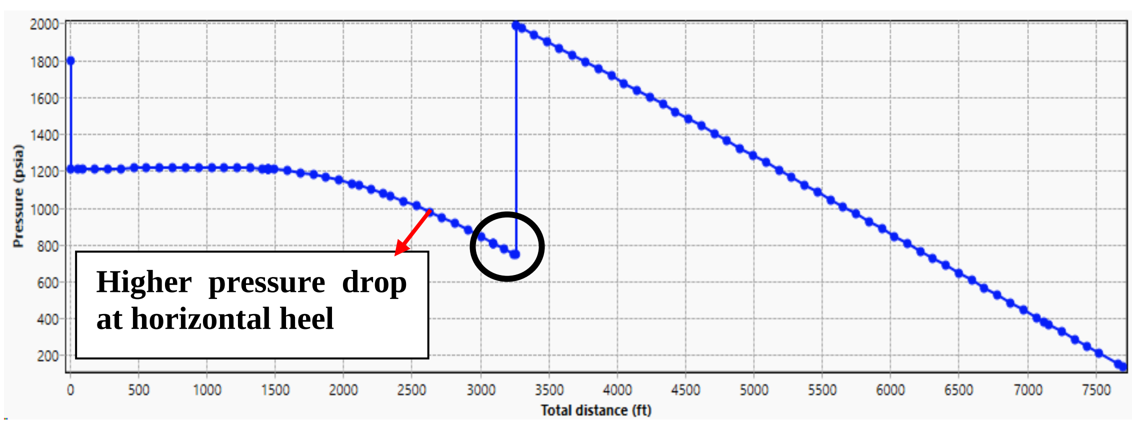


Figure 4.37 well pressure profile in scenario-3

From the above Figure 4.37, it is evident that the pump intake pressure at ESP is 750 psia, while the discharge pressure is 2000 psia. This indicates that even when the pump is set up at the original pump setting depth of 4436 ft, the well exhibits higher pump intake pressures. This observation can be attributed to the influence of the fracture properties of Well-A, which has resulted in the maintenance of elevated pump intake pressures in Well-C.

4.2.4 Scenario-4

In this scenario, Well-A's fracture properties are used similarly to scenario-3. In addition, in this case, changing the pump setting depth from 4436 ft to 5550 ft. Based on the results obtained from the Nodal analysis, it is clear that the well is currently producing 484 stb/d with an ESP intake pressure of approximately 1116 psia. To mention, this intake pressure is operating above our critical intake pressure threshold. By considering the change in fracture properties and pump setting depths from Well-A, it is observed that Well-C has the potential to produce as high as 484 stb/d with pump intake pressures reaching 1116 psia, signifying an improvement in well performance.

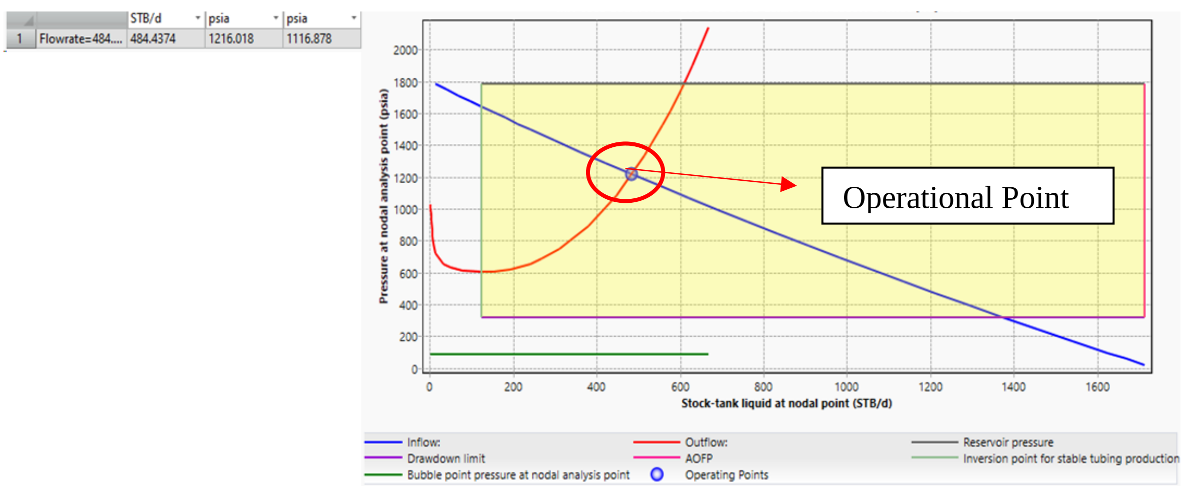


Figure 4.38 Nodal Analysis of scenario-4

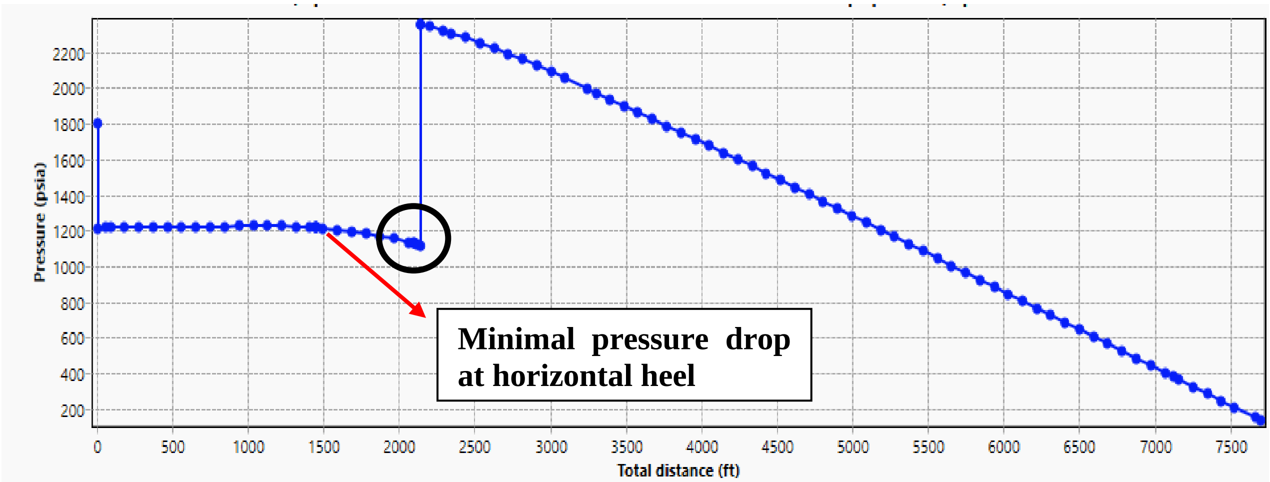


Figure 4.39 Well pressure profile in scenario-4

In the above Figure 4.39, it can be observed that the Intake Pressure at ESP (Electrical Submersible Pump) is 1120 psia (pounds per square inch absolute), and the discharge pressure is 2300 psia. This indicates that the pump setting depth at 5550 ft has contributed to achieving a higher pump intake pressure while minimizing the pressure drop at the horizontal heel from the bottom hole.

4.2.5 Discussion and Recommendations

Table 4.6 Four scenarios current conditions

Case No	PSD (ft)	Q (stb/d)	PIP (psia)	Pd (psia)
Scenario-1	4436	184	140	1989.644
Scenario-2	5500	181	514	2357.508
Scenario-3	4436	490	745	1988.79
Scenario-4	5500	484	1117	2356.185

The above table shows the summary of the 4 scenarios. As can be seen, fractures are the main reason for the low production and PIP of Well-C, and pump setting depth is another concern for the low PIP. To further evaluate the current status of Well-C, forecast transient rates and PIP are simulated from current Jan 2023 to the future Jan 2024.

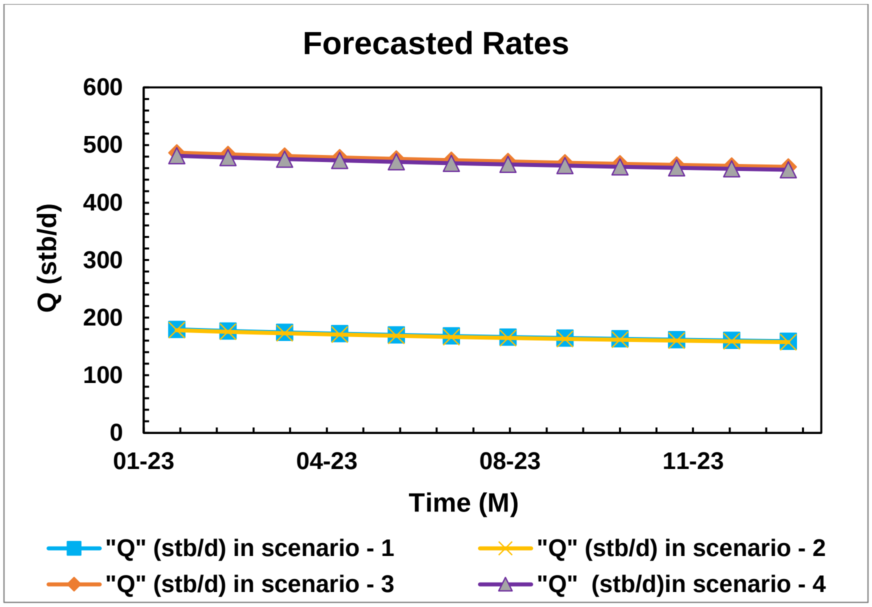


Figure 4.40 Forecasted rates of four scenarios

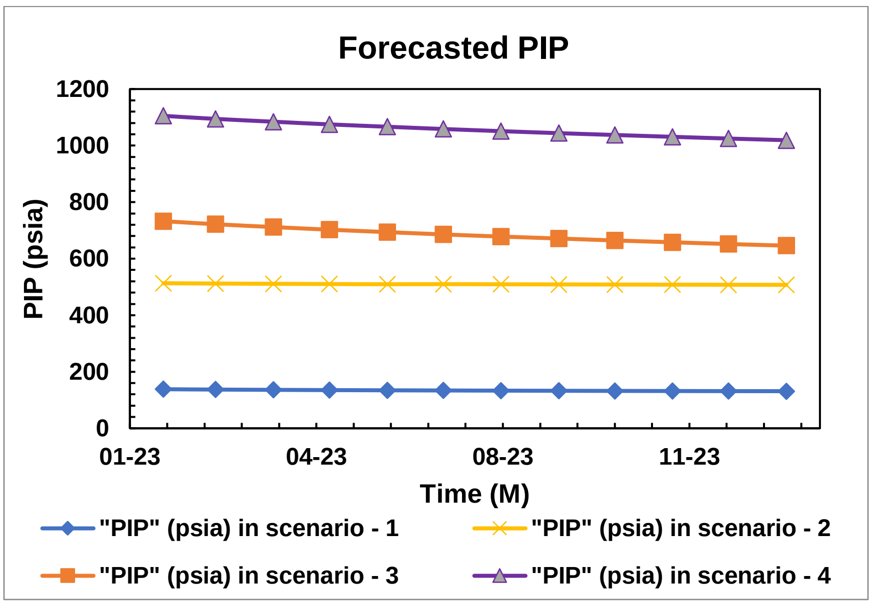


Figure 4.41 Forecasted PIP of four scenarios

As shown in the Figure 4.40 and Figure 4.41, Well-C already reaches a steady production period, in which the production rate and PIP does not change much with time. There are few stimulation methods that can be improved from the artificial lift side since the low production is mainly due to the reservoir properties and fractures. Increasing the pump setting depth can help maintain the PIP above the preferred critical PIP (300 psia). However, it cannot help in increasing the total liquid production rate since it is already lower than 200 bpd and most ESP’s minimum working range is more than 400 bpd. Although changing ESP to PCP may slightly increase the production rate and help maintain a more stable PIP as discussed in Chapter 4.1, a new fracturing technology that can help increase the fracture number and length should be a better recommendation to increase the production rate. Considering the nearby well’s performance and simulation in this study, it is possible that the well's production rate can be improved and maintained stably for a period of time.

CHAPTER 5

CONCLUSIONS

In this section, conclusions are summarized with following recommendations for the comprehensive study of artificial lifts in unconventional reservoirs and their behavior based on various conditions of the well.

5.1 Summary and Conclusions

Following are the summarized conclusions that are contributed to this study:

1. ESPs are suitable for higher flowrates and higher pump intake pressures, while PCPs are more effective for producing constant flowrates with lower pump intake pressures. Therefore, there is a transition period that ESPs should be switched to PCPs to avoid future failures. The transition and pump design should be carefully evaluated.
2. Generally, ESP is designed for production higher than 400-500 stb/d. It is hard to find an ESP designed for low flow rates. Therefore, it is less effective for low production wells. According to a current study, it is possible to control the ESP speed to avoid low PIP and gas effect. However, for low production rate conditions (e.g., 200 bpd), it is hard to accurately control the pump speed, since 1-2 Hz can cause a huge difference in ESP's boosting ability when it is used below its preferred flow rate range.
3. On the other hand, PCP is preferred for mid-low flow rates, for example 500 stb/d. PCP requires higher head in producing higher rates and the torque of the pump increases

drastically, which increases the temperature of the pump and leads to elastomeric swell. Therefore, PCP is not an ideal candidate for high flowrates.

4. Low pump intake pressures lead to an increase in GVF, presence of GVF leads to pump failures. ESP is not a suitable candidate for those wells without a proper gas treatment equipment, for example a gas handle and downhole separator.

5. Fracture properties have a significant effect on unconventional well's performance. For example, short horizontal lateral sections can lead to less fracture number, resulting in faster decline of near wellbore reservoir pressure and low production.

6. Pump setting depth is another affecting factor of the pump failures. Higher pump setting depth usually results in a low pump intake pressure due to the pressure drop from bottom hole to the pump intake. However, setting pump deeper may be affected if the lateral section shows a tow up shape. Further study should be conducted using transient simulator like OLGA.

5.2 Recommendations

Following are the recommendations for the future study:

1. Well operating below bubble point pressures are leading to an increase in GOR (gas oil ratio). It is always advised to monitor the pump intake pressures and make sure operations are carried out above bubble point pressures to avoid pump tripping. Therefore, gas properties effect should be included in future study. The critical pressure for ESP operation can be different for each well and each reservoir.

2. In M-field due to low GORs it is not recommended to have a downhole separator due to the supplier capability. In future studies, downhole gas treatment equipment and its effect on pump design should be evaluated.
3. Pump temperatures should be monitored continuously to avoid pump failures and tripping. When the pump intake pressures of the well are higher, it is recommended to increase operating frequencies and operating speeds of the pumps to obtain higher flowrates. However, increasing pump speed has a counter effect on PIP and will cause gas issues. Therefore, pump motor cooling effect and gas handling ability should be studied.
4. The pump model used in PIPESIM is simplified homogenous hydraulic institute model. A better pump performance prediction method or specific pump performance table should be incorporated into the simulator to increase the accuracy.

NOMENCLATURE

A	Drainage area [ft^2]
Bo	Formation volume factor [bbl/STB]
C	Wellbore-storage coefficient [bbl/psi]
C_A	Shape factor
C_D	Wellbore-storage coefficient, dimensionless
C_{FD}	Hydraulic fracture conductivity, dimensionless
C_{RD}	Reservoir Conductivity, dimensionless
c	Compressibility [psi^{-1}]
$\tilde{c}$	Bulk compressibility [psi^1]
D	Distance between outermost fractures [ft]
d	Distance between two adjacent fractures [ft]
h	Reservoir thickness [ft]
h_f	Thickness of natural fractures [ft]
h_{ft}	Total thickness of natural fractures [ft]
h_m	Thickness of matrix slabs [ft]
h_{ft}	Total thickness of matrix slabs [ft]
J	Transient productivity index [stb/d/psi], [Mscf/d/psi^2/cp]
k	Permeability [md]
k_I	Permeability of the inner reservoir [md]

k_f	Natural fracture intrinsic permeability [md]
$\tilde{k}_f$	Natural fracture bulk permeability [md]
k_F	Hydraulic fracture permeability [md]
k_O	Permeability of the outer reservoir [md]
k_m	Matrix intrinsic permeability [md]
L	Length [ft]
ℓ	Reference length [ft]
n_F	Number of hydraulic fractures
n_f	Number of natural fractures
n_m	Number of matrix blocks
p	Pressure [psia]
$\tilde{p}$	Average reservoir pressure [psia]
q	Volumetric rate [bbl/day; Mscf/day]
r_w	Wellbore radius [ft]
r_{wj}	Fracture effective wellbore radius [ft]
r_{wt}	Total system effective wellbore radius [ft]
s	Laplace parameter
T	Reservoir Temperature [°R]
t	Time [hours]
v	Velocity vector [ft/hours]
w_F	Hydraulic fracture width [ft]
x	Point coordinate in x-direction [ft]
y	Reservoir size, y-direction [ft]

y_e	Hydraulic fracture half-length [ft]
z	Point coordinate in z direction [ft]

Greek

α	Parameter defined in trilinear flow model
β	Parameter defined in trilinear flow model
Δ	Difference operator
η	Diffusivity [ft^2/hr]
μ	Viscosity [cp]
π	Pi constant
ρ	Fluid density [lbm/ft^3]
σ	Shape factor [ft^{-2}]
φ	Porosity

Subscripts

D	Dimensionless
e	External boundary
f	Natural fracture
F	Hydraulic Fracture
wf	Flowing wellbore

H	Horizontal
i	Initial
I	Inner reservoir
m	Matrix
O	Outer reservoir
p	Producing
R	Reservoir
sf	Sandface
t	Total
w	Internal boundary (wellbore)
x, y, z	3-D cartesian-direction

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APPENDIX A

ARTIFICIAL LIFT SELECTION SCREENING TABLE

A detailed comparison of parameters in between artificial lifts during the selection process.

Table A.1 AL selection parameters: production rate

<table>
<tr><th>Characteristic</th><th>Specific</th><th>Gas Lift</th><th>ESP</th><th>PCP</th><th>Rod Pump</th><th>Jet Pump</th></tr>
<tr><td rowspan="3">Production rate</td><td>Less than 1000 B/D</td><td rowspan="3">The full range of production rates can be handled. An AOF production rate cannot be achieved with gas lift because as much drawdown as for an ESP cannot be achieved.</td><td rowspan="3">The full range of production rates can be handled. When unconstrained an ESP can be designed to produce the full well potential to the surface (AOF), thus achieving higher flow rates than with gas lift.</td><td>The rate is dependent on setting depth, the deeper the setting depth the lesser rates. Generally, PCP is suitable for low-rate wells.</td><td>Rate is dependent on setting depth. Feasible for low rates (<100 B/D) and low GOR (<250). Typically, are used with 1.5-in nominal tubing.</td><td rowspan="3">The full range of production rates can be handled. Less than 50 B/D up to 15000 B/D with adequate flowing bottom hole pressure, tubular size, and horsepower. Guideline as below: Piston Hydraulic lift: 50 to 4000 BFPD. Jet Hydraulic lift: >15,000 BFPD of total fluid. AOF production rate cannot be achieved.</td></tr>
<tr><td>1000 to 10,000 B/D</td><td>Up to 4000 b/d at 3000 feet</td><td>Up to 2000 b/d at 4000 feet. Restricted to shallow depths using large plungers. In general, due to efficiency, rod pumps are not recommended as a lift mechanism of choice on high producing wells.</td></tr>
<tr><td>Greater than 10,000 stb/d</td><td>Not available.</td><td>Not available.</td></tr>
</table>

Table A.2 AL selection parameters: Well depth

Characteristic	Specific	Gas Lift	ESP	PCP	Rod Pump	Jet Pump
Well depth	Less than 2500 ft	Not restricted by well depth. The benefit of gas lift will be larger with greater depth, as there is more fluid to 'lighten' to enable increased well productivity.	Not restricted by well depth. The benefit of ESP will be larger with greater depth as there is more fluid head to overcome to enable increased well productivity.	Pump must be landed below dynamic fluid level. Optimal to have intake below perforations, which will allow natural gas separation and vent to annulus. Depth is tied to dynamic fluid level.	Pump must be landed below dynamic fluid level. Optimal to have intake below perforations, which will allow natural gas separation and vent to annulus. Depth is tied to dynamic fluid level.	Not restricted by well depth. However, limited by powerfluid pressure or horsepower as depth increases. A practical depth of 20,000 ft is *possible*. Guideline as below: Piston Hydraulic lift: up to 17,000 ft TVD. Jet Hydraulic lift: up to 20,000 ft TVD.
	2500 to 7500 ft					
	Greater than 7500 ft			Maximum 8000 feet.	Maximum 14,000 ft TVD. Due to excessive polished rod load, depth is limited. Rods or structure may limit rate at depth. H_2S limits the depth at which a large volume pump can be set. Effectively, about 500 B/D at 7,500 ft TVD and 150 B/D at 14,000 ft TVD.	

Table A.3 AL selection parameters: dogleg severity

Characteristic	Specific	Gas Lift	ESP	PCP	Rod Pump	Jet Pump
Dogleg severity	Less than 3° per 100'	Gas lift causes no constraint.	ESP can be deployed without problem.	No constraint	No constraint.	No constraint.
	3 to 10° per 100'		ESP system may be limited as ideal system cannot be readily deployed through this dogleg.	Pump length dependent. Typical pump length = 35 feet which is relatively short and easy to deploy through doglegs.	No big constraint. Centralizer could be utilized.	No constraint.
	Greater than 10° per 100'		Not recommended.	Same as above	Zero to 90º landed pump. Some success is accomplished in pumping 15º/100 ft using rod guides.	Applicable for slanted and crooked wells. Short jet pumps can pass through doglegs up to 24-deg/100 ft in 2 in. nominal tubing. Zero to 90 Degrees pump placement. Guideline as below: Piston Hydraulic lift: <15º/100 ft build angle. Jet Hydraulic lift: <24º/100 ft build angle.

Table A.4 AL selection parameters: well inclination

Characteristic	Specific	Gas Lift	ESP	PCP	Rod Pump	Jet Pump
Well inclination	Vertical	Well suited to vertical wells. Retrieval of gas lift valves from side pocket mandrels is straightforward.	Well suited to vertical wells.	No constraint- typical installation with top drive and rods.	Well suited to vertical wells.	Well suited for vertical completions.
	Deviated	Well suited to deviated wells. Retrieval of gas lift valves from side pocket mandrels can be difficult when the deviation angle > 65 degrees.	Well suited to deviated wells, however size and running of ESP limited by well trajectory. A straight section of casing is required at ESP depth.	Can deal with deviation however rod wear is a reliability constraint. Rod guides are used to reduce friction on rods. REDA PC has application where the well is deviated and the reduced risk of failure due to rods is required.	Not highly recommended. Slanted and crooked wells present a friction problem. There are increased load and wear problems in high angle deviated holes (>70º).	Well suited for deviated completions.
	Horizontal	Well suited to horizontal wells unless the tubing is large preventing produced fluid mixing with lift gas. Retrieval of gas lift valves from side pocket mandrels can be difficult when the deviation angle > 65 degrees.	Well suited to horizontal wells, however size and running of ESP limited by well trajectory. A straight section of casing is required at ESP depth.	Pumps have been installed in horizontal section but same remarks for deviated well are applicable.	Not recommended.	Could suit for horizontal completions. However, due to well trajectory, slickline work to pull nozzle could be a problem.

Table A.5 AL selection parameters: Temperature

Characteristic	Specific	Gas Lift	ESP	PCP	Rod Pump	Jet Pump
Temperature	Less than 250°F	Recommended for all temperatures	Standard ESP design will handle this temperature.	Standard PCP design with suitable elastomers will handle this temperature.	Can lift in high temperature and viscous oils.	
	250 to 350°F		Medium range equipment required.	Above current limit		
	Greater than 350°F		Higher temperatures require specialised ESP designed equipment, which have been shown to operate at 550 F. Note that the motor temperature is significantly higher than the bottom hole temperature. Extremely high temperatures will cause a short run life.	Above current limit	Operating temperature range from 0 to 550ºF.	Temperature limitation is excellent. It is possible to operate from 0 to 500+ºF.

Table A.6 AL selection parameters: flowing bottom hole pressure

Characteristic	Specific	Gas Lift	ESP	PCP	Rod Pump	Jet Pump
Flowing bottom hole pressure	Greater than 1000 psi	The efficiency of the gas lift determines the achievable FBHP. A gas lifted well normally works with a FBHP in this range.	Achieving any FBHP is not a constraint with ESP. AOF can be achieved if the well and reservoir properties do not constrain the ESP design.	The pump depth and the dynamic head restrict achieving a low FBHP.	The pump depth and the dynamic head restrict achieving a low FBHP.	
	100 to 1000 psi	Gas lift can work in the upper end of this range for low reservoir pressure and productivity wells, however, there needs to be enough reservoir energy to deliver the produced fluids to the surface.		Small dynamic head will allow low FBHP to be achieved.		A typical design target is a minimum of 100 psi per 1000 feet of lift. Intake pressure should be > 350 psig to 5,000 ft with low GLR. Typical design target is 25% submergence.
	Less than 100 psi	Cannot deliver fluids to surface.			The excellent result can obtain at intake pressure less than 25 psig providing adequate displacement and gas venting, typically about 50 to 100 psig.	Cannot deliver fluids to surface.

Table A.7 AL selection parameters: drawdown, gas coning, oil gravity, water cut, corrosive fluid

Characteristic	Specific	Gas Lift	ESP	PCP	Rod Pump	Jet Pump
Drawdown		Achievable drawdown is limited by ability to lighten head of fluid above gas lift point. AOF can never be achieved.	Any drawdown can be achieved with a given ESP design, however well and reservoir constraints limit final drawdown.	The pump depth and the dynamic head limit achievable drawdown.	The pump depth and the dynamic head limit achievable drawdown.	Good drawdown but cannot completely deplete a well.
Gas coning		Gas lift can be effective in producing a well that cones gas.	Not recommended.	Can be used if free gas < 40% by volume. This limit is imposed, as at least 60% liquid is required for cooling of the elastomer.	For gassy reservoir, Rod pump handling is fair to good.	Not recommended. Cavitation in jet pump likely.
Oil Gravity		No limitations. Preferable > 15 ºAPI.	No limitations. Preferable > 12 ºAPI.	Not used for oil with gravity greater than 40 degrees API due to high aromatic content (C6 to C9 should be under 20%) that will deteriorate elastomers. Preferable < 30 ºAPI.	> 8 ºAPI.	> 8 to 45 ºAPI.
Water Cut	Low	Recommended.	Recommended for the full range of water cut. The ESP is largely insensitive to increasing water cut.	Recommended	Recommended	Recommended
	Moderate	Reduced efficiency due to heavier column of fluid to lighten.		Recommended	Recommended	Recommended
	High	Reduced efficiency due to heavier column of fluid to lighten. May not be able to lift well if reservoir pressure is low.		Recommended	Recommended	Recommended Up to 100%
Corrosive fluid		Recommended. Compatibility of metallurgy and elastomers with the total completion is only required.	Run life will be shortened in a more aggressive environment. Special metallurgy and elastomers will be required leading to more costly equipment.	Run life will be shortened in a more aggressive environment. Design with rotor in stainless steel and matched elastomers. Rod string and tubing is at risk as typically not special	Using corrosion-resistant materials in the construction of subsurface pumps.	Using special metallurgy and/or chemical treatment. Chemicals in the power fluid can treat the tubular for corrosion.

Table A.8 AL selection parameters: fluid viscosity

Characteristic	Specific	Gas Lift	ESP	PCP	Rod Pump	Jet Pump
Fluid viscosity	Less than 100 cp gas free viscosity at reservoir temperature	Recommended	Recommended	Recommended	Recommended	Recommended
	100 to 500 cp gas free viscosity at reservoir temperature	Recommended	The efficiency of ESP will be reduced.	Recommended. Pump efficiency will increase as viscosity increases.	Good for < 200 cp fluids and low rate. Rod fall problem for high rates. Higher rates may require diluents to lower viscosity.	Recommended
	Greater than 500 cp gas free viscosity at reservoir temperature	Has been used with success up to 1000 cp but little case history for extremely high viscosity.	Not recommended. Pump efficiency is reduced, motors cool poorly in the high viscous fluid, more power is required to pump high viscous fluid and emulsions form. A mixture of ESP and progressive cavity pump technology is a potential alternative.	Recommended for all high viscosity crude. Up to 80,000 cp.	Not recommended, as pump efficiency will reduce.	Mixture of power and producing fluid is not a major issue in Jet pump. The system is capable of handling high-viscosity fluid. Production with up to 800 cp possible. Oil power fluid in the range of >24ºAPI and <50 cp could be used. If waterpower fluid is used, it will reduce friction losses.
	Paraffin	Paraffin may deposit near an operating gas lift valve due to temperature and pressure drop. This may lead to blockage of the gas lift valves and an inability to be able to retrieve them		Not a problem due to the nature of PCP however efficiency will be reduced.	Susceptible to paraffin problems. Hot water/oil treating and/or uses of scrapers possible, but they increase operating problems and costs.	Can be treated. Paraffin handling capability is good/excellent. Circulate heat to downhole pump to minimize build up. Mechanical cutting and inhibition possible.
	Asphaltene	Introduction of lift gas into the produced fluid stream may increase the risk of asphaltene deposits. Production chemistry analysis for individual fields will determine whether this is likely to occur.		Does not increase deposition and will produce asphaltene to surface as a solid.	Can be treated.	Difficult to control.

Table A.9 AL selection parameters: treatment and well intervention

Characteristic	Specific	Gas Lift	ESP	PCP	Rod Pump	Jet Pump
Treatment	Scale inhibitor	Recommended when any treatment is required. These treatments have little to no effect on a gas lifted system.	Materials design will need to be modified to ensure continued service of the ESP after treatment.	Elastomer compatibility is a constraint so needs to be reviewed in detail for design.	Corrosion and scale treatments are easy to perform. Good batch treating inhibitor down annulus used frequently for both corrosion and scale control.	Corrosion/scale ability is good and sometimes excellent. The inhibitor with power fluid mixes with produced fluid at entry of jet pump throat. Batch treat down annulus feasible.
	Corrosion inhibitor				Corrosion handling good to excellent.	Corrosion handling good to excellent. Can be surfaced at a predetermined schedule.
	Solvent					
Well intervention		For gas lift valve changeouts slick line intervention > 5 years. For subsea wells may not be required for life of well. For	The run life of ESP determines intervention frequency. Change out of total completion required for ESP failure.	The run life of PCP determines intervention frequency. Change out of total completion required for ESP failure. Average run life	Workover or pulling rig. Run time efficiency is greater than 90% if good operating practices are followed and if corrosion,	Hydraulically removed or wirelined. A “free” jet pump can be circulated to the surface without pulling the
		remedial well work as required with the ability to perform through tubing workovers.	The average run life approximately two years. Remedial work will require completion to be removed	approximately one to one and a half years. Remedial work will require completion to be removed. Total change out can be avoided by using wireline retrievable with REDA PC or put rotor and stator on rod string so does not have to pull tubing.	wax, asphaltenes, solids, etc… are controlled.	tubing or it can be retrieved by wire line. Must avoid operating in cavitation range of jet pumps throat; related to pump intake pressure.
CAPEX		High for compression and gas distribution system	High for power generation and cabling	Moderate cost for facilities and down hole equipment.	Capital costs are low to moderate. Cost increase with depth and larger surface units.	Capital costs are competitive with sucker-rod pumps. Cost increases with higher horsepower. Wellhead equipment has a low profile. Requires surface treating and high-pressure pumping equipment.
OPEX		Low. Gas lift systems have an extremely low OPEX due to the downhole reliability.	Moderate to high. Costly interventions are required to change out conventional ESP completions, but productivity and improved run life can offset these costs.	Moderate cost for equipment but high intervention frequency.	Operating costs are extremely low for shallow to medium depth (< 7500 ft) and low production (< 400 BFPD). Units easily changed to other wells (i.e., reuse) with minimum cost.	High power cost owing to horsepower requirement to pump power fluid. Typical jet pump efficiency is 30% thus power fluid at 2-3 times the produced fluid rate is required. No moving parts in pump; simple repair procedures. Low pump maintenance cost typical with properly sized throat and nozzle.